From: Baker, Kate H (UNKNOWN BUSINESS PARTNER)
Sent: Tue May 18 04:44:50 2010
To: Kirton, Bill; benner@lanl.gov; Sprague, Jonathan D; jack.bullman@nasa.gov; cwmorro@sandia.gov; Perfect, Scott A (Lawrence Livermore National Laboratory); jmredmo@sandia.gov; cmstone@sandia.gov; Wapman, Derek (Lawrence Livermore National Laboratory); Mix, Kurt; Wood, Douglas G; Ole B. Rygg
Cc: Tatro, Marjorie (Sandia National Laboratories); Tooms, Paul J; majumdar@me.berkeley.edu; MC252_Email_Retention
Subject: Draft for yor comment; summary points from the KWOP discussion
Importance: Normal
Attachments: KWOP Notes from Discussion.doc

Dear "To" Line: Attached for your comment. I will take on board all those received by 6 p.m. Houston time Tuesday, 18 May and issue a version 2 incorporating all changes, deletions and additions received, reconciling orthogonal advice as best I can. I will send this version 2 to Paul and Marjorie for their acceptance or further improvement. Thanks! Kate

<<KWOP Notes from Discussion.doc>>

Summary points from the Kill the Well on Paper Discussion
18 May, 2010

Present at the review:

Kate Baker	John Benner
Bob Grace	Jon Sprague
Bill Kirton	Charles Morrow
Kurt Mix	Scott Perfect
Ole Rygg	Jim Redmond
Dan Wood	Mike Stone
Jack Bullman (NASA)	Derek Wapman
Curtt Ammerman	Arun Majumdar (for part of the time)

Summary Points

- **The need for accurate, low latency gauges and a system that permits rapid reaction of pumping operations to measured pressures was a point raised several times in discussion.**
- **Modeling indicates that a that a dynamic kill can be achieved for a well flowing oil at a rate of 5000 STBpd if the pressure in most of the flowing wellbore is above the bubble point**
- **Modeling indicates that a dynamic kill cannot be successfully executed if the oil flow rate is 15000 STBpd**
- **Knowledge of the flow rate is needed to form a view of the probability of success, as is knowledge of the position of flow restrictions.**
- **The dynamic kill operation is likely to put solids-laden fluid at a substantial rate through the BOP stack and riser, which may erode restrictions**

Background Information – MC252 #1 (Kurt Mix) included the wellbore schematic, a plot of pore pressure and fracture gradient variation with depth, and an inflow performance curve for a 300 md reservoir with 86 feet of net pay all contributing. The weak points in the well are the 3 burst/collapse disks in the 16" casing. The modeled fluid flowing in the well prior to kill is 35 °API oil with a GOR of 3000 scf/STB. The potential for contribution to flow from an open gas zone above the oil bearing horizons was discussed but BP geoscientists and reservoir engineers (not present at the meeting) were represented as doubtful that the gas zone is contributing to flow. At these pressures and temperatures, and given the fluid properties of the reservoired oil, the difference in density of the two fluids is not great.

Dynamic Kill General Principles and Modeling Results (Ole Rygg) While the OLGA program was originally written to model two-phase flow in pipes, and is widely used for this purpose in industry, Dr. Rygg has used it on numerous occasions to model blowouts using tailored bolt-ons to the source code. In the Macondo well, given a measured reservoir pressure of 11,850 psi and a measured pressure at the mudline (below the test ram cavity) of 3000 psi, "chokes" must exist along the flow path which reduce flow at surface. A successful dynamic kill relies on being able to create enough frictional pressure drop (or backpressure) by the combined flow of hydrocarbons and kill fluid across a choke in the well that the kill fluid can begin to flow upstream away from that point in the flow path and toward the influx source. This is achieved by pumping fluid into the wellbore above some minimum rate. To achieve a static wellbore situation at the end of the pumping schedule, the mud weight pumped in is chosen to overbalance the flowing reservoir. If there will ultimately be a seawater gradient above a certain subsea depth, this must be taken into consideration in the choice of mud weight. Also, the maximum pump pressure must be chosen so as not to compromise well integrity. For MC252 #1, the not-to-exceed pressure used in the calculations was 8,000 psi at the wellhead.

If the main chokes are deep in the wellbore, e.g. formation damage or "skin" that reduces the effective permeability in the near-wellbore region, or partial cement across the flow path, then the main pressure drop occurs deep in the well and the pressure along much of the flow path will be below the bubble point pressure. This provides a large cushion of compressible volume into which fluid can be injected at relatively high rate without raising the pressure above that which would exceed the collapse pressure of the pressure relief disks in the 16" casing. If, however, the main choke is shallow, e.g. at the 9-7/8" seal assembly, then there is no such cushion. In this case, the not-to-exceed pressure will be achieved within a couple of minutes making a dynamic kill impossible and creating the possibility to overshoot that pressure without attentive pumping and accurate, low-latency gauges.

The need for accurate pressure measurements was raised in other contexts also: For example, it was noted that, pressures above and below the BOP stack could be nearly the same given a +/- 400 psi reported accuracy. Pressure measurement in more places and more accurate measurement of pressure would help understand the nature of the choke(s) provided by the various BOP elements and aid in job design. During execution, gauge accuracy can affect the ability to deliver the as-designed pumping schedule.

Even if the main chokes are deep, models indicate that the dynamic kill cannot be successfully executed if the oil flow rate is 15,000 STBpd. We did not look at cases other than 5000 and 15000 STBpd. Knowledge of the flow rate is needed to inform the probability of not succeeding with the dynamic well kill.

For the purposes of modeling, the ramp-up to this pump rate was assumed instantaneous. The suggestion was made to evaluate the pump rate that would be needed assuming some ramp-up time. Even if ramp-up to full rate is expected to take no more than a couple of minutes, it may be worthwhile examining some "what if"s, as the effect of including a ramp-up time will be to increase the stabilized pump rate needed for the job.

General Discussion (All) Operational limitations are believed to be 50 bpm on the pumping rate; this was the maximum rate modeled. Pumping a solids laden fluid (weighted mud) at a substantial rate through the BOP stack and riser may erode restrictions. This same solids-laden fluid must also travel through the choke and kill lines to access the flowing well.

We touched on additional effects of the dynamic kill operation on the system downstream of the BOPs. Whilst the maximum pressure above the BOP stack during injection is modeled as remaining at 2600 psi, there is the possibility that as flow rates increase this pressure also will rise during the dynamic kill operation and might affect the kink in the riser. This possibility was suggested, but not quantified in any way in our discussion. Likewise it was asked whether BP plans to continue operating the riser insertion tube during the process.