SUPERIOR
ENERGY SERVICES, INC.

Pat Campbell
Executive Vice President
Technology Solutions Group

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Richard Lynch – Macondo Project Team Leader
BP
200 Westlake Park Blvd.
WL4 office 411
Houston, TX 77079BP

Subject: Macondo 252 #1 Well Kill Plan

I'm Pat Campbell, EVP of the Technology Solutions Group of Superior Energy Services, Inc. More specifically, I'm responsible for Wild Well Control, Inc. (WWCI). WWCI is contracted by BP to act as advisors and participants for the Macondo 252 #1 well control event. WWCI's personnel are imbedded in teams that are participating in the Capping; Relief Well; Top-Hat; Top Kill; Offshore firefighting & Logistics, and Deepwater intervention (Hot Tap) initiatives within The 'Source Control' Module of BP's Incident Command structure. I've been a well control specialist working with personnel of Red Adair Company, Bobby Joe Cudd Company, Boots & Coots, and Joe Bowden's Wild Well Control for total of 32 years. I worked on well control situations as consultant and technical advisor for 10 years prior to that while employed by Regan Forge & Engineering, Cameron Iron Works, FMC Corporation, and Lockheed Petroleum Services.
The purpose of this letter is to ask that you consider this summary document, based on my personal experiences, regarding the forward operations at the Macondo site. Specifically, I'm providing the Incident Command and Unified Command with my reasoning concerning The Team's election to perform the so-called 'Static Kill' on the well.

I wasn't privy to the discussion surrounding the decision to select a bullhead kill, as opposed to the relief well bottom kill. There are no doubt issues about which I'm not fully informed. The purpose of the memo is to convey my personal experience and WWCI's experience concerning the technology (rather than the smallest details).

1. **I don't support the planned /suggested kill methodology:**

The only justification I've ever accepted, authorized, or personally invoked for performing an operation that's been similar to the present proposed "Static Kill" has been:

- No relief well was possible or timely
- No alternative means of entering the blowout wellbore while flowing on diversion,(i.e.: a 'snubbing unit'), was available or timely
- Relative assurance that the wellbore would deteriorate substantially (and catastrophically) while waiting to implement one or both of the other two solutions mentioned above.

None of the above imperatives are present in the BP Macondo 252 #1 well event.

2. **Why I'm opposed to this method of killing the well:**

There are many variable factors about the internal geometry of the wellbore & tubulars that are:

- Not Known and Cannot Be Known prior to the static/bullhead kill attempt
- Diagnostics that could provide greater clarity are not available or possible under the present well conditions.
- A Static (or Bullhead) type kill imposes the ***greatest stresses/forces*** along the length of the wellbore when compared to a relief well dynamic kill or circulating type kill. The relief well kill introduces kill density fluids at the bottom of the wellbore, thereby imparting the ***lowest kill-related stresses/forces*** along the entire length of the wellbore.

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3. Why I support a dynamic or circulating bottom-type kill from the relief well:

When one is faced with so many uncertainties that can't be further resolved prior to a kill attempt, the significant uncertainties suggest that the path forward is to "Initiate no action that may / will make final P&A more problematic **or** create a situation in which all possible control and means of killing the well is eliminated.

- The risk matrix cannot be fully evaluated for the static /bullhead type kill option.
- Although the probability a single negative occurrence may be low, the consequences of failure are simply too high - if other alternatives exist.
- No one knows (or can accurately predict in advance) the flow path of the well.
  - Inside 9 7/8" x 7" combination casing;
  - Outside 9 7/8" x 7" combination casing;
  - Inside and outside 9 7/8" x 7" combination casing;
  - Outside casing and inside casing through DP fish seated at 9 7/8" x 7" crossover, etc., etc.
- If flowing outside casing – what has happened to the open-hole gauge of the wellbore along its length?
- Is the casing burst/collapsed/split/parted? No one knows, and moreover- no one could know-"At what elevation does the damage exist."
- If no circulating path exists around the bottom of the casing x open hole, and if there is damage above the bottom of the casing, then fluids trapped in the casing below the damage point can't be circulated out. Since the kill fluid will follow the path of least resistance, it will leave those fluids trapped inside the casing below the point of damage.
- Originally that would have been 14.2 PPG SOBM. What is in that volumetric space (if it exists) currently is unknown. Whatever it is, it cannot be displaced or circulated out unless the relief well penetrates the 7" casing just above the zone of interest. If the trapped volume of fluids in this area is hydrocarbons, there is no straightforward way to evacuate them.
- This particular situation occurs often on bullhead kills with failed casing. If the fluids need to be evacuated, the only solution is lubricate and bleed (volumetric method), gravity segregation, or as mentioned above, penetration of the 7" casing by the relief well just above the zone of interest. Doing do provides a displacement pathway.
- A relief well dynamic kill or circulating type kill introduces kill density fluids at/near the bottom of the wellbore - thereby imparting the ***lowest kill related stresses/forces*** along the entire length of the wellbore.

4. What's wrong with this picture?

- The instant shut-in pressure (ISIP) at the DH BOP stack was 6,652 PSI
- Slightly lower than the lowermost range predicted before shut-in. There are many estimates of density of the media and whether any radial drawdown of the reservoir has occurred around the wellbore
- The ISIP would tend to support some reservoir depletion (excepting differences of opinion about media density)
- The SIP has continued to climb from 3-5 PSI/hr. to about +-.5 PSI/hr. presently. That suggests some radial drawdown rather than reservoir depletion, but the overall numbers are still below our lowest predictions.
- The present shut in pressure is +- 6,920 PSI

I've been told by the WWCI team working on the project that:

- Everything is sealed and is holding fine at the capping assembly
- There are minor gas bubbles from the 16" x 9 7/8" annulus access valve on the Macondo wellhead housing
- The kill team has established a max surface pump pressure of **8,000 PSI** during the bullhead kill.
- ***Where did that number come from?***
- That's +- 1,000PSI greater than the current shut-in pressure (and it's very convenient), but it's not (and cannot be) based on knowledge of the competency of the exposed casings/cement jobs/seal assemblies, etc.).
- No one knows what erosive (metal loss) effects or other damage may have occurred over the 85 day flowing period.
- No one knows if the Drill String fell down hole and may have caused damage to the casing.
- The only fact known by ***ANYONE*** at the present time is that the well is holding 6,950 PSI at the sea floor.
- There isn't ***ANYONE*** who knows the degree of damage to the tubulars in the wellbore that will/may reduce their ability to hold pressures (forces) exceeding 6,950 PSI applied during the static/bullhead kill.
- It may be that the very next additional 1 PSI applied to the system will cause a failure. I don't know that it will, or won't do so, and neither does anyone else. Any indication to the contrary is their opinion and/or their guess. The only rationale for the 8,000 PSI max injection pressure is some derivative from reducing/down rating the original casing performance values by some factor. In my personal view, anyone willing to bet the success of the well-kill on this limited and incomplete information does not fully appreciate the consequences of being incorrect.

5. What's 'Even More Wrong' with this picture?

If I felt compelled to attempt a bullhead kill (as noted in #1 on page 1 of the memo), I would **NOT**:

- Install the capping device; shut it in, and let it build up to its highest internal pressure, before initiating the kill. ***That's the worst scenario for the application of that methodology.***

If I felt compelled to attempt a bullhead kill (as noted in #1 on page 1 of the memo), I would:

- Install the capping device; divert it to flowback to surface vessels, monitor the flowing pressure; perform a soft shut –in; observe the ISIP; then immediately proceed with the highest possible (allowable/agreed) pump pressure/rate to try to get achieve a 'clean sweep' of wellbore liquids and gas and to obtain maximum hydrostatic force in the blowout well in the shortest possible time.
- Procedurally, one would initiate the bullhead kill when the well is at its weakest (i.e. lowest pressure) possible. *That would have been the ISIP on the day the valves were closed on the capping BOP.*
- That possibility is already lost as related to Macondo as a result of the "integrity test", (which may be extended to infinity the way things are going). If BP elected to follow that process earlier, the ISIP was 6,652 PSI. If the arbitrary 1,000 PSI figure was then applied, the Static Kill maximum allowable injection pressure could be 7,650 PSI (or lower if by mutual agreement of the team), producing less stress on the total wellbore.
- If one begins the static/bullhead kill with the well already at a high shut-in pressure, that reduces the maximum pressure (and injection rate) that can be applied in the earliest stages of the kill.
- If that rate is insufficient to create a clean sweep of the wellbore fluids then there is a mixture of oil & gas (maybe produced water), and kill fluid being pushed back toward the reservoir. Historically, in many similar cases that mixture could be contaminated with solids falling out of the kill fluid, emulsified hydrocarbons, or a lot of different contamination scenarios in which the contaminated mixture *cannot* be injected back into the reservoir.
- Without going into detail, that's a bad deal. Happy to discuss it further).
- Most of these are ***not*** issues for a Dynamic/U-Tube/Circulating type bottom kill from a relief well.
- The fluids circulated into place will have to be handled via the flow back system and surface vessels. Other than inconvenience and additional work, it is not too big a deal
- The relief well offers the possibility of penetrating the exterior and interior wellbore (outside casing and inside casing)
- The static kill offers only 'path of least resistance' with no options unless facilitated by damaged casing at some unknown depth.

There are many, many experienced personnel on the well kill team from BP, their other advisors, and contributors, as well as your own staff via the unified command. There are certainly folks that have vastly more experience about well fluids and nuance of techniques, etc. than I will ever know. Some of the issues from #1 & #3 on page 1 (uncertainty of flow path, reliability of pipe, etc.), apply to the relief well also.

I'd suggest that you check with other well capping and intervention experts for their opinion on this issue.

This is not about the "how you do it", this is about the "Should you do it?"

I'd be happy to discuss or provide all the calculations, illustrations, drawings, charts, curves, etc. that would tend to set out what's known, and what's unknown. I'd be happy to share WWCI's methodology for isolating, reducing, managing, or eliminating risks in well control situations. I think all of those issues have been set forth and discussed at length by the well killing teams already on the Macondo Project.

In the end, this comes down to some logic that should be able to be agreed. Imposing the Static/Bullhead kill under the prevailing circumstances defies the way we have always done things in the well control/capping/killing business for about 40 years. That being said, it's not indicative of some 'Universal and Irreversible Theory" that suggests that only 'one way' can be the 'correct way'.

I'd certainly be in favor of having the Static/bullhead kill lines connected to the Helix Q-4000 for use if needed.
I'd certainly be in favor of one (or more) of the surface vessels being connected to the CDP manifold for flowback
I'd certainly favor having the casing liner in place on the relief well and then execute the primary kill from the DD III

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Unless the extenuating circumstances demanded immediate action, I've never voluntarily tried to bullhead kill wells with so many unknown and unquantifiable issues as MC 252 #1. I'd only do so in those cases where it was being directly imposed on me by the observed results of the well performance or activity.

The only known and verified fact is that the well indicates the ability to hold 6,920 PSI at the present time.

Sure you want to chance it?

Thanks for taking the time to look over this letter. Please feel free to call if you'd like to discuss any issue further.

Pat Campbell

Pat Campbell
Executive Vice President
Technology Solutions Group
Superior Energy Services, Inc.
2202 Oil Center Court
Houston, Texas 77073
Phone 281-784-4700
Fax 281-784-4750
Cell [redacted]
E-Mail: pcampbell@wildwell.com
Visit us at: www.superiorenergy.com

CC:
Mark Mazzella, BP Senior Worldwide Well Control Advisor - Incident Command Team Leader
Adm. Thad Allen, USCG (retired) - Deepwater Horizon Unified Command
RADM Kevin Cook, USCG – Deepwater Horizon Unified Command