Chapter 4 | Technical Findings

The Chief Counsel's team's overall technical findings are straightforward. The Macondo well blew out because the cement that BP and Halliburton pumped down to the bottom of the production casing on April 19 failed to seal off, or "isolate," hydrocarbons in the formation. As rig personnel replaced heavy drilling mud in the well and riser with seawater on April 20, they steadily reduced the pressure inside the well. At approximately 8:50 p.m., the drilling fluid pressure no longer balanced the pressure of hydrocarbons in the pay zone at the bottom of the well. At this point, the well became "underbalanced."

Once the well was underbalanced, hydrocarbons began to flow into the annular space around the production casing. In oil field terms, the Macondo well was "taking a kick." Those hydrocarbons flowed down through the annular space to the bottom of the well, into the production casing through the "shoe track," then up the well and into the riser. As they traveled up the well, the hydrocarbons expanded at an ever-increasing rate and the kick escalated into a full-scale blowout. Transocean's rig crew did not respond to the kick before hydrocarbons had entered the riser, and perhaps not until mud began flowing out of the riser onto the rig floor. Within 10 minutes of the rig crew's first response, hydrocarbon gas from the well ignited, triggering the first explosion.

Underlying Technical Causes

Behind this simple story is a complex web of human errors, engineering misjudgments, missed opportunities, and outright mistakes. Chapter 4 of the Chief Counsel's Report divides technical analysis of the blowout into 10 subchapters. Each subchapter presents the Chief Counsel's team's findings on specific technical issues.

- Chapter 4.1 presents the basis for the Chief Counsel's team's conclusions regarding the precise flow path of hydrocarbons during the blowout.
- Chapter 4.2 explains a number of the well design decisions that BP's engineering team made at Macondo and presents several findings regarding the impact of those decisions. The Chief Counsel's team finds that BP's decision to use a long string production casing increased the difficulty of achieving zonal isolation during the cement job. While the decision did not directly cause the blowout, it increased the risk of cementing failure. The Chief Counsel's team also finds that BP's decisions to include rupture disks and omit a protective casing from its well design complicated post-blowout containment efforts.
- Chapter 4.3 presents findings regarding the final cement job at Macondo. The cement job failed to isolate hydrocarbons. While it may never be possible to determine precisely why, the Chief Counsel's team identified a number of risk factors and other issues that

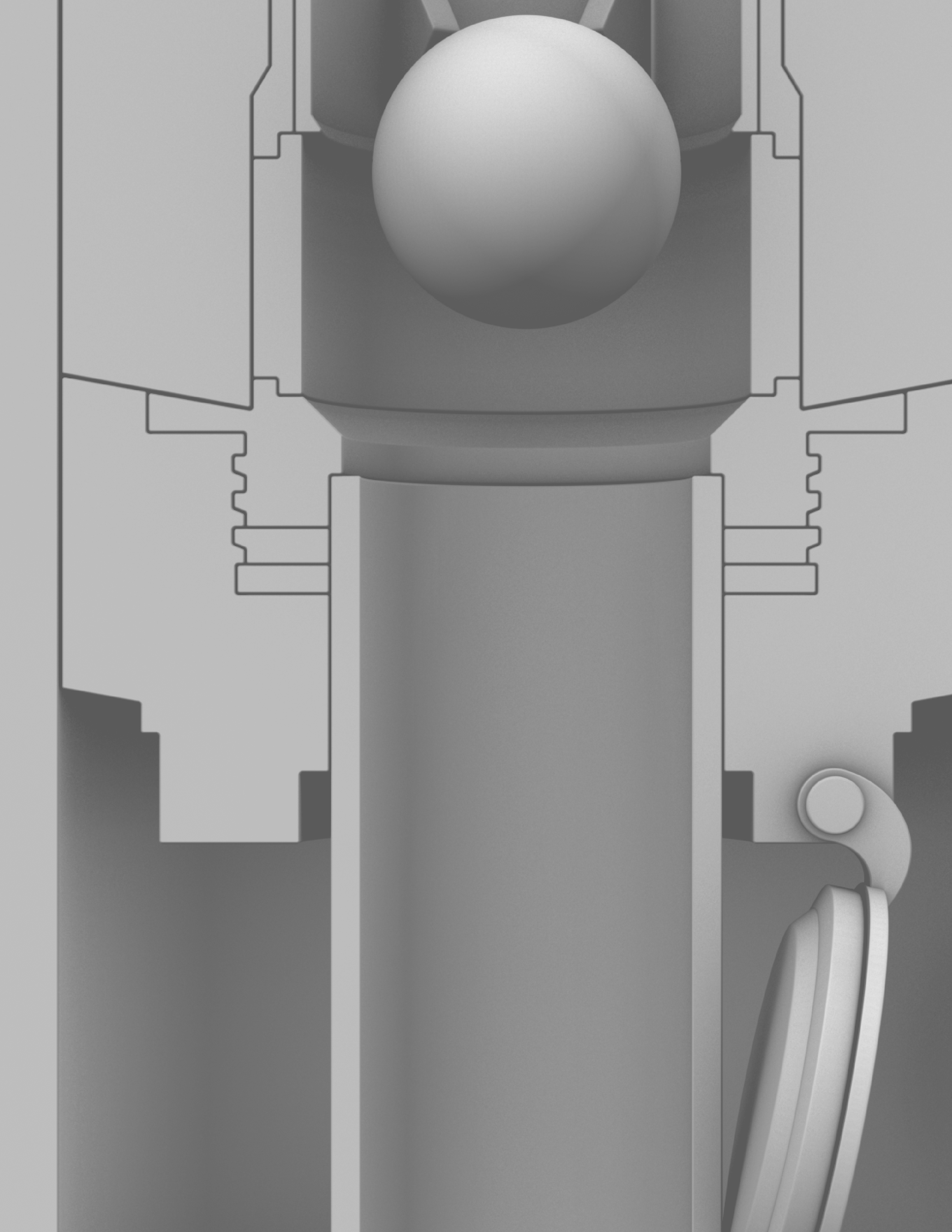
could have contributed to cement failure. The rig crew, cement contractors, and engineering team do not appear to have fully appreciated these risk factors.

- Chapter 4.4 presents findings regarding pre- and post-blowout testing of the foamed cement slurry design used at Macondo. The Chief Counsel's team finds that the foamed cement used at the well was very likely unstable and that this could have been a major contributing factor to overall cement failure.
- Chapter 4.5 presents findings regarding the temporary abandonment procedures that BP developed and employed at the Macondo well. The Chief Counsel's team finds that those procedures reduced the number of barriers that would be present in the well when it became underbalanced, and significantly and unnecessarily increased the risk of a blowout.
- Chapter 4.6 presents findings regarding the negative pressure test conducted on April 20. The Chief Counsel's team finds that the test clearly showed that the cement had failed to isolate hydrocarbons. BP and Transocean rig personnel both failed to interpret the test properly and instead reached a consensus that the test had demonstrated well integrity.
- Chapter 4.7 explains that the Transocean crew and Sperry-Sun mudloggers missed warning signs of a kick on the evening of April 20. The Chief Counsel's team finds that data from the rig show signs of an anomaly as early as 9:01 p.m. Some of the signs went unnoticed; others the crew detected. But even after rig personnel detected the anomaly, they did not identify it as a kick until after hydrocarbons had entered the riser. If rig personnel had identified the kick earlier, they could have prevented the Macondo blowout.
- Chapter 4.8 presents findings regarding the crew's response to the blowout after it occurred. The Chief Counsel's team finds that the crew might have mitigated the size and impact of the fires and explosions on April 20 if they had immediately diverted flow during the blowout overboard rather than to a mud gas separator system that was incapable of handling that extreme flow volume.
- Chapter 4.9 presents findings regarding the rig's blowout preventer, or BOP. Hydrocarbons had entered the riser well before the crew attempted to activate the BOP, and even a perfectly functioning BOP could not have prevented the explosions that killed 11 men on April 20. Nevertheless, BOP failures may have contributed to the magnitude of the oil spill. While BOP forensic testing is ongoing, the Chief Counsel's team presents findings regarding maintenance history and certain BOP failure theories.
- Chapter 4.10 presents findings regarding the role of rig maintenance in the blowout. The Chief Counsel's team finds that Transocean did not maintain its BOP according to manufacturer recommendations. And the Chief Counsel's team cannot rule out that this may have contributed to BOP failures. While the Chief Counsel's team found some

indications of other maintenance problems on the *Deepwater Horizon*, it does not find that any of these contributed to the blowout.

Underlying Management Causes

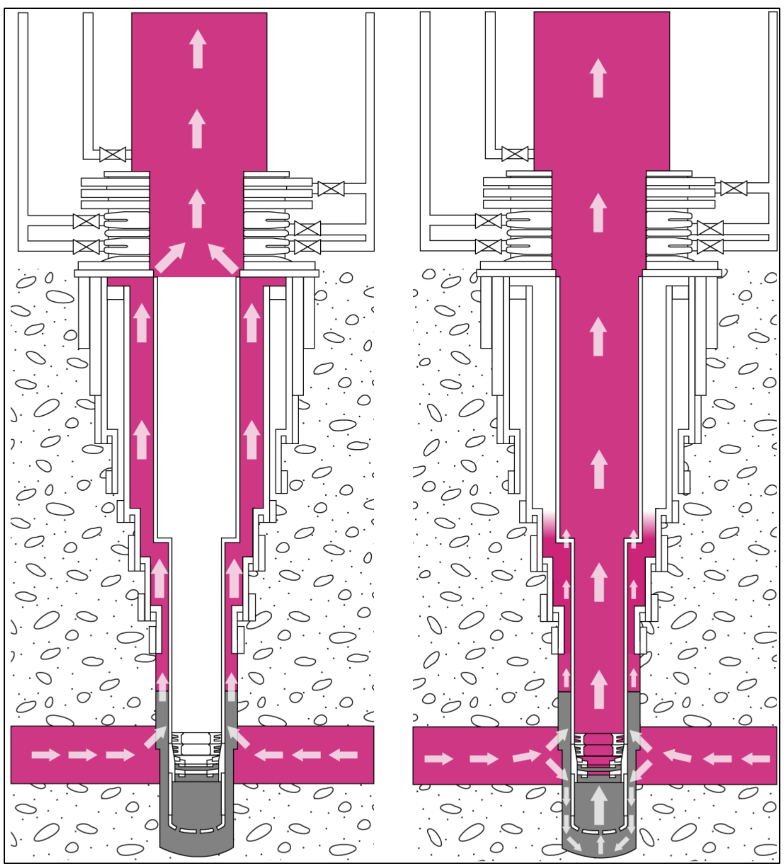
Each of these chapters also presents management findings that relate specifically to the technical findings in the chapter. The Chief Counsel's team finds that management failures lay at the root of all of the technical failures discussed in this Report. Chapter 5 discusses management failures in detail.



Chapter 4.1 | Flow Path

Before addressing potential technical causes of the blowout, the Chief Counsel's team presents its findings regarding the flow path of hydrocarbons from the well. These findings form an important background to the subsequent technical analyses. Because different kinds of well failures cause hydrocarbons to flow through different paths, these findings can help to refine theories about what caused the blowout.

Figure 4.1.1. Possible flow paths for hydrocarbons.



TrialGraphix

Hydrocarbons can reach the surface by traveling up the annulus and through the seal assembly (left). Hydrocarbons can also enter and migrate up the inside of the production casing, through a number of possible flow paths (right).

The Chief Counsel's team finds that hydrocarbons came to the surface by traveling through the inside of the production casing, as seen on the right side of Figure 4.1.1. It is almost certain that hydrocarbons entered the production casing because of a failure of the shoe track cement. However, the Chief Counsel's team cannot entirely rule out the possibility that hydrocarbons may have entered the production casing from the annulus through a breach in the production casing somewhere near the bottom of the casing.

The analysis in this section reflects information currently available to the Chief Counsel's team. The team recognizes that various parties continue to gather additional information that may be relevant to flow path analysis.[1]

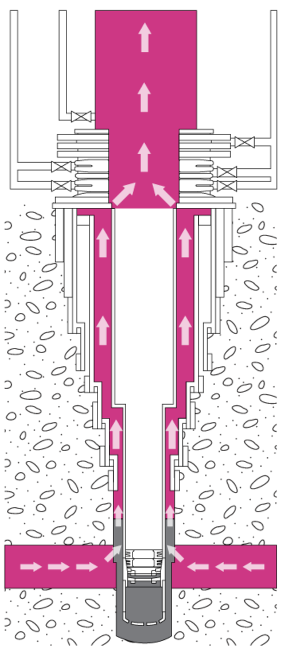
Potential Flow Paths

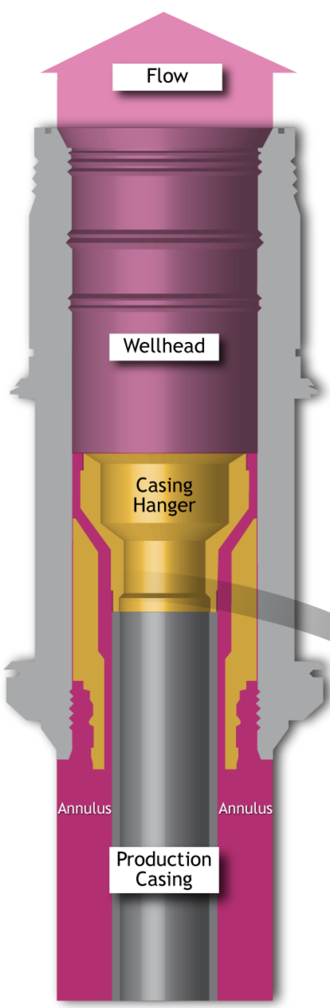
For the Macondo blowout to have occurred, hydrocarbons must have traveled from the formation into the wellbore and then up to the surface through the blowout preventer (BOP) and the riser. The fact that hydrocarbons entered the wellbore at all means, at the very least, that the annular cement did not isolate the pay zones.[2] For hydrocarbons to have traveled up to the surface, they must either have gone up the annulus and through the seal assembly at the wellhead or into and up through the production casing.

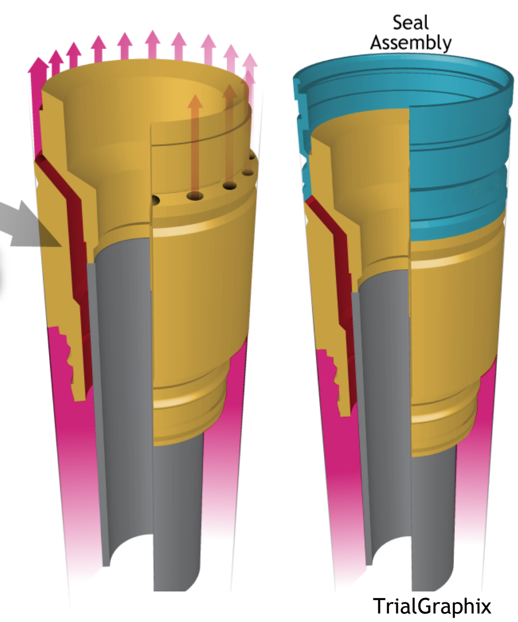
Flow up the Annulus and Through the Seal Assembly

The **seal assembly** is in the wellhead. It seals the interface between the **casing hanger** for the production casing and the inside of the high-pressure wellhead housing. A **lockdown sleeve** locks the casing hanger and seal assembly in place so that hydrocarbons traveling up the wellbore during production do not lift them up.

Figure 4.1.2. Flow through the seal assembly.







As Figure 4.1.2 illustrates, there are small **flow passages** through the casing hanger connecting the annulus to the inside of the wellhead.[3] The flow passages permit mud in the annulus to flow into the wellhead and up into the riser, thereby allowing the crew to circulate drilling fluids through the annulus even after the crew has set the production casing in place. The flow passages remain open prior to and during the final cement job.

The crew sets the seal assembly atop these flow passages to seal them off once there is no longer a need to circulate fluids in the annulus. At Macondo, the crew set the seal assembly shortly after pumping the bottomhole cement job.

The Macondo seal assembly included both metal and elastomeric sealing elements. The primary seal was a metal-to-metal seal between the polished bore of the wellhead, the seal assembly, and the polished mandrel of the casing hanger. The secondary seal was highly resilient elastomeric material.

There were at least two ways in which hydrocarbons could have flowed up the annulus and through the seal assembly.

First, there could have been a leak through the flow passages. This might have occurred because debris obstructed the seal area during the setting process, the seal failed to expand and set properly, or the seal dislodged after it was set.[4]

Second, because the lockdown sleeve had not yet been set at the time of the blowout, pressure and forces from the well below could have lifted the casing hanger up and out of place in the wellhead. Several forces could have generated such uplift, alone or in combination:

- upward pressure in the annulus that exceeded the weight of the production casing;[5]
- sustained flow of high-temperature hydrocarbons that caused the metal production casing to expand and lengthen;[6]
- sufficiently forceful hydrocarbon flow; and
- nitrogen gas that escaped from unstable foamed cement (explained in Chapter 4.4).[7]

If the casing hanger lifted up as a result of net upward pressure in the annulus, the casing would have dropped back down once pressurized fluids escaped and the pressure equalized. That lifting and dropping motion would have occurred repeatedly, resulting in intermittent flow through the seal assembly. Repeated up-and-down movement could also dislodge the shoe track cement, creating an easier path for continuous flow.

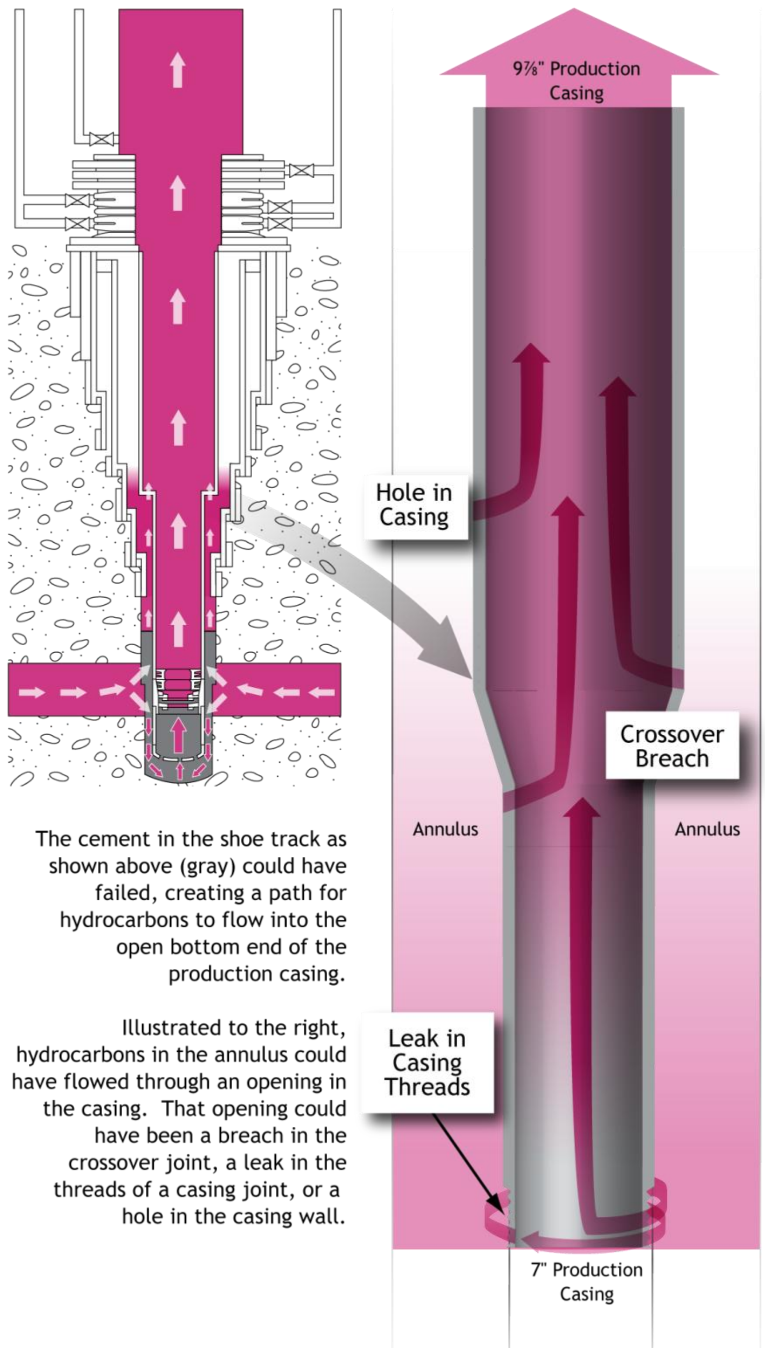
Flow up the Inside of the Production Casing

Hydrocarbons could have traveled into and up through the production casing in two different ways.

First, the cement in the shoe track could have failed, creating a path for hydrocarbons to flow into the open bottom end of the production casing. Those hydrocarbons would also have had to bypass two mechanical float valves (explained in Chapter 4.3).

Second, hydrocarbons in the annulus could have flowed into the production casing through an opening in the casing. That opening could have been a breach in the 9⅞-inch × 7-inch tapered crossover joint,[8] a leak in the threads of a casing joint,[9] or a hole in the casing wall, as illustrated in Figure 4.1.3.

Figure 4.1.3. Flow up the production casing.



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Expert and Investigator Opinions on Flow Path Scenarios

Each of the four general flow path scenarios described above are plausible during a blowout. Hydrocarbon flow up through the annulus is a more common problem[10] that has "long plagued the petroleum industry."[11] But hydrocarbons have also been known to flow through shoe track cement and breaches of casing.[12]

Experts involved in the Macondo containment operations initially speculated that flow had come up through the annulus and the seal assembly.[13] But based on the evidence now available, expert opinion has shifted to favor the scenario in which flow came up through the inside of the production casing.[14]

BP internal investigators have concluded that hydrocarbons came up through the shoe track, based in large part on post-blowout well flow modeling.[15] Transocean internal investigators have expressed agreement with this finding.[16] Halliburton representatives, by contrast, continue to posit a theory in which seal assembly liftoff contributed to or caused annular flow.[17] Halliburton has also speculated that there may have been a breach in the production casing.[18]

The Chief Counsel's team finds that hydrocarbon flow came up through the production casing, most likely due to a failure of the shoe track cement.[19]

Forensic Evidence Suggests That Hydrocarbons Did Not Flow up the Annulus and Through the Seal Assembly

On September 5, 2010, BP removed the *Deepwater Horizon*'s blowout preventer from the Macondo wellhead and replaced it with the blowout preventer from the *Development Driller II*, one of the rigs drilling the two relief wells. With a new blowout preventer and riser in place, the crew of the *Development Driller II* performed a series of forensic operations in and through the upper portions of the Macondo production casing.[20]

If hydrocarbons had flowed up the annulus and through the seal assembly, one would have expected to see at least the following two things:

- hydrocarbons should have been present throughout the annular mud; and
- the outside surfaces of the casing hanger and seal assembly should have been eroded by sustained high-volume flow through the flow passages.[21]

If the casing hanger had lifted up, one would further expect the casing hanger not to have been seated properly in the wellhead housing after the blowout. The evidence does not bear out these expectations.

No Significant Presence of Hydrocarbons in the Annulus

Post-blowout operations analyzing the density of the fluid in the upper annular space suggest that the annular space contained insufficient hydrocarbons to support an annular flow path theory.[22]

Perforation of the Production Casing

On October 7, BP perforated the 9⅞-inch production casing midway down the well (from 9,176 to 9,186 feet), creating a path from the inside of the production casing into the annulus.[23] BP did this in order to determine the density of the fluids in the annular space.

If the annulus had been filled with gaseous hydrocarbons (which are low in density, generally 7 ppg or less[24]), high-density drilling mud (14.3 ppg[25]) inside the production casing would have flowed into the annulus until the densities in the annulus and production casing had equalized.[26] This would have led the crew of the *Development Driller II* to observe two signs: lost mud returns and a significant decrease in drill pipe pressure caused by the decrease in density of the fluid column in the production casing.

Rig personnel did not observe either of those signs. Following perforation, they observed only a slight decrease in drill pipe pressure (from 250 to 143 psi[27]), indicating that the fluids in the annulus were similar in density to the mud in the production casing.[28] (The bottomhole cementing procedure before the blowout left 14.17 ppg drilling mud in the annulus.[29]) After perforation, rig personnel monitored the well for 10 minutes and recorded no change in returns; the well was static.[30]

Both of these observations suggested that the fluids present in the annulus after the blowout were the drilling fluids that BP and Halliburton had left in the annulus before the blowout.[31] If hydrocarbons had flowed through the annulus, they would have flushed those drilling fluids out of the annulus during the course of the blowout.

Sampling of the Annular Fluid

Subsequently, in mid-October, the *Development Driller II's* crew cut the production casing midway down the well (at 9,150 feet),[32] detached the production casing hanger from the wellhead,[33] and lifted the cut portion of the casing up 15 feet.[34] The crew then circulated the annular fluid up to the rig by pumping mud down into the production casing, around the corner of the cut portion, and up through the annulus into the riser, taking mud samples intermittently during the circulation.[35] Those samples ranged from 13.0 to 14.3 ppg in density.[36] Once again, those density measurements were consistent with the density of the drilling fluids that BP and Halliburton had left in the annulus at the end of the bottomhole cement job before the blowout.[37] This indicated again that hydrocarbons likely had not flowed through the annulus.[38]

No Erosion on the Outside of the Casing Hanger and Seal Assembly

A tremendous volume of oil and gas flowed out of the well at a tremendous rate during the course of the blowout.[39] If that flow had traveled through the annulus, past the casing hanger, and through the seal assembly, it would have severely eroded the casing hanger and seal assembly.

On October 13, BP recovered the production casing hanger and seal assembly from the Macondo wellhead.[40] Neither piece of equipment showed any signs of damage in locations where annular flow would have caused serious erosion. Instead, the relevant areas were totally undamaged.

Figure 4.1.4. Exterior of the Macondo production casing hanger and seal assembly.

Dril-Quip

- Figure 4.1.4. Exterior of the Macondo production casing hanger and seal assembly. The outside surfaces of the Macondo casing hanger and seal assembly show no damage (left). They have no erosion-induced channels. Instead, they resemble the condition of brand-new equipment (right).
- The white square placed on the casing hanger before it was set remains. If hydrocarbons had flowed past that area, they almost certainly would have removed this mark.[41]
- The 18 flow passages in the casing hanger show no signs of erosion.[42] If hydrocarbons had flowed through those passages at the velocities estimated for this blowout, they likely would have eroded and enlarged the holes.[43]
- The rubber elastomeric element of the seal assembly (removed post-incident and circulated out into the shaker[44]) still retains its original shape, including a protrusion that one would expect to have been eroded away by annular hydrocarbon flow.[45]

By contrast, the interior of the BOP[46] (through which hydrocarbons definitely flowed) showed serious erosion, as did the interior of the casing hanger, seen in Figure 4.1.5.[47]

Figure 4.1.5. Interior of the Macondo production casing hanger compared to new equipment.

Dril-Quip

Macondo Equipment **New Equipment**

This is strong evidence that hydrocarbons progressed up the inside of the production casing, not up the annulus past the casing hanger and through the seal assembly.[48]

No Detachment of the Casing Hanger

Post-blowout operations on the production casing hanger and seal assembly also suggest that the casing hanger and seal assembly remained in precisely the same place they had been set before the blowout. That observation is inconsistent with the theory that upward forces in the well lifted the casing hanger out of the wellhead. If the casing hanger had been lifted out of place, vented pressure, and then dropped back down, one would almost certainly expect the metal edges of the casing hanger and seal assembly to show damage and expect the casing hanger to have landed in a different position than the one in which it had originally been set.

No Apparent Damage to Metal Edges

The casing hanger and seal assembly contain a series of circular metal lips (as shown in Figure 4.1.6) that protrude and fit inside a corresponding profile on the inside of the wellhead housing. The parts fit together very precisely to create a metal-to-metal seal. If the casing hanger had lifted out of place, it would have caused significant damage to these metal lips. Post-blowout photographs of the casing hanger and seal assembly show no such wear.[49]

Figure 4.1.6. Undamaged metal edges of the casing hanger and seal assembly.

Dril-Quip

Macondo Equipment **New Equipment**

Casing Hanger Properly Seated

In order to set a casing hanger, rig personnel normally lower the casing hanger into the wellhead. When in the correct position, a load transfer ring pops into place to support the load of the casing.[50] The crew must lower the casing hanger *slowly* to avoid missing the correct landing spot.

If the casing hanger had lifted up and dropped down during the blowout, it is highly likely that such movement would have been neither gentle nor slow. As a result, the load ring probably would have passed by its intended seat, and the casing hanger would not have reseated properly in its original position.[51]

On September 9, the crew of the *Development Driller II*, along with representatives from Dril-Quip (the manufacturer of the casing hanger), ran a **lead impression tool**.[52] The tool indicated that the 9⅞-inch casing hanger was "seated properly" in the 18¾-inch high-pressure wellhead housing, where it had been placed prior to the blowout.[53] Because none of the post-blowout operations would have reconnected the casing hanger, this is strong evidence that it never disconnected, and the casing hanger did not lift up during the blowout.[54]

Lead Impression Tool. A **lead impression tool** is a small block with soft metal (usually lead). Rig personnel lower it into the wellhead and take an impression to identify the internal profile of the wellhead, including the elevation of the casing hanger.[55]

Passing Post-Blowout Positive Pressure Test

On September 10, the crew of the *Development Driller II* conducted a positive pressure test on the production casing and saw no significant change in pressure or flow.[56] (Chapter 4.6 describes a positive pressure test in detail.) This is inconsistent with the casing hanger liftoff theory. A positive pressure test examines the pressure integrity of the casing hanger and seal assembly for a sustained period of time. If the casing hanger had lifted up or the seal assembly had leaked, the crew of the *Development Driller II* likely would have observed a significant decrease in pressure or return flow from the well, or both.[57]

Successful Installation of the Lockdown Sleeve

Finally, on September 11, the crew of the *Development Driller II* successfully installed and pressure tested a lockdown sleeve in the Macondo wellhead.[58] The fact that BP was able to install a lockdown sleeve after the blowout suggests that the casing hanger was properly seated in the wellhead.[59] In order for the lockdown sleeve to properly set onto the casing hanger, the casing hanger itself must be properly seated in its high-pressure housing.[60]

Circulation of Fluids During the Pre-Blowout Cement Job

Despite the evidence described above, Halliburton argues that "hydrocarbons may have already been present in or even flowing into the annulus before the production casing cement job was complete."[61] The company bases its hypothesis on the "discernable drop in surface pressure at the conclusion of the cement job" that occurred on April 20 (illustrated in Figure 4.1.7).[62]

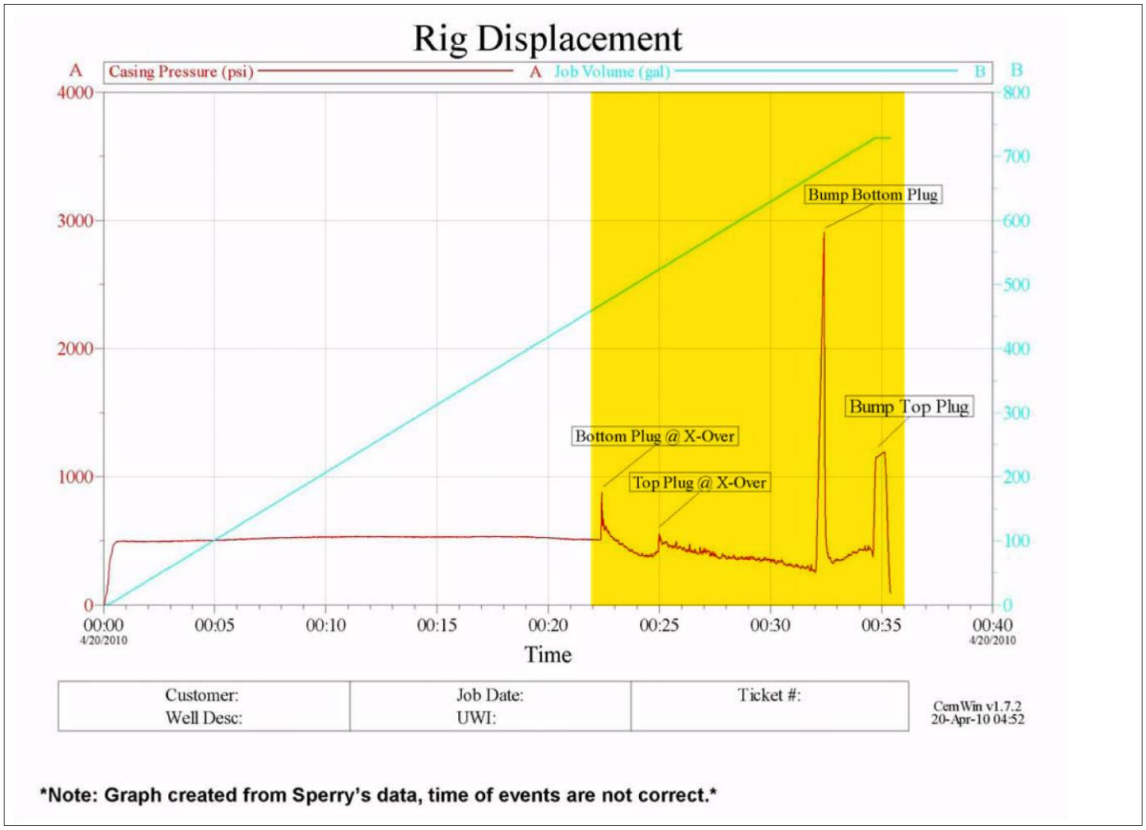
Halliburton's argument is unpersuasive for several reasons.

First, the observed fluctuation in surface pressure can be explained by the wellbore geometry at Macondo.[63] Macondo had a **tapered** production casing string—9⅞ inches from wellhead to 12,488 feet below sea level, tapering to 7 inches from 12,488 feet below sea level to the bottom of the casing. In wells with a tapered production casing (and hence a tapered annulus), "each discrete volume of fluid will grow in column height as it travels down the well [past the crossover joint] and shrink as it comes up the well [past the crossover joint]."[64] As a result, the hydrostatic pressure differential between the casing and the annulus will change over the course of the cement job (as it did at Macondo).

Second, the drop in surface pressure did not appear particularly anomalous at the time. In fact, Halliburton's own pre-job cementing model predicted that pressure would decrease by some amount.[65] The Chief Counsel's team has not identified any evidence to suggest that rig personnel monitoring the Macondo cement job thought that the pressures they were seeing were abnormal.[66]

Finally, the cement job pressure readings cannot alone support a theory of annular flow (a point that Halliburton concedes[67]), and the other evidence discussed above is inconsistent with annular flow.

Figure 4.1.7. Halliburton post-cement-job report.

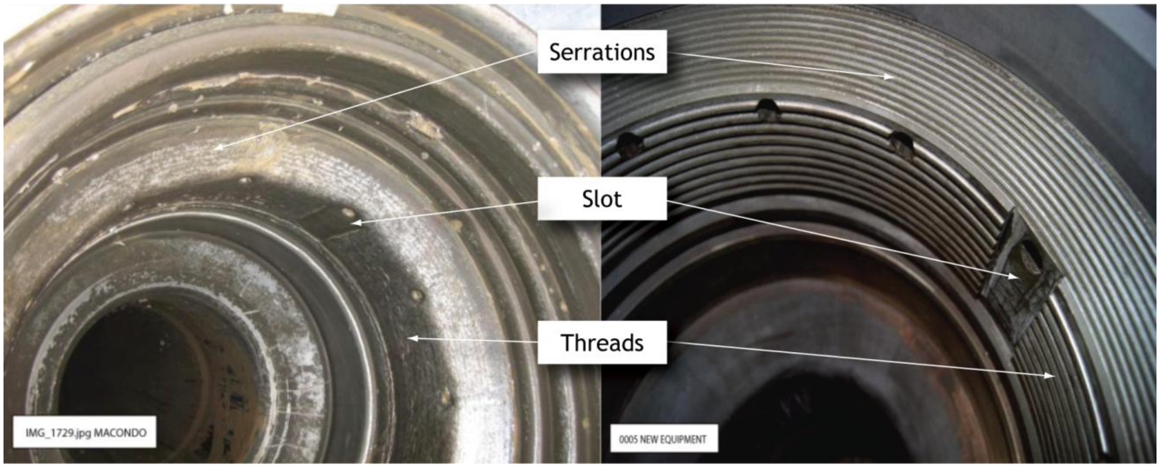


Halliburton

Hydrocarbons Appear to Have Flowed Into and up the Production Casing

Post-blowout inspection of the production casing hanger and seal assembly retrieved from the Macondo well shows severe erosion on the inside of the casing hanger (shown in the left-side photo in Figure 4.1.8). Serrations near the top of the casing hanger—normally ⅛-inch deep—are almost completely abraded away.[68] Threads that normally run around the inside of the casing hanger are flattened.[69] The slot that normally interrupts the threads—¼-inch deep when new—appears as an almost nonexistent indentation.[70] These observations all suggest that hydrocarbons came up through the production casing.

Figure 4.1.8. Erosion of the inside of the casing hanger.



Dril-Quip

Macondo Equipment **New Equipment**

The remaining question is precisely how hydrocarbons entered the inside of the production casing. Currently available evidence leads the Chief Counsel's team to conclude that hydrocarbons almost certainly entered the production casing through the shoe track. At the same time, the Chief Counsel's team cannot rule out the possibility that hydrocarbons entered the production casing from the annulus through a breach in the side of the casing string.

Hydrocarbons Likely Entered the Production Casing Through the Shoe Track

Problems With the Primary Cement Job Could Have Compromised the Shoe Track Cement

The bottomhole cement job at Macondo involved an unusual number of risk factors. Some were inherent in the conditions at the well; others developed during the course of the design and execution of the bottomhole cement job. This includes a cement slurry that may have been unstable, uncertainties with regard to cement placement (because of doubts about float conversion and centralization), and concerns over cement contamination (as a result of limited pre-cementing circulation and low cement volume and flow rate). Chapter 4.3 discusses these risks in more detail.

The Float Valves Would Not Have Provided an Independent Barrier to Flow Through the Shoe Track

It is not clear whether the float valves in the Macondo well converted prior to the pumping of the bottomhole cement job. A failure to convert these two-way valves into one-way valves would have allowed the cement to flow back in the wrong direction and therefore could have compromised the bottomhole cement job. Even if they had converted, the float valves may not have closed fully due to malfunction or debris. In any case, float valves are not typically considered independent barriers to hydrocarbon flow. Chapter 4.3 discusses these issues in more detail.

Evidence From the Static Kill Operation Suggests Flow Through the Shoe Track

Data from the August 4 static kill operation on the Macondo well suggest that flow came up through the shoe track. In the static kill operation, BP planned to pump 13.2 ppg mud into the well, from the top of the wellbore to the bottom, monitoring pressures along the way.[71] Before doing so, the company modeled expected pressures and volumes for several flow path scenarios, including flow up the annulus and flow up the production casing (with the drill pipe in different positions).[72] Pressures observed during the operation more closely matched flow up the production casing.[73]

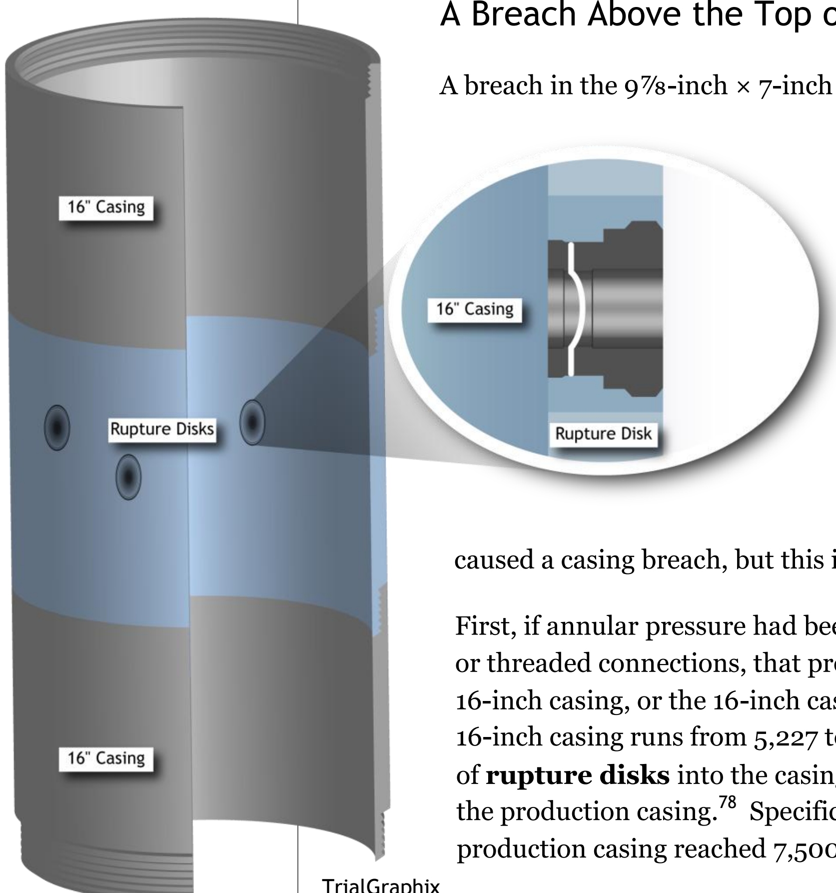
The static kill data analysis has several shortcomings. First, BP performed its analysis with imperfect knowledge of the wellbore geometry and without knowing whether there was debris or other obstructions in the well.[74] Second, the observed pressures matched the modeled pressures only up to a certain point and then diverged.[75] Third, it is unlikely that the pressure observations were sensitive enough to distinguish a casing breach near the bottom of the production casing (such as near the float collar).[76]

Analysis of the static kill data is still ongoing and subject to future revision.

The Chief Counsel's Team Cannot Rule Out the Possibility of Flow Through a Breach in the Production Casing

Hydrocarbons may have entered through a breach in the production casing, although the Chief Counsel's team considers this scenario unlikely.

Figure 4.1.9. 16-inch casing and rupture disks.



TrialGraphix

A Breach Above the Top of Cement Is Unlikely

A breach in the 9⅞-inch × 7-inch tapered crossover joint or anywhere above the top of the annular cement is unlikely. If hydrocarbons went from the formation into the annulus and then through such a breach, one would expect to observe hydrocarbons in the annular space. As explained above, there is no evidence of a significant hydrocarbon presence in the annulus.

A Breach as a Result of External Pressure Is Unlikely

External pressure in the annulus (caused by hydrocarbon flow or nitrogen gas) could have caused a casing breach, but this is unlikely for at least two reasons.

First, if annular pressure had been sufficient to cause a breach in the production casing or threaded connections, that pressure should first have caused rupture disks in the 16-inch casing, or the 16-inch casing itself, to burst (shown in Figure 4.1.9). The 16-inch casing runs from 5,227 to 11,585 feet below sea level.[77] BP installed three sets of **rupture disks** into the casing wall. The rupture disks were designed to fail before the production casing.[78] Specifically, if pressure between the 16-inch casing and the production casing reached 7,500 psi, the rupture disks should have burst outward.[79]

This pressure is, by design, less than the 11,140 psi that the production casing and its threaded connections are designed to withstand.[80] Even if the rupture disks did not function as designed, the 16-inch casing probably would have failed in some manner once pressures significantly exceeded 6,920 psi.[81] But it appears that neither the rupture disks nor the 16-inch casing failed. Chapter 4.2 discusses this issue in more detail.

Second, there is no evidence to date that the production casing was designed improperly, or that crew members improperly made up one or more casing joints before sending them downhole. A Weatherford representative was on the rig, monitoring the makeup of the casing, tracking torques and turns through a computer program, and verifying that all of the connections were up to standard.[82] Furthermore, the Weatherford daily log and data from the computer program do not show any mishaps in casing makeup for most of the production casing.[83] (The integrity of connections made up onshore—including the reamer shoe, centralizer subs, float collar, and crossover joint—remains unconfirmed.[84]) While members of the rig crew inadvertently dropped and damaged some pipe when making up the 7-inch portion of the casing,[85] the evidence shows that they subsequently replaced the damaged joints before sending them downhole.[86]

A Breach Below the Top Wiper Plug as a Result of Internal Pressure Cannot Be Ruled Out

The Chief Counsel's team cannot completely rule out a casing breach below the top plug, though it is unlikely.[87] If such a breach occurred prior to the cement job, it could have jeopardized the placement of the bottomhole cement.

Testimonial evidence shows that in the day before the blowout BP personnel were concerned about a possible casing breach. (Chapter 4.3 discusses these facts in more detail.) On April 19, after attempting to convert the float equipment and establishing circulation, one witness recalls well site leader Bob Kaluza saying, "I'm afraid that we've blown something higher up in the casing joint."[88] Kaluza was presumably referring to the possibility that the unusually high 3,142 psi pressure that BP directed the rig crew to apply to convert the float valves created a breach in the production casing.[89] BP and rig personnel subsequently observed lower-than-expected circulating pressures, which could be consistent with mud being circulated through a breach in the casing and back up to the rig through the upper part of the annulus, rather than out the bottom of the casing and up the entire annulus. Kaluza expressed his concern to BP drilling engineer Brian Morel, who was also on the rig.[90] Morel relayed the concern to BP wells team leader John Guide, who was onshore.[91] Meanwhile, Morel also emailed Weatherford sales representative Bryan Clawson, "Yah we blew it at 3140, still not sure what we blew yet."[92]

After discussing the issue, the BP Macondo team determined that if there were a casing breach, they could not fix it at that point in the operations.[93] They also concluded that they would detect any such breach in later well integrity pressure tests and could take remedial measures at that time.[94] There is no evidence that anyone actually revisited the issue prior to the blowout.

BP personnel may not have detected a casing breach near the float collar. After the cement job, rig personnel performed a positive pressure test on the well to test the integrity of the production casing. But a positive pressure test does not test the casing below the top wiper plug.[95]

(Chapter 4.6 discusses positive pressure tests in more detail.)* After the blowout, BP conducted a static kill operation on the well and observed pressure data consistent with shoe track flow. But the modeled and observed pressure and volume data were not sensitive enough to distinguish a casing breach near the bottom of the production casing (such as near the float collar) from flow through the shoe track cement.[96] And although a Weatherford log tracking the makeup of the production casing showed no mishaps, the log did not contain data on the integrity of connections made up onshore—including the float collar.[97]

Technical Findings

The Annular Cement Did Not Isolate the Hydrocarbon Zones

The Chief Counsel's team finds that the cement in the annular space did not isolate the hydrocarbon zones. This finding calls into question the quality of the bottomhole cement job. Chapters 4.3 and 4.4 identify possible shortcomings in that cement job including mud contamination, improper cement placement, and cement slurry instability.

Hydrocarbons Came to the Surface by Traveling Through the Production Casing

The Chief Counsel's team finds that hydrocarbons came to the surface through the inside of the production casing. This finding calls into question BP's temporary abandonment procedure and design. Chapter 4.5 discusses the risks attendant to the temporary abandonment.

The Shoe Track Cement Probably Failed

The Chief Counsel's team finds that flow almost certainly came up through the shoe track of the production casing. Cement in the shoe track should have blocked this flow. This finding again calls into question the quality of the bottomhole cement job. Chapter 4.3 discusses possible reasons for shoe track cement failure.

* Rig personnel also performed a negative pressure test on the well. A negative pressure test does test the integrity of the casing down through the shoe track as well as the shoe track cement. But rig personnel misinterpreted the negative pressure test. Chapter 4.6 discusses this in more detail.

Chapter 4.2 | Well Design

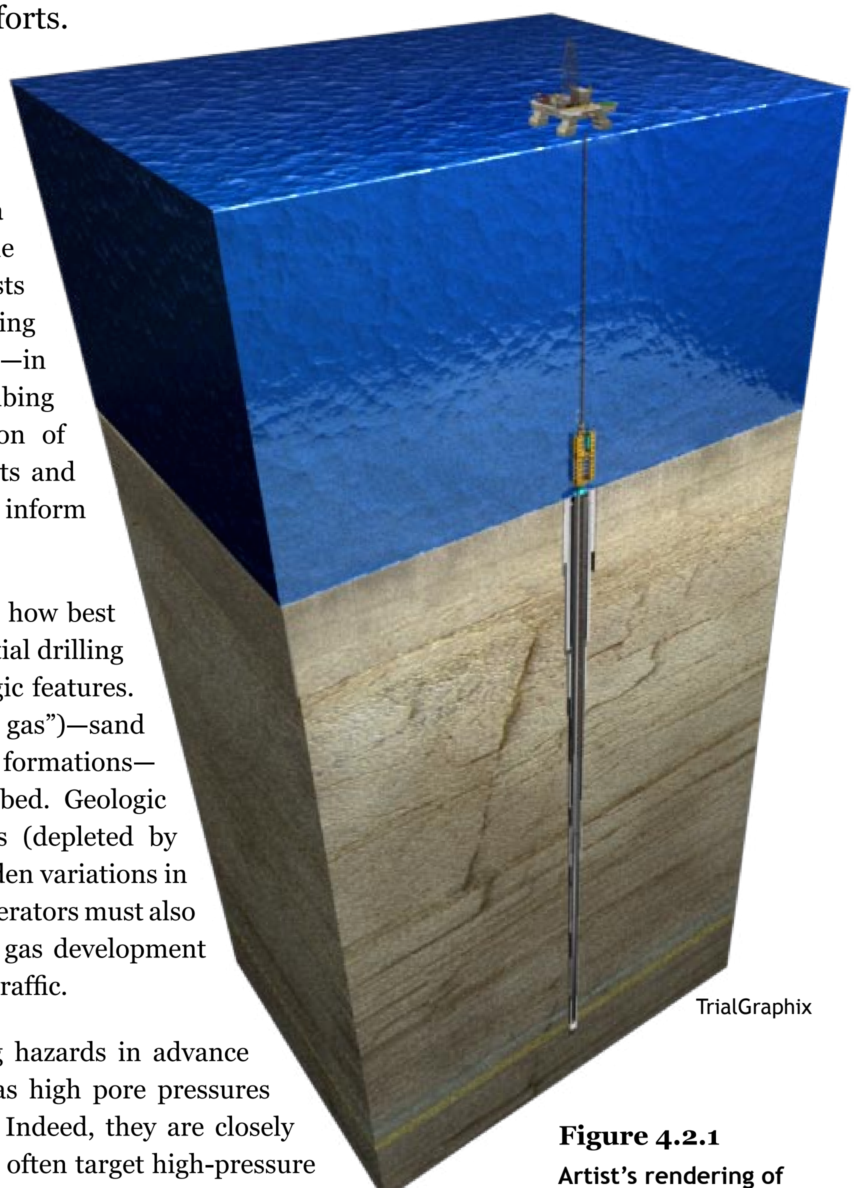
BP's engineering team made a number of important well design decisions that influenced events at Macondo. Among other things, the engineers (1) decided to use a long string production casing, (2) installed rupture disks in the well, and (3) decided to avoid creating trapped annular spaces by omitting a protective casing and leaving annular spaces open to the surrounding formation. The Chief Counsel's team finds that these decisions complicated pre-blowout cementing operations and post-blowout containment efforts.

Deepwater Well Design

Wells are drilled for a reason: either to explore for oil and gas, appraise an earlier discovery, or create a development well in an existing oil field. By the time the well is designed, subsurface geologists and geophysicists will have identified subsurface objectives, usually using seismic reflection data. They will also have prepared—in as much detail as possible—a geologic prognosis describing lithology, pressure, and fluid content as a function of depth. If there are other wells nearby, the geologists and geophysicists will have used data from those wells to inform their prognosis.

The design team that plans the well must determine how best to achieve the well's objectives while managing potential drilling hazards. The hazards can include a variety of geologic features. For instance, porous gas-bearing intervals ("shallow gas")—sand layers containing pressurized gas or water, or unstable formations—may occur in the first few thousand feet below the seabed. Geologic faults and low-pressure hydrocarbon-bearing sands (depleted by nearby oil production) can also present hazards. Sudden variations in subsurface pore pressure can pose hazards as well. Operators must also consider man-made hazards such as nearby oil and gas development infrastructures (wells, platforms, pipelines) and ship traffic.

In many cases the design team can identify drilling hazards in advance and avoid them. But some geologic hazards, such as high pore pressures and hydrocarbon deposits, are impossible to avoid. Indeed, they are closely associated with the drilling objectives—oil companies often target high-pressure hydrocarbon reservoirs. High pore pressures are a common feature of the deepwater Gulf of Mexico environment, and often signal the presence of oil and gas.



TrialGraphix

Figure 4.2.1

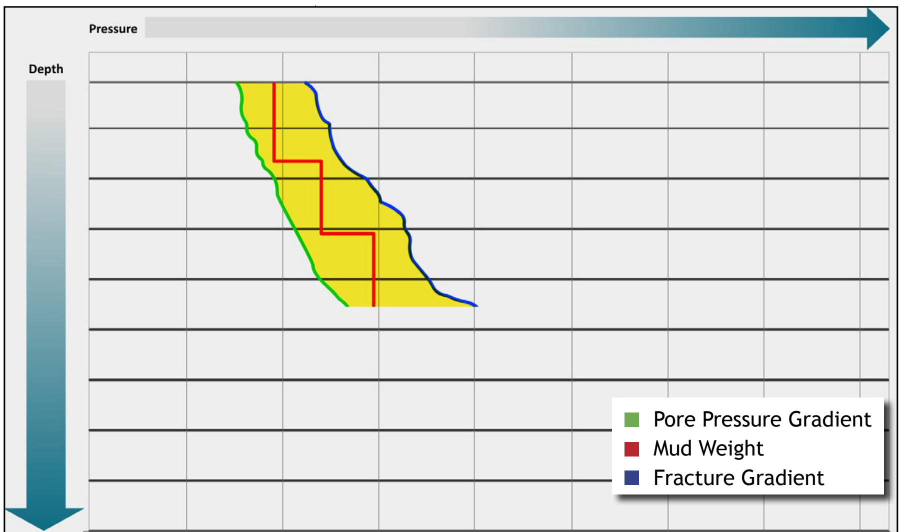
Artist's rendering of the Macondo well from rig to rathole.

Drilling engineers must therefore keep several key issues in mind as they design a deepwater well.

Pore Pressure and Fracture Gradients

Drilling engineers must design wells to manage intrinsic risks. Specifically, they must develop drilling programs that will manage and reflect the pore pressure and fracture gradients at a given drilling location as shown in Figure 4.2.2. (Chapter 2 describes these concepts in more detail.) The design team must specify the kinds of drilling fluids that will be used and the number and type of casing strings that will extend from the seafloor to the total depth of the well. The drilling fluids and casing strings must work together to balance and contain pore pressures in the rock formation without fracturing the rock.

Figure 4.2.2. Narrow drilling margins.



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Creating this plan can be difficult if engineers have limited information about subsurface geology and if actual pore pressures vary significantly from predictions.[1] This is often the case in exploration wells or in the first well in a new field. The problem frequently crops up in the Gulf of Mexico, which is prone to having a narrow window between the pore pressure and fracture gradients as well as zones of pore pressure repression (where the pore pressure gradient suddenly reverses and decreases with depth).[2]

Because drilling conditions often differ significantly from predictions, engineers often design and redesign a deepwater well as the well progresses. They work constantly to keep two factors within tolerable limits: **equivalent static density** (ESD) and **equivalent circulating density** (ECD). ESD refers to the pressure that a column of fluid in the wellbore exerts when it is static (that is, not circulating). ECD refers to the *total* pressure that the same fluid column exerts when it *is* circulating. When drillers circulate fluids through a well, ECD exceeds ESD because the force required to circulate the fluids exerts additional pressure on the wellbore.

In planning the well, engineers will design a mud program to keep both ESD and ECD below the rock's fracture gradient. Drillers monitor these parameters carefully as they work.

Barriers to Flow

As discussed in Chapter 2, operators typically employ redundant **barriers** to prevent hydrocarbons from flowing out of the well before production operations. One important barrier in any well is the mud and drilling fluid system in the wellbore. When properly designed and operated, the drilling fluid system should balance the pressure of any hydrocarbons in the well formation. Engineers can also use other kinds of barriers during drilling and completion. Those barriers include cemented casing, mechanical and cement plugs, and the blowout preventer (BOP). Sound industry practice—and BP's own policy—generally requires an operator to maintain two verified barriers along any potential flow path.[3]

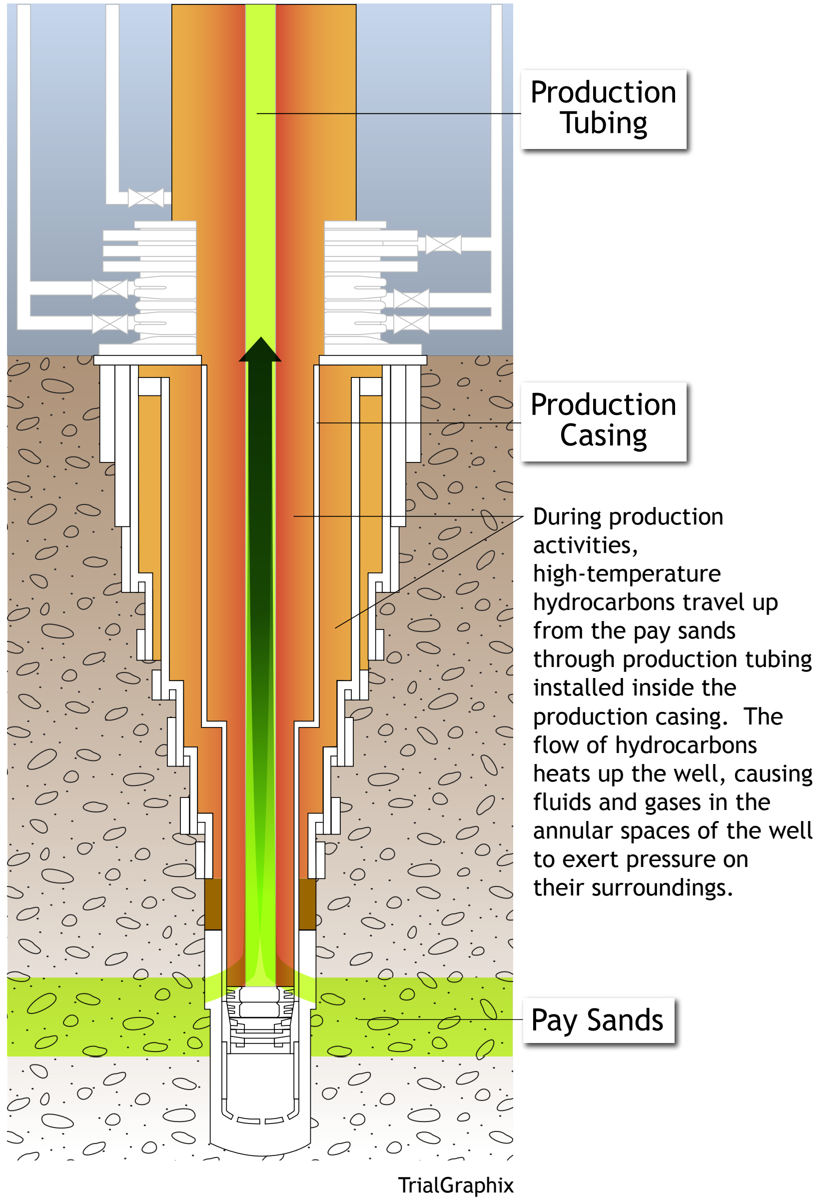
Annular Pressure Buildup

If an operator plans to use a given well to produce oil in the future (rather than merely to learn about subsurface geology), its design team must consider the environmental and mechanical stresses that the well will experience over its lifetime. The casing and completion program must ensure that these stresses do not compromise well integrity over the life of the well, which could be as long as several decades.

In deepwater production wells, engineers pay special attention to a phenomenon called **annular pressure buildup** (APB). Figure 4.2.3 illustrates that during production activities, high-temperature hydrocarbons travel up from the pay sands through production tubing installed inside the production casing. The flow of hydrocarbons heats up the well. As a result, fluids and gases in the annular spaces of the well expand. If the well design creates annular spaces that are enclosed, the fluids and gases trapped within those spaces will exert increasing pressure on the well components as they heat up. In some cases, the pressure can become high enough to collapse casing strings in the well and to force the operator to abandon the well.

Managing annular pressure buildup in a deepwater well requires careful planning and design. Engineers can use a number of design features to manage annular pressures or mitigate the risks of casing collapse. These include rupture disks, compressible fluids in the annular space, and insulated production tubing. Finally, they can design wells in ways that avoid creating trapped annular spaces at all.

Figure 4.2.3. Annular pressure buildup (APB).

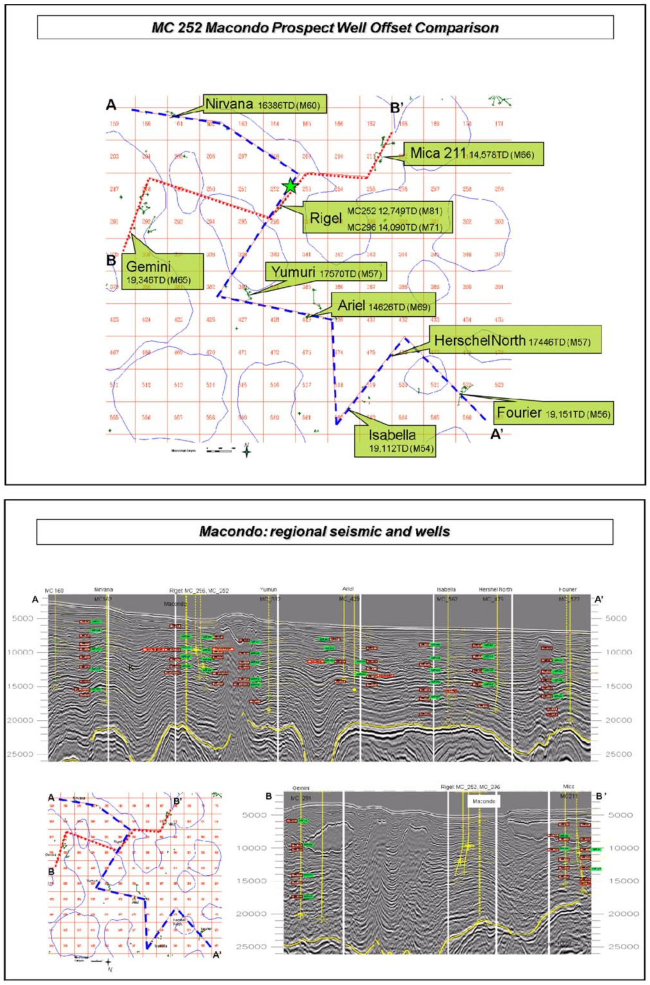


The Macondo Well Design

Even before it began drilling Macondo, BP believed that the well might encounter a substantial hydrocarbon reservoir.[4] But BP also recognized that it might also encounter a number of hazards, including shallow gas sands, overpressures, and depleted reservoir zones, as well as the expected oil and gas in the mid-Miocene objective reservoir. BP chose the particular drilling location for Macondo to penetrate the objective section while avoiding shallow gas sands that it had identified. BP identified potential minor drilling hazards beneath 8,000 feet below sea level: thin gas-charged sands and depleted (low-pressure) zones.[5]

Using seismic imagery, BP had a high degree of confidence that the formation below contained a significant accumulation of oil and gas.[6] BP therefore planned the Macondo well as an exploration well that it could later complete and turn into a production well.[7]

Figure 4.2.4. Offset wells and seismic data.



BP

The green star indicates Macondo's location.

BP drilling engineer Brian Morel and senior engineer Mark Hafle had the primary responsibility for the Macondo well design work.[8] They worked with a number of BP engineers and geoscientists to develop their plans.[9] Geologists and petrophysicists from BP's Totally Integrated Geological and Engineering Resource (TIGER) team helped develop a pore pressure profile for the well based on other wells in the vicinity ("offset wells") as shown in Figure 4.2.4.[10] A BP casing and tubular design team independently reviewed the well design.[11] Fluid experts and rock strength experts checked the geomechanical aspects of the well.[12] And because the well was being designed as a producer, BP completion engineers also provided input during the design process.[13] The completion engineers recommended, among other things, an analysis of the well's potential for annular pressure buildup and possible mitigation measures.[14]

In June 2009, the initial Macondo well design underwent peer review.[15] The reviewers concluded that the Macondo design team "did a lot of good work," that the initial design was "[r]obust" and "supported by good data and analysis," and that "all major risk[s] [were] addressed and mitigations developed."[16] Over the course of the next year, the Macondo engineering team would update its drilling program several times. But three key design features never changed.

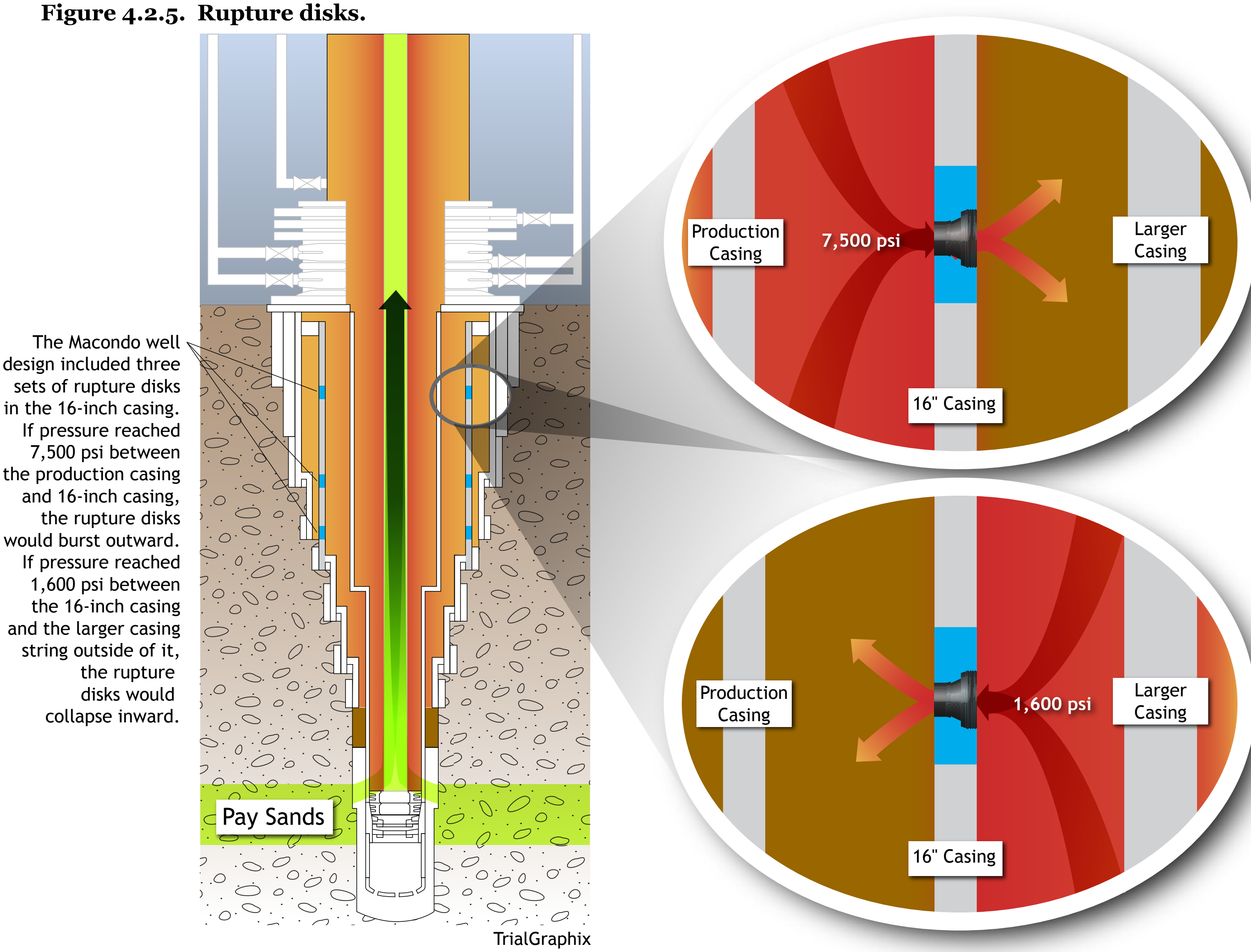
Rupture Disks

All of BP's Macondo well designs included three sets of rupture disks in the 16-inch casing.[17] The 16-inch casing was the longest piece of pipe outside of the production casing. The **rupture disks** (or burst disks) would relieve annular pressure before that pressure could build up high enough to cause a collapse of the production casing or the 16-inch casing.

The disks worked in two ways as shown in Figure 4.2.5. First, if pressure between the 16-inch casing and the production casing reached 7,500 pounds per square inch (psi), the rupture disks would *burst outward* and release that pressure.[18] Because the production casing was rated to withstand 11,140 psi of pressure, this would prevent annular pressure from rising to the point at which it could collapse the production casing.[19] Second, if pressure *outside* of the 16-inch casing (that is, between the 16-inch casing and the other larger casing strings outside it) exceeded 1,600 psi, the rupture disks would *collapse inward* to release that pressure.[20] Because the 16-inch casing was rated to withstand 2,340 psi of pressure, this would prevent pressure outside the 16-inch casing from rising to the point at which it could collapse the 16-inch casing.[21]

Once ruptured, the disks would leave small holes in the 16-inch casing through which pressure could bleed into the surrounding rock formation.[22]

Figure 4.2.5. Rupture disks.



Protective Casing

BP's well design consistently and deliberately omitted a **protective casing**. A protective casing is an intermediate casing string outside the production casing that runs from deep in the well all the way back to the wellhead.[23] A protective casing supplies a "continuous pressure rating" for the interval that it covers (as shown in Figure 4.2.6) and seals off potential leak paths at the tops of previous liner hangers.[24]

It is common industry practice to use a protective casing whenever running a long string production casing.[25] But the Macondo team never planned for a protective casing[26] because installing such a casing would also have negated their efforts to mitigate annular pressure buildup.[27] Specifically, it would have sealed off the rupture disks and the previously open annuli in the casing design.

Figure 4.2.6. Protective casing.

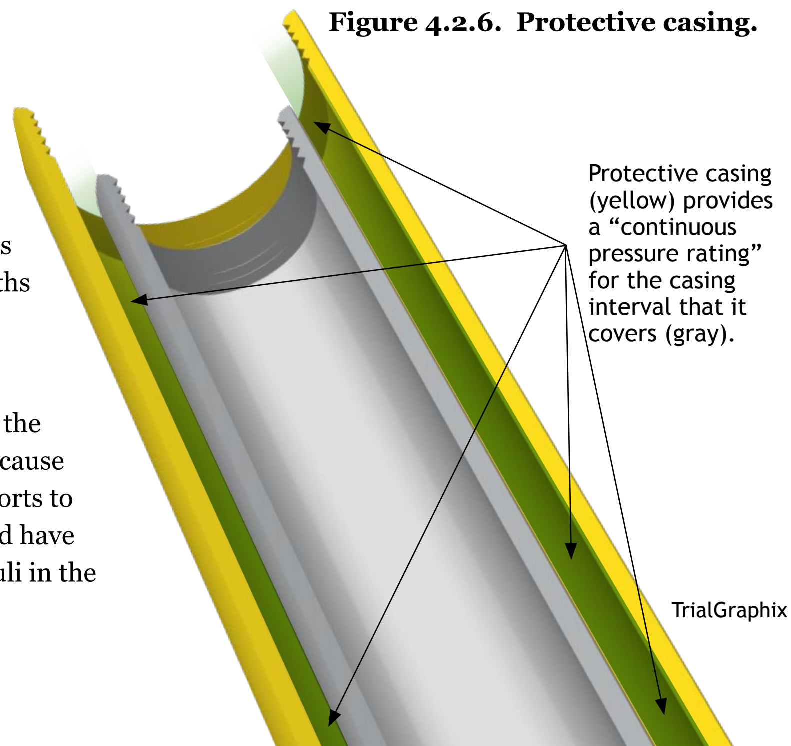
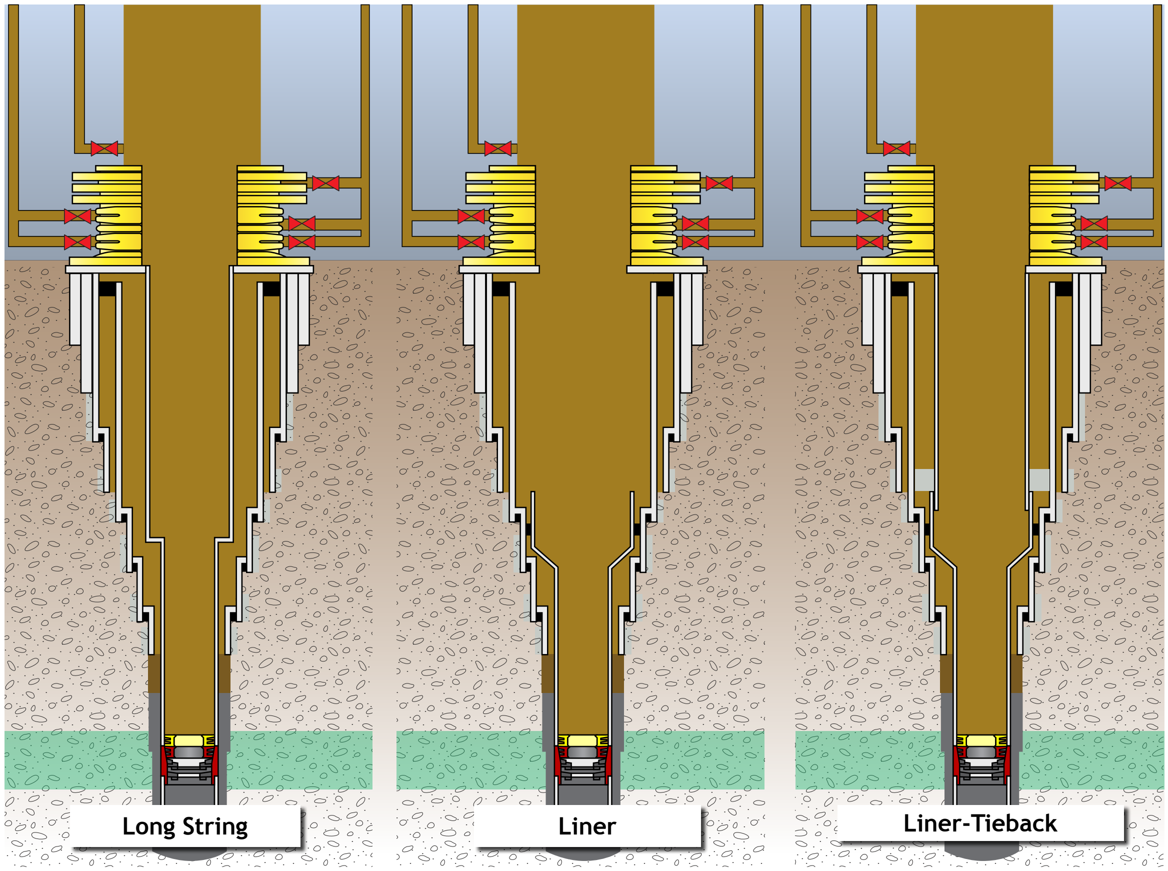


Figure 4.2.7. Casing options in deepwater drilling.



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Long String Production Casing

Third, BP's Macondo well design called for a long string production casing, or **long string**, stretching from the bottom of the well all the way to the wellhead. This was true of the initial well design as well as the final well design.[28]

As shown in Figure 4.2.7, the alternative to a long string production casing would have been a **liner**. A liner is a shorter string of casing hung from a casing hanger lower in the well. In order to connect the liner back to the wellhead, BP would eventually have had to install a **tieback**—a string of casing pipe stretching between the top of the liner on one end to the wellhead on the other end. Setting the tieback adds two annular flow barriers to the well design.

In the weeks just prior to the blowout, BP briefly considered using a liner instead of a long string at Macondo. There is no evidence that the Macondo team ever considered having the *Deepwater Horizon* crew install the tieback before temporarily abandoning the well.[29] They presumably would have left that job for a completion rig.

Drilling the Macondo Well

BP encountered a series of complications while drilling the Macondo well. This included two previous kicks, a ballooning event, lost circulation events, and trouble determining pore pressures (as shown in Figure 4.2.8). Together, these issues made Macondo "a difficult well."[30]

Kicks and Ballooning

Twice prior to April 20, the Macondo well experienced an unwanted influx into the wellbore, or a "kick." On October 26, 2009, the well kicked at 8,970 feet. The rig crew detected the kick and shut in the well. They were able to resolve the situation by raising the mud weight and circulating the kick out of the wellbore.[31] On March 8, 2010, the well kicked again, at 13,305 feet.[32] The crew once again detected the kick and shut in the well.[33] But this time, the pipe was stuck in the wellbore.[34] BP severed the pipe and sidetracked the well.[35]

On March 25 the Macondo well also had a ballooning, or "loss/gain," event. The rig lost fluids into the formation. When the crew decreased the pressure of the mud in the wellbore, the rig then received an influx of fluids from the formation.

Lost Circulation During Drilling

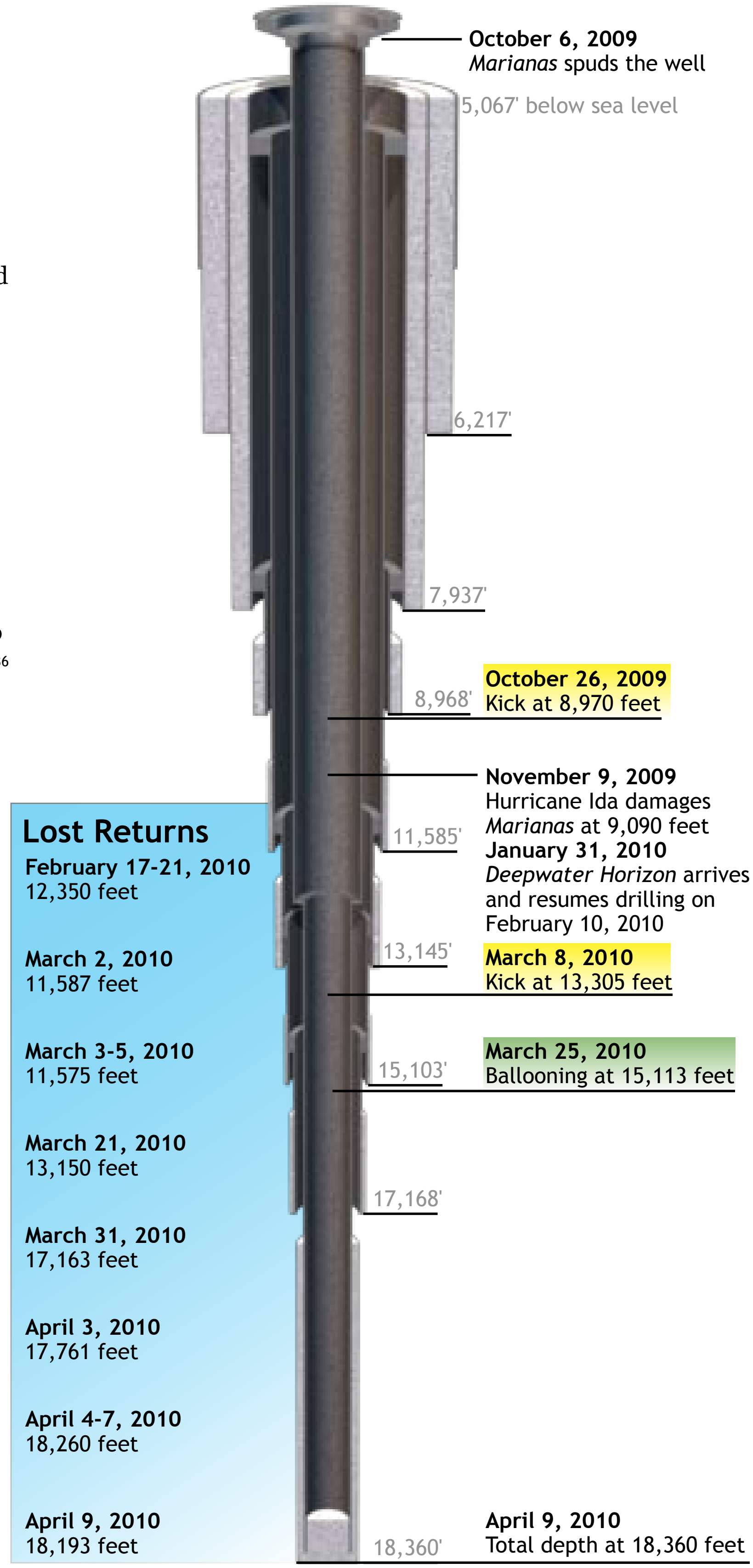
A major risk at Macondo was the loss of drilling fluid into the formation, called **lost circulation** or **lost returns**.[36] At various points in February, March, and April, the pressure of drilling fluid exceeded the strength of the formation, and drilling fluid began flowing into the rock instead of returning to the rig.[37] Lost circulation events are common in offshore drilling. The *Horizon* rig crew generally responded with a standard industry tactic: It pumped thick, viscous fluid known as **lost circulation material** into the well and thereby plugged the fractures in the formation.

The *Horizon* crew successfully addressed repeated lost circulation events while drilling the Macondo well.[38] The events occurred frequently and at various depths, and sometimes lasted several days: once in mid-February, four times in March, and three times in April.[39] In total, BP lost approximately 16,000 barrels of mud while drilling the well, which cost the company more than $13 million in rig time and materials.[40]

Uncertain Pore Pressures Affect the Well Design

The kicks, ballooning, and lost circulation events at Macondo occurred in part because Macondo was a "well with limited offset well information and preplanning pressure data [were] different than the expected case."[41] Given BP's initial uncertainty about the pore pressures

Figure 4.2.8. Timeline of drilling events.



of the rock, the company had to adjust its well design as it drilled the well and gained better pore pressure information.

This was particularly true after the March 8 kick. According to contemporaneous communications among BP engineers, the "kick and change in pore pressure…completely changed" the forward design[42] and did so "rapidly."[43] "Due to well pressure uncertainty, it [was] unknown how many more liners [BP would] need to set before getting to TD."[44] Accordingly, the Macondo team decided to proceed more conservatively and set casing strings shallower in the well.[45] They installed an intermediate 11⅞-inch liner (at 15,103 feet) that had been set aside as a contingency in the original plan.[46] They then set an additional liner, 9⅞ inches in diameter, above the reservoir (at 17,168 feet).[47] And they planned for yet another smaller casing size in the final hole section.[48]

Rig Crew Calls Total Depth Early Due to Narrow Drilling Margin

The last of the lost circulation events occurred on April 9, after the rig had begun to penetrate the pay zone.[49] At 18,193 feet below sea level, the drilling mud pressure exceeded the strength of the formation, and the rig crew observed lost returns. The point at which the formation gave way—when ESD was approximately 14.5 pounds per gallon (ppg)—came as a surprise to the Macondo team.[50] The crew had to stop drilling operations until they could seal the fracture and restore mud circulation. They pumped 172 barrels of lost circulation material down the drill string, hoping to plug the fracture.[51] The approach worked, but BP's onshore engineering team realized the situation had become delicate.[52] In order to continue drilling, they had to maintain the weight of the mud at approximately 14.0 ppg in order to balance the pressure of hydrocarbons pushing out from the formation. But drilling deeper would exert even more pressure on the formation. Engineers calculated that drilling with 14.0 ppg mud would yield an ECD of nearly 14.5 ppg—presenting the risk of once again fracturing the rock and losing returns.[53] At that point, "it became a well integrity and safety issue."[54] The engineers had "run out of drilling margin."[55] The well would have to stop short of its original objective of 20,600 feet.

Rig personnel were able to carefully drill ahead an additional 167 feet and called total depth at 18,360 feet. In that sense, drilling was successful: BP reached the targeted reservoir zone and was able to run a comprehensive suite of evaluation tools.[56]

ECD Concerns Influence Final Production Casing Design

BP engineers then began preparing to install a production casing. BP had Halliburton run a series of computer models to help plan for cementing the production casing.

March 23 Meeting Considers Both Long String and Liner Production Casing

On March 23, Hafle, Morel, and in-house BP cementing expert Erick Cunningham met with Halliburton cementing engineer Jesse Gagliano to discuss ECD concerns in the modeling.[57] The team was trying to decide what size production casing to install and cement at the bottom of the well.[58] Earlier that month, the engineers had modeled both long string and liner production casing designs on two sizes of pipe—7⅝-inch and 7-inch.[59] They were concerned the 7⅝-inch pipe would create a narrow annulus and increase friction to the point that the formation would break.[60] According to Halliburton's models, a smaller 7-inch pipe reduced ECD significantly.[61] Though no decision was made as to casing design or diameter, the group decided to find out how much 7-inch pipe was available should they decide to use that size production casing at the bottom of the well.[62]

April Meetings Finalize Well Design

BP and Halliburton continued to meet and review Halliburton's computer models of the production casing. The team met on April 9 but decided Halliburton's model was inaccurate because it predicted an ESD of 13.9 ppg, which was erroneously low because the weight of the mud in the wellbore was itself heavier than 13.9 ppg.[63] Gagliano created a new model, but on April 12 BP drilling and completions operations manager David Sims determined the ESD in this model was now too *high*[64] and requested that Cunningham review and lend his expertise to the well plan.[65]

At that point, the team considered running a liner instead of a long string in the production interval. The Macondo team believed that ECD would be lower in running the liner.[66] But BP engineering manager John Sprague raised additional technical concerns and requested a review of annular pressure buildup issues related to running a liner.[67]

The potential for a last-minute switch had BP engineers scrambling. Morel asked casing design specialist Rich Miller for a "quick response" on the annular pressure buildup review.[68] "Sorry for the late notice," he added, "this has been a nightmare well which has everyone all over the place."[69] Miller replied, "We have flipped design parameters around to the point that I got nervous," but with respect to annular pressure buildup issues related to the liner he determined "[a]ll looks fine."[70]

Although the onshore engineers had not yet decided the final casing parameters, the rig crew was still supposed to set the casing in a few days, so BP wells team leader John Guide instructed the BP well site leaders on the rig to ready the equipment necessary to run either a liner or a long string.[71] BP had a number of boat and helicopter runs to the rig over the next several days, trying to coordinate the logistics of equipment and people necessary for the upcoming casing and cement jobs. Well site leader Don Vidrine complained to Guide about the last-minute changes. "[T]here [have] been so many last minute changes to the operation that the WSL's have finally come to their wits end," Guide recounted. "The quote is 'flying by the seat of our pants.'"[72]

Transocean also expressed concern to Guide about the long string/liner decision being made "very late in the day."[73] The contractor needed sufficient advance notice to verify logistics and, in particular, that the rig's equipment was fit to handle the final casing string's weight.[74]

Engineers Decide to Run Long String at April 14 Meeting

On April 14, Hafle, Morel, Cunningham, BP operations engineer Brett Cocales, and drilling engineering team leader Gregg Walz met to review Halliburton's ECD modeling.[75] The group identified another limitation of the model—they determined that its data inputs did not reflect the actual latest data acquired during the well logging process.[76] After reassessing well conditions with Cunningham,[77] the team decided they could successfully run and cement a long string.[78]

Several factors appear to have motivated the decision to install and cement a long string production casing:[79] a desire to stick with the original design basis of the well,[80] a desire to mitigate future annular pressure buildup by avoiding a trapped annulus,[81] a desire to eliminate an extra mechanical seal that could leak during production,[82] and a desire to save $7 million to $10 million in future completion costs.[83]

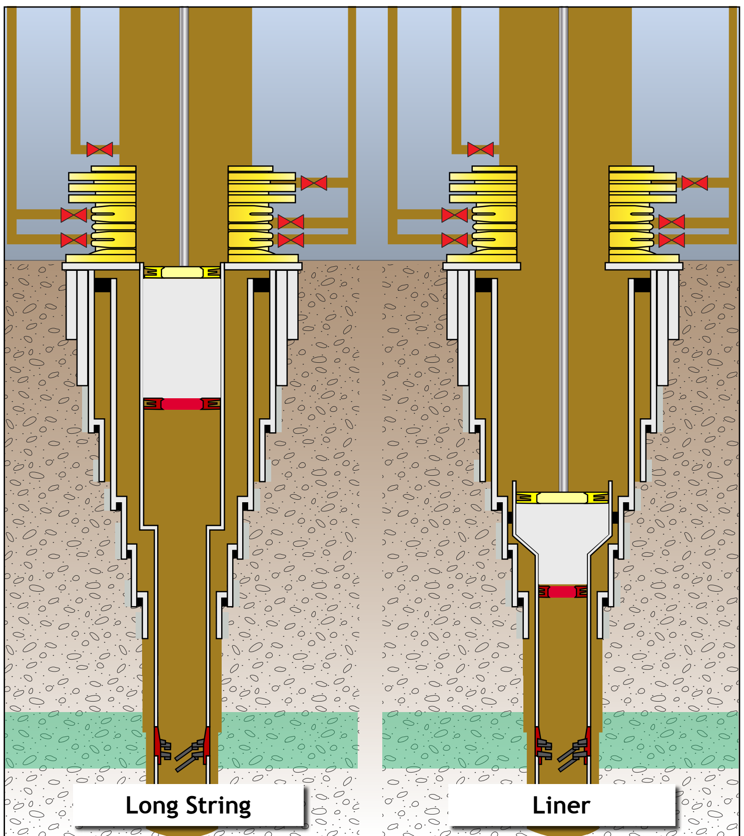
The team made the decision official in a **management of change** (MOC) document—part of BP's process for documenting changes in well design.[84] According to the MOC, the long string provided the best "well integrity case for future completion operations," "the best economic case" for the well, and could be cemented successfully with careful cement job design.[85] The document also discussed the risk that the primary bottomhole cement would not act as a barrier (as discussed in Chapter 4.3).[86] Senior BP managers—including Sims, Walz, Guide, Sprague, and others—reviewed the management of change document and approved.[87]

Technical Findings

Choosing a Long String Production Casing Made the Primary Cement Job at Macondo More Difficult

Operators in the Gulf of Mexico routinely use long string production casings in deepwater wells.[88] But BP's decision to use a long string at Macondo triggered a series of potential problems, particularly with the bottomhole cement job.

Figure 4.2.9. Cementing a long string vs. cementing a liner.



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The lost circulation event at the pay zone in early April led the company's engineers to carefully analyze whether they could circulate cement successfully around the production casing (or liner) without fracturing the already delicate formation. Because cementing a liner is typically easier than cementing a long string, the decision by BP engineers to stay with the long string design further complicated an already complex cement procedure in several ways.[89]

First, the use of a long string increased the risk of cement contamination. Cementing a long string instead of a liner required cement to travel through a larger surface area of casing before reaching its final destination, as shown in Figure 4.2.9. That increased surface area translates into increased exposure of cement to the film of mud and cuttings that adheres to the casing.[90] That risk was exacerbated by the fact that the long string production casing was tapered, making it more difficult for wiper plugs to reliably wipe clean.[91]

Second, using a long string eliminated the possibility of rotating or otherwise moving the casing in place during the cement job. Rig personnel could have rotated a liner, which would have improved the likelihood of a quality cement job.[92] But it is more difficult to rotate a long string than it is to rotate a liner, so choosing that design eliminated one option for mitigating cementing risks.

Third, cementing a long string typically requires higher cement pumping pressure (and higher ECD) than cementing a liner.[93] To compensate for that pressure increase in a fragile wellbore like the one at Macondo, BP engineers made other adjustments to the cement job. As Chapter 4.3 explains, some of the adjustments the engineers made to reduce ECD increased the risk of cementing failure. If BP engineers had chosen to use a liner, they not only could have obtained lower ECDs, but also may have been able to ignore ECD entirely. This is because the liner hanger includes a mechanical seal that serves as a barrier to annular flow.[94] By relying on that seal, engineers can design a more robust primary cement job—they can, for instance, deliberately exceed ECD limits, risk lost returns, and then plan to remediate cement problems later without having to rely on the cement as a barrier to flow.[95]

Fourth, it is harder to remediate a cement job at the bottom of a long string than it is to remediate one at the bottom of a liner. With a liner, rig personnel can remediate the cement job, before completing the setting of the liner, by lifting the stinger above the liner hanger and pumping additional cement over the top of the liner hanger.[96] That method is more effective and less complex than remediating a long string.[97] With a long string, rig personnel must perform a squeeze job (as defined in Chapter 4.3). A squeeze job is complicated and time-consuming—it can take several days.[98] And BP classifies the time spent squeezing as nonproductive time,[99] an undesired disruption that the company expects its employees to minimize.[100]

BP's Design Efforts to Mitigate the Risk of Annular Pressure Buildup Compromised Containment Operations

BP's decision to install rupture disks at Macondo and not to use a protective casing complicated its containment efforts and may have delayed the ultimate capping of the well. (Commission Staff Working Paper #6, titled "Stopping the Spill: the Five-Month Effort to Kill the Macondo Well," discusses these issues in more detail.) Had BP's design omitted the disks and included the casing, the company would have had increased confidence about the Macondo well's integrity. This, in turn, may very well have allowed the company to shut in the well earlier.

In BP's early analyses of its failed late-May top kill attempt, the company concluded that the rupture disks in the 16-inch casing may have collapsed inward during the initial blowout.[101] The disks could have collapsed if hydrocarbons had entered the annular space between the 16-inch casing and the production casing. Those hydrocarbons would have been much lighter than the heavy drilling mud that would have been in the annular space outside the 16-inch casing. That weight difference would have generated a pressure differential significant enough to collapse the rupture disks.[102]

Based on this theory, as well as pressure readings and visual observations from the field,[103] BP concluded that its top kill operation may have failed because the mud it pumped down the well had flowed out through the collapsed rupture disks rather than remaining within the well as intended.[104] Although BP vice president of engineering Paul Tooms emphasized several months later that rupture disk collapse was just one of several theories that could have explained the top kill results,[105] BP presented the theory to the government as the most likely scenario and changed its subsequent containment strategy to reflect it.[106] Although the government remained skeptical of certain elements of BP's analysis,[107] it too believed the rupture disks may have collapsed and that emergency workers needed to consider that possibility when moving forward.[108]

Before the top kill operations, BP had told Interior Secretary Ken Salazar and Energy Secretary Steven Chu that if the top kill failed, the company might try next to cut the riser, remove the lower marine riser package, and install a second blowout preventer on top of the existing one to shut in the well.[109] But BP and others deemed this approach unwise after theorizing that the rupture disks had collapsed.[110] If hydrocarbons had entered the annular space between the production casing and 16-inch casing and the rupture disks had collapsed, capping the well might divert hydrocarbon flow out the rupture disks and sideways into the rock formation around the well. This would have caused a "subsea blowout" in which hydrocarbons would have flowed up to the surface through the rocks below the seafloor. It would have been nearly impossible to contain that flow. To avoid this situation, BP and the government temporarily stopped trying to shut in the well.

A few weeks after the top kill operation, in mid-June, BP and the government revisited the idea of shutting in the well, this time using a tight-fitted capping stack. Although BP was prepared to install the capping stack in early July,[111] it appears that the government delayed installation for a few days to further analyze the stack's impact on the risk of a subsea blowout.[112] The government's team insisted on monitoring for signs of a subsea blowout using several different methods. BP eventually used ships and remotely operated vehicles (ROVs) to gather visual, seismic, and sonar information about the area around the well. It also used wellhead sensors to monitor acoustic and pressure data. All of these efforts were aimed at determining whether the Macondo well lacked the integrity to prevent oil from flowing sideways into the rock.[113] The government and BP were also concerned that closing the capping stack could increase pressures inside the well sufficiently to create new problems or burst the rupture disks (if they had not already collapsed).[114]

Management Findings

BP Appears to Have Sought the Long-Term Benefits of a Long String Without Adequately Examining the Short-Term Risks

BP engineers displayed a strong and perhaps unwarranted bias in favor of using a long string production casing.

Industry experts have stated that successfully cementing a long string casing is a more difficult enterprise than cementing a liner. BP's own engineers appear to have agreed—they considered using a liner as a means of mitigating the risks of losses during cementing. (Chapter 4.3 discusses this issue in more detail.) BP asked Halliburton to run numerous computer cementing models in an effort to find a way to make the long string casing a viable option. They appear to have approached the problem by trying to find a way to make a long string work instead of asking what design option would best address the cementing difficulties they faced.

BP has argued that its team preferred to use a long string casing because a long string offers better long-term well integrity than a liner-tieback. This may be so. But because the Macondo team did not adequately appreciate the risks of a poor cement job (as described in Chapter 4.3), they could not adequately have compared the risks and benefits of using a long string casing at Macondo. BP engineers appear to have been reluctant to switch to a liner for other reasons as well. They had already obtained peer review and approval of the long string design. And the long string approach costs substantially less than the liner.

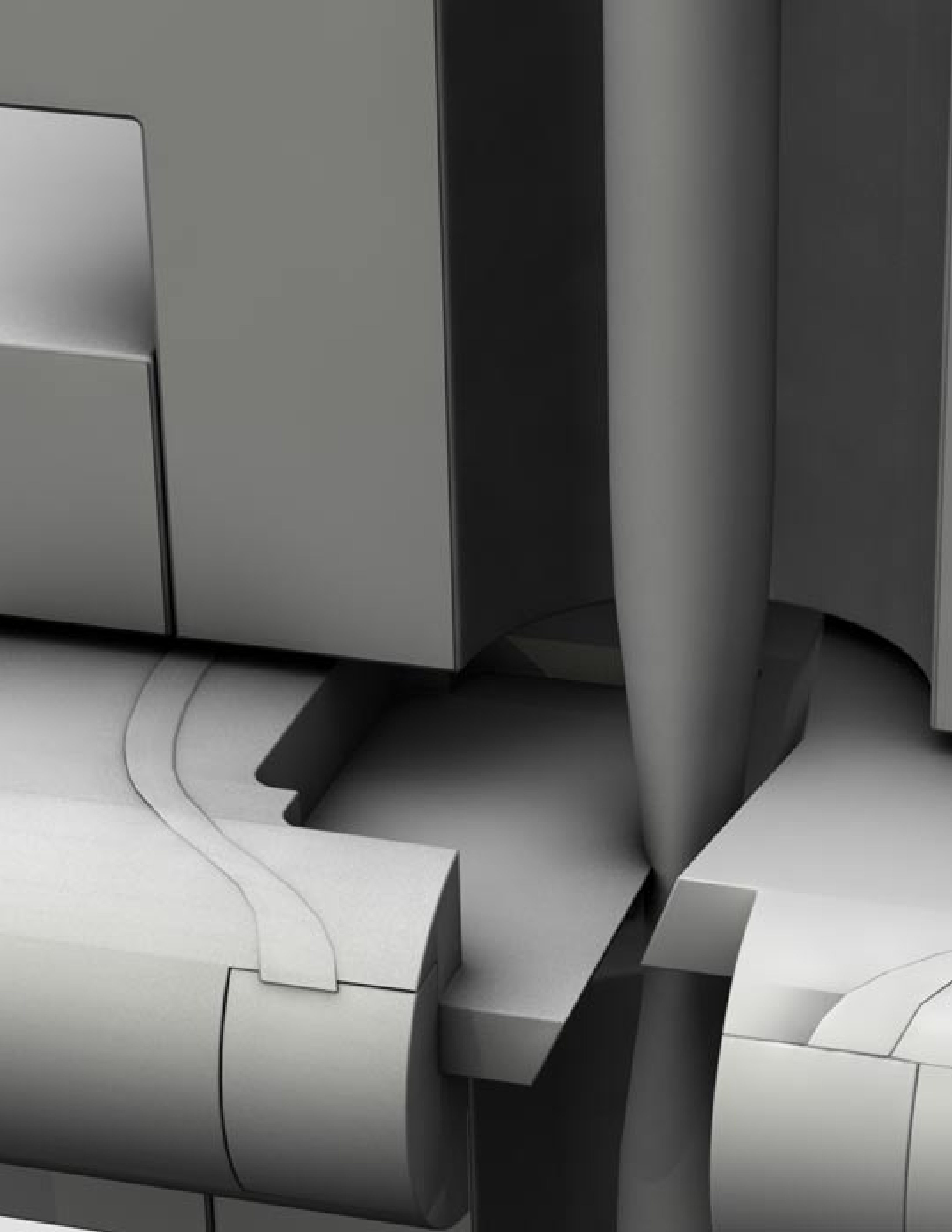
BP's Special Emphasis on the Risk of Annular Pressure Buildup Overshadowed Its Identification and Mitigation of Other Risks

BP made several of the well design decisions discussed above in order to mitigate the risk of annular pressure buildup. Proper well design requires consideration of annular pressure buildup if the company plans to use the well for production.[115] But BP was particularly sensitive to the issue because of its experience at the Marlin platform at the Atlantis field.[116] BP attempted to mitigate the risk of annular pressure buildup in its Marlin wells by leaving the casing annuli open to the surrounding formation. But in late 1999, one of those wells nevertheless collapsed due to annular pressure buildup.[117] Debris or sediments had apparently plugged the opening in the relevant annulus. The event was a major loss for BP because casing collapse essentially destroys a well.[118]

In the aftermath of the Marlin incident, BP made it a top priority to minimize the risk of annular pressure buildup in its wells.[119] It created a dedicated group of design specialists who analyzed annular pressure buildup issues for every production well and recommended design features to mitigate those risks.[120] BP also developed standard guidance instructing its engineers to leave annuli open as part of a deepwater well's design.[121] And it encouraged the use of rupture disks as a primary annular pressure buildup mitigation measure.[122]

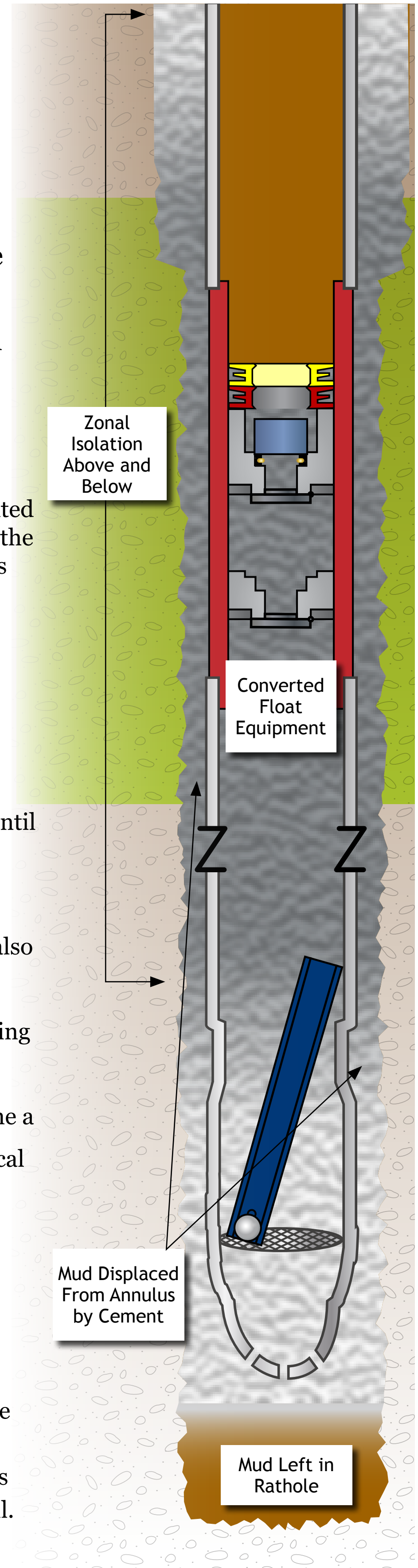
BP's focus on and approach to annular pressure buildup concerns effectively de-emphasized other risks and discouraged certain well design approaches. Because the Macondo team planned the well as a producer, they made several design decisions to mitigate the risk of annular pressure buildup.[123] These included adding rupture disks in the 16-inch casing, omitting a protective casing (which would have created a trapped annulus), leaving an open annulus below the 9⅞-inch liner, and using a long string production casing instead of a liner.[124] As described above, those design features complicated the cement job as well as post-blowout containment efforts.

While BP's methods of mitigating annular pressure buildup created risks, there were alternatives. For example, BP could have used insulated production tubing to protect the well from the heat generated during production. This might have allowed the company to omit burst disks and include a protective casing. BP could also have pumped compressible fluids (such as nitrogen foamed spacer or syntactic foam) into any trapped annular spaces to mitigate the risk of annular pressure buildup rather than designing its well to eliminate such spaces. This approach would have allowed BP to use a liner-tieback without worrying that the tieback would create a trapped annulus.[125]



Chapter 4.3 | Cement

Figure 4.3.1. Typical completed cement job.



Well Cementing

Cement performs several important functions in an oil well. It fills the annular space between the outside of the casing and the formation. In doing so, it structurally reinforces the casing, protects the casing against corrosion, and seals off the annular space, preventing gases or liquids from flowing up or down through that space. A cement job that properly seals the annular space around the casing is said to have achieved **zonal isolation**.

The cementing process is procedurally and technically complex. This chapter first describes the steps in the cementing process, the ways in which cement can be evaluated and remediated, and methods for laboratory cement slurry testing. It then describes the Macondo cementing operation in detail. Finally, it sets out the Chief Counsel's team's technical and management findings regarding the Macondo cementing process. The Chief Counsel's team finds that the Macondo cement failed to achieve zonal isolation. While the Chief Counsel's team cannot be sure why the cement failed, the team has identified several risk and other factors that may have contributed to cement failure, either alone or together.

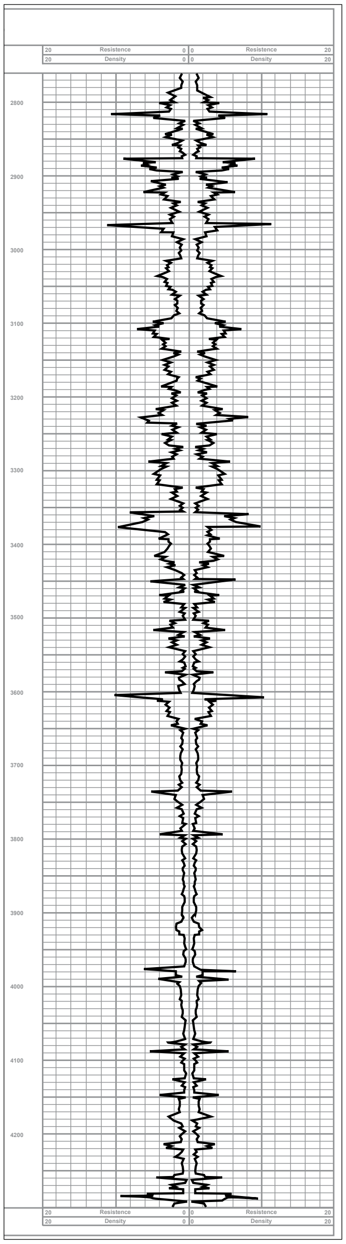
The Cementing Process

The cementing process involves pumping cement down the inside of a casing string until it flows out the bottom and back up into the annular space around the casing string. Achieving zonal isolation requires several things.

- First, the cement should fill the annular space in the zone to be isolated and also a specified space above and below that zone.
- Second, cement flowing into the annular space should displace all of the drilling mud from that space so that no gaps or uncleared **channels** of mud remain behind. If mud channels remain after the cement is pumped, they can become a flow path for gases or liquids from the formation. Good mud removal is critical for a successful cement job.[1]
- Third, the cement should be formulated so that it sets properly under wellbore conditions.

Although each cement job presents unique challenges, the principal steps involved in pumping cement at Macondo were the same as those for most deepwater wells. The following subsections describe the process in simplified form. These sections describe the process for running and cementing a production casing—the last casing string to be run in the well once a hydrocarbon-bearing zone has been penetrated. The process generally applies to running and cementing shallower casing strings and liners as well.

Figure 4.3.2. Sample caliper log data showing open hole diameter by depth.



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Primary Cementing. Primary cementing refers to an operator's initial attempt to seal a casing with cement. By contrast, **remedial cementing** refers to subsequent cementing efforts undertaken if the primary cement does not achieve zonal isolation.

Logging and Mud Conditioning

After rig personnel finish drilling a well that will be completed as a production well, they typically **condition** the mud in the wellbore and then log the wellbore itself before lowering the final production casing and performing the final cement job.

During drilling operations, mud engineers manipulate the characteristics of drilling mud in the wellbore to optimize the removal of cuttings and to maintain hydrostatic pressure in the well. At the end of drilling operations, the mud is normally circulated to homogenize its properties and modify those properties as necessary to facilitate wellbore logging and eventual mud removal. That circulation process is called mud conditioning. Drillers normally circulate the mud in order to remove cuttings from the mud and ensure that it displays uniform and appropriate density and viscosity characteristics.[2] American Petroleum Institute (API) recommendations state:

> Well preparation, particularly circulating and conditioning fluids in the wellbore, is essential for successful cementing. Many primary cementing failures are the result of fluids that are difficult to displace and/or of inadequate wellbore conditioning.[3]

Logging refers to the process of examining and recording the characteristics of the wellbore (first discussed in Chapter 2). Prior to running a production casing string, drillers typically examine the open section of the wellbore with an extensive suite of logging tools that use electric, sonic, and radiologic sensors to measure the physical characteristics of the formation and any fluids it might contain in order to learn as much as possible about the nature of the hydrocarbon-bearing formation.[4] One such tool, shown in Figure 4.3.2, is a **caliper log**, which measures the diameter of the wellbore. Because the wellbore diameter can vary significantly as a result of normal drilling variations, these data can be an important input in designing and modeling a primary cement job.

Lowering the Production Casing String in Place With Centralizers

After logging is complete, rig personnel lower the production casing into place. During this process, they may install **centralizers** , shown in Figure 4.3.3, which serve an important role in the cementing process.

Figure 4.3.3. Centralizer.

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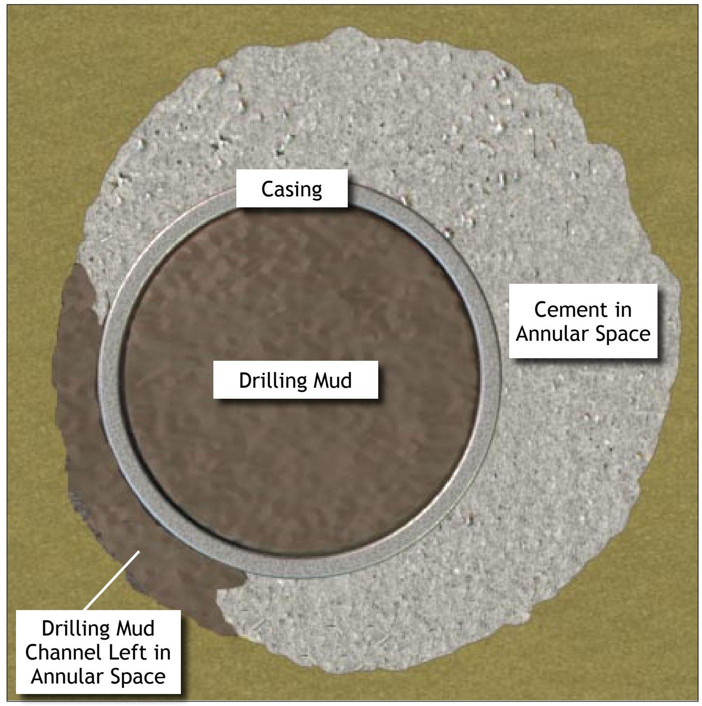
When the cementing crew pumps cement (or any other fluid) down the production casing and back up the annular space around it, the cement tends to flow preferentially through paths of least resistance. When the casing is not centered in the wellbore, the wider annular space becomes the path of least resistance,[5] shown in Figure 4.3.4. Cement tends to flow up through those spaces. This can seriously compromise mud removal and leave channels of mud behind in the narrower annular spaces.[6] Because of this problem, cementing experts consistently emphasize the importance of keeping the casing centered in the wellbore.[7]

Figure 4.3.4. Top view of off-centered casing.



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Centralizers help keep the casing as close to the center as possible. They come in a variety of designs. Centralizer **subs**, shown in Figure 4.3.5, may be screwed between casing sections while bow spring centralizer **slip-ons** are attached to the outside of existing casing using collars. Sometimes **stop collars** (so named because they stop the centralizer from sliding up or down the casing) are separate pieces from the centralizer; sometimes they are integrated into the centralizer itself.[8]

Engineers measure the degree to which a pipe is centralized in a wellbore by calculating the "pipe standoff ratio."[9] A perfectly centered casing has a standoff ratio of 100% while a casing that touches the walls of the wellbore has a standoff ratio of 0%. Although the industry rule of thumb is to achieve a standoff of 75%,[10] cementing experts state that operators should achieve the highest possible standoff in order to facilitate mud displacement from the annular space.[11] Engineers must calculate the standoff not only at each centralizer location, but also between the centralizers. Casing can bend and sag between centralizers, dramatically lowering the standoff in the intervals between them.[12]

Float Valves and Float Valve Conversion

Illustrated in Figure 4.3.6, float valves are one-way valves (also called check valves) installed at or near the interior bottom end of a casing string. Once operational, float valves permit fluid (such as mud or cement) to flow down through the inside of the casing while preventing fluids from flowing in the reverse direction back up the inside of the casing. By doing so, float valves prevent cement that is pumped down through the casing, into the shoe track, and up into the annular space from flowing back up through the valves once the cement is in place, an occurrence known as "reverse flow" or "u-tubing."[13]

Shoe and Shoe Track. The **shoe** refers to the bottom of the casing. The **shoe track** is the section of the casing between the shoe and the float valves above it.

Figure 4.3.5. Centralizer sub.

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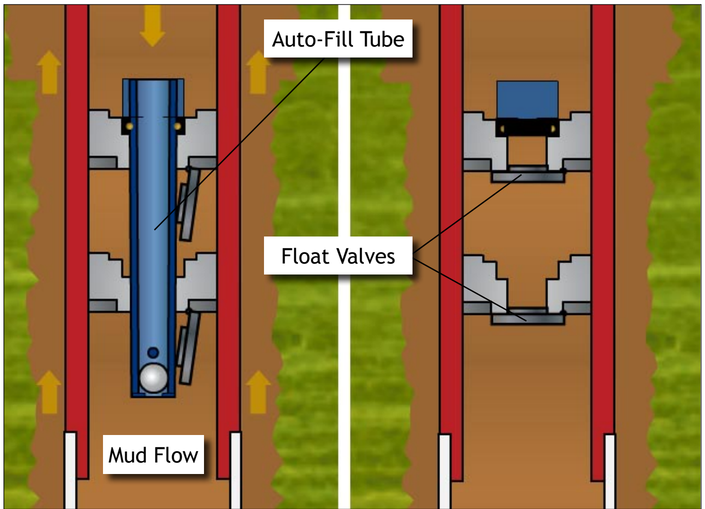
A **float check** examines whether the float valves are working properly—that is, preventing cement from flowing back up through the valves due to u-tube pressure. **U-tube pressure** is created by the differential hydrostatic pressure between the fluid column inside the casing and the fluid column in the annulus. In cases where the cement density is close to drilling mud density, the u-tube pressure may be very small—too small to induce backflow or to be detected at the rig. The smaller the density differential between the cement and mud, the smaller the u-tube pressure and its expected effects.[14]

Float valves are important during the cementing process but can interfere with the process of lowering a casing string. As the casing string is lowered, it is generally preferable that mud be allowed to flow up the inside of the casing string. Otherwise, the casing will, as it descends, force mud down the well and back up through the annular space, greatly increasing the pressure that the casing string exerts on the formation as it is lowered.[15]

Figure 4.3.6. Float valve conversion.



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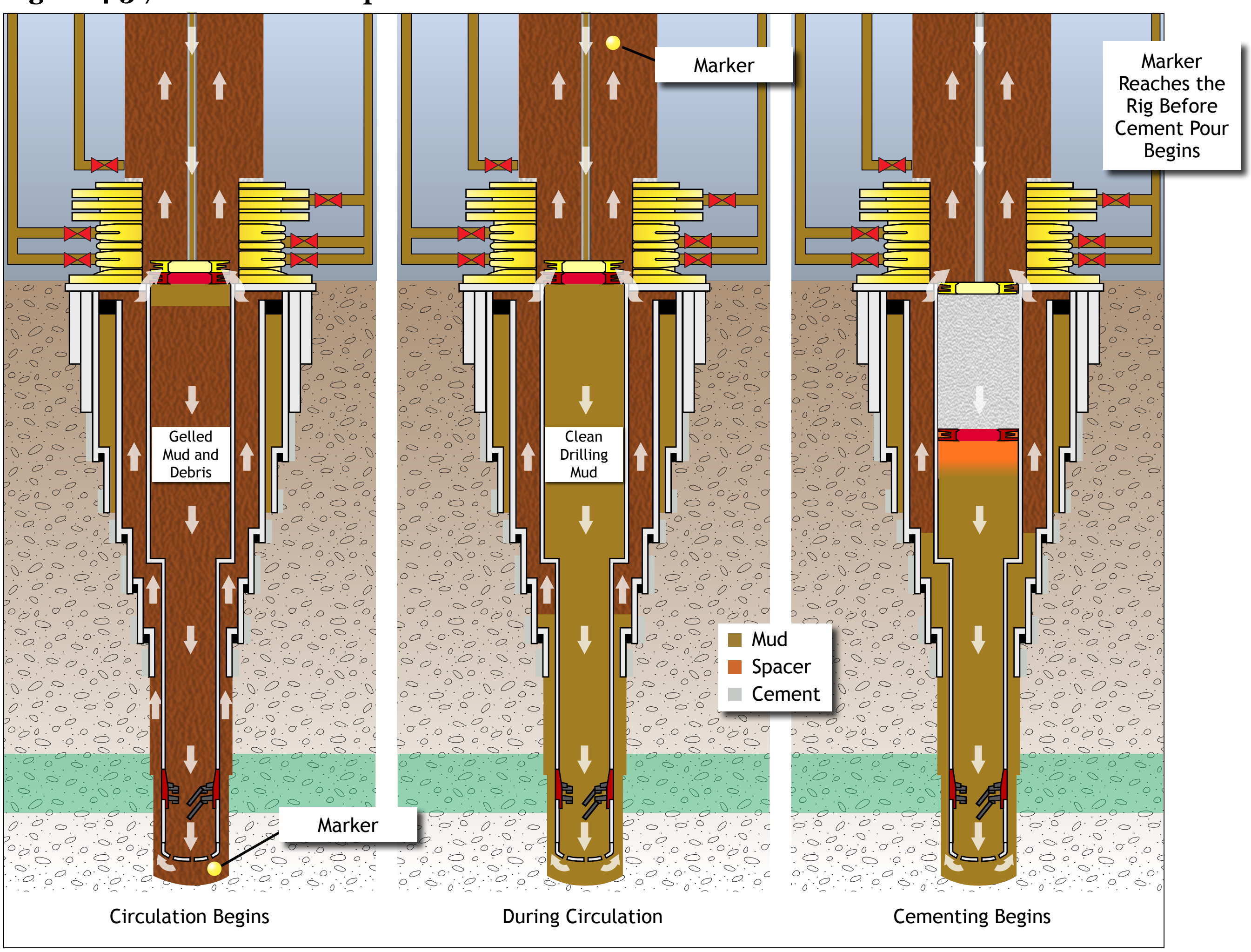
To allow mud to flow into the casing string while it is being lowered, operators typically use an **auto-fill tube**. An auto-fill tube is a hollow tube that extends through and props open the two float valves, allowing mud to flow up through the casing while the casing is being run into the well. Once rig personnel finish lowering the casing, they **convert** the float valve assembly by pushing the auto-fill tube down and out of the float valves. This allows the float valves to close, converting them into one-way valves before cementing begins.

Wellbore Conditioning

After converting the float valves, rig personnel normally circulate mud through the newly installed casing and wellbore again. Like the earlier mud circulation process, this has at least two benefits. First, it cleans the casing, drill pipe, and wellbore of cuttings, gelled mud, and other debris that can interfere with good cement placement and performance.[16] Second, the mud flow conditions the mud itself by breaking its gel strength, decreasing its viscosity, and increasing its mobility.[17]

Figure 4.3.7. Full bottoms up.



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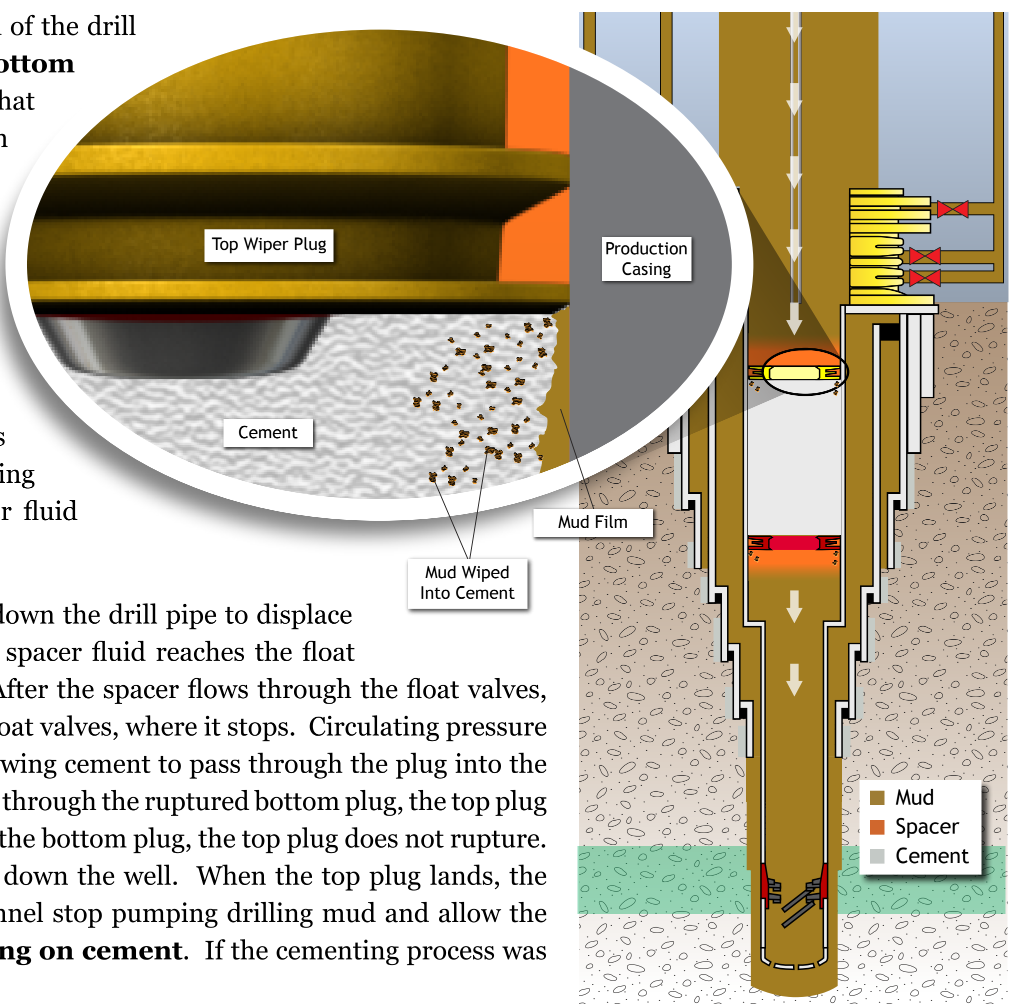
Under optimum conditions, operators prefer to circulate enough drilling mud through the casing after landing it to achieve what is known as a full **bottoms up**.[18] Circulating bottoms up means that the rig crew pumps enough mud down the well so that mud originally at the well bottom returns back to surface[19] as shown in Figure 4.3.7. The extended circulation required to do this confers a third benefit in addition to the two described above: It allows rig crews to physically inspect mud from the bottom of the well for the presence of hydrocarbons before cementing.

Pumping Cement

After completing the pre-cementing mud circulation, rig personnel pump cement down the well, then pump additional drilling mud behind the cement to push (or **displace**) the cement into the desired location at the bottom of the well. As they pump the cement, rig personnel must ensure that the oil-based drilling mud does not contaminate the water-based cement. The oil and gas industry has developed a variety of techniques to ensure that this does not occur. Rig personnel at Macondo used a common approach called the "two-plug method."[20] The two-plug method uses rubber **darts** and **wiper plugs** to separate the cement from the drilling mud as the cement travels down the well.

Rig personnel begin the cement pumping process by pumping water-based **spacer fluid** down the drill pipe. They then drop a **bottom dart** into the drill pipe, followed by the cement, then a **top dart** and more spacer fluid. After pumping the final spacer fluid down the drill pipe, rig personnel resume pumping drilling mud to push the spacer-dart-cement-dart-spacer train down the drill pipe.

Figure 4.3.8. Wiper plugs cause cement contamination.



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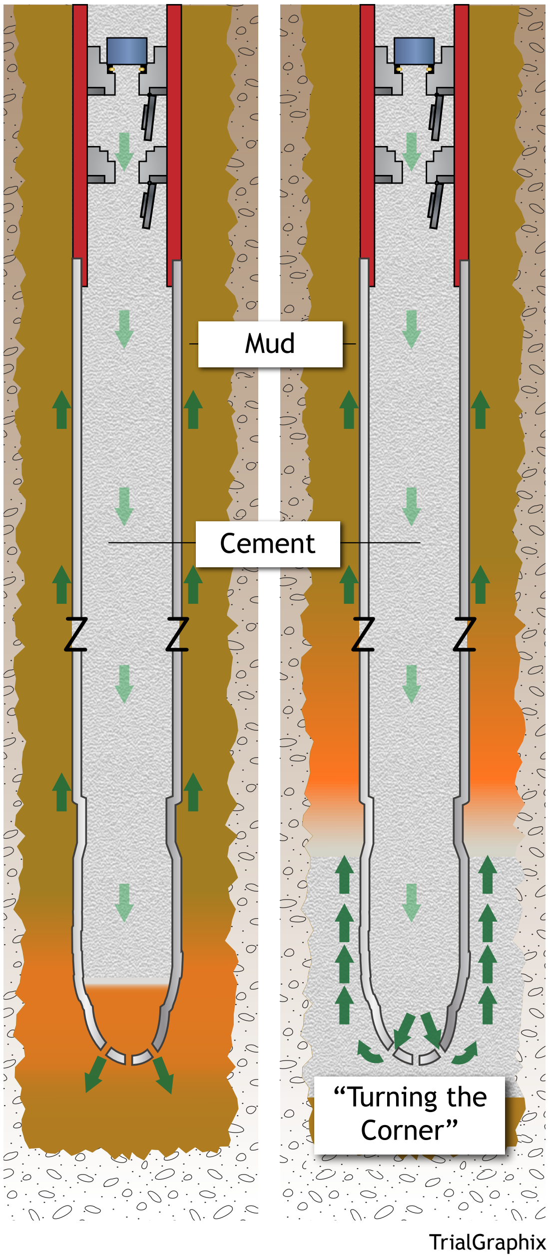
When the bottom dart reaches the end of the drill pipe, it fits into and launches a **bottom wiper plug** from the running tool that attaches the drill pipe to the production casing. The bottom plug then travels down inside of the production casing, separating the cement behind it from the spacer fluid and drilling mud ahead. Similarly, when the top dart reaches the end of the drill pipe, it launches a **top wiper plug** from the running tool. The top plug also travels down the inside of the production casing and separates the cement from spacer fluid and drilling mud behind.

The rig crew continues to pump mud down the drill pipe to displace the cement into position. Eventually, spacer fluid reaches the float valves and flows through the valves. After the spacer flows through the float valves, the **bottom plug** lands on top of the float valves, where it stops. Circulating pressure causes the bottom plug to rupture, allowing cement to pass through the plug into the shoe track. After all of the cement flows through the ruptured bottom plug, the top plug lands on top of the float valves. Unlike the bottom plug, the top plug does not rupture. It instead blocks further flow of fluids down the well. When the top plug lands, the cement should be in place. Rig personnel stop pumping drilling mud and allow the cement to set in a process called **waiting on cement**. If the cementing process was

Figure 4.3.9. Lift pressure.



Pressure increases to lift cement in the annulus.

designed and executed properly, the cement should at this point fill the shoe track and should cover the hydrocarbon zone in the annular space outside the production casing.

Even if rig personnel execute a two-plug cementing process precisely according to plan, cement can still be contaminated by drilling mud. As the wiper plugs travel down the casing, they wipe a film of mud away from the casing walls. The bottom plug removes most of the mud film but not all of it. The remaining mud film can contaminate the cement between the plugs as shown in Figure 4.3.8. The top plug also wipes the casing, but instead of wiping mud out of the way of the cement, it wipes that mud *into* the back portions of the cement flow.

The casing shoe track is designed to provide room for contaminated cement at the tail end of the pumping process. Absent a shoe track, that contaminated cement would travel into the annular space, potentially compromising zonal isolation.

Cement Evaluation

It is not easy for rig personnel to be sure about the progress or final result of a cement job at the bottom of a deepwater well. Cement does its work literally miles away from the rig floor, and there is no way to observe directly if the cement slurry arrives at its intended location, let alone whether it is contaminated or otherwise compromised. As a result, rig personnel cannot know whether the cement will isolate the well from the hydrocarbons in the reservoir as they pump the cement.

Because cementing is difficult to observe directly, the oil and gas industry has developed a number of methods for evaluating cement jobs indirectly. And because proper cementing is critical to well integrity, the API calls proper cement evaluation "indispensable."[21] But each of the various methods of cement evaluation has limitations, and the API standard on cement evaluation therefore notes:

> Anyone who wants to competently evaluate the quality of a cement job must thoroughly understand all the variables, assemble and comprehend the relevant pieces of information, and reach the proper judgment.[22]

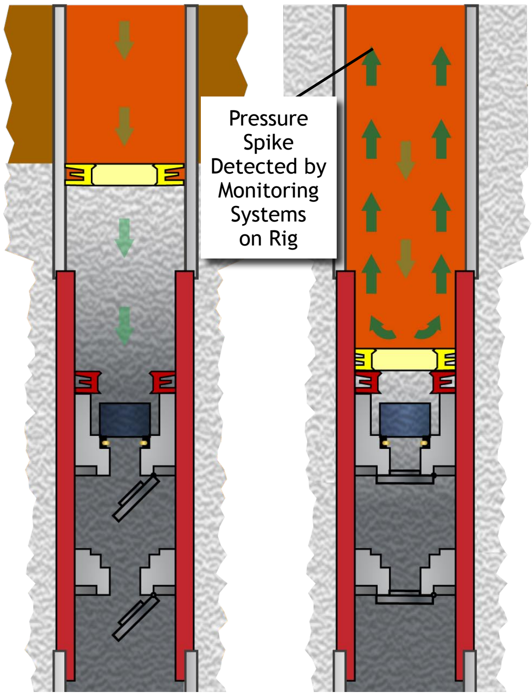
By understanding the full set of variables at play for a particular cement job, the right mix of tools can be employed to evaluate the cement.

Volume and Pressure Indicators

While pumping a cement job, a cementing crew knows only how much cement and mud they have sent down the well and how hard the pumps have been working to push it. Using these volume and pressure readings, the rig crew looks for three general indicators of success during the job: full returns, lift pressure, and on-time plug landing.

A cementing crew gets **full returns** when the volume of mud returning from the well during a cement job equals the volume of fluids (spacer, cement, and mud) pumped down into the well. To determine whether they are getting full returns, the cementing crew monitors mud tank volumes.

Figure 4.3.10. Bumping the plugs.



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If the volume of fluid flow into the well equals the fluid flow out, the crew can infer that the well is behaving properly as a closed and leak-free container. If flow out is less than flow in, the crew has **lost returns** or **lost circulation**, and can infer that mud and/or cement has flowed into the formation.[23] The crew cannot tell *where* the rock fractured, however, and where the mud might have gone.[24]

Lift pressure, shown in Figure 4.3.9, is a steady increase in pump pressure that begins when the cement flows out the bottom of the well casing and "turns the corner" to flow upward against gravity. The pressure increases because cement is generally heavier than drilling mud (and has a different viscosity). If the cementing crew observes a steady pressure increase at the appropriate time after pumping cement down into a well, they can infer that the increase is lift pressure and that cement has arrived at the bottom of the well and has begun flowing upward into the annular space. Seeing the expected lift pressure also allows the crew to infer that cement is not being lost into the formation.

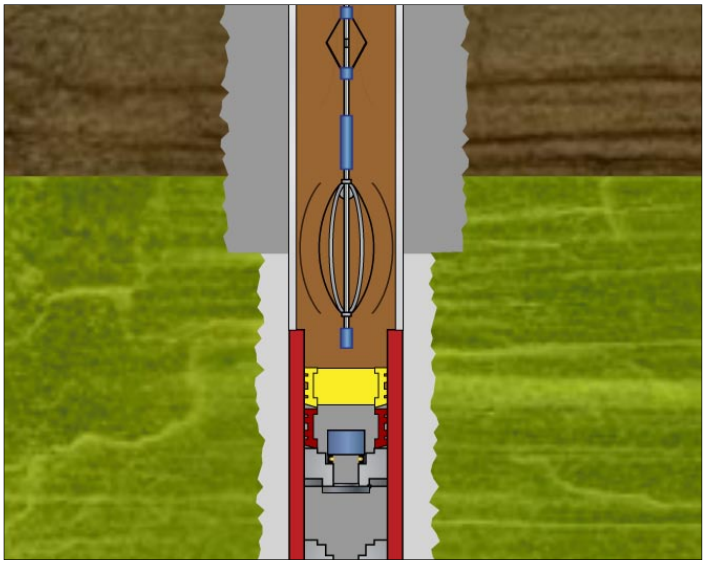
Finally, the rig crew can also watch pressure gauges to infer whether the wiper plugs used to separate the cement from surrounding drilling mud have **landed** or **bumped** on time at the bottom of the well as shown in Figure 4.3.10. By calculating the volume of the inside of the well and the rate at which they are pumping fluids into it, cementing crews can predict when the bottom plug and top plug should land. They then watch the rig's pressure gauges for telltale pressure spikes that indicate when the plugs actually land. If the pressure spikes show up when expected, the cementing crew can infer that the plugs landed properly, that cement arrived at the bottom of the well and flowed out of the shoe track into the annulus, and that substantial volumes of mud did not contaminate the cement as it moved down the well. If the pressure spikes do not appear on time, that suggests problems. For instance, large volumes of mud may have bypassed one or both of the wiper plugs. (Some volume of mud always bypasses the plugs; the plugs do not wipe the casing walls perfectly.)[25]

While pressure and volume indicators can suggest that a cement job has gone as planned, they do not give cementing crews any direct information about the location and quality of the cement at the bottom of the well. In particular, they do not indicate whether there has been channeling in the annulus or shoe track, or the location of the **top of cement** (TOC) in the annulus.[26] These indicators also are not sensitive to all of the issues that can cause cement to fail.

Cement Evaluation Logs

Because pressure and volume readings during the cement job are imperfect indicators of cementing success, the oil and gas industry has also developed tools for more directly examining a cement job after it is pumped. These cement evaluation tools generate data, or "logs," known as cement evaluation logs. Technicians commonly lower cement evaluation tools down inside the well on a **wire line.**[27] Once the tools reach an area that has been cemented, sensors in the tools probe the integrity of the new cement, measuring whether and to what extent the cement has

Figure 4.3.11. Cement bond log tool.



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filled the annular space between the cement and the formation.[28]

The most basic element in a cement evaluation system is the **cement bond log** tool.[29] The cement bond log tool works by measuring the well casing's response to acoustic signals. The tool includes an acoustic transmitter and receiver that are separated from each other by several feet of distance. The transmitters emit bursts of acoustic waves, and the receivers record the reverberations from those waves[30] as illustrated in Figure 4.3.11. Because steel casing, set cement, and fluids all respond differently to the waves, a technician can use the recordings to evaluate the quality of the cement job, just as one can discern a muffled bell from a free-swinging bell by ringing it.[31]

Modern cement evaluation systems combine the fairly straightforward cement bond log with variable-density logs,[32] ultrasonic imaging tools, and flexural attenuation logs.[33] By interpreting the combined data from these tools, a technician can assess the amount and quality of the cement in the annular space,[34] including the TOC and the location and severity of channels in that cement.[35]

Although modern cement evaluation logs have become increasingly sophisticated and reliable, they still have limits.[36] First, they are not easy to read; it takes an experienced technician to properly interpret the data. Second, very low-density cement, such as cement produced with nitrogen foam technology, can be difficult to evaluate with these tools.[37] (The density of the foamed cement at Macondo was not low enough to cause evaluation difficulties, however.[38]) Third, cement evaluation tools must be adjacent to annular cement in order to examine it. That means that the tools cannot evaluate cement in the shoe track or in the annular space below the float equipment. Float equipment and the shoe track cement block the tools from physically accessing those areas. Fourth and finally, cement evaluation logs work best after cement has completely hardened—a process that can take more than 48 hours.[39] Consequently, operators typically do not run cement evaluation logs until completion operations.

Additional Methods

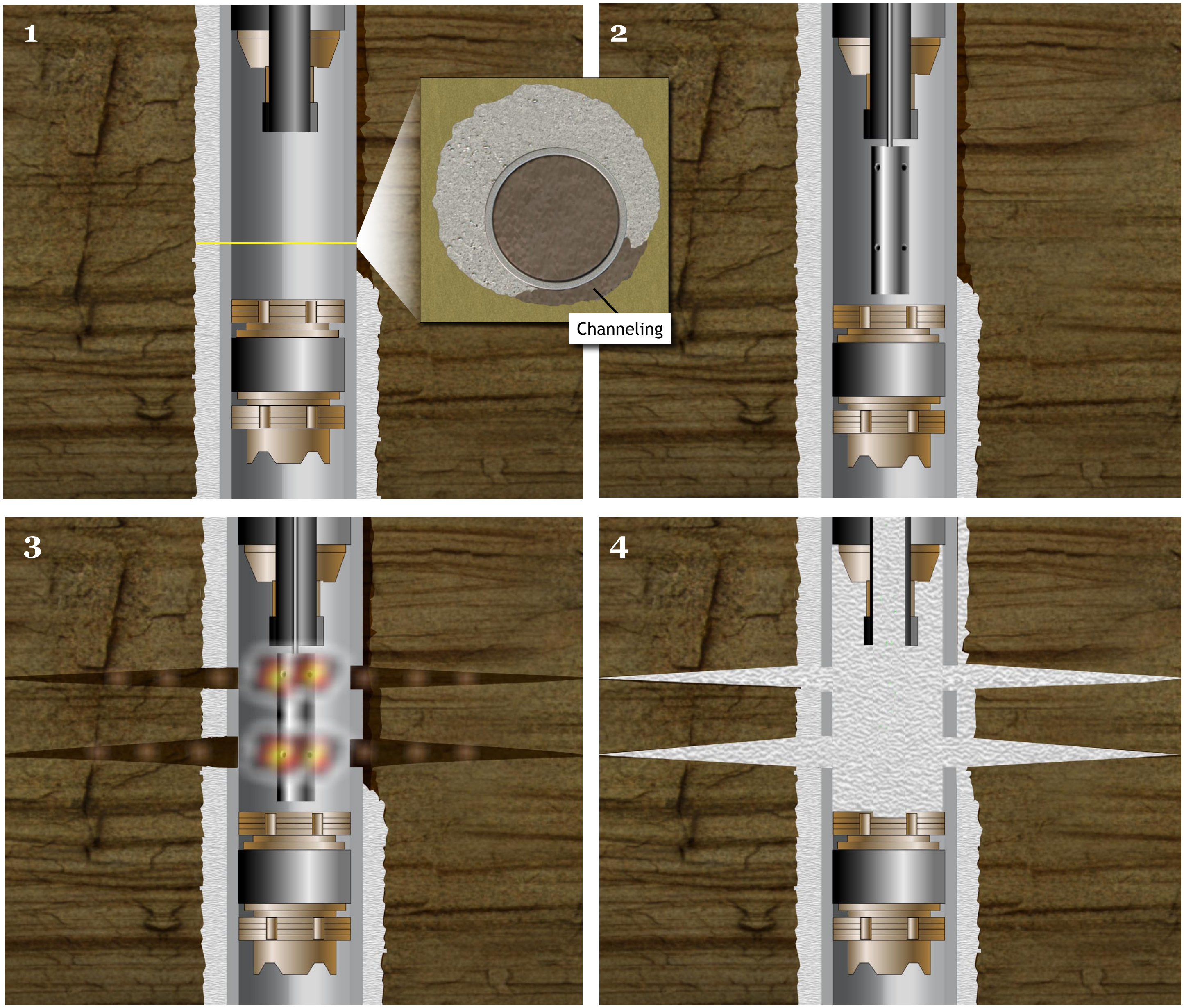
There are other methods to evaluate a cement job in addition to cement evaluation logs and pressure and volume indicators. In particular, a negative pressure test assesses whether a bottomhole cement job contains pressures outside the well and seals the well off from formation pressure. Chapter 4.6 of this report discusses negative pressure tests in detail.

Remedial Cementing

If cement evaluation reveals problems with the primary cement job, rig personnel can **remediate** the primary cement after pumping it. At a well like Macondo, the most common method for remediating the primary production casing cement is called **squeeze cementing**.

Figure 4.3.12 illustrates that squeeze cementing first involves perforating the production casing to provide access to the annular space around it. Rig personnel perforate the casing by lowering a tool that uses shaped explosive charges to punch holes through the casing and into the formation. Rig personnel then pump, or "squeeze," cement under pressure through the holes. In a properly

Figure 4.3.12. Remedial cementing—squeeze job.



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From upper left: 1) Poor centralization has led to channeling; 2) a bridge plug is placed below the remediation area, and a packer is positioned above; 3) a perforation gun is lowered and fires shells through the casing and into the formation; 4) cement is pumped into the area, forced through the perforations, and into the formation, creating a seal.

executed squeeze job, the remedial cement then flows into the annular spaces where the primary cement has failed, filling in any channels and isolating zones as necessary.

Cement Slurry Testing

Cement hardens as a result of chemical reactions that depend on pressure and temperature. In the field, cement slurries are normally mixed at ambient temperature and pressure, then exposed to increasing temperatures and pressures as they are pumped down the well. These increasing temperatures and pressures can not only alter the chemical and physical properties of the liquid slurry and cured cement, but also can affect the cement curing process itself. Because every well presents a different combination of cementing conditions, it is critical for a cementing company to test a cement slurry design against expected conditions in the particular well before pumping it into that well.

Cement slurries consist of a number of ingredients, including dry Portland cement (which itself is a combination of several chemical compounds), water, and various dry and liquid chemical additives. Cementing personnel adjust the concentrations of these ingredients to suit the particular needs of a given well. Cement slurry designs thus vary from well to well. To complicate matters further, many of the ingredients used in a cement slurry are made from naturally occurring materials, and their precise chemical composition depends on their source.[40] The liquid chemical additives may vary from batch to batch, and the mix water composition can vary depending on its source. This means that each batch of cement slurry is different. Finally, the constituents of a given cement slurry also may degrade in storage upon exposure to heat, humidity, and atmospheric gases such as carbon dioxide. To address this variability, cementing companies usually perform their pre-job testing with representative samples of the actual ingredients that will be pumped into the well.

Pilot and Pre-Job Testing

A cementing company typically conducts at least two rounds of cement testing prior to pumping a challenging or uncertain cement job. First, it performs “pilot tests” substantially in advance of pumping the job in order to develop an appropriate cement slurry design (the recipe). At the time of the pilot tests, the operator gives the cementing company the best available information about the downhole conditions. That information may be incomplete, especially in the case of an exploratory well (such as Macondo). Sometime prior to pumping the cement, when the operator has learned the actual downhole job conditions, the cementing company typically performs pre-job tests using the actual cement ingredients that have been stored on the rig and will be pumped downhole. These pre-job tests are meant to confirm that the cement design will perform successfully during the upcoming job.

Laboratory Tests

To isolate hydrocarbons at the bottom of a well, the cement must display several attributes. First, as the cement is pumped into place at the bottom of the well, it must remain in a pumpable fluid state and not thicken prematurely. Second, once in place, it must set and develop strength within a reasonable time period. And third, the set cement must be sufficiently strong to provide casing support and zonal isolation. To check these things, cementing companies typically run a number of tests to evaluate a cement design during pilot and pre-job testing. The API has published recommended procedures for running these tests.[41]

Cement Test. Cement tests examine various properties of the cement slurry and the set cement, and investigate the curing process. **Thickening time** tests determine how long the cement slurry will remain pumpable (before starting to set up) under the temperature and pressure conditions in the wellbore. **Compressive strength** tests determine the length of time required for the cement slurry to develop sufficient strength to provide casing support and zonal isolation. **Rheology** tests examine various cement slurry flow properties. The slurry viscosity and yield point affect the pumping pressure required for slurry placement and the displacement efficiency by which drilling fluid is removed from the annular space. The yield point also provides information concerning slurry stability—the ability of the slurry to keep solids in suspension and prevent fluid-phase separation. **Static gel strength** is a measure of the degree to which an unset cement slurry develops resistance to flow when at rest. **Free-fluid** tests directly examine slurry stability.

As cement slurry travels down a well, it encounters increasing heat and pressure. Laboratory technicians sometimes stir the slurry at elevated temperatures (and sometimes at elevated pressures) to simulate these conditions in order to better understand how the cement will behave when it reaches its intended location. This practice is known as **cement conditioning** (not to be confused with mud conditioning, described above).

Modeling the Cementing Process

Before pumping cement, engineers can also model the cementing process using computer simulation programs. Engineers run these simulations using data about wellbore and casing geometry, mud conditioning, the number and placement of centralizers, and the volume, pumping rate, and characteristics of the various fluids pumped down the well. The simulations, in turn, predict various things about the cementing process such as the pressure that will be required to pump cement.

Engineers routinely use cement simulations to model the complex process of mud displacement from the annular space. Predicting mud displacement is important for at least two reasons. First, if the cement flow does not displace mud and spacer from the annular space, those materials may create a flow path for hydrocarbons. Second, and relatedly, poor mud displacement increases the potential for gas to flow into the cement column as it sets.[42] This gas flow can itself cause channeling and further compromise zonal isolation.

As the oil and gas industry develops deeper wells and more complicated well designs, engineers rely increasingly on computer modeling to predict mud removal. Operators and cementers can use these models to predict the impact of changing parameters such as cement flow rate and centralizer placement. By doing so, they can optimize these interrelated parameters for individual well conditions rather than relying on rules of thumb to guide their decisions. At the same time, the fluid mechanisms of mud displacement, gas flow, and other cementing phenomena are exceedingly complex. Computer simulations cannot model these phenomena precisely. In addition, even the best computer models depend entirely on their input data; if the input data are inaccurate, the modeling results will be inaccurate as well.

Preparing for the Macondo Cement Job

Lost Returns at Macondo

BP and Halliburton designed crucial features of the Macondo cement job in response to the April 9 lost returns event (when drilling mud flowed out of the wellbore and into the formation) described in Chapter 4.2. Although BP engineers successfully restored mud circulation by pumping 172 barrels of heavy, viscous "lost circulation" fluids down the drill pipe,[43] they also realized the situation had become delicate. Based on data from the lost circulation event, the engineers calculated that they had to maintain the weight of the mud in the wellbore at approximately 14.0 pounds per gallon (ppg) in order to maintain well control.[44] Drilling ahead with that mud weight would exert even more pressure on the formation, raising the equivalent circulating density (ECD). BP engineers calculated that drilling with 14.0 ppg mud in the wellbore would yield an ECD of nearly 14.5 ppg—an increase that the engineers believed could induce lost returns again.

The engineers concluded they had "run out of drilling margin" and that they could no longer drill to their planned total depth of 20,600 feet below sea level.[45] Instead, they cautiously drilled ahead from 18,193 to 18,360 feet in order to extend the wellbore beyond the pay zone. Optimally, engineers prefer to drill far enough beyond the pay zone to ensure that the float collar and shoe track will both be entirely below the pay zone. Among other things, this allows the operator eventually to use logging tools to evaluate all of the cement in the annular space in the pay zone. In March, before the April 9 lost circulation event, a BP engineer stated that BP planned an extended shoe track at Macondo.[46]

Wellbore Logging and Conditioning

After drilling, BP directed Schlumberger to run a series of logs to collect data from the well. Between April 10 and 15, 2010, Schlumberger technicians evaluated the formation to determine its porosity and permeability, and gathered fluid and core samples from the well. The logging data led BP to conclude that it had drilled into a hydrocarbon reservoir of sufficient size (at least 50 million barrels[47]) and pressure that it was economically worthwhile to install a production casing. Schlumberger also ran a caliper log to determine the exact diameter of the wellbore.[48]

On April 16, before running the final 9⅞-inch × 7-inch long string production casing, the rig crew circulated the open wellbore bottoms up.[49] They did not record any mud losses during this process.[50] The crew inspected mud from the bottom of the well and found that it contained 1,120 gas units on a 3,000-unit scale.[51] This was not an unusual amount of gas because the mud at the bottom had been sitting in place in the well for about a week at that point.[52] After circulating on April 16, gas eventually decreased to 20 to 30 units.[53]

Designing the Macondo Cement Job

BP's cement planning focused heavily on reducing the risks of further lost returns. BP recognized that if the formation fractured again during cementing, it could compromise the cement job and force the rig crew to conduct remedial cementing operations. BP engineers focused particular attention on ensuring that the ECD during cementing would not exceed the threshold that they believed would induce further losses. In order to minimize the ECD during cementing, BP: (1) reduced the volume of cement that would be pumped, (2) reduced the rate at which the cement would be pumped, and (3) used nitrogen foamed cement for reduced density.[54]

Cement Volume

Wellbore conditions are rarely optimal, and it is difficult to be sure precisely where cement has flowed during a cement job. Engineers can therefore improve the odds of achieving zonal isolation by increasing the volume of cement in the well design. Pumping more cement is a standard industry safeguard against uncertain cementing conditions. It reduces the risk of contamination by diluting the amount of contaminants in the cement. It also decreases the impact of errors in cement placement.

MMS Cement Volume Requirements

At the time of the Macondo blowout, MMS regulations included very few requirements that related to the cement design process at Macondo. One of those requirements concerned the volume of cement for a primary production casing cement job. According to 30 C.F.R. § 250.421: "As a minimum, you must cement the annular space at least 500 feet above the casing shoe and 500 feet above the uppermost hydrocarbon-bearing zone."

In other words, MMS required that the TOC in the annular space of the production casing be at least 500 feet above the "uppermost hydrocarbon-bearing zone."

BP's Internal Guidelines

BP's Engineering Technical Practice 10-60 (ETP 10-60), titled "Zonal Isolation Requirements during Drilling Operations and Well Abandonment and Suspension," lists the company's internal engineering design rules for cementing. ETP 10-60 states:

> **1.3** Zonal Isolation design criteria for cementing of primary casing strings to meet well integrity and future abandonment requirements, shall meet one of the following:
>
> - 30 m TVD [total vertical depth] (100 ft TVD) above the top of the distinct permeable zone where the top of cement (TOC) is to be determined by a proven cement evaluation technique (Section 5.3).
> - 300 m MD [measured depth] (1000 ft MD) above the distinct permeable zone where the hydraulic isolation is not proven except by estimates of TOC (Section 5.3). For each well the actual TOC shall be recorded along with the method used for this determination. Where the actual TOC is below the plan, the TOC shall be reviewed with stakeholders for its impact on future well integrity, operability, suspension and abandonment operations.[55]

Section 5.3 of ETP 10-60 distinguishes a "proven cement evaluation technique" from an "estimate" of TOC by stating that "to accurately assess TOC and zonal isolation cement sonic and ultrasonic logs should be used." By contrast, the ETP states that temperature logs (which can detect the heat exuded by cement) and cement column backpressure measurements can be used to "estimate" TOC. This means that unless a BP engineering team plans to run sonic and ultrasonic logs, it should design the cement job so that there is 1,000 feet of cement above the highest distinct permeable zone in the well.

In addition to zonal isolation, BP also considers annular pressure buildup (APB) in planning TOC.[56] The high temperatures caused by bringing hydrocarbons to the surface during later production can cause pressure buildup in the annular space. If trapped, the annular pressure will build up and can potentially collapse the inner casing string on itself and ruin the well. One way drillers avoid this is by allowing annular pressure to escape into the formation. By not cementing all the way up to the next liner—which necessarily means a lower TOC and lower volume of cement—the drillers allow a route for escape.[57] It is likely that APB concerns were a factor in determining TOC and cement volume at Macondo.[58]

Macondo Cement Volume

After the early April lost returns events, the BP Macondo team decided to limit the height of the cement column in the annulus. They had little room to maneuver: A higher cement column in the annulus would have exerted more pressure on the fragile formation below, increasing the ECD of the cement job and risking further lost returns.

Driven by ECD concerns, BP's engineering team focused its attention on determining where TOC should be. While the main hydrocarbon reservoir zone at Macondo began at 18,100 feet,[59] BP estimated that the "top HC [hydrocarbon] zone" began at 17,803 feet.[60] BP engineers decided to pump only as much cement above that zone as MMS required.[61] On or about April 14,[62] they determined that TOC should be 17,300 feet below the ocean surface—503 feet above the top hydrocarbon zone and 830 feet above the main hydrocarbon zone.[63]

On April 14, BP senior drilling engineer Mark Hafle initiated a formal management of change review of the plan to set the production casing.[64] He marked the document as a high priority and asked that its approval be completed by the next day.[65] Hafle incorporated the design decision regarding TOC in the management of change document. The document discussed the risk that the primary bottomhole cement would not act as a barrier: "If losses occur during the cement job, possible cement evaluation, remedial cement operations, dispensations and/or MMS approvals will be required prior to performing TA operations due to a lower than required Top of Cement in the annulus. Possible hydrocarbon zones could be left exposed in the annulus with only the casing hanger seal as the single barrier for the TA."[66] In the event that occurred, the document went on to note, "A perf[oration] and squeeze operation could be performed to add a second barrier in the annulus."[67] BP drilling and completions operations manager David Sims reviewed the management of change document and commented that the "[c]ontent looks fine."[68] BP drilling engineer team leader Gregg Walz, BP wells team leader John Guide, BP engineering manager John Sprague, and others also reviewed the document—all approved.[69]

Keeping TOC to a minimum necessarily reduced the total volume of cement that Halliburton pumped down the well. Several other features of the Macondo well also limited the total amount of cement that could be pumped:

- the relatively short distance the well had been drilled below the main pay sands;
- the relatively narrow annular space between the production casing and the formation; and
- BP's decision not to pump any cement behind the top plug.[70]

Halliburton calculated that it should pump approximately 51 barrels of cement (about 60 barrels after foaming) down the well in order to fill the shoe track and the annular space up to BP's specified TOC.[71] BP engineers recognized that this was a relatively small volume of cement that would provide little margin for error.[72]

Cement Flow Rate

Just as increased mud flow rate improves wellbore conditioning, higher cement flow rates tend to increase the efficiency with which cement displaces mud from the annular space. Cement must be pumped fast enough so that it will scour mud from the side of the wellbore instead of merely flowing past. The API notes that "[h]igher pump rates introduce more energy into the system allowing more efficient removal of gelled drilling fluid."[73] However, increased pump pressure required to move the cement quickly would mean more pressure on the formation (ECD) and an increased risk of lost returns.[74]

One way in which BP reduced the risk of lost returns at Macondo was by lowering the rate of cement flow. BP pumped cement down the well at the relatively low rate of four barrels or less per minute.[75] This was a lower rate than called for in earlier drilling plans,[76] but BP did inform Halliburton of the change and Halliburton's computer models accounted for the reduced flow rate.

Use of Nitrogen Foamed Cement

One very direct way to reduce the amount of pressure that a column of cement exerts on the formation below is to use lightweight cement. While there are several ways to generate lightweight cement, BP and Halliburton chose to use nitrogen foamed cement. Cementing personnel create nitrogen foamed cement by injecting inert nitrogen gas into a base cement slurry. This produces a slurry that contains fine nitrogen bubbles. Because nitrogen gas weighs so little compared to cement, the nitrogen bubbles make the overall cement mixture less dense than the base cement slurry.

BP and Halliburton jointly decided to use foamed cement technology at Macondo. (Chapter 4.4 discusses the choice in more detail.) This would reduce the weight of the middle portion of the Macondo cement slurry from the base slurry density of 16.74 ppg down to a foamed slurry density of 14.50 ppg.[77]

While using foamed cement slurry brought certain benefits, it brought risks as well. Chapter 4.4 explains in more detail how an unstable foamed cement slurry can fail to provide zonal isolation. A BP cementing expert specifically advised one of the Macondo engineers in March that cementing the production casing using foamed cement would "present[] some significant stability challenges for foam, as the base oil in the mud destabilizes most foaming surfactants and will result in N_2 [nitrogen] breakout if contamination occurs."[78] To guard against this possibility, the expert advised the team to pump non-foamed cement ahead of the foamed cement. This would create a "cap slurry" on top of the foamed slurry in the annular space that would mitigate the risk of foam instability.[79]

Planning for and Installing Centralizers at Macondo

BP procured only six centralizers for its production casing ahead of time, even though its plans had originally called for a greater number. Shortly before running the casing, however, Halliburton's modeling revealed that BP would need more centralizers to prevent channeling. In response, BP decided at the last minute to purchase 15 more centralizers and send them out to the rig. But unlike the six centralizer subs that BP had purchased earlier, these additional centralizers were slip-on centralizers with separate stop collars. Once BP realized this, it reversed itself and decided not to use them, reasoning that the risks of using them outweighed the risks of channeling.

API's Centralization Guidance

While the API recognizes the importance of centralization, it has no recommended specific standoff ratio for casing. Rather, the API encourages drillers to determine the appropriate standoff ratio based on individual well conditions. Nor does the API have any recommendation or standard for how far above the pay zone casing should be centralized.[80]

BP's Centralization Guidance

BP's official technical guidance instructs engineers to design centralization programs to ensure there is at least 100 feet of "centrali[z]ed pipe" above the "permeable zone" in the event a cement bond log is not run.[81] The technical guidance does not provide any further detail on the number or type of centralizers that should be used or the overall standoff that should result. BP in-house cementing expert Erick Cunningham explained that the guidance does not provide specific instruction on the number of centralizers that must be used to create a "centralized pipe." A casing could have centralizers on every joint or every three joints; both could be considered "centralized pipe" depending on the particular well. Cunningham stated that the only way to predict the effect of centralizer placement on mud displacement is through computer modeling.[82]

Macondo Team's Early Centralizer Plans

The Macondo team's September 2009 well plan included enough centralizers to likely satisfy BP's internal technical guidance. That plan's formula would have required the team to install at least 16 production casing centralizers given the then-planned total depth of 20,200 feet.[83] BP then produced another well plan in January 2010. Its formula would have called for at least 11 centralizers on the production casing.[84] Given the ambiguity of BP's technical guidance, it is unclear whether the January 2010 plan would have satisfied BP's internal requirements.[85] Both of these plans were based on a deeper well depth and larger casing diameter than BP eventually used at Macondo.

The Macondo Team Procured Six Centralizers for the Production Casing

On March 31, BP drilling engineer Brian Morel emailed a Weatherford sales representative, Bryan Clawson, and asked for "7-10" centralizer subs.[86] Clawson emailed Morel to say that Weatherford could only supply six centralizers immediately, explaining that it would take up to 10 days to manufacture more. Though it is common for Weatherford to manufacture centralizers to order, Morel did not ask Clawson to do so, even though Weatherford could at that point have made additional subs in time.[87] Instead, the BP team decided that six centralizers would be sufficient.[88] These six centralizer subs that Morel ordered were ultimately the only centralizers that the Macondo team used.

The Macondo Team Decided to Increase the Number of Centralizers to Address Potential Channeling Problem

During the long string decision-making process, Halliburton cementing engineer Jesse Gagliano had run a cementing model that predicted that the long string could be cemented successfully. Though Gagliano was a Halliburton employee, he worked at BP's Houston campus, and his office was on the same floor as those of BP's Macondo team.[89] Gagliano's April 14 model assumed proper centralization (by assuming a 70% standoff ratio) instead of calculating standoff based on centralizer placement plans.[90] It also assumed optimal wellbore size and geometry because BP did not yet have caliper log data from the well.[91] The April 14 model report did not predict significant channeling.[92]

On April 15, BP provided additional data to Gagliano from the Schlumberger logs, including caliper data, that could improve the accuracy of his cementing predictions. Based on the new data, Gagliano modeled the cementing process again, this time without assuming optimal centralization.[93] His new model predicted that using only six centralizers would result in lower standoff ratios and that this would be inadequate to ensure good mud removal and avoid mud channeling.[94] It also predicted that the mud channeling would increase the height of the cement column in the annulus (measured as TOC). That, in turn, would increase the effective pressure that the cement column would exert on the well formation below (ECD).[95]

That afternoon, Gagliano alerted Walz and BP operations engineer Brett Cocales to his predictions. Although Guide was out of the office, BP's engineering team acted on the information. The team was already concerned that the ECD during cementing operations could lead to lost returns during cementing and viewed lost returns as the biggest risk they faced during the cement job.[96] Based on Gagliano's predictions of increased ECD, Walz sought and obtained agreement from Guide's superior, Sims, to procure more centralizers and fly them to the rig immediately.[97] It appears that Walz and the BP team were concerned at this point about

Figure 4.3.13. Centralizer sub (top) and slip-on centralizer with stop collars (bottom).

Weatherford

the impact that channeling might have on ECD and were not directly concerned about the impact channeling might have on zonal isolation. [98]

Gagliano ran and distributed two additional cementing models from the afternoon into the evening of April 15 to evaluate the impact of adding additional centralizers.[99] His first model predicted that there would be reduced channeling with 10 centralizers, but still a significant amount. He emailed the model to the team, writing what he had already warned them about in earlier conversation: "Updating [the model with caliper and other data] now shows the cement channeling and the ECD going up as a result of the channeling. I'm going to run a few scenarios to see if adding more centralizers will help us or not."[100] Morel, who was on the rig and unaware that the team had made the unusual decision to fly centralizers to the *Deepwater Horizon*, responded that it was "too late" to get any more centralizers to the rig.[101] Gagliano's second model showed even less channeling with 21 centralizers. Both models showed that increasing the number of centralizers at Macondo would reduce the potential for gas migration in the annular space, though the centralizers' effect on gas flow was apparently of minor concern to the team compared with its effect on ECD.[102]

Sitting in the Houston conference room with Gagliano, Cocales carried out Walz's instructions to secure additional centralizers. Cocales called Clawson and ordered 15 additional Weatherford centralizers, the most that could be sent on a single helicopter.[103] BP also arranged for a Weatherford technician to accompany the centralizers and oversee the installation.[104] These 15 centralizers were leftovers from another BP project called Thunder Horse. Unlike the six centralizer subs already on the *Deepwater Horizon*, however, the Thunder Horse centralizers were slip-on centralizers as shown in Figure 4.3.13. BP's engineering team assumed that the Thunder Horse centralizers had integrated stop collars.[105] But the centralizer schematics that Clawson sent to Cocales on April 15 (and that Cocales forwarded to the rest of the BP engineering team) showed that the stop collars would be separate from the centralizers.[106]

Figure 4.3.14. Gregg Walz April 16, 2010 email to John Guide about centralizers.

From: Walz, Gregory S
To: Guide, John
Sent: Fri Apr 16 00:50:27 2010
Subject: Additional Centralizers

John,
Halliburton came back to us this afternoon with additional modeling after they loaded the final directional surveys, caliper log information, and the planned 6 centralizers. What it showed, is that the ECD at the base of sand jumped up to 15.06 ppg . This is being driven by channeling of the cement higher than the planned TOC.
We have located 15 Weatherford centralizers with stop collars (Thunder Horse design) in Houston and worked things out with the rig to be able to fly them out in the morning. My understanding is that there is no incremental cost with the flight because they are combining the planned flights they already had. The maximum they could fly is 15.
The model runs for 20 centralizers (6 on hand + 14 new ones) reduce the ECD to 14.65 ppg, which is back below the 14.7+ ECD we had when we lost circulation earlier.
There has been a lot of discussion about this and there are differing opinions on the model accuracy. However, the issue, is that we need to honor the modeling to be consistent with our previous decisions to go with the long string.
Brett and I tried to reach you twice to discuss things. David was still here in the office and I discussed this with him and he agreed that we needed to be consistent with honoring the model.
To be able to have this option we needed to kick things off at 6:00 pm tonight, so I went ahead and gave Brett the go ahead. We also lined up a Weatherford hand for installing them to go out on the same flight. I wanted to make sure that we did not have a repeat of the last Atlantis job with questionable centralizers going into the hole.
John, I do not like or want to disrupt your operations and I am a full believer that the rig needs only one Team Leader. I know the planning has been lagging behind the operations and I have to turn that around. I apologize if I have over step my bounds.
I would like to discuss how we want to handle these type of issues in the future.
Please call me tonight if you want to discuss this in more detail.

Gregg
Drilling Engineering Team Leader
GoM Drilling & Completions
Office: 281-366-0281
Cell: 281-543-8634
E-Mail: Gregory.Walz@bp.com

BP

Walz later explained his decision, as shown in Figure 4.3.14, to order the additional 15 centralizers to Guide in the following email, sent that night.[107]

Walz justified the decision to order additional centralizers because "we needed to be consistent with honoring the model." That model had convinced the team that a long string could be successfully cemented, so long as ECDs were kept in a low, narrow range. That model had also assumed that the centralizers would achieve a 70% standoff ratio.

The Macondo Team Decided Not to Install the Additional Centralizers

Sometime after 5 a.m. on April 16, a helicopter arrived at the *Deepwater Horizon*, carrying the 15 additional centralizers and Weatherford service technician Daniel Oldfather.[108] The helicopter did not, however, carry the stop collars and accessories that would be needed to secure the centralizers on the casing. Those had been shipped by boat and were scheduled to arrive by 4 p.m. (before the casing would be run).[109] Oldfather explained this to the rig crew when he landed.[110]

Figure 4.3.15. Centralizers delivered to the *Deepwater Horizon* on April 16, 2010.

BP

Morel was still visiting the rig at the time the helicopter landed. He examined the centralizers when they arrived. Like the other BP engineers, he had expected that the centralizers would have integrated stop collars. He now recognized that this was not the case.[111] Morel called Guide and told him that these were not the "one-piece" centralizers that he was expecting. Guide agreed they were not what he had planned on using either.[112] Morel took digital pictures of the centralizers and emailed them to Guide, telling him that "the centralizers do not have the stop [collars] on them."[113] However, Morel also told Guide that the centralizers could still be used because the boat carrying the collars would arrive in "plenty of time before needing them."[114]

After learning that the new centralizers had separate stop collars, Guide reversed Walz's decision to install them on the production casing in an email to him midday on April 16,[115] shown here in Figure 4.3.16.

Guide's email explained to Walz that the separate stop collars were prone to coming off the casing as it was being run into the well. Not only did this mean that the centralizers could slip away from their predetermined positions on the casing, but the centralizers could also get "hung up" against other parts of the well as the casing was being run. This could prevent the casing from being

Figure 4.3.16. John Guide April 16, 2010 email to Gregg Walz about centralizers.

From: Guide, John
Sent: Fri Apr 16 17:48:11 2010
To: Walz, Gregory S
Subject: Re: Additional Centralizers
Importance: Normal
Attachments: David Sims.vcf

I just found out the stop collars are not part of the centralizer as you stated. Also it will take 10 hrs to install them. We are adding 45 pieces that can come off as a last minute addition. I do not like this and as David approved in my absence I did not question but now I very concerned about using them

BP

lowered all the way to the bottom of the wellbore—a serious problem that would take significant time to fix.[116] Guide also noted that installing this type of centralizer would alone take 10 hours.[117] In a phone call with Walz, Guide weighed the risks of losses that fewer centralizers presented against the risk of a "last minute" addition of unfamiliar centralizers. There was no discussion at that point of stopping the job in order to procure the "correct" style of centralizers.[118] Instead, Guide told Walz and Sims he was reverting to the original plan. Sims agreed. Walz also accepted the reversal, saying, "I agree. This is not what I was envisioning," and apologized to the rest of the drilling team for the "miss-step" of ordering centralizers.[119]

During the same time period, Morel was attempting to position BP's six centralizers where they would be most effective, rather than place them at fixed intervals. As early as April 14, he had emailed Gagliano his suggested placement.[120] On April 15, when he mistakenly told Gagliano that it was "too late" to get more centralizers to the rig, he changed his recommendation, switching the position of two centralizers.[121] The next afternoon, the day BP reverted to the six centralizer plan, Morel changed the position of two other centralizers on his own "casing tally."[122] Morel supposedly based his recommendation on the caliper data and a wellbore image, though it is unclear precisely how he used them.[123]

Morel's placement of the centralizer subs was different than Gagliano's. Gagliano had assumed the centralizer subs would be evenly spaced apart while Morel placed them at irregular intervals.[124] It appeared that Morel expected Halliburton to run a new model based on his casing tally and centralizer placement. Morel's discussion with Cocales regarding the placement concluded, "We can argue this one out after we get the actual vs model data and see how it reacts."[125] As it turned out, BP never requested a model that reflected the actual centralizer placement, and Halliburton never ran one.

Neither Halliburton nor the BP engineering team appears to have considered that inadequate centralization might increase the chance of a blowout. Rather, they concluded that the worst-case result of using only six centralizers would be the need to conduct a remedial cement squeeze job.[126] As Cocales emailed Morel, "I would rather have to squeeze than get stuck above the WH [wellhead]. So Guide is right on the risk/reward equation."[127] In other words, Cocales preferred the increased risk of having to perform a remedial squeeze job to the increased risk of one or more of the 15 slip-on centralizers getting stuck in the well while the crew was running the production casing.

The BP team did not explicitly communicate its decision to use only the six centralizer subs on the rig to Halliburton or Weatherford.[128] When Gagliano eventually learned of the decision (from a Halliburton cementer aboard the rig), he asked BP to confirm it, and when he received no reply, he ran a new model on April 18.[129] It predicted poor centralization, "SEVERE" gas flow potential, and mud channeling. When Gagliano emailed the latest cement job procedures to the BP team at 9 p.m. that night, he attached this report.[130] He spoke with Walz the next morning (April 19) about the potential for channeling.[131] Walz in turn spoke with Guide about the issue.[132] BP nevertheless proceeded with its plan to run only six centralizers.

As BP has pointed out, Gagliano's April 18 model was based on several imperfect inputs. Notably, Gagliano assumed that BP would use seven centralizers, not six, and again, that BP would space them evenly along the casing, not place them in sections of the borehole where they might be especially effective.[133] Gagliano also utilized an incorrect pore pressure in the reservoir zone, which could influence the model's prediction of gas flow into the cement column.[134] It is unclear, however, whether eliminating these inaccuracies could have eliminated the channeling and gas flow predicted by the model. The use of fewer centralizers would decrease centralization, and the actual placement of two-thirds of the centralized joints was within 15 feet of the placement of the centralizers in the model.[135] In any case, the April 18 model was the most accurate model of the cementing process that existed before the blowout,[136] and it predicted that channeling would occur.[137] (As of 10 months after the blowout, Halliburton had still not produced modeling results that more accurately reflect Macondo conditions.)

BP began installing the casing at 3:30 a.m. on April 18 and finished at 1:30 p.m. on April 19.[138]

Float Collar Installation and Conversion at Macondo

Once the production casing string had been run, the crew turned to converting the valves in the float collar. Until this time, the float valves had been propped open by an auto-fill tube. Rig personnel needed to push the auto-fill tube down and out of place, thereby converting the float valves and allowing them to close (Figure 4.3.1). Once closed, the float valves would become one-way valves that would permit drilling mud and cement to flow down through the inside of the casing but would prevent "reverse flow" or "u-tubing."[139]

Shoe Track Length and Placement

The shoe track is the space between the float collar and the reamer shoe at the bottom of the casing. (A **reamer shoe** is a bullet-nosed, perforated piece of equipment that guides the casing toward the center of the hole as it is lowered into the well). At the end of the cement job, this space is filled with the "tail" portion of the cement that was pumped down the well. That tail cement may be contaminated by mud scraped from the casing by the top wiper plug. Indeed, one purpose of the shoe track is to contain contaminated tail cement.

A longer shoe track increases the volume for capturing contaminated tail cement, which in turn reduces the likelihood that such cement will flow into the annular space. A larger shoe track also dilutes the impact of any contamination in the tail cement. Morel suggested the shoe track at Macondo may not have been long enough but ultimately left the decision whether to extend the length up to the well site leaders on the rig.[140] According to Guide, BP also wanted to set the shoe track deeper in the well so that it was entirely below the hydrocarbon-bearing zone.[141] Ultimately, the shoe track was not below all of the hydrocarbon-bearing zones because the total depth of the well was shallower than planned due to problems of losing returns into the formation.[142]

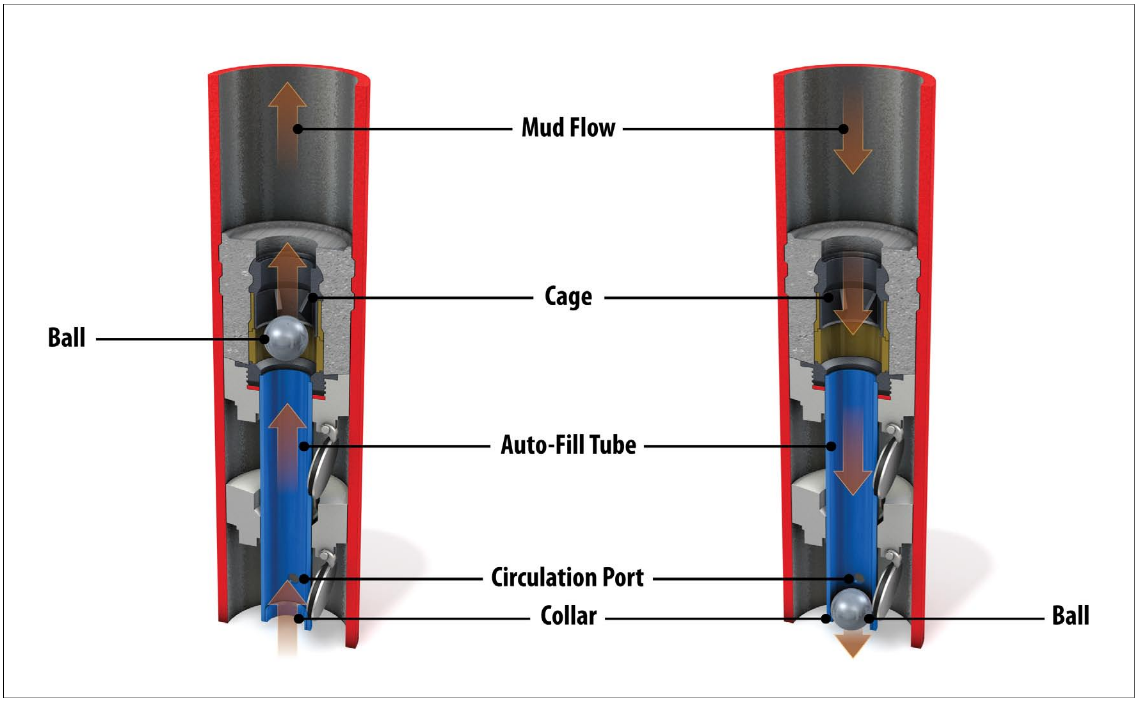
Macondo Float Collar

The production casing at Macondo contained a Weatherford Flow-Activated Mid-Bore Auto-Fill Float Collar, which rig personnel had installed just above the 180-foot shoe track at the bottom of the casing string.[143]

The Weatherford float collar held two aluminum float valves set approximately 6 inches apart and propped open by an approximately 14-inch-long auto-fill tube (made out of phenolic resin).[144] As shown in Figure 4.3.17, the auto-fill tube allowed mud to flow up through the float valves while the casing string was run. Once the production casing had landed, however, the crew needed to push the tube out of the way to allow the float valves to close.

The float collar's auto-fill tube contains a 2-inch weighted ball, which is free to move within the tube but not out of it. At the top of the float assembly is a plastic cage that prevents the ball from escaping but allows mud to flow through. At the bottom is a phenolic resin collar that is less than 2 inches in diameter, which also allows mud, but not the ball, to flow through. When casing is being run, mud flowing up through the tube pushes the ball against the inside of the cage. When the casing lands, the ball falls to and plugs the bottom of the tube, leaving two small holes on the side of the tube as the only path through the tube for mud circulated down through the well.[145]

Figure 4.3.17. Auto-fill float collar.



TrialGraphix

Flow while casing is being lowered (left) and flow during conversion (right).

The crew converts the float valves by pumping mud down through the tube, against the ball, and out the two holes in the side. As rig personnel increase the flow rate of mud, the constricted flow path creates a differential pressure against the auto-fill tube. Once the flow rate exceeds a certain threshold, the differential pressure should break four shear pins that hold the auto-fill tube in position and force the tube downward and out of the float collar assembly. With the auto-fill tube removed, the float valves spring shut, "converting" the float collar into a one-way valve system.[146]

According to calculations based on Weatherford's specifications, the Macondo float collar assembly would have converted at a flow rate of approximately 6 barrels per minute (bpm), which would have created a 500 to 700 pounds per square inch (psi) differential pressure across the auto-fill tube.[147] Achieving the requisite flow rate through the two small holes is the only way to convert the collar. Significantly, increasing pump pressure above 500 to 700 psi would not push the auto-fill tube through and convert the valves unless the flow through the two side holes exceeds the flow rate recommended by Weatherford.

Attempted Float Conversion at Macondo

Rig personnel prepared to convert the float collar at approximately 2:30 p.m. on April 19.[148] The crew turned on the pumps and began pumping mud down the well in an effort to establish circulation to convert the float equipment. Morel and BP well site leader Bob Kaluza oversaw the operation.

The crew ran into a problem. They could not establish circulation (and hence had a zero flow rate), suggesting that the float collar or shoe track was somehow plugged. The crew increased pump pressure nine times before finally establishing mud circulation. They increased pump pressure to 1,800 psi, then to 1,900 psi, but could not establish circulation.[149] Rig personnel then pressured up to 2,000 psi four times but still could not circulate. The crew then pressured up to 2,250 and then 2,500 psi and again failed to establish circulation.[150] The crew then made a ninth attempt to establish circulation, pressuring up to 2,750 psi, then 3,000 psi. At 3,142 psi, the pressure finally dropped and mud began circulating down through the float collar assembly.[151] Significantly, however, the crew never thereafter achieved sustained flow rates of 6 bpm, which were required for conversion of the float valves based on calculations using Weatherford specifications.

The rig crew sought advice from shore during these attempts to establish circulation. At 3:28 p.m., Hafle emailed a representative from Allamon, another equipment supplier, and asked for the specifications of the auto-fill float equipment. The Allamon representative responded and suggested "rocking the casing in 1000 psi increments up to 5,000 psi."[152] Morel called Clawson at Weatherford, reported that they could not break circulation, and asked how much pressure could be applied.[153] After checking with the Weatherford engineering department, Clawson called back Morel and told him they could increase pressure up to 6,800 psi.[154] However, he also told Morel that at 1,300 psi the ball would pass through the bottom of the auto-fill tube without converting the floats.[155] Morel called Guide onshore and received permission to increase pressure to 2,200 psi.[156] The crew pressured up to 2,250 and then 2,500 psi but still failed to establish circulation.[157] Guide later gave permission to increase pressure to 5,000 psi.[158]

Questions remained after establishing circulation. At 5:30 p.m. on April 19, Clawson of Weatherford emailed BP's Morel inquiring about progress.[159] Morel responded, "[W]e blew it at 3140, still not sure what we blew yet," indicating the rig crew did not know what they had dislodged with the amount of pressure applied.[160] Kaluza said, "I'm afraid we've blown something higher up in the casing string."[161] Hafle said, "Shifted at 3140 psi. Or we hope so."[162] Despite these uncertainties, the rig crew proceeded onward.

Low Pressure After Circulation Established

After establishing circulation, BP observed another anomaly. The pump pressure required to circulate mud through the well was significantly lower than expected.[163] As shown in Table 4.3.1, mud engineers from M-I SWACO had calculated that 370 psi would be required to circulate at 1 bpm and 570 psi at 4 bpm post-conversion. However, after the crew established circulation, it took only 137 psi to circulate at 1 bpm, which made Kaluza uncomfortable.[164] The crew increased circulation to 4 bpm, which required only 340 psi of pressure—230 psi less than M-I SWACO had predicted.

The low circulating pressure raised concern among personnel on the rig floor.[165] Kaluza spoke to Morel, who was on the rig.[166] Morel called Guide onshore, who agreed the pressures appeared low.[167] Cocales asked M-I SWACO to rerun its model to confirm that the original calculations had not been mistaken; M-I SWACO's models continued to predict substantially higher circulating pressures than actually observed.[168]

Guide and Kaluza instructed the crew to switch from pump 4 to pump 3 to see if changing pumps might change the circulation pressure.[169] They observed a slightly higher circulation pressure (396 psi at 4 bpm) after switching pumps, but this was still significantly lower than the expected pressure.[170]

Table 4.3.1. Low pressure observed after circulation established.

Circulation Rate	1 bpm	4 bpm
Pressures Observed	137 psi[171]	340 psi (on pump 4)[172] 396 psi (on pump 3)[173]
Pressures Modeled	370 psi[174]	570 psi[175]

At Guide's suggestion, the crew checked whether the Allamon **diverter** in the drill pipe might be leaking. The diverter is a valve opened during casing installation to allow drilling fluid flowing up inside the casing to flow into the annulus and back to the surface. At Macondo, the diverter was located in the drill pipe, above the wellhead at a final depth of 4,424 feet.[176] The test confirmed the diverter was closed.[177] Morel and Kaluza considered the possibility of a breach somewhere in the casing string.[178] However, they determined that a leak in the casing could not be fixed at the moment and, if present, would be revealed by later pressure tests (such as the positive pressure test).[179]

BP never resolved the low circulation pressure issue, concluding instead based on discussions with the rig crew that the pressure gauge was likely broken.[180] Morel and others felt comfortable proceeding because of the fact that the cement would be pressure tested later.[181] According to BP interview notes, Kaluza later described the low circulation pressure as an anomaly and said that after he had discussed it with Guide and well operations advisor Keith Daigle, Guide instructed Kaluza to begin pumping cement.[182]

Pre-Cementing Wellbore Conditioning at Macondo

Circulation After Landing the Long String

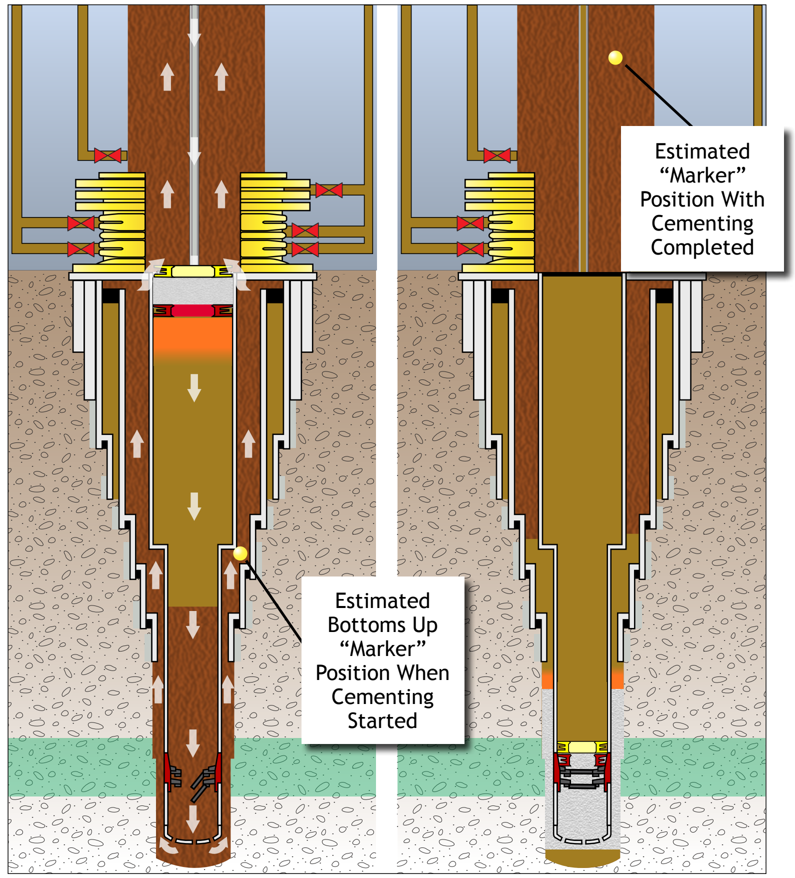
After converting the float valves, BP circulated mud again to clean the inside of the production casing string, remove any debris and cuttings dislodged by the casing installation, and condition the mud in the wellbore for cementing.

Planned Pre-Cement Circulation Volumes and Rates

An API recommendation from May 2010 was to circulate a minimum of 1.5 annular volumes or one casing volume after casing installation, whichever is greater.[183] Had this recommendation been in place at Macondo, this would have meant circulating 4,140 barrels (bbl) of drilling fluid. Halliburton recommends performing at least one full bottoms up circulation on a well before pumping a cement job.[184] This standard would have required BP to circulate 2,760 bbl of drilling fluid through the wellbore.[185]

Early BP drilling plans discussed pre-cementing circulation but did not call for a full bottoms up circulation. Omitting a full bottoms up is not unusual at deepwater wells because of the large mud volumes involved—circulating bottoms up could have taken as long as 12 hours at Macondo.[186] BP's September 2009 and January 2010 drilling programs called for circulating and conditioning 1.5 × pipe volume of drilling fluid "unless loss returns are experienced."[187] Although the plan did not specify which "pipe" volume it was referring to, circulation volumes are typically based on the volume of the casing used. The total long string casing and drill pipe volume at Macondo was 884 bbl, so it appears the plan called for the rig crew to circulate 1,326 bbl of mud before cementing.[188]

Figure 4.3.18. BP's pre-cementing mud circulation.



TrialGraphix

BP changed its plans in response to the April 9 lost circulation event, decreasing both the pre-cementing circulation volume and rate in order to reduce ECD. BP's April 12 plan thus called for circulating volume equal to one casing plus drill pipe capacity if hole conditions allowed, at a reduced rate of 8 bpm.[189] In its subsequent April 15 plan, BP further lowered the pump rate to "reduced rates (3 bpm) based on MI-SWACO models to keep ECD below 14.5 ppg."[190]

Even after receiving full returns during circulation on April 16, BP engineers remained concerned about lost returns during pre-cementing circulation.[191] They feared that circulating too extensively could damage the inside of the wellbore or instigate another lost returns event.[192] Onshore, Walz discussed whether to circulate full bottoms up with Gagliano late in the morning on April 19.[193] Afterward, Walz also spoke with Guide about circulation.[194] Ultimately, Guide recommended against circulating bottoms up because of concern over lost returns and gave approval to begin cementing.[195] On the rig, Halliburton cementing engineer Nathaniel Chaisson brought up the idea of circulating a full bottoms up but was told by a BP well site leader that a lower volume would be pumped.[196] Halliburton's April 18 cementing proposal lists reduced volumes, calling for 111 barrels at 1 bpm, followed by 150 barrels at 4 bpm for a total of 261 bbl.[197] Chaisson noted in the April 18 plan that the volumes and pump rates listed were "as per co. man,"[198] indicating that one of the BP well site leaders had provided it.

Pre-Cement Circulation Volumes and Rates

At approximately 4:18 p.m. on April 19, the rig crew re-established mud circulation after running the long string.[199] The rig crew then circulated a total of approximately 350 barrels of mud at rates up to 4 bpm before beginning the cementing process.[200] This figure exceeds the 261 bbl called for in the April 18 Halliburton cement job procedure[201] but is significantly lower than the 2,760 bbl required for a full bottoms up.[202]

Additional Circulation During Course of Cementing

BP has argued that the Chief Counsel's team must also take into account the additional mud volume circulated up the annulus from the bottom during the cement job itself in determining the total volume of mud circulated prior to the conclusion of the cement job. During the cement job, rig personnel pumped approximately 1,020 bbl of base oil, spacer, cement, and mud down into the well, which would have displaced an equal volume of mud.[203]

When combined with the pre-cementing circulation, this means that rig personnel pumped a total of 1,370 bbl of fluids (mud, spacer, and cement) down the well by the time cementing was complete.[204] This would have brought the bottomhole mud up into the riser to a depth of 4,250 feet below the ocean surface by the end of the cement job as shown in Figure 4.3.18. It would have taken a total of 2,760 bbl of circulation to bring the bottom mud all the way back to the rig.[205]

Table 4.3.2. Plans reduce pre-cement circulation volumes and rates.

Plan	Recommended Volume	Volume in Barrels	Recommended Circulation Rate
API RP 65, Part 2[206] (First edition)	1.5 annular volumes or one casing volume, whichever is greater	4,140 bbl (1.5 annular volumes)	
Full Bottoms Up		2,760 bbl[207]	
BP September 2009 Plan[208] and January 2010 Plan[209]	1.5 x pipe volume	1,325.73 bbl[210]	—
BP April 12 Plan[211]	1 casing and drill pipe capacity, if hole conditions allow	883.82 bbl[212]	~ 8 bpm
BP April 15 Plan[213]	1 casing and drill pipe capacity, if hole conditions allow	883.82 bbl[214]	3 bpm, based on M-I SWACO models to keep ECD below 14.5 ppg
April 18 Halliburton Cement Proposal[215]	—	111 bbl 150 bbl per company man	1 bpm 4 bpm
April 19 Actual Circulation		350 bbl	1-4 bpm

Cementing Process at Macondo

Halliburton's cementing team began pumping cement for the production casing on April 19.[216] In all, they pumped the following fluids down the well:

Table 4.3.3. Cementing volumes.

Material Pumped	Volume
Base oil	7 bbl[217]
Spacer fluid	72 bbl[218]
Unfoamed lead cement	5 bbl[219]
Foamed cement	39 bbl (Foamed to 48)[220]
Unfoamed tail cement	7 bbl[221]
Spacer	20 bbl[222]

After pumping these fluids, the cementing crew pumped mud into the drill pipe to push the cement down the well into position.[223]

Over the next three-and-a-half hours, the cement traveled down the drill pipe and into the well. During that time, rig personnel watched pump pressures at the rig for signs of cementing progress. Morel saw small pressure spikes suggesting that the top and bottom plugs had passed through the crossover joint in the long string.[224] Personnel on the rig agreed that the plugs bumped.[225] At 12:38 a.m. on April 20, Chaisson marked in his tally book that the plugs bumped at a pressure of 1,175 psi.[226]

Morel noted that the bottom plug landed 9 bbl ahead of plan.[227] This meant that the rig crew had to pump 9 bbl less fluid down the well than they planned before the bottom plug reached the float collar, potentially suggesting that the bottom plug had bypassed mud on its way down the well, and that the bypassed mud had contaminated the cement.

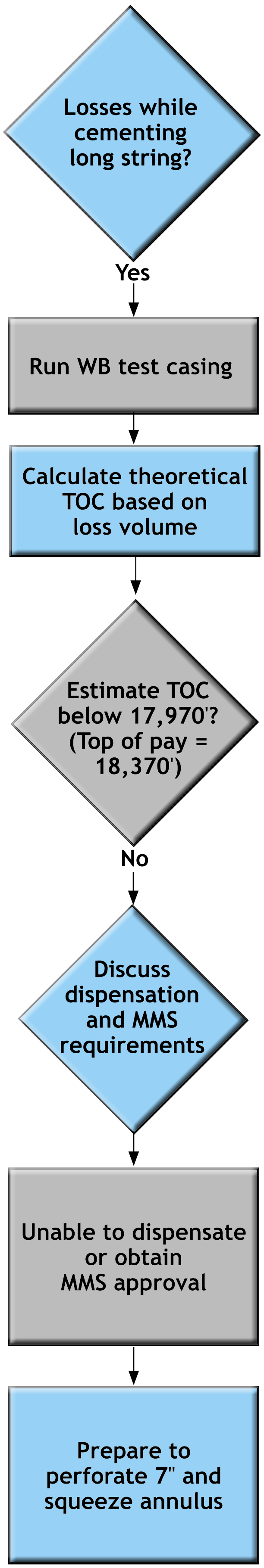
The top plug landed according to plan.[228] Chaisson watched the Sperry-Sun data[229] and estimated 100 psi of lift pressure before the top plug bumped.[230] Guide looked at the data from shore and thought it "easy" to see lift pressure.[231] Throughout cementing, the rig crew saw "full returns."[232]

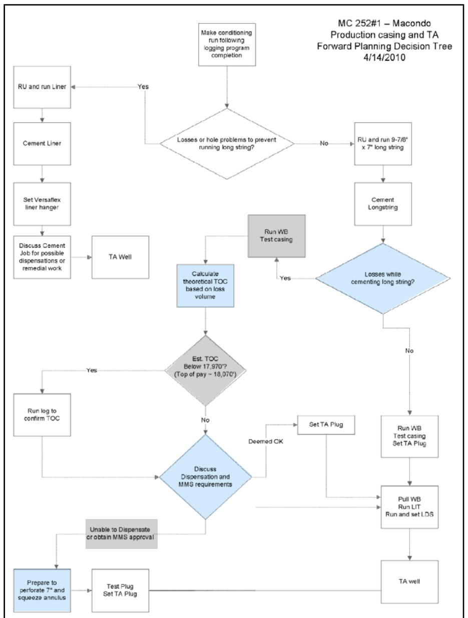
BP and Halliburton declared the job a success based on the indirect indicators—lift pressure, bumping the plugs on time, and full returns. Chaisson sent an email to Gagliano at 5:45 a.m. saying, "We have completed the job and it went well."[233] He attached a detailed report stating that the job had been "pumped as planned" and that "full returns were observed throughout."[234] Just before leaving the rig, Morel emailed the rest of the BP team: "Just wanted to let everyone know the cement job went well. Pressures stayed low, but we had full returns the entire job, saw 80 psi lift pressure and landed out right on the calculated volume.... We should be coming out of the hole shortly."[235] Later, Morel followed up with an email saying "the Halliburton cement team...did a great job."[236] Sims congratulated Morel and the BP team, writing, "Great job guys!"[237]

The Float Check at Macondo

After cementing was complete, rig personnel conducted a **float check** to ensure the float valves had closed properly. Rig personnel began by pressuring up the system after bumping the top wiper plug.[238] They then released the pressure and monitored the system for pressure differentials and flow back from the well.[239] BP well site leader trainee Lee Lambert and Halliburton cementer Vincent Tabler opened a valve at the cementing unit to see how much mud flowed out of the well when they released the pressure. [240] (Some modest flow back is expected due to the compressibility of fluids during the pumping of the cement job.) Models had predicted 5 or 6 bbl of flow back.[241] The two men observed 5.5 bbl of flow, which tapered off to a "finger

Figure 4.3.19. Decision tree.





BP/TrialGraphix

tip" trickle.[242] Tabler testified they watched flow "until it was probably what we call a pencil stream," which stopped, started up again, and then stopped altogether.[243] The total flow at that point was close to the predicted flow,[244] and the two men concluded the float valves were holding.[245]

Cement Evaluation at Macondo

BP's Decision Tree for Cement Evaluation

BP's decision process for determining whether to run evaluation tools after the cement job focused on lost circulation concerns as shown in Figure 4.3.19. On April 15, Hafle developed a cementing decision tree that effectively reduced the decision process to a single question: "Losses while cementing long string?"[246] If the cementing crew reported losses while pumping the cement job, the decision tree stated that BP engineers would "Calculate theoretical [top of cement] based on loss volume." If that calculation estimated that TOC was *below* 17,970 feet that would mean that there was less than 100 feet of cement above the top of the pay zone—400 feet less than MMS requires.[247] In that situation, the decision tree required a "log to confirm" the TOC.

If the theoretical calculation predicted that TOC was *above* 17,970 feet, the decision tree stated that the Macondo team would discuss MMS requirements and consider seeking a dispensation. If unable to get dispensation or "obtain MMS approval," then BP would "perforate" the casing and "squeeze" the annulus to remediate the cement job. An operator would not normally run a cement evaluation log and plan to remediate cement before temporary abandonment operations; the Macondo team's explicit discussion of these contingencies illustrates how concerned they were about the possibility of cement losses.[248]

On April 15, Morel distributed a full plan for the temporary abandonment procedures at Macondo. The plan summarized the cement evaluation decision tree and provided further detail on the criteria for how to evaluate the cement job:[249]

1. If cement job **<u>is not</u>** successful: (no returns or lift pressure seen): set wear bushing / Run IBC-CBL log / Wait on decision to do remedial work (MMS and BP).
2. If cement job **<u>is</u>** successful (partial returns or lift pressure seen) **<u>or</u>** IBC-CBL log and required remedial work is completed.

The plan thus stated that the BP team would declare the cement job "successful" if it saw "partial returns" or "lift pressure." It anticipated that the team might need to run cement evaluation tools ("IBC-CBL log") but required doing so only if "no returns or lift pressure seen." Steps one and two were the only steps in the BP plan that contemplated cement evaluation: In step three, the crew would move on to the temporary abandonment phase of the well and begin to displace mud in the wellbore with seawater.

BP Ordered Cement Evaluation Services From Schlumberger

On the same day that Morel distributed the temporary abandonment procedures, BP well site leader Ronnie Sepulvado placed an order with Schlumberger for cement evaluation services.[250] Sepulvado did so to ensure that a cement evaluation team would be available on the rig if the cement job did not go as planned. The order included a "full suite of logs,"[251] including a cement bond log, isolation scanner, variable density log, and inclinometer survey.[252] Schlumberger planned to evaluate the annular cement from the float collar to about 500 feet above the expected TOC.[253] The total cost for the services would be about $128,000.[254]

On April 18 and 19, a team of technicians from Schlumberger flew out to the rig.[255] BP told the team that the cement evaluation log would be run only if there were lost returns.[256] The Schlumberger team waited for more than a day on the rig to see if BP needed their services.

BP Sent Schlumberger Home

At 7:30 a.m. on April 20, the Macondo team discussed the cement job during its daily morning phone call with its contractors. BP concluded during the call that the cement job had gone well enough that it could send home the Schlumberger technicians. According to Guide, "everyone involved with the job on the rig site was completely satisfied with the job."[257] Having seen lift pressure and no lost returns during the cement job, BP sent the Schlumberger team home and moved on to prepare the well for temporary abandonment. At approximately 11:15 a.m., the Schlumberger crew left the rig on a regularly scheduled BP helicopter flight.[258] Not running the cement log probably saved BP about eight hours of rig time.[259]

Technical Findings

The Primary Cement at Macondo Failed to Isolate Hydrocarbons

It is undisputed that the primary cement at Macondo failed to isolate hydrocarbons in the formation from the wellbore—that is, it did not accomplish zonal isolation.[260] If the cement had set properly in its intended location, the cement would have prevented hydrocarbons from flowing out of the formation and into the well. The cement would have been a stand-alone barrier that would have prevented a blowout even in the absence of any other barriers (such as closed blowout preventer rams, drilling mud, and cement plugs).

Although the Chief Counsel's team is certain that the Macondo cement failed, data currently available do not allow the team to determine precisely why. It may never be possible to make such a determination. Government investigators recovered samples of debris from the blowout that may be cement, but they have not currently determined whether it came from the well and, if so, from where within the well.[261] There are no plans to directly examine the annular cement currently remaining at Macondo for clues. Even if someone were to plan such an examination, the blowout and subsequent remedial efforts may have obscured or erased any clues that might otherwise have been discovered.

BP, Halliburton, and Transocean have each speculated about potential failure mechanisms. Based on information currently available, the Chief Counsel's team can conclude that most (if not all) of the cement pumped at Macondo flowed through the float valves and that most of the cement that rig personnel intended to place in the annular space around the production casing did in fact reach that location. (Chapter 4.1 discusses the remote possibility of a casing breach that would have affected cement placement.) Several events may have contributed to cement failure, either alone or in combination:

- cement in the annular space may have flowed back into the production casing due to u-tube pressure and failure to convert the float valves;
- drilling mud may have contaminated the cement in the shoe track and/or annular space badly enough to significantly slow cement setting time;
- cement in the annular space may not have displaced mud from the annular space properly, leaving channels of mud behind;
- cement in the shoe track may have flowed down into the rathole (the open section of wellbore below the reamer shoe), "swapping" places with drilling mud and increasing the potential for flow through the shoe track;
- cement slurry characteristics (such as retarder concentration, base slurry stability/ rheology, or foam instability) may have compromised the sealing characteristics of the cement (discussed in Chapter 4.4); and
- severe foam instability may have allowed nitrogen bubbles to break out of the slurry, with unpredictable consequences (also discussed in Chapter 4.4).

Any theory regarding the precise mechanisms of the Macondo cement failure must account for several issues that the Chief Counsel's team has identified. Most importantly, if our team is correct that hydrocarbon flow came through the shoe track and up the production casing, then the tail cement in the shoe track must have failed to block that flow. It would have taken only a relatively small amount of properly set cement in the shoe track to block that flow. This suggests one of three nonexclusive possibilities to the Chief Counsel's team.

Drilling mud contamination. The first is that enough drilling mud contaminated the shoe track to delay cement setting time so that the shoe track cement did not provide a competent flow barrier at the time of the blowout. This probably would have taken a significant amount of mud; testing by Chevron indicated that even with 25% mud contamination, the Macondo cement formulation would develop adequate compressive strength without serious delay.[262]

The mud in question could have been entrained in the cement flow during cement placement by, for instance, the wiping action of the plugs. If the plugs landed off-schedule (as post-blowout statements by Morel suggest), that would support this theory. Cementing experts emphasize that the shoe track is designed to prevent cement contaminated by plug bypass from entering the annular space. Shoe track cement should therefore properly be treated as one part of the overall cement barrier system and may not bar hydrocarbon flow on its own.

Drilling mud could also have "swapped" into the shoe track from the open hole section below the casing (sometimes called the rathole). The rathole volume was similar to the shoe track volume. Mud contamination could also have come from the annular space around the production casing if channeling or other phenomena caused contamination of that area and float equipment malfunctions allowed this material to flow back into the shoe track under u-tube pressure.

Gross nitrogen breakout. The second possibility is that the foamed middle section of the cement slurry was so unstable (as discussed in Chapter 4.4) that nitrogen gas bubbles in it "broke out" of suspension while the cement was flowing down the drill pipe and production casing. This could have left large gas-filled voids not only in the middle section of cement that was injected with nitrogen, but also in the tail cement (which became the shoe track cement). That tail cement should not otherwise have had nitrogen in it. A problem with this theory is that pumping data from the cement job do not show the sorts of gross anomalies that one would expect if cement and nitrogen flowed through the float collar separately.

Nitrogen breakout could also have occurred after the cement arrived at the bottom of the well. This might not have produced anomalies in the pumping job data but still could have compromised the quality of the set cement. As described in Chapter 4.4, unstable nitrogen foamed cement can be excessively porous and permeable once set. Hydrocarbons can flow through such cement.

Gross cement slurry failure. A final possibility is that the Macondo cement slurry was unstable even before being foamed with nitrogen. As Chapter 4.4 explains in greater detail, pre-blowout testing shows that the Macondo slurry had a very low yield point, and post-blowout testing shows that a cement slurry produced using the Macondo recipe had a tendency to settle as it set. It is possible that these problems compromised the quality of the Macondo cement job so that cement in the shoe track could not have prevented hydrocarbon flow. A problem with this theory is that it appears, based on available information, that the cap cement in the annulus above the pay zone set up properly and created a barrier to flow up the annulus.

Using Six Centralizers Increased the Risk of Cement Failure

Reduced pipe centralization increases the risk of poor mud displacement, the risk that mud channels will compromise zonal isolation, and the risk that hydrocarbons will migrate into and through the annular cement as it sets. Without a direct examination of the Macondo cement, the Chief Counsel's team cannot determine whether any of these things occurred, let alone whether they caused or contributed to the blowout. The team can only conclude that BP's engineering decision increased the risk of cementing failure.

The Chief Counsel's team cannot at this time accept Halliburton's conclusory assertion that the limited number of centralizers at Macondo caused inadequate mud displacement, channeling, and cement failure.[263] To support its view, Halliburton relies heavily on the results of the model that Gagliano produced on April 18.[264] But Gagliano produced the April 18 report using several assumptions that did not match the eventual Macondo conditions. Halliburton points out that Gagliano received these assumed figures from BP, but that it is irrelevant; because the April 18 modeling inputs were inaccurate, the modeling output was unreliable even if one were to assume that those models accurately predicted problems with a cement job.[265] (Halliburton personnel have argued that their model would still have predicted channeling even with corrected inputs. However, Halliburton has yet to provide the results of a corrected model to the Chief Counsel's team or the public. This leads the Chief Counsel's team to infer that the results are not favorable to Halliburton.)

The Chief Counsel's team also cannot accept BP's equally conclusory assertion that the decision to use only six centralizers "likely did not contribute to the cement's failure to isolate the main hydrocarbon zones…."[266] Chapter 4.1 explains that the Chief Counsel's team finds it likely that hydrocarbon flow came up the production casing through the shoe track. But even though insufficient centralization may not have directly affected the integrity of the cement in the shoe track, it very well could have damaged the integrity of the cement in the annular space around the pay zone. If that cement had worked properly, shoe track cement failure would have been irrelevant.

BP's technical guidance and early Macondo well plans called for more centralizers than were actually run and for centralizers to be used over a larger casing interval.[267] If BP believed that its engineers could reliably reduce the number of centralizers (and hence cost) by scrutinizing caliper logs and pinpointing the placement of centralizers, one would expect its guidance documents and well plans to describe this practice. And while BP has repeatedly questioned the accuracy of the Macondo cementing models and the value of Halliburton's model in general,[268] it offers little affirmative technical analysis of its own to support its claim that centralization was not an issue at Macondo. Moreover, *before* the Macondo blowout, BP engineers thought the model's predictions of channeling were sufficiently credible that they flew 15 more centralizers to the rig in response.

Limited Pre-Cementing Mud Circulation Increased the Risk of Cement Failure

BP's decision to circulate a limited volume of mud at a relatively low rate before cementing may have led to inadequate mud conditioning and wellbore preparation. BP's decision was perhaps an understandable response to its concerns about formation integrity and lost returns, but it also increased the risks of cementing failure.

BP has defended its decision not to circulate bottoms up before cementing. It has argued, among other things, that modern technologies can identify wellbore cleanliness problems without full mud circulation and that the Macondo team took other measures to prepare the wellbore for cementing. For instance, the team circulated bottoms up *before* running the production casing[269] and pumped additional spacer during the cementing process to remove debris from the well.[270] At the same time, BP cannot dispute that circulating bottoms up is a "best practice" specified by Halliburton and other cementing experts,[271] and that its team did not do so. Although circulating less mud may have reduced the particular risk of lost returns, it nevertheless increased other aspects of the risk for cement failure, as compared to completing a full bottoms up.

Low Cement Volume Increased the Risk of Cement Failure

The limited volume of cement used at Macondo increased the risk of cement failure. BP pumped only about 60 barrels of cement (after nitrogen foaming) at Macondo. While BP may have thought it necessary to pump a small amount of cement to reduce the risk of lost returns, this approach magnified three other risks.

First, it meant there would be less cement in the annular space above the hydrocarbon zones—less even than BP's technical guidance recommends.[272] Second, it increased the risk that placement errors would leave insufficient cement in the shoe track or in the annular space corresponding to the hydrocarbon zone. And third, it increased the detrimental effects of any mud contamination. Mud contamination may have been a particular problem at Macondo because the design called for a tapered long string casing. That casing design called for the top and bottom wiper plugs both to wipe mud from a relatively long length of casing and to wipe two different casing diameters.[273]

Before the blowout, BP's engineering team recognized that their design called for a low cement volume that would provide little room for error. [274] And since the blowout, BP has recognized that "small cement slurry volume" increased cementing difficulties at Macondo.[275]

Cementing Pump Rate Increased the Risk of Cement Failure

In concert with Halliburton, BP chose to pump the primary cement at a relatively low rate.[276] This low rate would have decreased the efficiency with which the cement would have displaced mud from the annular space, especially given Halliburton's predictions regarding the impact of a reduced number of centralizers.[277] This, in turn, would have increased the risk of mud-related cementing failures such as channeling, contamination, and gas flow.

Using a Reamer Shoe Instead of a Float Shoe May Have Increased the Risk of Cement Failure

BP could have decreased cementing risks using a float shoe. Like a reamer shoe, a float shoe is a rounded piece of equipment that attaches to the bottom of a casing string and helps to guide the string down. But unlike the reamer shoe, the float shoe includes a check valve that functions much like the valves in the float collar. That extra check valve serves as an extra line of defense against cement contamination and helps keep debris and contaminants away from the float collar's valves. The existence of the extra check valve also helps to ensure proper cement placement by preventing cement from flowing back up the casing. Industry engineers often install float shoes where they are concerned about cement contamination.[278] While cement contamination was (or should have been) a concern at Macondo, BP chose not to install a float shoe on its production casing.

Rathole Issues Could Potentially Have Increased the Risk of Cement Failure

BP chose not to take precautions against **rathole** swapping. The rathole, again, is the open section of wellbore below the end of the production casing. As described above, mud in this portion of the wellbore can swap places with cement in the shoe track if the mud is less dense than the tail cement. This can contaminate the cement in the shoe track or potentially create a flow path through the cement in the shoe track.

One common precaution to guard against this phenomenon is to pump a small volume of dense mud into the rathole. If this mud is more dense than the cement, it will tend to stay in place rather than swap places with the cement. Although early BP plans called for this procedure,[279] the engineers eventually chose not to do it because the volume was small and improper placement could cause ECD concerns.[280] They reasoned that this created relatively small risks: the density differential between the mud and tail cement was not large, and the rathole volume was relatively low.[281] Halliburton personnel admitted after the blowout that rathole swapping could create a problem, but they had not considered the issue before pumping the job.[282]

Rig Personnel May Not Have Converted the Float Valves

Although rig personnel and BP concluded that they successfully converted the float valves, the Chief Counsel's team finds that the float valves at Macondo may not have actually converted.[283] Unconverted float valves could have compromised the bottomhole cement job at Macondo.

Rig Personnel Never Pumped Mud at the Rates Weatherford Specified to Convert the Float Collar

Planning documents and pumping data show that rig personnel never pumped mud down the well at sustained rates high enough to ensure float valve conversion. While well plans specified mud circulation rates that would have converted the float valves, actual rates never exceeded 4.3 bpm—significantly less than the 6 bpm required to convert the equipment:

Table 4.3.4

	Flow Rate Needed to Convert	Differential Pressure Needed to Convert
BP September 2009 Plan[284] and BP January 27, 2010 Final Drilling Program[285]	12 bpm maximum	~ 600 psi
BP April 12, 2010 Drilling Plan[286] and BP April 15,2010 Drilling Plan[287]	8 bpm minimum	~ 500 to 700 psi per Weatherford recommendation
Weatherford Manufacturer Recommendation[288] Adjusted for 14.1 ppg Mud Weight[289]	6 bpm[290]	600 psi[291]
April 19 actual[292] steady flow rate never exceeds 4.3 bpm,[293] which would result in a differential pressure of approximately 328 psi[294]		

BP contracted Stress Engineering Services, a third-party engineering firm, to conduct post-blowout testing on float collars similar to those used at Macondo.[295] On the basis of this testing, BP asserts that temporary surge flow rates caused by sudden pressure changes in the well would have converted the float equipment.[296] BP contends that there were two potential surge-inducing events. The first was the sudden drop in pressure from 3,142 psi once mud circulation began.[297] The second was during the cement job when the bottom plug burst at 2,392 psi.[298]
The Stress Engineering analysis shows that the Macondo float valves may have converted because of pressure-induced surge flows. But if this in fact happened, it was by happenstance, not design. More importantly, without having pumped mud consistently through the float collar at Weatherford-prescribed rates, BP personnel had no sound basis for concluding that the float valves had converted. And the later float check that they performed was not a reliable indicator that the float collar had sealed.[299] BP's own report agrees.[300]

Although rig personnel deemed the Macondo float check to be a success, the check was actually inconclusive because of the small density differential between the cement and drilling mud in the well. Halliburton's April 18 model predicted 38 psi of differential pressure.[301] (The Chief Counsel's team's calculations based on actual volumes pumped indicate a u-tube pressure of about 56 psi—an inconsequential difference.[302]) A Weatherford representative confirmed that 38 psi of differential pressure is "pretty tiny,"[303] and other experts agree that it would be hard to detect.[304] The small u-tube pressure would also have meant that any cement backflow may have been too small and gradual for rig personnel to detect in the time that they monitored for flow.

The Drop From 3,142 psi May Have Been Due to a Clogged Reamer Shoe or a Failure of the Float Collar System

Rig personnel assumed that the sudden drop in pump pressure from 3,142 psi indicated that they had converted the float collar. If the float collar did not actually convert, then something else must have caused this pressure drop. The Chief Counsel's team has identified two possible explanations.

The Reamer Shoe May Have Been Clogged

The first possibility is that the unexpected pressure increases and sudden pressure drop may have been caused by a clog in the reamer shoe that eventually cleared in response to elevated pump pressure.

Drilling mud pumped down the Macondo production casing and through the float collar assembly had to exit the bottom of the casing through three 1⅝-inch holes ("circulation ports") at the

Figure 4.3.20. Clogged reamer shoe.

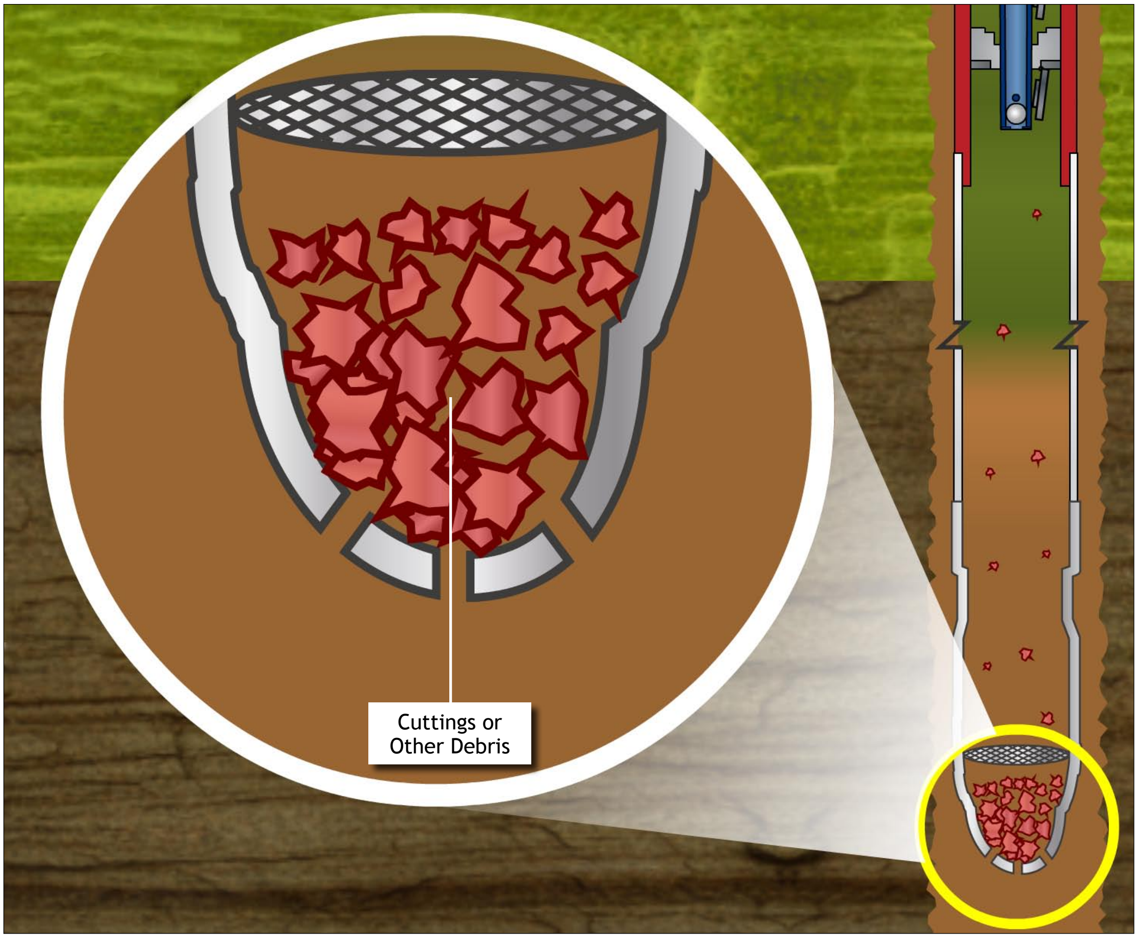
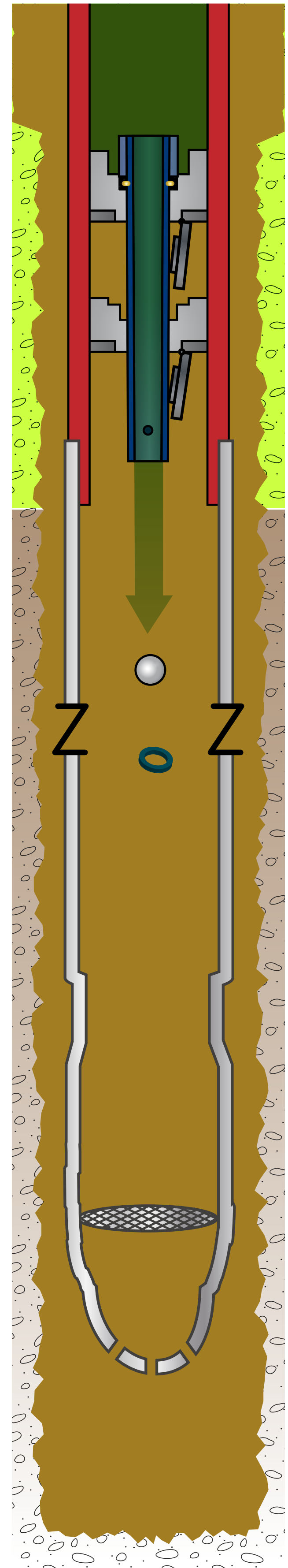


Figure 4.3.21. Ball forced through tube.



bottom of the reamer shoe.[305] Debris and/or cuttings may have plugged these holes during the course of casing installation as shown in Figure 4.3.20. This could explain why the rig crew was unable initially to establish mud circulation after landing the production casing. It could also explain why the pressure dropped suddenly from 3,142 psi—that pressure may have been sufficient to clear a clog in the reamer shoe to allow mud to flow again.

After the blowout, at least two BP personnel identified a clogged reamer shoe as a factor that may have complicated the float conversion process. Morel told BP investigators soon after the blowout that he believed the reamer shoe may have been plugged.[306] Sepulvado, who was onshore at the time of the blowout, similarly told the Chief Counsel's team that the only reason such high pressures would have been needed was because differential pressure was not getting to the ball,[307] which may have been caused by a clogged reamer shoe.[308] Besides interfering with float conversion, a clogged reamer shoe could have complicated cementing by altering cement flow out of the reamer shoe.

The Ball May Have Been Forced Through the Auto-Fill Tube

A second possibility, shown in Figure 4.3.21, is that the sudden pressure drop may have been caused when pump pressure forced the ball inside the auto-fill tube through the end of the auto-fill tube. The collar that would normally have retained the ball within the auto-fill tube was held in place with brass pins. It is possible those pins and the collar failed, allowing the ball to pass through.[309] This would have left the auto-fill tube in place between the float valves and created a path for flow in either direction.

If the ports in the bottom of the auto-fill tube were clogged, the rig pumps may have placed enough force on the collar to shear the brass pins instead of the pins holding the auto-fill tube in place. Clawson informed Morel on April 19 that it would only take 1,300 psi of pressure to force the ball through the collar without converting the float valves.[310] It is not apparent whether Morel considered or informed others of this possibility.[311]

Unconverted Float Valves Would Have Increased the Risk of Cement Failure

If rig personnel never converted the float valves at Macondo, it would have left an open flow path through the float collar assembly. That flow path may have allowed cement to flow back into the casing from the annular space outside the casing, which would in turn have left less cement in the annular space. This flow would also have: (1) increased the potential for contamination of the shoe track cement with mud; (2) brought foamed cement from the annulus into the shoe track (which should have contained only unfoamed tail cement); and (3) allowed any nitrogen that broke out of the foamed cement to compromise the shoe track cement. The open flow path would also have made it easier for any hydrocarbons that bypassed the cement to flow through the float collar assembly.[312]

Properly Converted Float Equipment Is Not a Reliable Barrier to Hydrocarbon Flow

The Chief Counsel's team does not believe that even properly converted float valves would have constituted a reliable physical barrier to hydrocarbon flow. While BP's internal investigation report appears to state that float valves could be a barrier,[313] several senior BP personnel disagreed with that statement.[314] Weatherford does not consider float equipment a barrier to hydrocarbon flow and instead provides the equipment only to prevent backflow of cement.[315] The API similarly states only that "float equipment is used to prevent the cement from flowing back into the casing when pumping is stopped"[316] and does not include float equipment among its list of subsurface mechanical barriers.[317]

Management Findings

BP's Management Processes Did Not Force the Macondo Team to Identify and Evaluate All Cementing Risks and Then Consider Their Combined Impact

BP engineers failed to fully appreciate the cementing challenge they faced at Macondo. Every deepwater cement job presents a technical challenge, but the Macondo cement job involved an unusual number of risk factors. Several were inherent in the conditions at the well. BP and Halliburton created several others during the course of the design and execution of the primary cement job. The list includes:

- narrow pore pressure/fracture gradient;
- use of nitrogen foamed cement;
- use of long string casing design;
- short shoe track;
- limited number of centralizers;
- uncertainty regarding float conversion;

- limited pre-cementing mud circulation;
- decision not to spot heavy mud in rathole;
- low cement volume;
- low cement flow rate;
- no cement evaluation log before temporary abandonment; and
- temporary abandonment procedures that would severely underbalance the well and place greater stress than normal on the cement job.

BP engineers certainly recognized some of these risk factors and even tried to address some of them. For instance, the team asked Halliburton to use additional spacer during the cement job to compensate for the limited pre-cementing circulation.[318] But it does not appear that any one person on BP's team—whether in Houston or on the rig—ever identified all of the risk factors. Nor does it appear that BP ever communicated the above risks to its other contractors, primarily the Transocean rig crew. For instance, Transocean was never aware that Halliburton had recommended more than the six centralizers that were used.[319]

More importantly, there is no indication that BP's team ever reviewed the *combined impact* of these risk factors or tried to assess the overall likelihood that the cement job would succeed, either on their own or in consultation with Halliburton. Rather, BP appeared to treat risk factors as surmountable and then forgettable. For instance, after Guide had decided to use only six centralizers despite the risk of channeling, one BP engineer wrote to another team member, "But who cares, it's done, end of story, [we] will probably be fine and we'll get a good cement job."[320] Reviewing the aggregate effect of risk factors may not even have led BP to change any of its design decisions. But if done properly, it may have led BP engineers to mitigate the overall risk in ways that could have prevented the blowout. Indeed, a major oil company representative stated that the risk factors at Macondo were so significant that his organization would not have counted the Macondo cement job as a barrier to annular flow outside the production casing even after a successful negative pressure test.[321]

A closely related issue is that once BP's engineering team properly identified a risk, it often examined and addressed the risk without a full appreciation of other risks its *response* might create. For instance, BP's team focused almost exclusively on the risk of lost returns in designing its cementing program. BP engineers may well have been right to view this as the largest individual risk they faced. But they failed to consider the secondary impacts of their numerous responses to that risk, which included reducing pre-cementing circulation, cement volume, and cement flow rate. Those responses may have increased the overall likelihood of cement failure even as they decreased the potential for lost returns.[322]

BP Did Not Properly Manage Design Changes and Procedural Modifications

Impact of Changes to Its Mud Circulation Plan

BP's engineering team does not seem to have recognized that late-stage changes to mud circulation plans might impact float collar conversion. Before the early April lost circulation event, the team intended to circulate fluids at 8 bpm—a rate that would have converted the float valves. But the BP team later reduced the planned circulation rate to 4 bpm because of ECD concerns—a rate that would not have converted the float valves according to the manufacturer's specifications. The April 15 drilling plan highlights the disjoint: It simultaneously calls for circulation rates of *at least* 8 bpm to convert the float equipment but recommends circulating mud at 3 bpm "to keep ECD below 14.5 ppg."[323] Circulating at 8 bpm would clearly exceed that ECD threshold, and an independent expert found this inconsistency irreconcilable.[324]

If BP had recognized that lowering planned circulation rates could impact float collar conversion, it could have solved the problem easily. Weatherford can readily produce float collars that convert at different flow rates—changing the conversion flow rate can be as simple as changing the number of shear pins or the size of the holes in the bottom of the auto-fill tube. BP could therefore have used a different float collar assembly that would have converted at the lower flow rates it planned. Its engineering team does not appear to have considered this possibility or the internal inconsistency in its drilling plan.

Centralizer Sub Procurement

By January 2010, BP's well plan had called for at least 11 centralizers for its final production casing string. Weatherford, BP's centralizer supplier, recommends that its clients notify it of equipment needs four to six weeks in advance.[325] But BP engineers waited until the last day of March to begin the process of ordering centralizers, leaving themselves less than three weeks of lead time. If BP had ordered centralizers earlier, Weatherford personnel would have had ample lead time to manufacture more centralizer "subs" to meet BP's request,[326] and BP's team would not have been forced to decide whether to use slip-on centralizers.

When BP eventually ordered centralizers from Weatherford, the engineer who made the request only asked for a range of "7-10" centralizers rather than the 11 centralizers that BP's January 2010 plan specified. It appears that BP engineers relied on their own estimates of centralizer needs given well conditions, but it is unclear why those conditions would have been any different than when the original well plan was designed.[327] When Weatherford responded that it had only six centralizers in stock, BP's team viewed this as sufficient even though it was less than the number the engineer requested and about half the number called for in the well plan. There is no indication that BP's team even asked whether additional centralizer subs could be manufactured in time, nor is there any evidence that BP attempted to secure acceptable equipment from other suppliers besides Weatherford.[328]

Managing equipment procurement is a key part of safe and efficient offshore drilling. By failing to plan centralizer procurement properly, BP's engineering team forced itself to choose between using only a few centralizer subs, adding slip-on centralizers that its team believed posed mechanical risks, or incurring costs by waiting for Weatherford to manufacture additional subs at the last minute.

Decision Not to Run Additional Slip-On Centralizers

BP also mismanaged its engineering response to Halliburton's advice to add centralizers. First, BP and Halliburton could have considered centralizer availability during the mid-April design review that led them to determine they could cement a long string without exceeding ECD thresholds. Instead, they simply assumed optimal centralization without examining whether they had the materials on hand to achieve it.

Once Gagliano advised BP's team that additional centralizers would be needed to avoid channeling, the team responded by procuring 15 additional centralizers immediately. The immediate response reflects appropriate levels of concern, but also highlights the problems with making complex design changes at the last minute. The engineering team believed that it was ordering slip-on centralizers with integrated stop collars even though a Weatherford representative sent the team specifications that showed otherwise. It appears that BP's team did not review these specifications carefully, perhaps because of time pressure. Careful review here would have avoided last-minute decision making on April 16.[329] The decision to send these additional centralizers prompted Guide to complain to his supervisor Sims the next day:

> David, over the past four days there has been so many last minute changes to the operation that the WSL's have finally come to their wits end. The quote is "flying by the seat of our pants." More over we have made a special boat or helicopter run everyday. Everybody wants to do the right thing, but this huge level of paranoia from engineering leadership is driving chaos.... The operation is not going to succeed if we continue in this manner.[330]

After the centralizers were delivered, BP made its final decision not to use them without careful engineering review. After Guide found out the type of centralizers Weatherford had provided, he argued that they should not be used because of recent problems that BP had experienced with the design.[331] (Guide mentioned time and cost concerns as well.) But Guide and the rest of the BP team appear to have been motivated by personal experience rather than any disciplined analysis. Notably, they did not consult the Weatherford centralizer technician that they had flown to the rig, who could have provided valuable input on the relative risks of centralizer hang-up.[332] It is not even clear whether BP believes *now* that its Macondo team should or should not have used the centralizers; the Bly report states that the team "erroneously believed that they had received the wrong centralizers."[333]

BP also did not examine whether the mechanical risks of running additional centralizers outweighed the cementing risks of *not* using them. BP's team could easily have asked Gagliano to run a new model to predict the impact of using only six centralizers and could have provided up-to-date wellbore and well design data to improve the accuracy of those predictions. The team also could have consulted its in-house cementing expert Cunningham.[334] BP could have asked Halliburton to incorporate Morel's irregular placement of centralizers into its model, rather than simply relying on Morel's apparent ad hoc analysis to determine their placement. It did none of these things.[335] BP's engineering team may have been motivated by skepticism of Halliburton's modeling,[336] but this was the only analytical tool the team had at the time.

Having made a last-minute decision to use fewer centralizers than planned, BP's team should have recognized that decision would increase the risks, first, of lost returns (by increasing ECD), and second, of overall cementing failure. Instead, the team appears to have viewed its centralizer decision-making process as a "miss-step"[337] that had little significance after it occurred. Had BP at least noted the risks of using fewer centralizers than it had planned, its rig personnel and contractors might have been better prepared for the events that followed.

Communication of Centralizer Decisions Hampered Risk Identification and Management

Once BP decided not to run the additional centralizers, it made no effort to inform its contractors of its decision. Weatherford's technician only learned that the centralizers would not be used by asking about the issue hours after the installation should have occurred.[338] When he did learn of it, the technician was concerned enough to call his supervisor—he had never been on an installation job that had been canceled.[339] But neither he nor anyone else at Weatherford expressed concerns to BP. Instead, the technician's supervisor instructed him to defer completely, stating: "Third party, we do what the company man requests."[340]

Gagliano only learned about the decision from Tabler, who in turn learned it from Chaisson, who in turn learned of the decision by happenstance.[341] Gagliano stated that he was "frustrated,"[342] and emailed BP's team to confirm the decision and to ask if he should rerun his models, but nobody ever responded to him.[343] Gagliano eventually updated the cement model on his own, but his model lacked up-to-date information from BP, and he sent it only after the casing run had begun. A prompt response from BP to Gagliano might have improved the Macondo team's appreciation of the risks they faced.

Use and Management of Modeling Results

BP engineers mismanaged their use of Halliburton's computer cementing models.

It is unclear why BP did not review Halliburton's modeling results more carefully and continually update Halliburton's data after April 14. Industry experts say that it is not uncommon for operators to depart from cementing rules of thumb (such as full bottoms up) in reliance on favorable modeling predictions. But operators who do so should continually update such models to ensure that their departures do not cause cementing problems. At Macondo, BP appears to have done little after April 14 to ensure that Halliburton was using up-to-the-minute data. BP provided Halliburton a caliper log but not updated information about reservoir pressure and centralizer placement. Instead, it appears that BP's engineering leadership paid little attention to refining the model once it produced results they found favorable.

BP's willingness to disregard Halliburton's April 18 modeling predictions is especially questionable given the degree to which BP relied on the model's earlier predictions. On April 14, BP relied almost exclusively on a Halliburton model to conclude that it could successfully cement a long string casing. At this time, BP engineers knew that the model was based on incomplete data. BP then disregarded the April 18 predictions even though the concerns it identified were similar to those that motivated more serious analysis on April 14. BP's apparent skepticism of the value of the April 18 results is hard to square with its near-total reliance on the April 14 results.

BP Did Not Adequately Evaluate the Significance of Float Conversion Difficulties

BP's management and review of the float collar conversion process were inadequate. As explained above, BP should have secured different float equipment once it modified its planned circulation rates. BP also mismanaged its evaluation of the float conversion process on the rig. BP rig personnel properly consulted their shore-based engineering team after encountering difficulties when converting the float collar. But after reinitiating circulation at much higher pressures than expected, BP's team appears to have assumed the float valves converted. If the team had instead reviewed the data carefully, it would have recognized that it had not yet circulated mud in excess of 4.3 bpm and might have increased circulation to ensure conversion.

Making matters worse, BP and Transocean personnel then tried to explain away concerns about lower-than-predicted circulation pressures by blaming a faulty pressure gauge. BP has since pointed out that the circulating pressures predicted by M-I SWACO were erroneous and that the circulation pressure observed was actually what should have been expected. But rig personnel believed at the time that M-I SWACO's predictions were accurate, and yet there is no evidence that they took steps to confirm the gauge was actually faulty or tried to replace it.[344]

If BP or Transocean had adequately considered the possibility that the float valves did not convert, they could have undertaken efforts to mitigate the potential risks. For instance, one standard industry tactic to address float valve failure is to add pressure inside the casing system after pumping cement and to thereby counterbalance any u-tube pressure that might otherwise induce flow back through open float valves.[345]

BP Focused Excessively on Full Returns as an Indicator of Cementing Success

The Macondo team's approach to cement evaluation at Macondo was flawed. Because the team focused its attention so heavily on the risk of lost returns, it overemphasized the significance of full returns as an indicator of cementing success.

Receiving full returns showed that cement had not flowed into the weakened formation but provided little or no information about: (1) the precise location where the cement had ended up; (2) whether channeling had occurred; (3) whether the cement had been contaminated;[346] or (4) whether the foamed cement had remained stable. Similarly, reports of on-time top plug arrival indicated, at most, only one thing for certain: The cement flowed through the float collar. (Morel's report that the bottom plug bumped early may suggest that mud contaminated the cement during job placement.) Accordingly, BP's technical guidance documents do not list reports of full returns or on-time plug bumping as indicators of zonal isolation.[347]

BP engineers also considered lift pressure a positive indication. Company technical guidance documents state that lift pressure can provide a coarse indication of TOC (if not zonal isolation) but that it "is unlikely to provide a sufficiently accurate estimate" of TOC when "cement and mud weights are very similar,"[348] as they were at Macondo. While one BP engineer stated that lift pressure was "easy" to see at Macondo,[349] another admitted after the blowout that it was not a valid confirmation of good cement placement.[350] Industry experts who reviewed the data after the fact were also skeptical. The Chief Counsel's team spoke with several experts who agreed that the roughly 100 psi pressure increase that rig personnel observed at Macondo after the bottom plug landed was too low to be a reliable indication that cement had turned the corner and flowed up into the annulus.[351] One described 100 psi of lift pressure as "nearly unreadable."[352] That relatively small pressure increase might have been caused by cement "turning the corner" into the annulus, but it might also have been caused by friction from cement flow.[353]

Better management would have encouraged the BP team to question the overall value of its pressure and volume indicators. BP's own report appears to agree. It states:

> A formal risk assessment might have enabled the BP Macondo well team to identify further mitigation options to address risks such as the possibility of channeling; this may have included the running of a cement evaluation log.... Improved technical assurance, risk management and management of change by the BP Macondo well team could have raised awareness of the challenges of achieving zonal isolation and led to additional mitigation steps.[354]

Rather than aiding decision making, the Macondo team's cementing decision tree reinforced the flaws in its analytic approach. Proper risk management in a complex engineering project requires a constant awareness of risks and potential risks. The decision tree instead encourages a simplified linear approach in which complex risks (such as the risk of failed cementing) can be forgotten or ignored on the basis of simple and incomplete indicators (such as partial returns or lift pressure).

Most Operators Would Not Have Run a Cement Evaluation Log in This Situation, but BP Should Have Run One Here, in Part Because of Its Chosen Temporary Abandonment Procedures

At least some personnel appear to have believed that the Macondo team was planning to run a cement bond log no matter what. On April 20, a BP completions engineer emailed Morel to ask for cement bond log data. When Morel responded "No CBL," the completions engineer wrote "Can you explain why? I thought y'all were planning to run one."[355]

A cement evaluation log would have provided more direct and reliable information about the cement job than pressure and volume indicators on which BP relied. While most operators would not have run a cement evaluation log until the completion phase, BP should have run one here[356] for at least two reasons. First, BP engineers recognized or should have recognized that this was a "finesse" cement job that presented higher-than-average risks.[357] Full returns would not identify if channeling had occurred; a cement bond log could.[358] Second, BP's temporary abandonment procedures would force the rig crew to rely on this finesse cement job as the sole hydrocarbon barrier in the Macondo wellbore. Alternatively, BP should have sought other means for addressing the risk of unsuccessful cementing.

Halliburton Did Not Adequately Inform BP of Cementing Risks or Suggest Design Alternatives

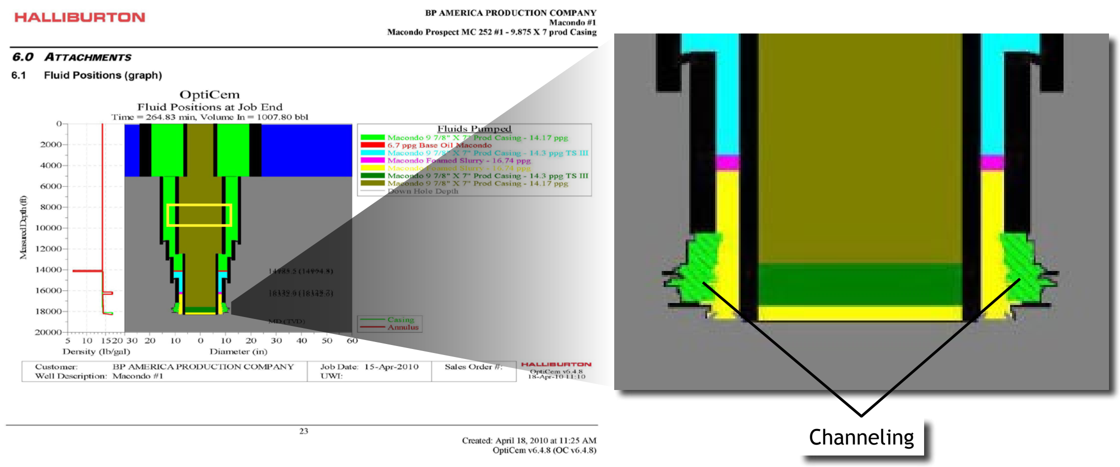
Halliburton did not provide BP the full benefit of its corporate cementing expertise. Since the blowout, senior Halliburton personnel have repeatedly and forcefully emphasized the complexity and difficulty of the Macondo cement job and the limitations of indicators such as full returns.[359] But Halliburton's personnel did not raise all of these concerns before the blowout, let alone emphasize them with the same force.

It appears that Gagliano mentioned the possibility of cement channeling to individual BP engineers on April 15 and then again later on April 19.[360] But he did not flag the concern in his emails or express serious reservations. Gagliano told Congressional investigators that he "recommended to BP that they use 21 centralizers" but admitted that he "did not think there would be a well control issue."[361]

Gagliano also testified that he would have recommended that BP perform a cement bond log given the reduction in the number of centralizers but did not do so because "we do not recommend running a [cement] bond log"[362] and, anyway, he "was never asked."[363] Although Gagliano was present when BP discussed criteria for the cement bond log, he never told anyone full returns alone could not identify channeling.[364] Moreover, the only risk factor that Halliburton identified during the design process was the relatively low number of centralizers. Halliburton did not discuss any other risk factors or recommend other design changes that might have mitigated those risks. Halliburton personnel were aware that BP's design called for a low cement volume and a low cement flow rate. They also knew of the decision not to circulate bottoms up, the float valve conversion difficulties, and the low post-conversion circulating pressures. [365] But they never raised concerns about these risk factors, let alone offered BP an independent assessment of the overall likelihood of success of the cement job.

The format of Halliburton's modeling reports exacerbated communication difficulties. After the blowout, Halliburton personnel argued that the reports included predictions of channeling and gas flow that BP engineers should have heeded.[366] Halliburton could have highlighted these warnings—along with overall assessments of cementing success—in a simple summary early in

Figure 4.3.22. Page 23 of Halliburton's April 18, 2010 OptiCem™ report.

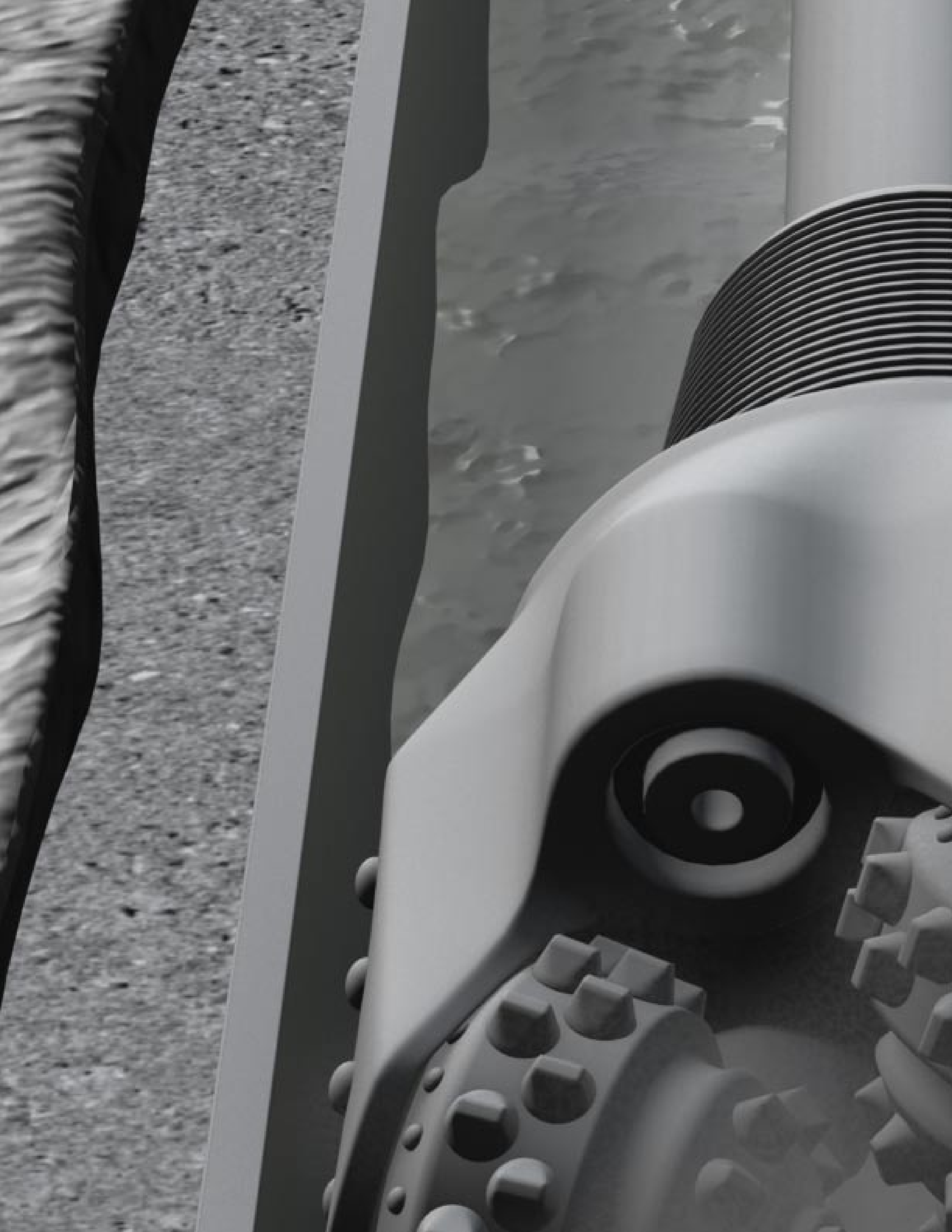


Halliburton

Halliburton personnel explained the green areas as predicted channeling.

the report. Instead, the reports presented information in an obscure and unnecessarily technical manner. (For instance, as shown in Figure 4.3.22, the reports present channeling predictions only as unexplained jagged lines in a well diagram).[367] As a result, BP engineers reviewed the predictions in a cursory fashion, if at all.[368]

Halliburton missed another opportunity to communicate its concerns when it reported the overall success of its cement job. Chaisson expressed complete satisfaction with the cement job in his post-job report but later clarified that "[cementing] was successful on the surface. As far as being successful downhole, actually if it were successful at getting zonal isolation, I cannot be sure of that."[369] Halliburton explains the difference between its pre-blowout reports and its post-blowout skepticism by suggesting that it is BP's responsibility as the operator to evaluate the significance of cementing indicators and BP's responsibility to mitigate risks at the well. Whether that turns out to be true as a legal matter, Halliburton could have helped avoid the blowout if it had highlighted the risks of the cement job and the limitations of the few cementing indicators it had reviewed.



Chapter 4.4 | Foamed Cement Stability

BP and Halliburton chose to cement the final Macondo production casing into place using nitrogen foamed cement. That technology offered several advantages at Macondo, but it also posed a risk: An improperly designed or incorrectly pumped nitrogen foamed cement slurry can be unstable and lead to a failed primary cement job. Data from pre- and post-job laboratory testing lead the Chief Counsel's team to conclude that the foamed cement slurry pumped at Macondo was very likely unstable. The Chief Counsel's team finds that Halliburton failed to review properly the results of its own pre-job tests, and that a proper review would have led Halliburton to redesign the cement slurry system. The Chief Counsel's team also finds that BP inadequately supervised the cement design and testing process.

Foamed Cement

Cementing personnel create **nitrogen foamed cement** by injecting inert nitrogen gas into a base cement slurry. This produces a slurry that contains fine nitrogen bubbles. If the system is properly designed, the bubbles will remain evenly dispersed in the slurry as it cures, and the set cement will retain the bubbles in the same form.

Foamed cement offers two principal technical advantages. First, the nitrogen bubbles in the foamed cement slurry make the overall cement mixture less dense than the base cement slurry. Second, cementing personnel can adjust the density of the foamed cement slurry in response to well conditions by adjusting the rate at which they inject the nitrogen into the base cement slurry. Whereas a base cement slurry typically weighs about 15 pounds per gallon (ppg), foamed cement can weigh as little as 5 ppg.[1] All other things being equal, a low-density column of cement in the annular space around a well casing will exert less hydrostatic pressure on the formation than a high-density column of cement. As a result, using a low-density foamed cement can reduce the risk of formation breakdown. Such a breakdown may result in the loss of cement into the formation, compromising zonal isolation and reducing the productivity of the well over the long term.[2]

Risks of Unstable Foamed Cement

A foamed cement system must exhibit good foam **stability**.[3] A stable nitrogen foamed cement slurry will retain the nitrogen bubbles internally and maintain its design density as the cement cures. The result is hardened set cement that has tiny, evenly dispersed, and unconnected nitrogen bubbles throughout. If the foam does not remain stable as the cement cures, the small nitrogen bubbles may coalesce into larger ones, potentially rendering the hardened cement porous and permeable to fluids and gases, including hydrocarbons.[4] If the instability is particularly severe, the nitrogen can **break out** of the cement, with unpredictable consequences.[5] While technical authorities do not appear to have definitively determined the effects of pumping unstable foamed cement downhole, they uniformly agree that only stable foamed cement designs should be used.[6]

Foamed Cement Testing

When designing a nitrogen foamed cement system, it is critical to test the stability of the foamed slurry.[7] The American Petroleum Institute (API) has published recommended procedures for conducting **foam stability tests**.[8] The technician mixes a volume of base cement slurry with air (not nitrogen) in a sealed blender to generate a foamed slurry of the same density that will be used in the field (see Figure 4.4.1). The laboratory may then conduct foam stability tests using one of two methods.

Figure 4.4.1. Foam testing apparatus.

Five-blade blender.

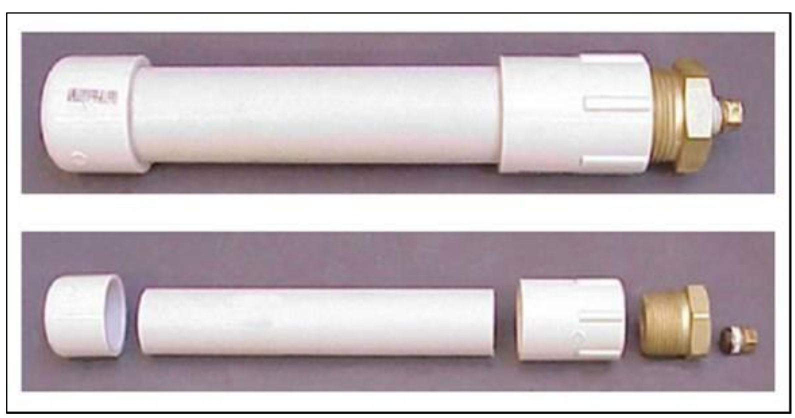
API RP 10b-4

The first method involves pouring a sample of the foamed cement into a graduated cylinder (see Figure 4.4.2). After two hours, the technician visually examines the foamed slurry for signs of instability, such as large coalescing bubbles or cement density variations caused by nitrogen bubble migration or escape.

The second method involves pouring the foamed cement into a plastic cylinder, sealing it, and then allowing it to cure and set (see Figure 4.4.3). The technician then removes the solid cement sample from the cylinder and measures the density of solid cement at the top, middle, and bottom of the sample. If there are density variations from top to bottom, or if the densities are equal to one another but significantly higher than the target density, the foamed cement is deemed unstable.

Figures 4.4.2 and 4.4.3. Foam testing apparatus.

Sambhav N. Sankar



API RP 10b-4

Left: Graduated cylinder for unset foam test.
Above: Curing mold for set cement tests.

The API lists five signs of foamed slurry instability in the laboratory:[9]

- more than a trace of free fluid;
- bubble breakout noted by large bubbles on the top of the sample;
- excessive gap at the top of the specimen;
- visual signs of density segregation as indicated by streaking or light to dark color change from top to bottom; and
- large variations in density from sample top to bottom.

None of these criteria is quantitative. All rely to some degree on the judgment of laboratory personnel or cementing experts.

Foamed Cement at Macondo

Decision to Use Foamed Cement

BP and Halliburton planned from the very beginning to use foamed cement technology for at least some of the cementing work at Macondo. It is common to use foamed cement on the first few casing strings in a deepwater well because shallow formations are often too weak to withstand the hydrostatic and dynamic pumping forces exerted by a heavier, normal-density cement slurry. (The *Marianas* crew and Halliburton cemented at least two of Macondo's early casing strings with foamed cement.)[10]

Operators use foamed cement less frequently for deeper casing strings and in applications for which synthetic oil-based mud is being used as a drilling fluid. While at least one operator—Shell—often uses foamed cement in deepwater Gulf of Mexico production casings, BP appears to have had relatively little experience with using the technology for this purpose.[11]

To cement the final long string production casing at Macondo, Halliburton and BP began planning as early as February 2010 to start with a base slurry having a density of 16.7 ppg and then to add enough nitrogen to reduce the density to 14.5 ppg. It appears that BP drilling engineer Brian Morel first raised the idea of using foamed cement technology for the production casing. He suggested the idea because using foamed cement might provide long-term strength benefits over the life of the well.[12] Halliburton cementing engineer Jesse Gagliano agreed that foamed cement would be useful at Macondo.[13] But an internal BP cementing expert cautioned Morel as early as March 8 that:

> Foaming cement after swapping to [oil-based drilling mud] presents some significant stability challenges for foam, as the base oil in the mud destabilizes most foaming surfactants and will result in N_2 [nitrogen] breakout if contamination occurs. This drives the need for a lot of attention to the spacer programs and often results in non-foamed cap slurries being placed on top of the foamed slurry to mitigate breakout.[14]

The early April lost returns problems appear to have further solidified the decision to use nitrogen foamed cement. According to BP and Halliburton's calculations, using the lighter foamed cement would reduce the risk of fracturing the formation at the well and thereby reduce the risk of losing returns during the cementing process.

Pre-Blowout Cement Testing

When the *Deepwater Horizon* arrived at Macondo to replace the *Marianas*, it had on board a large quantity of cement dry blend that Halliburton had originally designed for use at Kodiak #2, the previous BP well the *Horizon* crew had drilled.[15] Gagliano had designed the primary features of that blend in late 2009.[16]

Dry Blend. The term **dry blend** refers to the combination of dry cement components that are blended together onshore for use on the rig. The Macondo dry blend included Portland cement, two different grades of silica powder, potassium chloride, a proprietary antisettling agent, and a proprietary flow-enhancing additive. The rig cementing team added water, two liquid chemical additives, and a glass fiber material to the dry blend to produce the base slurry.

On February 10, Gagliano instructed technicians in Halliburton's Broussard, Louisiana, laboratory to conduct pilot tests on a cement slurry recipe based on this dry blend. The slurry recipe specified the amount of water and the type and quantity of liquid chemical additives that should be mixed with the dry blend to produce the cement slurry. If the dry blend had been unsuitable—either because of its original design or because it had degraded during storage—then Halliburton could have delivered a new dry blend to the rig for use at Macondo.

Foamed Cement Pilot Testing

Gagliano's February 10 pilot cement design listed the precise amount of liquid retarder, surfactant, and fresh water that the laboratory should add to the dry blend to produce a cement slurry for testing. The "recipe" that Halliburton tested in February was identical to the recipe that it eventually used at Macondo, with one exception: The February recipe included roughly twice the amount of liquid chemical "retarder" that Halliburton eventually used (0.20 gallons per sack (gal/sack) vs. the final 0.09 gal/sack) and correspondingly less water. (Adding retarder extends the setting time of cement.)[17] The laboratory used the dry blend from the *Deepwater Horizon* but used local tap water and stock liquid chemicals rather than water and liquid chemicals from the rig.

The Broussard laboratory conducted several tests in February, including two separate foam stability tests.[18] Both foam stability tests were "set" slurry tests, in which personnel poured foamed cement into a cylinder, allowed it to cure for 48 hours, and then examined the density of the top and bottom of the set cement cylinder.

Laboratory personnel appear to have conducted the first February foam stability test on or about February 13. The top and bottom of this sample weighed 16.8 ppg and 17.6 ppg, respectively. These measurements indicated serious instability because they differ significantly from each other, and they are both higher than the target density of 14.5 ppg. *The test measurements showed either that: (1) The lab personnel were unable to generate a proper foamed slurry; (2) gas bubbles migrated within the foamed slurry; (3) gas escaped from the slurry before it could set; or (4) some combination of these things occurred.*

Laboratory personnel appear to have conducted a second February foam stability test on or about February 17. The top and bottom of this sample weighed 15.9 ppg and 15.9 ppg, respectively.

While these two measurements were identical, the data still indicated serious instability because both measurements were significantly higher than the target density of 14.5 ppg. Again, nitrogen gas must have escaped from the tested slurry before it could cure, or the lab personnel had been unable to generate a proper foamed slurry.

These two February 2010 lab tests should have caused Halliburton technical personnel to conclude that the foamed cement Halliburton was planning to pump at Macondo was likely unstable.

Three other facts about the February tests are worth noting. First, laboratory personnel did not condition the cement before conducting the February 13 foam stability test but conditioned the cement for two hours before conducting the February 17 test. Second, rheology test results showed that the yield point of the base slurry was quite low. This can be an independent warning that the base slurry may be unstable and that a foamed slurry prepared from that base slurry may also be unstable.[19] Third, time-lapse strength testing showed that the pilot cement recipe set extremely slowly, suggesting that the recipe included too much retarder.

Halliburton did not report any of the February pilot testing data to BP until March 8.[20] On that date, Gagliano attached an official data report of the February test results to an email in which he discussed his recommended plan for cementing one of the Macondo casing strings.

The official data report included only the results of the February 17 foam stability test, in which the top and bottom portions of the set cement both weighed 15.9 ppg. (The official laboratory reports list the results in terms of specific gravity (SG) rather than pounds per gallon.) Because the top and bottom weights matched, the test did not demonstrate density segregation, but the test was still a clear failure because both weights were significantly higher than the target density.

For some unexplained reason, Halliburton's official data report to BP *incorrectly* stated that laboratory personnel had not conditioned the cement prior to the February 17 foam stability test.

Apparently, Halliburton did no further testing of the proposed Macondo cement slurry until April 2010, as the final production casing planning was under way.

April 13 Pre-Job Testing

On April 1, Morel sent an email to Gagliano, BP senior drilling engineer Mark Hafle, BP operations engineer Brett Cocales, and Quang Nguyen of Halliburton requesting that Halliburton begin testing cement for the final production casing cement job. Morel wrote, "This is an important job and we need to have the data well in advance to make the correct decisions on this job."[21] Gagliano responded on the same day with an email stating that he had already run the February pilot tests, and that he would run further tests "[o]nce I get samples from the rig sent into the lab" and once he had the latest data on the downhole temperatures at the well.[22] Gagliano attached the same official laboratory report that he had sent on March 8.

Gagliano appears to have first ordered additional testing on April 12.[23] This time, the laboratory tested samples of dry blend, additives, and water from the rig, and used a design recipe that was nearly identical to the one that Halliburton eventually pumped. (The tested recipe contained slightly less retarder than the pumped recipe—0.08 gal/sack instead of 0.09 gal/sack.) According to Gagliano, the main goal of this test was to determine how much retarder the recipe should use.[24]

It appears that the laboratory performed a foam stability test on this recipe on or about April 13 and conditioned the cement slurry for 1.5 hours at 180 degrees before conducting the test.[25] They finished the test on or about April 15. After curing, the top and bottom of the set cement sample weighed 15.7 ppg and 15.1 ppg, respectively.

This April 13 test result, just a week before the blowout, indicated serious instability.[26]

On April 17, Gagliano sent an email to Morel, Cocales, and BP drilling engineer team leader Gregg Walz and attached two official laboratory reports.[27] The data reports included results from various tests on cement slurry recipes with two slightly different retarder concentrations: 0.08 gal/sack and 0.09 gal/sack. BP and Halliburton had discussed increasing the retarder concentration in order to compensate for the fact that they planned to pump the cement at a low rate. The slow pumping rate would translate to increased cement travel time, which would in turn raise the risk of premature cement thickening.

Neither data report included the results of the April 13 foam stability test (or any other foam stability test). *Gagliano did not otherwise alert BP to the foam stability test results*. Gagliano's cover email discussed the data from recently completed thickening time tests, presumably because this measured the cement characteristic that would vary depending on retarder concentration. Gagliano also stated that he had not yet obtained compressive strength results for the final cement recipe that BP planned to use—which included slightly more retarder.

Morel complained to Hafle that Gagliano had started the compressive strength tests later than he should have. Morel asked Hafle if Morel would be "out of line" by sending the following message to BP wells team leader John Guide and Walz:

> I need help next week dealing with Jesse. I asked for these lab tests to be completed multiple times early last week and Jesse still waited until the last minute as he has done throughout this well. This doesn't give us enough time to tweak the slurry to meet our needs.... As a team we requested that [Gagliano] run another test with 9 gals on Wednesday, I know the first [compressive strength] test had issues, but I do not understand what took so long to get it underway and why a new one wasn't put on right away. There is no excuse for this as the cement and chemicals we are running has been on location for weeks.[28]

Hafle agreed that Morel's concerns were reasonable and that BP should ask Halliburton to replace Gagliano soon (a request that BP appears to have made earlier as well).[29] Morel and Hafle conveyed their concerns to Walz, Cocales, and Guide, and on April 18, Walz responded that he and Guide would be meeting soon with Halliburton.[30]

Meanwhile, on April 17, Morel responded directly to Gagliano's email. Morel wrote:

> I would prefer the extra pump time with the added risk of having issues with the nitrogen. What are your thoughts? There isn't a compressive strength development yet, so it's hard to ensure we will get what we need until it[']s done.[31]

Morel thus told Gagliano that he would prefer to alter the cement slurry recipe to include more retarder to increase the thickening time (or "pump time") of the cement. In the same email, he appears to have recognized that adding more retarder would potentially increase the risk of nitrogen foam instability.

Laboratory personnel appear to have conducted a second April foam stability test on or about April 18.[32] They used the same amount of retarder (0.08 gal/sack) but conditioned the cement at 180 degrees for three hours—the longest period yet. The top and bottom of the set cement sample weighed 15.0 ppg and 15.0 ppg, respectively.

While these numbers are the same as each other, they are both 0.5 ppg higher than the target of 14.5 ppg. This means one of two things. First, laboratory personnel may have generated a foamed cement slurry that *initially* weighed 15.0 ppg and retained that density throughout the test. If this was the case, however, the laboratory documents should at least have noted the difficulty; API standards state that if laboratory procedures generate a foamed slurry density that is above the design density, "it will be difficult to obtain the proper foamed cement density in the field, and the slurry should be redesigned."[33]

Second, laboratory personnel may have generated a foamed slurry of 14.5 ppg, but some nitrogen gas may have escaped from the slurry as it set, making the slurry more dense. Because the change from 14.5 to 15.0 ppg is not indisputably "large" within the meaning of API testing criteria, this might suggest that the foamed cement was stable. Halliburton appears to contend that this is what happened and argues that the April 18 test shows that its cement slurry was stable.

Internal documents provided by Halliburton do not clarify which of these two things happened.

Availability of April 18 Test Results

The documents also do not establish conclusively *when* Halliburton completed its April 18 foam stability testing. Handwritten notes in the documents suggest that laboratory personnel began the test at 2:15 a.m. on April 18,[34] and Halliburton has confirmed this time in correspondence to the Chief Counsel.[35] Halliburton at one point stated publicly that the test took 48 hours to complete.[36] If that were true, the test results would not have been complete until at least 2:15 a.m. on April 20, which would have been after the time Transocean's rig crew and Halliburton's cementing personnel *finished* pumping the primary cement job at 12:35 a.m. on April 20.[37]

Six months after the blowout, and after the Chief Counsel's team publicly questioned the stability of the Macondo cement design and the timing of lab testing, Halliburton still had not determined whether its personnel had completed the April 18 foam stability test before pumping the Macondo job.[38] Finally, eight months after the blowout, Halliburton informed the Chief Counsel that it had "learned more about the specific facts surrounding the cement lab testing," including that "the second April foam stability test was finished before the final cement job started."[39] In the words of its counsel:

> Halliburton can now demonstrate that an email notification was sent to Jesse Gagliano on April 19, 2010, at approximately 4:14 pm indicating that all tests associated with the final cement job were then "finished in lab," more than three hours before the cement job commenced. Attached to this letter is a copy of a spreadsheet containing the "web log" data referenced above and explained further in Halliburton's January 7th letter to you. This constitutes objective evidence…that the foam stability test was run in less than 48 hours and that the test was completed prior to the final cement job.[40]

Halliburton contended that the "finished" notification "would not have been generated had the foam stability test failed or been incomplete."[41]

The Chief Counsel's team cannot accept or reject Halliburton's contentions based on these statements by its counsel. While Halliburton did provide a one-page spreadsheet that it views as "objective evidence" of the timing of its test, the Chief Counsel's team cannot decipher the document (displayed as Figure 4.4.4) without the aid of Halliburton personnel.

Halliburton flatly refused to produce any witness who could explain this document (or any of the other timing and testing issues discussed above) in a transcribed interview.

Figure 4.4.4. Halliburton evidence of test times.

IP Address	UserID	Time Stamp	Web Server Log Information
		18.04.2010 09:52:03	From: noreply@halliburton.com; To: jesse.gagliano@halliburton.com; Subject of Email: Daily Summary Report
34.34.133.22	HBAM242	2010-04-18 20:44:50	GET /pls/viking/labdb_report.stepTwo?p_trid=73909 HTTP/1.1
34.34.133.22	HBAM242	2010-04-18 20:44:58	GET /pls/viking/labdb_report.stepThree?p_trid=73909&p_tsid=151852 HTTP/1.1
34.34.133.23	-	2010-04-19 02:49:26	GET /osso_login_success?urlc=v1.4~5E653963CE68A4ED43251CE43A205D9B7086D803CCD13504E93F7EDF2732CFF6B5E3D3C3D127BCED52C25007DEE121C4867F0A323F67857B2056890280CDFC276BB16694F32B2E517C34927EE5F3421FAE4DDD7B19F9A62217A75D98E86E0458774B5442DEACD45A94060FC6F84ED7CA753A3110216F883F68CCC6E1DCD36A7D7EE6EA99B9941A2F46D0A007F83612A1C80AF89CF3E1CD36079B34349877C6EF0801CA307D846FD6B91BB7BD9D93CCD005E52554B7B66A7D354B877ED5A7C45D824A2D7584E66100764AE13369CB2D5E9B0324C30262DDA8A5ED681B9F2771A64FE5C0F1DD6ADC47C0C73E9508698E6A779C20B90D5626F110209015A07D32D95E542D4971949FD79B82645EA26D68BC1B73F1E4528ACE1558AC30B311F1619B3CA6025ACF3EAD1D0B10747619CAF240468D01B991ECB5CB14C3E93EE3C484795C6DA60084EF081A661C18FDF8C195B21FEA9DCD749C07D3CFD43C29A9165898D409359D739095C534F3CAB83DBBF84D HTTP/1.1
		19.04.2010 09:52:08	From: noreply@halliburton.com; To: jesse.gagliano@halliburton.com; Subject of Email: Daily Summary Report
		19.04.2010 16:04:13	From: noreply@halliburton.com; To: jesse.gagliano@halliburton.com; Subject of Email: Test Status Changed (US-73909/2)
34.34.133.23	HX11269	2010-04-19 16:13:27	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=806072 HTTP/1.1
34.34.133.23	HX11269	2010-04-19 16:13:28	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=813603 HTTP/1.1
34.34.133.23	HX11269	2010-04-19 16:14:25	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=813603&p_message=Results%20successfully%20updated HTTP/1.1
34.34.133.23	HX11269	2010-04-19 16:14:32	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=806072 HTTP/1.1
34.34.133.23	HX11269	2010-04-19 16:14:33	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=813603 HTTP/1.1
		19.04.2010 16:14:43	From: noreply@halliburton.com; To: jesse.gagliano@halliburton.com; Subject of Email: Request 73909, Status: Finished in Lab
34.34.133.23	HX11269	2010-04-19 16:14:46	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=813603 HTTP/1.1
34.34.133.23	HX11269	2010-04-19 16:14:47	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=806072 HTTP/1.1
34.34.133.22	HX46076	2010-04-20 08:36:37	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=806072 HTTP/1.1
34.34.133.23	HX46076	2010-04-20 08:36:37	GET /pls/viking/labdb_test.testresults?p_request_id=73909&p_slurry_id=150924&p_test_id=43&p_request_test_id=813603 HTTP/1.1
		20.04.2010 09:52:11	From: noreply@halliburton.com; To: jesse.gagliano@halliburton.com; Subject of Email: Daily Summary Report
34.34.133.22	-	2010-04-20 11:31:10	GET /osso_login_success?urlc=v1.4~78AECBB7DF3421DD9F6E1C845ED7C386DE726BE1B2FEFD0F1D9669DB7EED49633BB73DB640D6B484F56E44FA456B225B05EDFA2F96C9E5746825AB490FE2BC191E21939751490E4610FC302D5388AB16E487526D7CEBDFDCD3D36256E14B7BD9941406DB3169C961B56D01AAEEC3A0B77054D1B9CD7739644856C67DE5FF4C6CD6A9C4E50A10E61076E13624C863709003F5A1CFA9C4F6E6B7ADA26F7F2137EB8639F3710D5E4B13A60D60B4F55E5472F673D6D0516F206C34815F3337CC9F1F482317526A47ED03BC5CD212B71B24A511513D26C63F2A697CD02682641532D96BFE33AAD34BA87A71395D802D528FF058447F4BDEC0C66E9BCA2CA64893EE4CF3E2FE2FC7B82B9A49CA1FF6B0A2C354851DF5729CB6A0E31CE58E2837390911D8F9EE1E1645D331D7403CD66B04F38A6ED5B251AE849E0C5CE19E0FA6F7DCBBC9B429F477A6BC7557574C6D20503333D5E9759002670D43DAB9B479C6BC6DA91D3F03065B3B5119 HTTP/1.1

Halliburton

Significant problems remain even if the Chief Counsel's team accepts Halliburton's assertions about when the April 18 test had been completed. While Halliburton argues that its computer system generated a notice that the April 18 test results were available before its personnel pumped the cement job, it has carefully avoided saying that any of its engineers actually *knew* that the results were available, let alone *reviewed* them, before pumping the job. Indeed, BP documents show that Halliburton first reported the April 18 result to BP on April 26, six days after the blowout.[42] And while Halliburton contends that the "finished" notification meant that the April 18 foam stability test did not fail by its standards, it refuses to identify those standards, let alone the person who actually applied them.

Halliburton presumably would not deny this information to the Chief Counsel if it were favorable to the company.

Post-Blowout Cement Testing

Testing by BP

BP's internal investigation raised several questions about Halliburton's cement slurry design and pre-job testing procedures.[43] BP asserted that the final April 18 foam stability test "indicated foam instability based on the foamed cement weight of 15 ppg."[44]

BP also commissioned third-party testing by CSI Laboratories, an independent cement consulting company.[45] CSI could not conduct these tests on the actual materials that had been used at the Macondo well because those materials sank into the ocean with the rig.

CSI also could not conduct these tests using the precise off-the-shelf ingredients specified by the cement slurry recipe because Halliburton refused to provide its proprietary additives to CSI. CSI therefore developed a model slurry to mimic the characteristics of the slurry used at Macondo. CSI prepared the model slurry by mixing commercially available cement and additives according to the final Macondo cement recipe. To replace proprietary Halliburton additives, CSI used third-party chemicals that served similar purposes (for example, using a commercially available third-party retarder instead of Halliburton's proprietary SCR-1000 retarder). Despite these differences, BP's investigation team asserted that the model slurry was "sufficiently similar to support certain conclusions concerning the slurries actually used in the Macondo well."[46]

CSI reported that foamed cement generated from the model slurry was unstable under several test conditions. Based in large part on this analysis, BP's investigation team concluded in its report that "the nitrified foamed cement slurry used in the Macondo well probably experienced nitrogen breakout, nitrogen migration and incorrect cement density."[47]

Testing by Chevron and Chief Counsel's Team

The Chief Counsel's team conducted its own independent tests of cement slurry stability on behalf of the Commission.

The Chief Counsel's team worked with an independent expert and cement experts from Chevron to conduct these tests.[48] Halliburton recognized that Chevron's laboratory personnel were highly qualified for this work; Chevron maintains a state-of-the-art cement testing facility in Houston, Texas, and employs a staff of cement experts to supervise cement design and testing for its oil wells. Halliburton also agreed to supply the Chief Counsel's team with off-the-shelf cement and additive materials of the same kind used at the Macondo well. Although these materials did not come from the specific batches used at the Macondo well, they are in all other ways identical in composition to the slurry pumped there.

Halliburton refused to provide the Chief Counsel's team with full details of the methods and protocols that its laboratory used to conduct its February and April cement tests. *Most notably, Halliburton refused to provide any information on whether and how its staff had conditioned the cement before conducting the foam stability tests.* (At the time Chevron conducted its tests, Halliburton had not yet produced any internal laboratory documents to the Commission staff. Halliburton later provided some internal documents that disclosed conditioning times.) When the Chief Counsel's team sought input from BP and other parties regarding these and other issues, Halliburton demanded that the team refrain from doing so.[49] The Chief Counsel's team agreed to honor Halliburton's request by working solely with Chevron experts and an independent expert to develop protocols for testing Halliburton's cement materials.

Chevron conducted numerous tests on the Commission's behalf. Chevron's laboratory report states that many of its results "were in reasonable agreement" with results reported by Halliburton. However, Chevron's staff did not obtain foam stability test results that agreed with Halliburton's. Instead, Chevron's report stated that its staff was "unable to generate stable foam with any of the tests" that they conducted to examine foam stability.[50] Chevron's testing strongly suggests that the foamed cement slurry actually used at Macondo was unstable. Appendix D is Chevron's letter to the Chief Counsel's team that accompanied its report.

Technical Findings

The Foamed Cement Slurry Used at Macondo Was Very Likely Unstable

Of all the tests done so far to evaluate the stability of the Macondo foamed cement slurry design, only one (the April 18 Halliburton pre-job test) even arguably suggests that the design would be stable.

Even the April 18 test result predicts only borderline stability. Industry experts believe that the three-hour high-temperature conditioning regimen for this test biased it in favor of success. Several have stated that cement laboratories should not condition a slurry sample *at all* before running foam stability tests, let alone at such elevated temperatures.[51] They reason that during field cementing operations, crews do not usually mix or circulate the base slurry before foaming it with nitrogen. Halliburton explained that its laboratory personnel derived the conditioning time from pumping time,[52] and then contended in writing that there is "sound operational basis" for conditioning cement in a laboratory prior to foam stability testing.[53] But when the Chief Counsel's team asked Halliburton to provide "[a]ny scientific study or other document" supporting the latter statement,[54] Halliburton cited only one thing: API Recommended Practice 10b-2.[55] Section 15 of that document states, "The cement slurry is conditioned to simulate dynamic placement in a wellbore." But this document discusses methods for testing the static stability of *unfoamed* cement slurries. By contrast, API's practice recommendations for testing *foamed* cement do not mention pre-test conditioning at all.

Halliburton also declined to provide any information that would help the Chief Counsel's team determine whether lab personnel had difficulty generating a proper density foamed slurry sample on April 18, which might account for the 15.0 ppg density of that sample.

Indeed, Halliburton repeatedly flatly refused Chief Counsel's personal requests for documents or recorded testimony regarding many otherwise unsupported assertions from Halliburton's lawyers. For example, Halliburton's lawyers have consistently asserted that the April 18 foam stability test produced passing results. Commission staff requested "any document specifying or prescribing the conditioning time…test duration, or success criteria" for this and other tests, and requested the opportunity to conduct and transcribe interviews with Gagliano, his supervisors, and any "individual or individuals competent to testify regarding standard Halliburton laboratory practices."[56] Halliburton produced no documents and provided no witnesses. It noted that it had allowed the Chief Counsel to interview Gagliano and a Halliburton cement expert early in the investigation—*before* the Chief Counsel had learned of the failed February and April tests and *before* the Chief Counsel's testing had identified concerns with the Macondo cement slurry recipe. Halliburton then stated:

> [H]alliburton is compelled to view these requested "interviews" as being more in the nature of adversarial depositions designed to defend the [Chief Counsel's] preliminary conclusions as opposed to furthering an objective evaluation of what occurred. Given Staff's apparent shift in purpose, Halliburton respectfully declines to make such witnesses available.

In contrast to the April 18 test, 12 other stability tests—three by Halliburton and nine by Chevron—clearly predict that the foamed cement slurry design would be unstable. One can debate the significance of these tests individually. For instance, the February Halliburton tests predicted severe instability but were performed with a recipe containing more retarder, which can potentially reduce slurry viscosity and make it more unstable.[57] And one can also debate how well laboratory testing approximates field conditions.[58] However, the sheer number of failed foam stability tests combined with other indicia of instability (discussed below) lead the Chief Counsel's team to conclude that the foamed cement slurry used at Macondo was very likely unstable.

The Commission-sponsored tests further suggest that the Halliburton base slurry was unstable even *before* being foamed with nitrogen. Chevron's lab report notes that its personnel observed base slurry "settling" in six of the nine tests it performed. The base slurry also consistently showed a very low yield point, which can be a warning that the slurry will be unstable before and after foaming. Base slurry instability also could have severely compromised the bottomhole cement job at Macondo.

The Chief Counsel's team notes that Halliburton's Broussard laboratory did retain a small sample (1.5 gallons) of dry blend material from the *Deepwater Horizon*. This material was left over from Halliburton's April pre-job testing process. At the time of this writing, the federal government had taken custody of the material and was holding it pending laboratory testing. Industry experts have informed the Chief Counsel's team, however, that the dry blend material has probably chemically degraded by now to the point where any laboratory testing results would be inconclusive. If this is the case, Halliburton's four pre-blowout tests and the Commission's nine post-blowout tests are the most probative information regarding the performance of the Macondo cement slurry.

Halliburton May Not Have Reviewed the April 18 Test Results Before Beginning the Cement Job

Currently available data lead the Chief Counsel's team to conclude that Halliburton did not fully review its April 18 foam stability tests before pumping the Macondo cement job. While Halliburton states that its personnel completed the test at approximately 4:14 p.m. on April 19, it has provided neither documentary nor testimonial evidence to show that its personnel actually reviewed that data before pumping the job or communicated it to anyone at BP.

Once again, the Chief Counsel repeatedly offered Halliburton opportunities to produce witnesses with relevant knowledge to be examined by the Chief Counsel. Halliburton consistently refused to support its lawyers' assertions with sworn testimony or additional documentation.

Even if Halliburton did review final test results before pumping the cement job, it did not transmit those results to BP until April 26—six days after the blowout.[59] On that date, Jesse Gagliano sent BP an official laboratory data report containing the results of the second April foam stability test. Halliburton never sent BP the results of the April 13 foam stability test.

Halliburton Should Have Redesigned the Slurry Before Pumping It

Halliburton personnel should have redesigned the Macondo slurry before pumping it. Richard Vargo, a Halliburton cementing expert who testified at the Commission's hearings on November

8, 2010, appears to agree. He testified: "I don't think at this point I would choose to run this slurry."[60]

Table 4.4.1 summarizes Halliburton's internal laboratory data concerning the stability of the Macondo cement slurry.

Table 4.4.1

Test ID	Apparent Date	Target Density in ppg	Top Density in ppg	Bottom Density in ppg	Retarder Concentration in gal/sack	Conditioning Time in Hours	Stable?	Available Before Job?	Sent to BP Before Job?
65112/1	Feb. 13	14.5	16.8	17.6	0.20	0:00	Unstable	Yes	No
65112/3	Feb. 17	14.5	15.9	15.9	0.20	2:00*	Unstable	Yes	Yes
73909/1	Apr. 13	14.5	15.7	15.1	0.08	1:30	Unstable	Yes	No
73909/1	Apr. 18	14.5	15.0	15.0	0.09	3:00	Arguable	Uncertain	No

* Reported to BP as 0:00

Halliburton personnel should have redesigned the cement slurry design after receiving the February pilot test results. Both of the February foam stability tests clearly indicated that the pilot cement design was severely unstable.

Halliburton has repeatedly argued that these pilot tests do not reliably predict the stability of the cement system used during the Macondo cement job. Specifically, Halliburton notes that the final cement design was different and that the final well conditions differed from BP and Halliburton's assumptions in February.[61]

These facts are irrelevant to the question of whether Halliburton should have redesigned its slurry. The pilot test results showed that Halliburton's then-current design would be unstable under BP's then-available predictions of well conditions.[62] This should have led Halliburton to inform BP of the problem and to redesign the slurry as necessary. Instead, the Chief Counsel's team has found nothing to suggest that Halliburton personnel seriously considered the issue.

Halliburton missed another clear warning in April. The April 13 foam stability test data should again have prompted Halliburton to inform BP of stability problems and to redesign the slurry immediately. Halliburton personnel have since testified that they would not use a slurry that generated such test results.[63]

Halliburton contends that its laboratory personnel conducted the April 13 test improperly and that the results are therefore "irrelevant."[64] Halliburton cites a laboratory document to support this conclusion, but the Chief Counsel's team and an independent cementing expert were unable to confirm the conclusion merely by reviewing that document. The Chief Counsel asked Halliburton to provide witness testimony to support this assertion, but Halliburton declined.

Even if Halliburton personnel did conduct the April 13 test improperly, this is again irrelevant to the question of whether Halliburton should have redesigned the slurry. As of April 15, the *only* data Halliburton had in hand predicted that the Macondo slurry design would be unstable, and Halliburton had very little time before it would have to pump the cement job. Under the circumstances, Halliburton should have immediately redesigned the slurry and immediately retested the new design. It appears that some Halliburton personnel recognized the problem and responded by rerunning the test two days later with additional conditioning time, perhaps hoping for a more favorable result. But that response was wholly inadequate given how soon the job was to be pumped and the fact that the April 13 test results were consistent with the two earlier February test results. On April 15 or shortly thereafter, Halliburton should have immediately alerted BP to the stability problem and immediately begun redesigning the Macondo slurry.

The Chief Counsel's team is not certain why Halliburton chose not to redesign its slurry. There are at least two possible explanations. One is that the Halliburton personnel who were responsible for approving or recommending the design were unaware of the foam stability test results or their importance. The other is that those personnel *were* aware of the results but did not consider them sufficiently problematic.[65]

Management Findings

Halliburton Mismanaged Its Cement Design and Slurry Testing Process

The number and magnitude of errors that Halliburton personnel made while developing the Macondo foamed cement slurry point to clear management problems at that company. In addition to the errors described above, the Chief Counsel's team believes that Halliburton personnel:

- began pumping the Macondo job without carefully reviewing laboratory foam stability data and without solid evidence that the foamed cement design would be stable;
- reported foam stability data to BP selectively, choosing in February not to report the more unfavorable February 13 test, and choosing in April not to report the more unfavorable April 15 test result (although Halliburton contends these results were erroneous);
- selected the pre-test conditioning time informally, choosing different conditioning times (ranging from no time to three hours) in each of the four foam stability tests without any stated explanation;
- assumed, without apparent scientific basis, that conditioning the base slurry before foaming was scientifically equivalent to foaming the cement then pumping it down the well; and
- recommended a cement design without conducting any formal internal review of that design. Notably, the only design element that Halliburton manipulated between February and April was retarder concentration, even though BP's well design changed significantly during that period and even though bottomhole well conditions were unknown in February. Halliburton has provided no evidence that a supervisor or senior technical expert ever reviewed the final cement slurry design.

To date, Halliburton has not provided any documents or testimony to suggest that established company rules or guidelines prohibited its personnel from doing any of these things. And if such guidelines did exist, it appears that Halliburton failed to enforce them on the Macondo job.

Halliburton's Lab Report Format Complicated Data Evaluation

Halliburton's lab reports to BP were highly technical. As with its modeling runs, discussed in Chapter 4.3, Halliburton did not provide a summary of results, an overall assessment of slurry design, or even reference values for any of the laboratory data it provided to BP. Halliburton could have improved the value of the reports by, for instance, inserting its criteria for a successful foam stability test alongside the reported foam stability data. This would not only have helped BP personnel understand the significance of relatively obscure numerical data, but might also have helped Halliburton personnel do so as well.

BP Did Not Adequately Supervise Halliburton's Work

BP technical guidance documents for cementing emphasize the importance of timely cement testing,[66] and BP Macondo team members themselves recognized that timely cement testing was important.[67] The team also expressed internal concern well before the blowout that Jesse Gagliano was not providing "quality work"[68] and was not "cutting it"[69] by waiting too long to start important tests. They had already asked Halliburton to reassign Gagliano, and Halliburton had apparently agreed to do so.[70] But while BP engineers discussed "how to handle Jesse's interim performance" by email on the very day of the blowout,[71] they did not double-check his work or supervise him more closely pending his replacement.

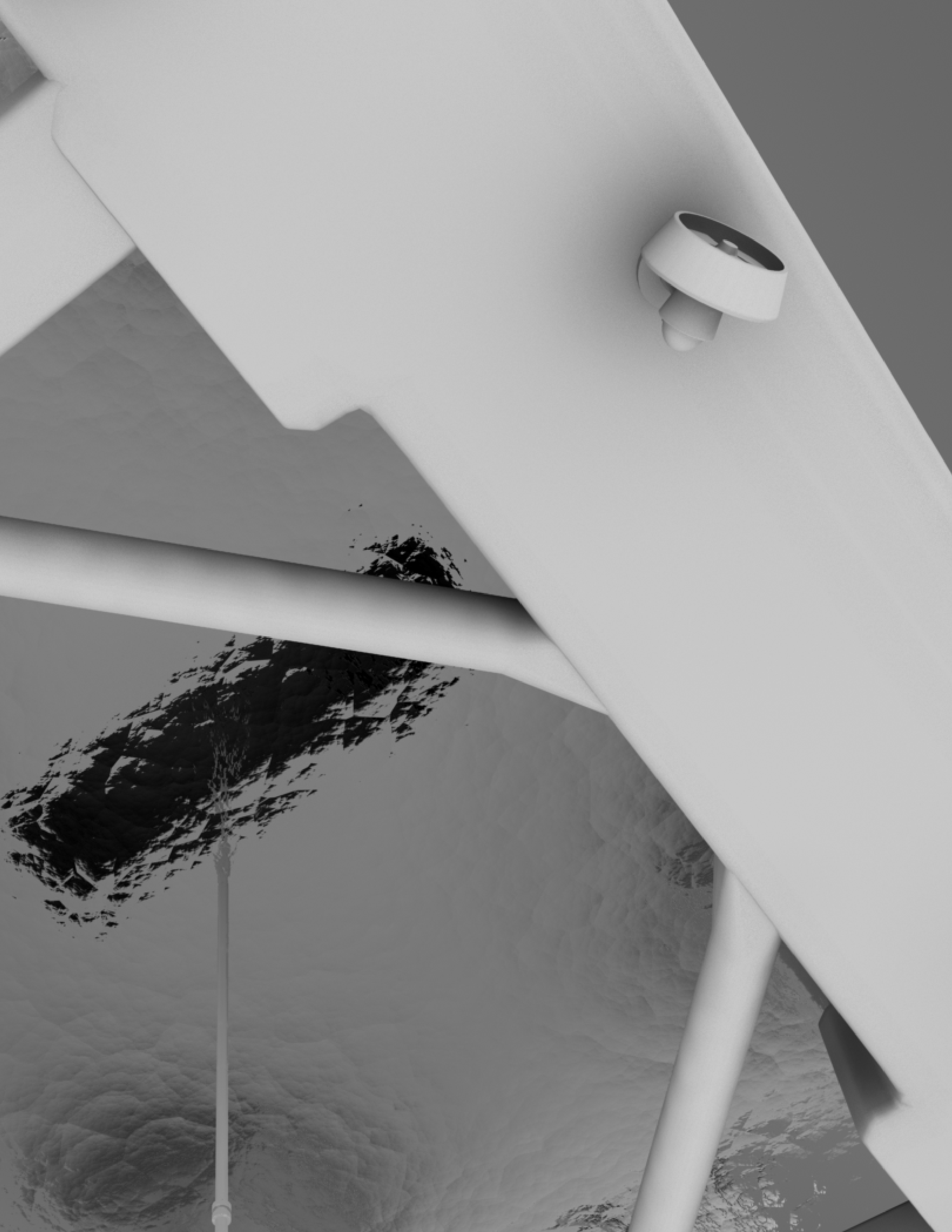
In particular, although BP personnel recognized the "significant stability challenges" of using foamed cement for the Macondo production casing,[72] and that changes to the retarder concentration in the cement design might increase the risks of foam instability,[73] BP does not appear to have insisted that Halliburton complete its foam stability tests—let alone report the results to BP for review—before ordering primary cementing to begin.[74] When asked why, a BP representative said, "I think we didn't appreciate the importance of the foam stability tests."[75]

BP also did not adequately supervise the slurry design process or review earlier test results.[76] BP documents show that its engineers questioned Gagliano's slurry recipes in other instances.[77] But the Chief Counsel's team found nothing to suggest that BP questioned the Macondo slurry recipe, even after the slurry failed to perform properly during the cement job for the 16-inch casing string. (A BP engineer explained that Halliburton dismissed the failure as the result of cement contamination and noted that this is a typical response for any cementing contractor.)[78] While the Macondo team consulted its in-house cementing expert on other issues, they did not ask him to review the foamed slurry recipe.[79] The expert raised several concerns as soon as he reviewed the recipe after the incident—among other things, he expressed surprise that the slurry design did not include a fluid loss additive and did include a defoamer additive.[80]

BP's failures are especially troubling because it had previously identified several relevant areas for concern during a 2007 audit of Halliburton's capabilities. In that year, BP hired Cemtech Consulting to review a Halliburton foamed cement job on the Na Kika project in the Gulf of Mexico.[81] Cemtech's report identified several issues that mirror problems at Macondo. For instance, Cemtech observed that Halliburton's initial foamed slurry design at Na Kika "had tendencies to stratify" (that is, was unstable) and required redesign. Cemtech also made broader observations such as:

- "The HES [Halliburton] Fluids Center chemists and senior lab technicians do a very good job of testing cement slurries, but they do not have a lot of experience evaluating data or assisting the engineer on ways to improve the cementing program."
- "COMMUNICATION and DATA TRANSFER/DOCUMENTATION could be improved to help avoid unnecessary delays or errors in the slurry design testing, data reporting, and evaluation of the cement program."
- "Lab reports could be improved! They are difficult to evaluate; often incomplete; and are submitted WITHOUT supporting lab charts and DATA to validate the test results. LAB DATA SHOULD BE MANDATORY!"

It does not appear that BP pressed Halliburton or its own Gulf of Mexico engineering teams to improve in these areas.



Chapter 4.5 | Temporary Abandonment

BP developed a temporary abandonment procedure for Macondo that unnecessarily introduced significant risks into the operation. BP disagrees with this finding and argues instead that the specific procedure it used at Macondo was necessary under the circumstances.[1] The Chief Counsel's team disagrees. BP could have avoided the additional risks created by the procedure by making a few simple changes.

Temporary Abandonment

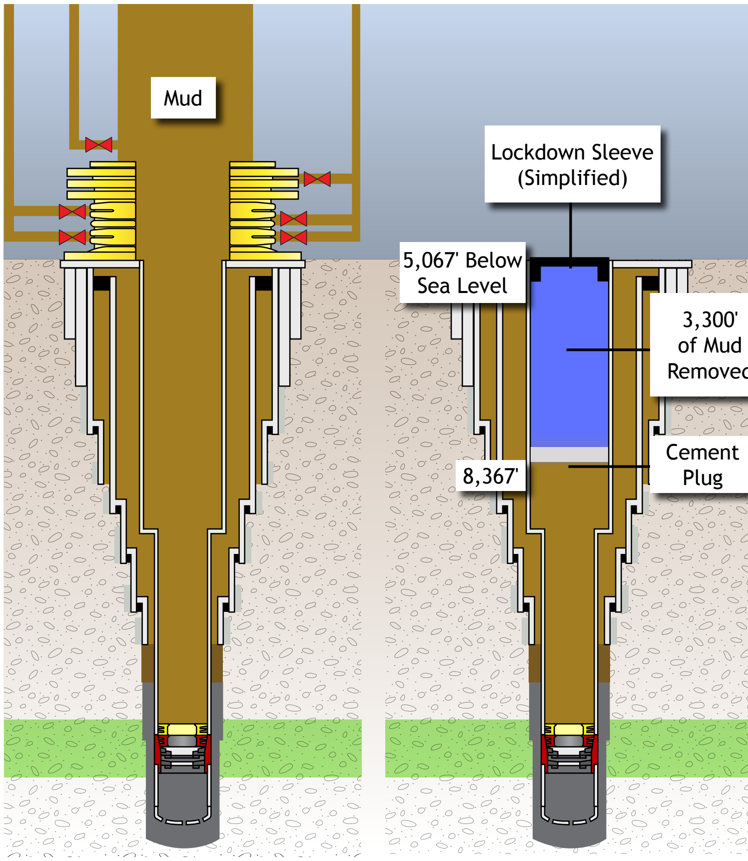
Temporary abandonment refers to the procedures that a rig crew uses to secure a well so that a rig can safely remove its blowout preventer (BOP) and riser from the well and leave the well site. BP planned to have the *Deepwater Horizon* temporarily abandon the Macondo well after the rig finished its drilling operations so that another rig could later move to the Macondo site and complete the well construction process. (That rig would perforate the casing and install equipment to collect hydrocarbons.)

Many operators divide operations in this way to save costs; deepwater drilling work requires a large and expensive rig like the *Horizon*, but completion work can be done by a smaller and less expensive rig.

There does not appear to be any standard industry procedure for temporary abandonment. Instead, different operators perform the process differently based on their internal technical guidance, the design preferences of individual engineers, the capabilities of individual rigs, and the needs of particular wells.

At the time of the Macondo incident, MMS regulations did impose some important requirements on operators that wished to temporarily abandon a well. The regulations specified that the operator must set "a retrievable or a permanent-type bridge plug or a cement plug at least 100 feet long in the inner-most casing" and that the top of the plug must be "no more than 1,000 feet below the mud line"[2] (as discussed in Chapter 6). Operators typically refer to this plug as a **surface plug** to distinguish it from other plugs that may be set deeper in the well. Despite the name, surface plugs are not set at the surface or even at the very top of the well.

Figure 4.5.1. Planned configuration after temporary abandonment.



After finishing cementing the production casing (left), the rig crew began temporary abandonment procedures that would have allowed the *Deepwater Horizon* to remove its riser and BOP from the well and move on to another job (right). The blowout occurred before the rig crew set the cement plug and lockdown sleeve.

Temporary Abandonment at Macondo

BP's temporary abandonment procedure for the Macondo well had the following basic sequence:

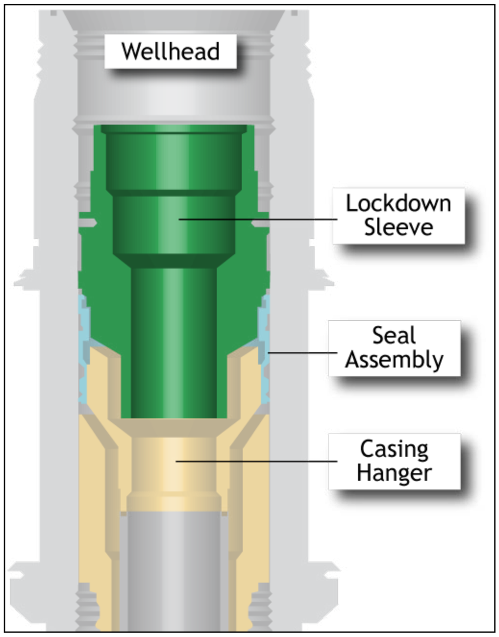
- run the drill pipe into the well to 8,367 feet below sea level (3,300 feet below the mudline);
- displace 3,300 feet of mud in the well with seawater, lifting the mud above the BOP and into the riser;
- perform a negative pressure test to assess the integrity of the well (including the bottomhole cement) and ensure that outside fluids (such as hydrocarbons) are not leaking into the well;
- displace the mud in the riser with seawater;
- set the surface cement plug at 8,367 feet below sea level; and
- set the lockdown sleeve (LDS) in the wellhead to lock the production casing in place.

This procedure is notable in at least two respects. First, it called for rig personnel to set a surface plug deep in the well, 3,000 feet below the mudline. (BP requested and obtained authorization to depart from MMS regulations in order to do this.) Second, the procedure called for rig personnel to displace the wellbore and riser to seawater before setting the surface plug.

After the incident, the BP Macondo team uniformly explained that it developed its particular temporary abandonment procedure in order to set a lockdown sleeve during temporary abandonment and to do so as the last step in the process.[3] The lockdown sleeve decision triggered a cascade of derivative decisions regarding the temporary abandonment procedure that are summarized here and described in greater detail below.

- BP engineers decided to set the lockdown sleeve during temporary abandonment because the *Deepwater Horizon* could do that job more quickly and efficiently than a completion rig.
- Having decided to set the lockdown sleeve during temporary abandonment, BP engineers wanted to ensure that other temporary abandonment operations would not damage the sleeve. To address this concern, they decided to set the sleeve last.[4]

Figure 4.5.2. Lockdown sleeve.



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BP's desire to set a lockdown sleeve during temporary abandonment drove the development of its temporary abandonment procedure. The lockdown sleeve locks down the casing hanger and seal assembly.

- Deciding to set the sleeve last then drove BP's decision to set its "surface" cement plug unusually deep in the well. The process of setting the Macondo lockdown sleeve would require the rig crew to press (or pull) down on the sleeve with 100,000 pounds of force. The Macondo team chose to generate that force by hanging close to 3,000 feet of drill pipe below the lockdown sleeve.[5] In order to leave room for that length of drill pipe, BP needed to set the surface cement plug even farther down, from 3,000 to 3,300 feet below the mudline.[6]
- Deciding to set the cement plug deep in the well in turn led BP engineers to decide to remove a great deal of drilling mud from the well during temporary abandonment. The Macondo team believed that cement plugs set up better in seawater than in mud.[7] To set the deep cement plug in seawater, the team instructed the rig crew to replace 3,300 feet of mud in the well with seawater before setting the plug.[8]

Lockdown Sleeve. BP planned to set a **lockdown sleeve** during its temporary abandonment procedure at Macondo. A lockdown sleeve is a piece of equipment that is installed in the wellhead to guard against uplift forces that may be generated during the production of hydrocarbons at a well. The sleeve locks the production casing hanger and seal assembly to the high-pressure wellhead housing so that the forces generated during hydrocarbon production do not lift the casing hanger and seal assembly out of place.

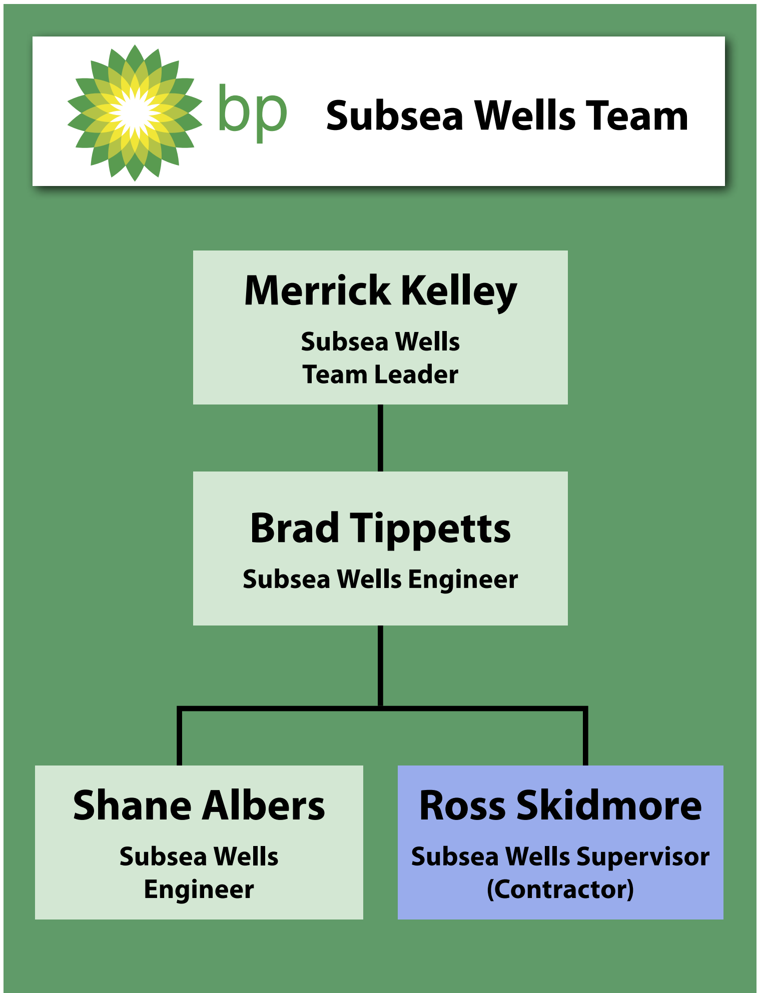
Operators do not normally set lockdown sleeves during temporary abandonment.[9] They normally set lockdown sleeves later in the life of a well.[10] BP decided to set the lockdown sleeve during temporary abandonment because it believed that a drilling rig, such as the *Marianas* or *Deepwater Horizon*, could do this job more quickly and at a lower cost than a completion rig.

This series of design decisions ultimately led BP to instruct the *Deepwater Horizon* crew to replace 8,367 feet of drilling mud from the riser and well with lighter seawater *before* setting *any* additional mechanical barriers in the well, such as the surface cement plug.

Decision to Set Lockdown Sleeve During Temporary Abandonment

Lockdown sleeves need not be set during temporary abandonment. Indeed, the Macondo team originally planned to leave the job for a completion rig.[11]

Figure 4.5.3. BP subsea wells organization.



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BP decided to set the lockdown sleeve during temporary abandonment because it believed that a drilling rig could do this job more quickly and at lower cost than a completion rig. As Chapter 3 discusses, BP began drilling Macondo with Transocean's *Marianas* rig. BP's subsea wells team (Figure 4.5.3) accordingly developed a lockdown sleeve setting procedure in October 2009 for the *Marianas*.[12] They reviewed the procedure on November 10, 2009, with Dril-Quip representative Barry Patterson.[13] Two days later, BP subsea wells engineer Brad Tippetts sent a request to Patterson for the information necessary to develop a final lockdown sleeve setting procedure.[14] Patterson included BP drilling engineer Brian Morel in this initial November conversation, but it does not appear that Morel participated or responded.[15]

After BP decided that the *Deepwater Horizon* would replace the hurricane-damaged *Marianas,* BP engineers developed a revised drilling program. On December 31, BP subsea wells team leader Merrick Kelley checked in to ask if the Macondo engineering team still planned to install the lockdown sleeve as part of its new drilling program.[16] Senior drilling engineer Mark Hafle said no: "We do not plan on installing lock down sleeve with the Horizon."[17]

Kelley responded by noting the time (and hence money) that BP could save by setting the lockdown sleeve with the *Horizon*. He explained that setting the lockdown sleeve during temporary abandonment "saves an incremental 5.5 days of rig time on the back side" and, with it, more than $2 million.[18] (Doing the job with a completion rig would take seven days, whereas the *Horizon* could do the job in 1.5 days during temporary abandonment.[19]) Hafle discussed the issue with BP drilling and completions operations manager David Sims,[20] and the Macondo team eventually decided to set the lockdown sleeve using the *Horizon*.

The Macondo team also considered an **open water** lockdown sleeve installation, in which a boat would set the lockdown sleeve using ROVs.[21] The open water installation process would save $120,000 in additional costs over having the *Horizon* do the installation.[22] But it also presented a greater risk of damaging the lockdown sleeve.[23] Kelley therefore recommended against it: "At the end of the day it boils down to the amount of risk we are willing to take to potentially save $120,000 by using a boat. To be honest and frank with you, performing this operation from the rig is the easiest and simplest way I know to install a[n] LDS.... For my money, it is just the right thing to do...."[24]

Ultimately, the Macondo team decided to set the lockdown sleeve with the *Horizon* during temporary abandonment.[25]

Development of the Lockdown Sleeve Setting Procedure

Finalizing the procedure for setting the lockdown sleeve was a necessary first step in developing the overall temporary abandonment procedure. The Macondo team did not finalize its lockdown sleeve setting procedure until very late in the drilling process. Indeed, as late as mid-April, the Macondo team was still reconsidering its decision to have the *Horizon* set a lockdown sleeve at all.

On April 8, 2010, Patterson again sent Morel the information about setting the lockdown sleeve that Morel had first received five months earlier.[26] Morel reviewed the procedure later that day.[27] Four days later, on April 12, BP well site leader Murry Sepulvado asked Morel via email for the temporary abandonment procedures (among other things), saying that rig personnel were "in the dark and nearing the end of logging operations."[28] Morel emailed BP subsea wells engineers Shane Albers and Tippetts to ask for a lockdown sleeve running procedure: "I need a procedure this morning, do you have one available?"[29] Tippetts responded five minutes later by attaching the detailed lockdown sleeve setting procedure that the subsea team had originally written for the *Marianas*. Tippetts said, "this should do for now," but noted that Albers was modifying the procedure "slightly" for the *Horizon* and that Albers "will send out the updated version later today."[30] Morel told Sepulvado, "I will have you something this morning."[31]

Later in the afternoon of April 12, Morel asked Kelley via email when BP would be setting a lockdown sleeve at Isabela, another BP well.[32] Morel knew that BP planned to set the Isabela lockdown sleeve using open water installation tools. Morel's question therefore suggests that he (and perhaps the Macondo team) was still considering another option for setting the lockdown sleeve—namely, using the open water tools that BP would use at Isabela instead of using the *Horizon*. But late that night, Kelley advised Morel and Hafle against that approach. Kelley said that the subsea team would not make it a priority to "combine the Isabela and Macondo lock down sleeve jobs." Kelley also warned that others in BP might challenge a decision to use open water tools to set the lockdown sleeve in order to save just 24 hours of rig time.[33]

Morel did not send out a final updated procedure on April 12. Instead, after the close of business on April 13, Morel sent BP wells team leader John Guide the *Marianas* procedure, with the caveat that the subsea wells engineers "are updating for the Horizon, but mostly will remain the same."[34] A little less than an hour later, at 6:50 p.m. on April 13, Albers sent Morel the final updated procedure.[35]

Numerous Last-Minute Changes During the Final Development of the Temporary Abandonment Procedure

In the nine days before BP began the temporary abandonment of the Macondo well, the company went through at least four different versions of temporary abandonment procedures.[36] Each version switched the order of several key steps.

April 12 Well Plan

In response to the April 12 prodding from Murry Sepulvado, Morel circulated a draft plan for upcoming operations at Macondo later that day.[37] The draft plan included temporary

Figure 4.5.4. Multiple last-minute revisions to the temporary abandonment procedure.

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abandonment procedures that instructed the rig crew to set the lockdown sleeve *first* and then to set a surface cement plug in seawater. The plug would be set just 933 feet below the mudline.[38]

Morel's draft did not include a negative pressure test. After reviewing it, well site leader Ronnie Sepulvado reminded Morel that he needed to include a negative pressure test.[39]

April 14 Morel Email

Two days later, Morel sent out a procedure that was different in several important respects.[40]

First, the new procedure stated that BP would set the cement plug first and *then* set the lockdown sleeve.

Second, Morel changed the depth of the cement plug in order to create the clearance necessary to set the lockdown sleeve. Morel moved the cement plug from 933 feet below the mudline to 3,300 feet below the mudline.

Third, Morel changed the procedure so that the rig crew would set the surface cement plug in *drilling mud instead of seawater*.

Fourth, Morel included a negative pressure test. Morel's procedure instructed the rig crew to perform the test "with base oil in kill/choke line to the wellhead."[41] Using **base oil** for a negative pressure test is a normal industry practice. Filling the choke or kill lines with base oil can simulate the pressure effects of displacing drilling mud in the riser and some portion of the wellbore with seawater *without* actually displacing any mud. This is because base oil is lighter than seawater. Morel presumably included this step to account for the new procedure to displace a large amount of mud from the wellbore before setting the surface cement plug. (Interestingly, the procedure called for the negative pressure test to be done after the cement plug had been set,[42] so that the test would examine the quality of the cement in the surface plug rather than the bottomhole cement.)

April 15 Well Plan and April 16 MMS-Approved Procedure

By April 15, with the approval of Guide and drilling engineering team leader Gregg Walz, Morel changed the plan again in at least two important respects.[43]

First, Morel's new plan required rig personnel to conduct a negative pressure test before setting the surface cement plug, so that the test would check the integrity of the bottomhole cement.[44]

Second, the new plan called for the rig crew to displace the riser to seawater immediately after conducting the negative pressure test.[45] Morel apparently made this change because one of the well site leaders had asked to set the cement plug in seawater.[46]

The Macondo team clearly recognized that its plan called for an unusually deep cement plug. Morel included an alternative plan with a shallower plug in the event that MMS did not approve the deep plug.[47]

Morel and Hafle worked together to develop an application for an MMS permit allowing the team to use the "deep plug" option. As part of that application, filed on April 16, Morel listed BP's planned temporary abandonment procedure and included a negative pressure test (even though MMS regulations did not require a negative pressure test, as discussed in Chapter 6). That test would now be conducted "with [the] kill line"—yet another change in the procedure.[48] MMS approved the permit application—and with it, BP's plan to use a deep plug—in less than 90 minutes.[49]

The language in BP's April 16 permit application describing the negative pressure test and displacement procedure was unclear. Some have said that the language, like that in the April 15 well plan, required BP to conduct its negative pressure test *before* displacing mud in the well with seawater.[50] Others have said (after the blowout) that the only sensible time to do the negative pressure test would have been *after* the rig crew displaced the mud beneath the wellhead with seawater to the depth of the cement plug.[51] This argument may be important; if the former interpretation is correct, the rig crew did not adhere to the approved MMS procedure.[52] In any event, the debate highlights the lack of specificity in the permitted language.

After MMS approved the temporary abandonment procedure, Morel realized there was a problem. By planning to set its surface cement plug very deep in the well *and* set it in seawater, BP would be severely underbalancing the well during temporary abandonment. BP could not generate enough differential pressure to simulate those conditions merely by pumping base oil through the kill line down to the wellhead. Accordingly, the base oil negative pressure test procedure would not constitute a proper negative pressure test of the system.[53]

The solution, as the drilling team saw it, was to conduct two negative pressure tests. The rig would conduct the first test as planned, with base oil to the wellhead *before* displacement to 8,367 feet. They would conduct the second test *after* that displacement.[54]

April 20 "Rig Call" and Morel "Ops Note"

The Macondo team had still not resolved the negative pressure test procedures even during the 7:30 a.m. "rig call" between the rig crew and shoreside personnel on April 20—the day of the blowout. The rig crew asked wells team leader Guide how they were supposed to run the negative pressure test. Guide responded that he would confer with the engineers onshore and get back to them.[55]

Guide decided that the crew would conduct only one negative pressure test. There would be no “first” test using base oil in the kill line. Instead, there would be a single test midway through the displacement at 8,367 feet. It is difficult to determine whether there was significant disagreement with this decision. Hafle stated that there was “some discussion but [that] John Guide [was] hard to argue with” and that “Walz was in discussion but didn’t argue with John.”[56] Morel (who was visiting the rig) stated that the well site leaders did not have strong opinions either way.[57] According to Guide, however, there was never any plan to perform more than one negative pressure test.[58]

Three hours after the rig call, Morel sent an “Ops Note” to the shoreside team and well site leaders. The Ops Note reflected the Macondo team’s final changes to the temporary abandonment procedure.[59] The first time the rig crew saw the procedure was during the 11 a.m. pre-tour meeting on April 20.[60]

Whereas BP’s April 16 submission to MMS may have stated that rig personnel would conduct the negative pressure test before displacement, the April 20 Ops Note directed the crew to conduct the negative pressure test midway through the displacement process.[61] The rig crew would first displace mud with seawater from beneath the wellhead to 8,367 feet. The crew would then conduct the negative pressure test on the kill line. After the test, the crew would displace the mud remaining in the riser and then set the cement plug.[62] Like the other procedures, the Ops Note lacked basic information about how the negative pressure test was to be conducted.[63]

The Macondo team apparently recognized that conducting a negative pressure test midway through displacement (rather than before displacement) was different from the procedure MMS had approved. But BP decided not to notify MMS of the change or seek further MMS approval.[64] According to members of the Macondo team, such notification and further approval were unnecessary because conducting the negative pressure test during displacement would be a more rigorous test than conducting it beforehand.[65] This explanation is called into question by the fact that BP did seek MMS approval before making a similar change in a negative pressure test procedure during temporary abandonment operations in 2006.[66]

According to BP well site leader Bob Kaluza, Hafle called him on the afternoon of April 20 to discuss the Ops Note. Hafle had been away on vacation while the rest of the shoreside team had put together the procedures in the Ops Note. Reviewing it, Hafle was concerned that the Ops Note procedure was different than the procedure MMS had approved. Kaluza woke up Morel. Morel explained that the rest of the shoreside team had decided to “deviate” from the procedure in the MMS-approved permit, which called for conducting the negative pressure test before displacement. “The team in town wanted to do something different,” Kaluza later explained according to notes of BP’s post-blowout interviews. “They decided we could do the displacement and negative test together – don’t know why – maybe trying to save time.... Anytime you get behind, they try to speed up.”[67]

It is impossible to know whether the changes to the negative pressure test procedure (including elimination of a second negative pressure test at a different depth) contributed to the blowout. As Chapter 4.6 explains in detail, personnel on the *Deepwater Horizon* missed clear warning signals from the negative pressure test they did conduct. Conducting an earlier version of the test may have removed one of the factors confounding successful interpretation of the test and eliminated the crew’s erroneous explanation for the warning signals they observed.[68] And conducting a second test at a different depth might have given the rig crew another opportunity to recognize those signals.

Technical Findings

BP's Temporary Abandonment Procedure Created Significant Risks

BP's design decisions had significant consequences and increased the risks associated with the temporary abandonment at Macondo in several important ways.

First, the procedures created a severe hydrostatic underbalance in the well. By requiring the rig crew to remove so much mud from the wellbore during temporary abandonment, BP's procedures greatly reduced the balancing pressure that the mud column in the wellbore exerted on the hydrocarbons below. This increased stress on the bottomhole cement.[69] While temporarily abandoning a deepwater well typically involves placing some amount of stress on the bottomhole cement, BP's procedures stressed the cement more than usual[70]—to an extent never before seen by many in the industry.[71]

Second, the procedures led the rig crew to conduct riser displacement operations with *only one physical barrier in the well* (the bottomhole cement) and only one backup barrier (the BOP).[72] That backup barrier, in turn, was highly dependent on well control monitoring. As a result, BP's temporary abandonment procedure placed a high premium on kick detection and response during the displacement.[73] Unless the rig crew recognized a kick, they could not activate the BOP in time for it to function as a barrier.

Third, and as a result, the procedures placed a high premium on the integrity of the bottomhole cement and the negative pressure test that evaluated it.[74] Rig personnel could not rely on the bottomhole cement as a barrier until it had been verified, and the only procedure BP planned to use to verify the cement's integrity was the negative pressure test.

BP Did Not Need to Set a Lockdown Sleeve as the Last Step in Temporary Abandonment

As explained above, BP made many of its procedural decisions regarding temporary abandonment based on its decision to set a lockdown sleeve during the temporary abandonment phase of the well. BP did not need to set a lockdown sleeve during the temporary abandonment phase. The fact that BP nevertheless chose to do so is not problematic in itself. Indeed, locking down the casing earlier rather than later can increase safety by mitigating against potential uplift forces during drilling and abandonment (explained in Chapter 4.1). But BP increased overall risks by deciding to set the lockdown sleeve last in the temporary abandonment sequence.

A lockdown sleeve need not be set last in the temporary abandonment sequence. It can be set in mud prior to displacement and setting of the surface plug.[75] This is commonly done in the industry,[76] and BP engineers considered doing it this way at Macondo.[77]

Outer Lock Ring. Setting a lockdown sleeve before temporary abandonment can reduce the risk that underbalancing a well might lift the production casing out of place in the wellhead. Another mechanism for locking a production casing in place is an **outer lock ring**. Rig personnel can install an outer lock ring when they first set the casing in place. While this was not a common practice at the time of the Macondo incident,[78] some industry experts have recommended that it become standard.[79]

Indeed, the Macondo team initially planned to set the lockdown sleeve in mud, before setting a shallow surface cement plug in seawater. In a March 3 email, Hafle stated that the team would "set the plug after [lockdown sleeve] installation"; with no plug in the way, they could easily "supply the correct weight for installation."[80] On April 8, Morel checked with Dril-Quip representative Barry Patterson to make sure the lockdown sleeve procedure was compatible with "100,000 lbs air weight in 14.0 ppg mud."[81] On April 12, Morel emailed Tippetts to confirm that the plan was "to still have mud in the riser and wellbore when we set the LDS."[82] Subsea well supervisor Ross Skidmore preferred to set the lockdown sleeve in mud because the hole would be in its cleanest state at that point.[83]

As described above, by April 14, BP had changed its plan so that it would run the lockdown sleeve last, after setting a surface plug and displacing the riser to seawater.[84] When Skidmore heard about the change, he approached one of the BP drilling engineers on the rig and expressed his preference to set the lockdown sleeve in mud; the engineer indicated the decision had come from personnel onshore and was final.[85]

BP Did Not Need 3,000 Feet of Drill Pipe Below the Wellhead to Achieve the 100,000 Pounds Necessary to Set the Lockdown Sleeve

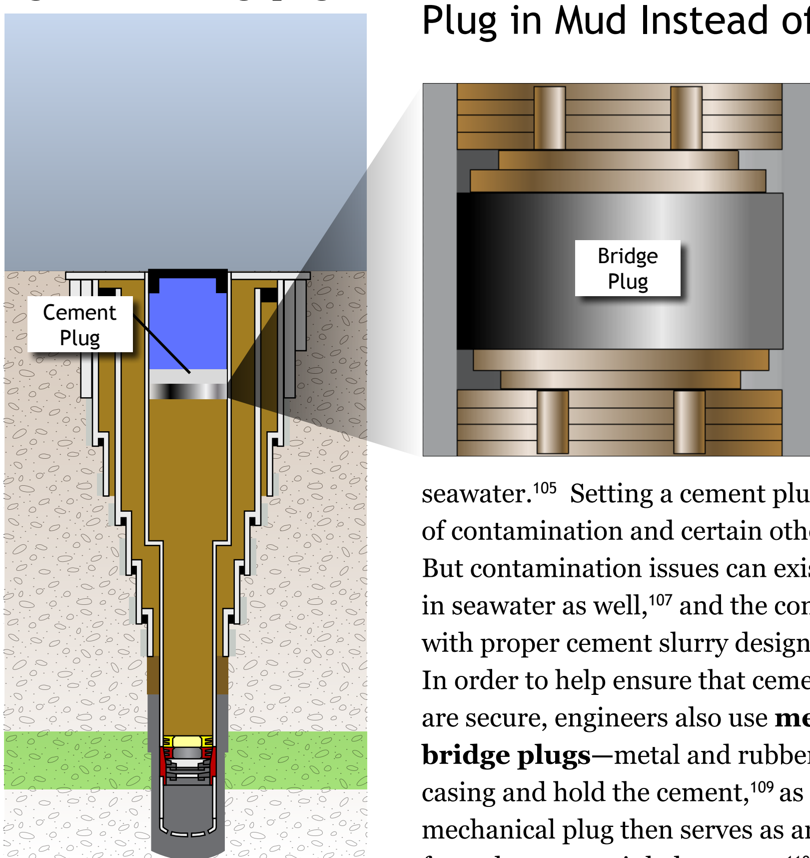
BP did not need to use 3,000 feet of drill pipe in order to generate the 100,000 pounds of downward force necessary to set the lockdown sleeve. Instead, BP could have instructed the rig crew to hang a much shorter length of pipe that included **drill collars** (a heavier type of drill pipe). Because drill collars are much heavier than other drill pipe, the crew could have used a much shorter length of them to generate the same downward force. BP could also have instructed the rig crew to generate some of the setting force using weight pushing down from *above* the running tool instead of hanging below it.[86] Using these methods, BP could have set the lockdown sleeve in place without requiring 3,000 feet of clearance beneath the sleeve, as called for in its final plan.[87]

BP engineers were well aware that they did not have to set the lockdown sleeve using 3,000 feet of hanging drill pipe. BP had previously set a lockdown sleeve with the same running procedures and weight requirement (100,000 pounds) at another well in the Gulf of Mexico, in Mississippi Canyon Block 129.[88] BP used drill collars at that well to generate the required setting force[89] and was thus able to set its surface plug only 1,600 feet below the mudline.[90] Similarly, BP set a lockdown sleeve with an even greater force requirement (125,000 to 135,000 pounds) in Mississippi Canyon Block 777.[91] There again, BP used drill collars to generate the required setting force and set a surface plug 1,500 feet below the mudline.[92] Such depths were more typical for pre-lockdown sleeve plugs.[93]

At one point, the Macondo lockdown sleeve was supposed to be set in much the same manner.[94] As far back as November 12, 2009, the Macondo team had planned to run drill collars beneath the lockdown sleeve in order to achieve the necessary setting weight.[95] That was still the plan on February 3 when the lockdown sleeve setting procedure was submitted for inclusion in the Macondo well planning spreadsheet.[96] But by March 2, Hafle had told Tippetts, "Here's the final plan.... We will *not* be using any drill collars. The rig has 5-1/2" [heavyweight drill pipe] and we will rent additional 5-1/2" [heavyweight drill pipe] to have 100k buoyed weight below" the lockdown sleeve.[97]

Despite Hafle's email, BP obtained drill collars and had them on the rig by April 17.[98] As late as April 12, Walz mentioned using drill collars to set the lockdown sleeve in an email to Morel,[99] and Morel included them in the April 12 drilling program.[100] The last final updated procedure that Albers sent to Morel on April 13 also included drill collars.[101] But by the time drill collars arrived on the rig, Morel had changed the procedures to specify a deep surface plug, 3,000 feet below the mudline, which suggests that he had not envisioned using drill collars to set the lockdown sleeve.[102] According to BP wells team leader Guide, the team changed the plan because the rig already had heavyweight drill pipe "racked back" and ready to run into the well.[103] In order to use drill collars at that point, the rig would need to make up each piece of pipe individually, which would take time and add to the general risk of personal injury.[104]

Figure 4.5.5. Bridge plug.



BP could have used a mechanical plug in lieu of or in addition to a cement plug.

BP Could Have Set Its Surface Cement Plug in Mud Instead of Seawater

BP did not have to displace mud from the well and riser in order to set a cement plug; it could have set the cement plug in drilling mud instead.

Surface cement plugs can be set in mud just as they can be set in seawater.[105] Setting a cement plug in mud can present a risk of contamination and certain other chemical complexities.[106] But contamination issues can exist with cement plugs set in seawater as well,[107] and the complexities can be managed with proper cement slurry design and the use of spacer.[108] In order to help ensure that cement plugs set in drilling mud are secure, engineers also use **mechanical retainers** or **bridge plugs**—metal and rubber devices that fit into the casing and hold the cement,[109] as shown in Figure 4.5.5. The mechanical plug then serves as an additional barrier, apart from the cement it helps to set.[110]

BP generally, and the Macondo team specifically, were familiar with these options.[111] When an earlier surface cement plug at Macondo failed to set up, Morel and another BP engineer involved with the earlier plug discussed how "the biggest single factor for plug success is having a good base."[112] The engineers discussed how they could design that base by several means, including by contrasting fluid densities (lighter cement on heavier drilling fluid) and by using mechanical devices (retainers and bridge plugs).[113] Another engineer involved with the earlier plug commented, “We need to get better at setting plugs regardless of the method.”[114]

BP representatives have acknowledged that surface cement plugs can be set in mud[115] and that doing so is not a mistake.[116] Indeed, BP has set surface cement plugs in mud before[117] and apparently considered doing so at Macondo as late as April 14.[118] BP has also frequently made use of mechanical devices for surface plugs, including both drillable and retrievable bridge plugs.[119]

In fact, BP engineers affirmatively considered running a mechanical plug at Macondo—specifically, a Baker Hughes model GT retrievable bridge plug.[120] The GT plug was much more expensive than a cement plug, but Morel preferred it (at least initially) because of its greater reliability. In an email to Hafle and others, he noted: “If Baker’s GT plug wasn’t available, we would either set a cement plug in its place or a Halliburton Fast Drill plug. Both are much cheaper options, but leave us with potential issues during the completions. They could potentially cost us more as well, because extra rig time might be involved with removing these type of plugs.”[121]

BP engineers planned at various points to use a GT plug at Macondo.[122] The Macondo team would have rented that plug pursuant to a long-term GT plug rental contract that BP was arranging with Baker Hughes for several wells at the same time.[123] Because the BP personnel arranging the contract believed there was a “high probability of a long term installation of this plug at Macondo,” they affirmatively committed to the rental.[124] BP initiated rental of the Macondo plugs on April 6.[125] The company paid $42,902 to Baker Hughes to make up, test, and keep a primary and backup GT plug on standby.[126]

On April 9, a Baker Hughes representative emailed Morel and Hafle to ask for an update on whether BP had decided to use the standby plug or not.[127] Morel responded with additional details but still no final decision: “If we need it, the rig will probably want to call it out next weekend or early the following week (18-19th of April). I will keep you informed.”[128] Morel explained that the Macondo team would not commit to using the GT plug until it had decided if production casing was required.[129] But by April 12, two days before finalizing the decision to run production casing, the Macondo team decided to use a plain cement surface plug.[130] When the Baker Hughes representative emailed the two BP engineers again on April 19 to ask if they would need the plug he had kept on standby “since early April,”[131] Hafle responded, “We will be setting a cement plug instead.”[132] Baker Hughes stopped the rental.[133]

It is not clear why the Macondo team chose to set a plain cement plug. Morel told one engineer that the reason was cost:[134] “Plan is to set a cement plug instead of running the GT plug as it doesn’t cost us anything to leave it in the hole.”[135] Morel told another set of engineers (the completion engineers) that the reason was risk: The “GT plug poses risks leaving it in the wellbore for an unknown amount of time.”[136*]

BP Could Have Planned a Safer Temporary Abandonment Procedure Even Without Changing Its Design Assumptions

Even assuming that BP truly had to set the lockdown sleeve last and set its surface cement plug

[*] Some members of the Macondo team were concerned that leaving a mechanical plug in the well for an indefinite period of time might present complications during re-entry and completion. Retrievable plugs left in the wellbore for too long can corrode and become difficult to retrieve. Drillable plugs (like cement plugs) can produce debris when drilled out. Nevertheless, BP appears to have addressed or accepted these complications in other wells where the company set mechanical plugs. Indeed, a BP completion engineer reacted to Morel’s email with wonderment: “I am curious about what risks he speaks of with leaving GT plugs in place for long periods. We had them in place at Dorado for a couple of years without problems.”

deep in the well in seawater, BP could have taken at least three measures to mitigate the risk created by its unusual procedure. Each of these measures would have increased or improved the physical barriers in the wellbore during the displacement. While each would have taken some additional time,[137] they would have ensured that the cement job at the bottom of the well was not the only barrier physically in place during the displacement.

BP Could Have Retained Hydrostatic Overbalance

BP still could have retained hydrostatic overbalance even with the removal of 3,300 feet of mud from the wellbore. To do so, they could have replaced the mud at the bottom of the wellbore with heavier "kill weight" mud.[138] BP engineers should have been familiar with this concept,[139] and it is a common industry practice.[140] In doing so, they would have retained mud as a physical barrier in the wellbore during the displacement.[141†]

BP Could Have Set Intermediate Plugs

BP could have set additional plugs between the bottomhole cement and the surface plug.[142] BP engineers were familiar with this option, as the company had set multiple intermediate plugs (often including mechanical plugs) on previous wells.[143] Indeed, some in the industry treat the setting of intermediate plugs as standard practice.[144] But it appears that the Macondo team never considered it.[145] Setting intermediate mechanical or cement plugs would have increased the number of physical barriers in the wellbore during the displacement.

BP Could Have Conducted the Displacement (of Both the Wellbore and the Riser) With the BOP Closed

BP could have closed an annular preventer (or variable bore ram) before beginning the displacement and, in various configurations, then displaced the casing and riser using the drill pipe and choke, kill, and boost lines.[146] This would have been considered a particularly conservative approach in the industry, and unnecessary for most wells.[147] But the unusually deep cement plug and the uncertain nature of the bottomhole cement job at Macondo warranted extra caution.[148] Indeed, since the blowout, the industry appears to be moving in the direction of making this practice more prevalent.[149] Closing the BOP before the displacement would have eliminated the BOP's dependence on human monitoring and thereby converted it into a physical barrier in place during the displacement. The well would already have been shut in at the time of the kick, enabling the crew to more easily respond to and control the kick.

Management Findings

BP Failed to Develop Its Temporary Abandonment Procedure in a Timely Manner

The moment an operator designs a production well, it can (and should) develop a temporary abandonment procedure.[150] Even though BP planned Macondo as a production well from the start,[151] it did not include temporary abandonment procedures in its initial drilling program.[152]

† BP wells team leader John Guide suggested that for some wells underbalance is necessary because mud is simply not heavy enough to compensate for the loss of the riser. That was not true of the Macondo well. To be sure, if BP had insisted on using only one plug and setting that plug at 3,300 feet below the mudline, then replacing just the mud above that plug with kill weight mud would not have prevented underbalance. But BP could have set an intermediate plug deeper in the well (about 6,900 feet below the mudline), replaced the mud above that deeper plug with kill weight mud, and then set a surface plug higher up in the well. Therefore, BP could have left the Macondo well overbalanced by using a combination of kill weight mud and intermediate plugs.

As early as January 2010, the Macondo team planned to use the *Horizon* to install a lockdown sleeve and then temporarily abandon the well. But the company's January 2010 drilling program still did not include a temporary abandonment procedure.[153] By April 9, the Macondo team knew the total depth of the well.[154] At that point, they had enough information to design a temporary abandonment procedure specifically tailored to the final conditions at Macondo.[155] But three days later, on April 12, the well site leader was forced to ask the shoreside team for procedures himself, saying, "we are in the dark and nearing the end of logging operations."[156]

The Macondo drilling team did not begin developing a procedure in earnest until after this request. Perhaps because of the delays, the Macondo team changed its procedures repeatedly at the last minute, even up until the day the procedure was to begin (the day of the blowout). As Walz acknowledged in another context, "planning [was] lagging behind the operations."[157]

BP Changed Its Temporary Abandonment Procedure Repeatedly at the Last Minute Without Subjecting Those Changes to Any Formal Risk Assessment

BP's temporary abandonment procedures for Macondo changed at least four times over the last nine days before the blowout. This was an unusual number of changes so close to the procedure's execution.[158] BP also changed its lockdown sleeve setting procedures over time.

Several of BP's decisions—not using drill collars, not using a mechanical plug, setting the plug in seawater, setting the lockdown sleeve last—may have made sense in isolation. But the decisions also created risks, individually and especially in combination with the rest of the temporary abandonment operation. For instance, BP originally planned to install the lockdown sleeve at the beginning of the temporary abandonment. BP's decision to change plans and set the lockdown sleeve last triggered a cascade of other decisions that led it to severely underbalance the well while leaving the bottomhole cement as the lone physical barrier in place during displacement of the riser.

There is no evidence that BP conducted any formal risk analysis before making these changes or even after the procedure as a whole.[159] For example, on April 15, Morel (who was on the rig at the time) emailed the rest of the Macondo onshore engineers about setting a deep plug in seawater: "Recommendation out here is to displace to seawater at 8300' then set the cement plug. Does anyone have issues with this?"[160] The response, from Hafle, was simply: "Seems ok to me."[161] According to Guide, the team never discussed the risk of having such a deep surface plug.[162]

Post-incident interviews with the Macondo team confirm that it made significant procedural changes in a relatively casual manner. Walz admitted that there was "no structured approval process" and that "changes [were] made with email and verbal discussion."[163] Cocales stated that there was "no formal process on communicating changes to [the] well plan." Murry Sepulvado stated that it was not unusual to receive emails like the Ops Note containing procedural changes that had not been risk assessed through a formal process.[164] And according to Guide, such Ops Notes would not even flag whether changes had been made to the well plan.[165]

BP Allowed Equipment Availability to Drive Design and Procedure Decisions

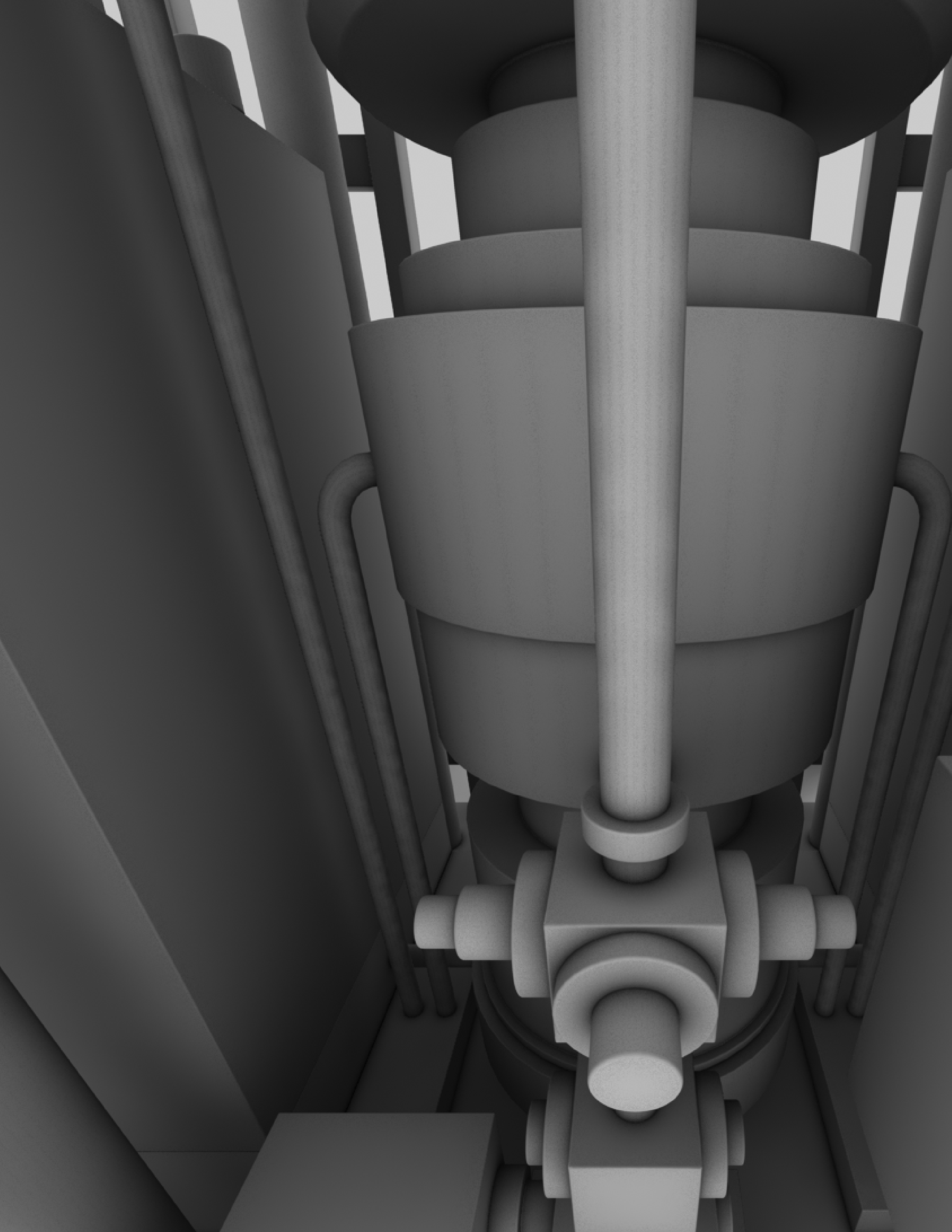
BP inverted the normal process of well design in determining the depth of the surface cement plug, and the type and length of pipe to use in setting the lockdown sleeve.

Drilling engineers normally begin by considering their objective and the attendant risks and developing a well design and procedures that are efficient and safe. They then arrange for the equipment and materials necessary to execute the design.[166] BP did the opposite at Macondo. BP made decisions about what type of drill pipe to use (ordinary, heavyweight, or drill collars), and hence where to set its surface cement plug, based on the type of pipe available on the rig.[167] The *Deepwater Horizon* apparently already had heavyweight drill pipe "racked back" and ready to run into the well, which led the Macondo team to use that pipe instead of drill collars.[168]

BP's lockdown sleeve setting procedure underscored this logic: "To achieve 100,000 lbs of tail pipe weight drill collars & drill pipe will be used. The combination will depend on availability and will be determined while onsite." The caveat was repeated in step seven of the procedure, which stated "the decision on the pipe size & length will be made on the rig."[169]

BP Failed to Provide Written Standardized Guidance for Temporary Abandonment Procedures

BP had no consistent or standardized temporary abandonment procedure across its Gulf of Mexico operations.[170] Formal written guidance was minimal: The Drilling and Well Operations Practice manual and relevant Engineering Technical Practice (GP 10-36) mandated that, in each flow path, there should be two independent mechanical barriers isolating flow from the reservoir to the surface and that those barriers should be independently tested.[171] The documents did not specify the location of those barriers or the procedure by which they should be set. This left the Macondo engineers to determine such issues for themselves on an ad hoc basis. For example, when Hafle emailed the subsea engineers—"Can we set the plug after the LDS is in place?"—one subsea engineer wrote to another, "I do not know about setting the plug after the LDS. Do you? Could you ask someone around the office tomorrow about this to figure this out?"[172] Such uncertainty existed even with something as basic as regulatory requirements.[173]

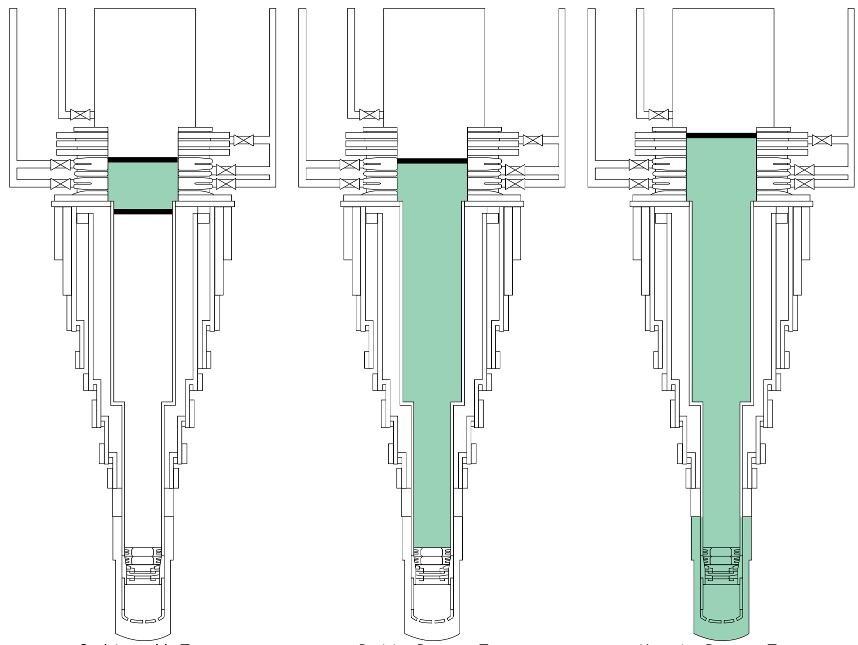


Chapter 4.6 | Negative Pressure Test

The negative pressure test performed at Macondo showed repeatedly over a three-hour period that the well lacked integrity and that the cement had failed to seal off the hydrocarbons in the pay zone. BP well site leaders, in consultation with Transocean rig personnel, nevertheless mistakenly concluded that the test had demonstrated well integrity and then proceeded to the next phase of temporary abandonment.

The Chief Counsel's team finds that the failure to properly conduct and interpret the negative pressure test was a major contributing factor to the blowout.

Figure 4.6.1. Well integrity tests.



The rig crew conducted three pressure tests as part of the temporary abandonment procedure to verify the integrity of the well. From left to right: the seal assembly test, the positive pressure test, and the negative pressure test. Test regions are shown in green.

Well Integrity Tests

After cementing the production casing, BP was nearly ready to **complete** the Macondo well and turn it into a producing well. (Completion refers to the process of preparing the well for production and installing equipment to collect oil from the well.)

However, BP only planned to use *Deepwater Horizon* to drill the well, not to complete it. After installing the production casing, BP planned to have the *Deepwater Horizon* leave Macondo for a different drilling job elsewhere in the Gulf of Mexico. Another rig would perform the completion work at some undetermined time in the future.

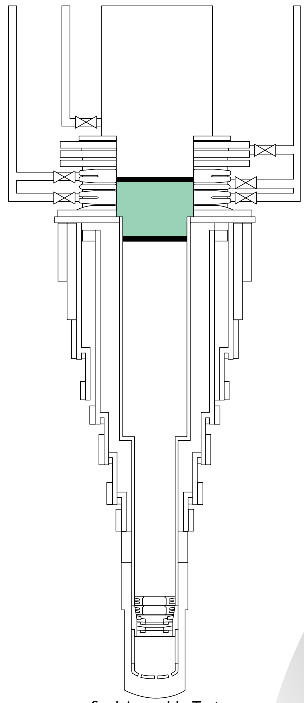
The well would be temporarily "abandoned" during the time between *Deepwater Horizon*'s departure and the completion rig's arrival. The *Deepwater Horizon* crew's last responsibility would be to secure the well to ensure that nothing could leak in or out—to confirm the **well's integrity**—during that intervening time. It was during this **temporary abandonment** process, rather than during drilling, that the blowout occurred.

As part of the temporary abandonment procedure, the rig crew conducted tests to check the well's integrity. If there were a leak in the system of cement, casing strings, and mechanical seals that comprised the well, these tests should have revealed it. The rig crew conducted three different tests: a seal assembly test, a positive pressure test, and a negative pressure test. The tests each checked different parts of the well's integrity.

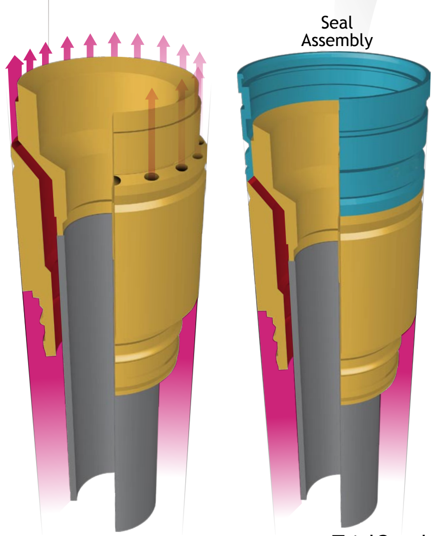
Significantly, however, the negative pressure test was the only one that tested the integrity of the cement at the bottom of the well.[1] That cement is what the rig crew would rely on to isolate hydrocarbons in the pay zone and keep them from coming up the well.

Testing this cement was thus critical to safety of everyone on the rig.

WELL INTEGRITY TESTS



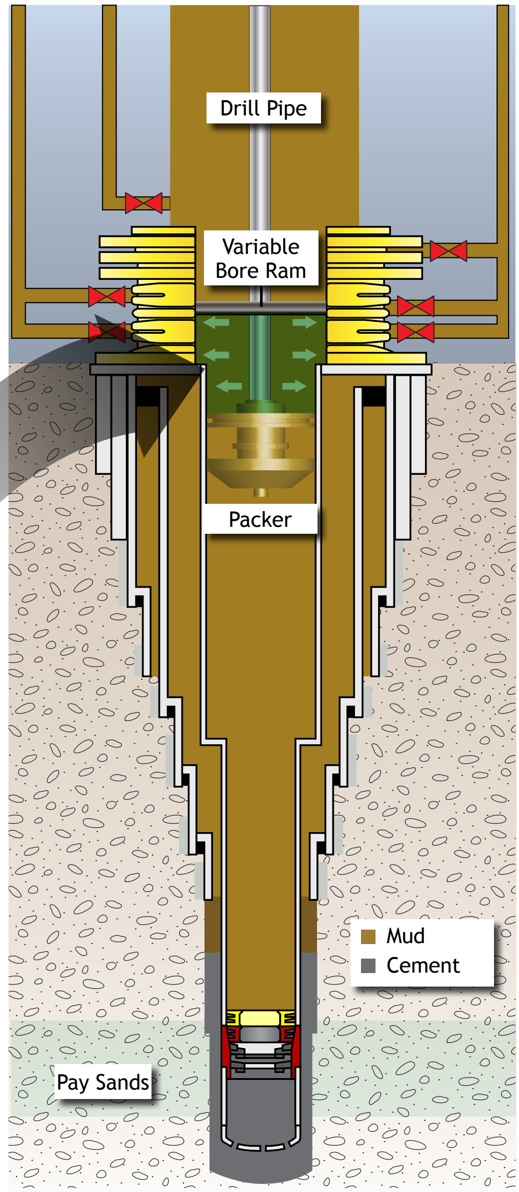
Seal Assembly Test



TrialGraphix

The casing hanger, as described in Chapter 4.1, has flow passages that facilitate the flow of fluids during normal drilling operations. The seal assembly (blue) is fitted atop the casing hanger to halt annular flow after the primary cement job is complete. Together, the two bind the casing to the wellhead.

Figure 4.6.2



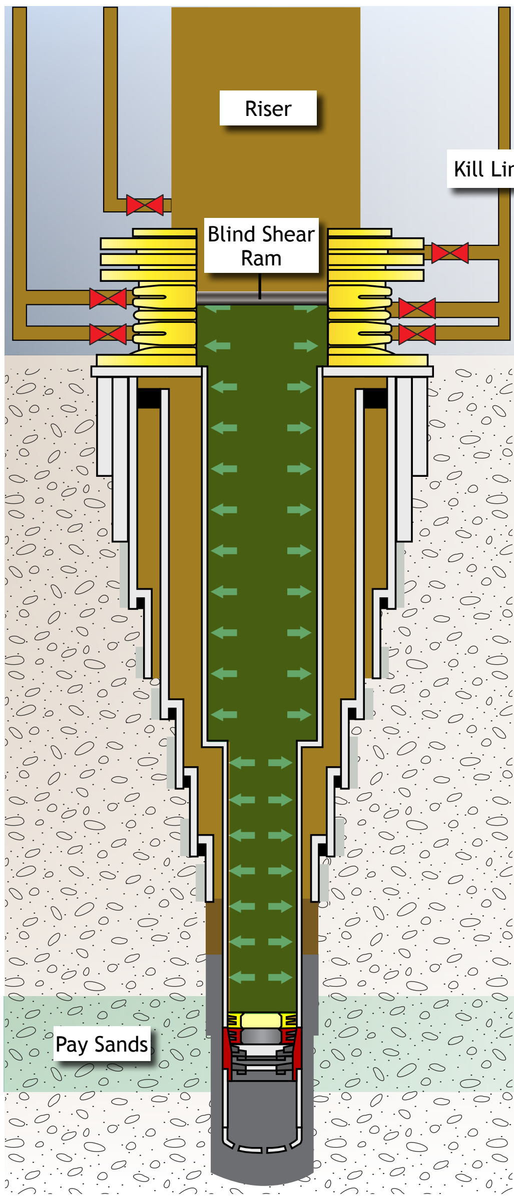
TrialGraphix

The seal assembly test checked the integrity of the interface between the casing and the wellhead. After lowering a packer into the well, the rig crew closed a variable bore ram around the BOP, sealing the space above and below the seal assembly. The rig crew then pumped fluid into this space, increasing the pressure inside it. If fluid did not leak out of the seal assembly, the pressure would remain constant.

Seal Assembly Test

The **seal assembly test**, as its name implies, tests the casing hanger seal assembly. A long string production casing hangs from a casing hanger inside the wellhead. The casing hanger both supports the casing and seals off the annular space outside the top of the casing. After installing the casing, rig personnel conduct a test to determine that the casing hanger seal does not leak. To do so, the crew installs a plug, or **packer**, on the bottom of the drill pipe and lowers it beneath the seal assembly. The crew closes a variable bore ram of the blowout preventer (BOP) (above the seal assembly) around the drill pipe. This creates a small enclosed space inside the casing at the mudline. The rig crew then pumps additional fluid into this space, increasing the pressure. They then monitor the pressure for a predetermined time period. If the pressure remains constant, it means that the casing hanger seal is capable of containing high internal pressure. If the pressure drops, fluid is escaping through a leak. In the early morning hours of April 20, the rig crew performed two separate pressure tests on the seal assembly, both of which passed.[2]

Figure 4.6.3



TrialGraphix

The positive pressure test checks the integrity of the well by testing whether the casing and wellhead seal assembly can contain higher pressure than surrounds them. The *Deepwater Horizon* crew increased the pressure in the production casing string by pumping fluid into it through the kill line. If fluid does not leak out of the casing, the pressure again remains constant.

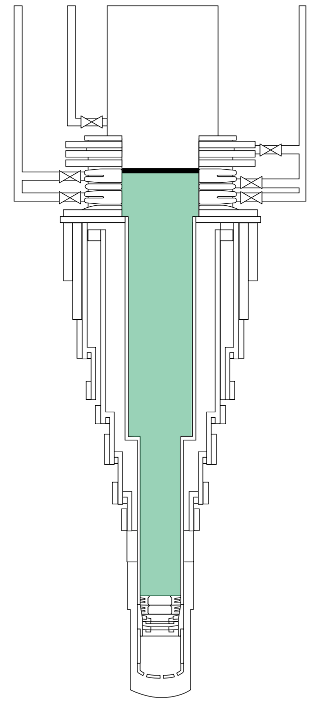
Positive Pressure Test

Later that morning, the rig crew conducted a **positive pressure test**. A positive pressure test is like a seal assembly test, but over a larger area of the well. With the drill pipe pulled out of the well, the rig crew shuts the blind shear rams on the BOP to isolate the well from the riser. The crew then pumps additional fluid into the well below the BOP and monitors the pressure. If the pressure remains constant with the pumps shut off, that means that the casing, wellhead seal assembly, and BOP are containing internal pressure and are not leaking. Between 10:30 a.m. and noon, the crew conducted a positive pressure test to 250 pounds per square inch (psi) for five minutes and then a second to 2,700 psi for 30 minutes. In both instances, pressure inside the well remained constant over the test period.[3]

Because the seal assembly and positive pressure tests at Macondo appear to have been performed and interpreted correctly, this report does not explore them further.

Neither the seal assembly test nor the positive pressure test could check the integrity of the cement in the shoe track or in the annular space at the bottom of the production casing. The seal assembly test could not test anything below the packer. Similarly, the positive pressure test does not test anything below the wiper plug on top of the float collar.

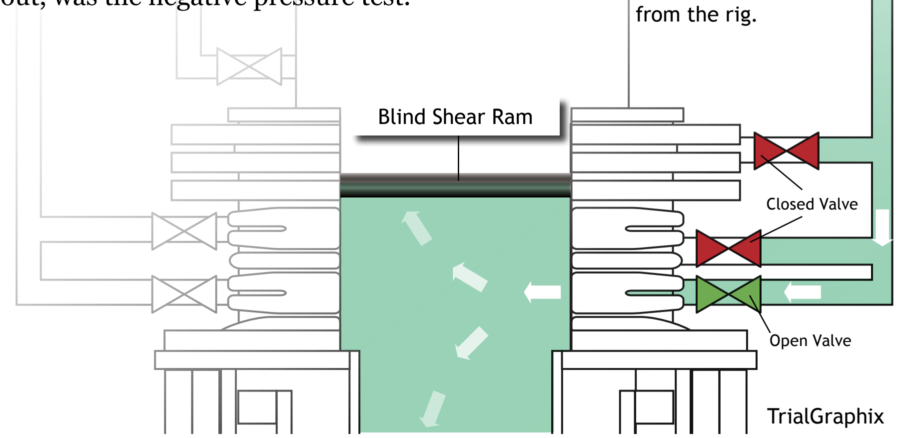
The only test that was capable of testing the bottomhole cement, which was essential to preventing a blowout, was the negative pressure test.[4]



Positive Pressure Test

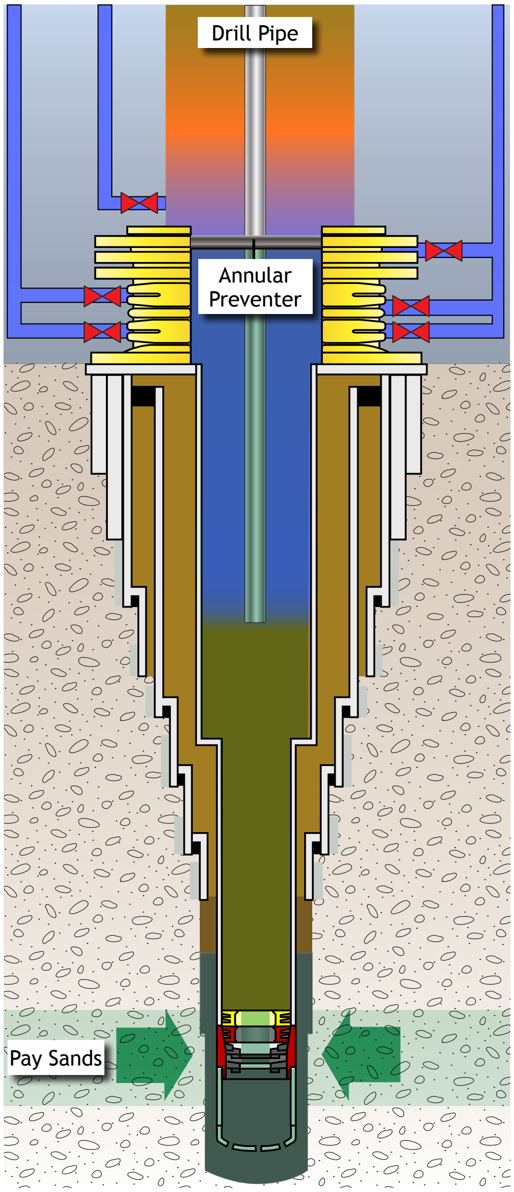
Kill Line

Pressurizing the well during integrity testing requires the rig crew to seal the well at the BOP. Opening and closing valves, such as the kill line, allow the crew to manipulate pressures in the well from the rig.



TrialGraphix

Figure 4.6.4



By moving mud from the production casing into the riser (displacement), the rig personnel reduced the pressure inside the well below the pressure outside the well (underbalancing). If there was good well integrity, the pressure inside the well would remain constant during the negative pressure test. If there was a leak of hydrocarbons into the well, the pressure in the well would rise (if the drill pipe or lines to the rig were closed) or fluid in the wellbore would be forced up and flow out at the rig (if the lines were open).

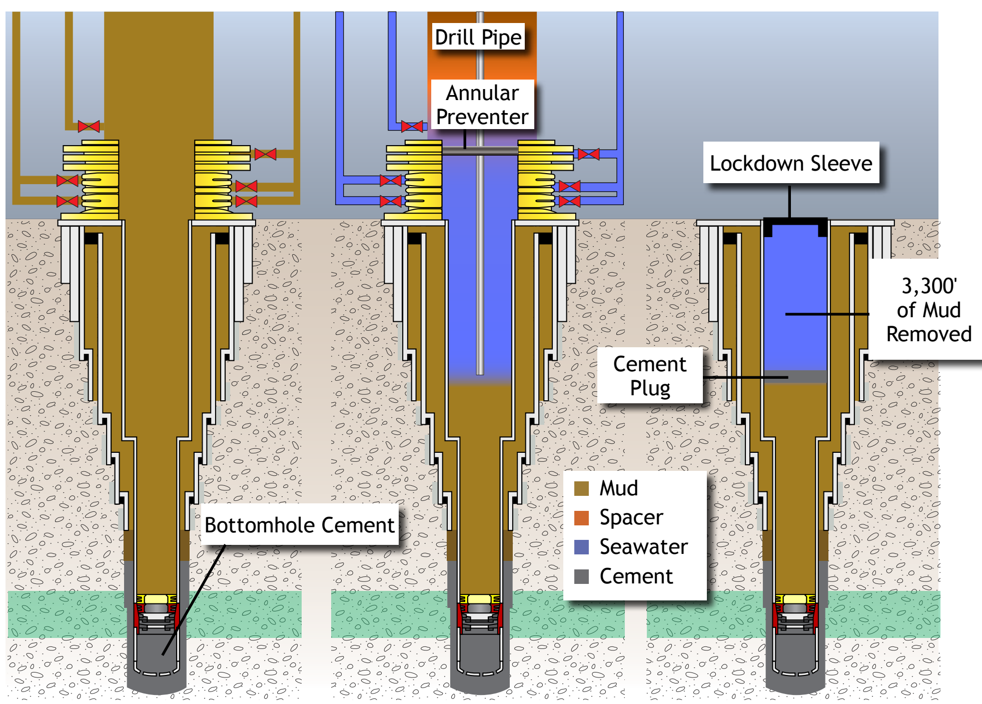
Negative Pressure Test

The **negative pressure test** is essentially the inverse of a positive pressure test. Rig personnel reduce the pressure inside the well below the pressure outside the well and then monitor the well to determine whether any hydrocarbons from the pay zones leak into the well from the formation outside it.

Whereas rig personnel identify a failed positive pressure test by observing diminishing internal pressure, they identify a failed negative pressure test when they observe *increasing* internal pressure while the well is shut in or *flow* from the well while it is open. In a successful negative pressure test, there should be no pressure increase inside the well and no flow from the well for a sustained period of time.[5] Increased pressure during this period indicates that the primary cement job at the bottom of the well has failed and hydrocarbons from the pay zone are entering the well.

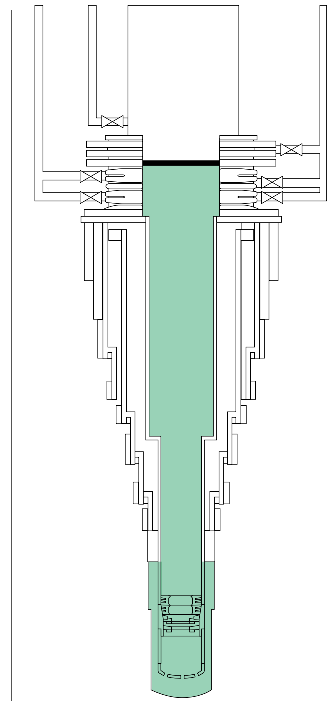
The negative pressure test simulates the conditions rig personnel will create inside the well once they remove drilling mud from the riser (and from some portion of the well below the mudline) in order to temporarily abandon the well. Removing that mud removes pressure from inside the well.

Figure 4.6.5. End of cement to temporary abandonment.



After the final casing string was cemented, heavy drilling mud filled the riser and the well (left). After the temporary abandonment planned for Macondo, the riser and its drilling mud would be removed. The drilling mud in the final casing string would be replaced with lighter seawater to a depth of over 8,000 feet below sea level (right). The removal of the hydrostatic pressure this drilling mud applied to the bottom of the well would increase the stress on the casing, seals, and cement. The negative pressure test simulated the conditions of temporary abandonment to confirm the integrity of the well in a controlled environment (middle).

The purpose of the negative pressure test is to make sure that when that pressure is removed, the casing, cement, and mechanical seals in the well will prevent high-pressure hydrocarbons or other fluids in the pay zone outside the well from leaking in. The test thus evaluates the integrity of the wellhead assembly, the casing, and the mechanical and cement seals in the well—indeed, it is the *only* pressure test that checks the integrity of the primary cement (see Figure 4.6.4).



Negative Pressure Test

For these reasons, both BP and Transocean have described the negative pressure test as critically important.[6]

Negative Pressure Test at Macondo

The negative pressure test at Macondo occurred in three separate phases over a five-hour period between approximately 3 and 8 p.m. on April 20.

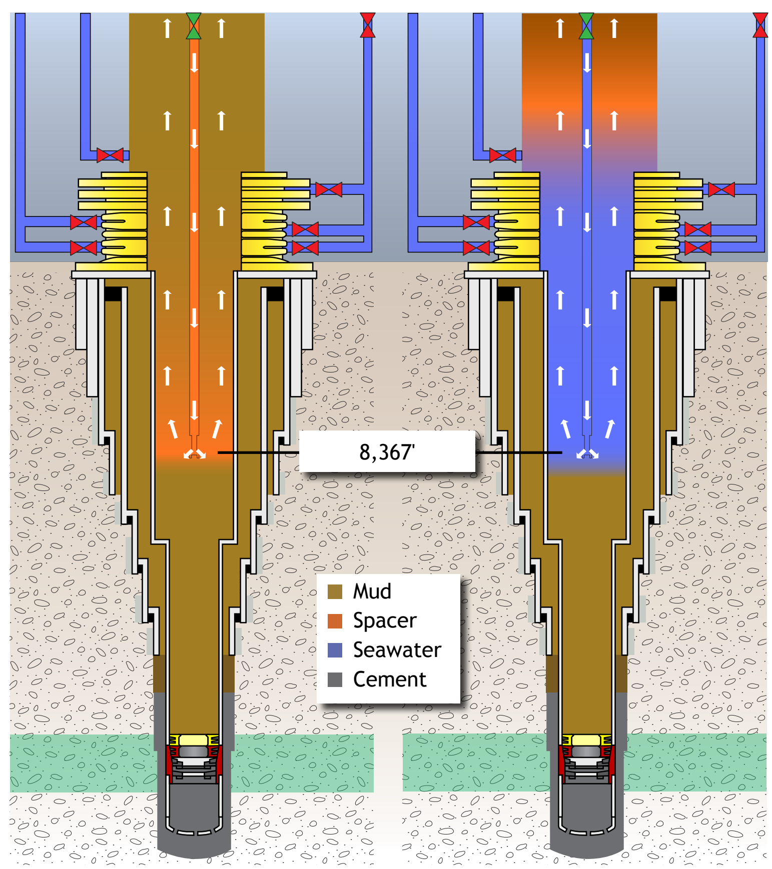
First, the crew prepared to conduct the negative pressure test. To replicate conditions after temporary abandonment, the crew needed to "remove" the column of mud to a depth of 8,367 feet below sea level. In its place, the crew would "substitute" a column of seawater (see Figure 4.6.5). The crew accomplished this by pumping seawater (preceded by a buffer fluid known as **spacer** to separate it from the mud) down through a drill pipe lowered to that depth, illustrated in Figure 4.6.6. As they exited the stinger at the end of the drill pipe, the spacer and seawater would force—or **displace**—the surrounding mud up through the casing and into the riser. Once the seawater had displaced the mud and spacer into the riser above the BOP stack, the crew would close an annular preventer on the BOP around the drill pipe.

Closing the annular preventer would isolate the well below from the hydrostatic pressure exerted by the column of heavy drilling mud and spacer in the riser. At that point, the well would instead be subject to the lower hydrostatic pressure exerted by the lighter 8,367-foot column of seawater in the drill pipe. This would simulate the reduced hydrostatic pressure inside the well after temporary abandonment.

The next step was to conduct what became the first negative pressure test (the crew originally planned to conduct only one test). The crew would open a valve on the drill pipe at the rig and **bleed off** any pent-up pressure inside the drill pipe. In other words, the crew would allow fluids to flow out of the drill pipe until the flow stopped and the pressure in the pipe fell to 0 psi. The crew would then close—or **shut in**—the drill pipe and monitor the pressure inside it to see whether it remained at 0 psi or increased. This **drill pipe pressure** reflected the internal pressure of the well.

At Macondo, the crew had unexpected difficulty in bleeding the drill pipe pressure down to 0 psi. After each attempt, the crew would shut in the well, and the pressure would build back up. The rig crew attempted three times to bleed

Figure 4.6.6. Preparations for the negative pressure test.



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To prepare for the negative pressure test, the rig crew needed to displace the mud in the drill pipe and casing string from a depth of 8,367 feet to above the BOP. The crew did so by pumping spacer fluid (left) and then seawater (right) down the drill pipe until the mud was above the BOP.

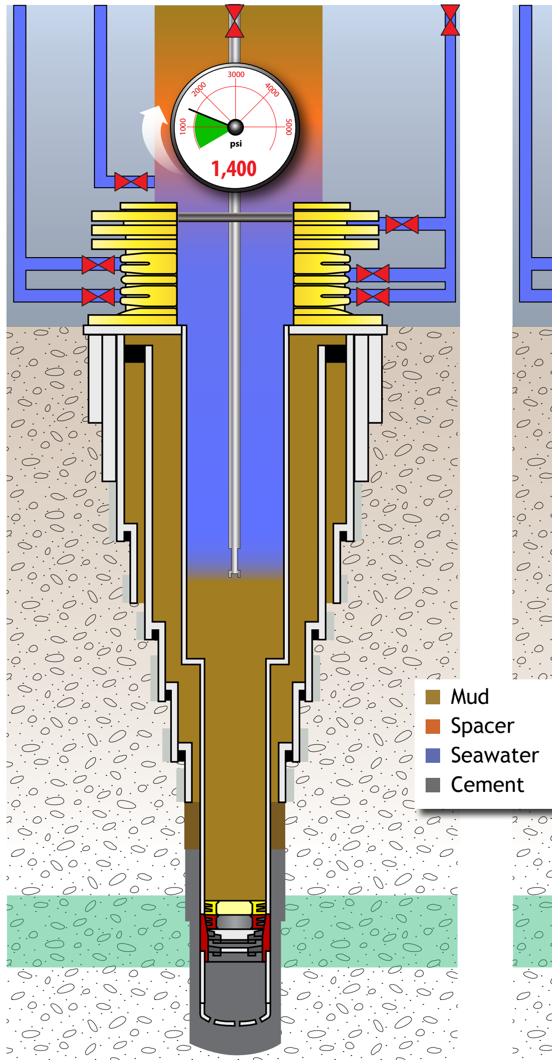
off the drill pipe pressure, but each time, the drill pipe pressure rose after being bled off. After the third attempt, drill pipe pressure rose from 0 to 1,400 psi as shown in Figure 4.6.7.

All parties now agree that this 1,400 psi pressure reading indicated that the well had failed the negative pressure test and that the cement job would not prevent hydrocarbons in the pay zones from entering the well.[7] The 1,400 psi pressure was the pressure of the hydrocarbon-bearing pay zone that was not properly sealed off by the primary cement.

The crew did not recognize that this first negative pressure test had identified a problem with the well—or if they did, they did not act upon that fact. Instead, they conducted a second test.

BP had submitted a permit modification to MMS stating that it would conduct the negative pressure test on the kill line rather than the drill pipe.[8] At least in part for this reason, BP well site leaders decided to follow up their first test on the drill pipe with a second negative pressure test in which they monitored pressure and flow on the kill line.[9] Rig personnel therefore opened the kill line, bled the pressure down to 0 psi, and monitored the line for 30 minutes. This time, there was no flow or pressure buildup in the kill line. The well site leaders and rig crew decided this was a successful negative pressure test and moved on to the next steps in the temporary abandonment procedure. But, as shown in Figure 4.6.8, although the pressure on the kill line may have stayed at 0 psi, drill pipe pressure remained at 1,400 psi.

Figure 4.6.7. First test failure.



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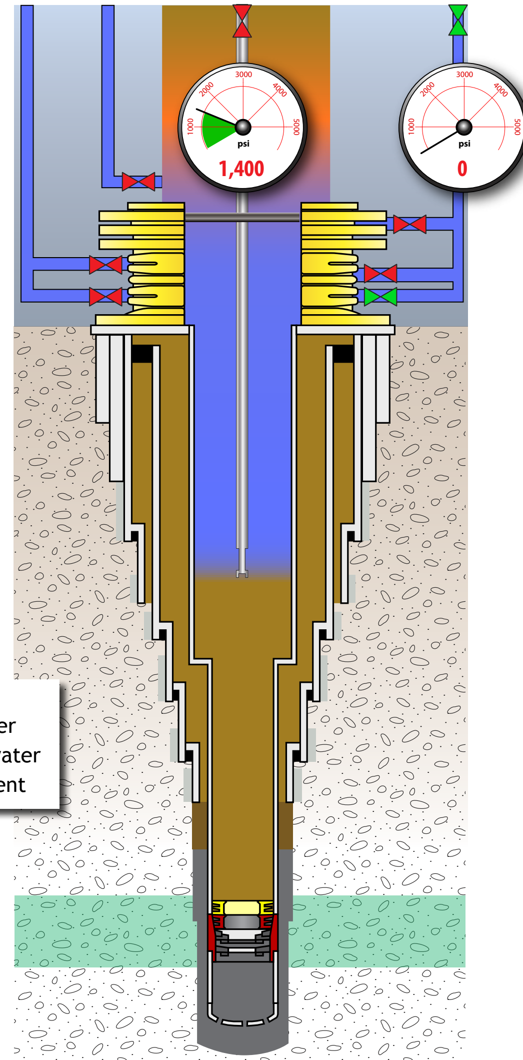
During the first negative pressure test, the crew repeatedly bled the drill pipe pressure down to 0 psi. However, more fluids bled than expected, and the drill pipe pressure repeatedly increased. After the last bleed, the drill pipe pressure rose from 0 to 1,400 psi, a clear failure.

Figure 4.6.8. Second test failure.



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During the second negative pressure test, the crew bled off the pressure in the kill line, rather than the drill pipe. The crew observed no excessive flow or pressure buildup on the kill line. The well site leaders and rig crew decided this was a successful test. But they had never accounted for the pressure on the drill pipe, which remained at 1,400 psi throughout the second test.

The well site leaders and rig crew never adequately accounted for that elevated pressure in the drill pipe.

The negative pressure test at Macondo "failed" in the sense that it did not show that the well had integrity. It was successful, however, in that it repeatedly and accurately identified a serious problem. All parties have since agreed that the 1,400 psi pressure reading on the drill pipe showed that hydrocarbons from the formation were entering the well from the pay zones and that the cement had failed to isolate or block off those pay zones. The larger question is why the men on the rig floor, who depended on this test to ensure well integrity, did not interpret the results of the negative pressure test correctly.

Answering this question is difficult because of the lack of consistent and detailed witness accounts. Some of the most valuable facts will never be known because many of the men involved in the test died in the rig explosion. The well site leaders involved in the test did survive but declined to speak to investigators about what happened (one citing his medical condition and the other invoking his Fifth Amendment rights).

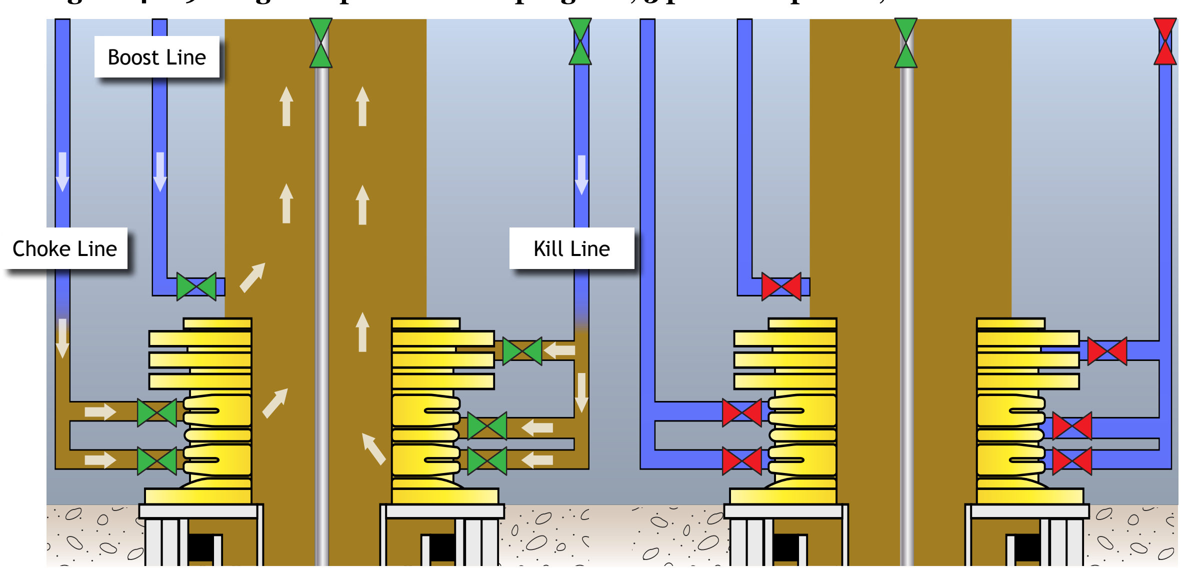
However, the Chief Counsel's team did review notes taken by BP investigators who spoke with both well site leaders soon after the blowout. The Chief Counsel's team also had access to data records showing the pressures that the rig crew observed as well as testimony from witnesses who observed certain events in the drill shack that evening. The Chief Counsel's team based the following account on these information sources.

Preparations for the Negative Pressure Test

The rig crew began preparations for the negative pressure test at about 3 p.m. with a pre-job safety meeting. Because the crew would have to displace drilling mud to conduct the test, Leo Lindner, M-I SWACO's mud engineer, led the meeting. Well site leader Bob Kaluza was present for the meeting, though he left soon after it ended.[10] The meeting was held in or near the drill shack.

Shortly after 3 p.m., Transocean driller Dewey Revette pumped water to displace mud from three pipes, or "lines," that ran from the rig to the BOP stack: the **boost**, **choke**, and **kill lines** (see Figure 4.6.9).

Figure 4.6.9. Negative pressure test progress, 3 p.m. on April 20, 2010.



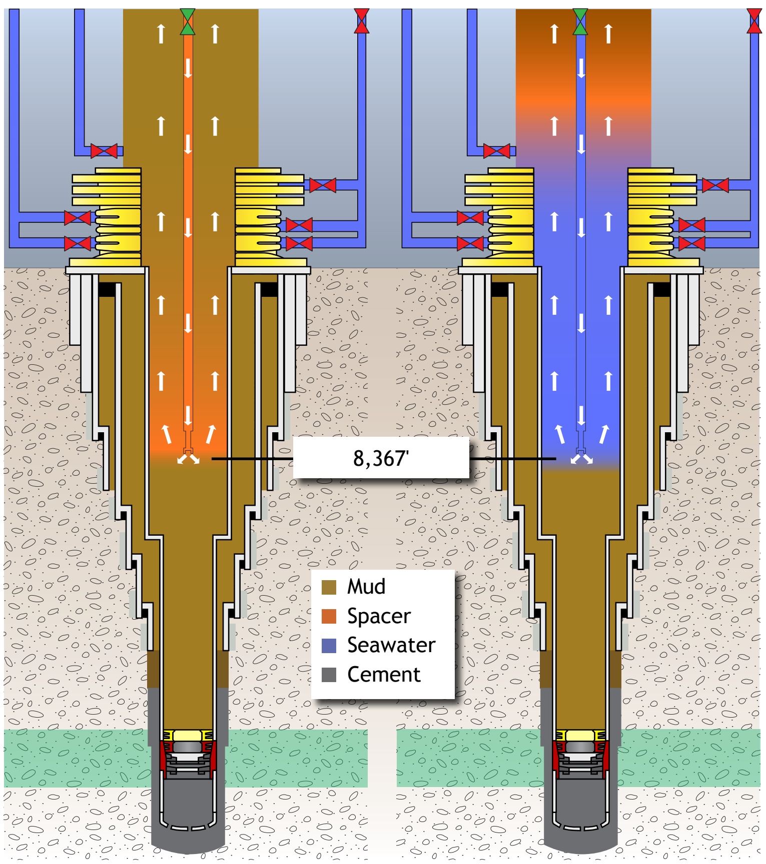
To begin preparations for the negative pressure test, the rig crew displaced the boost, choke, and kill lines with seawater. Seawater was pumped into the lines on the rig, forcing mud into and up the riser (left). After the lines were displaced, the crew closed the valves connecting them to the riser and BOP (right).

Rig personnel could use these lines to pump fluids into the well without pumping fluids through the drill pipe.[11]

The boost line was connected to the well immediately above the BOP. Rig personnel could pump fluids through it to accelerate the displacement of mud in the riser, literally "boosting" mud up toward the rig. The rig crew anticipated pumping seawater through the boost line later in the temporary abandonment process and prepared for doing so by displacing mud inside the line with seawater.

The choke and kill lines were connected to the BOP at various points on the stack. Rig personnel could use these lines to pump fluids in and out of the well even while certain BOP elements were fully sealed. These lines were therefore crucial to controlling kicks during drilling operations: After shutting the well in with the BOP, rig personnel could use them to "kill" the well (that is, overbalance it) with heavy mud and then "choke it off" by circulating hydrocarbons out. The rig crew could also use these lines instead of the drill pipe to conduct the negative pressure test. The men on the *Deepwater Horizon* eventually did use the kill line for this purpose.[12]

Figure 4.6.10. 4 p.m.



The crew displaced the mud in the drill pipe and in the casing from 8,367 feet to above the BOP. The crew first pumped a spacer fluid down the drill pipe, which forced the mud out and up the casing and the riser (left). Following the spacer, the crew pumped seawater into the drill pipe. This forced the spacer and the mud up the casing. The crew's intent was to pump enough seawater to displace the spacer and mud above the BOP (right).

Just before 4 p.m., the crew took its next preparatory step. They pumped seawater down the drill pipe to displace the drilling mud in the pipe and then continued pumping seawater until they displaced mud in the casing above 8,367 feet with seawater as shown in Figure 4.6.10.[13] Because mud is expensive and reusable, and because direct contact with seawater would contaminate it, the crew used spacer fluid as a buffer to separate the seawater from the mud. The crew's goal was to displace the heavy mud and spacer fluid entirely above the BOP.

Use of Lost Circulation Material as Spacer

Operators commonly choose to use a spacer during displacement. However, BP chose to use a somewhat unusual *type* of spacer fluid at Macondo. BP chose to use a fluid composed of leftover **lost circulation materials** stored on the rig. As previously discussed, BP engineers had been concerned about the risk of further lost returns since the lost circulation event in early April. BP had asked M-I SWACO to make up at least two different batches, or "pills," of lost circulation material for that contingency—one commercially known as Form-A-Set and the other as Form-A-Squeeze. BP decided to combine these materials for use as a spacer during displacement.

The combined spacer material that BP chose thus had two unusual characteristics. First, the material was denser than the drilling mud in the well and, at 16 pounds per gallon (ppg), much denser than 8.6 ppg seawater.[14] While using such a dense spacer would arguably assist in displacing mud down and out of the drill pipe, it could prove problematic as well. BP's plan called for the spacer to be pushed up through the wellbore and into the riser by the seawater flowing behind it. By using a spacer that was so much denser than the seawater, BP increased the risk that the spacer would instead flow downward *through* the seawater, potentially ending up *beneath* the BOP and confounding the negative pressure test.[15]

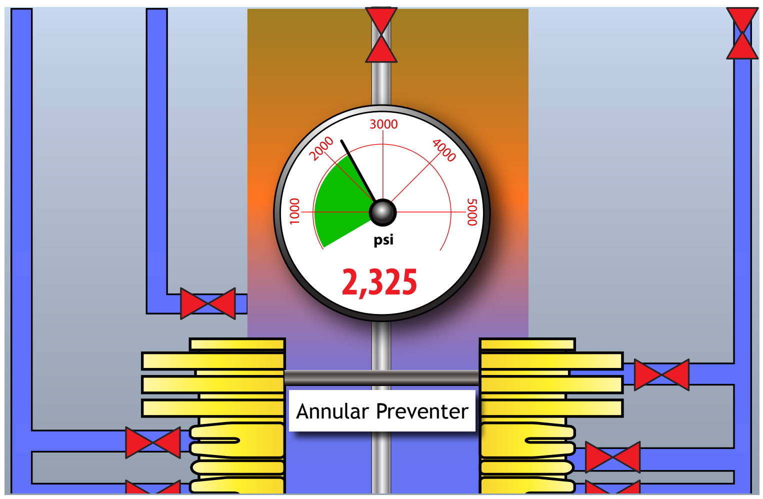
Second, the lost circulation materials that BP combined to create its spacer created a risk of clogging flow paths that could be critical to proper negative pressure testing. Much as blood clots to stop a bleeding wound, viscous lost circulation materials are designed to plug fractured formations to prevent mud from leaking out of a well. M-I SWACO therefore warned BP before the negative pressure test that spacer composed of lost circulation material could "set up" or congeal in "small restrictions" in tools on the drill pipe.[16]

The Chief Counsel's team found no evidence that anyone in the industry had ever used (or even tested) this type of spacer before, much less that anyone at BP or on the rig had done so.[17] There also appears to be no operational reason BP chose to use the lost circulation material as a spacer.[18] Rather, according to internal BP emails and the testimony of various witnesses, BP chose to use the lost circulation pills as a spacer in order to avoid having to dispose of the material as hazardous waste pursuant to the Resource Conservation and Recovery Act (RCRA).[19]

RCRA regulations would normally have required BP to treat and dispose of the two pills as hazardous waste. But BP and M-I SWACO reasoned that once the two pills had been circulated down through the well as a spacer they could be dumped overboard pursuant to RCRA's exemption for water-based drilling fluids.[20] This is what prompted BP to direct M-I SWACO to use the lost circulation material as a spacer.[21] This decision would save BP the cost of shipping the materials back to shore and disposing of them as hazardous waste.[22]

These disposal concerns also led BP to use an unusually large volume of spacer material at Macondo. Typically, 200 barrels of spacer are enough to provide an adequate buffer between mud and seawater.[23] BP chose to pump 454 barrels of its unusual combined spacer fluid at Macondo.[24]

Figure 4.6.11. 4:53 p.m.



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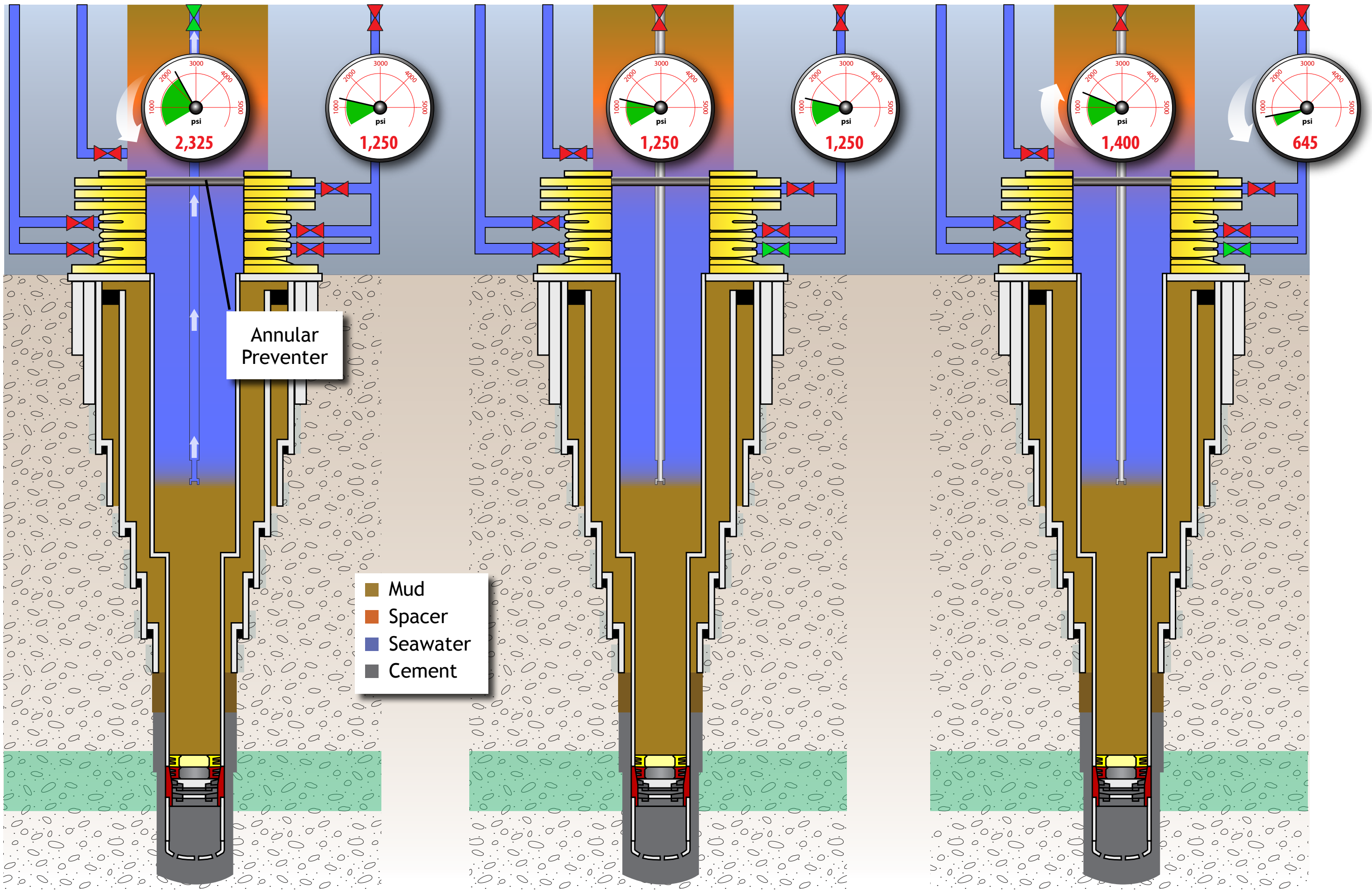
The crew closed the annular preventer around the drill pipe. The drill pipe pressure was approximately 700 psi higher than should have been expected, a sign that some spacer may have remained beneath the BOP.

Unlikely Displacement of All Spacer Above the BOP

After pumping 352 barrels of seawater behind the spacer, the crew closed the upper annular preventer, believing that they had displaced all of the spacer above the BOP.[25] BP's post-incident report calculates that the crew was correct, albeit by a slim margin of just 12 feet.[26] But that calculation is optimistic. It assumes that none of the heavy spacer fell back down through the much lighter seawater that was pushing it upward through the wellbore. Given the substantial density differential between the spacer and seawater and the substantial amount of time it took to displace 454 barrels of spacer, it is likely that at least some of the spacer fell backward through, or mixed with, the seawater on its way up the casing into the riser. Even putting aside that complication, Transocean and at least one independent expert have calculated that the tail end of the spacer did not end up above the BOP.[27]

Figure 4.6.12. 4:55 p.m.



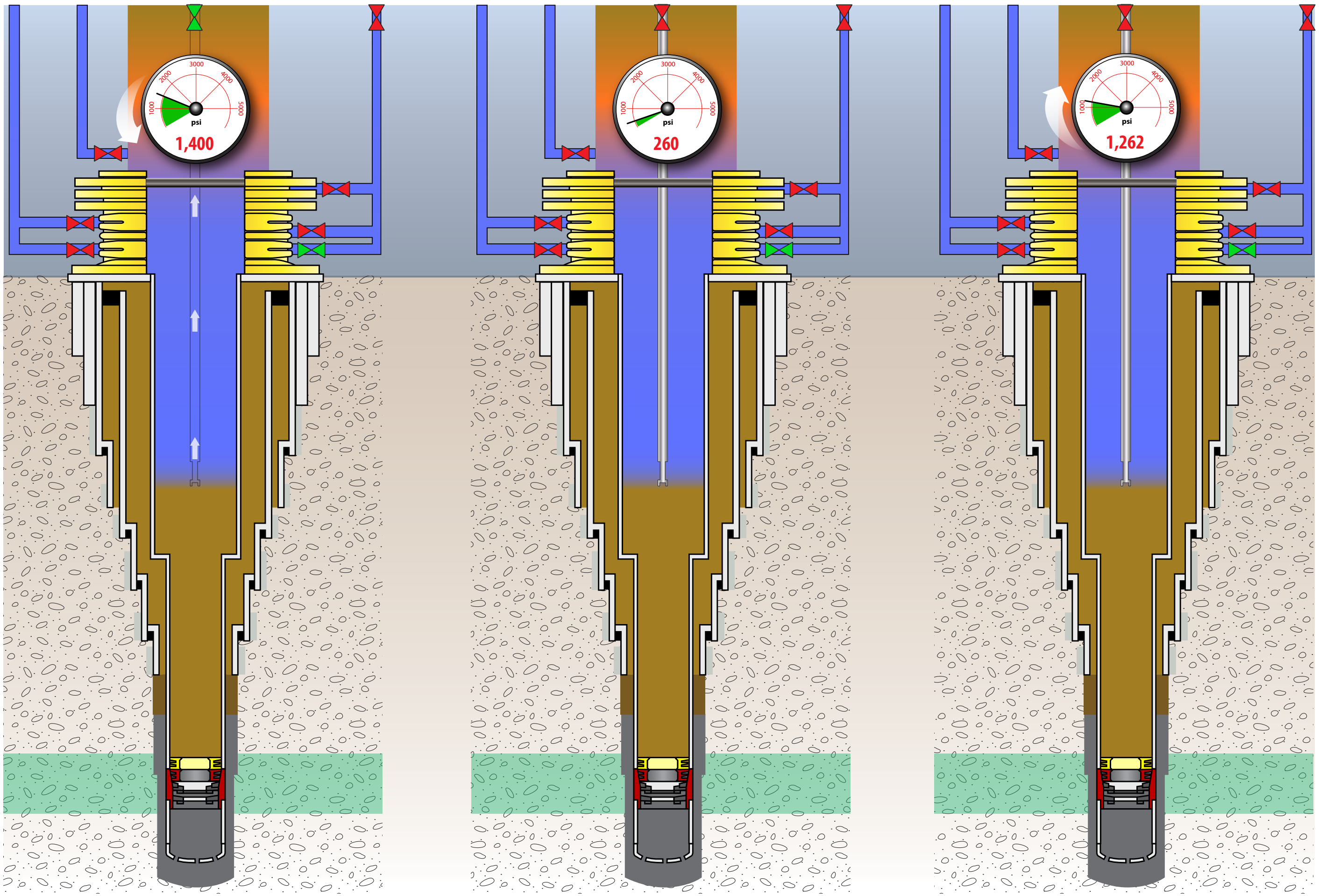
After the annular preventer was closed (left) the crew bled down the pressure in the drill pipe to equalize its pressure with the pressure in the kill line. Because both the drill pipe and the kill line go to the same vessel, when the valve connecting the kill line to the BOP is opened, the pressures should remain equal (middle). Instead, when the valve was opened, the pressures diverged (right).

Because the BOP and wellhead were a mile beneath the rig, the crew had no way of observing directly whether they had displaced all of the spacer above the annular preventer. But pressure readings on the drill pipe should have alerted them that something was amiss. When the crew first closed the annular preventer around the drill pipe (see Figure 4.6.11), the pressure on the drill pipe was approximately 700 psi higher than it should have been.[28] That anomaly should have merited further investigation because it could have indicated that spacer remained below the BOP. But it does not appear that anyone in the drill shack had ever calculated what the drill pipe pressure should have been.[29]

This higher-than-expected pressure was the first of many unrecognized and unheeded anomalous readings during the negative pressure test.

The rig crew next bled the drill pipe to 1,250 psi, in an effort to equalize pressure on the drill pipe with pressure on the kill line (which was 1,250 psi at the time, as shown in Figure 4.6.12).[30] Once the crew had bled the drill pipe pressure down to 1,250 psi, it opened a valve on the kill line at the BOP so that both the drill pipe and kill line were open to the well. At this point, the drill pipe and kill line should have behaved like two straws in the same glass of water: The pressure in both should have been a steady 1,250 psi. Instead, when rig personnel opened the valve, the drill pipe pressure jumped, and the kill line pressure dropped.[31]

Figure 4.6.13. 4:58 p.m.



The crew began the negative pressure test by attempting to bleed the drill pipe pressure to 0 psi (left). However, the crew was unable to reduce pressure to below 260 psi (middle). This bleed returned an unknown amount of water to the rig. The crew shut in the drill pipe, and the pressure built up to 1,262 psi (right). In a successful negative pressure test, pressure does not build up.

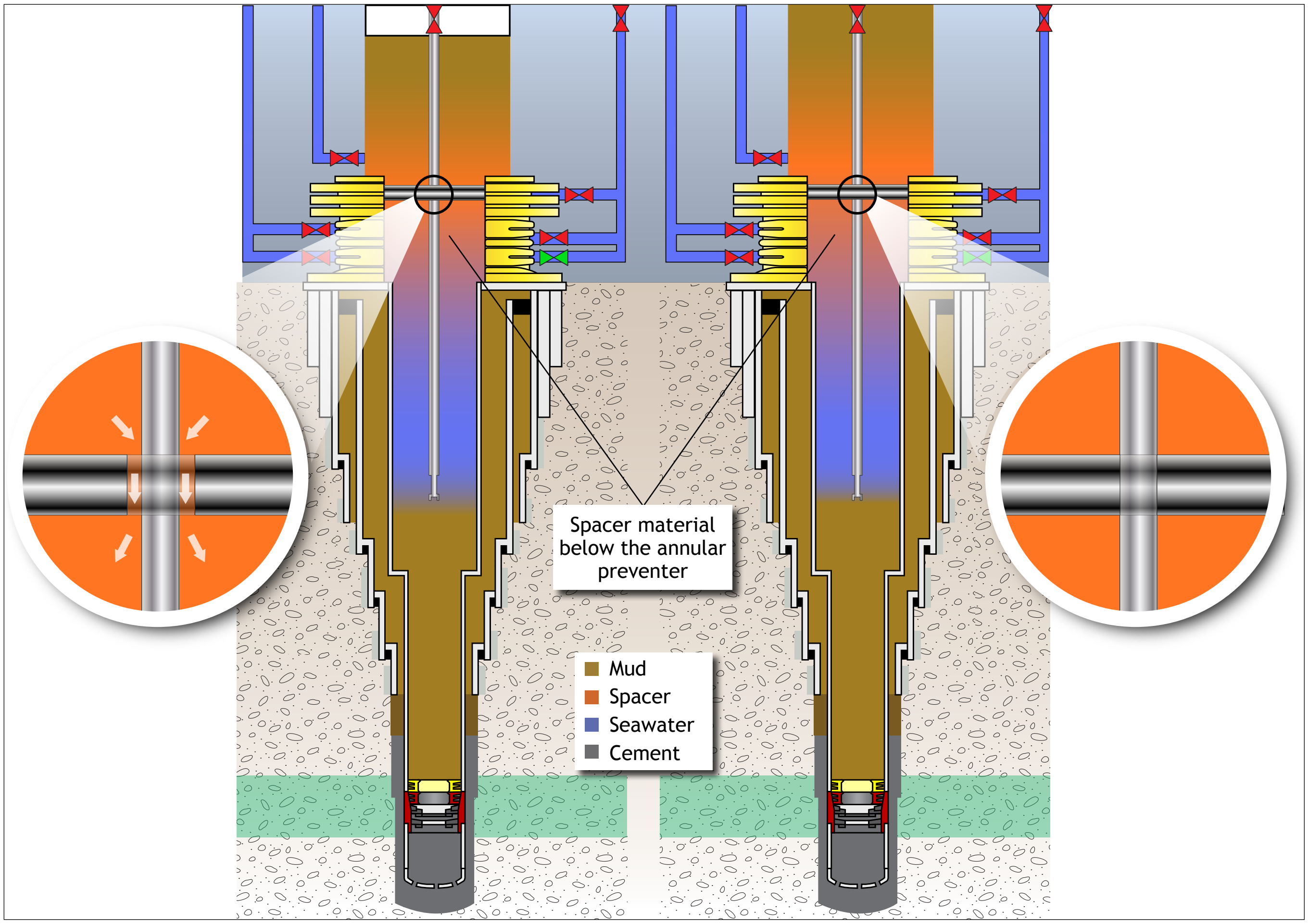
This should have been another indication that spacer might have ended up beneath the BOP or that something else was amiss.[32] There is some evidence that the crew or well site leaders may have recognized a concern, but nobody appears to have acted upon it.[33] In what became a pattern, individuals on the rig did not take a simple precaution: They could have opened up the annular preventer, pumped more seawater into the well to ensure that all spacer had been displaced above the BOP, and begun the negative pressure test anew.[34] This would have taken time but also would have ensured that misplaced spacer did not confound the test results.

The First Negative Pressure Test

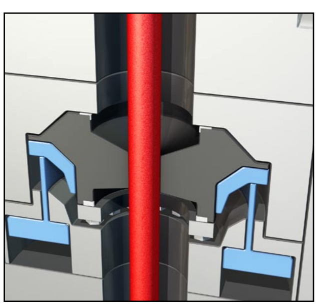
Just before 5 p.m., the crew opened a valve at the top of the drill pipe on the rig and attempted to bleed the drill pipe pressure down to 0 psi, as shown in Figure 4.6.13. The crew was unable to do so and could only reduce pressure to 260 psi.[35] It is not clear how many barrels of fluid the crew bled off at this point. Three witnesses have testified that 23 to 25 barrels were bled off; other accounts suggest it may have been more or less.[36]

The uncertainty over how much fluid flowed from the well during the bleed-off suggests that the well site leaders and crew failed to monitor the bleed-off volumes with requisite rigor. It does not appear that anyone had calculated ahead of time how many barrels should have flowed from the

Figure 4.6.14. 5:10 p.m.



The rig crew noticed that the fluid level in the riser was falling. Because the annular preventer was not sufficiently tight around the drill pipe, spacer fell beneath the BOP (left). In response, the rig crew tightened the seal of the annular preventer and refilled the riser (right), but did not circulate the spacer back above the BOP.



Annular Preventer. The annular preventer is a hard rubber donut that surrounds the drill pipe; when activated it expands and fills the space around the drill pipe, sealing the well below (see also Figure 2.9).

well during the bleed, even though such calculations would have been relatively straightforward.[37] After failing to bleed the pressure down to 0 psi, the crew closed the valve on the drill pipe, and the pressure built back up to 1,262 psi.[38]

These events indicated that the well was not behaving as a closed system. Something was entering the well, although the source of the material entering the well was indeterminate. If the well had been a closed system, the crew would have had no difficulty bleeding the drill pipe pressure down to 0 psi, and the well would have returned far less than 23 barrels of fluid during the bleed-off.[39] Also, the drill pipe pressure would not have increased.

As one independent expert has pointed out, this series of events actually constituted a failed negative pressure test, although the crew did not recognize that fact.[40]

At 5:10 p.m., the rig crew apparently noticed that the level of fluid in the riser was falling.[41] Spacer in the riser was leaking down through the annular preventer and into the well below the BOP.[42] Unlike many other indications, the crew could observe the fluid levels in the riser with their own eyes. When one rig crew member arrived on the rig floor, he saw others standing around the rotary table and using a flashlight to peer down into the riser to see how much fluid was missing.[43]

Around this time, the night crew began to gather at the drill shack in anticipation of the 6 p.m.

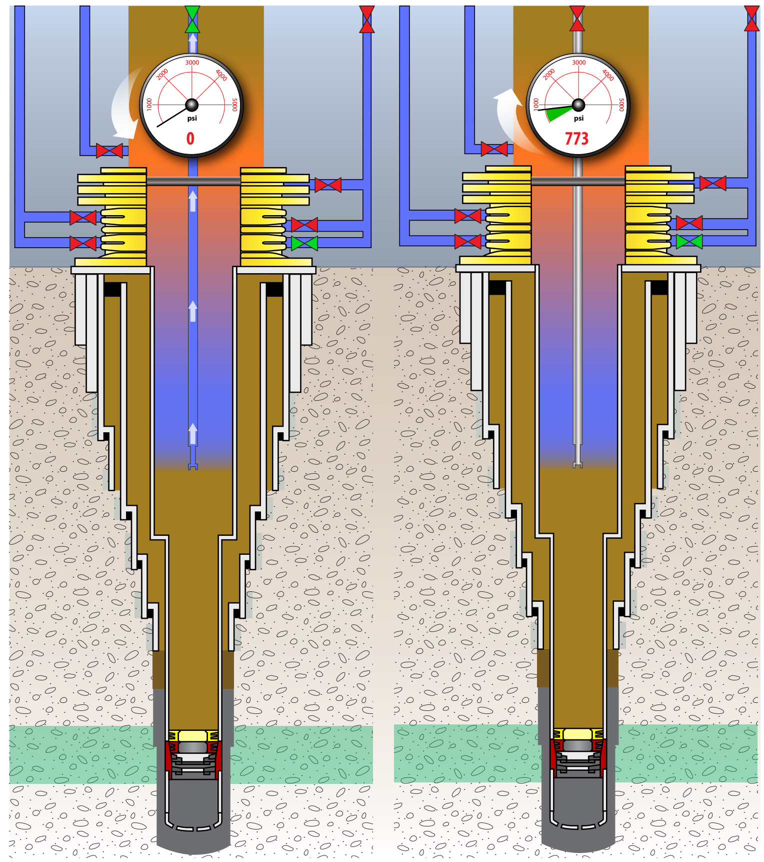
shift change. The night crew would include Transocean toolpusher Jason Anderson and M-I SWACO mud engineer Gordon Jones.

A group of visiting BP and Transocean executives also entered the drill shack as a part of a rig tour. They were escorted by Transocean offshore installation manager Jimmy Harrell and senior toolpusher Randy Ezell. The drill shack was so crowded with the shift relief and tour group that it was "standing room only,"[44] Transocean executive Daun Winslow recognized that the drilling team was confused about something. When the tour group left the drill shack, Winslow asked Harrell and Ezell to remain behind to assist.[45]

In response to the dropping levels of fluid in the riser, Harrell instructed the rig crew to tighten the seal of the annular preventer against the drill pipe as shown in Figure 4.6.14. Wyman Wheeler, the Transocean toolpusher on duty at the time, then topped off the riser with 20 to 25 barrels of mud, and the fluid level in the riser stayed steady.[46] The crew had thus identified and eliminated a leak in the well system that could have explained the anomalous pressure readings they had seen and their inability to bleed the drill pipe pressure to 0 psi.[47] By this time Kaluza returned to the rig floor.[48]

Despite clear evidence that spacer had probably leaked below the BOP, rig personnel again did nothing to ensure that they had fully displaced the spacer above the BOP and instead proceeded with the test.[49]

Figure 4.6.15. 5:26 p.m.



The rig crew attempted again, this time successfully, to bleed the drill pipe pressure down to 0 psi. Fifteen barrels of seawater were returned during this bleed (left). The drill pipe was shut in, but the drill pipe pressure rose to 773 psi. Fifteen barrels is a higher return than should have been expected, and the drill pipe pressure should not have built back up.

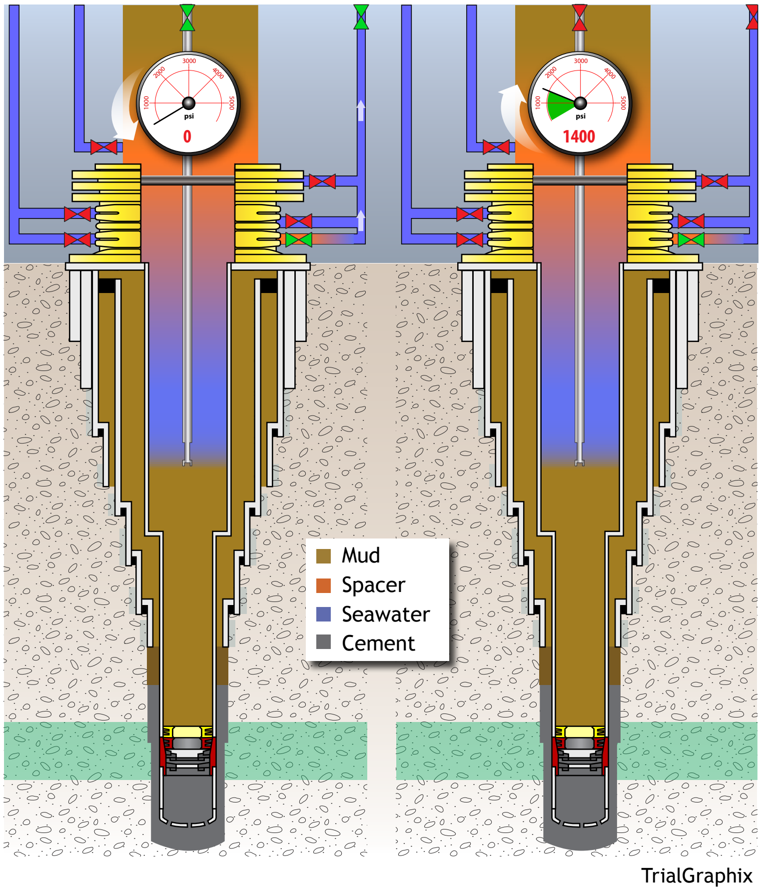
Having tightened the annular preventer, the crew once again tried to bleed the pressure in the drill pipe to 0 psi as shown in Figure 4.6.15. This time they were successful. According to witness accounts, 15 barrels of fluid were bled off from the drill pipe in the process.[50] Again, nobody had done any calculations to predict the returns. Those calculations would have predicted only three to five barrels of returns; the bleed-off process had produced more fluids than it should have.[51]

The crew shut in the drill pipe, but the pressure again built back up.[52] In this case, the pressure reached 773 psi and most likely would have gone higher had the crew not begun immediately bleeding it off.[53]

This second series of bleed-offs, excessive flows, and pressure buildups constituted another failed "negative pressure test" that the crew again did not recognize as such. With the annular preventer fully closed and sealed, the only explanation for the excessive returns and pressure increase would be that the primary cement job had failed to seal off the pay zone. Hydrocarbons were leaking from the formation into the well. Individuals involved in the test at this point should have recognized that the well lacked integrity.

According to at least one witness, shortly before 6 p.m. Kaluza directed the crew to bleed down

Figure 4.6.16. 5:53 p.m.



The rig crew bled drill pipe pressure down for a third time, this time through the kill line. Witnesses reported that three to 15 barrels were returned as the drill pipe reached 0 psi (left). When the drill pipe was shut, the drill pipe pressure rose to 1,400 psi. According to BP witnesses, the Transocean rig crew attributed this rise to a "bladder effect." A 15-barrel return would have been excessive, and the rise of drill pipe pressure to 1,400 psi was a clear sign that the negative pressure test had failed (right).

the drill pipe pressure by opening the kill line rather than the drill pipe. Because the kill line and drill pipe both led to the same place (again, like two straws in the same glass of water), bleeding pressure from the kill line would also cause drill pipe pressure to drop to 0 psi. It is not clear why Kaluza directed the crew to bleed down the drill pipe pressure by opening the kill line. The switch may be significant, however, as it suggests uncertainty about the pressure readings and flow observations. "Let's open the kill line and see what happens," Kaluza reportedly said.[54] Shortly afterward, Kaluza left the rig floor to speak with the Don Vidrine, the other BP well site leader whose shift was about to begin.[55]

Witnesses have provided differing estimates of the amount of seawater the crew bled from the kill line, ranging from three to 15 barrels.[56] Flows in the upper end of this range would have been more than expected—but once again, nobody calculated ahead of time what flows to expect. As the pressure on the drill pipe dropped almost to 0 psi,[57] the kill line continued to flow and spurt water until the crew closed the line's upper valve on the rig.[58] Over the next 30 to 40 minutes, the drill pipe pressure rose to 1,400 psi as shown in Figure 4.6.16.[59]

This was the clearest indication yet that the well lacked integrity. The 1,400 psi pressure buildup can only have been caused by hydrocarbons leaking into the well from the reservoir formation.

One expert described this test result as a "conclusive failure."[60] Later analysis has shown that 1,400 psi is approximately the reading that one would have expected reservoir hydrocarbon pressure to produce at the surface if there had been *no cement* at the bottom of the well during the negative pressure test.[61]

Kaluza returned to the rig floor with Vidrine, who would soon be relieving him.[62] While personnel at the rig had not treated earlier pressure readings and flow observations as problematic indications, the two well site leaders and other rig personnel did recognize that the rise in drill pipe pressure to 1,400 psi was a cause for concern.[63] According to witness accounts, Kaluza and Vidrine discussed the test in the drill shack together with Anderson, Revette, assistant driller Steve Curtis, and BP well site leader trainee Lee Lambert.[64] Because Kaluza's and Vidrine's accounts are only known through BP internal investigation notes, and the Transocean personnel principally involved did not survive (Ezell has stated that he did not take part in any such conversation and that he left the drill shack before the drill pipe pressure reached 1,400 psi), the details of the discussion are unclear. Transocean has challenged the accounts of the three BP witnesses, but those three accounts are consistent with each other, and at this point the Chief Counsel's team has no testimonial or documentary evidence that conflicts with them.

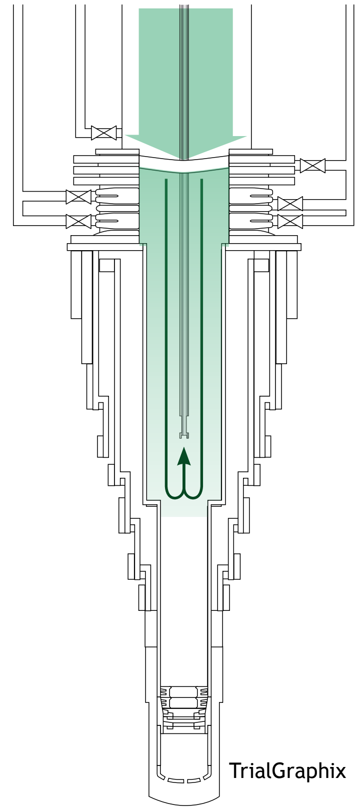
According to notes from BP's post-incident interviews of Kaluza and Vidrine, as well as testimony from Lambert, Anderson explained that the 1,400 psi pressure on the drill pipe was being caused by a "bladder effect" or "annular compressibility."[65] According to Lambert, Anderson explained that "heavier mud in the riser would push against the annular and transmit pressure into the wellbore, which in turn you would expect to see up the drill pipe," as illustrated in Figure 4.6.17.[66]

The Chief Counsel's team found no evidence to support this theory. Indeed, every industry expert that the Chief Counsel's team spoke with agreed that no such phenomenon exists. Even if it did exist, any pressure caused by this "bladder effect" would have disappeared after the rig crew bled off the drill pipe and kill line.[67]

Any "bladder effect" could not explain the 1,400 psi on the drill pipe.

Although there was a long discussion about the drill pipe pressure, it does not appear as though anyone in the discussion seriously challenged the bladder effect. According to BP witness accounts, Anderson explained that the pressure buildup after bleeding was not unusual. He told the well site leaders, "Bob and Don, this happens all the time."[68] Revette, the driller, apparently agreed that he had seen the bladder effect before.[69] Lambert testified that he asked about the phenomenon but accepted Anderson's explanation. On later reflection after the blowout, however, Lambert agreed that the explanation did not make sense.[70]

Figure 4.6.17

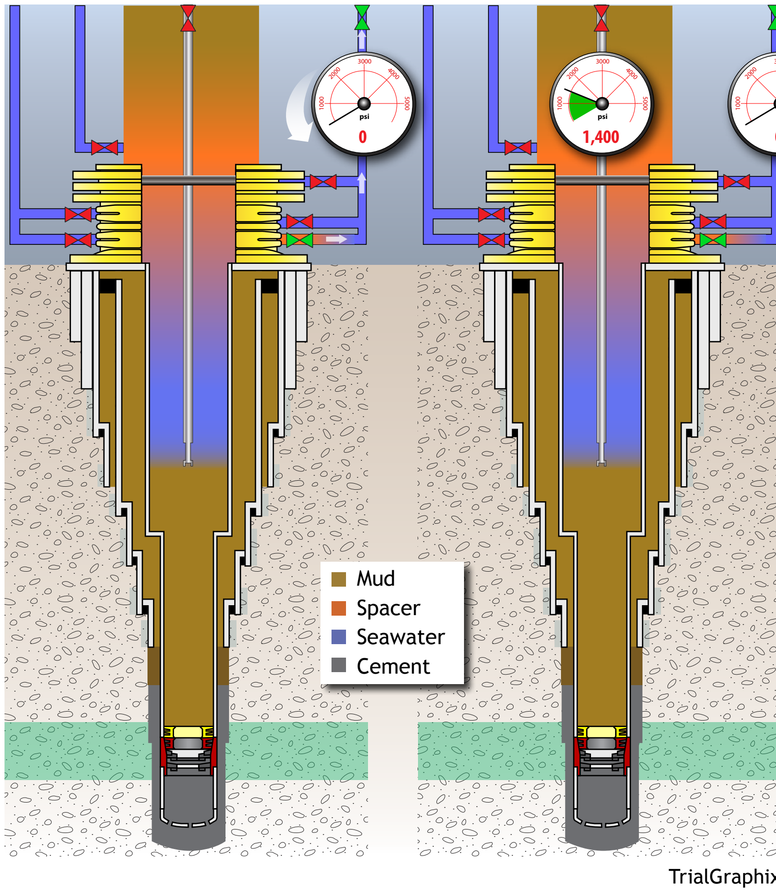


Bladder Effect. This figure represents the Chief Counsel's team's understanding of the "bladder effect" theory that supposedly explained the elevated pressure on the drill pipe. The "bladder effect" explanation contends that heavy fluids (mud and spacer) displaced to the riser were exerting force on the annular preventer from above, which in turn communicated pressure into the well. The Chief Counsel's team found no evidence to support this theory.

The conversation apparently turned to conducting another negative pressure test, this time on the kill line instead of the drill pipe. According to witness accounts, Vidrine insisted that the crew perform a new negative pressure test on the kill line because the latest permit that BP had submitted to MMS stated that BP would conduct the test on the kill line.[71] But it is unlikely that Vidrine made this decision solely because of the permit language; the rig crew had conducted the first test on the drill pipe without regard to the permit. Moreover, the BP team had already consciously deviated from the permit when it instructed the crew to conduct a combined displacement and negative pressure test–the permitted procedure did not specify such a step.[72] It appears instead that Vidrine insisted on a kill line test at least in part out of concern over the results of the negative pressure test on the drill pipe.[73] But again, neither Vidrine, Kaluza, nor the rig crew treated the test on the drill pipe as a failure. Instead, they chose to disregard it in favor of a new test on the kill line.

The Second Negative Pressure Test

Figure 4.6.18. 6:40 p.m.



The rig crew conducted a negative pressure test on the kill line. The rig crew reduced the pressure on the kill line to 0 psi, bleeding an insignificant amount of water (left). No flow or pressure buildup was observed on the kill line, which on its own would have been a successful negative pressure test. However, the 1,400 psi on the drill pipe remained and was never properly accounted for (right).

Sometime after 6:40 p.m. on April 20, while the group in the drill shack continued to discuss the test, the crew moved the negative pressure test to the kill line at Vidrine's behest. The crew pumped a small amount of fluid into the kill line from the rig to ensure the kill line was full. They plumbed the kill line so that fluids could be bled off into the "mini trip tank" near the drill shack and then bled the pressure on the kill line down to 0 psi as shown in Figure 4.6.18. According to witness accounts, less than one barrel of seawater flowed from the kill line, an insignificant amount. Once that flow stopped, beginning at about 7:15 p.m., the crew monitored the kill line for 30 minutes and observed no additional flow or pressure buildup.[74]

The lack of pressure or flow on the kill line, on its own, would have meant a successful negative pressure test. *But the 1,400 psi on the drill pipe had never disappeared.*

The well site leaders and rig crew carried on their discussion about the test and whether the 1,400 psi on the drill pipe was acceptable. Vidrine later told BP interviewers that he continued talking about the 1,400 psi reading for so long that the rig crew found it "humorous."[75] Anderson and Revette apparently continued to explain the pressure as a "bladder effect." Kaluza's statements to BP investigators suggest that he was present for the discussion as well and that he too accepted the Transocean explanation. He justified his acceptance to the investigators by saying that if Anderson had seen this phenomenon so many times before it must be real.[76] In an email written after the blowout, Kaluza explained to BP management:

> Please consider this suggestion in the analysis about how this happened. I believe there is a bladder effect on the mud below an annular preventer as we discussed.... Due to a bladder effect, pressure can and will build below the annular bladder due to the differential pressure but can not flow – the bladder prevents flow, but we see differential pressure on the other side of the bladder.[77]

In the end, everyone apparently accepted that the negative pressure test on the kill line established that the primary cement job had successfully sealed off hydrocarbons in the pay zone.[78]

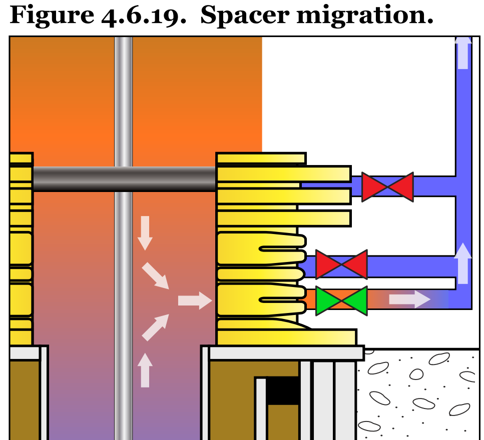
Transocean and BP have each contested their relative involvement in the negative pressure test and their relative legal responsibilities for interpreting it. The determination of legal responsibility is beyond the scope of this Report. However, experts and witnesses alike agree that industry practice requires the well site leader to make the final decision regarding whether the test has passed or failed.[79] There is also widespread agreement that the rig crew plays some role in interpreting tests, given their experience in running them and their authority to stop work if they recognize a safety concern.[80]

The Chief Counsel's team believes that the group of personnel involved in the Macondo negative pressure test—including Transocean drilling personnel and the two BP well site leaders—decided as a group that the test had succeeded.[81] It appears that the highly experienced Transocean crew[82] affirmatively advocated the view that the first and second negative pressure tests were acceptable once the "bladder effect" was considered, and the well site leaders eventually agreed. The long time spent conducting and discussing the tests shows a desire for consensus. It is possible, even likely, that this desire obscured the parties' responsibilities.

It does not at this time appear that either the BP well site leaders or the Transocean drilling crew ever sought guidance from others on the rig or onshore. For instance, based on available evidence, it does not appear that the BP well site leaders ever called the shoreside BP engineering team to ask for advice on interpreting or conducting the negative pressure test (Ezell also stated that nobody spoke with him regarding the test results).[83] BP did not require its well site leaders to obtain shoreside approval before directing the rig crew to begin temporary abandonment operations.[84] But the shoreside team had valuable expertise and experience. They could have answered questions about the test results, just as they often did regarding other drilling operations.[85] John Guide, BP's Houston-based wells team leader, later stated that given the pressure readings, he would have expected a call from the rig.[86]

Instead, Vidrine apparently deemed the test successful. No one disagreed,[87] and the rig crew moved on to begin displacing the remaining mud from the riser. Vidrine did speak to BP senior drilling engineer Mark Hafle by telephone shortly before 9 p.m., roughly an hour after the negative pressure test was finished. Hafle had called from Houston to see how operations were proceeding. Hafle had the transmitted Macondo drilling data up on his monitor. Vidrine told Hafle that there had been issues with the negative pressure test. He may specifically have told Hafle about the 1,400 psi seen on the drill pipe, and Hafle would have been able to see on his computer the recorded pressures from the test. But Vidrine explained that the test issues had been resolved.[88] The Chief Counsel's team has not seen any evidence of any further discussion of the test with BP personnel onshore.[89]

Figure 4.6.19. Spacer migration.



Leftover lost circulation material used as spacer for the negative pressure test could have migrated into the kill line during bleeds.

The second negative pressure test showed again that the well lacked integrity. The 1,400 psi reading from the drill pipe indicated that hydrocarbons were leaking into the well. The fact that the kill line pressure was 0 psi at this time suggests that something may have been blocking fluids from flowing through the kill line and transmitting pressure to the gauges on the rig. One possibility, alluded to earlier, is that the spacer below the BOP had migrated into the $3\frac{1}{16}$-inch diameter kill line and clogged it.[90] It is also possible that rig crews accidentally closed a valve that should have been open. The kill line could also have been clogged by undisplaced mud in the kill line or by gas hydrates that solidified during the test (the same type of hydrates that complicated containment operations).[91] The exact reason may never be known.

Technical Findings

The Negative Pressure Test Showed That the Cement Failed

The pressure readings and flow indications during the negative pressure test were not ambiguous. In retrospect, BP, Transocean, independent experts, and other investigations all agree that this critical test showed that the cement had failed and there was a leak in the well.[92]

There were three instances in which pressure built up after being bled off, including the buildup experts have deemed a "conclusive failure" wherein pressure inside the drill pipe rose from 0 to 1,400 psi.[93] On at least one occasion, bleed-off procedures produced more flow than should have been expected. And while the rig crew observed no flow from the kill line during the second negative pressure test, the drill pipe pressure remained at 1,400 psi.

The test failure should have been clear even though the well site leaders and rig crew had complicated matters by using an untested spacer and by allowing the spacer to leak below the BOP during the test. The well site leaders and rig crew never should have accepted the test as a success or continued with displacement operations.

BP's Spacer Choice Complicated the Negative Pressure Test

BP's decision to use 454 barrels of a highly viscous spacer may have confounded the negative pressure test. All parties agree that at some point during the negative pressure test the spacer had leaked beneath the BOP and that the rig crew never circulated it out. That spacer may have migrated into and clogged the open kill line. If there had been a clear path through the kill line down to the wellhead, the rig crew would have observed the same 1,400 psi pressure inside the kill line that they saw on the drill pipe.[94] If that had happened, the crew might have recognized that the second negative pressure test had failed.

The Chief Counsel's team did not examine the legal significance of BP's decision to use lost circulation materials as spacer and then discharge them directly into the Gulf of Mexico. But the Chief Counsel's team does conclude that greater care should have been taken first in testing and then in monitoring the placement of this unusual spacer.

BP's own investigative report states that its team used the spacer because of a "perceived expediency."[95] Although BP had never used this material as a spacer before or tested it for such use, and although BP used twice as much spacer at Macondo as it had used at other similar jobs, the company did not undertake a risk analysis to consider the consequences of its decision.

BP thus did not consider the risk that a dense spacer made of lost circulation materials could be left beneath the BOP, potentially clogging crucial piping paths.

Rig Personnel Should Have Displaced All Spacer Above the BOP

Personnel involved in the test may have further confounded the negative pressure test by failing to set up the test as intended. They knew for at least two reasons that heavy spacer fluid had leaked beneath the BOP where it could potentially confuse test results. First, they observed that the pressure inside the drill pipe was 2,325 psi when the annular was closed at 5 p.m. Second, when they opened the kill line, they observed a drop in pressure on the kill line and a simultaneous jump in pressure on the drill pipe.

Despite these indicators, the individuals conducting the test did not try to correct the problem even after they decided to run a second negative pressure test. They could easily have circulated the spacer out of the wellbore to ensure that the test was set up as planned. They should have done so.[96]

Management Findings

Given the risk factors attending the bottomhole cement, individuals on the rig should have been particularly attentive to anomalous pressure readings. Instead, it appears they began with the assumption that the cement job had been successful and kept running tests and proposing explanations until they convinced themselves that their assumption was correct. The fact that experienced well site leaders and members of the rig crew believed that the Macondo negative pressure test established well integrity demonstrates serious management failures.

There Were No Established Procedures or Training for Conducting or Interpreting the Negative Pressure Test

Lack of Standard Procedures

Neither BP nor Transocean had pre-established standard procedures for conducting a negative pressure test.[97] While BP required negative pressure tests under certain conditions, one of its employees admitted that the tests "could be different on every single rig depending on what the [well] team agreed to."[98] Transocean likewise required negative pressure tests but did not have set procedures.[99] For example, the crew of the *Marianas* had done the immediately preceding negative pressure test at Macondo in a different way than the *Deepwater Horizon* crew did the April 20 test.[100] Partly because Transocean rigs conducted tests differently (in part because different rigs have different equipment), Kaluza and BP drilling engineer Brian Morel both spoke with an M-I SWACO engineer on April 20 to ask how the rig had previously conducted the negative pressure test.[101]

Unfortunately, the lack of standard test procedures is unsurprising. In April 2010, MMS regulators did not require operators even to conduct negative pressure tests, let alone spell out how such tests were to be performed.[102] (The Chief Counsel's team notes that some wells need not be negative tested.[103]) Nor had the oil and gas industry developed standard practices for negative pressure tests.[104] An independent expert admitted that he had to consult an academic text to find a description of a negative pressure test procedure.[105]

The recent regulatory proposal to require negative pressure test information in permit applications to MMS may trigger companies and the industry to establish standard negative pressure test procedures[106] (discussed further in Chapter 6). A negative pressure test procedure ought to include the depth of mud displacement, the volumes of fluids to be pumped into the well, the pressures and fluid returns to be expected during the test, and criteria for determining whether the negative pressure test passes or fails. The procedure should also include explicit instructions for diagnosing and addressing problematic or anomalous test readings.

Lack of Training at Macondo

BP well site leaders displayed troubling unfamiliarities with negative pressure test theory and practice. Neither Kaluza nor Vidrine calculated expected pressures or volumes before running the negative pressure test even though other BP well site leaders routinely do so.[107] Vidrine, Kaluza, and Morel all described the criteria for a successful test in terms of "flow or no-flow," which ignores the importance of monitoring pressures in the well.[108] Both well site leaders apparently accepted the "bladder effect" explanation, and Kaluza continued defending the theory and describing the Macondo test results as "rock solid" a week after the blowout.[109] These are clear signs that BP needs to train its personnel better.

Transocean has acknowledged that it does not train its personnel in the conduct or interpretation of negative pressure tests and that its Well Control Handbook does not describe a negative pressure test. Instead, Transocean states that its rig crews learn how to conduct a negative pressure test through general work experience.[110]

Partly because of this, Transocean has been unable to conclude whether its *Deepwater Horizon* rig crew had enough experience to conduct and interpret the negative pressure test on April 20.[111] Transocean is not unique in omitting training for the negative pressure test. Experts have stated that academic training on the negative pressure test may only be included in coursework as time allows.[112]

Transocean has argued that the members of its rig crew were tradesmen, not engineers, and could not have been expected to interpret the complex results of the Macondo negative pressure test. Transocean's training approach certainly supports that view.

However, a negative pressure test essentially consists of underbalancing a well and then watching to see if a hydrocarbon kick enters the well as a result. Transocean expected its rig crew to recognize signs of a kick during complex drilling operations. It appears inconsistent for Transocean to claim that its crew is trained in and skilled in recognizing kick indicators during drilling but is unable to recognize the same kick indicators during controlled testing.

Inadequate Procedures for Macondo

The most conspicuous problem with the negative pressure test procedures at Macondo is that there were almost no written procedures at all. As described in Chapter 4.5, although BP eventually developed temporary abandonment procedures that included a negative pressure test, the procedures stated only when the test would be done in relation to other operations. BP did not explain to the crew or its well site leaders how they should perform or interpret the test. The final M-I SWACO procedure, for instance, said simply, "[c]onduct negative test." After the incident, BP engineering managers opined that the Transocean crew knew how to conduct a negative test, and that these limited instructions should have been adequate.[113] Whether justified or not, the events of April 20 prove that BP's expectation was incorrect.

BP's early plans for abandonment repeatedly failed to mention a negative pressure test at all.[114] On April 12, Morel circulated a draft temporary abandonment plan that did not include a negative pressure test.[115] Morel's omission may have been a mere oversight, but it may also have signaled his unfamiliarity with the test.

Ronnie Sepulvado, one of BP's *Deepwater Horizon* well site leaders who was not on the rig for the negative pressure test, needed to tell Morel that he should include one.[116] Similarly, Kaluza's pre-tour briefing to the rig crew described temporary abandonment procedures that did not include a negative pressure test. This prompted Harrell to state that Kaluza needed to add a negative pressure test.[117] Kaluza's omission, like Morel's, may have signaled unfamiliarity with the test and its importance.

Although Morel and other BP engineers continually refined their temporary abandonment procedures, they never expanded their negative pressure test procedures to explain what pressures or flow volumes the crew should expect to see.[118] Even more importantly, they did not add criteria for determining if the test had passed, nor contingency procedures in case the test failed. Kaluza admitted "[w]e didn't talk about what if the negative test fails."[119] Moreover, several of the BP Macondo team's early descriptions of the negative pressure test (including the one approved by MMS) were written so imprecisely that team members disagree even today about what they mean (as described in Chapter 4.5). Nor were the later descriptions passed along in "Ops Notes" or telephone calls necessarily better. When Hafle called Kaluza to discuss the test on the afternoon of April 20, he "had [the] impression that Kaluza wasn't really clear on neg[ative pressure] test procedure."[120] Unfortunately, neither Hafle nor Kaluza seemed to think this uncertainty was a problem, because they appear to have ended the call without resolving it.

Lindner eventually wrote a displacement procedure for BP that contained the most detailed procedure for running the negative pressure test. Lindner's document spelled out how much spacer and seawater the rig crew should pump into the well before conducting the test. His was the first procedure that reflected BP's decision to use a large combined spacer fluid to help displace mud from the well.[121] But it told rig personnel nothing about expected bleed-off volumes, how to interpret the negative pressure test, or what to do about anomalous pressure readings. It may also have included errors. For example, Lindner's calculations directed rig personnel to pump a volume of seawater that may have been too small to fully displace spacer above the blowout preventer. In retrospect, it is inexcusable that the most detailed written procedures for the negative pressure test were written by a mud engineer in the course of specifying fluid volumes to be displaced prior to the test.

Finally, the men on the rig did not always follow the few clearly written procedures that they had. Beginning April 14, the procedures directed that the negative pressure test would be conducted on the kill line. But rig personnel did not follow this instruction during the first negative pressure test. Instead, they conducted the initial negative pressure test on the drill pipe. This may suggest that in addition to creating better test procedures, BP and Transocean need to ensure that those procedures are followed.

BP Failed to Recognize and Alert Rig Personnel to the Exclusive Reliance on the Negative Pressure Test at Macondo

Both the Macondo well plan and the challenges surrounding the Macondo cement job put a premium on the negative pressure test. BP's temporary abandonment procedures required the crew to severely underbalance the well and to rely solely on the high-risk bottomhole cement as the exclusive barrier in the wellbore to flow while they displaced mud from the riser.

Despite these facts, BP never emphasized to rig personnel the particular importance of the Macondo negative pressure test. BP personnel forgot even to mention the test during relevant communications on at least two occasions. (See "Inadequate Procedures for Macondo" section, above). Had BP properly emphasized the importance of the test and the need for special scrutiny of its results, BP and Transocean personnel on the rig may have reacted more appropriately to the anomalous pressure readings and flows they observed.

Leadership and Communication

Even in the absence of detailed procedures, BP well site leaders should have exercised better judgment and initiative. When they confronted a 1,400 psi pressure reading from the drill pipe and a 0 psi reading from kill line, they should have insisted on probing and fully resolving the issue. Instead, interview notes suggest that they deferred to a toolpusher's explanation without fully understanding, questioning, or testing it.

Kaluza was not on the rig floor during most of the preparations for the test and may have missed the first part of the attempted negative pressure test on the drill pipe. He was in the well site leader's office doing calculations for the planned cement plug.[122] Had he been on the rig floor and participating in the test the entire time, Kaluza would have been in a better position to observe several anomalies, including:

- the excessive pressure (2,325 psi) at the end of the pre-test fluid displacement;
- the pressure changes in the drill pipe and kill line when the rig crew opened the kill line valve at the BOP;
- the rig crew's inability to bleed the drill pipe below 260 psi and the abnormally large volume of fluid flow during that bleed; and
- the drop in the fluid level in the riser.[123]

One BP well site leader who was not on the rig on April 20 stated that his practice during negative pressure tests is to remain on the rig floor from the beginning of preparations until he signs off on the test.[124] Independent experts have stated that well site leaders should certainly be present as seawater is pumped out of the drill pipe during displacement and before the crew begins any bleeds.[125]

Kaluza also apparently never personally analyzed the unusual spacer that the rig crew used during his shift.[126] And notes of his statements to BP investigators suggest that he did not recognize that such a spacer could confound the negative pressure test.[127] One independent expert has stated that it would have been standard industry practice for the well site leader to "personally confirm[] the properties of the final blend."[128]

Most significantly, it appears that neither the BP well site leaders nor the Transocean drilling team ever called shore-based personnel to ask for assistance, to report the anomalous pressure readings, or to check the "bladder effect" explanation. Neither company had specific policies in place that required their personnel to report the results of the test to shore.[129] But both BP and Transocean expected rig personnel to call if they needed help or were uncomfortable.[130] Indeed, BP personnel called to shore on April 19 to discuss the problems the rig crew was experiencing while trying to convert the float collar.[131] Instead, the well site leaders and drilling team relied solely on their own limited experience and training to wrongly interpret the test results as a success.

Chapter 4.7 | Kick Detection

The Chief Counsel's team finds that rig personnel missed signs of a kick during displacement of the riser with seawater. If noticed, those signs would have allowed the rig crew to shut in the well before hydrocarbons entered the riser and thereby prevent the blowout. Management on the rig allowed numerous activities to proceed without ensuring that those operations would not confound well monitoring. Those simultaneous activities did confound well monitoring and masked certain data.

Despite the masking effect, the data that came through still showed clear anomalies.[1] The crew either did not detect those anomalies or did not treat them as kick indicators.

Well Monitoring and Kick Detection

A **kick** is an unwanted influx of fluid or gas into the wellbore. The influx enters the wellbore because a barrier, such as cement or mud, has failed to control fluid pressure in the formation. In order to control the kick, personnel on the rig must first detect it, then stop it from progressing by adding one or more barriers.[2] The crew must then circulate the influx out of the wellbore. If the crew does not react properly, fluids will continue to enter the wellbore. This will eventually escalate into uncontrolled flow from the well—in other words, a blowout.[3]

In order to detect a kick, rig personnel examine various indicators of surface and downhole conditions. These indicators include pit gain, flow-out versus flow-in, drill pipe pressure, and gas content in the mud.[4]

Pit Gain (Volumetric Comparison)

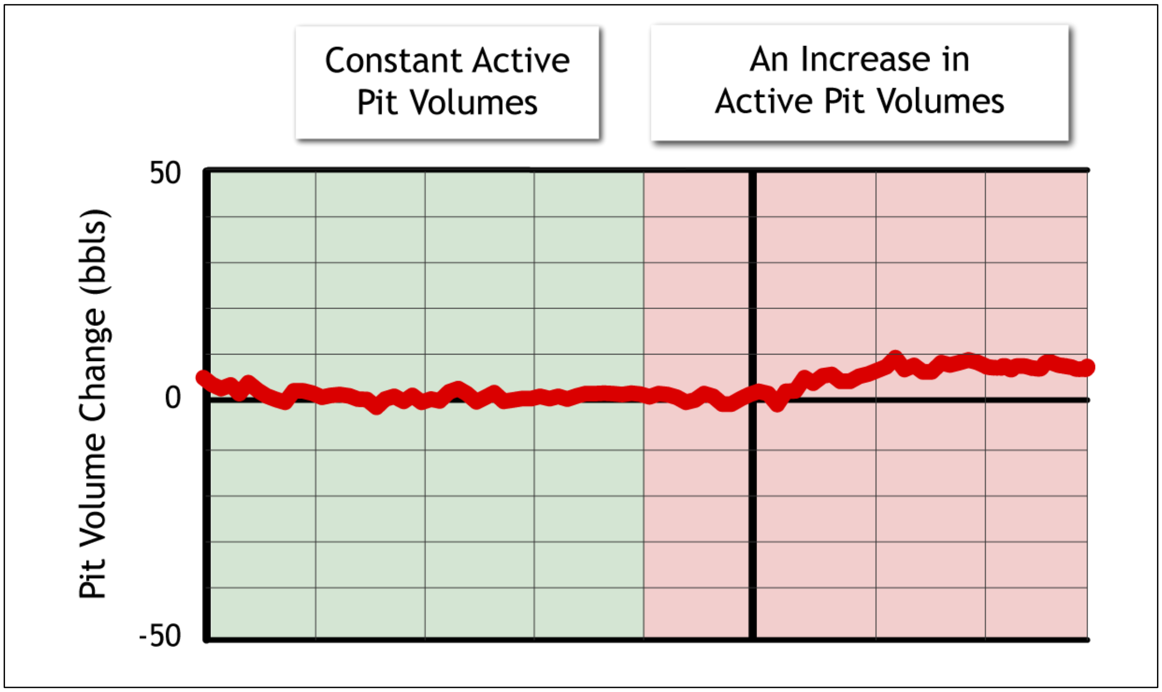
Pit gain is the difference between the volume of fluid pumped into the well and the volume of fluid pumped out of the well. If the well is stable (that is, there are no gains or losses) the two should be equal.

The easiest way to monitor pit gain is to pump fluids into the well from a single pit and route returns from the well into the same pit. This is called **single-pit monitoring**. However, when dealing with several different fluids (mud, spacer, seawater), the crew must use several different pits to prevent the fluids from mixing. In order to monitor multiple pits, the crew can use the active pit system.

Active Pit System. The **active pit system** refers to a computer setting that allows the driller (and others) to select several pits and aggregate their volumes into one "active pit volume" reading. Even though there are several different pits involved, the rig's computer system displays them as a single pit for volume monitoring purposes.[5]

There are several ways to configure the active pit system. In a closed-loop system, the fluids going into the well are taken from the active pit system, and the fluids coming out of the well are returned to the active pit system. Because volume-in should equal volume-out, the active pit volume will stay constant when the well is stable. If the active pit volume increases, that strongly indicates that a kick is under way.[6] A volume increase should be easily detectable by a positive slope in the trend line (seen in Figure 4.7.1) or an uptick in the numerical data.

Figure 4.7.1. Active pit volume in a closed-loop system.



Sperry-Sun data/TrialGraphix

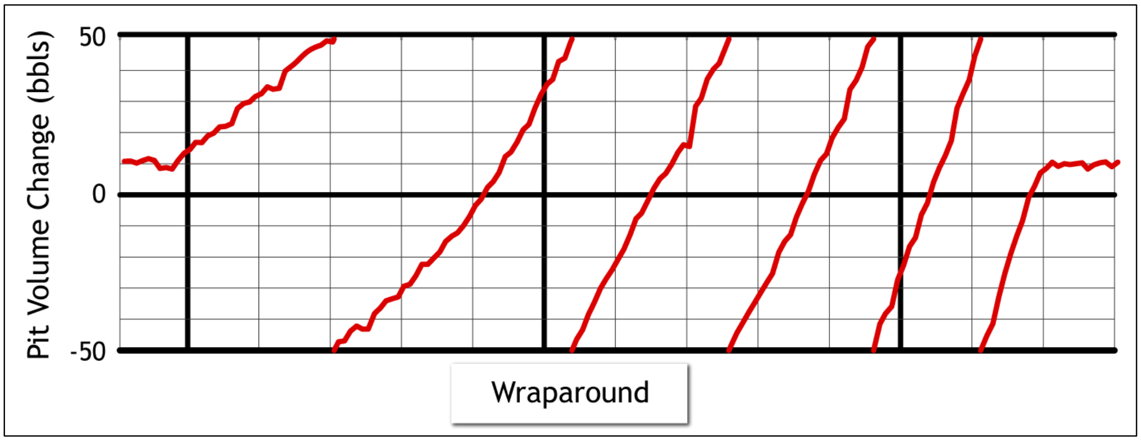
In a closed-loop system, active pit volume will remain constant so long as the well is stable. An increase in active pit volume strongly indicates that a kick is under way.

Monitoring pit gain in a non-closed-loop system is more complex. In a non-closed-loop system, fluids are either taken from or returned to places other than the pits on the rig. For instance, when rig crews use seawater to displace mud from a well, the rig may pump the seawater in from the ocean (and bypass the pits) but still direct mud returns back to the pits.[7] In that case, active pit volume will increase over time because the returns are filling up the pits (seen in Figure 4.7.2).

To monitor pit gain in a non-closed-loop system, rig personnel must manually calculate the volume of seawater pumped into the well (pump strokes × volume per pump stroke) and compare it to the volume of mud returning from the well (measured by changes in pit volume).[8]

Certain kinds of operations can make it impossible to use pit gain as a kick indicator. For example, this happens when return flow from the well goes overboard instead of into a pit. Rig personnel generally cannot measure the volume of flow overboard, so they cannot make a volume-in/volume-out comparison during such operations.

Figure 4.7.2. Active pit volume in a non-closed-loop system.



Sperry-Sun data/TrialGraphix

In a non-closed-loop system, active pit volume will increase continuously regardless of the well's stability.

Flow-Out (Rate Comparison)

Flow-in is a calculation of the rate at which fluid is being pumped into the well (pump rate × volume per pump stroke). Because it is calculated from known and reliable values, flow-in has a small margin of error. It is a trusted value.

Flow-out is a measurement of the rate at which fluid returns from the well. It is typically measured by a sensor in the flow line coming out of the well. As a result, the accuracy of the flow-out measurement depends on the quality of the sensor. It is a less reliable value than flow-in.[9]

If the well is stable, flow-in and flow-out should be equal.[10] An unexplained increase in flow-out is a kick indicator. For example, if the pump rate is constant but flow-out increases, the additional flow is likely caused by fluid or gas coming into the wellbore from the formation.[11]

The simplest application of this principle occurs when the rig is not pumping fluids into the well at all. At this point, flow-in is zero, so flow-out should also be zero. Rig personnel can confirm that flow-out is zero in two ways: by reading the data from the flow-out meter and by visually inspecting the return flow line (performing a **flow check**). If rig personnel see flow from the well at a time when the pumps are off, that is an anomalous observation. While such flow can indicate thermal expansion of the drilling fluid, rig heave, or ballooning, it can also indicate that a kick is under way.[12] In any case, further investigation is warranted.

When the rig crew first shuts pumps down, it generally takes some period of time for flow-out to drop to zero. This reflects the time it takes for the pumps to drain and for circulation to come to a stop. During this time period, there continues to be some **residual flow**.[13]

Each rig has its own residual flow-out **signature**—a pattern wherein flow-out dissipates and levels off over the course of several minutes.[14] It is important that rig personnel identify that signature and monitor flow-out for a sustained period of time afterward to confirm that there is indeed no flow after the pumps have been shut down.[15]

Flow checks constitute an important safeguard and "double-check" ensuring that the well is secure. It is therefore a common practice to assign one member of the rig crew to always visually confirm that flow has stopped whenever the pumps have been shut down, and announce it to the rest of the rig's personnel.

Drill Pipe Pressure

Drill pipe pressure is a measurement of the pressure exerted by fluids inside the drill pipe.[16] When the rig pumps are off, drill pipe pressure should remain constant.[17] When the density of fluids in the well outside the drill pipe is higher than the density of fluids inside the drill pipe, drill pipe pressure will be positive. This is because the heavier fluid outside the drill pipe exerts a u-tube pressure on the fluids inside the drill pipe.

When the rig crew turns pumps on, drill pipe pressure will fluctuate depending on the relative densities of fluids inside and outside of the drill pipe and the circulating friction generated by moving those fluids.[18] When the pumps are pushing lighter fluid down the drill pipe to displace heavier fluid outside it, drill pipe pressure should steadily decrease as the lighter fluid displaces the heavier one.

Drill pipe pressure can be a difficult kick indicator to interpret because so many different factors can affect that pressure. For instance, drill pipe pressure might change because of a washout in the drill pipe or wear-out of the pump discharge valves.[19] But such causes should still prompt the driller to stop and check that the rig and well are all right.[20]

In a situation where there are changing fluid densities, changing pump rates, and changing wellbore geometry, close monitoring of drill pipe pressure can be facilitated by advance planning and charts describing what pressures to expect.[21] Unexplained fluctuations in drill pipe pressure can indicate a kick.

Some kicks exhibit an increase in drill pipe pressure,[22] although an increase can also indicate a clog in the pipe or that the crew is pumping the wrong fluids into the well.[23] More commonly, it is a decrease in drill pipe pressure that indicates a kick; lighter oil and gas flow into the annulus around the drill pipe and thereby lower the drill pipe pressure.[24] But a decrease in drill pipe pressure can also indicate a hole in the drill pipe.[25] In any case, unexplained fluctuations in drill pipe pressure are a cause for concern and warrant further investigation.[26]

Gas Content

Gas content refers to the amount of gas dissolved or contained in a fluid. Fluid returns from a well can contain gas for several reasons. Some amount of gas is often present in a well during normal operations, depending on the mud type and the location of the well. And "trip gas" appears when tripping out of the hole and conducting a bottoms up circulation after a trip.

An increase in the gas content of fluid returns over time can indicate an increase in pore pressure,[27] penetration of a hydrocarbon-bearing zone, or a change in wellbore dynamics allowing more effective cuttings removal.[28] But unexplained increases in gas content are always a cause for concern. They can indicate either that a kick is occurring or that wellbore conditions are becoming conducive for a kick.[29]

Sensors and Displays

Rig personnel rely on data that are recorded and displayed by proprietary sensors, hardware, and software. For the *Deepwater Horizon*, Transocean hired National Oilwell Varco (NOV) to provide **Hitec**-brand sensors, driller's chairs, and displays for the rig.[30] BP contracted Sperry Drilling, a Halliburton subsidiary, to conduct additional independent mud logging and well monitoring services.[31]

NOV placed a comprehensive set of sensors on the rig that measured various drilling parameters and surface data, including flow-in, flow-out, pit volume, drill pipe pressure, block position, and hook load.[32] The Hitec system recorded and displayed only the data from the Hitec sensors. Sperry Drilling's **Sperry-Sun** system collected data from many of the Hitec sensors,[33] including the sensors for pit volumes, flow-in, drill pipe pressure, and kill line pressure.[34] It also collected data from separate Sperry-Sun sensors, including Sperry-Sun sensors for flow-out and gas content.[35]

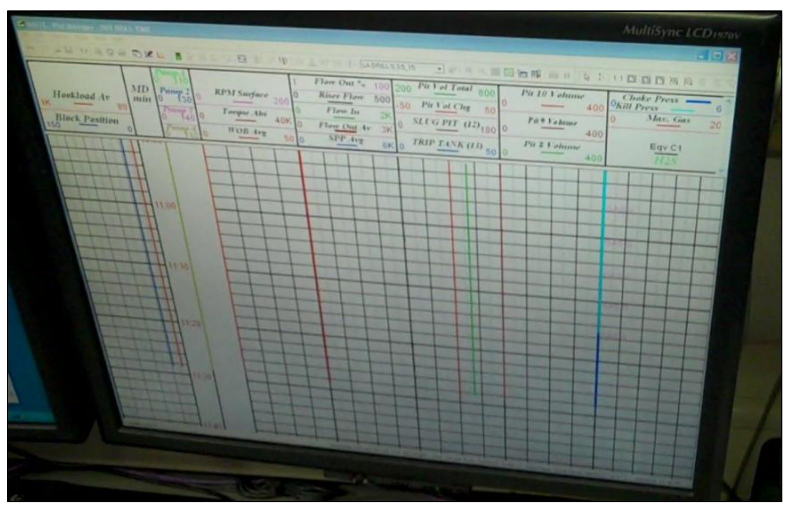
Sperry Drilling and NOV both provided BP and Transocean with proprietary displays consisting of real-time numerical data, historical trend lines, and other features like tables and charts.[36] Each of the systems allowed users to manually set (and constantly adjust) audible and visual alarms for various data parameters, including pit gain, flow-out, and drill pipe pressure.[37] The alarms could be set to trigger whenever incoming data crossed preselected high and low thresholds, and could also be shut off.[38]

While the Hitec and Sperry-Sun data systems displayed similar data, they did so using significantly different visual design (seen in Figures 4.7.3 and 4.7.4).

Figure 4.7.3. Hitec data display.

Sambhav N. Sankar

Figure 4.7.4. Sperry-Sun data display.



Fred H. Bartlit, Jr.

Photos taken on Transocean's *Deepwater Nautilus*.

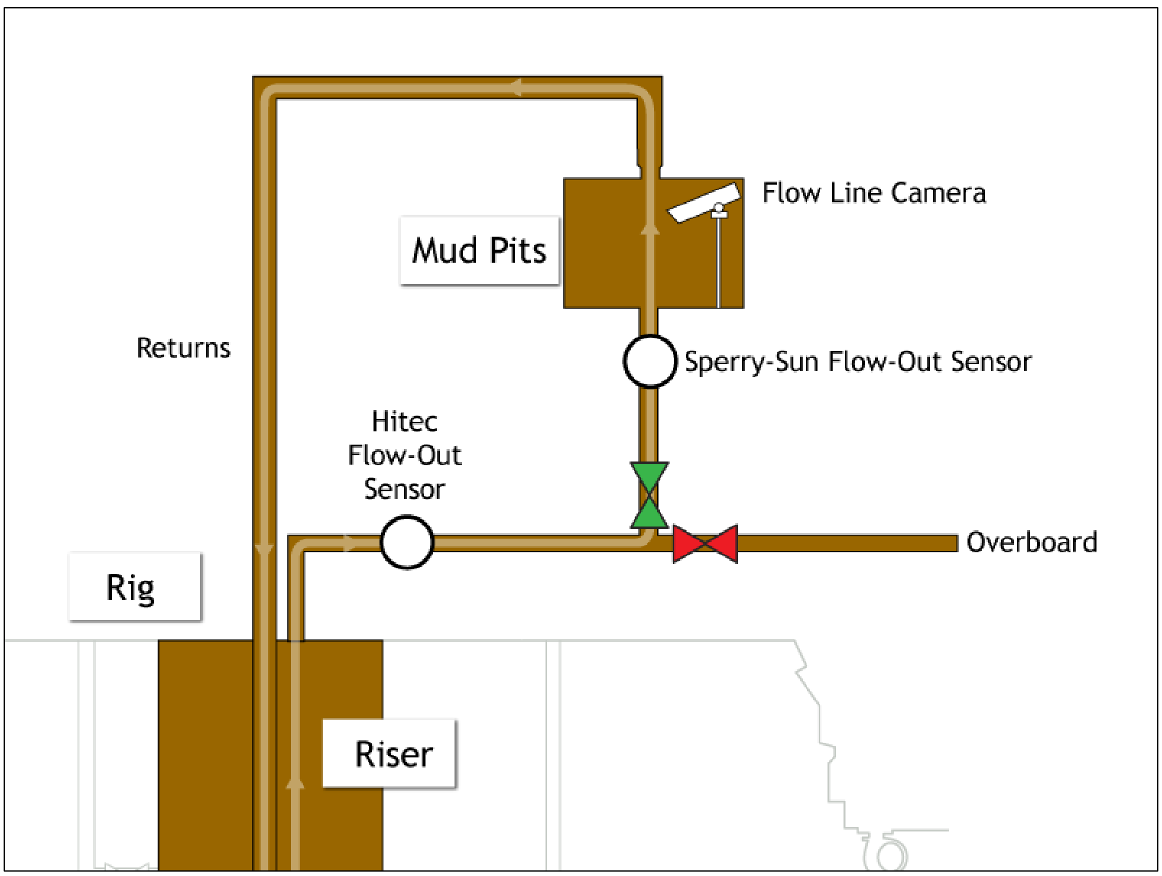
Because the two systems in many cases used the same underlying sensors, most of the numerical values should have been close if not identical.[39] Where they displayed data from different sensors, the differences were usually predictable and could generally be dealt with through calibration.[40]

Hitec and Sperry-Sun each had its own flow-out sensor in the return flow line. These flow-out sensors differed in type, location, and format. Hitec had a paddle-type flow-out sensor.[41] As fluid rushed past, it pushed and lifted the paddle. The Hitec system inferred the rate of flow from the degree of paddle elevation. Sperry-Sun, by contrast, used a sonic-type sensor.[42] The sensor emitted a beam to ascertain the height of the fluid. The Sperry-Sun system inferred the rate of flow from the fluid level.[43]

The Hitec flow-out sensor was located in the return flow line before the line forked to either send returns to the pits or send them overboard.[44] The Sperry-Sun sensor was located after the fork, capturing flow-out only when returns from the well were routed to the pits.[45] (Positioning of both sensors is illustrated in Figure 4.7.5.) This means that the Hitec flow-out sensor could register returns going overboard, but the Sperry-Sun sensor could not.[46]

In addition to the data display systems, the rig also had video cameras that monitored key areas and components, including the rig floor and the flow line. The flow line camera (also illustrated in Figure 4.7.5) simply pointed at the flow line. Like the Sperry-Sun flow-out sensor, this camera was located after the fork; rig personnel could use it to observe flow returning to the pits but not flow that had been routed overboard.[47] When returns were sent overboard, rig personnel could still visually inspect for flow but could not do so using the video camera. They had to physically look behind the gumbo box (which was located before the fork).[48]

Figure 4.7.5. Flow-out sensors and flow line camera.



TrialGraphix

The Sperry-Sun flow-out sensor and the rig's flow line camera could not register returns going overboard. The Hitec flow-out sensor could, but data from the Hitec flow-out sensor sank with the rig.

The rig's sensors and display equipment appear to have been working properly at the time of the blowout. There is no evidence that the Sperry-Sun system malfunctioned. It continued recording and transmitting data up until the first explosion. The Hitec system was also "in satisfactory condition," as an April 12 rig condition assessment recorded in some detail.[49]

The crew had expressed some complaints about the driller's and assistant driller's control chairs, known as the "A-chair" and "B-chair" respectively.[50] The computer system powering the chairs' controls and displays had "locked up" or crashed on several occasions.[51] When this happened to the A-chair, the driller's screens would either freeze or revert to a blank blue screen, disabling real-time data display on the screen and requiring the driller to move to the adjacent B-chair.[52] In response, Transocean replaced the chairs' hard drives.[53] This appears to have corrected the problem.[54] The April 12 assessment found that the software on all of the chairs "was stable and had not shown (excessive) crashes."[55] There is no evidence that the chairs malfunctioned on April 20.[56]

Personnel and Places

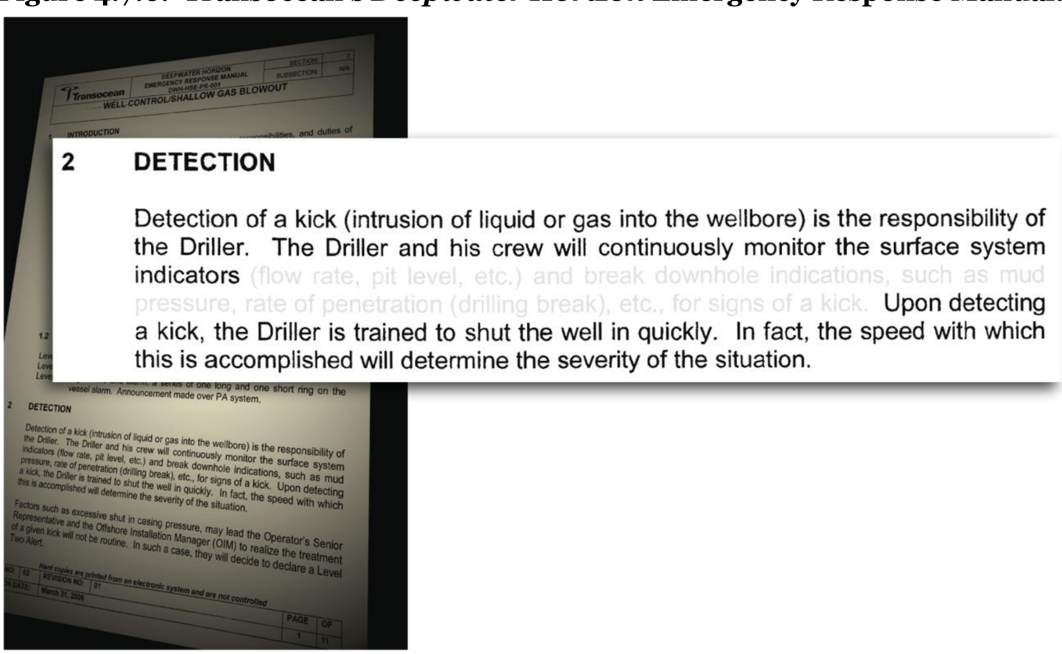
On the Rig

Rig data are available in various forms to personnel on the rig and onshore. The Hitec data, Sperry-Sun data, and video feeds were all available to personnel on the rig, in real time, anywhere there was a television.[57] Certain individuals had more extensive data displays depending on their level of well monitoring responsibility.

On the *Deepwater Horizon*, the Transocean driller and assistant driller, and the Sperry Drilling mudlogger, were directly responsible for well monitoring.

The **driller** was responsible for monitoring well conditions at all times, interpreting and responding to downhole conditions, and securing the well in a well control situation (see Figure 4.7.6).[58] The driller sat in the A-chair in the drill shack. He normally monitored three screens: two screens in front of him that displayed Hitec data and a screen to the side with

Figure 4.7.6. Transocean's *Deepwater Horizon* Emergency Response Manual.



Transocean

Sperry-Sun data.[59] He also had a screen with live video feeds and a window straight ahead with a direct view of the rig floor.[60] The driller was supposed to actively look at his data screens during well operations.[61] He contemporaneously recorded rig activities for each day's daily drilling report.[62]

The driller was the central point of contact for all well control concerns: Anyone with "an understanding of something that may have indicated a well control event, would have called back to the driller, most likely, and informed him." [63] He was the one who had the most information about current operations on the rig and the ability to react to them.[64]

The assistant driller was also responsible for monitoring the well and taking well control actions. He served as a crucial backup and assist to the driller. The assistant driller was expected to have "a comprehensive understanding of well control" and "be able to recognize the signs of a well kick or blowout before it develops into an emergency condition."[65] He assisted the driller in monitoring the drilling instrumentation and recognizing and controlling well conditions.[66] As part of that assistance, he monitored the pit volumes and from time to time would go to the pits and check in with the derrickhand to make sure all was well.[67]

There were two assistant drillers on duty at any one time. One sat in the B-chair, adjacent to the driller in the drill shack.[68] He had access to the same screens as the driller. If there was activity on the deck—like pipe handling—another assistant driller would sit in the "C-chair" in the auxiliary driller's shack.[69] Although the assistant drillers had many responsibilities, at least one should have been monitoring the well at any given time.[70]

The Sperry Drilling mudlogger also monitored the well, serving as a second set of eyes for the Transocean crew.[71] BP specifically contracted the mudloggers for this purpose.[72] It was the mudloggers' duty to continuously monitor operations and provide well and drilling data upon request. They watched the data but did not have any control over rig operations and could not respond directly themselves. If the mudloggers identified problems, they would notify the driller (or drill crew).[73]

The mudlogger sat in the mudlogger's shack, one flight of stairs away from the drill shack.[74] He had 12 monitoring screens arranged in two rows of six. These screens displayed both Hitec and Sperry-Sun data.[75] Among the screens, the mudlogger had a display to the left showing all of the rig's pit volume levels. Below that, the mudlogger had a graphical log and a digital readout of the Hitec numbers.[76] He also had a screen with live video feed from the rig's cameras—he could switch between channels showing the flow line, the rig floor, and other areas.[77] In addition to monitoring the well, the mudlogger performed formation analysis when the rig was drilling and provided data printouts and reports.[78]

Several individuals supervised well monitoring work by the driller, assistant driller, and mudlogger.

The BP **well site leader** had responsibility for overseeing all operations on the well. That responsibility involved delegating duties like minute-by-minute monitoring of data.[79] Some well site leaders did monitor the well during critical operations.[80] To facilitate such monitoring, the well site leaders' office had screens that constantly displayed the Hitec data, Sperry-Sun data, and live video feeds.[81] The Sperry Drilling mudloggers reported to the BP well site leader.

The Transocean **toolpusher** supervised the driller and ensured that all drilling operations were carried out safely, efficiently, and in accordance with the well program.[82] That included confirming that all well control requirements were in place, performing all well control calculations, and assisting in killing the well in emergency situations.[83] The toolpusher was generally on the rig floor at all times, had access to the driller's and assistant driller's monitors, and had a small office inside the drill shack.[84]

The toolpusher reported to the **senior toolpusher**. The senior toolpusher had a similar job description as the toolpusher but was one level higher in the hierarchy.[85] Although he had no continuous role in operations and was not generally on the rig floor, the senior toolpusher was supposed to be consulted when there were anomalies or emergencies. In a well control event, the senior toolpusher organized response actions and acted as a liaison to the well site leader.[86] The senior toolpusher reported to the offshore installation manager.

The **offshore installation manager (OIM)** was the senior-most Transocean drilling manager on the rig and oversaw the entire Transocean crew. He assisted with abnormal or emergency situations.[87] Both the senior toolpusher and OIM had separate offices away from the rig floor, near their living quarters, that included data displays.[88]

Onshore

Onshore, only the Sperry-Sun data were available in real time.[89] The Hitec data and video feeds did not go to shore.[90]

BP personnel could view the Sperry-Sun data in their Houston offices and in an operations room for the *Deepwater Horizon* that had dedicated data displays.[91] They could also view the data over a secure Internet connection.[92] Personnel at Anadarko and MOEX could access the Sperry-Sun data onshore as well.[93] BP, Anadarko, and MOEX appeared to have used real-time data to examine geological and geophysical issues.[94]

Sperry Drilling personnel could access the Sperry-Sun data in their Houston real-time center and Lafayette operations office.[95] They appeared to have used their access to provide customer support and quality control.[96]

None of the entities receiving the Sperry-Sun data onshore appears to have monitored the data for well control purposes.[97] (Transocean did not receive data onshore.[98])

Table 4.7.1. Personnel and places with access to the rig's Sperry-Sun data.

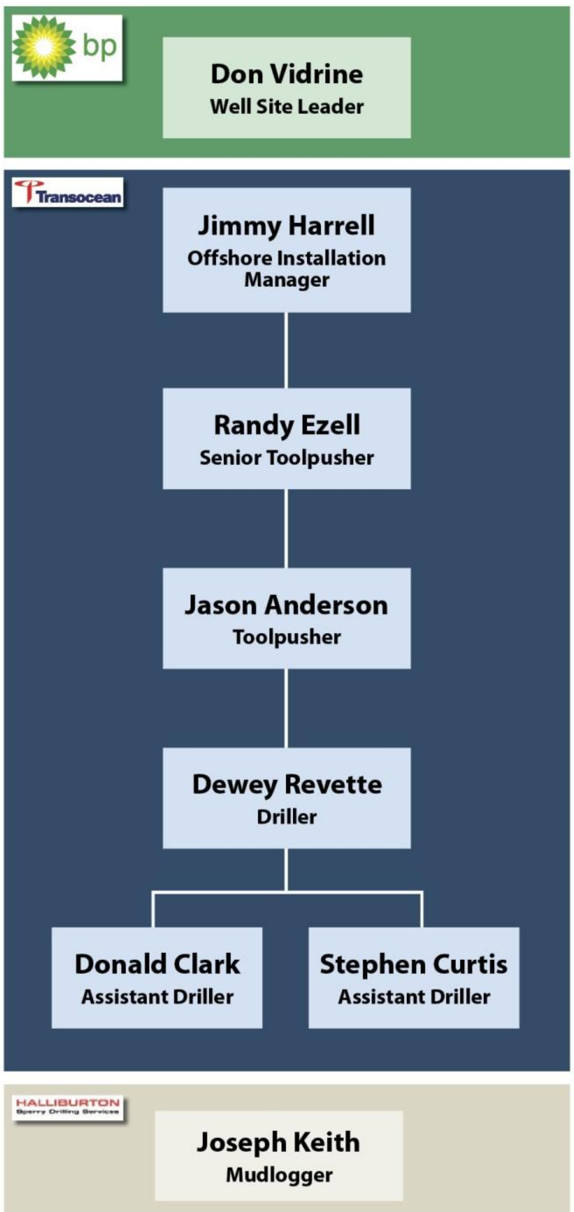
Rig: Responsible for Monitoring Data	Rig: Accountable for Operations	Onshore: Could Access Data in Real Time
▪ Transocean driller ▪ Transocean assistant driller ▪ Sperry-Sun mudlogger	▪ BP well site leader ▪ Transocean OIM ▪ Transocean senior toolpusher ▪ Transocean toolpusher	▪ BP ▪ Anadarko ▪ MOEX ▪ Sperry-Sun

Well Monitoring at Macondo

It is difficult to know exactly what data screens rig personnel were looking at during their final hours on the *Horizon*.[99] There were multiple screens, with multiple data types, and each was highly customizable.[100] This Report relies on the Sperry-Sun historical log for its data analysis because that log is the only surviving dataset and display from the rig.[101]

The Sperry-Sun data log is valuable. This log (or something very close to it) was “the actual log that they were watching on the Horizon”[102]—it was displayed on one of the several screens in front of the driller, assistant driller, mudlogger, and company man. The drill pipe pressure presented on the Sperry-Sun screen was collected from Transocean’s Hitec data sensors. Accordingly, the data values shown on the available Sperry-Sun screen formats would also have been shown on the Hitec screens.

Figure 4.7.7. Rig personnel on duty during the final displacement.



TrialGraphix

Witness accounts suggest that the driller, assistant driller, and mudloggers all watched the Sperry-Sun data log.[103] The numerical values reflected in the data log would have been available on other screens as well.[104] And one can reasonably expect that rig personnel monitoring the well would have had (or should have had) pit volumes, flow-out, flow-in, and drill pipe pressure reflected in the log somewhere on their screens—no matter the format.[105]

At the same time, the Sperry-Sun data have significant limitations. The log is not fully inclusive: It does not contain data from the Hitec flow-out sensor. And scrutinizing the complete log carefully in retrospect is significantly different from monitoring it in real time, while the trend lines are developing.[106]

The First Hour

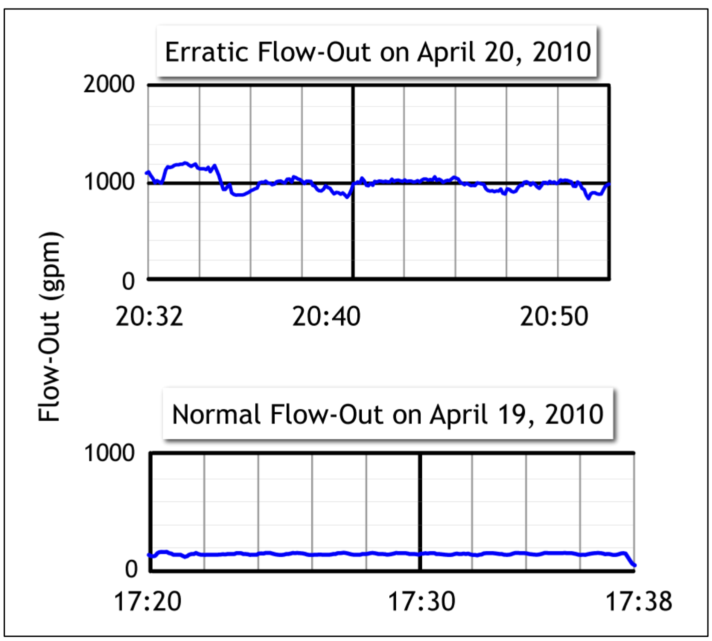
After cementing the production casing and conducting pressure tests that had been deemed successful, the crew moved on to the remainder of the temporary abandonment procedure. The crew would displace mud and spacer from the riser with seawater. There were several stages in the planned displacement. First, rig personnel would pump seawater down the drill pipe to displace mud from the riser until the spacer fluid behind the mud reached the rig floor. They would then shut down the pumps and conduct a “sheen test.” That test would confirm that the crew had displaced all of the oil-based mud from the riser. The crew would then change the lineup of valves to send further returns from the well (spacer) overboard rather than to the mud pits. They would then resume the displacement until all of the spacer was out of the wellbore and the riser was full of nothing but seawater.[107]

At the start of the displacement process, Transocean driller Dewey Revette was in the drill shack’s A-chair, monitoring the well. Transocean assistant driller Stephen Curtis was likely in the drill shack’s B-chair, also monitoring the well.[108] BP well site leader Don Vidrine was in the drill shack to oversee the initiation of the displacement.[109] Donald Clark, the other Transocean assistant driller, was at the bucking unit (a machine for making up pipe) on the port aft deck, working with personnel from Transocean, Weatherford, and Dril-Quip to prepare for setting the lockdown sleeve.[110] Sperry Drilling mudlogger Joseph Keith was in the mudlogger's shack, monitoring the well.[111]

At 8:02 p.m., the crew began displacing the mud and spacer in the riser with seawater.[112] The pumps were not lined up in a closed-loop system. Instead, the crew was pumping seawater from the ocean through the sea chest and into the well. This bypassed the pits. Returns from the well were flowing into the active pits (in this case, pits 9 and 10).[113] As a result, individuals monitoring the well could not rely on the "pit volume change" display.[114] To monitor pit gain, rig personnel would have had to perform volumetric calculations comparing the increase in pit volume (reflecting returns) against the volume of seawater pumped into the well (pump strokes × volume per stroke).[115] There is no evidence, one way or the other, as to whether the crew performed such volumetric calculations.

This setup should not have impaired rig personnel's ability to monitor flow-out versus flow-in. However, the flow-out readings appear to have been more erratic than readings captured the previous day (seen in Figure 4.7.8). This may be because cranes were moving on the rig's deck, causing the rig to sway and thus affecting the level of fluids in the flow line.[116] Otherwise, flow-out appeared normal.[117]

Figure 4.7.8. Erratic vs. normal flow-out.



Sperry-Sun data/TrialGraphix

Flow-out readings appear to have been more erratic than normal during the final displacement, perhaps because crane operations were causing the rig to sway.

This setup also should not have impaired rig personnel's ability to monitor drill pipe pressure. The drill pipe pressure appears to have behaved as expected. It rose initially as the pumps turned on and then decreased gradually as lighter seawater replaced the heavier mud and spacer in the riser. At 8:10 p.m., mud engineer Leo Lindner looked at the drilling screen and "thought everything was fine."[118] At 8:16 p.m., the data showed an increase in gas units—not atypical at the start of circulation.[119] The gas readings then tapered off as the last of the mud left the wellbore.[120]

From 8:28 to 8:34 p.m., the crew emptied the trip tank (pit 17), with the fluid going into the flow line and pits with the rest of the returns. This complicated the monitoring of both the pits and flow-out. To accurately monitor either parameter, the crew had to perform calculations to subtract the effect of emptying the trip tank from the pit volume and flow-out readings that appeared on-screen. It is unknown whether the crew did so.

At 8:34 p.m., the crew did three things simultaneously. They (1) directed returns away from the active pits (pits 9 and 10) and into a reserve pit (pit 7); (2) emptied the sand traps into the active pits (pits 9 and 10); and (3) began filling the trip tank (pit 17).[121] Each of these actions further complicated pit monitoring for well control purposes. The active pit system was eliminated as a well monitoring tool. In order to know the volume coming out of the well, the crew had to perform calculations taking into account that returns were going to two different places—the reserve pit (pit 7) and the trip tank (pit 17). In addition, routing returns to the trip tank bypassed the flow-out meter, so the flow-out reading appeared artificially low and had to be added to the rate of entry of fluids into the trip tank to ascertain actual flow-out.[122] Again, it is unknown whether the crew was performing any such calculations. In addition, communication between the rig crew and mudlogger may have broken down at this time: The drill crew did not inform Keith about the switch in pits.[123] Keith did notice a slow gain in the active pits and called M-I SWACO mud engineer Leo Lindner to inquire; Lindner said they were moving the mud out of the sand traps and into the active pits.[124]

Trip Tank. A trip tank is a small tank. Its primary purpose is to hold fluid that the drill crew may need to rapidly send into the well, for example, to compensate for the volume removed when pulling out the drill pipe (known as tripping the pipe). The drill crew also uses the trip tank to monitor the well. The trip tank is situated between the well and the mud pits. When emptied, fluid from the trip tank goes into the return flow line, past the flow-out meters, and into the same pits as the returns from the well. The *Horizon* had two trip tanks.

At 8:49 p.m., the crew again rerouted returns, this time from one reserve pit (pit 7) to another (pit 6). At about this time, the displacement process had underbalanced the well. The combined hydrostatic pressure at the bottom of the well (generated by the mud and spacer still in the riser, the seawater in the riser and the well, and the mud remaining in the well beneath 8,367 feet below sea level) dropped below the reservoir pressure.

Transocean's post-explosion analysis estimates that the well became underbalanced at 8:50 p.m.[125] BP's post-explosion modeling estimates that the time was 8:52 p.m.[126] Given the failed bottomhole cement job, hydrocarbons would have begun flowing into the well at this time.

At 8:52 p.m., Vidrine called BP's shoreside senior drilling engineer Mark Hafle to ask about the procedure for testing the upcoming surface cement plug. Hafle asked Vidrine if everything was OK. Hafle had the Sperry-Sun real-time data up on-screen in front of him. It does not appear that the two discussed the rig crew's handling of the displacement or rig activities complicating well control monitoring.[127]

In retrospect, it does not appear there were (or would have been) any signs of a kick prior to about 9 p.m. Nevertheless, between 8 and 9 p.m., rig personnel did not adequately account for whether and to what extent certain simultaneous operations, such as emptying the trip tanks, may have confounded their ability to monitor the well.

Indications of an Anomaly as Early as 9:01 p.m.

Just before 9 p.m., Keith left the mudlogger's shack to take a short break.[128] He notified the drill crew (by calling Curtis) and then stepped out.[129] He went downstairs, used the restroom, got a cup of coffee, and smoked half a cigarette.[130] He was apparently gone for about 10 minutes before returning to his post.[131]

At 8:59 p.m., the crew simultaneously decreased the pump rate on all three pumps and began emptying the trip tanks.[132] The decrease in the pump rate should have caused a decrease in the flow-out, but because emptying the trip tanks sent additional fluid flowing past the flow-out meter, the flow-out reading actually increased. That increase potentially masked any sign of a kick from the flow-out reading.[133]

At 9:01 p.m., drill pipe pressure changed direction. Instead of continuing to steadily decline, it began to increase. This change in direction was a significant anomaly. If lighter seawater were replacing the heavier mud and spacer in the riser as should have been the case, drill pipe pressure should have continued to drop, as it had done for at least the previous 40 minutes.[134] In retrospect, this change in drill pipe pressure likely indicated that hydrocarbons were pushing heavier mud up from the bottom of the well against and around the drill pipe.

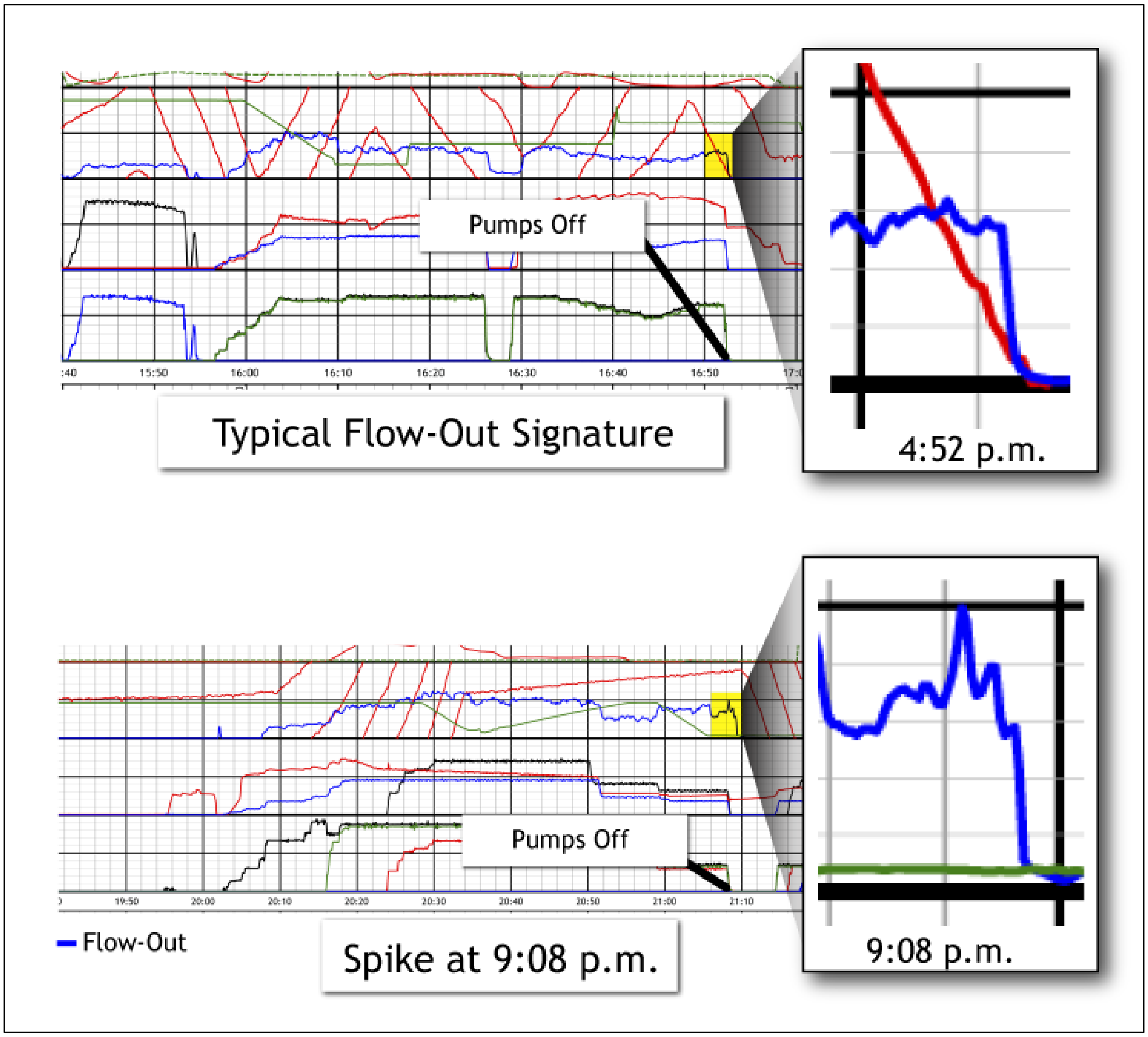
By 9:08 p.m., with the pump rates constant, drill pipe pressure had increased by approximately 100 pounds per square inch (psi). The magnitude of the increase would have appeared subtle on the Sperry-Sun screen showing only trend lines, but it likely would not have been subtle on the numerical displays.[135]

The change in direction was by now clear and clearly anomalous. An individual who saw the drill pipe pressure increase should have been seriously concerned and should have investigated further.[136] But Keith, who would have returned from his break by that time, reviewed the logs for the period he was absent and did not notice any indication of a problem: "I went back over it and looked, and to my recollection, I didn't see nothing wrong."[137]

At 9:08 p.m., after the top of the spacer column reached the rig, the crew shut down the pumps and switched the lineup to route returns overboard.[138] Keith looked at the video feed from the flow line camera and visually confirmed that there was no flow.[139] He likely communicated this to the rig floor.[140] According to Vidrine, who was on the rig floor, everything looked fine.[141]

Everything was not fine. For about a minute after the pumps stopped, flow-out continued beyond the *Horizon*'s typical flow-out signature.[142] This was a kick indicator (Figure 4.7.9 depicts a typical flow-out signature at 4:52 p.m. and the 9:08 p.m. spike). A driller, assistant driller, or mudlogger watching the screen could have seen it.[143] Instead, they thought they had visual confirmation of no flow, based at least on Keith's observations.[144]

Figure 4.7.9. Typical flow-out signature vs. spike at 9:08 p.m.



Sperry-Sun data/TrialGraphix

For about a minute after the pumps stopped at 9:08 p.m., flow-out continued beyond the *Horizon*'s typical flow-out signature.

There are several possible explanations for this contradiction: (1) Keith may have seen some flow but attributed it to residual flow; (2) Keith may not have looked at the camera for long enough to realize that it was not residual flow;[145] (3) the flow may have been too modest to detect from the video feed;[146] or (4) the flow may already have been rerouted overboard before Keith performed his flow check.[147] Rig personnel could have performed a secondary flow check by sending someone to physically look behind the gumbo box, but apparently they did not do so. On many rigs (including the *Horizon*[148]), this would have been a common practice, especially if rig personnel had noted anomalies.[149]

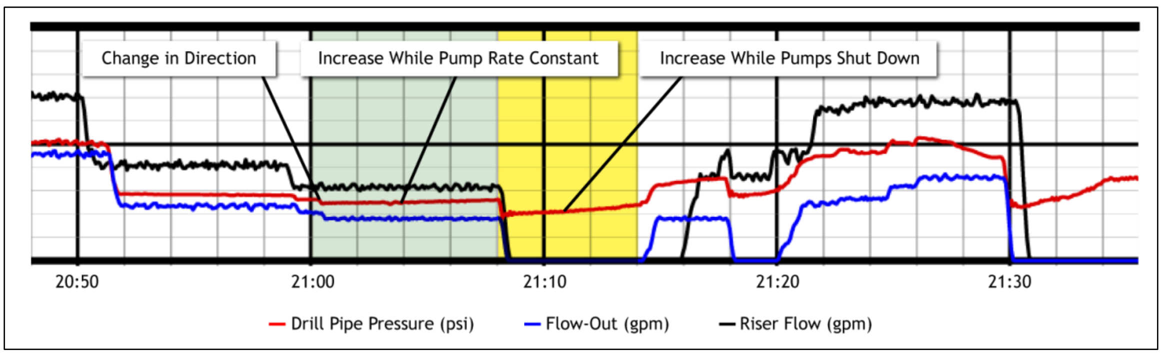
By 9:10 p.m., the crew had rerouted returns overboard. Doing so bypassed the pits, the Sperry-Sun flow-out meter, and the gas sensors.[150] That equipment could no longer be used to monitor the well. The flow did not bypass the Hitec flow-out meter, but for some reason—perhaps malfunction, perhaps neglect—data from that meter never alerted the crew to the kick. At about the same time that they rerouted returns overboard, the crew also transferred mud from the active pits (pits 9 and 10) to the reserve pit that had been taking returns from the well (pit 6).

The crew probably made this pit transfer to prepare for cleaning out the active pits (pits 9 and 10).[151] The immediacy of the transfer suggests that the crew did not take the time to compare the volume of fluid pumped into the well with the volume of fluid returned from the well.

Meanwhile, the mud engineers conducted the sheen test and communicated to the drill shack that it passed. Vidrine directed the crew to get in place to start sending returns overboard and ordered the displacement to begin again. He then returned to his office and did paperwork.

During the course of these activities, drill pipe pressure gradually increased. From 9:08 to 9:14 p.m., while the pumps were shut down, drill pipe pressure increased by approximately 250 psi (see Figure 4.7.10). This was a significant anomaly.[152] By 9:14 p.m., the increase would have been noticeable and a cause for concern.[153] The driller apparently missed this increase, perhaps because "having looked and seen 60 seconds of constant pressure…he may have then turned to do the next step in the process which was line up another mud pump to pump down the kill lines."[154] It is unclear why the assistant driller and the mudlogger also missed the increase.[155]

Figure 4.7.10. Drill pipe pressure anomalies from 9:01 to 9:14 p.m.



Sperry-Sun data/TrialGraphix

At 9:01 p.m., drill pipe pressure changed direction. By 9:08 p.m., with the pump rates constant, drill pipe pressure had increased by approximately 100 psi. From 9:08 to 9:14 p.m., while the pumps were shut down, drill pipe pressure increased by approximately 250 psi. Each of these changes in drill pipe pressure was an anomaly that should have prompted rig personnel to stop and investigate, but the signs apparently went unnoticed.

At 9:14 p.m., the drill crew turned the pumps back on: first, pumps 3 and 4 at 9:14 p.m., then pump 1 at 9:16 p.m. Keith called Curtis and asked why the drill crew was turning the pumps on gradually and not at full rate. Curtis replied, "That's the way we're going to do it this time."[156] Shortly after 9:17 p.m., the crew also turned on pump 2 to pump down the kill lines. Within seconds of turning on pump 2, the pressure relief valve (PRV) on pump 2 blew.[157] The PRV probably blew because the crew had inadvertently started the pump against a closed kill line valve (a rare but not unheard-of mistake).[158]

After the PRV blew, at 9:18 p.m., the crew shut down the primary pumps (pumps 3 and 4). They left the riser boost pump (pump 1) on. The driller organized a group of individuals including Clark to go to the pump room and fix the PRV on pump 2.[159] In addition, the driller ordered someone to open up the closed kill line valve that had caused the PRV to blow.[160]

At 9:20 p.m., the drill crew restarted the primary pumps (pumps 3 and 4). Transocean senior toolpusher Randy Ezell called the drill shack and spoke with toolpusher Jason Anderson. He asked how the displacement was going. Anderson said, "It's going fine. It won't be much longer…I've got this."[161] From 9:14 to 9:27 p.m., the data did not clearly reflect any anomalies. The return flow bypassed the pits, Sperry-Sun flow-out meter, and gas sensors. Drill pipe pressure appeared to be behaving roughly as expected—increasing as the pumps ramped up and then decreasing as seawater replaced the last of the spacer.[162]

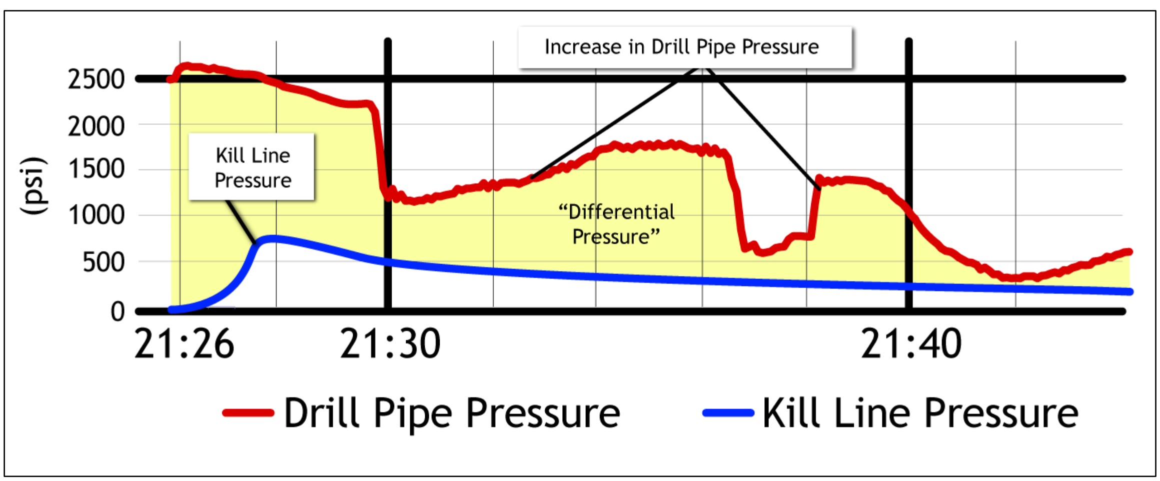
Drill Crew Notices Anomaly but Does Not Treat It as a Kick

By 9:27 p.m., an obvious anomaly appeared. The pressure on the kill line—now discernable because the drill crew had just opened up the previously closed kill line valve—rose to approximately 800 psi.[163] This kill line pressure was anomalous.[164] The crew noticed a "differential pressure" between the kill line (approximately 800 psi) and the drill pipe (approximately 2,500 psi).[165] At 9:30 p.m., they shut down the pumps to investigate.[166]

Around that time, Transocean chief mate David Young went to the drill shack to speak with Anderson and Revette about the timing of the surface plug cement job.[167] Revette, sitting in the driller's A-chair, and Anderson, standing next to him, were speaking to each other.[168] At times, they looked at the driller's screens.[169] Revette noted that they were "seeing a differential."[170] The two men appeared concerned but calm. According to Young, "It was quiet…there was no panic or anything like that."[171]

From 9:30 to 9:35 p.m., drill pipe pressure increased by approximately 550 psi (see Figure 4.7.11). This was another significant anomaly: With the pumps shut off, there should have been no movement in the well.[172] (The increase might have reflected mud continuing to travel up the wellbore with oil and gas below.)[173] Revette and Anderson were intently watching the screens, but they did not shut in the well. Instead, Revette ordered Transocean floorhand Caleb Holloway to bleed off the drill pipe pressure[174]—apparently to eliminate the differential pressure. At 9:36 p.m., Holloway cranked open a valve on the stand pipe manifold to bleed down the pressure.[175] But it was taking longer than usual to bleed off.[176] Revette told Holloway, "Okay, close it back."[177]

Figure 4.7.11. Drill pipe pressure and kill line pressure anomalies from 9:27 to 9:40 p.m.



Sperry-Sun data/TrialGraphix

At 9:27 p.m., kill line pressure reached approximately 800 psi. From 9:30 to 9:35 p.m., while the pumps were shut down, drill pipe pressure increased by approximately 550 psi. After the crew attempted to bleed it down, drill pipe pressure again shot up, at 9:38 p.m., by approximately 600 psi. Each of these anomalies was a sign that fluids were moving in the well. Despite observing those signs, the crew did not yet shut in the well.

Once he did, at 9:38 p.m., the drill pipe pressure shot back up. It increased by approximately 600 psi. Again, the increase was a serious anomaly.

By this point, rig personnel had observed several serious anomalies. Each was "a sign that fluids are moving" in the well.[178] Those anomalies should have "caused alarm."[179] But there appears to have been no hint of alarm.

The crew actively investigated the anomalies and performed diagnostic interventions. But it appears that the crew did not perform the most basic kick detection intervention—a flow check. If they had done so, they would have directly seen flow coming out of the well and should have shut in the well.[180] The fact that the crew apparently did not perform a flow check suggests that Revette and Anderson either did not consider or had already ruled out the possibility of a kick.

Anderson thought "it would be a little bit longer" before they figured out the differential pressure and told Young that they probably wouldn't need him for the cement job meeting for another couple of hours.[181] According to Young, Anderson "wasn't sure if they were going to need to circulate."[182] Anderson then left to go to the pump room.[183] Young also left at about the same time.[184] He ran into Holloway, who was coming down from the stand pipe manifold; they spoke for a couple of minutes and joked.[185] There was no sign of concern or hurry.[186]

Not long afterward, Holloway was leaving the rig floor and ran into Curtis. Curtis was on his way to the drill shack. He was in no rush. Curtis and Holloway spoke for a few minutes.[187]

Throughout this period of investigation, the drill crew did not communicate with the mudlogger about the anomaly.[188] Nor did they contact the senior toolpusher, OIM, or well site leader to ask for their help or to notify them that something was amiss.

Mud Overflow and Recognition of the Anomaly as a Kick

Sometime between 9:40 and 9:43 p.m., mud overflowed onto the rig floor, shot up to the top of the derrick, and poured down onto the main deck.[189] By about that time, drill pipe pressure had decreased by approximately 1,000 psi. At 9:41 p.m., the trip tank (pit 18) abruptly gained about 12 barrels in volume. The crew likely routed flow back to the trip tank intentionally to help diagnose whether the riser was static.[190] The gain showed that there was still flow from the well up the riser.

At about the same time, Anderson returned to the drill shack. At 9:41 p.m., he activated the blowout preventer's (BOP's) annular preventer.[191] Drill pipe pressure began to increase (as it should when a well is shut in). By now, gas would already have been in the riser, expanding rapidly on its way to the surface. This may have made it more difficult to successfully activate the blowout preventer. In any case, even if the crew had successfully shut in the well, they should have expected flow from the well to continue at least until all of the gas in the riser had escaped.

Interviews and testimony after the blowout recount what happened next. Anderson called Vidrine to say the crew was getting mud back and had diverted flow to the mud gas separator and closed the annular.[192] Curtis called Ezell and said: "We have a situation. The well is blown out. We have mud going to the crown.... [Anderson] is shutting it in now."[193] Someone, perhaps Revette, called Andrea Fleytas on the bridge, said "We have a well control situation," and hung up.[194] Vidrine started for the rig floor.[195] Ezell did the same.[196] Fleytas turned to Yancy Keplinger and yelled, "We're in a well control situation."[197] Keplinger radioed the *Damon Bankston*, alongside the rig,[198] and told the vessel to disconnect and move off 500 meters: The *Horizon* was in a well control situation.[199]

Although Anderson had activated the annular preventer, that action had not fully shut in the well. Instead of reaching the expected shut-in pressure (approximately 6,000 psi), drill pipe pressure plateaued at about 1,200 psi.[200] In response, the drill crew either tightened the annular to create a seal or activated a variable bore ram.[201] At 9:47 p.m., drill pipe pressure increased dramatically. At this point, the well may have been shut in.[202]

At 9:48 p.m., pit 20 abruptly gained 12 barrels in volume. The data also show an increase in active pit volume (pits 9 and 10) and several upward spikes in flow-out. Flow from gas already in the riser might have been jostling the rig or otherwise overwhelming the rig's systems.[203]

The first explosion happened at 9:49 p.m. At the time, Anderson, Revette, and Curtis were in the drill shack, trying to get the well under control. Vidrine had been on his way to the drill shack but, seeing mud blowing everywhere,[204] turned back toward the bridge.[205] Ezell was at the doorway of his office, on his way to the rig floor. Clark and three others were in the pump room; they had just finished fixing the PRV.[206] Keith was in the mudlogger's shack, apparently surprised that anything went wrong.[207] Transocean OIM Jimmy Harrell was in the shower, with no knowledge that there had been a well control situation.[208]

Technical Findings

The data available to rig personnel showed clear indications of a kick.[209] The change in direction of drill pipe pressure (9:01 p.m.) and its subsequent steady increases (9:01 to 9:08 p.m., 9:08 to 9:14 p.m.) should have been a cause for concern but apparently went unnoticed. Even after the drill crew noticed an anomaly (9:30 p.m.), they do not appear to have seriously considered the possibility that a kick was occurring.

The anomaly the rig crew noticed at 9:30 p.m. and discussed occurred before hydrocarbons had entered the riser and 10 to 13 minutes before mud appeared on the rig floor. If the rig crew had at all considered that a kick might be occurring, they had plenty of time to activate the blowout preventer.

Rig Activities Potentially Confounded Kick Detection

The crew on the *Deepwater Horizon* engaged in a number of concurrent activities during displacement of the riser. Each could have interfered with the data.[210]

First, rig personnel were pumping seawater directly into the well from the sea chest. The crew had to pump water in from the sea chest for the displacement. But pumping it in directly from the sea chest to the rig pumps, thereby bypassing the pits, made it harder for the crew to monitor the pits. It created a non-closed-loop system that made it impossible to detect a kick by visually monitoring pit gain. Instead, pit monitoring required volumetric calculations. The crew could have, and should have, performed those calculations[211]—it was the rig crew's regular practice to do so[212]—but there is no evidence that they did so here. They also could have routed the seawater through the active pit system before sending it down the well.[213] That approach would have preserved visual monitoring of pit gain.

Second, rig personnel sent returns overboard during the latter part of the displacement. Sending returns overboard was an inherent part of the displacement. But pumping it directly from the well overboard—bypassing the pits, Sperry-Sun flow-out meter, and both gas meters—eliminated the crew's ability to monitor the pits and the Sperry-Sun flow-out meter for kick indicators.[214] The crew could still monitor the well by using the Hitec flow-out meter and by physically checking the overboard line whenever the pumps were stopped. But there is no evidence that they did so. The crew could also have lined up the displacement so that it did not confound well monitoring by taking returns to the pits first and then channeling it overboard.

Third, rig personnel were using the cranes. From early in the displacement (about 8:20 p.m.) until the explosion, rig personnel were operating one or both of the cranes.[215] Crane movement can cause the rig to sway,[216] affecting the flow-out levels and pit volumes,[217] and "complicat[ing] kick recognition."[218] Rig personnel can still detect kicks when there is rig sway, but the movement increases the level of background noise in the data and thereby reduces the minimum detectable kick sensitivity with respect to flow-out and pit volumes.[219] The crane movement was not necessary for the displacement. Rig personnel could have waited until the displacement was complete to engage in crane activity.

Fourth, rig personnel appear to have begun emptying the mud pits without first checking for pit gain. During the sheen test, the rig crew began emptying the active pits into reserve pit 6. Until that point, returns from the well had been flowing to pit 6. The problem is, the crew does not appear to have measured the volume in pit 6 before emptying the active pits into it. This suggests that the crew was not mathematically comparing the actual volume of returns to the expected volume of returns to verify that there had been no gain. The apparent reason that rig personnel emptied the active pits was to prepare for cleaning them.[220] It was unnecessary to clean the active pits, or even empty them in preparation for cleaning, during the displacement.

Fifth, rig personnel were emptying the sand traps into the pits.[221] Sand traps separate sand from mud. After a while, they fill up with clean mud. When that happens, the crew empties the mud from the sand traps into the pits. Emptying the sand traps was not problematic by itself. The problem was that the crew emptied them into the active pit system and thereby complicated pit monitoring. The crew could have simplified pit monitoring by using the active pit system to monitor the volume of fluid returning from the well and routing mud from the sand traps to a reserve pit instead.

Sixth, rig personnel were emptying the trip tanks during the displacement. It appears that the crew had to do so at this point in the displacement process.[222] It also appears that the rig's plumbing forced the crew to route flow-out from the trip tank past the flow-out meter.[223] This flow added to pit gain and flow-out, making both figures higher than they would have been otherwise. The crew could nevertheless have preserved pit monitoring and flow-out monitoring if they calculated the effect of emptying the trip tank in this manner, but there is no evidence that they did so. Alternatively, the crew could have stopped displacing the riser while they emptied the trip tanks.

Kick Detection Instrumentation Was Mediocre and Highly Dependent on Human Factors

The data sensors on the rig had several shortcomings. First, the system did not have adequate coverage. For example, there was no camera installed to monitor returns sent overboard and no sensor to indicate whether the valve sending returns overboard was open or closed. Therefore, while video monitoring of flow was possible when returns went to the pits, it was not possible when returns went overboard.

Second, some of the sensors were not particularly accurate. For example, electronic sensors for pit volumes can be unreliable, so much so that the crew would sometimes revert to using a string with a nut to measure pit volume change.[224]

Third, the sensors often lacked precision and responded to movement unrelated to the state of the well. For example, a fluctuation in flow-out might result from crane activity on the rig.[225] These shortcomings can result in rig personnel not receiving quality data and, furthermore, discounting the value of the data they do receive.

The data display systems also had notable limitations. There were no automated alarms built into the displays. Rather, the system depended on the right person being in the right place at the right time looking at the right information and drawing the right conclusions.[226] Although the systems did contain audible and visual alarms, the driller was required to set them manually.[227] He could also shut them off. Manually setting and resetting alarm thresholds is a tedious task and not always done. For example, there is typically no alarm set for flow-in and flow-out because the pumps stop and start so often that the alarms would trigger too frequently.[228]

There was also no automation of simple well monitoring calculations. For example, if the displacement is set up as a non-closed-loop system, and rig personnel want to keep track of volumes, they must perform the calculation by hand (return volume – (pump strokes × volume per pump stroke)). If the rig is emptying its trip tank while taking returns, and rig personnel want to disaggregate the two activities, they must perform the subtraction by hand. Each of those calculations could easily be automated and displayed for enhanced real-time monitoring.

There was also no advance planning or real-time modeling of expected pressures, volumes, and flow rates for the displacement. Although well flow modeling has been employed in post-explosion analysis,[229] there was no comparable modeling technology in place for real-time analysis.[230]

Finally, the displays themselves sometimes made fluctuations in data hard to see.[231] Indeed, in post-explosion reports and presentations, BP has consistently chosen to rotate the vertical Sperry-Sun log and enlarge it so that viewers can understand the data from April 20.

These limitations made well control monitoring unnecessarily dependent on human beings' attentions and abilities.

Management Findings

One of the most important questions about the Macondo blowout is why the rig crew and mudlogger failed to recognize signs of a kick and did not diagnose the kick even when they shut operations down to investigate a well anomaly. The Chief Counsel's team finds that a number of management failures, alone or in combination, may explain those errors.[232]

BP, Transocean, and Sperry Drilling Rig Personnel Exhibited a Lack of Vigilance During the Final Displacement

The evidence suggests that BP, Transocean, and Sperry-Sun personnel on the rig were not sufficiently alert to the possibility that a loss of well control might occur during the final displacement. There are several reasons why this might have been the case. First, kicks are not commonly associated with the temporary abandonment phase of well operations. In a 2001 study of 48 deepwater kicks in the Gulf of Mexico, the vast "majority of kicks occurred during drilling operations."[233] By contrast, only one kick "occurred in association with a well abandon[ment] operation."[234]

Second, confidence in barriers, particularly tested barriers, can make rig personnel overconfident in the well's overall security. A satisfactory negative pressure test generally confirms that the well is secure and that hydrocarbons will not flow into the well during riser displacement operations. Once rig personnel deemed the Macondo negative pressure test a success, they may have believed that a kick was no longer a realistic hazard.[235] Investigations of a 2009 North Sea blowout and a 2009 Timor Sea blowout found that rig personnel were "blinkered" by a successful negative pressure test or drew an "unwarranted level of comfort" from the presence of a barrier.[236] Both attitudes "reflected and influenced a lax approach to well control."[237]

Third, end-of-well activities tend to be marked by a hasty mindset and loss of focus.[238] This can result simply from a desire to finish and move on, particularly when a well has been difficult to drill (like Macondo).[239] Rig personnel have noted in post-blowout interviews that "[a]t the end of the well sometimes they think about speeding up."[240] This may be because "everybody goes to the mindset that we're through, this job is done…everything's going to be okay."[241]

Together, these factors appear to have contributed to reduced well monitoring vigilance, diminished sensitivity to anomalous data, delayed reactions, a failure to undertake routine well monitoring measures (like flow checks and volumetric calculations), and a willingness to perform rig operations in a manner that complicated well monitoring.

Such a lack of vigilance was particularly surprising at this well. Given the risk of a poor bottomhole cement job and the fact that the final displacement would severely underbalance the well, rig management—and the well site leader in particular—should have treated the displacement as a critical operation and personally monitored the data.[242]

Transocean Personnel Lacked Sufficient Training to Recognize That Certain Data Anomalies Indicated a Kick[243]

Several times during the evening of April 20, data anomalies indicated that hydrocarbons were flowing into the well.[244] Despite noticing the anomalies—and taking time to discuss them—the rig crew did not recognize that a kick was under way.

Earlier in the evening, during the negative pressure test, hydrocarbons flowed into the well. Pressure anomalies signaled the kick. But rig personnel did not heed those signals.

During the final displacement, the pressure anomalies reappeared. Although some went unnoticed, the rig crew did recognize an anomaly at 9:30 p.m. and shut the pumps down to investigate. Over the next 10 minutes or so, the crew watched the drill pipe pressure visibly increase—steadily at first (9:30 to 9:35 p.m.) and then, after they attempted to bleed it off, rapidly (9:38 p.m.)—even though the pumps were off. They also saw an anomalous kill line pressure. Each indicator was "a sign that fluids are moving" in the well—in other words, a sign of a kick.[245]

To a skilled observer, those anomalies "would have caused alarm."[246] But there appears to have been no hint of alarm. Instead, the rig crew spent at least 10 minutes "discussing" the "anomaly," "scratching their heads to figure what was happening."[247] Even in retrospect, Transocean's internal investigator asserts that it was "a very strange trend," "a confusing signal," explained only after "months of work."[248]

Transocean leaves open the possibility that its rig crew "did not have the experience" or training to interpret pressure anomalies during the negative pressure test.[249] If true, then the crew likely did not have sufficient training or ability to interpret the recurrence of those anomalies during the final displacement.

Transocean further states that its crew relied on the operator (BP) to make a final assessment of anomalies during the negative pressure test.[250] But when those anomalies reappeared during the displacement, the rig crew did not notify BP rig personnel and ask for their help in interpreting the data.[251]

BP and Transocean Allowed Rig Operations to Proceed in a Way That Inhibited Well Monitoring

BP and Transocean management on the rig allowed simultaneous operations without adequately ensuring that those operations would not complicate or confound well monitoring.[252]

Simultaneous activities can interfere with well monitoring in several ways. First, they can influence data that are used to monitor for kicks (for example, by altering fluid levels) and thereby obscure signals of a kick.[253] Second, they can make it more difficult to interpret data because rig personnel may attribute data anomalies to rig activities instead of a kick. Third, even when simultaneous operations are necessary, such as when changing the lineup of pipes and valves or fixing a mud pump, they can distract rig personnel who would otherwise be monitoring the well.[254] Rig personnel can reduce these difficulties by identifying relevant rig activities, calculating or otherwise predicting their probable effect, and communicating any expected effects to well monitoring personnel. Rig management should ensure that *someone* is watching the screens at all times, despite ongoing activities.

BP, Transocean, and Sperry Drilling Rig Personnel Did Not Properly Communicate Information

Insufficient communication, both prior to and during the final displacement, affected risk awareness and well monitoring on the *Deepwater Horizon*.

BP did not adequately inform Transocean about the risks at the Macondo well, particularly the risks of a poor bottomhole cement job.[255] Transocean argues that if BP had done so, its crew might have demonstrated "heightened awareness."[256] But it is unlikely that this particular communication failure compromised kick detection; the crew would probably have dismissed warnings about cement risks anyhow after the successful negative pressure test.

BP and Transocean did not do enough to ensure that rig personnel were aware of the objectives, procedures, and hazards of the riser displacement operation.[257] The individuals conducting the pre-job meetings should have emphasized that BP's temporary abandonment procedures would leave only a single barrier in the well besides the BOP and would produce an unusually underbalanced well.[258] They should have warned against complacency stemming from the negative pressure test and emphasized that tested barriers can fail.

The pre-job meetings should also have informed well monitoring personnel that certain kick indicators such as pit gain and flow-out would be compromised or unavailable during the planned operations. Well monitoring personnel should have been told that, as a result, they would need to perform volumetric calculations to keep track of pit gain, pay special attention to other parameters (such as drill pipe pressure), and conduct visual flow checks whenever the pumps were stopped.[259] In addition, to facilitate well monitoring, those personnel should have been given a pump schedule for the different phases of the displacement, along with guidance regarding how much deviation from that schedule should be considered anomalous.[260]

Transocean and Sperry Drilling personnel did not communicate effectively about the displacement operation.[261] And the BP well site leader did not play a sufficiently active role in ensuring such communication.[262] Communication broke down between the drill crew and the mudloggers on several occasions. For example, when rig personnel announced early on April 20 that they would be pumping mud to a supply boat, Cathleenia Willis (the mudlogger on shift) told Clark she was concerned that this would limit her ability to monitor pit gain.[263] Clark said he would address the matter but never got back to Willis.[264] Keith reported after the explosion that he was concerned that simultaneous activities would complicate monitoring but never expressed those concerns to others.[265] The drill crew repeatedly failed to inform Keith of various activities that influenced well monitoring data.[266]

Even after the Transocean crew shut down the pumps to investigate an anomaly, they did not inform the Sperry Drilling mudlogger, senior Transocean personnel, or the BP well site leader of the anomaly or ask for their help in resolving it.[267]

The Chief Counsel's team cannot conclude that any one of these problems contributed to the failure to detect the kick. But together they suggest a communication breakdown that made kick detection more difficult. Knowledge of ongoing rig activity "is essential to accurate interpretation of the data."[268] Absent that knowledge, it is difficult to ascertain whether anomalous data are benign or problematic.[269]

While BP and Transocean Management Were Taking Steps to Improve Well Monitoring, These Steps Had Not (Yet) Improved Kick Detection on the *Deepwater Horizon*

BP

BP recognized that well control was critically important to its operations. In a 2009 Major Hazard Risk Assessment, the company identified "Loss of Well Control" as first among the two "major accident risks" in drilling and completions operations.[270]

BP specifically gave the *Deepwater Horizon* a mid-range risk rating for loss of well control[271] and acknowledged the potentially severe consequences of a well control failure: "Catastrophic health/safety incident" with the "potential for 10 or more fatalities," "extensive" and "widespread" damage to sensitive environments, "$1 billion - $5 billion" in financial impact, "severe enforcement action," government intervention, and "[p]ublic and investor outrage."[272]

To address this risk, BP checked to ensure that all drilling and completions workers had well control training and certification, developed tools to further assess the risk ("BowTie diagrams," "Risk Mitigation Plans," "Asset-specific" risk assessments, a "Barrier Assessment Tool"), and emphasized that risk management in this area would be "under continual review."[273] The company also planned to evaluate the effectiveness of barriers with each rig's team and train personnel in the new well control response guide.[274]

BP understood the risks presented by less severe well control events too. An April 14, 2010 presentation to the drilling and completions Extended Leadership Team noted that half of all nonproductive time in the company's offshore drilling sector was the result of "downhole problems (wellbore instability, losses, gains, tight hole) and stuck pipe."[275] The presentation continued: "Post analysis of the...incidents clearly indicates that in most cases[,]...events could have been prevented or decisions influenced if the drilling data that is already generally available had been appropriately presented and analysed." That is, "early warning indicators were usually present albeit invisible in the mountain of data."[276] Therefore, as Macondo senior manager David Sims stated, downhole problems were "low hanging fruit" for decreasing nonproductive time.[277]

Reviews conducted in late 2007 and early 2008 similarly showed that "the quality of monitoring, detection and reaction to downhole hazards during drilling operations" was "variable."[278] In response, BP planned to develop a program to facilitate Efficient Reservoir Access, the "ERA Advisor." This ambitious program would monitor data in real time onshore, generate expert and automated advice in response to that data, and use new software and sensors to track and diagnose the data.[279] The program's goal was to "ensure the *right information is in the right place at the right time*."[280] It would focus, however, on monitoring data during the drilling of the well (not end-of-well activities).[281] BP's Extended Leadership Team developed and endorsed the ERA in 2009; initial pilot testing of the first stage of the system was to begin in the fourth quarter of 2010.[282]

Even before planning its ERA program, BP contracted Sperry-Sun to relay rig data to its Houston offices. But despite recognizing the risks associated with poor well monitoring and the usefulness of onshore assistance, BP did not monitor this data for well control purposes. Even though each of its working rigs had an operations room with dedicated Sperry-Sun data displays,[283] BP typically used these rooms only for meetings and the data were "not ever monitored."[284] Thus, before BP implemented its ERA Advisor system, it failed to take the interim step of ensuring that someone onshore was monitoring the data systems it already had in place.

This is surprising in light of the fact that BP was particularly concerned about well monitoring at Macondo. Less than two months before the blowout, on March 8, 2010, the Macondo well took a kick.[285] The kick occurred while the rig was drilling.[286] The "well kicked for 30 minutes before the trends were obvious enough."[287] The Transocean drill crew and Sperry Drilling mudlogger—indeed, the very same Revette, Curtis, Clark, and Keith—observed a gain in flow-out, a slow gain in the pits, a decrease in equivalent circulating density (ECD), and an increase in gas content.[288] The drill crew stopped the pumps, performed a flow check, and shut in the well.[289] The situation soon went "from bad to worse."[290] There were "[m]ajor problems on the well":[291] The pipe was stuck. BP ultimately had to sever the pipe and sidetrack the well.[292]

After the event, BP involved its in-house Totally Integrated Geological and Engineering Resource team (the "TIGER team"), to conduct an engineering analysis, and (on March 18) distributed a "lessons learned" document to its Gulf of Mexico drilling and completions personnel.[293] BP recommended that its personnel "evaluate the entire suite of drilling parameters that may be indicative of a shift in pore-pressure" (including gas, flow-out, and flow checks), "ensure that we are monitoring all relevant [pore pressure] trend data," "have [pore pressure] conversations as soon as ANY indicator shows a change," "no matter how subtle," and "*be prepared to have some false alarms and not be afraid of it*."[294] The "lessons learned" document also specified that "[b]etter lines of communication, both amongst the rig subsurface and drilling personnel, and with Houston office needs to be reestablished. Preceding each well control event, subtle indicators of pore pressure increase were either not recognized, or not discussed amongst the greater group."[295]

In addition, BP wells team leader John Guide initiated several conversations to address the rig's response to the kick, which he thought was "slow and needed improvement."[296] Guide specifically instructed the BP well site leaders to "up their game."[297] He spoke with Transocean and Sperry Drilling personnel about "tighten[ing] up wellbore monitoring."

The goal of Guide's conversations and of the TIGER team's involvement was to maintain heightened attentiveness "for the remainder of the Macondo well,"[298] up to the point when the *Horizon* unlatched its BOP and left.[299] Evidently, the team fell short of that goal. As Guide conceded after the incident, the Macondo team's heightened attentiveness to well monitoring lasted all the way up until, apparently, the negative pressure test.[300] This is likely because BP's focus, once again, was on monitoring data during the drilling of the well (not end-of-well activities).[301]

Transocean

Transocean also recognized the importance of well control. In a 2004 Major Accident Hazard Risk Assessment, the company gave *Deepwater Horizon* a 5B risk rating for reservoir blowout,[302] meaning that there was a "Low" likelihood of a blowout occurring, but if one did occur, the event would have "Extremely Severe" consequences:[303] "Multiple personnel injuries and/or fatalities," "Major environmental impact," and "Major structural damage and possible loss of vessel."[304] As prevention and mitigation measures, Transocean listed (among other things) well control procedures, training of drill crew, and instrumentation indicating well status.[305]

As discussed in greater detail in Chapter 5, despite those concerns, Transocean did not inform the *Deepwater Horizon*'s crew of lessons learned from an earlier well control event on another rig. On December 23, 2009, Transocean barely averted a blowout during completion activities on a rig in the North Sea. Rig personnel were in the process of displacing the wellbore from mud to seawater.[306] They had just completed a successful negative pressure test, and they had lined up the displacement in a way that inhibited pit monitoring. [307] During the displacement, a critical tested barrier failed, and hydrocarbons came up the wellbore, onto the drill floor, and into the sea.[308]

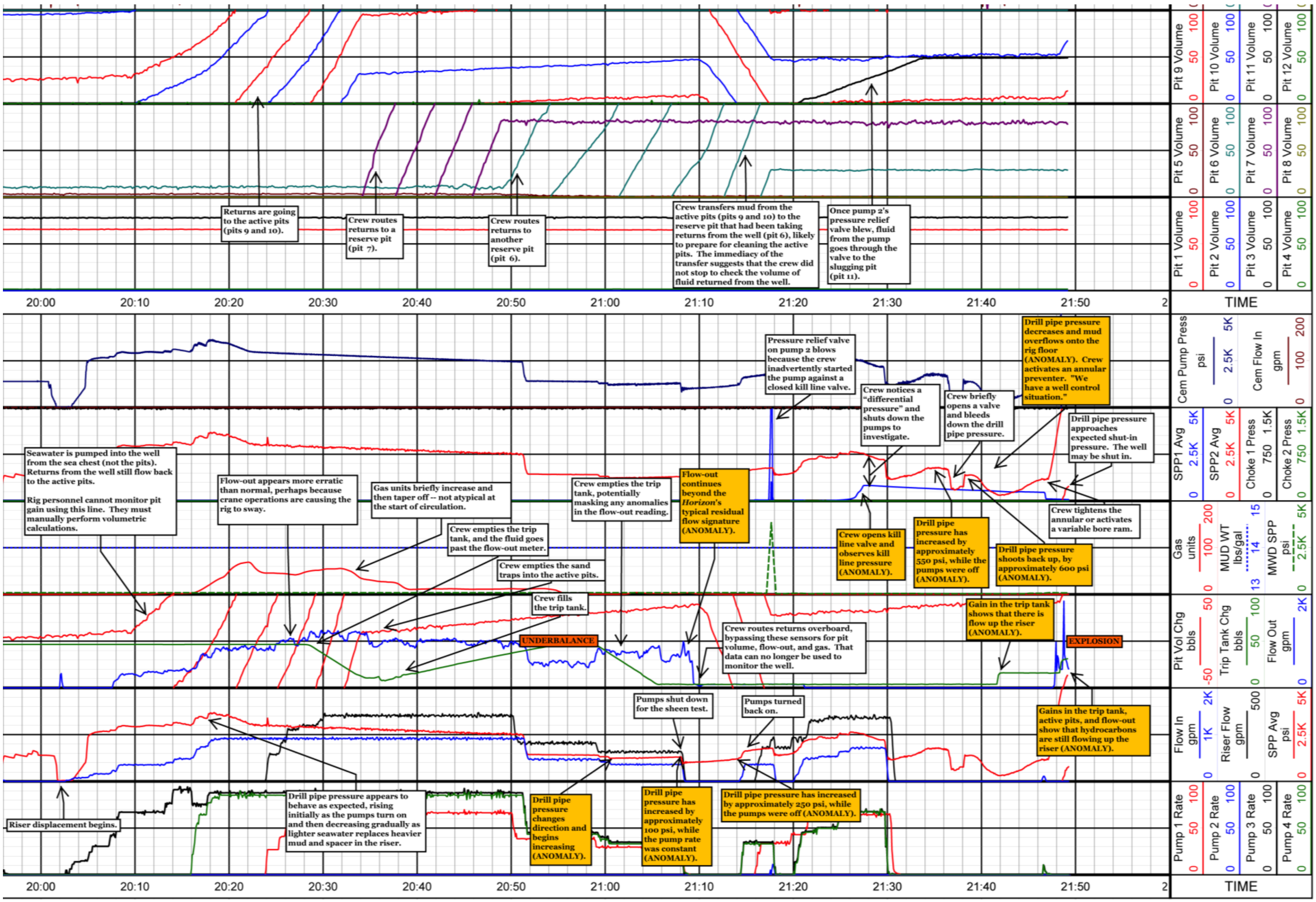
The incident differed from Macondo in some respects: It occurred during the completion phase of the well, not drilling or temporary abandonment, and the failed barrier was a mechanical valve, not cement.[309] But the incident was identical to Macondo in crucial respects:

- the rig crew underbalanced the well while displacing mud to seawater;

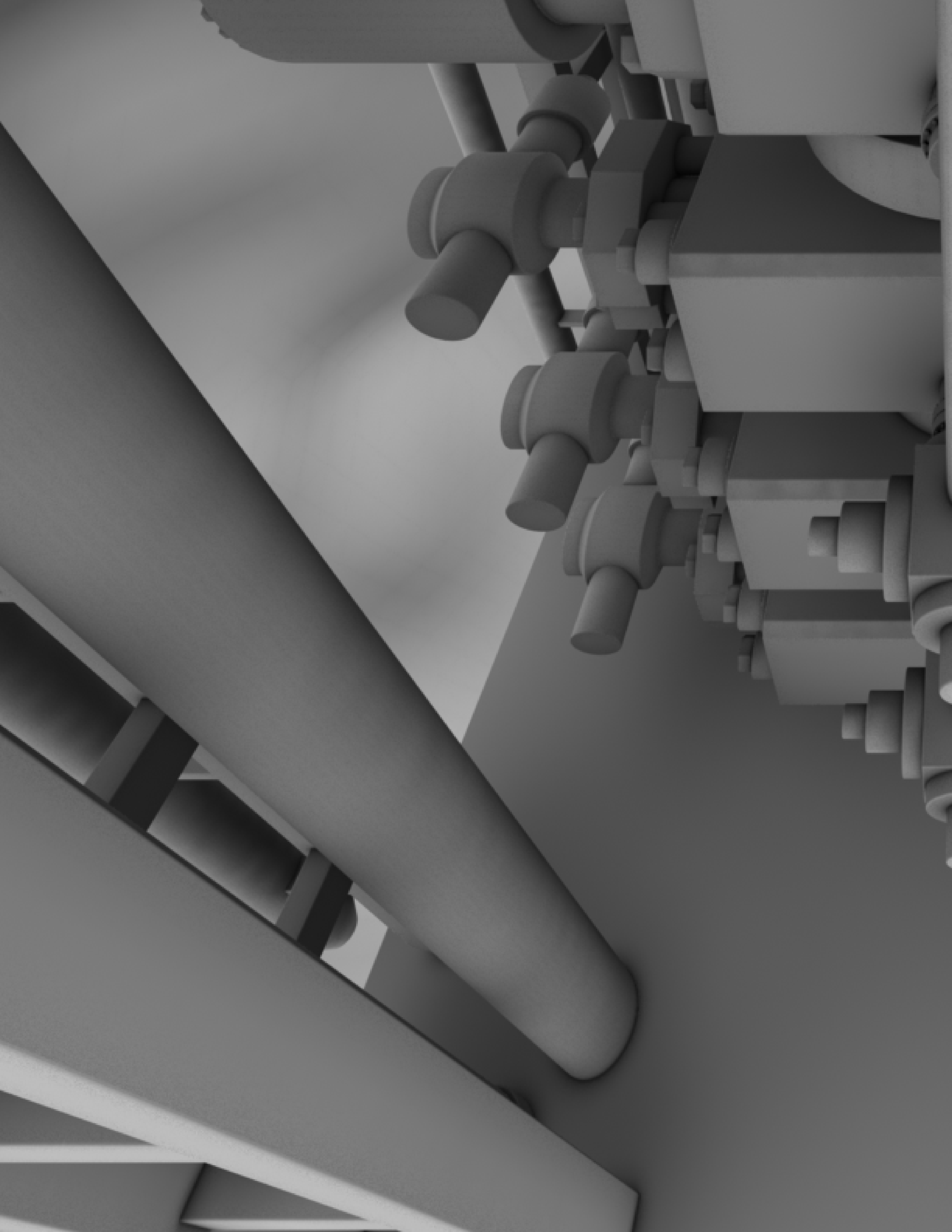
- a successful negative pressure test “blinkered” the crew and produced an improper “change in mindset”;
- the crew conducted displacement operations in ways that inhibited pit monitoring; and
- the crew discounted kick indicators by attributing them to other occurrences on the rig.[310]

Transocean nevertheless failed to effectively share and enforce the lessons learned from that event with all relevant personnel. The company held two conference calls and distributed an advisory for its North Sea personnel only. It also posted a shorter advisory about the event on its electronic documents platform—accessible fleetwide—but it did not alert crews of the advisory’s existence. Indeed, there is no evidence that anyone on or affiliated with the *Deepwater Horizon* knew of the North Sea incident or read any of its lessons prior to the Macondo blowout.

Figure 4.7.12. Last two hours of Sperry-Sun data.



Saritha Komatireddy Tice



Chapter 4.8 | Kick Response

In the event of an unwanted influx of fluid or gas into the wellbore (a "kick"), the safety of a drilling rig turns on split-second responses by the rig crew.

The *Deepwater Horizon*'s crew did not respond to the April 20 kick before hydrocarbons had entered the riser, and perhaps not until mud began spewing from the rig floor. If the rig crew had recognized the influx earlier, they might have been able to shut in the well. But the crew still had response options even at the point that they eventually did recognize the kick. If the crew had diverted the flow overboard immediately, they might have delayed the ignition and explosion of the gas flowing out of the well. Instead, the crew sent the flow to the mud gas separator.[1] The mud gas separator was not designed to handle this flow volume and was overwhelmed. Sending flow to the mud gas separator, rather than overboard, therefore increased the risk that gas from the well would explode on the rig.

The crew appears to have followed standard Transocean procedures for dealing with hydrocarbon kicks. But those procedures were written to guide the crew's response to routine hydrocarbon kicks. They did not address extreme emergencies like the one the *Deepwater Horizon* crew faced on the evening of April 20. In the future, Transocean and other companies must provide better training and drills to ensure that their crews are prepared to respond quickly to low-frequency, high-risk events like the Macondo blowout.

Well Control Equipment

Blowout Preventer and Emergency Disconnect System

The last piece of equipment that can prevent hydrocarbons from flowing into the riser above the wellhead is the **blowout preventer** (BOP). As Chapter 4.9 explains in more detail, the *Deepwater Horizon*'s BOP had several annular preventers, pipe rams, and shear rams that the rig crew could use to control flow coming from the well from going up the riser.

Most of the barriers in the wellbore, such as drilling mud and cement, block hydrocarbon flow without active supervision by the rig crew. By contrast, BOP elements are typically open during well operations. The BOP does not block flow unless the rig crew spots an influx and closes a BOP element, or an automated backup system activates the blind shear ram. Chapter 4.9 explains the BOP's automated backup systems in detail.

In addition to directly activating the BOP rams, the rig crew can activate the blowout preventer's **blind shear ram** and disconnect the rig from the well using an **emergency disconnect system** (EDS).[2] In accord with Transocean policy, the rig crew had tested the *Deepwater Horizon*'s EDS at surface prior to deploying the blowout preventer at the Macondo well.[3]

Emergency Disconnect System. The crew can activate the emergency disconnect system (EDS) from either the driller's control panel, the toolpusher's control panel, or the bridge.[4] Power and communication signals are sent from the rig to the BOP through multiplex (MUX) cables.[5] The signals initiate a sequence in which pod receptacles de-energize and retract, choke and kill line connectors unlatch, the blind shear ram closes, and the lower marine riser package unlatches from the BOP stack,[6] separating the rig and riser from the well. Once initiated, this sequence typically takes about a minute.[7] Emergency disconnect is not generally considered a well control response. Rather, it is used in emergency dynamic positioning scenarios to separate the rig from the well. The rig may begin to "drift off" from its station if the rig loses power, or the rig may "drive off" if the dynamic positioning system mistakenly directs the rig to move away. The riser would likely be damaged if the rig drifted or drove off, potentially resulting in an uncontrolled release of hydrocarbons into the water.

Once gaseous hydrocarbons move past the blowout preventer, they expand exponentially with decreasing depth[8] and reach the rig within minutes.[9] Timely BOP activation is therefore crucial to drilling safety.[10] If the BOP is activated quickly, little or no gas will enter the riser and travel to the rig. Transocean advises its personnel: "If the volume of gas above the BOP stack is kept small by detection equipment and shut-in, then the gas can be safely handled at [the] surface."[11] If this is not done, the consequences can be severe. On March 14, BP well site leader Jimmy Adams cautioned BP senior drilling engineer Mark Hafle: "Rigs have been burn[ed] down and people killed from gas in the riser."[12]

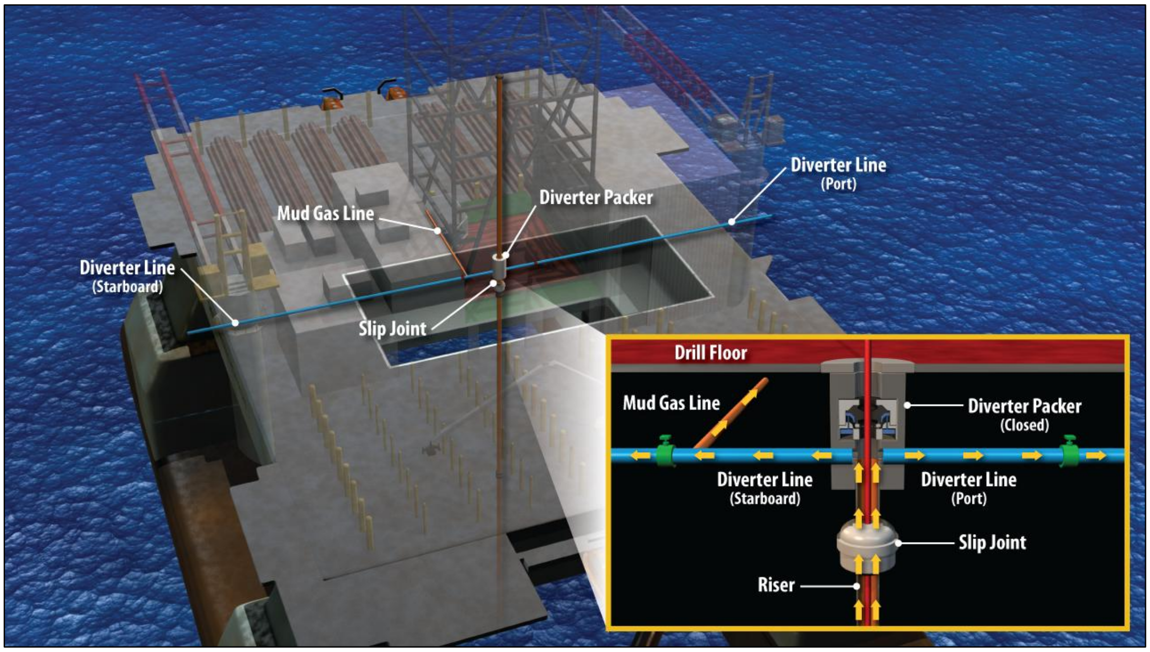
Diverter and Mud Gas Separator

Transocean's Well Control Handbook warns that "[l]arge amounts of gas above the BOP stack can rise rapidly and carry a large volume of mud out of the riser at high rates."[13] In those situations, the rig's **diverter** becomes the last line of defense. The diverter on the *Deepwater Horizon* sat directly beneath the rig floor.[14] It could prevent gas from flowing uncontrollably onto the drilling rig,[15] in order to "keep combustible gases safely away from sources of ignition."[16]

As Chapter 4.7 explains, mud coming out of the well normally flows up the riser, through the mud cleaning system and into the mud pits. When the rig crew activates the diverter, an annular packer in the diverter closes around the drill pipe (or closes the open hole if no drill pipe is in the hole) and prevents flow up the riser and onto the drill floor. The *Deepwater Horizon's* diverter packer had a 500 pounds per square inch (psi) working pressure rating,[17] meaning that it could safely withstand 500 psi of pressure exerted by fluids flowing up the riser. Although the diverter is designed to handle worst-case scenarios,[18] pressures above the pressure rating could cause it to fail and allow an influx to continue up the riser.

When closed, the packer forced flow to one of two 14-inch diameter **overboard lines**—one going to the port side of the rig, the other to starboard (see Figure 4.8.1).[19] The rig crew could select the direction of overboard flow in order to discharge gas on the downwind side of the rig. The starboard-side overboard line was also connected to another pipe that led to the mud gas separator. The rig crew could close a valve in the starboard line in order to route flow from that line to the mud gas separator.[20]

Figure 4.8.1. Diverter system.



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On April 20, the rig crew diverted the influx to the mud gas separator rather than sending it overboard. That caused mud and gas to spray onto the rig from the derrick.

A mud gas separator consists of a series of pipes, valves, and a tank. When gas-bearing mud flows into the tank, the mud falls to the bottom of the tank while the gas rises. The mud flows out through a pipe in the tank bottom to the rig's mud pits. The gas flows out through a separate pipe. On the *Deepwater Horizon*, that pipe ran to a vent high atop the derrick where gas could discharge into the open air.

When using the diverter system, the crew's most important decision is whether to send the fluid influx overboard or to send it to the **mud gas separator**.[21] The choice depends on the size of the hydrocarbon influx in the riser.[22] The mud gas separator is the right choice for small quantities of mud and hydrocarbons. By separating mud from gas, it allows the crew to collect and reuse the mud rather than discharge it overboard and pollute the sea. Moreover, it vents gas out of a gooseneck pipe on the derrick at the center of the rig. But sending a large influx to the mud gas separator can create a large flammable cloud of gas over the rig.[23] If a sufficiently large and sustained influx of gas from the riser goes to the mud gas separator, ignition becomes more likely, with the potential for explosion.[24] As a result, it is inappropriate to send large flows through the mud gas separator.[25] In the event of a large hydrocarbon influx into the riser, the crew should send flow overboard through the downwind line.[26]

Kick Response at Macondo

On April 20, gas moved through the *Deepwater Horizon's* open blowout preventer and shot up the riser. As it rose, the gas expanded, pushing the mud and gas faster and faster toward the rig.[27] Sometime between 9:40 and 9:43 p.m.,[28] mud spewed from the rotary table,[29] sprayed onto the rig floor,[30] and shot up and out the crown of the derrick[31] about 200 feet above the rig floor.

A Transocean representative likened the force of the gas to "a 550-ton freight train hitting the rig floor,"[32] followed by a "jet engine's worth of gas coming out of the rotary."[33]

The Rig Crew Sends the Influx to the Mud Gas Separator

After drilling mud began spraying out from the rig floor, the crew activated the diverter system.[34] Transocean toolpusher Jason Anderson was in the drill shack. He called BP well site leader Don Vidrine to say that the crew was taking action in response to mud coming back from the well.[35] It appears that rig personnel had previously set the valves on the diverter system to route diverted flow through the mud gas separator rather than overboard.[36] The crew may have done this to avoid inadvertently discharging oil-based drilling mud or other pollution into the Gulf of Mexico in violation of environmental regulations. Whatever the reason, it appears that the rig crew did not change the valve settings to route the flow overboard in response to the sudden mud influx.

Diverting flow to the mud gas separator stopped the flow of mud onto the rig floor within seconds. Micah Sandell, a Transocean gantry crane operator, testified: "I seen mud shooting all the way up to the derrick…then it just quit…I took a deep breath thinking, 'Oh, they got it under control.'" [37]

Any relief was temporary. Given the size of the influx, routing the influx to the mud gas separator rather than overboard made ignition all but inevitable. The capacity of a mud gas separator depends on the size of the outlet lines,[38] and these lines are generally not large enough to handle very high flow rates.[39] The Macondo blowout therefore quickly overwhelmed the *Deepwater Horizon*'s mud gas separator.[40] Sandell observed: "Then all the sudden the…mud started coming out of the degasser…so strong and so loud that it just filled up the whole back deck with a gassy smoke…loud enough…it's like taking an air hose and sticking it to your ear."[41]

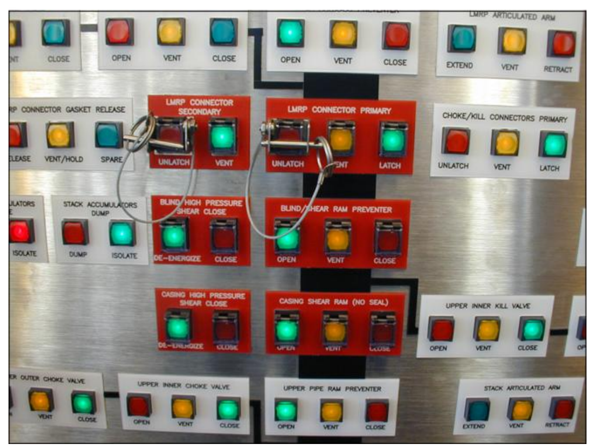
A Weatherford specialist on the rig watched mud come out of the gas vent lines of the mud gas separator.[42] Gas likely entered the line to the mud system, which would have sent gas to the pump room, the mud pit room, and the shaker room.[43] Components of the mud gas separator may have failed at that time as well.[44] There was little wind on April 20,[45] creating "worst-case" conditions for gas dispersion.[46] A flammable gas cloud started accumulating on the rig.

The Rig Crew Activates the Blowout Preventer

In addition to activating the diverter, the crew also attempted to shut in the well with the BOP's annular preventer.[47] (Though there is evidence that the rig crew activated the lower annular preventer at 9:41 p.m., Transocean has recently contended the rig crew activated the upper annular, not the lower annular.)[48] At about the same time, Transocean assistant driller Stephen Curtis called Transocean senior toolpusher Randy Ezell to tell him that the well was blowing out, that mud was shooting through the crown on top of the derrick, and that Anderson was shutting the well in.[49] Pressure data indicate the crew activated a variable bore ram—or tightened the annular preventer—on the BOP at about 9:46 p.m.[50]

Activating the annular preventer and variable bore rams are "normal and appropriate" responses to a typical kick.[51] But this was not a typical kick. By the time the *Deepwater Horizon's* rig crew attempted to activate the BOP, substantial volumes of hydrocarbons probably had already entered the riser, where they would have been rapidly expanding upward toward the rig.[52] The flow rate of mud and hydrocarbons may have been high enough to prevent the annular preventer from sealing.[53]

Figures 4.8.2 and 4.8.3.
BOP control panels on the rig floor and bridge.



BP

The blind shear ram can be activated from the BOP's control panels on the rig floor and bridge.

In addition to activating the annular preventers or pipe rams, the crew could have activated the blind shear ram to cut the drill pipe and shut in the well.[54] The blind shear ram can be activated directly by the rig crew from the control panels, seen in Figures 4.8.2 and 4.8.3.[55] There is no evidence the rig crew attempted to activate the blind shear ram prior to the explosion.[56]

The rig crew's response generally followed the procedures that Transocean's Well Control Handbook specified "upon taking a kick."[57] The "shut-in" procedure in the handbook that applied to the April 20 situation specifies that the rig crew should first close the "annular" and then close "pre-determined rams" later if necessary.[58] The handbook's shut-in procedures do not offer any specific guidance on the use of the blind shear ram. (The handbook elsewhere advises that the blind shear rams may be used "only in exceptional circumstances."[59]) By closing the annular preventer and then a variable bore ram, the rig crew thus appears to have followed Transocean procedures.

Gas Ignites Minutes After Mud Reaches the Rig Floor

The first explosion occurred at about 9:49 p.m.[60] Ezell was on his way to the rig floor when the explosion "threw [him] against the wall in the toolpusher's office."[61] "Debris" covered him.[62] Transocean performance division manager Daun Winslow was smoking in the coffee room when he felt the walls suck in and the roof panels collapse on top of him.[63] The explosion injured several of the rig crew[64] and likely killed the men on the rig floor instantly.

The precise source of ignition may never be known. Most of the equipment on a drilling rig is not classified to protect against ignition.[65] One of the engines likely exploded first—or at least shortly after an initial explosion. Transocean motor operator William Stoner testified that he heard gas hissing and Engine 3 starting to overspeed before the first explosion.[66] The engine revved higher than Mike Williams, Transocean's electronics technician, had ever heard before.[67] Engine 6 was also on and began to rev.[68] Transocean chief mechanic Douglas Brown testified that the first explosion came from the direction of Engine 3.[69] After the explosion, the exhaust stacks, wall, handrail, and walkways around Engine 3 were all missing.[70] Seconds after the first explosion, another explosion occurred.[71] Parts of the rig were in flames.[72] Fewer than 10 minutes, and perhaps as few as six minutes, had elapsed since mud first hit the rig floor.

The Rig Crew Attempts to Activate the Emergency Disconnect System

After the explosions, crew members elsewhere on the rig attempted to activate the emergency disconnect system. Transocean subsea supervisor Chris Pleasant rushed to the bridge and informed Transocean Captain Curt Kuchta that he was activating the emergency disconnect.

Captain Kuchta replied, "[c]alm down, we're not EDSing."[73] Nevertheless, with the backing of Vidrine and Transocean offshore installation manager (OIM) Jimmy Harrell, Pleasant initiated the emergency disconnect at approximately 9:56 p.m.[74] It appears that the panel's electronic signals responded, but there was no indication of hydraulic flow closing the blind shear ram.[75] The low accumulator alarm was sounding, indicating a loss of surface hydraulic power.[76]

The Chief Counsel's team believes that by this time the explosion had already damaged the MUX cables connecting the rig and the blowout preventer, preventing the command from reaching the stack.[77] Pushing the EDS button does not appear to have activated the blind shear ram or the remainder of the emergency disconnect system. This left the rig attached to the riser. Gas continued to flow up the riser, fueling the fires on the rig.[78]

Technical Findings

If the Rig Crew Had Recognized the Kick Earlier, They Could Have Shut in the Well Before Gas Entered the Riser

The crew would have been able to prevent gas from reaching the rig if they had recognized the influx before gas entered the riser and responded by shutting in the well. At that point, closing the annular preventer or the variable bore ram should have controlled the kick and stopped flow. By the time the *Deepwater Horizon* crew actually did recognize the influx and activate the blowout preventer, hydrocarbons had almost certainly entered the riser and begun expanding rapidly upward toward the rig.

The *Deepwater Horizon* crew recognized that there was an anomaly, but they did not identify that anomaly as a kick. If rig personnel suspect a kick, they perform a flow check and shut in the well.[79] The same cannot be said for responses to anomalies. The *Horizon* crew suspected that something was amiss when they shut down the pumps at 9:30 p.m. Over the next 10 minutes or so, they conducted diagnostics and discussed the anomalous pressures they were seeing. Only after hydrocarbons had entered the riser, and about when mud started emerging from the rotary, did the crew act to shut in the well. Apparently, the crew did not suspect a kick until 10 minutes after they detected the anomaly. A more conservative initial approach to the anomaly—of shutting in *first* and investigating *afterward*—would have resulted in rig personnel shutting in the well while hydrocarbons were still confined to the wellbore and thereby preventing the blowout.

By the time the crew activated the annular preventer, mud and hydrocarbons may have been flowing through the BOP at a high enough rate to prevent it from sealing.[80] Data on drill pipe pressure indicate that the annular preventer did not achieve shut-in pressure. Only 1,200 psi registered,[81] well below what would have been required.[82] Later, the drill pipe pressure climbed above 5,500 psi.[83] That appears to have been due either to tightening of the annular or to activation of the variable bore ram.[84] Though the well may have been shut in by 9:49 p.m.,[85] it appears that there was already a substantial volume of gas above the BOP at this time because this is when the first explosion took place.

Previous modifications to the BOP may have compromised the ability of the lower annular preventer to seal the well. (As noted above, Transocean has recently contended the rig crew activated the upper annular and not the lower annular. If true, modifications to the lower annular would not have affected the BOP's performance during the blowout.) As discussed further in Chapter 4.9, BP asked Transocean in 2006 to modify the lower annular to a "stripping" annular.

This change reduced the rated working pressure from 10,000 to 5,000 psi,[86] and allowed the rig crew to raise or lower pipe through the BOP while the annular was closed. The 10,000-psi-rated annular body was not replaced.[87] While the stripping annular would still be able to close in pressures above 5,000 psi, it is not clear whether it would completely seal at these higher pressures.[88]

Diverting Overboard Might Have Delayed the Explosion

The rig crew should have diverted the flow overboard when mud started spewing from the rig floor.[89] The flow of mud at this point was tremendous—it shot 200 feet up to the crown of the derrick. That should have prompted the crew to take immediate emergency measures.

Transocean's Well Control Handbook advises that "at any time, if there is a rapid expansion of gas in the riser, the diverter must be closed (if not already closed) and the flow diverted overboard."[90] The handbook also provides: "[I]f large volumes of gas have entered the riser, it will flow rapidly on its own and there will be no way to control it by adjusting the circulation rate. Then, the surface gas and liquid rates become very high, especially as the gas bubble reaches surface and *the flow* ***must*** *be diverted overboard.*"[91]

Although mud flow at the rig floor does not always mean that gas is in the riser, the *Deepwater Horizon*'s crew should have assumed that this was the case for two reasons. First, the fact that *mud* was *spewing* from the rig floor after the crew had displaced the well with seawater down to 8,367 feet below sea level should have indicated that hydrocarbon flow had already proceeded a substantial distance up the well. Second, and more significantly, the high mud flow rate and volume should have warned the crew that the kick was severe and prompted them to send the influx overboard.

While the Chief Counsel's team finds that the rig crew should have sent the influx overboard immediately, doing so may not have prevented an explosion. Two factors determine whether diverting flow overboard would have prevented an explosion: (1) the ability of the diverter packer, overboard lines, and other equipment to handle the flow rate and volume, and (2) the way in which gas dispersed away from the rig.[92]

With regard to equipment capabilities, currently available information leads the Chief Counsel's team to conclude that the diverter packer probably would have been able to handle the flow rate and volume during the blowout, though it is not certain. The diverter packer on the *Deepwater Horizon* was rated to withstand 500 psi of pressure. Two post-blowout computer models commissioned by BP for its internal investigation offer perspective on the forces that may have been exerted on the diverter packer during the blowout; the Chief Counsel's team is not aware of any other modeling that has been performed at this time. One model predicts that the maximum pressure exerted on the diverter packer during the blowout was 145 psi,[93] not even close to the packer's limit. Another model indicates that the pressures may have been much higher, peaking at 500 psi.[94] But even under that scenario, the diverter packer probably would not have failed. That model only predicted that the packer would have been subject to 500 psi for an instant,[95] and this type of equipment can generally handle pressures beyond rated capacity for a short period of time. Moreover, if the rig crew had sent the influx overboard, the pressure on the diverter element likely would have been even lower.[96] The Chief Counsel's team therefore believes that the diverter packer probably would not have failed if the rig crew had sent the influx overboard.[97]

Though the diverter packer probably could have withstood the blowout flow rate and pressure, the **slip joint** could have failed. The slip joint sat below the diverter packer, permitting the rig to heave vertically while maintaining the riser connection to the sea floor. It had two modes: a low-pressure mode with a 100 psi working pressure[98] and a high-pressure mode with a 500 psi working pressure.[99] If the slip joint had been in low-pressure mode, it would have been vulnerable to failure.[100] That would have allowed gas to escape into the moon pool area of the rig. Additionally, because the diverter packer does not seal off the riser, there is a possibility that gas could have also traveled up the drill pipe and onto the rig.

With regard to gas dispersion, the calm wind conditions on April 20 would have limited the rate at which gas dispersed away from the rig. The wind speed was low, about 2 to 4 knots.[101] The wind also appears to have been blowing from starboard to port,[102] though the precise direction is difficult to ascertain.[103] Because of this, gas flowing out of the starboard overboard line would have stayed close to the rig and perhaps even blown back onto the rig rather than drifting away.[104] Nevertheless, diverting overboard would have substantially reduced the risk of ignition of the rising gas and given the rig crew more time to respond.[105] An MMS study of offshore blowouts between 1992 and 2006 found that the "success rate for diverter systems was very high…16 of the 20 diverter uses were considered successful because the desired venting of gas was sustained until the well bridged."[106]

The Chief Counsel's team concludes that diverting flow overboard likely would have sent a substantial amount of gas off the rig.[107] This may not ultimately have prevented an explosion but probably would have given the rig crew more time to respond to the blowout. BP has concluded that "diversion of fluids overboard, rather than to the MGS, may have given the rig crew more time to respond and may have reduced the consequences of the accident."[108] Transocean agrees that "diverting overboard might have delayed the explosion…."[109]

Management Findings

Transocean Should Have Trained Its Employees Better on How to Respond to Low-Frequency, High-Risk Events

There are at least three explanations for why the crew did not immediately divert the flow overboard.

- First, the crew may not have recognized the severity of the situation, though that seems unlikely given the amount of mud that spewed from the rig floor.
- Second, they did not have much time to act. At most, the drill crew had six to nine minutes after mud emerged from the rig floor before the first explosion.
- Finally, and perhaps most significantly, the rig crew had not been trained adequately regarding how to respond to such an emergency situation. It appears that the crew followed the procedures for dealing with a kick set forth in Transocean's Well Control Handbook. Those procedures were inadequate given the circumstances.[110]

Transocean has highlighted to the Chief Counsel's team the "extensive curriculum of courses" available to its rig crew, including courses on well control.[111] Transocean contends that the "initial response…was the appropriate first normal response"[112] and that the "crew utilized the proper sequencing."[113] The Chief Counsel's team recognizes that the rig crew may simply have done what it had been trained to do. But that assertion indicates the inadequacy of the crew's training and guidance in the first place.

Though Transocean's protocols provide that a severe influx should be sent overboard, the sequence of "procedures for handling gas in the riser"[114] (Transocean document shown in Figure 4.8.4) specifically recommends the overboard line—instead of the mud gas separator—only in the ninth step after actions such as monitoring for flow and circulating the riser. Here, there was *no time* to get to the ninth step.[115] In the future, well control training should include simulations and drills for low-probability, high-consequence emergency events and well-control protocols should specifically address such emergencies.[116]

Figure 4.8.4. Transocean's "procedures for handling gas in the riser."

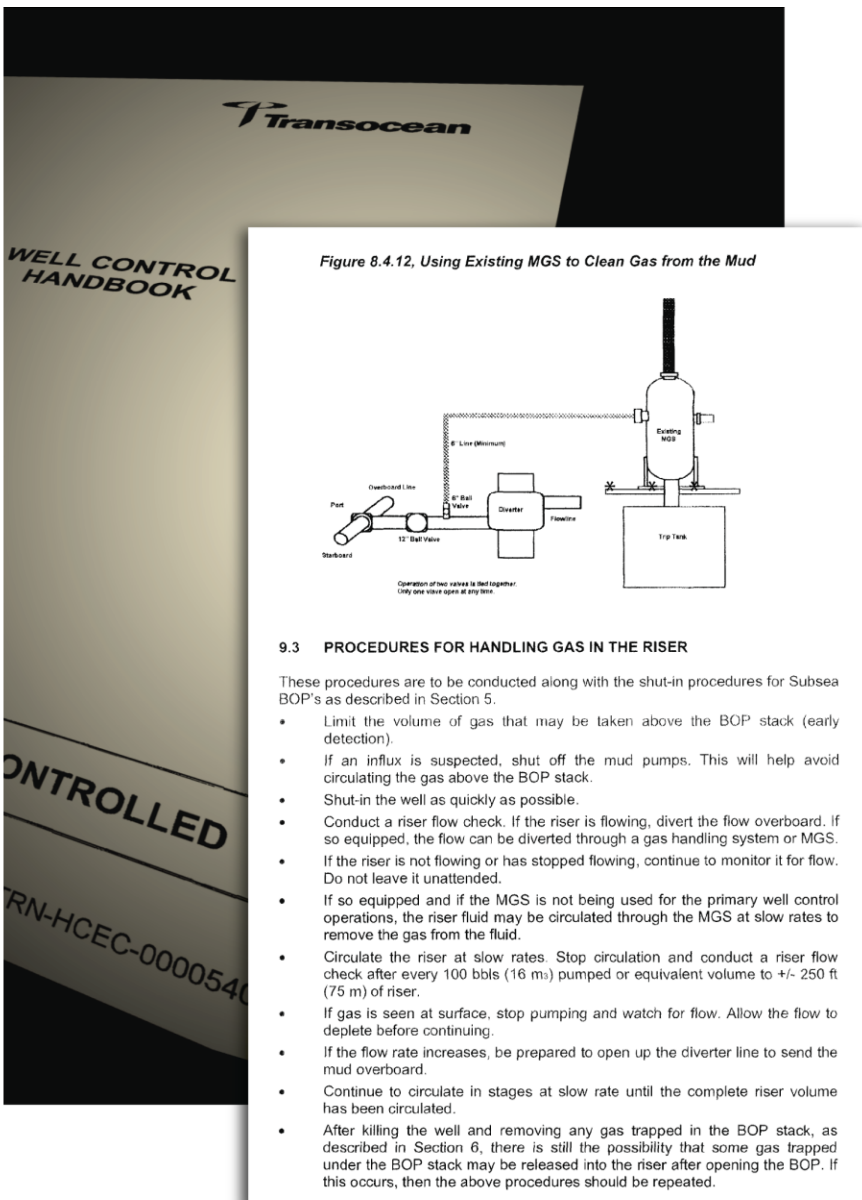


Figure 8.4.12, Using Existing MGS to Clean Gas from the Mud

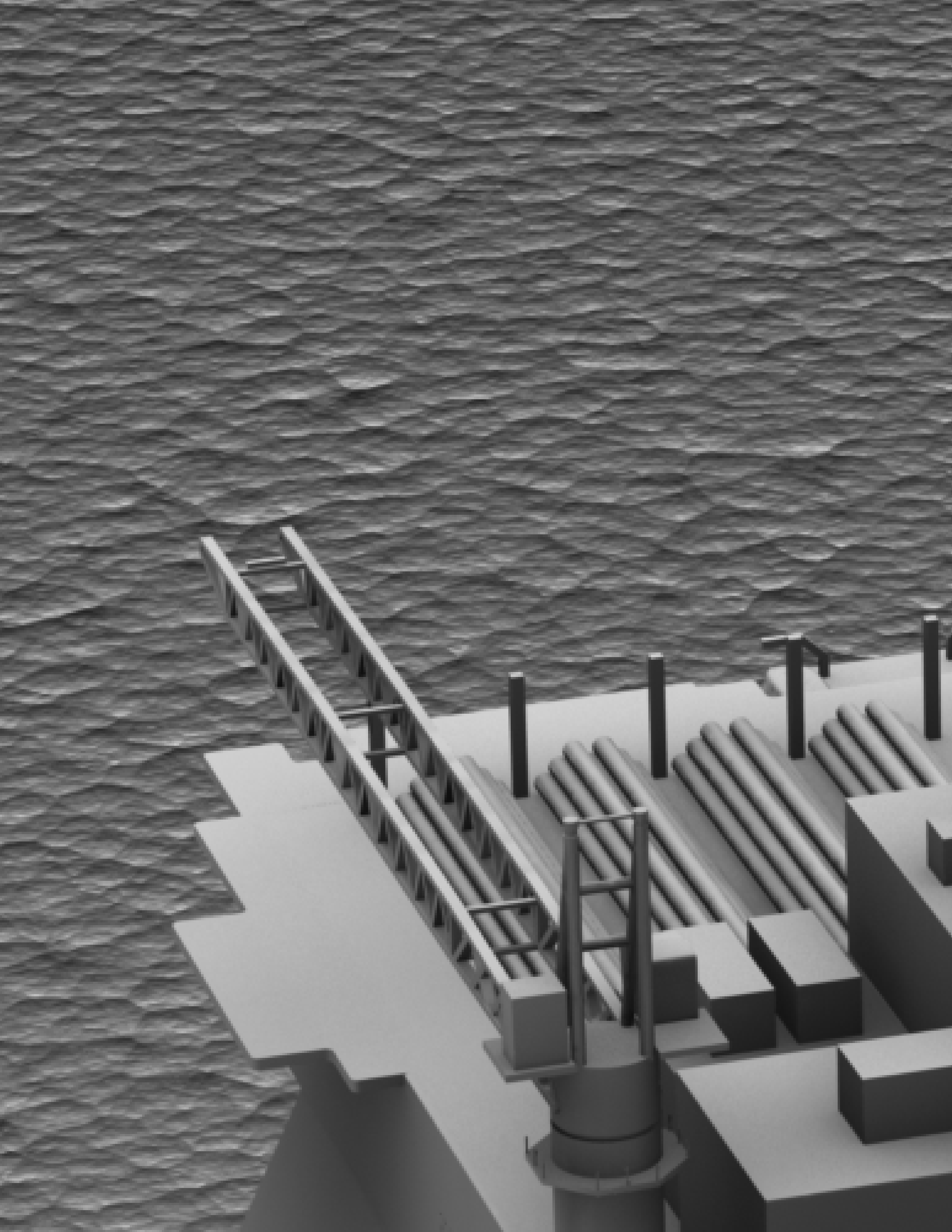
9.3 PROCEDURES FOR HANDLING GAS IN THE RISER

These procedures are to be conducted along with the shut-in procedures for Subsea BOP's as described in Section 5.

- Limit the volume of gas that may be taken above the BOP stack (early detection).
- If an influx is suspected, shut off the mud pumps. This will help avoid circulating the gas above the BOP stack.
- Shut-in the well as quickly as possible.
- Conduct a riser flow check. If the riser is flowing, divert the flow overboard. If so equipped, the flow can be diverted through a gas handling system or MGS.
- If the riser is not flowing or has stopped flowing, continue to monitor it for flow. Do not leave it unattended.
- If so equipped and if the MGS is not being used for the primary well control operations, the riser fluid may be circulated through the MGS at slow rates to remove the gas from the fluid.
- Circulate the riser at slow rates. Stop circulation and conduct a riser flow check after every 100 bbls (16 m^3) pumped or equivalent volume to +/- 250 ft (75 m) of riser.
- If gas is seen at surface, stop pumping and watch for flow. Allow the flow to deplete before continuing.
- If the flow rate increases, be prepared to open up the diverter line to send the mud overboard.
- Continue to circulate in stages at slow rate until the complete riser volume has been circulated.
- After killing the well and removing any gas trapped in the BOP stack, as described in Section 6, there is still the possibility that some gas trapped under the BOP stack may be released into the riser after opening the BOP. If this occurs, then the above procedures should be repeated.

Transocean

Protocol from Transocean's Well Control Handbook.

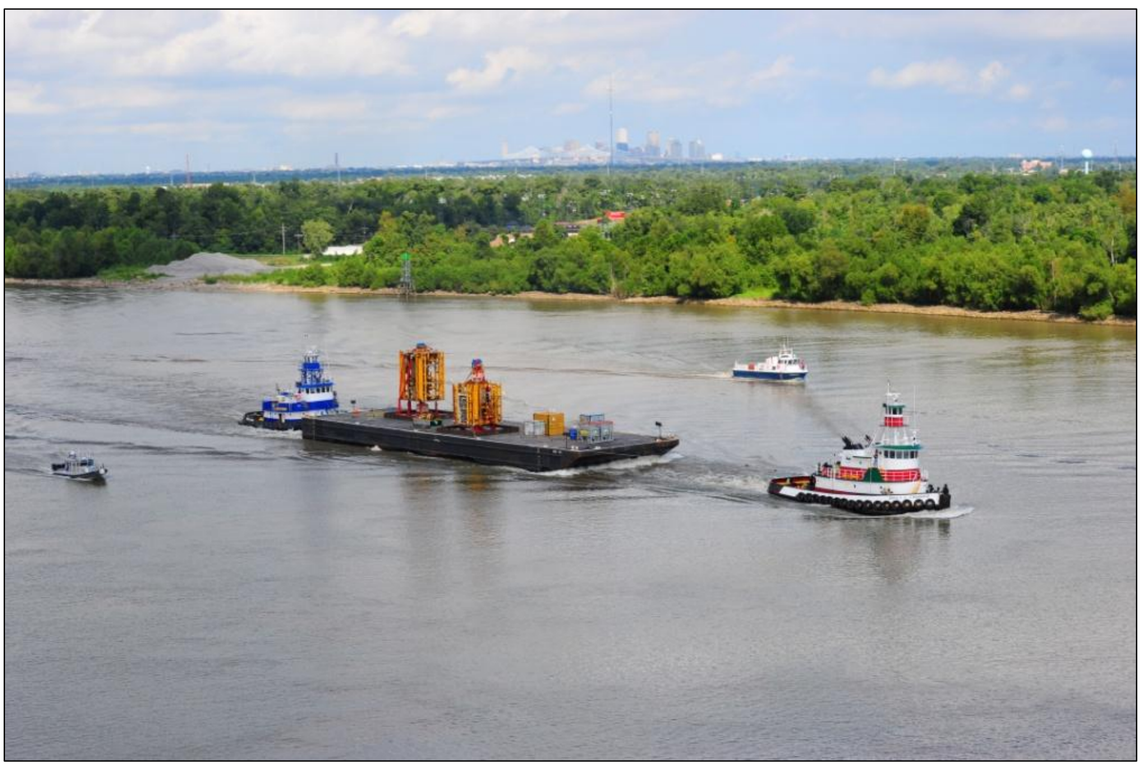


Chapter 4.9 | The Blowout Preventer

The **blowout preventer** (BOP) is a routine drilling tool. It is also designed to shut in a well in case of a kick, thereby "preventing" a blowout. As described in Chapter 4.8, the rig crew attempted to close elements of the BOP and to activate the emergency disconnect system (EDS) in response to the Macondo blowout. Automatic and emergency activation systems should have also closed the BOP's blind shear ram and shut in the well. Though preliminary evidence suggests one of these systems may have activated and closed the blind shear ram, the blind shear ram never sealed the well.

The federal government has recovered the BOP from the blowout site, and forensic testing is ongoing. Until that testing is complete, a full examination of blowout preventer failure is impossible. In the meantime, the Chief Counsel's team has made preliminary findings and identified certain technical faults that may have prevented the BOP system from activating and shutting in the well.

Figure 4.9.1. Transporting the *Deepwater Horizon* BOP.



U.S. Coast Guard photo/Petty Officer 3rd Class Stephen Lehmann

The *Deepwater Horizon*'s blowout preventer on the Mississippi River in transit to Michoud, Louisiana, to undergo forensic testing, September 11, 2010.

Figures 4.9.2 and 4.9.3. The *Deepwater Horizon* blowout preventer stack.

U.S. Coast Guard photo/ Petty Officer 1st Class Thomas M. Blue

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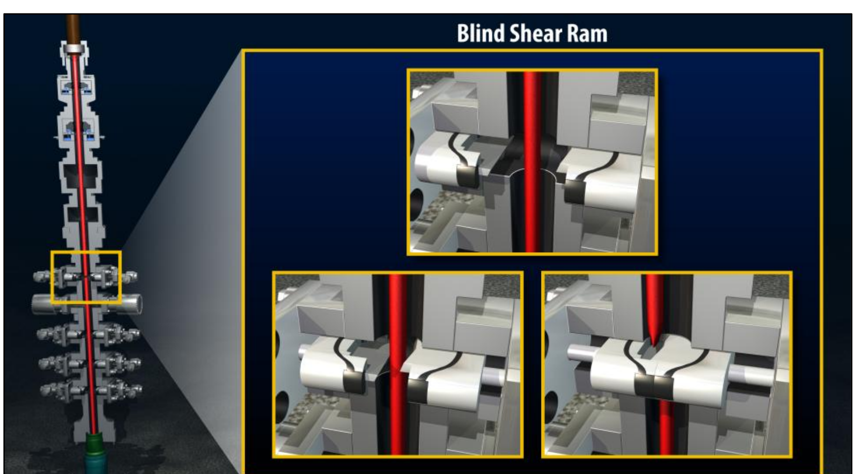
Left: Photo of the recovered *Deepwater Horizon* BOP.
Right: 3-D model of the *Deepwater Horizon* BOP.

Figure 4.9.4. Blind shear ram.



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Blind Shear Rams

Federal regulations required the *Deepwater Horizon* to have a BOP that included a **blind shear ram** (BSR).[1] The blind shear ram is designed to cut drill pipe in the well (as shown in Figure 4.9.4) and shut in the well in an emergency well control situation.[*] But even if properly activated, the blind shear ram may fail to seal the well because of known mechanical and design limitations. In order for a blind shear ram to shut in a well where drill pipe is across the BOP, it must be capable of shearing the drill pipe.[2] And blind shear rams are not always able to perform this critical function, even in controlled situations.

Blind Shear Rams Cannot Cut Tool Joints or Multiple Pieces of Drill Pipe

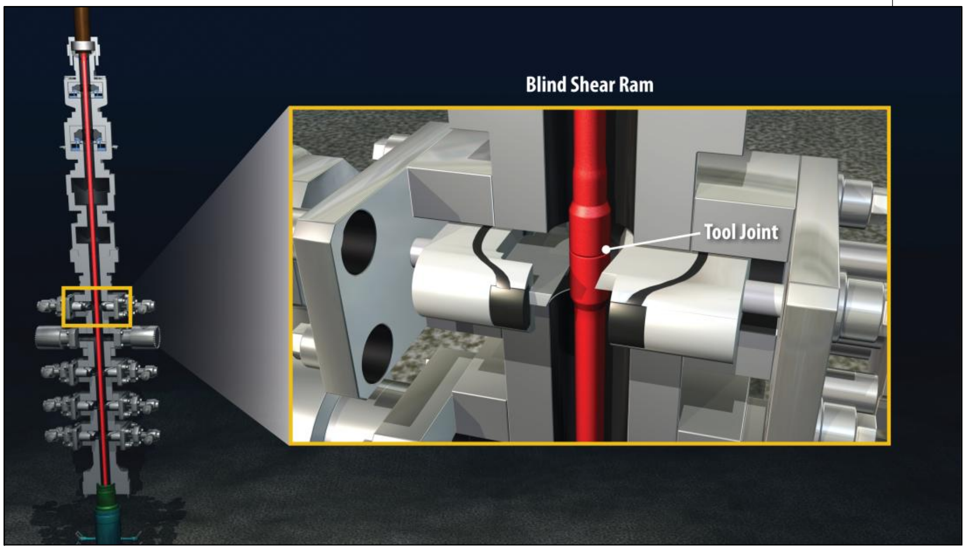
Blind shear rams are not designed to cut through multiple pieces of drill pipe or **tool joints** connecting two sections of drill pipe.[3] It is thus critically important to ensure that there is a piece of pipe, and not a joint, across the blind shear ram before it is activated.[4] This fact prompted a 2001 MMS study to recommend every BOP to have two sets of blind shear rams such that if a tool joint prevented one ram from closing, another adjacent ram would close on drill pipe and would be able to shear the pipe and shut in the well.[5] MMS never adopted the recommendation.

The *Horizon*'s blowout preventer had only one blind shear ram. Sections of drill pipe are joined by a tool joint at each interval and are often about 30 feet in length, though some of the drill pipe used on the *Horizon* varied in length.[6] If one of those joints was in the path of the blind shear ram at the time of attempted activation, as portrayed in Figure 4.9.5, the ram would have been unable to shear the pipe and shut in the well.

[*] Although not separately depicted in Figures 4.9.3 and 4.9.4, there are hydraulic, power, and communications lines (cables), as well as the choke, kill, and boost lines (pipes) running from the rig to the blowout preventer.

Even if a tool joint did not prevent the blind shear rams from shutting in the Macondo well, the inability to shear tool joints is a recognized and significant limitation. The Chief Counsel's team agrees with the MMS study that installing a second blind shear ram would mitigate this risk and increase the probability of success in shutting in a well.[7]

Figure 4.9.5. Tool joint in the blind shear ram.



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Blind shear rams cannot cut tool joints.

Study Finds Deepwater Exacerbates Limitations

A 2002 MMS study conducted by West Engineering Services, a drilling consulting firm, presented "a grim picture of the probability of success when utilizing [shear rams] in securing a well after a well control event."[8] The study found that only three of six tested rams successfully sheared drill pipe under operational conditions.[9] It also found that "operators often do not know how their shear rams would perform in a high pressure environment."[10] These problems worsen in deepwater because, among other things, deepwater operators often use stronger drill pipes that are more difficult to cut.[11] Increased hydrostatic and dynamic pressures in deepwater wells also increase the difficulty of shearing.[12]

Although the study found that these factors were "generally ignored,"[13] it is not certain whether these factors affected the blind shear ram at Macondo.

Deepwater Horizon Blind Shear Ram Testing

Earlier Tests Establish Shearing Ability

The shearing ability of the *Deepwater Horizon*'s blind shear ram was demonstrated on at least two occasions. During the rig's commissioning, the rams sheared a 5.5-inch, 21.9-pound pipe at a shear pressure of 2,900 pounds per square inch (psi).[14] According to pipe inventory records, this was the same thickness and weight of the drill pipe retrieved from the Macondo well.[15] The ram also successfully sheared drill pipe during a 2003 EDS function.[16]

The Rig Crew Regularly Tested the *Deepwater Horizon*'s Blind Shear Ram, but Often at Reduced Pressures

Regulations require frequent monitoring and testing of the BOP blind shear ram both on surface and subsea. This includes testing the blind shear ram on the surface prior to installation[17] and subsea pressure testing after installation.[18] The BOP stack was inspected almost daily by remotely operated vehicle (ROV).[19] Like the positive pressure test, other **pressure tests** of the blind shear ram established that the ram was able to close and seal in pressure.[20] The rig crew also regularly **function tested** the blind shear ram, which tested the ability of the ram to close but did not test its ability to withhold pressure.[21] Subsea pressure and function tests do not demonstrate the ability of the blind shear ram to shear pipe.[22]

MMS regulations include, among other things, requirements regarding the amount of pressure a BOP must be able to contain during testing. MMS regulations normally require rams to be tested to their rated working pressure or maximum anticipated surface pressure, plus 500 psi.[23] However, BP applied and received MMS approval to downgrade test pressures for several of the *Deepwater Horizon*'s BOP elements. The departure that MMS granted allowed BP to test the *Deepwater Horizon*'s blind shear ram at the same pressures at which it tested casing.[24] Though the rig crew tested the blind shear ram to 15,000 psi prior to launch (showing that it would contain 15,000 psi of pressure), subsequent tests were at pressures as low as 914 psi.[25] The rig crew also tested the annular preventers at reduced pressures. MMS regulations require that high-pressure tests for annular preventers equal 70% of the rated working pressure of the equipment or a pressure approved by MMS.[26] BP's internal guidelines similarly call for annular preventers to be tested to a maximum of 70% of rated working pressure "if not otherwise specified."[27] In May 2009, BP filed an application to reduce annular tests to 5,000 psi.[28] In January 2010, BP filed another application to further reduce testing pressures for both annular preventers to 3,500 psi.[29] It is likely BP sought to test equipment at lower pressures in order to reduce equipment wear.[30]

BP's lowered pressure testing regime was both approved by MMS and consistent with industry practice. BOP elements are designed to withstand and should be able to withstand higher pressures even if tested to lower pressures.[31] Nonetheless, low-pressure testing only demonstrates that equipment will contain low pressures. At Macondo, many tests did not prove the blowout preventer's ability to contain pressures in a worst-case blowout scenario.[32]

Blind Shear Ram Activated and Sealed During April 20 Positive Pressure Test

On the day of the blowout, the rig crew used the blind shear ram to conduct a positive pressure test.[33] As discussed in Chapter 4.6, the blind shear rams closed and sealed as expected during the test. This fact suggests that the rams were capable of sealing the well when the blowout occurred. But the evidence on its own is inconclusive that the rams could have functioned in an emergency; during the positive pressure test the crew closed the blind shear rams using a low-pressure hydraulic system, rather than the high-pressure hydraulic system that would have activated the rams in the event of a blowout.

Blind Shear Ram Activation at Macondo

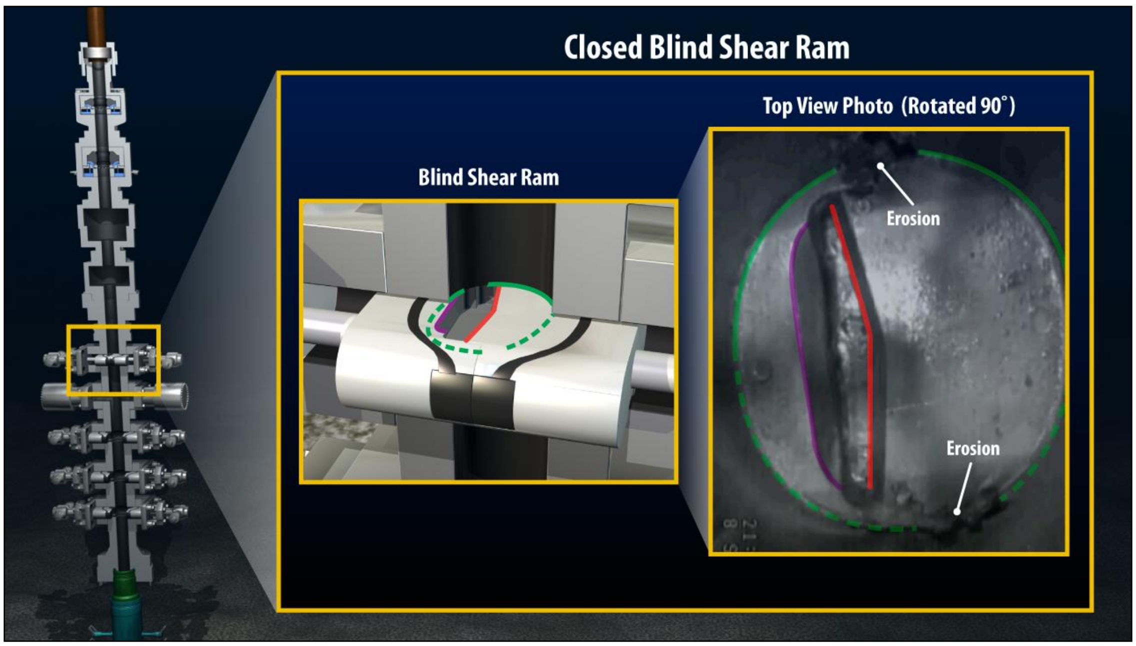
There are five ways the blind shear ram on the *Deepwater Horizon* blowout preventer could have been activated:

- direct activation of the ram by pressing a button on a control panel on the rig;
- activation of the EDS by rig personnel;
- direct subsea activation of the ram by an ROV "hot stab" intervention;[34]

- activation by the automatic mode function (AMF) or "deadman" system due to emergency conditions or initiation by ROV; and
- activation by the "autoshear function" if the rig moves off location without initiating the proper disconnect sequence or if initiated by ROV.

Preliminary information from the recovered blowout preventer suggests the blind shear ram may have been closed and indicates erosion in the BOP on either side of the ram as pictured in Figure 4.9.6.[35] This suggests one of these mechanisms may have successfully activated the blind shear ram but failed to seal the flowing well because high-pressure hydrocarbons may have simply flowed around the closed ram.

Figure 4.9.6. *Deepwater Horizon* blowout preventer's closed blind shear ram (top view).



TrialGraphix, BP photo

As discussed in Chapter 4.8, there is no evidence that rig personnel attempted to directly activate the blind shear ram from the rig's control panels. Rig personnel did attempt to activate the EDS system after the explosions, but those attempts did not activate the blind shear ram. Emergency personnel in the days following the blowout were unable to shut in the well by directly activating the blind shear ram using an ROV. At various points in time, the deadman function should have closed the ram. Though Transocean has suggested that this system activated the blind shear ram, faults discovered post-explosion may have prevented the deadman from functioning. BP has suggested that post-explosion ROV initiation of the autoshear system activated the blind shear ram.

It is clear that some of these mechanisms failed to activate; forensic testing will likely confirm which, if any, of these triggering mechanisms successfully activated. Even if activated, none of these mechanisms shut in the flowing well.

ROV Hot Stab Activation at Macondo

Rig personnel can also close the blind shear ram by using an ROV to pump hydraulic fluid into a **hot stab** port on the exterior of the BOP. The hot stab port is connected to the blind shear ram hydraulic system; fluid flowing into the port actuates the ram directly, bypassing the BOP's control systems.

In theory, this function should close the blind shear ram when other methods fail. But an MMS study by West Engineering found ROVs may be unable to close rams during a well control event due to lack of hydraulic power.[36] The study also found that a flowing well may cause rams to erode or become unstable in the time it takes for an ROV to travel from the surface to the BOP on the seafloor.[37]

ROVs deployed at Macondo at about 6 p.m. on April 21.[38] ROV hot stab attempts to shut in the well on April 21 and 22 with the pipe rams and the blind shear ram failed.[39] As discussed below, on April 22 ROVs may have successfully activated the blind shear ram through the AMF/deadman system or autoshear system.[40] But despite these efforts, the blind shear ram did not shut in the well.[41] Efforts to shut in the BOP through an ROV hot stab continued without success until May 5.[42] By May 7, BP had concluded that "[t]he possibility of closing the BOP has now been essentially exhausted."[43]

Efforts to close the BOP stack were frustrated by organizational and engineering problems. In December 2004, Transocean had converted the lower variable bore ram on the BOP into a test ram[44] at BP's request.[45] Because of an oversight that likely occurred during the modification, a hot stab port on the BOP exterior that should have been connected to a pipe ram was actually connected to the test ram, which could not shut in the well.[46] Unaware of this fact, response teams tried to use that hot stab port to shut in the well.[47] For two days, they tried to close a pipe ram but were actually activating the test ram instead.[48] This error frustrated response efforts[49] until crews discovered the mistake on May 3.[50] After discovering the mistake, response crews attempted on May 5 to activate the BOP's pipe rams again, with no success.[51]

None of the attempted hot stab activations prevented the flow of hydrocarbons from the well. The rig crew had tested the hot stab function before installing the *Deepwater Horizon* BOP, in accord with Transocean's Well Control Handbook.[52]

There are a number of possible reasons why ROVs were unable to activate the rams using hot stabs. First, the ram may have activated, but the presence of a tool joint or more than one piece of pipe prevented the ram from shearing the pipe and sealing the well. Second, ROV pumps failed during early intervention efforts.[53] Third, ROVs were incapable of pumping fast enough and as a result were not able to build pressure against a leak in the BOP hydraulic system.[54]

Automatic Blind Shear Ram Activation at Macondo

Transocean and BP both claim an automated backup system activated the blind shear ram. According to Transocean, the automatic mode function activated.[55] According to BP, the autoshear system activated.[56] If activated, neither system sealed the well.

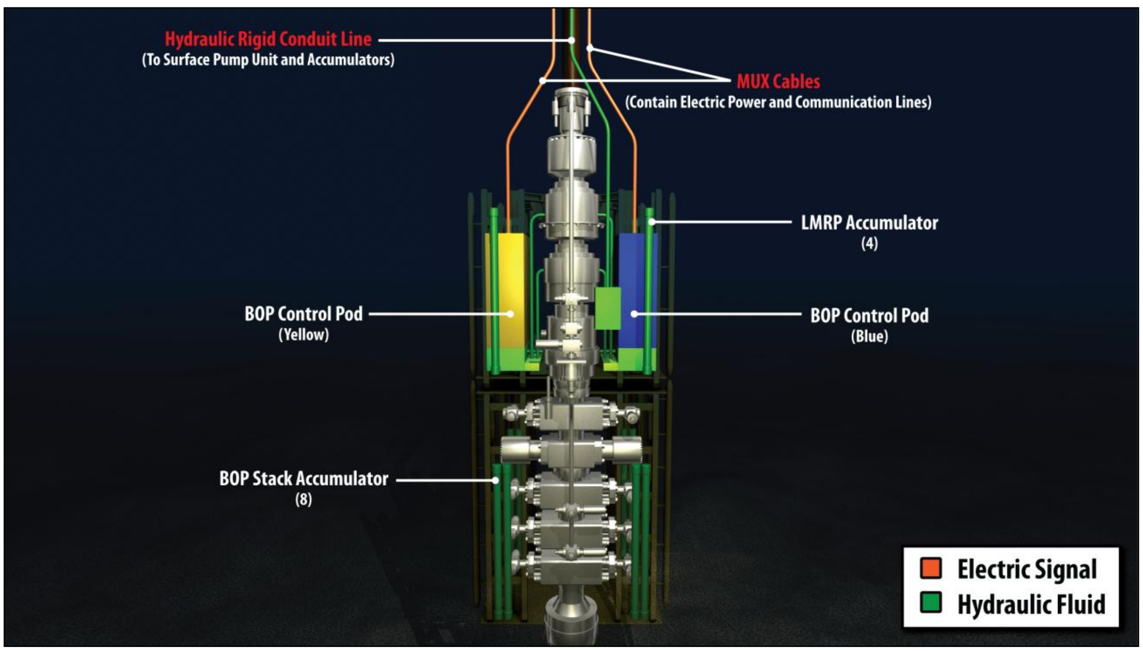
Automatic Mode Function (AMF)/Deadman

The **AMF** or **deadman** system is designed to close the blind shear ram under certain emergency conditions. The system should activate when all three of the following conditions are met:

- loss of electrical power between the rig and BOP;[57]
- loss of communication between the rig and the BOP;[58] and
- loss of hydraulic pressure from the rig to the BOP.[59]

Catastrophic events on a rig can create these conditions, or emergency workers can trigger them by using an ROV to cut power, communication, and hydraulic lines to the BOP (these components are labeled in Figure 4.9.7.).[60] The AMF will not operate unless rig personnel "arm" it at a surface control panel.[61] Notes from response crews and post-explosion analysis of the BOP **control pods** indicate the AMF system on the *Deepwater Horizon* BOP was likely armed.[62]

Figure 4.9.7. AMF system.



TrialGraphix

The AMF, or deadman, system is activated in emergency conditions.

Based on available information, it appears likely that the explosion on April 20 created the conditions necessary to activate the deadman system. The multiplex (MUX) cables, which carried the power and communication lines, were located near a primary explosion site in the rig's moon pool and would probably have been severed by the explosion.[63] The hydraulic conduit line was made of steel[64] and less vulnerable to explosion damage.[65] However, the BOP would have likely lost hydraulic power at least by April 22 when the rig sank, and the deadman should thus have activated by that date.[66] Response crew personnel also tried to activate the deadman on April 22 by cutting electrical wires using an ROV.[67] According to Transocean, the AMF activated the blind shear ram.[68]

Unclear Whether AMF Activated

It is currently not clear whether the AMF activated the blind shear ram. However, the Chief Counsel's team has identified issues that may have affected the AMF.

First, the universe of available test records may be limited because Transocean destroyed test records at the end of each well.[69] Second, the deadman system was not regularly tested.[70] Although Transocean's Well Control Handbook calls for surface testing the deadman system,[71] based on available evidence the AMF was not tested prior to deployment.[72]

Third, the deadman system relied upon at least one of the BOP's two redundant control pods (yellow or blue) to function. If both pods were inoperable, the system would not have functioned. The rig crew function tested and powered both pods at the surface in February 2010 prior to splashing the BOP.[73] But post-explosion examination revealed low battery charges in one BOP control pod and a faulty solenoid valve in another. If these faults were present at the time of the incident, they would have prevented the deadman and autoshear functions from closing the blind shear ram.

Low Battery Charge in the Blue Pod

In the event that electric power from the rig to the BOP is cut off, the BOP's control systems are powered by a 27-volt and two 9-volt battery packs contained in each pod.[74] These batteries power a series of relays that cause the pod to close the blind shear ram if there is a loss of power, communication, and hydraulic pressure from the rig.[75] BP tests suggest that it takes at least 14 volts of electricity to power the relays,[76] and a Transocean subsea superintendent has stated that the activation sequence may require as many as 20 volts.[77]

Tests on the blue pod conducted by Cameron after the blowout on July 3 to 5, revealed that battery charge levels may have been too low to power the sequence to shut the blind shear ram. The 27-volt battery was found to have only a 7.61-volt charge.[78] One of the 9-volt batteries was found to have 0.142 volts, and the other 9-volt battery had 8.78 volts.[79] If these battery levels existed at the time the deadman signaled the pods to close the blind shear ram, the low battery levels very likely would have prevented the blue pod from responding properly.[80] Transocean disputes whether the batteries were depleted at the time of the explosion. Transocean has suggested battery levels were adequate to power the AMF but, due to a software error, may have been left activated and discharged after the explosion.[81] The Chief Counsel's team has not received evidence in support of this assertion but anticipates ongoing forensic testing of the pods will evaluate expected battery levels at the time of the incident.

Available records suggest that Transocean did not adequately maintain and replace its BOP pod batteries.[82] Cameron recommends replacing pod batteries at least annually, and recommends yearly battery inspection.[83] Transocean itself recommends yearly inspection of batteries.[84]

An April 2010 Transocean ModuSpec rig condition assessment stated that all three pods had new batteries installed.[85] But internal Transocean records suggest that the crew had not replaced the batteries on one pod for two-and-a-half years prior to the Macondo blowout and had not replaced the batteries in another pod for a year.[86] This appears to have been a pattern: Company records show that rig personnel found all of the batteries in one *Deepwater Horizon* BOP pod dead in November 2007.[87]

Table 4.9.1. Control pod battery replacements (based on available records).[88]

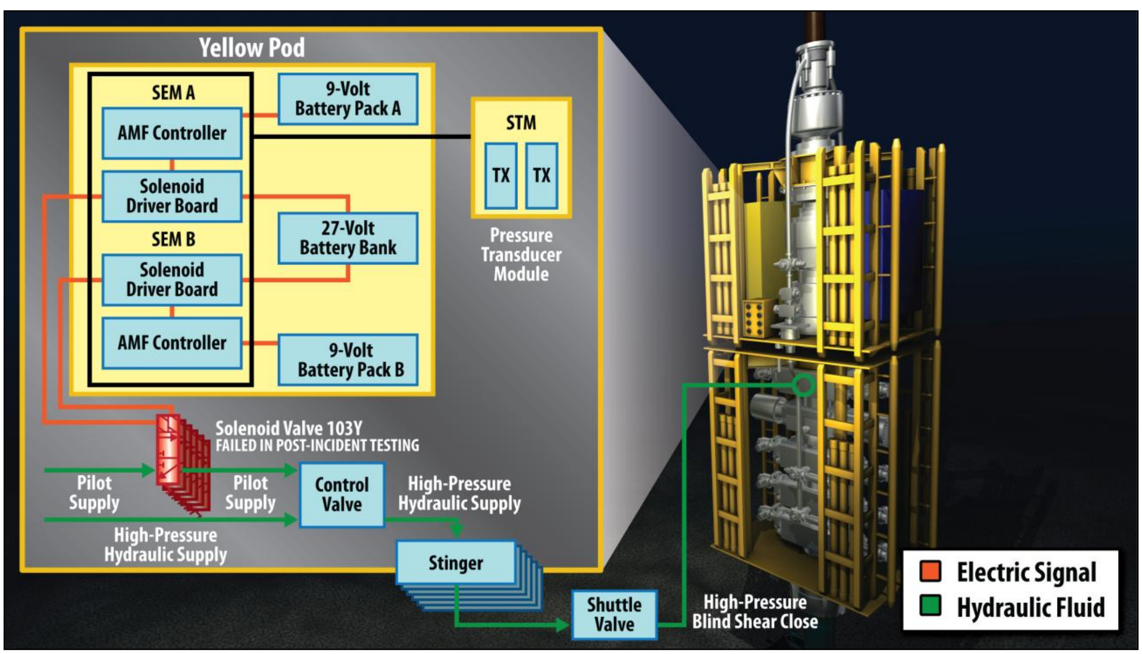
Pod	Battery Replacement Dates	Time Between Battery Replacements	Time Between Replacement and Blowout
Pod 1*	January 26, 2006; April 25, 2009	3 years	1 year
Pod 2	May 28, 2004; December 29, 2005; October 13, 2009	1-3 years	6 months
Pod 3	March 26, 2004; November 4, 2007	3 years	2.5 years

*The *Deepwater Horizon* had three pods for its BOP; at any given time, one was the "blue" pod, one was the "yellow" pod, and one remained on the surface.

Solenoid Valve Problems in the Yellow Pod

Control pods also rely on functioning solenoid valves (diagrammed in Figure 4.9.8). The solenoid valves open and close in response to electrical signals and thereby send hydraulic pilot signals from the pods to the BOP elements.[89] The pilot signals in turn open hydraulic valves, which then deliver pressurized hydraulic fluid into BOP rams to close them.[90] Each solenoid activates when electric signals energize one of two redundant coils in the solenoid.[91]

Figure 4.9.8. BOP's electrical schematic.



TrialGraphix

Tests on the *Deepwater Horizon*'s yellow pod revealed that the solenoid valve used to close the blind shear ram was inoperable.

According to maintenance records, the yellow pod's solenoids were changed on January 31, 2010.[92] However, tests on the yellow pod conducted by Cameron after the blowout on May 5 to 7[93] revealed that a key solenoid valve used to close the blind shear ram was inoperable.[94]

If this fault existed prior to the blowout, an alarm on the rig's control system should have notified the rig crew and triggered a record entry by the rig's event logger.[95] According to witness testimony, the rig crew believed the solenoid valve in the yellow pod was functioning as of April 20.[96]

Autoshear System May Have Activated but Failed to Shut in Flowing Well

Like the emergency disconnect system (EDS), the **autoshear** function is designed to close the blind shear ram in the event that the rig moves off position. The autoshear is activated when a rod linking the lower marine riser package (LMRP) and BOP stack is severed. The rod can be severed by rig movements; if the rig moves off position, it will pull the LMRP out of place and sever the rod. Rig personnel can also sever the rod directly by cutting it with an ROV.[97] Like the deadman, the rig crew must arm the autoshear system at the driller's or toolpusher's control panel.[98] According to BP's internal investigation, the autoshear function was armed at the time of the incident.[99] Transocean policy required its personnel to surface test the autoshear system before deploying the BOP, and the *Deepwater Horizon* rig crew conducted a test on January 31, 2010.[100]

Response crews used an ROV to activate the autoshear function directly by cutting the rod on April 22 at approximately 7:30 a.m.[101] According to BP, response crews reported movement on the stack, which may have been the accumulators discharging pressure and activating the blind shear ram.[102] Even if the autoshear did activate and close the blind shear ram, the blind shear ram did not stop the flow of oil and gas from the well.

Potential Reasons the Blind Shear Ram Failed to Seal

Figure 4.9.9. Erosion in the BOP.

BP

Erosion above the blind shear ram on the BOP's kill side.

Flow Conditions Inside the Blowout Preventer

Even if the blind shear ram activated, it failed to seal the well. One possible explanation is that the high flow rate of hydrocarbons may have prevented the ram from sealing. Initial photos from the recovered BOP show erosion in the side of the blowout preventer *around* the ram, which was a possible flow path for hydrocarbons, as seen in Figure 4.9.9.[103] Therefore even if the ram closed, the hydrocarbons may have simply flowed around the closed ram.

Presence of Nonshearable Tool Joint or Multiple Pieces of Drill Pipe

As discussed above, the ram may not have closed because of the presence of a tool joint across the blind shear ram. If a tool joint or more than one piece of drill pipe was across the blind shear ram when it was activated, the ram would not have been able to shear and seal the well. Though preliminary evidence suggests these factors may not have impacted the blind shear ram's ability to close, the Chief Counsel's team cannot rule out the possibility of such interference.[104]

Accumulators Must Have Sufficient Hydraulic Power

The *Deepwater Horizon* blowout preventer had subsea **accumulator bottles** that provided pressurized hydraulic fluid used to operate different BOP elements. If the hydraulic line between the rig and BOP is severed, these accumulators must have a sufficient charge to power the blind shear ram.

The lower marine riser package had four 60-gallon accumulator bottles were on.[105] On the BOP stack, eight 80-gallon accumulator bottles capable of delivering 4,000 psi of pressure provided hydraulic fluid for the deadman, autoshear, and EDS systems.[106] These tanks were continuously charged through a hydraulic rigid conduit line running from the rig to the blowout preventer.[107] Should the hydraulic line disconnect, the tanks contained compressed gas that could energize hydraulic fluid to activate the blind shear ram. The rig crew checked the amount of pre-charge pressure in the accumulators prior to deploying the BOP in February.[108] However, the available amount of usable hydraulic fluid in the accumulators at the time of autoshear and AMF activation is unknown. If the charge levels were too low, the accumulators would not have been able to successfully power the blind shear ram.[109]

BP's internal investigation suggests accumulator pressure levels may have been low based on fluid levels discovered post-explosion.[110] Responders discovered 54 gallons of hydraulic fluid were needed to recharge accumulators to 5,000 psi.[111] BP's investigation suggests a leak in the accumulator hydraulic system may have depleted available pressure levels but not to levels that would have prevented activation of the blind shear ram.[112] Response crews observed additional leaks from accumulators during post-explosion ROV intervention.[113]

Leaks

It is relatively common for BOP control systems to develop hydraulic fluid leaks on the many hoses, valves, and other hydraulic conduits in the control system. Not all control system leaks affect the ability of the BOP to function: Because BOP elements are designed to close quickly, a minor leak may slow, but not likely prevent, the closing of the BOP.[114]

Even if a leak is minor, rig personnel must first identify the cause of a leak to ensure that more severe system failures do not occur.[115] Constant maintenance, inspections, and testing are required to prevent and detect such leaks.[116] Leaks discovered during surface testing should be repaired before deployment.[117] If rig personnel discover a leak after deployment, they must decide whether the leak merits immediate repair. Raising and lowering a BOP stack is a complicated operation with risks of its own; taking this action to repair a minor control system leak may actually increase rather than reduce overall risk.[118]

Leaks May Have Been Unidentified Prior to Incident

According to Transocean senior subsea supervisor Mark Hay, the *Deepwater Horizon*'s BOP had no leaks at the time it was deployed at Macondo.[119] Even if no leaks existed when the BOP was deployed, rig personnel identified at least three leaks in the months before the blowout after the BOP was in service.[120] And rig personnel identified several more leaks during response efforts that according to independent experts were not likely created during the explosion.[121] It is possible leaks developed during the response effort. But it is also possible leaks already existed and the rig crew had not identified or analyzed the impact of the leak.

A leak on the ST lock close hydraulic circuit (leak 3 in Table 4.9.2) may have prevented ROVs from pumping enough pressure to fully close the blind shear ram.[122] Both BP and Transocean have suggested that a leak on the ram lock circuit (leak 4 in the table) may be proof that the blind shear ram in fact closed.[123] Ongoing forensic testing will likely determine if leaks on the BOP control system otherwise affected the BOP's functionality, though it is unlikely these leaks prevented the BOP from sealing.

Table 4.9.2. Leaks on the *Deepwater Horizon* blowout preventer (partial list).

	Leak	Time of Identification
1	Test ram, pilot leak on yellow pod open circuit shuttle valve[124]	Pre-explosion (February 23, 2010[125])
2	Upper annular preventer, blue pod leak on the hose fitting connecting the surge bottle to operating piston[126]	Pre-explosion (February 19, 2010[127])
3	ST lock close hydraulic circuit leak (this is in the same hydraulic circuit as the blind shear ram)[128]	Post-explosion (April 25, 2010[129])
4	Blind shear ram ST lock circuit leak[130]	Post-explosion (April 26,2010[131])
5	Lower annular preventer open circuit[132]	Pre-explosion (date not available[133])

Identified Leaks Not Reported to MMS

Even if forensic testing concludes leaks on the BOP control system did not impact functionality, it is not clear BP and Transocean adequately responded to known leaks. According to Transocean senior subsea supervisor Owen McWhorter, "the only thing I'd swear to is the fact that leaks discovered by me, on my hitch, were brought to my supervisor's attention and the Company man's attention."[134]

Under 30 C.F.R. § 350.466(f), drilling records must contain complete information on "any significant malfunction or problem."[135] This provision may require control system leaks or other anomalies to be recorded in daily drilling reports and thus subject to review by MMS inspectors.[136] At least two of the leaks identified pre-explosion were not listed in daily drilling reports. A pilot leak on the test ram open circuit shuttle valve (leak 1 in the table) was not mentioned in the daily drilling report for February 23.[137] However, the leak was reported in BP's internal daily operations report from February 23 until March 13.[138] BP wells team leader John Guide and BP regulatory advisor Scherie Douglas made the decision not to report the leak to MMS, a failure which Guide admits was "a mistake in hindsight."[139] BP well site leader Ronnie Sepulvado also admits this leak should have been noted in the daily drilling report but stated that it was not reported because the leak did not affect the ability to control the well since it was on a test ram and the test ram was still operable.[140]

The rig crew failed to include at least one other known leak in the daily drilling reports. Although the rig crew discovered a leak on an upper annular preventer hose fitting (leak 2 in the table) on February 19,[141] the leak was not listed on the daily drilling report.[142] Although subsea personnel in the past had been required to produce documentation on the leak so that the leak could be explained to MMS, McWhorter was not asked to produce documentation for this leak.[143] A failure to report these leaks potentially violated MMS reporting regulations.[144]

Inconsistent Response to Identified Leaks

There is little industry guidance as to what constitutes an appropriate response to minor leaks.[145] It appears the rig crew was able to identify the cause and impact of some leaks but not others. Evidence indicates both BP and Transocean personnel assessed the leak on the test ram shuttle valve (leak 1 in the table) and determined the ram would still function properly.[146] Records appear to indicate the rig crew planned to further evaluate this leak when the rig moved from Macondo to the next well.[147]

In response to a leak on an upper annular hose fitting (leak 2 in the table), the rig crew appears to have isolated and monitored hydraulic pressure.[148] The crew eventually measured this leak at 0.1 gallons per minute.[149] Sepulvado noted the leak on his office white board.[150] Although the leak was later erased from the board, Transocean crew questioned whether the leak was resolved and a similar leak was still present during post-explosion ROV intervention.[151] According to witness testimony, the rig crew never determined the source of a leak on the lower annular (leak 5 in the table).[152]

BOP Recertification

Recertification of a blowout preventer involves complete disassembly and inspection of the equipment.[153] This process is important because it allows individual components to be examined for wear and corrosion. Any wear or corrosion identified can then be checked against the manufacturer's wear limits.[154] Because this process requires complete disassembly of the BOP at the surface, it can take 90 days or longer[155] and generally requires time in dry dock.[156] Industry papers suggest that "the best time to perform major maintenance on a complicated BOP control system [is] during a shipyard time of a mobile offshore drilling unit (MODU) during its five-year interval inspection period."[157] The *Deepwater Horizon* had not undergone shipyard time since its commission.[158]

MMS regulations require that BOPs be inspected in accordance with American Petroleum Institute (API) Recommended Practice 53 Section 18.10.[159] This practice requires disassembly and inspection of the BOP stack, choke manifold, and diverter components every three to five years.[160] This periodic inspection is in accord with Cameron's manufacturer guidelines, and Cameron would have certified inspections upon completion.[161]

The *Deepwater Horizon* Blowout Preventer Was Not Recertified

It was well known by the rig crew and BP shore-based leadership that the *Deepwater Horizon* blowout preventer was not in compliance with certification requirements.[162] BP's September 2009 audit of the rig found that the test ram, upper pipe ram, and middle pipe ram bonnets were original and had not been recertified within the past five years.[163] According to an April 2010 assessment, BOP bodies and bonnets were last certified December 13, 2000, almost 10 years earlier.[164]

Although the September 2009 audit recommended expediting the overhaul of the bonnets by the end of 2009 and emails between BP leadership discussed the issue,[165] the rams had not been recertified as of April 2010.[166] A Transocean rig condition assessment also found the BOP's diverter assembly had not been certified since July 5, 2000.[167] Failure to recertify the BOP stack and diverter components within three to five years may have violated the MMS inspection requirements.[168] An April 1, 2010 MMS inspection of the rig found no incidents of noncompliance and did not identify any problems justifying stopping work.[169] The inspection did not identify the fact that the *Deepwater Horizon*'s BOP had not been certified in accordance with MMS regulations.[170]

"Condition-Based Maintenance"

Transocean did not recertify the BOP because it instead applied "condition-based maintenance."[171] According to Transocean's Subsea Maintenance Philosophy, "[t]he condition of the equipment shall define the necessary repair work, if any."[172] Condition-based maintenance does not include disassembling and inspecting the BOP on three- to five-year intervals,[173] a process Transocean subsea superintendent William Stringfellow described as unnecessary.[174] According to Stringfellow, the rig crew instead tracks the condition of the BOP in the Rig Management System and "if we *feel* that the equipment is—is beginning to wear, then we make...the changes that are needed."[175] Transocean uses condition-based monitoring to inspect all of its BOP stacks in the Gulf of Mexico.[176] According to Transocean witnesses, its system of condition-based monitoring is superior to the manufacturer's recommended procedures and can result in identifying problems earlier than would occur under time-based intervals.[177]

The Chief Counsel's team disagrees. Condition-based maintenance was misguided insofar as it second-guessed manufacturer recommendations, API recommendations, and MMS regulations.

Moreover, the decision to forego regular disassembly and inspection may have resulted in necessary maintenance not being performed on critically important equipment. As discussed in Chapter 4.10, the Rig Management System used to monitor the BOP was problematic and may have resulted in the rig crew not being fully aware of the equipment's condition. Given the critical importance of the blowout preventer in maintaining well control, the Chief Counsel's team questions any maintenance regime that could undermine the mechanical integrity of the BOP.

Technical Findings

As discussed above, this report does not make any conclusive findings regarding whether and to what extent the *Deepwater Horizon*'s BOP may have failed to operate properly because forensic testing is still ongoing. At this point, the Chief Counsel's team can only identify possible reasons why the BOP's emergency systems failed to activate.

The possibilities include:

- explosions on the rig may have damaged connections to the BOP and thereby prevented the rig crew from using the emergency disconnect system to successfully activate the blind shear ram;
- ROV hot stab activation may have been ineffective because ROVs could not pump at a fast enough rate to generate the pressure needed to activate the relevant rams; and
- BOP control pods may have been unable to activate the blind shear ram after power, communication, and hydraulic lines were severed; low battery levels in the blue control pod and solenoid faults in the yellow control pod may have prevented pod function.

Even if activated, the blind shear ram did not seal in the well on April 20 or in subsequent response efforts. Possible reasons for failing to seal include:

- the high flow rate of hydrocarbons may have eroded the BOP and created a flow path around the ram;
- the BOP's blind shear ram may have been mechanically unable to shear drill pipe and shut in the well because it was not designed to operate under conditions that existed at the time. For instance, the ram may have been blocked by tool joints or other material that it was not designed to cut;
- subsea accumulators may have had insufficient hydraulic power; and
- leaks in BOP control systems may have delayed closing the BOP, though it is unlikely that they prevented the BOP from sealing. Leaks may have existed on the BOP control system but not been identified. Identified leaks were not reported to MMS and may have been inconsistently monitored.

Management Findings

Whether or not BOP failures contributed to or prolonged the blowout, the Chief Counsel's team has identified several major shortcomings in the overall program for managing proper functioning of the BOP stack.

- MMS regulations require only one blind shear ram on a BOP stack. But blind shear rams cannot cut the joints that connect pieces of drill pipe, which comprise a significant amount of pipe in a well. The Chief Counsel's team agrees with a 2001 MMS study that two blind shear rams would mitigate this risk.
- MMS approved the testing of the *Deepwater Horizon* blowout preventer at lower pressures than required by regulation. Though testing at lower pressures is in accord with industry practice, most tests of the blind shear ram did not establish the ability of the equipment to perform during blowout conditions with large volumes of gas moving at high speed through the BOP into the riser.

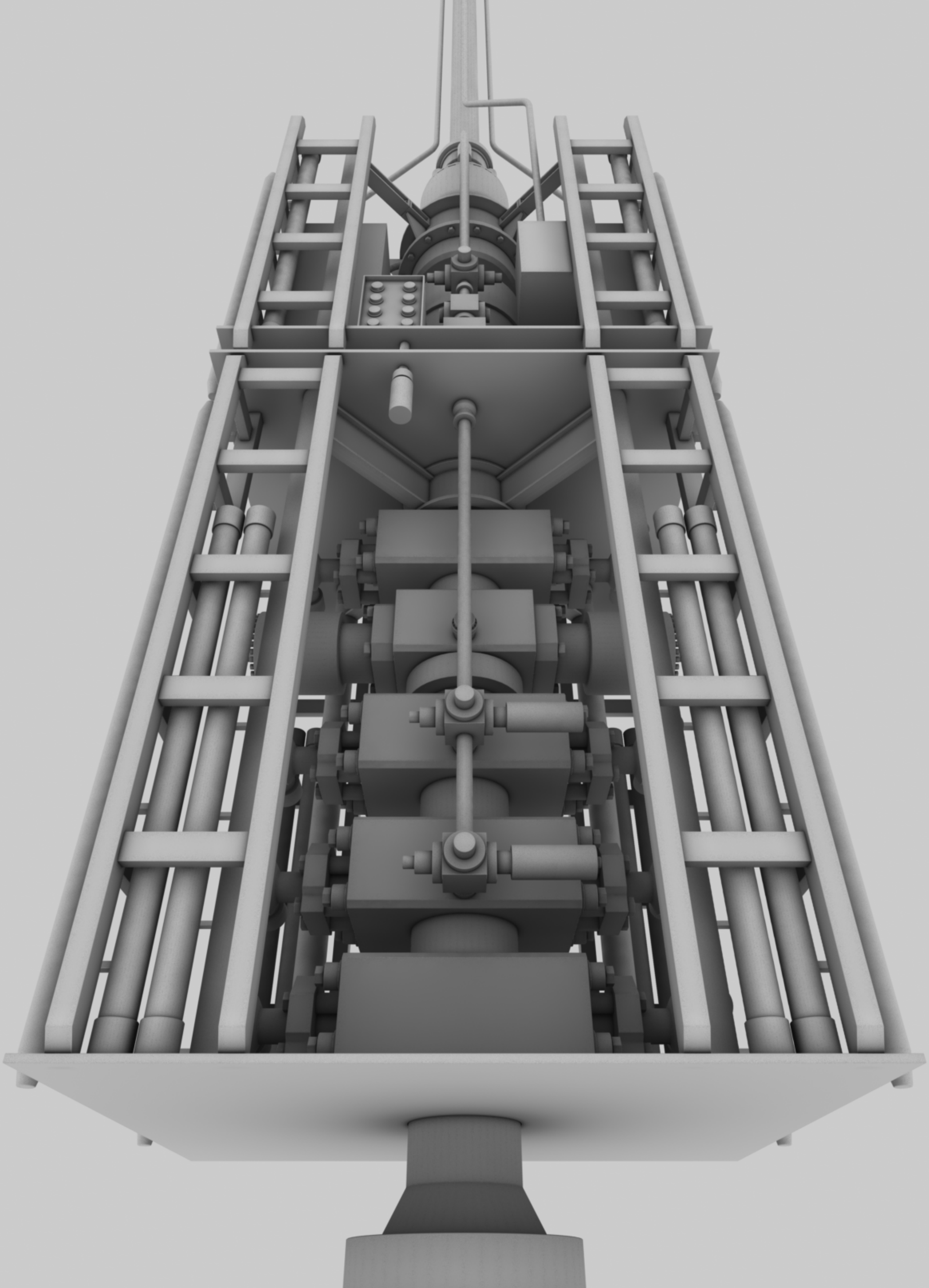
- Transocean's practice of destroying test records at the end of each well creates unnecessary information gaps that may undermine BOP maintenance.
- Critical BOP equipment on the *Deepwater Horizon* may have been improperly maintained. The BOP ram bonnets, bodies, and diverter assembly had not been certified since 2000, despite MMS regulations, API recommendations, and manufacturer recommendations requiring comprehensive inspection every three to five years. Transocean and BP's willingness to disregard regulatory obligations on a vital piece of rig machinery is deeply troubling.

Table 4.9.3. Modifications to the *Deepwater Horizon* blowout preventer.

Date	Modification
November 2001	Control pod subsea plate mounted valves changed from 1-inch to 0.75-inch valves.[178]
October 2002	Increased power supply to control pod subsea electronic modules (SEMs) to higher amp. rating.[179]
December 2002	ST locks modified.[180]
January 2003	Three high-shock flow meters were installed in BOP control pods, replacing ultrasonic flow meters.[181]
January 1, 2003	Changed retrievable control pods to nonretrievable control pods.[182] *This required the LMRP to be retrieved to surface in order to perform maintenance on control pods.*[183]
November 2003	New high-interflow shuttle valve replaced on LMRP and BOP stack.[184]
May 2004	Control pod regulators modified.[185]
June 2004	Control pod subsea electronic modules (SEMs) software upgraded by Cameron.[186]
July/August 2004	New rigid conduit manifold installed and riser-mounted junction boxes removed.[187]
August 2004	Cameron conduit valve package replaced with ATAG conduit valve package.[188] *This isolates LMRP accumulators if pod hydraulic power is lost.*[189]
August 2004	Fail-safe panels on choke and kill valves removed from LMRP and BOP stack.[190] *Valves will close only by spring force.*[191]
November 2004	"Add a second pod select solenoid functioned by an existing pod select switch—to add double redundancy to each control pod."[192]
December 2004	AMF/deadman accumulators: "[T]he pre-charge required on the subsea accumulators is 6800 psi while the maximum working gas pressure for subsea bottles is 6000 psi. This will mean different fluid volumes than are normal on the BOP control system."[193] The deadman accumulators "have now become part of the subsea accumulators since the deadman system has been modified.… There will be little appreciable differences in the system operability but it is important to know how the reduced pre-charge and extra accumulators work on the system."[194]
December 2004	Lower variable bore ram converted to test ram.[195] *A test ram holds pressure from above, instead of below.*[196] *Possibly overlooked relabeling ROV hot stab connections, resulting in ROVs activating test ram during post-explosion efforts to close the BOP.*[197]
February 2005	Control pod modified: "[R]eplace all unused functions on pod with blind flanges. Possible failure points resulting in stack pull."[198]
September 2005	Control system pilot regulator: "[R]eplace pilot regulator with a better designed, more reliable regulator leaks. (Gilmore is a larger unit and will require a bracket to be fabricated for mounting.)"[199]
February 2006	Control panel: "Modification to Cameron control software to sound an alarm should be a button stay pushed for more than 15 [seconds]. If a button is stuck and not detected it will lock up panel."[200]

Table 4.9.3 (continued)

Date	Modification
June 26, 2006	Installed new repair kit in autoshear valve. New repair kit came with new rod and the rod was too long, had to use old rod.[201]
July 2006 (proposal for modification approved)	At BP's request, the lower annular preventer was changed to a stripping annular.[202]
January 2007	AMF/deadman—Cameron will remove the SEM from the MUX section to replace the pipe connectors (customer provided) and to install the AMF/deadman modification kit.[203]
September 2008	Riser flex joint replaced.[204]
June 10, 2009	Software changes made to allow all functions that were previously locked out from any of the BOP's control panels to become unlocked whenever the EDS command was issued from any control panel.[205]
August 3, 2009	Autoshear valve replaced with new Cameron autoshear valve.[206]
2010	Combined the following ROV hot stab functions:[207] blind shear ram close; ST lock close; and choke and kill fail-safe valves.



Chapter 4.10 | Maintenance

A deepwater drilling rig like the *Deepwater Horizon* has literally thousands of pieces of equipment that need routine monitoring and repair.[1] The *Deepwater Horizon*'s crew performed more than 550 preventative maintenance jobs each month on the *Deepwater Horizon* and had spent more than 30,000 work hours on maintenance in the 10 months prior to the explosion.[2]

In some respects the *Horizon* appeared to be operating quite well. The rig received several safety awards[3] and a place inside Transocean's "excellence box," which compares rigs based on safety performance and equipment downtime.[4] BP wells team leader John Guide described the rig as BP's most successful in terms of performance,[5] and one reason leaders from BP and Transocean were visiting the rig on the day of the blowout was to recognize the rig's high performance.[6]

It is nevertheless possible that poor maintenance contributed to technical failures. According to pre-explosion BP emails, the rig was "getting old and maintenance has not been good enough."[7] Most notably, Chapter 4.9 of this report explains that certification of blowout preventer (BOP) equipment was overdue and that if blowout preventer maintenance was inadequate, it could have affected the ability to shut in the well. Other issues may have affected maintenance but, based on available information, likely did not contribute to the blowout.

Transocean's Rig Management System

Transocean had in place comprehensive procedures and systems for scheduling, implementing, and monitoring maintenance.[8] Like all Transocean rigs, the *Deepwater Horizon* used the computerized "**Rig Management System II**" (RMS), which Transocean had implemented as a result of its merger with Global Santa Fe.[9] Transocean personnel used RMS to schedule maintenance work based on information including equipment data, maintenance records,[10] information on certification and surveys,[11] and risk assessments.[12] Based on these materials, the automated system generated preventative maintenance[13] items for the rig.[14] The rig crew would perform these tasks and then record their completion in the system.[15] Transocean's goal in using the system was to ensure consistency, consolidate information, and facilitate personnel movement from rig to rig.[16]

While the Chief Counsel's team interviewed *Deepwater Horizon* crew members who found the RMS useful (despite the fact that it "definitely had some bugs in it") and who used it daily,[17] the team also found evidence to suggest that the system had problems. Transocean installed the RMS on the *Horizon* in September 2009,[18] but according one witness it was "still a work in progress" at the time of the blowout.[19] For instance, while the system produced thousands of preventative maintenance orders for Transocean's fleet,[20] many orders were disorganized, erroneous, or irrelevant to individual rig crews. The *Deepwater Horizon*'s rig crew was forced to actively search the system for the *Deepwater Horizon*'s maintenance items and to continually submit requests to remove duplicate maintenance orders or orders meant for another rig.[21] The system also generated work orders for equipment that had already been repaired, leaving the rig crew to determine if work orders generated by the system actually needed to be performed.[22] According to chief engineer Stephen Bertone, the rig crew "went through them as much as [they] could just poking through the system, but…there were still issues with it."[23] According to assistant driller Allen Seraile, the system was chaos at one time.[24] Chief electronics technician Mike Williams described the system as "overwhelming."[25]

The crew expressed confusion regarding the new system and concerns about its implementation. In a March 2010 Lloyd's Register survey, crew members stated that system changes to the RMS and other rig systems were ineffectively implemented.[26] They thought that new systems were introduced too frequently and before the previous system was understood.[27] The rig crew also thought there was insufficient support to implement changes and that system changes required a level of technical capability not typically available throughout the rig.[28] An April 2010 Transocean assessment also found that the maintenance system was not understood by the crew.[29]

Competing Interests Between Drilling and Maintenance

The rig services contract between BP and Transocean specifies that shutting down the rig to perform certain types of maintenance will trigger financial consequences. BP paid Transocean a daily operating rate of $533,495 for the *Deepwater Horizon*, but under the contract BP was not obligated to pay for time in excess of 24 hours each month spent on certain equipment repairs.[30]

The Chief Counsel's team cannot be certain whether these provisions or other financial pressures influenced maintenance decisions. However, some of the rig crew raised concerns that drilling priorities took precedence over planned maintenance.[31] The *Deepwater Horizon* had never been to dry dock for shore-based repairs in the nine years since it had been built.[32] BP and Transocean appear to disagree as to whether financial considerations influenced this decision. While Guide suggested the *Horizon* did not go to dry dock because Transocean insisted on being paid its daily rate during repairs,[33] Transocean operations manager Daun Winslow testified that any necessary repairs would have been made regardless of financial constraints.[34]

Lack of Onshore Maintenance

Some maintenance can only be performed when a rig is moving between well sites or when the rig is brought into shore.[35] But the *Horizon* had never been to dry dock since it was built in 2001. Transocean instead conducted "Underwater Inspection in Lieu of Dry-docking" (UWILD) and other at-sea inspections.[36] In the March 2010 Lloyd's Register survey some of the rig crew expressed concern that the lack of dry dock time could generally undermine equipment reliability.[37] According to the survey, the maintenance department was looking forward to a scheduled dry dock visit in 2011 "to carry out evasive [preventative maintenance] routines that they normally could not do."[38] Lack of time in dry dock may have resulted in a lapse in BOP certification.[39]

Following company policy,[40] Transocean commissioned an inspection in April 2010 to assess equipment and prepare for the rig's scheduled 2011 shipyard maintenance.[41] The inspection found that some problems identified in September 2009 remained unaddressed and identified several new maintenance issues.[42] As of April 2010, Transocean documents listed 35 critical items of equipment that either were in bad condition, had shown excessive downtime, had passed manufacturer wear limits, or that the manufacturer no longer supported.[43] As discussed in Chapter 4.9, the list included BOP elements that had passed their certification date.[44] According to witness testimony, Transocean had decided to extend the *Horizon*'s anticipated time in dry dock because of the number of repairs necessary.[45] The Chief Counsel's team requested but was not able to obtain a list of repairs scheduled for the *Horizon*'s 2011 dry dock visit.

Maintenance Audits and Inspections

The *Horizon* was subject to audits and inspections by various government and private entities, including BP,[46] Transocean,[47] MMS,[48] the Coast Guard,[49] the American Bureau of Shipping,[50] and the Marshall Islands (the ship's flag state in 2010).[51] These audits varied in scope and duration. Both BP and Transocean had a vested interest in keeping the *Horizon* in working order. Witness testimony describing the response to a fall 2009 audit indicates collaboration by both companies to ensure necessary repairs were made.

Transocean Resolved Many Maintenance Issues Identified in the September 2009 BP Audit

In September 2009 BP audited the *Deepwater Horizon*'s drilling equipment and the vessel itself.[52] The audit found 390 maintenance jobs overdue and identified some of those as high-priority items.[53] BP estimated that the work would require 3,545 man-hours of labor.[54] The audit may have overestimated the sheer number of jobs that were overdue because of errors and duplicates in the RMS system, which Transocean had recently installed.[55] BP asked Transocean to undertake certain repairs before allowing the *Horizon* to resume operations.[56] A few days later, BP determined that the rig was operational,[57] and the rig resumed operations on September 22, 2009, five days after the audit ended.[58]

BP and Transocean increased communication and coordination to monitor implementation of outstanding audit recommendations.[59] For example, auditors communicated conditions to the rig crew during the audit itself in order to ensure that certain repairs were made promptly.[60] BP and Transocean held weekly meetings to track progress,[61] and Guide or well site leaders signed off on corrective actions taken in response to the audit.[62] By March 30, 2010, 63 of 70 had been completed, progress BP described as "commendable."[63] Twenty-six other outstanding items were in progress and deemed not safety-critical.[64]

BP and Transocean Believed the Rig Was in Safe Working Order

At the time of the blowout, both BP and Transocean believed the *Deepwater Horizon* was in safe operating condition.[65] Well site leader Ronnie Sepulvado did not believe there were serious outstanding safety issues,[66] and neither he nor the other well site leaders indicated that the vessel was unsafe to operate.[67] Guide recognized that the rig was operating safely and making very good progress on addressing audit items.[68]

An April 1, 2010 MMS inspection of the rig found no incidents of noncompliance and did not identify any problems justifying stopping work.[69] But, as discussed in Chapter 6, the inspection did not identify that the *Deepwater Horizon*'s BOP had not been certified.[70]

Maintenance Findings

Inspections, audit programs, and statements by rig- and shore-based leadership indicate that BP, Transocean, and government regulators believed the *Deepwater Horizon* was in safe operating order at the time of the blowout. With the exception of potential BOP maintenance issues, the Chief Counsel's team found no reason to believe that maintenance problems may have contributed to the blowout. However, the Chief Counsel's team believes the following issues may have compromised the rig's maintenance regime:

- Transocean's RMS system may have complicated routine maintenance and monitoring. The rig crew appears to have been confused about the system, and the system issued duplicate and erroneous maintenance instructions; and
- the fact that the *Deepwater Horizon* had never been in dry dock may have delayed or prevented certain repairs that could only have been done onshore.