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DRAFT

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July 30, 2010

Pat Campbell
Executive Vice President
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Superior Energy Services, Inc.
2202 Oil center Court
Houston, Texas 77073

Subject: MC 252 #1 Well Kill Plan

Dear Mr. Campbell,

Thank you for sharing your insights on the Macondo MC 252 #1 well kill plan. This letter summarizes the highlights of information provided in response to your letter of July 28th, 2010 and our subsequent meeting on July 29th.

HOW THIS SUPPORTS THE RELIEF WELL:
As we discussed, the Static Diagnostics Test will collect data and provide additional clarity on the condition of the well, help discern potential flow paths, assist with the strategy to kill and isolate the well and will complement the upcoming Relief Well operations. It has some attributes of bullheading, a routine industry practice. Depending on the pressure responses, the Diagnostics Test may lead to a successful static kill and cement isolation, which will supplement, but not replace the later relief well operations.

The diagnostic test will help define flowpath and enhance efficient success of relief well; however, the diagnostics test will not result in static well for all configurations. The relief well remains part of base plan.

There are still issues with the relief wells.

- Weather and operational issues could induce delays.
- Multiple flowpaths may exist, which creates complexity....
- The relief wells on their own will likely result in substantial volumes of hydrocarbon and synthetic oil-based mud release to the sea. The combination of a successful Hydrostatic Kill + relief well eliminates the flow to surface during relief well operation, relieves pressure on relieve well.
- Current rig up precludes snubbing
- Continued & delayed operation with the extraordinary SIMOPS creates additional operational complexity

REDUCING RISK AND UNCERTAINTY
The purpose of the shut-in was to evaluate well integrity. Over past two weeks, pressure build up has increased our confidence of well integrity and narrows uncertainty on pressures required to kill the well. We know a significant amount about the well through our diagnostics, jointly developed and evaluated with the Government science team.

STATIC KILL CONDITIONS and METHODS
This procedure closely resembles our standard operating procedures for many wells after initial flowback.

Bullheading this type of fluid back into this type of formation is standard production practice and well defined.

PRESSURES
Pressures at the subsea wellhead are expected to increase 500 psi during the static diagnostics test. Pressures at the wellhead may actually be higher during Relief Well kill. Maximum pressures lower down the well may well be less by a bottom kill method depending on the level of operational control.

How much detail to add?
In our opinion the worst case is a leak at 18" shoe. The probability is very low and the consequence can be defined. It would result in flow to the sea for some period; but the relief well process alone will certainly involve significant flow to the sea. In order to realize the worst case scenario, it would be required to breach the 9 7/8" casing and rupture the 16" string (either the discs or the casing itself). The 8000 psi limit is well within casing burst values.
ISIP & FSIP are within predicted range (mid-range)

a. Next 1 psi increase – 8,000 psi remains within original Well Integrity Test envelope, which was up to 8,500 psi..

Although there must be drawdown in the near wellbore region, it recovers very quickly. The well pressure response indicates reservoir boundaries and significant reservoir depletion.
The Diagnostics Test team has established a maximum pressure of 8,000 psi at the capping stack, not a max surface pump pressure of 8,000 psi. Number is based on:

i. Staying below rupture disc burst pressure in case 16" is exposed.
ii. In case 22" is exposed, staying within its burst limits.
iii. Staying with seabed equipment design envelope (limiting point is transition spool at 10,000 psi.

Limiting the maximum injection rate is not an issue as we are not attempting high rate bullhead in this diagnostics test.

iv. Higher rate displacement (fraccing) would only occur if pressure if pressure substantially reduced.

b. Injection test will be performed to assess injectivity. This is standard operating procedure for this type of production well. Injectivity is unlikely to be an issue in formations of this permeability if we have hydrostatic column of mud to formation. We have seen 0% BS&W

ADDITIONAL INFOMRATION (PC WAS NOT AWARE OF)

- There are no signs of general erosion in any surface or recovered equipment except drill pipe & tool joint in the kinked riser section.
- There is no sand (in fact no BS&W).
- Velocity modeling of flow in the well is in the range of 30-45 ft/sec for all cases; this is well within the operating guidelines per our production facilities even with sand. (normal guidelines equate to approximately 75 ft/sec).
- Damage to 7" cross-over due to dropped drill pipe is in our opinion unlikely, but would be deep and does not present a significant catastrophic risk scenario.
- With regard to containment, flowback to vessels is a very difficult scenario. This will require direct connection to capping stack with associated risks. (Enterprise). This also requires reducing pressure to collection system to below 4,400 psi, and gradual ramp up to avoid sanding. Outcome is an estimated 2-3 days of venting hydrocarbons to the sea.
- Capping assembly is holding, but weeping.

Need to define conditions for worst case scenario and decide whether they are likely to make P&A more problematic or eliminate all possible means of controlling and killing the well.

c. If flowing outside of casing (9-7/8" & 7" ?) then open hole section may be enlarged/collapsed but not sure why this would lead to significant issue.
d. If casing burst/parted/split, then it must be deep, (as per diagnostics) in which case it does not present a significant catastrophic risk scenario.
e. As per 2b, a relief well dynamic or circulating kill may or may not impart the lowest kill related stresses along the entire length of the well bore.

We have and will continue to consult widely on this test.
Concept of hard-connecting production vessels is inconsistent with process safety design of systems.

In closing, we appreciate your perspective and appreciate any additional insights you would offer.

Sincerely,

Richard Lynch

cc:
Paul Tooms
Mark Mazalla
Admiral Thad Allen
Rear Admiral Kevin Cook