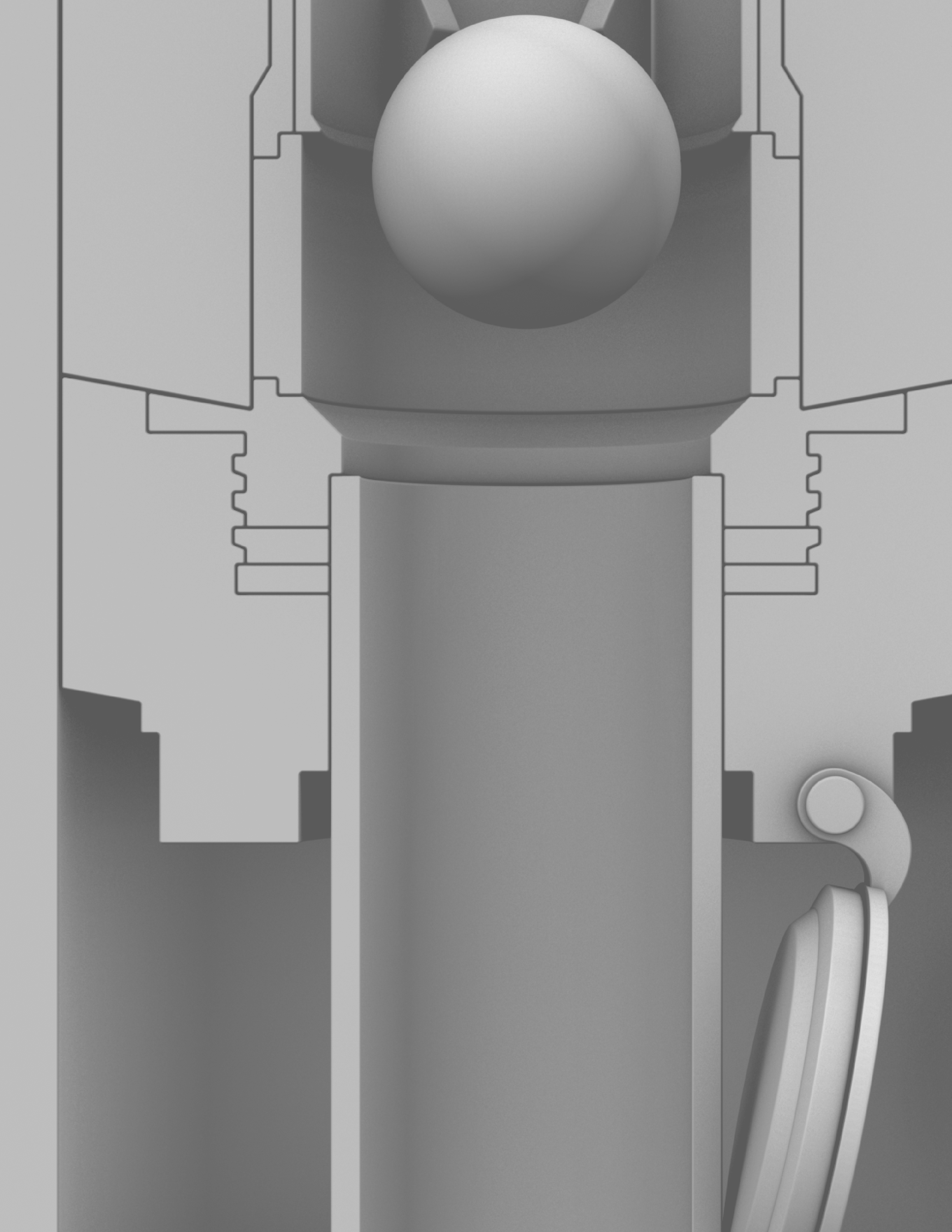
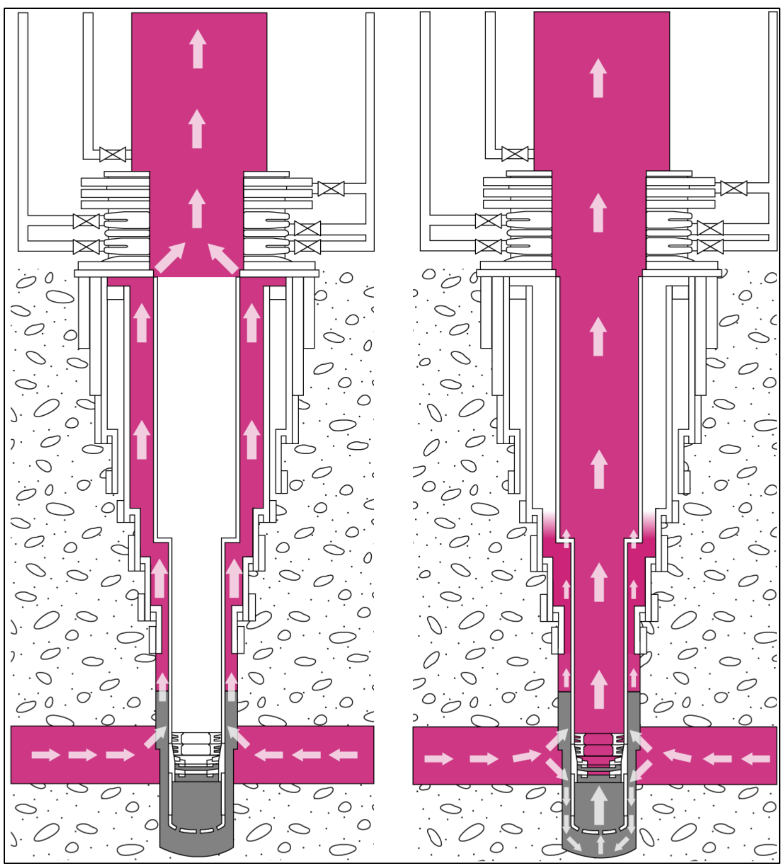


Chapter 4.1 | Flow Path

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]

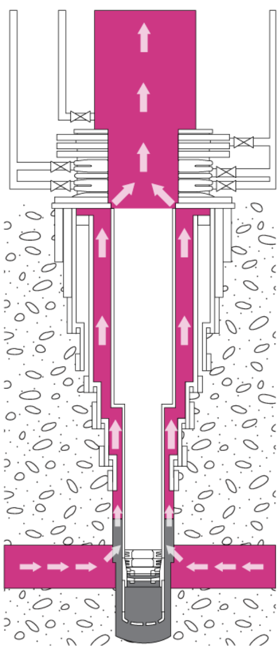
Potential Flow Paths

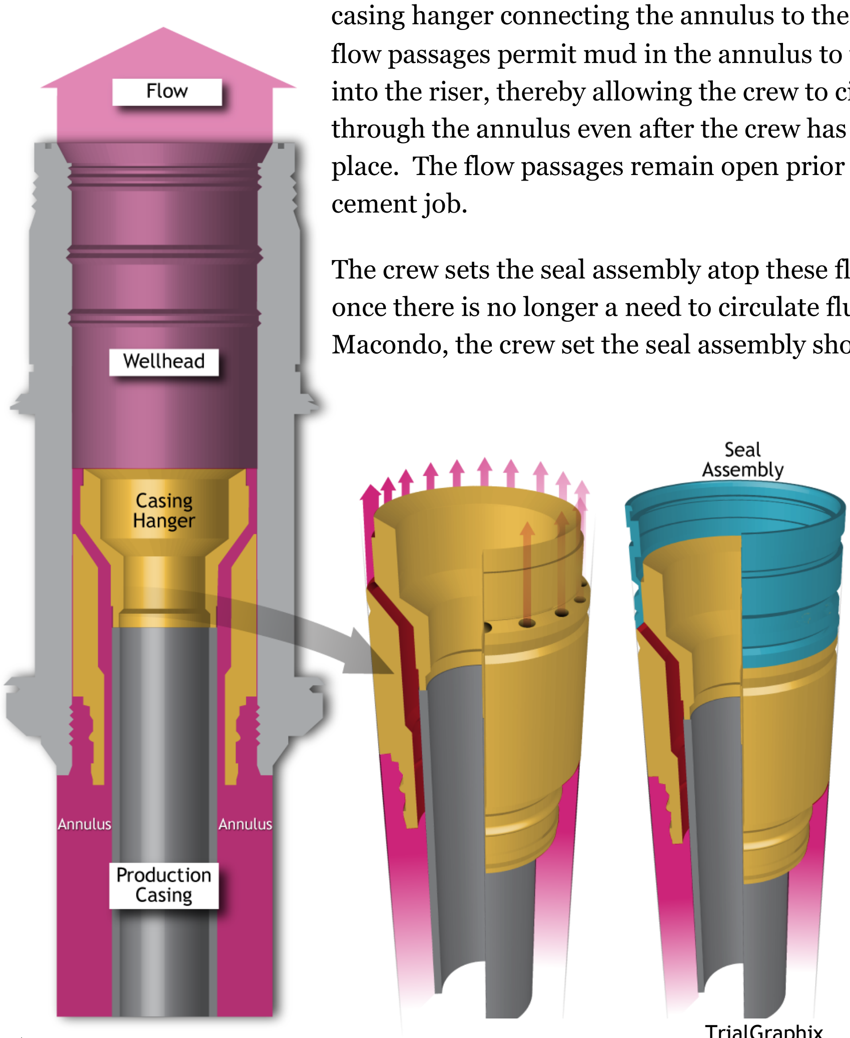
For the Macondo blowout to have occurred, hydrocarbons must have traveled from the formation into the wellbore and then up to the surface through the blowout preventer (BOP) and the riser. The fact that hydrocarbons entered the wellbore at all means, at the very least, that the annular cement did not 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.

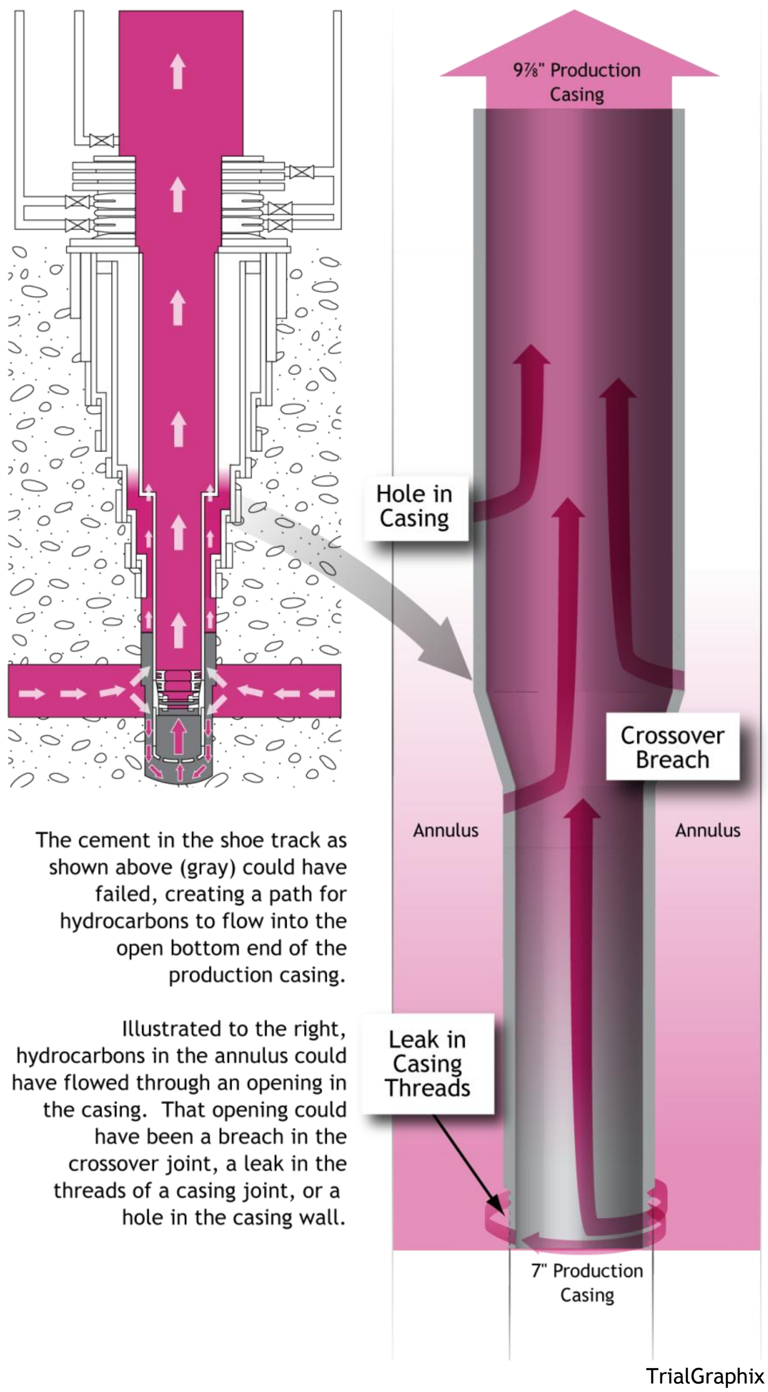
Flow up the Inside of the Production Casing

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.



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.

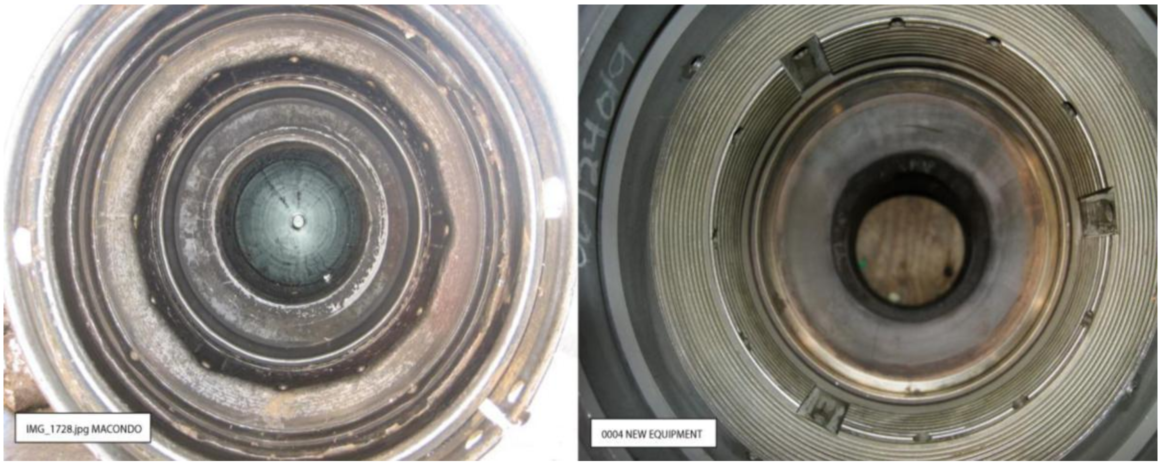
Figure 4.1.4. Exterior of the Macondo production casing hanger and seal assembly.

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.

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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]

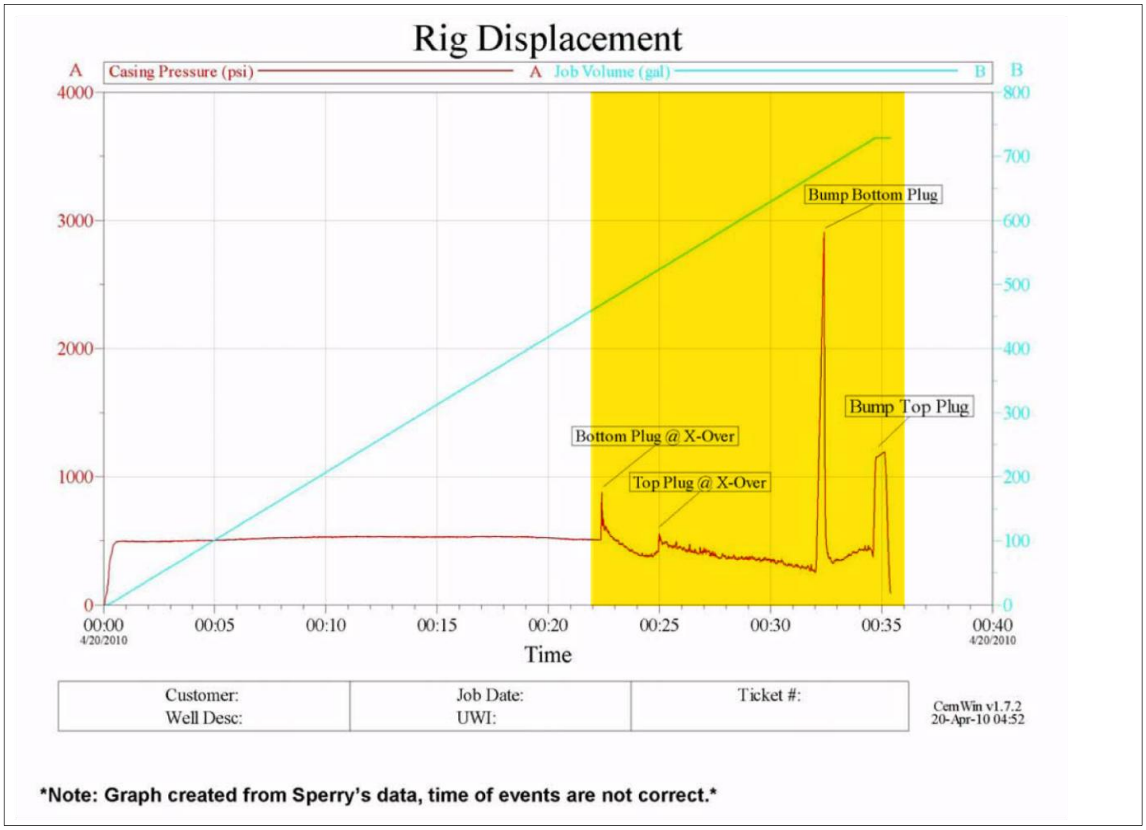
Halliburton's argument is unpersuasive for several reasons.

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.

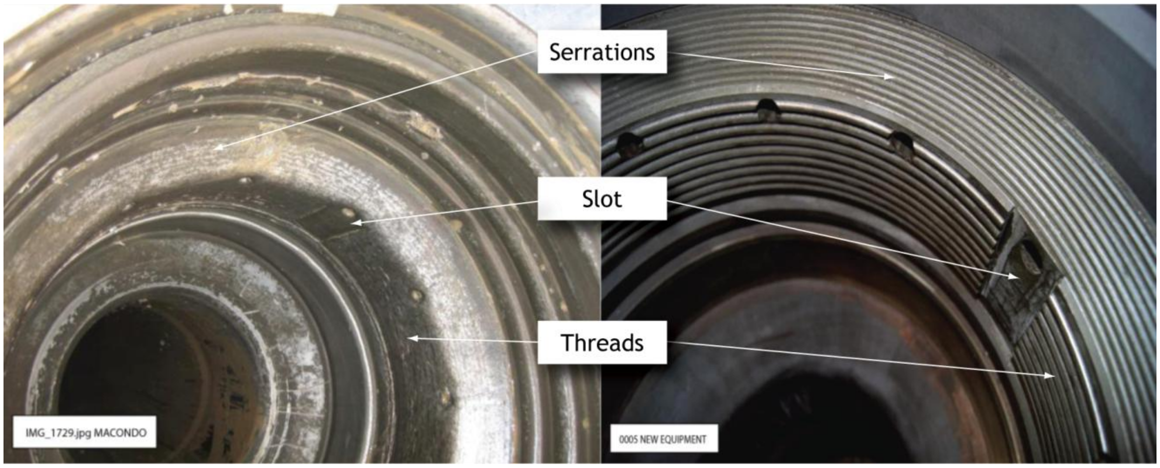


Halliburton

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.

A Breach Above the Top of Cement Is Unlikely

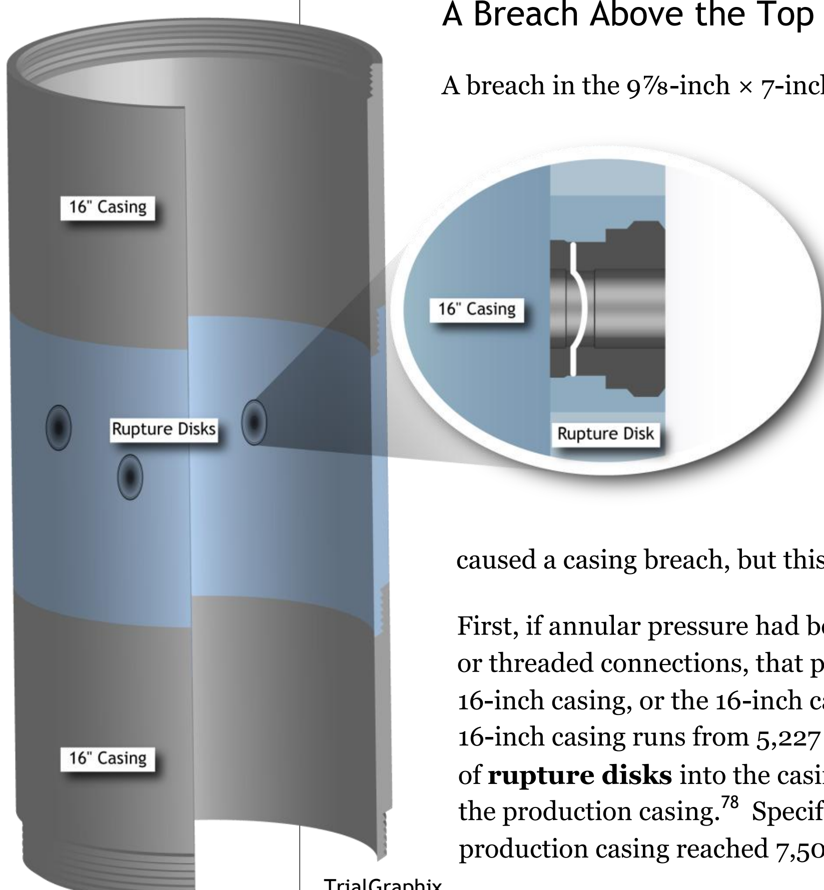
A breach in the 9⅞-inch × 7-inch tapered crossover joint or anywhere above the top of the annular cement is unlikely. If hydrocarbons went from the formation into the annulus and then through such a breach, one would expect to observe hydrocarbons in the annular space. As explained above, there is no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

Figure 4.1.9. 16-inch casing and rupture disks.



TrialGraphix

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.

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* 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.