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BP Deepwater Oil Spill - Energy and Commerce Committee's Letter Outlining Risky Practices in Anticipation of Hayward's Thursday Testimony

Posted by Gail the Actuary on June 15, 2010 - 10:36am
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Because of interest in this subject, we are keeping this thread open, as well as the analysis of BP's new plans shown in thread http://www.theoildrum.com/node/6603.

Congress wrote a letter to Tony Hayward outlining its concerns that BP took shortcuts and undertook risky practices, in an attempt to keep costs down. This letter was written in preparation for Tony Hayward's testimony on Thursday of this week. Below the fold is a scanned-in copy of that letter, excluding the footnotes. The letter can be accessed at this link.

Dear Mr. Hayward:

We are looking forward to your testimony before the Subcommittee on Oversight and Investigations on Thursday, June 17, 2010, about the causes of the blowout of the Macondo well and the ongoing oil spill disaster in the Gulf of Mexico. As you prepare for this testimony, we want to share with you some of the results of the Committee's investigation and advise you of issues you should be prepared to address.

The Committee's investigation is raising serious questions about the decisions made by BP in the days and hours before the explosion on the Deepwater Horizon. On April 15, five days before the explosion, BP's drilling engineer called Macondo a "nightmare well." In spite of the well's difficulties, BP appears to have made multiple decisions for economic reasons that increased the danger of a catastrophic well failure. In several instances, these decisions appear to violate industry guidelines and were made despite warnings from BP's own personnel and its contractors. In effect, it appears that BP repeatedly chose risky procedures in order to reduce costs and save time and made minimal efforts to contain the added risk.

At the time of the blowout, the Macondo well was significantly behind schedule. This appears to have created pressure to take shortcuts to speed finishing the well. In particular, the Committee is focusing on five crucial decisions made by BP: (1) the decision to use a well design with few barriers to gas flow; (2) the failure to use a sufficient number of "centralizers" to prevent channeling during the cement process; (3) the failure to run a cement bond log to evaluate the effectiveness of the cement job; (4) the failure to circulate potentially gas-bearing drilling muds out of the well; and (5) the failure to secure the wellhead with a lockdown sleeve before allowing pressure on the seal from below. The common feature of these five decisions is that they posed a trade-off between cost and well safety.

<u>Well Design.</u> On April 19, one day before the blowout, BP installed the final section of steel tubing in the well. BP had a choice of two primary options: it could lower a full string of "casing" from the top of the wellhead to the bottom of the well, or it could hang a "liner" from the lower end of the casing already in the well and install a "tieback" on top of the liner. The liner-tieback option would have taken extra time and was more expensive, but it would have been safer because it provided more barriers to the flow of gas up the annular space surrounding these steel tubes. A BP plan review prepared in mid-April reconunended against the full string of casing because it would create "an open annulus to the wellhead" and make the seal assembly at the wellhead the "only barrier" to gas flow if the cement job failed. Despite this and other warnings, BP chose the more risky casing option, apparently because the liner option would have cost $7 to $10 million more and taken longer.

<u>Centralizers.</u> When the final string of casing was installed, one key challenge was making sure the casing ran down the center of the well bore. As the American Petroleum Institute's recommended practices explain, if the casing is not centered, "it is difficult, if not impossible, to displace mud effectively from the narrow side of the annulus," resulting in a failed cement job. Halliburton, the contractor hired by BP to cement the well, warned BP that the well could have a "SEVERE gas flow problem" if BP lowered the final string of casing with only six centralizers instead of the 21 recommended by Halliburton. BP rejected Halliburton's advice to use additional centralizers. In an e-mail on April 16, a BP official involved in the decision explained: "it will take 10 hours to install them . ... I do not like this." Later that day, another official recognized the risks of proceeding with insufficient centralizers but commented: "who cares, it's done, end of story, will probably be fine."

<u>Cement Bond Log.</u> BP's mid-April plan review predicted cement failure, stating "Cement simulations indicate it is unlikely to be a successful cement job due to formation breakdown." Despite this warning and Halliburton's prediction of severe gas flow problems, BP did not run a 9- to 12-hour procedure called a cement bond log to assess the integrity of the cement seal. BP had a crew from Schlumberger on the rig on the morning of April 20 for the purpose of running a cement bond log, but they departed after BP told them their services were not needed. An independent expert consulted by the Committee called this decision "horribly negligent. "

<u>Mud Circulation.</u> In exploratory operations like the Macondo well, wells are generally filled with weighted mud during the drilling process. The American Petroleum Institute (API) recommends that oil companies fully circulate the drilling mud in the well from the bottom to the top before commencing the cementing process. Circulating the mud in the Macondo well could have taken as long as 12 hours, but it would have allowed workers on the rig to test the mud for gas influxes, to safely remove any pockets of gas, and to eliminate debris and condition the mud so as to prevent contamination of the cement. BP decided to forego this safety step and conduct only a partial circulation of the drilling mud before the cement job.

<u>Lockdown Sleeve.</u> Because BP elected to use just a single string of casing, the Macondo well had just two barriers to gas flow up the annular space around the final string of casing: the cement at the bottom of the well and the seal at the wellhead on the sea floor. The decision to use insufficient centralizers created a significant risk that the cement job would channel and fail, while the decision not to run a cement bond log denied BP the opportunity to assess the status of the cement job. These decisions would appear to make it crucial to ensure the integrity of the seal assembly that was the remaining barrier against an influx of hydrocarbons. Yet, BP did not deploy the casing hanger lockdown sleeve that would have prevented the seal from being blown out from below.

These five questionable decisions by BP are described in more detail below. We ask that you come prepared on Thursday to address the concerns that these decisions raise about BP's actions.

Background

BP started drilling the Macondo well on October 7, 2009, using the Marianas rig. This rig was damaged in Hurricane Ida on November 9, 2009. As a result, BP and the rig operator, Transocean, replaced the Marianas rig with the Deepwater Horizon. Drilling with the Deepwater Horizon started on February 6, 2010.

The Deepwater Horizon rig was expensive. Transocean charged BP approximately $500,000 per day to lease the rig, plus contractors' fees.] BP targeted drilling the well to take 51 days and cost approximately $96 million.

The Deepwater Horizon was supposed to be drilling at a new location as early as March 8, 2010. In fact, the Macondo well took considerably longer than plarmed to complete. By April 20, 2010, the day of the blowout, the rig was 43 days late for its next drilling location, which may have cost BP as much as $21 million in leasing fees alone. It also may have set the context for the series of decisions that BP made in the days and hours before the blowout.

Well Design

Deepwater wells are drilled in sections. The basic process involves drilling through rock, installing and cementing casing to secure the well bore, and then drilling deeper and repeating the process. On April 9, 2010, BP finished drilling the last section of the well. The final section of the well bore extended to a depth of 18,360 feet below sea level, which was 1,192 feet below the casing that had previously been inserted into the well.

At this point, BP had to make an important well design decision: how to secure the final 1,192 feet of the well. On June 3, Halliburton's Vice President of Cementing, Tommy Roth, briefed Committee staff about the two primary options available to BP. One option involved hanging a steel tube called a "liner" from a liner hanger on the bottom of the casing already in the well and then inserting another steel liner tube called a "tieback" on top of the liner hanger. The other option involved rurming a single string of steel casing from the seafloor all the way to the bottom of the well. Mr. Roth informed the Committee that "Liner/Tieback Casing provides advantage over full string casing with redundant barriers to annular flow." In the case of a single string of casing, there are just two barriers to the flow of gas up the arullliar space that surrounds the casing: the cement at the bottom of the well and the seal at the wellhead. Mr. Roth told the Committee that in contrast, "Liner/Tieback provides four barriers to annular flow." They are (I) the cement at the bottom of the well, (2) the hanger seal that attaches the liner to the existing casing in the well, (3) the cement that secures the tieback on top of the liner, and (4) the seal at the wellhead. The liner-tieback option also takes more time to install, requiring several additional days to complete.

Internal BP documents indicate that BP was aware of the risks of the single casing approach. An undated "Forward Plan Review" that appears to be from mid-April recommended against the single string of casing because of the risks. According to this document, "Long string of casing ... was the primary option" but a "Liner ... is now the recommended option."

The document gave four reasons against using a single string of casing, They were:

• "Cement simulations indicate it is unlikely to be a successful cement job due to formation breakdown, "
• "Unable to fulfill MMS regulations of 500' of cement above top HC zone,"
• "Open annulus to the wellhead, with", seal assembly as only barrier."
• "Potential need to verify with bond log, and perform remedial cement job(s)."

In contrast, according to the document, there were four advantages to the liner option:
• "Less issue with landing it shallow (we can also ream it down),"
• "Liner hanger acts as second barrier for HC in arlllulus,"
• "Primary cement job has slightly higher chance for successful cement lift,"
• "Remedial cement job, if required, easier to justify to be left for later."

Communications between employees ofBP confirm they were evaluating these approaches, On April 14, Brian Morel, a BP Drilling Engineer, e-mailed a colleague, Richard Miller, about the options. His e-mail notes: "this has been [aJ nightmare well which has everyone all over the place."

Despite the risks, BP chose to install the single string of casing instead of a liner and tieback, applying for an amended permit on April 15. The company's application stated that the full casing string would start at 9 7/8 inches diameter at the top of the well and narrow to 7 inches diameter at the bottom. This application was approved on the same day.

The decision to run a single string of casing appears to have been made to save time and reduce costs. On March 25, Mr. Morel e-mailed Allison Crane, the Materials Management Coordinator for BP's Gulf of Mexico Deepwater Exploration Unit, that the long casing string "saves a lot of time ... at least 3 days." On March 30, he e-mailed Sarah Dobbs, the BP Completions Engineer, and Mark Hafle, another BP Drilling Engineer, that "[n]ot running the tieback ... saves a good deal oftime/money." On April I5, BP estimated that using a liner instead of the single string of casing "will add an additional $7 -$10 MM to the completion cost." The same document calls the single string of casing the "[b]est economic case and well integrity case for future completion operations."

Around this time, BP prepared another undated version of its "Forward Plan Review." Notably, this version of the document reaches a different conclusion than the other version, calling the long string of casing "the primary option" and the liner "the contingency option." Like the other version of the plan review, this version acknowledges the risks of a single string of casing, but it now describes the option as the "Best economic case and well integrity case for future completion operations."

Centralizers

Centralizers are attachments that go around the casing as it being lowered into the well to keep the casing in the center of the borehole. If the well is not properly centered prior to the cementing process, there is increased risk that channels will form in the cement that allow gas to flow up the annular space around the casing. API Recommended Practice 65 explains: "If casing is not centralized, it may lay near or against the borehole wall. ... It is difficult, if not impossible, to displace mud effectively from the narrow side of the annulus if casing is poorly centralized. This results in bypassed mud channels and inability to achieve zonal isolation."

On April 15, BP informed Halliburton's Account Representative, Jesse Gagliano, that BP was planning to use six centralizers on the final casing string at the Macondo well. Mr. Gagliano spent that day running a computer analysis of a number of cement design scenarios to determine how many centralizers would be necessary to prevent channeling. With ten centralizers, the modeling resulted in a "MODERATE" gas flow problem. Mr. Gagliano's modeling showed that it would require 21 centralizers to achieve only a "MINOR" gas flow problem.

Mr. Gagliano informed BP of these results and recommended the use of 21 centralizers. After running a model with ten centralizers, Mr. Gagliano e-mailed Brian Morel, BP's drilling engineer, and other BP officials, stating that the model "now shows the cement channeling" and that "I'm going to run a few scenarios to see if adding more centralizers will help us or not. Twenty-five minutes later, Mr. Morel e-mailed back:

> We have 6 centralizers, we can run them in a row, spread out, or any combination of the two. It's a vertical hole, so hopefully the pipe stays centralized due to gravity. As far as changes, it's too late to get any more product on the rig, our only option is to rearrange placement of these centralizers.

The following day, April 16, the issue was elevated to John Guide, BP's Well Team Leader, by Gregory Walz, BP's Drilling Engineering Team Leader. Mr. Walz informed Mr. Guide: "We have located 15 Weatherford centralizers with stop collars ... in Houston and worked things out with the rig to be able to fly them out in the morning." The decision was made because "we need to honor the modeling to be consistent with our previous decisions to go with the long string." Mr. Walz explained: "I wanted to make sure that we did not have a repeat of the last Atlantis job with questionable centralizers going into the hole." Mr. Walz added: "I do not like or want to disrupt your operations . ... I know the planning has been lagging behind the operations and I have to turn that around."

In his response, Mr. Guide raised objections to the use of the additional centralizers, writing: "it will take 10 hrs to install them . ... I do not like this and ... I [am] very concerned about using them."

An e-mail from Brett Cocales, BP's Operations Drilling Engineer, indicates that Mr. Guide's perspective prevailed. On April 16, he e-mailed Mr. Morel:

> Even if the hole is perfectly straight, a straight piece of pipe even in tension will not seek the perfect center of the hole unless it has something to centralize it.
>
> But, who cares, it's done, end of story, will probably be fine and we' ll get a good cement job. I would rather have to squeeze than get stuck .... So Guide is right on the risk/reward equation.

On April 17, Mr. Gagliano, the Halliblllton account representative, was informed that BP had decided to use only six centralizers. He then ran a model using seven centralizers and found this would likely produce channeling and a failure of the cement job. His April 18 cementing design report states: "well is considered to have a SEVERE gas flow problem."

Mr. Gagliano said that BP was aware of the risks and proceeded with knowledge that his report indicated the well would have a severe gas flow problem.

Mr. Gagliano's findings should not have been a surprise to BP. As noted above, BP's mid-April plan review found that if BP used a single string of casing, as BP had decided to do, "Cement simulations indicate it is unlikely to be a successful cement job." Nonetheless, BP ran the last casing with only six centralizers.

Cement Bond Log

A cement bond log is an acoustic test that is conducted by running a tool inside the casing after the cementing is completed. The cement bond log determines whether the cement has bonded to the casing and surrounding formations. If a channel that would allow gas flow is found, the casing can be perforated and additional cement injected into the annular space to repair the cement job.

Mr. Roth, the Halliburton Vice President of Cementing, informed the Committee staff that BP should have conducted a cement bond log. According to Mr. Roth, "If the cement is to be relied upon as an effective barrier, the well owner must perform a cement evaluation as part of a comprehensive systems integrity test. Minerals Management Service (MMS) regulations also appear to direct a cement bond log or equivalent test at the Macondo well. According to the regulations, if there is an indication of an inadequate cement job, the oil company must "(1) Pressure test the casing shoe; (2) Run a temperature survey; (3) Run a cement bond log; or (4) Use a combination of these techniques."

In the case of the Macondo well, the Halliburton and internal BP warnings should have served as an indication of a potentially inadequate cement job.

On April 18, BP flew a crew from Schlumberger to the rig. As described in a Schlumberger timeline, "BP contracted with Schlumberger to be available to perform a cement bond log ... should BP request those services. But at about 7:00 a.m. on the morning of April 20, BP told the Schlumberger crew that their services would not be required for a cement bond log test. As a result, the Schlumberger crew departed the Deepwater Horizon at approximately 11:15 a.m. on a regularly scheduled BP helicopter flight. The Schlumberger crew was scheduled for departure before pressure testing of the well had been completed, indicating that the results of those tests were not a factor in BP's decision to send the crew away without conducting a cement bond log.

BP's decision not to conduct the cement bond log test may have been driven by concerns about expense and time. The cement bond log would have cost the company over $128,000 to complete. In comparison, the cost of canceling the service was just $10,000.45 Moreover, Mr. Roth of Halliburton estimated that conducting the test would have taken an additional 9 to 12 hours. Remediating any problems found with the cementing job would have taken still more time.

The Committee staff asked an independent engineer with expertise in the analysis of well failure about BP's decision not to conduct a cement bond log. The engineer, Gordon Aaker, Jr., P.E., a Failure Analysis Consultant with the firm Engineering Services, LLP, said that it was "unheard of" not to perform a cement bond log on a well using a single casing approach, and he described BP's decision not to conduct a cement bond log as "horribly negligent." Another independent expert consulted by the Committee, Jolm Martinez, P.E., told the committee that "cement bond or cement evaluation logs should always be used on the production string."

Mud Circulation

Another questionable decision by BP appears to have been the failure to circulate fully the drilling mud in the well before cementing. This procedure, known as "bottoms up," involves circulating drilling mud from the bottom of the well all the way to the surface. Bottoms up has several purposes: it allows workers on the rig to test the mud for influxes of gas; it permits a controlled release of gas pockets that may have entered the mud; and it ensures the removal of well cuttings and other debris from the bottom of the well, preventing contamination of the cement.

API's guidelines recommend a full bottoms up circulation between running the casing and beginning a cementing job. The recommended practice states that "when the casing is on bottom and before cementing, circulating the drilling fluid will break its gel strength, decrease its viscosity and increase its mobility. The drilling fluid should be conditioned until equilibrium is achieved .... At a minimum, the hole should be conditioned for cementing by circulating 1.5 annular volumes or one casing volume, whichever is greater."

BP's April 15 operations plan called for a full bottoms up procedure to "circulate at least one (I) casing and drill pipe capacity, if hole conditions allow." Halliburton Account Representative Jesse Gagliano said it was also "Halliburton's recommendation and best practice to at least circulate one bottoms up on the well before doing a cement job. " According to Mr. Gagliano, a Halliburton engineer on the rig raised the bottoms up issue with BP.

Despite the BP operations plan and the Halliburton recommendation, BP did not fully circulate the mud, Instead, it chose a procedure "written on the rig" which Mr. Gagliano "did not get input in. " BP's final procedure called for circulating just 261 barrels of mud, just a small fraction of the mud in the Macondo well. Mr. Roth of Halliburton told the Committee that one reason for the decision not to circulate the mud could have been a desire for speed, as fully circulating the mud could have added as much as 12 hours to the operation. Mr. Gagliano expressed a similar view, saying, "the well probably would not have handled too high of a rate, so it would take a little bit . . . longer than usual to circulate bottoms up in this case."

Lockdown Sleeve

A final question relates to BP's decision not to install a critical apparatus to lock the wellhead and the casing in the seal assembly at the seafloor. When the casing is placed in the wellhead and cemented in place, it is held in place by gravity. Under certain pressure conditions, however, the casing can become buoyant, rising up in the wellhead and potentially creating an opportunity for hydrocarbons to break through the wellhead seal and enter the riser to the surface. To prevent this, a casing hanger lockdown sleeve is installed. On June 8, 2010, Transocean briefed Committee staff on its investigation into the potential causes of the explosion on board the Deepwater Horizon. In the presentation, Transocean listed the lack of a lockdown sleeve as one of its "areas of investigation." Slide seven of Transocean's presentation asks: "Were Operator procedures appropriate?" A subpoint details: "Operator did not run lock down sleeve prior to negative test or displacement." Mr. Roth of Halliburton raised a similar concern in his June 3 briefing for Committee staff.

In BP's planned procedure for the well, BP describes two options involving the lockdown sleeve. BP was seeking permission from MMS to install the final cement plug on the well at a lower depth than previously approved. If permission was granted, BP's plan was to displace the drilling mud in the riser with seawater and install the cement plug prior to installation of the casing hanger lockdown sleeve. BP's alternative plan, if MMS did not approve the proposed depth of the final cement plug, was to run the lockdown sleeve first, before installing the cement plug at a shallower depth. On April 16, Brian Morel, BP's drilling engineer, e-mailed BP staff that: "We are still waiting for approval of the departure to set our surface plug . ... If we do not get this approved, the displacement plug will be completed shallower after running the LDS." The LDS stands for the lockdown sleeve.

Conclusion

The Committee's investigation into the causes of the blowout and explosion on the Deepwater Horizon rig is continuing. As our investigation proceeds, our understanding of what happened and the mistakes that were made will undoubtedly evolve and change. At this point in the investigation, however, the evidence before the Committee calls into question multiple decisions made by BP. Time after time, it appears that BP made decisions that increased the risk of a blowout to save the company time or expense. If this is what happened, BP's carelessness and complacency have inflicted a heavy toll on the Gulf, its inhabitants, and the workers on the rig.

During your testimony before the Committee, you will be asked about the issues raised in this letter. This will provide you an opportunity to respond to these concerns and clarify the record. We appreciate your willingness to appear and your cooperation in the Committee's investigation.

Sincerely,

Henry A. Waxman
Chairman

Bart Stupak
Chairman
Subcommittee on Oversight and Investigations