When is UBO better? Decision tree guides choice

IN 1998, TIM HARRISON and others, working under the auspices of what was originally the International Underbalanced Operations (UBO) Forum (the predecessor of the current IADC Underbalanced Operations Committee), developed a simplified flow chart to help in the determination of what constitutes a proper UBO candidate. While this decision tree has proved to be useful in screening and identifying candidates for underbalanced operations over the intervening years, it has inherent limitations.

The primary limitation is also its biggest benefit: it offers a very simple process for eliminating candidates that have no business being considered in the first place. One question that appears in the chart at the end of each branch is "Cost/safety benefits?" a question that should be obvious, but which too often goes unanswered in the drilling industry in the wake of each latest fad.

Obviously, in order to successfully implement any technology there should be cost and/or safety benefits. The question of cost benefit of UBO has been answered primarily by concentrating on either drilling less expensively or increasing productivity.

Many still question whether or not there can be such a thing as safety benefits to UBO, and still others have at least made a case for the safety benefits inherent in some forms of UBO. However, if we accept that economic and safety benefits do accrue to underbalanced operations, how do we determine what they are, and when do we know it is time to implement the UB part of the operation to take advantage of these benefits?

PRIMARY CONSIDERATION

The one condition that must exist before making a change from conventional drilling to any form of underbalanced drilling is a good reason for making the change. For example, a switch to mudcap drilling (MCD) will not be made until a formation is encountered that contains a fracture or extensive karst system or other extremely high permeability rock that allows a low injection pressure for sacrificial (Sac) fluid injection. Simply put, we must encounter a condition that can be mitigated by utilization of underbalanced techniques.

Once the primary circumstance has been encountered in the wellbore, the decision to actually make the switch from conventional circulation to MCD will depend on several other conditions: safety, drilling economics (mud loss rate and drilling time per day for MCD), and logistics (ability to mix mud, supply mud, or inject mud). All other factors are dependent, and each one impacts the other.

SAFETY CONSIDERATIONS

Safety is the greatest issue to be considered. When any operation increases the risk of compromising personnel safety, changes in the operation must occur.

During conventional circulation, drilling in the presence of severe loss of circulation, particularly with sour hydrocarbons, is especially risky. Upon drilling into a large fracture/karst, the annulus fluid level may drop rapidly toward equilibrium or the "balanced" point in the wellbore.

Unfortunately, the fluid level does not stop at the equilibrium point. Momentum of the annular fluid mass can cause the level to drop below the point of balance with the reservoir pressure (an underbalanced condition) and result in a "kick" of formation fluid.

This kick may result in the emission of sour crude and gas at the surface when circulation is resumed. There is also a risk that something on the surface may prevent the crew and/or equipment from delivering mud to the wellbore in a timely manner, resulting in a critical well control situation.

Any interruption in fluid delivery will increase the danger and raise the risk to personnel. Even where there is sufficient surface equipment to handle a sour crude emission, there is still personnel risk involved.

MCD, also known as Pressurized MCD (PMCD) and Light Annular MCD (LAM CD), involves injecting a liquid "mudcap" into the drillpipe/casing annulus from the surface. This liquid will most commonly be weighted and viscous and the annulus will always remain shut-in while drilling potentially productive formations in order to prevent hydrocarbon migration to the surface accompanied by pressure. A rotating control device (RCD) is used to keep the annulus shut-in.

In the safest form of MCD, mud is pumped down the annulus only when annular pressure increases, and only until that annular pressure returns to a pre-determined lower limit. The upper and lower limits of the annular pressure are set by the actual reservoir pressure and the working pressure rating of the RCD.

Drilling massively fractured formations in this manner, with casing set into the top of the formation, can be very forgiving in that the well can always be killed or subdued by injecting kill mud down the drill pipe (and/or annulus) while the annulus is shut in at the surface.

Furthermore, when a formation is known to contain sour gas, monitoring and maintaining the annular pressure precisely minimizes migration of this sour gas as well as any hydrocarbons into the annulus.

Increases in pressure are directly indicative of the level and amount of hydrocarbon or sour gas in the annulus, allowing more precise control over what is allowed into the annulus. This not only minimizes the amount of mud lost into a highly conductive formation but also prevents "surprises" such as gas suddenly appearing at the surface.

The MCD process is designed to keep all sour hydrocarbons downhole. The absence of circulation in MCD eliminates H2S emissions to the surface.

While drilling conventionally, when the risk to personnel is increased due to massive lost circulation, the safety criteria for making a switch to MCD will be satisfied. Meeting these criteria presumes that the switch will be a preplanned event, including all aspects of the MCD operation. For example, unless casing is set into or just above the formation top in question, unless an RCD has been installed, unless appropriate volumes of mud and SAC fluid have been provided for, it will not be possible to make the switch.

ECONOMIC CONSIDERATIONS

Economic factors should always drive the decision to switch to MCD or any other form of UBO. The economics considered for MCD can be further divided into a mud loss rate factor, a drilling time factor, and a drilled depth factor to simplify the analysis. Fortunately, the economic factors are more objective in nature than the safety considerations, and are thus more easily understood and accounted.

MUD LOSS RATE FACTOR

Before making a switch to MCD, we must first be satisfied that the lost circulation problem cannot be solved using conventional, less expensive means. Consequently, in fields with no historic use of MCD techniques, one or more attempts to repair the loss zone utilizing conventional lost circulation material (LCM) and/or plugging methods may be carried out until those methods are shown to be ineffective.

To address the mud loss rate issue, the break-even point between the cost of mud losses while drilling conventionally and the cost of MCD fluid losses can be determined in a relatively few easy steps:

1. Determine the average cost per barrel of drilling mud;

2. Estimate the cost of the total conventional mud loss, using different amounts of loss. For example, determine the cost of lost mud if the loss rate is 30, 50, and 75 barrels per hour (or 5, 8, and 12 cubic meters per hour);

3. Determine the total cost to rig up the sacrificial water delivery system as well as the cost of any modifications required to allow injection into the annulus. This total will include lines, transfer pumps, rental high-pressure injection pumps and manpower to operate them, and installation of manifolds;

4. Determine the unit cost of sacrificial (injection) fluid. For example, in some cases the water will not require treatment, so the cost per barrel is essentially zero. When corrosive elements are present in the reservoir, however, inhibitors must be added to the SAC fluid, resulting in a cost typically ranging from $0.50 to $2.00 per barrel, depending on the location and the amount of inhibition required.

Also estimate the volume of sacrificial water required for the entire MCD job. This amount can be estimated based upon the desired annular velocity to clean the hole. In the case of an 8 ½-in. hole drilled while using 5-in. drill pipe, this amount will be about 9,000-12,000 barrels (1,430-1,910 m3) per day.

5. Determine the cost per barrel of MCD annular mud and the total volume to be pumped down the annulus during the job. The calculation for this volume is based on the rate of hydrocarbon migration from the reservoir into the wellbore. In the case described in item 4 above, this

would be approximately 460 bbl/day (75 cubic meters/day).

Based on these parameters, a break-even volume of conventional mud loss can be determined.

Example: Assume a 14-day period; \$65/bbl conventional and MCD mud cost; \$0.50/barrel sacrificial fluid handling cost; \$250,000 cost of mobilizing and rigging up MCD equipment and personnel and \$15,000 per day equipment rental and specialized personnel cost during MCD.

A simple calculation including these assumptions reveals a break-even conventional mud loss rate of 44 bbl/hr (7.0 cubic meters/hr). If loss of circulation occurs at this rate or higher, it will be more economical to switch to MCD. If sacrificial fluid cost is \$0.00/bbl, break-even is only 6.4 cubic meters/hr loss.

The example above includes only the cost of lost mud and does not include lost time for the conventional case. The cost of mud losses plus extra personnel and equipment required is included for the MCD case. Obviously, actual cost values should be used for accurate analysis.

It is interesting to note that conventional drilling fluid losses are dependent upon depth in a vertically communicated formation. In other words, once total or near total loss of circulation is encountered, the more productive interval exposed to the vertical well bore, the more severe the loss of mud and money.

However, fluid losses related to the MCD process are constant and independent of vertical section in the reservoir. Other than a few optimizing efforts at the beginning of the MCD process, fluid losses are consistent throughout the drilled section and resulting costs are highly predictable.

DRILLING TIME FACTOR

Drilling time issues (or, more accurately, rotating time issues) may also drive the decision to switch to MCD. The lost circulation intervals that may occur in the target formation present an ultra low injection resistance to the flow of both drilling fluid and cuttings. Consequently, the suspended cuttings in the vertical wellbore as well as those coming from the bit freely move into the fractures.

Large fractures, vugular porosity, or karst openings do not typically offer a bridging opportunity for drilled cuttings in these wells. The mechanical issues we are concerned with are related to wellbore hydraulics and control of mud losses.

Conventional overbalanced drilling in a thick karst zone or vertically fractured and communicated formation eventually becomes impossible. This is due to the natural pressure variation within this type reservoir. The driller will measure the bottomhole pressure (BHP) of the topmost fracture/karst as soon as loss of circulation occurs.

The circulating mud weight will be adjusted to balance the pressure in the top karst. Pore pressure in each new fracture or karst encountered in the same target section will increase in pressure by an amount equivalent to the gradient afforded by the hydrocarbon present.

There will be a corresponding decrease in equivalent mud weight (EMW) for each fracture encountered. This means that a circulating fluid designed to balance the top-most lost circulation zone will be overbalanced in deeper intervals. The overbalanced situation will worsen with depth and eventually become unmanageable with conventional circulation.

The mechanical indicator for the switch to MCD will be decreased daily drilling hours while the bit is on bottom. The mechanical limit for continued conventional circulation drilling will be exceeded typically when drilling hours drop below approximately 8-12 hours per day.

The actual limit can also be determined with economic analysis by comparing the cost per meter of depth drilled. Decreased rotating hours during conventional drilling will be the result of encountering new fractures or other lost circulation intervals and the subsequent time required addressing them with LCM, gunk plugs, and conventional well control.

Example: Assume conventional drilling cost is \$6,000 per hour (24 hour day). Since only the time involved is being evaluated, no cost of lost mud is included for the conventional case. MCD costs are as above, \$8,120/hour plus the mobilization cost of \$250,000. Assume conventional penetration rate is 4 meters per hour (while drilling) and that MCD penetration rate will be the same, even though this is a conservative estimate.

Increases in penetration rate of over 30% have been documented for MCD. In both the conventional and the MCD cases, assume 700 m total are drilled. Assuming 18 hours per day drilling on average with the MCD operation is again conservative since once MCD begins it is not uncommon to drill all day.

Using these values, the break even time for conventional drilling is only 11 ¾ hours of rotation per day. In other words, once less than 11 ¾ hours is spent rotating each day because of lost circulation, it will be more economical to drill with the MCD technique.

If the cost of the mud lost in the conventional case is included, the result will be a break even point with more rotating hours allowed in the conventional case. Again, note that the cost of drilling with MCD per meter or per day will remain constant and highly predictable once the switch is made.

DRILL DEPTH FACTOR

Accounting for the drill depth issue involves a higher level of analysis than the other two economic factors described. The calculations described above for the mud-loss rate and the actual time spent drilling are based on drilling the same interval length with conventional and MCD techniques.

This is highly conservative because it does not include the benefits associated with opening up additional reservoir and increasing recoverable reserves by using MCD.

This is somewhat akin to comparing the economics of a vertical well to those of a horizontal well without accounting for the fact that the horizontal well has much more wellbore open to the productive formation and consequently may produce at a much higher rate and for a longer time above the economic limit of the well.

In fact, in most cases where MCD is the answer, conventional drilling stops completely and the well is ultimately declared to be at total depth at the depth where total loss of circulation was encountered.

While the cost per meter of drilling with the MCD technique is higher than that for conventional drilling without losses, use of the MCD technique routinely allows full penetration of reservoirs that cannot be drilled conventionally. This will have a significant effect on project economics.

Even without accounting for the additional drill depth, when the cost of the MCD operation is estimated to be less than the cost of conventional drilling, either because of high mud losses or because of low rotating time, the economic criteria will be satisfied.

LOGISTICAL CONSIDERATIONS

Logistics factors also play an important role in making the decision to switch to MCD.

Available Mud Delivery Rate. The effort to deliver mud to the standpipe may strain the existing mud handling and mixing capability. The rate of mud delivery may be driven either by the capability to mix whole mud, especially offshore or at isolated locations, or by the ability to have whole mud delivered, usually a consideration for onshore locations.

The drilling rig equipment and crews must be capable of mixing mud and getting it into the wellbore during any loss of circulation scenario. The first consideration will be the storage capacity of the rig on location. A fairly typical scenario is to have between 2,000 and 3,000 barrels (320–475 cubic meters) of mud storage on location.

The second consideration when looking at mud delivery rate is the capability to blend new mud to the appropriate weight and parameters. This should typically be accomplished on the rig at a rate of approximately 100-200 barrels per hour (16 - 32 cubic meters/hr), although MCD has been carried out successfully with mud mixing capability as low as 65 bph (10 cubic meters/hr).

At this low mixing rate, the conventional drilling operation would have to exceed 65 barrels per hour losses for an extended period of time to exhaust the logistical capability of conventional drilling.

Keep in mind that the rate of mud losses in a lost returns situation while attempting to utilize conventional drilling theory will generally far exceed the rate of mud loss experienced during MCD. This is because whole mud loss with MCD is a function of the hydrocarbon migration rate and is predictable and consistent once the MCD operation is underway. While utilizing conventional techniques with total loss of circulation, every time a new loss zone is encountered the rate of loss will increase.

The other loss rate that must be accounted for is the rate of SAC fluid loss down the drill string. Unless a secure source of inexpensive water and a system capable of delivering this water to the drill string at 9-12,000 b/d can be put in place, MCD is not a viable option.

MUD LOSS RATE, PART 2

Not only must it be economical to replace mud and sacrificial fluid in the wellbore, but the operator must have some level of comfort that the reservoir will take fluid at an acceptable rate.

In addition, the reservoir must be capable of continuing to take fluid at an acceptable rate over a potentially long interval of time or after the injection of cuttings from a potentially long interval of drilled hole.

MCD has been successfully carried out over intervals more than 600 m in 8 ½-in. vertical wellbores. Normally, the fractures, karsts or high permeability lost circulation zone can receive injected fluid with a friction loss of less than 100 psi.

However, if the fractures or karsts encountered present an injection pressure for Sac water greater than 700 to 800 psi, we may not be able to execute MCD operations.

Prior to making a switch to MCD from conventional operations, an injectivity test should be carried out whereby fluid is injected into the zone of lost circulation at three or four different rates while recording injection pressure, until a breakpoint is noted where the rate of pressure increase changes.

This only gives an indication of the likely upper limit of injection, and indicates a situation where the pressure rating of the circulation system on the rig will be exceeded, but more likely it simply represents the point where a low probability exists of being able to continue injecting fluid.

The decision to switch to MCD is usually made long before either logistical limit above is exceeded. However, when the ability to deliver mud to the wellbore during conventional operations is exceeded by the rate of lost returns for an extended period of time, or when the injectivity of the reservoir is acceptable, the logistics criteria will be satisfied.

WHY NOT TO MAKE A SWITCH

After all criteria have been determined, agreed upon and satisfied, there is still plenty of opportunity to never make the switch from conventional to UBO in general and to MCD in particular.

Misunderstanding. Often there is a failure on the part of those responsible for making the switch to the new process to understand the reason for the change (much less to understand the new process itself). This barrier can be overcome with a site-specific training program that covers the underlying concept, the new process, and provides hands-on practice in utilizing the new process.

Miscommunication. Often poor communication is blamed for failure related to new processes, when in actuality the problem may be something as simple as either not having a written plan or procedure or having a written procedure that is far too detailed and complicated for anyone to understand. In addition, the roles of each team member must be spelled out, including designation of who will actually make the final call that it is time to switch over to MCD (or whatever form of UBO is to be carried out).

Misfiring. Failure to "pull the trigger" or reluctance to make the decision. Everyone may know the criteria, understand the criteria, and agree with the criteria, but no one in a position of authority may be willing to make the call.

The statement was made earlier that we must be convinced that conventional methods of solving the problem encountered will be less safe or more expensive (or both) than employment of the underbalanced technique in question.

Unless management has bought into the concept, and even when they have bought in but have never actually done it, extensive effort may be required to fully convince them that the time has come.

You can get assent to almost any proposition as long as you are not going to do anything about it. We must find a way to induce those in position of authority to do something about it.

Once all the criteria have been calculated or otherwise determined, the decision making process can be facilitated by incorporating the main criteria into a simple decision flow chart.

The chart should remove as much subjectivity as possible from the decision. This means it must be site specific, based on the economic conditions and equipment and personnel capabilities present on site at the time of the operation in question.

CONCLUSIONS

Simplified techniques for deciding when to switch over from conventional drilling operations to UBO in general and MCD in particular must account for safety, economics and logistics considerations.

Everyone involved should understand the process of making the decision. Understanding can be encouraged through appropriate training and through the use of a simple decision flow chart, which removes as much subjectivity from the process of deciding as possible. The decision flow chart for MCD must be site specific.

In general only a few questions must be answered any time there is a question concerning when to switch to MCD:

1. Has the hole exhibited behavior consistent with the condition for which UBO is being considered? (In the MCD case, has the hole exhibited lost circulation consistent with an open fracture or multiple fractures having low injection pressure?)

2. Has personnel risk increased since the hole exhibited this behavior?

3. Have the economic criteria been met? (In the MCD case, does the hourly rate of mud loss exceed the break-even limit? Are the daily rotating hours less than the break-even limit? Can any more formation even be drilled using conventional techniques, or has the geologic objective been achieved?)

4. Have the logistics criteria been met? (In the MCD case, does the rate of lost returns exceed the capability to deliver mud to the standpipe? Is a system in place that can deliver SAC fluid to the standpipe in sufficient, sustained quantity?)

A yes answer to any two of the questions above justifies a switch to MCD from conventional drilling operations.

ABOUT THIS ARTICLE

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