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A Scientific Root Cause Analysis of the Deepwater Horizon Disaster

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Thesis for the degree of Philosophiae Doctor

Trondheim, April 2020

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Dedication

This Doctoral thesis is dedicated to the eleven men who lost their lives as a result of the explosion and fire aboard Deepwater Horizon on April 20, 2010.

Jason Anderson

Aaron Dale Burkeen

Donald Clark

Stephen Ray Curtis

Gordon Jones

Roy Wyatt Kemp

Karl Kleppinger, Jr.

Keith Blair Manuel

Dewey A. Revette

Shane M. Roshto

Adam Weise

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Summary

On April 20, 2010 eleven men lost their lives in the explosion and fire on Deepwater Horizon. Previous investigations have assumed that the experienced drilling crew must have missed a cumulative gain of about 1 000 barrels before the blowout preventer (BOP) was closed. However, this fatal incident did not occur because the drilling crew failed to observe that the well was flowing. The fact that no gain or flow from the riser was observed as late as a couple of minutes before the first explosion is almost unbelievable. That is probably also why previous investigation reports have concluded that this cannot be the case. Instead of investigating *why* the flow meters showed no flow, they have assumed that this must be wrong.

This PhD thesis will explain the root cause of the Deepwater Horizon disaster. The gas that caused the initial explosion and fire on Deepwater Horizon, originated from a gas kick that lasted for days prior to the cement job. The hydrocarbon gas that caused the first explosion, entered the wellbore undetected during the static period between April 16 and April 19. The large gas influx that occurred over a long time period was probably not discovered due to thermal effects, gas solubility in synthetic oil-based mud (SOBM) and possibly gas hydrate formation.

The cement job was unsuccessful probably due to a crossflow event that occurred when the bottom wiper plug burst at the float collar. The high burst pressure probably fractured the formation and a large amount of fluids were lost to the formation. The loss was probably not discovered because of a simultaneous gas influx higher up in the wellbore. Simulations carried out by SINTEF shows that the gas rich sandstone with high pore pressure was underbalanced prior to bursting the bottom wiper plug.

Gas cut mud was already present in the riser when preparation for the negative pressure test took place. The booster line probably contained large amount of free gas, originated from the gas kick during the static period between April 16 and April 19. The gas was present in the well and booster line because the final step of bottoms-up circulation prior to and after the cement job was not completed. When the auxiliary lines (boost, choke and kill lines) was displaced with seawater, large amount of gas hydrates could form. Seawater and water-based spacer probably mixed with freshwater were also pumped into the well to displace the SOBM up to above the subsea BOP. Large amount of relative cold water was therefore pumped into the sealed well (production casing) that already contained large amount of gas.

Gas hydrates probably plugged the displacement string during the first negative pressure test. This confused the drilling crew to believe the first test was successful.

Gas hydrates may also have contributed to the upper BOP annular did not close properly during bleed down and preparation for the negative pressure test and during the final well control actions.

Gas hydrates probably also plugged the kill line during the second negative pressure test. This confused the drilling crew to believe the second test also was successful.

Kick detection based on gain does not always work. Thermal effects, simultaneous loss of drilling fluids, hydrate formation and free gas that exit the riser at the top, may hide that a gas kick is ongoing and show net loss instead of gain. Improved methods for kick detection are strongly recommended.

Real time data and witness observations confirms that the blowout occurred extremely fast. Tons of gas hydrates had probably been circulated up the drilling riser like a "Trojan horse" after the negative pressure test was assumed to be successful. Less than 3 minutes before the first explosion a hydrate plug in the upper part of the riser came out of control. The hydrate plug travels the last part of the riser driven by liberated gas from the dissociation process of gas hydrates.

Gas hydrates partly plugging the diverter housing, probably contributed to the attempt to divert the fluids overboard through the starboard overboard line failed.

Gas hydrates probably also contributed to the variable bore rams did not close properly during the final well control actions.

Gas hydrates may also have contributed to the fact that the drill pipe ended up being off center in the BOP and that the blind shear ram did not seal properly.

The fact that the subsea BOP failed to shut-in the well and that the cement job was unsuccessful allowed gas to enter the production casing from the bottom. A second "attack" probably from the same high pressure gas rich sandstone could then proceed without any restriction. The "Trojan horse" (gas hydrates) with gas from the April 16 to April 19 gas influx event has done the job. Both the subsea blowout preventer and the riser diverter system had lost their capability be prevent the blowout as intended. In this way the fatal explosion could escalate to be the largest marine oil spill in the history of the petroleum industry.

Acknowledgements

I will use this opportunity to thank and give recognition to BP for their openness and willingness to share insights in an early stage of the investigation by taken the decision to release the internal *BP Deepwater Horizon Accident Investigation Report, September 8, 2010*, publicly.

I would also acknowledge Transocean for sharing their investigation report and results from the investigation in an early stage.

I also want to thank the National Oil Spill Commission for publicly release its final report to the President, the Chief Counsel's Report (CCR) on January 11th, 2011. A special thanks goes to Adjunct Professor Richard Sears who comment on my early work from 2014 and that he took the time to meet me in California in an early stage of my research. Richard Sears who was part of the commission, also gave me valuable information and video material prepared for presenting the CCR to the public. Thank you!

Without the insights to the public that these comprehensive reports contributed to, this PhD thesis would not have been possible, and I would never have started my research work and PhD program in collaboration with NTNU.

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I would like to thank my supervisor, Professor Sigbjørn Sangesland, for early show interest in my work and giving me the opportunity to carry out my doctoral work in collaboration with NTNU. Thanks also to my co-supervisor Professor Pål Skalle, and other lecturers at NTNU. That is Dr. John-Morten Godhavn, Dr. Sigve Hovda and Dr. Erling I. Heinz Siggerud. A special thanks to Runa Nilssen who has been very helpful and kind every time I have contacted her with all kinds of questions.

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Thanks also to Robert (Bob) Kaluza for valuable comments, opinions and firsthand information about the activity onboard Deepwater Horizon at the day of the incident.

Thanks also to my childhood friend, table tennis player and Professor Pål (Paul) Wessel at University of Hawaii for proofreading part of this thesis.

Last but not least I want to thank my family and friends that has supported me all the way. A special thanks to my fiancée for all the love, support, friendship, valuable feedback and understanding during long working hours in the home office. Thanks for making my life complete!

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APPENDICES

Chapter 1 - Introduction

This year (2020) it is ten years since the Macondo blowout and explosion on Deepwater Horizon. The incident has been referred to as an industrial disaster and considered to be the largest marine oil spill in the history of the petroleum industry.[1.1] Numerous investigation reports and scientific papers have been published to explore the causes of the disaster. Finding the root cause for how large amount of gas could enter the marine drilling riser undetected and later cause explosions and fire onboard Deepwater Horizon is of paramount importance in order to prevent such incidents from ever happen again.

This is also why I choose this topic. The question is why did the experienced drilling crew wait until it was too late to shut-in the well and close the blow-out preventer (BOP)? The simple answer to this question is that there was no gain. The fact that no gain or flow from the riser was observed as late as a couple of minutes before the first explosion is almost unbelievable. That is probably also why previous investigation reports have concluded that this cannot be the case. Instead of investigating *why* the flow meters showed no flow returning from the riser, they have assumed that this must be wrong. Based on OLGA® flow simulations rather than real-time data, previous investigations have assumed that the experienced drilling crew must have missed a cumulative gain of about 1 000 bbls, before they activated the BOP.[1.2] The investigators have also assumed that the Hitec flow-out sensor data sank with the rig and that the Sperry-Sun flow-out sensor was bypassed.[1.3] In this way they justify or explain why the Sperry-Sun data showed that no fluid was returning from the riser until less than two minutes before loss of power at 21:49:15 [1.4] followed by the first explosion a second or two later. [1.5]

In *Chapter 2 – Pattern of Anomalies*, questions that previously have not been raised or not previously answered, will be discussed. A likely or possible answer to these questions will also be outlined. Chapter 2 will also show how previous investigations have based their conclusions on assumptions rather than facts, see chapter ***2.3 Assumptions or Facts***. For example, it is a fact that several witnesses and several different types of real-time data show that mud blew out from the riser about a minute before the explosion. However, when the OLGA® flow simulations show that this is not possible, the investigation teams have ignored this fact also. Rather than looking for other possible explanations why everything happens so fast, previous investigations has ignored that there is a significant difference between observed time of riser blowout and simulated time of blowout. While real-time data shows that no fluid was returning from the riser until less than two minutes before the explosion, previous investigations have assumed that the blowout from the riser must have happened several minutes before the explosion. [1.6]

For readers not familiar with the terms used within the drilling industry, I refer you to Appendix E. *Appendix E – Definition and Glossary of Terms*, was also prepared because the industry sometimes has a different definition and explanation for an observed phenomenon. The meanings of the words or expressions used in this thesis are therefore described in this appendix for clarity.

Chapter 3 – The Macondo Well is perhaps the most important chapter in this thesis. The Macondo well was a difficult well to drill and the crew experienced many of the common well problems that may occur when drilling for oil and gas. Challenges such as ballooning, lost circulation, gas kicks and narrow drilling margin were all phenomena observed during drilling the last section. To understand the cause or explain the mechanism behind these phenomena is paramount in order to find the best solutions or method to avoid or minimize the consequences of future well control events. Different hypotheses or theories on the cause of well ballooning and gas kicks are discussed in this chapter.

In chapter 4 to 7 the different events and anomalies that occurred from running and cementing the 9 $^{7}/_{8}$" x 7" long string production casing and up to the time of the first explosion are discussed and analyzed in more detail.

A separate *Chapter 8 – Main Contributions and Discoveries,* has been made to summarize the major findings and work that has been done in conjunction to this PhD thesis. Finally, conclusion and recommendations are given in chapter 9.

It is my hope that the work that has been done in conjunction with this PhD will contribute to improve process safety in our industry. It is important that the industry is capable of learning from this event to prevent similar accidents in the future. Although ten years has gone since the incident, it is never too late to revise the lesson learned from this fatality.

It is also my hope that this thesis will contribute to give the families and colleagues of the eleven men who lost their lives as a result of the explosion and fire, a better understanding on what really happened the last 45 minutes before the explosion.

Chapter 2 - Pattern of Anomalies

2.1 A Mystery

In November 2010 the National Commission on the BP Deepwater Horizon Oil Spill released its preliminary findings on the causes of the oil rig explosion in the Gulf of Mexico. On day 2 of the meeting Frances "Fran" Ulmer, a member of the National Commission, asked the panel of three scientific experts the following question;

"I direct this question to Mr. Lewis, but if others on the panel wish to address it, that would be fine. Yesterday, we heard many things that raised questions that were not directly answered, but of all of them, the two mysteries that were described, I'd like to put before you and ask you if you have opinions about them.

The first mystery was why in the world BP changed its temporary abandonment plan three times in the last week and what implications that had for safety.

And secondly, why the experienced drilling crew and all of the others who were on this rig did not see the pattern of anomalies, one after another after another after another, to get to that heightened sense of concern that they should have had. I know it's easy in retrospect, but Mr. Bartlit laid out a dozen things that should have put people on high alert." [2.1]

The drilling expert Steve Lewis´ answer to the question was both generic and specifically related to the Deepwater Horizon incident;

"As was said, none of these guys made this conscious decision, okay, I'm going to do this because it's faster but it's not as safe. I don't believe they did that. But the overall impetus to make progress and to, in some cases of design and execution, choose a route that was quicker that involved fewer steps, that part of it does come from management.

So, I can't tell you why they continued step after step after step to miss the point, to not go into high alert, to not go, shut her down, we don't know what's going on here, we got to get this figured out. I can't tell you that." [2.2]

This second mystery, why the experienced drilling crew did not see the pattern of anomalies, and why they shut in the BOP as late as they probably did is the questions that this thesis will seek answers to. Twenty minutes before the explosion, at 21:29, the experienced tool pusher Jason Andersen and driller Dewey Revette had already experienced several anomalies. Shortly after they shut down all pumps to investigate. The big question and mystery are why Anderson and Revette notice anomalies but do not treat them as a kick? [2.3]

Both Jason Anderson and Dewey Revette lost their lives as a result of the explosion and fire aboard Deepwater Horizon. It is not possible to be certain of what anomalies they observed and which they may have missed. However, based on witness testimonies and real-time data we can reconstruct some of the anomalies and actions that were taken by the drilling crew that fatal evening. Figure 2.1, 2.2

and 2.3 shows a reconstruction of some important real-time data [2.4] and anomalies that occurred in a crucial last hour from 20:40 up to the first explosion (21:49:15).

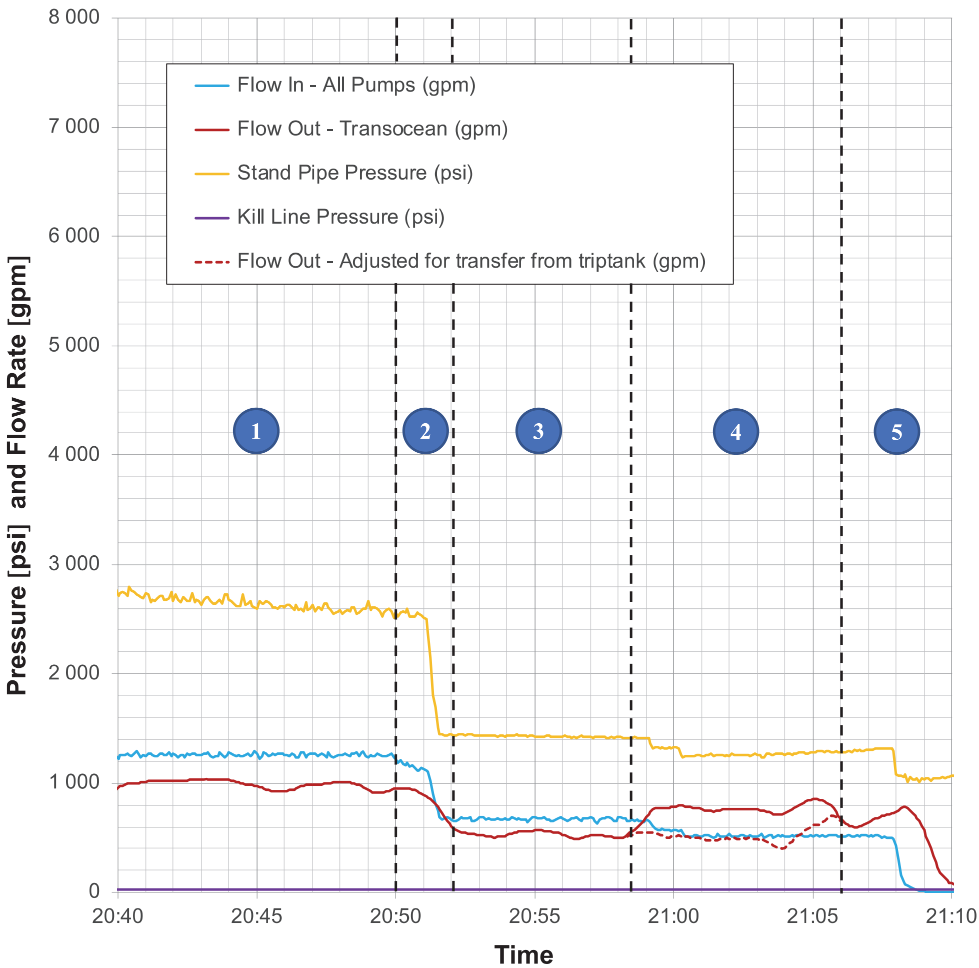


Figure 2.1 – Real-time data and anomalies from 8:40 – 9:10 p.m.

2.1.1 Anomaly 1 – Partial loss of circulation

At 20:40 in the evening the drilling crew was displacing synthetic oil-based mud (SOBM) in the marine drilling riser with seawater. As the heavier SOBM was displaced with seawater the pump pressure or standpipe pressure will decrease. It is therefore an expected or normal observation that the standpipe pressure will decrease, see figure 2.1.

However, during a ten minutes period from 20:40 to 20:50, while seawater was pumped both down the work string and down the booster line, considerably less

SOBM was returning to the rig. During these ten minutes an average of 1 257 gpm of seawater were pumped into the riser through the booster line and down the work string. Yet, the flow-out meter only shows an average of 987 gpm with SOBM returning back to the rig from the riser. This is a partial loss of 21% or a total of 64 barrels loss of fluid during this ten-minute period only.[2.5]

The drilling crew may not have noticed this anomaly. Or, they may have notice it but believed that something must have happened to the mud pumps. Since flow-in was calculated based on the stroke counter on the mud pumps, [2.6] an increase in leakage rate in one or several of the pumps liners could result in decreased pump efficiency.

Another possible explanation for this loss of fluid is that seawater was cooled on the way down and that gas hydrates were produced from natural gas already present in the riser and wellhead area. When gas hydrates are formed, gas is consumed resulting in a significant volume reduction (Vavik et al. 2016, Table 2). This phenomenon may explain why 21% less fluid was coming back to the rig.

A more likely explanation is that free gas was leaving the riser at the top of the riser, resulting in less fluid (SOBM) will be recorded in the flow-out meter.

2.1.2 Anomaly 2 – Reduction in pump rate and gain

At 20:50 the pump speed was reduced slightly and considerably more at 20:51, see figure 2.1. Based on the stroke counter (total flow pumped in), the crew was soon expecting the water-based spacer to return to the rig. [2.7] Maybe it was because of this that the crew wanted to slow down the circulation. The drilling crew may also already have discovered anomalies and slow down the circulation to investigate.

Water-based spacer was used between the SOBM returning to the rig and seawater used to displace the fluid in the riser. Before the drilling crew was allowed to dump the water-based spacer into the GoM, a test had to be carried out by compliance specialist Greg Meche to ensure that the spacer did not contain any traces of oil.[2.8]

The anomaly is that, as the pump speed was lowered, the return flow goes from loss of circulation to show gain for a short period. It is not abnormal that some extra fluid is returning when mud pumps are shut down. Due to the compressibility of oil-based mud (OBM) and sometimes high circulating pressure, the fluid will expand when pump pressure is removed. However, in this case the work string was full of seawater. The observed pressure drop from approx. 2 500 psi to 1 200 psi, does not comply with a large gain caused by seawater expansion.

The drill crew may or may not have noticed this anomaly. The gain soon changed back to a situation where less fluid was coming back from the well compared with the total flow of seawater pumped into the well.

The gain may have been an indication that the wellbore was in underbalanced conditions and that gas was being “produced” through the production casing. However, gain loss scenario may also be a typical observation when gas is being circulated out of the riser. For further discussion and analysis on this anomaly, see chapter 6.

2.1.3 Anomaly 3 – Change in standpipe pressure decrease rate

During the next 6 minutes and 30 seconds period from 20:52:00 to 20:58:30 the standpipe pressure (SPP) only decreases by 23 psi, see figure 2.1. However, based on a total flow of 82 bbl returning from the riser, the decrease in SPP would have been expected to be higher, see figure 6.3

The pumping rate of seawater into the wellbore had been decreased, however the loss of circulation still remains at about 21%. This indicate that the loss of fluids is related to the rate of circulation. For further discussion and analysis on this anomaly, see chapter 6.

2.1.4 Anomaly 4 – Increase in standpipe pressure (SPP)

During the next 7 minutes and 30 seconds from 20:58:30 to 21:06:00 the SPP starts to increase gradually, see figure 2.1. At the same time the real time data tell us that the trip tank was being emptied. Maybe the drilling crew already observed this abnormal change in SPP and emptied the trip tank to be prepared for further investigation?

2.1.5 Anomaly 5 – Increase in SPP and Gain

From 21:06:30 to 21:08:00 the drilling crew may have observed the anomaly that both the SPP and flow-out was increasing. That is probably also why they stopped all pumps at 21:08:00. This anomaly was a clear indication that something was wrong. The fact that the flow out from the riser did not stop after the pumps had stopped was also an observation that required further investigation, see figure 2.1.

2.1.6 Anomaly 6 – Flow out and increase in SPP while all pumps are off

During the next four minutes from 21:10 to 21:14 the drilling crew was probably watching that fluid was returning from the riser. With all pumps shut down, fluid at a rate between 64 to 77 gpm was returning to the rig. There was a slight increase in the beginning, however the flow stabilized around 75 gpm for the last 2 to 3 minutes.

2.1.7 Anomaly 7 – Pumps 3&4 started up and flow out remains unchanged

The crew started up pumps no. 3 and 4 again which had been used for circulating seawater down through the string, see figure 2.2. The total flow pumped into the production casing stabilized at around 366 gpm. However, the flow returning back to the rig from the riser stayed unchanged around 75 gpm. This is a very abnormal observation.

2.1.8 Anomaly 8 – Pumps 1&2 started up and kill line pressure increase

The crew started up pump no. 1 again which had been used for circulating seawater down through the booster line at 21:15:20, see figure 2.2. The total flow pumped into riser through the booster line and drill pipe (displacement string) increased to 534 gpm at 21:17:00. However, the flow returning back to the rig from the riser had only increased to around 80 gpm. This is a very abnormal observation.

It is not possible to imagine what the crew was thinking at this moment. Maybe they suspected that the water-based viscous spacer, that was actually a lost circulation material (LCM) [2.9], in some way had settled and partly blocked the riser annulus? Maybe that was also the reason why they started the last pump no. 2, lined up to the kill line? In less that 30 seconds after the pump started, the kill line pressure increases to over 7 000 psi and the pop-off (pressure relief valve) opens and relives the pressure.[2.10] Now the drilling crew has probably gotten confirmation that the kill line also was plugged. Pump no. 2 (lined up to the kill line) was stopped immediately, and shortly after also pump no. 3 and 4 were stopped, probably to reset the pop-off.

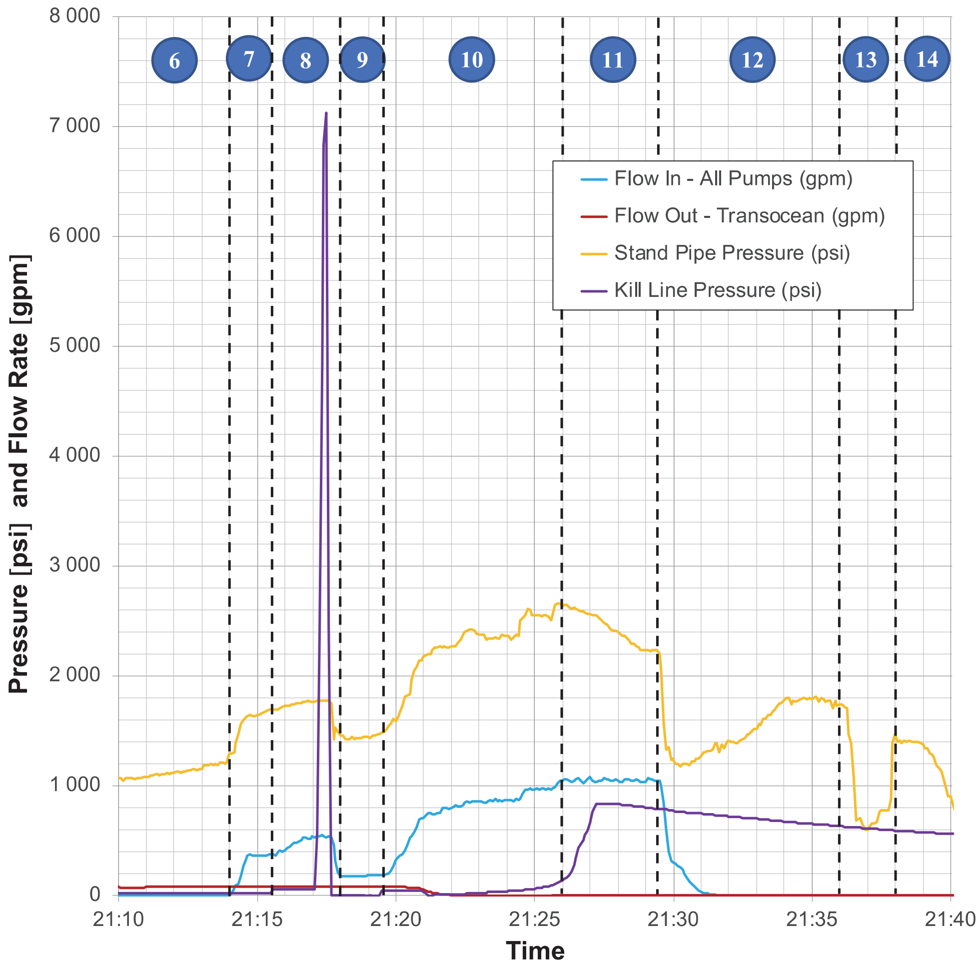


Figure 2.2 – Real-time data and anomalies from 9:10 – 9:40 p.m.

2.1.9 Anomaly 9 – Booster pump running, and flow out remains constant

For a short while only the booster pump was running at around 180 gpm. Flow returning from the riser remains unchanged at around 80 gpm. This anomaly shows that the drilling riser annulus probably was partly or totally plugged.

2.1.10 Anomaly 10 – Pumps 3&4 started up again and flow out drops to zero

Shortly after the pop-off on pump no. 2 (kill line) had opened, the drilling crew started pumps no. 3 and 4 again. Maybe they wanted to try and clear the partly plugged riser annulus as soon as possible, while they still have some flow returning from the riser. Between 21:19:30 and 21:26 the drilling crew increased the total flow to more than 1000 gpm. However, rather than clearing the blockage and increasing the flow-out from the riser, the flow out drops to zero shortly after they increased the flow, see figure 2.2.

The situation for the drilling crew had now become worse. Rather than clearing the riser annulus plug, it seems that they have packed the plug completely, leaving no flow passing through the riser annulus.

2.1.11 Anomaly 11 – Kill line pressure increase and SPP decrease

During the next three and a half minutes the flow into the well was kept at a steady rate above 1000 gpm, with still no flow returning from the riser. However, the SPP decreases during this period. The SPP decreases about 400 psi within 3 minutes and then leveled out at about 2 200 psi, see figure 2.2. This is very abnormal. If you pump a large amount of seawater into the cemented and closed production casing, you would expect the SPP to go up and not down. Maybe the drilling crew thought that they must have burst the casing or a riser joint, explaining why the SPP decreases.

In addition to the decreasing SPP pressure the kill line pressure suddenly increase to more than 800 psi, and then also that pressure starts to decrease, see figure 2.2. Leaving a differential pressure between the kill line pressure and the drill pipe pressure (SPP) of more than 1 400 psi.

2.1.12 Anomaly 12 – SPP increase and kill line pressure decrease

At 21:29:30 pumps no. 3 and 4 was shut down and shortly after also the booster pump was shut down. With all pumps shut down the drilling crew was watching the SPP pressure increase and the kill line pressure decrease. Still with no flow returning from the riser, see figure 2.2.

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. Revette, sitting in the driller‘s A-chair, and Anderson, standing next to him, were speaking to each other. At times, they looked at the driller‘s screens. Revette noted that they were “*seeing a differential*.” The two men appeared concerned but calm. According to Young, “*It was quiet...there was no panic or anything like that*.” [2.11]

2.1.13 Anomaly 13 – Rapid decrease and increase in SPP

During the next two minutes from 21:36 to 21:38, a rapid decrease followed by an increase in SPP can be observed. This observation is later explained by a surviving witness Caleb Holloway.

Revette ordered Transocean floorhand Caleb Holloway to bleed off the drill pipe pressure, apparently to eliminate the differential pressure. At 9:36 p.m., Holloway cranked open a valve on the standpipe manifold to bleed down the pressure. But it was taking longer than usual to bleed off. Revette told Holloway, "*Okay, close it back.*" [2.12]

After the valve was closed the SPP increased rapidly back to 1 400 psi. The drilling crew probably knew at this point, although still no flow was coming back true the riser, that they must in some way be in communication with the well.

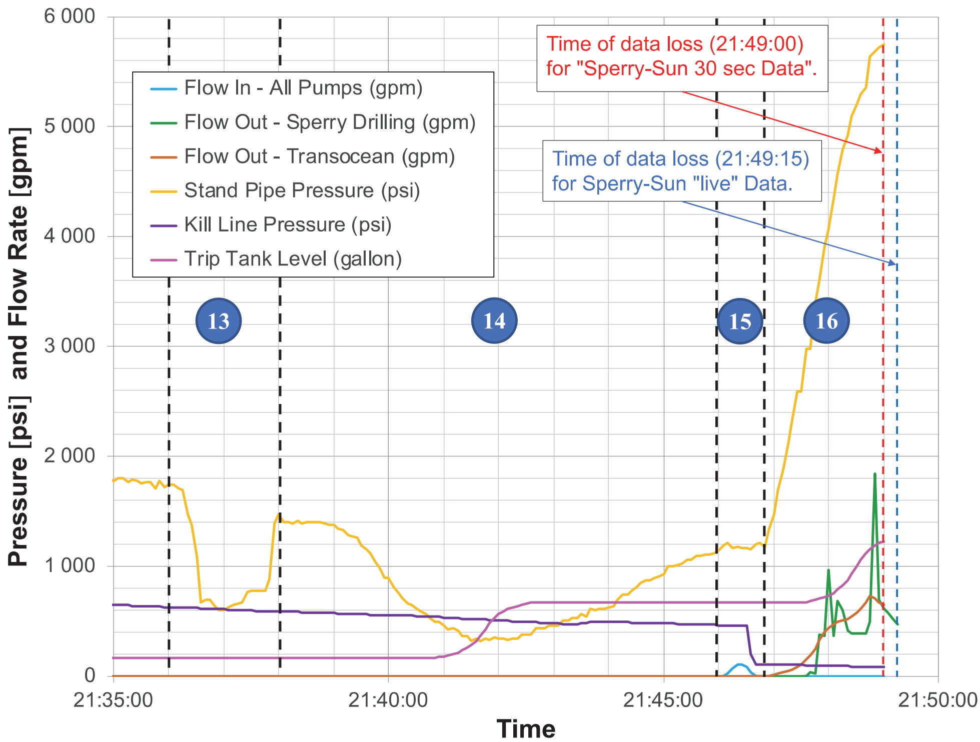


Figure 2.3 – Real-time data and anomalies from 9:35 – 9:50 p.m.

2.1.14 Anomaly 14 – Decrease and increase in SPP

Real-time data for fifteen minutes is shown in figure 2.3, compared to thirty minutes shown in the two previous figures. Note also that two more data sets are added. The green line called "*Flow Out – Sperry Drilling (gpm)*" and the magenta colored line called "*Trip Tank Level (gallon)*".

At 21:39 the SPP starts to decrease from 1 400 psi down to about 300 psi about 21:41:30. It stays low for about 40 seconds and then SPP climes up again during the next four minutes to about 1 200 psi, see figure 2.3. At the same time there is an increase in the fluid level in the trip tank of 510 US gallons or approximately 12 barrels.

Since there was still no flow returning from the riser, maybe the drilling crew wanted to do one more attempt to bleed down the SPP pressure to verify that they in fact were in communication with the wellbore. However, they probably also knew at this stage that both the drilling riser and kill line were plugged. A normal flow check through the flowline and into the trip tank was therefore useless.

Probably the drilling crew also conducted this second flow check through the tapered string connected to the standpipe manifold. Possibly, the flow was routed via the mini trip tank and back to the trip tank, see figure 2.4. [2.13]

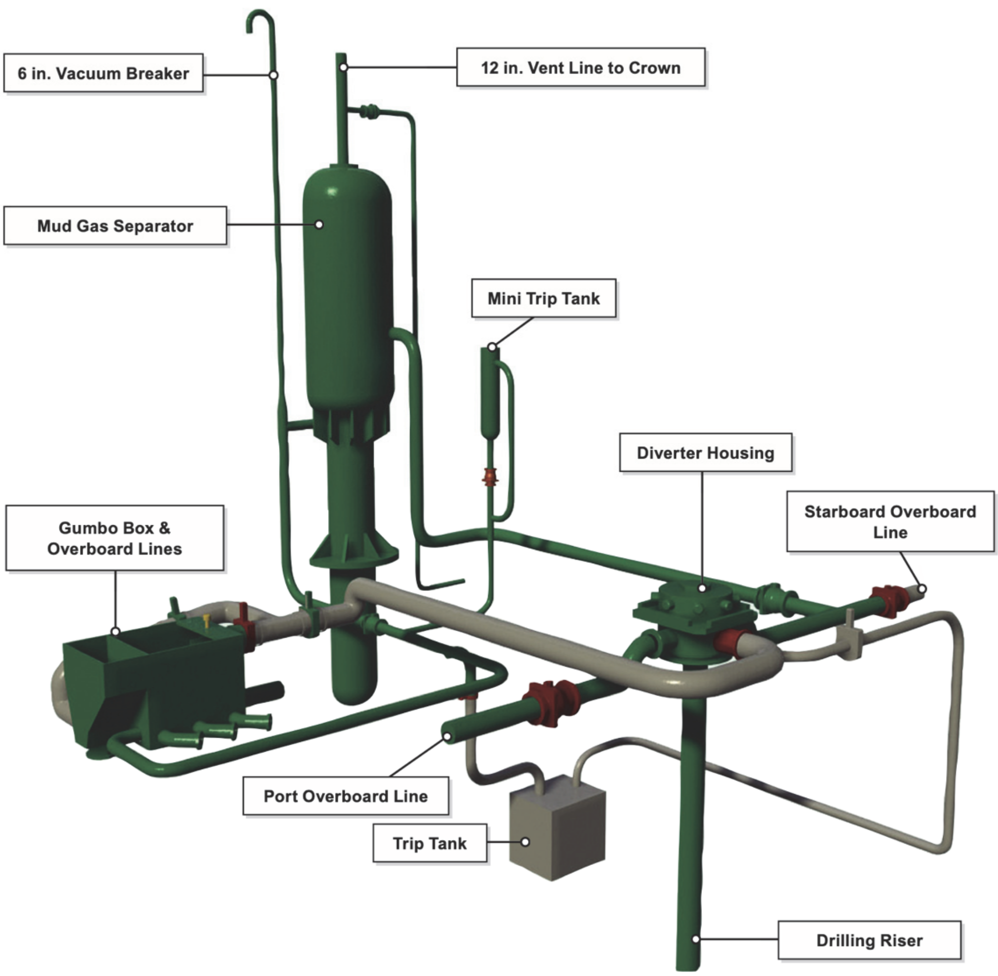


Figure 2.4 – Deepwater Horizon diverter system including MGS, flow line and trip tank. [2.13]

Conducting the flow check in this way also explains why the trip tank gained 12 barrels between 21:40:40 and 21:42:50, see figure 2.3.

This can also explain why, according to BP internal documents and interview with Donald Vidrine, the well site leader received a phone call at approximately 21:44 from the toolpusher Jason Anderson. According to Vidrine, Anderson stated that they were; "*getting mud back, and that they had diverted to the mud gas separator*". According to Vidrine they had also either closed or were closing the annular. [2.14] However, closing the BOP annular would have no effect on the flow out of the riser at this point, since the drilling riser annulus was already plugged, see figure 2.3 showing no flow out from the riser.

2.1.15 Anomaly 15 – Pumps no. 3 and 4 runs for 45 second and then stopped

Real-time data show that pump no. 3 and 4 were started approximately at 21:46:00. However, only after 30 to 45 seconds before they have reached normal speed, the pumps were shut down. About the same time at 21:46:35 the "*Flow Out – Transocean (gpm)*" shows that fluid start coming back from the riser. About the same time at 21:46:30 the kill line pressure also drops suddenly more than 200 psi in less than ten seconds, see figure 2.3.

The drilling crew had probably started on a well control procedure. After the flow check with 12 barrels gain in the trip tank, they have probably also already closed the BOP. Maybe they wanted to check if it was possible to circulate down the drillpipe and back up through the booster line since the kill line and riser annulus was plugged. However, they were probably at this time on high alert to sudden changes in either flow out from the riser or sudden changes in the kill line pressure. The sudden drop in the kill line pressure followed by flow out from the riser is probably also why they suddenly aborted the attempt to start up circulation again.

2.1.16 Anomaly 16 – Rapid increase in SPP followed by flow from riser

Just a few seconds before 21:47 the SPP starts to increase rapidly, see figure 2.3. The "*Flow Out – Transocean (gpm)*" also increases. From showing a slow and steady increase from 0.1 gpm at 21:46:35 to 14 gpm at 21:47:00, after one minute the flow had increased to 150 gpm. At approximately this time (21:47:35) the "*Flow Out – Sperry Drilling (gpm)*" (green line) also starts to detect flow. Also, about the same time (21:47:35) the fluid level in the trip tank (magenta colored line) starts to increase again.

The "*Flow Out – Sperry Drilling (gpm)*" (green line) has got two peaks. The first peak is at approximately 21:48:00 and the second peak approximately fifty seconds later, at 21:48:50. The "*Flow Out – Transocean (gpm)*" (red line) starts to decrease at approximately 21:48:45.

Last registration of "real-time" data transmitted to shore used in this thesis is at 21:49:00. Figures 2.1, 2.2 and 2.3 are generated from an excel file of real-time data called "*Sperry-Sun 30 sec Data*". This is the same data set used in the Transocean investigation report. Based on this Transocean has assumed that the time of the first explosion or that the rig lost power at approximately 21:49.[2.15] However, there is also a second set of data which is used in the BP investigation report. The data set for "*Flow Out – Sperry Drilling (gpm)*" (green line) is taken from the BP report. This second set of flow out data ends at 21:49:15,[2.16] see figure 15, page 101, in the BP investigation report.[2.17] Based on this it is assumed that loss of power and the first explosion occur sometime shortly after 21:49:15. For further discussion about the two different sets of flow out data, see chapter 2.3.

A possible explanation for the increasing flow out of the riser is that the plug in the riser started to travel upwards driven by rapid expansion of natural gas. One possible hypothesis is that the plug in the riser annulus was made from gas hydrates. A plug made of gas hydrates will also explain how a rapid increase in flow out was caused by melting or dissociations of gas hydrates in the upper part of the drilling riser annulus.

Probably the drilling crew activated the diverter sequence shortly before 21:48. When the (automated?) diverter sequence is activated the overboard line to the leeward side should open first. This is because the fluid from the riser needs an alternative way to go before the flowline and diverter element closes. See figure 2.5 showing the 14" starboard overboard line on Deepwater Horizon.[2.18]

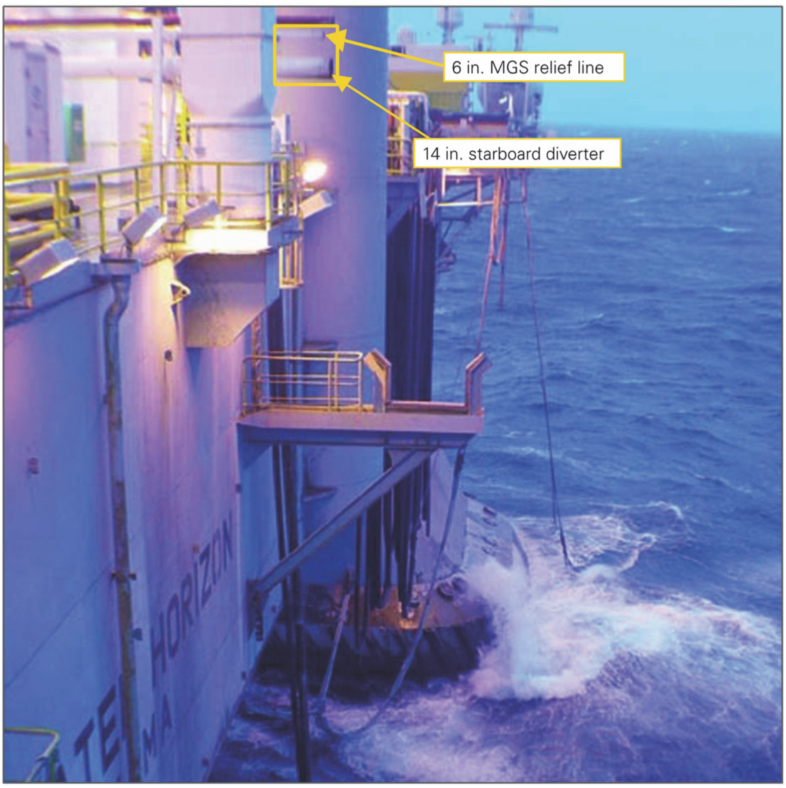


Figure 2.5 – Photograph of Deepwater Horizon starboard overboard lines.[2.18]

The first reduction or change in flowrate observed in the flowline at approximately 21:48 may be due to the effect of the 14" starboard overboard line starting to open. Previous investigations have concluded that the drilling crew diverted the return flow from the riser to the mud gas separator and that this contributed to the accident.[2.19] However, through the work done with this thesis there has not been any evidence to support such conclusions. On the contrary, it is more likely that the drilling crew followed the well control instruction written down in the Transocean well control handbook; "*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*." [2.20]

The photograph showing a jet flame believed by the BP investigation team to be the 6" relief line from the MGS, is probably rather the relief from the 14" starboard overboard line, see figure 2.6. [2.21]

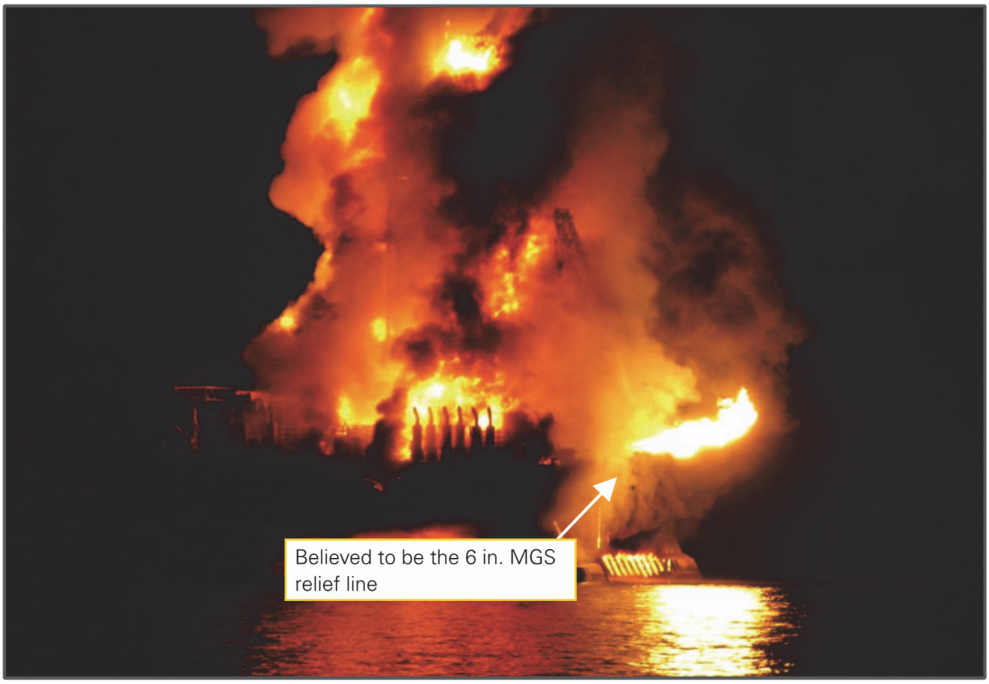


Figure 2.6 –Deepwater Horizon photograph showing a starboard jet flame. [2.21]

The second reduction in flow through the flowline at 21:48:45 is probably caused by the (automated?) diverter sequence closing the flow from the diverter housing to the flowline, see figure 2.3.

The activation of the diverter sequence and the observation of riser blow out into the derrick during these last two to three minutes before the explosion are also supported by several witnesses. One of the key witnesses is senior tool pusher

Miles "Randy" Ezell, who was laying down in his bed watching TV when he received a phone call shortly before the first explosion. This is what Ezell testified to the joint investigation team about the phone call he received from assistant driller Steve Curties who was killed in the explosion and fire on Deepwater Horizon:

"*I laid there and had turn my overhead light off in the bunk, and I was still watching a little TV, and my room phone rang. Well, I hit my little alarm clock light, and according to that alarm clock it was ten minutes to ten. And, the person at the other end of the line there, was the assistant driller Steve Curtis. Ahh…, Steve open up by saying; we have a situation. He said; the well is blowing out, he said; we have mud going to the crown. And, I said what ..., I was just horrified, and I said; what…? Did you all have it shut-in? He said; Jason is shutting it in now. And, he said; Randy we need your help! And I will never forget that. And, I said; Steve, I´ll be right there. So, it took only minutes for me to put my coveralls on, they were hanging on the hook, I put my socks on. My boots and my hard hat were right across that hallway I was telling about, in the tool pusher's office. So, I open my door, and I remember, a couple of people standing in the hallway, but I kind of had tunnel vision, I looked straight ahead, and I don´t…, didn´t even remember who does people were. And.…, about the time I made it to the doorway to the tool pushers office, was when a tremendous explosion occurred. It blew me probably 20 feet against the bulkhead, against the wall, in that office.*" [2.22]

By reconstructing the telephone conversation between Curtis and Ezell highlighted in yellow above, it may only have taken 15 to 20 seconds. By reconstruction the time it took for Ezell to get out of bed, put the coveralls and socks on and to run the short distance to the doorway in the tool pushers office, the time of the phone call can be estimated. The tool pusher's office where Ezell needed to go to get to his boots and hard hat was only five feet away across the hallway. [2.23] When you are in a hurry, it would probably take about 30 to 40 seconds to get out of bed rather than minutes. If we assume the time of explosion was at 21:49:15, this mean that Curtis probably called Ezell sometimes between 21:48:15 and 21:48:30. Ezell´s testimony about the phone call with Curtis, therefore supports the real time data that the riser was blowing out and diverter sequence activated as late as approximately 21:48 or one minute and 15 seconds before the first explosion. A typical diverter sequence for the flowline valve and diverter element to close, can also typically take up to 45 seconds, which may explain the dip in flow out at about 21:48:45.

2.2 Confirmation Bias

Confirmation bias is the tendency to search for, interpret, favor, and recall information in a way that affirms one's prior beliefs or hypotheses. [2.24]

For example, when the drilling crew observed no flow returning to the rig under the negative pressure test, it is easy to interpret this and believe that this was solid evidence that the cement plug was holding back the reservoir pressure. Other observations or anomalies that do not support the same conclusion are either ignored or alternative explanations that support the prior beliefs that the cement job was successful are created.

In the same way, the investigations teams may have a hypothesis that prior to the explosion and fire there must have been explosive gas or hydrocarbons traveling up the riser and expanding as the pressure gets lower. Information that supports this hypothesis is searched for, like performing dynamic OLGA® simulations. When the simulations show that the experienced drilling crew must have missed 1 000 barrels of gain before they closed the BOP, this does not directly support the hypothesis. Alternative explanations, like "simultaneous operations" [2.25] are used to explain why they missed the signs of hydrocarbons were under way. Other evidence, such as the real-time data of the flow out meter do not match the data from the OLGA® simulations or show no flow returning from the flow at all, does not support the hypothesis either. These evidences are either ignored [2.26] or alternative explanations such as the Sperry-Sun flow-out meter must have been bypassed are created. [2.27] Then new information to support this explanation is again searched for.

For a researcher there will always be tempting to search for or interpret observations and information in a way that affirms the hypothesis. In this thesis different wording is used in an attempt to avoid and to be aware of this temptation.

Maybe or ***possible*** are used when the information (real-time data, witness testimony, physical relationship, calculations, etc.) cannot reject the hypothesis.

Probably or ***likely*** are used when the sum of information is supporting the hypothesis.

Unlikely or ***probably not*** are used when the sum of information is not supporting the hypothesis.

Facts or ***observation*** are used to differentiate between observations of a symptom or phenomenon from the cause of the observation.

2.3 Assumption or Facts

In this chapter three important questions will be discussed. These questions are selected to show where the work done related to this thesis has resulted in a different conclusion then previous work and investigation reports.

2.3.1 Was the Sperry-Sun flow-out sensor bypassed?

Deepwater Horizon was equipped with two flow-out sensors. Transocean had a sensor and monitoring system from Hitec. Sperry Drilling had their own Sperry-Sun flow-out sensor and system. These flow-out sensors differed in type, location, and format. Hitec had a paddle-type flow-out sensor. 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. 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. [2.28]

The Hitec (Transocean) sensor was located in the return flow line before the line forked to either send returns to the pits or send them overboard. [2.29] The rig was equipped with a gumbo box with the possibility to bypass the shakers and send returns directly overboard. Figure 2.4 is from the Transocean investigation report and shows how it is possible to route returns directly overboard to the gumbo chute, bypassing the distribution box to the shakers.

According to the Chief Counsel´s Report (CCR) the Sperry-Sun sensor was located after the fork, capturing flow-out only when returns from the well were routed to the pits, see figure 2.7 showing a simplified drawing of where the sensors were located according to CCR. [2.30]

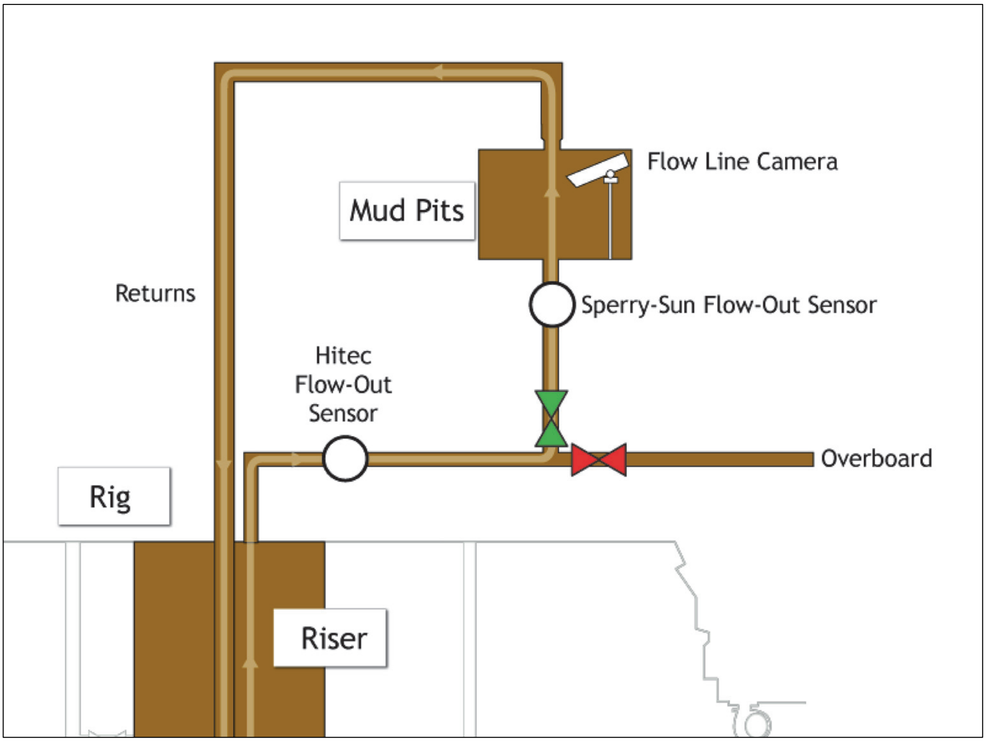


Figure 2.7 – Locations of flow-out sensors according to Chief Counsel Report. [2.30]

To justify this explanation of where the Sperry-Sun flow-out sensor were located, CCR are referring to the testimony by John Gisclair, October 8, 2010 (CCR Endnotes, page 309, note 45, Chapter 4.7). However, if you examine Gisclair´s testimony he is not stating that the Sperry-Sun sensor was located after the line forked to either send returns to the pits or send them overboard. On the direct question from the examiner;

"*Do you know specifically were the meters, that is the Sperry meters one, where they were actually located for flow-in and flow-out on the Deepwater Horizon?*"

Gisclair´s answer was;

"*The flow-out sensor for Sperry was located a couple of feet, ahh…, it was located on the return line a couple of feet before the return line enters the gumbo box*." [2.31]

The interesting part about Gisclair´s testimony is that he testified that the flow-out sensor was on the return line before the return line enters the gumbo box. The layout from Transocean of the gumbo box and flow line shown in figure 2.4 is therefore particularly interesting. If this layout is correct, the gate valve marked in red color (closed position), where the return line enters the gumbo box, is downstream of where the Sperry-Sun flow-out sensor was located according to Gisclair. This is the same valve which is marked in green color on figure 2.7. I.e., the simplified drawing made by CCR may then not be correct. The green isolation valve should be located downstream the Sperry-Sun flow-out sensor. Any fluid from the return line that bypass the shaker distribution box and mud pits and routed directly to the gumbo chute (left chamber in figure 2.4), will result in increased level in the return line upstream the closed gate valve, see figure 2.4.

However, as an expert witness to interpret the real-time data Gisclair later explains how the Sperry-Sun flow-out sensor was bypassed. This explanation is in contradiction to the layout shown in figure 2.4 and the explanation previously given about the location of the Sperry-Sun flow-out sensor;

"*So, after they shut down for the sheen test at 21:08, they conducted their sheen test and open the overboard line, close, ehhh…, close the gate, so that the fluids would…, the returning fluids would not go through the pit system, it were not going to the gumbo buster near where the Sperry sensors were located. It would essentially go…, pump that fluid into the Gulf. When they brought the pumps up, again to continue displacing, now all of the mud is out of the hole, they wanted to get rid of all that spacer. This is at 21:14, this is when they started to displace the spacer. At this point, the Sperry flow-out sensor was bypassed. Essentially all of the fluid that is coming out of that hole is not going past our sensor, it´s not going to the pit system, so it is not going past our gas detectors and there is no way to accurately track pit volume changes.*" [2.32]

Is it possible that this testimony conducted on October 8th, 2010 [2.32] was influenced by the conclusion in the BP report published September 8th, 2010?

However, let us assume that there was a way that the Sperry-Sun flow-out sensor could be bypassed and that the return after 21:10 was routed directly overboard. This is also what other investigation teams have assumed, ref. CCR, figure 4.7.12 on page 191.[2.33] Part of the figure showing real-time data and comments related to this question, is copied with a red circle around the comments and shown in figure 2.8. The first statement (with red circle around) is essentially the same statement that John Gisclair made;

"*Crew routes returns overboard, bypassing these sensors for pit volume, flow-out, and gas. That data can no longer be used to monitor the well.*" [2.33]

The second statement however, regarding observed flow from the riser during the last two minutes before the explosion, is again a contradiction;

"*Gains in the trip tank, active pits and flow-out show that hydrocarbons are still flowing up the riser (ANOMALY).*" [2.33]

This contradiction that flow past the Sperry-Sun flow-out meter is coming back after the sensor according to previous explanation was bypassed is partly explained;

"*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.*[2.34]

The part that is not explained is how the fluid got into the return flow line where the Sperry-Sun flow-out sensor was located? Let us assume for the time being that the return flow from the riser was routed to the mud gas separator, see figure 2.4. How do we explain that flow is detected in the flow return line, see figure 2.8, during the last minute before the explosion?

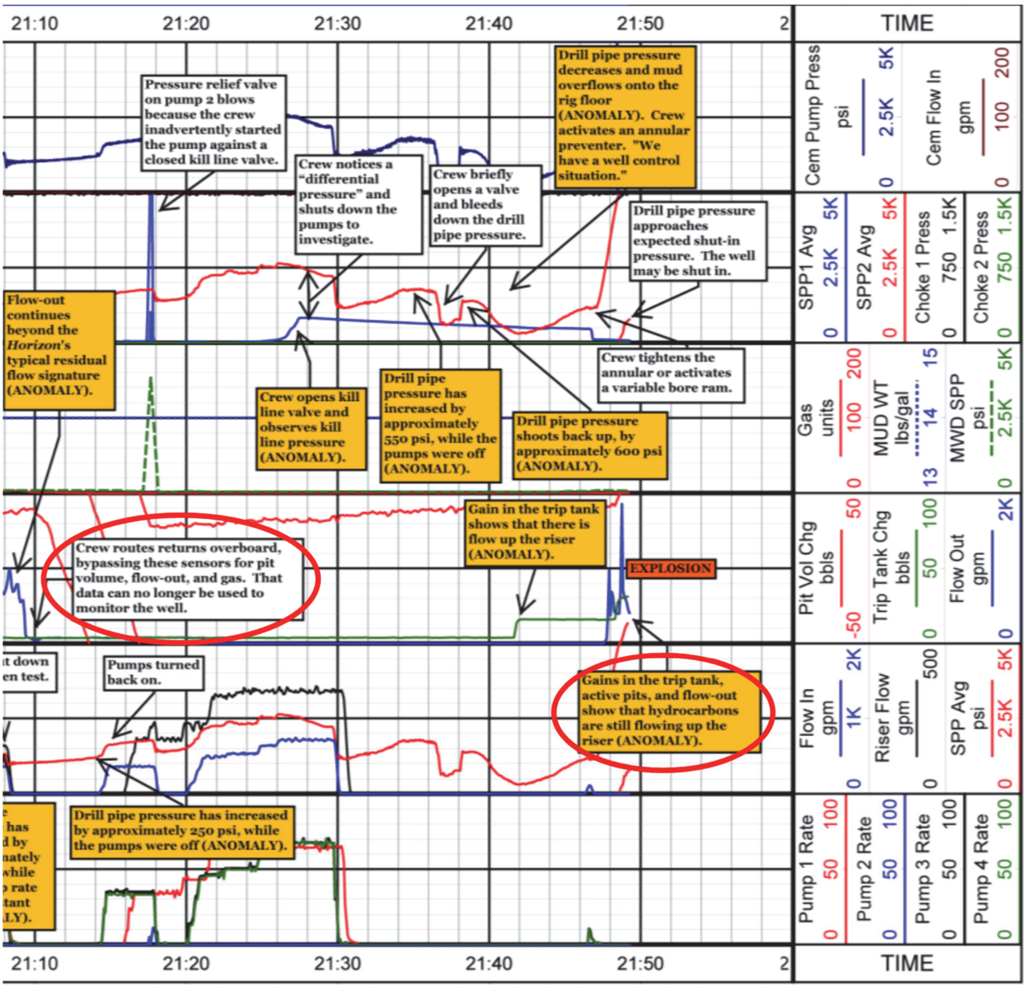


Figure 2.8 – Sperry-Sun real-time data from the last 40 minutes.[2.33]

John R. Smith has commented in his report to the joint investigation team about the flow recorded during this last minute before transmission of data to shore ended;

"*Flow out is also detected. The reason is unknown, e.g. whether flow was routed intentionally to the flow line and meter or a diverter valve is leaking or has failed open*." [2.35]

Smith´s proposal that the diverter valve is leaking or has failed open could be a possible explanation. However, if this was the case, he does not explain why the Sperry-Sun flow-out meter suddenly was not bypassed anymore?

Before the drilling crew was allowed to dump the water-based spacer into the GoM, a test had to be carried out by compliance specialist Greg Meche to ensure that the spacer did not contain any traces of oil.[2.8] This test is called the "sheen test". The assumption that previous investigations have made is that this test was carried out between 21:09 after the pump was shut down, and before the crew resumed pumping again at 21:14.[2.36] However, this does not explain why the Sperry-Sun flow-out meter continue to record flow after the pumps were shut down. Figure 2.9 is taken from the BP investigation report and show how flow-out continue with pumps off. [2.37]

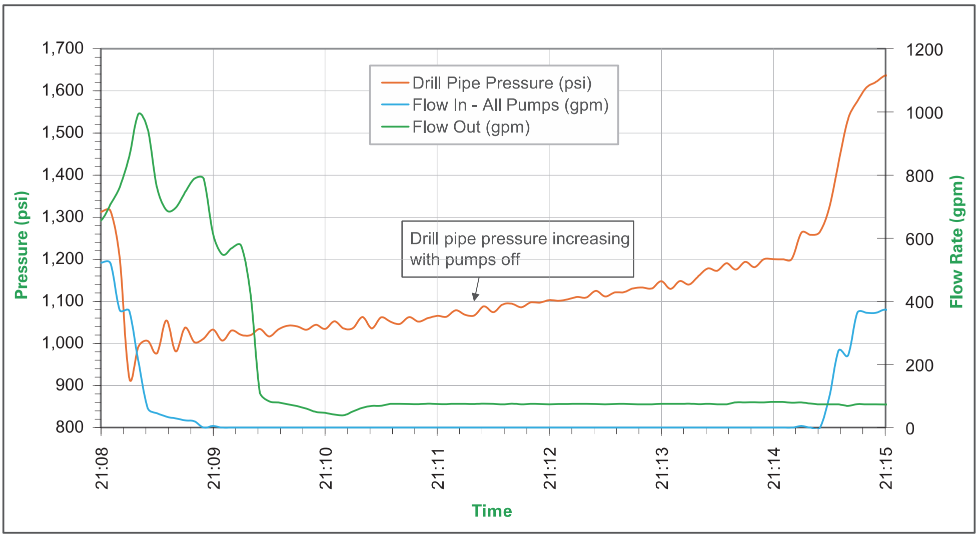


Figure 2.9 – Pressure increase and flow-out continue with pumps off. [2.37]

John R. Smith has commented in his report to the joint investigation team this anomaly that the flow-out continue with pumps off;

"*The calibrated flow out during this period begins at 75 gpm or almost 2 bbl/min. Industry practice would be to conclude that this is a positive flow check* *indicating a kick is in progress, i.e. that formation fluids were flowing into the well, and to shut the well in*." [2.38]

Smith also commented that the flow-out continue with apparently the same amount after the pumps were started up again;

"*Some flow out continued to be indicated until 21:22 although most flow out was apparently by-passing the meter as intended*." [2.39]

However, he does not explain why the flow-out rate did not change when the pumps started up again or routed overboard after the sheen test was done?

Also, according to compliance specialist Greg Meche any fluid going into the water had to be approved by him.[2.8] Meche was collecting the sample of the water-based spacer at the gumbo box in the shaker house, where the fluid was returning from the riser return line. Meche was standing by the Gumbo Box about ten minutes before the spacer returned and the sample was taken. [2.40] Meche gave the following testimony about what time he got a visual identification that the spacer was coming back and when he caught the sample of the spacer;

"*My sample was caught at 21:16, 9.16 pm.*" [2.41]

This is interesting statement because this is after the point in time were the investigation team has assumed that the sheen test was carried out. In fact, the pumping was resumed again at 21:14. Meche also stated later that after he had caught the sample, done the sheen test and measured the specific weight of the sample he went to mud engineer Gordon Jones in his mud shed to tell him what weight he got on the sample and that he and Gordon Jones agreed that the spacer was "*good to go*". He estimated the time of this last conversation with Jones to be 15 to 20 minutes before the explosion. [2.42] That will be around 21:30 or 20 minutes after the drilling crew routed returns overboard, according to the BP investigation report.[2.43]

Probably the returns were never routed overboard, since at the time mud engineer Gordon Jones and compliance specialist Meche agreed that the spacer was "*good to go*" [2.42], the drilling crew were already way into the process of investigating abnormal pressure readings, ref. figure 2.2 and anomaly 11 and 12.

2.3.2 Did data from the Hitec flow-out sensor sink with the rig?

With reference to figure 2.7 in chapter 2.2.1, Chief Counsel´s Report (CCR) has assumed or stated that;

"*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*." [2.30]

The question is whether this assumption or statement from the CCR that the Hitec (Transocean) flow-out sensor data are no longer available is correct or not. The BP investigation report has a more moderate statement about the two independent and different type of flow-out sensors;

"*Based on the information made available to the investigation team, there were two independent systems for measuring flow: Transocean's flow meter for the* *driller and a Sperry-Sun flow meter for the mudlogger. Only the Sperry-Sun real-time data was available to the investigation team.*" [2.44]

The interesting fact is that Transocean has used a different set of flow-out data in their investigation. Figure 2.10 is taken from Transocean investigation report.[2.45] If we compare the data for flow-out used in this figure (2.10) with the flow-out data used in the BP report (figure 2.9) and the CCR (figure 2.8) you will find out that these data are not the same.

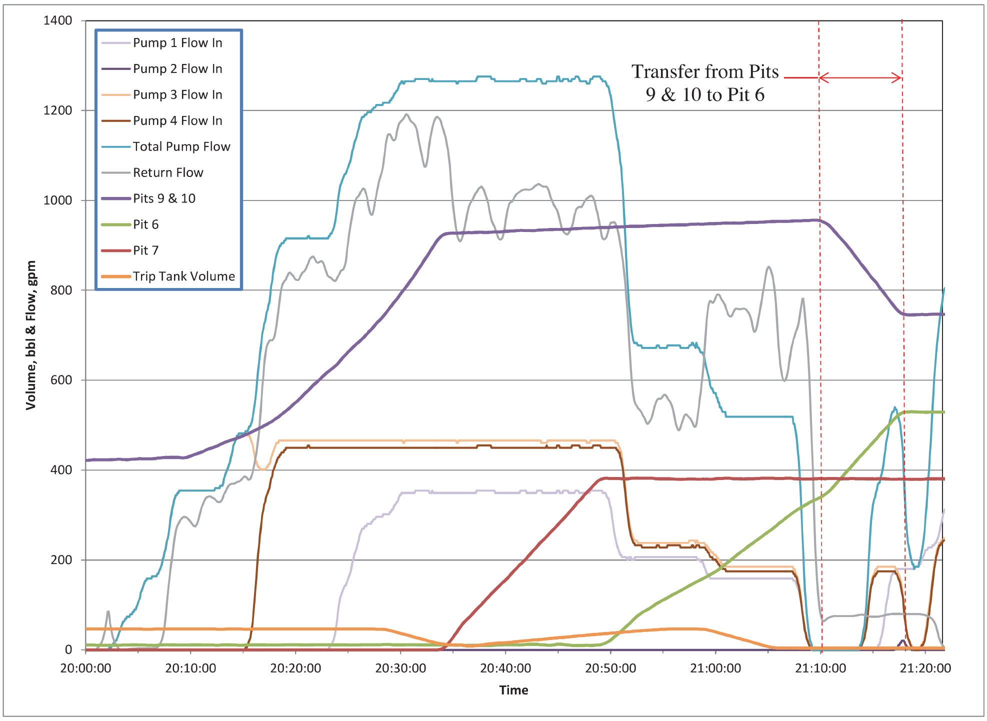


Figure 2.10 – Pit volume (bbl), pump flow in (gpm) and flow-out or return flow (gpm). [2.45]

The peak flow-out is about 1000 gpm in the CCR (figure 8) and BP report (figure 9) just after 21:08. However, in the Transocean report (figure 2.10) the peak flow-out shortly after 21:08 is less than 800 gpm.

To make it easier to compare the two different set of flow-out data, the two data sets have been plotted in the same diagram for a fifteen minutes period from 21:07 to 21:22. Total pump flow has also been added, in order to compare flow in with flow-out, see figure 2.11.

What are the possible explanations for why "*Flow Out – Sperry Drilling (gpm)*" (green line) and "*Flow Out – Transocean (gpm)*" (red line) are so different? One important difference between the data set used in the CCR and BP report compared with the data set used for the Transocean report is probably the number of sampling points. In the data set that was available for the research related to this thesis, an excel file named "Sperry-Sun 30 sec Data" has been used. This is the same data set that Transocean has used in their investigation. This data set gives a value every 5 seconds. That means that in figure 2.11, there are 12 data points for every minute. This also means that in time periods when the value recorded changes very fast, taking samples every 5 seconds may produce too few data points to give an accurate presentation of the current value. The value presented in figure 2.11 is therefore either a minimum, maximum or average value during the last 5 seconds.

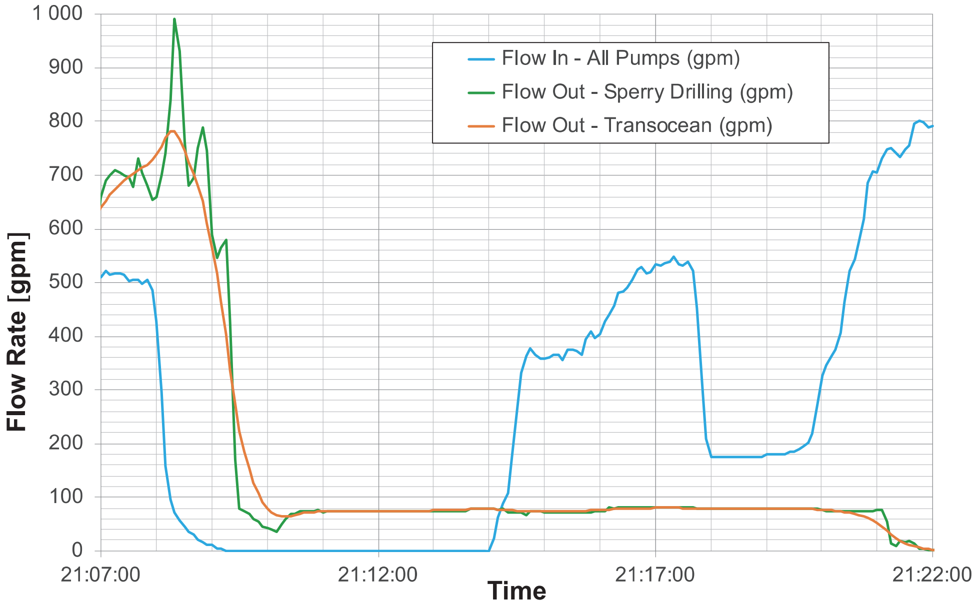


Figure 2.11 – Pump flow in and flow-out from riser between 21:07 and 21:22.

The values presented in the real-time plot (figure 2.8) from the CCR or the data presented in the BP report (figure 2.9), have probably got more sample points. If these figures for example were plotted with a new value every second, this would give 60 sample points in a minute. This difference is probably the main reason why the flow in data (blue line) looks slightly different when the pumps are shut down at 21:08, since the value then changes very fast. By comparing the "*Flow In – All Pumps (gpm)*" in figure 2.11 with "*Flow In – All Pumps (gpm)*" in figure 2.9 between 21:08 and 21:09, you will see that the plot does not look the same although it is generated from the same stroke counter on the mud pumps. [2.6]

This also explains why "*Flow Out – Sperry Drilling (gpm)*" in figure 2.11 looks slightly different from "*Flow Out (gpm)*" in figure 2.9. Since "*Flow Out – Sperry Drilling (gpm)*" in figure 11 is generated manually from pdf plot with only a data value every 5 second, it does not look quite as "smooth" as the original in figure 2.9 which is generated from the "live" feed of Sperry-Sun real-time data.

However, this difference in sampling rate does not explain the difference in "*Flow Out – Sperry Drilling (gpm)*" (green line) and "*Flow Out – Transocean (gpm)*" (orange line) in figure 2.11.

One possible explanation could be that the "Sperry-Sun 30 sec Data" represent the average value during the last 30 seconds. However, the average of "*Flow Out – Sperry Drilling (gpm)*" (green line) from 21:08:00 to 21:08:30 is 810 gpm. Which is higher than the value given in "Sperry-Sun 30 sec Data" used in the Transocean report. "*Flow Out – Transocean (gpm)*" (orange line) in figure 2.11 and "Return flow" (grey line) in figure 2.10 at datapoint 21:08:30 is 745.6 gpm. A more likely explanation is therefore that 745.6 gpm at 21:08:30 is the average recorded value during the last 5 seconds.

A more likely explanation is that the "Sperry-Sun 30 sec Data" represent all the data collected by Sperry-Sun from the Transocean sensors, such as pump speed, pit level, etc. including the Hitec flow-out sensor data. These data may have been transmitted to shore with updated values every 30 seconds, hence the name "30 sec Data". I.e. every 30 seconds 6 new data points or values were transmitted to shore. This transmission of "raw" data collected from Transocean would then come in addition to the "live" feed of processed data (ref. figure 2.8). In this "live" feed of processed data transmitted to shore, Sperry-Sun would use their own sonic type transmitter and not the paddle type flow meter provided by Hitec.[2.28]

Probably the data from the Hitec (Transocean) flow-out sensor did not sink with the rig after all but is used in the Transocean report. The reason why "*Flow Out – Sperry Drilling (gpm)*" (green line) and "*Flow Out – Transocean (gpm)*" (orange line) in figure 2.11 are similar but different can then by explained by different types of sensors (sonic vs mechanical paddle), location in the flow return line and sampling rate of data recorded. If an update of the "Sperry-Sun 30 sec Data" was transmitted to shore every 30 seconds, this would also explain why this data transmission ended at 21:49:00 and the "live" feed ended 15 seconds later at 21:49:15, see figure 2.3.

2.3.3 At what time did mud overflow onto the drill floor?

As hydrocarbon and in particularly gas travels up the riser it will typically expand due to lower pressure as the static weight of the mud above is reduced. At some point the fluid outflow from the riser will exceed the capacity of the return flow line and overflow onto the drill floor. If the gas expansion is rapid, it can push drilling mud all the way up to the top of the derrick (crown block). [2.20]

Since only the Sperry-Sun real-time data were available to the BP investigation team[2.44] and since the Sperry-Sun flow-out sensor was assumed bypassed, an OLGA® dynamic simulation to predict fluid flow out of the riser was made, see figure 2.12. [2.46]

Based on this flow modeling, assumptions about what may have caused the change in SPP at 21:39 have been made. Although there is a significant difference between <u>modeled</u> drill pipe pressure and <u>actual</u> drill pipe pressure at 21:39, the investigation team has assumed that the drop in actual drill pipe pressure is caused by mud exiting from the riser. Based on this the BP investigation team has estimated the timeline of some important events, see BP investigation report, page 111, table 1.[2.47] According to this analysis mud overflowed onto the drill floor at approximately 21:40 and mud shuts up to the crown block at approximately 21:41. They also have assumed that the BOP was closed shortly after causing the increase in actual drill pipe pressure at 21:42, see figure 2.12.

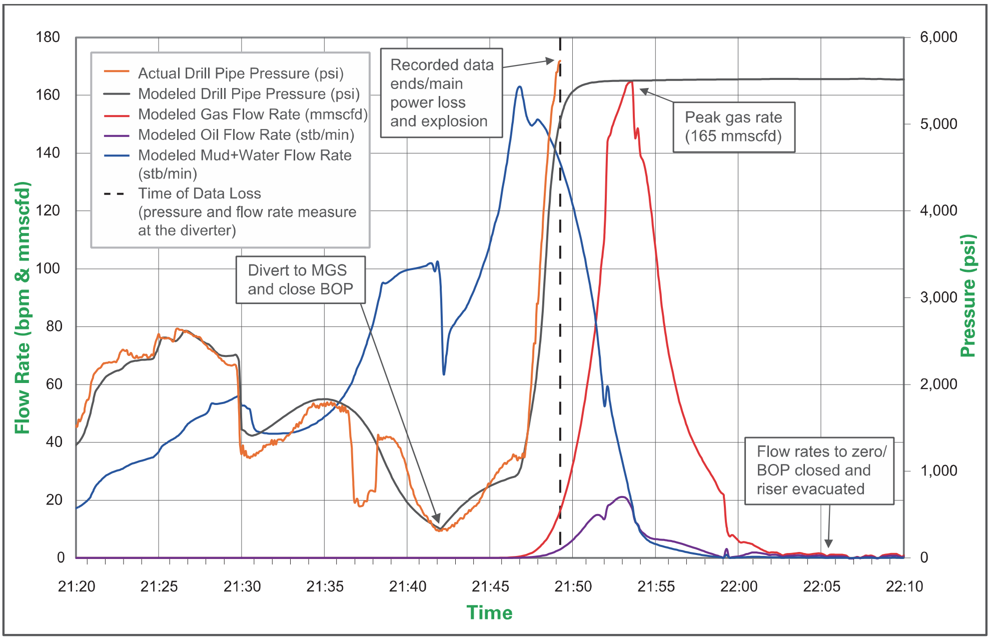


Figure 2.12 – OLGA® well flow modeling prediction of fluid outflow from the riser. [2.46]

However, the BP report also states that; "*Witness accounts contained some contradictions regarding when key events leading up to the accident occurred; therefore, the times stated in Table 1 are approximate.*" [2.48]

One of the key witnesses is Drill-Quip service technician Charles Credeur who was working on the aft port deck at the time of the incident. In his testimony he gave the following description of what happened shortly before the explosion.

Credeur: "*Mr. Don Clark came to me and told me he had to go to the pits.*"

Interviewer: "*And who is Don Clark?*"

Credeur: "*He was one of the AD´s with Transocean. And he left the area and approximately 30 seconds to a minute later, someone says; The well is blowing out! At the time I was approximately 50 feet from the rig floor on the main deck, with my back to the rig floor, so I just turned this way, and observed uhh…, drilling mud just…., the only way I could describe it, it looks just like a waterfall coming off the rig floor and onto the main deck. And it´s.., it was apparent to me that they just filled up with drilling mud, and we proceeded, myself and another gentleman,* *proceeded to walk along the port side of the rig, on the main deck, going towards…, forward lifeboats.*"

Interviewer: "*And who was that gentleman?"*

Credeur: "*Brandon Buyard. And we..ahh, we got approximately half way there, and my first thought was, at this time we were getting rained on by this drilling mud that is blowing out of the well, so my first thought was to get under the heliport, to get away from this mud and from that point we would see what we needed to do. Which we did, which on the Horizon you had a walkway which went all the way around the bridge, we went on the backside of the bridge, and uhh.., Brandon made a comment we needed to go to the lifeboats. At that time there was no one there at the lifeboats, but we proceeded to that area. We walked back along the, ehh…, bridge area, when we got back to the main pipe deck and turned the corner on one of the handrails, all the lights went off, and a second or two later I heard the first explosion."*

Interviewer: "*Do you know where that first explosion came from on relation to the rig?*"

Credeur: "*I have no idea. I really don´t. I just heard a loud explosion, and proceeded to walk down the stairways, going down to the lifeboat area. I was approximately half way down these set of stairs, when I heard a second explosion, and a watertight door right in front of me, well…, let me reword that, not directly in front of me but maybe 10, 15 foot from me, just kind of blew open and all kind of debris were just flying out. And, ehh…., I observed people coming out of the living quarter on the other door, I proceeded to lifeboat box, got a life preserver, put it on and when I got to the lifeboat no. 2, we ehh…, me and another gentleman, and I really didn´t see who it was at the time, we proceeded to open up the door and I proceeded to lifeboat 2."*

Interviewer: "*When you left the area, you were going to towards the helideck, were you continuously being rained on with this mud?*"

Credeur: "*I seemed to recall when initially when he…, the gentlemen said the well is blowing out, I can´t really say that I was rained on at that time. It seem more like, whenever we left from that area and walked along the port side, we got above half way, that´s when I first realized that.., that the mud was hitting us, you know, fly…, just kind of rained down on us."*

Interviewer: "*Was it mud or mud/water? Ahh, if you could differentiate…*"

Credeur: "*I ….., to me.., to my recollection it was mud."*

Interviewer: "*Prior to the…., you leaving the area, did you hear any gas or air release noises?"*

Credeur: "*No."*

Interviewer: "*And did you see about…, when did you look back at the derrick and identify that the mud was coming directly out of the derrick?*

Credeur: "*Yes, when I…, when we were at the back side of the bridge area, you know locking down on the lifeboats, you could also look up to the rig floor, and yes I could see….."*

Interviewer: "*So…, So from the time you got from where you were, to the…, to the lifeboat area, you could still see it? Flowing.."*

Credeur: "*Right.*"
Interviewer: "*…through the derrick. And how long about was that?*
Credeur: "*Ehhh…, maybe a minute. You know, it was pretty quick.*"[2.49]

The interesting part of this testimony is the detailed description and timeline from someone says*; "The well is blowing out!"* until the first explosion or power failure is observed. From the area where Credeur was working, (aft port main deck 50 feet from the rig floor) he proceeded to walk on the main deck along the port side of the rig in the forward direction. When he reaches the central control room (bridge), and got shelter from the helideck, he took a detour around the bridge. The detour around the bridge added approximately 55 meters (180 feet) in their walk towards the forward lifeboats.[2.50] When he walked back in the aft direction along the bridge towards the main pipe deck and turned left (starboard) at the corner of the handrails all the lights went off. Depending on where at the aft port deck Credeur was when someone says*; "The well is blowing out!*", he must have walked about 130 to 150 meters (426 to 492 feet), before the lights went off.[2.50] Considering the circumstances that the well is blowing out and they were getting rained on by mud blowing out from the well, they were probably walking fast. A fast walk of 130 to 150 meters may take approximately 1 minute and 15 to 20 seconds. His evaluation that it took; "*maybe a minute, you know, it was pretty quick*", is therefore not a poor estimate.

Credeur´s testimony and timeline also correspond with the testimony from senior tool pusher Miles "Randy" Ezell and the telephone call he had with assistant driller Steve Curties only seconds before the first explosion.[2.22] It also correspond to observations by Mike Holloway. He worked on the starboard aft deck at the time of the riser blowout and had a detour up to the rig floor and heavy tool store.[2.51]

These witness observations confirm that everything happened very fast. The fact that two different sets of flow-out data, increase in trip tank and increase in active pit no. 9 and 10, all happen during the last two minutes, is also a strong indication that everything went very fast. Probably water based viscous spacer flooded the rig floor at approximately 21:48. The diverter sequence, i.e. open overboard line to the leeward (starboard) side, close the flow return line and close the diverter element, was also probably activated about the same time (21:48).

This conclusion is totally different from previous investigations. BP´s investigation team reconstruction of the last minutes prior to the explosion concluded that mud overflowed the flow-line and onto the rig floor at approximately 21:40 and that mud shot up through the derrick at 21:41.[2.47] The investigation team apparently believed the OLGA® simulation model, which estimated the influx volume or cumulative gain to be approximately 1 000 barrels before the first well control action was taken at 21:41 according to the BP investigation.[2.52]

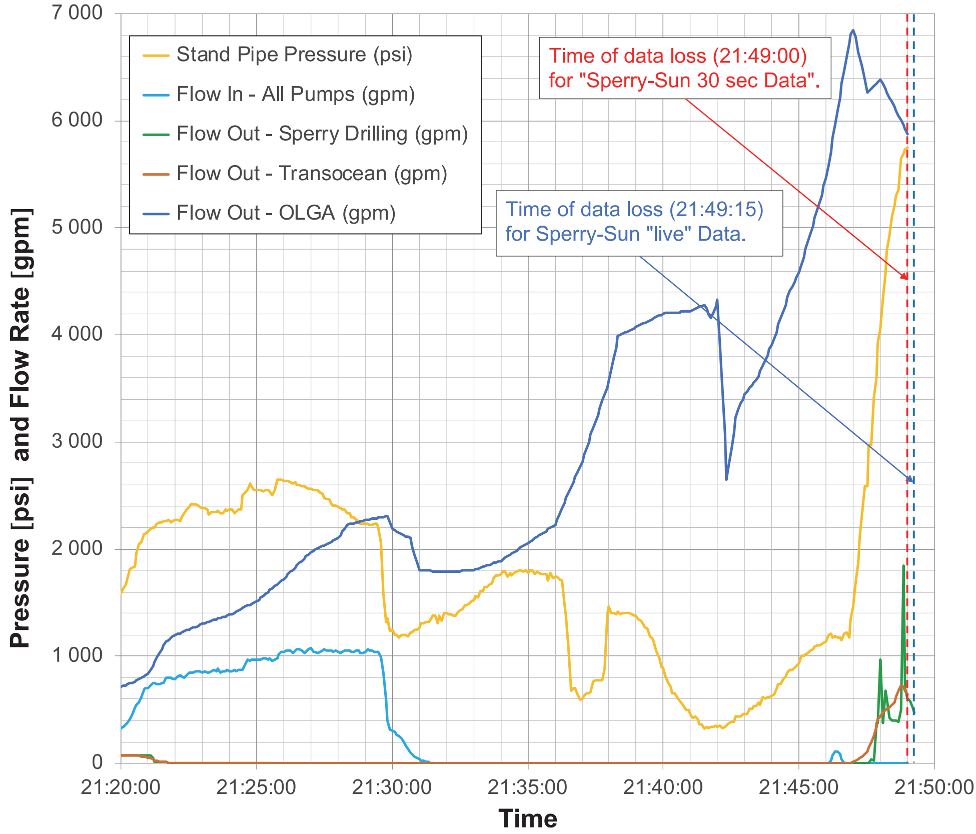


Figure 2.13 – OLGA® well flow modeling compared with real-time data.

In figure 2.13 the results from OLGA® simulation (see figure 2.12) of prediction of flow out from the riser (gpm) is plotted and compared with real-time data during the last 30 minutes.

Previous investigations have assumed that there must have been flow coming out of the riser also after all pumps were shut down at 21:30. Even after David Young testified that both Anderson and Revette at times were looking at the driller's screens[2.11] and even if previous investigations seem to agree that the Hitec flow-out meter could not have been bypassed, [2.53] it seems that they all believe that in some way the experienced drilling crew must have missed that the well was flowing. According to the OLGA® simulation, the flow out from the riser, passing the Hitec flow-out meter, increased from 43 bpm (1806 gpm) at 21:31 to 53 bpm (2226 gpm) at 21:36, see figure 2.12 and 2.13. During these five minutes the rig should have received a total gain of 227 barrels according to the OLGA® simulation. During these five minutes Anderson and Revette were observing anomalies[2.12], and apparently discussing internally what to do next. It is highly unlikely that the drilling crew should have missed flow from the riser of this magnitude. It does not correspond with a drilling crew that had discovered anomalies, "*appeared concerned but calm*" and at times were looking at the screens. [2.11]

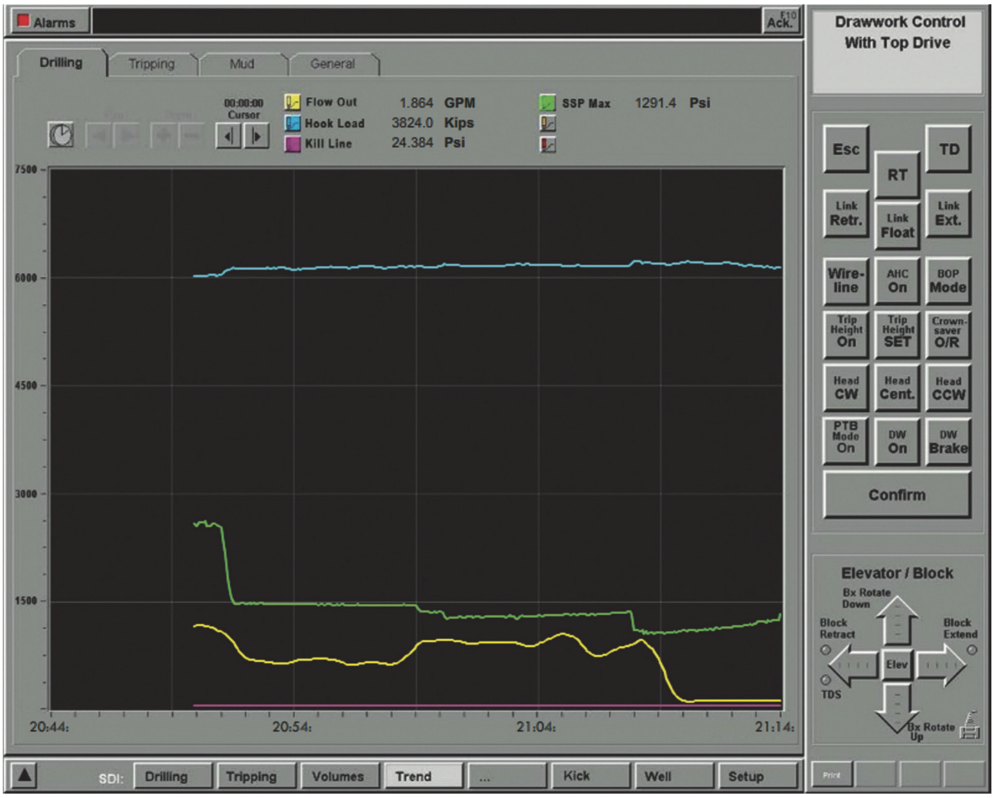


Figure 2.14 – Simulated Hitec screen based on real-time data up to 21:14. [2.54]

It seems even more unlikely when according to Transocean, the Hitec screen that the drilling crew were watching contained trends of flow out, kill line pressure and standpipe pressure on the same screen, see figure 2.14 simulating how the Hitec screen that the drilling crew were watching probably locked like a few minutes earlier.[2.54]

It is also highly unlikely that their next step to order Transocean floor hand Caleb Holloway to bleed off pressure on the standpipe manifold, is consistent with flow from the riser at this time. [2.12]

On the contrary, the action taken to bleed pressure from the drill pipe (standpipe manifold) is consistent with a belief by the driller and tool pusher that a plug existed. [2.55] The fact that two different sets of flow-out data also show that no flow was coming out of the riser at this time (21:36) also indicates that the drilling crew likely was right in their assumption that a plug existed. It is therefore problematic when all the previous investigations; that is BP[2.56], Transocean[2.57], BOEMRE[2.58] and CCR[2.59], all conclude that the well was flowing (gaining) and therefore did not investigate the possibility of the existence of a plug. First of all, it is problematic because the industry needs to understand what could have caused such a disaster in order to prevent similar accidents to happen again. Secondly, it is problematic because both Anderson and Revette lost their life in the explosion and fire on Deepwater Horizon, and cannot explain why they apparently believed in the existence of a plug and justifying the attempt to bleed down the pressure on the standpipe. [2.55]

The work done and presented in this thesis is based on a hypothesis that a plug in the riser existed at the time when Holloway opened a valve on the standpipe manifold to bleed of pressure. The work done is also based on real-time data and testimonies from key witnesses that confirm that flow from the riser started to come back approximately 21:46:35 [2.60], outflow then increased until mud/spacer overflowed the flow-line and onto the rig floor at approximately 21:48:00 and shot up through the derrick shortly after. [2.49]

Chapter 3 – The Macondo Well

The Macondo well after running the 9 7/8" x 7" production casing and prior to the cement job is shown in figure 3.1.[3.1]

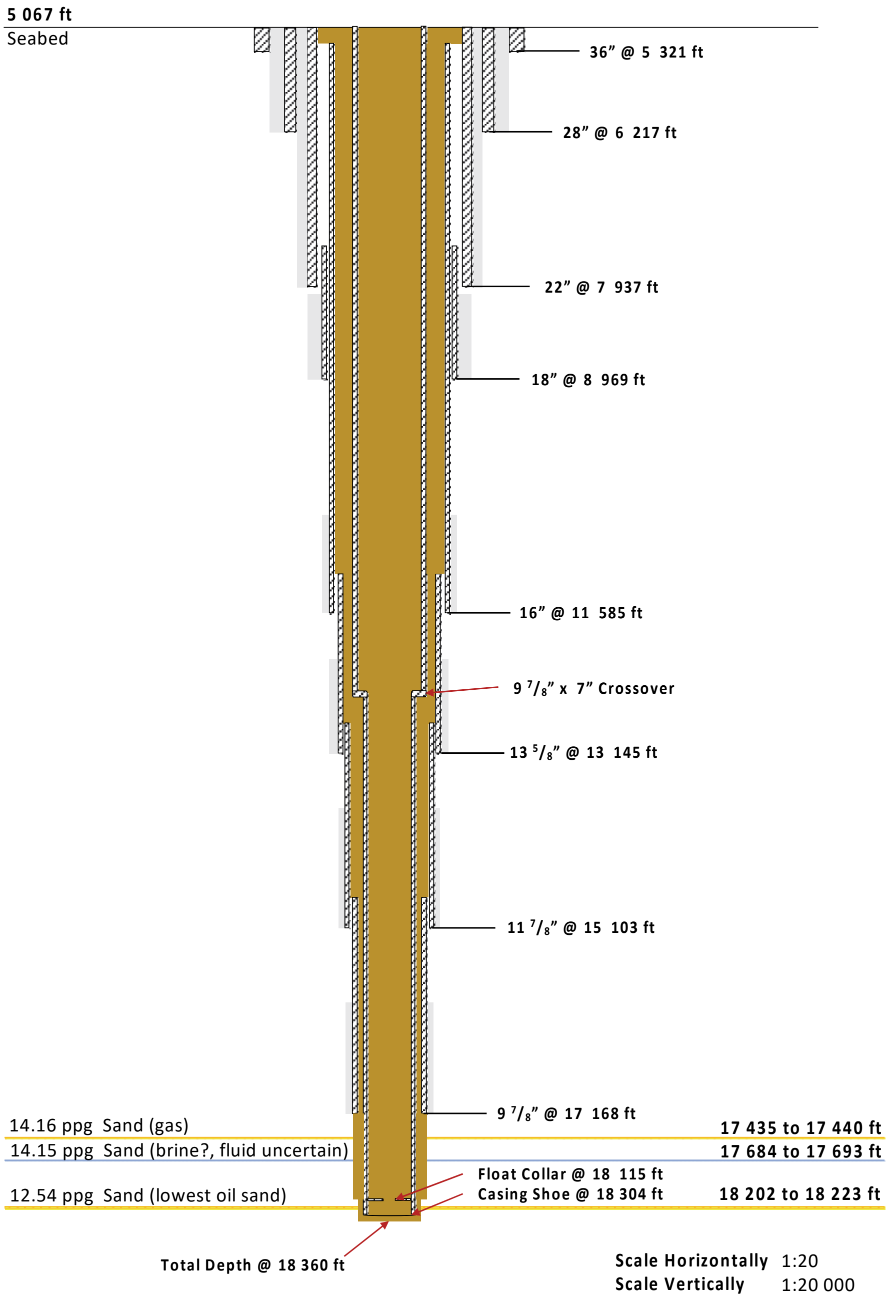


Figure 3.1 – Macondo well after running the 9 7/8" x 7" production casing.

3.1 Lost Circulations

While drilling the Macondo well a series of complications occurred. It was a difficult well to drill.[3.2] Lost circulation occurred several times as well as ballooning and kicks, see figure 3.2 taken from the Chief Counsel´s Report.[3.3]

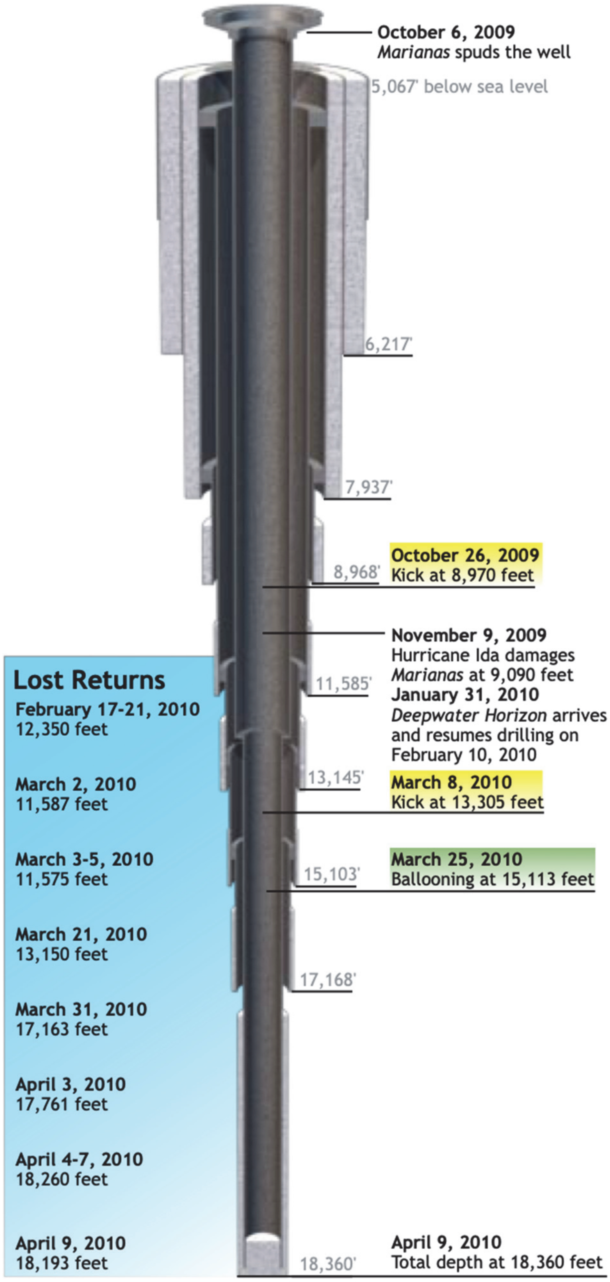


Figure 3.2 – Timeline of drilling events.[3.3]

Events of particular interest is the lost circulation events that occurred after the 9 $^7/_8$" casing was cemented in place at 17 168 ft depth. There are some inconsistencies between the different investigation reports on how many and when the lost circulations events occurred during drilling this final production casing zone from 17 168 ft down total depth of 18 360 ft.

According to the BP accident investigation report it seems that they had one lost return event that occurred on April 4, 2010: "*Drilling of the final 8 1/2 in. x 9 7/8 in. hole section started on April 2, 2010, and continued until April 4, 2010, when the well encountered lost circulation at 18,260 ft. Lost circulation pills were pumped to the bottom of the wellbore, and the mud weight was reduced from 14.3 ppg to 14.17 ppg. This solved the lost circulation problems. Full circulation was regained on April 7, 2010, and on April 9, 2010, the well was drilled to a final depth of 18,360 ft.*" [3.4]

However, Chief Counsel´s Report (CCR) has stated that; *"The last of the lost circulation events occurred on April 9, after the rig had begun to penetrate the pay zone."* [3.5] The source for this statement is given to be; "*Internal Transocean document (TRN-USCG_MMS 11596)*". [3.6] CCR has also shown, that in addition to this last lost circulation on April 9, and the event on April 4-7, there was also a lost circulation event on April 3 at 17 761 ft, see figure 3.2. [3.3]

The BOEMRE report has also an interesting statement about mud loss at this depth (17 761 ft). "*Mud logging data for the Macondo well demonstrated that the production casing zone started ballooning between 17,530 feet and 17,761 feet. The daily IADC reports also show that the well flowed back during flow checks following mud loss at those depths.*" [3.7] BOEMRE report has also an interesting statement about mud losses during drilling of this final section of the well. *"According to IADC daily reports, the well experienced mud losses of approximately 3,000 bbls across the hydrocarbon zones of interest during the drilling of the production casing open-hole section."* [3.8]

3.2 Running out of Drilling Margin

Figure 3.3 is from BP unpublished report, July 26, 2010. Reprinted with BP permission in; National Academy of Engineering and National Research Council. 2012. *"Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety*". [3.9] Comments about pore pressure are added for clarity.

After the lost circulation event that occurred on April 4, mud weight was reduced to 14.0 ppg at surface temperature and atmospheric pressure. When heated up and compressed to downhole conditions, this corresponds to an average effective mud weight at approximately 14.17 ppg. [3.10] This effective mud weight is also called equivalent static density (ESD). However, despite lowering the mud weight another lost circulation event probably occurred on April 9. [3.5] This loss was unexpected, and engineers concluded they had "*run out of drilling margin*". The well would have to stop short of its original objective of 20,600 feet.[3.11]

The reason for this decision is shown in figure 3.3. Since the mud weight had already been reduced to effectively 14.17 ppg and the pore pressure prediction of the uppermost gas sand in the open hole was approximately 14.16 ppg and the initial GeoTap pressure was measured to 14.15 ppg in the sand below, the mud weight could not be lowered any further. At the same time the ECD needed to be kept below 14.5 ppg in order to avoid fluid losses.[3.12]

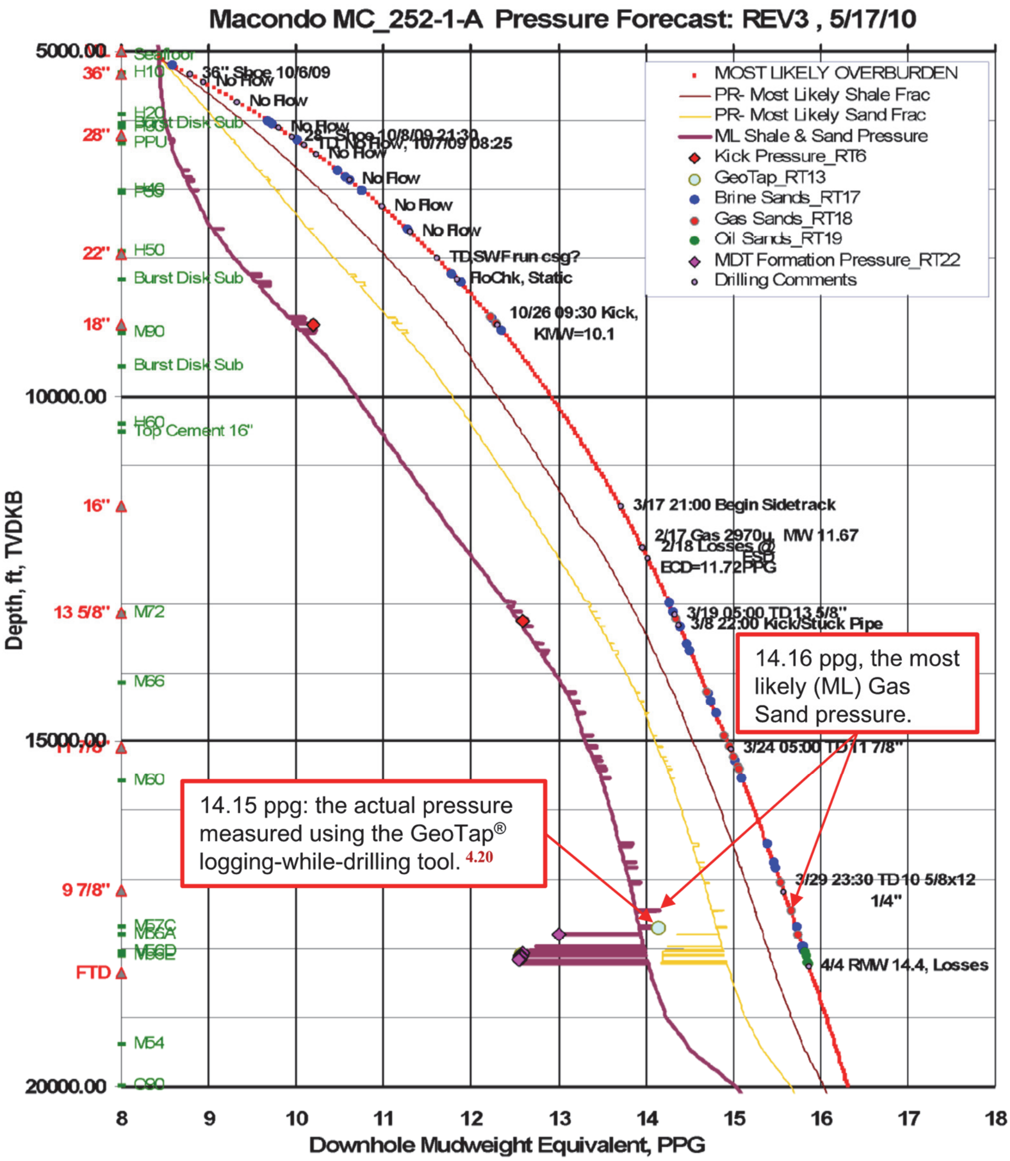


Figure 3.3 – Macondo Well Pore Pressure Prediction [3.9]

On April 13 an internal BP email explained that the team decided to stop drilling because it had become *"a well integrity and safety issue."* The email [3.12] also states:

"We had one major problem however: the sand that we took the initial GeoTap pressure in was measured at 14.15 ppg. The absolute minimum surface mud weight we could use to cover the pore-pressure in this sand was 14.0 ppg. This would give us approximately a 14.2 ppg ESD over the aforementioned sand. If we were to drill ahead with a 14.0 surface mud weight/14.2 ESD, our equivalent circulating density (ECD) would be approximately 14.4-14.5 ppg. We had already experienced static losses with a 14.5 ppg ESD! It appeared as if we had minimal, if any, drilling margin . . . Drilling ahead any further would unnecessarily jeopardize the wellbore. Having a 14.15 ppg exposed sand, and taking losses in a 12.6 ppg reservoir in the same hole-section had forced our hand. We had simply run out of drilling margin."

3.3 Well Ballooning

The observed loss of mud followed by flow between 17 530 ft and 17 761 ft is an interesting phenomenon. BOEMRE report has characterized these observations as well ballooning. [3.13] This phenomenon is also generally referred to as wellbore breathing, (Baldino et al., 2019A). When loss of mud is followed by flow back, it is essential to find out if the flow back only contains the mud that was lost, or if the flowback also contains formation fluids (Richert 2019). BOEMRE describe this in their report in the following way:

"Well ballooning is a common phenomenon in which the formation absorbs drilling mud while the rig's pumps are activated and then releases the mud back into the well when the pumps are not active. Well ballooning is significant because it can mimic a kick. Rig crews can therefore miss critical kick indicators if they mistakenly believe that ballooning is occurring in the well." [3.14]

These observations of flow back during flow checks [3.7] are important. The observed flow back when drilling this production casing zone between 17 530 ft and 17 761 ft may have been a gas kick and not ballooning. Since there are sometimes different opinion of what a *kick* is, this thesis will use the definition given in Appendix E. In other words, a *gas kick* is an *unexpected and unwanted entry of gas into the wellbore*. The drilling crew may have confused a gas kick with ballooning. Again, since there is also different opinion of what *ballooning* is, this thesis will use the definition given in Appendix E. In other words, *ballooning* occurs only when the drilling or completion fluid that is lost to the formation is returning to the wellbore and are not swapped out partly or totally with formation fluids.

The common understanding of the mechanism of ballooning is that the additional frictional pressure caused by circulation of drilling mud can cause fractures into the formation. If equivalent circulating density (ECD) exceeds formation fracture pressure, micro fractures are created, and drilling mud will be lost into small induced fractures. When pumps are turned off, the annular pressure will be reduced because frictional pressure loss becomes zero. The induced micro fractures will close, and the drilling mud will flow back into the wellbore. [3.15]

Several authors and publications have made mathematical models to better understand the mechanism of ballooning or wellbore breathing. The common understanding or assumption is that no appreciable flow occurs through the pores of the formation, (Baldino et al., 2019A). In other words, the loss of drilling mud and subsequent flow back, are caused by mechanical opening and closing of induced fractures only. Furthermore, if the fracture already exists (naturally fractured formations), a common assumption is that; "*The fractures are initially empty, or otherwise saturated with fluid that has the same properties as the wellbore fluid.*" (Baldino et al., 2019B; Lavrov and Trondvoll 2005).

In the case of Macondo, they were probably drilling trough thin layers of gas sand with high pore pressure. [3.1] In these cases the porosity or void fraction of the rock that contains compressed gas becomes important. When drilling fluids are lost, either through induced fractures or through the openings in the porous gas sand, the gas in the void space is displaced alternatively going into solution with the filtrate (base oil) invading the pore space. The fluid properties of the mud, filtrate, pore fluid (natural gas) and permeability of the gas sand become important.

Natural gas under the pressure and temperature that was present when drilling this production casing zone in the Macondo well, is in what generally is referred to as *dense phase*. In dense phase the fluid has a viscosity similar to that of a gas, but a density closer to that of a liquid. [E.7] Since the gas has been trapped in the void space for millions of years it has no way to go. The only escape route is up the borehole. Another alternative is that the pressure in the pore space close to the drilling fluid invasion zone increases and the formation is charged to a temporary higher pore pressure. Although the density or compressibility is similar to a liquid, both liquids and gas in dense phase are highly compressible fluids. [E.7] The observed flow back when pressure in the wellbore is reduced during connection may therefore be caused by expanding natural gas or other reservoir fluid in the formation. This is a different but old explanation of the observed phenomenon of ballooning (Gill 1986), compared to what seems to be an industry accepted theory of opening and closing of fractures [3.15] (Baldino et al., 2019A & B; Lavrov and Trondvoll 2005).

In a paper from 1986 called; *Charged Shales: Self-Induced Pore Pressures*, J.A. Gill explains the observed phenomenon of ballooning in the following way:

"The borehole apparently balloons or breathes, slightly, when long sections of already over-pressured, wet, plastic shales are drilled greatly in overbalance (but not by then easily recognizable as overbalance); taking 20-30 bbls of mud while circulating and giving it back (if we let it) when pumps are shut down.

This new, superimposed and "bottled-up" hydrostatic pressure in the wellbore from the (excessive) mud density is then very real." (Gill 1986)

To understand how pore pressure can increase due to high ECD and invasion of drilling fluids into the formation, earlier work on shale may be helpful. In a recent study carried out by Eric Van Oort and Total E&P to understand the complicated relationship between transport in shales (e.g. hydraulic flow, osmosis, diffusion of ions and pressure) and chemical change that governs the stability of shales was investigated. The integrated study clearly identified the root cause(s) of historical well problems. The problems with wellbore caving were not related to low mud weight or type of mud selected (WBM or OBM) but were instead caused by mud pressure invasion into the shales, which destabilizes them over time. Both WBM and OBM to an equal extent (van Oort et al. 2019).

The mechanism described by Eric von Oort to understand how cavings are spalling off from the walls of the open hole shale sections due to elevated near bore hole pore pressure is interesting. Effect of mud-pressure penetration and near-wellbore pore-pressure elevation in time, is shown in figure 3.4 (van Oort et al. 2019, Fig. 2).

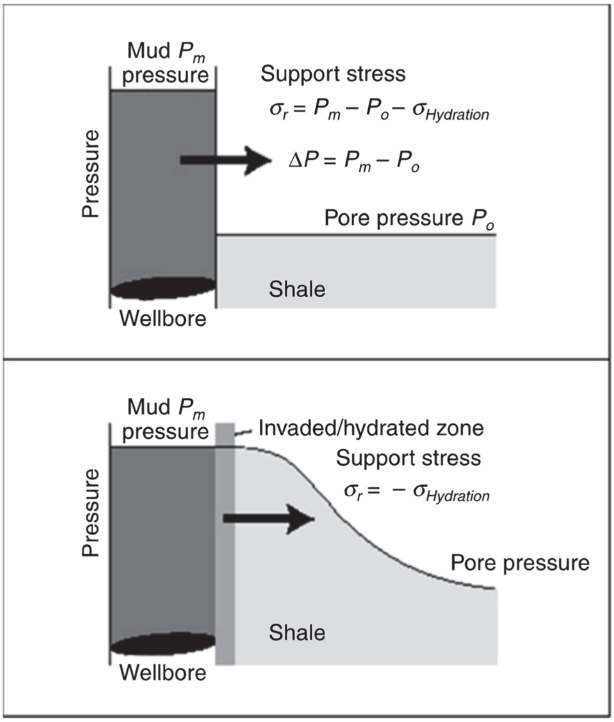


Figure 3.4 – Pore pressure elevation in shale (van Oort et al. 2019, Fig. 2).

These results from both experiments and field experience is that the pressure invasion in the relatively low permeability shale developed over time. The pressure invasion front travels relative slowly in the shale. The borehole instability problems and wellbore cavings occurred after 3 to 5 days (van Oort et al. 2019).

Drilling through relatively high permeable gas sand is a different problem than wellbore instability problems related to shale. The result from previous research on shale may therefore not be used directly. One of the factors that should be investigated is the effect of gravity in high permeability gas sands.

3.3.1 Effect of gravity

One important difference in fluid properties between the wellbore fluid (typically drilling mud) and formation fluid (typically natural gas) is the specific weight. Since drilling fluid is typically heavier than gas, the differential pressure between wellbore pressure and the formation pore pressure will increase with depth, see figure 3.5.

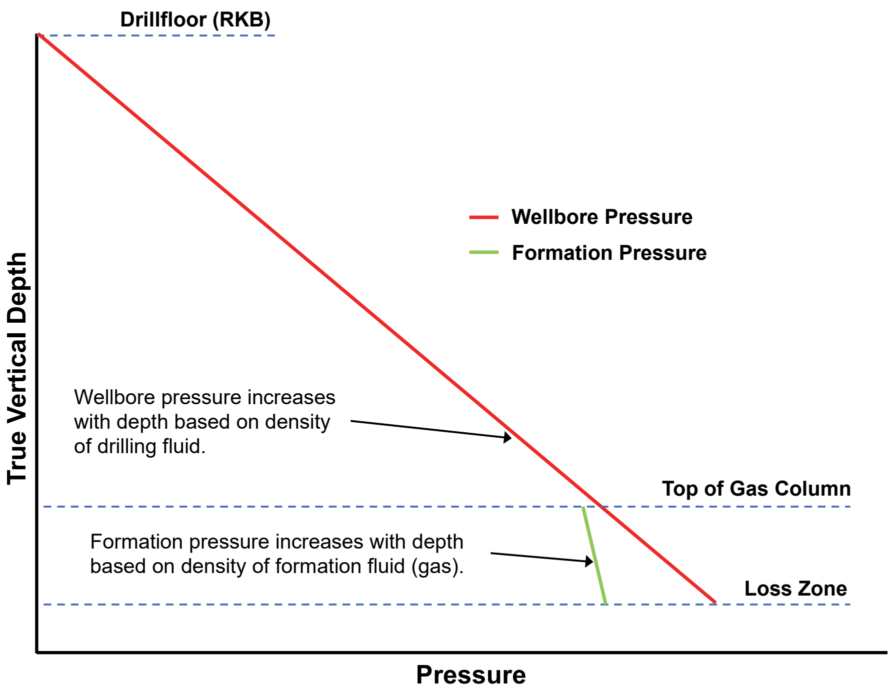


Figure 3.5 – Differential Pressure between wellbore pressure and formation pressure.

Assuming that the rock formation throughout the gas sand is uniform. The loss of drilling fluid into the formation will then typically be greater in the bottom of the gas sand where the differential pressure is the greatest. The drilling mud "invasion zone" will therefore be larger in the bottom of the gas column (gas sand) than in the top of the gas column. Likewise, the risk of gas flowing back into the wellbore will be greater in top of the gas column, where the mud invasion zone is not as thick, and the pressure differential is less.

The effect of gravity (g) and difference in specific weight or density (ρ) between the two different fluids can be illustrated in a simple experiment. In the experiment a water dam was made of sand in a box made of transparent glass walls. As the water level got higher (h), pressure ($p = \rho\ g\ h$) in the bottom of the box increases. The pressure difference (Δp) between the pressure in the bottom of the box due to the difference in air density (ρ_{air}) and water (ρ_{water}) is then given by the following formula (1).

$$\Delta p = (\rho_{water} - \rho_{air})\, g\, h \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \ (1)$$

It is a very simple formula, however important to understand why the invasion of water into the dam made of sand, is greater in the bottom of the sand column than it is in the top. See figure 3.6 showing a picture of the experiment. The zone of water invasion into the void or air space between the sand grains can be seen with a darker color in the sand. [3.16]

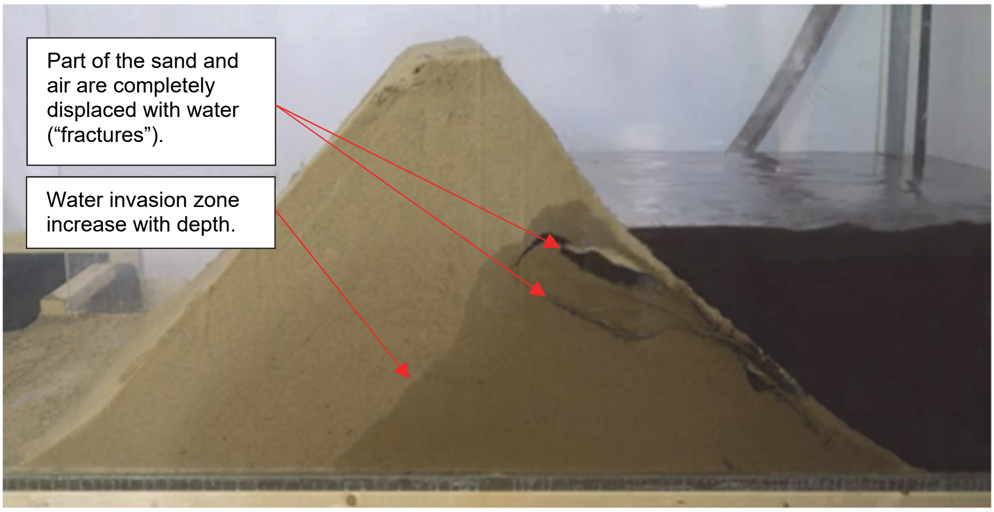


Figure 3.6 – Picture of a water displacing air in a water dam made of sand. [3.16]

Although the simple experiment shown in figure 3.6 is made under atmospheric conditions, with water and the displaced air allowed to escape to the atmosphere, it can be useful to understand the mechanism of ballooning. Loss of drilling fluids into the formation during circulation and high ECD followed by flow back when pressure is reduced may then be explained by other means than closing of fractures.

Probably a better explanation is that the drilling or completion fluid invasion into the formation displace the formation fluids in the pore space, which again results in a temporary pressure increase in the pore pressure close to the zone affected by the loss. When the pressure in the wellbore is reduced, this will result in a flow back of fluids into the wellbore to equalize the pressure (Gill 1986). The flow back into the wellbore is likely to be larger in the top of the gas column where the static pressure in the wellbore is lower, see figure 3.5. The flow back into the wellbore is also likely to be larger in the top of the gas column which will typically be less effected by the loss of drilling fluid. Since the lower part of the gas column (or gas sand) is more likely to be plugged and cemented with mud particles, it can be assumed that flow restriction is less in the top of the gas sand, see figure 3.6.

The effect of viscosity should also be considered. Flow through a porous media such as sandstone will be affected by the viscosity. Thick mud needs higher differential pressure to flow through the same formation compared to natural gas in dense phase which has a viscosity similar to that of a gas [E.7]. Likewise, clean completion fluids are typically less viscous than drilling mud.

It should also be noted that if the formation pore pressure is close to the wellbore pressure, i.e. only slightly overbalanced, the effect of the differential pressure caused by the difference in specific gravity between the gas and the wellbore fluids, becomes more important. If we imagine a wellbore that is in balance with the formation pore pressure, due to gas cut drilling/completion fluid or for some other reason, it is possible to end up in a situation where the well is underbalanced in top of the gas column and overbalanced in the bottom. In this way drilling or completion fluid can be lost or seep into the formation in exchange with gas influx from the top of the gas column simultaneously. This phenomenon may have been a contributing factor in the Hercules 265 blowout in GoM in 2013, see figure 3.7 taken from the investigation report. [3.17]

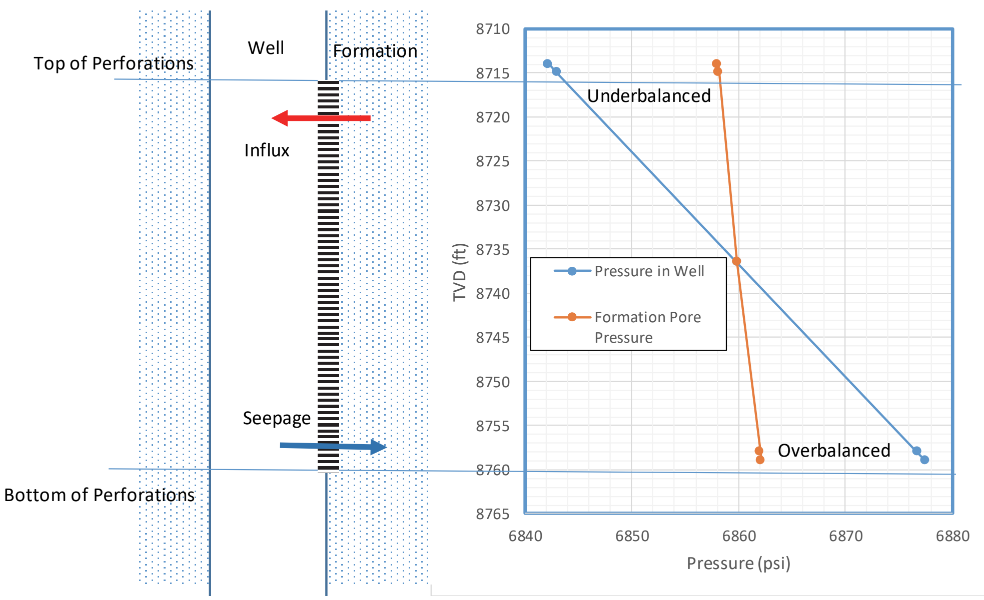


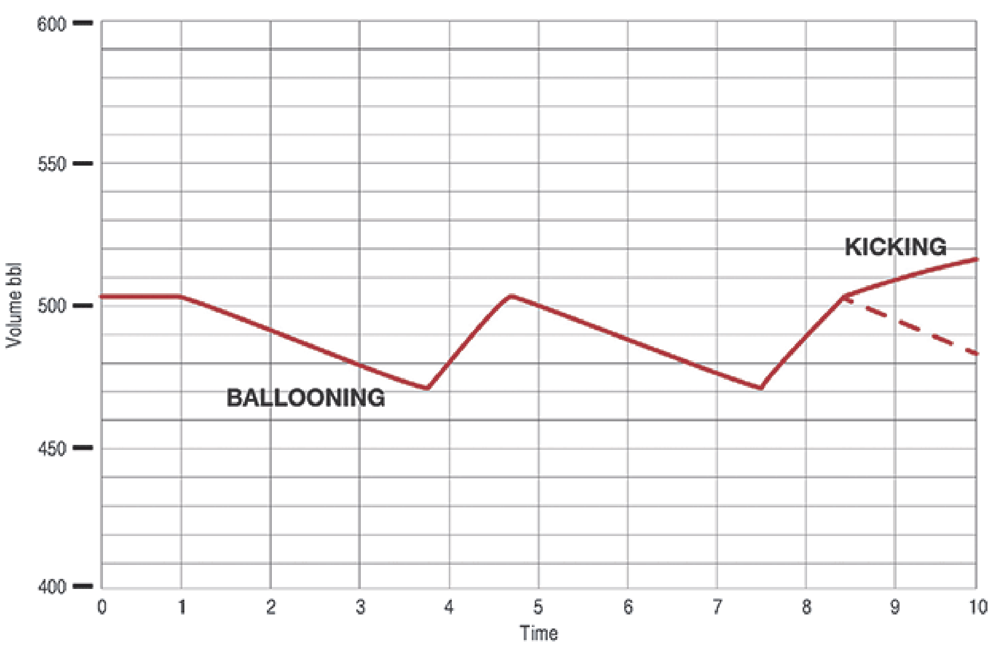
Figure 3.7 – Pressure gradient across perforation at balanced conditions. [3.17]

However, this effect of gravity and difference in density to explain the exchange or swap out mechanism will only work when the wellbore pressure balance the pore pressure and the height of the gas column is high enough to build up a differential pressure large enough to allow for mud/completion fluid seepage or loss to the formation. In the case of Macondo, the 14.16 ppg gas sand was thin and in addition the well was drilled largely overbalanced when ballooning was observed. The effect of gravity will therefore be further discussed in chapter 3.5.2.

3.3.2 Ballooning perception may be flawed

It is crucial to determine whether the observed flowback during connection is caused by ballooning or in fact a kick or influx of gas has occurred. A very interesting article by Steve L. Richert called "*Ballooning Perception May Be Flawed*", gives some examples on misinterpretation and belief that the well was ballooning, when instead the well had taken an influx (Richert 2019).

An accepted industry practice is to fingerprint or compare flow lost during start of circulation and drilling, with the amount that flows back during connection (pumps off). See figure 3.8 taken from the same article (Richert 2019, Fig. 2).



Fingerprinting is a graphical tracking of fluid losses into the formation that makes it possible to recognize if a well is ballooning or kicking.

Figure 3.8 – Fingerprinting to determine if the well is ballooning or kicking. (Richert 2019)

However, this method shown in figure 3.8 may not be reliable. If some of the drilling fluid that was lost into the formation during circulation has been swapped out with formation fluids typically gas, this will not necessarily result in net gain.

The reason why gas kick has been taken in the case of ballooning similar behavior, is probably **not** due to the well was statically underbalanced before the formation was charged. I.e. the well may not be statically underbalanced (except from a short period after circulation stops) and will therefore not continue to flow after the pressure in the wellbore has equalized.

On the contrary, the displacement of gas due to drilling fluid lost into the formation may have resulted in an increase in the gas pore pressure, resulting in gas influx when pumps are shut-off and pressure in the wellbore decreases. This is probably the same mechanism that occur when seeing connection gas. However, in this case the amount of drilling fluids that is lost to the formation can be severe and consequently the flow back period and amount of connection gas increases. Since the temporary increased pore pressure decrease and balance the static wellbore pressure, the flow back will also stop and not continue as shown in figure 3.6.

Secondly, if gas has entered the wellbore this will not necessarily result in gas migration and expansion, resulting in flow or gain observed at the surface. When oil-based drilling fluids are used, the gas may go into solutions and not cause any migration at all. The formula given by DrillingFormulas.Com to estimate gas migrate velocity [3.18]; $V_{gas} = 12 \text{ x } e^{-0.37 \text{ x Current Mud Weight}}$, is therefore not a good estimate to calculate how fast the gas will migrate and expand. Particularly when oil-based drilling fluids are used and the natural gas that has entered the wellbore is in the dense phase region, the gas loading capability in the drilling fluid is unlimited (Skogestad et al., 2017).

Thirdly, since the gas typically is in dense phase it will not expand according to Boyles law (Vavik et al., 2016, Fig. 4). Typically, the gas will not expand dramatically before the gas is circulated up into the riser and the pressure is low enough to allow for the gas to "boil out" of the solutions and the free gas to expand between the phase transition between *dense phase* and *gas phase*. This phase transition occurs typically when the pressure drops below *cricondenbar*, typically 150 to 160 bar, see figure E.2 in Appendix E. In the case of Macondo, with a mud density of 14.0 ppg, the gas will then have passed the subsea BOP before it expands. The expected gain as a gas kick is being circulated towards the surface will therefore be delayed until the gas has passed the BOP and is far up into the riser. The effect on *mud rate in* (pump rate) to the well compared to *mud rate out* of the riser, when circulating out a 4 m^3 large gas kick, with constant applied surface back pressure of 3 bar, is shown in figure 3.9 (Gomes et al., 2018, Fig. 6).

Consequently, to stop and perform a flow check or fingerprint flow during connections as suggested in figure 3.8, to determine whether the well is ballooning or kicking, may not be a reliable method.

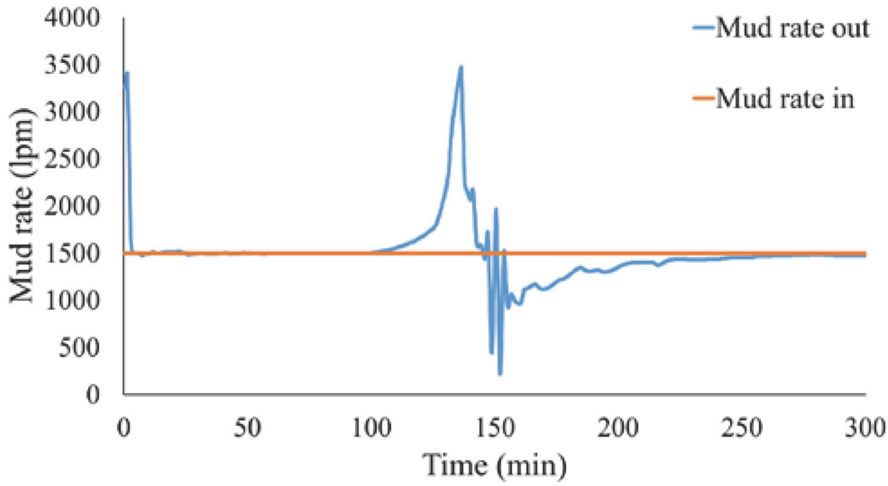


Figure 3.9 – Mud rate in and out during kick circulation (Gomes et al., 2018, Fig. 6).

A better way to determine if a gas kick has occurred will be to compare the actual measured density of the fluid in the annulus below the subsea BOP, with what would be the expected density if the annulus only contained mud and cuttings. By using the bottom hole pressure sensor (MWD) or alternatively the standpipe pressure the bottom hole annulus pressure can be measured. Likewise, the subsea BOP annulus pressure can be measured using the pressure sensor located on the BOP alternative using pressure sensor on either kill or choke line (fluid density in kill and choke line is assumed known, for example kill and choke line can filled with water and glycol with known density). In this way the amount of gas influx can by calculated based on assumed or known density of the gas (Vavik, 2017C). The effect of this method to determine whether the well is ballooning, or kicking is shown in figure 3.10 (Gomes et al., 2018, Fig. 3).

It should be noted that the simulation performed by Gomes et al. (figure 3.9 and 3.10) were carried out with an initial bottom hole pressure (BHP) of 686 bar. The initial increase in BHP to approximately 700 bar (figure 3.10) and increase in return flow (figure 3.9) will not occur if the gas kick has entered as a result of gas being swapped out with drilling fluid. However, the almost instant drop in BHP from initial 686 bar to approximately 660 bar, caused by gas entering the wellbore annulus is an early warning that a gas kick has occurred. In this case a large gas kick of 4 m^3 (25 barrels) results in an instant pressure drop of 26 bar (377 psi). However, after approximately 25 minutes the kick reaches the subsea BOP and enters the much larger lateral area in the riser annulus. The height of the kick decreases then significantly resulting in a rapid increase in BHP, see figure 3.10.

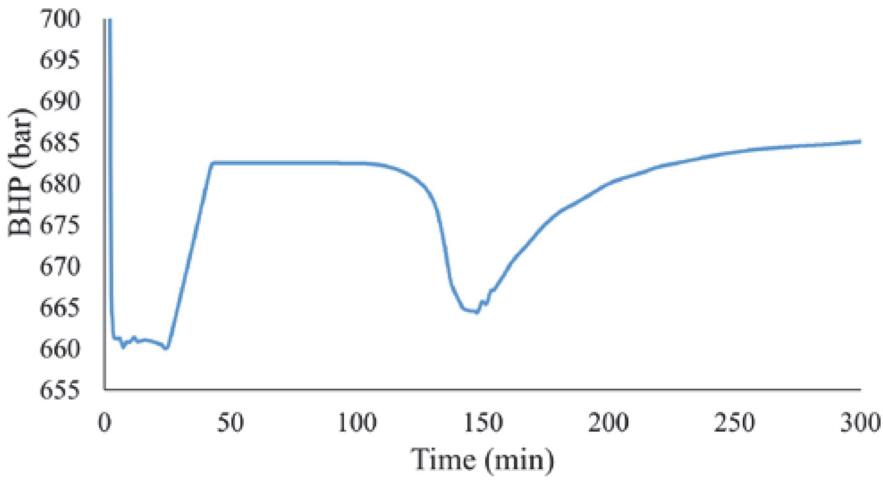


Figure 3.10 – BHP vs. time during the circulation of a 4 m^3 kick (Gomes et al., 2018, Fig. 3).

It should also be noted that if the conventional method of checking for influx by comparing flow in vs. flow out (gain) this method will give a delay in kick detection of almost 100 minutes, see figure 3.9.

3.3.3 Outcome bias

Outcome bias arises when a decision is based on the outcome of previous events, without regard to how the past events developed. [3.19] 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. [3.20]

Although an unexplained increase in gas content returning to the rig always is a concern, it seems that the industry practice has been to accept this concern or risk. In most cases the outcome of such events has been that the gas is safely vented out by the extraction fans above the shakers and running degassers if necessary. Alternatively, the drilling crew circulate the gas cut mud to the mud gas separator.

To explain or normalize the observation of high gas content in the mud following lost circulation, the phenomenon has been linked to wellbore ballooning. In an article about well ballooning by DrillingFormulas.com (accessed October 2019) the last sentence states that: "*Sometimes, mud flow back from formations can bring gas or formation water with the mud therefore you may see gas peak or mud contaminated with water while circulating bottom up.*" [3.15] If we stick to the definition for well ballooning this is a phenomenon where drilling fluids (mud) are lost to the formation when pumps are on and the mud comes back when pumps are turned off. If the formations return large quantities of gas in an exchange with the lost mud, we have by definition a gas kick and swap out phenomenon rather than a ballooning event.

The Macondo well was by some called the "*well from hell*".[3.21] When Mike Williams in his testimony was asked about this characterization, he referred to a previous well that was drilled in an area called "*Devil´s tower*", hence the name. Part of his reply related to the characteristic of the Macondo well was: "*This well exhibited a lot of the same characteristics, where we lost circulation, we were getting tons of gas back all the time, we got stuck, we had to sever the pipe, it was just…, it was déjá vu all over again.*"[3.22]

Based on the outcome of previous events and regardless of how these past events developed, it seems that the industry and BP believed that the worst possible outcome is that the pipe gets stuck or that the well is lost.[3.23] Even when the outcome of these events probably is more determined by chance than anything else, given the current available technology and until the understanding on how a gas kick may occur and develop is revealed.

3.4 Wellbore Breathing Mechanism (as accepted by the industry)

As previously stated, several authors and publications have been made to better understand the mechanism of wellbore breathing (Baldino et al., 2019A & B; Lavrov and Trondvoll 2005). The common understanding in the industry is that that breathing is caused by opening and closing of fractures. In SPE Petroleum Engineering Handbook (PEH) the geomechanics have been explained in more detail. Figure 3.11 is taken from *PEH: Geomechanics Applied to Drilling Engineering*, chapter 5, *Building the Geomechanical Model* and shows an extended leakoff test is used to determine *formation breakdown pressure* (FBP), *fracture propagation pressure* (FPP) and *fracture closure pressure* (FCP).[3.24]

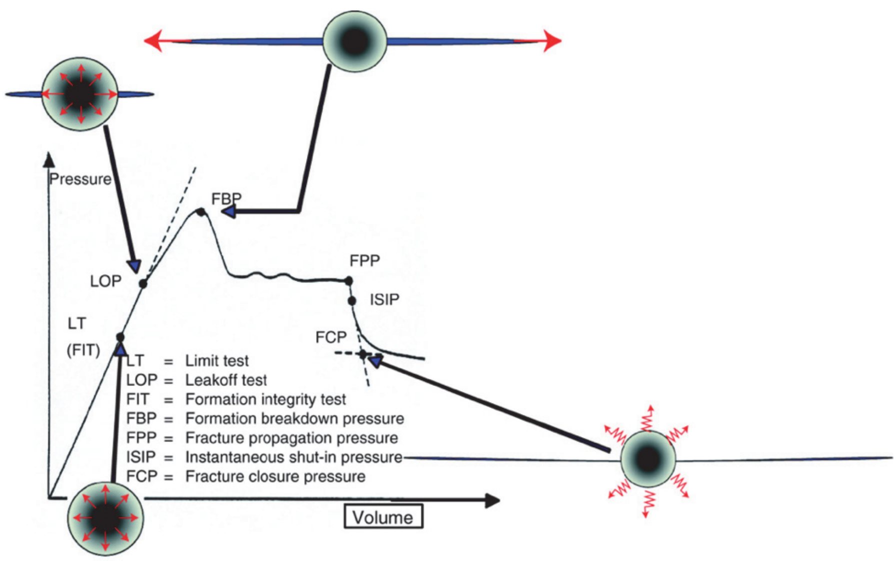


Figure 3.11 – Extended leakoff test to determine FBP, FPP and FCP.[3.24]

This pure geomechanical approach to understand wellbore breathing, assume *no appreciable flow occurs through the pores*. Ref. *September 2019 SPE Drilling & Completion*, page 249 last paragraph:

"As previously mentioned, when breathing happens, no appreciable flow occurs through the pores. Moreover, the mud may as well generate an impermeable layer (or an interfacial mudcake) between the fracture walls and the porous block, thus enhancing further isolation of the two phases." (Baldino et al., 2019A)

The characteristic given for the Macondo well where they after lost circulations *"were getting tons of gas back"* [3.22], does not fit into the mechanism of wellbore breathing (Baldino et al., 2019A & B; Lavrov and Trondvoll 2005).

In some previous field cases the swap-out mechanism has been explained by a *fracture breathing formation*. [E.13] Two interesting case studies are; *Well Control of an Influx from a Fracture Breathing Formation* (Ashley, 2000) and *Gas-Influx Events in a Deep Water Exploratory Well* (Lage et al., 2002). These papers have both explained the influx or swap-out mechanism with *fracture breathing formation*, without explaining how the actual swap-out mechanism works.

A hydraulic fracture will normally propagate perpendicular to the least principal stress. In some shallow formations, the least principal stress is the overburden stress; thus, the hydraulic fracture may be horizontal. These pure geomechanical models may therefore work in shallow formations, where the hydraulically induced fracture may lift the overburden. In other words, *no appreciable flow occurs through the pores* if the entire porous block with the pore fluid is lifted.

However, in deeper reservoir such as the Macondo the least principal stress will likely be horizontal; thus, the hydraulic fracture will be vertical. In these cases, the fractured rock matrix and the pore fluid has nowhere to go when being displaced by whole mud invading the formation.

The theory of poroelasticity should therefore be considered, since the pore fluid in the fracture or deformed zone will be affected by the mud loss. Poroelasticity is the term used to describe the interaction between fluid flow and solid deformation within a porous medium. This theory is also called *Biot poroelasticity*, after Maurice Anthony Biot, who was accredited as the founder of the theory of poroelasticity. Modeling poroelasticity requires the coupling of two laws. The first of these is Darcy's law, which describes the relation between fluid motion and pressure within a porous medium. The second law is the structural displacement of the porous matrix. [3.25] In other words when the fracture gradient is exceeded and the formation accepts whole fluid from the well bore, the pressure in the affected area will increase. Likewise, the formation pore pressure in the borderline of the fractures or deformed area will increase. This increase in pore pressure will result in a flow of pore fluid according to Darcy's law to an area with lower pressure. In a gas sand the pore fluid (gas) is generally fluidly connected and trapped by a relatively impermeable cap rock or seal. A better approach to understand wellbore breathing or ballooning mechanism is therefore to consider the time-dependent induced or elevated pore pressure caused by drilling fluids lost or injected to the formation (Monfared and Rothenburg 2017).

3.5 Gas Kick Induced by Elevated Pore Pressure

In this chapter, why and how gas probably entered the Macondo well on April 3 is discussed, i.e. ballooning perceptions were probably flawed.

3.5.1 Ballooning perception at Macondo was probably flawed

The BOEMRE report has an interesting statement that the well started ballooning after they had drilled through the 14.16 ppg gas sand, see figure 3.1 and 3.3.

"*Mud logging data for the Macondo well demonstrated that the production casing zone started ballooning between 17,530 feet and 17,761 feet. The daily IADC reports also show that the well flowed back during flow checks following mud loss at those depths.*" [3.7]

The observed flowback following mud loss at those depths may have been caused by near borehole elevated pore pressure rather than closing of fractures. According to the BOEMRE report the mud weight when they start drilling the production section on April 2 was 14.3 ppg and was further increased to 14.5 ppg (surface density) on April 3 at 17 321 ft depth, see figure 3.12. [3.26]

Open Hole Interval below 9 7/8-in Liner @ 17,168 - FIT 15.98 PP 13.9						
Date	Depth	MW	Losses	PP	Remarks	Hydrocarbon Zones
2-Apr	17,007 - 17,321	14.3			17,168 FIT 16.22 PPG	17,684 - 17,693 M-57C 14.1 PPG
3-Apr	17,321 - 17,835	14.5	233 bbls		17,723 - GeoTap 14.15 ppg (PP)	17,786 - 17,791 M-56A 13.1 PPG
3-Apr	17,835 - 17,909	14.3				
4-Apr	17,909 - 18,195	14.3		12.58 @ 18,089	Schematic - 12.6 ppg at 18,066	18,061 - 18,223 M-56E 12.6 PPG
4-Apr	18,215 - 18,250	14.4	639 bbls		Lost full returns	
5-Apr	18,260	14.0	1263 - Total			
6-Apr		14.0	1586 - Total			
7-Apr		14.0				
8-Apr		14.0				
9-Apr	18,360	14.0			called TD	

Figure 3.12 – Drilling data, losses and remarks when drilling the production section. [3.26]

Another interesting paper about the pore pressures and mud weights in the Macondo well was published in May 2019, see figure 3.13 (Pinkston & Flemings 2019, Fig. 5b and 5c).

According to the figure 3.13 (Pinkston & Flemings 2019, Fig. 5b and 5c) a formation integrity test (FIT) was performed shortly after drilling of the final production section had started. The mud weight (MW) measured at surface conditions was thereafter increased from 14.0 ppg to 14.3 ppg (straight brown line). The change in surface MW results in a gradual increase in the downhole annular pressure while drilling (APD) as recorded on the drill string (MWD) (thick brown line).

At approximately 17 400 ft, a gas kick is shown on the diagram (white triangle). This is interesting because at this depth the recorded pore pressure (u_{ms}), interpreted from the (sonic) velocity log (blue line), was approximately14.16 ppg. This is probably the same 14.16 ppg gas sand as shown in figure 3.3. At this depth the effect of increasing the MW to 14.3 ppg, had already got time to be effective and the measured downhole APD was approximately 15.0 ppg.

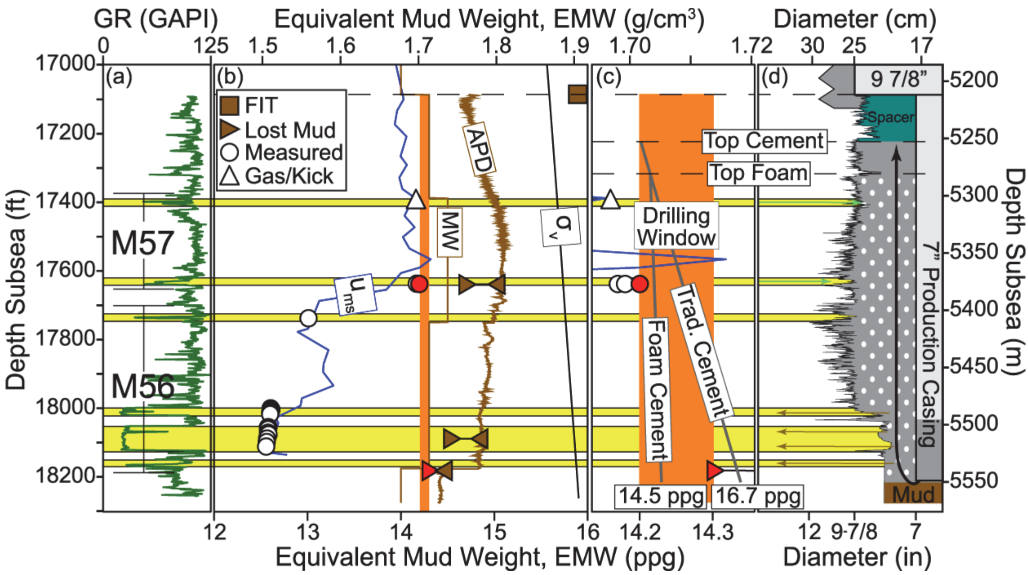


Figure 3.13 – Pore pressure and annular pressure while drilling production section. (Pinkston & Flemings 2019, Fig.5)

The APD is transported to surface only during mud circulation, since MWD tools typically use pressure pulses created by the circulation and a downhole transmitter. [3.20] The APD is therefore the same as equivalent circulation density (ECD), since downhole pressure cannot be transmitted during static conditions. The downhole equivalent static density (ESD), due to mud compressibility, is assumed to be approximately 14.5 ppg. The gas kick, according to figure 3.13, was therefore taken with 0.34 ppg or 21.3 bar (310 psi) overpressure. During circulation the formation was exposed to 52.6 bar (763 psi) superimposed overpressure.

It should be noted that none of the other investigation reports have commented on or discussed that a gas kick was taken at approximately 17 400 ft. The influx that is referred to as gas kick (white triangle) in figure 3.13, may therefore be increase in drilled gas that expands rapidly in the riser, and hence mistakenly been interpreted as a kick. Alternatively, a small gas kick caused by gravity induced swap out. Meaning that the high overpressure mud pushed and displaced near wellbore gas from the gas sand and into the wellbore.

Regardless of the reason, it seems that the drilling crew increased surface MW again from 14.3 ppg to 14.5 at this depth, see figure 3.13 (straight brown line). The BOEMRE report also states that the drilling crew were drilling with 14.5 ppg surface MW from 17,321 feet to 17,835 feet, see figure 3.12.

According to the BOEMRE report, "*Mud logging data for the Macondo well demonstrated that the production casing zone started ballooning between 17,530 feet and 17,761 feet.*" [3.7] This statement is interesting because it starts ballooning shortly after the drilling crew had increased the surface MW to 14.5 ppg. At the same time, you also see that the measured downhole APD starts to gradually decrease. At 17 761 ft you would expect that the effect of the increased MW would give an APD of approximately 15.2 ppg, given the crew was drilling (ROP) and circulating with approximately the same rate. However, at 17 761 ft before they decreased the surface MW back to 14.3 ppg, the downhole APD was measured to approximately 15.0 ppg, see figure 3.13. This downhole annular pressure reduction of 12.8 bar (185 psi) [3.27], may be due to gas cut mud (Vavik 2017C). I.e. the formation may have returned gas during flow back during connection when pumps are off, at those depth (*between 17,530 feet and 17,761 feet)*.

Another indication that the annulus may contain large amount of gas at these depths is the change in oscillations on the APD readings at approximately 17 540 ft, see figure 3.13. The MWD tool (APD) use pressure pulses to communicate with the surface. If the pulsation dampener on the mud pumps are not working correctly, this will disturb or in the worst case destroy the signal from the MWD tool (Mark May 2013). On the other hand, if the annulus contains gas, this may work as an additional pulsation dampener and reduce the pressure oscillation from the mud pump giving a smoother APD signal.

As earlier mentioned, an article about well ballooning by DrillingFormulas.com states that; "*Sometimes, mud flow back from formations can bring gas...*" Gas kick or gas influx during what, appears to be ballooning is therefore not an unnormal phenomenon. [3.15] According to the BOEMRE report and figure 3.12, the drilling crew lost 233 barrels of mud, on April 3, while drilling with 14.5 surface MW between 17,321 feet and 17,835 feet, see figure 3.12. If we assume this is net loss of mud observed at surface during what appeared to be *ballooning between 17,530 feet and 17,761 feet,* we do not know what the real amount of loss of mud to the formation is. Net loss in this context is defined by what is lost during circulation, minus the amount of fluids that flow back during connection. If the flow back from the formations contains large amount of gas or formation fluids, the real or gross loss of mud to the formation can be much larger. Even more important is that the gas influx, assumed to have occurred during connections, could not be measured on observed gain at the surface, since this was concealed by the loss that occur during circulation. Kick detection based on flow out vs flow in or active pit gain, which was the case for Deepwater Horizon, would therefore not work in these cases when flow back from the formations contains gas.

As discussed in chapter *3.3.2 Ballooning perception may be flawed,* performing a flow check after the gas has entered the wellbore may not be a reliable method to check if a gas kick has been taken, for several reasons (Vavik et al., 2016, Fig. 4). See also figure 4.7 (Gomes et al., 2018, Fig. 6). However, given that the;

- ⇒ *"the well flowed back during flow checks following mud loss at those depths"* [3.7]
- ⇒ the gradual reduction in BHP observed from 17 530 ft and 17 761 ft
- ⇒ and the change in APD signal oscillation after 17 540 ft depth,

the ballooning perception at Macondo was probably flawed. In other words, it is likely that large amounts of gas were present in the wellbore at this stage, when the wellbore was overbalanced, and drilling was performed with 14.5 ppg surface MW.

3.5.2 Swap out mechanism caused by gravity and elevated pore pressure

In this chapter a new theory on how gas may have entered the wellbore on April 3, when drilling was performed with 14.5 ppg surface MW and what appeared to be *ballooning between 17,530 feet and 17,761 feet* is discussed.

Modeling the swap out mechanism requires the coupling of two laws. The first of these is Newton´s law of universal gravitation. The second is Darcy's law, which describes the relation between fluid motion and pressure within a porous medium. Capillary forces will also play an important a role and should be considered to understand the swap out mechanism completely. Other mechanism such as osmosis and Fick´s law of diffusion may play an important role for reactive shale or clay but is assumed to be less important when drilling through the gas sand in the Macondo well. In conventional reservoirs osmosis is of little significance compared with other mechanisms, such as capillarity and gravity (Li et al. 2016). In this thesis and chapter, the discussion will be limited to the effect of gravity and fluid flow according to Darcy´s law, since these are assumed to be the most important factors when the well show symptoms of ballooning.

Newton´s law of universal gravitation states that every particle attracts every other particle in the universe with a force which is directly proportional to the product of their masses and inversely proportional to the square of the distance between their centers (Newton 1999). The equation can be written as:

$$F = G\,\frac{m_1 m_2}{r^2} \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \; (2)$$

where:

F is the force between the masses (N or kg m/s^2);
G is the gravitational constant (6.674 x 10^{-11} N (m/kg)^2);
m_1 is the first mass (kg);
m_2 is the second mass (kg);
r is the distance between the centers of the masses (m).

If m_1 is the mass of the earth (5.97237 x 10^{24} kg) and r is the distance from the center of the earth to the surface of the earth (6.371 x 10^6 m), we can calculate the gravitational force F acting on a particle, object or substance with mass m_2 at the surface of the earth. F can then be expressed as:

$$F = g\,m_2 \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \; (3)$$

where g is the gravitational acceleration (m/s^2). In our example above using the mass and radius of the earth, g can be calculated to be 9.82 m/s^2. However, the radius of the earth is larger at the equator than the at the poles. Hence, the distance to the center of the mass is larger at equator and the gravitational acceleration goes down (9.78 m/s^2 at equator). Likewise, the gravitational acceleration will increase with depth, as the distance to the earth center decrease. For simplicity the value of 9.81 m/s^2 is used in this thesis. For further research and modelling of gravitational forces, both location on earth, depth of the well as well as centripetal forces caused by the earth rotation should be considered.

When a loss of drilling fluids into a porous formation occurs, most of the formation fluid will probably be displaced by the fluid invasion driven by high ECD (radial flow). However, at the borderline between the invading fluid (filtrate) and the formation fluid, the radial flow or velocity of filtrate drops towards zero. The gravitational force acting on the pore fluid and the invading fluid will be more important as the radial velocity decreases. Since the density of the drilling fluid or filtrate invasion fluid can be several times larger than the in-situ formation fluid (natural gas), the gravitational force acting on the invasion fluid will be much larger than the gravitational force acting on the natural gas.

Darcy's law, as refined by Morris Muskat, in the absence of gravitational forces is a simple proportional relationship between the instantaneous flow rate through a porous medium of permeability (k), the dynamic viscosity of the fluid (μ) and the pressure drop over a given distance in a homogeneously permeable medium. Darcy´s law to determine the flow (Q) through a homogeneous permeable rock formation with cross-sectional area (A), can be expressed as;

$$Q = \frac{kA}{\mu}\left(\frac{\partial p}{\partial x}\right) \text{ .... } (4)$$

As discussed earlier in chapter 3.1, the BP investigation report does not mention any loss of circulation event on April 3, ref: "*Drilling of the final 8 1/2 in. x 9 7/8 in. hole section started on April 2, 2010, and continued until April 4, 2010, when the well encountered lost circulation at 18,260 ft.*" Let us therefore assume that the loss of 233 barrels, reported on April 3, was not caused by a sudden breakdown of the formation. The loss of mud was probably rather caused by a gradual partial loss of circulation, ballooning and hydraulically induced micro fractures. Flow of fluids according to Darcy´s law may therefore have caused a net loss of 233 barrels to the formation, see figure 3.14.

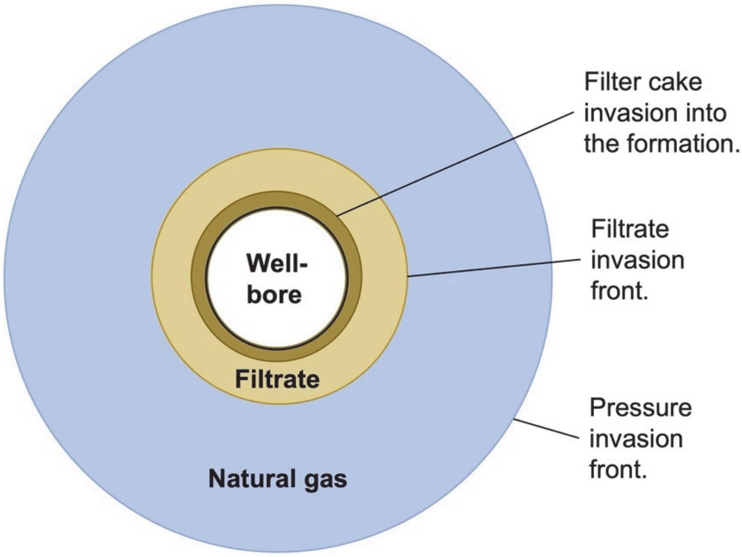


Figure 3.14 – Partial loss of circulation and flow of fluids according to Darcy´s law

The flow of fluids and pressure fronts is shown in figure 3.14, based on Darcy´s law to determine the flow (Q) through a homogeneous permeable rock formation. Figure 3.14 is inspired by van Oorts early work on shale (van Oort 1997, Fig.6). In shales with low permeability, diffusion is a more prominent, faster process than Darcy flow (van Oort 1997). However, in the high pore pressure gas sand at Macondo, permeability is probably higher, and hence Darcy flow is assumed to be the dominating process. The focus on ion diffusion due to chemical potential gradient (Fick´s law of diffusion), valid for low-permeability shales, is therefore assumed not relevant for high permeability gas sands.

The reported 233 barrels (net?) loss may have charged the formation to a higher pore pressure driven by high ECD. When large losses to a gas sand with high pore pressure and possible high permeability occur, it may indicate that an effective filter cake have not been achieved. Furthermore, if a filter cake is obtained, either external on the matrix wall or partly inside the formation, filtrate is likely to flow through the pores, preceded by a pressure front or flow of formation fluid (natural gas), see figure 3.14.

Transmitting pressure waves through a liquid is a relative fast process. Mud pulse telemetry is typically used to transmit MWD signals from the bottom of the well to the surface (Gearhart et al. 1981). MWD pressure pulses travel at 4 000 ft/s (1219 m/s), which is a typical speed of sound in liquid (Mark May 2013). However, the speed of a pressure pulse in a porous rock is totally different, since this is related to fluid flow through the porous rock. In an experiment to investigate the gas permeability in tight sands, a pulse-decay permeameter was used (Walls et al. 1982, Fig.1). A two-inch (5.08 cm) diameter core sample of the rock was used in the experiment. The pores in the rock was filled (pressured up) with nitrogen up to 14 or 15 MPa (140 to 150 bar), to simulate in-situ pore pressure. Then a pressure pulse or pressure increase of 1 bar was initiated on one side of the core and the time for the pressure pulse or nitrogen to travel the distance of two inch, was measured. The time required for each measurement ranges from 2 minutes to more than 4 hours, depending on permeability (Walls et al. 1982).

This relative slow speed of Darcy flow for a low viscosity fluid such as nitrogen or natural gas is important. The main contributing factor to why it is possible to charge the formation to an elevated pore pressure is probably due to this relative slow speed of formation fluid (natural gas) through the pores. Unless the gas sand reservoir is very small, the pore fluid volume affected by the loss is very small compared with the total gas volume of the reservoir. The elevated or induced gas pore pressure caused by mud invasion would therefore be expected to revert back to almost the native pore pressure when circulation stops and wellbore pressure falls. However, since the speed of natural gas flow through the pores is relative slow, the elevated gas pore pressure caused by mud invasion will decrease slowly. In contrast to the pressure in the wellbore where the pressure will typically drop rapidly after circulation has stopped. In order to get a reversed flow from the reservoir, the elevated pore pressure must be higher than the static pressure in the wellbore. In addition, the differential pressure must be high enough to overcome the capillary forces trying to restrict flow through the pores.

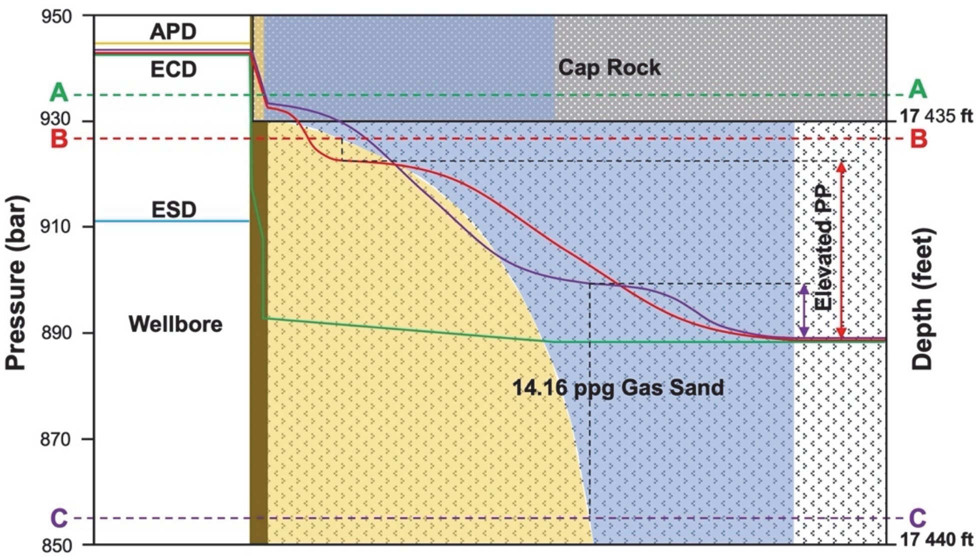


Figure 3.15 – Possible pressure profiles in 14.16 ppg gas sand when drilling at 17 500 ft

Figure 3.15 is showing how the formation pressure profiles may have looked like, on April 3, when drilling the last stand before ballooning or flow back during connection was observed. The figure is meant to be a snapshot in time, of possible pressure profiles, when the drill bit was at 17 500 ft, after the drill crew had drilled through the 14.16 ppg gas sand and shortly after the surface MW was increased to 14.5 ppg. The pressure profiles are given for three different depths. A-A is in the cap rock just above the 14.16 ppg gas sand (green dashed line), assumed to start at 17 435 ft. B-B (red dashed line) is in top of the gas sand and C-C (purple dashed line) is in the bottom of the gas sand.

The actual pressures at any given place while drilling (circulating), either in the wellbore or in the formation, is given by a solid line in the same color (green, red and purple). The pressure curves (solid lines) should be read in conjunction with the pressure scale given on the left side of figure 3.15. The pressure curves are guesstimates based on measured wellbore pressures and formation pressures.

In the wellbore annulus two other reference pressures are also given for information. The annular pressure while drilling (APD) (orange line) is the measured downhole pressure in the annulus at 17 500 ft. From figure 3.13 this is approximately 15.1 ppg or 947.1 barg (13 737 psi).[3.28] The ECD or circulating pressure at C-C, B-B and C-C is slightly lower since this is at a higher elevation in the wellbore. The equivalent static density (ESD) or static pressure (blue line) in the wellbore is also added. The downhole ESD is assumed to be approximately 14.6 ppg, which gives a downhole static pressure of 912.3 barg (13 232 psi).[3.29] The downhole ESD is given at the top of the 14.16 gas sand at 17 435 ft, since this is the most likely place to get a gas influx.

On the right-hand side of figure 3.15 the virgin in-situ formation pore pressure, not effected by the loss of mud is shown. The pore pressure is interpreted from the (sonic) velocity log to 14.16 ppg, see figure 3.3 and 3.13. The in-situ pressure in top of the gas sand at 17 435 ft can be calculated to 884.7 barg (12 831 psi).[3.30] The pore pressure in the bottom of the virgin gas sand (purple line) will be slightly higher due to the static weight of the natural gas, see figure 3.15.

With reference to figure 3.15 the pressure profile through the tight cap rock, **section A-A**, from left to right is discussed. It is assumed that an effective filter cake earlier has been established on the wellbore walls and that there is no current flow going into the formation. It is further assumed that there is no flow in the filtrate invasion zone either. Pressure drops through the filter cake and filtrate rapidly (green line) due to low permeability. However, the pressure invasion zone will gradually increase in size as the pressure fades away and falls towards the in-situ pore pressure.

The pressure profile through the upper part of the gas sand, **section B-B**, is different. During circulation flow of fluids according to Darcy´s law from left to right, driven by high ECD is assumed to be the dominating force. The gas sand is assumed to have a much higher permeability than the caprock. Due to high permeability and observed loss (233 bbls) it is assumed that an effective filter cake on the wellbore wall is not achieved. The expected result is that whole mud is invaded into the gas sand and filter cake is partly built up inside the formation. The filtrate will be expected to flow further out from the wellbore into the gas sand as illustrated in figure 3.14. As the filtrate invasion front gets further away from the wellbore the cross-sectional flow area (*A*) will increase exponentially and hence the velocity of the filtrate invasion front will decrease. The expected effect is that the gravitational force acting on the filtrate will gradually be the dominant force, since the filtrate density is greater than the pore fluid (natural gas). In the same way as a bullet from a gun will eventually fall to the ground when velocity decreases, the filtrate invasion front will be expected to have a curved and not a vertical invasion front, see figure 3.15. It is assumed that the result will be that natural gas (pore fluid) is displaced and pushed against the ceiling formed by the caprock. Hence the pressure drop profile (red line) in the upper part of the gas sand will be dominated by the pressure invasion front or Darcy flow of natural gas.

Likewise, the pressure profile through the lower part of the sand, **section C-C**, is different. In this part of the gas sand the pressure drops (purple line) are assumed to be dominated by the pressure drop caused by mud and filtrate invasion. The result of this is that the elevated pore pressure (PP) during circulation and loss of mud to the gas sand will be greater in the top of the gas sand, compared to the lower part of the gas sand, see figure 3.15.

When circulation is stopped for a connection, the pressure in the annulus will rapidly fall to ESD (blue line). However, the elevated PP in the formation will drop at a much slower rate (Walls et al. 1982). The result may be that the elevated PP in the upper part of the gas sand is higher than ESD, see figure 3.15. If the elevated PP is high enough to overcome the restriction and capillary forces in the filter cake and filtrate invasion, this may result in a reversed flow. The reversed flow will typically decline and fade out as the elevated PP falls towards the ESD. Due to gravity and the profile of the filtrate invasion front, the flowback may contain gas.

According to the BOEMRE report, "*Mud logging data for the Macondo well demonstrated that the production casing zone started ballooning between 17,530 feet and 17,761 feet.*"[3.7] Figure 3.15 is illustrating how mud lost to the 14.16 ppg gas sand located higher up in the formation, may have caused the observed ballooning, while drilling at 17 500 ft. This is 30 feet before the observed ballooning starts. This is also before the drilling crew entered the second sand formation at 17 684 ft, see figure 3.1. In a similar way loss of drilling mud into this sand may also explain why the attempts to obtain fluid samples were unsuccessful and why the sand was interpreted to contain water (brine). If the PP measurement of this 14.15 ppg sand (measured with GeoTap®) initially contained gas, the gas may have been displaced with filtrate invading the pore fluid space. Ref. statement in the BP report: "*The interpretation of fluid content was deemed uncertain, but it was probably water (brine)*."[3.31] In other words, the sand formation between 17 684 ft and 17 693 may also have contained gas, contributing to the ballooning and loss while circulating "*between 17,530 feet and 17,761 feet*". Ref. also statement in the BOEMRE report, *"the well flowed back during flow checks following mud loss at those depths"*[3.7]

3.6 Gas Kick Induced by Dynamic Pressure Drop in the Wellbore

According to the BP accident investigation report, drilling continued until April 4, when the well encountered lost circulation at 18 260 ft. Lost circulation pills were pumped to the bottom of the wellbore, and the mud weight was reduced. Full circulation was regained on April 7. [3.4]

According to the BOEMRE report they lost full returns and 639 bbls on April 4. Huge losses also occurred on April 5 and 6 after the surface mud weight was reduced to 14.0 ppg, see figure 3.12.

These losses may have resulted in a dynamic temporary pressure drop in the open wellbore, leaving the 14.16 gas sand temporary underbalanced resulting in gas influx. During circulation the ECD will be higher than ESD due to frictional pressure drop as the fluid is circulated up the annulus. When total loss of circulation is encountered the fluid in the annulus will turn and flow down into the loss zone, driven by gravitational forces. This will result in a lower ESD due to a shorter fluid column. In addition, this downward-going flow in the annulus will also result in a frictional pressure drop. Since the pressure in top of the annulus fluid column is atmospheric, the ECD in the 14.16 ppg gas sand will be lower than ESD. This may result in a gas kick. The 14.16 gas sand may go temporary underbalanced as long as there is a downward-going flow of fluid into the loss zone. In this way loss of drilling mud and gas influx may occur simultaneously.

The available method for kick detection on Deepwater Horizon was therefore inadequate, since this was mainly based on pit gain or volumetric comparison between flow-out versus flow-in.[3.32] When a gas kick occurs simultaneously with loss of drilling mud, neither amount of fluid lost to the formation nor the amount of gas influx can be measured based on volumetric comparison at the surface alone.

Due to lack of real-time data from these loss events between April 4 and April 9, further research on these events are not part of the scope of this thesis. However, further research on this phenomenon of gas kick induced by a dynamic pressure drop in the open wellbore annulus caused by breakdown of the formation and sudden loss of drilling fluid is recommended.

3.7 Gas Kick Induced by Geothermal Heating of Wellbore Fluid

On April 9, 2010, the well was drilled to a final depth of 18,360 ft.[3.4] Upon reaching final well depth, five days were spent logging the well to evaluate the reservoir. [3.33]

A series of logs to collect data from the well was carried out between April 10 and 15, 2010. On April 16, before running the final 9⅞-inch × 7-inch long string production casing, the rig crew circulated the open wellbore bottoms up. They did not record any mud losses during this process. 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. After circulating on April 16, gas eventually decreased to 20 to 30 units. [3.34]

According to CCR, 1,120 gas units on a 3,000-unit scale 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. [3.35] This may not be unusual (?), however it is interesting to discuss how the gas entered the wellbore. Since drilling had been completed it was probably not drilled gas.

Significant increases in gas units were not only observed when bottoms up was circulated on April 16, but also at the end of the cement job after midnight on April 20. The gas that entered the wellbore between April 16 and April 19, when the cement job started, could not have been drilled gas since the well was circulated bottoms up on the April 16. In the Smith Report the following comments have been given to this increase in gas content in the mud returning from the riser at the end of the cement job;

"*Significant increases in gas units during this period, to levels exceeding that when drilling non-productive formations, implies that trip gas from previous trip out of the hole had not been circulated out prior to the cement job. However, assessment of pre-job preparations is outside the scope of this review.*" [3.36]

The gas in the wellbore recording during circulating bottoms up on April 16 and April 20 at the end of the cement job, may be due to trip gas entering as a result of swabbing effects caused by pulling the drill string to surface.

There is also a possibility that gas has entered the wellbore even if the well is in an overbalanced condition. Gas may have entered the wellbore due to diffusion. This is the case where the drilling fluid has a large loading capacity of natural gas and is exposed to the reservoir gas via the filter cake, with diffusivity favoring natural gas flux (Linga et al. 2017).

As previously discussed in chapter 3.5 influx may also have entered the wellbore due to near borehole elevated pore pressure. Elevated pore pressure could be a result of surge effects when lowering production casing into the wellbore. However, the hypothesis that gas may have entered the wellbore either by swabbing, diffusion or elevated pore pressure due to pressure surges, will not be discussed any further in this thesis.

Another possible explanation on how the gas may have entered the wellbore during these long static periods, is that the downhole mud weight was reduced due to geothermal heating.

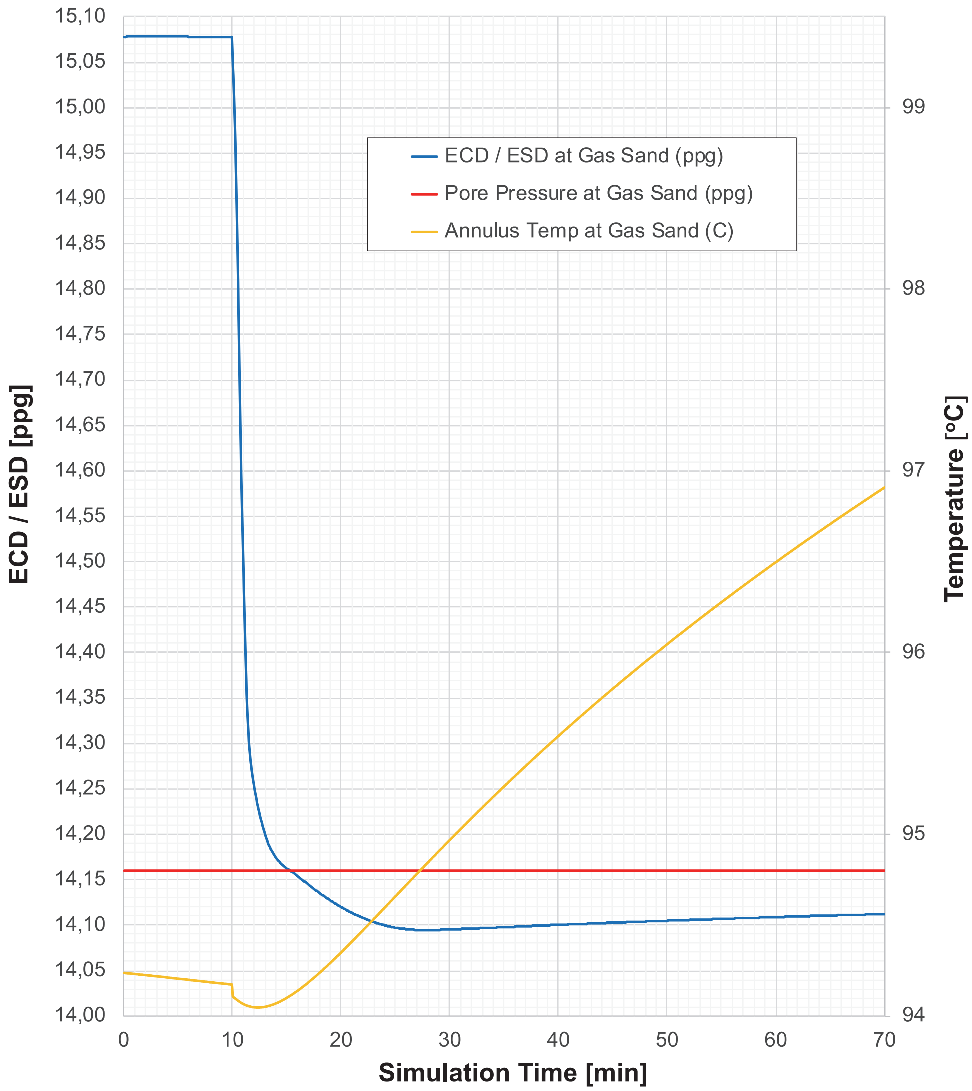


Figure 3.16 – Changes to ECD/ESD and temperature at the 14.16 ppg gas sand

To test this hypothesis that gas may have entered the wellbore due to geothermal heating, a simulation has been carried out. The simulation has been carried out by Knut Steinar Bjørkevoll and SINTEF and a report of the result is attached in Appendix D.

Since the well was last circulated full bottoms up on April 16 and circulation was not performed again before preparation for the cement job was carried out in the evening of April 19, a static period of 72 hours has been put into the simulation.

A fast pre-simulation of 6 hours to stabilize temperatures in the well and simulate the bottoms-up circulation was also carried out. The changes in the ECD/ESD and annulus temperature at the 14.16 ppg gas sand (17 437.5 feet), during the last 10 minutes out the fast pre-simulation and the first hour after the bottoms up circulation in the wellbore ended, are shown in figure 3.16.

Simulated standpipe pressure (SPP) is used to analyze the effect of geothermal heating. Since the same mud weight (14.0 ppg surface density) and no cuttings are used in the simulation, a positive standpipe pressure during static condition will indicate a U-tube effect. To analyze the effect of geothermal heating, different phases from A to E has been added, see figure 3.17.

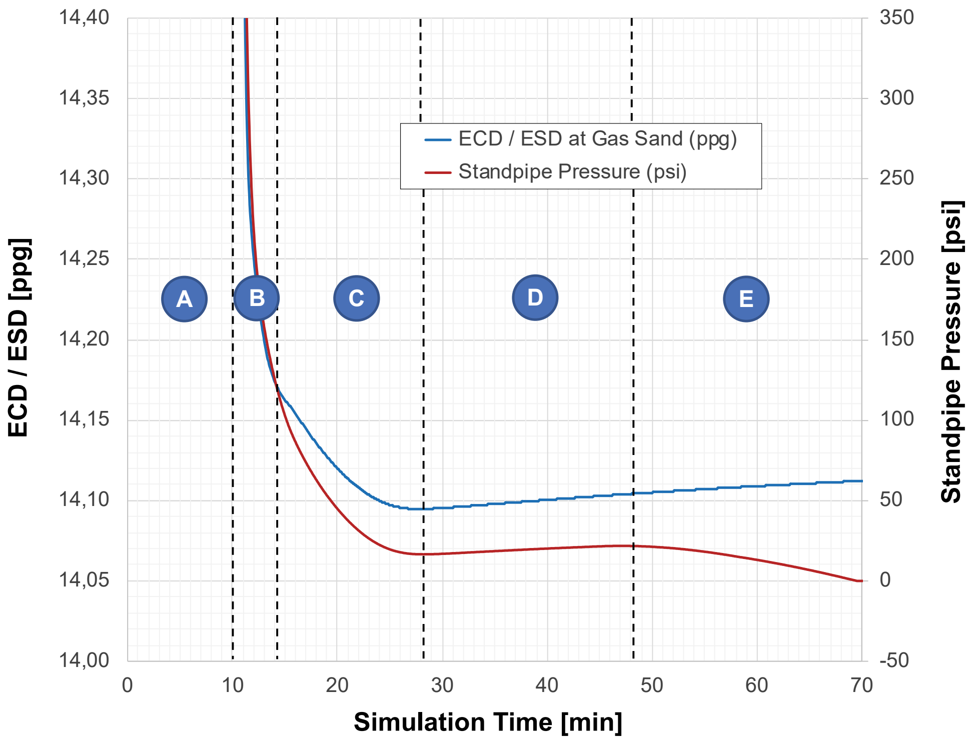


Figure 3.17 – Changes to ECD/ESD at the 14.16 ppg gas sand and SPP after pump stop

The different phases (A to E) and the observed changes in downhole annulus pressure (ECD/ESD) and the SPP are discussed in the following sections.

3.7.1 Phase A – Circulating bottoms up on April 16, 2010

Bottoms up was circulated on April 16 [3.34], however this circulation has not been simulated. The detailed information required to simulate this bottom up circulation was not available. However, a pre-simulation of 6 hours to stabilize temperatures in the well was performed. Figure 3.16 and 3.17 show the last 10 minutes of this circulation to stabilize temperatures. The simulation was performed to have an estimate of the fluid temperature distribution in the annulus and a starting point to evaluate the effect of temperature changes after pumps shutdown.

3.7.2 Phase B – Pumps shutdown and mud expansion due to reduced ECD

When the pumps are stopped at simulated time 10 minutes, both ECD and SPP drops quickly, see figure 3.16 and 3.17. A controlled ramp down of the pumps of about 1 minute and 30 seconds is simulated, until complete stop of fluid being pumped down is obtained at 11:30 simulated time. Due to compressibility of the OBM, fluid will continue to expand as pressure falls in parallel until SPP and ECD take different directions at approximately 14 minutes simulated time, see figure 3.17. Both in phase A and B the downhole pressure or ECD is dominated by frictional pressure drop in the annulus as drilling fluid is transported up the riser annulus. At the end of phase B, the downhole ESD at the 14.16 ppg gas sand is approximately 14.17 ppg, i.e. in overbalanced condition.

3.7.3 Phase C – Decrease in ESD and SPP due to geothermal heating

Four minutes after pumps are stopped the dynamic effects are less dominating and it is assumed that fluid density changes and pressures are dominated or at least influenced by thermal effects. From 14 to 28 minutes simulated time, both ESD and SPP decreases, see figure 3.17. At the same time the annulus fluid temperature in the open wellbore increases due to geothermal heating, see figure 3.16. Probably there is a connection between the increased annulus fluid temperature in the gas sand and the reduced pressure due to decrease in fluid density as fluid temperature increases. This effect can also be seen in figure 4 in Appendix D (see 104 minutes).

The in-situ pore pressure of the 14.16 ppg gas sand corresponds to a formation pressure of 884.7 barg (12 831 psi).[3.37] Due to geothermal heating and mud expansion the simulated downhole ESD falls from approximately 14.17 ppg to approximately 14.09 ppg. A reduction in ESD of 0.08 may not be significant, but when operating close to pore pressure this becomes important. It means that the pressure in the open wellbore at the top of the 14.16 ppg gas sand goes from being 0.5 bar (7 psi) overbalanced [3.38] to 4.2 bar (61 psi) underbalanced [3.39] in 14 minutes. This probably led to gas influx during this static period, shortly after the crew circulating bottoms up on April 16. This may also explain why significant increase in gas content in the mud returning from the riser at the end of the cement job was observed. [3.36] This also shows how important it is to consider thermal effects on a static well, to ensure that ESD always is greater than estimated pore pressure.

3.7.4 Phase D – Increase in ESD and SPP due to net cooling of annulus fluid

After a period when both ESD and SPP rapidly decrease, both values start to slowly increase again. It is uncertain why this suddenly changes. It could be caused by dynamic effects due to thermal expansion of the drilling fluid in the wellbore. Or it could be due to different length and cross-sectional area of the annulus exposed to heating verses cooling. Or probably a combination of these two effects.

The areas of the annulus such as the wellhead area (large cross-sectional area) and the annulus at the gas sand (small cross-sectional area), change also temperatures at a different rate, see figure 3.18.

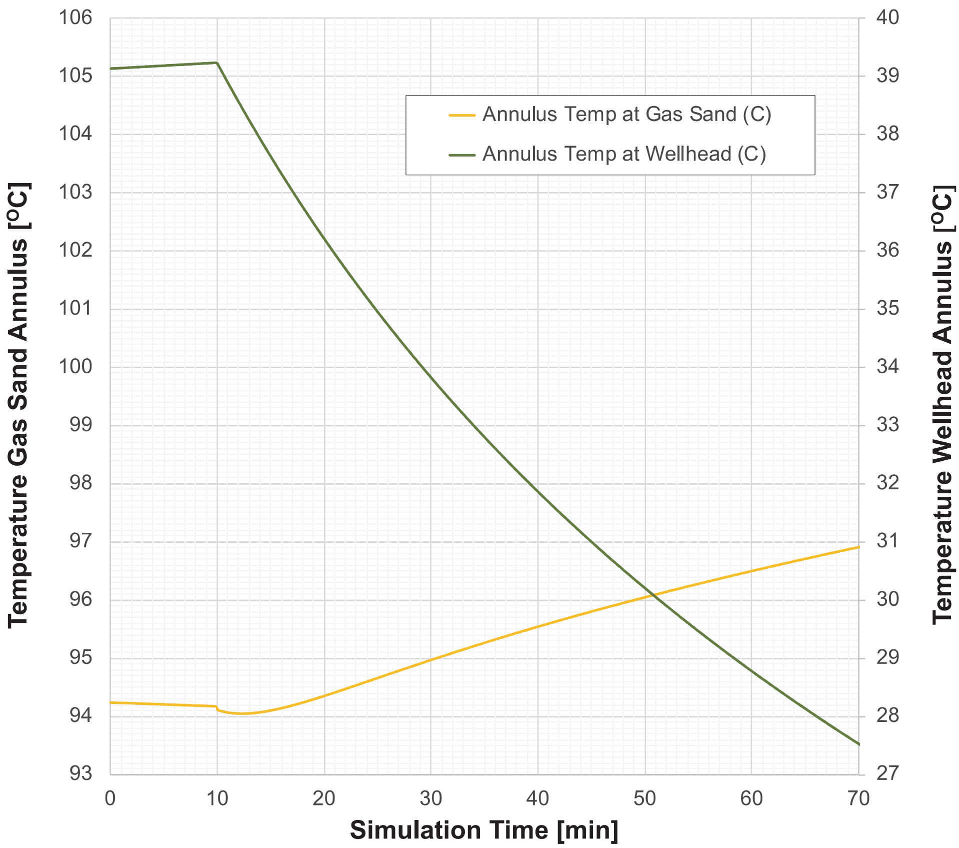


Figure 3.18 – Changes in annulus temperature after pump stop

The simulation shows that during the first hour after circulation stops, the temperature in the wellhead area surrounded by cold seawater falls approximately 4 times faster than the temperature in the open wellbore increases due to thermal heating, see figure 3.18. Cooling of annulus fluid in riser and wellhead area is probably one explanation of why the simulation shows that ESD starts to increase after 28 minutes simulated time (18 minutes after shutdown), see figure 3.17.

3.7.5 Phase E – Decrease in SPP due to net cooling of fluid inside tubulars

While ESD continue to increase SPP suddenly starts to decrease at simulated time 48 minutes (38 minutes after shutdown), see figure 3.17. If the temperature inside the tubulars (drill string) was constant, an increase in ESD down in the annulus wellbore would also result in an increase in SPP. However, the deviation and sudden decrease in SPP 38 minutes after shutdown may be due to a delayed net cooling effect inside the tubulars. The net cooling effect may start after 18 minutes in the annulus and is delayed another 20 minutes inside the tubulars. When the average fluid temperature inside the tubulars starts to decrease, the average density inside the tubulars will increase. This may result in decreasing SPP, see figure 3.17.

It is also interesting to see that approximately one hour after pumps shutdown the SPP pressure drops below zero. In other words, during the first hour after shutdown of the pumps, simulation show that the average temperature in the annulus is probably colder than the average annulus temperature inside the tubulars. The U-tube effect is caused by heavier fluids in the annulus compared to the fluid inside the tubulars. This observation is important because it shows that during the first hour after circulating bottoms up, a flow check to confirm gas influx may not work. In other words, the annulus fluid may contain some gas before it starts to flow and show positive flow during a flow check. Again, it also shows how important it is to have real-time simulations that takes thermal consideration into account, particularly during periods with no circulation. Without simulations taking thermal effects into account it is also difficult to differentiate flow from geothermal heating (phase C) from possible flow caused by gas influx. Particularly in deep water, in HPHT wells and when oil-based mud (OBM) is used, real-time temperature simulations are important.

When OBM is used and a gas kick (influx) occurs in the dense phase region, the gas loading capability in the drilling fluid is unlimited (Skogestad et al., 2017). However, although the gas may go into solution and the OBM gets "loaded" with gas, it will still reduce the overall density of the gas cut mud to some extent. Density of OBM with dissolved methane compared with overall (mixed) density of OBM and free methane is shown in Appendix D, table 7.

3.7.6 Discussion on uncertainties about the temperature simulation

Temperature calculations are considered highly uncertain. SINTEF´s model is used in this simulation study of the Macondo well. For general uncertainties reference is made to ***Appendix D, Chapter 4.2.5 Temperature calculations uncertainties***. In this chapter, two uncertainties that may play an important role are discussed in more detail. These uncertainties are; *formation temperature draw-down* and input data related to *bottoms up circulations*.

The undisturbed formation temperature vs depth for the Macondo well is based on Figure C.13 in Appendix C. According to Pinkston and Flemings this slightly curved temperature profile is based on BP´s temperature model used at the Macondo (Pinkston and Flemings 2019, Figure 8). This undisturbed ambient temperature curve is therefore uncertain to some extent, since it is mainly based on a model and since measurement taken may have been affected by circulation and/or losses of drilling fluid to the formation. Fractured formation, severe losses, filter cakes and filtrate going into the formation may also have affected the overall thermal conductivity. There is also a general uncertainty in thermal conductivity. Thermal conductivity used in the SINTEF temperature simulations are listed in table 3, Appendix D.

To reflect these uncertainties and to give an idea of the magnitude of the uncertainties involved, the SINTEF simulations have been carried out with two different undisturbed formation temperatures; The BP temperature model (called curved temperature model) and a linear approach which gives slightly lower ambient temperatures. A comparison of the two different approach can be seen in figure 3.19.

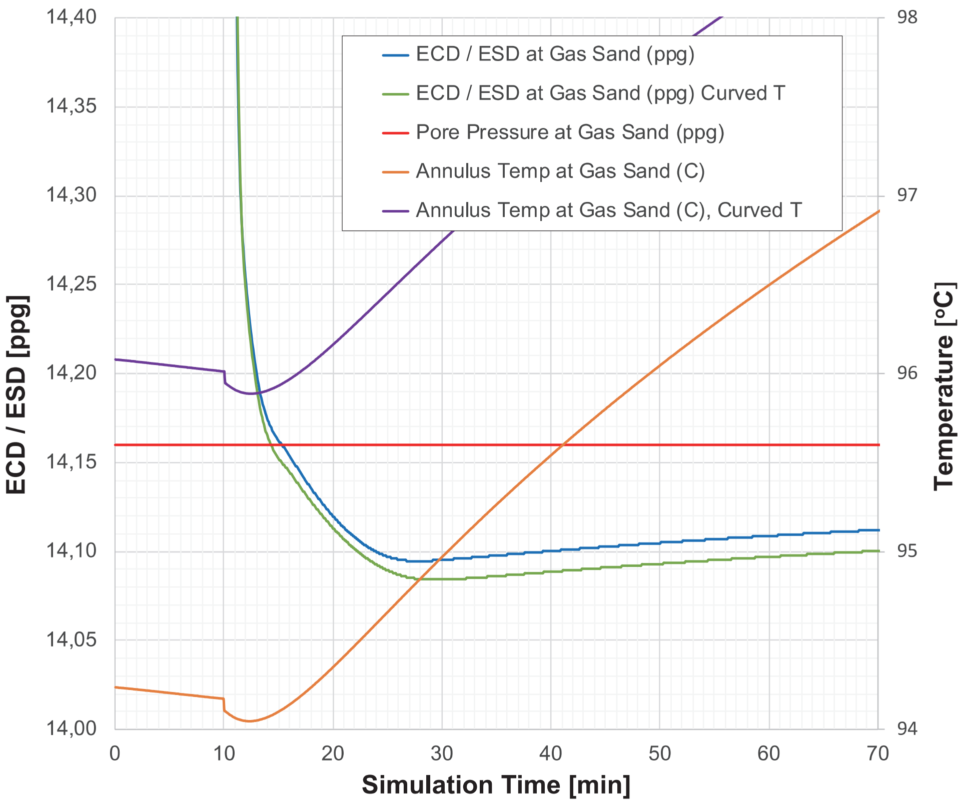


Figure 3.19 – ECD/ESD with two different formation temperatures at the 14.16 ppg gas sand

The “curved temperature model” (BP model) will give approximately 0.01ppg lower ESD since this also gives higher annulus temperatures, see figure 3.19.

During phase B (from 10 to 14 minutes after pump shut down), the two different temperature models start to be effective from 13 to 14 minutes simulated time.

When bottoms up was circulated last time on April 16, after 5 days with well logging activities, it is likely that the annulus fluid temperature was close to ambient due to the long static period. When bottoms up circulation starts, cold fluid is pumped down the well and the near borehole formation, casing, cements and casing annulus fluids will be cooled down. This near borehole formation temperature draw-down or cooling will continue for several hours or days before a new annulus temperature profile is stabilized. From the last 10 minutes of the fast pre-simulation of 6 hours circulation to stabilize temperatures in the well, it can be seen that the annulus fluid temperature is still not stable, see figure 3.19.

A stable annulus temperature profile is obtained when the heat added by the downhole formation is equal to the energy lost in the wellhead and riser area to the cold sea. The 6 hours pre-simulation to stabilize temperatures is uncertain since we do not know the configuration of the circulating string, the flow rate used for how long they circulated the well on April 16. Another important factor that affects the downhole temperatures is the use of booster line. When drilling fluids are pumped down the booster line it will be cooled down by the cold seawater surrounding the booster line. The cold drilling fluid is then pumped into the bottom of the riser and mixed with the warmer annulus fluid coming from the well. The riser will act as a large shell and tube heat exchanger. The amount of heat removed from the drilling fluid pumped down through the drill string (tube) will increase when booster pump is used. Deeper water or longer riser and the use of booster line will increase the time it takes before thermal equilibrium and stable temperature profile is reached (Vavik et al. 2017A, Figure 3, 4 and 5).

It is likely that the booster line was used when bottoms up was circulated, both when TD was reached and after well logging on April 16. The use of a booster line is important to minimize the time it takes to perform this operation and to ensure sufficient velocity in the riser annulus to get any potential cuttings out of the riser. The booster line may have been used simultaneously with drilling fluid being pumped down the drill string, throughout the entire operation. In this case this will probably give a lower annulus temperature than the simulations show, since these simulations was performed without any fluid pumped through the booster line.

However, it is uncertain how the booster line was used. In the hearing after the accident, BP well team leader (John Guide) was asked about the decision to not circulate bottoms up after they have landed the casing and prior to cement job on April 19. Part of Mr. Guide´s answer was that the biggest risk that was associated with this cement job was losing circulations. He also explains that due to the volumes pumped during the cement job, they will have bottoms up above the wellhead after the cement was in place. They could then circulate that up (through kill, choke or booster line) to see if there was any gas.[3.40] The concern of losing circulation may also have affected the bottoms up circulation that was performed on April 16. If this bottoms up was performed in a similar two stage operation, i.e. no drilling fluid was pumped down the drill string after the bottoms up was above the wellhead area, this may have resulted in higher bottom hole temperatures and lower ESD after end of circulation.

3.8 Gas Kick Concealed by Gas Hydrate Formation

Although there are uncertainties in the temperature simulations it seems likely that the well became underbalanced during the first 10 to 15 minutes after end of bottoms up circulation on April 16, see figure 3.19. The SINTEF simulation shows that ESD during the 3-day static period from April 16 to 19 after the initial drop, will gradually increase again, see figure 3.20.

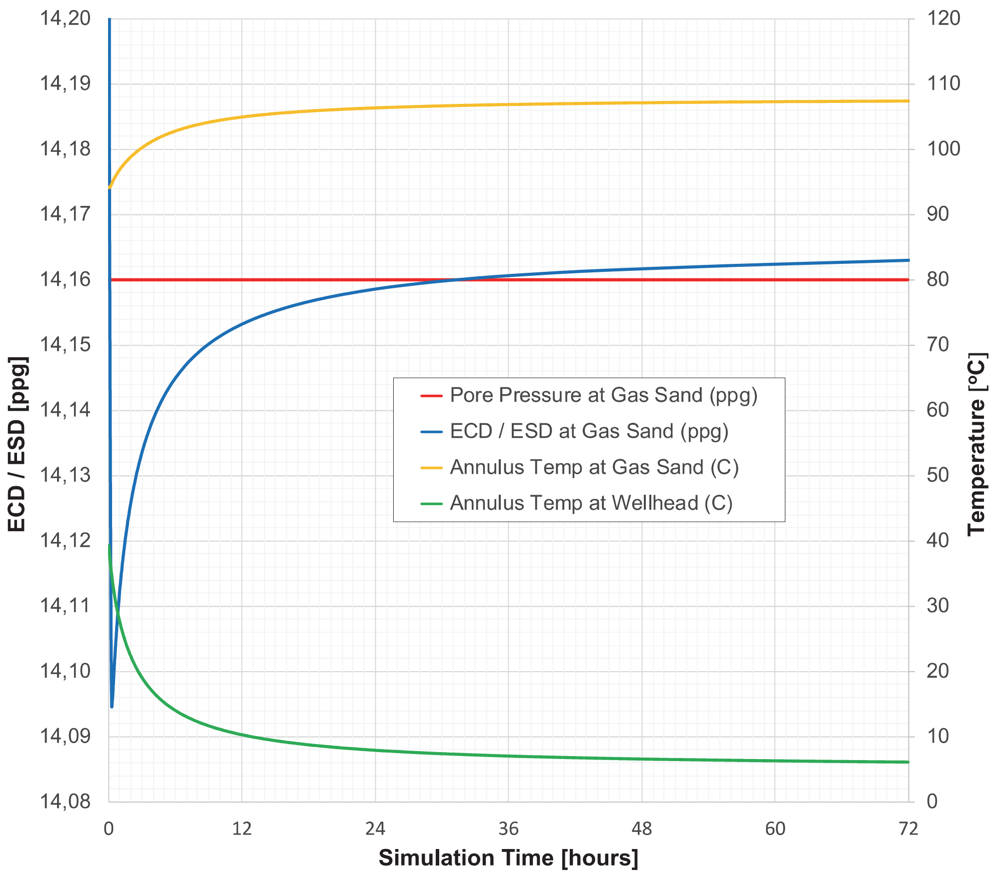


Figure 3.20 – ESD at gas sand for 72 hours static period between April 16 and April 19

This simulation is without considering the effect of reduced ESD due to gas cut mud caused by gas kick as the well become underbalanced at the 14.16 ppg gas sand. The simulation shows that the well was underbalanced for several hours. This would probably lead to a large amount of gas influx into the well. If this was the case it would also be expected that the well become more underbalanced as more and more OBM will be diluted with gas. Even if the gas goes into solution and the OBM gets "loaded" with gas, it will still reduce the overall density of the gas cut mud to some extent, ref table 7, Appendix D. It is therefore likely that the well will stay underbalanced and sooner or later blow-out if no action is taken.

There is however at least one other possible explanation that the wellbore could reach a new stage of "equilibrium" where the well appears to be stable. If the gas in the mud forms hydrates with the water in the mud the wellbore may reach a new stage of "equilibrium" where the well appears to be stable. However, in order to form gas hydrates, the mud/gas temperature has to be cooled down below the hydrate formation temperature, i.e. to the left of the hydrate equilibrium curve, see figure 3.21. See chapter 4 for further discussion of this hypothesis.

Figure 3.21 contains both hydrate equilibrium curves generated from experiments (Grigg & Lynes 1992, Table 2) and simulated values. [3.41] To test the hypothesis that gas hydrates may have formed during the static period between April 16 and April 19, information about water content and salt concentration for the SOBM used in the well are required. This information was not available for this thesis. However, it is common to have both oil and water in OBM. The ratio of the oil percentage to the water percentage in the liquid phase of an oil-based system is called its oil/water ratio. Oil-based systems generally function well with an oil/water ratio in the range from 65/35 to 95/5, but the most commonly observed range is from 70/30 to 90/10. [3.42] The presence of oil and salt dissolved in the water inhibit the formation of hydrates. Grigg and Lynes experiments show that OBM with 20-vol% freshwater (oil/water ratio 80/20) will form hydrates at approximately 24 ºC if the pressure is 250 bar, see figure 4.20 (brown curve). The experiment also shows that if the freshwater was replaced with 19.22 wt% brine, this will inhibit the formation down to approximately 10 ºC (grey curve).

If we assume that the gas cut mud reaches the wellhead area (5 060 ft) during the 3-day static period after the bottoms up circulation on April 16, the static pressure will be approximately 257.5 barg (3 735 psi) at the wellhead. [3.43] The gas will probably be dissolved in the SOBM since the gas will still be in the dense phase region, see figure E.2 in Appendix E.

Since the exact oil/water ratio or salt concentration in the aqueous phase are not known, these values are also assumed. If we assume that the SOBM contains 20 vol% brine and that the brine contains 19.22 wt% $CaCl_2$ (salt), Grigg and Lynes experiments show that hydrates may form if temperatures in the wellhead fall below approximately 10 ºC, see figure 3.21 (grey curve). From the SINTEF simulation we know that the annulus temperature in the wellhead area will drop rapidly during the first hours after end of circulation, see figure 3.20. After about 12 hours after pump stop, the simulation shows that the wellhead annulus temperature will drop below 10 ºC and hydrates may have formed if the gas cut mud have reached this high up in the open wellbore.

When hydrates forms gas is "consumed", meaning that gas goes from being dissolved in the SOBM (dense phase) to be trapped within a crystal structure of water molecules (solid). During this phase transition from dense phase to solids the total volume of the gas cut mud is reduced. I.e. the density of the overall gas cut mud increases. (Vavik et al. 2016, Table 2). In deep water such as the Macondo well, the potential for forming hydrates after gas influx will increase. In deep water the hydrostatic pressure in the Wellhead, BOP and riser area is sufficiently high and due to the cold surrounding water, temperature may drop below the hydrate equilibrium curve, see figure 3.20. Despite the possibility of forming gas hydrates after a gas kick is well known in the industry (Barker and Gomez, 1989), (Grigg & Lynes 1992), (Kotkoskie et al. 1992), (Ebeltoft et al. 1997 & 2001), (Lage et al., 2002), it seems that this operational hazard has not received much attention after 2001.

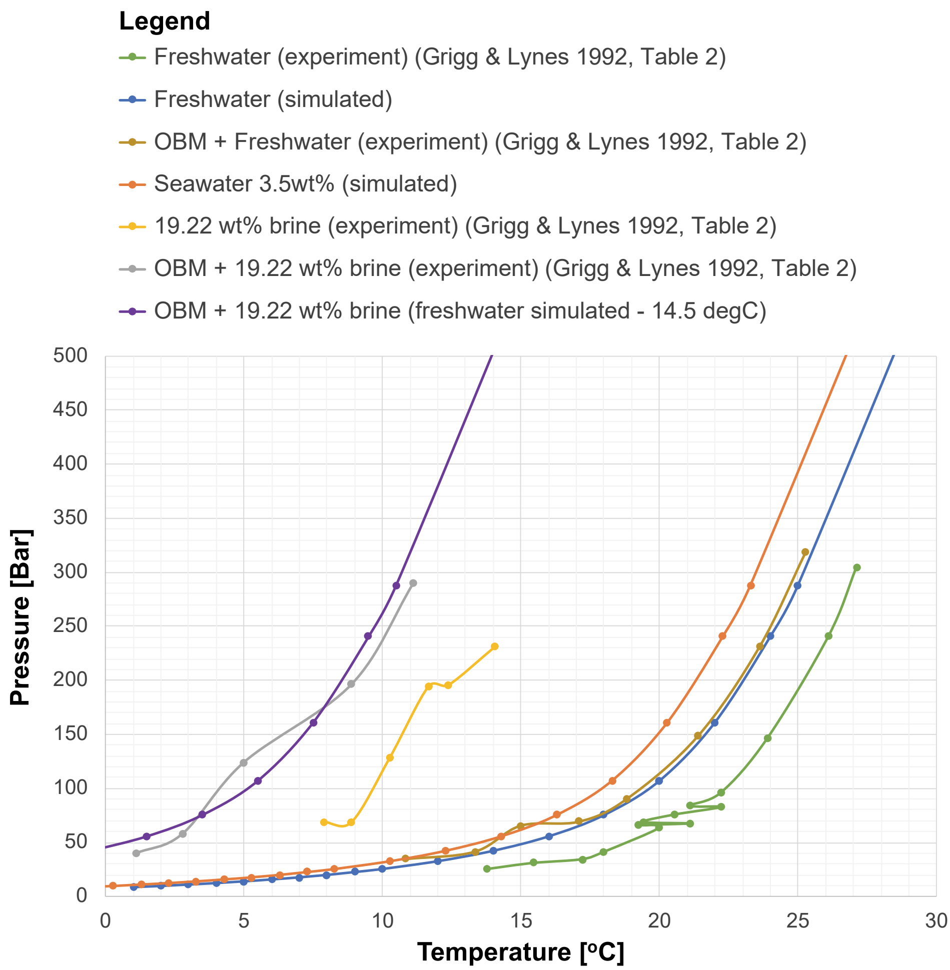


Figure 3.21 – Hydrate equilibrium curves, simulated and experimental (Grigg & Lynes 1992)

Thierry Botrel wrote in 2001: "*With more deep-water wells drilled, hydrate blockages impairing well control equipment is a possibility that can no longer be ruled out. Chemical inhibition of drilling mud is only partially effective. A sound strategy to prevent and remedy hydrate incidents during drilling operations must be implemented*." (Botrel 2001)

Despite this clear warning from Botrel at the Offshore Technology Conference (OTC) in Houston in 2001, the possibility that gas hydrates may have played a role in Deepwater Horizon incident has not been discussed to any great extent. The only investigation report that opens up for this possibility is the Chief Counsel Report (CCR). However, they also end the discussion as soon as it has started because it was concluded that gas could not have been present in the wellhead and riser area at the time of the negative pressure test: "*While well site leader John Guide and drilling engineer Brian Morel have suggested that hydrates from migrating gas may have frozen in the kill line, no evidence has been produced suggesting that this actually took place or that gas had made it to the BOP as early as the time of the negative pressure test.*"[3.44]

The hypothesis that hydrates may have plugged the kill line during the negative pressure test will be further discussed in *Chapter 5 – Well Integrity Tests*.

Another hypothesis is that influx from the 14.16 ppg gas sand was present in the well already prior to running the production casing. The hypothesis that the gas kick was concealed by natural gas hydrates forming in the wellhead and riser area will be further discussed in *Chapter 4 – Running and Cementing the Casing*.

3.9 Pore Pressure Prediction and Potential for Crossflow

After drilling was completed at April 9 at a final total depth of 18,360 feet, a series of logs were run to collect data from the well.[3.4] Formation pore pressure of the lower most pay sand was measured to approximately 12.56 ppg[3.9] at a depth of 18,223 feet. This corresponds to a formation pressure in the lower most pay sand of 820 barg (11 893 psi).[3.45] At the same time the uppermost 14.16 ppg gas sand[3.9] at 17,435 feet, corresponding to a formation pressure of 885 barg (12 831 psi).[3.37] This means that the pore pressure in the gas sand were approximately 65 bar (938 psi) higher than the pore pressure down in the pay sand.

The kind of pore pressures seen in the Macondo well with a progressive shift in pore pressure in the sealed upper gas sand (14.16 ppg) and regressive behavior in the pay sand (12.56 ppg) is a challenge and may have contributed to the blowout of the Macondo well (Pinkston and Flemings 2019).

When these two pressure zones are connected with an open borehole, there is also a potential for crossflow. The upper gas sand has approximately 65 bar (938 psi) higher pore pressure than the lower pay sand, where the drilling crew earlier had experienced losses. A potential massive loss in the pay sand during the cement job may have started a crossflow event that jeopardized the cement job.

The hypothesis of crossflow during the cement job will be further discussed in *Chapter 4 – Running and Cementing the Casing*.

Chapter 4 – Running and Cementing the Casing

In this chapter a hypothesis that gas and gas hydrates was already present in the wellbore when the production casing was lowered into the well will be discussed.

Another hypothesis that loss of drilling fluid, spacer or cement during the cement job was partly concealed by a simultaneous gas kick in the upper gas sand will also be discussed.

4.1 Running the 9 $^{7}/_{8}$ x 7 -inch Long String Production Casing

At 3:30 a.m. on April 18, 2010, the Deepwater Horizon drill crew began lowering the long-string production casing into place. [4.1] Approximately 35 hours later, on April 19, 2010, the drill crew completed running the production casing. [4.2]

Lowering the casing string into the well pushes drilling fluid ahead of it and can create surge pressures that can fracture the formation, leading to loss of drilling fluids. To reduce surge pressure, BP incorporated a surge reduction system including an auto-fill type of float collar and reamer shoe. The float collar used at Macondo contained two flapper check valves that are held open during installation by an auto-fill tube. While open, these valves allow mud to pass through the float collar and up into the casing. [4.3]

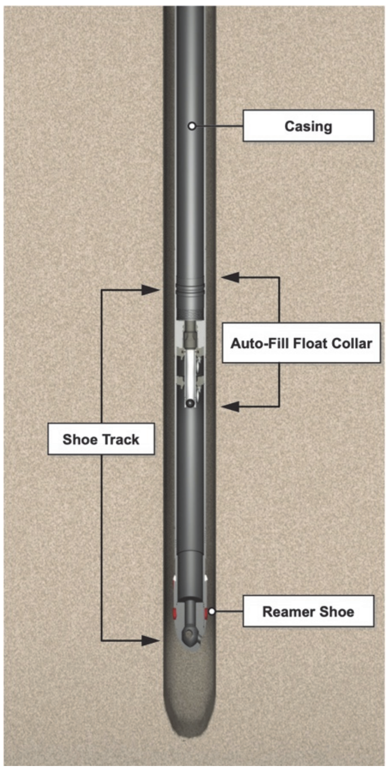


Figure 4.1 – Example of casing shoe and auto-fill float collar [4.4]

4.1.1 Allamon diverter tool and diverter test device

The surge reduction system also included an Allamon diverter sub and diverter test device. [4.5] 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. [4.6] The diverter test device (DTD), was located approximately 300 feet below the diverter tool. [4.7]

The purpose of the DTD is to pressure test the sealing element of the diverter tool after it has been closed. Minerals Management Service (MMS) [4.8] approved a regulatory dispensation that modified the standard testing regime for the diverter sealing element. [4.9] Information on why BP needed a regulatory dispensation, is not known by the author when this thesis is written. It may be related to the location and long distance between the Allamon diverter sub located at 4 434 feet, the DTD 300 feet below and the auto-fill float collar located at 18 115 feet. It may also be related to the type of surge reduction system that was used. The Allamon diverter sub and DTD located in the landing string above the wellhead in the riser, was probably designed and produced by the Allamon Tool Company. The auto-fill float collar with float valves was probably manufactured by Weatherford. [4.10]

After the production casing was run to a depth of 18 304 feet on April 19, 2010, the diverter tool was closed by inserting a 1 $^5/_8$-inch diameter brass ball into and down the drill string to a seat in the diverter tool. A pressure of 1,000 psi was then applied to the drill pipe. This pressure activated the shear pins holding the diverter tool sleeve, which shifted the sleeve down, isolating the circulation ports and closing the diverter tool. Pressure was then increased to 2,433 psi to push the ball through the diverter sub-ball seat, allowing it to free-fall to the diverter test device (DTD), located approximately 300 feet below the diverter tool. Pressure was then further increased to 2,765 psi, to confirm that (1) the diverter tool ports had closed, and (2) the DTD seat had sheared, and the ball had free-fallen to the float collar located 189 feet above the casing shoe. [4.11]

The Transocean investigation team concluded that no problems were encountered during the conversion and test of the diverter tool. [4.11] The conversion of the Allamon diverter tool to closed position and verification that the diverter was closed using the DTD was carried out shortly after 2:10 pm (14:10) on April 19, 2010, see figure 4.2. [4.12]

The real-time data showing standpipe pressure and flowrate during closing and testing of the Allamon diverter is however important to discuss the hypothesis that gas and gas hydrates was already present in the wellbore when the production casing was lowered into the well. The blue arrows and letters from a) to f) have been added to the figure 4.2 for this analysis.

a) While pumping down the drill pipe (casing landing string) at a flow rate of 2 bpm the pump pressure is low and increasing very slowly. The main reason for this is probably that the 1 $^5/_8$-inch diameter brass ball has not reached the seat in the Allamon diverter and that mud is allowed to flow out of the diverter and up the annulus. Since the diverter is open at this time, this probably explains why the pump pressure is much lower than the simulated values, we can see in figure 2 in Appendix D. The slightly increase in pressure during this circulation may be due to compressibility of the SOBM or it may indicate that gas is present in the mud increasing compressibility. However, if gas hydrates had been formed in the SOBM this is likely to happened below the Allamon diverter located at 4 434 feet. As discussed in chapter 3.8 the probability of gas hydrates formed in the wellhead, BOP and lower part of the riser is likely if gas was present. If gas hydrates form it is also possible that migration of gas ceases. If a gas kick was occurring before and during running the running the production casing, this may therefore result in very little gas present in the upper part of the riser from the Allamon diverter location and upwards, see chapter 4.2 for further discussion.

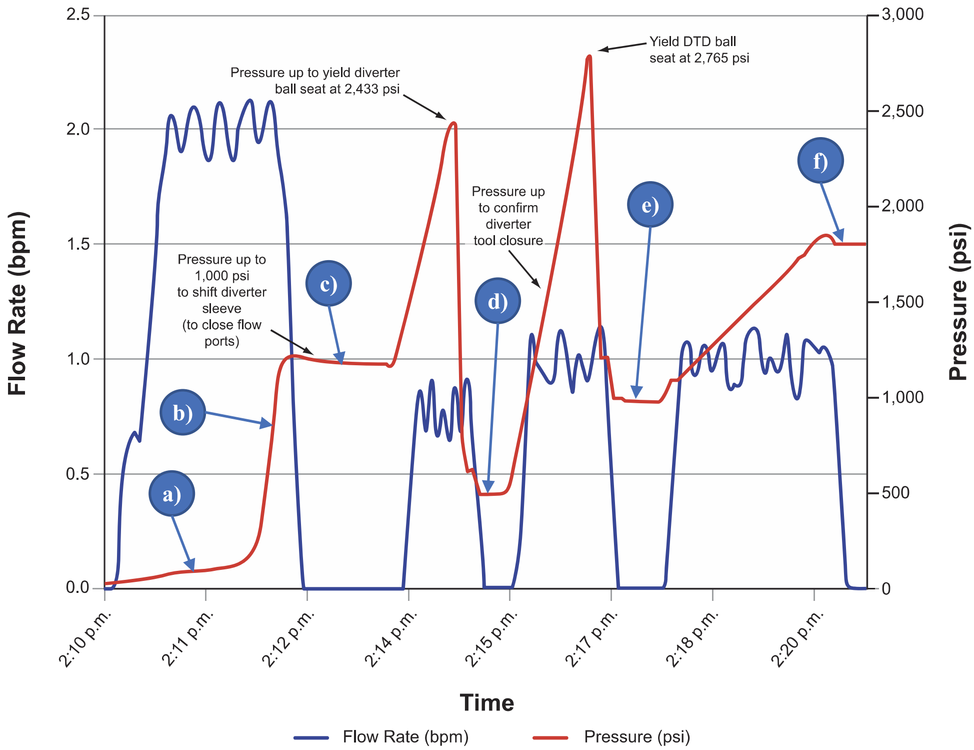


Figure 4.2 – Conversion of Allamon diverter to closed position and verification by DTD [4.12]

b) The rapid increase in pump pressure is probably caused by the brass ball has reached the seat in the Allamon diverter and that the diverter sliding sleeve or similar closing mechanism is closing the diverter flow ports.

c) After the diverter probably was closed the pump is stopped. The pressure decreases approximately 45 psi (3.1 bar) in less than 2 minutes after the pump is stopped. The pressure is probably trapped at around 1 200 psi,[4.13] because the ball forms a seal with the seat in the Allamon diverter. The pressure decrease may be due to leakage, thermal cooling of the SOBM or gas hydrates forming in the landing string. If gas was present in the SOBM in the landing string halfway up the riser, the increase in pressure may have caused gas hydrates to form. The static pressure at 2 500 ft is approximately 126.3 bar (1 832 psi). [4.14] When a trapped pump pressure of approximately 82.7 bar (1 200 psi) is added on top of the static pressure, this means that the pressure inside the landing string at 2 500 ft increase to 209 bar (3 031 psi).

   If we assume that the SOBM has got similar properties to the OBM with 19.22 wt% brine used in the Grigg and Lynes experiment, hydrates may form if the temperature drops below 4 to 5 ºC under static pressure, see figure 3.21. Since the temperature is probably close to ambient temperature of 6.5 ºC [4.15], the static pressure is probably not high enough to form hydrates (126 bar). [4.16] This also means that any dissolved gas may have started to "boil out" under these static conditions (126 bar). [4.16] However, when the pressure suddenly increases to 209 bar (3 031 psi), the increase in pressure may have pushed the gas back into the dense phase region again. [4.17] Even more important is that when pressure is increased to 209 bar, the hydrate formation temperature is typically increased by almost 5 ºC (from approximately 4.5 ºC to 9.5 ºC) according to Grigg and Lynes experiment, see figure 3.21. This increase in hydrate formation temperature caused by increase in pressure may have caused hydrates to form in the landing string. The pressure decrease may therefore also have been caused by gas hydrates forming in the landing string, if gas was present.

d) About 30 seconds after the Allomon diverter ball seat yield at 2 433 psi, the pressure levels out at about 500 psi. This may be due to the brass ball has fallen the 300 ft down to the DTD. This correspond to an average velocity of the free-falling ball of 10 ft/sec (3 m/s). This seems possible taking into account that the brass ball typically has a density of 8 500 kg/m^3 which is several times the density of the SOBM. [4.18] In any case the sudden level outs of the pressure at 500 psi indicates that pressure was trapped either by the brass ball seated in the DTD or by some other plug in the landing string or casing.

e) About 30 seconds after the DTD ball seat yield at 2 765 psi, the pressure again levels out but this time at about 1 000 psi. This time the brass ball has no obvious restriction before it falls to the float collar located at 18 115 ft. It is therefore unlikely that the 1 $^5/_8$ -inch diameter brass ball should have caused any restriction or trapped pressure in the landing string or casing. Another important observation is that the trapped pressure increases from

500 psi to 1000 psi after pumping only about 1.2 barrels [4.19] into the landing string. By considering the mud compressibility (c_m) of the SOBM, the total amount of mud (V_m) or trapped volume can be estimated according to the following equation.

$V_m = V_c \;/\; (\Delta p\ c_m)$ where .... (5)

V_m = total volume of mud (trapped volume) (bbl);
V_c = volume compressed (bbl);
Δp = applied pressure (psi); and
c_m = mud compressibility (bbl/bbl/psi).

The compressed volume (V_c) to compress the trapped volume from 500 to 1 000 psi is 1.2 bbl. [4.19] Applied pressure (Δp) is then 500 psi. The SOBM compressibility (c_m) is assumed to be 3.3358 x 10^{-6} (bbl/bbl/psi).[4.20] Trapped volume (V_m) in the 1 000 psi trapped pressure case, or total mud volume (V_m) can then be calculated.

$$V_m = 1.2 \text{ bbl} / (500 \text{ psi x } 3.3358 \text{ x } 10^{-6} \text{ bbl/bbl/psi}) = 719 \text{ bbls}$$

The total volume inside the landing string and casing down to the float collar is 892 bbls. [4.21] The total volume down to the wellhead is 152 bbls. [4.22] Although there are many uncertainties in this calculation, such as possible gas in the mud that may affect the compressibility of the SOBM, it seems likely that pressure was trapped due to a plug down in the lower part of the production casing. It is possible or likely that the float collar was plugged. If the flow ports in the flow tube located at 18 115 feet (see figure 5.3), had been open the pressure would be expected to fall after the pumps were shut down and not level out at about 1 000 psi.

f) Since the pressure did not fall any further but leveled out at 980 psi, the pump was once again started up and pumped at a flow rate of 1 bpm. This time the pressure climbs to 1 850 psi, before it levels out at about 1 800 psi. This is another indication that the line was plugged. Another important observation is that the pressure climbs with a slower rate than previously although the pump rate is the same (1 bpm). When the line was blocked with the brass ball in the DTD, the pressure climbed 5.158 times faster. [4.23] This is a direct indication that the trapped volume (V_m) this time is 5.158 times larger than the previously when the DTD was used to verify that the diverter had closed properly. This is however assuming that the average compressibility of the mud is the same in both cases.

The volume down to the DTD located at 4 734 feet is 142.77 bbls.[4.24] The total trapped volume (V_m) in this first attempt to convert the auto-fill float collar, can then be calculated. V_m = 142.77 bbls x 5.158 = 736.4 bbls. As previously stated, the total volume down to the float collar is 892 bbls. The total volume down to the 9 $^7/_8$ x 7 -inch crossover is 689 bbls. [4.25] In other words, if we assume uniform compressibility, the plug should be located in the 7-inch casing at a depth of about 12 488 ft. [4.26] The temperature would be expected to be close to ambient, since the well had not been circulated since April 16. At this depth 7 421 ft below seafloor the ambient temperature would be about 75 °C. [4.27] It is therefore highly unlikely that the casing should be plugged with gas hydrates at this depth. It is also highly unlikely that the 1 $^5/_8$ -inch diameter brass ball or any other solids particles inside the 7-inch production casing should block the line at this depth. A more likely explanation is that the flow ports in the flow tube located at 18 115 feet was plugged.

The calculation trapped mud volume (V_m) of 736.4 bbls, is smaller compared with the assumed correct trapped volume down to the float collar of 892 bbls. This deviation may be due to the compressibility of the SOBM was not uniform. If the SOBM contained gas, this gas would have less effect on the compressibility down in the well where the gas is in dense phase and probably also dissolved in the SOBM. Also, potential gas in the wellhead and lower part of the riser area would probably be in solids form (gas hydrates) and have less effect on the mud compressibility. However, potential gas in the upper part of the riser or more correct the landing string will have great effect on compressibility, since it will start to boil out of the dense phase region at these pressures, (Vavik et al., 2016, Fig. 4). If we rearrange equation (5) used to calculate total trapped mud volume, the same equation can be used to calculate the observed mud compressibility (c_{mo}).

$$c_{mo} = \frac{V_c}{V_m \ \Delta p} \quad \text{where} \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \ (6)$$

c_{mo} = mud compressibility observed (bbl/bbl/psi)
V_m = total trapped volume of mud (bbl);
V_c = volume compressed (bbl); and
Δp = applied pressure (psi).

During the test to verify that the Allamon diverter had closed properly the trapped mud volume (V_m) of 142.77 bbls, was compressed with a pumped volume (V_c) of 1.2 bbls, this resulted in an observed pressure increase (Δp) of 2 265 psi.

The observed mud compressibility (c_{mo}) can then be calculated.

$$c_{mo} = (1.2 \text{ bbl}/ 142.77 \text{ bbl}) / 2\ 265 \text{ psi} = 3.71 \times 10^{-6} \text{ bbl/bbl/psi}$$

The observed mud compressibility (c_{mo}) is 11% larger than the expected compressibility of the SOBM. [4.28] This may indicate that the mud contained some gas. Gas in the mud may also explain why the location of the plug was calculated to be shallower than the float collar.

4.1.2 Attempts to convert the auto-fill float collar failed

Before cement is pumped down the string the auto-fill float collar has to be converted. The flapper valves in the float collar are made to prevent u-tubing after the cement has been pumped down. Figure 4.3 shows how this conversion of the float collar was planned to be carried out. [4.29]

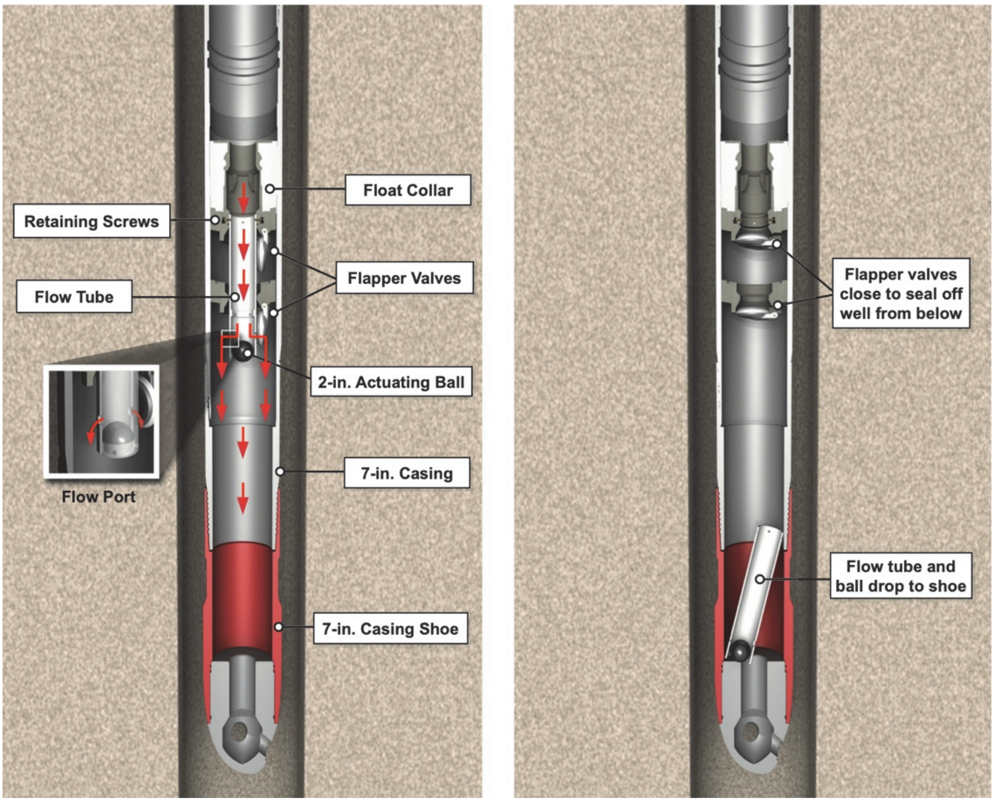


Figure 4.3 – Auto-fill float collar before and after conversion [4.29]

When the production casing was lowered into the wellbore, fluid was allowed to flow or u-tube up through the float collar flow tube to minimize downhole surge.

Unlike the Allamon diverter conversion where the actuating 1 $^{5}/_{8}$ -inch diameter brass ball was dropped from the top, the 2-inch actuating ball is trapped in the float collar also when the casing was lowered into the wellbore. When the casing was lowered, the ball was pushed up to a cage above the flow tube, allowing wellbore fluids and dissolved solids to u-tube and fill up the casing, see figure 4.4. [4.30]

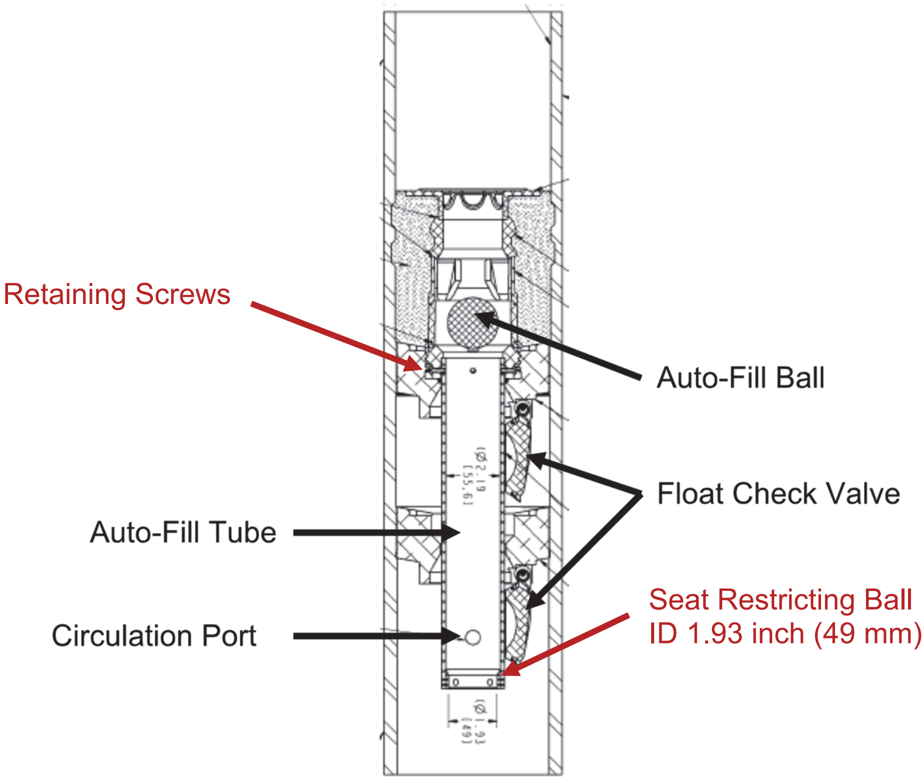


Figure 4.4 – Auto-fill float collar utilized in the Macondo well [4.30]

The auto-fill flow tube also has small circulation ports that will allow fluids to be circulated at low rate without converting the float. However, during the attempt to convert the auto-fill float collar, these flow ports was probably partly or totally blocked, since the pressure increases rapidly typically associated with a blocked line. The lack of flow during the attempts to convert the float has led previous investigations to imply that this have contributed to the many failed attempts to convert the float. [4.31] However, it is the differential pressure between the auto-fill flow tube inside pressure compared with the outside pressure below the ball resting on the seat in the bottom of the tube that matters. One way of obtaining the necessary differential pressure is by circulating 5 to 7 bpm through the flow ports, which will create a differential pressure between 400 to 700 psi. [4.32] In the case of the Macondo well the flow ports were probably plugged since the static pressure after pump is shut down was about 1 000 psi, see figure 4.2, point e). In the subsequent first attempt to convert the float collar the static pressure after pump is shut down was increased to about 1 800 psi, see figure 4.2, point f). This is about 3 to 4 times the normal differential pressure required to convert the float.

4.1.3 Plugged flow ports triggered by hydrate formation and barite sagging?

On April 18, 2010, the Deepwater Horizon drill crew began lowering the long-string production casing into place. [4.1] When the bottom of the casing reamer shoe had reached the wellhead at 5 060 ft below drillfloor, the drill crew was still connecting and running 7 -inch casing into the marine drilling riser. [4.33] When the casing is lowered into the well between each connection, SOBM will be displaced and flow up the annulus and out of the riser, see simplified drawing of the trip tank system when tripping in figure 4.5. [4.34]

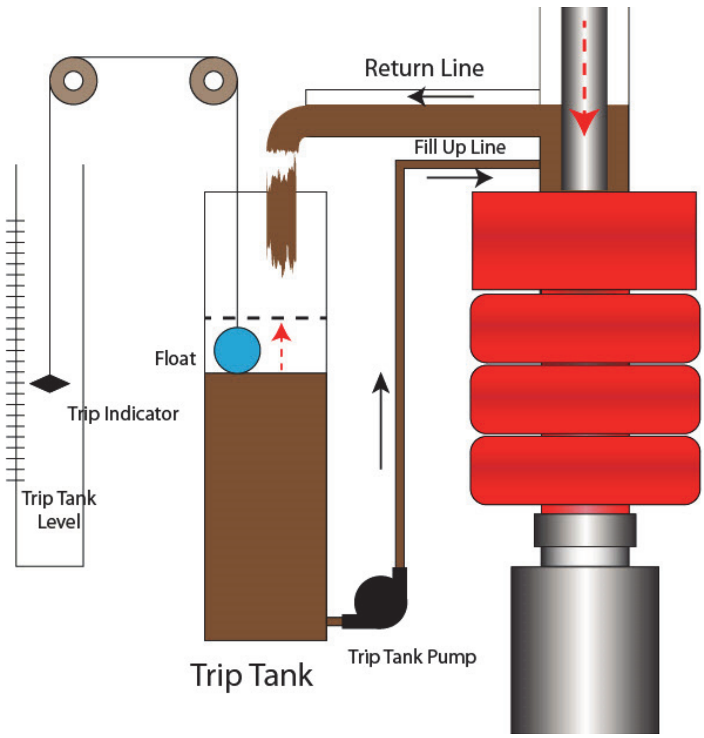


Figure 4.5 – Trip tank while tripping in [4.34]

The minimum displaced mud volume will be the volume of the steel that is lowered into the riser. However, the cross-sectional flow area in the bottom of the casing shoe and through the flow tube and ball in the float collar are limited, see figure 4.3 and 4.4. The fluid level inside the casing will therefore typically be lower than the fluid level in the annulus just after the casing has been lowered. This difference in fluid level is the driving force that makes it possible for the wellbore fluids to u-tube and fill the casing from the bottom through the auto-fill tube. Surplus mud outflow from the riser when the casing is lowered, needs to be filled up from the trip tank system during connection to avoid temporary fall in riser level. To ensure that the annulus is always full (also during connections) it is normal to use the trip tank pump and fill up line also when tripping in. [4.35] The net volume change in the trip tank will increase equal to the steel volume lowered into the well.

If we assume that the trip tank pump was used to circulate on top of the riser when the production casing was lowered into the well, this may have turned out to be important. When the trip tank pump is used in this way, the riser annulus will typically be kept full all the time also during connection, resulting in a "reversed" flow down the annulus and up the auto-fill flow tube during connections. In this way gas cut mud from below the wellhead may have been pushed up to a higher location inside the casing, where it will be cooled down by the cold annulus fluid. In this way gas hydrates may have been produced inside the casing during the last 25 hours of the casing run. [4.36] For each connection a small amount of gas cut SOBM may have been pushed up inside the casing and into the hydrate zone in the wellhead and lower part of the riser.

When gas hydrates form it will create a crystalline solid formed from a mixture of water and natural gas, mainly methane. The gas molecule is trapped in a crystal-like structure or cage made of water molecules. Since both liquid water and dense gas is consumed in this process, this may affect the rheology of the SOBM. This may result in increased barite sagging, since more solids and less fluids (liquid water and gas in dense phase) is the result of hydrate formation. Hydrate formation inside the casing may therefore have triggered barite sagging and weighting material such as barite may separate from the liquid phase and settle out in the flow tube and plugged the flow ports.

Further research is recommended to investigate how hydrate formation and gas cut SOBM affect rheology and barite sagging, see discussion in chapter 4.2.7.

4.1.4 Circulation obtained after pressure up to 3 142 psi

Total of 9 attempts to convert the flout was carried out. Circulation was obtained on the ninth attempt after pressure up to 3 142 psi, see figure C.12 in Appendix C. This is about 4.5 to almost 8 times the required differential pressure to convert the flout, according to the supplier.[4.32] What happened when circulation was obtained on the ninth attempt? The BP investigation team identified three possible failure modes for the float collar: [4.37]

- Damage caused by the high load conditions required to establish circulation.
- Failure of the float collar to convert due to insufficient flow rate.
- Failure of the check valves to seal.

At the time the BP report was written, the investigation team had not determined which of these failure modes occurred. [4.37]

As discussed earlier in chapter 4.1.2 the possibility that the float collar failed to convert due to insufficient flow rate, is unlikely since the blockage or plug probably was in the flow ports and that conversion is depending on differential pressure across the ball and not flow rate through the flow ports.

After the BP report was written Transocean carried out extensive float collar testing to investigate the two other possibilities mention by BP. The conclusion of this testing was that the failure of the check valves to seal, was probably not the case if the float collar had converted and flapper valves actuated as planned. The test confirmed that the double flapper valves closed upon sleeve actuation and held 3 000 psi of fluid pressure from below once properly converted. [4.38]

Another important test that was performed was to test the pressure required to force the ball through the seat in the flow tube. The 2-inch (50.8 mm) ball had only 0.07 inch (1.8 mm) larger diameter then the seat in the bottom of the flow tube, see figure 4.4.

The ball broke through at 1 477 psi on the first float and 1 840 psi on the second. This generally confirms the Weatherford representative's assertion that the setting ball would pass through the tube without converting the floats if the pressure reached or exceeded 1 300 psi. [4.39] See figure 4.6 showing a picture of the seat in the bottom of the tube after the ball has been forced through. [4.40]

Figure 4.6 – Actuation ball ejected through seat of flow tube [4.40]

Given the total pressure of 3 142 psi that had to be applied to obtain circulation, it seems likely that the ball was forced through the seat in the bottom of the tube.

The Transocean investigation team also believes that the ball may have been ejected from the ball seat without converting the float collar given the pressures that were applied. [4.41]

4.2 Low Pump Pressure After Circulation was Established

After establishing circulation, the drilling crew observed another anomaly. The pump pressure required to circulate mud through the well was significantly lower than expected. The low circulating pressure raised concern among personnel on the rig floor. [4.42]

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. However, after the crew established circulation, it took only 137 psi to circulate at 1 bpm. The crew increased circulation to 4 bpm, which required only 340 psi of pressure. This was 230 psi less than M-I SWACO had predicted. [4.43]

M-I SWACO reviewed the modeling with BP and could not estimate pressures as low as those seen on the drill pipe. M-I SWACO later emailed BP and informed that several individuals had double checked the input and still could not explain the difference. [4.44]

BP never resolved the low circulation pressure issue, concluding instead based on discussions with the rig crew that the pressure gauge was likely broken. [4.45] After the incident BP investigation team wrote in the report: "*The investigation team found no indication that hydrocarbons entered the wellbore prior to or during the cement job.*" [4.46]

4.2.1 Circulating bottoms up to check for gas

If gas had entered the wellbore prior to the cement job, it would likely be coming from the 14.16 ppg gas sand. The wellbore was likely to be underbalanced during the static period between April 16 and April 19 at this location, see chapter 3 and figure 3.20.

The best evidence to check if gas had entered the wellbore prior to the cement job would be to circulate bottoms up. Halliburton recommends performing at least one full bottoms up circulation on a well before pumping a cement job. [4.47] However, due to the risk of losing returns during circulation, BP´s plan was to circulate bottoms up and check for gas in three steps. [4.48] The first step was to circulate mud prior to the actual cement job. The second step was to perform the cement job. When all the spacer and cement had been pumped the fluid located in the bottom in the well would be circulated up and into the riser annulus, see figure 4.7. [4.49] BP and the drilling crew would then be able to circulate that up to see if there was any gas.

The third step to circulate any potential gas cut mud out of the riser was partly performed during preparation for the negative pressure test, see chapter 5. The bottoms up circulation was completed when the riser was partly displaced with seawater, see chapter 6.

The best evidence that gas did entered the wellbore prior to the cement job would be that gas cut mud was actually detected in the gas meter that Sperry Drilling´s had installed, when wellbore fluids were circulated up. The Sperry-Sun system measured and collected data on the gas content in the mud returning from the riser. If gas entered the wellbore prior to the cement job, gas should have been detected on this gas content meter, either during the cement job or after the cement job, when the riser annulus was circulated up.

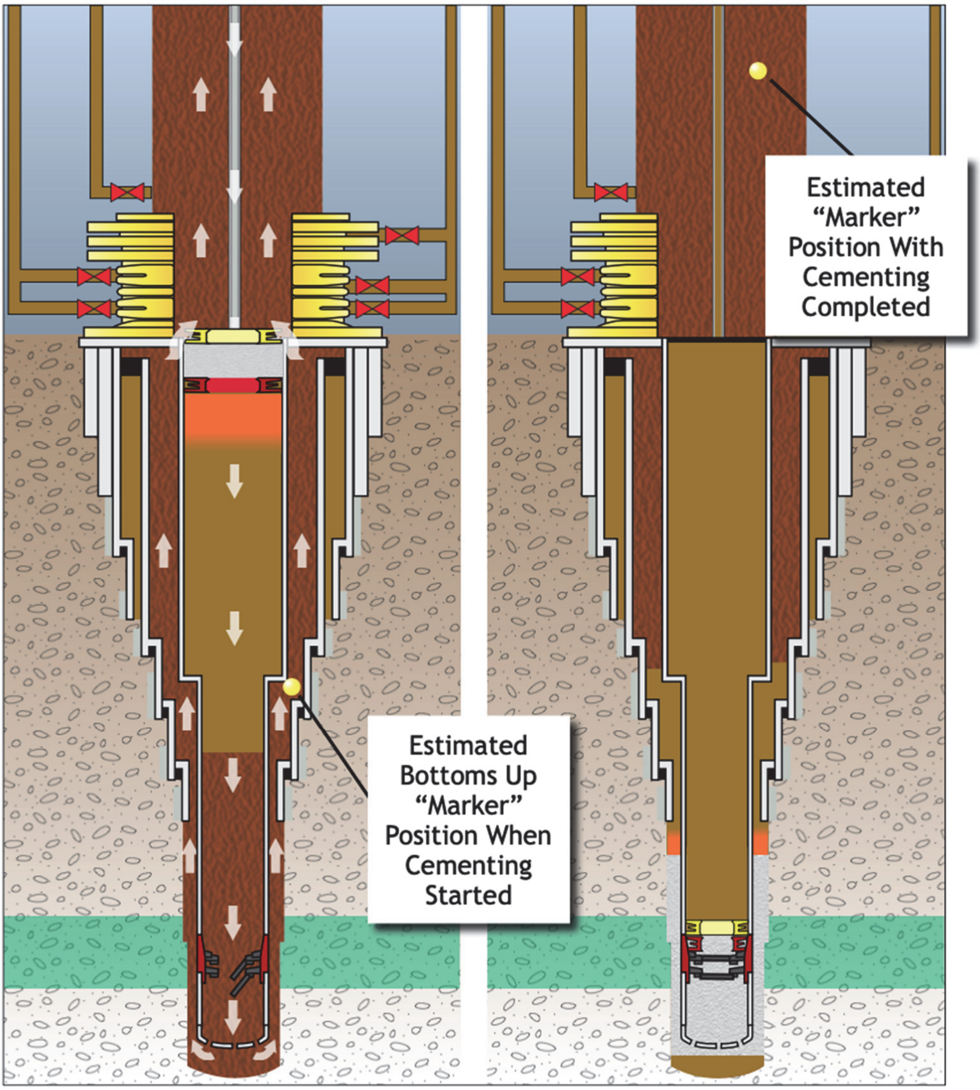


Figure 4.7 – Estimated bottoms up “marker” prior to and after cementing [4.49]

Dr. John Roger Smith reviewed real time data collected by the Sperry-Sun system the last 24 hours prior to the blowout. In the report to the joint investigation team, he made comments on abnormally high gas content observed at the end of the cement job (time period from 00:00 to 00:20 after midnight on April 20);

"*Significant increases in gas units during this period, to levels exceeding that when drilling non-productive formations, implies that trip gas from previous trip out of the hole had not been circulated out prior to the cement job.*" [4.50]

Also, during the final stage of circulating bottoms up gas was recorded in the mud returning from the riser. During preparation for the negative pressure test between 3:00 pm and 5:00 pm and partly during displacement of the riser after the negative pressure test at 8:17 pm (20:17) on April 20, abnormal increase in gas units can be seen on the collected real time data. [4.51]

This abnormal increase in gas units when fluids from the wellbore annulus was circulated up, is evidence that gas was present in the wellbore prior to the cement job. Is it possible that this gas cut mud could have caused the low circulation pressure observed prior to the cement job?

4.2.2 Simulated and observed circulation pressure

Standpipe pressure (SPP) after circulation was obtained has been simulated using SINTEF´s thermohydraulic model, see figure 4.8.

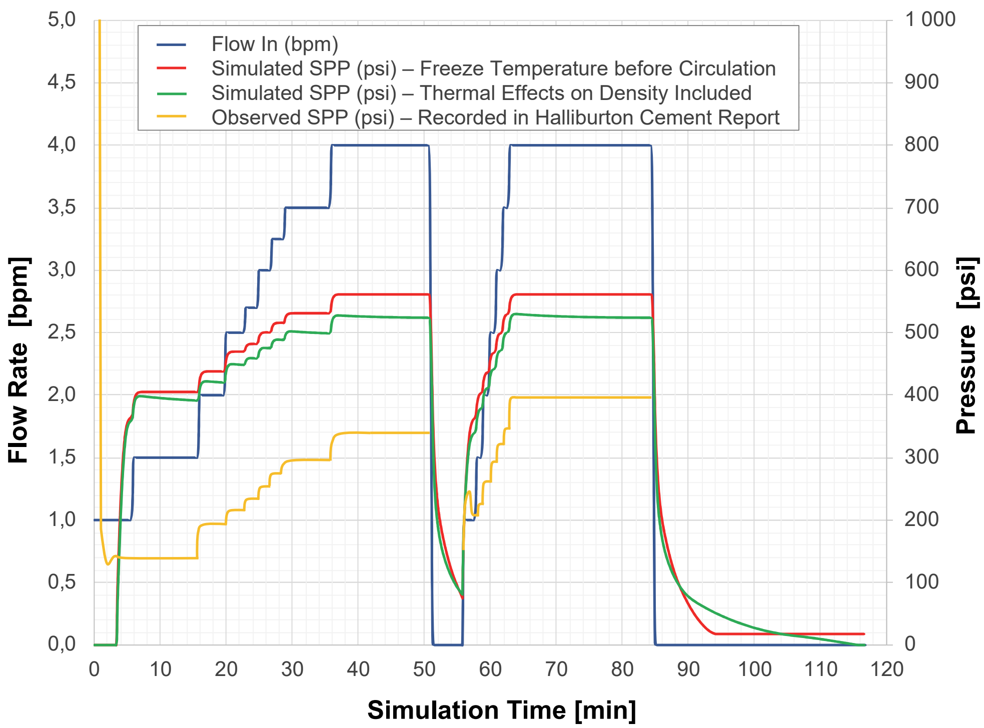


Figure 4.8 – Simulated and observed standpipe pressure after establishing circulation

When circulation was obtained after nine attempts, circulation was carried out with two different rig pumps. The first pre-cementing circulation sequence ongoing for about 51 minutes is shown in figure 4.8. To investigate the effect temperature has on the SOBM, the simulations were carried out both with dynamic temperature effects included (green line) and one simulation where fluid temperature in the wellbore was kept constant equal to the temperature distribution when circulation starts (red line). The simulations show that the circulation pressure will be expected to slightly decrease over time. When circulating at 4 bpm the simulated SPP had dropped by 37 psi after 50 minutes of circulation. However, the observed SPP (yellow line) show a different trend. After 10 minutes circulation and when the flow had stabilized at 1.5 bpm, the observed circulation pressure was 258 psi lower than expected. Later after circulation had been carried out for 50 minutes and when circulation rate was increased to 4 bpm the observed circulation pressure was 184 psi lower than expected. [4.52]

During the second pre-cementing circulation sequence, after circulation has been shut down for about 4 minutes, a similar trend can be observed. At simulated time of 58 minutes and 45 seconds, circulating at 1.5 bpm, the observed circulation pressure was 156 psi lower than expected. Later after circulation rate was increased to 4 bpm and kept at this flowrate for more than 20 minutes the observed circulation pressure was 128 psi lower than expected.

Another interesting observation about this simulation is that although the circulation pressure decreases during circulation, the opposite seems to occur during static periods. Between end of first pre-cementing circulation (at simulated time 50 minutes) and the start of the second circulation period after flow rate has reached 4 bpm (at simulated time 64 minutes) there is a small increase in simulated SPP due to the thermal effects. During these 14 minutes (from 50 to 64 minutes) the wellbore was static for less that 4 minutes and in circulation for more than 10 minutes. This means that the increase in SPP in the beginning of static periods is several times larger than the decrease in SPP during circulation periods.

If the low circulation pressure of up to 230 psi should be explained by gas cut mud, it also implies that the 14.16 ppg gas sand would be underbalanced, during static condition. This do not correspond with an apparently stable well prior to the cement job. This may also be the reason why BP never resolved the low circulation pressure issue [4.45] and concluded that; "*The investigation team found no indication that hydrocarbons entered the wellbore prior to or during the cement job.*" [4.46]

In the following sections other thermal, dynamic or chemical reactions that may have occurred simultaneously will be discussed in order to strengthen the hypothesis that gas may have caused the observed low circulation pressure during the pre-cementing circulation sequences.

4.2.3 Gas influx during casing run concealed by gas hydrate formation

In order to test the hypothesis that gas in the annulus prior to the cement job caused the low circulation pressure, both static and dynamic effects needs to be examined.

Figure 4.9 is a simplified drawing on a complex problem. The figure shows the Macondo well after running the production casing including the lower part of the riser and landing string and how gas may have caused low circulation pressure.

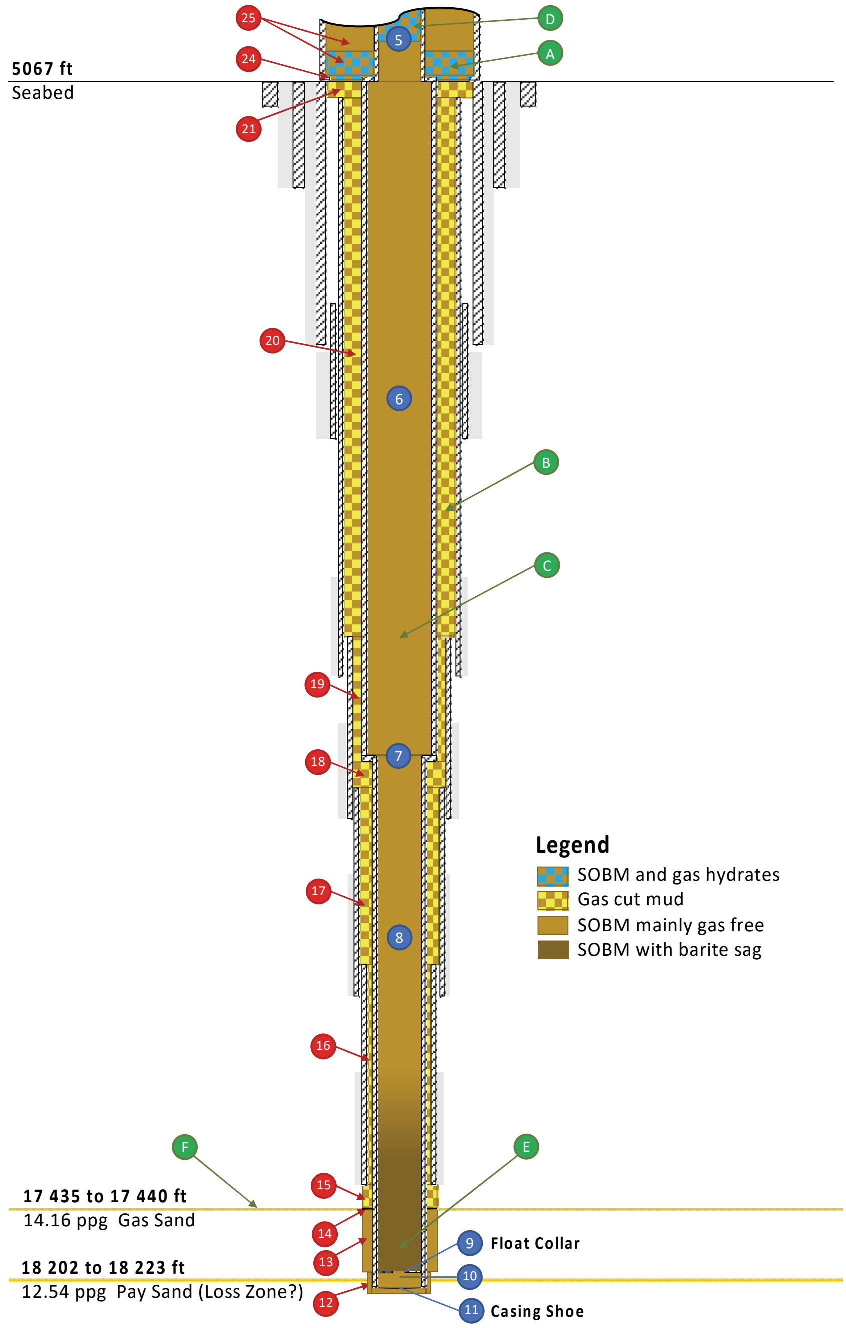


Figure 4.9 – Simplified drawing on how gas may have caused low circulation pressure

The red and blue circles with numbers in are the flow segments according to table C.1 in Appendix C. The green circles with letter A, B, C, D, E and F are added for reference only.

If gas in the annulus should explain the low circulation pressure, this would probably be combined with some other phenomenon occurring simultaneously.

One such phenomenon could be crossflow. Crossflow can occur with the wellbore full of fluid and the appearance of a dead well at surface. [E.6] As discussed in chapter 4.9 the Macondo well also had potential for crossflow. The SPP pressure were reported to be low but relative stable except from the start of the second circulation sequence. Flow out also seems to be relative stable, based on real time date from the second pre-cementing circulation sequence. [4.53] The possibility of crossflow occurring already prior to the cement job is therefore considered unlikely.

On April 16 shortly after the last bottoms up circulation, the wellbore probably became underbalanced due to thermal expansion, see figure 3.20. Gas from the 14.16 ppg gas sand would then probably have entered the wellbore. This gas kick may have been small in the beginning and gradually increase as the wellbore become more and more underbalanced due to gas cut mud. Since the gas will be in the dense phase [E.7] region it would probably not migrate as air bubbles in shallow water. Neither would the hydrocarbons displace the entire mud column as indicated in the BP report, when they explain how hydrocarbons (oil) reach the riser undetected during the final displacement. [4.54] A more likely scenario is that the gas would go into solution with the SOBM in the wellbore. OBM has shown to have unlimited loading capabilities when the natural gas is in the dense phase region (Skogestad et al., 2017). Further work to examine the loading capabilities of the SOMB used in the Macondo well is recommended. Although it is expected to have similar effects on density and solubility, the effective density of gas cut SOMB may be different, see Appendix D page 21 and 22 for further discussion.

One interesting question would then be how much more gas in the annulus (B) compared to any potential gas inside the casing (C) is required to reduce the SPP by about 260 psi in the beginning of the first circulation sequence to about 130 psi during the end of the second circulation sequence, see figure 4.8. This question is partly discussed in Appendix D page 21 and 22. To lower the ESD at the gas sand with 165 psi approximately 4 wt % of dissolved methane in the SOBM (or 2 wt % of free methane) is required, distributed evenly from the 14.16 ppg gas sand and up to the wellhead. However, since the gas kick probably has been continued for the entire static period from April 16 to circulation was obtained on April 19, the wt % of dissolved gas in the SOBM is probably not evenly distributed. The SOBM would probably have a higher wt % dissolved gas in the lover part of the annulus (B), i.e. in flow segment 15 to 19 then higher up in the annulus in flow segment 20 to 25 which are further away from the source of the gas influx, see figure 4.9. Since the lower flow segment (15) will continuously be fed with more gas molecules from the gas sand, the gas (solute) may move from high-concentration areas (15) in the lower part of the well to low-concentration areas (21) higher up in the well according to Fick´s law of diffusion. Eventually at some time after April 16 but before the end of April 19, gas from the 14.16 ppg gas sand would probably have reach the wellhead and lower part of the riser.

After midnight on April 20, when the cement job was almost complete, significant increase in gas content of the returning mud was recorded. [4.50] The total amount of fluid pumped during the cement job including pre-cementing circulation was about 1 370 bbls of fluids. [4.55] The total volume of the riser annulus (25) is about 1 637 bbls. [4.56] This implies that the fluid returning at the end of the cement job, came from the lower part of the riser and not from the wellbore annulus below the seabed. This is probably the best indication that the SOBM in the riser also contained some wt % gas when the cement job started.

Another phenomenon that may have occurred simultaneously with gas influx from the 14.16 ppg gas sand, is gas hydrate formation in the wellhead and riser area. As discussed earlier in chapter 3, the temperature in the annulus at the seabed will also rapidly fall below 10 ºC where gas hydrates may form, see figure 3.20 and 3.21. Any gas that may have diffused to the lower part of the riser a day or two after the last bottoms up circulation on April 16, would probably form gas hydrates with the water in the SOBM due to the relative low temperature, see figure 3.20 and 3.21. When gas hydrates form the methane molecules (solute) will be trapped in a cage of water molecules in the SOBM (solvent) and the diffusion process may therefore stop. When the crew start running the casing on April 18 you may therefore have a wellbore and riser with three different zones. Below the hydrate formation zone, you will have gas cut mud with higher wt % gas in the lower parts and lower wt % gas in the upper zone where hydrates may form. In large part of the riser above the hydrate zone you may have gas free SOBM.

When gas hydrates form the volume occupied by the gas will also be reduced (Vavik et al. 2016, Table 2). If we assume that hydrates formed in the riser when the casing was lowered on April 18, this volume reduction due to hydrate formation may have partly concealed that gas influx from the 14.16 ppg gas sand (F) took place at the same time. It is also possible that the surge pressure created when the casing was lowered into the wellbore may have resulted in some loss of fluid in the lower part of the well (G). These two effects may have contributed that influx detection based on trip sheets and net gain did not work when running the casing down into the wellbore.

Another important factor that needs to be considered is that the gas hydrates will dissociate, and gas will expand when the gas hydrates melt. This reversed process will occur if the hydrates are transported up to an area in the riser were the hydrostatic pressure is low enough or down the well were the temperature is high enough. When hydrates dissociate the sudden gas-expansion caused by melting hydrates, will probably result in what would be recorded as an unexpected gain in the active pits.

4.2.4 Why did the observed circulation pressure increase over time?

During the first pre-cementing circulation sequence the observed SPP increase with more than 200 psi, between 8- and 48-minutes simulated time, see figure 4.8. The observed pressure is about 260 and 180 psi lower than simulated SPP (green line) respectively. However, the difference between observed SPP (yellow line) and simulated SPP (green line) is reduced by about 80 psi during these 40 minutes of circulation.

The explanation to this observation may partly be that the gas influx from the 14.16 ppg gas sand stops due to higher ECD during circulation, see figure 4 in Appendix D. Another equally important contributing factor may also be that gas cut mud with high wt % gas in the lower part of the annulus, i.e. flow segment 15 and 16 will be replaced with gas free or nearly gas free mud from inside the casing (E) during this circulation period, see figure 4.9.

This may also explain why the difference between simulated and observed SPP during the second circulation sequence continue to decrease. However, it does not explain why the observed SPP increase by almost 60 psi after they changed to another rig pump. It may be that this pump was more effective and that the first pump was leaking in some way which gave a lower flow rate per stroke. However, it may also have a natural explanation. By comparing the simulated SPP (green line) taking thermal effects into account this has 6 psi increase in SPP. The question is therefore why is the observed SPP increase (yellow line) 10 times larger?

There are probably several reasons for this difference, but the one important factor is probably that the difference still decreases during circulation. When the pump rate was increased from 1.5 to 4 bpm, the difference is decreased by 28 psi. This is 52% of the observed difference in increased SPP of 54 psi (60 – 6 psi).

The remaining difference in SPP may therefore be explained by immediate cooling of the gas cut annulus fluids (A and B) and heating of the SOBM in the casing (C) after the pump is shut down, see figure 6 in Appendix D. Since the fluid in the annulus (A and B) are assumed to contain more gas than the fluid in the casing (C) the difference in volumetric thermal expansion coefficients for SOBM and gas influx may be an important contributing factor. The volumetric thermal expansion coefficients for natural gas is about 4 to 12 times larger than the factors used in the simulations for clean mud without gas content depending on depth (pressure) and temperature. [4.57]

4.2.5 How to determine the size of a gas kick?

To determine the size of a gas kick based on accumulated gain at the surface is not a recommended method, although this has been the dominated method in the industry for more than 100 years. The main reason for this is that you may have loss of drilling fluid to the formation (during high surge pressure or high circulating pressures) and still have gas influx during static periods. Another reason is that the gas may be dissolved in the drilling fluid (OBM) and volume occupied by the gas is about 50% of the volume of free gas, see table 7 in Appendix D. A third reason is that in deep water gas hydrates may form and the gas migration or maybe more correctly gas diffusion when we talk about gas dissolved in the OBM, may complete cease and the volume will be reduced again compared to the volume occupied by free gas (Vavik et al. 2016, Table 2). A fourth, but also important reason is thermal effects. In deep water and particularly HPHT wells, the density changes due to temperature fluctuations in the riser and wellbore may dominate or conceal that a kick is taken place, see chapter 4.2.6 for further discussion.

A better method to determine the size of a gas kick when partial (or total) loss has occurred would be to compare the simulated density of the fluid in the annulus (B) with the observed density of the fluid in annulus fluid (B) (Vavik 2017C). Let us make some simplifications and assume that any gas inside the casing (C) and landing string (D) is equalized with gas in the riser annulus (A) and gas that may have diffused to the annulus below the 14.16 ppg gas sand. In this case the observed low circulation pressure will probably be caused by gas cut mud in the annulus (B) between the gas sand and the wellhead, see figure 4.9.

The simulated average density of the relative hot SOBM in annulus (B) after the long static period between April 16 and April 19 is 1 695 kg/m^3 (14.14 ppg).[4.58] The observed average density in annulus (B), assuming gas is causing the reduction in observed circulation pressure of about 260 psi in the beginning of the first pre-cementing circulation sequence, will be 1 646 kg/m3 (13.74 ppg). [4.59] A typical average density of gas influx in annulus (B) will be 273 kg/m^3 (2.28 ppg). [4.60] The volume of annulus (B) is 167.3 m3 (1 054 bbls). [4.61] In other words to reduce the total weight of the annulus (B) volume by 2.9 %, a volume of 5.7 m3 (36 bbls) free gas is required. [4.62] This is equal to 1.6 metric tons of free gas or about 3.2 metric tons of dissolved gas, ref. discussion in Appendix D page 22.

A gas kick of 36 bbls (gain) or more than 3 metric ton of dissolved gas is a relatively large kick. You may think a kick of this size would probably have been detected assuming no loss occurred. However, there are some important factors that will need to be discussed in order to understand how a gas kick of this magnitude may have been missed.

4.2.6 Gas kick may have been dominated and concealed by thermal effects

To understand how the drilling crew may have missed a gas kick of this magnitude the total time for the gas to enter the wellbore is important. Assuming the gas kick started shortly after the bottoms up circulation on April 16 and continued to the first pre-cement circulation on April 19, the gas kick may have been going on for 72 hours or more depending on when bottoms up circulation on April 16 was carried out. If we simplify and assume a linear gas influx rate during a period of 72 hours, this will give and average flowrate of 0.5 barrel per hour or 0.35 gpm (1.3 lpm). This is not more than what typically is called a “pencil stream”.

Gas influx will dilute the SOBM and lower the density. A similar effect on the density of SOBM will be expected when drilling fluid is heated up by geothermal energy. On the other hand, when the drilling fluid is cooled down by the cold water surrounding the riser and during circulation were the relative cold fluids are circulated down into the wellbore, the opposite effect occurs. SOBM that are being cooled down will increase in density.

Based on our earlier assumptions that gas in the annulus (B) has lowered the circulation pressure by 260 psi, the effect of gas cut mud can be compared with thermal effects taking place simultaneously. Lowering the hydrostatic pressure by 260 psi, will be equivalent to lowering the ESD at the gas sand by 0.286 ppg. [4.63] If we simplify and assume a linear gas influx rate, this will give a reduction in ESD at the gas sand of 0.048 ppg 12 hours after the last bottoms up circulation on April 16. Thermal effects vs gas influx effect on ESD in the 14.16 ppg gas sand, are compared and illustrated in figure 4.10. [4.64]

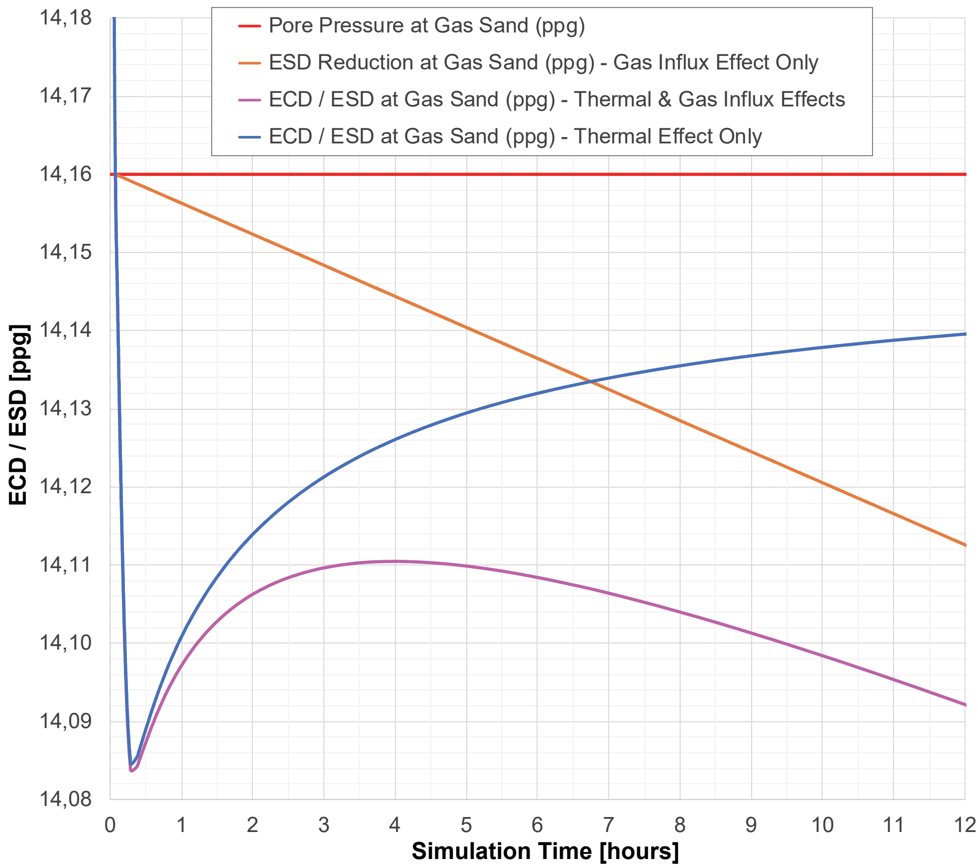


Figure 4.10 – Thermal effects vs gas influx effect first 12 hours after bottoms up on April 16

In high-pressure high-temperature (HPHT) wells located in deep water and when SOBM are used the volume change due to compressibility and thermal expansion are significant. When the mud pumps are shut down at simulated time 0 the drilling fluid will continue to flow back since the drilling fluids was compressed due to increased ECD during bottoms up circulation. The SOBM will expand and ESD at the 14.16 ppg gas sand will fall due to thermal expansion in the wellbore, until the well became underbalanced at about 4 minutes and 20 seconds after the pump was shut down.

Due to thermal expansion in the wellbore the SOBM will continue to expand and ESD at the gas sand will be totally dominated by this thermal expansion until about 20 minutes simulated time. During these first 20 minutes after pump shut down the volume expansion due to thermal effects (blue curve) will be the dominating factor and it will not be possible to distinguish the flow back or gain caused by thermal expansion and gas influx (orange and magenta curve).

After about 20 minutes the thermal effects (blue curve), the ESD at the 14.16 gas sand starts to rapidly increase. In the next few hours up to about 4 hours simulated time, it will not be possible to detect the influx on gain. However, there will probably be a net loss of drilling fluid in this period were fluid contraction due to thermal effects are greater than fluid expansion due to gas influx in the annulus fluids above the gas sand.

The drilling crew may have started tripping out of the wellbore after filling up the trip tank and performed a flow check. However, performing a flow check to check for influx during the first 5 hours after bottoms up circulation, is not a reliable method due to thermal effects on the mud volume.

If tripping out starts 30 minutes after the pumps were shut down (30 minutes simulated time), the trip sheet may still show a net loss of fluids due to thermal effects after 12 hours simulated time.

Gas that entered the wellbore during the first 12 hours may have reached the wellhead and riser area, depending on how fast gas in SOBM diffuses. After 12 hours the temperature in the wellhead and riser area may have fallen to below the temperature where gas hydrates may form. Gas hydrate formation with increased formation rate as the wt % gas in the mud increase over time, may have contribute to conceal the gas kick in the same way thermal effects may have concealed the kick during the first hours after the kick started.

4.2.7 Dissolved gas in SOBM and effect on viscosity

If dissolved gas is the explanation for the observed low circulation pressure, it will not only affect the density of the SOBM, but also the viscosity will change. The plastic viscosity used in the simulation for the SOBM is 39 centipoise (cP).[4.65] This also implies that the observed reduction in circulation pressure of about 260 psi when circulation was obtained is probably not only a result of reduced hydrostatic head, since viscosity and frictional pressure drop will be lower for the gas cut mud.

In an experimental study the effect of gas influx into oil-based drilling fluids (OBDF) on viscosity at high pressure and temperatures have been examined. The result of methane dissolved or absorbed in OBDF are shown in figure 4.11. The experiment shows that with a gas content of 1.15% the viscosity is reduced by almost 50%, and with a gas content of 5.81% the viscosity is reduced by approximately 80% at high shear rates (Torsvik et al., 2017, figure 4a).

If we assume that the SOBM had a reduced plastic viscosity from 39 cP (gas free mud) to somewhere between 5 to 20 cP for gas cut mud, this will also reduce the dynamic pressure drop during circulation. The observed reduction in circulation pressure may therefore not only be caused by reduced density and hydrostatic head but also by reduced frictional pressure drop while circulating due to reduced viscosity.

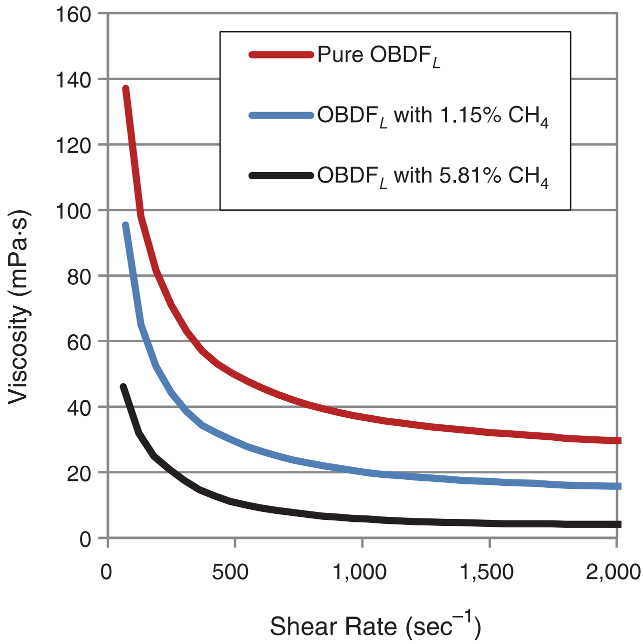


Figure 4.11 – Effect of gas absorbed in OBDF on viscosity (Torsvik et al., 2017, Fig. 4a)

Although a lot of simulations was done by SINTEF there was more work that we would like to do. Simulating the effect of different scenarios with gas cut mud and reduced viscosity and the effect this will have on the circulation pressure, is one topic that would be interesting to study. However, the time and resources (funding) available for this thesis was limited. Further work and more simulations to test the different hypothesis discussed in this Chapter 4 are proposed as further work, see also Appendix D, chapter *6.1 Proposed further work*.

4.2.8 Main cause of observed low circulation pressure

Considering all the evidence available, it seems likely that a large amount of gas was present in the annulus (B) prior to starting the pre-cementing circulation.

There are several ways the gas may have entered the wellbore. Underbalanced well initially due to thermal expansion while tripping out on April 16 and April 17 seems to be the main reason, see figure 3.20. Swabbing effects while tripping out on April 16 and April 17, may also be a contributing factor.

Thermal effects may have contributed to conceal the ongoing gas kick particularly during the first 12 hours after bottoms up was circulated on April 16, see figure 4.10.

Gas cut mud in the wellbore likely contributed to the wellbore became underbalanced also later during the casing run. Surge pressure when the casing was lowered or heave during connection on April 18 and April 19, may have result in partial losses that contributed to conceal the ongoing gas kick. Formation of gas hydrates in the wellhead and riser area may also have contributed to conceal the ongoing gas kick when the casing was lowered.

The conclusion is that that a large amount of gas present in the annulus (B), was the main reason for the low pump pressure when circulation was established.

4.3 Cementing the Casing

Pumping SOBM, base oil, spacer, cap cement, foam cement, tail cement, spacer and SOMB with different densities and compressibility is a complex task to simulate. The different type of fluids while pumping and planned fluids location after the cement job is shown in this simplified drawing taken from the BP investigation report, see figure 4.12. [4.66]

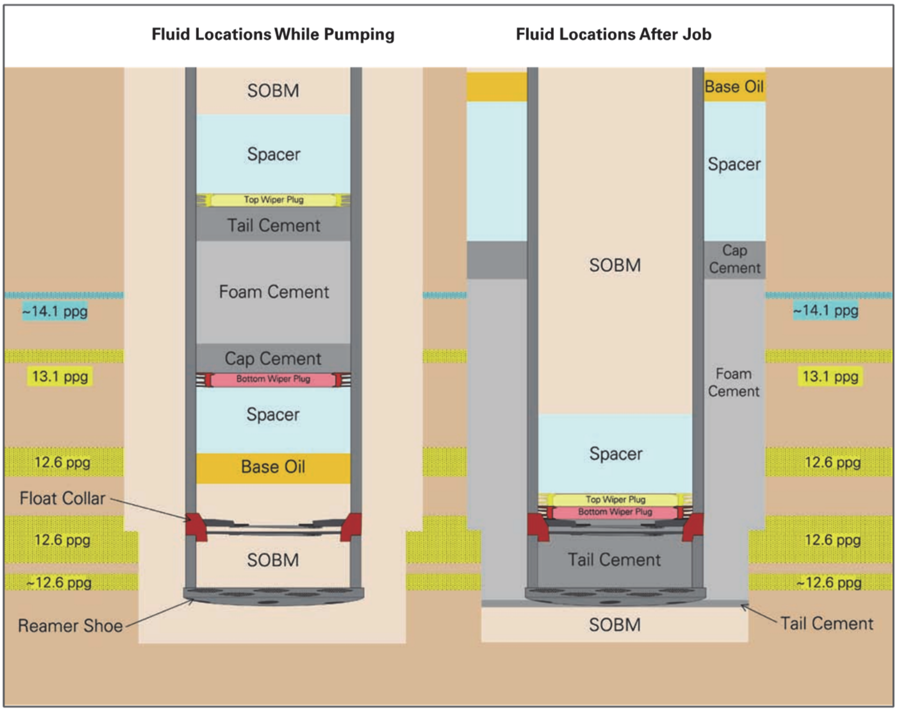


Figure 4.12 – Planned cement fluid locations [4.66]

The different cross-sectional areas in the different flow sections will also affect the standpipe pressure while circulating, see figure 4.9.

The simulations were performed by SINTEF using SINTEF´s thermohydraulic model, see Appendix D. To get the best realistic simulation all the different fluids pumped and standby periods, to account for thermal effects, from circulation was established at about 16:21 on April 19 to the cement job was finished at about 00:43 on April 20 has been simulated. To investigate the thermal effects of the long static period from April 16 to April 19, a static period of 72 hours was added prior to circulation, see figure 3.20.

The cement job started with pumping SOBM, base oil and spacer fluids at about 19:43 on April 19.[4.67] During the next two hours the cement pump was used to pump different types of fluids down the landing string, see figure 4.12. This circulation may have resulted gas hydrates (A) in the riser annulus being transported up the riser annulus were it at some stage will melt and expand. The same circulation may also have resulted gas hydrates (D) in the landing string (5) being transported down the wellbore where it may melt due to higher temperatures, see figure 4.9.

The statement in the Smith report, reviewing the real time data for this time period where fluids was pumped with the cement pump is therefore interesting.

"*Significant gains, roughly equivalent to the volumes of cement and spacer pumped, and losses, which were not explained, are present in the data record. After pumping all of the cement and spacer, there was essentially no net pit gain. An implication is that there were some lost returns during this period, but there was never a total loss of returns.*"[4.68]

Significant gains, roughly equivalent to the volumes of cement and spacer pumped cannot be explained with partial loss of circulation. It may be explained by gas influx from the 14.16 ppg gas sand (F) during periods with low circulation rates and low ECD due to gas cut mud in the annulus (B), but that is also unlikely due to high ECD during circulation. More likely the unexplained significant gain was caused by gas hydrates (A) melting or gas cut mud (B) expanding as it is being transported higher up in the riser annulus (25), see figure 4.9. Significant gains, roughly equivalent to the volumes pumped is also the expected behavior when gas influx is circulated up the riser annulus, see figure 3.9 (Gomes et al., 2018, Fig. 6). However, since the author of this thesis do not have flow out data from these two first hours when the cement unit was used, the reason for the unexplained significant gain will not be discussed any further other than it again is a clear indication that gas was present in the well prior to starting the cement job.

The partial loss of returns observed after the significant gains, may have several contributing factors. Partial loss of fluid to the weaker formation (G) may have occurred. Another possible explanation is the volume reduction caused by hydrate formation when gas cut mud (B) is transported up into the colder region in the lower part of the riser annulus (25). Gas cut mud being pumped down the production casing (6, 7 and 8) after the gas hydrates (D) have been melted, may also have contributed to the volume reduction. The same is also relevant for the nitrogen foamed cement being pumped down. As gas (nitrogen) is pumped down the landing string the volume will decrease as hydrostatic pressure increase. However, the observed partial loss of returns after the significant gains, roughly equivalent to the volumes of gain (no net pit gain) is also the expected behavior when gas influx is circulated up the riser annulus, see simulated time 150 to 250 minutes in figure 3.9 (Gomes et al., 2018, Fig. 6).

The last 3 hours of the cement job the displacement was carried out using a rig pump. Pumping all the fluids and wiper plugs with the cement unit was then complete and the rig pump was used to complete the cement job. All the pre-cement circulated SOBM, base oil, spacer and cement train has entered the 9 $^{7}/_{8}$ -inch casing below the wellhead at this moment in time when the rig pump was lined up and turned on to complete the displacement, se left side of figure 4.7 for illustrations.

Figure 4.13 shows simulated and real time values from approximately 21:43 (simulated time 0) on April 19 after displacement was turned over to the rig pump to 00:43 on April 20, after the cement job was complete.

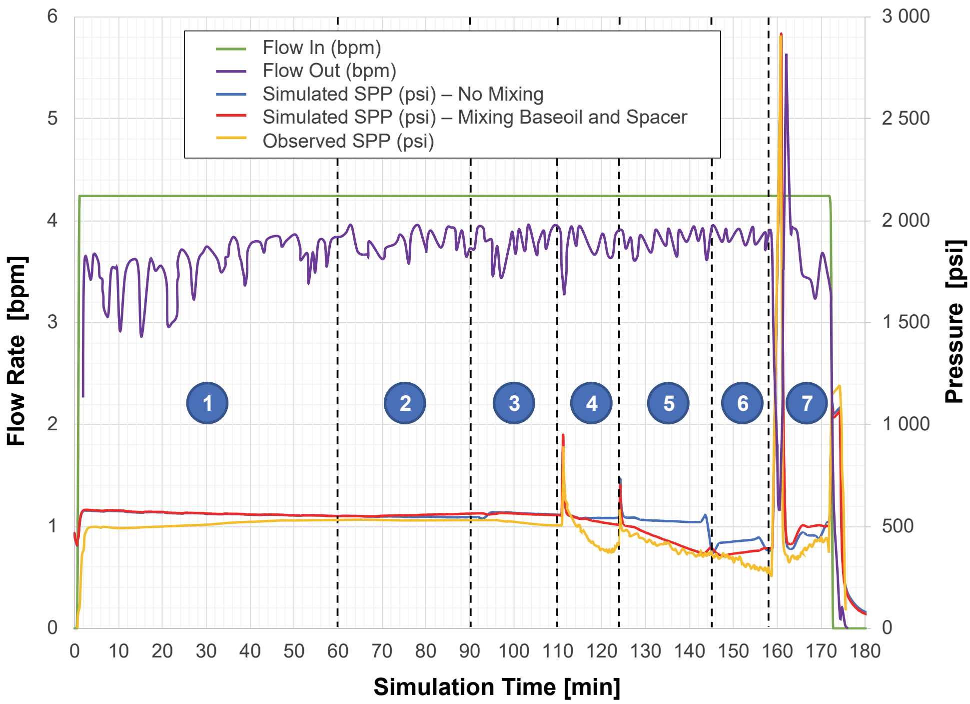


Figure 4.13 – Cement job last 3 hours, displacement with rig pump

Flow In (green line) is the actual volume pumped with the rig pump during the displacement. [4.69] *Flow out* (purple line) is the recorded flow rate returning from the riser during the displacement. [4.70] *Simulated SPP – No Mixing* (blue line) partly concealed by the red line, is the simulated standpipe pressure as the different fluids with different densities are circulated down the casing and up the annulus, assuming no mixing between the heavy spacer and the light base oil. The simulation is carried out taking dynamic temperature effects [4.71] and fluid compressibility into account. The simulation takes into account the amount of nitrogen used in the foam cement, but otherwise it is assumed that the mud was gas free. *Simulated SPP – Mixing Baseoil and Spacer* (red line) partly concealed by the yellow line, is the same simulation but with assuming mixing between base oil and spacer occurs during circulation. *Observed SPP* (yellow line) is the recorded real time standpipe pressure during the displacement performed with the rig pump. [4.72]

In the following sections possible causes for the abnormal observations and deviations for each of the seven time periods (reference no. 1 to 7) will be discussed.

4.3.1 Partial loss of circulation and erratic flow out (21:43 to 22:43)

When gas influx is circulated out and up in the riser annulus erratic flow out is expected. First there will be a significant gain when the gas boils out of the solution (or gas hydrates dissociate) followed by erratic flow and partial loss of circulation.

Since we did not have time and funding to simulate the Macondo with different scenario of gas influx, previous work by Gomes et al., have been shown again with comments (three phases) added. The effect on *mud rate in* (pump rate) to the well compared to *mud rate out* of the riser, when circulating out a 4 m^3 large gas kick, with constant applied surface back pressure of 3 bar is shown in figure 4.14 (Gomes et al., 2018, Fig. 6). Although, at Deepwater Horizon they were circulating with open riser (atmospheric back pressure) a similar effect would be expected during the three different phases of the circulation, see figure 4.14.

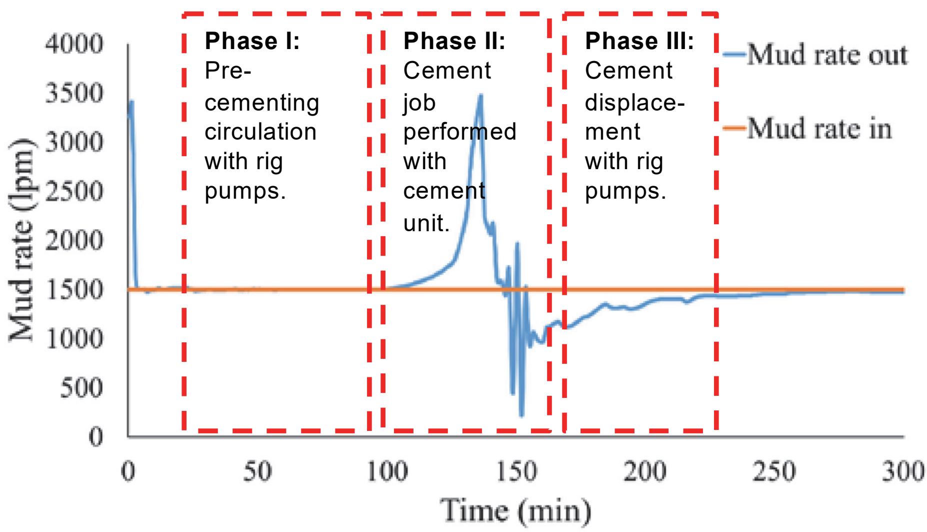


Figure 4.14 – Three different phases when gas kick is circulated out of the riser.

There are some major differences between the simulated gas kick and the gas kick that probably took place at Macondo. In this simulation (Gomes et al., 2018, Fig. 6) the gas kick was taken in a few minutes. At Macondo a similar or larger gas kick was taken over a period of about 72 hours. At Macondo the gas probably had time to diffuse over a larger area in the annulus (B), before circulation started.

Despite the differences the three phases shown in figure 4.14 are useful to understand the observed erratic flow out that could be observed. Both during cement displacement (see figure 4.13), later during preparation for the negative pressure test (see figure 5.13) and during the final displacement of the riser with seawater, the erratic flow out could be observed, see figure 4.15.[4.73]

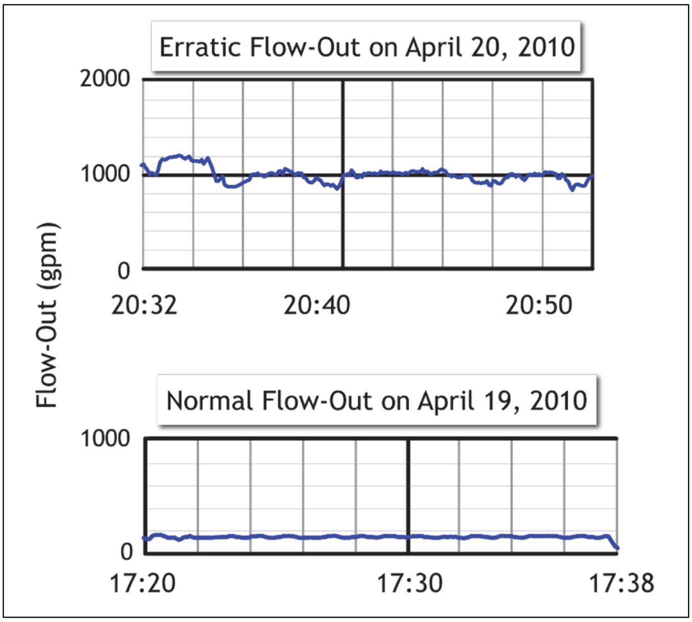


Figure 4.15 – Erratic vs. normal flow-out [4.73]

The top flow out data in figure 4.15 is recorded during the final displacement of the riser, about one hour before the first explosion on April 20. Since a full bottoms-up circulation was not carried out before the cement job but decided to be carried out in three stages (ref discussion in chapter 4.2.1), the upper figure also represent the final stage of circulation bottoms up. Any potential gas in the wellbore prior to the cement job will reach the surface about this time. Significant high gas readings on the return flow is also recorded during this period, especially between 20:16 and 20:40 on April 20, confirms that gas came out of the riser at this time.[4.74] In previous investigation reports crane operations causing the rig to sway has been used as a possible cause of the erratic flow out.[4.75] However, more likely the erratic flow out can be explained by gas being circulated out of the riser. The bottoms up circulation will then have come to what can be called phase III of circulating gas influx out of the riser, see figure 4.14.

The normal flow out data in figure 4.15 is recorded during the second pre-cementing circulation sequence on April 19. In this case the gas in the riser, possible trapped as gas hydrates (A) and the gas cut mud (B) had not reached a high enough location in the riser annulus. Before the gas kick is circulated high enough up in the riser to allow for any potential gas hydrates to dissociate and gas in dense phase to boil out of the solution, the expected flow out will be normal, since the gas kick circulation at this time was in phase I, see figure 4.14.

As discussed earlier, the observed gain followed by losses, when the cement unit was used for cement circulation, may be explained by phase II, see figure 4.14. Ref. statement in the Smith report: "*Significant gains, roughly equivalent to the volumes of cement and spacer pumped, and losses, which were not explained, are present in the data record.*"[4.68] The significant gains recorded may be associated with gas hydrates trapped in the bottom of the riser (A) that later dissociate and expand as well as dense gas (B) coming out of the solutions, when the hydrostatic pressure become low enough. Gas coming out of the riser at the end of the cement job [4.76] also confirms that gas was in the riser when the significant gains were recorded.

During the first hour of cement displacement with the rig pump, both loss of circulation and erratic flow out was recorded, see figure 4.13. At the same time there is a decreasing trend on how much fluid that is lost during this first hour of rig pump displacement. In the beginning about 20% of the pumped volume where not returning from the riser and in the end the loss was reduced to about 10%. This may imply that the gas influx circulation has reached phase III, see figure 4.14.

4.3.2 Constant SPP and partial loss of circulation continue (22:43 to 23:13)

To understand the observed SPP as displacement of the cement continue is a bit more complicated. The simulated SPP is helpful to understand what kind of circulation pressure that would be expected if no gas influx was expected. The SPP would be expected to decrease during the first hour mainly due to compressibility on the nitrogen foam cement, see figure C.16 in Appendix C. Depending on the potential mixing of the base oil and spacer it would after this first initial decrease be expected to level out until the bottom plug reaches the crossover, see figure 4.13 time period 1, 2 and 3 up to simulated time 110 minutes.

The observed SPP on the other hand do not follow the exact same pattern. There could be and probably are, many explanations for the observed deviations. As explained in the previous section the observed loss of circulation and erratic flow out, may be explained by gas accumulated in the lower part of the riser har reached the upper part of the riser or phase III of gas influx circulation, see figure 5.14. The observed SPP may however be explained by the different phases of gas influx being circulated out occurring simultaneously. Gas cut mud from the bottom of the well may be on the way up the riser annulus while some gas is leaving the riser, since the gas probably had time to diffuse over a larger area from the bottom of the well to the lower part of the riser during the gas kick period from April 16 to April 19.

While the erratic flow out pattern could be explained by three different phases, the corresponding SPP typically follows four phases. The same simulation performed by Gomes et al. to show how flow out changes has also been used to show how bottom-hole pressure (BHP) changes during the same 300 minutes of simulated time (Gomes et al., 2018, Fig. 3). As a gas kick is circulated out the BHP and consequently also the SPP will typically change in four different phases, see figure 4.16. These four phases may also explain some of the observed SPP anomalies.

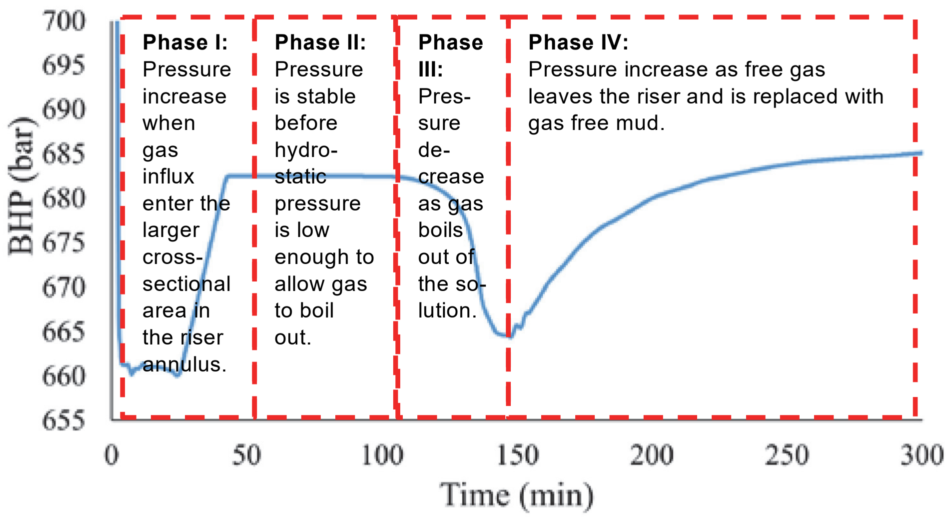


Figure 4.16 – Pressure changes in four different phases when gas kick is circulated out

The increase in observed SPP during the first hour (1) of the rig displacement and the constant observed SPP during the next 30 minutes (2), may be to two different phases are occurring simultaneously. Most of the gas cut SOBM from the annulus (B) will probably during the first 90 minutes simulated time be displaced with gas free mud from below. At about 98 minutes simulated time the entire annulus volume (B) has been changed out and entered the riser. [4.77] As expected, when a gas kick is circulated out and enters the BOP and riser area the BHP pressure (and SPP) will increase, see figure 4.16 phase I.

Simultaneously gas cut SOBM from top of annulus (B) that has entered the riser several hours earlier during pre-cementing circulation will typically be higher up in the riser and therefore be in phase II and III, se figure 4.16. This may explain why the effect from phase I becomes less dominant and a constant SPP can be observed in this time period (2) between 60- and 90-minutes simulated time, see figure 4.13.

4.3.3 Reduced SPP and partial loss of circulation continue (23:13 to 23:33)

Figure 4.17 shows the situation at about 23:33 on April 19 (110 minutes simulated time) when the bottom wiper plug reached the 9 $^7/_8$ x 7-inch crossover (7).

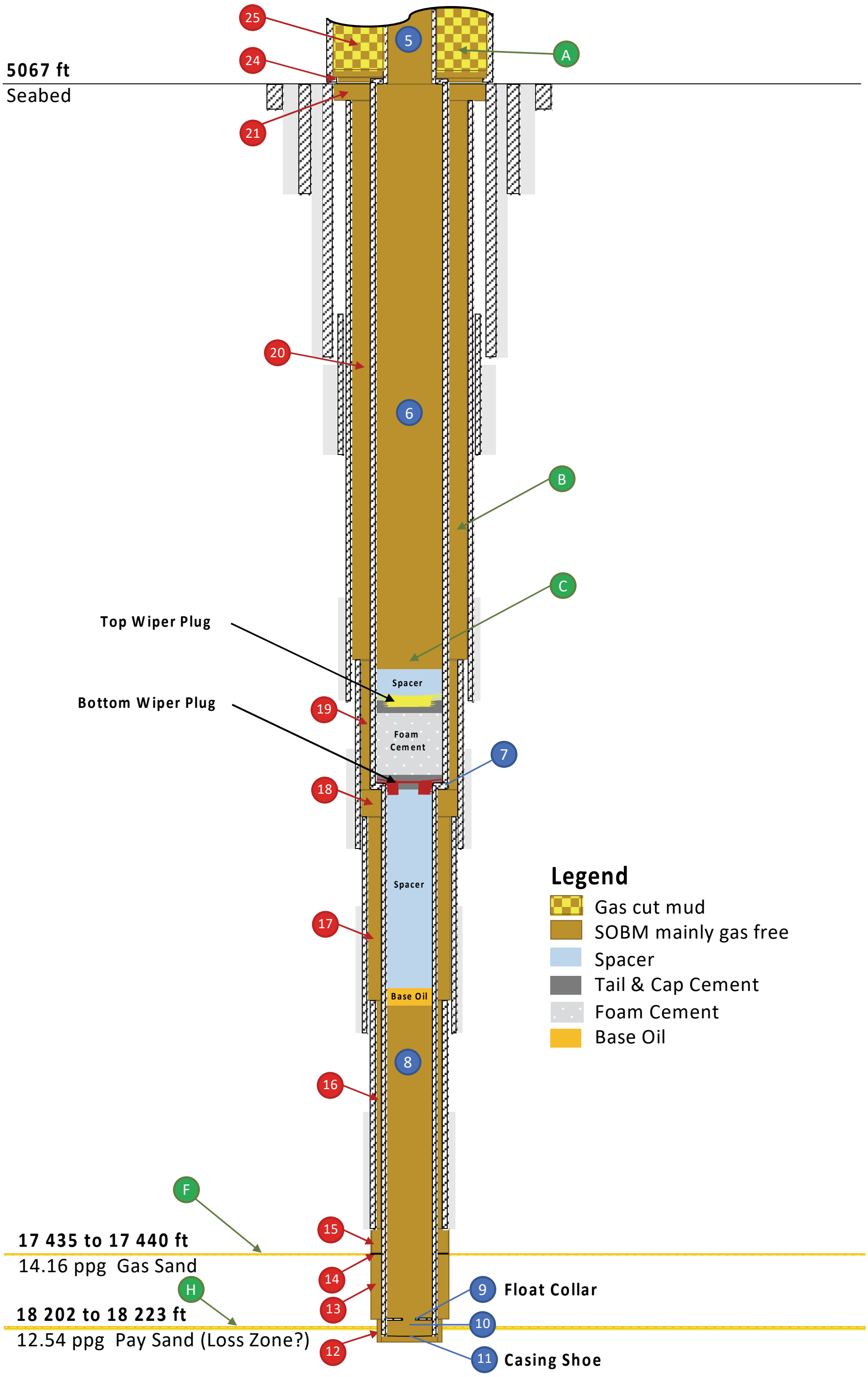


Figure 4.17 – Simplified drawing on fluid location when bottom plug at crossover

Gas cut SOBM from top of annulus (B) that has entered the riser several hours earlier, will typically continue to expand as gas boils out of the solutions, phase III, se figure 4.16. Simultaneously gas originally from the lower part of the riser (A) potentially initially trapped as gas hydrates (see figure 4.9), has made its way up in the riser annulus. The gas cut mud in top of the riser will typically be in phase IV (figure 4.16) and phase III (figure 4.14).

When the bottom wiper plug reaches the crossover, the entire annulus volume (B) has been displaced and entered the lower part of the riser (A). [5.77] As discussed in previously (chapter 4.3.3), when a gas kick is circulated out and enters the BOP and riser area the BHP pressure (and SPP) will increase, see figure 4.16 phase I. However, this effect will no longer appear since gas cut mud in this time period is out of the wellbore annulus (B), see figure 4.16 phase II.

This simultaneous effect may therefore explain why observed SPP starts to decrease and why partial loss of circulation with erratic flow out continue, see figure 4.13 time period (3).

4.3.4 Abnormal drop in SPP followed by abnormal increase (23:33 to 23:47)

During the next 14 minutes after the bottom plug enters the 7-inch casing an abnormal drop in SPP followed by an abnormal increase can be observed, see figure 4.13 time period (4). This could be connected to rapid gas expansion in the riser see figure 4.16 phase III & IV. However, this is unlikely since the gas kick was not concentrated in a small area, but probably spread over a large area in the riser annulus. When the gas is spread over a larger area in the annulus a more gradual decrease in SPP as observed in the previous time period would be expected.

Another scenario is that gas may have accumulated in the lower part of the riser between April 16 and April 19, since gas diffusion may cease when or if gas hydrates were formed. If gas hydrates were circulated up the riser you may see similar erratic change in SPP, since the gas expansion will be very fast. Potential gas hydrates that may have been circulated up the riser annulus will be heated up by the warmer fluid pumped down the casing landing string simultaneously as the hydrostatic pressure is reduced. When hydrates dissociate under relative low pressure below cricondenbar, see figure E.2 (Appendix E) and since this phase change goes directly from solids to gas phase, the expansion will not be according to Boyles law but faster (Vavik et al., 2016, Fig. 4). However, the gas hydrates would probably have melted by this time were more than 2/3 of the riser annulus volume had returned to the rig.

Another important factor to consider is flow out. If the sudden abnormal drop in SPP should have been caused by a rabid gas expansion in the riser annulus, a simultaneous increase in flow out would be expected, see figure 4.16 phase III and figure 4.14 phase II. This abnormal increase in flow out associated with rapid gas expansion in the riser, as observed earlier when the cement job was performed with the cement unit [4.78], but this was not observed this time when cement displacement was performed with the rig pump, see figure 4.13. It is therefore considered unlikely that the abnormal drop in SPP should have been caused by a rabid gas expansion in the riser annulus.

A more likely explanation is that something happened in the wellbore. Prior to the cement job the biggest risk that was associated with the cement job was losing circulations. [4.48] During drilling of the final section of the well at 18 260 ft with ECD of 14.7 ppg the formations fractured, and fluid was lost from the well to the formations. [4.79] The concern was therefore that the downhole pressure in the lower pay sand (H) should exceed 14.7 ppg during the cement job. At the same time the pressure needed to be above the pore pressure in the upper gas sand (F) to avoid gas influx, see figure 4.18.

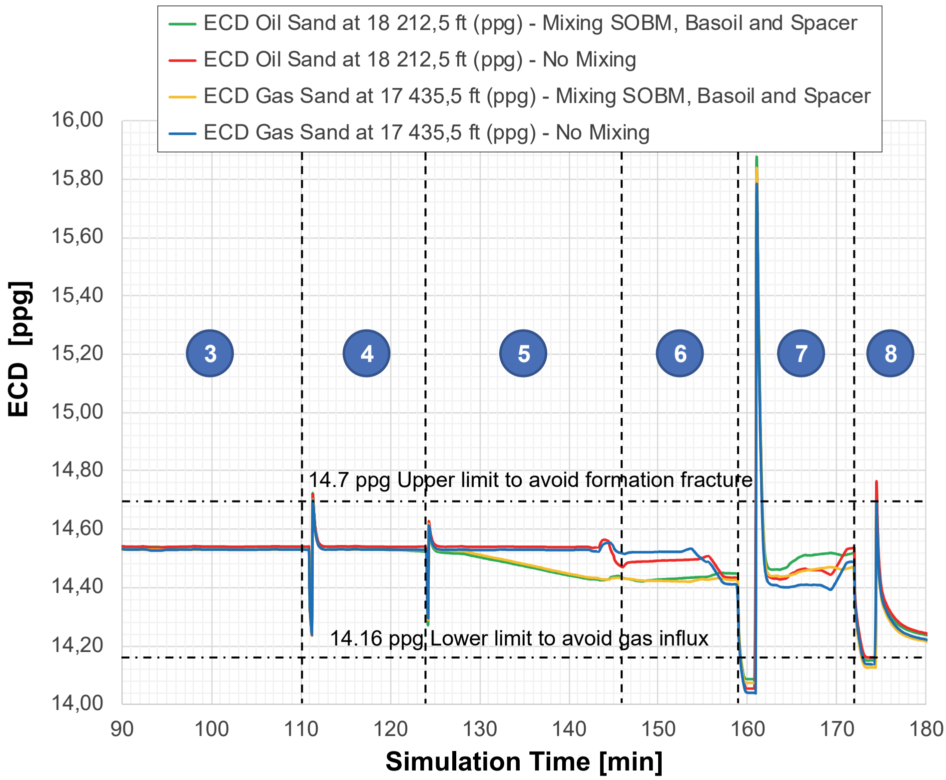


Figure 4.18 – Simulated downhole ECD with upper and lower limits (cementing window)

When the bottom wiper plug reached the crossover the observed SPP increases suddenly with about 400 psi and at about the same time also flow out is reduced significantly. This is probably caused by the bottom plug stops the flow for a short moment while pressure is building up upstream of the bottom plug. When pressure is sufficiently high the bottom plug will suddenly be released, and the circulation continues. The pressure that was built up will send a pressure wave down the casing when it is released.

SINTEF has simulated how a similar break in the circulation and pressure build-up of about 400 psi may influence the ECD in the well. The result shows that there will be first a reduction in downhole ECD followed by a pressure spike when the plug is released. The simulation also shows that it is possible that the pressure spike generated is larger than the ECD of 14.7 ppg that by earlier experience was the required pressure to break the formation, see figure 4.18.

If the formation fractured and they suddenly start losing SOBM to the lower pay sand (H), this may explain the sudden abnormal drop in SPP. However, if they suddenly lost SOMB to the formation, why did they not lose complete returns as previously experienced? [4.48] There could be many reasons for why complete lost returns was not observed. In this thesis I will limit the scope to discuss a few possible contributing factors.

The annulus fluid in the riser probably contained free gas at this moment. This free gas will expand rabidly if pressure is reduced. A similar effect can be expected by the nitrogen foam cement. A sudden pressure reduction will make the foam cement to expand. To show this effect we could make simple calculation making some simplification. If instantly a volume om 10 bbls was lost below the bottom plug when it was released, the foam cement may expand by about 10 bbls. Calculation shows that there was enough nitrogen in the cement to allow the foam cement to expand from about 14.2 ppg to 11.7 ppg, which will be required to obtain this volume expansion. [4.80] The nitrogen in the foam cement and the free gas in the riser annulus may therefore have worked as a pulsation damper towards sudden pressure and volume changes in the bottom of the well.

The volume lost to the formation from inside the casing, could probably rabidly be replaced with expanding nitrogen. However, the flow through the float collar and casing shoe was probably too small to compensate for the instant loss of fluid to the formation (H). The instant volume lost from the open wellbore annulus would therefore need to be replaced to avoid complete loss of returns. If we do the same simplified example an assume that 10 bbls of SOBM was lost instantly or in a few seconds or at least less than a minute, there would require a significant pressure drop to supply this from top of the riser annulus, see figure 4.17 for an impression of required annulus flow path. Most likely the pressure in the annulus at the 14.16 ppg gas sand would therefore be underbalanced for a short period until the loss of SOBM to the formation is reduced. This dynamic pressure drop in the annulus may have resulted in a simultaneous gas influx that partly has replaced the fluid lost to the formation. Note that the dynamic annulus pressure drop due to any potential loss as fracture pressure is exceeded is not simulated by SINTEF.

Another contributing factor for not observing complete lost returns, may have been the short pressure fluctuation. Unlike when the drilling crew were circulating at 14.7 ppg ECD, the pressure spike of possible 14.72 ppg was only there for a very short period. When the ECD in the loss zone returns to a more normal 14.54 ppg this may not be high enough pressure to keep the fractures continue to propagate.

The lost circulation event may therefore have been over in less than a minute, see figure 4.18.

In this way both nitrogen expansion in the foam cement, gas expansion (in upper part of the riser where the gas is no longer in dense phase), gas influx due to instant pressure drop in the open wellbore annulus and duration of the formation fracture event may have contributed that total loss of return was not observed.

4.3.5 SPP decrease in an erratic manner (23:47 to 00:09)

By comparing the pattern of the observed SPP in time period (3) and this period (5) it is clear that the pressure is much more erratic, see figure 4.13. This strengthen the hypothesis that a gas kick was taken during the formation fracture event that probably took place when the bottom plug entered the 7-inch casing.

There could be many reasons for why observed SPP decreases and there are many uncertain factors contributing to the change in SPP. In this chapter only the uncertainty in fluid mixing will be discussed.

There is and uncertainty on how much the SOBM, base oil and spacer are mixed when this train of fluids with different densities are pumped down the casing, see figure 4.17. How much these fluids are mixed will affect the SPP, see difference between blue and red curve on simulated values of SPP in figure 4.13.

In a similar way there is also uncertainties on how fast a potential gas kick will mix or disperse into a larger area or annulus volume of the SOBM in the annulus. In particular the different cross-sectional area and the rate of gas dispersion in the wellbore annulus will affect the change in observed SPP.

4.3.6 SPP continue to drop although expected to increase (00:09 to 00:22)

During this period (6) before the bottom wiper plug reach the float collar both simulations (with and without mixing) shows that the SPP is expected to increase as the spacer fluid turns and starts filling the annulus. If we also assume that gas in the riser are leaving the riser at the top [4.76] and replaced with gas free SOBM from the bottom, this implies that the BHP should increase even more, see figure 4.16 phase IV. It is therefore very interesting that the observed SPP has a clear decreasing trend during this period (6), see figure 4.13.

One possible explanation for this observed deviation in SPP may be that a gas kick was taken during the previous formation fracture event as discussed earlier. If gas has got time to disperse into a larger area of the annulus, this may reduce both viscosity and static density, which again will lower the required circulation pressure. If gas cut mud is being circulated into a smaller cross-sectional area of the wellbore annulus this also may contribute to the observed decrease in SPP.

In the next chapter a simplified figure on fluid locations when the bottom wiper plug reaches the float collar are made, see figure 4.19. This figure shows how gas cut mud (B) entering a smaller cross-sectional area at the crossover may have contributed to the observed decrease in SPP. [4.81]

4.3.7 Increased loss of circulation after bottom plug burst (00:22 to 00:35)

Figure 4.19 shows a crucial moment when the bottom wiper plug reaches the float collar.

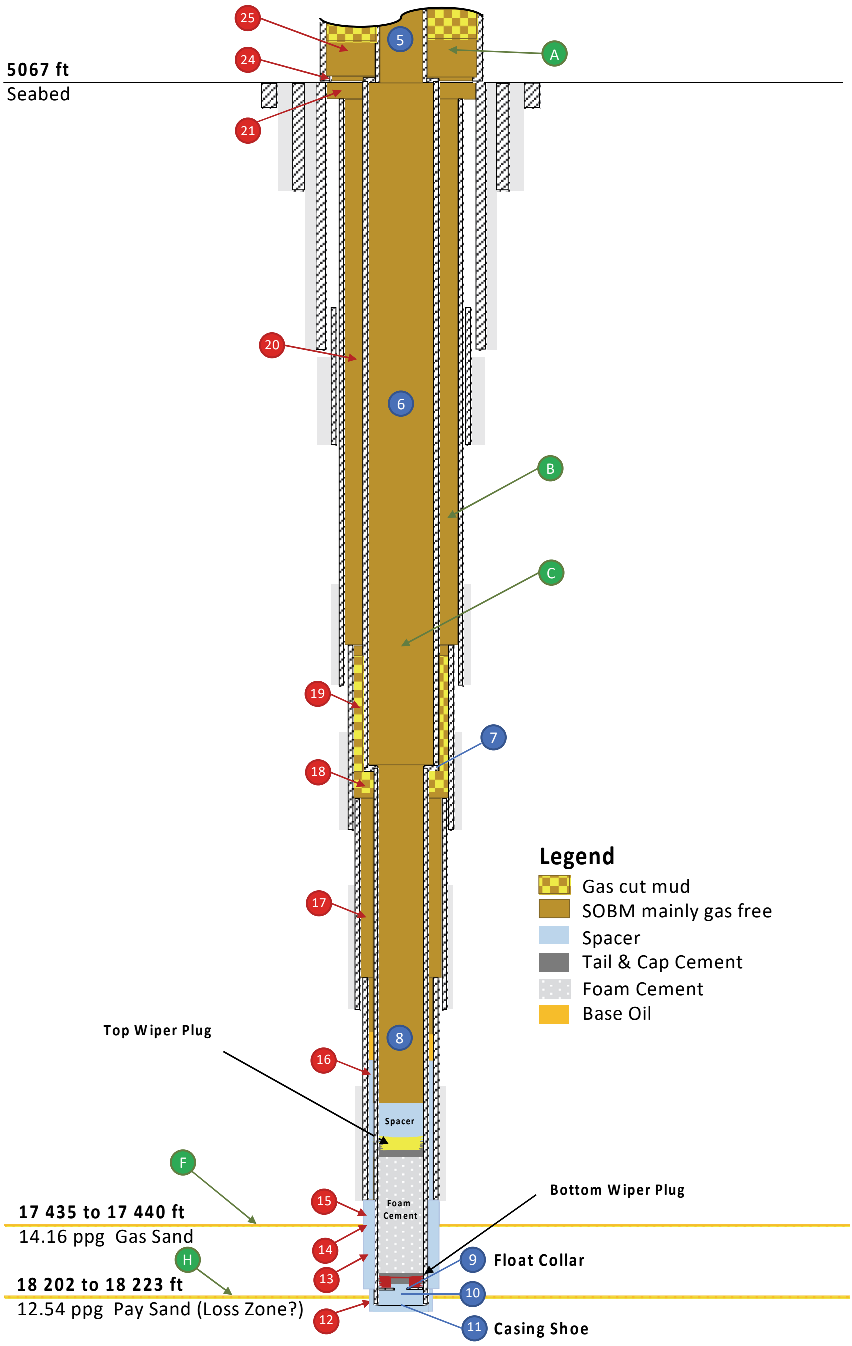


Figure 4.19 – Simplified drawing on fluid location when bottom plug at float collar

When the bottom wiper plug reaches the float collar, the pressure needs to be increased until the bottom plug burst and cement is allowed to be pumped to the final destination. The observed pressure build-up required to burst the bottom plug was 2 900 psi and occurred at about 24 minutes past midnight. [4.82] This high pressure will create a pressure surge down into the wellbore when the bottom plug burst. The peak pressure in the lower oil sand would be about 15.88 ppg when the plug burst, see figure 4.18. This is equivalent to 1 114 psi (76.8 bar) above the "not to exceed limit" to avoid fractures and loss of fluids to the formation. [4.83] This high pressure in the lower part of the wellbore probably fractured the formation and lead to a relatively large loss of water-based spacer fluid, [4.84] see figure 4.19.

The pressure surge in the wellbore also generated increased flow out of the riser shortly after the plug burst. The flow out from the riser thereafter decreases significantly, see figure 4.13. As discussed earlier in chapter 4.3.4, the question is why did they not lose complete returns as previously experienced? [4.48] In the previous event when the bottom plug went through the crossover, the simulated peak pressure down in the oil sand was also just above the fracture pressure. However, this time the simulated peak pressure was way over the fracture pressure which would be expected to result in massive losses and complete loss of returns, see figure 4.18.

The main reason for why complete loss of returns were not seen was probably due to simultaneous gas and possible water influx. When the bottom plug reaches the float collar the circulation stops for about 2 minutes while pumping about 8-9 bbls of SOBM into the casing while pressure is building up. However, in the wellbore the pressure goes the other way and ECD is reduced due to the short break in circulation. The simulation shows that during these two minutes the 14.16 ppg gas sand and the 14.15 ppg formation (containing water or gas?) [4.85] below become underbalanced. One minute before the bottom plug burst the simulation shows that due to the base oil located in the annulus (see figure 5.19) the well was about 5.7 (83 psi) to 7.3 bar (106 psi) [4.86] underbalanced depending on how much the base oil was mixed with the spacer and SOBM. In addition to the base oil the gas in the wellbore and riser annulus (see figure 4.19) could add another 7.5 bar (109 psi) to 8.2 bar (119 psi) [4.87] underbalance based on observed SPP, see figure 4.13. This total underbalance in the gas sand of about 13.9 bar (202 psi) to 14.8 bar (215 psi) probably lead to a gas kick even before the bottom plug burst. [4.88]

When the bottom plug burst it is not unlikely that a large loss of 40 to 50 bbls or more of the spacer fluid was lost in very few minutes. In this way the entire spacer volume between the upper gas sand and the bottom plug may have been lost to the formation. [4.89] Since the wellbore was hydrostatically underbalanced when the loss occurred it is also likely that a large part of this volume was replaced with gas from the 14.16 ppg gas sand. This is probably the main reason why complete loss of returns were not observed. When or if this occurred the possibility of establishing a crossflow with gas from the upper 14.16 ppg gas sand flowing down to the lower pay sand or loss zone increases, ref. discussion in chapter 3.9.

The conclusion is that a crossflow occurring shortly after the bottom plug burst probably was the main reason for why the cement job was unsuccessful and why natural gas later under preparation for the negative pressure test could enter the production casing from the casing shoe.

4.3.8 Float check and flow back analysis (00:35 to 00:43)

The top wiper plug reaches the float collar at about 35 minutes past midnight (172 minutes simulated time). Unlike the bottom wiper plug this plug is not designed to burst. The rig pump was therefore shut down as soon as pressure starts to build up, see figure 4.13. During the next two minutes after the pumps were shut down but before the pressure was bled down, a small pressure build-up can be observed on the SPP. During these two minutes the spacer and SOBM used to displace the cement was trapped in the casing and landing string behind the top wiper plug blocking the outlet to the wellbore. SINTEF has calculated that the observed pressure build-up during these two minutes likely is caused by thermal effects to the trapped volume, see discussion in Appendix D, chapter *5.3.3 Increasing pressure after pump stop*.

At about 00:37 on April 20 a valve at the cementing unit was opened to see how much mud flowed out of the well when they released the pressure. Models had predicted 5 or 6 bbl of flow back due to fluid compressibility. Two men observed 5.5 bbl of flow, which tapered off to a “finger tip” trickle. The total flow was close to the predicted flow, and the two men concluded the float valves were holding. [4.90]

The float check valves were designed to close once the auto-fill tube was removed and the float valves converted to two check valves, see figure 4.4. This should have prevented flow to go in the reversed direction. At the same time previous investigations have concluded that it is almost certain that the gas that exploded on Deepwater Horizon came up through the shoe track and past these two check valves, ref. statement in the Chief Counsel´s report summarizing the technical findings. “*The Chief Counsel‘s team finds that flow almost certainly came up through the shoe track of the production casing.”* [4.91] One interesting question is therefore why did the well not flow back during the float check?

In a conventional cement job, the hydrostatic pressure in the annulus will normally be higher than hydrostatic pressure caused by the fluid column in the casing and running string. However, it this cement job due to narrow cement window and concern that the formation might fracture, foam cement and base oil was used to reduce the hydrostatic pressure. The ESD after the pumps were shut down and after the top wiper plug had pumped in the float collar, was simulated to be between 14.15 ppg and 14.16 ppg at the lower oil sand (18 212.5 ft), see figure 4.18. [4.92] This is probably less that the hydrostatic column of shoe cement (16.74 ppg), spacer (14.3 ppg) and SOBM (14.0 ppg surface density) located inside the casing and running string. In addition, the observed SPP while circulating seconds before the top plug bumps, was more than 100 psi lower than the simulated values. This implies that due to gas influx the real hydrostatic annulus pressure almost certainly was lower than the hydrostatic pressure inside the casing.

If we assume that the gas came up through the shoe track of the production casing and that the quality of the cement was ruined by a crossflow event, why did not any gas flow back during the float check? As discussed in chapter 3 the highest pore pressure in the Macondo well was located in the 14.16 ppg gas sand. This means that even if the crossflow event made it possible for spacer and gas to flow down the annulus and into the loss zone, the pore pressure was not high enough to lift the top wiper plug and cause gas to flow back and up through the shoe track. However, later during preparation for the negative pressure test when part of the SOBM (average ESD of about 14.17 ppg) inside the casing was removed and replaced with seawater, gas was allowed to flow up through the shoe track.

One last question remains to be discussed on the cement job. Simulation shows that the 14.16 ppg gas sand was underbalanced if the cement job had gone according to plan. Depending on how much the base oil would be mixed with the spacer and SOBM the simulated ESD at the 14.16 ppg gas sand was between 14.13 ppg and 14.14 ppg shortly after the bottom plug pumped, see simulated time 174 minutes in figure 4.18. In addition to this, the observed SPP while circulating seconds before the top plug bumps, was more than 100 psi lower than the simulated values. This again implies that due to gas influx from previous gas kicks, the real hydrostatic annulus pressure at the gas sand was even more underbalanced. The question is therefore why did not the riser continue to flow out of the riser after the pump was shut down?

The industry practice has been to shut down pumps and perform a flow check if suspicion of a kick has taken place. The author of this thesis has no information if a flow check on the riser actually was performed after the cement job. However, based on flow out data recorded in the Sperry-Sun system it seems that the flow out of the riser ceases shortly after the rig pump was shut down. A flow check would therefore probably not work in this case and rather show a net loss, as seen for the last 3 hours on the recorded flow out data. [4.70] The reason why flow out from the riser or no gain was recorded after the cement job, despite a gas kick probably was ongoing, could be several as discussed earlier. However, one obvious reason could be that loss of fluids in the lower part of the wellbore took place simultaneously. Reference are made to Society of Petroleum Engineers (SPE) glossary and definition of crossflow: "*Flow between formations via a connected wellbore. Crossflow, as seen by downhole cameras, can occur with the wellbore full of fluid and the appearance of a dead well at surface.*" [E.6]

Chapter 5 – Well Integrity Tests

After the cement job and float check was complete at about 00:40 on April 20 the integrity of the well was tested. To verify the integrity of the well three different pressure tests were conducted; *seal assembly test*, *positive pressure test* and a *negative pressure test*.[5.1]

5.1 Seal Assembly Test

During the cement job and pre-cementing circulation the 9 $^{7}/_{8}$-inch casing hanger allowed fluids to be circulated. Once the cement job was complete the seal assembly was set to close the flow path in the casing hanger, see figure 5.1 below and figure C.5 in Appendix C.

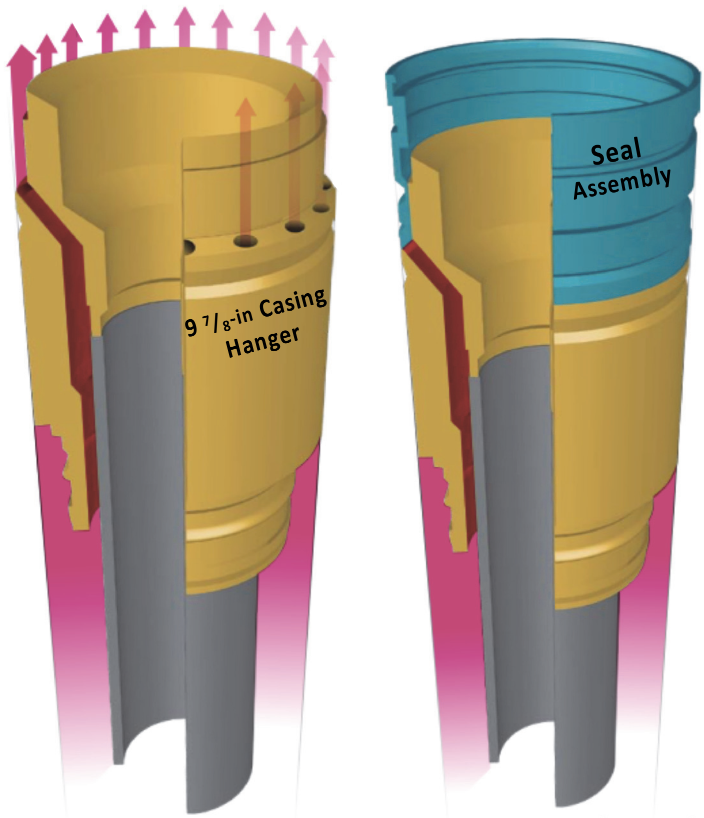


Figure 5.1 – Seal assembly and 9 $^{7}/_{8}$-inch casing hanger in the Macondo wellhead [5.2]

Closing the flow path in the casing hanger also isolate the wellbore annulus from the subsea BOP and riser. Any gas influx that probably came into the wellbore when the bottom plug passed the crossover and later burst at the float collar, was therefore trapped in the annulus and prevented from flow up the annulus.

The actual seal assembly was installed in the subsea wellhead and tested successfully between 00:40 and 07:00 on April 20. In this period the drill pipe used to test the seal assembly was also pulled out of the riser. [5.3]

After the blowout the subsea casing hanger and seal assembly was brought up to surface for investigation. The examination revealed serious erosion inside the casing hanger and no signs of erosion through the 18 flow passages. This is strong evidence that hydrocarbons progressed up the inside of the production casing and not up the annulus past the casing hanger and through the seal assembly. [5.4]

5.2 Positive Pressure Test

After the seal assembly test and as part of the temporary abandonment procedure, the drill crew ran a tapered drill string into the hole to proceed with the preparation for the negative pressure test and final displacement. While the drill string was at 4 817 ft, just above the BOP stack, the blind shear ram (BSR) was closed to perform a positive casing test. [5.5]

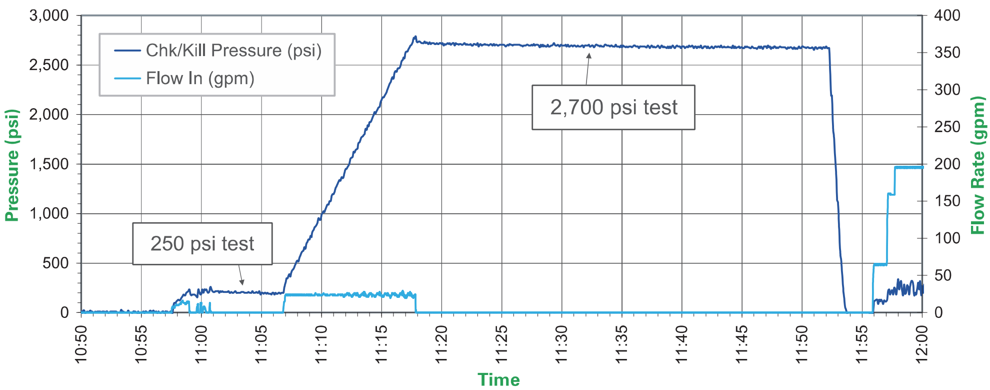


Figure 5.2 – Positive pressure test conducted on April 20 [5.6]

The positive pressure test was conducted in two stages: a low-pressure test and a high-pressure test. First, after closing the blind shear ram (BSR) in the BOP, wellbore pressure was increased through the kill line to 250 psi and held for 5 minutes. Second, after no leaks were observed, wellbore pressure was increased to 2 700 psi and held for 30 minutes. The rig crew determined that the test was successful after the observed pressure did not decline more than the criteria specified by the MMS (no more than 10% decline in 30 minutes). [5.7]

Note that the positive pressure test was against the rubber cement displacement wiper plug on top of the float collar and did not test the integrity of the cement in the shoe track. [5.8] 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. Figure 5.3 is a simplified illustration on the set-up when the positive pressure test was conducted.[5.9]

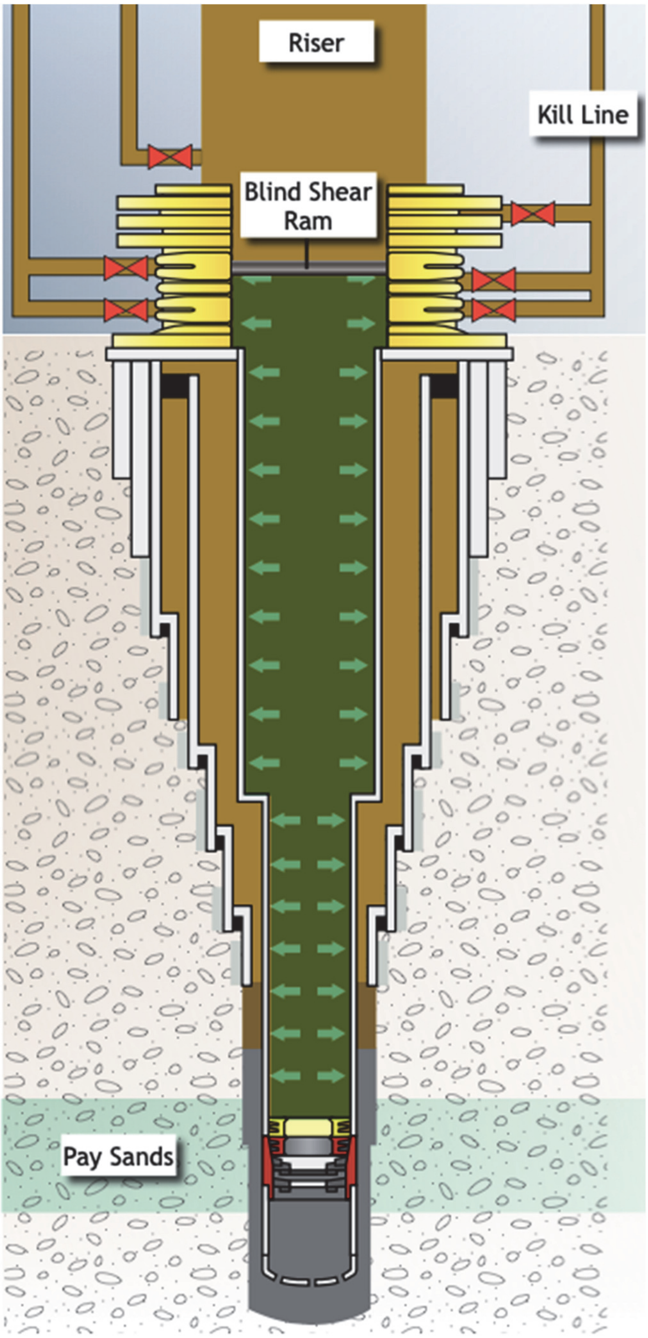


Figure 5.3 – Integrity test of casing and wellhead performed with positive pressure test [5.9]

After successfully conducting the positive pressure test, the rig crew prepared for the negative pressure test by opening the BSR and running the drill pipe into the well to a depth of 8 367 ft. [5.10] However, before the negative pressure test is discussed, two topics suitable for further research related to the positive pressure test will be discussed. These two topics are *natural gas diffusion in SOBM* and *dissolved gas in SOBM and effect on density and compressibility*.

5.2.1 Natural gas diffusion in SOBM

After more than 100 pages into this thesis, it is easy to get lost in the analysis of the root cause of the Deepwater Horizon disaster. It is time to recap some of the important events that probably took place, prior to the positive pressure test that started at about 11:00 on April 20.

Between April 16 and April 19, tons of gas probably entered the wellbore, ref. discussion in chapter 4.2.5. The main gas influx mechanism was not by gas diffusion that may occur in an overbalanced wellbore, (Bodwadkar and Chenevert, 1997) and (Petersen 2018). In the Macondo case it was probably caused by the gas sand(s) with high pore pressure and an underbalanced wellbore due to thermal expansion of the SOBM, ref. discussion in chapter 4.2.6 and figure 4.10.

An interesting question is how does the gas kick behave after it probably entered the wellbore filled with SOBM? It will probably be dissolved in the SOBM and not migrate upwards like it probably would with WBM (Skogestad et al., 2017). Or will it behave significant different since Macondo had a synthetic oil-based drilling fluid and the study made by Skogestad et al. was based on different types of mineral oil as base fluid?

A resent paper with the promising title; "*Understanding Gas Kick Behavior in Water and Oil-Based Drilling Fluids*" is interesting in order to understand how a gas kick will behave after it enters the wellbore. This study simulated the gas behavior of a gas kick in a 10 000 ft vertical well. The simulations predicted that if there is a constant kick influx of 1 scf/sec, the first gas bubbles would reach the wellhead in this, non-circulating well in 4.45 hours. Incorporating gas solubility into these simulations revealed that the choice of drilling fluid volume factor (B_o) correlation affects the results significantly. It also showed that some of the existing B_o correlations failed, for drilling fluid swelling calculations, at higher pressures and temperatures. Finally, the results indicate that a gas kick would take longer to reach the wellhead when it is soluble in the mud than when it is not, regardless of the choice of B_o correlation (Manikonda et al., 2019).

This study (Manikonda et al., 2019) did not simulate gas kick influx behavior over a longer period in non-circulating well with oil-based drilling fluids. However, it may be useful to understand the time frame it probably took for a potential gas kick to migrate from the 14.16 ppg gas sand (17 435 ft) to the wellhead located at the seabed (5 067 ft), see figure 3.1. If it took 4.45 hours for and influx to migrate 10 000 ft in a static vertical well onshore with WBDF, the case would be totally different for the Macondo well. At Macondo it probably took a much longer time for several reasons.

First of all, with oil-based mud and in deep water the word migration is probably not a good word to use. In an onshore well the annulus temperature 5 000 ft below the wellhead is much higher, particularly in a static well. The high temperature has a large effect on gas properties. With high temperature the gas will start to boil out at a much higher pressure, see figure 5.4 (Torsvik et al., 2017, Fig.11).

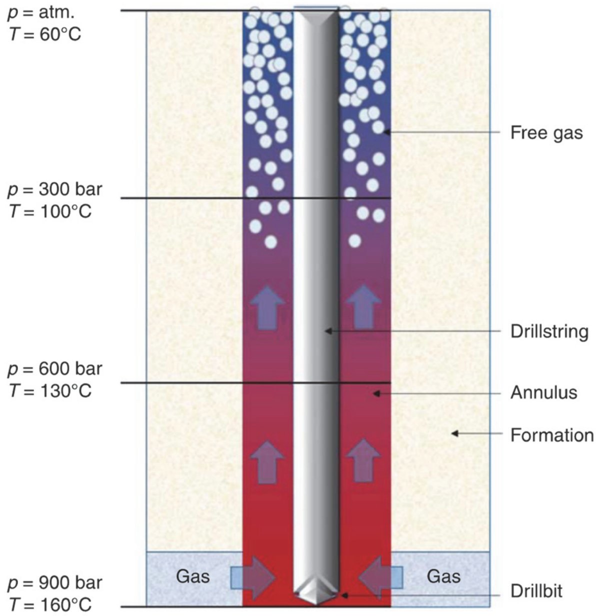


Figure 5.4 – Onshore HP/HT well with gas influx (Torsvik et al., 2017, Fig.11)

In deep water however the temperature in the riser annulus in particular will be much lower and the gas properties changes. When the temperature is lowered the gas change from having normal properties for a superheated fluid (gas) and is transferred into the dense phase region. If the gas influx is cooled down to around 20 to 30 ^{O}C, the gas will stay in the dense phase region down to about 150 to 160 bara, see figure E.2 (Appendix E). The result will typically be that the gas will boil out of the OBM at a lower pressure. This effect can be seen when circulating out a 25 bbl gas kick dissolved in OBM with the wellhead located in 1 500 m (4 921 ft) water depth. In this case the gas kick dissolved in the OBM starts to boil out of about 120-minute simulated time, see figure 4.16. At this moment, the kick is located at around 600 -700 m depth, which is in the upper half of the riser (Gomes et al., 2018).

So rather to investigate the effect of migration of free gas it is probably the effect of gas kick diffusion dissolved in SOBM in a static wellbore such as the Macondo which would be interesting to have better estimates on. A dissolved gas kick will probably diffuse according to Fix´s law from an area in the wellbore with high gas concentration to an area with low gas concentrations. Since gas diffusion is less dependent (or independent?) on pressure but driven by difference in concentration, it would probably also spread out over a wide area of the wellbore depending on time. The gas kick assumed to come from the 14.16 ppg gas sand (17 435 ft), will therefore probably also go down to the bottom of the well at a total depth of 18 360 ft, driven by Fix´s law of diffusion.

On April 18 the drill crew began lowering the long-string production casing. The casing was run into the wellbore with an auto-fill tube allowing potential gas cut mud to enter the casing. The gas cut mud may also have resulted in barite sagging (Saasan, 2002), that eventually plugged the auto-fill tube, ref. discussion in chapter 4.1.3. For some part of the casing run, it is also possible that the casing was filled with relative gas free mud through the Allomon diverter, although flow in the Allomon diverter was intended to go the other way (from inside casing to outside).

In any case, when the production casing had reached the final location on April 19, tons of gas was probable spread over a wide area as a result of gas diffusion from the bottom of the well and all the way up to the wellhead and lower part of the riser. Some gas was probably also present inside the casing, assuming the auto-fill tube worked, at least for most of the casing run.

The possibility to check for gas in the wellbore is also one of the reasons why a full "bottoms-up" is recommended prior to a cement job. This means circulating the entire annulus volume of mud from bottom of the well to surface. [5.11] In the case of Macondo a full "bottoms-up" meant circulating about 2 750 bbls. [5.12] The total amount of fluid pumped during the cement job including pre-cementing circulation was about 1 370 bbls of fluids.[5.13] This means that at the end of the cement job, when high gas readings were recorded in the mud returning from top of the riser, 1 380 bbls of fluids still remains to be pumped in order to carry out a full "bottoms-up".

The total volume of the riser annulus during the cement job, with the casing running string in the riser, was about 1 637 bbls.[5.14] In other words, when the cement job was completed, potentially 80 to 90 % of the riser annulus volume contained gas cut SOBM. Probably also with a higher wt% gas in the bottom of the riser, since this fluid came from the bottom of the well. At the same time both the casing running string and the inside of the long string production casing were probably gas free, since this was filled with clean SOBM and spacer pumped from the surface. The question is what happens, when the casing running string in the riser was disconnected and tripped out of the riser?

In the upper part of the riser (about 3 000 ft) the gas will probably boil out and migrate towards the surface, see figure 5.4. In the lower part (about 2 000 ft) of the riser the gas in the annulus will still be in dense phase and probably dissolved in the SOBM. What will happened when the casing running string is tripped out and the gas free SOBM inside the string mixes with the gas cut SOBM on the outside of the string? Probably it will be like mixing coffee and milk in a cup. Pulling the casing running string out, lowering the seal assembly test string down and then up again and then lowering a new displacement string down, will be like stirring the cup with a teaspoon. The gas rich annulus SOBM will probably mix with the gas free mud inside the string to form a uniform solution with equal wt% gas.

Another question is what happens with the gas cut SOBM in the riser during this relative long static period of about 10 hours where drill pipes where tripped in and out of the riser? Probably the free gas in the upper part has got time to migrate and escaped out of the riser.

The gas from the lower part of the riser with high concentration of gas will probably diffuse down into the production casing which in the beginning was full of gas free SOBM. The production casing shown in figure 5.3 in green color, may therefore have contained gas when the positive pressure test was carried out, about 10 hours after the casing running string was pulled.

The gas probably entered the casing due to gas diffusion from the gas rich SOBM in the riser and BOP area. However, further research is recommended to see how fast gas in dense phase, diffuses in a static vertical well with SOBM and if or how it may be affected by gravity?

5.2.2 Dissolved gas in SOBM and effect on density and compressibility

If we go back to figure 5.2 during the second part of the positive pressure test the pressure inside the casing was increased by 2 550 psi. To achieve this the drilling crew had to pump a total amount of 6.1 bbls of fluid into the kill line. [5.15]

If we assume that the kill line valves has been closed at the subsea BOP up to the time where the positive pressure test start, the gas cut mud can be assumed to have a much higher wt% gas in the BOP and casing, than the basically gas free mud in the kill line, see figure 5.3 for arrangement during the positive pressure test.

The question is then how would the assumed dissolved gas in the SOBM in the BOP and casing affect the compressibility of the SOBM? By intuition you may think that with gas dissolved in the mud you would need to pump more fluid to obtain the same pressure increase. However, it may not be this simple, se figure 5.5 (Torsvik et al., 2017, Fig. 6).

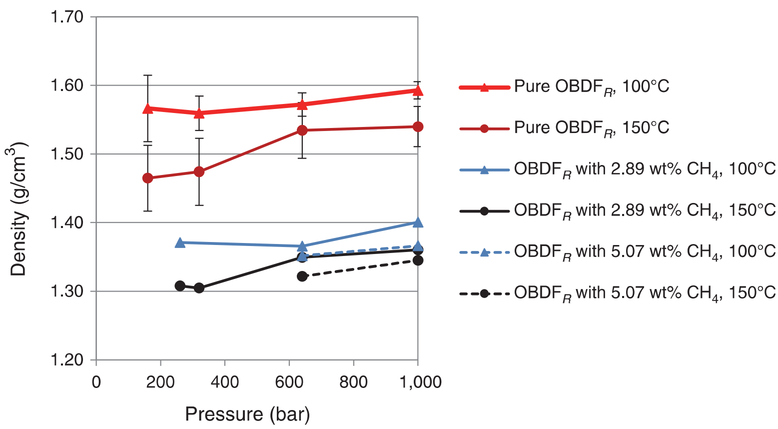


Figure 5.5 – Impact of gas absorption on density of refined OBDF (Torsvik et al., 2017, Fig.6)

The hydrostatic pressure of the SOBM will increase with depth, from about 255 bar in the subsea BOP to about 634 bar at the bottom of the 9 7/8-inch casing and 919 bar at the bottom of the 7-inch casing. [5.16] Most of the volume of the casing is therefore in the interesting pressure range between 300 and 600 bar, see figure 5.5.

If the pressure for refined OBDF with 2.89 wt% methane at 150 ^{O}C (**black** data set) was increased from 400 to 600 bar, the expected increase in density will occur. However, if the same fluid still with 2.89 wt% methane (**blue** data set) had a lower temperature (100 ^{O}C) and the pressure was increased from 400 to 600 bar, the expected increase in density will no longer occur. In fact, the density will decline, see figure 5.5.

The reason for this behavior is probably that at 150 ^{O}C the gas will be superheated and way above the saturation pressure. The natural gas or methane in this case will therefore follow more expected behavior for a gas. However, when the temperature is lowered to 100 ^{O}C the gas will be going into the dense phase region, and the fluid density properties changes to be more like a liquid, ref. figure E.2 in Appendix E.

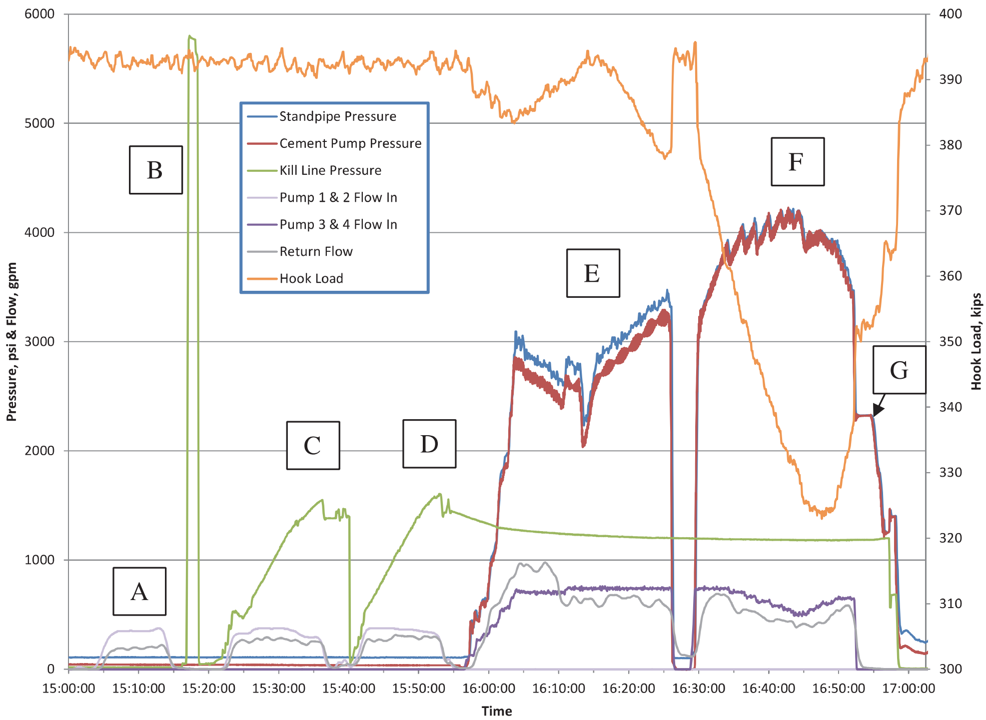
In the case of the positive pressure test carried out on the Macondo casing, most of the SOBM, except for the bottom part of the 7" casing had a temperature far below 100 ^{O}C. In the BOP and wellhead area after about 10 hours without circulation the temperature would be about 11 ^{O}C. Any dissolved gas in the mud would typically be in the dense phase region. Hence, the "gas" will have density properties closer to that of a liquid. When the drilling crew increased the pressure in the production casing by 2 550 psi (175.8 bar), it would therefore be expected to have similar compressibility whether the SOBM contained gas or not. In fact, if there would be any changes it may be expected that with gas in the mud you could require even less fluid to be pumped to obtain the same pressure increase, since pure OBDF at 100 ^{O}C (**red** data set) show a slight increase in density (from 400 to 600 bar) compared to the gas cut OBDF at the same temperature (**blue** data set), which show a slight decrease in density.

As mention earlier the drilling crew pumped 6.1 bbls to increase the pressure by 2 550 psi (175.8 bar), this is less than 7.1 bbls that theoretically would be required if the production casing and subsea BOP contained pure SOBM without any dissolved gas. [5.17] This may be an indication that the BOP and casing contained gas. However, as discussed above the changes in density due to gas cut mud is difficult to predict when the dissolved gas is in the dense phase region.

A better way to find out if there is any gas in the riser, the subsea BOP or casing is to compare the actual density of the fluid and not the change in density due to pressure changes. Although, gas dissolved in OBM or gas trapped in gas hydrates, will give less density changes compared to the same mass of free gas, the gas in the mud will result in a reduction in the overall density of the mud, see figure 5.5.

5.3 Displacement to Prepare for the Negative Pressure Test

Stress Engineering Services Inc. has made an excellent report and documented both events, real time data and compared this with results from simulations. The complete report can be found in Transocean Investigation Report, Vol. 2.[5.18] In the following chapters in this thesis figures from this report will be used and new explanations for the observed anomalies will be discussed based on the assumptions that a large gas kick was taken during the static period between April 16 and April 19, and that this influx had yet not been completely circulated out of the well.



Event	Description	Time
A	Displacement of booster line with seawater	15:03 to 15:15
B	Pressure test of surface lines	15:17 to 15:19
C	Displacement of choke line with seawater	15:21 to 15:38
D	Displacement of kill line with seawater	15:38 to 15:55
E	Displacement of riser with 16 ppg spacer	15:55 to 16:27
F	Displacement of riser with seawater	16:28 to 16:53
G	Pumps stopped; annular BOP closed	16:53 to 16:54

Figure 5.6 – Overview of important events that took place from 15:00 to 17:00 on April 20 [5.19]

At about 15:00 on April 20 the crew had lowered the tapered displacement string down to a depth of 8 367 ft. At this moment in time the well had been stagnant for more than 14 hours after the cement job was completed at 00:40. The annulus temperature in the wellhead area had got time to drop below 10 ^{O}C. [5.20]

After 15:00 and until the first explosion at about 21:49:15 the crew did not perform any tripping operation. During this time, the well, displacement string and riser system were maintained as shown in figure 5.7. [5.21]

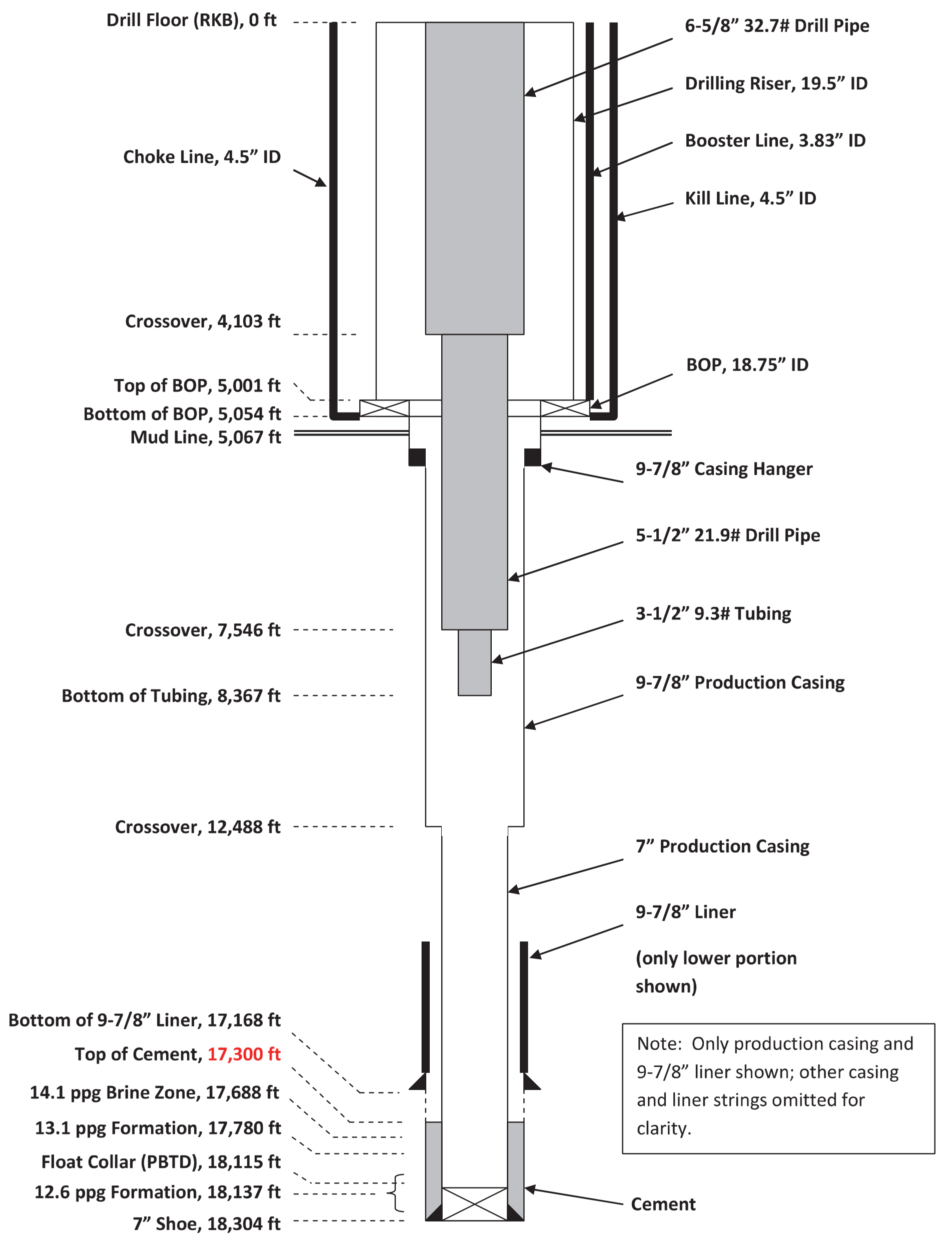


Figure 5.7 – Schematic overview over the Macondo well during the final hours [5.21]

Figure 5.7 is taken from the report made by Stress Engineering Services (SES).[5.21] Note that this schematic has not included the 14.16 ppg gas sand formation at 17 435 ft, see figure 3.1 and 3.3. In the simulations made by SES [5.22] for Transocean and in the simulations made for the BP investigation report,[5.23] the hydrocarbon influx has been assumed to come from the lower pay sands. This assumption will also affect the simulated or calculated time for when the well become underbalanced during the displacement to prepare for the negative test. Although the long-string casing had been set and casing hanger properly sealed in the wellhead, the highest absolute formation pressure independent of depth was the 14.16 ppg gas sand, ref. discussion in chapter 3.9.

5.3.1 Displacing the booster line with seawater (Event A)

At about 15:03 the drilling crew start displacing the surface piping, drape hose in the moonpool and the booster line with seawater. A total amount of 78.5 bbls of seawater was pumped with the rig pump. [5.24] However, only 42.6 bbls of fluid returned from the risers.[5.25] This gives a loss of fluid of 35.9 bbls during the short displacement sequence of about 12 minutes, see figure 5.8. [5.26]

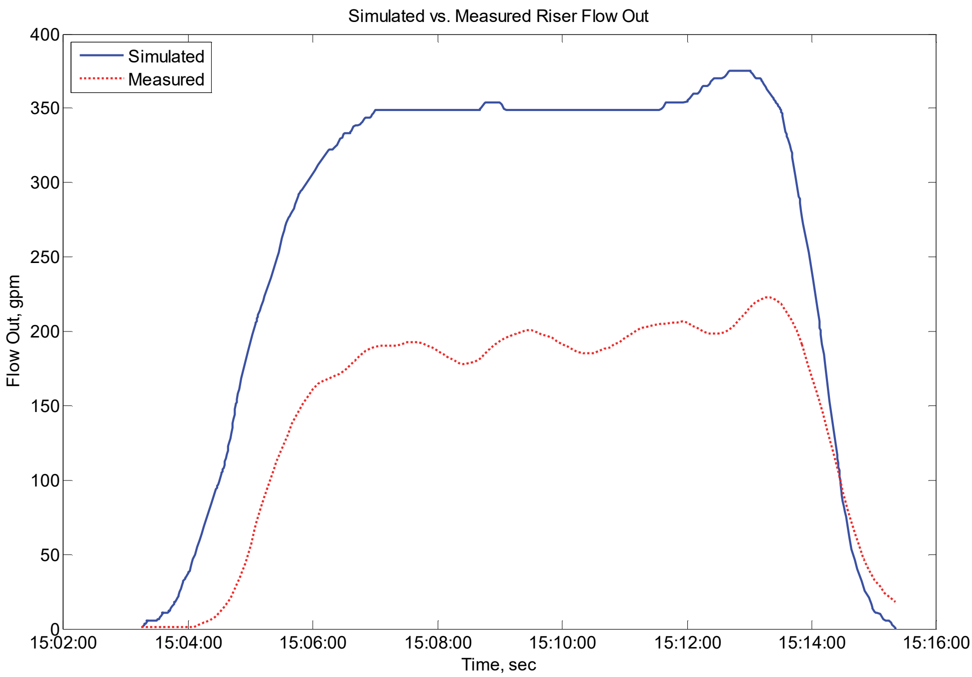


Figure 5.8 – Schematic overview over the Macondo well during the final hours [5.26]

This anomaly was newer resolved by Transocean or the SES team. In the SES report the possibility that fluid was lost to the formation through a leak in either the casing or through the wiper plugs and casing shoe was discussed. However, the possibility of such a scenario is unlikely since the casing had past the positive pressure test a few hours earlier.

A more likely explanation to this anomaly is that the booster line was partly filled with gas when the displacement started. However, if free gas in top of the booster line should have caused a reduction in volume of 35.9 bbls when it was compressed, you will need a lot of gas! This hypothesis will therefore need further discussion.

First of all, it is important to understand how such a large gas kick that would be required could go on for so many days without being detected. Even during the pre-cementing circulation and during the cement job when the well was circulated the gas kick was not discovered. Also, even Dr. Smith in his report given the scope to review the real time data wrote; "*Significant gains, roughly equivalent to the volumes of cement and spacer pumped, and losses, which were not explained, are present in the data record.*"[5.27] The question is why was the gas kick that probably started on April 16 not discovered? Secondly, why has previous investigation reports not discussed the possibility of a large gas kick prior to the cement job?

The answers to these questions have already been discussed in chapter 4.3.1 and 4.3.2 and figure 4.14, 4.15 and 4.16. However, a better answer may be that the potential gas kick was not discovered or discussed after the accident because the industry still relies on a net gain over time in your active pits or flow check as your primary kick detection method.[5.28]

A very good paper to explain why these kick detection methods not necessary work is; "*A Transient Flow Model for Investigating Parameters Affecting Kick Behavior in OBM for HPHT Wells and Backpressure MPD systems*", (Gomes et al., 2018). Figure 3.9 in this thesis (Gomes et al., 2018, Fig. 6) and the same figure with comments added as figure 4.14, show why kick detection based on gain does not work. If the drilling crew for some reason (typically simultaneous loss or thermal effects) as discussed earlier do not catch the initial influx or the sudden gain that occur when the gas are in the riser, you are beyond the point where a gas kick can be detected by gain. It is also important to understand that after the observed gain subsequent losses and erratic flow out, will typically occur when the first bubbles of gas reaches the surface and exit the riser. In the Gomes et al. study this effect occurred at about 150 minutes simulated time, see figure 4.14.

Another important aspect to be discussed is in which way the free gas leaves the riser? During the final cement displacement when circulation was carried out with the rig pump a total of approximately 80 bbls was lost,[5.29] see figure 4.13. If most of the free gas leaves the SOBM before it reaches the flow sensors in the return line this may be a contributing factor for the observed loss.

It should also be noted that OBDF and gas loading capacities is totally depended on pressure. When gas is in the dense phase region, the gas loading capability in the drilling fluid is unlimited (Skogestad et al., 2017). However, at atmospheric pressure the gas will boil out of the mud and probably a large amount will escape before it even reaches the flowline in an open return system such as the one used at the Deepwater Horizon.

Another tragic accident that support such a statement is the Oklahoma fatal gas well blowout in 2018. Less than an hour before the blowout and explosion workers could observe that gas was "boiling" in the open wellbore, ref. statement CSB´s final report. "*The motorhand pulled away the steel plate that had been covering the hole in the rig floor over the well. He waved over another worker (who was not a member of the Patterson drilling crew or RMO), and that worker walked to the open hole and saw mud bubbling in the open wellbore, which in hindsight was evidence of gas in the mud. This worker was not a part of conversations in the driller's cabin and does not know if the mud bubbling was communicated to the driller. The rig crew continued testing the BHA.*" [5.30]

With the experience of the Pryor Trust Well in Oklahoma, it may be possibly that the drilling crew at Macondo did not discover that gas was boiling in the open wellbore below the rotary table at the end of the cement job. Is it then possible that 50 to 100 bbls of gas at atmospheric pressure have escaped at the top of the riser, during the cement job explaining the observed loss of fluid? [5.29] The author of this thesis does not know the answer to this question and further research is recommended.

However, if we accept the fact that significant amount of gas was recorded in the return line at the end of the cement job, [5.31] the booster line could also be exposed to gas cut mud. The booster line had probably not been used since the bottom up circulation on April 16. It is therefore likely that the booster line had been exposed for gas cut SOBM located in the riser at the booster line inlet, most of the time between April 16 and April 20. Gas from the riser will probably diffuse into the booster line and later boil out and migrate higher up in the booster line. However, unlike gas in the riser, gas in the booster line has no way to escape but will probably be trapped in top of the booster line. The goose neck and drape hose in the moonpool will act as a liquid seal, trapping the gas in the booster line.

Let´s assume that the maximum amount of free gas that could be present in the booster line would be located in the upper 3 000 ft of the booster line (or 60% of the total booster line volume). Below this point the gas will typically be in dense phase due to the high pressure. [5.32] When the booster line displacement started, they may have had a situation where the lower 40% of the booster line (28.5 bbls) contained SOBM with dissolved gas. The upper 60% of the booster line (42.8 bbls) contained free gas pressurized by the u-tube effect and SOBM in the riser and trapped in by gas free SOBM in the drape hose and surface piping (7.2 bbls). [5.33] If the maximum amount of free gas (42.8 bbls) that could be present in the booster line was displaced down to bottom of the riser, the volume of the free gas will be reduced to 25.6 bbls. However, this is only 17.2 bbls in total volume reduction. In other words, gas compression alone cannot explain the observed loss of 35.9 bbls during the displacement of the booster line. [5.34]

If the hypothesis of gas in the booster line should explain the observed loss of 35.9 bbls, the free compressed gas volume of 25.6 bbls would need to be reduced further in volume by 73 %.[5.35] Gas hydrate formation could be an explanation for the additional volume reduction. When 28.5 bbls of gas cut SOBM + 25.6 bbls of free gas + 7.2 bbls of gas free SOBM is displaced with 78.5 bbls of seawater, gas hydrate formation could be a possible explanation (Vavik et al., 2016, Table 2).

5.3.2 Displacing the choke line with seawater (Event C)

After pressure testing of the surface lines, the drilling crew continue to displace the choke line. A total amount of 109.9 bbls of seawater was pumped. [5.36] However, only 84.8 bbls of fluid returned from the risers.[5.37] This gives a loss of fluid of 25.1 bbls during the displacement of the choke line with seawater.

When the booster line was displaced, the pump pressure was not recorded and transmitted to shore. However, when the choke and kill lines was displaced, we also have the advantage to analyze the pump pressure, since this was recorded in the Sperry Sun system, see figure 5.9. [5.38]

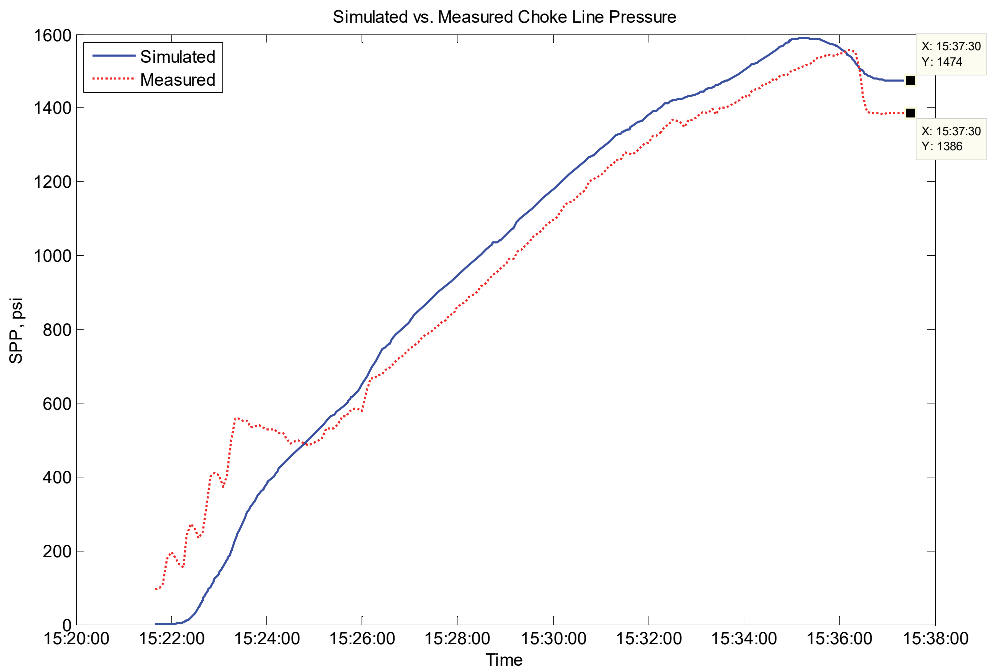


Figure 5.9 – Simulated vs. measured choke line pressure during displacement [5.38]

When the rig pump was lined up to the choke line the measured pressure was about 100 psi higher than expected. This is an indication that also the choke line contained some free gas. If the ESD in both the riser and choke line was equal, the expected pressure should be zero pressure differential with no flow.

Another strong indication that the choke line contained gas, is the change in observed pressure during displacement. After the displacement was complete the measured pressure was 88 psi lower than expected. In other words, during the circulation the average density differential between the fluid in the booster line and the riser decrease with 188 psi compared to what was expected.

For about two minutes between 15:23 and 15:25 the observed pump pressure decreases, when it is expected to increase. This anomaly is a strong evidence that hydrates were forming. When hydrates form in a confined space you typically see a distinct pressure drop due to the instant volume reduction due to gas consumed during the formation process (Vavik et al., 2016, Table 2).

As part of the work behind this thesis, Future Well Control AS (FWC) carried out a hydrate experiment in collaboration with SINTEF and NTNU. In the experiment seawater and a typical natural gas mixture in a pressure vessel shaped as a wheel, was cooled down by controlling the ambient temperature to form hydrates, see picture of the set up in figure 5.10.

Figure 5.10 – Martin Fossen (SINTEF) and Dag Vavik (FWC) in the flow wheel container

The hydrate experiment was carried out at SINTEF multiphase laboratory at Tiller, Trondheim, Norway. The main purpose with the test was to reproduce and verify volume reduction and observe how pressure changes when hydrates forms in a confined space. In addition, the experiment also created both expected and unexpected hydrates plugs, which showed us how easy it is to be confused by unexpected hydrate plugs.

Several tests were carried out and figure 5.11 shows the distinct pressure drop when hydrates start to form.

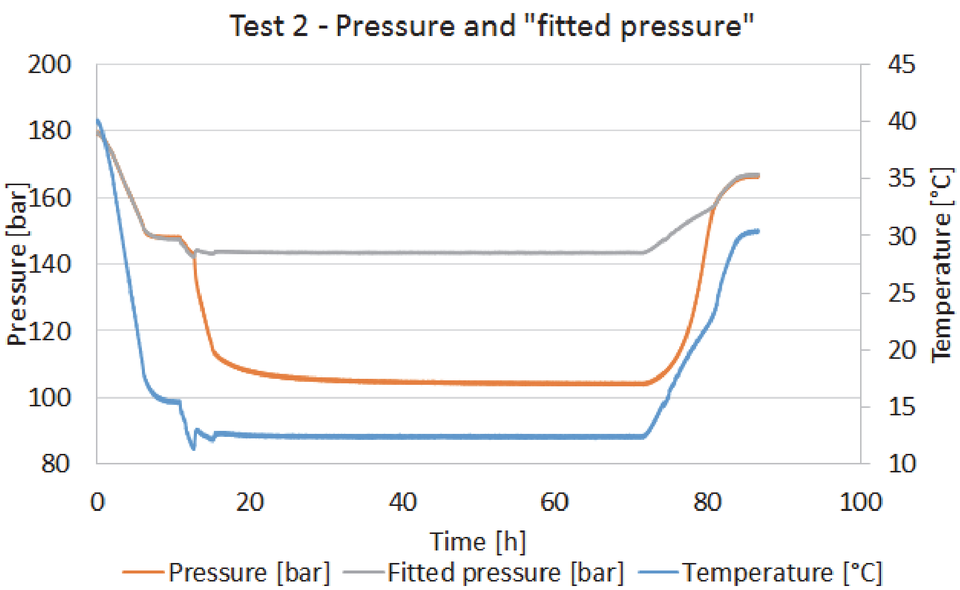


Figure 5.11 – Pressure and temperature in the flow wheel during hydrate formation

The actual pressure (orange curve) inside the flow wheel drops dramatically when hydrates starts to form, compared to the expected (simulated) pressure (grey curve) if no hydrates had formed. The reason why the hydrate formation ceases may be due to no rotation on the wheel and gas and water are in different phases. Unlike OBDF which typically will form a solution, seawater and gas will segregate with gas on top. The hydrates where forming where water and gas were in contact. After a while the gas and water were separated with solid gas hydrates.

Another reason for why the hydrate formation ceases may be due to drop in pressure. Since the pressure rapidly drops to 110 bar, the hydrate formation temperature also increases, which may have slowed down the rate of hydrate formation.

The reason for showing this result from the hydrate experiment carried out with natural gas and seawater is to strengthen the hypothesis that gas hydrates were forming during displacement of the booster line, choke line and kill line. Although the riser as such is not a confined space, but open in top of the riser, the well was still sealed off from the formation with the casing and casing hanger seal assembly. Other explanation, such as sudden leak through the casing or seal assembly is unlikely since this was pressure tested to a much higher pressure during the positive pressure test.

The sudden drop in pump pressure that occurred shortly after the displacement began, between 15:22 and 15:23, is also a strong indication that hydrates were forming, see figure 5.9.

5.3.3 Displacing the kill line with seawater (Event D)

After the booster and choke line had been displaced, the drilling crew continue to displace the kill line. A total amount of 106.1 bbls of seawater was pumped. [5.39] However, only 84.8 bbls of fluid returned from the risers.[5.40] This gives a loss of fluid of 21.3 bbls during the displacement of the choke line with seawater. Again, the pressure plot from SES of expected verses observed pump pressure is very interesting, see figure 5.12. [5.41]

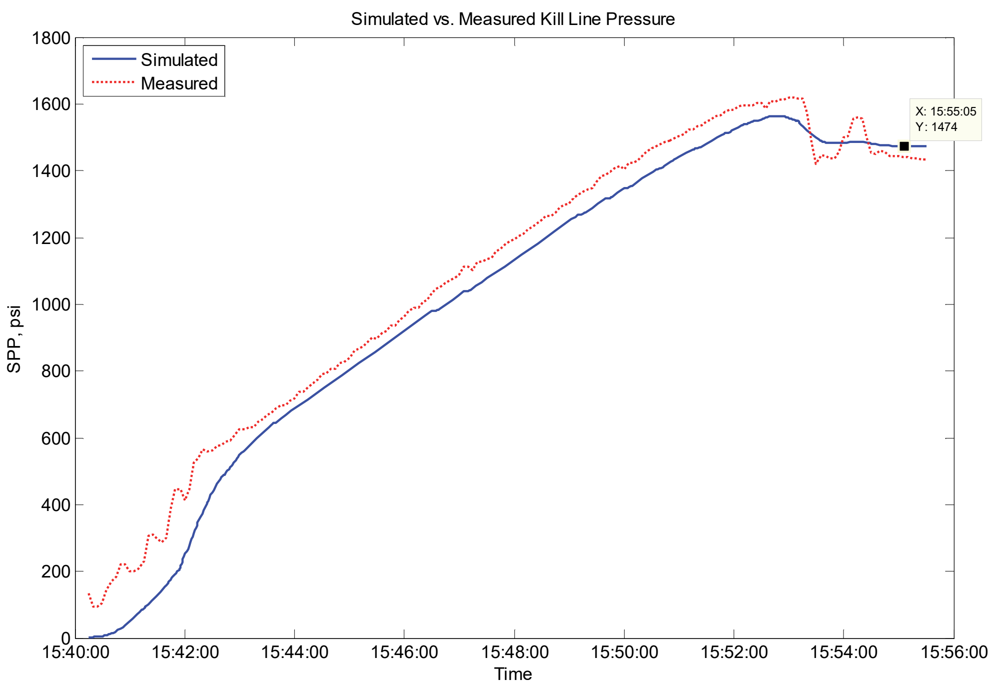


Figure 5.12 – Simulated vs. measured kill line pressure during displacement [5.41]

Again, the measured pressure was about 135 psi higher than expected when pumping starts. This is an indication that also the kill line contained some free gas. The sudden drop in pump pressure during the first two minutes, from 15:40 to

15:42 after the pump had started, is also a strong indication that gas hydrates were forming.

Also, this time the measured pump pressure ends up lower than simulated values. However, the kill line pressure ends up higher than the choke line pressure, 1 435 psi versus 1 386 psi after the end of displacement of the choke line. The complete reason for this is unknown. But it is probably due to increased density in the riser fluid over time. If free gas from the choke line was compressed into dense phase and injected into the riser, the expected result should be reduced fluid density and not increased, see figure 5.5.

The seawater injected into the, booster line, choke and kill line may have been mixed with the SOBM and gas that probably was present. You may then end up with a situation with an uncomplete displacement and at the same time end up with seawater in the riser. Seawater in the riser may have caused more hydrate formation in the riser and hence an increase in density.

After the displacement was complete the kill and choke line were probably isolated by closing the valves on the subsea BOP. During the next hour the kill line pressure declines slowly and eventually settling out at about 1 200 psi, see figure 5.6. The choke line pressure (not shown in figure 5.6), follow a similar trend however with about 140 psi lower pressure than the kill line. Thermal effect may explain this decline in pressure or at least contributing to the reduction in pressure, since the cold seawater surrounding the kill and choke line will cool down the fluid inside. If gas was still left in the kill and choke lines due to uncomplete displacement, hydrate formation may also have contributed to this decline in pressure in these confined spaces, see figure 5.11.

5.3.4 Displacing with spacer, freshwater and seawater

The drilling crew continue displacing by pumping spacer and freshwater through the tapered string down to 8 367 ft, see figure 5.7. A total amount of 454.7 bbls of spacer and freshwater was pumped. [5.42] However, 459.8 bbls of fluid returned through the flow out sensor.[5.43] This gives a net gain of fluid of 5.1 bbls during the spacer/freshwater displacement.

This gain followed by loss is typical flow behavior when circulating out a gas kick, ref. figure 3.9 (Gomes et al., 2018, Fig. 6). Remember that at this moment bottoms up circulation had yet not been completed. The real time data also show that high gas readings was recorded in the return line prior to and during the spacer circulation. Expanding gas coming out of dense phase may therefore be an explanation for this observed gain.

However, previous investigation teams have not believed that gas could have been present at this time since the well was currently not underbalanced. An alternative explanation has therefore been accepted that fluid from the trip tank was pumped up and into the flowline. It is possible that this was the case. However, a more likely explanation given the circumstances, is that the observed gain is caused by expanding gas in the riser, see figure 5.13. [5.44]

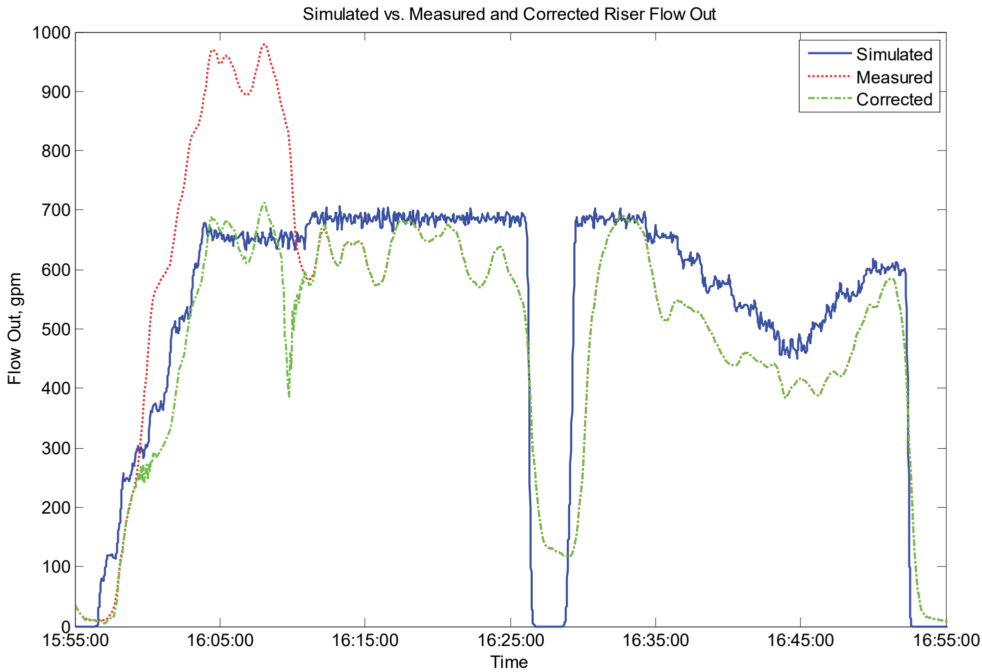


Figure 5.13 – Simulated vs. measured riser flow out during displacement [5.44]

After the spacer and freshwater was pumped, pump 3&4 was stopped for a minute or two, at about 16:27. In deep offshore wells with SOBM the well normally flow after pumps are shut down, due to high annulus frictional pressure and high ECD. However, in the case above the crew were pumping a water-based spacer with low annulus pressure. The flow out would therefore be expected to drop rapidly after pumps are shut down. The observed flow of more than 100 gpm after pumps are shut down may have been caused by migrating and expanding gas in the upper part of the riser.

The drilling crew continue displacing by pumping seawater. A total amount of 352.8 bbls of seawater was pumped. [5.45] However, only 280.9 bbls of fluid returned through the flow out sensor.[5.46] This gives a loss of fluid of 71.9 bbls during the displacement with seawater.

5.3.5 Summary on the displacement prior to the negative pressure test

A total volume of 82.3 bbls was “lost” during displacement of the auxiliary lines. In addition, 71.9 bbls was lost during displacement of the well with seawater. This gives a total loss of 154.2 bbls, not counting with the loss and possible gain that took place during the spacer and freshwater displacement.

The possibility that this loss can be explained with volumetric efficiency on the pumps are highly unlikely, since all four pumps were used with similar results.

The possibility of a sudden loss to the formation is also highly unlikely since the casing and casing hanger seal assembly had passed the positive pressure test with higher test pressure a few hours earlier.

Most likely the loss of fluid can be explained by the combination of gas hydrate formation, free gas in the auxiliary lines being compressed and free gas exiting from top of the riser before it goes through the flow out sensors.

The temperature at the wellhead and lower part of riser was probably between 8 to 9 ^{O}C [5.20] and pressure about 250 bar. For seawater and gas, the corresponding hydrate formation temperature is about 22.5 ^{O}C. For the spacer probably mixed with freshwater, the corresponding hydrate formation temperature is about 24 ^{O}C, see experimental and simulated hydrate curves figure 3.21.

The gas probably entered the well during the static period between April 16 and April 19, however had not yet been circulated out of the well.

5.4 The Negative Pressure Tests

No detail piping and instrument diagram (P&ID) of the surface piping arrangement during the negative pressure test was available for this thesis. However, on many deep-water rigs of this type, there is usually a fixed permanent connection between the cement unit and the choke and kill (C&K) manifold, for emergency kill operations.

There is also a possibility to connect the standpipe manifold (and hence the rig pumps) with the C&K manifold if required. However, this connection is usually not permanent due to the different pressure rating between the C&K manifold and the standpipe manifold. During preparation for the negative pressure test, when the choke and kill line was displaced with seawater using rig pump 2, this temporary connection was likely used and tested, see figure 5.6.

Since no detail overview of piping surface arrangement is available, only some of the main observed anomalies will be discussed in addition to some general considerations in this chapter.

5.4.1 Minimum pressure required to lift the wiper plug?

To calculate the exact ESD acting on the top wiper plug sitting down at the float collar is probably not possible due to the many uncertainties. How much freshwater was actually mixed with the 16 ppg water-based spacer? How much gas was in the riser and wellbore, thermal effects, etc. However, sometimes simple assumption may be useful. There are three different cases that is interesting;

a) Before displacement
b) After displacement but before negative pressure test
c) During the negative pressure test when pressure was bled down

Before displacement and with assumed ESD of 14.15 ppg. The hydrostatic pressure on top of the wiper plug at the float collar will be 918.6 bar (13 323 psi). [5.47] This is considerably higher than the pore pressure of 820.0 bar (11 893 psi) in the lower most pay sand, where probably the crossflow or loss took place. [5.48] It is also considerably higher than the pore pressure of 884.7 bar (12 831 psi) in the top of the 14.16 gas sand which is assumed to be the source of the gas kick. [5.49]

After displacement from the middle of the subsea BOB stack (5 040 ft) and up there was a mixture of seawater (8.58 ppg), freshwater (8.33 ppg), Spacer (16.0 ppg surface density) and SOBM (14.0 ppg surface density). In addition, there was probably also gas in three different phases. In dense phase dissolved in the SOBM, as gas hydrates trapped in a cage of water molecules and as free gas in the top part of the riser. It is difficult to simulate the ESD for this mixture, however let us assume 14.0 ppg. The weight or hydrostatic pressure at the subsea BOP will then be 252.8 bar (3 667 psi). [5.50]

From the subsea BOP and down to bottom of displacement string (8 367 ft) assuming seawater, gives a total hydrostatic pressure at the bottom of the displacement string of 355.1 bar (5 150 psi). [5.51] Assumed mixed ESD of the SOBM and spacer down to float collar of 14.15 ppg, gives a total hydrostatic pressure on top of the wiper plug at the float collar of 849.4 bar (12 320 psi). [5.52]

After displacement the pressure on top of the wiper plug is 35.3 bar (512 psi) lower than the highest pore pressure, meaning that it is possible for the gas pressure to lift the top wiper plug and flow into the 7" casing through the shoe track. However, at the same time the pressure on top of the wiper plug is 29.4 bar (426 psi) higher than the pore pressure in the lower most pay sand, where possible the loss or flow of gas still takes place. The gas will find the flow path with less resistance. It is therefore uncertain if gas influx into the 7" casing through the shoe track, took place during or after the displacement.

During the negative pressure test when pressure was bled down, assuming seawater from 8 367 ft and up, will give a total hydrostatic pressure on top of the wiper plug at the float collar of 751.5 bar (10 900 psi). [5.53] This is far below both the 14.16 gas sand pressure (884.7 bar) and the pore pressure in the assumed loss zone (820.0 bar). It is therefore likely that the well start flowing during the negative pressure or later during displacement of the riser with seawater, depending on the cement quality in the casing shoe and float collar.

It should also be noted that if or when hydrocarbon gas started to lift the top wiper plug inside the casing this will probably keep the spacer and SOBM separated from the gas influx below. Some gas may have passed the plug, but more likely the dense gas would push the plug up the casing, preventing the gas to be dissolved in the SOBM.

5.4.2 BOP annular is leaking

After the drilling crew had completed the displacement, they turn off the pumps and closed the subsea BOP annular. After they have bleed of the trapped residual pump pressure (H), the standpipe pressure settles out (3) on 1 400 psi, see figure 5.14. [5.54]

This pressure shows that the BOP annular probably was leaking, since this is very close to the calculated hydrostatic pressure of 1 420 psi, [5.55] given the uncertainties in how much freshwater, gas hydrates, free gas that was in the riser at the time. The reason for why the BOP annular probably was leaking is uncertain. It could be due to damage on the annular during previous stripping operations or due to gas hydrates in the subsea BOP preventing it from closing properly.

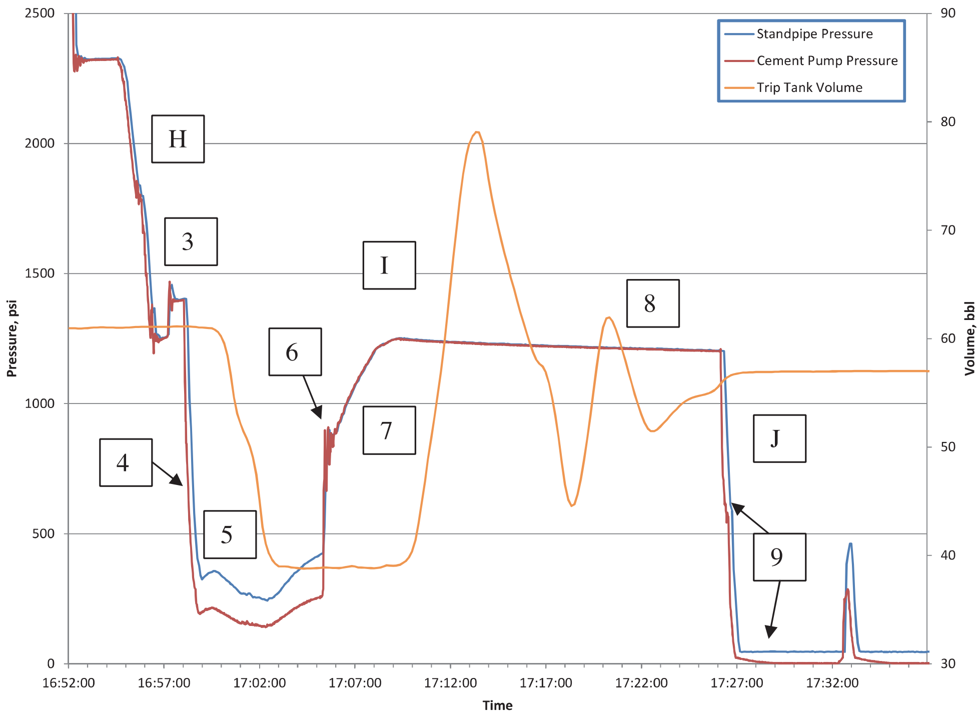


Figure 5.14 – Standpipe pressure and trip tank activity shows that annular was leaking [5.54]

To prepare for the negative pressure test the drilling crew try to release the pressure in the displacement string by letting fluid flow back up through the tapered string to the standpipe manifold, through the temporary connection probably connected to the C&K manifold and down to the cement unit. For about 7 minutes the crew let fluid flow back to cement unit (5), see figure 5.14. The differential pressure between the standpipe pressure (**blue curve**) and the cement unit (**red curve**) indicate high and stable flowrate. The SES team estimated that with the initial bleed down (H) and the seven minutes attempt to bleed down the pressure to zero (4 & 5), a total volume of 65 bbls flowed back up through work string. [5.56]

The annulus volume around the 3 $^{1}/_{2}$-inch drill pipe (tubing) in the lower part of the tapered displacement string is 29.3 bbls. [5.57] The annulus volume around the 5 $^{1}/_{2}$-inch drill pipe up to the wellhead is 45.2 bbls. [5.58] In other words, if 65 bbls of seawater was bled off up through the displacement string 87% of the annulus volume between the tapered displacement string and the 9 $^{7}/_{8}$" casing up to the wellhead may have been changed out, assuming no simultaneous influx.

Shortly after 17:05 the drilling crew probably closed the valve to the cement unit and pressure initially increase to about 880 psi (6), see figure 6.14. This pressure is far below the expected pressure of around 1 400 psi, given that at this point there probably have a leaking BOP and pressure communication to the riser fluid. This abnormal pressure was probably caused by a hydrate plug in the 3 $^1/_2$-inch tubing, in the lower part of the tapered displacement string.

The trapped residual pressure in the tapered displacement string then increases (7) to 1 262 psi [5.59] before it slowly decreases (8) to about 1 200 psi. The first increase (7) may be due to fluid expansion of the trapped fluid as "ECD" reduces after reversed flow was shut off. The subsequent decrease (8) may be due to thermal effects and possible hydrate formation in the trapped volume inside the tapered displacement string, see figure 5.14.

Note that during the reversed flow back of about 7 minutes, pressure in top of the bottom plug probably never fall below the pressure in the lower pay sand and assumed loss zone. Due to high flow rate and corresponding high "ECD", the pressure probably stayed above the pressure in the lower pay sand/loss zone. However, the pressure was already below the pressure generated by the 14.16 gas sand, but as discussed in previous chapter (5.4.1) this may not necessarily result in influx due to possible loss taking place simultaneously.

Shortly after the first attempt to bleed down the standpipe pressure, the crew discovered that the level in the riser had dropped. [5.60] The reason why they discover this was probably that they activated the trip tank system. Probably the crew started the trip tank pump at about 17:00 and pumped about 22 bbls, from the trip tank and into the riser without getting any return from the riser, see figure 5.14. Apparently, the riser was not full at this time. Since no returns were seen they probably stopped the trip tank pump at about 17:03. For those who are not familiar how a trip tank system works, see figure 4.5 for a simplified schematic.

Three times the trip tank pump was probably used to fill up the riser, and a total of 67.3 bbls [5.61] were pumped before returns were seen, see figure 5.14. This show that most probably the fluid returning to the cement unit during this first attempt to bled down the standpipe pressure, was caused by hydrostatic pressure from the riser and not from the well.

5.4.3 Standpipe pressure drops rapidly during first negative pressure test

After the drilling crew had been told to increase the annular pressure, [5.62] and after they have filled up the riser the drilling crew made a second attempt to bled off the pressure. This time the pressure dropped rapidly (9) to zero on the cement unit, see figure 5.14. According to witness accounts, 15 bbls of fluid were bled off from the drill pipe in the process. The test was regarded as successful. [5.63]

The pressure at the standpipe stayed however at 50 psi, see figure 5.14. Dr. Smith reviewing the recorded data, have concluded that this was due to the IBOP being closed and hence isolated the standpipe pressure from the tapered displacement string. [5.64] However, if the standpipe manifold was isolated it does not explain why both standpipe pressure and cement pump pressure spikes simultaneously and stay at the same level (50 psi) before and after the pressure spike. Neither does it explain why the experienced drilling crew could conclude in a successful test and why the real time data show no pressure on the cement unit, see figure 5.14 and figure 5.15.[5.65]

Why the cement pump pressure went down to zero and why the standpipe pressure (SPP2) stayed at 50 psi is unclear. One explanation could be that a static column of approximately 35 meter of seawater in the standpipe going up in the derrick to the drape hose (standpipe mud hose to top drive), and that the line down to the cement unit was taken directly from a temporary test connection as shown in figure 5.15.[5.65]

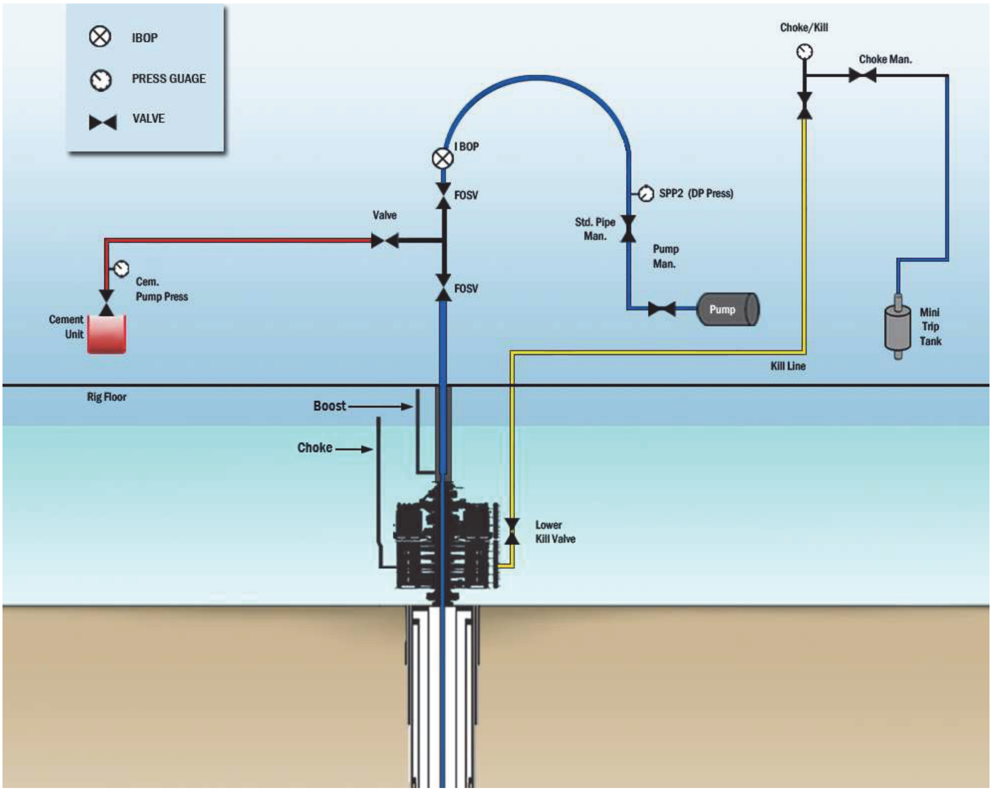


Figure 5.15 – Simplified schematic of piping arrangement during negative test [5.65]

The reason why the drilling crew and BP company man called the first negative test successful, was probably because there was no now pressure build-up or flow through the tapered displacement string (drill pipe). The reason why there was no flow was probably due to a hydrate plug in the tapered string.

5.4.4 Cement pump pressure increase to 1 400 psi

After what was believed to be a successful negative pressure test, the drilling crew prepared for a second test through the kill line. During the rearrangement of valves for this second negative test, the company man and drilling crew watch the pressure buildup (14) to 1 400 psi, see figure 5.16. [5.66]

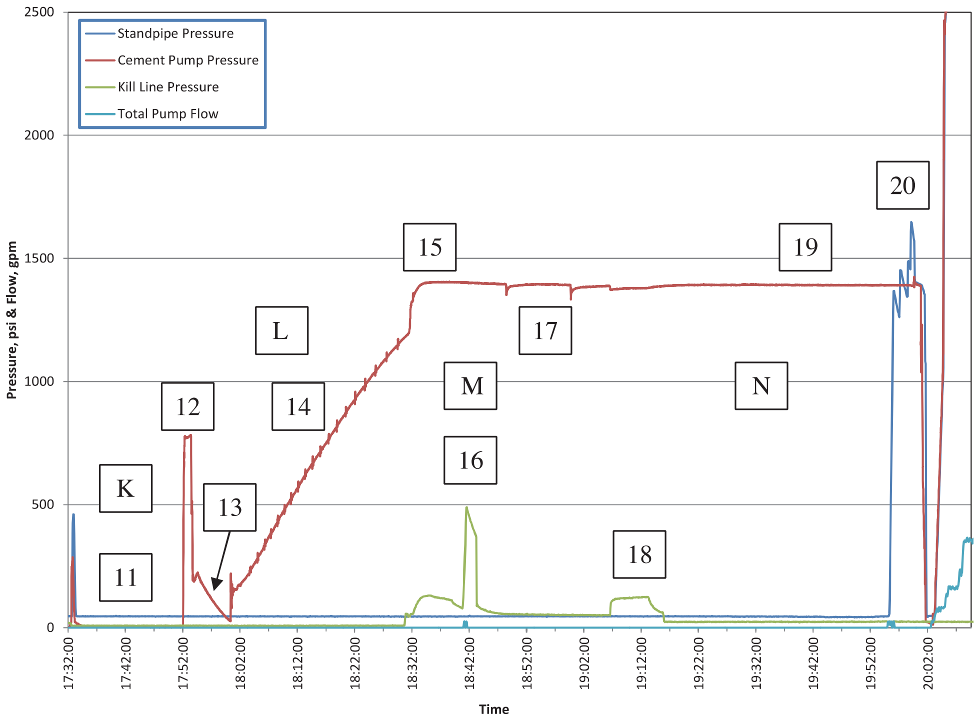


Figure 5.16 – Pressure readings and pump flow during negative test [5.66]

The reason why the decision to perform a second test through the kill line is uncertain. Possible this was after a conversation between the two company men, since BP originally was used to do it through the kill line. Maybe, high flow back (15 bbls) and pressure spike at 17:32 also contributed to perform a second test? Maybe, the drilling crew still suspected the annular to leak?

When Jason Anderson was asked about the pressure buildup (14), he claimed the pressure came from the heavy mud in the riser and predicted that it would stop at 1 400 psi (Kaluza and Karinch, 2018). The author of this thesis believe that Anderson was correct in this statement. Previous investigation team has believed that this pressure buildup was on the drill pipe and that the 1 400 psi pressure buildup could only have been caused by hydrocarbons leaking into the well from the reservoir formation. [5.67] However, if this should have been caused by and influx from the well, it would probably not have stopped at exactly 1400 psi as predicted by Anderson.

The pressure buildup to 1 400 psi most probably came from leakage through the annular, up the choke line and back to the cement unit. The pressure stops at 1 400 psi which is exactly the same pressure as seen after circulation stops and residual pressure bled down at 16:57, see figure 5.14. This is also the same pressure predicted by Jason Anderson (Kaluza and Karinch, 2018).

The observed “stick-slip” pressure fluctuations during the pressure buildup to 1 400 psi is probably due to a hydrate plug in the riser annulus above the subsea BOP. When fluid is leaking down through the annular the pressure below the hydrate plug in the riser will drop and differential pressure across the hydrate plug increase. When the hydrate plug suddenly slips, this will result in a small pressure spike on the choke line, monitored at the cement unit. Jason Anderson claimed that he had seen this behavior before and called it the “bladder effect”. [5.68] However, he was probable wrong (like many others) in the understanding on what may have caused the observed “stick-slip” pressure fluctuations.

5.4.5 Conduct negative test with no flow on kill line

When the drilling crew rearranged the setup for the second test through the kill line, they may have chosen what can be called a “double block and bleed”. The choke and kill line may have been arranged differently to have maximum control over any potential leak through the upper annular, given the experience with the leaking annular during the first attempt to bleed down the pressure. Possible, the drilling crew closed one of the variable bore rams, to have a double block against the heavy mud in the riser, see figure 5.17. [5.69]

By lining up the choke line back to the cement unit, any potential leak through the upper or lower annular could be monitored through any potential pressure buildup on the choke line. Simultaneously the kill line, with the lower kill valve *below* the bore ram, could be lined up back to the mini trip tank for the negative pressure test, as shown in figure 5.15.

The pressure variation (12) and (13) was probably due to choke line being lined up to the cement unit for monitoring any potential leaks through the annular. The pressure variation on the kill line (16) and (18) was probably due to lining up and preparing the kill line for the negative test. Apparently, the drilling crew had to start one of the pumps to fill the kill line from the top (16). [5.70]

The negative pressure test was carried out with no flow from the kill line for at least 30 minutes between 19:21 and 19:22, see figure 5.16.

The reason for no flow was observed was probably caused by a hydrate plug in the subsea kill line. This possibility was also apparently discussed earlier. [5.71] However, previous investigations have concluded that gas could not have been present at the BOP as early as the time of the negative pressure test. In one way they were right since the gas present, had probably not come into the wellbore *after* the cement job. Most probably tons of gas dissolved in the SOBM or trapped as gas hydrates, were present in the riser and wellhead area at the time of the negative pressure test. However, this gas entered the wellbore *before* the cement job in the static period between April 16 and April 19.

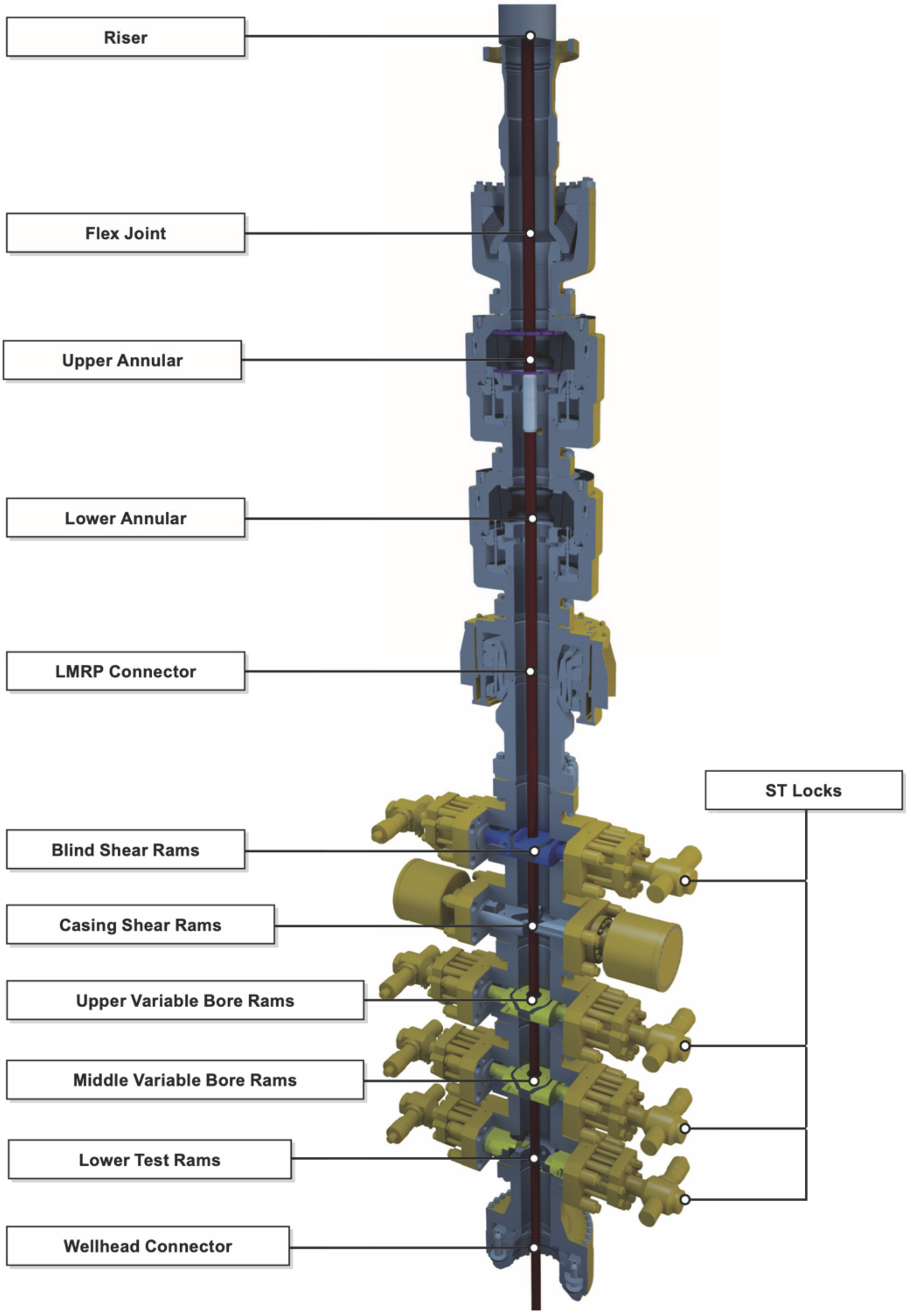


Figure 5.17 – Deepwater Horizon BOP stack with LMRP [5.69]

In addition to having no flow on the kill line for more than 30 minutes, the drilling crew could also observe no pressure on the standpipe (except for the 50 psi possible caused by a static seawater column up to the drape hose in the derrick). The drilling crew therefore believed they had performed a successful test, since both the kill line and the tapered displacement string (SPP2 on figure 5.15) showed no flow and no pressure buildup for 30 minutes, see figure 5.16.

However, with the benefit of hindsight we know that this was not the case. Probably the well was never underbalanced during the negative pressure test. Probably the only thing that was bled down was the kill line and the drill pipe, due to hydrates plugs in the lower part of the kill line and the tapered displacement string.

Chapter 6 – Displacing Riser with Seawater

Many of the anomalies that occurred during the final displacement of the riser with seawater is covered in *Chapter 2 – Pattern of Anomalies*.

During the first hour of the displacement the Chief Counsel´s Report have concluded that real time data appears to behave as expected or have other natural explanations not related to the blowout. Regarding flow out CCR team have comment on abnormal erratic flow. However, this has been explained with simultaneous crane operations that may have affected the level of fluids in the flow line.[6.1] Other anomalies like observed gain in the beginning of the circulation, has been explained by fluids being pumped from the trip tank and into the flow line.[6.2]

Regarding the drill pipe circulating pressure, CCR team states that 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. [6.3]

This chapter will cover three major anomalies that occurred during the first hour of the final displacement with seawater. These anomalies show that neither circulation pressure nor the erratic flow out behaved as expected.

6.1 Abnormal pressure and flow readings after the negative test

After the negative pressure test and before displacement of the riser with seawater abnormal pressure and flow readings were recorded. The author of this thesis has not read any plausible explanations for the strange pressure and flow readings in any previous investigation reports. In this chapter the anomalies during the 15 first minutes after the negative test will be discussed, see figure 6.1.[6.4]

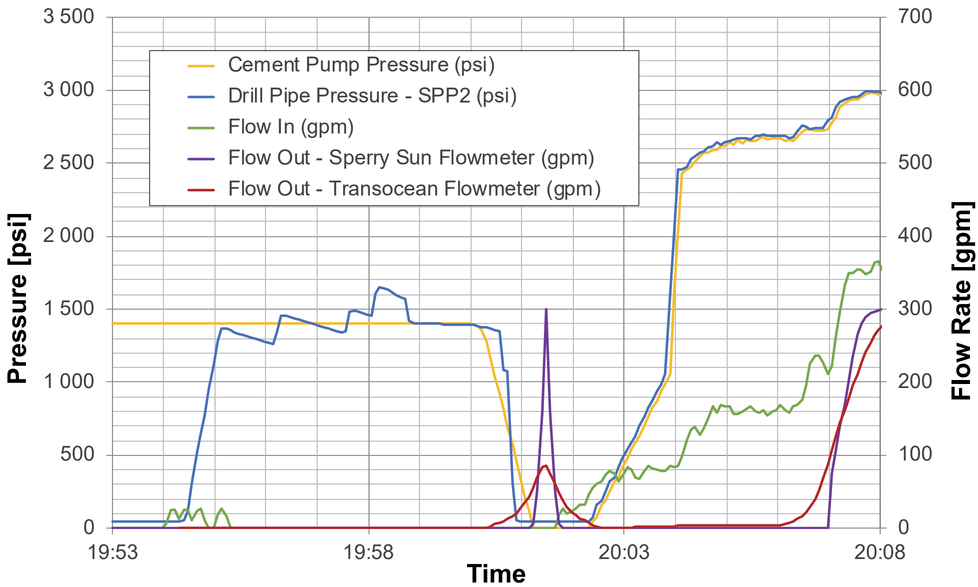


Figure 6.1 – Abnormal pressure and flow readings after the negative pressure test [6.4]

6.1.1 Probably no hydrocarbon influx during the negative pressure test

After the negative pressure test was completed at about 19:54 a rapid increase in the standpipe pressure can be seen simultaneously with one of the rig pumps was started.

One possible explanation to this observation may have been that the drilling crew wanted to equalize the pressure over a closed bore ram before they open it. The crew may have expected the pressure to increase and that this behavior was expected when the rig pump was started against what may have been a closed BOP, see figure 6.1.

The only unexpected in this scenario is the rate of which the pressure increase. Due to the large SOBM volume in the production casing you would expect to pump a few barrels before the pressure equalizes. Particularly if an air pocket where trapped in part of the piping and mud hose in the derrick. Since seawater had been drained down to the cement unit through the temporary connection on drill floor during the negative pressure test, this may have left air in the system, see figure 5.15. If the crew drain down 15 bbls to bleed down the pressure, they should also expect a similar volume to be pumped in to pressure it up again. However, less than 0.5 bbls was pumped when suddenly pressure make a jump and starts to oscillate.

Note that during the first 9 minutes, the “Cement Pump Pressure” (yellow curve) and the “Drill Pipe Pressure - SPP2” (blue curve) is not synchronized. This strengthen the hypothesis that the cement pump pressure was connected to the choke line during the second negative test performed through the kill line. The cement unit pressure sensor obviously could not be fluidly connected to the same drill pipe when the standpipe pressure (SPP2) starts to oscillate around 1 400 psi, see figure 5.15 and 5.16.

Note also when pressure starts to increase again shortly after 20:02 the two pressures are synchronized, see figure 6.1. This indicate that the valve in the temporary connection between the cement unit and the standpipe manifold (SPP2) was open.

The fact that the standpipe manifold pressure (SPP2) stabilize at 1 400 psi after it again was fluidly connected to the wellbore, shows that the static pressure inside the casing has not changes since the first attempt to blead down the pressure at 16:58, see figure 5.14. This implies that probably no hydrocarbon influx entered the production casing during the negative pressure test. Not because the cement job was successful, but because the negative pressure test failed to create sufficient low enough pressure to cause the wiper plug on top of the float collar to lift and hydrocarbon to enter the production casing.

6.1.2 Abnormal pressure drop simultaneous with flow out of riser

At about 20:00 both the cement pump pressure (assumed to be choke line) and standpipe pressure (assumed to be tapered displacement string) starts to drop. At about 20 seconds later flow is recorded coming out of the riser, see figure 6.1.

For many years the author of this thesis believed that this strange behavior must have been caused by abnormal high pressure in the production casing. The hypothesis was that a hydrate plug inside the 9 $^{7}/_{8}$-inch casing below the tapered displacement string had formed, since seawater was "injected" into the gas cut SOBM with high velocity through the 3 $^{1}/_{2}$-inch tubing, see figure 5.7. In this way high pressure caused by gas influx may have caused a pressure build up below the hydrate plug. However, this hypothesis is unlikely since the circulating pressure shortly after the sudden relief of pressure that occurred at 20:00 is lower than simulated values, see figure 6.3.

The current hypothesis is therefore that the strange behavior was not caused by abnormal *high* pressure in the production casing, but abnormal *low* pressure in the riser. There are several reasons why the hydrostatic pressure in the riser may have changed during the negative pressure test. Free gas may have expanded, migrate and left the riser making the riser level to drop. The fact that the rig pump was running for more than 5 minutes before any returns could be seen, may be an indication that the riser was not completely full when the pressure was released at 20:00.

Gas in the SOBM may also have boiled of from the solution making the ESD become lower. Gas in the SOBM may also have reduced the viscosity and caused barite sagging, ref. discussion in chapter 4.2.7. If the weight material in the SOBM no longer was kept suspended and dispersed throughout the entire length of the riser, this may have changed the overall ESD of the riser fluids during the negative pressure test. A considerably lower observed circulation pressure compared to expected (simulated) pressure during the first 10 minutes of circulation also support this hypothesis, see figure 6.3.

Probably the pressure trapped in the choke line, the production casing and the tapered displacement string was suddenly released causing the fluid inside to expand. The fluid expansion may have been higher than expected due to free gas in top of the choke line. Compressed air trapped in top of the test pipe, may also have contributed to the excessive fluid expansion, causing SOBM to "blow out" of the riser. [6.5] The sudden release of pressure may have been caused by a hydrate plug in the riser suddenly slips, ref. "stick-slip" discussion in chapter 5.4.4.

6.2 Observed flow out does not match simulated values

During the first hour of riser displacement abnormal erratic flow could be observed. Sometimes flow out show gain and sometimes loss of fluid. In earlier investigation reports these anomalies has been explained by fluid being pumped from the trip tank and into the flow line and hence adding to the total flow recorded at the flow meter. Possible inaccuracy of the flow meter and crane operations has also been mentioned as possible causes for this observed anomaly.

Fluids may or may not have been pumped from the trip tank and into the flow line. However, making correction for these volumes still the observed values does not match the simulated values, see figure 6.2. [6.6]

A more likely explanation is that the observed erratic flow, sometimes gain, sometimes loss, is caused by gas being circulated up the riser, ref. earlier discussion and figure 3.9 (Gomes et al., 2018, Fig. 6).

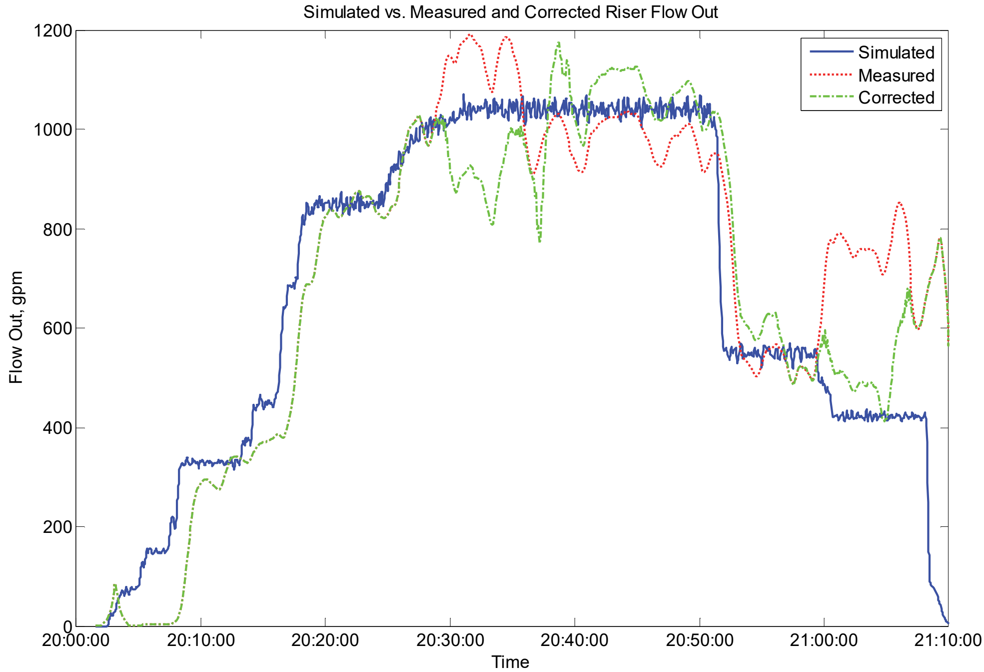


Figure 6.2 – Measured flow rates out of the riser does not match simulated values [6.6]

The erratic flow observed during the first hour of displacing the riser with seawater, is a clear indication that gas was probably present in the riser at the time of circulation.

6.3 Observed standpipe pressure does not match simulated values

As discussed earlier detecting gas influx based on gain has never been a reliable method, ref. discussion in chapter 4.2.5. In particular when gas has made its way up to the riser, the erratic flow may be very confusing, ref. discussion in chapter 6.2.

A better method is to compare the measured ESD of the fluid in the annulus and compare this with expected (simulated) values of the density of the fluid in the annulus (Vavik, 2017C). If you are sure of what fluid you have in your drill pipe, this can be done by comparing the measured circulated pressure with an expected or simulated circulation pressure. Low circulation pressure may indicate that there is gas in the annulus. However, low circulation pressure may also be caused by other possible scenarios such as leak in your circulating loop, washout of the drill bit nozzles or gas hydrates forming.

The SES team performing the simulation for the Transocean investigation team have simulated such a washout scenario. Since the tapered displacement string did not have a normal drill bit, they have simulated a washout scenario in the 821 ft

(250 m) long 3 ½-inch tubing at the end of the tapered string. The simulation was performed in order to explain the observed low circulation pressure, see figure 6.3.

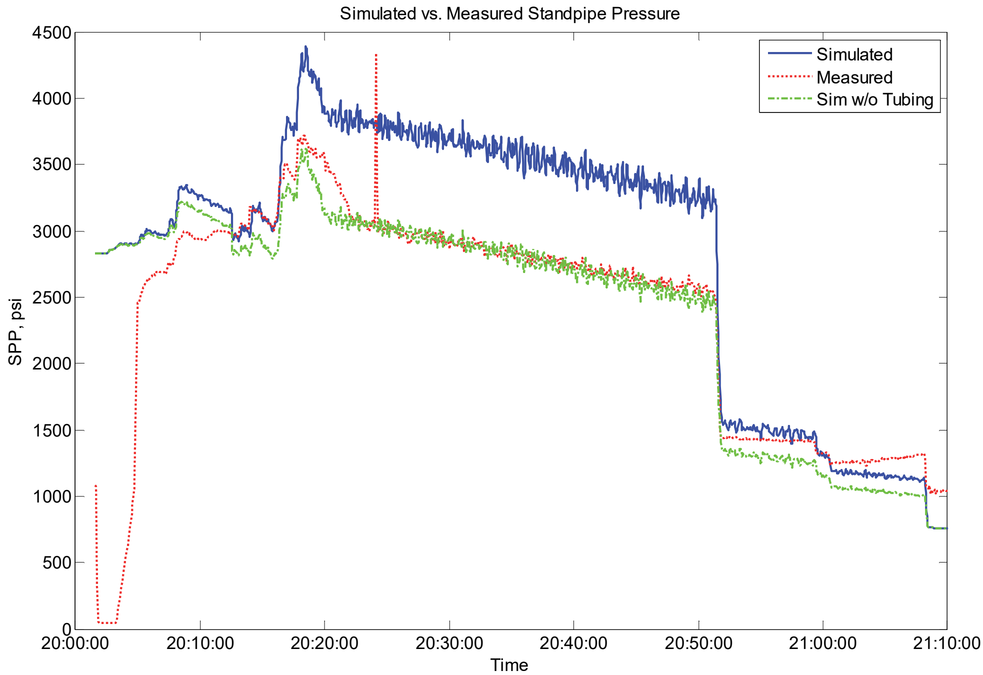


Figure 6.3 – Measured standpipe pressure compared with simulated values [6.7]

The trouble with the washout scenario (green curve) is that if this adjusted to match the measured or observed pressure at one time period, it will not match the measured values (red curve) before and after this time period.

The reason why the observed pressure is lower than the simulated pressure (blue curve) is probably due to gas in the riser annulus. The reason why the observed and simulated values are more or less equal for four minutes, between 20:12:30 and 20:16:30 may have been to gas and/or trapped air "stretching" out as it goes through the 3 ½-inch tubing in the tapered string. A vertical column with air or gas in the narrow 3 ½-inch tubing may compensate for the gas in the riser annulus.

The observed pressure spike at about 20:24 may have been caused by a "stick-slip" event, caused by a hydrate plug in the annulus. Either by the assumed hydrate plug in the riser or possibly by the assumed hydrate plug in the tapered displacement string, now being circulated up the annulus between the 5 ½-inch drill pipe and the 9 $^{7}/_{8}$-inch production casing, see figure 5.7.

Between 20:30 and 20:50 the total pumped flowrate (including booster pump) was kept at a constant rate of more than 1 000 gpm, see figure 6.2. Simultaneously the observed pressure is about 750 psi (52 bar) lower than expected. Gas in the riser probably contributed to this. However, this is a complex dynamic process that should be simulated with different scenarios. As seen by previous work by Gomes et al. the bottom hole pressure (BHP) will drop dramatically when a single gas kick boils out of the solution in the riser, see figure 3.10 (Gomes et al., 2018, Fig. 3).

Assuming the fluid in the tapered displacement string at this time contains seawater, (i.e. any gas or air in the string has been circulated out), the instant pressure drop of the BHP will also be reflected on the standpipe pressure when gas is being circulated out of the riser. The Macondo scenario is however totally different from the single gas kick being circulated out in figure 3.10 (Gomes et al., 2018, Fig. 3). One possible scenario could be that most of the water in the SOBM, or maybe as much as 20% of the total mud volume contained gas hydrates. When this is circulated up the riser the gas will expand rapidly when hydrates dissociate, see figure 6.4 (Vavik et al., 2016, Fig. 4).

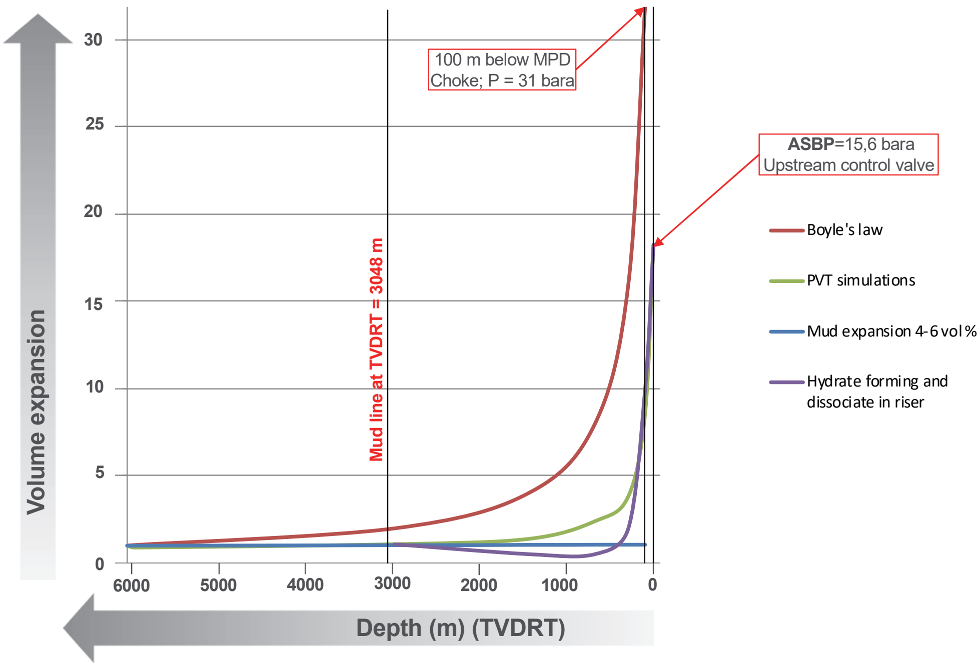


Figure 6.4 – Gas expands rapidly in upper part of the riser (Vavik et al., 2016, Fig. 4).

The reduction in circulation pressure is therefore not only a function of how much gas present in the annulus but also a function of flow rate or how much gas that are allowed to expand. When the pump rate is reduced this also reduce the amount of gas going through the phase transition. This may explain the dramatic change when circulation rate is lowered. From having a circulation pressure of about 750 psi (52 bar) lower than simulated, the observed circulation pressure is only about 100 psi (6.9 bar) lower when the total pump rate is reduced, see figure 6.3 at about 20:51.

When the flow rate is lowered, this will also reduce the ECD in the bottom of the 7-inch casing. The fact that the observed standpipe pressure starts to increase relative to the simulated pressure, and the two curves are no longer parallel, may be an indication that the production casing become underbalanced at about 20:51. Gas influx entering through the casing shoe and lifting the wiper plug, may have caused the observed standpipe pressure to be higher than the simulated value from about 21:00, see figure 6.3.

6.4 Drilling crew discover anomalies and starts troubleshooting

The drilling crew probably discover the anomalies shortly after 21:00 when both standpipe pressure and flow out start to increase, see figure 6.3 and 6.2.

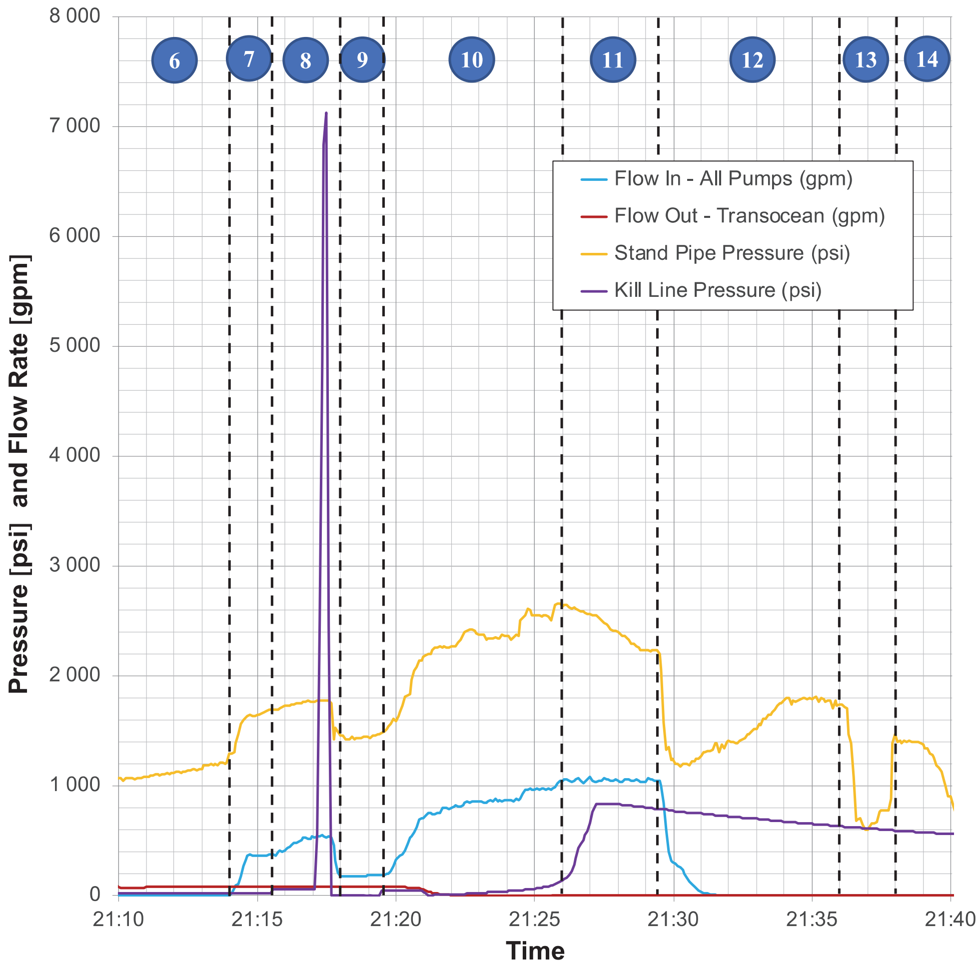


Figure 6.5 – Crew discover anomalies and starts troubleshooting (copy of Figure 2.2)

The shutdown of the circulation at 21:09 was probably not for the “sheen test”. The shutdown was probably because the drilling crew had discovered anomalies. In the next 30 minutes the drilling crew probably tried to find out what was going on. This chapter is a short summary of possible causes for the observed anomalies.

When the circulation stops, gas hydrates was probably in the upper part of the riser annulus and starts to dissociate. This is and endotherm reaction that may have cooled down the drill pipe. The hydrates did then probably plug the riser annulus. The flow out from the riser was possibly caused by expanding gas in the upper part of the riser as hydrates now slowly dissociate, since circulation has stopped (6).

Simultaneously the standpipe pressure increase, probably because the well was underbalanced and gas influx continue pushing the wiper plug up the casing (6).

At about 21:14 the drilling crew started up pump 3 and 4 again, which probably was still connected to the tapered displacement string, probably to investigate (7). Less than two minutes later at about 21:16 they also started up pump 1 (the booster pump). However, this did not increase the flow out of the riser, probably due to a hydrate plug still blocking the riser. However, the increased pressure in the well caused by injecting the fluid probably has reduced the gas influx, and the standpipe pressure is not increasing at the same rate (8).

At about 21:17 pump 2, probably connected to the kill line was started. The drilling crew may have done this also to increase flow into the riser annulus in an attempt to release the plug. Possibly the crew assumed the spacer made of LCM material and freshwater in some way have caused the plug. [6.8] The pressure relief valve or “pop-off” on pump 2 opens (8) and pump 3 and 4 is then also shut down. From about 21:18 to 21:20 only booster pump (pump 1) is running. This reduced the ECD and gas influx and standpipe pressure start to increase again (9).

At about 21:20 the crew starts up pump 3 and 4 again and gradually all three pumps (1, 3 and 4) are brought up to a total flow of more than 1 000 gpm in an attempt to release the plug in the riser (10). The drilling crew probably new after the “pop-off” event that they probably also had a plug in the kill line.

While the crew increased the flow rate of the three mud pumps, the flow out of the riser ceases completely at 21:21. One of several possible causes could be that so much gas has already left the top of the riser, that the level in the riser dropped.

At 21:26 the crew reached desired total flow rate of more than 1 000 gpm (11). Shortly after they probably also discover that the standpipe pressure starts to decrease. Simultaneously the crew probably also discover that the kill line pressure starts to increase. They may have thought that the kill line plug had released and that they possible were pumping fluids into the kill line, explaining the pressure buildup.

Probably the decrease in standpipe pressure was caused by wiper plug and gas influx being pumped down the casing and back into the well. The rise in kill line pressure was possibly caused by some hydrate migrating and dissociate (11).

At about 21:30 the crew stopped all pumps (12) to investigate. What they then observed probably came as a surprise. For several minutes they were watching the differential pressure between the kill line and standpipe pressure, to try and figure out what was going on. [6.9]

Chapter 7 – BOP Failed to Close the Well

When a well gets out of control, the purpose of the BOP is to shut-in the well to prevent a blowout. However, for some reason the subsea BOP at Macondo did not prevent the well to blow out and cause a gas explosion shortly after.

This chapter will discuss some possible reasons why this system failed to prevent the disaster and what well control actions that probably was taken by the drilling crew.

7.1 Well control actions probably taken by the drilling crew

After the drilling crew observed the differential pressure between the kill line and the standpipe pressure, they tried to bleed of the standpipe pressure (13). [7.1] Possible the crew already knew that they had a trapped pressure, but apparently believed that this must have been caused by all the fluids pumped into the well in order to unplug the "LCM plug" in the riser.

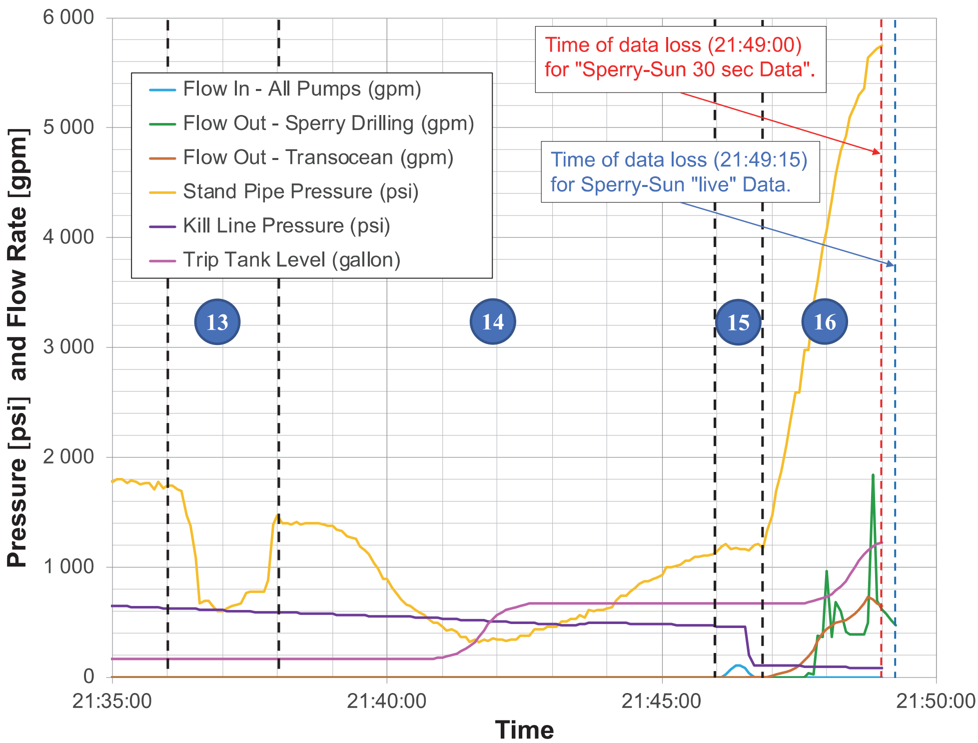


Figure 7.1 – Well control actions and real time data during the last 15 minutes [7.2]

Since the attempt (13) to bleed down the pressure on the standpipe failed, [7.1] the drilling crew may have believed that they must have damaged the production casing and in some way were communicating with the open wellbore. The drilling crew probably already knew that they had a plug in the kill line and a second plug in the riser annulus, since no flow was returning from the open riser.

The drilling crew may therefore have performed this second "flow check", either through the choke line or more likely again through the tapered displacement string. At about 21:39, they probably open a valve and bleed 12 bbls back to the trip tank (14). Possibly routing may have been from the tapered displacement string, through the mini trip tank and back to the trip tank. This routing may also explain the reduction in standpipe pressure followed by the increase to about 1 200 psi, on both the cement unit and the standpipe, but no change in pressures on the C&K manifold. [7.3] After this second flow check that confirms that they were getting mud or probably seawater back the BP well site leader (company man) was called. At about 21:44 the company man on duty received a phone call and was informed about the "flow check" and the well control action they were about to take. [7.4]

Before or during the phone call to the company man, the drilling crew probably closed the temporary connection to the trip tank, closed the BOP annular preventer and lined up the normal return in a well control situation, up through either choke or kill line, to the C&K manifold and back to the mud gas separator. [7.4] Note that the possibility that Deepwater Horizon had to route flow from the riser to the mud gas separator was probably never used, see figure 2.4.

Shortly after 21:46 or about 3 minutes before the first explosion the drilling crew start rig pump 4. [7.3] This action may have started a chain of reactions. Possibly the warmer water being pumped down the drill pipe may have contributed to large hydrate plug in the riser made of spacer (LCM), freshwater, seawater and gas starts moving. "Stick-slip" pressure fluctuations in the wellhead may have caused a hydrate plug in the kill line to rapidly move down for a few seconds, hence the sudden drop in kill line pressure (15), see figure 7.1. When the crew probably discovered that the well starts to flow, the pump was stopped immediately.

When a hydrate plug in a vertical open riser starts to move, this may start a chain reaction. As hydrostatic pressure gets lower more gas hydrates will dissociate and more liberated gas will increase the pressure below the plug. This pressure was probably the cause of the observed pressure increase on the standpipe pressure (16), see figure 7.1. At about 21:48 the first "spike" on the flow out meters can be observed. This may have been caused by the hydrate plug hitting the diverter housing. The second spike at about 45 seconds later, may have been caused by the diverter sequence closes the flow line valve.

7.2 Why did the BOP fail to prevent the blowout and fire?

The obvious answer to this question is that the first explosion and fire on Deepwater Horizon was probably caused by gas from the riser that came into the wellbore prior to the cement job. If a gas kick enters the riser undetected, the BOP located at the seabed will have no effect on gas that already have passed into the riser. In deep water this is particularly important because the gas will typically not expand before higher up in the riser, see figure 6.4.

In other words, the BOP failed to prevent the initial blowout and fire, because the gas kick that probably took place between April 16 and April 19 was not discovered. Previous investigation has concluded that the drilling crew must have failed to discover 1 000 bbls of gain, and that this was the reason for why hydrocarbon could enter the riser undetected. [7.5] However, this was not the case according to the observed real time data.

Probably the main contributing factor for why such a large gas kick required to have caused the initial explosion and fire, could enter the well undetected was that the kick detection system available on Deepwater Horizon was mainly based on gain. This method does not work in many cases when a gas kick occurs, see figure 4.10 and discussion in chapter 3 and 4.

The next question is why did the BOP fail to prevent the blowout to escalate after the initial explosions and fire? Gas hydrates in the subsea BOP probably also contributed to this. Without going into detail failure mode analysis of the complete BOP stack (see figure 5.17), the author will refer to earlier experience and conclusion done by Barker, J.W. and Gomez, R.K. (1989).

"Conclusions

1. Natural gas hydrates can cause major complications in deepwater drilling, as evidenced by experience in two wells, one in 1,150 ft [350 m] of water, the other in 3,100 ft [945 m].

2. Natural gas hydrates can be handled safely in deepwater wells. In neither of the two reported occurrences did the formation of hydrates cause human injury, uncontrolled flow, or pollution. The formation of gas hydrates increases risk and can be very costly.

3. Natural gas hydrates can plug the choke line and kill line, prevent the opening and closing of BOP's, seal wellbore annuli, and immobilize the drillstring. Once hydrates form a plug, they will not move under a pressure differential."

Gas hydrates may have contributed to the upper BOP annular did not close properly during the negative pressure test and during the final well control actions when the drilling crew started rig pump 4.

Gas hydrates probably contributed to variable bore rams did not close properly during the final well control actions.

Gas hydrates partly plugged the diverter housing, probably contributed to an attempt to divert the gas hydrates and riser blowout overboard through the starboard overboard line, see figure 2.5 and 2.6.

In previous investigations and examination of the subsea BOP stack, also the blind share ram was found to be activated. However, the drill pipe in the BOP was found to be off-center, see figure 7.2. [7.6] The CSB investigation report has concluded that this was likely caused by a result of increased internal pressure inside the drill pipe. [7.7] However, this theory of pipe buckling due to effective pressure differential between the inside and outside is probably wrong. A more likely and possible explanation for the off-center drill pipe, can be that gas hydrates also contributed to the fact that the drill pipe ended up being off center.

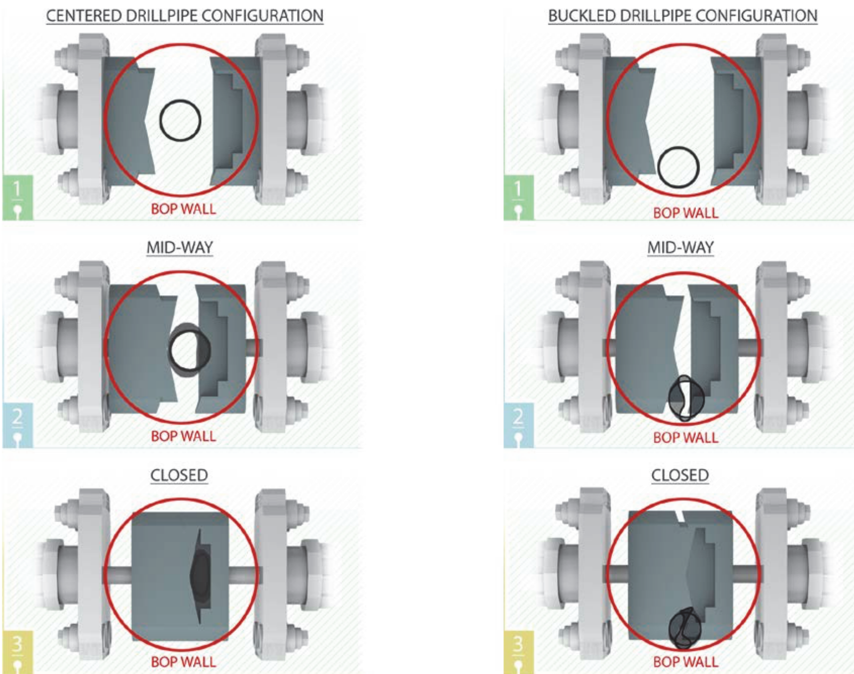


Figure 7.2 – Examination of the BOP stack found drill pipe to be off-center in the BSR [7.6]

At what time the upper BOP annular was closed, is not possible to see from the real time data. Probably there was no attempt to circulate up the riser after the drill crew shut down the rig pumps at about 21:30, see figure 6.5. Between 21:30 and 21:46 gas hydrates may have migrated in the seawater and got trapped under the BOP annular. The BOP annular was possibly closed by the drilling crew to perform the flow checks or closed shortly after. Between 21:46 and 21:47 the gas hydrates may have escaped up through the leaking BOP annular into the riser and seawater may have been drawn in from the kill line into the BOP, see figure 7.1.

During the final well control actions probably also a variable bore ram was activated. Gas hydrates may therefore have been trapped inside the BOP between a variable bore ram and the upper BOP annular preventer. If the choke side was packed with hydrates and the kill side was filled with seawater drawn in from the kill line, this may have contributed to bend the drill pipe. When the blind share ram (BSR) was activated the displaced volume from the rams going in will reduce the volume in the BOP. This may have resulted in seawater equal to the volume of the BSR escapes to the riser. However, the corresponding volume of solid gas hydrates trapped on the choke side has no way to go and may have pushed the drill pipe over to the kill side, driven by the hydraulic force of the BSR closing.

Chapter 8 – Main Contributions and Discoveries

Six years ago, I discovered that the two similar but different set of recorded flow out data of fluid returning from the riser beyond any reasonable doubt could not originate from the same sensor. In my opinion this was a major discovery. It implies that previous assumptions and conclusions that the Transocean flow meter sensor data sank with the rig was wrong.[8.1]

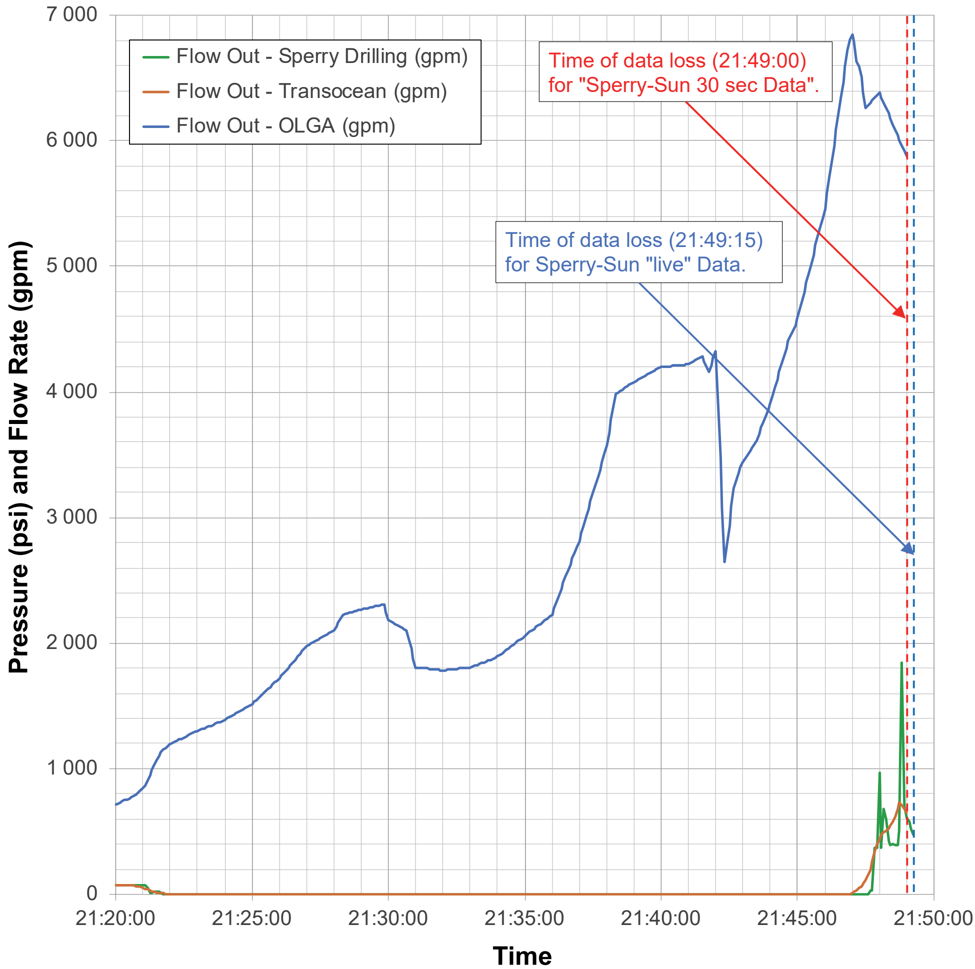


Figure 8.1 – OLGA® simulations compared with recovered real-time data.

Another important discovery was that several witness statements supports what the recovered flow meter data was telling us. The situation developed extremely fast. Flow from the riser started to come back only a couple of minutes before the first explosion, see figure 8.1 (red and green curves).

Previous investigation team has concluded that the drilling crew must have missed a cumulative gain of about 1 000 bbls before the first well control action was taken. Previous investigations have based this conclusion on OLGA® simulations and assumptions that thousands of gallons of fluids were returning from the riser every minute during the last 30 minutes before the explosion, see figure 8.1 (blue curve). However, this was not the case. Previous investigations have been based on wrong assumptions and conclusions. [8.2]

Two different and independent flow sensors are showing that the return flow ceases at about 21:21. This implies that the riser annulus must have been plugged. The purpose and motivation for my PhD work has been to find out why the riser was plugged and how an accident like the Deepwater Horizon disaster could occur. It is my hope that the major findings and discoveries listed in the next sections will contribute to a safer future. Reference is also made to *Chapter 9 – Conclusion and Recommendations*.

8.1 Gas hydrates plugging the riser annulus

To the best of my knowledge the only possible plug in the riser annulus that could cause a complete blockage in the riser and later cause rapid riser blowout and explosion is a gas hydrate plug. The fact that gas hydrates can plug choke and kill lines and wellbore annulus has previously been described by Barker and Gomez (1989), Grigg & Lynes (1992), Kotkoskie et al. (1992), Ebeltoft et al. (1997 & 2001) and Lage et al. (2002). The suggestion that gas hydrates contributed to plug the kill line during the negative pressure test on Deepwater Horizon has also been discussed before. [8.3] However, to my knowledge it is the first time the rapid riser blowout and explosion on Deepwater Horizon has been linked to gas hydrate dissociation and gas expansion. [8.4]

In order to form a plug of gas hydrates that seals off the riser annulus, large amount of gas is required. The most important contribution to improve safety and reduce non-productive time may therefore be the research work done to understand and explain how large amount of gas could enter the riser undetected, see chapter 8.2, 8.3 and 8.4.

8.1.1 Improved process safety standards for deep water MPD

When I in 2014 discovered beyond any reasonable doubt that the entire riser annulus had been plugged with gas hydrates, I decided to do what I could do to improve process safety if this happens again. One of the things I did was to join the International Association of Drilling Contractors (IADC) Underbalanced Operations (UBO) & Managed Pressure Drilling (MPD) Committee. My motivation for joining the committee was to learn from experienced industry leaders how current practice for MPD and in particular potential gas in riser was handled. The committee also provide recommended practice (RP) for the American Petroleum Institute (API) to ensure safe and efficient execution of UBO and MPD worldwide. My main contribution in this work has been to improve process safety standards by recommend a higher safety standard when managed pressure drilling (MPD) with a subsea BOP and applied surface backpressure is used. [8.5]

Previously process safety system standards such as API RP 14C (or ISO 10418) have been applicable to offshore production facilities and not for drilling operations that only inadvertently handle gas or other hydrocarbons. These process safety system standards describe the methods that should be used to protect against loss of containment of hydrocarbons or other hazardous materials. The system analysis methods should be used to determine safety requirements to protect any process component. A process component could be a flow segment such as the drilling riser. The drilling riser for a mobile offshore drilling unit with a subsea BOP is particular vulnerable since it is not designed for full reservoir shut-in pressure. An undesirable event could therefore be that the drilling riser are being exposed to overpressure.[8.6]

Overpressure of a process component may result in a leak and potentially uncontrolled release of hydrocarbon gas. Figure 8.2 is taken from the BP investigation report [8.7] and show how gas may have rapidly dispersed across the drilling rig from an uncontrolled release from a potential weak process component such as the riser slip joint.

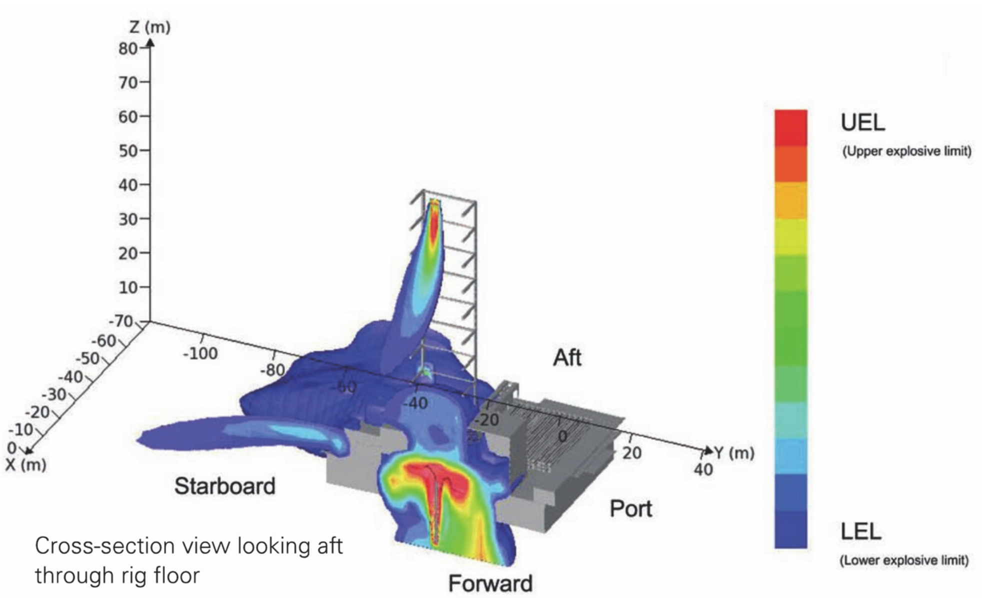


Figure 8.2 – Gas dispersion study (simulations). [8.7]

To protect the drilling riser from overpressure and potential uncontrolled release of hydrocarbon gas is particularly important when MPD operations, such as riser gas handling with surface back-pressure and a subsea BOP is carried out. That is why the new recommended practice (API RP 92S) for *Managed Pressure Drilling Operations – Surface Back-pressure with a Subsea Blowout Preventer*, states specifically that; "*The riser shall be protected from overpressure.*" [8.8]

One way of protecting the riser from overpressure would be to design the riser for full reservoir shut-in pressure. This is typically done during test production, were a dedicated test pipe from the wellhead to the rig floor is designed for full shut-in pressure. The downstream process components after the first shut-off valve are protected according to API RP 14C or ISO 10418. This can also be done for MPD operations with a subsea BOP (Vavik 2019A).

MPD operations from a floating drilling unit with a subsea BOP were the drilling riser is pressurized with surface back-pressure are commonly used. [8.9] In these cases it is important that the pressure protection system for the drilling riser is in accordance with API RP 14C or ISO 10418. [8.5] Figure 8.3 is a safety analysis table taken from API RP 14C. The table shows a typical exercise that shall be carried out as part of the required safety analysis to ensure that each process component is adequately protected. [8.10]

Table A.1—Flowline Segment Safety Analysis Table

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted line	High pressure
	Downstream choke plugged	
	Hydrate plug	
	Upstream flow control failure	
	Changing well conditions	
	Closed outlet valve	

Figure 8.3 – Safety analysis table for a process component taken from API RP 14C. [8.10]

A process component could be a flowline segment such as the drilling riser. To protect the drilling riser against overpressure, a pressure protection system that can handle all types of possible causes that may result in high pressure is required. A hydrate plug in the riser annulus or hydrate plug in top of the riser that is blocking all outlets from the riser are scenarios that shall be considered, see figure 8.3.

There are different ways that the riser can be protected from overpressure. One way is to install a pressure relief valve (PRV) in the bottom of the riser (Vavik 2018). Another way is to install a PRV system on the booster line since this line already is connected to the bottom of the riser (Vavik 2019B). In this way pressure can be relived from the bottom of the riser in the scenario were a hydrate plug in the riser or riser outlets is causing detectable abnormal high pressure in the riser.

8.2 Swap out

Swap out is a term not currently (March 2020) defined by PetroWiki, IADC Drilling Lexicon or Schlumberger Oilfield Glossary. In Appendix E the term ***Swap out*** has been defined by the author of this thesis as a general term when; *Drilling fluids or completion fluids are lost to the formation and is partly or totally replaced with formation fluids, typically natural gas.*

This thesis is discussing the different theories and different mechanism that may cause a swap out event to take place. I believe this phenomenon and the different ways this may occur when drilling for oil and gas is very important. To fully understand the different ways in which this phenomenon may occur, will result in a safer future and reduced non-productive time. Probably this phenomenon is also much more common than previously assumed. It is my hope that this thesis and the discussion and questions brought up will contribute to a better understanding.

The swap out phenomenon can be divided into two different main groups. Common for both types of swap out is that influx detection based on gain does not work. Swap out may also result in wellbore instability problems and stuck pipe.

8.2.1 Swap out caused by elevated pore pressure and high ECD

The theory or hypothesis that wellbore ballooning or breathing is caused by elevated or charged pore pressure is not new (Gill 1986). Resent publications also concludes that elevated or charged pore pressure is the root cause of wellbore instability problems such as wellbore caving (van Oort et al. 2019).

I hope that the discussion in chapter 3 may have contributed to a better understanding of the swap out phenomenon caused by elevated pore pressure. See also chapter *9.2.6 Further research on "ballooning" and "fracture breathing formation"*.

8.2.2 Swap out caused by loss and temporary annulus pressure drop

This is probably the most dangerous way of creating a swap out. Particularly in complicated wells with narrow drilling and cementing windows. It is dangerous because loss of fluid and gas influx typically occur simultaneously. Influx or kick detection based on gain would therefore not work. You may see abnormal pressure fluctuations on the standpipe pressure. However, these fluctuations may be concealed by expected pressure fluctuation caused by other phenomena occurring simultaneously for example when a cement wiper plug reaches a restriction. Gas influx and drilling fluid compressibility/elasticity may also eliminate or limit the observed standpipe pressure drop when the loss occurs.

I hope that the discussion in chapter 4 may have contributed to a better understanding of the swap out phenomenon initiated by loss of fluids and why it may be difficult to detect. See in particular figure 4.13 and 4.18.

It should also be noted that a loss of fluids to the formation may also be initiated when drilling into a fault or naturally fractured zone. Drilling operations in fractured carbonates, karst and gouge/rubble zone below salt are therefore particularly exposed to this kind of swap out initiated by loss.

8.3 Thermal effect on equivalent static density (ESD)

The fact that fluid density is affected by temperature is well known. However, that thermal effects probably caused the static Macondo well to go underbalanced between April 16 and April 19, 2010, came as a surprise to me. Although, there are many uncertainties in the simulations carried out by SINTEF, in particular with respect to fluids and solids thermal properties, it seems likely that a large amount of gas entered the wellbore during this period, see figure 3.20.

I hope that this discovery will contribute to increased awareness of thermal effects on ESD, particularly in deep water wells, and that more operators see the value in investing in a real time downhole PVT simulator in the future.

8.4 Gas solubility and hydrate formation

When gas influx in dense phase mixes with OBM it will go into a solution with the OBM (Skogestad et al., 2017). When the gas is dissolved in the OBM the volume occupied by the gas is reduced with approximately about 50%, see table 7 in Appendix D. A similar effect would occur again when or if gas hydrates are forming (Vavik et al. 2016, Table 2). When gas hydrates have formed the diffusion of gas may potentially cease, see figure 4.9 and discussion in chapter 4.2.3. These phenomena are important to consider when procedures for flow checks and influx detections are developed (Vavik 2017C).

There are some uncertainties and further research are recommended. A better understanding of dense gas diffusion and hydrate formations in SOBM and OBM in general would be beneficial. See chapter *9.2 Recommendations for further work* and in particular 9.2.1, 9.2.2, 9.2.3, 9.2.4 and 9.2.5.

Chapter 9 – Conclusion and Recommendations

This final chapter will cover the main conclusion and findings of the work related to this PhD thesis. A separate chapter with recommendations for further work is also included.

9.1 Conclusions

The root cause of the Deepwater Horizon disaster can be summarized in a few main bullet points. Based on the total amount of evidence, witness observation, simulations and experiments, these are the main findings that probably caused the disaster.

- The initial fatal explosion and fire on Deepwater Horizon came from hydrocarbon gas that entered the wellbore prior to the cement job.

- Probably tons of gas entered the Macondo Well during the static period between April 16 and April 19.

- The large gas kick was probably not discovered due to thermal effects, gas solubility in SOBM and possibly gas hydrate formation.

- Kick detection based on gain does not always work. Thermal effects, simultaneous loss of drilling fluids, hydrate formation, gas leaving the riser and "ballooning" may hide that a gas kick is ongoing. Improved methods for kick detection are strongly recommended, ref. chapter 9.2.1.

- Full bottoms up circulation was not carried out prior to the cement job. The final step of the bottoms up circulation (from riser and up) was not completed after the cement job and prior to the negative pressure test. This probably contributed to the fatal incident.

- The cement job was unsuccessful due to a crossflow event that probably occurred when the bottom wiper plug burst at the float collar. The high burst pressure probably fractured the formation and a large amount of fluids were lost to the formation. The loss was probably not discovered because of a simultaneous gas kick (influx) from the 14.16 ppg gas sand higher up in the wellbore. The 14.16 gas sand was underbalanced prior to bursting the bottom wiper plug.

- Real time data and witness observations confirms that the blowout occurred extremely fast. Tons of gas hydrates had probably been circulated up the drilling riser like a "Trojan horse" after the negative pressure test. Less than 3 minutes before the first explosion a hydrate plug in the upper part of the riser came out of control. The hydrate plug travels the last part of the riser driven by liberated gas from the dissociation process of gas hydrates.

- Gas hydrates partly plugging the diverter housing, probably contributed to an attempt to divert the gas hydrates and riser blowout overboard through the starboard overboard line failed.

- Gas hydrates probably plugged the tapered displacement string during the first negative pressure test. This confused the drilling crew to believe the first test was successful.

- Gas hydrates probably plugged the kill line during the second negative pressure test. This confused the drilling crew to believe the second test also was successful.

- Gas hydrates may have contributed to the upper BOP annular did not close properly during the negative pressure test and during the final well control actions.

- Gas hydrates probably contributed to variable bore rams did not close properly during the final well control actions.

- Gas hydrates may also have contributed to the fact that the drill pipe ended up being off center in the BOP and that the blind seal ram (BSR) did not seal properly.

9.2 Recommendations for further work

Recommendations for further work is both related to recommendations to prevent future blowouts and fire related to drilling, workover and completion. However, recommendations are also given for further research on some specific topics.

9.2.1 Enhanced early kick detection methods

The industry needs enhanced early kick detection (EKD) methods. EKD based on gain does not always work. The industry cannot solely rely on an EKD method that not always work.

As the drilling equipment and methods has been improved, such as managed pressure drilling (MPD), the industry is capable of drilling longer open wellbore section and challenging prospect with narrow drilling margin. However, longer open hole sections, horizontal wells and narrow drilling margins, increase the risk of getting simultaneous loss and gas kicks. Drilling fluids may get lost to the formation in a weak zone resulting in a gas kick higher up in the wellbore were ECD is suddenly lowered due to the sudden loss of drilling fluid to a weak zone.

The Oklahoma blowout and fire in 2018 may be one of many incidents were the drilling crew probably would have had benefits of an enhanced EKD system. One of the key issues in the CSB Investigation Report was that; "*Signs of Influx Either Not Identified or Inadequately Responded To*". [9.1] The author of this thesis recommends CSB to do further work and investigate *why* the influx was not discovered earlier. [9.2] Is it possible that the gas kick started simultaneously with a loss event occurring prior to the incident? [9.3]

9.2.2 Improved gas hydrate awareness

Barker, J.W. and Gomez, R.K. (1989), Botrel, T. (2001), Lage et al. (2002), Vavik et al. (2016) and Vavik et al. (2017A), are just examples on how important gas hydrate awareness are in conjunction with drilling and completion in deep water.

To improve hydrate awareness a thermohydraulic real time model (simulator) is recommended for deep water drilling operations. Not only for hydrate awareness but also to consider other thermal effects on the ESD. A minimum requirement should be real time monitoring of pressure and temperature in the annulus fluids at the subsea BOP.

See also *Method for Predicting Hydrate Formation* (Vavik, 2017B). This method will help to increase drilling personnel's awareness of gas hydrate formation and help the crew to take necessary preventive actions.

9.2.3 Further research on gas diffusion in SOBM in a static wellbore

Gomes et al. (2018), Manikonda et al. (2019), Skogestad et al. (2017) and Torsvik et al. (2017), have all contributed with important research in order to get a better understanding of gas influx behavior. When oil-based drilling fluids are used and the gas influx is in the dense phase region, the gas loading capability in the drilling fluid is unlimited (Skogestad et al., 2017). However, how fast will the gas diffuse in static vertical wellbore filled with SOBM? Will the diffusion process follow Fick´s law of diffusion? Will temperature and specific gravity affect the diffusion process? If the gas kick continue for days, will wt % gas be much higher closer to the influx?

9.2.4 Further research on how gas influx affects viscosity and barite sag

Torsvik et al. (2017), have documented how gas cut mud will affect viscosity. Saasen, A. (2002) have performed research on sag of weight materials in oil-based drilling fluids. Saasen writes in his paper:

"*Often, there is a danger for gas influx during drilling. The gas will in most cases be dissolved 100% into the drilling fluid. The result is a reduction in base oil viscosity and an increase in base oil volume down in the well. Within this scenario the drilling fluid is vulnerable for sag if the water fraction of the drilling fluid is low, say 20% or less. In this case it may be more efficient to use a thinner base oil such that the water fraction could be increased to 25-30%. With this higher water* *fraction the drilling fluid could adsorb larger gas influx volumes before the sag problem becomes problematic*." (Saasen, A., 2002)

Further research is recommended to find out if barite sag due to gas cut mud inside the production casing may have caused the float collar to plug, see figure 4.9.

9.2.5 Further research on hydrate formation in SOBM

Grigg and Lynes (1992) have made experiments on how oil-based mud (OBM) will lower the hydrate formation temperature, see figure 3.21. Further research on the SOBM used in the Macondo well is recommended. Unfortunately, required information on water and salt content for the SOBM used at Macondo was not available for this thesis.

Experiments on how hydrate formation in SOBM and OBM potential effect on barite sag, volume reduction and gas diffusion is also recommended.

Interesting research questions would typically be; Will the weight material attach to the hydrates or will it sag? Will the hydrate migrate or will hydrate/weight material sag? Will gas diffusion cease if the gas form hydrates?

9.2.6 Further research on "ballooning" and "fracture breathing formation"

The drilling crew on Deepwater Horizon experience ballooning when the final section was drilled. Further research to get a better understanding on how this phenomenon occurs is recommended.

Gill, J.A. (1986) introduced a hypothesis that these phenomena were caused by self-induced pore pressures:

"Perhaps, in such cases, we are imposing additional increments of pore pressure (on top of the natural pore pressure) when we drill long sections of already over-pressured (wet, plastic) shales in a greatly overbalanced condition (which is no longer easily recognizable as overbalance); causing the borehole to balloon, or breathe." (Gill, J.A., 1986)

The author of this thesis support Gill´s hypothesis that ballooning or breathing is caused by superimposed or elevated pore pressure (compression of fluids), rather than geo-mechanical opening and closure of fractures, ref. discussion in chapter 3.

Further research is recommended so that the industry can have a common understanding and consensus of what is causing these observed phenomena.

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Appendix A

Abbreviations and Acronyms

Abbreviations and Acronyms

APD	Annular Pressure while Drilling
API	American Petroleum Institute
bbl	US oil barrel
bbls	US oil barrels
BHP	Bottom-hole pressure
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement
BOP	Blow-out preventer
BSR	Blind shear ram
C&K	Choke and kill
DTD	Diverter test device
ECD	Equivalent circulating density
EKD	Early kick detection
ESD	Equivalent static density
FIT	Formation integrity test
GoM	Gulf of Mexico
gpm	Gallon per minute
HPHT	High pressure high temperature
IADC	International Association of Drilling Contractors
ISO	International Organization for Standardization
LCM	Lost circulation material
LMRP	Lower marine riser package
LWD	Logging while drilling
MD	Measured depth
MGS	Mud gas separator
ML	Most likely
MMS	Minerals Management Service
MPD	Managed pressure drilling

MW	Mud weight
MWD	Measurement while drilling
OBDF	Oil-based drilling fluids
OBM	Oil-based mud
PRV	Pressure relief valve
psi	Pound per square inc
RP	Recommended practice
RKB	Rotary kelly bushing (drillfloor level)
ROP	Rate of penetration
SOBM	Synthetic oil-based mud
SPE	Society of Petroleum Engineers
SPP	Standpipe pressure
TVD	True vertical depth
TVDKB	True vertical depth kelly bushing
UBO	Underbalanced operations

Appendix B

Endnotes

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Table of Contents Endnotes

Endnotes

Chapter 1 – Introduction

1.1 Deepwater Horizon oil spill, from Wikipedia.
https://en.wikipedia.org/wiki/Deepwater_Horizon_oil_spill

1.2 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 106, figure 18. "*Annular preventer activated. Cumulative gain at 21:41 ~ 1,000 bbls*".

1.3 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 96, figure 11 and page 94, table 1.

1.4 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, page 111, table 1.

1.5 Gharles Credeur Testimony, C-Span video. See from time 07:30 to 07:40 in the video:
"*When we got back to the main pipe deck and turned the corner on the handrail, all the lights went off, and a second or two later I heard the first explosion*."
https://www.c-span.org/video/?293803-1/investigation-deepwater-horizon-explosion-charles-credeur-testimony

1.6 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, Hydrocarbons Ignited on Deepwater Horizon, page 111, table 1. According to this analysis (table 1 in the BP Report) mud overflowed onto the drill floor at approximately 21:40 and mud shuts up to the crown block at approximately 21:41. This is several minutes before witness observed this event, ref. chapter 2.3.3.

Chapter 2 – Pattern of Anomalies

2.1 Gulf of Mexico Oil Spill Report, Day 2, Scientific Experts, C-Span video, November 9, 2010. See Frances Ulmer questions to the experts from time 1:17:18 to 1:18:20 in the video. https://www.c-span.org/video/?296487-1/gulf-mexico-oil-spill-report-day-2-scientific-experts

2.2 Gulf of Mexico Oil Spill Report, Day 2, Scientific Experts, C-Span video, November 9, 2010. See the last part of drilling expert Steve Lewis long answer to Frances Ulmer questions from time 1:25:40 to 1:26:30 in the video. https://www.c-span.org/video/?296487-1/gulf-mexico-oil-spill-report-day-2-scientific-experts

2.3 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 180. "*Drill Crew Notices Anomaly but Does Not Treat It as a Kick*".

2.4 An excel file containing real-time data from the last two hours is used to generate some of the figures in this thesis. The excel file was generated by Transocean after the incident. The excel file has been named by Transocean to "*Sperry Sun 30 sec Data*". The reason for this name is not known. The excel file apparently contains real-time data for transmitters collected from Tranocsean (Hitec) sensors, such as pump stroke, pit levels, hock load, etc. Data are given for every 5 seconds. The last 6 datapoints are at 21:48:35, 21:48:40, 21:48:45, 21:48:50, 21:48:55, 21:49:00. The last data set recorded in this excel file ("*Sperry Sun 30 sec Data*") are 21:49:00. A column called "Flow Out Avg (gpm)" is also in this set of real-time data. This data set may be from the Transocean (Hitec) sensor and the value presented may be the average value in the last period of five seconds. The excel file does not contain a second set of flow out data or data from the Sperry-Sun installed gas sensor.

2.5 The loss of fluid is calculated from the "*Sperry Sun 30 sec Data*" excel file based on total flow in derived from stroke counter on the mud pumps, minus the recorded flow out.

2.6 John Gisclair Testimony, Part 1, C-Span video. See from 04:15 to 04:23 in the video of the testimony. "*The Flow In is a calculated measurement based on the volume output of the pumps, plus their stroke rate*." https://www.c-span.org/video/?295902-3/deepwater-horizon-incident-joint-investigation-john-gisclair-testimony-part-1

2.7 Greg Meche Testimony, C-Span video. See from 05:55 to 06:23 in the video of the testimony:
"*At this point I´am watching our drill screen, which you know gives the information that I need for me to go outside, like you said, to do what I needed to do. Eh.., so from 5:30 until, I guess it was about, close to 9 pm, I noticed that the stroke count, which is the number I was looking for, was at.., in the range where I needed to go out and be present*."
https://www.c-span.org/video/?293776-3/investigation-deepwater-horizon-explosion-greg-meche-testimony

2.8 Greg Meche Testimony, C-Span video. See from 02:38 to 02:50 in the video of the testimony:
"*…anything, that we.., that is going into the water, has to.., has to be tested or…, approved I guess, by me*."
https://www.c-span.org/video/?293776-3/investigation-deepwater-horizon-explosion-greg-meche-testimony

2.9 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.6 | Negative Pressure Test, page 151, second paragraph. "*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."*

2.10 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.3.5, page 127.

2.11 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 180. "*Drill Crew Notices Anomaly but Does Not Treat It as a Kick"*

"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. Revette, sitting in the driller's A-chair, and Anderson, standing next to him, were speaking to each other. At times, they looked at the driller's screens. Revette noted that they were "seeing a differential". The two men appeared concerned but calm. According to Young, "It was quiet... there was no panic or anything like that.""

2.12 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 180. "*Drill Crew Notices Anomaly but Does Not Treat It as a Kick"*

"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 - apparently to eliminate the differential pressure. At 9:36 p.m., Holloway cranked open a valve on the standpipe manifold to bleed down the pressure. But it was taking longer than usual to bleed off. Revette told Holloway, "Okay, close it back.""

2.13 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.4 Blowout Preventer (BOP), page 144, Figure 8, *Deepwater Horizon Diverter System*.

2.14 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Section 3. Chronology of the Accident, page 28. *"~21:44 hours—Toolpusher called well site leader and stated they were "getting mud back" and that they had "diverted to the mud gas separator" and had either closed or were closing the annular preventer."*

2.15 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.2 Temporary Abandonment, page 108, last sentence. "*At approximately 9:49 p.m., the real-time Sperry Sun data feed to shore ended. It is assumed that the rig lost power at this time."*

2.16 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, page 111, table 1. *"21:49:15 hours – Power lost on Deepwater Horizon – Anchor Point".*

2.17 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 101, figure 15. The real-time data shows that flow out came back during the last two minutes, before loss of power at 21:49:15.

2.18 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, page 119, figure 6. *"Photograph of Starboard Overboard Lines."*

2.19 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Executive Summary, page 11, key finding no. 5 *"**5 Well control response actions failed to regain control of the well**. The first well control actions were to close the BOP and diverter, routing the fluids exiting the riser to the Deepwater Horizon mud gas separator (MGS) system rather than to the overboard diverter line. If fluids had been diverted overboard, rather than to the MGS, there may have been more time to respond, and the consequences of the accident may have been reduced."*

2.20 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 104, second bullet point. "*The TWCH allowed diversion to the MGS in certain well control situations. However, the handbook stated 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.""*

2.21 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, page 120, figure 7. *"Deepwater Horizon Photograph Showing a Starboard Jet Flame."*

2.22 Miles "Randy" Ezell Testimony, C-Span video. See from 44:37 to 46:35 in the video of the testimony. https://www.c-span.org/video/?293776-4/investigation-deepwater-horizon-explosion-haire-ezell-testimony

2.23 Miles "Randy" Ezell Testimony, C-Span video. See from 44:14 to 44:22 in the video of the testimony:
"*So I went to my cabin which is, ehh…, a short distance, probably 5 feet away from the tool pushers office."*
https://www.c-span.org/video/?293776-4/investigation-deepwater-horizon-explosion-haire-ezell-testimony

2.24 Plous, Scott (1993), The Psychology of Judgment and Decision Making, p. 233

2.25 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 91, Chapter 3.1 Simultaneous Activities. "*Other simultaneous operations, such as preparing for the next operation (setting a cement plug in the casing) and bleeding off the riser tensioners, were occurring and may have distracted the rig crew and mudloggers from monitoring the well."*

2.26 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 95, figure 9 and figure 10 and figure 13 on page 98. The real-time data shows that flow out continues not only after the pumps were shut down, but also after the Sperry-Sun flow out meter should have been bypassed. The flow continued for at least 11 minutes. However, this anomaly has not been commented on or explained. Likewise, why the Sperry-Sun flow out suddenly came back during the last two minutes has not been commented on or explained, ref. figure 15 on page 101.

2.27 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 94, table 1.

2.28 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 169 and 170.

2.29 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 170, second paragraph.

2.30 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 170, figure 4.7.5. "*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*."

2.31 John Gisclair Testimony, Part 1, C-Span video. See from 17:45 to 17:53 in the video of the testimony for the question from commission member Jason Mathews; "*Do you know specifically were the meters, that is the Sperry meters one, where they were actually located for flow-in and flow-out on the Deepwater Horizon?"*
The answer from John Gisclair about the location of the Sperry-Sun flow meter can be heard from 18:04 to 18:15. "*The flow-out sensor for Sperry was located a couple of feet, ahh…, it was located on the return line a couple of feet before the return line enters the gumbo box*."
https://www.c-span.org/video/?295902-3/deepwater-horizon-incident-joint-investigation-john-gisclair-testimony-part-1

2.32 John Gisclair Testimony, Part 2, C-Span video. See from 16:08 to 17:00 in the video of the testimony for the explanation from John Gisclair about why their own Sperry-Sun flow-out sensor did not detect any flow. The testimony was given October 8, 2010, according to C-span link below. That is one month after BP Deepwater Horizon Accident Investigation Report, was published on September 8, 2010.
https://www.c-span.org/video/?295902-4/deepwater-horizon-incident-joint-investigation-john-gisclair-testimony-part-2

2.33 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 191, figure 4.7.12.

2.34 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 182, third paragraph.

2.35 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Page 14, last paragraph.
https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

2.36 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 96, Chapter 3.3 Prepared to Discharge Fluid Overboard. "*At 21:14 hours, after concluding that the sheen test was successful, the rig crew resumed pumping to continue displacement of the well to seawater and to discharge the spacer fluid overboard.*"

2.37 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 95, figure 9.

2.38 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Page 13, paragraph 6 from the top.
https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

2.39 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Page 14, first paragraph.
https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

2.40 Greg Meche Testimony, C-Span video. See from 07:22 to 07:37 in the video of the testimony:
"*I meet with a couple of guys that were at the…, we call the gumbo box, it's in the shaker house,* and, ehh…, *I actually got up there at almost perfect timing, within ten minutes I actually caught my sample.*"
https://www.c-span.org/video/?293776-3/investigation-deepwater-horizon-explosion-greg-meche-testimony

2.41 Greg Meche Testimony, C-Span video. See from 08:23 to 08:27 in the video of the testimony:
"My sample was caught at 21:16, 9.16 pm."
https://www.c-span.org/video/?293776-3/investigation-deepwater-horizon-explosion-greg-meche-testimony

2.42 Greg Meche Testimony, C-Span video about the time of completing the test. See from 33:35 to 36:04 in the video of the testimony:
https://www.c-span.org/video/?293776-3/investigation-deepwater-horizon-explosion-greg-meche-testimony

2.43 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 94, table 1 and page 95, figure 10. "*Overboard line opened/Sperry-sun flow meter bypassed.*"

2.44 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, Hydrocarbons Entered the Well Undetected and Well Control Was Lost, page 90, first paragraph.

2.45 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 95, figure 38.

2.46 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, Hydrocarbons Ignited on Deepwater Horizon, page 113, figure 1.

2.47 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, Hydrocarbons Ignited on Deepwater Horizon, page 111, table 1.

2.48 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, Hydrocarbons Ignited on Deepwater Horizon, page 111, first paragraph.

2.49 Gharles Credeur Testimony, C-Span video. See from time 05:52 to 10:00 in the video:
https://www.c-span.org/video/?293803-1/investigation-deepwater-horizon-explosion-charles-credeur-testimony

2.50 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C, Hydrocarbons Ignited on Deepwater Horizon, page 132, figure 18 and page 134, figure 20.
The two layout drawings in the BP report of rig floor (El. 46 000) and main deck (El. 41 500) have been used to estimate the length of Creduor´s walk on main deck prior to the explosion.

2.51 The New York Times has made an interview with Caleb Hollooway on how he managed to escape from the Deepwater Horizon. Holloway were working on the starboard aft deck at the same time as Credour was working on the port aft deck. Holloway; "*I so a start of a blowout and I said, oh shit, and took of running.*" He ran from the starboard aft, a detour up the stairs to the rig floor elevated 4.5 meters above the main deck, where he could see the blowout from the center of the rig floor. "It was just everywhere. It was blowing up so intense that is was just bouncing off of everything." Shortly after he smelled gas. "*GAS.., just felt it, all over me, I felt it, and I smelled it, tasted it and I just knew that.., that was bad! And..., that´s when I kind of panicked a little bit, and I looked at Daniel, and I said; Daniel that´s gas, we have to get out of here*!"

The interview and a 3D animation by New York Times of the escape can be seen on YouTube.
https://www.youtube.com/watch?v=0I44ok9vYp0

2.52 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, Hydrocarbons Entered the Well Undetected and Well Control Was Lost, page 106, figure 18. "*Annular preventer activated. Cumulative gain at 21:41 ~ 1,000 bbls*".

2.53 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, Hydrocarbons Entered the Well Undetected and Well Control Was Lost, page 94, table 1.
"*Data available - Transocean Flow Meter should have indicated flow*".

2.54 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.3 Drill Floor Activities, page 121, figure 4, *Sheen Test on Simulated Hitec Screen*.

2.55 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.3.8 Drill Pipe Bleed and Recognition of Influx, page 130.
"*At 9:36 p.m., the driller instructed a floor hand to bleed the drill pipe on the standpipe manifold, and for the next one-and-a-half minutes, flow was taken from the drill pipe. Based on the experience and work of the investigation team, the team concluded that the action taken to bleed pressure from the drill pipe is consistent with a belief by the driller that a plug existed.*"

2.56 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, Hydrocarbons Entered the Well Undetected and Well Control Was Lost, page 106, last paragraph. "*When the annular preventer was activated at approximately 21:41 hours, the model estimated the influx volume to be approximately 1,000 bbls. By the time the explosion occurred at approximately 21:49 hours, the model estimated the gain to be approximately 2,000 bbls.*"

2.57 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.3.8 Drill Pipe Bleed and Recognition of Influx, page 130.
"*At this time, the well had taken more than 385 bbl of fluid from the formation and was flowing at more than 38 bpm…*"
This conclusion (that the well was flowing) is based on hydraulic analysis (simulations) carried out by Stress Engineering Services Inc. (Vol 2, Appendix G in the Transocean report).

Although the Transocean investigation team concluded that the action taken to bleed down the standpipe pressure *is consistent with a belief that a plug existed*, ref. endnote 2.55, the investigation team apparently have chosen to believe in the hydraulic analysis (simulations). Rather than believe in the real-time data showing no flow from the riser, the investigation team seems to believe that the well "*was flowing at more than 38 bpm…*" .

2.58 BOEMRE Report Regarding the Causes of the Aril 20, 2010 Macondo Well Blowout, September 14, 2011. *Page 109.*
"A. Kick Detection and Response Failure Cause
At approximately 9:42 p.m., the crew detected flow and diverted the gas influx from the well to the mud gas separator in accordance with the Transocean well control manual."

Although real-time data show no flow from the riser at 9:42 pm, and even after several testimonies are describing that flow from the riser was observed approximately six minutes later (9:48 pm), BOEMRE has concluded that it was flow from the riser at 9:42 pm.

2.59 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 181.
"***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."

Although real-time data show no flow from the riser between 9:40 and 9:43 pm, and even after several testimonies are describing the observed flow from the riser was later (9:48 pm), CCR has concluded that it was flow from the riser sometime between 9:40 and 9:43 pm.

2.60 The time of first return of flow from the riser at 21:46:35 is taken from the "*Sperry-Sun 30 sec Data*", which is the real-time data Transocean used in their investigation report. At 21:46:35 a recorded flow through the flow out meter of 0.1 gpm was recorded. This is probably the average recorded flow out between 21:46:30 and 21:46:35, since data is only given every 5 seconds. The kill line pressure starts to drop suddenly at 21:46:25. It may be a connection between pump start at 21:46:00, sudden drop in kill line pressure at 21:46:25, slowly increase in flow out at 21:46:35 and pump stop again at approximately 21:46:45. The flow out increased slowly to a rate of 14 gpm at 21:47:00, then it starts to increase more rapidly to 407 gpm at 21:47:55. The real-time data used in the BP report also show spikes of flow at 21:48:00. See real-time data in figure 1.3, for more detail.

Chapter 3 – The Macondo Well

3.1 The actual casing run shown in figure 3.1 is taken from the BP report, see endnote C.2. The pore pressure prediction (14.16 ppg) and depth of the highest gas sand in the open wellbore, is taken from an unpublished BP report of July 26, 2010 and reprinted and published with BP permission by National Academy of Engineering and National Research Council in 2012, see endnote C.1. Depth for this thin (14.16 ppg) gas sand layer is estimated from the same pore pressure prediction, see figure 3.3 in the main thesis.

3.2 Transocean driller Micah Burgess Testimony, C-Span video. See from 28:47 to 29:04 in the video of the testimony:
Question: "*When you had been on the rig for the duration of the well, did you feel that this well had more balloon effects than any other well?*"
Answer from Burgess: "It was a difficult well, I don´t….., I wouldn´t say it was…, proportion to other…., some..., *it was difficult*."
https://www.c-span.org/video/?293803-2/investigation-deepwater-horizon-explosion-micah-burgess-testimony&start=1390

3.3 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.2 | Well Design, page 59, figure 4.2.8.

3.4 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Section 2, The Macondo Well, page 17, last paragraph.

3.5 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.2 | Well Design, page 60, first sentence in third paragraph.

3.6 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Endnotes, page 269, note 49 in Chapter 4.2.

3.7 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*F. Well Ballooning"*, page 34, second paragraph.

3.8 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*E. Mud Losses"*, page 33, Last paragraph.

3.9 National Academy of Engineering and National Research Council. 2012. *"Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety*", Fig. 2.3, page 23. Washington, DC: The National Academies Press.
https://doi.org/10.17226/13273

3.10 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, Hydraulic Analysis of Macondo #252 Well Prior to Incident of April 20, 2010, page 27, Note 1, in the bottom of the page:
"*Note that the nominal surface density of the SOBM is 14.00 ppg; however, its actual measured average density in the well, which is used for all calculations herein, is 14.17 ppg (due to compressibility). The terms 'SOBM', 'mud', '14 ppg mud', etc. are used interchangeably herein; all refer to 14.17 ppg synthetic oil-based mud*."

3.11 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.2 | Well Design, page 60.
"*Rig Crew Calls Total Depth Early Due to Narrow Drilling Margin*" third sentence:
"*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*."

3.12 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*B. Drilling Margin"*, page 30, last paragraph. The BOEMRE report is referring to an internal BP email on April 13, one week before the accident:
"We had one major problem however: the sand that we took the initial GeoTap pressure in was measured at 14.15 ppg. The absolute minimum surface mud weight we could use to cover the pore-pressure in this sand was 14.0 ppg. This would give us approximately a 14.2 ppg ESD over the aforementioned sand. If we were to drill ahead with a 14.0 surface mud weight/14.2 ESD, our equivalent circulating density (ECD) would be approximately 14.4-14.5 ppg. We had already experienced static losses with a 14.5 ppg ESD! It appeared as if we had minimal, if any, drilling margin… Drilling ahead any further would unnecessarily jeopardize the wellbore. Having a 14.15 ppg exposed sand, and taking losses in a 12.6 ppg reservoir in the same hole-section had forced our hand. We had simply run out of drilling margin."

3.13 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*F. Well Ballooning"*, page 34.

3.14 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*F. Well Ballooning"*, page 34, first paragraph.

3.15 DrillingFormulas.com. Well ballooning (wellbore breathing or micro fracture). http://www.drillingformulas.com/well-ballooning-wellbore-breathing-or-micro-fracture/

3.16 Dam Breach Experiment: Failure of a Model Dam. https://youtu.be/RcNqv0dm2lA

3.17 BSEE investigation report, figure 39, page 65. https://www.bsee.gov/sites/bsee.gov/files/panel-investigation/incident-and-investigations/st-220-panel-report9-8-2015.pdf

3.18 DrillingFormulas.com. Estimate gas migration rate in a shut in well. http://www.drillingformulas.com/estimate-gas-migration-rate-in-a-shut-in-well/

3.19 Investopedia.com. Outcome Bias. https://www.investopedia.com/terms/o/outcome-bias.asp

3.20 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 168, last paragraph.

3.21 Mike Williams Testimony, C-Span video. See from 37:32 to 37:40 in the video of the testimony.
Question from interviewer Jason Mathews: *".... she referred to this well as; Quote: "Well from hell", have you heard that term before?*"
https://www.c-span.org/video/?294728-1/investigation-deepwater-horizon-explosion-mike-williams

3.22 Mike Williams Testimony, C-Span video. See from 38:24 to 38:37 in the video of the testimony.
https://www.c-span.org/video/?294728-1/investigation-deepwater-horizon-explosion-mike-williams

3.23 U.S. Chemical Safety and Hazard Investigation Board (CSB), Investigation Report, Drilling Rig Explosion and Fire at the Macondo Well, Volume 3, page 182, last paragraph.
"*The outputs of the risk register for the Macondo well were used to create a risk rating matrix. BP determined in the Macondo risk matrix that the impact of an uncontrolled well control event—just considering cost—would be "medium," judged to be $1-3 million based upon the team's subjective evaluation that comparable events were within their direct experience. However, the case was not a well control event involving a kick and blowout, but rather a lost wellbore due to an unspecified problem within the well, presumably due to stuck pipe or lost circulation; in fact, both did occur earlier in the Macondo well. The risk register also listed PP/FG (pore pressure/ fracture gradient) uncertainty as a risk, implying a possible kick, but one that would be controllable and therefore a "medium" risk for cost.*"

3.24 SPE Petroleum Engineering Handbook (PEH)*: Geomechanics Applied to Drilling Engineering*, chapter 5, *Building the Geomechanical Model,* figure 1.39.
https://petrowiki.org/PEH:Geomechanics_Applied_to_Drilling_Engineering#cite_note-r22-22

3.25 Poroelasticity as defined by Multiphysics Cyclopedia:
https://www.comsol.com/multiphysics/poroelasticity

3.26 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*B. Drilling Margin*", figure 2, page 30.

3.27 Annular Pressure while Drilling (APD) at 17 761 ft:
15.00 ppg = 15.00 x 119.85 kg/m3 = **1 798 kg/m3**.
17 761 ft = 17 761 x 0.3048 m = **5 414 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = ρ x g x h = **95.49 MPa = 954.9 barg (13 850 psi).**

Expected APD at 17 761 ft:: 15.20 ppg = 15.20 x 119.85 kg/m3 = **1 822 kg/m3**.
17 761 ft = 17 761 x 0.3048 m = **5 414 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = ρ x g x h = **96.77 MPa = 967.7 barg (14 035 psi).**

Reduction in downhole pressure is (967.7 -954.9) = 12.8 bar (185 psi).

3.28 Annular Pressure while Drilling (APD) at 17 500 ft:
15.10 ppg = 15.10 x 119.85 kg/m3 = **1 810 kg/m3**.
17 500 ft = 17 500 x 0.3048 m = **5 334 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = ρ x g x h = **94.71 MPa** = **947.1 barg (13 737 psi).**

3.29 Equivalent Static Density (ESD) at 17 435 ft:
14.60 ppg = 14.60 x 119.85 kg/m3 = **1 750 kg/m3**.
17 435 ft = 17 435 x 0.3048 m = **5 314 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = ρ x g x h = **91.23 MPa** = **912.3 barg (13 232 psi).**

3.30 Pore pressure 14.16 ppg Gas Sand:
14.16 ppg = 14.16 x 119.85 kg/m3 = **1 697 kg/m3**.
17 435 ft = 17 435 x 0.3048 m = **5 314 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = ρ x g x h = **88.47 MPa** = **884.7 barg (12 831 psi).**

3.31 BP *Deepwater Horizon* Accident Investigation Report, September 8, 2010, page 64, third paragraph, last sentence. *"The interpretation of fluid content was deemed uncertain, but it was probably water (brine)."*

3.32 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 165.
"***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.*"

3.33 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Section 2, The Macondo Well, page 18, first paragraph.

3.34 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. On page 78, third paragraph, third and fourth sentence.
"*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. After circulating on April 16, gas eventually decreased to 20 to 30 units.*"

3.35 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. On page 78, third paragraph, fifth sentence.
"*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.*"

The source or justification for this statement that this was not an unusual amount of gas for a static well, was described by endnote 52 in the CCR. Endnote 52, in Chapter 4.3 states:
"*Confidential source, interview with Commission staff.*"

3.36 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report.
Se last paragraph of the section covering real-time data review from period 00:00 to 00:30 on April 20, page 5:
"*Significant increases in gas units during this period, to levels exceeding that when drilling non-productive formations, implies that trip gas from previous trip out of the hole had not been circulated out prior to the cement job. However, assessment of pre-job preparations is outside the scope of this review.*"
https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

3.37 Pore pressure in top of the 14.16 ppg Gas Sand:
PP Gas sand = 14.16 ppg = 14.16 x 119.85 kg/m^3 = **1 697 kg/m3**.
17 435 ft = 17 435 x 0.3048 m = **5 314 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pore pressure gas sand = ρ x g x h = **88.47 MPa** = **884.7 barg (12 831 psi).**

3.38 Overbalance pressure in top of the 14.16 ppg Gas Sand 4 minutes after pump stop: ESD = 14.17 ppg = 14.17 x 119.85 kg/m^3 = **1 698 kg/m3**.
17 435 ft = 17 435 x 0.3048 m = **5 314 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Static pressure in well = ρ x g x h = **88.52 MPa** = **885.2 barg (12 838 psi).**
Overbalance in top of gas sand = (885.2 – 884.7) = **0.5 bar (7 psi).**

3.39 Underbalance pressure in top of the 14.16 ppg Gas Sand 18 minutes after pump stop: ESD = 14.09 ppg = 14.09 x 119.85 kg/m^3 = **1 689 kg/m3**.
17 435 ft = 17 435 x 0.3048 m = **5 314 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Static pressure in well = ρ x g x h = **88.05 MPa** = **880.5 barg (12 770 psi).**
Underbalance in top of gas sand = (884.7 – 880.5) = **4.2 bar (61 psi).**

3.40 John Guide Testimony, C-Span video. See Mr. Guide answer from time 00:45 to 02:06 in the video:
"*We were actually drilling the well, we got to the depth of 18 260 ft, which was not TD yet, and it appeared that the underreamer was worn out, and we circulated bottoms up a couple times, getting all the cuttings out, and what we routinely do is once we get the cuttings out, the ECD is lower, so we add a little bit of mud weight to replace that, so when the static mud weight…, it´s equal, and when we did that, everything was fine and all of a sudden, we just lost complete returns. The biggest risk that was associated with this cement job was losing circulations. That was the, No. 1 risk. So, based on the fact that we had lost circulation, just LIKE THAT, out of the clear blue, we decided to go ahead and ahhh… Get circulation established, and then…ahh, because of the actual volumes, we would actually have bottoms up ABOVE the wellhead, once the ahhh…, once the cement was in place, and then we would be able to circulate that up to see if there was any gas. So that was our plan.*"
https://www.c-span.org/video/?294696-2/investigation-deepwater-horizon-explosion-john-guide-testimony

3.41 The simulated hydrate equilibrium curves for freshwater and seawater was perform by Martin Fossen at SINTEF laboratory at Tiller, Trondheim, Norway. The simulation was carried out in conjunction with a hydrate formation experiment carried out in the SINTEF laboratory in collaboration with Future Well Control AS. The gas composition in the table to the left was used in the simulation. The table to the right was the gas composition used in the Grigg and Lynes experiment (Grigg & Lynes 1992, Table 1).

Component	Mol %
Methane	84.17
Ethane	5.49
Propane	2.63
i-butane	0.42
Nitrogen	6.79
CO2	0.50

Component	Mol %
Methane	87.27
Ethane	7.59
Propane	3.09
i-butane	0.49
n-butane	0.79
i-pentane	0.19
n-pentane	0.19
Nitrogen	0.39

3.42 PetroWiki by SPE, Drilling fluid types. Chapter 1.3 Oil-based fluids.
https://petrowiki.org/Drilling_fluid_types#Oil-based_fluids

3.43 Equivalent Static Density (ESD) at wellhead, see figure 3, Appendix D:
14.20 ppg = 14.20 x 119.85 kg/m^3 = **1 702 kg/m3**.
5 060 ft = 5 060 x 0.3048 m = **1 542 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pressure at wellhead (p) = ρ x g x h = **25.75 MPa** = **257.5 barg (3 735 psi).**

3.44 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Endnotes, page 305, note 91 in Chapter 4.6.

3.45 Pore pressure Pay Sand: 12.56 ppg = 12.56 x 119.85 kg/m^3 = **1 505 kg/m3**.
18 223 ft = 18 223 x 0.3048 m = **5 554 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pressure (p) = ρ x g x h = **82.00 MPa** = **820.0 barg (11 893 psi).**

Chapter 4 – Running and Cementing the Casing

4.1 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 26, Chapter 2.1 Running Production Casing, third paragraph, first sentence.

4.2 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 26, Chapter 2.1 Running Production Casing, fourth paragraph, first sentence.

4.3 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 26, Chapter 2.2 Converting the Float Collar, second paragraph.

4.4 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 49, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, figure 9.

4.5 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 26, Chapter 2.2 Converting the Float Collar, note B bottom of page 26.

4.6 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. Page 90, second paragraph, second and third sentence.

4.7 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 49, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, last paragraph.

4.8 See link to Wikipedia for history of the Minerals Management Service:
"*The **Minerals Management Service (MMS)** was an agency of the United States Department of the Interior that managed the nation's natural gas, oil and other mineral resources on the outer continental shelf (OCS).*

*Due to perceived conflict of interest and poor regulatory oversight following the Deepwater Horizon oil spill and Inspector General investigations, Secretary of the Interior Ken Salazar issued a secretarial order on May 19, 2010 splitting MMS into three new federal agencies: the Bureau of Ocean Energy Management, the Bureau of Safety and Environmental Enforcement, and the Office of Natural Resources Revenue. MMS was temporarily renamed the **Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE)** during this reorganization before being formally dissolved on October 1, 2011.*"
https://en.wikipedia.org/wiki/Minerals_Management_Service

4.9 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Endnotes, page 279, note 176 in Chapter 4.3:

“ 176 Internal BP document (BP-HZN-MBI 129221). MMS approved a regulatory dispensation that modified the standard testing regime for the diverter sealing element at Macondo. Internal BP document (BP-HZN-OSC 512). The Chief Counsel‘s team has not found evidence suggesting that this dispensation affected the ability of the diverter sealing element.”

4.10 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – *Chapter 3: Background on the Macondo Well, the Deepwater Horizon, and the Companies Involved*. Page 34, last paragraph.

4.11 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 49, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, last paragraph.

4.12 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 50, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, figure 10.

4.13 The text in the figure (“Pressure up to 1,000 psi”) taken from figure 10 on page 50 in the Tramsocean report is an error. The correct pressure is shown to the right of the diagram. The correct pressure should have been pressure up to 1 220 psi, then it falls after pump shut down to 1 175 psi (45 psi drop).

4.14 Equivalent Static Density (ESD) at 2 500 ft is estimated to 14.1 ppg. This is based on surface mud density of 14.0 ppg and wellhead average density of 14.20 ppg, see figure 3, Appendix D:
14.1 ppg = 14.1 x 119.85 kg/m^3 = **1 690 kg/m3**.
2 500 ft = 2 500 x 0.3048 m = **762 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pressure at wellhead (p) = ρ x g x h = **12.63 MPa** = **126.3 barg (1 832 psi).**

4.15 Ambient seawater temperature is estimated based on table C.5 in Appendix C.

4.16 If gas was present in the SOBM under static conditions of 6.5 ^{o}C and 126 bar, this means that the gas may have started to boil out of the solution since the gas has left the dense phase region, see figure 3.2.

4.17 If gas was present in the SOBM under trapped conditions of 6.5 ^{o}C and 209 bar, this means that the gas may go back into the dense phase region, see figure 3.2.

4.18 The density of brass is taken from Engineeringtoolbox.com which gives density of brass (casting) to be in the range 8 400 to 8 700 kg/m^3. https://www.engineeringtoolbox.com/metal-alloys-densities-d_50.html

4.19 The volume pumped is calculated based on figure 5.2. Note that the time is not accurate, since it has been rounded off to the closest minute; 2:10 pm, 2:11 pm, 2:12 pm and then a jump to 2:14 pm. Between d) and e) it is estimated that the pump was running for approximately 1.2 minutes (1 min 12 seconds) at an average flowrate of 1.0 bpm. This gives a total pumped volume between d) and e) of 1.2 bbl.

4.20 The mud compressibility factor for the SOBM used in Macondo and the equation to calculate trapped volume is taken from the National Academy of Engineering and National Research Council. 2012. *"Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety*", Chapter 2, *Well Design and Construction*, page 35. Reference for the compressibility factor (c_m) of 3.3358 x 10^{-6} (bbl/bbl/psi) is given to be taken from the BP report Appendix R.

4.21 The volume is calculated as the sum of the flow segments from the pressure transmitter assumed located at the standpipe manifold. The actual volume is the sum of flow ID 1 to 8 listed in Appendix C*, Table C.1 – Flow segment geometry after landing the production casing*.

4.22 The volume is calculated as the sum of the flow segments from the pressure transmitter assumed located at the standpipe manifold. The actual volume is the sum of flow ID 1 to 5 listed in Appendix C*, Table C.1 – Flow segment geometry after landing the production casing*.

4.23 The climbing rate after point d) is compared with the climbing rate after point e). Since the time scale is assumed equal but rounded out to the nearest minute this is probably a better method to find the trapped volume.

4.24 Total length of the landing string is 5 064 ft. Four feet of the landing string is assumed to be above drillfloor and 5 060 ft below RKB. The DTD was located at 4 734 ft. The volume of the landing string above the DTD is (4734/5060 + 4/5064) x 144.832 bbls (total volume of the landing string) = 135.50 bbls. The topside volume is the sum of flow ID 1 to 4 listed in Appendix C*, Table C.1 – Flow segment geometry after landing the production casing*. The total volume above the TDT including topside volume is then 7.269 bbls (topside volume) + 135.50 bbls (part of landing string above DTD) = 142,77 bbls.

4.25 The volume is calculated as the sum of the flow segments from the pressure transmitter assumed located at the standpipe manifold and down to the crossover. The actual volume is the sum of flow ID 1 to 7 listed in Appendix C, *Table C.1 – Flow segment geometry after landing the production casing*.

4.26 See Appendix C, *Table C.1 – Flow segment geometry after landing the production casing*, for numbers used in the calculation. The total volume of the 7-inch casing down to the float collar is 203 bbls. The total volume above including the crossover is 689 bbls. The total calculated trapped mud volume (V_m) is 736.4 bbls. The "trap" or plug will therefore be 47.4 bbls (736.4 – 689) down in the 7-inch casing. The total 7-inch casing length down to the float collar is 5 627 ft. The upper depth of the 7-inch casing is at 12 488 ft. The plug will therefore be expected to be at 12 488 ft + (47.4/203) x 5 627 ft = 13 802 ft.

4.27 The ambient temperature for the Macondo well at 7 421 ft below seafloor is taken from Appendix C, page 28, *Figure C.13 – Temperature vs Depth below seafloor at Macondo and 562-1.*

4.28 In the calculation of the observed mud compressibility (c_{mo}) the time scale used in figure 5.2 is the most uncertain parameter. Since real-time data from April 19 was not available when this thesis was made, this figure (figure 5.2) from the Transocean report has been used. In the time scale from 2:10 pm to 2:20 pm, this 10-minute period has been divided into 7 equal parts. Which will give an average period of 1 minute and 26 seconds between each time step. Two time-steps is equal to 2 minutes 51 seconds. The text is probably rounded up or down to the nearest minute. Figure 5.2 starts with 2:10 pm, 2:11 pm, 2:12 pm and then a jump to 2:14 pm before it goes back to 2:15 pm. This means that if the 2:10 pm mark was accurate the 2:12 pm mark would be actually be 2:12 and 51 seconds and should be rounded up to 2:13 pm. It is therefore likely when the first mark says 2:10 pm, it is probably closer to up to 30 seconds earlier. If the 10-minutes period actually is 10 minutes and 30 seconds this will give 5% error in the calculation. Meaning that the measured pumped volume during the pumping which started around 2:15 would increase from 1.20 bbl to 1.26 bbl. The corresponding observed mud compressibility (c_{mo}) would then be 3.8955×10^{-6} bbl/bbl/psi or 17 % higher than the mud compressibility given in the BP report (3.3358×10^{-6} bbl/bbl/psi).5.20

4.29 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 51, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, figure 11 and 12.

4.30 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011. Section; "*E. Float Collar"*, figure 4, page 50. The red text and arrows in figure 5.4 are added for information.

4.31 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011. Section; "*E. Float Collar"*, part 2. "*Float Collar Conversion Attempts*", page 51, second paragraph. The BOEMRE investigation team implies that the lack of flowrate contributed to the failure to convert the float collar:

"*The pump rate required to move mud into the well and through the shoe track (circulating pressure) never exceeded approximately 4 bpm, which was less than the five to seven bpm that Weatherford determined was necessary for float collar conversion.*"

4.32 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011. Section; "*E. Float Collar"*, part 2. "*Float Collar Conversion Attempts*", page 51, first paragraph:

"*Based on information that Weatherford supplied, the float collar conversion should have occurred with a differential pressure of between 400 and 700 pounds per square inch (psi), which required a calculated pump rate of five to seven barrels per minute (bpm)."*

4.33 The total length of the 7-inch casing shoe, float collar and 7-inch casing are about 5 816 feet, see item 8 to 11 listed in Appendix C*, Table C.1 – Flow segment geometry after landing the production casing*. This means that when the bottom of the casing shoe has reached the wellhead at 5 060 feet, there is almost 800 feet of 7-inch casing and more then 5 000 feet of 9 7/8 -inch casing to be run before the drilling crew start running the landing string, DTD and the Allamon diverter. Most of the casing run was therefore performed without any diverter installed.

4.34 The figure is taken from an article by DrillingFormulas.Com, dated Nov. 2, 2014. See "*Trip Tank and Its Importance to Well Control*", Figure 2. http://www.drillingformulas.com/trip-tank-and-its-importance-to-well-control/

4.35 Reference is made to an article by DrillingFormulas.Com, dated Nov. 17, 2010, "*What is a trip tank?*". In the response to the article a question by a reader dated November 26, 2010 was raised: "*Is the trip tank pump still on during tripping in hole?*" The answer from DrillingFormulas.Com dated November 27, 2010 was: "*Yes. Trip tank will be running all time while tripping in or tripping out.*" DrillingFormulas.com is created by Rachain J. in order to share drilling knowledge.
http://www.drillingformulas.com/what-is-a-trip-tank/

4.36 The long string production casing was run to a total depth of 18 304 ft. It took about 35 hours to run. 5.2 When the casing shoe had reached the wellhead at 5 060 ft there was still 13 244 ft for the casing to be lowered or 72%. Assuming that lowering of the casing was performed in about the same speed, means that there was still more than 25 hours before the casing reached the target. Lowering 13 244 ft of casing into the well, implies many connections and potential for u-tube flow, down the annulus and up inside the casing.

4.37 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. **Key Finding 2.** *The shoe track barriers did not isolate the hydrocarbons*. On page 37 the BP Investigation team wrote:

"*Three possible failure modes for the float collar were identified:*

- *Damage caused by the high load conditions required to establish circulation.*
- *Failure of the float collar to convert due to insufficient flow rate.*
- *Failure of the check valves to seal.*

At the time this report was written, the investigation team had not determined which of these failure modes occurred."

4.38 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, page 54. "*Float Collar Conversion Conclusions*", third conclusion (dot).

4.39 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, page 53. "*Post-Incident Float Collar Testing*", third paragraph.

4.40 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, page 53. "*Post-Incident Float Collar Testing*", figure 14.

4.41 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, page 54. “Float Collar Conversion Conclusions”, last sentence on page 54.

4.42 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. On page 89, last paragraph.

See also endnote 165, in Chapter 4.3, page 279 in the CCR.:
Halliburton cementer Nathaniel Chaisson testified before the U.S. Coast Guard/ BOEMRE Joint Investigation “*concern was shown by many people on the rig floor.*”

4.43 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. On page 89, last two paragraphs.

4.44 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Endnote 168, in Chapter 4.3, page 279.

4.45 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. In the middle of page 90, endnote 180.

4.46 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. **Key Finding 1.** *The annulus cement barrier did not isolate the hydrocarbons*. First sentence in last paragraph on page 33.

4.47 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. Last paragraph of page 90, endnote 184.

4.48 John Guide Testimony, C-Span video. Mr. Guide was asked why BP did not circulate bottoms up prior to the cement? See Mr. Guide answer on this question from time 00:45 to 02:06 in the video:
"*We were actually drilling the well, we got to the depth of 18 260 ft, which was not TD yet, and it appeared that the underreamer was worn out, and we circulated bottoms up a couple times, getting all the cuttings out, and what we routinely do is once we get the cuttings out, the ECD is lower, so we add a little bit of mud weight to replace that, so when the static mud weight…, it´s equal, and when we did that, everything was fine and all of a sudden, we just lost complete returns. The biggest risk that was associated with this cement job was losing circulations. That was the, No. 1 risk. So, based on the fact that we had lost circulation, just LIKE THAT, out of the clear blue, we decided to go ahead and ahhh… Get circulation established, and then…ahh, because of the actual volumes, we would actually have bottoms up ABOVE the wellhead, once the ahhh…, once the cement was in place, and then we would be able to circulate that up to see if there was any gas. So that was our plan.*"
https://www.c-span.org/video/?294696-2/investigation-deepwater-horizon-explosion-john-guide-testimony

4.49 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. *Figure 4.3.18. BP´s pre-cementing mud circulation*, on page 91.

4.50 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Se last paragraph of the section covering real-time data review from period 00:00 to 00:20 on April 20 (end of cement job circulation), page 5.
https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

4.51 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection. *Figure 4.7.12. Last two hours of Sperry-Sun data*, on page 191. This figure shows how gas was present in the return system under the final displacement of the riser with seawater after the negative pressure test.

A similar figure of the Sperry-Sun real time data from the period when preparation was made for the negative pressure test show gas in the mud returning to the rig. Sperry-Sun real time data from this time period was made available to the author of this thesis in a video, received from Richard Sears in a meeting in 2016. Richard Sears was the senior science and engineering adviser for the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (Chief Counsel´s Report).

4.52 Note that the author of this thesis has not got access to real time data during the pre-cementing circulation sequences. The *Observed SPP – Recorded in Halliburton Cement Report* (yellow curve in figure 5.8) is therefore not a copy of the Sperry-Sun real time data, but a curve made from circulating flow rates and pressures recorded in the cement job report. See, Joint Investigation Report, Appendix F, Halliburton Report, *9.875" x 7" Foamed Production Casing Post Job Report*, page 4.

4.53 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection. *Figure 4.7.8. Erratic Flow-Out vs. normal flow-out*, on page 175.

The lower part of figure 4.7.8 in the CCR show that flow out on April 19 during the second pre-cementing circulation sequences was normal.

4.54 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. **Key Finding 4.** *Influx was not recognized until hydrocarbons were in the riser.* Figure 4 on page 43 show how hydrocarbons (oil) from the pay sand entered the riser during the final displacement by displacing the entire mud column.

4.55 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. Second paragraph on page 92.

4.56 Appendix C, Table C.1, Flow ID 25, Riser annulus.

4.57 The relative thermal volumetric expansion coefficient used in the SINTEF model was between 0.0005 (1/oC) and 0.00065 (1/oC) depending on depth and temperature. Thermal volumetric expansion coefficient for natural gas at 580 bar (58 MPa) and 60 oC, is calculated by the Unitrove Natural Gas Density Calculator to be 0.00264 (1/oC). At 250 bar (25 MPa) and 10 oC thermal volumetric expansion coefficient for natural gas is calculated to be 0.00588 (1/oC). This means that any natural gas influx may be up to 4 to 5 times more sensitive to temperature changes down in the wellbore and up to 9 to 12 times more sensitive to annulus fluid cooling in the wellhead and riser area. https://www.unitrove.com/engineering/tools/gas/natural-gas-density

4.58 Just before circulation is obtained after the casing has landed on April 19, the simulated ESD in the annulus at the wellhead (5 060 ft) and in the gas sand (17 437.5 ft) are 14.206 ppg (1 702.3 kg/m^3) and 14.162 ppg (1 697.0 kg/m3) respectively. This correspond to a hydrostatic pressure at the wellhead of 257.557 barg and at the gas sand 884.818 barg. The difference in hydrostatic pressure is 627.261 bar, which correspond to an average density of the SOBM without any gas of 1 694.8 kg/m^3 (14.143 ppg) between the wellhead and the gas sand.

4.59 For simplicity it is assumed that the observed 260 psi (17.926 bar) reduction in circulation pressure also will reduce the hydrostatic pressure by 260 psi. However, this is quite not through since gas in the mud also will lower the circulation frictional pressure drop, see discussion in chapter 5.2.7. In this conservative calculation to check how much gas that will be required to lower the hydrostatic differential pressure from 627.261 bar down to 609.335 bar (627.261-17.926 bar), a simplification that gas is equally distributed in the annulus between the wellhead and gas sand is also used. Based on the distance between the wellhead and gas sand (3 772.7 m) and standard acceleration due to gravity (9.81 m/s^2), the gas cut SOBM density in the annulus is calculated to be 1 646.4 kg/m^3 (13.739 ppg).

4.60 The average temperature between the wellhead and the gas sand prior to the circulation on April 19 is about 60 ^oC. The average hydrostatic pressure is about 571 bar (57.1 MPa). The average gas density (with 96.5 % Methane) is calculated by the Unitrove Natural Gas Density Calculator to be 273.2 kg/m^3 (2.28 ppg).
https://www.unitrove.com/engineering/tools/gas/natural-gas-density

4.61 See Appendix C, table C.1 for volume calculations. Volume of annulus (B) is the sum of flow segments 15 to 21 (2 + 9.13 + 19.7 + 5.37 + 11.4 + 112 + 7.73) = **167.33 m^3**.

4.62 The mass of annulus (B) with gas free SOBM is 1 694.8 kg/m^3 x 167.33 m^3 = **283 591 kg**. The mass of annulus (B) with gas cut mud is 1 646.4 kg/m^3 x 167.33 m^3 = **275 492 kg**. This is a reduction of 8 099 kg or 2.9%. The volume of free gas (V_{gas}) with average density (ρ_{gas}) of 273.2 kg/m^3 and volume of SOBM (V_{mud}) with average density (ρ_{mud}) of 1 694.8 kg/m^3 required to obtain a total volume (V_{total}) of 167.33 m^3, can be calculated to obtain a total mass (M_{total}) by the following equation: $M_{total} = (V_{gas} \times \rho_{gas}) + (V_{total} - V_{gas}) \times \rho_{mud}$
By solving this equation volume of free gas V_{gas} = **5.695 m^3 (35.8 bbls)**.

4.63 Lowering the pressure by 260 psi = 17.9 bar = **1.79 MPa**.
Depth at the gas sand 17 437.5 ft = 17 437.5 x 0.3048 = **5 315 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Equivalent Static Density (ESD) reduction at 17 437.5 ft:
ESD reduction = 1.79 MPa / (9.81 m/s2 x 5 315 m) = 34.3 kg/m3 **= 0.286 ppg.**

4.64 Figure 5.10 show simulated ECD / ESD at the 14.16 ppg gas sand assuming no circulation was carried out while tripping out of hole after bottoms up had been circulated on April 16. The simulation is carried out with the 9 7/8 x 7 -inch casing in the wellbore. Result may therefore be slightly different if simulation was carried out with drill pipe tripping out of the hole, however the trend and effects are expected to be the same since the well was static.

It should also be noted that changes to ESD at the gas sand only take into account density changes in the annulus above the gas sand. Density changes in the annulus/open wellbore below the gas sand and density changes inside the drill pipe used to circulate bottoms up may also have influence on total gain/loss calculation due to thermal effects and gas influx.

4.65 Plastic viscosity measured in centipoise (cP) or (mPa s) = Reading at 600 rpm – Reading at 300 rpm. In appendix D, table 6, page 15, the Fann readings at 600 rpm and 300 rpm, used in the simulations are 93 and 54 respectively. This gives a plastic viscosity of 93 – 54 = **39 cP**. See link below for more information about viscosity of drilling mud.
http://www.drillingformulas.com/viscosity-of-drilling-mud/

4.66 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5A, page 61, figure 3. *"Planned Cement Fluid Locations."*

4.67 The time used in the Halliburton cement report is different from the clock in the Sperry Sun system sending real time data to shore. In the Halliburton cement report the clock seems to be about 5 to 6 minutes behind the clock in the Sperry Sun system. For example, in the Halliburton report the bottom plug and top plug where reported to go through the X-over at about 23:39 and 23:53 respectively, while in the Transocean report the same peak in the 23:34 and 23:47. The correct time of the different events is therefore uncertain. However, this will not affect simulated time used in the study, because this is independent of when the actual events took place.

4.68 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Se last paragraph of the section covering real-time data review from period 20:00 to 22:00 (April 19): Performed cement job (with the cement unit), page 4. https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

4.69 Total volume pumped with the rig pump are given to be 728.5 bbls in the Halliburton cement job report. This gives a pump rate of 4.245 bpm used in the simulation.

4.70 Flow out is taken from a figure made by the joint investigation team. The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011. *Figure 5 – Flow-out vs. Flow-in on the Production Casing Cement Job*, page 57.

4.71 The actual curved temperature profile for the Macondo well is used, see figure C.13 in Appendix C.

4.72 Observed SPP is taken from real time plot in the Joint Investigation Report, Appendix F, Halliburton Report, *9.875" x 7" Foamed Production Casing Post Job Report*, page 12.

4.73 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection. *Figure 4.7.8. Erratic Flow-Out vs. normal flow-out*, on page 175.

4.74 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection. *Figure 4.7.12. Last two hours of Sperry-Sun data*, on page 191. This figure shows how gas was present in the return system under the final displacement of the riser with seawater after the negative pressure test.

4.75 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection. Figure 4.7.8. Erratic Flow-Out vs. normal flow-out, on page 175. The text under the figure explain possible cause of the observed erratic flow out. "*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.*"

4.76 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Se last paragraph of the section covering real-time data review from period 00:00 to 00:30 on April 20, page 5:
"*Significant increases in gas units during this period, to levels exceeding that when drilling non-productive formations, implies that trip gas from previous trip out of the hole had not been circulated out prior to the cement job. However, assessment of pre-job preparations is outside the scope of this review.*"
https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

4.77 Wellbore annulus (B) from the 14.16 ppg gas sand and up to the wellhead consist of flow segment 15, 16, 17, 18, 19, 20 and 21, see table C.1 in Appendix C and figure 5.9 in the main report. The total volume of annulus (B) is (12.6 + 57.4 + 124 + 33.8 + 71.9 + 706 + 48.6) about 1 054 bbls. The total volume pumped including pre-cementing circulation, was about 1 370 bbls. [5.55] This means that (1 370-1 054) 316 bbls before the end of the cement job, or 74 minutes (316/4.245) before the top wiper plug reaches the float collar, the assumed gas influx during the static period between April 16 and April 19, will be out of the well and into the riser. The top plug reaches the float collar at about 172 minutes simulated time, see figure 5.13. This means that the entire wellbore annulus volume (B) above the gas sand was displaced at about 98 minutes simulated time.

4.78 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Se last paragraph of the section covering real-time data review from period 20:00 to 22:00 (April 19): Performed cement job (with the cement unit), page 4. "*Significant gains, roughly equivalent to the volumes of cement and spacer pumped, and losses, which were not explained, are present in the data record.*"
https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

4.79 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.1, last paragraph, page 63. "*During the drilling of the final section of the well, BP correspondence noted that when picking up off bottom (lifting the drill string from the bottom of the well) with a 14.7 -ppg equivalent circulating density (ECD) at 18,260 ft., the formations fractured and fluid was lost from the well to the formations.*"

4.80 To make the foam cement 39 bbls of unfoamed cement with density 16.74 ppg was pumped and mixed with about 748 kg nitrogen. Just above the crossover were the foam cement was located, the foam density was about 14.2 ppg due to the hydrostatic pressure, see figure C.16 in Appendix C. In other words, the total volume of foam cement was about 39 x (16.74/14.2) = 46 bbls. Assuming the foam cement expand by 10 bbls to 56 bbls, will give a new foam density of 14.2 ppg x (46/56) = 11.7 ppg.

4.81 The gas kick was assumingly taken simultaneously with a fracture formation event that possibly took place between 111- and 112-minute simulated time, see figure 5.13 and figure 5.18. The bottom wiper plug reaches the float collar at about 159-minute simulated time. The circulation has been carried out for about 47 minutes (159-112) at a rate of 4.245 bpm, which gives a total pumped volume of about 200 bbls. The volume of annulus flow segment (15), (16) and (17) is 194 bbls (12.6 + 57.4 + 124). This implies that 6 bbls of manly gas free mud has been circulated up and into flow segment (18) see figure 5.19. The simplified figure 5.19 also assume the dense gas influx disperse upward with the flow, since gas is lighter than the OBDF. This assumption should be investigated and might not be correct?

4.82 Observed SPP is taken from real time plot in the Joint Investigation Report, Appendix F, Halliburton Post Job Report, page 12. The burst pressure of 2 900 psi is also noted down in the same job report on page 6, time 00:29. However, in the BP daily report the burst pressure was reported to be 2 932 psi. Ref. Smith report, page 5: "*The reported pressure of 2932 psi to seat and burst the bottom plug is more than that recorded in the data, probably because the data record is an average.*" The reason for this is probably that Mr. Smith has reviewed the "*Sperry-Sun 30 sec Data*" which gives the average data over a period of 5 seconds. This set of data that probably also were the same data set that Halliburton have used, shows a peak pressure of 2 900 psi, ref page 12 in the job report. While BP has probably used the Sperry-Sun live data which has a higher resolution or more data points.
Note also that the time used in the Halliburton job report for bursting the plug (00:29) are not accurate or consistent with the Sperry Sun system clock. The clock on the real time data from the Sperry Sun system has been used in this thesis. Assuming the Sperry Sun clock is correct a better estimate would be that the pressure starts to increase at about 00:22 and that the bottom plug burst at about to minutes later at 00:24. In the Smith report, page 5, reviewing the data records Smith has noted that: "*The top plug bumped and cement was in place at 00:35, which was reported as 12:35 in BP daily report.*" According to the real time data there is about 11 minutes between top plug burst and bottom plug bumped. In other words, the BP daily report and Smith report confirms that the correct time for the peak burst pressure was probably 00:24 and not 00:29.

4.83 The drilling crew had observed total loss of returns when the ECD exceeded 14.7 ppg, ref. endnote 5.48 and 5.79. Lower oil sand ECD at 18 212.5 ft:
14.7 ppg = 14.7 x 119.85 kg/m^3 = **1 762 kg/m3**.
18 212.5 ft = 18 212.5 x 0.3048 m = **5 551 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pressure (p) = ρ x g x h = **95.95 MPa** = **959.5 barg (13 916 psi).**
The simulated peak pressure at the lower oil sand (18 212.5 ft) was 15.88 ppg:
15.88 ppg = 15.88 x 119.85 kg/m^3 = **1 903 kg/m3**.
Pressure (p) = ρ x g x h = **103.63 MPa** = **1 036.3 barg (15 030 psi).**
In other words the simulated downhole pressure at the oil sand was **76.8 bar (1 114 psi)** higher than the fracture pressure.

4.84 In the Joint Investigation Report, Appendix F, Halliburton Report, 9.875" x 7" Foamed Production Casing Post Job Report, page 5, the cement spacer is specified as 14.3 ppg Tuned Spacer III. For more information about Halliburton Tuned Spacer III, see link below:
https://www.halliburton.com/en-US/ps/cementing/materials-chemicals-additives/spacers-and-flushes/tuned-spacer-iii-cement-spacer.html

4.85 BP *Deepwater Horizon* Accident Investigation Report, September 8, 2010, page 64, third paragraph. *"However, the report does not include a prediction of gas flow potential for this zone. In fact, this zone would not be expected to present a possibility of gas flow or hydrocarbon ingress, since the BP subsurface team for the Macondo well assigned this interval a value of zero net pay. This was because they found the thin sand layers in the interval to be below log resolution, and that attempts to obtain fluid samples were unsuccessful. The interpretation of fluid content was deemed uncertain, but it was probably water (brine)."*

4.86 Pore pressure in gas sand **14.16 ppg (1 697 kg/m^3)**. Simulated annulus pressure at gas sand at 160 minutes simulated time is **14.04 ppg (1 683 kg/m^3)** with no mixing of the base oil and **14.07 ppg (1 686 kg/m^3)** assuming mixing of base oil, SOBM and spacer fluid.
Depth at the gas sand 17 437.5 ft = 17 437.5 x 0.3048 = **5 315 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pore pressure (p) = ρ x g x h = **88.48 MPa** = **884.8 barg (12 833 psi).**
Annulus pressure No mixing = **87.75 MPa** = **877.5 barg (12 727 psi).**
Annulus pressure mixing fluids = **87.91 MPa** = **879.1 barg (12 750 psi).**
Minimum hydrostatically underbalanced due to base oil is **5.7 bar (83 psi).**
Maximum hydrostatically underbalanced due to base oil is **7.3 bar (106 psi).**

4.87 The observed SPP seconds before pressure increase when the bottom plug landed on the float collar was about 275 psi. The simulated SPP with the mixing of fluids and NO base oil mixing scenario, was 394 psi and 384 psi respectively. This implies that due to gas in riser and wellbore annulus the hydrostatic pressure down in the wellbore may have been up to 109 psi (7.5 bar) to 119 psi (8.2 bar) lower, than simulated values.

4.88 Total underbalanced No mixing of base oil = 7.3+7.5 bar = **14.8 bar (215 psi)**.
Total underbalanced mixing of base oil = 5.7+8.2 bar = **13.9 bar (202 psi)**

4.89 The volume below the bottom plug and up to the gas sand consist of flow segment (9), (10), (11), (12) and (13), see figure 5.19. The total volume of these segments is about 43 bbls. The total annulus volume flow segment (12) and (13) to establish a crossflow, is about 36 bbls, see Appendix C, table C.1.

4.90 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. Paragraph with heading "*The Float Check at Macondo*" , on page 93 and 94.

4.91 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.1 | Flow Path. Last paragraph on page 52 with heading "*The Shoe Track Cement Probably Failed* ".

4.92 Note that in Appendix D figure 13 and figure 16, a free fall fluid gap inside the running string when stopping pumps as if there were no active valves or plugs in the casing has been simulated. This calculation is performed by artificially removing the top wiper plug from the casing, and hence allow fluids to u-tube into the annulus. However, this is not what happened in the Macondo wellbore. At Deepwater Horizon the high pressure after bottom plug bumped was released at the cement unit. According to witnesses 5.5 bbls was bled off into the cement unit. 5.90 The pressure spike and elevated ECD/ESD that can be seen after 174 minutes simulated time in figure 5.18 in the main report (503 minutes simulated time in figure 13 in Appendix D) does therefore not reflect what happened. The elevated ECD/ESD of about 14.2 ppg in the simulation is mainly due to heavy tail cement u-tubing into the annulus when the bottom plug was artificially removed in the simulation.

Chapter 5 – Well Integrity Tests

5.1 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.6 | Negative Pressure Test. Paragraph with heading "*Well Integrity Tests*", on page 143.

5.2 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.6 | Negative Pressure Test. The illustration is made by TrialGraphix for the CCR, ref. figure 4.6.2, on page 144.

5.3 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Section 3, Chronology of the Accident, page 23, table *"Cement Job."* Date: April 20, Time: 00:30 – 07:00, Description: "*Dril-Quip seal assembly installed in subsea wellhead. Two pressure tests successfully completed. Drill pipe pulled out of riser.*"

5.4 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.1 | Flow Path. Figure 4.1.4, on page 44, picture and text no. 3 from top and figure 4.1.5, on page 45, see picture and text below the pictures: "*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.*"

5.5 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 86, Chapter *3.2.2 Positive Casing Test and Initial Displacement*, first paragraph.

5.6 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 83, figure 1. *"Positive-pressure Test (Real-time Data)."*

5.7 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 82, chapter 2.1. *"Conducting the Positive-pressure Test"*, first and second paragraph.

5.8 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 82, chapter 2.1. *"Conducting the Positive-pressure Test"*, first paragraph, second sentence.

5.9 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.6 | Negative Pressure Test. The illustration is made by TrialGraphix for the CCR, ref. figure 4.6.3, on page 145.

5.10 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 83, chapter 2.2. *"Displace Mud to Seawater"*, first paragraph, first sentence.

5.11 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 2.2 Converting the Float Collar, page 27, fourth paragraph, third sentence. "*Circulating a full "bottoms-up" using the full volume of mud from bottom to surface is considered a best practice prior to cementing."*

5.12 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 2.2 Converting the Float Collar, page 27, fifth paragraph, second sentence. "*The total volume circulated, including circulation after float conversion, was 346 bbl, significantly less than the 1,315 bbl required in the original drilling program and the 2,750 bbl required for a full bottoms-up circulation."*

5.13 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.3 | Cement. Second paragraph on page 92.

5.14 Appendix C, Table C.1, Flow ID 25, Riser annulus.

5.15 Based on real time data from figure 6.2 6.6 the drilling crew pumped 23.3 gpm for about 11 minutes or total of 256.7 gallons or 6.1 bbls total to increase the pressure with about 2 550 psi.

5.16 The SINTEF simulations show that after about 15 hours of static wellbore condition the wellhead ESD will be about 14.20 ppg due to thermal cooling of the annulus fluid. Pressure at the subsea BOP about 5 020 ft with 14.20 ppg:
14.20 ppg = 14.20 x 119.85 kg/m3 = **1 702 kg/m3**.
5 020 ft = 5 020 x 0.3048 m = **1 530 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = ρ x g x h = **25.55 MPa** = **255.5 barg (3 706 psi).**

The SINTEF simulations also show that after about 15 hours of static wellbore condition the ESD at the bottom of the will be about 14.14 ppg due to thermal heating of the annulus fluid. If we assume the casing fluids is slightly colder, the average ESD at the float collar (18 115 ft) may have been about 14.15 ppg and at the crossover (12 483 ft) may have been about 14.17 ppg. The corresponding hydrostatic pressure will then be **918.6 barg** and **633.8 barg**.

5.17 The formula required to calculate the pumped or compressed volume (V_c) for a total volume of gas free SOBM or total volume of mud (V_m) to increase the pressure (Δp) with 2 550 psi is given by the following equation.

$V_c = V_m \Delta p\, c_m$ where

c_m = mud compressibility (bbl/bbl/psi) = 3.3358×10^{-6} (bbl/bbl/psi).

The equation and value for the mud compressibility factor for the SOBM used at Macondo originate from BP, ref. National Academy of Engineering and National Research Council. 2012. *"Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety*", Chapter 2, *Well Design and Construction*, page 35.

The total volume of surface piping is estimated to 3 bbls. The volume of the kill line is 99 bbls and the hose in the moonpool is estimated to 4 bbls. (Transocean Investigation Report, Vol. 2, Chapter 4.1 3.1 *Strokes Pumped*, page 50.)
The volume of the BOP annulus below blind shear rams is estimated to 6 bbls, see figure C.6 and table C.1 in Appendix C. The volume of the 9 7/8-inch and 7-inch casing is taken from C.1 in Appendix C, 536 bbls and 203 bbls respectively. Total mud volume (V_m) is then 3+4+99+6+536+203= 851 bbls.

V_c = 851 bbl x 2 550 psi x 3.3358×10^{-6} (bbl/bbl/psi) = 7.2 bbl

Since the pressure increase during the positive pressure test took place over a period of 11 minutes after the well had been static for about 10 hours, thermal effects is not considered significant. However, if we assume that the drop in pressure of 40 psi from 2 740 psi and down to 2 700 psi, in 11 minutes during the pressure test are due to thermal effects or leakage, we can subtract this from the calculation, and get a theoretical pumped or compressed volume (V_c).

V_c = 851 bbl x 2 510 psi x 3.3358×10^{-6} (bbl/bbl/psi) = **7.1 bbl**

5.18 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, *Hydraulic Analysis of Macondo #252 Well Prior to Incident of April 20, 2010.*

5.19 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 95, figure 38.

5.20 The anulus temperature at the wellhead after 14 hours and 20 minutes in a non-circulating well was simulated by SINTEF to be about 9.6 ^{o}C. However due to the no. of grid point used in the seabed and wellhead area in the simulation, this is probably a slightly high value. Real temperature may have been about 8 ^{o}C.

5.21 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 25, figure 1.

5.22 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 98, fourth paragraph. SES discuss the possibility at which time the well become underbalanced to the 13.1 ppg and 12.6 ppg formations. *"Comparing the modified simulation results to the measured standpipe pressure data, the two results begin to diverge slightly starting at about 20:40. This observation may be compared to the simulated bottom-hole EMW results in Figure 41, which indicate that the well became underbalanced to the 13.1 ppg formation at 20:38, and to the 12.6 ppg formation at 20:52. If both formations had been exposed to the well during the negative test activity, the divergent pressure response would match the 13.1 ppg underbalance event."*

5.23 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 106, Figure 18. *"Well starts to flow when well goes underbalanced at 20:52".*

5.24 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 41, chapter *4.1.1.1 Strokes Pumped*. The total volume pumped based on 623 strokes and anticipated pump volumetric efficiency of 96.1 % is 78.5 bbls, see Table 9 and note 3 on page 41.

5.25 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 43, chapter *4.1.1.3 Riser Flow Analysis*. First paragraph, third sentence: "*Integrating the sensor data over the pumping interval indicates a return volume of 42.6 bbl, compared to the anticipated pump volume of 78.5 bbl.*"

5.26 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 43, chapter *4.1.1.3 Riser Flow Analysis*. Figure 11.

5.27 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Se last paragraph of the section covering real-time data review from period 20:00 to 22:00 (April 19): Performed cement job (with the cement unit), page 4. "*Significant gains, roughly equivalent to the volumes of cement and spacer pumped, and losses, which were not explained, are present in the data record."* https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

5.28 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout., September 14, 2011, page 98, heading ***A. Kick Detection Methods and Responsibilities***, second paragraph.
"*Personnel responsible for well monitoring use a number of methods to determine whether the well is stable. One method is monitoring pit gain, which involves tracking fluid gains in the pits that might indicate flow from the well. Another method is the analysis of flow-out versus flow-in data – which should be equal if the well is stable. As discussed by Dr. John Smith in his report, these two methods – pit gain and comparison of flow-in to flow-out – are critical to effective well monitoring. In addition, other data (including drill pipe pressure changes and gas content information) can also indicate if a well is flowing. A warning from any of these indicators should prompt personnel to stop circulating fluid and to perform a flow check. If flow continues, the well should be shut in using the BOP*."

5.29 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout., September 14, 2011, page 56, second paragraph, first sentence.
"*The Panel independently assessed the difference between the flow-in and flow-out data and calculated that a maximum of approximately 80 bbls of fluids (+/- 10 percent based on the flow-in and flow-out data) could have been lost during the cementing job.*"

5.30 U.S. Chemical Safety and Hazard Investigation Board, Investigation Report, Published: June 12, 2019. *Gas Well Blowout and Fire at Prior Trust Well 1H-9,* Pittsburg County, Oklahoma. See page 46, second paragraph.
https://www.csb.gov/csb-issues-final-report-into-fatal-gas-well-blowout/

5.31 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report.
Se last paragraph of the section covering real-time data review from period 00:00 to 00:30 on April 20, page 5:
"*Significant increases in gas units during this period, to levels exceeding that when drilling non-productive formations, implies that trip gas from previous trip out of the hole had not been circulated out prior to the cement job. However, assessment of pre-job preparations is outside the scope of this review.*"
https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

5.32 If we assume that the booster line goose neck is 30 ft below the flow line outlet on the riser, this gives a total column of SOBM of 3 000 ft + 30 ft = 3 030 ft (923.5 m) acting or u-tubing on the gas in the booster line from below. If we assume an average mud weight of 14.1 ppg (1690 kg/m^3), this gives a pressure of 153 bar in the bottom of the gas column in the booster line. This is also the pressure (*Cricondenbar*) were natural gas may go over to the dense phase region, ref. figure 3.2 in the main report.

5.33 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 41, chapter *4.1.1.1 Strokes Pumped*. The booster line capacity is 71.3 bbls. The total volume pumped based on 623 strokes and anticipated pump volumetric efficiency of 96.1 % is 78.5 bbls, see Table 9 and note 3 on page 41. The over-displaced volume of 7.2 bbls is assumed to be the calculated volume of drape hose and surface piping volume.

5.34 If we assume that the temperature of the free gas in the booster line at about 3 030 ft (923.5 m) depth is equal to ambient seawater temperature, this will be equal to about 6 ^oC, see table C.5 in Appendix C. The typical natural gas density at 153 bar,6.32 will then be 150 kg/m^3 (unitrove.com).

If we assume 141 bar and 25 ^oC gas condition at top of the 3 000 ft gas column at in the booster line, this will give a gas density of about 119 kg/m^3. This will give an average gas density of about **134 kg/m^3**. In other words, pressure at the bottom of the gas column = 141 bar + (134 kg/m^3 x 9.81 m/s^2 x 914.4 m) = 141 bar + 12 bar = 153 bar.

This gives a total mass for the assumed 42.8 bbls (6.8 m^3) free gas of **911 kg**. If we assume average SOBM density of 14.17 ppg (1 698 kg/m^3) at the 5 030 ft (1 533 m) depth, this correspond to a hydrostatic pressure of 255 bar. If we assume that the 911 kg free gas was pumped down to a pressure of 255 bar and annulus temperature of 8 ^oC, this will give a gas density of 224 kg/m^3. The free gas of 42.8 bbls (6.8 m^3) free gas in the riser annulus will then be compressed to 25.6 bbls (4.1 m^3) during the seawater displacement of the booster line. This is a volume reduction du to compression of **17.2 bbls**.
https://www.unitrove.com/engineering/tools/gas/natural-gas-density

5.35 Total lost volume was 35.9 bbls. Since the reduction due to compression could count for 17.2 bbls, this leaves 18.7 bbls (35.9–17.2), not accounted for. This uncounted volume of 18.7 bbls is equal to 73 % of the total compressed free gas volume.

5.36 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 46, chapter *4.1.2.1 Strokes Pumped*. The total volume pumped based on 872 strokes and anticipated pump volumetric efficiency of 96.1 % is 109.9 bbls, see Table 11.

5.37 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 48, chapter *4.1.2.3 Riser Flow Analysis*. First paragraph, third sentence: "*Integrating the sensor data over the pumping interval indicates a return volume of 84.8 bbl, compared to the anticipated pump volume of 109.8 bbl.*" Note that based on Table 11 on page 46 the correct pumped volume is probably 109.9 bbls.

5.38 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 47, chapter *4.1.2.2 Pressure Response*. Figure 13.

5.39 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 50, chapter *4.1.3.1 Strokes Pumped*. The total volume pumped based on 842 strokes and anticipated pump volumetric efficiency of 96.1 % is 106.1 bbls, see Table 13.

5.40 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 52, chapter *4.1.3.3 Riser Flow Analysis*. First paragraph, third sentence: "*Integrating the sensor data over the pumping interval indicates a return volume of 84.8 bbl, compared to the anticipated pump volume of 106.6 bbl.*"

5.41 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 51, chapter *4.1.2.2 Pressure Response*. Figure 15.

5.42 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 54, chapter 4.2.1 Strokes Pumped. The total volume pumped is based on a total of 3 609 strokes (pump 3&4) and anticipated pump volumetric efficiency of 96.1 % equal to 454.7 bbls, see Table 15.

Note that there has been some discussion in the SES report (Transocean Investigation Report, Vol. 2, Appendix G) on how many barrels that actually was pumped. BP investigation team states on page 83 in their report that. "*A review of real-time data showed that the rig crew pumped 424 bbls of spacer, followed by 30 bbls of fresh water and 352 bbls of seawater*."

Probably spacer and freshwater was pumped simultaneously from pit #5. While pump nr. 3&4 pumped 454.7 bbls (i.e. 424 + 30) from pit #5 only, 421 bbls was drawn from the pit. This discrepancy is probably due to the 16 ppg spacer were being diluted with freshwater added to #5 during the pump sequence.

5.43 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 57, chapter *4.2.3 Riser Flow Analysis*. First paragraph, first sentence: "*Integrating the Sperry-Sun flow sensor data over the spacer displacement interval indicates a return volume of 459.8 bbl, compared to the anticipated pump volume of 454.7 bbl.*"

5.44 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 59, chapter *4.2.3 Riser Flow Out*. Figure 19.

5.45 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 54, chapter 4.2.1 Strokes Pumped. The total volume pumped is based on a total of 2 800 strokes (pump 3&4) and anticipated pump volumetric efficiency of 96.1 % equal to 352.8 bbls, see Table 16.

5.46 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 57, chapter *4.2.3 Riser Flow Analysis*. Fourth paragraph, first sentence: "*Integrating the flow sensor data over the seawater displacement interval indicates a return volume of 280.9 bbl, compared to the anticipated pump volume of 352.8 bbl.*"

5.47 Pressure at float collar 18 115 ft with 14.15 ppg:
14.15 ppg = 14.15 x 119.85 kg/m^3 = **1 696 kg/m3**.
18 115 ft = 18 115 x 0.3048 m = **5 521 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pressure (p) = ρ x g x h = **91.86 MPa = 918.6 barg (13 323 psi).**

5.48 Pore pressure Pay Sand: 12.56 ppg = 12.56 x 119.85 kg/m^3 = **1 505 kg/m3**.
18 223 ft = 18 223 x 0.3048 m = **5 554 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pressure (p) = ρ x g x h = **82.00 MPa = 820.0 barg (11 893 psi).**

5.49 Pore pressure in top of the 14.16 ppg Gas Sand:
PP Gas sand = 14.16 ppg = 14.16 x 119.85 kg/m^3 = **1 697 kg/m3**.
17 435 ft = 17 435 x 0.3048 m = **5 314 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pore pressure gas sand = ρ x g x h = **88.47 MPa = 884.7 barg (12 831 psi).**

5.50 Pressure at subsea BOP 5 040 ft with 14.0 ppg:
14.0 ppg = 14.0 x 119.85 kg/m^3 = **1 678 kg/m3**.
5 040 ft = 5 040 x 0.3048 m = **1 536 m**.
Standard acceleration due to gravity (g) = **9.81 m/s^2**.
Pressure (p) = ρ x g x h = **25.28 MPa = 252.8 barg (3 667 psi).**

5.51 Pressure at bottom of displacement string at 8 367 ft:
8.58 ppg = 8.58 x 119.85 kg/m3 = **1 028 kg/m3**.
8 367 ft - 5 040 ft = 3 327 x 0.3048 m = **1 014 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = **10.23 MPa** + 25.28 MPa = **355.1 barg (5 150 psi).**

5.52 Pressure at float collar 18 115 ft:
14.15 ppg = 14.15 x 119.85 kg/m3 = **1 696 kg/m3**.
18 115 ft - 8 367 ft = 9 748 x 0.3048 m = **2 971 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = **49.43 MPa** + 35.51 MPa = **849.4 barg (12 320 psi).**

5.53 Pressure at float collar 18 115 ft during negative pressure test:
8.58 ppg = 8.58 x 119.85 kg/m3 = **1 028 kg/m3**.
8 367 ft = 8 367 x 0.3048 m = **2 550 m**.
Standard acceleration due to gravity (g) = **9.81 m/s2**.
Pressure (p) = **25.72 MPa** + 49.43 MPa = **751.5 barg (10 900 psi).**

5.54 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 79, "*Figure 32: Trip tank activity following annular preventer leakage*".

5.55 Expected static u-tube pressure on the standpipe with 14.0 ppg ESD, from BOP and up in the riser and seawater below BOP down to end of displacement string (8 367 ft) and up to standpipe will be: 35.51 MPa 6.51 – 25.72 MPa 6.53 = **9.79 MPa = 97.9 bar (1 420 psi).**

5.56 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 79, **Event 5**, fourth sentence: "*The total bleed volume between Events 2 and 5 was 65 bbl, which may be attributed (in total or in part) to the leakage through the annular.*"

5.57 OD of 3.5" pipe is 88.9 x 10^{-3} m. ID of 9 7/8" casing is 177.8 x 10^{-3} m. Length is 8 367 ft – 7 546 ft = 821 ft = 821 x 0.3048 = 250 m.
Annulus volume = 4.66 m^3 = **29.3 bbls**.

5.58 OD of 5.5" pipe is 139.7 x 10^{-3} m. ID of 9 7/8" casing is 177.8 x 10^{-3} m. Length is 7 546 ft – 5 062 ft = 2 484 ft = 2 484 x 0.3048 = 757 m.
Annulus volume = 7.19 m^3 = **45.2 bbls**.

5.59 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Page 10, third paragraph, last sentence. "*The actual pressure (SPP2) of 1262 psi at 17:09 is apparently indicates a leak in the annular BOP, the casing, and/or the casing hanger packoff.*" https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

5.60 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Endnotes, page 301, note 41 in Chapter 4.6. "*Testimony of Randy Ezell (Transocean), Hearing before the Deepwater Horizon Joint Investigation Team, May 28, 2010, 279-80. The leakage beneath the annular preventer after displacement is not unusual. Murry Sepulvado, interview.*"

5.61 The 67.3 bbls pumped from the trip tank is taken by measurement from figure 6.14 and trip tank levels. The trip tank pump was probably run in three periods, and the level in the tank dropped by 22.3 bbls, 34.3 bbls and 10.7 bbls during these pump periods, giving a total of 67.3 bbls pumped.

This is also the same amount given in the Smith report, page 10, fift paragraph. "*A total of 67 barrels were measured as having been removed from the trip tank during this period. The trip tank is the most likely source of fluids to fill the riser*."

The reason why the SES team (Appendix G in the Transocean Investigation Report, Vol. 2) has used 65 bbls as amount of fluid being bled of is probably that they have subtracted some fluid that overflowed from the riser during the two last fill-up sequences, ref endnote 6.56.

5.62 Transocean Offshore Installation Manager (OIM), Jimmy Harrel visit the drillers cabin shortly after the first attempt to bled down the pressure. Since they had problem holding the pressure on the annular, he told the driller to increase the annular pressure. Jimmy Harrel testimony, C-Span video. See from time 24:30 to 24:45 in the video. https://www.c-span.org/video/?293757-1/deepwater-horizon-incident-joint-investigation-jimmy-harrell-testimony

5.63 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.6 | Negative Pressure Test. Fifth paragraph on page 155. "*This time they were successful. According to witness accounts, 15 barrels of fluid were bled off from the drill pipe in the process.*"

5.64 Report of John Roger Smith, Deepwater Horizon Operational Data Review. Appendix B in the Deepwater Horizon Joint Investigation Team Report. Page 11, second paragraph. *"The "test" was continued by closing the "IBOP," presumably a drillstring valve in the top drive, which prevented monitoring the drillpipe pressure, and waiting for about 20 minutes. Evidence in the following period indicates that the drillpipe pressure below the IBOP built up during this period confirming the test was not a success. There is no obvious operational intent for this period."* https://www.bsee.gov/newsroom/library/deepwater-horizon-reading-room/joint-investigation-team-report

5.65 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.2, figure 16, page 97.

5.66 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 70, figure 27.

5.67 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.6 | Negative Pressure Test. Second paragraph on page 148. *"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."*

5.68 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.6 | Negative Pressure Test. Second paragraph on page 157. *"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." 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…".*

What Jason Anderson may have tried to explain, is that when heavier mud in the riser push against the annular the annular is compressed and fluid may slip through and generate pressure up the choke line. Anderson probably knew at the time that the choke line had been rerouted to the cement unit and that pressure increase that they were seeing came from the choke line and heavy mud in the riser and not from the drill pipe and the wellbore.

5.69 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.4, figure 2, page 139.

5.70 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 88, figure 4, bullet point 9. “*Fluid pumped into kill line to confirm full; kill line opened to mini trip tank for monitoring*.”

5.71 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Endnotes, page 305, note 91 in Chapter 4.6. “*While well site leader John Guide and drilling engineer Brian Morel have suggested that hydrates from migrating gas may have frozen in the kill line, no evidence has been produced suggesting that this actually took place or that gas had made it to the BOP as early as the time of the negative pressure test.”*

Chapter 6 – Displacing Riser with Seawater

6.1 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection. *Figure 4.7.8. Erratic Flow-Out vs. normal flow-out*, on page 175.
"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."

6.2 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 57, chapter ***4.2.3 Riser Flow Out***.
"Integrating the Sperry-Sun flow sensor data over the spacer displacement interval indicates a return volume of 459.8 bbl, compared to the anticipated pump volume of 454.7 bbl. This puzzling result seems to indicate a pumping efficiency of greater than 100%; however, further examination of the data reveals that the measured flow rate was artificially increased at the beginning of the spacer displacement because the trip tanks were emptied into the flow line."

6.3 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection. Page page 175, fourth paragraph.
"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". At 8:16 p.m., the data showed an increase in gas units - not atypical at the start of circulation."

6.4 The figure is generated from real time data from the Sperry-Sun computer by the author of this thesis. Note that to sets of flow out data exist. The data set that show peak flow of 300 gpm at about 20:01:30 is assumed to be the Sperry-Sun flow sensor. The flow out data that simultaneously shows about 90 gpm is assumed to be the Transocean paddle type flow sensor located in the flowline upstream the Sperry-Sun sensor. The Sperry-Sun system probably collected the raw data from the Transocean transmitter and send an update possible every 30 second to shore. This transmission of raw data was probably done in addition to the "live data" with Sperry-Sun data sent on a higher frequency.

6.5 On Friday, April 30th of 2010, an anonymous caller contacted the Mark Levin Show (talk show on radio) to clarify the events that preceded the Deepwater Horizon tragedy. The anonymous caller claimed he had observed the well blow out and up in the derrick at the time the drilling crew open the BOP annular after the negative pressure test. If this observation is correct, this may have been caused by compressed air in top of the displacement string and probably not by dense hydrocarbon gas in the wellbore.

6.6 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 96. ***Figure 39: Simulated vs. measured flow out of riser during second seawater displacement***.

6.7 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix G, page 96. ***Figure 40: Simulated vs. measured standpipe pressure during second seawater displacement, with tubing washout scenario***.

6.8 Note that there has been some discussion in the SES report (Transocean Investigation Report, Vol. 2, Appendix G) on how many barrels of spacer and freshwater that actually was pumped. The SES team has based the total volume pumped i on a total of 3 609 strokes (pump 3&4) and anticipated pump volumetric efficiency of 96.1 % equal to 454.7 bbls. In other words, 454.7 bbls spacer and no freshwater. However, the BP investigation team states on page 83 in their report that. "*A review of real-time data showed that the rig crew pumped 424 bbls of spacer, followed by 30 bbls of fresh water and 352 bbls of seawater*."

However, as the SES team has concluded not only 424 bbls was pumped from #5 but 454.7 bbls. This discrepancy is probably due to the 16 ppg spacer were being diluted with freshwater (possible freshwater that has been used to clean tanks) added to #5 during the pump sequence. Probably spacer and freshwater were pumped simultaneously from pit #5.

6.9 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 180. "*Drill Crew Notices Anomaly but Does Not Treat It as a Kick"*
"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. Revette, sitting in the driller's A-chair, and Anderson, standing next to him, were speaking to each other. At times, they looked at the driller's screens. Revette noted that they were "seeing a differential". The two men appeared concerned but calm. According to Young, "It was quiet... there was no panic or anything like that.""

Chapter 7 – BOP Failed to Close the Well

7.1 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 180. "*Drill Crew Notices Anomaly but Does Not Treat It as a Kick"*
"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 - apparently to eliminate the differential pressure. At 9:36 p.m., Holloway cranked open a valve on the standpipe manifold to bleed down the pressure. But it was taking longer than usual to bleed off. Revette told Holloway, "Okay, close it back."".

7.2 The figure is generated from real time data from the Sperry-Sun computer by the author of this thesis. Note that two sets of flow out data exist. The data set that show erratic flow behavior during the last minute or two (green line) is assumed to be the Sperry-Sun flow sensor. The flow out data that starts recording flow out at about 21:46:45 is assumed to be the Transocean paddle type flow sensor located in the flowline upstream the Sperry-Sun sensor. The Sperry-Sun system probably collected the raw data from the Transocean transmitter and send an update possible every 30 second to shore. This transmission of raw data was probably done in addition to the "live data" with Sperry-Sun data sent on a higher frequency.

7.3 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Chapter 4.7 | Kick Detection, page 191, figure 4.7.12.

7.4 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Section 3. Chronology of the Accident, page 28. *"~21:44 hours—Toolpusher called well site leader and stated they were "getting mud back" and that they had "diverted to the mud gas separator" and had either closed or were closing the annular preventer."*

7.5 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 106, figure 18. "*Annular preventer activated. Cumulative gain at 21:41 ~ 1,000 bbls*".

7.6 U.S. Chemical Safety and Hazard Investigation Board (CSB), Investigation Report, Drilling Rig Explosion and Fire at the Macondo Well, Volume 2, June 5, 2014 version, page 43, figure 3-4.

7.7 U.S. Chemical Safety and Hazard Investigation Board (CSB), Investigation Report, Drilling Rig Explosion and Fire at the Macondo Well, Volume 2, June 5, 2014 version, page 45, figure 3-5.

Chapter 8 – Main Contributions and Discoveries

8.1 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 96, figure 11 and page 94, table 1.

8.2 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5B, page 106, figure 18. "*Annular preventer activated. Cumulative gain at 21:41 ~ 1,000 bbls*".

See also endnote 2.56, 2.57, 2.58 and 2.59 in this Appendix B.

8.3 Macondo, The Gulf Oil Disaster, Chief Counsel´s Report | 2011, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling – Endnotes, page 305, note 91 in Chapter 4.6. "*While well site leader John Guide and drilling engineer Brian Morel have suggested that hydrates from migrating gas may have frozen in the kill line, no evidence has been produced suggesting that this actually took place or that gas had made it to the BOP as early as the time of the negative pressure test."*

8.4 The first time I wrote about the possibility of a gas hydrate plug in the riser in connection with Deepwater Horizon was in 2014. The first report with the title *"Is the Deepwater Horizon disaster a "Black Swan Event"?"* was prepared 6th of October 2014. Later the same year I made a revised version called "*Hydrates the last Puzzle Piece in the Deepwater Horizon disaster*" was prepared 29th of December 2014. Neither of the two reports got much attention and they were newer published. In 2015 a decided to apply for a PhD program at NTNU to further investigate what caused this disaster and why gas in the riser was not discovered before it was too late. This PhD thesis is the result of the work done in the four years period from 2016 to 2020.

8.5 The first recommended practice (API RP 92S) for *Managed Pressure Drilling Operations – Surface Back-pressure with a Subsea Blowout Preventer*, was prepared by the IADC UBO & MPD Committee for the American Petroleum Institute and issued in September 2018. My contribution in this document was limited to section 6.1.3 and 6.2.2.5, with respect to which standards that should be followed with respect to pressure protection of pressurized components. Section 6.2.2.5 on page 20 in this document states the following:
6.2.2.5 *Riser pressure protection provided by PRV designed in accordance with the following standards:*
— *API 14C or ISO 10418;*
— *API 520 (all parts);*
— *API 521;*
— *IEC 61511-1.*

8.6 Overpressure is defined as pressure in a process component in excess of the maximum allowable working pressure (MAWP).

8.7 BP Deepwater Horizon Accident Investigation Report, September 8, 2010. Analysis 5C *Hydrocarbons Ignited on Deepwater Horizon*, page 122, figure 10.

8.8 API RP 92S - *Managed Pressure Drilling Operations – Surface Back-pressure with a Subsea Blowout Preventer*, section ***6.2.2. General Principles*** and section **6.2.2.3** on page 19. "*The riser shall be protected from overpressure.*" https://www.apiwebstore.org/publications/item.cgi?c7681adb-8b54-478f-9b3d-e35d560ed5e1

8.9 See API RP 92S figure 2 on page 25 for an example of *Above Tension Ring System* and figure 3 on page 27 for an example of *Below Tension Ring Installation* of MPD systems with surface back-pressure and subsea BOP. https://www.apiwebstore.org/publications/item.cgi?c7681adb-8b54-478f-9b3d-e35d560ed5e1

8.10 API RP 14C – Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities, 8th Edition, February 2017. See Annex A – Process Component Analysis, Table A.1 – Flowline Segment Safety Analysis Table. https://www.apiwebstore.org/publications/item.cgi?fb2078d9-b1e6-4ec8-bb7d-11acb7fac6a4

Chapter 9 – Conclusion and Recommendations

9.1 U.S. Chemical Safety and Hazard Investigation Board, Investigation Report, Published: June 12, 2019. *Gas Well Blowout and Fire at Prior Trust Well 1H-9,* Pittsburg County, Oklahoma. See front page, Key Issues. "*Signs of Influx Either Not Identified or Inadequately Responded To*". https://www.csb.gov/csb-issues-final-report-into-fatal-gas-well-blowout/

9.2 U.S. Chemical Safety and Hazard Investigation Board, Investigation Report, Published: June 12, 2019. *Gas Well Blowout and Fire at Prior Trust Well 1H-9,* Pittsburg County, Oklahoma.
See chapter 5 *Incident Description*, page 24, first sentence including note [a].
"*On Sunday, January 21, 2018, at 6:30 am, while drilling at about 13,000 feet MD in the horizontal section of the well, gas began entering the wellbore.*[a]"

Note [a] is written in bottom of page 24.
" [a] At 7:29 am, gas units rose at the surface. The ***lag depth*** *at that time was 13,090 feet MD, indicating the gas originated at a depth of 13,090 feet. The bit was drilling at a depth of 13,090 feet MD at 6:29 am."*

If this (note [a] above) is the best available EKD method to detect and determine when an unexpected and unwanted entry of gas into the wellbore takes place this is not good enough because you want to detect the gas before it reaches the surface.

9.3 The CSB team has assumed that gas entered the wellbore about 6:30 based on gas recorded at the surface at 7:29. The CSB team has also assumed that this first influx apparently came from a measured depth (MD) of 13 090 ft, ref. comment "*indicating the gas originated at a depth of 13,090 feet."* However, it is possible that the initial influx originated from a gas zone at 7 093 - 7 136 ft MD? Secondly, is it possible that the gas influx was triggered by loss in the carbonaceous rock formation that the drilling crew accidently had drilled into at about 13 090 ft MD? See, page 25, figure 10 in the CSB Investigation Report. https://www.csb.gov/csb-issues-final-report-into-fatal-gas-well-blowout/

Appendix C – Input to SINTEF Calculations

C.1 National Academy of Engineering and National Research Council. 2012. *"Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety*", Fig. 2.3, page 23. Washington, DC: The National Academies Press.
https://doi.org/10.17226/13273

C.2 Actual casing run is shown in the BP Deepwater Horizon Accident Investigation Report, September 8, 2010, figure 3, page 19. The same figure is also shown as figure C.3 in Appendix C.

C.3 BP *Deepwater Horizon* Accident Investigation Report, September 8, 2010, last paragraph page 17: "*Drilling of the final 8 1/2 in. x 9 7/8 in. hole section started on April 2, 2010, and continued until April 4, 2010, when the well encountered lost circulation at 18,260 ft. Lost circulation pills were pumped to the bottom of the wellbore, and the mud weight was reduced from 14.3 ppg to 14.17 ppg. This solved the lost circulation problems. Full circulation was regained on April 7, 2010, and on April 9, 2010, the well was drilled to a final depth of 18,360 ft.*"

C.4 BP *Deepwater Horizon* Accident Investigation Report, September 8, 2010, page 22, Events Prior to April 19, 2010. April 5-6: "*Stripped drill pipe through upper annular preventer from 17,146 ft. to 14,937 ft. while addressing wellbore losses*."

C.5 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*B. Drilling Margin"*, page 30, last paragraph. The BOEMRE report is referring to an internal BP email on April 13, one week before the accident:
"We had one major problem however: the sand that we took the initial GeoTap pressure in was measured at 14.15 ppg. The absolute minimum surface mud weight we could use to cover the pore-pressure in this sand was 14.0 ppg. This would give us approximately a 14.2 ppg ESD over the aforementioned sand. If we were to drill ahead with a 14.0 surface mud weight/14.2 ESD, our equivalent circulating density (ECD) would be approximately 14.4-14.5 ppg. We had already experienced static losses with a 14.5 ppg ESD! It appeared as if we had minimal, if any, drilling margin… Drilling ahead any further would unnecessarily jeopardize the wellbore. Having a 14.15 ppg exposed sand, and taking losses in a 12.6 ppg reservoir in the same hole-section had forced our hand. We had simply run out of drilling margin."

C.6 Chief Counsel´s Report – Chapter 4.3, page 78, third paragraph.

C.7 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.2, figure 16, page 97.

C.8 BP *Deepwater Horizon* Accident Investigation Report, September 8, 2010, figure 3, page 19.

C.9 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.1, figure 2, page 43.

C.10 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.4, figure 2, page 139.

C.11 Macondo Well Incident, Transocean Investigation Report, Vol. 2, Appendix B, Macondo Casing Calculations, Table 1, page 3.

C.12 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011. Section; "*E. Float Collar*", figure 4, page 50.

C.13 Macondo Well Incident, Transocean Investigation Report, Vol. 1, page 51, Chapter 3.1.4 Conversion of the Auto-Fill Float Collar, figure 11 and 12.

C.14 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.4, figure 21, page 166.

C.15 OCS Report, BSSE Panel 2015-02, page 65, figure 39.

C.16 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*F. Well Ballooning*", page 34.

C.17 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, Section; "*B. Drilling Margin*", figure 2, page 30.

C.18 BP *Deepwater Horizon* Accident Investigation Report, September 8, 2010, figure 1, page 54.

C.19 BP *Deepwater Horizon* Accident Investigation Report, September 8, 2010, page 64, third paragraph.

C.20 National Academy of Engineering and National Research Council. 2012. *"Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety*", Chapter 2, *Well Design and Construction*, page 35.

C.21 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.1, figure 13, page 52.

C.22 Joint Investigation Report, Appendix F, Halliburton Report, *9.875" x 7" Foamed Production Casing Post Job Report*, page 4.

C.23 Seawater temperatures is generated from ocean viewer. A location of 88.5 W and 27.5 N is used to generate the table, which is at 1 500 m water depth south of Macondo.
http://iridl.ldeo.columbia.edu/SOURCES/.LEVITUS94/oceanviews2.html

C.24 Scientific Reports published online 07 May 2019. "*Overpressure at the Macondo Well and its impact on the Deepwater Horizon blowout*, (Pinkston & Flemings, 2019), figure 8, page 9.
https://www.nature.com/articles/s41598-019-42496-0

C.25 Vavik, D., Sangesland, S. and Shayegh, M. 2016. "Loss of Circulation an Indication of Hydrocarbon Influx?", figure 2, page 8. (SPE-179712-MS)
http://dx.doi.org/10.2118/179712-MS

C.26 Grigg and Lynes 1992. Oil-Based Drilling Mud as a Gas-Hydrates Inhibitor. *SPE Drilling Engineering* **7** (01): 32 – 38. SPE-19560-PA.

http://dx.doi.org/10.2118/19560-PA

C.27 Vavik, D., Sangesland, S. and Shayegh, M. 2016. "Loss of Circulation an Indication of Hydrocarbon Influx?", table 2, page 10. (SPE-179712-MS)
http://dx.doi.org/10.2118/179712-MS

C.28 Joint Investigation Report, Appendix F, Halliburton Report, *9.875" x 7" Foamed Production Casing Post Job Report*, page 5 & 6.

C.29 The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout*., September 14, 2011, figure 5, page 57.

C.30 National Academy of Engineering and National Research Council. 2012. *"Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety*", Fig. 2.6, page 30. Washington, DC: The National Academies Press.
https://doi.org/10.17226/13273

C.31 Halliburton datasheet for "Tuned Spacer III Cement Spacer".
https://www.halliburton.com/content/dam/ps/public/cem/contents/Data_Sheets/web/I_through_Z/Tuned-Spacer-III-Ultra-HT-spacer-fluid_H010314.pdf?nav=en-US_cementing_public

C.32 Macondo Well Incident, Transocean Investigation Report, Vol. 1, Chapter 3.1, figure 25, page 67.

Appendix E – Definitions and Glossary of Terms

E.1 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Glossary:Ballooning

E.2 IADC Drilling Lexicon.
https://www.iadclexicon.org/bullheading/

E.3 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Glossary:Cap_rock

E.4 Schlumberger Oilfield Glossary.
https://www.glossary.oilfield.slb.com/en/Terms/c/cavings.aspx

E.5 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Glossary:Connection_gas

E.6 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Glossary:Cross_flow

E.7 Variation of properties in the dense phase region; Part 2 – Natural Gas. PetroSkills – John M. Campbell, 2010.
http://www.jmcampbell.com/tip-of-the-month/2010/01/variation-of-properties-in-the-dense-phase-region-part-2-—natural-gas/

E.8 IADC Drilling Lexicon.
https://www.iadclexicon.org/drilling-margin/

E.9 IADC Drilling Lexicon.
https://www.iadclexicon.org/equivalent-circulating-density-ecd/

E.10 IADC Drilling Lexicon.
https://www.iadclexicon.org/equivalent-mud-weight/

E.11 Equivalent Static Density (ESD) is not defined by PetroWiki or IADC Drilling Lexicon. The definition is made for this thesis for clarity.

E.12 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Glossary:Filter_cake

E.13 Fracture Breathing Formation is not defined by PetroWiki or IADC Drilling Lexicon. The theory or hypothesis was presented in an unpublished paper at the IADC Well Control Europe 2016 Conference. The theory was presented to explain how extensive loss of drilling fluids resulted in large amount of gas returning from the well. Three other theories or hypotheses were considered and discussed to explain the observation of gas influx. The conclusion was however that the gas influx was caused by wellbore breathing.

Fracture Breathing Formation is also used to explain the swap out mechanism, where mud is lost to the formation in exchange with formation fluids in other field stories (Ashley, 2000, and Lage et al., 2002).

E.14 Gain in the context of drilling and completion is not defined by PetroWiki or IADC Drilling Lexicon. The definition is made for this thesis for clarity.

E.15 Gas Hydrates in the context of drilling and completion is not defined by PetroWiki or IADC Drilling Lexicon. The definition is made for this thesis for clarity. For further information about gas hydrates related to drilling and completion, see paper; "*Oil-Based Drilling Mud as a Gas-Hydrates Inhibitor*" (Grigg and Lynes, 1992), "*Inhibition of Gas Hydrates in Water-Based Drilling Muds*" (Kotoskie et al., 1992), "*Gas-Influx Events in a Deep Water Exploratory Well: A Field Case History*" (Lage et al., 2002), "*Loss of Circulation an Indication of Hydrocarbon Influx?*" (Vavik et al., 2016), "*Gas in Riser – The Elephant in the Room*" (Vavik et al., 2017A) and "*Method for Predicting Hydrate Formation*" (Vavik, 2017B).

E.16 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Glossary:Gas_kick

E.17 IADC Drilling Lexicon.
https://www.iadclexicon.org/influx/

E.18 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Glossary:Kick

E.19 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Lost_circulation

E.20 Schlumberger Oilfield Glossary.
https://www.glossary.oilfield.slb.com/Terms/m/mud_pulse_telemetry.aspx

E.21 IADC Drilling Lexicon.
https://www.iadclexicon.org/outflow/

E.22 The term “Primary well control” used in this thesis is a modified version of the definition by IADC Drilling Lexicon.
https://www.iadclexicon.org/primary-well-control/

E.23 PetroWiki by Society of Petroleum Engineers (SPE).
https://petrowiki.org/Glossary:Shale

E.24 Swap out is not defined by PetroWiki or IADC Drilling Lexicon. The definition is made for this thesis for clarity.

E.25 Wellbore breathing is not defined by PetroWiki or IADC Drilling Lexicon. The definition is made for this thesis for clarity. Some use the term wellbore breathing or fracture breathing formation to explain observed swap out.

E.26 Wellbore caving is not defined by PetroWiki or IADC Drilling Lexicon. The definition is made for this thesis for clarity.

Appendix C

Input to SINTEF Calculations

Table of Contents

Introduction

Figure C.1 below is from BP unpublished report, July 26, 2010. Reprinted with BP permission in; National Academy of Engineering and National Research Council. 2012. *"Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety"*.[C.1]

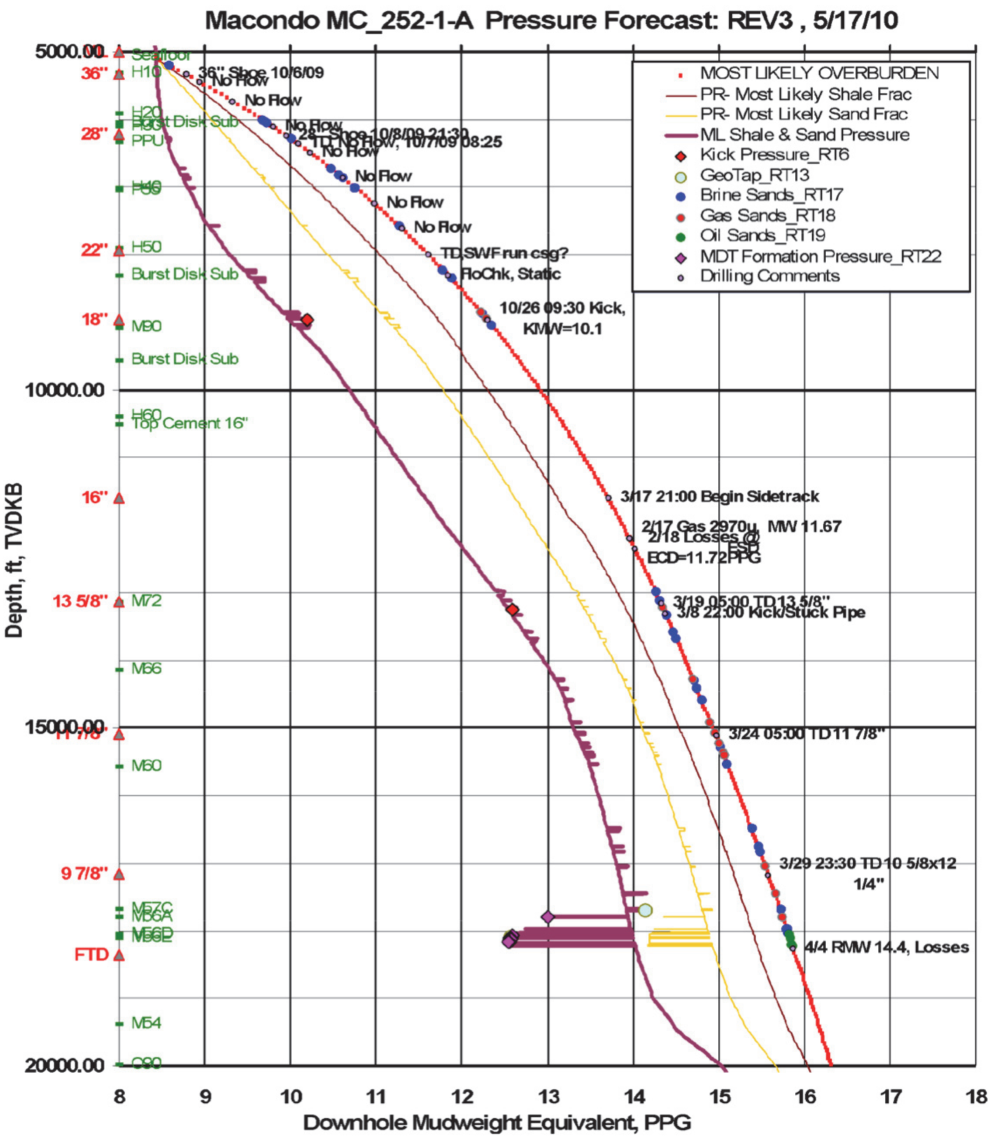

Figure C.1 – Macondo Well Pore Pressure Prediction [C.1]

This pore pressure prediction plot made from actual pore pressure measurements (and *most likely* (ML) prediction), is probably the best estimates of the pore pressures present prior to the Macondo well incident. The section of interest is the section between the 9 $^{7}/_{8}$" casing set at 17 168 feet and TD at 18 360 feet MD.[C.2] For hydraulic calculations the well can be considered to be vertical, i.e. measured depth (MD) equals true vertical depth (TVD). The two reservoirs of interest are a thin gas sand located at approximately 17 435´-17 440´ TVDKB and the lower oil sand located at 18 202´- 18 223´ TVDKB. The gas sand is assumed to have a vertical thickness of five feet.

From the pore pressure prediction plot (figure C.1) the pore pressure in the gas sand is approximately 14.16 ppg. This correspond to a pressure of 884.5 barg or 88.55 MPa absolute gas pressure in top of the gas sand.

The oil sand in the area where the lost circulation event occurred [C.3] has a considerably lower pressure. The pore pressure in top of the lower must oil sand was measured to be 12.54 ppg, see figure C.1. This corresponds to a pressure of 817.8 barg or 81.88 MPa absolute pore pressure in top of the lower most oil sand.

The pressure in the upper gas sand is approximately 6.67 MPa (967 psi) higher than the pore pressure in the lower oil sand. After the lost circulation event that took place on 4th of April 2010, the mud weight was reduced to 14.17 ppg.[C.3] This is only 0.01 ppg or 0.6 bar (9 psi) higher than the gas sand pore pressure according to figure C.1. There is also an indication that following the lost circulation event that took place on April 4, they may also have had a simultaneous gas influx or well control event. BP reported that on April 5 to April 6, the rig was stripping drill pipe through an upper annular preventer while addressing wellbore losses.[C.4] However, since no detailed information about the event that took place April 4 to April 7 is available, it is not possible to conclude why they closed the BOP. Full circulation was regained on April 7, 2010, and on April 9, 2010, the well was drilled to a final depth of 18,360 ft.[C.3]

According to Chief Counsel Report (CCR), the last of the lost circulation events occurred on April 9. The point at which the formation gave way, was with an ESD of approximately 14.5 ppg. The decision was taken to stop drilling. For any practical purpose they had run out of drilling margin.[C.5]

On April 16, before running the final 9⅞-inch × 7-inch long string production casing, the rig crew circulated the open wellbore bottoms up. 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. After circulating on April 16, gas eventually decreased to 20 to 30 units.[C.6] The high gas content after circulating bottoms up is an indication that the wellbore had taken some gas influx. Gas may have entered the wellbore during the last lost circulation event on the last day of drilling, during tripping or during well logging.

The main purpose of the calculations made by SINTEF is to test a hypothesis that gas also entered the wellbore and was present in the wellbore after the wellbore bottoms up was circulated on April 16. The hypothesis can be more specifically described and broken down into separate events leading up to the tragic accident:

1) During running the $9\frac{7}{8}$-inch × 7-inch long string production casing, a pressure surge in the wellbore may have resulted in drilling mud being exchanged with gas in the gas sand located at approximately 17 435´-17 440´ TVDKB.

2) The low circulation pressure observed prior to the cement job may have been caused by gas in the annulus.

3) The sudden reduction in circulation pressure observed during the cement job, shortly after the bottom plug reached the $9\frac{7}{8}$ × 7-inch cross-over, may have been caused by crossflow from the high-pressured gas sand and down to a loss zone located in a lower part of the wellbore, where loss have been observed when ECD exceed 14.5 ppg.

4) The abnormalities of loss and gain observed after the cement job and during tripping out the production casing running string may have been caused by gas hydrate forming and later dissociation of gas hydrates in the riser.

Further description and input for the hypothesis to be tested are given in this Appendix C.

Geometric Input to SINTEF Calculations

Topside cementing setup

Figure C.2 below is taken from Transocean Investigation Report, which shows the set-up during a negative pressure test.[C.7] A nitrogen unit for foam production during the cement job is added. Flowline segment identification numbers used for pressure drop calculation are also added for clarity. See Figure C.2 below and Table C.1.

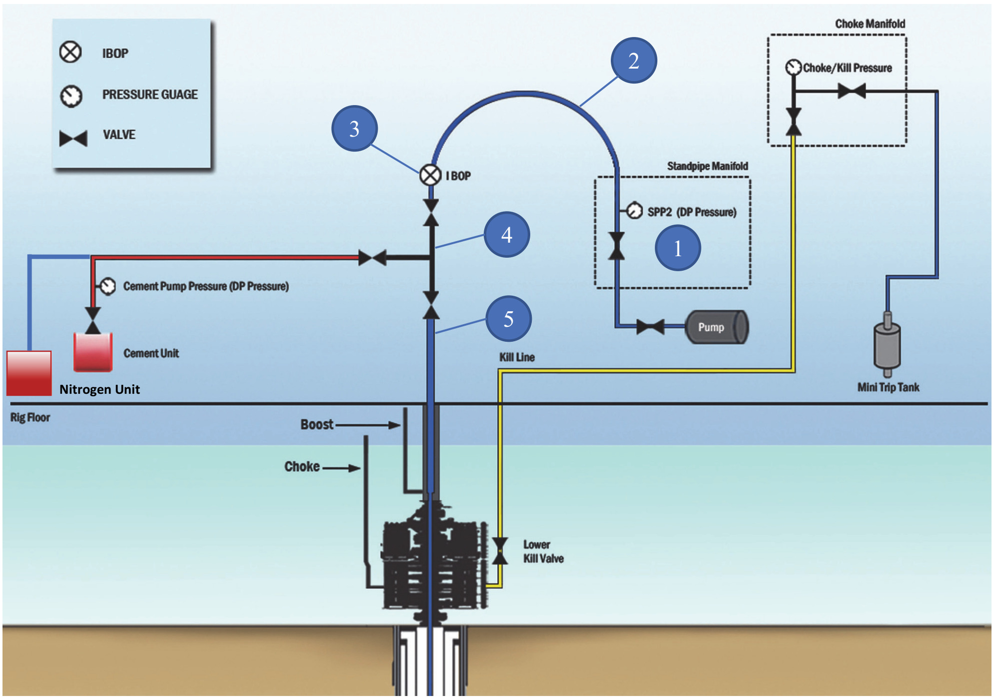

Figure C.2 – Simplified Schematic of the Assumed Line-up During Cementing Circulation [C.7]

Macondo well actual casing program

The actual casing run is shown in Figure C.3 below, taken from BP Deepwater Horizon Accident Investigation Report.[C.8]

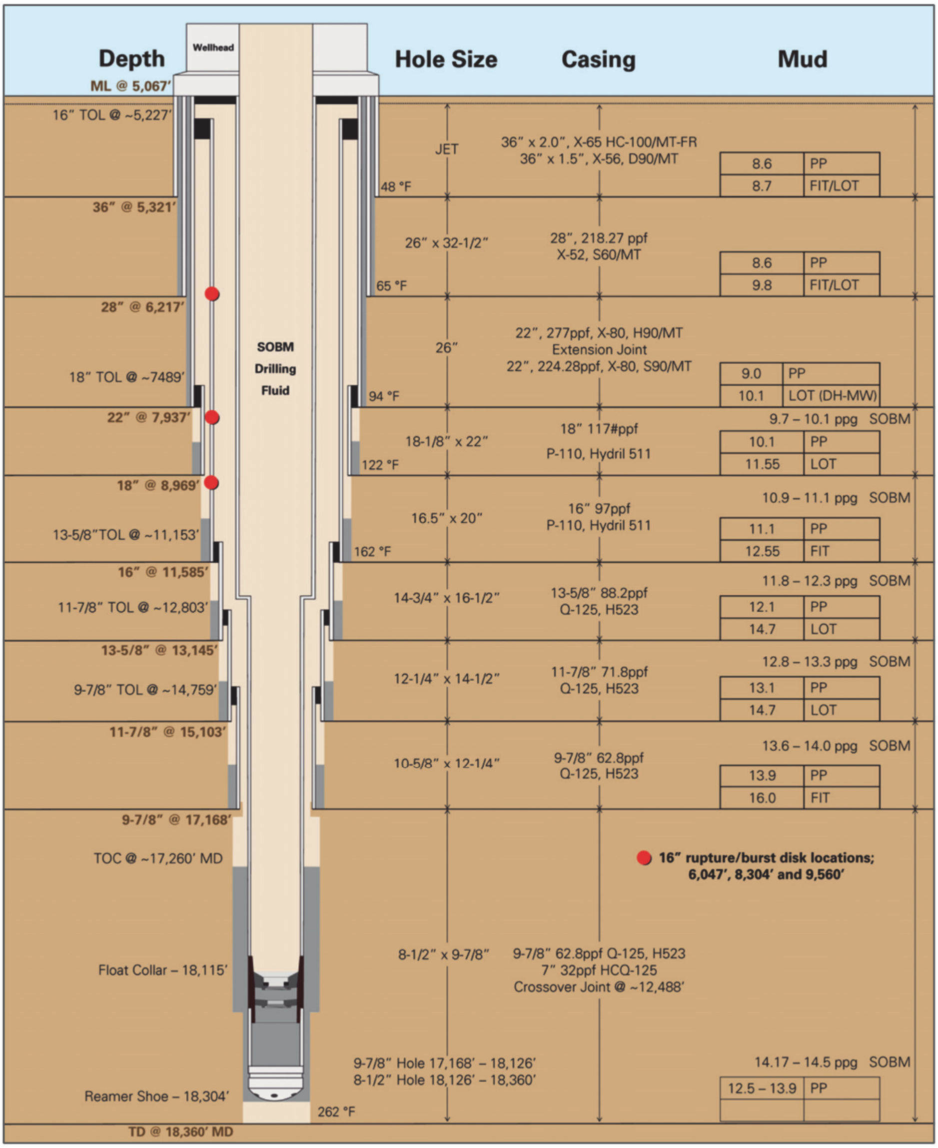

Figure C.3 – Actual Casing Run [C.8]

Figure C.4 is a drawing of the same wellbore with flow segments numbers. Blue numbers indicate internal tubular flow segments. Red numbers indicate internal casing flow segments.

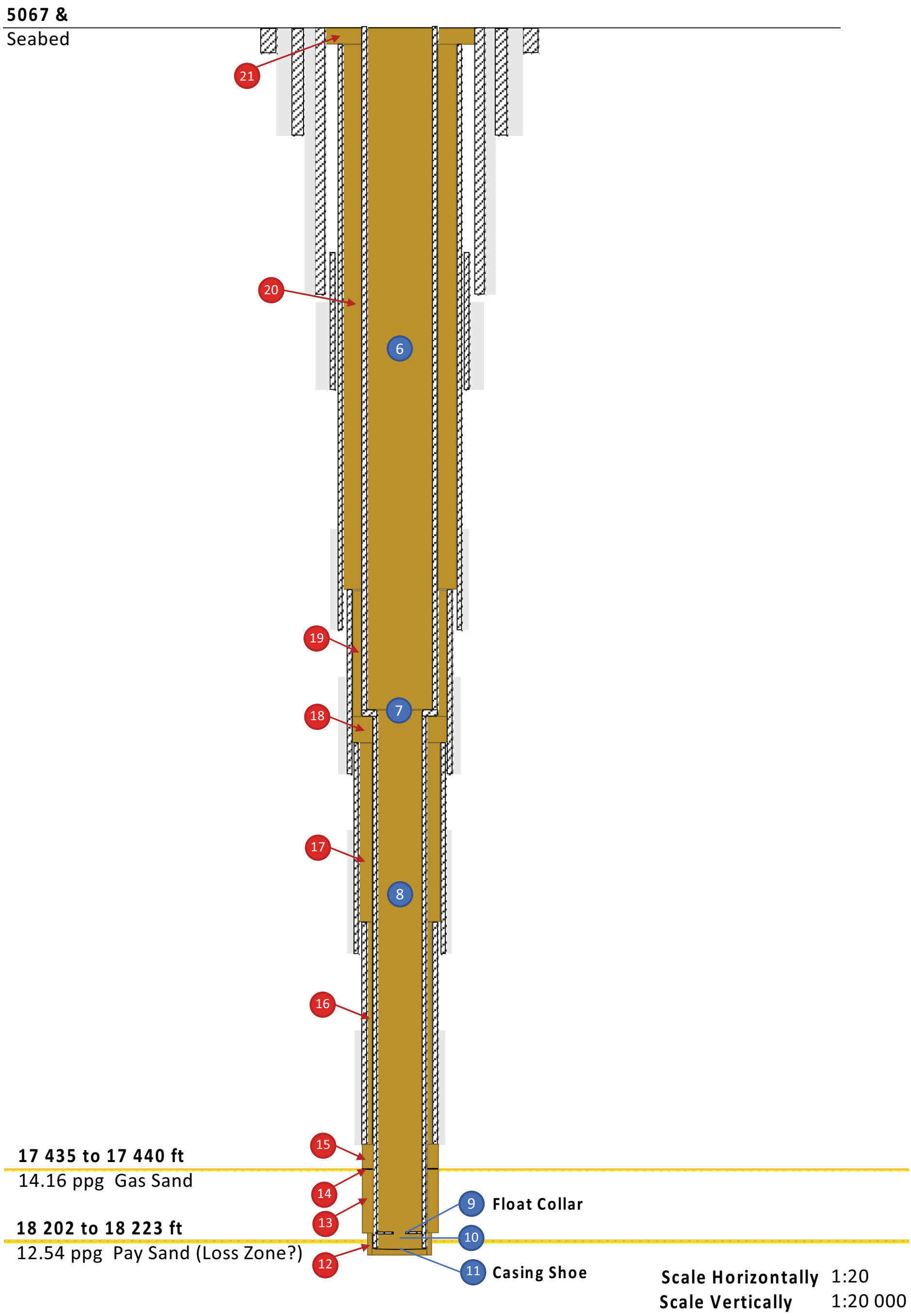

Figure C.4 – Wellbore Geometry with Flow Segment Numbers

Wellhead and Casing Hanger Geometry

Figure C.5 is a drawing of the subsea wellhead system taken from the Transocean Investigation Report.[C.9] Flow segment numbers added for clarity. Casing running tool and landing string not shown in this drawing.

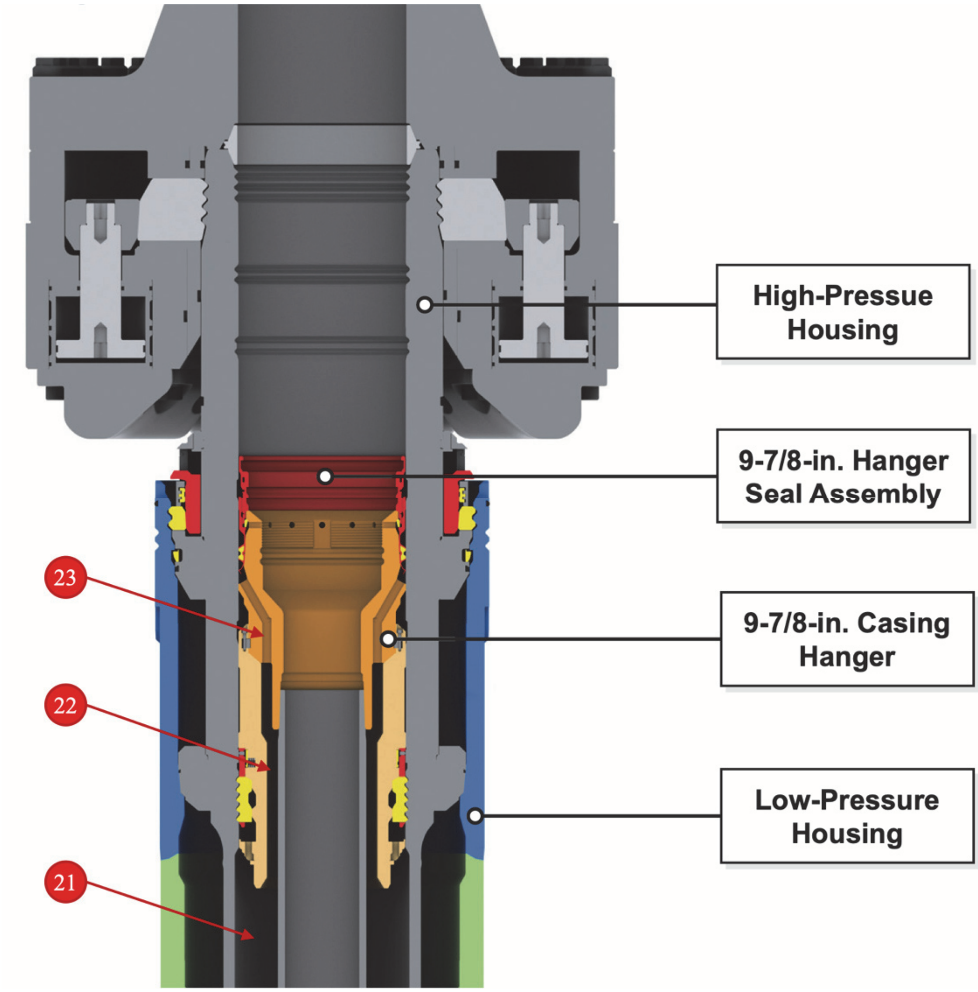

Figure C.5 – Wellhead and 9 7/8” Casing Hanger Geometry with Flow Segment Numbers [C.9]

BOP, LMRP and Riser

Figure C.6 is a drawing of the wellhead connector, BOP, LMRP and riser flex joint taken from the Transocean Investigation Report.[C.10] Flow segment numbers added for clarity.

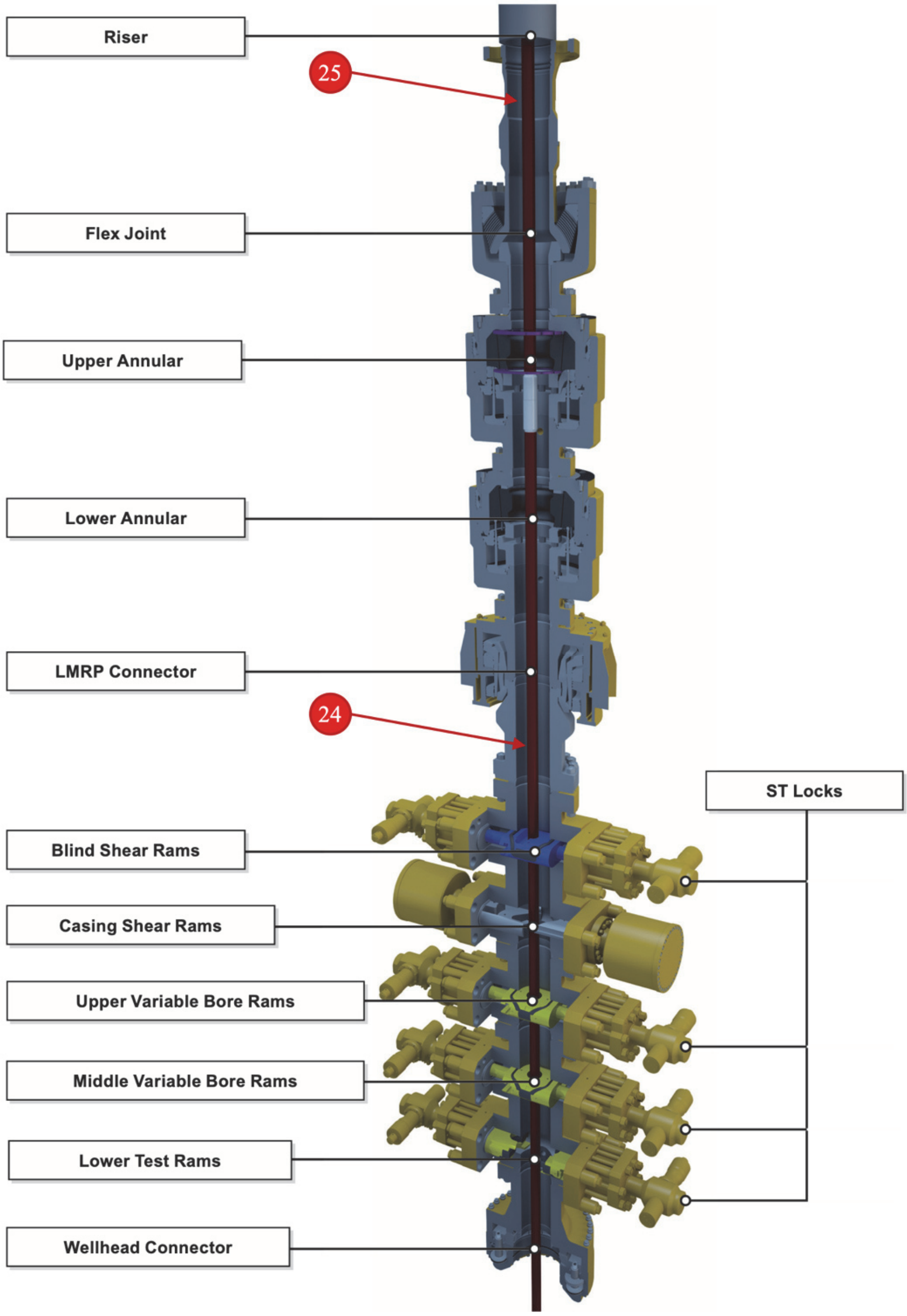

Figure C.6 – BOP, LMRP and Riser Flex Joint with Flow Segment Numbers [C.10]

Flow segment geometry

Flow ID	Flowline Segment Description	Diameter (OD only relevant for annulus)		Depth Lower	Depth Upper	Length (Equivalent Length)		Volume	
		OD in	ID in	ft	ft	ft	m	bbls	m^3
1	Standpipe Manifold		4.063	-5	-100	125	38.1	1.6	0.25
2	Mud Hose		5.000	-20	-100	200	61.0	4.9	0.77
3	IBOP and Top Drive		4.063	-11.5	-20	60	18.3	0.5	0.08
4	Cement Head		6.500	-4	-11.5	7.5	2.3	0.3	0.05
5	Landing String		5.426	5060	-4	5064	1543.5	145	23
6	9 $^7/_8$" Casing		8.625	12483	5060	7423	2262.5	536	85
7	9 $^7/_8$" x 7" Crossover		8.625	12488	12483	5	1.5	0.4	0.06
8	7" Casing		6.094	18115	12488	5627	1715.1	203	32
9	Float Collar		2.190	18117	18115	1.666	0.5	0.008	0.001
10	7" Casing		6.094	18302	18117	185	56.4	6.7	1.06
11	Casing Reamer Shoe		2.500	18304	18302	2	0.6	0.012	0.002
12	8 ½" Open Hole	8.500	7	18304	18126	178	54.3	4.0	0.64
13	9 $^7/_8$" Open Hole	9.875	7	18126	17440	686	209.1	32.3	5.14
14	14.16 ppg Gas Sand	9.875	7	17440	17435	5	1.5	0.2	0.04
15	9 $^7/_8$" Open Hole	9.875	7	17435	17168	267	81.4	12.6	2.00
16	9 $^7/_8$ x 7" Casing	8.575	7	17168	14759	2409	734.3	57.4	9.13
17	11 $^7/_8$ x 7" Casing	10.711	7	14759	12817	1942	591.9	124	19.7
18	13 $^5/_8$ x 7" Casing	12.375	7	12817	12483	334	101.8	33.8	5.37
19	13 $^5/_8$ x 9 $^7/_8$" Casing	12.375	9.875	12483	11153	1330	405.4	71.9	11.4
20	16 x 9 $^7/_8$" Casing	14.850	9.875	11153	5241	5912	1802	706	112
21	22 x 9 $^7/_8$" Casing	19.500	9.875	5241	5064	177	53.9	48.6	7.73
22	Wellhead annulus	12.000	9.875	5064	5062	2	0.6	0.090	0.014
23	Casing Hanger		18 x 1	5062	5060	2	0.6	0.035	0.006
24	BOP & LMRP			5060	5013	47	14.3	14.0	2.23
25	Riser Annulus			5013	4	5009	1526.7	1636	260

Table C.1 – Flow segment geometry after landing the production casing

Standpipe Manifold (Flow ID 1)

The standpipe manifold pressure sensors for real-time monitoring are assumed to be located approximately 5 feet above drillfloor or RKB. The top of the standpipe is assumed to about 100 ft above RKB and have an equivalent length for flow calculation of 125 ft (38.1 m). The internal diameter is assumed to be 4 $^1/_{16}$" (103.2 mm). Alternatively, the standpipe could also be 5 $^1/_8$" (130.2 mm), however this is not known, since a P&ID for the Deepwater Horizon is not available. Length of 30 m pipe is used for volume calculation.

Mud Hose (Flow ID 2)

The mud hose is assumed to be an API Spec 7K hose, rated for 7 500 psi and with an internal diameter of 5" (127 mm) and 200 ft (61 m) long. Mud hose is estimated to run from stand pipe 100 ft above RKB and down to top drive inlet 20 ft above RKB.

IBOP and Top Drive (Flow ID 3)

The IBOP and top drive flow segment is uncertain. However, the internal diameter is assumed to be 4 $^{1}/_{16}$" (103.2 mm). The flow path typically consists of three 45 deg. bends and two 90 deg. bends. Total equivalent length of the flow segment including the bends is estimated to 60 ft (18.3 m). Length of 10 m pipe is used for volume calculation.

Cement Head (Flow ID 4)

The cement head flow segment is uncertain. However, a Halliburton 6 $^{5}/_{8}$" FH SSR cementing head (Continuous – Head Plug Container) with internal diameter of 6.5" (165.1 mm) is assumed. Total length is estimated to 7.5 ft (2.3 m).

Landing String (Flow ID 5)

The landing string dimension is given in the Halliburton cement job report to have ID of 5.426" and length of 5060 ft. The landing string is assumed to start from 4 ft above RKB. For simplicity the running tool and 9 $^{7}/_{8}$" production casing hanger is included in flow segment 4. Total length of landing string is estimated to 5064 ft, including running tool and 9 $^{7}/_{8}$" production casing hanger.

9 $^{7}/_{8}$" Casing (Flow ID 6)

The 9 $^{7}/_{8}$" production casing dimension is given in the Transocean report, Vol 2, Appendix B to have ID of 8.625". Length is calculated from figure C.3 and table C.2 below. Start of the 9 $^{7}/_{8}$" production casing, is estimated at 5060 ft below RKB and not 5054 ft as given in table C.2 below. [C.11]

Macondo MC 252 #1 Well Casing Summary Table

Size	Weight (ppf)	Grade	Couplings	Set From MDBRT (ft)	Set To MDBRT (ft)
36"	2" / 1.5" wall	X65	HC-100 / D90	5071	5335
28"	218.3	X52	S60	5076	6231
22"	277 / 224.28	X80	H90 / S90	5068	7952
18"	117.0	P110	Hydril 511	7503	8983
16"	97.0	P110	Hydril 511	5241	11585
13.625"	88.2	Q125	SLIJ-II	11153	13145
11.875"	71.8	Q125	Hydril 513	12817	15103
9.875"	65.0	Q125	Hydril 523	14759	17168
7 x 9.875"	32 / 62.8	Q125	Hydril 523	5054	18285

Table C.2 – Macondo Casing Program [C.11]

9 $^7/_8$" x 7" Crossover (Flow ID 7)

The crossover is assumed to be a normal pipe reducer (not a sudden contraction). Downstream ID / upstream ID = 0.7. Equivalent length based on upstream ID is 18 times diameter = 155 ft (47.2 m). The actual length of the joint is estimated to be 5 ft and go from 12483 to 12488 ft below RKB.

7" Casing (Flow ID 8 and 10)

The 7" production casing dimension is given in the Transocean report, Vol 2, Appendix B to have ID of 6.094". Length is calculated from figure C.3 and table C.2. The 7" production casing goes from 12488 ft below RKB down to the float collar at 18115 ft. Flow ID 10 goes from the float collar (18117 ft) down to casing reamer shoe at 18302 ft below RKB.

Float Collar (Flow ID 9)

The float collar tube has an internal diameter of 2.19" (55.6 mm) and a length of approximately 0.5 m. See figure C.7 for details. [C.12]

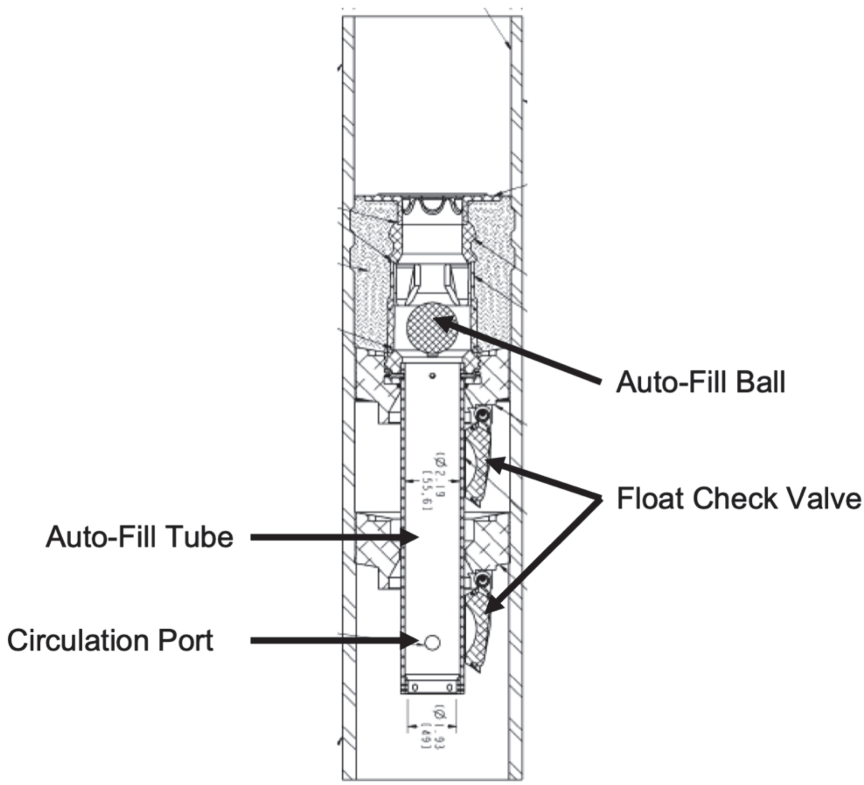

Figure C.7 – Auto-Fill Float Collar - Tube ID 2.19" (55.6 mm) [C.12]

Casing Reamer Shoe (Flow ID 11)

The casing reamer shoe outlet is estimated to be equivalent to a 2.5" ID tube of 2 ft. From elevation 18302 ft to 18304 ft below RKB.

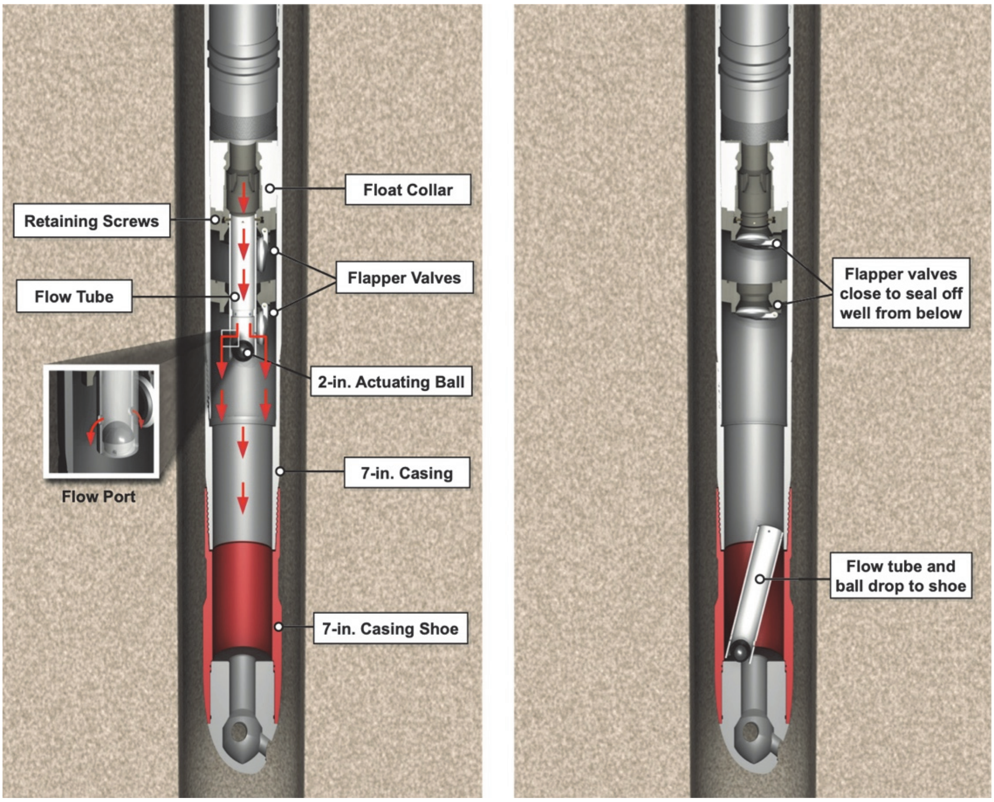

Figure C.8 – Auto-Fill Float Collar and Casing Shoe [C.13]

8 ½" Open Hole Annulus (Flow ID 12)

The outer diameter (OD) of the annulus (red color in table C.1) is 8.5 ". The inner diameter (ID) of the annulus is 7". Length is calculated from figure C.3 and table C.2.

9 $^{7}/_{8}$" Open Hole Annulus (Flow ID 13, 14 and 15)

The outer diameter (OD) of the annulus is 9.875 ". The inner diameter (ID) of the annulus is 7". Length is calculated from figure C.3 and table C.2. The 14.16 ppg Gas sand is assumed to be 5 ft thick going from 17435 ft down to 17440 ft below RKB. The purpose of the flow segment 14, is to calculate dynamic pressure (ECD) in top of the 14.16 ppg gas sand at 17435 ft below RKB.

9 $^7/_8$ x 7" Casing Annulus (Flow ID 16)
The outer diameter (OD) of the annulus is 8.575". The inner diameter (ID) of the annulus is 7". Length is calculated from figure C.3 and table C.2.

11 $^7/_8$ x 7" Casing Annulus (Flow ID 17)
The outer diameter (OD) of the annulus is 10.711". The inner diameter (ID) of the annulus is 7". Length is calculated from figure C.3 and table C.2.

13 $^5/_8$ x 7" Casing Annulus (Flow ID 18)
The outer diameter (OD) of the annulus is 12.375". The inner diameter (ID) of the annulus is 7". Length is calculated from figure C.3 and table C.2.

13 $^5/_8$ x 9 $^7/_8$" Casing Annulus (Flow ID 19)
The outer diameter (OD) of the annulus is 12.375". The inner diameter (ID) of the annulus is 9.875". Length is calculated from figure C.3 and table C.2.

16 x 9 $^7/_8$" Casing Annulus (Flow ID 20)
The outer diameter (OD) of the annulus is 14.850". The inner diameter (ID) of the annulus is 9.875". Length is calculated from figure C.3 and table C.2.

22 x 9 $^7/_8$" Casing Annulus (Flow ID 21)
The outer diameter (OD) of the annulus is 19.500". The inner diameter (ID) of the annulus is 9.875". Length is calculated from figure C.3 and table C.2.

Wellhead Annulus (Flow ID 22)
The outer diameter (OD) of the annulus is estimated based on figure C.5 to be 12". The inner diameter (ID) of the annulus is 9.875". Length is estimated to approximately 2 ft, based on figure C.5.

Casing Hanger (Flow ID 23)
Before the casing hanger seal assembly is set, return flow is allowed to flow through 18 holes with ID of approximately 1". Length is estimated to approximately 2 ft, based on figure C.5.

BOP and LMRP Annulus (Flow ID 24)
The outer diameter (OD) of the annulus in the BOP and LMRP up to the flex joint is 18 ¾" (18.750"), see figure C.9. The inner diameter (ID) of the annulus (i.e OD of the landing string) is 6.625". Length is estimated to approximately 568 inch or 47 ft, based on figure C.9. [C.14]

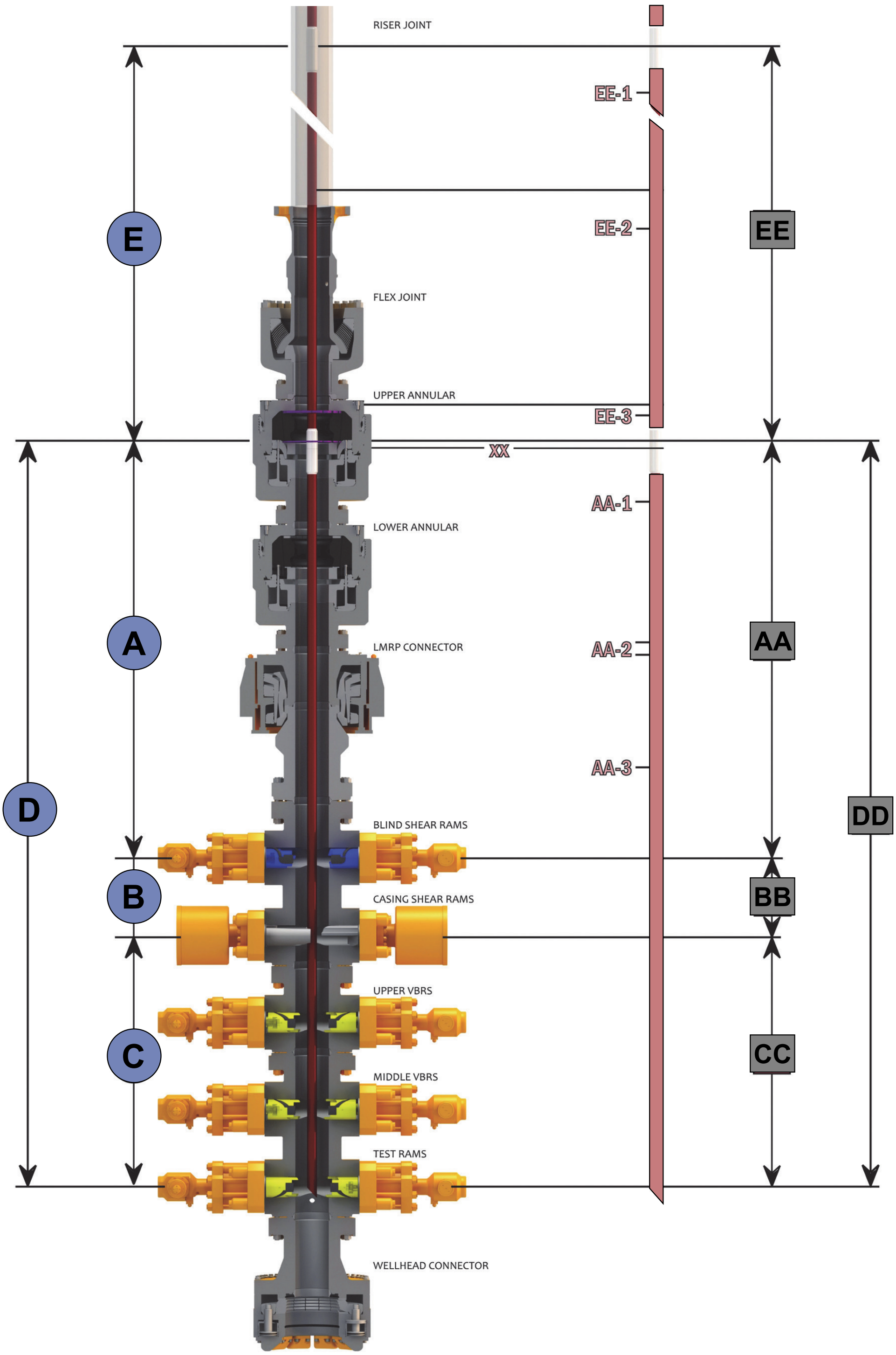

Figure C.9 – BOP, LMRP, Flex Joint and Drilling Riser [C.14]

Riser Annulus (Flow ID 25)
The outer diameter (OD) of the annulus in the riser is 19.5”. The inner diameter (ID) of the annulus (i.e OD of the running string) is 6.625”. Length is calculated from flex joint up (top of flow ID 24) to approximately 4 ft below RKB.

Hypothesis Description and Fluid Properties Input

The hypothesis outlined in the introduction section is further described in this section. The hypothesis is split into four different topics:

1) Swap-out due to sudden pressure variations and pressure surges.
2) Low circulation pressure may be an indication of gas influx.
3) Crossflow during cementing.
4) Hydrates forming in the riser.

SINTEF should use their expertise on the subject matter, as well as results from calculations by their well control simulator to discuss the four topics. Results of the calculations and discussion on the subject matter should be presented in a separate report from SINTEF (Appendix D).

Swap-out due to sudden pressure variations and pressure surges

Swap-out or the phenomena when drilling fluid or mud from the wellbore are being exchanged with gas in a high permeability gas sand, is not very well described in the literature. However, one of the best descriptions of this phenomena is perhaps shown in the SEMS Accident Investigation Report, investigating the root cause of the Hercules Rig 265 blowout and fire that took place July 23, 2013 in GoM. The theory behind the influx mechanism is that due to the density difference between the gas in the formation and drilling fluid, the well will be overbalanced in the bottom of the gas sand and underbalanced in the upper part of the gas sand, see figure C.10 below. The figure is taken from BSSE´s investigation report of the incident. [C.15]

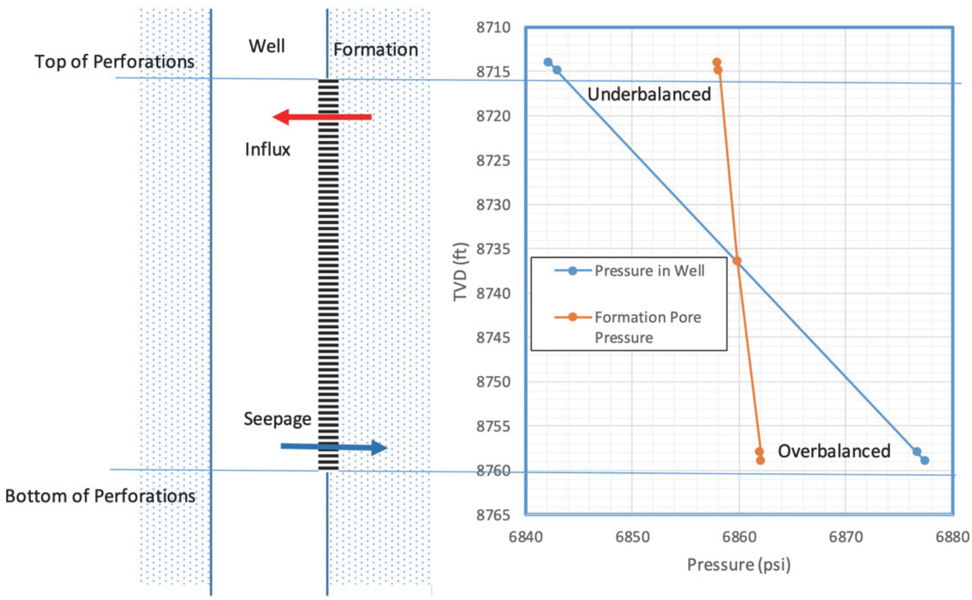

Figure C.10 – Seepage or Loss of Mud may Cause and Conceal Influx of Gas [C.15]

This situation may occur when the wellbore fluid or ESD is in balance with the pore pressure in the formation. In the case of the Macondo well we may assume that the wellbore was very close to or at the balanced condition, with an average mud density of 14.17 ppg and a gas sand pore pressure at 14.16 ppg.

The hypothesis is that gas influx was caused by increased downhole pressure due to pressure surge when the $9\frac{7}{8} \times 7$ -inch long string production casing was lowered. To explain the theory behind this hypothesis, the best way is to think of both the drilling fluid and the gas as relatively incompressible fluids. Although both fluids are compressible, natural gas in dense phase (supercritical fluid state), which will be the case at reservoir conditions (88.55 MPa), are less compressible than natural gas close to atmospheric conditions. The influx mechanism can in short be described in two stages similar to wellbore breathing, well ballooning and connection gas.

1) When the downhole pressure increases, mud will enter the highly permeable gas sand formation and displace the gas. The gas will be forced against the "sealing" or cap rock and result in increased pressure in the formation.
2) When a connection is made and the downhole pressure in the wellbore are back to static, the increased pressure in the formation will result in a gas influx in the top of the gas sand where the wellbore is in underbalanced conditions.

It is also possible that both of these stages occur more or less simultaneously. Meaning, that the mud loss in the lower part of the gas sand, due to increased downhole pressure results almost immediately in gas being pushed out in top of the gas sand and into the wellbore since the displaced gas has no other way to "escape".

Well ballooning is according to daily reports and the joint investigation BOEMRE report something that was experienced during drilling this critical stage with high pore pressure gas sand. This is what the BOEMRE report writes about well ballooning:

"*Well ballooning is a common phenomenon in which the formation absorbs drilling mud while the rig's pumps are activated and then releases the mud back into the well when the pumps are not active. Well ballooning is significant because it can mimic a kick. Rig crews can therefore miss critical kick indicators if they mistakenly believe that ballooning is occurring in the well.*

Mud logging data for the Macondo well demonstrated that the production casing zone started ballooning between 17,530 feet and 17,761 feet. The daily IADC reports also show that the well flowed back during flow checks following mud loss at those depths." [C.16]

It should be noted that when drilling these high pore pressure sand formations (M57) and experiencing well ballooning the mud weight (MW) was higher. On April 3, a 233 bbls loss was observed while drilling with 14.5 ppg surface MW. The MW was lowered to 14.3 ppg and the day after they lost full returns and 639 bbls of mud. Between April 4 and April 6 at 18 260 feet depth, the drilling crew lost a total 1586 bbls. To minimize losses the surface MW was lowered to 14.0 ppg and by that leaving the upper gas sand exposed for gas influx, see table C.3 below taken from the BOEMRE report.[C.17]

Open Hole Interval below 9 7/8-in Liner @ 17,168 - FIT 15.98 PP 13.9						
Date	Depth	MW	Losses	PP	Remarks	Hydrocarbon Zones
2-Apr	17,007 - 17,321	14.3			17,168 FIT 16.22 PPG	17,684 - 17,693 M-57C 14.1 PPG
3-Apr	17,321 - 17,835	14.5	233 bbls		17,723 - GeoTap 14.15 ppg (PP)	17,786 - 17,791 M-56A 13.1 PPG
3-Apr	17,835 - 17,909	14.3				
4-Apr	17,909 - 18,195	14.3		12.58 @ 18,089	Schematic - 12.6 ppg at 18,066	18,061 - 18,223 M-56E 12.6 PPG
4-Apr	18,215 - 18,250	14.4	639 bbls		Lost full returns	
5-Apr	18,260	14.0	1263 - Total			
6-Apr		14.0	1586 - Total			
7-Apr		14.0				
8-Apr		14.0				
9-Apr	18,360	14.0			called TD	

Table C.3 – Drilling margin data from IADC reports and BP Daily Reports [C.17]

Note also that the hydrocarbon zone (M-57C) between 17 684 - 17 693 feet depth in the last column of table C.3 is the same zone that is listed as *brine* sands in figure C.1 and figure C.11 below taken from the BP report.[C.18]

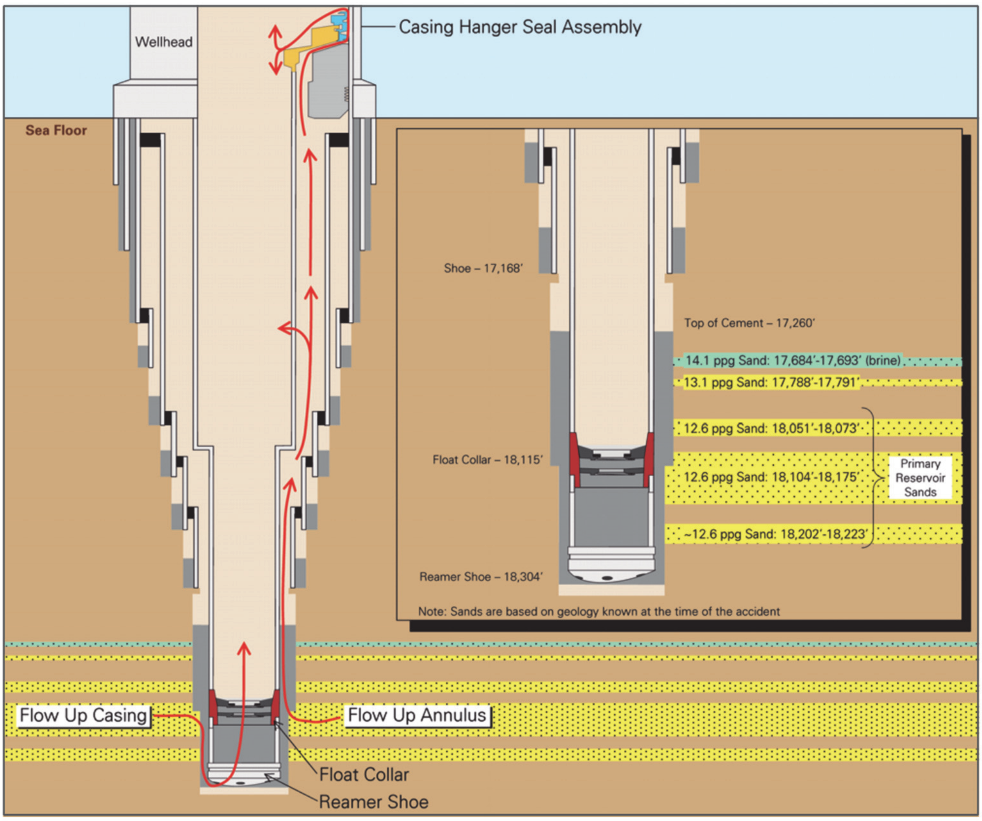

Figure C.11 – Hydrocarbon Zones and Potential Flow Paths [C.18]

In the BP report the potential for gas flow from this zone (M-57C) was discussed and evaluated.

"*The same OptiCem*^{TM} *report refers to a 14.01 ppg zone at 17,700 ft. (which, in fact, should be 14.1 ppg: the actual pressure measured using the GeoTap® logging-while-drilling tool). However, the report does not include a prediction of gas flow potential for this zone. In fact, this zone would not be expected to present a possibility of gas flow or hydrocarbon ingress, since the BP subsurface team for the Macondo well assigned this interval a value of zero net pay. This was because they found the thin sand layers in the interval to be below log resolution, and that attempts to obtain fluid samples were unsuccessful. The interpretation of fluid content was deemed uncertain, but it was probably water (brine)*." [C.19]

One reason that *the interpretation of fluid content was deemed uncertain* and that *attempts to obtain fluid samples were unsuccessful,* may have been that the formation was contaminated with mud. During the initial loss of 233 bbls on April 3, SOBM probably entered the sand formation (M-57C) at depth between 17 684 - 17 693 feet. Another possible explanation is that the GeoTap® tool that measured pressure to be 14.15 ppg at 17 723 feet depth, actually was logging in tight formation outside the sand zone (M-57C), see table C.3.

Although, the *BP subsurface team for the Macondo well assigned this interval a value of zero net pay,* it is a very interesting zone for potential well control issues. The potential for swap-out is even greater when this zone (M-57C) is considered together with the other gas sand located approximately 250 feet (76 m) higher up in the open wellbore with approximately pore pressure of 14.16 ppg, see figure C.1.

High permeability gas sands may explain the well ballooning and flow back observed between 17,530 feet and 17,761 feet while drilling with surface MW of 14.5 ppg.

Total loss of returns at 18,260 feet followed by reducing surface MW to 14.0 ppg, may explain the well control issues between April 4 to 6. There is an indication that following the lost circulation event that took place on April 4, they may also have a simultaneous gas influx in the upper gas sand having pore pressure at 14.16 ppg. The swap-out may occur when partial loss of mud in the lower gas/brine sand (M-57C) result in gas influx in the upper gas sand in the open wellbore. BP reported that on April 5 to April 6, the rig was stripping drill pipe through upper annular preventer while addressing wellbore losses.[C.4]

A similar swap-out may also have occurred on the final day of drilling. According to Chief Counsel Report (CCR), the last of the lost circulation events occurred on April 9. The point at which the formation gave way was with an ESD of approximately 14.5 ppg. The decision was taken to stop drilling.[C.5] On April 16, after several days with logging, the rig crew circulated the open wellbore bottoms up. 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. After circulating on April 16, gas eventually decreased to 20 to 30 units.[C.6] The high gas content after circulating bottoms up is an indication that the wellbore had taken some gas influx, possibly from a swap-out event that occurred on the April 9. The reason why the gas did not migrate and expand could be due to gas being dissolved or gas loading capability in the SOBM

(Skogestad et.al, 2017) and/or gas hydrates where forming higher up in the annulus (Vavik et.al, 2016).

In a similar way as described above it is also possible that SOBM are forced into either zone (M-57C) at depth between 17 684 - 17 693 or into the lower pay sands, due to the pressure surge when the 9⅞ × 7 -inch long string production casing was lowered, resulting in simultaneous influx of gas from the upper 14.16 ppg gas sand.

SOBM compressibility and density

The SOBM used in the Macondo well is far more compressible than WBM. This also results in that the MW increases with depth as the pressure gets higher. This is explained in the Transocean Report, Volume 2, Appendix G, Note 1 on page 27.

"*Note that the nominal surface density of the SOBM is 14.00 ppg; however, its actual measured average density in the well, which is used for all calculations herein, is 14.17 ppg (due to compressibility). The terms 'SOBM', 'mud', '14 ppg mud', etc. are used interchangeably herein; all refer to 14.17 ppg synthetic oil-based mud.*"

In calculating the correct downhole pressure SINTEF should use mud compressibility (c_m) taken from the BP Report, Appendix R to be 3.3358 x 10^{-6} (bbl/bbl/psi). [C.20] For example, if we consider one bbl of SOBM at 14.00 ppg surface density, how much will this one bbl be compressed when it is deep down in the wellbore balancing the 14.16 ppg gas sand (applied pressure is 884.5 barg or 12 829 psi). The following formula could be used to calculate the compressed volume (V_c). [C.20]

$$V_c = V_m \ \ \Delta p \ c_m \text{ where}$$

V_c = volume compressed (bbl);
V_m = total volume of mud (bbl);
Δp = applied pressure (psi); and
c_m = mud compressibility (bbl/bbl/psi).

$$V_c = 1 \text{ bbl x } 12\,829 \text{ psi x } 3.3358 \times 10^{-6} \text{ (bbl/bbl/psi)} = 0.0428 \text{ bbl}$$

This means that 1 bbl will be compressed down to (1 – 0.0428) = 0.9572 bbl, when transported down the well due to the static pressure above. In other words, the density of the SOBM will increase by 4.47 %. The 14.00 ppg surface density will increase to 14.62 ppg. If we assume a linear relationship as the mud compressibility (c_m) formula suggest, the average density down to the depth that will give this applied pressure (884.5 barg) will then be 14.31 ppg (1 715 kg/m^3). This is higher than the pore pressure of the gas sand with pore pressure of 14.16 ppg. The corresponding depth for applied pressure of 884.5 barg will be 5 257 m (17 248 feet). The 14.00 ppg will increase by 0.6260 ppg at a depth of 17 248 feet, corresponding to 0.036294 ppg/1000 feet.

It is not known why earlier reports have used an average density of 14.17 ppg for the SOBM in the well, since the density will increase with depth. The density in top of the riser is 14.00 ppg and the average density of the SOBM above, in the bottom of the well is 14.33 ppg. However, the average density half way down (at 9 180 feet) will be 14.17 ppg.

Low circulation pressure may be an indication of gas influx

Circulation was established after nine attempts to convert the float collar, see figure C.12 taken from the Transocean Report.[C.21]

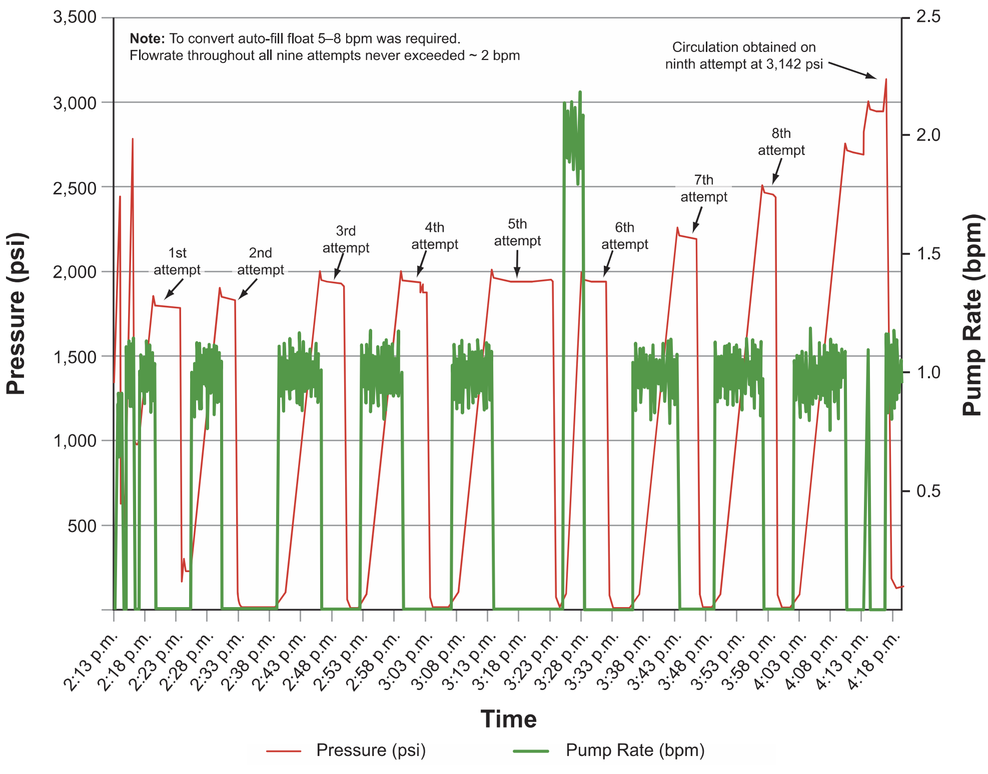

Figure C.12 – Nine Attempts Prior to Assumed Conversion of Auto-Fill Float Collar [C.21]

This implies that the flow path must have been plugged, possibly at the float collar. One assumption is that the sudden drop in pressure at 3 142 psi were not caused by the assumed conversion of the float collar, but by the ball being forced out of the tube. In the circulation pressure drop calculation SINTEF should carry out we assume that the ball is gone and the tube is left holding the two flapper valves open.

After the assumed conversion of the float and prior to the cement job, low circulation pressure was making the company man concerned. A description of the activities from 16:21 to 17:27 on April 19, is summarized in table C.4. The text is taken from the Halliburton cement job report. [C.22]

Time	Event
16:21	While attempting to increase to 3500 psi, pressure broke back with a max of 3142 psi (76 strokes / 9.6 bbls). Floats converted.
16:24	Circulating at 1 bpm with 137 psi. Company man feels uncomfortable with the circulating pressure being this low. Spoke with Jesse Gagliano about the situation.
16:30	Circulating at 1.5 bpm with 137 psi.
16:40	Circulating at 2.0 bpm with 190 psi.
16:44	Circulating at 2.5 bpm with 215 psi.
16:47	Circulating at 2.7 bpm with 233 psi.
16:49	Circulating at 3.0 bpm with 255 psi.
16:51	Circulating at 3.25 bpm with 274 psi.
16:53	Circulating at 3.5 bpm with 295 psi.
17:00	Circulating at 4.0 bpm with 340 psi. MI Swaco model estimates circulation pressure should be about 570 psi @ 4.0 bpm. Opticem estimated 370 psi at 1.0 bpm.
17:20	Rig decided to circulate with a different rig pump. Had been utilizing rig pump #4, will circulate utilizing rig pump # 3 to see the difference. Break circulation at 1 bpm with 245 psi. Pressure decreased to 205 psi.
17:22	Circulating at 1.5 bpm with 224 psi.
17:23	Circulating at 2.0 bpm with 260 psi.
17:24	Circulating at 2.5 bpm with 290 psi.
17:25	Circulating at 3.0 bpm with 320 psi.
16:26	Circulating at 3.5 bpm with 345 psi.
17:27	Circulating at 4.0 bpm with 396 psi. Note: Over time of circulating, driller noticed hookload had gradually decreased by 63k (from 450k to 387k). Did not drop off instantaneously, but gradually. Driller pulled up to initial hookload of 450k.

Table C.4 – Cement Job Log from 16:21 to 17:27 on April 19

Research questions

Was the low circulating pressure observed (see table C.4) caused by gas already present in the wellbore annulus? Meaning that gas has entered the well prior to landing the $9\frac{7}{8} \times 7$ -inch long string production casing at 13:40 or at least before the circulation was established at 16:21 on April 19.

The main research question above and the following additional tasks and research questions should be answered:

a) Use the SINTEF thermohydraulic flow model for drilling to simulate the circulation of 14.00 ppg SOBM (surface density) with mud compressibility factor (c_m) equals to 3.3358 x 10^{-6} (bbl/bbl/psi). Assume a viscosity normal for 14.00 ppg SOBM based on SINTEF experience. State your assumption in the SINTEF report about viscosity, and other important flow parameters used in your model.

- Use the circulation rate and time outlined in table C.4.
- Leave a period of 15 minute between 17:05 to 17:20 to simulate expected pressure with no circulation (static conditions).
- Compare the calculated circulation pressure upstream flow segment 1 (at the mud standpipe pressure (SPP) transmitter location) with the observed circulation pressure from table C.4.
- Calculate pressure and annulus temperature for at least the following locations, with special interest:
    i. Lower part of flow segment 12, in the 8 ½" open hole annulus at the casing reamer shoe depth of 18 304 ft.
    ii. Top of flow segment 14, in the 9 $^7/_8$" open hole annulus at top of the 14.16 ppg gas sand depth of 17 435 ft.
    iii. Top of flow segment 21, in the 22 X 9 $^7/_8$" casing annulus upstream the casing hanger.
    iv. Lower part of flow segment 23, in the BOP annulus downstream the casing hanger.
- For the dynamic temperature changes in the annulus due to circulation and fluid being heated and cooled down by ambient temperatures, see chapter **Input and assumptions to thermal calculations**.

b) Assume gas in the annulus was causing the low circulation pressure due to reduced U-tube effect. How much gas must have been present in the annulus, assuming gas is evenly distributed from top of the 14.16 ppg gas sand at 17 435 to the casing hanger annulus in the wellhead (top of flow segment 21)?

- Discuss based on SINTEF previous research how gas in SOBM effect the overall density of the gas cut mud.
- Based on temperature and pressure particularly in the wellhead area, assume that hydrates where forming in the BOP annulus. Discuss how the volume reduction or consumption of gas, when hydrates are forming effects the dynamic pressure and temperature distribution in the annulus. See chapter **Input and assumptions to gas influx and gas hydrates calculations**.

c) Based on the assumption of gas cut mud in the annulus below the casing hanger and gas hydrates forming in the BOP annulus, recalculate task a) above and check if it is possible to get the observed SPP in C.4 to match your simulations.

d) Discuss the observed pressure drop from 245 psi to 205 psi, when starting circulation up again at 17:20. Is it possible that this is caused by hydrates restricting/plugging the casing hanger flow passage?

e) Discuss the gradual decrease in hook load observed at 17:27. Is it possible that the this is caused by increasing flow and increased pressure differential across the casing hanger (from flow segment 21 to 23)?

Input and assumptions to thermal calculations

SINTEF should state the assumptions and constants used in their thermal calculations. SINTEF may use values based on the below input or use other values, if they feel that is more appropriate.

Seawater temperature profile

Depth (m)	Salinity (p.s.u.)	Temperature (°C)	Density (g/cm^3 above 1)
0.0	35.1112	25.5228	0.02326708
10.0	35.7415	25.40299	0.02382255
20.0	36.039	25.05732	0.02419602
30.0	36.1654	24.49263	0.0245058
50.0	36.3084	23.08835	0.02511606
75.0	36.3732	21.52332	0.02571905
100.0	36.3737	20.23932	0.02617929
125.0	36.3377	19.06235	0.02657127
150.0	36.2568	17.99938	0.02688949
200.0	36.0417	16.11302	0.0274016
250.0	35.7973	14.4602	0.0278104
300.0	35.5888	13.18018	0.02814628
400.0	35.2422	10.89691	0.02877906
500.0	35.0266	9.13901	0.02937965
600.0	34.9138	7.869442	0.02995702
700.0	34.9007	6.930855	0.03054968
800.0	34.9	6.163006	0.03112108
900.0	34.919	5.560816	0.03168064
1000.0	34.9369	5.153398	0.03220988
1100.0	34.9493	4.809706	0.03272518
1200.0	34.9587	4.613125	0.03321686
1300.0	34.9646	4.482824	0.03369601
1400.0	34.9935	4.379809	0.03418886
1500.0	34.9755	4.306252	0.03464019

Table C.5 – Seawater Salinity, Temperature and Density vs Depth [C.23]

To calculate the heat transfer between the cold seawater and the SOBM inside the riser annulus is a complex calculation that is depending on many factors such as insulation effect of buoyancy elements on the riser, type of coating, number of bare joints, and the velocity of fluids. SINTEF should use their best experience and state their assumption for these calculations.

SINTEF may use seawater temperatures based on table C.5. The table is generated from ocean viewer, from 1500 meter water depth in the GoM close to the Macondo prospect.[C.23]

Formation temperature profile

The formation temperature profile is shown in figure C.13. The figure is taken from the report "*Overpressure at the Macondo Well and its impact on the Deepwater Horizon blowout*", (Pinkston & Flemings, 2019). Temperatures between 113.3 and 113.7 °C were recorded at three MDT sample points in the Macondo well between 13,008 and 13,064 ft (3,965 and 3,982 m) below seafloor.[C.24]

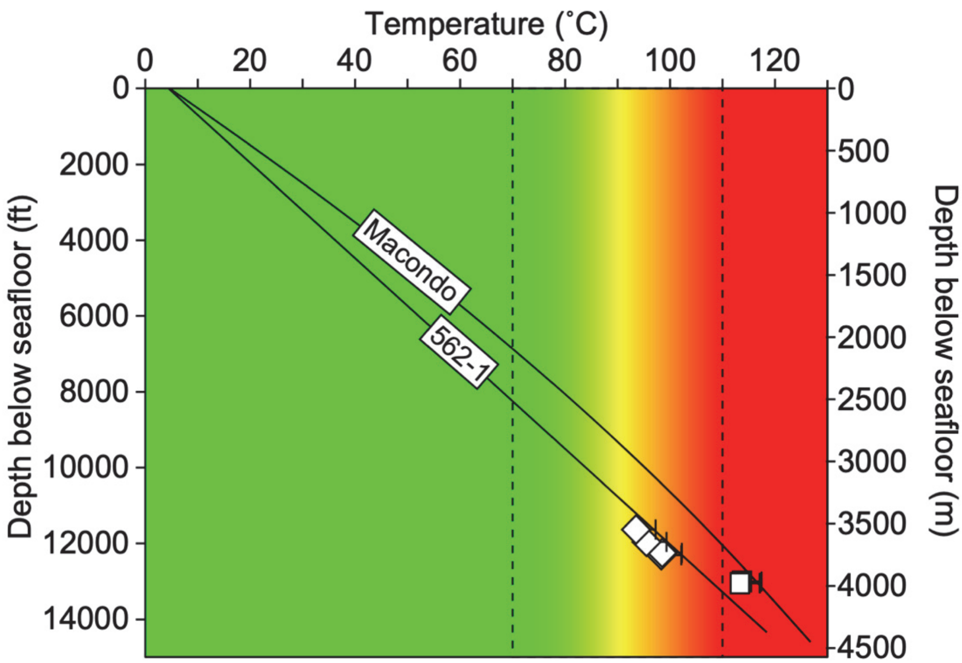

Figure C.13 – Temperature vs Depth below seafloor at Macondo and 562-1 [C.24]

Input and assumptions to gas influx and gas hydrates calculations

The gas influx is assumed to come from the 14.16 ppg gas sand, flow segment 14 in table C.1. Gas composition is not known. For calculation purpose SINTEF may use a typical natural gas composition with molecular weight around 20 g/mol.

Gas hydrate formation depends on pressure and temperature, see figure C.14 (Vavik et al., 2016).[C.25]

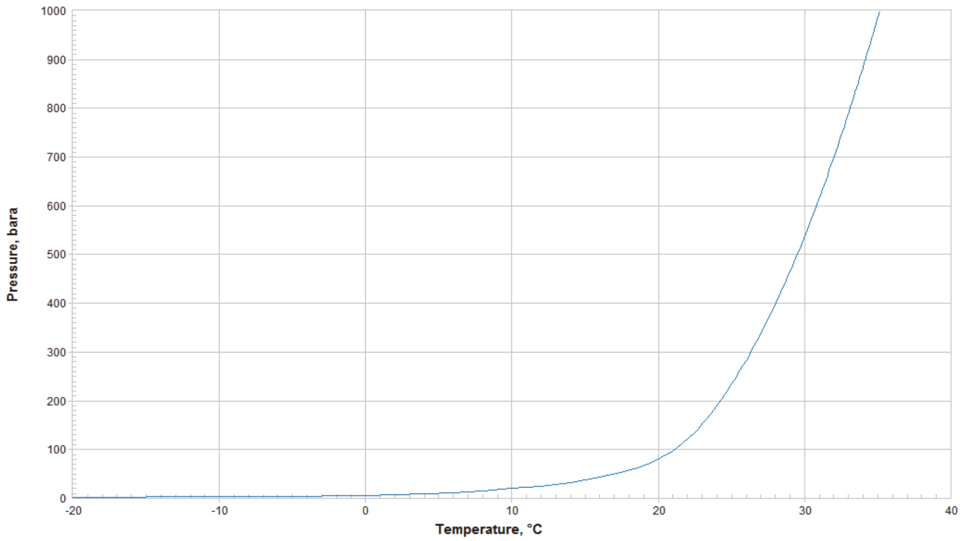

Figure C.14 – Hydrate pressure and temperature curve for natural gas and water [C.25]

In order for the gas to form gas hydrates with the water in the SOBM, the gas needs to be cooled down to below the temperature where hydrates may form. Composition of the SOBM used in the Macondo well is not known. However, oil-based mud usually contains 10-20% water (brine). In a paper called "*Oil-Based Drilling Mud as a Gas-Hydrates Inhibitor*", (Grigg & Lynes, 1992) experiments showed that with 19.22 wt % $CaCl_2$ brine in the oil-based mud, the gas-hydrate inhibition was 30 °F (16.7 °C).[C.26] SINTEF may use the hydrate curve in figure C.14 and subtract 16.7 °C to account for the brine in the SOBM.

If the pressure in the wellhead/BOP area is 250 bar, the corresponding hydrate formation temperature is approximately 25 °C, see figure C.14. With SOBM in the annulus the corresponding hydrate formation temperature will be approximately (25-16.7) 8.3 °C. If we assume the annulus SOBM has been cooled down to ambient temperature of 4.3 °C, this is approximately 4 °C lower than the hydrate formation temperature.

When hydrates are forming a volume reduction will occur. The volume reduction is mainly depending on the density of the gas when hydrates are forming, see table C.6. SINTEF may calculate the volume reduction when or if hydrates are forming based on this table C.6, (Vavik et al., 2016).[C.27]

Pressure (bara)	Temp-erature (ºC)	Molecular weight (g/mol)	Gas density (kg/m^3)	Hydrate density (kg/m^3)	Volume reduction relative to volume of gas (%)
700	27	16.04	311.1	917.7	47.4
520	4	20.29	321.2	932.5	51.9
500	5	16.04	291.3	912.3	47.3
500	10	16.04	286.5	913.9	49.1
500	15	16.04	281.9	915.2	50.8
260	4	20.29	289.7	930.3	56.4
200	5	16.04	172.5	909.9	68.7
200	10	16.04	166.7	911.9	70.5
200	15	16.04	161.4	913.6	72.0

Table C.6 - Volume reduction relative to volume of gas that form hydrates [C.27]

Crossflow during cementing

The cement job started about 19:47 on April 19 and finished about 00:43 on April 20. Time and events from the Halliburton cement job report are listed in table C.7.[C.28] A third column with comments and assumptions has been added for clarity.

From 19:47 up to 21:43 circulation was performed with the cement unit. At 21:12 all cement and spacer had been pumped and displacing cement with SOBM using the cement pump started. At 21:43 133 bbls of SOBM has been pumped, giving an average circulation rate of 4.29 bpm, see table C.7.

From approximately 21:45 to top plug pumped at the float collar at approximately 00:36, the circulation was carried out with the rig pump. Based on Halliburton log 728.5 bbls of SOBM was circulated with the rig pumps. Based on a total time of approx. 171 minutes, this gives an average continuous circulation rate of 4.26 bpm. This also correspond with the real-time data from the rig, see figure C.15. The joint investigation team has calculated based on real time data that the difference between flow-in and flow-out throughout the duration of the cement job was approximately 80 bbls.[C.29]

For foamed cement calculation, see figure C.16.[C.30]

Time	Event	Comments and Assumptions
19:47	Pump 7 bbls of 6.7 ppg base oil. Had 5 bbls of mud ahead of base oil.	Assume 14.0 ppg SOBM to fill up lines from cement unit before base oil.
19:53	Pump 10 bbls of 14.3 ppg Tuned Spacer III to break circulation.	Tuned Spacer III is a water-based spacer. [C.27]
19:54	Returns seen at wellhead.	
19:57	Test Cement Lines to 5000psi – bleed off no leaks noticed	
19:59	Pump 62 bbls of Tuned Spacer III at 14.3 ppg – Sem-8 online.	
20:17	Finished pumping spacer. Wash out measuring tanks.	
20:28	Start weighing up cement.	
20:37	Started pumping 16.74 ppg Unfoamed Lead Cement – ZoneSeal 2000 online. Pumped 4 bbls of Unfoamed Lead Cement (1 Downhole / 3 In Lines)	
20:39	Drop dart to release bottom plug.	
20:41	Completed Unfoamed Lead Cement. Total of 5 bbls.	
20:42	Started pumping Tail Cement foamed to 14.5 ppg – Nitrogen online.	Foam cement is 6.0 ppg at surface, 14.5 ppg down hole. [C.26]
21:00	Completed Foamed Tail Cement. Total of 39 surface bbls – Nitrogen offline.	Total foam cement is 39 bbls + nitrogen. 109 bbls at surface (6.0 ppg) and 45 bbls down hole (14.5 ppg). See figure C.16.
21:01	Started pumping 16.74 ppg Un-foamed Shoe Cement.	
21:03	Completed Un-Foamed Shoe Cement. Total of 7 bbls.	
21:04	Pump 3 bbls of 14.3 ppg Tuned Spacer to clear lines of cement.	
21:05	Drop dart to release top plug.	
21:06	Pump 17 bbls of 14.3 ppg Tuned Spacer – Sem-8 online.	
21:11	All spacer pumped.	
21:12	Start displacing cement with 14.0 ppg SBM using HES pumps.	
21:21	Dart #1 through diverter at 3500 psi with 43 bbls of SMB pumped using HES pumps.	
21:23	Dart #1 through DTD at 3200 psi with 50 bbls of SMB pumped using HES pumps.	
21:35	Dart #2 through diverter at 3150 psi with 101 bbls of SMB pumped using HES pumps.	
21:37	Dart #2 through DTD at 3350 psi with 109 bbls of SMB pumped using HES pumps.	
21:39	Dart #2 launched top plug at 3300 psi with 117 bbls of SMB pumped using HES pumps.	
21:43	Finished pumping 133 bbls of SBM & turn over to the rig to complete displacement.	
23:39	Bottom plug through X-over at 830 psi with 469.5 bbls of SBM pumped with the rig pumps.	
23:53	Top plug through X-over at 500 psi with 525 bbls of SBM pumped with the rig pumps.	
00:29	Bottom plug bumped at 2900 psi with 673 bbls of SBM pumped with the rig pumps	
00:40	Top plug bumped at 1150 psi (1000 psi over circulating) with 728.5 bbls of SBM with the rig pumps.	

Table C.7 - Cement Job Log from 19:47 on April 19 to 00:40 on April 20

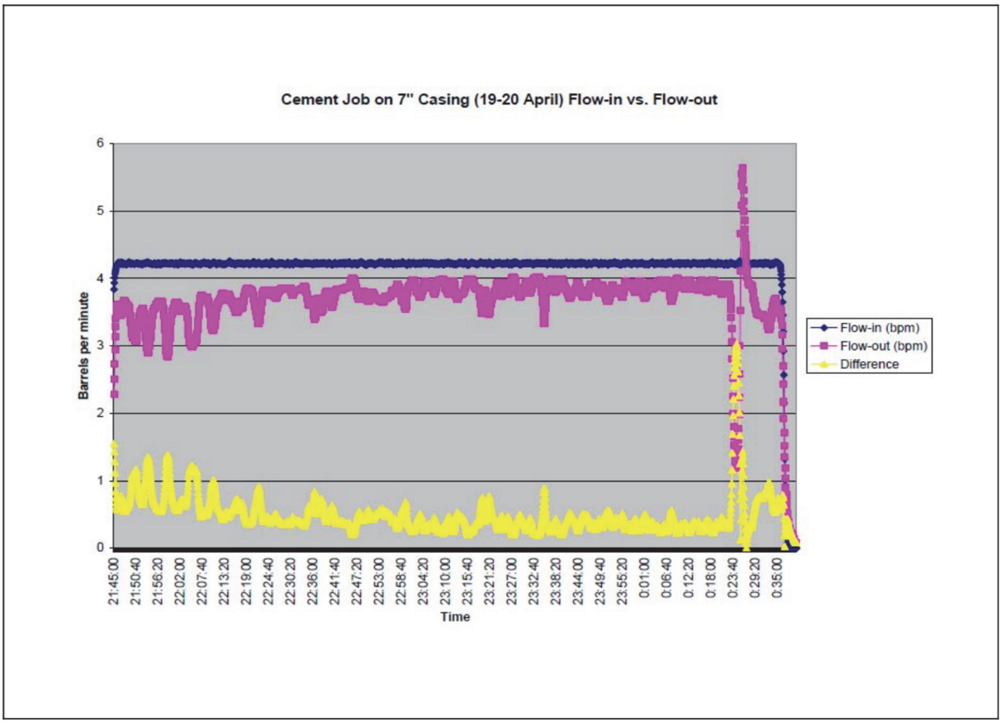

Figure C.15 – Flow-out vs flow-in during cement job, circulating with the rig pump [C.29]

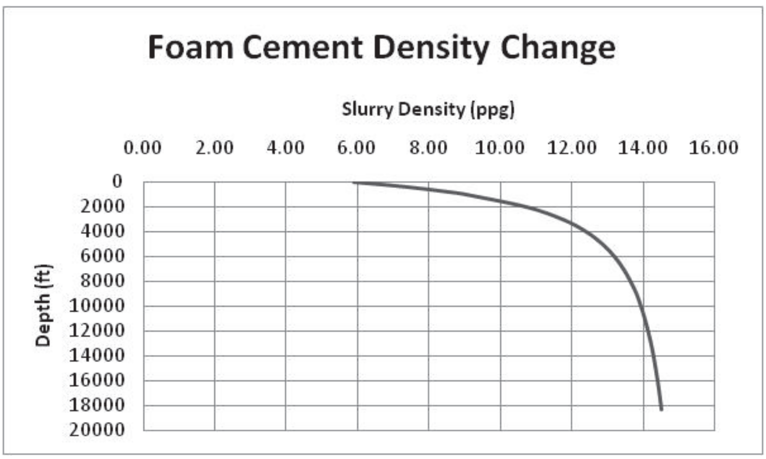

Figure C.16 – Calculated foam density versus depth during pumping [C.30]

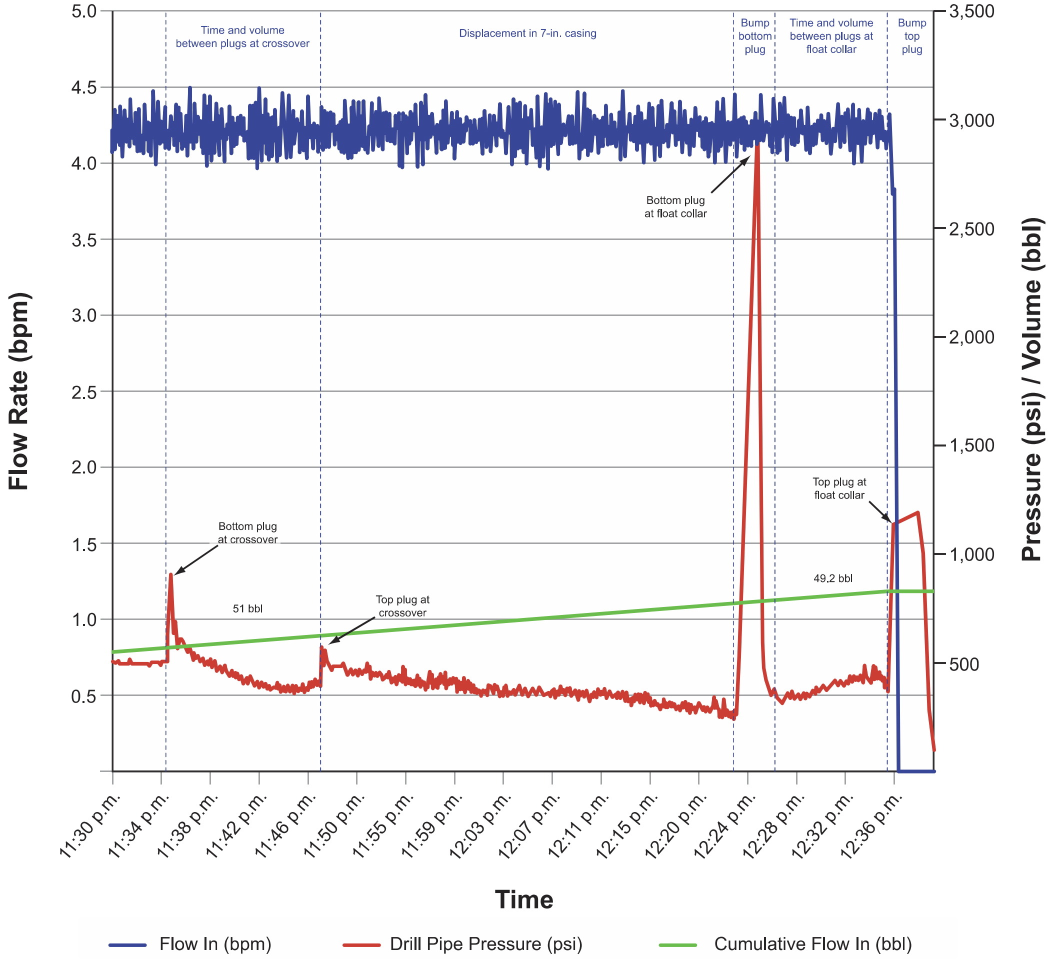

Figure C.17 – Standpipe pressure during the last hour of the cement job [C.32]

Research questions

Calculate standpipe circulation pressure during the cement job and compare results with pressure reported in table C.7 and figure C.17.[C.32] Based on the results from the simulation and SINTEF experience, the following research questions should be answered:

a) Is it possible that gas is present in the annulus and that gas influx is coming from the 14.16 ppg gas sand during the entire cement job and that the influx is concealed by a loss of fluids taking place simultaneously in a lower part of the open wellbore? I.e. the 80 bbls difference between flow-in and flow-out throughout the duration of the cement job, is the difference between the fluid lost and the gas influx.

b) Is it possible that the pressure spike when the bottom plug is at the crossover (23:35), results in an increased loss rate and reduction in annulus pressure allowing for increased gas influx from the 14.16 ppg gas sand? I.e. the reduction in standpipe pressure can partly be explained with more gas in the annulus (reduced U-tube effect).

c) Is it possible that the high pressure (1150 psi) when the top plug is at the float collar (00:36) after circulation has stopped and the increased pressure after the bottom plug burst at the float collar (00:24), is caused by a crossflow from the 14.16 ppg gas sand to a loss zone in the lower part of the well (12.54 ppg pay sand)?

Appendix D

SINTEF Simulation Study Macondo

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Report

Simulation study Macondo

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Report

Simulation study Macondo

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ABSTRACT
Simulations with SINTEF comprehensive flow model for drilling and well control of two sequences occurring shortly before the Macondo accident in 2010. Results are discussed with respect to alternative explanation of observations that deviate from expectations and calculations.

Dag Vavik is given the right to publish the report as part of his PhD thesis or elsewhere as an open report.

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APPROVED BY Harald Linga	SIGNATURE

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Table of contents

SINTEF

1 Introduction

This report describes results of simulations of some sequences in the Macondo well shortly before the disaster in 2010, using SINTEF's thermohydraulic model. Assumptions and simplifications were made due to lack of detailed data and restricted time for configuring and running the simulations. Details are given in Section 4 below.

Data used is taken from reports made available, including BP's accident investigation report (2010), the chief counsel's report by the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (2011), joint investigation report from the United States Coast Guard (2010), Lessons for Improving Offshore Drilling Safety by the Committee on the Analysis of Causes of the Deepwater Horizon Explosion (The National Academies Press 2012), and the Transocean investigation report (2011).

The simulations have mainly been based on a short overview of relevant input provided by the client Future Well Control AS, see **Appendix C – Input to SINTEF Calculations**. It was not possible for the author to go through and comprehend all details of the material provided, and therefore key elements of the configuration of simulations are listed and explained to give readers a chance to check whether it is according to their own comprehension.

2 The mathematical model

SINTEF's comprehensive model for drilling and well control operations, in this report denoted "the model", was used for all simulations. This model is made commercially available by the company eDrilling. The model has also been used commercially for automation of managed pressure drilling operation in cooperation with Halliburton, Equinor and others. Descriptions of the model with different applications can be found in many published papers, including those listed in Chapter 7.

3 Overview of simulations

Two sequences were simulated, a circulation period starting 16:24 19th April, and cementing displacement operation of 9 5/8 x 7" casing starting 19:47 on the same day and ending 00:40 next day when the top plug landed.

Prior to the circulation sequence 3142 psi pressure was applied to assumedly convert the auto-fill float collar from tripping mode to forward circulation mode, and thus break circulation. The conversion attempts are outside scope of this study, but for the record it is noted that there is uncertainty about what actually happened and whether any damage was done on the tool or well.

After the circulation period, which were at low rates (1-4 bpm[1]), preparations for cementing were made and the cementing sequence was run.

[1] Oil barrels per minute

4 Configuration of model

Some of the data was not, as far as the author has revealed, provided in the available material. The values used and given below were in such cases based on earlier experience from other drilling operations and educated guessing.

4.1 Geometry

4.1.1 Running string

The running string (also called working string) is described by Halliburton's cement report and consists of a 6 5/8" landing string and a 9 7/8" x 7" casing string.

Table 1 shows the running string as described in the input file (Appendix C, table C.1). Surface lines were excluded from the simulations, which means that shown inlet pressure is inside the landing string at RKB level. When using rig pumps, surface lines were 392.5 ft from standpipe manifold to cement head, and pressure loss through them has been calculated separately to range from 4.9 psi at 1 bpm to 6.6 psi at 4 bpm.

Flowline Segment	Length (ft)	ID (in)	OD (in)	TJ* length (ft)	TJ ID (in)	TJ OD (in)
6 5/8" Landing String	5060.3	5.426	6.625	3	4.625	6.625
9 7/8" Casing	7423	8.625	9.875	0	8.625	9.875
9 7/8" x 7" Crossover	5	8.625	9.875	0	8.625	9.875
7" Casing	5627	6.094	7	0	6.094	7
Float Collar	1.7	2.19	7	0	2.19	7
7" Casing	185	6.094	7	0	6.094	7
Casing Reamer Shoe	2	2.5	7	0	2.5	7

Table 1: Running string, input data for simulations. Data on tool joints was not found in available information and is based on educated guessing.

Total length of the string is 18 304 ft from RKB.

4.1.2 Riser, casing, liner

Table 2 shows actual casing run as described in the input file (Appendix C, table C.2). The elements that are marked with light blue background are hidden from the inner annulus by other elements; still they are used for heat transfer calculations.

Description	Top (ft)	Bottom (ft)	ID (in)	OD (in)	Hole diam (in)	TOC (ft)
Riser (+ BOP and Wellhead)	0	5068	19.5	21		5068
36" Casing	5071	5335	34	36	38	5335
28" Casing	5076	6231	26.5	28	30	5076
22" Casing / hanger	5068	5070	12	22	24	5068
22" Casing	5070	7952	19.5	22	24	5070
18" Liner	7503	8983	16.75	18	20	7503
16" Liner	5241	11585	14.85	16	18	5241
13 5/8" Liner	11153	13145	12.375	13.625	15.625	11153
11 7/8" Liner	12817	15103	10.711	11.875	13.875	12817
9 7/8" Liner	14759	17168	8.575	9.875	11.875	14759
9 7/8" Open hole	17168	18126			9.875	17168
8 1/2" Open hole	18126	18360			8.5	18126

Table 2: Riser (first line), casing and liner strings, not including the running string.

4.1.3 Casing hanger

Pressure drop through 18 channels at depth 5054 ft, each with diameter 1 inch and length 2 ft, are added to the pressure loss through the annular geometry given above. The exact depth is unimportant.

With open channels the pressure loss through the hanger is very small. A calculation at 1800 lpm (11.3 bpm) gave a pressure drop of 9267 Pa, or 1.3 psi, and less than 0.5 psi at 4 bbl. Therefore, calculated pressure at wellhead is almost independent on whether it is including hanger pressure loss or not.

4.2 Temperature

4.2.1 Ambient seawater temperature profile

Seawater ambient temperature as a function of water depth as given in the input file, Appendix C table C.5, has been used in the model after simplification that is justified in the same way as for described below for the formation temperature profile.

4.2.2 Formation temperature profile

With approx. 4.3 deg C at sea floor and 113.7 at 13 064 ft below, the average thermal gradient below seafloor is 0.837 deg C per 100 ft (1.51 deg F per 100 ft). Both a linear thermal gradient below seafloor and a curved temperature gradient closer to that shown in Appendix C, figure C.13 have been used in the model. The curved temperature profile is about 5 deg. C higher than the linear profile midway between seafloor and total depth. The difference between results with the linear gradient and the curved gradient is relatively small, as illustrated by the "curved temperature" curve in Figure 2.

4.2.3 Heat capacity

Thermal properties were estimated based on a combination of calculations and experience. Heat capacity was calculated by summing products of weight fraction and heat capacity for each of base liquid and weight material (using typical values for barite).

4.2.4 Heat conductivity

Thermal conductivity is calculated using the Maxwell Garnett formula[2]. Se Table 3 for thermal properties for different materials used in the study.

Material	Density (ppg)	Specific heat, C_p (J/kg K)	Thermal conductivity, λ or k (W/m K)
Steel	65	400	40
Synthetic based drilling mud (SBM)	14	1000	0.5
Base oil	6.7	1700	0.25
Spacer	14.3	2150	1.0
Cement (unfoamed)	16.74	1740	1.2
Formation	20.9	900	2.0

Table 3 —Thermal properties and density for the different materials and fluid used in the study.

4.2.5 Temperature calculations uncertainties

Temperature calculations are considered highly uncertain due to uncertainties in input data, material properties, and the general uncertainties in modelling of heat transfer in an annulus with rotation, vibrations and turbulence. If the wellbore fluid prior to start of circulation is heated up towards the curved temperature profile, this results in a slightly lower equivalent static density (ESD) in the gas sand than with the linear profile, see Figure 4 green and blue lines. The red line is with temperature profile frozen near the linear formation temperature profile before circulation starts. This is not considered a realistic scenario but is included to give a picture of the dependency on dynamic temperature changes.

The three curves, i.e. the two dynamic simulations with linear and curved temperature profile and the frozen temperature profile, give an idea of the magnitude of uncertainties involved.

4.3 Fluids

4.3.1 Drilling fluid

An SBM (synthetic based mud) was used for the simulated circulation sequence and for displacing cement. Density (14.0 ppg at surface) is given in the Halliburton report, but no field measurements of rheology were found. Further, reference temperature for the density is another important input parameter that was not found, and 25 ºC was assumed as it gave good match to given static pressure.

[2] https://en.wikipedia.org/wiki/Effective_medium_approximations#Maxwell_Garnett_equation.

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A rheology profile measured on 12.1 ppg SBM[3] was used as a starting point for simulations. The time of this measurement is not given, but it appears as an appendix to the appendix "Testing of cementing float" of Transocean's investigation report, which indicates that the measurement is after the incident. The actual fluid used during the simulated operations was 14 ppg, and viscosifying additives *may* have been added to increase parts of the rheology profile before or during operations. Therefore, adjusting rheology could be justified, and it was used as one of several calibration parameters.

Based on experience and similar data, it is reasonable to expect rheology at 14 ppg to be higher than at 12.1 ppg, possibly much higher if viscosifiers were added.

Compressibility of SBM was given to be $3.3358 \cdot 10^{-6}$ bbl/bbl/psi, but no data on composition, thermal expansion or pressure and temperature dependence of compressibility. Therefore, the following formula was used for density for base fluid weighted to 1 sg (using 1 sg rather than base oil density was done for practical reasons and does not influence results):

$$\rho_{\mathrm{STC,\,1\,sg}} = e^{\alpha p - \beta (T - T_0)}.$$

With pressure p given in psig and temperature T given in °F, the following values match specified compressibility for the actual SBM and the thermal expansion of two commercial OBMs after correcting for differences in densities:

$$\alpha = 4.2317 \cdot 10^{-6}$$
$$\beta = 3.9186 \cdot 10^{-4}$$

Thermal expansion is important as it may partly or fully cancel, or even be larger than, the effect of compressibility.

To derive compressibility and thermal expansion at the actual density 14 ppg, after adding 4.2 sg weight material enough to get from 1 sg to 14 ppg, the following formula can be used (using consistent units):

$$x_{\mathrm{solid}} = \left(\frac{1}{\rho_{\mathrm{STC,\,1\,sg}}} - \frac{1}{\rho_{\mathrm{solid}}}\right) \Bigg/ \left(\frac{1}{\rho_{\mathrm{SBM}}} - \frac{1}{\rho_{\mathrm{solid}}}\right)$$

$$[\alpha_{\mathrm{SBM}}, \beta_{\mathrm{SBM}}] = [\alpha, \beta](1 - x_{\mathrm{solid}}) \frac{\rho_{\mathrm{SBM}}}{\rho_{\mathrm{STC,\,1\,sg}}} = \left[3.3357 \cdot 10^{-6} \, \frac{1}{\mathrm{psi}}, 3.0889 \cdot 10^{-6} \, \frac{1}{^{\circ}\mathrm{F}}\right]$$

Steel roughness was set to 1.6 in/32, which is of marginal importance because flow is mostly laminar and therefore not much influenced by steel roughness. Further, frictional pressure loss inside the running string was multiplied by a correction factor 1.1. The latter is within a

[3] *"Testing of Cementing Float",* prepared for Transocean Offshore Deepwater Drilling, Inc., Houston, TX. February 2011, PN1101190DLG, Stress Engineering Services, Inc. Houston, Texas. Included as appendix C in Macondo Well Incident, Transocean Investigation Report, June 2011. The mentioned rheology profile is on page 80/636 in 12_TRANSOCEAN_Vol_2.pdf (under Testing of cement float).

typical range of value based on earlier experience, and accounts for irregularities and inaccuracies in input data and modelling.

4.3.2 Foam cement

A plot of density profile vs. depth (Appendix C, figure C.16) for the foamed cement was used as a validation of calculated density, which was consistent given uncertainties in input parameters, thus calibration of the model parameters was not considered.

The density of N2 gas was modelled using standard gas law with Z-factor as given by Hall and Yarborough[4] with critical temperature and pressure for nitrogen gas being 126.2 ºK and 33.999 Pa respectively.

Cement of density 16.74 ppg was mixed with Nitrogen, with nitrogen concentration 584 scf/bbl (or 104 sm3/m3). Using Nitrogen density 1.17 kg/m3 at 20 deg as standard conditions density, this means mass fraction Nitrogen is about 0.0572 relative to total mass of N2 and cement (or 0.0607 relative to mass of cement alone).

Rheology of foam cement was set equal to the rheology used for unfoamed cement, although it may some measurements indicate significantly higher values at high foam qualities (see e.g. Ramadan, Kuru and Saasen 2003[5]).

4.3.3 Other fluids

In addition to SBM and foamed cement, base oil, spacer and unfoamed cement were pumped during the cement operation. Rheology of these was not given, and values similar to values used in earlier simulations for other operations was used.

Densities at standard conditions were given for all fluids, see table below.

4.3.4 Density and rheology table

Fann RPM	Density (ppg)	600	300	200	100	60	30	6	3
SBM	14	93	54	41	26			11	10
Base oil	6.7	4	2						0.02
Tuned Spacer III	14.3		38	29	22	18	15	12	11
Unfoamed lead cement	16.74		102	74	44	29	17	6	5
Tail cement foamed[6]	16.74		102	74	44	29	17	6	5
Unfoamed shoe cement	16.74		102	74	44	29	17	6	5

Table 4: Density and rheology as used for the simulations.

[4] Hall, K.R. and Yarborough, L.: *"A new equation of state for Z-factor calculations",* Oil & Gas J. (June 18, 1973), pp82-86

[5] Ramadan, A., Kuru, E. and Saasen, A.: *"Critical Review of Drilling Foam Rheology",* Ann. Trans. Nordic Rheol. Soc. (2003) 11, pp63-72.

[6] Given density is for the liquid (unfoamed cement) part. For details on density of the foamed cement see discussion in Section 4.3.2.

4.4 Operational sequence

The simulations were run as one combined simulation ranging over a long pre-operations period to get a realistic temperature profile, then the circulation period ramping pumps in steps up to 4 bpm twice, and finally the cementing sequence.

Time[7] (min)	Duration (mm:ss)	Pump rate (bpm)	Volume pumped (bbls)	Fluid	Density (ppg)	Comments
	6 hours	11.9	-1	SBM	14	Pre-circulation/drilling, temperature model only
-4320.00	10:00	11.9	-1	SBM	14	Pre-circulation to stabilize temperature profile.
-4310.00	3 days	0	-1	SBM	14	Static period, no circulation since April 16.
10.00	6:00	1	-1	SBM	14	Circulating at 1 bpm at 16:24, April 19. Observed pump pressure 137 psi.
16.00	10:00	1.5	-1	SBM	14	Circulating at 1.5 bpm at 16:30, April 19. Observed pump pressure 137 psi.
26.00	4:00	2	-1	SBM	14	Circulating at 2.0 bpm at 16:40, April 19. Observed pump pressure 190 psi.
30.00	3:00	2.5	-1	SBM	14	Circulating at 2.5 bpm at 16:44, April 19. Observed pump pressure 215 psi.
33.00	2:00	2.7	-1	SBM	14	Circulating at 2.7 bpm at 16:47, April 19. Observed pump pressure 233 psi.
35.00	2:00	3	-1	SBM	14	Circulating at 3.0 bpm at 16:49, April 19. Observed pump pressure 255 psi.
37.00	2:00	3.25	-1	SBM	14	Circulating at 3.25 bpm at 16:51, April 19. Observed pump pressure 274 psi.
39.00	7:00	3.5	-1	SBM	14	Circulating at 3.5 bpm at 16:53, April 19. Observed pump pressure 295 psi.
46.00	15:00	4	-1	SBM	14	Circulating at 4.0 bpm at 17:00, April 19. Observed pump pressure 340 psi.
61.00	5:00	0	-1	SBM	14	Static period of 5 minutes, to change rig pumps. *Rig decided to circulate with a different rig pump to check if there was a difference.*
66.00	2:00	1	-1	SBM	14	Circulating at 1 bpm at 17:20, April 19. Observed pump pressure 245-205 psi.
68.00	1:00	1.5	-1	SBM	14	Circulating at 1.5 bpm at 17:22, April 19. Observed pump pressure 224 psi.
69.00	1:00	2	-1	SBM	14	Circulating at 2.0 bpm at 17:23, April 19. Observed pump pressure 260 psi.
70.00	1:00	2.5	-1	SBM	14	Circulating at 2.5 bpm at 17:24, April 19. Observed pump pressure 290 psi.
71.00	1:00	3	-1	SBM	14	Circulating at 3.0 bpm at 17:25, April 19. Observed pump pressure 320 psi.
72.00	1:00	3.5	-1	SBM	14	Circulating at 3.5 bpm at 17:26, April 19. Observed pump pressure 345 psi.
73.00	21:40	4	-1	SBM	14	Circulating at 4.0 bpm at 17:27, April 19. Observed pump pressure 396 psi.

[7] Here "Time" is simulated time in minutes, defined to be zero 10 minutes before circulation at 1 bpm starts. The same definition is used on the x-axes in Figures below and when referring to time in minutes in the text. References to time on HH:MM or HH:MM:SS format refers to the actual time on the rig.

Time[7] (min)	Duration (mm:ss)	Pump rate (bpm)	Volume pumped (bbls)	Fluid	Density (ppg)	Comments
94.67	01:02:20	0	-1	SBM	14	Circulation assumed stopped at 17:48:40. Static period of more than one hour, while landing string with Allamond diverter was tested for leaks and waiting for decision what will happen next.
157.00	27:30	4	-1	SBM	14	Circulating 110 bbls at 4.0 bpm at 18:51, April 19
184.50	29:00	0	-1	SBM	14	Static period while preparing for cement job and pressure testing nitrogen lines. Cement job starts at 19:47:30.
213.50	2:22	2.12	5	SBM	16.5	Displacement sequence start with pumping 5 bbls of SBM. Pump rate and average density of 16.5 ppg is taken from page 9 in Halliburton report.
215.86	3:18	2.12	7	Base oil	6.7	7 bbls of base oil pumped “on the fly” starting at 19:50:00 on April 19.
219.16	3:30	2.77	9.7	Spacer	14.3	Continue displacement sequence with spacer “on the fly” at 19:53:30. Pumped spacer is 9.7 bbls over a time period of approximately 3.5 minutes. Average pump rate calculated to 2.77 bpm.
222.66	3:00	0	-1	N/A	N/A	Static period to pressure test cement lines, between 19:57 and 20:00.
225.66	17:30	3.83	67	Spacer	14.3	Continue displacement sequence with spacer at 20:00. Pumped spacer is 67 bbls (not 62) over a time period of approximately 17.5 minutes. Average pump rate calculated to 3.83 bpm.
243.16	20:00	0	-1	N/A	N/A	Static period between 20:17:30 and 20:37:30.
263.16	4:00	2.125	8.5	Lead cement	16.74	Pumped 8.5 bbls unfoamed lead cement. Average pump rate 2.125 bpm. Bottom plug released with 1 barrel lead cement ahead of plug.
267.16	19:15	2.026	39	Foamed cement	16.74	39 bbls unfoamed cement + N2 concentration of 584 scf/bbl. Start injection N2 at 21:41:35. Total N2 injected is 22 776 SCF or 748 kg.
286.41	2:15	2	4.5	Shoe cement	16.74	Unfoamed shoe cement pumped between 21:00:45 and 21:03:00.
288.66	7:00	2.86	20	Spacer	14.3	20 bbls spacer pumped after bottom plug.
295.65	33:00	4.03	133	SBM	14	Pumping 133 bbls of SBM with cement pump between 21:10:00 and 21:43:00.
328.65	1:10	0	-1	N/A	N/A	Static period. Rig pumps starts 21:44:10
329.82	50:20	4.245	468.4	SBM	14	Bottom plug observed through X-over at 23:34:30.
440.16	0:20	4.245	1.4	SBM	14	Building up pressure to simulate observation.
440.49	12:50	4.245	54.5	SBM	14	Top plug observed through X-over at 23:47:40.
453.33	0:10	4.245	0.7	SBM	14	Building up pressure to simulate observation.
453.49	34:41	4.245	147.2	SBM	14	Bottom plug bumped at float collar at 00:22:30.
488.17	2:00	4.245	8.5	SBM	14	Building up pressure to simulate observation.
490.17	11:00	4.245	46.7	SBM	14	Top plug bumped at float collar at 00:35:30.
501.17	0:16	4.245	1.1	SBM	14	Building up pressure to simulate observation.
501.43	2:10	0	-1	SBM	14	Stop pumps with top plug closing the string
503.60	50:00	0	-1	SBM	14	Continue simulation with open string for comparison and to calculate net u-tubing with no plug (or simulating plug breaking)

Table 5: Circulation and cementing sequences with observed pump pressure given in the comments column. Note that the observed circulating pump pressures and comments (from row 3) are taken from the Halliburton cement job report and are not the result of the simulation.

4.4.1 Circulation, ramping from 1 to 4 bpm

The first operational sequence is prior to the cement job when circulation was carried out at low flowrates, ramping up from 1 to 4 bpm with SBM. The steps of the sequence are taken from the Halliburton cement job report (Appendix C, table C.4). The circulation period started at 16:24, 19th of April, which is equivalent to time 10 min in Figure 1. Prior to the circulating sequence, a long circulation and rotation period (6 hours + 10 minutes) with high flowrates to simulate drilling followed by a 72 hours static period to bring temperature profile back towards geothermal/seawater temperature was included, see first part of Table 5.

Observed pump pressure when circulating is given in comments in Table 5, and these are compared to our new calculations and to calculations by MI Swaco and Opticem referred to in Halliburton's report. According to the latter MI Swaco's model calculated circulation pump pressure to be 570 psi @ 4.0 bpm, and Opticem calculated the same to be 370 psi at 1.0 bpm.

4.4.2 Cement displacement, no mixing

The second part of the simulation, from 213.5 minutes, is the actual cement job. The operational sequence is taken from the Halliburton cement job report (Appendix C, table C.7). The cement displacement sequence started with base oil at 19:47, 19th of April, and ended with top plug pumped at 00:40, 20th of April.

The volumes pumped are taken from the Halliburton cement job report, page 2. Pump circulation rate with rig pump, from 329.82 mins, was calculated based on 728.5 bbls of SMB displaced with rig pumps during 171.6 min = 4.245 bpm.

4.4.3 Cement displacement with mixing of base oil with other fluids

The same sequence as shown in Table 5 was used for simulating displacement with mixing of base oil with fluids behind and ahead, except assuming that 5 bbl of base oil mixed with 115 bbl of the SBM ahead, and the remaining 2 bbl of base oil mixed with 10 bbl of the spacer behind it. This mixing of the relatively thin base oil with fluids ahead and behind is considered plausible, and it is further motivated by getting much better fit with the trend in measured pump pressure. Mixture densities were calculated accurately to preserve both masses and volumes pumped.

5 Results with discussion

5.1 Circulation

The simulation of the circulation period covers pump rates incremented in steps from 1 to 4 bpm two times, starting at 16:24 (at 10 min in figures) shortly after breaking circulation at pump pressure 3142 psi. The goal of the simulation is to understand more of why measured pump pressure reached only 340 psi first time and 396 psi second time at 4 bpm, while MI

Swaco calculated 570 psi. Neither measured downhole pressure nor MI Swaco's calculated downhole pressure were available for this work, and it is therefore not possible to tell from measurements how much of the deviation is inside the string and how much is in the annulus outside the string.

An initial simulation using the given rheology for 12.1 ppg SBM, calculated much lower pump pressure than that calculated by MI Swaco and OptiCem, with values closer to measured values. It is, however, according to experience highly unlikely that SINTEF's model calculates so different from the other two with identical input parameters, and hence the difference between models is attributed to differences in input data. There could be extra pressure losses included by MI Swaco and OptiCem, or the actual rheology could be higher than the 12.1 ppg rheology. The latter is considered plausible, both because adding weight materials influence rheology, and because adding viscosifiers during operations to adjust rheology is common, and this alternative was chosen for the shown simulations. Still one should keep in mind that also extra pressure losses inside the string is possible, and this alternative could be chosen to get close to measured pump pressure without influencing annular pressure loss in periods with stable flow conditions.

The following table shows how rheology was adjusted to get close to pump pressure calculated by MI Swaco and Opticem.

Fann RPM	Fann reading for 12.1 ppg test sample	Fann readings used in simulations, 14 ppg SBM
600	69	93
300	38	54
200	30	41
100	19	26
6	8	11
3	5	10

Table 6: Given rheology for 12.1 sg SBM used for later testing, and rheology of 14 sg SBM as used for simulations.

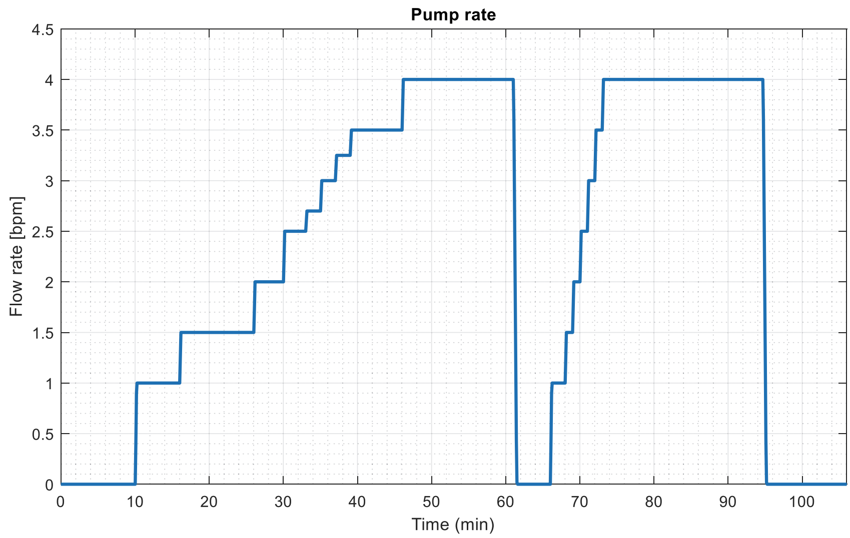

Figure 1: Pump rate when circulating prior to cementing.

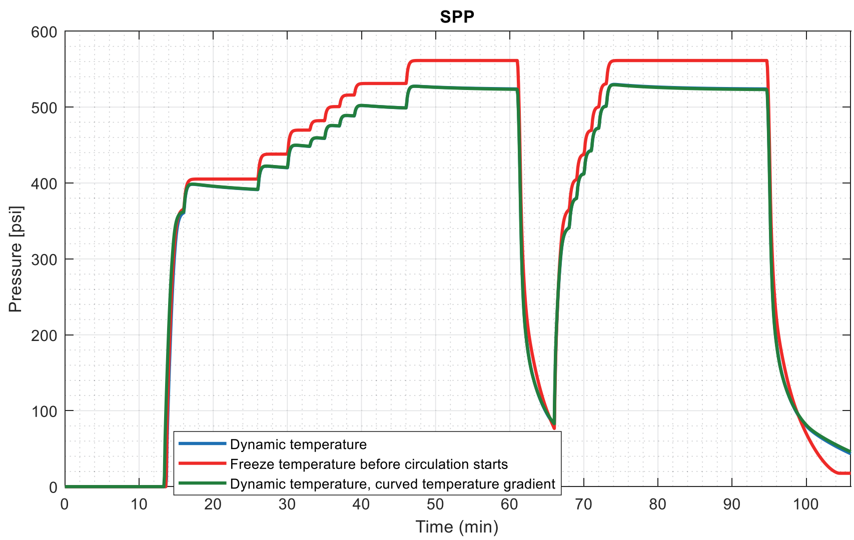

Figure 2: Pump pressure when circulating prior to cementing. Two simulations, one with constant and one with dynamic temperature, are included to indicate the magnitude of dynamic temperature effects. The temperature calculations depend on many parameters that are uncertain or not specified and the results must therefore be considered with some caution. "Curved temperature gradient" means ambient temperature profile was increased by up to 5 °C at intermediate depths, ref. Appendix C, figure C.13. For pump pressure, the two dynamic temperature curves cannot be distinguished on the graph because effects nearly cancel inside and outside the running string.

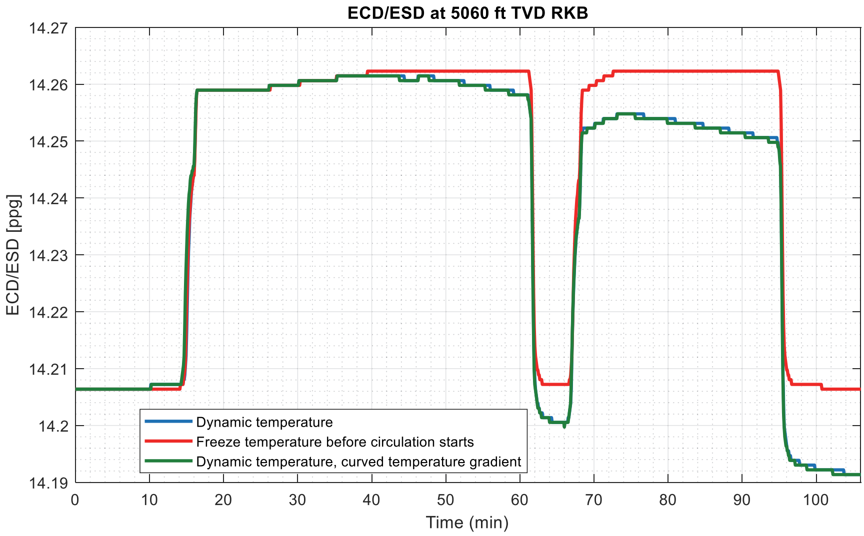

Figure 3: Equivalent mud weight near wellhead. For details see caption of Figure 2.

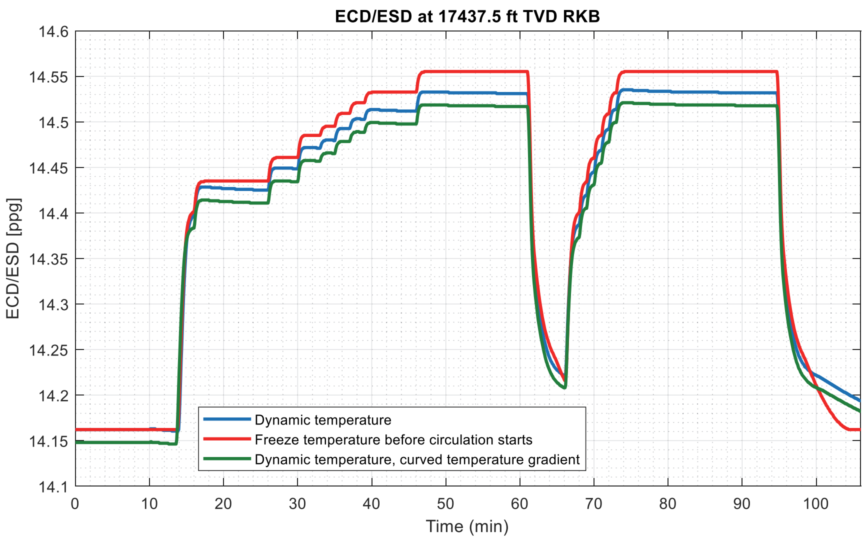

Figure 4: Equivalent mud weight in annulus at the gas sand. For details see caption of Figure 2.

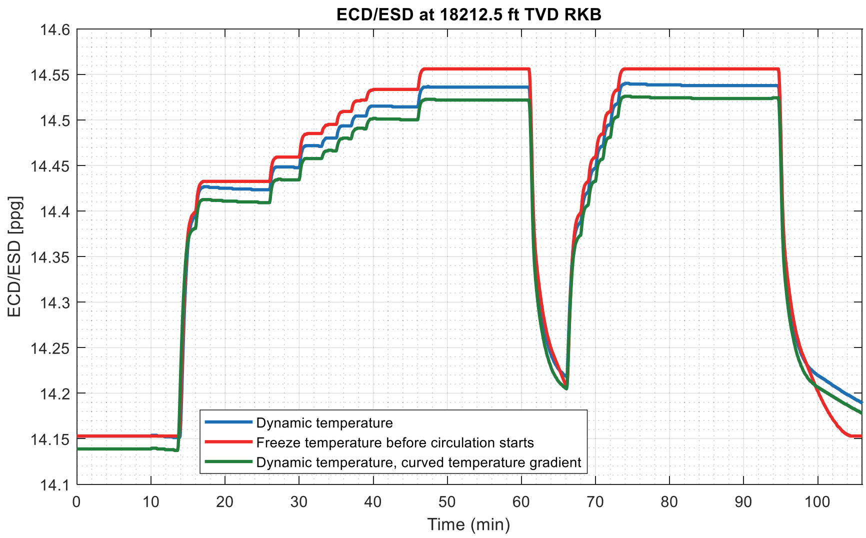

Figure 5: Equivalent mud weight in annulus at lowest oil sand (depth 18 212.5 ft). For details see caption of Figure 2.

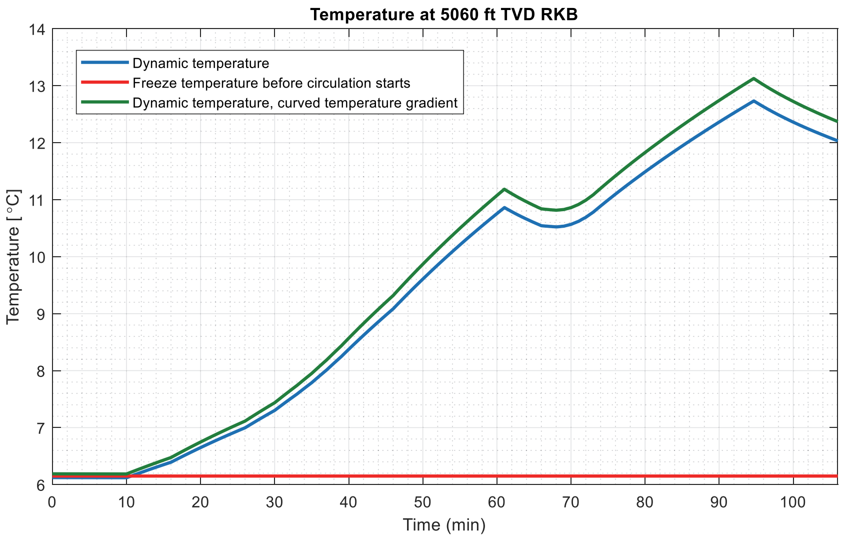

Figure 6: Temperature near wellhead. For details see caption of Figure 2.

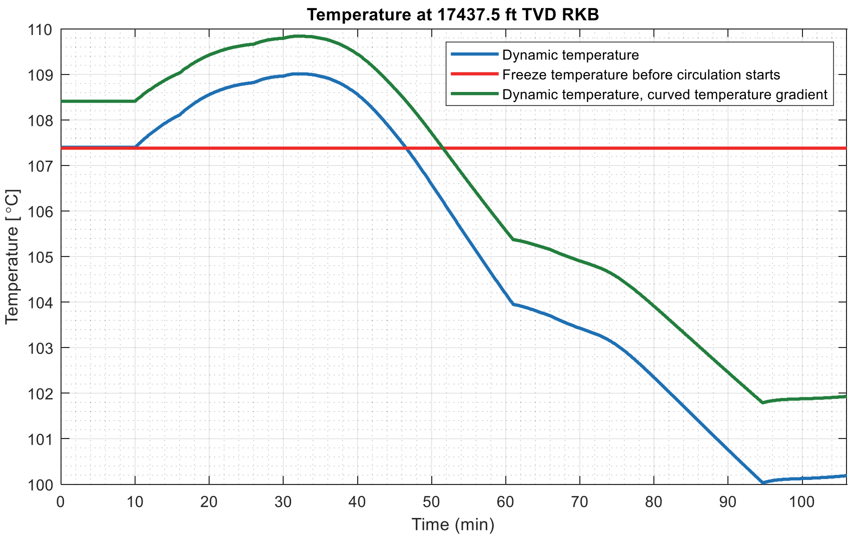

Figure 7: Temperature in annulus at the gas sand. For details see caption of Figure 2.

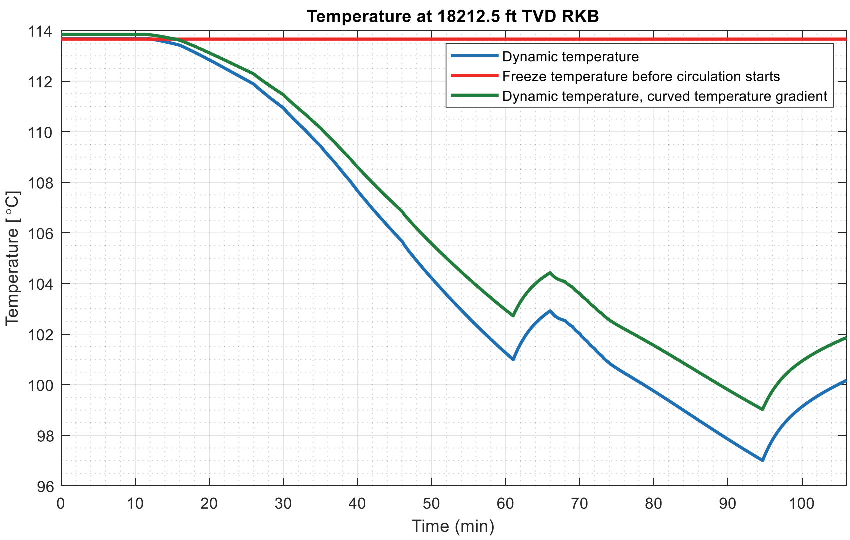

Figure 8: Temperature in annulus at oil sand. For details see caption of Figure 2.

5.2 Discussion of the circulation sequence

A key question for investigation is this: *Was the low circulating pressure observed (see table C.4) caused by gas already present in the wellbore annulus? Meaning that gas has entered the well prior to landing the $9^7/_8 \times 7$ -inch long string production casing at 13:40 or at least before the circulation was established at 16:21 on April 19.*

There are significant uncertainties w.r.t. details of fluid properties, and therefore the points made here from comparing simulations and measurements must be considered indications rather than firm conclusions.

Assuming that calculations by MI Swaco and Opticem are accurate because they normally have all relevant information available for such operations, and due to their long experience in doing such calculations, we see the following deviations in observations:

1. At 1 bpm, observed pressure is 137 psi 16:24 using first rig pump, and then decreases from 245 to 205 psi with second rig pump (rig pump #4). Calculation by Opticem was 370 psi, i.e. measured pump pressure was 233 psi lower with first pump and decreasing from 125 to 165 psi lower than Opticem/MI calculations with second pump.
2. At 4 BPM, observed pressure is 340 psi with first pump and 396 psi with second while MI calculated 570 psi, i.e. observed pressure were 230 and 174 psi lower respectively.

The observed increase in pressure when ramping pumps from 1 to 4 bpm first time (from 10 min in Table 5) is 203 psi (from 137 to 340 psi), and 191 psi (from 205 to 396 psi) when ramping up second time with a different pump (from 66 min in Table 5). Calculated[8] increase in pressure from 1 to 4 bpm is 167 psi (from 360 to 527 psi) taking thermal expansion in the annulus into account, see the green line in Figure 2, and 195 psi (from 366 to 561 psi) without considering temperature changes, see red line in Figure 2, which is close to the 200 psi difference between Opticem at 1 bpm and MI Swaco at 4 bpm. With the uncertainties in the calculation, the dynamic part of pump pressure is considered consistent over the two pumps and calculations, although the calculation with dynamic temperature is a bit lower. This indicates that the deviation between observation and calculations is mainly due to differences in hydrostatic pressure. Such a difference may have one or more of several explanations:

1. **Thermal expansion.** This is very unlikely because each percent change in volume and hydrostatic pressure requires about 18 degC change in average temperature from gas zone to wellhead. However, decrease in ESD of the SBM in the annulus due to thermal expansion may explain part of the observed low circulation pressure (from 570 psi to 540 psi when circulating at 4 bpm), see Figure 2.

2. **Gas in annulus.** If this alone causes 150 psi (or more) lower pressure between gas sand and wellhead than with no gas, a corresponding u-tubing when pumps stop will be expected, assuming flapper valves opens with low resistance, which is normally experienced. 150 psi corresponds to a little more than 200 ft of 14 ppg SBM, or 5.7 bbl gap inside the landing string. Accordingly, when pumps start at 4.2 bpm a more than one minute delay should be expected in pump pressure. There is, however, no data available that may show such a delay. When changing from cement to rig pump during displacement, calculated static pump pressure (assuming no gas in annulus) is approx. 300 psi, which would show up as a quick increase when starting rig pumps, but which could be removed by a reduction in static pressure due to gas in annulus. The rig pump startup is shown by the graph on page on page 12 in Halliburton's

[8] Calculated and calculation always refers to SINTEF's new calculations presented here, unless reference to Opticem or MI Swaco is stated explicitly.

report, but resolution is not good enough to confirm or reject a hypothesis on reduced static pressure, although the graph may indicate that static pump pressure is much less than 300 psi.

3. **Inaccurate PVT relations in calculations by Opticem and MI Swaco.** This is considered unlikely, as MI Swaco normally has very good data on how their liquids' density depends on pressure and temperature.

4. **Damage to the running string.** Inside restrictions giving extra pressure losses inside running string could have been removed by earlier events. This could also explain the difference between our calculations and those by MI Swaco and Opticem. It is, however, considered unlikely as such pressure losses typically depends on velocity raised to a power between 1.7 and 2, while the observed pressure seems to deviate about equally much from calculations at 1 bpm and 4 bpm.

5. **Loss zone near the bottom of the well and gas influx from the gas sand, with or without downwards crossflow of gas.** Detailed calculations of this scenario will require more resources than available for this study, but qualitatively it seems plausible. Observed return at surface will in this case be pump rate *minus* loss *plus* gain, and small changes may go on unnoticed in the case that loss and gain nearly cancel each other. In this scenario flow rate of SBM upwards in the annulus and associated pressure loss will be reduced between loss and gain zones, and the gas cause a reduction in hydrostatic pressure. These effects may explain the lower observed pump pressure.

   A boost in return would be expected when reducing pump rate or stopping pumps, because then the loss would decrease and the gain would increase due to reduced annular pressure loss. However, such data has not been available for this study.

6. **Hydrates formation combined with gas influx.** Formation of hydrates near the wellhead may mask a gas influx, which thereby may have contributed to a drop in hydrostatic pressure without being detected as a large gas kick. Further investigation of this alternative was not possible within given time constraints for this study.

In order to quantify the amount of gas needed to reduce hydrostatic pressure from gas sand to wellhead enough to explain the reduced pump pressure, some estimates have been done based on compositional calculations with commercial software PVTsim by Calsep (www.calsep.com). As composition of the SBM was unknown and because time for this study was limited, calculations done earlier for methane being dissolved in a mineral base oil was modified to generate the following tables. The difference between density with dissolved and free gas is expected to be similar, although not the same, as with synthetic oils. Calculations were done at pressure 580 bar / 8412 psi and 60 ºC / 140 ºF.

In the region of interest, from the gas zone at 17,435 ft to well head at 5,060 ft, calculated pressure ranges from 12,800-13,200 psi at the lower position to 3,750-3,770 at the upper position. The difference in measured and calculated pump pressure is up to 165 psi at 1 bpm (measured vs Opticem) and up to 230 psi at 4 bpm (measured vs. MI Swaco), or in the range 1.8-2.5 % of the pressure difference between the two positions. A key question is thereby how much gas is needed to change hydrostatic pressure by 1.8 %. In other word, how much gas does it take to change mixture density from the 1677.6 kg/m3 with no gas to 1647 kg/m3. From Table 7 it is seen that either ca 4 weight percent of *dissolved* methane or 2 weight percent of *free* methane is needed. Which means that it normally should be detected as a kick long before reaching this level, unless other effects took away the large gain.

Methane mass fraction	Density oil with methane dissolved	Average density with methane free	Ratio dissolved by free density change	Volume fraction free methane	Density SBM with dissolved methane	Mix density SBM + free methane
0 %	848.2	848.2	N/A	0 %	1 677.6	1 677.6
1 %	838.2	829.2	53 %	3 %	1 670.0	1 663.3
2 %	828.4	811.1	53 %	7 %	1 662.6	1 649.6
3 %	818.7	793.7	54 %	10 %	1 655.3	1 636.5
4 %	809.1	777.0	55 %	14 %	1 648.1	1 624.0
5 %	799.8	761.1	56 %	17 %	1 641.1	1 612.0
6 %	790.5	745.7	56 %	21 %	1 634.1	1 600.4
7 %	781.4	731.0	57 %	25 %	1 627.3	1 589.3
8 %	772.5	716.8	58 %	29 %	1 620.6	1 578.7
9 %	763.7	703.2	58 %	33 %	1 613.9	1 568.4
10 %	755.0	690.1	59 %	37 %	1 607.4	1 558.6
11 %	746.5	677.5	60 %	41 %	1 601.0	1 549.1
12 %	738.1	665.3	60 %	45 %	1 594.7	1 539.9
13 %	729.8	653.6	61 %	49 %	1 588.4	1 531.1
14 %	721.7	642.2	61 %	54 %	1 582.3	1 522.5
15 %	713.6	631.3	62 %	58 %	1 576.3	1 514.3
16 %	705.7	620.7	63 %	63 %	1 570.3	1 506.3
17 %	698.0	610.5	63 %	67 %	1 564.5	1 498.6
18 %	690.3	600.6	64 %	72 %	1 558.7	1 491.2
19 %	682.7	591.0	64 %	77 %	1 553.0	1 483.9
20 %	675.3	581.7	65 %	82 %	1 547.4	1 477.0

Table 7: Gas cut mud density with dissolved methane in mineral base oil and free gas

Also, frictional pressure loss depends on gas content. Without going into detailed calculation, this possibility is considered unlikely. Although some results[9] indicate that gas may have a large effect on rheology, the observation that reduction of pump pressure is about the same at 1 and 4 bpm indicates that effects that influence hydrostatic pressure only are dominant.

There was a 63 klb decrease in hook load observed over time of circulating. A question is whether this can be due to increased flow in the annulus. Detailed calculations are beyond scope of this study, but based on the simulations done the total upwards forces on the running string, the hole and the confining strings on the outer side can be calculated. Total calculated annular frictional pressure loss was about 390 psi, and integrating frictional pressure loss

[9] See e.g. *"Drilling fluid rheology at challenging drilling conditions - an experimental study using a 1000 bar pressure cell"* by Torsvik Anja, Myrseth Velaug, Linga Harald, presented on Nordic Rheology Conference 2015.

times cross-sectional annulus area times lengths along the whole annulus gives 8.4 tons or 18.6 klb. Taking half of this, 9.3 klb, as a rough high estimate of the force acting upwards on the *inner* string, we see that more than around 7 times this frictional pressure loss is needed to explain the reduction in hook load. And as most of the increase in frictional pressure loss is from 0 to 1 bpm, it is reasonable to argue a flow of the order 10 times 4 bpm (= 40 bpm) or more is needed to lift the string by 63 klb. A detailed calculation is needed to verify this rough estimate, as such a boost due to inflow will cause a change from mainly laminar flow of SBM to a turbulent two-phase flow. Pressure loss through the casing hanger channels discussed in Section 4.1.3 would, according to calculations, be about 16 psi at 40 bpm with single-phase SBM (assuming quadratic dependence on flow rate of nozzle pressure drop), and be only a minor contribution to reduced hook load.

5.3 Cementing

The base oil pumped between SBM and spacer has a large impact on pressure due to its low density. Assuming no mixing gives a result that disagrees strongly with observed pressure, and therefore mixing with fluids before and after base oil is considered, see Figure 9.

5.3.1 Details of pressure responses

The sequence of changes in pressure from 428 minutes simulated time for the no-mixing curve in Figure 14 is explained by the following table.

Simulated time (min)	Event	Details
473	6.7 ppg base oil front enters annulus, displacing 14 ppg SBM	Hydrostatic column will increase inside running string and decrease in annulus due to the low density of the base oil, hence drop in SPP (standpipe pressure / pump pressure). The short increase in SPP just before this is due to the 5 bbl of 16.5 sg SBM.
474.5	14.3 ppg spacer enters annulus.	After this hydrostatic column is constant inside string and increases outside.
476	14.3 ppg spacer at under-reamer.	The increase in hydrostatic column slows down due to wider geometry.
485.1	Base oil enters 9 7/8" casing	The oil stretches out due to narrower geometry and hydrostatic column in annulus and SPP decreases.
488.2	Bottom plug lands in float collar	The plug breaks at about 2900 psi. Pressure rise is while compressing fluid inside string.
492.8	16.74 lead cement enters annulus.	A quick increase in hydrostatic column in lower annulus and SPP due to the high lead cement density.
494.9	Foam cement enters annulus	SPP decreases slowly due to the lower density of foam cement.
498.8	Base oil enters 11 7/8" casing	Base oil column gets shorter in the wider geometry and annulus hydrostatic pressure increases, as does SPP.
501.2	Top plug lands in float collar	
501.4-502	Stop pumps	

Table 8: Details of pressure response due to difference in density and geometry

5.3.2 Landing of plugs

Landing of plugs was simulated by closing the bottom of the running string inside while pumping continued. Approximate durations were read out of the cementing pressure plot and gave nearly 2900 psi when the bottom plug landed, which is considered consistent with measurements given the large uncertainty of time. Duration of the pressure increases related to plugs passing x-over and landing in float collar was too short to allow accurate determination from figure, but in an order of magnitude manner it can be said that the height of the peaks correspond with fluid volume and compressibility.

Consistency between pumped volume behind plugs and time of pressure spikes can be checked by comparing calculated fluid front positions with positions of cross-over and float collar. After having pumped the given volume from dropping dart to release bottom plug till the pressure peak corresponding to landing of bottom plug starts, calculated front position of foamed cement is at depth 17594 ft as compared to the depth of the float collar being 18117 ft, i.e. front position is 523 ft above the float collar. At the start of the pressure build-up the foam density was calculated to be 14.17 ppg, i.e. very close to target density 14.1 ppg in open hole. As there is some uncertainty related to calculation of foam density, the effect of a change from 14.17 to 14.1 ppg was calculated. In the latter case calculated front position would change from 17594 to 17880 ft, which still is 500 ft above the float collar. Volume of the 500 ft is about 18 bbl. *Remark:* The volume of lead cement behind the bottom plug was unclear when configuring the simulations and is therefore not included here; hence it should be subtracted from the 18 bbl deviation.

The deviation is a little larger for the second spike, which corresponds to landing of the top plug. With the reported pumped volume when top plug landed, calculated front position of spacer (or tail of unfoamed shoe cement) was at 17549 ft, which is 568 ft higher up than the front of foamed cement was when landing of the bottom plug was reported. 17549 ft corresponds to a volume of 20.5 bbl above the float collar.

The cross-over was at 12483-12488 ft, and after having pumped volume reported for seeing peaks, front of foamed cement and tail of unfoamed shoe cement were at about 12315 and 12293 ft respectively. This gives deviations of about 170 and 193 ft respectively, corresponding to 12.3 and 13.9 bbl. *Same remark as above applies:* Volume of lead cement behind the bottom plug should be subtracted from the first volume (12.3 bbl).

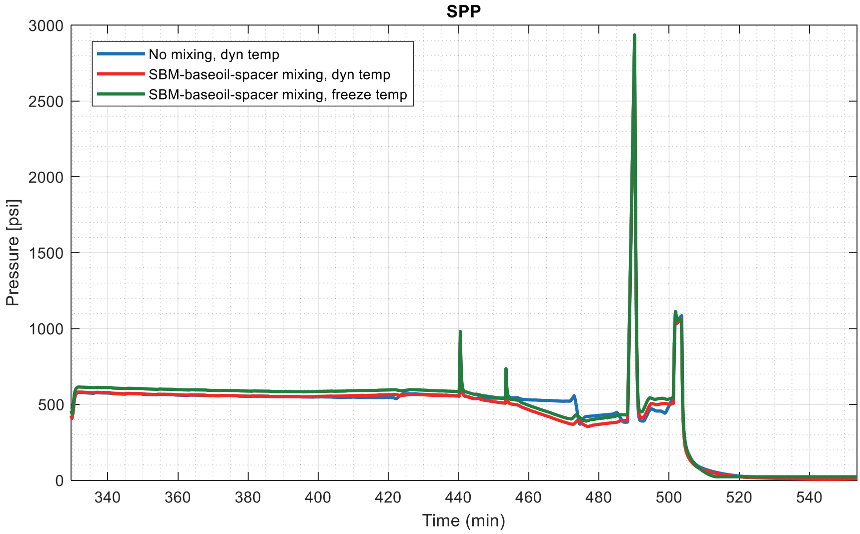

Figure 9: Pump pressure during cement displacement with and without strong mixing of base oil with fluids ahead and behind. A calculation with the pre-calculated temperature profile frozen before circulation starts is added to illustrate the significance of dynamic temperature effects.

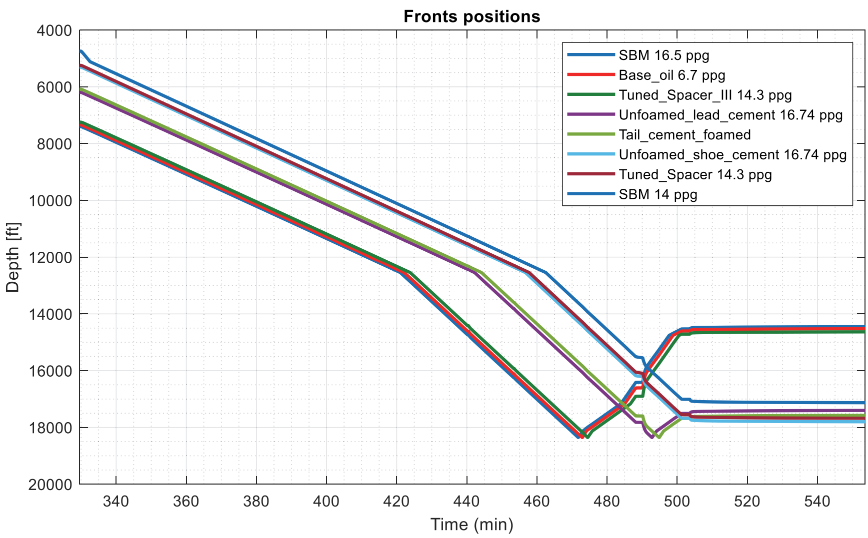

Figure 10: Front positions during cement displacement with no mixing, dynamic temperature, same period as Figure 9.

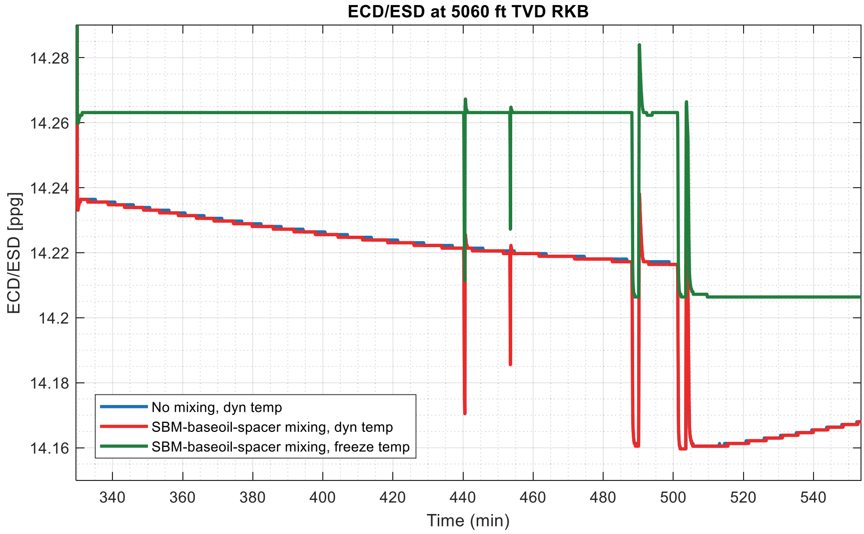

Figure 11: Equivalent mud weight near wellhead.

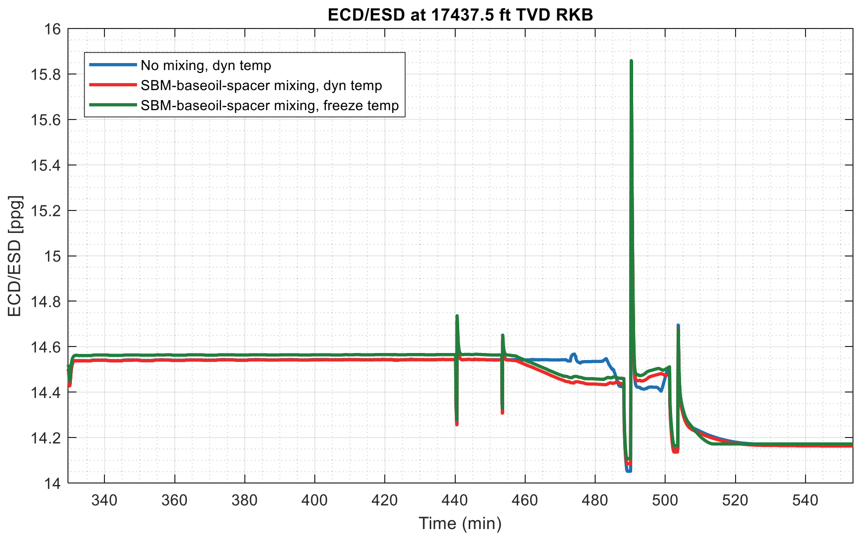

Figure 12: Equivalent mud weight in annulus at gas sand.

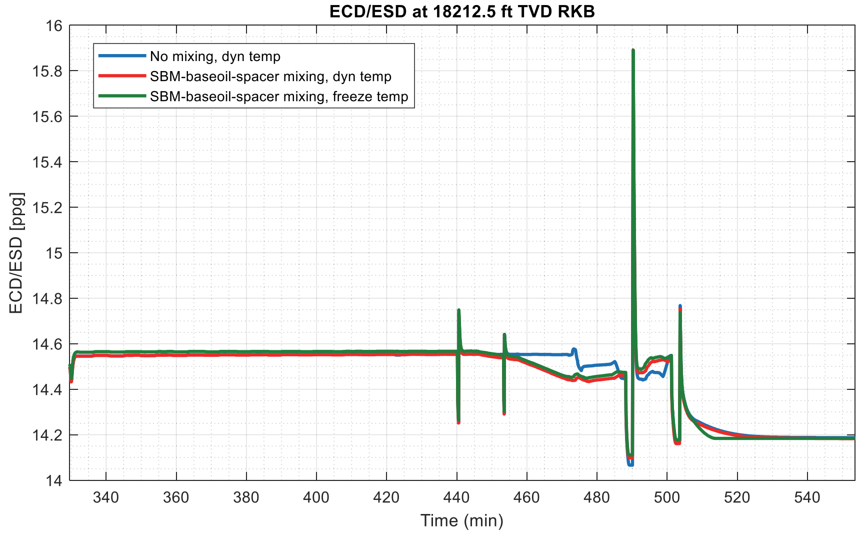

Figure 13: Equivalent mud weight in annulus at oil sand.

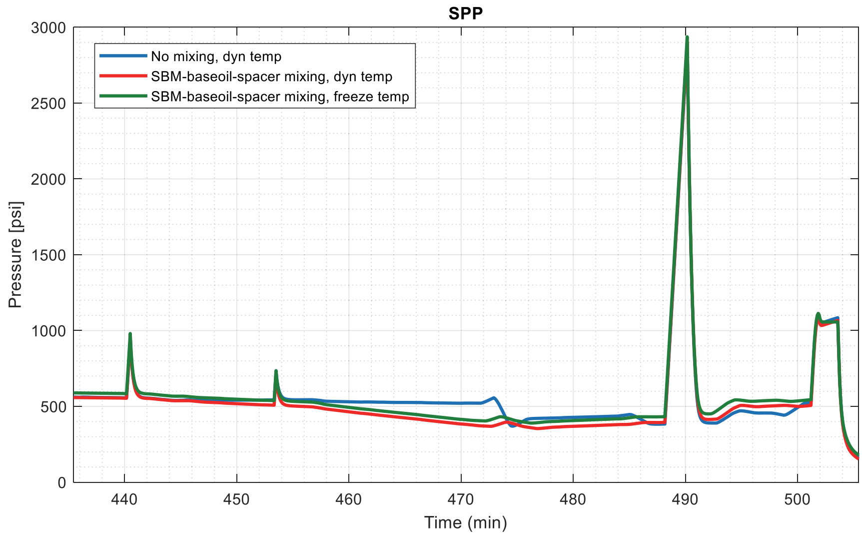

Figure 14: Pump pressure, last 70 minutes before bleeding off pump pressure on Figure 9.

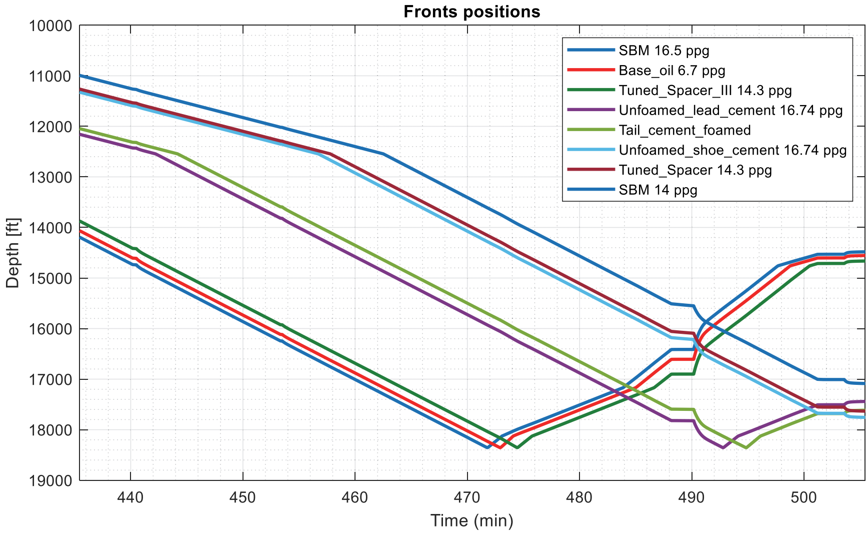

Figure 15: Front positions with no mixing, same period as Figure 14.

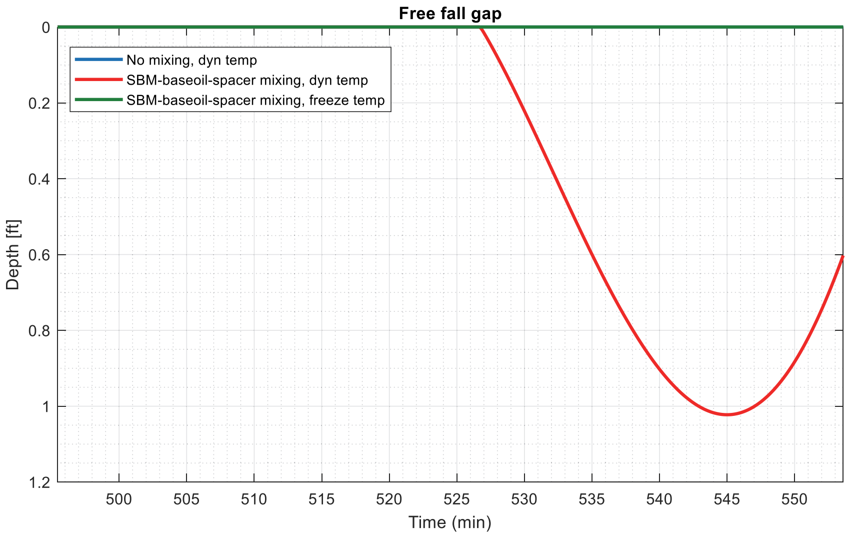

Figure 16: Fluid gap inside running string when stopping pumps if there were no active valves or plugs, increasing because hydrostatic pressure inside running string is a slightly higher than outside in the simulation with mixing and dynamic temperature. The blue line is hidden behind the green.

5.3.3 Increasing pressure after pump stop

When the rig pump stops after landing of top plug in float collar at about 12:36 (456 minutes), observed pressure continues to increase by about 60 psi over 2.13 minutes, or a build-up rate of 28 psi/min. Different hypotheses have been examined of which one is that temperature effects alone are enough due to the heating of closed in fluid after flow stops. Calculations show about 24 psi/min build-up rate, which is relatively close to observation given the large uncertainties in temperature-related parameters and compression vs. pressure and temperature, and thus the difference between observations and calculations is considered an indication that the temperature hypothesis is good.

Another hypothesis is that there is gas inside the string that migrates upwards, and for the observed pressure rise a significant volume of gas would have to migrate about 30 m (98 ft). This means migration speed is about 0.23 m/s (0.75 ft/s), which is fully possible with sufficiently large bubbles that can overcome the fluid's resistance to gas migration.

5.4 Discussion

Most of the detailed discussion in Section 5.2 applies also here.

The cement displacement simulations reproduce the main trends of the cement operations with some exceptions, which may have one or more of the following reasons:

1. Input data and information inaccurate
2. Educated guessing for missing data and information inaccurate
3. Well conditions deviate from expectations
4. Leakages and other anomalies in string, casings etc.
5. Loss and/or gain
6. Hydrate formation

Deviations of measured parameters from calculations include the following, of which some are discussed above:

1. **Timing.** Observed pressure peaks corresponding to landing of plugs come earlier than calculated.
2. **Pump pressure.** Some trends are not reproduced, including
    a. Pressure falling off after bottom plug passes crossover.
    b. Pressure increases a little shortly before top plug passes crossover, and pressure decreases from higher level after it has passed.
    c. Between top plug passing crossover and bottom plug landing in float collar, observed pump pressure has three about equally long parts; first falling off, then levelling out, then falling off.
    d. Between landing of bottom and top plugs, pressure increases by more than 100 psi followed by a short drop.

Trying to adjust simulations further in different ways trying to reproduce the mentioned effects would be interesting but was not possible within this study.

6 Conclusions

Simulations on a circulation sequence followed by cementing have been run with SINTEF's flow model for drilling and well control, and discussed in some detail to shed light on whether early gas influx and/or hydrate formation are likely explanations observations that deviated from expectations and calculations. Data and information are too sparse to allow firm conclusions but based on the work done it is considered likely that a large amount of gas is present in the annulus prior to the circulation sequence.

Some deviations between observed trends and calculations could not been explained within the constraints of this work, and further work is recommended to investigate possible explanations.

6.1 Proposed further work

The study had to be limited and simplified as compared to the complexity of the Macondo case, and assumption had to be made to get around uncertainties related to data and information lost. Therefore, an extended analysis is recommended to get more out of the information that is available, including the following elements:

- Run more simulations with systematic variation of assumptions and input data to try to reproduce better the trends that were poorly or not reproduced in this study.
- Search for additional data from earlier Macondo-related projects in SINTEF and elsewhere, if possible.
- Redo PVT calculations for typical synthetic oils to check consistency with the assumptions made here. Constituents may include linear alpha olefins (LAO), internal olefins (IO), poly alpha olefins (PAO), esters and ethers.
- Redo simulations with PVT calculations for chosen SBM composition embedded for a more holistic approach.
- Quantify effects of hydrate formation by including it in calculations.
- Study different loss-gain scenarios by inclusion in calculations.

7 References

[1] Linga, Harald, Bjørkevoll K.S., Skogestad J.O., Saasen A, *Study targets potential for gas loading in drilling fluids to improve influx detection, management*, Drilling Contractor Jul/Aug 2017.

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[7] Bjørkevoll K.S., *Use of High Fidelity Models for Real Time Status Detection with Field Examples from Automated MPD Operations in the North Sea*, paper presented at the 2nd IFAC Workshop on Automatic Control in Offshore Oil and Gas Production, May 27-29, 2015, Florianpolis, Brazil, https://doi.org/10.1016/j.ifacol.2015.08.021.

[8] Rommetveit R., Ødegrd S.I., Bjørkevoll K.S., Herbert M., *Testing a new software system for drilling supervision,* published in World Oil 230 (4), 47-52, 2009.

[9] Appendix C: Short overview of relevant information provided by Future Well Control.

Appendix E

Definitions and Glossary of Terms

Definitions and Glossary of Terms

In this Appendix E a brief description or explanation of terms used in the industry is listed in alphabetical order. Most of the definitions are taken from the Drilling Lexicon by IADC or from the PetroWiki Glossary by Society of Petroleum Engineers (SPE). Some of the descriptions are also taken from other sources. For abbreviations and acronyms in general, see Appendix A.

Ballooning

In the context of drilling, ballooning is the phenomenon in which fluids are lost to the rock during over-pressured operations, such as found in increased pressures from equivalent circulating density operations, and then flow back when pressure is reduced. This may be confused with a kick. [E.1]

Bullheading

A term to denote pumping into closed-in well without returns. [E.2]

Cap rock

A sealing formation of very low permeability that forms the top or the seal in a reservoir. [E.3]

Cavings

Pieces of rock that came from the wellbore but that were not removed directly by the action of the drill bit. Cavings can be splinters, shards, chunks and various shapes of rock, usually spalling from shale sections that have become unstable. The shape of the caving can indicate why the rock failure occurred. The term is typically used in the plural form. [E.4]

Figure E.1 – Pictures of cavings (van Oort et al. 2019, Fig. 1*)*

Connection gas
The small amount of gas that enters the wellbore when circulation is stopped to make a connection. The gas only enters the wellbore in this case when the static fluid pressure is less than the pore pressure. [E.5]

Crossflow
Flow between formations via a connected wellbore. Crossflow, as seen by downhole cameras, can occur with the wellbore full of fluid and the appearance of a dead well at surface. [E.6]

Dense phase
When a natural gas is compressed above the *cricondenbar* in the region between *critical temperature* and *cricondentherm*, it becomes a dense, highly compressible fluid that demonstrates properties of both liquid and gas. Figure E.2 presents different regions of the phase envelope for a typical natural gas mixture.

The dense phase has a viscosity similar to that of a gas, but a density closer to that of a liquid. [E.7]

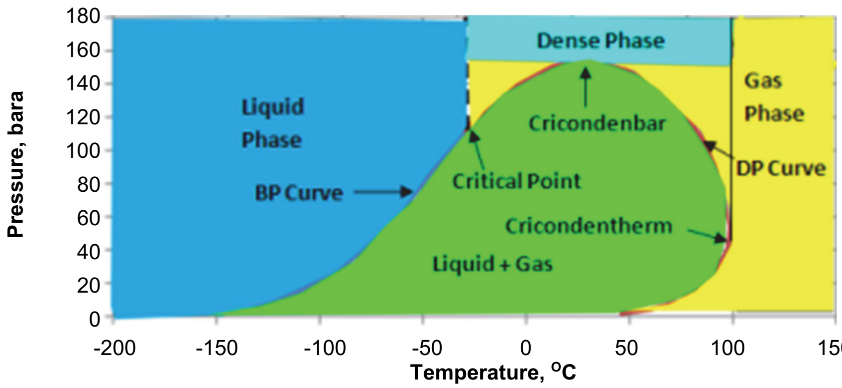

Figure E.2 – Identifying different phases for a typical natural gas.

Drilling margin
The difference between the maximum pore pressure and the minimum effective fracture pressure. It is used while drilling and can be determined for any point within an open-hole interval. NOTE Drilling margin is usually expressed in terms of equivalent mud weight. [E.8]

Equivalent Circulation Density (ECD)
The effective density of the circulating fluid in the wellbore resulting from the sum of the pressure imposed by the static fluid column, friction pressure and surface back-pressure. [E.9]

Equivalent Mud Weight (EMW)
The pressure at any given depth expressed in terms of mud density at that given true vertical depth. [E.10]

Equivalent Static Density (ESD)
The effective density of the circulating fluid at any given true vertical depth, when there is no circulation. The ESD takes compressibility of the circulation fluid due to increased pressure with depth and density changes due to temperature changes in the circulation fluid into consideration. [E.11]

Filter cake
The layer of solids stranded on the face of permeable formations by liquids driven into the rock by pressure differential towards the formation. When sized correctly the filter cake may completely stop losses. [E.12]

Fracture breathing formation
Theory of fluid exchange in the fractures as mud is lost into propagating fractures, where it is partly stripped from weighting material and in-situ gas would dissolve in the mud. When the fracture starts to close, oil-based mud, stripped from weighting material and now carrying dissolved gas returns into the well (breathing). [E.13]

Gain
Unexplained increase in active drilling or completion fluid volume or flow out from the well returning to the rig. [E.14]

Gas hydrates
Gas hydrates is an ice-like crystalline solid formed from a mixture of water and natural gas, usually methane. The gas molecule is trapped in a crystal-like structure or cage made of water molecules.

Gas hydrates can occur naturally in the pore spaces of sediments and may form a sealing formation of very low permeability and act as a cap rock in shallow reservoir with relative low temperatures.

Gas hydrates may also form after gas influx into the well. An ice-like solid may form from water in the drilling or completion fluids and light components from the natural gas, typically methane. Gas hydrates may also form in oil-based mud since this may contain up to 20% water.

When gas hydrates forms, gas is “consumed” resulting in a volume reduction, since the volume occupied by the solids (hydrates) is considerably less than the volume occupied by the equivalent fluids of the same amount of water and gas. This volume reduction may be observed at the surface as loss of drilling fluids and can be confused with lost circulation.

If gas hydrates (solids) are circulated up the riser, the static pressure is reduced. When the pressure is low enough, the gas hydrates will dissociate or "melt". The captured methane molecules will then escape, resulting in a rapid volume expansion. This phase transition from solid phase to gas phase, can be confused with a kick. The observed gain may be caused by gas hydrate dissociation.

Gas hydrate dissociation may also occur deep down in the wellbore. Hydrates may have formed in the wellhead area or the kill & choke line after a gas kick. If gas influx and gas hydrates are bullheaded back to the formation, the gas hydrates then typically will melt due to high ambient temperature in the formation. Again, the gas hydrates dissociation can be confused with a kick. [E.15]

Gas kick

An unexpected and unwanted entry of gas into the wellbore during drilling or well operations. [E.16]

Influx

The flow of fluids from the formation into the wellbore. [E.17]

Kick

An unwanted flow of fluids from a formation into the wellbore. Can happen during drilling, completions or interventions. [E.18]

Lost circulation

Loss of circulation is the uncontrolled flow of whole mud into a formation, sometimes referred to as a "thief zone. The loss can be either; a) partial loss or b) total loss, see figure E.3.

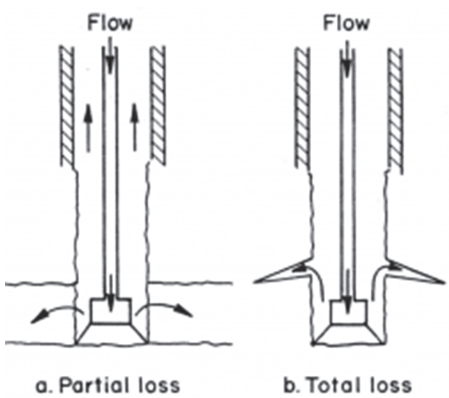

Figure E.3 – Lost circulation zones. [E.19]

In partial lost circulation, mud continues to flow to surface with some loss to the formation. Total lost circulation, however, occurs when all the mud flows into a formation with no return to surface. [E.19]

Mud pulse telemetry
A method of transmitting LWD and MWD data acquired downhole to the surface, using pressure pulses in the mud system. The measurements are usually converted into an amplitude- or frequency-modulated pattern of mud pulses. The same telemetry system is used to transmit commands from the surface. [E.20]

Outflow
Fluids that flow out of one place to another, typically out of a well. [E.21]

Primary well control
Prevention of unwanted flow of formation fluid into the well by maintaining a pressure in the entire open wellbore imposed by the static fluid column and surface back-pressure equal to or greater than the formation pressure at any given time or section of the well. [E.22]

Shale
A common sedimentary rock with porosity but little matrix permeability. Shales are one of the petroleum source rocks. Shales usually consist of particles finer than sand grade (less than 0.0625 mm) and include both silt and clay grade material. [E.23]

Swap out
Drilling fluids or completion fluids are lost to the formation and is partly or totally replaced with formation fluids, typically natural gas.

The loss of drilling or completion fluid to the formation may occur in one zone or section of the open wellbore simultaneously with gas or other formation fluids flow into the open wellbore in another section of the open well.

The loss of drilling or completion fluid to the formation may also occur during high ECD during circulation followed by a gas or other formation fluids influx during connection.

Swap out is a term used to describe that whole mud or completion fluids has been partly or totally exchanged with formation fluid, without discussing the actual kick or influx mechanism.

Swap out is particularly dangerous because kicks can occur without any gain or flow observed at the surface. [E.24]

Wellbore breathing
Same observed phenomenon as ballooning, however unlike ballooning, wellbore breathing may return formation fluids such as gas or formation water to the wellbore. [E.25]

Wellbore caving
The phenomenon or process where cavings are produced. [E.26]