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Gap Analysis Between Macondo Deep Water Horizon Drilling Blowout With Regulations And Industry Standards & Codes

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Abstract

Macondo blowout also known as the Deep Water Horizon incident has been one of the biggest oil field disaster in history, which resulted in negative impacts on Health Safety and Environmental.

This paper presents case study based GAP analysis between technical regulations (namely, recommended practices, guidelines, Industry standards and codes that existed prior to the blowout) and the implemented design /operation in Macondo well.

Based on the considered 17 key finding items, the Gap analysis results show that 60% of the technical GAPS were due to Cementing, followed by 17% due to Negative Pressure Test and 23% for other activities.

For each failure items, this paper indicates what was supposed to be done to comply with technical regulations. The intention of the paper is to highlight the importance of following recommended guidelines and best practices in order to mitigate and reduce the risk level of accident.

1 INTRODCUTION

Macondo blowout is one of the worst disaster in the oil and gas industry history, causing human causalities and environmental pollution of great magnitude. Over the years, it has been a case study for HSE, maintenance and inspection.

British Petroleum (BP) had been operating the Macondo well situated in the Mississippi canyon, which is a very vast oil rich area. The Macondo well is situated in the block 252, about 65 km south east of the American state Louisiana, about 23 square km in area (Figure 1a) [1]. It is reported that numerous other wells have successfully been drilled and produced prior to Macondo well.

With almost 1$ million/day rig rate, BP had originally planned to complete drilling of the Macondo well in 51 days. In November 2009, the well was drilled up to the depth of 3000ft with the Marianas but following the event of hurricane Ida, the Marianas was damaged, disconnected and taken to shipyard for repairs.

In January 2010, the Deepwater horizon from Transocean (Figure 1b), which was already on contract with BP was called to replace the damaged Marianas and further drilling continued from 6th February 2010 [2].

On April 20, 2010, a mile beneath the ocean disaster struck following a series of events in the world's biggest blowout (Figure 1c), causing 11 casualties and 17 were greatly injured. Thirty six hours later the fire and explosion on the rig caused the rig to sink to the sea floor. A huge among of hydrocarbon spilled from the reservoir into the ocean, which lasted for 87 days and damaged fauna and flora (Figure 1d). The environmental impact of the blowout in the Gulf of Mexico is still being discussed and researched. The incident also traumatized the livelihood of many people.

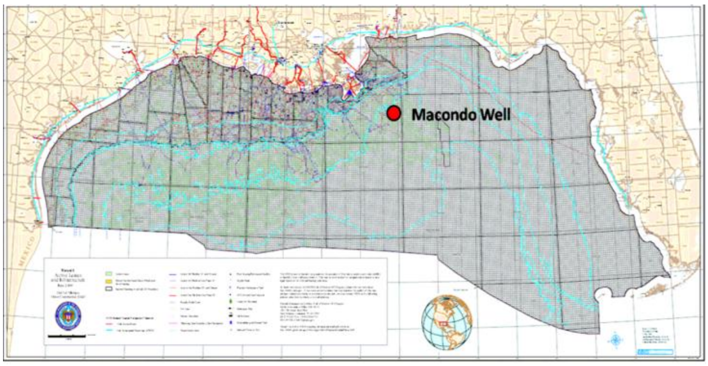

Figure 1a: Geographical location of Macondo well[1]

Figure 1b: Deepwater Horizon semisubmersible rig[1]

Figure 1c: Macondo Well Blowout [1]

Figure 1d: Environmental impacts on fauna and flora[1]

In the industry, GAP Analysis is an effective and cost efficient tool to identify key components, processes or procedures that need immediate attention or improvement. They are mainly used as a benchmark prior to maintenance activities, recertification or upgrading of existing system or part of a system. It is usually performed for every item of given recommended practice/ standard and codes.

The Macondo blowout incident concerns many number of standards & code, guidelines etc. Showing the technical gaps of every item is vast and would not fit in the limitations of a paper. Therefore, after examining all the relevant standards and codes, guidelines, recommended practices only the items /sections that are of major impact w.r.t. the Macondo blowout incident have been documented in this paper.

The Macondo well gave BP numerous challenges from the start and posed an array of risks including high pore pressures, lost circulation events, selection of long string production casing versus liner tie back, choice and selection of centralizers and the risk of channelling during cementing, cement slurry design, well testing, temporary well abandonment sequences [3]

The main purposes of this paper is to present a case study based gap analysis with the objective of investigating the technical gaps between the operators' / service company's recommended practice against what they actually followed.

2. PETROLEEUM INDUTRY STANDARDS

"The petroleum and natural gas industries use a great number of standards developed by industry organisations, through national and regional standardisation bodies, by the individual companies in the industries and by international standards bodies. The use of these standards enhances technical integrity, improves safety, reduces environmental damage, and promotes business efficiencies that result in reduced costs. The current, intensified period of international standards development reflects the global nature of the industry and the imperative to operate more effectively and reduce costs further. International standards for the petroleum and natural gas industries is the area that is the focus of the International Association of Oil & Gas Producers (OGP) through its Standards Committee" [4]

The following guidelines, recommended practices, regulations, standards and codes are of critical importance for the GAP Analysis.

2.1 API RP 65- "Isolating Potential Flow Zones During Well Construction"

API RP 65 is an important standard and code for the cementing operations, post cement job activities as well as casing shoe testing.

2.2 MMS Regulations (Pre-Macondo)

Minerals Management Service (MMS) was the US government administrative agency in charge of leasing, auditing, inspection etc. It is similar to the NPD (Norwegian Petroleum Directorate) in Norway. They had various regulations set forth for operators / service companies' w.r.t petroleum exploration, drilling, completions, production and abandonment.

2.3 BP/Transocean's Recommended Practices

BP and other service companies have their own internal recommended practices and guidelines for every operations in the petroleum industry. These guidelines are substantially based on their own experience within the industry. The companies in addition to their guidelines also use other relevant, well established Standards and Codes in conjunction with their own guidelines. .

3 GAP ASSESSMENT

Prior to GAP Analysis, about 17 key events leading to the blowout and their causes and effects has been identified.

GAP analysis is then peformed by comparing the technical gaps between the operator / Service Company's recommended practice and the implemented Macondo design. Table 1 shows the summary of the considered Gap analysis between the Base design vs three highly impactful Industry standards.

Table 1: Summary of Gap analysis

§3.1	Base design - Macondo Well	Vs	GAP w.r.t BP/Service Company Guidelines
§3.2	Base design - Macondo Well	Vs	GAP w.r.t MMS Regulations
§3.3	Base design - Macondo Well	Vs	GAP w.r.t API Regulations

NOTE: Color codes denotes that recommendation;

- Red: is a High Impact GAP
- Yellow: is a Medium Impact GAP
- Green: is a Low Impact GAP

3.1 GAP assesment of base BP design w.r.t BP/Service Company Guidelines

The first Gap assesment is carried out by analyszing the BP design with respect to BP guideline. The items considered for the assesement are related to cement, separator and casing/formation strength.

#	Base design followed in the Macondo Well	GAP w.r.t BP/Service Company Guidelines
1	BP had ran out of the drilling margin and had set the production liner casing shoe inside the reservoir section (M56 formation) and terminated the well at 18360ft from originally planned 20200ft. A consolidated shale section starting at ~20000ft was the original casing shoe bearing geology.	"BP internal guideliues for total well depth specify that drilling should not be stopped in a hydrocarbon interval, unless necessary due to operational, pressure and safety issues.**[80]** Typically, total depth is not called in a sand section because placing the casing shoe-the section of the casing between the bottom of the wellbore and the floar valve-in a laminated sand-shale zone increases the likeihood of cement channeling or contamination due to washout, and creates difficulties in logging well data.[80]" [5]
	GAP Analysis*: BP had terminated the well at 18360 feet since they had run out of drilling margin, at 18360 feet, the well was actually terminated inside the sand stone reservoir section. This decision laid the foundation for the series of events that led to the actual Blowout on April 20th 2010.*	
2	BP decided to place the Top of Cement (TOC) of the production liner casing just 500ft above the upper most reservoir section, just enough to comply with the MMS regulations, which only	"BP's engineering technical practices require that personnel determine the top of cement by a "**proven cement evaluation technique**" if the cement is not 1,000 feet above any distinct permeable zones.[149]

	asked for minimum 500ft above the uppermost reservoir zone. It was mandatory for BP, according to its own guidelines to perform a cement evaluation technique. But in Macondo BP decided to accept the primary cement job on the fact that they had no cement loss in to the formation based on fluid volume in vs fluid volume out calculation.	The acceptable proven techniques identified in BP's internal guidelines are cement evaluation logs, cement column back pressure, and temperature logs. BP's guidelines do not identify lift pressure or lost returns to be proven techniques for evaluating a cement job.[150] "**[5]**
	GAP Analysis: *In case BP had followed their internal guidelines, the cement bonding logs could have helped BP identify the poor cementing or shoe track contamination if any. (The CBL was never performed to is it very hard to say what was the exact cause of the failed cement)*	
3	BP and Transocean crew had no means to cross verify their negative pressure test result or even to interpret the results of the negative pressure test.	"Both BP and Transocean had general requirements for positive and negative testing, but neither provided specific guidelines for how the tests were to be performed or how the results from the tests were to be interpreted." [2]
	GAP Analysis*: Had there been any specific guidelines, then the rig crew could have interpreted the excessive flow and pressure built up on the drill pipe when it was shut in during the negative pressure tests. Instead of performing consecutive negative pressure test, the rig crew would have considered the test failed and could have sort advice or suggestions from onshore experts / personnel and possibly could have understood that well had started flowing. Rig crew could have had more time on an action plan to mitigate the consequences of the blowout.*	
4	Halliburton's own analysis of the cementing for the Macondo well, using 7 centralizers and nitrogen foam cement mix, showed that the cement slurry was unstable except for the last report (which was stable) but this third lab report was only sent to BP days after the actual blowout had happened. [3]	"Halliburton's post-blowout laboratory worksheets dated May 26, 2010, show that the foam-slurry cement did not meet American Petroleum Institute Recommended Practice ("API RP") 65.95" [5**]**
	GAP Analysis: *" laboratory tests conducted by Chevron on behalf of the National Commission on the BP Deepwater Horizon Oil Spill and Deepwater Drilling ("Presidential Commission") showed that the foamed cement slurry used on the Macondo well was not stable."* **[5]**	
5	The annular tolerance of the production line casing and the wellbore was 0.75 inches only.[5**]**	"Halliburton also recommends that, to improve the probability of success in the primary cementing job, "[t]he best mud displacement under optimum rates is achieved when annular tolerances are approximately 1.5 to 2.0 inches." "**[5]**
	GAP Analysis: *Higher annular tolerance gives higher volume of cement and at optimal cement flow rate can give a good cement job and could have potentially withheld the formation in flux in to the casing.*	
6	In the Macondo well, the float collar was at the top of the casing shoe adjacent to the reservoir sand section, followed by shoe track and then shoe with circulating ports at the bottom.	"BP chose to land the float collar across a hydrocarbon-bearing zone of interest in the Macondo well, instead of at the bottom of the shoe." **[5]**
	GAP Analysis*: If the float collar had been at the bottom of the casing shoe (casing shoe comes with flapper valves at the top or at the bottom), even if the flapper valves had failed to convert, the shoe track adjacent to the formation would not have been contaminated along with the lighter drilling mud in the rat hole. Additionally the casing shoe (shoe track + unconverted flapper valves + shoe) could have possibly held well barrier integrity against the formation fluid (when the float collars are moved to the bottom, the shoe track is at the top of the casing shoe and is now occupied with cement adjacent to pay zone).*	
7	BP performed the third negative pressure test on the kill line.	The negative pressure test procedure for BP, written by Lindner, an employee of MI-SWACO (BP's contractor) specified as follows "Lindner's procedure specifically instructed, as step two, to "[d]isplace choke, kill, and boost lines and close lower valves after each."[216] The procedure did not instruct the personnel to re-open the choke and kill lines, which would be necessary to perform a negative test on either line. In any event, Lindner

		presciently noted at the end of the procedure that "good communication will be necessary to accomplish a successful displacement. If you are not sure, stop and ask."[**5**]
	GAP Analysis: *Had BP followed the procedure as described, they would have at least had to clarify if a negative pressure test on a kill line can be accepted. After the first two negative pressure tests failed, BP chose to open the kill line valve and performed the third negative test on it*	
8	BP had used the mud gas separator to direct the gas flow, instead of overboard in to the sea, which was possible via two 14 inch pipes situated at portside and starboard side of the rig.	"Transocean's well control handbook indicates that if gas has migrated or has been circulated above the BOP stack before the well is shut in, the choke manifold and mud gas separator may no longer be available to control the flow rates when the gas in the riser reaches the surface.[273] Both companies recommend using the diverter lines when flow rates are too high for the mud gas separator." [**5**]
	GAP Analysis*: The mud gas separator should only be used to direct well kick of smaller quantity without overwhelming the diverter system, when the kick flows through the separator, the gas and mud are separated and the gas is flared off safely at the top of the rig.*	

Table 2: GAP assessment of base BP design w.r.t BP/Service Company Guidelines

3.2 GAP assessment of base BP design w.r.t MMS Regulations

Here three items were considered, namely Temporary Abandonment, Negative pressure test and cement slurry design. The designs and operations were compared with respect to MMS Regulations.

#	**Base design followed in the Macondo Well**	**GAP w.r.t MMS Regulations prior to Macondo Blowout**
9	During the events of Temporary Abandonment, BP had actually decided to set the cement plug at 3300ft below the seafloor, this caused the displacement of 3300ft of drilling mud with lighter seawater prior to negative pressure testing.	"As part of BP's plan to temporarily abandon the well, BP intended to install a 300 ft. cement plug in the well at a depth of approximately 3,300 ft. below the seafloor to prevent wellhead seal area contamination and to provide sufficient weight from the drill string to set the lockdown sleeve. **MMS regulations require the plug in the production casing be set no more than 1,000 ft. below the mudline,** (seafloor). This plan required two important interconnected simultaneous operations: displacement of the drilling mud with seawater and offloading the drilling mud to a supply vessel." [2]
	GAP Analysis: *If BP had followed the MMS regulation to place the cement plug at 1000ft below the mudline, then that would not have displaced 2300ft of heavier drilling fluid's hydrostatic pressure on the formation. Hypothetically, even if the following negative pressure test had failed (at this point the formation had actually started following in to the well) the BP team would still have been able to install the cement plug and the lockdown sleeve. And when the production rig was brought in with its own BOP, it could have identified and / or dealt with the formation flow more effectively. And the Deepwater horizon with its faulty drilling BOP when moved to a new well, has to be tested prior to installation according to NORSOK D-010 Rev.3, 2004 (or its equivalent international standard) which was in effect during 2010, this could have helped notice the faulty control pods.*	
10	BP did not perform the negative pressure tests based on any guidelines or procedure, they had done the test based on the experience of the rig crew and likely had no possible way of verifying the results with any benchmark standards.	" While the MMS had requirements for positive pressure testing of the casing, the MMS did not have any specific requirements or guidelines for the negative pressure testing." **[2]**
	GAP Analysis*: Had there been any specific guidelines, then the rig crew could have interpreted the excessive flow and pressure built up on the drill pipe when it was shut in during the negative pressure tests. Instead of performing consecutive negative pressure test, the rig crew would have considered the test failed and could*	

	have sort advice or suggestions from onshore experts / personnel and possibly could have understood that well had started flowing. Rig crew could have had more time on an action plan to mitigate the consequences of the blowout.	
11	The Halliburton's OptiCem analysis that BP had asked for did say that the nitrogen cement slurry in the Macondo well with long string production casing likely results in gas flow problems. BP still chose to go ahead. Before receiving the report from Halliburton, BP installed the long casing string with six centralizers.	"Halliburton's best practices document also addresses gas flow potential. It states: Although gas flow may not be apparent at surface, it may occur between zones, which can damage the cement job and eventually lead to casing pressure at the surface. The OptiCem program can be used as a tool to determine the gas flow potential of any primary cement job." **[5]**
	GAP Analysis: *If BP had waited for the OptiCem Report they could have known valuable information on the condition of the 'cement column' in the annulus. They would have known that they had poor cement job, cement contamination as well as crucial information on the compressive strength of the cement.*	
12	Based on the requirement of MMS, BP did not have to perform mandatory function test of the BOP shear rams, it only needed to provide documentation showing that the BOP was capable of shearing the pipe and MMS regulation did not specify anything about third party verification or proof of the same.	"The MMS regulatory response was to require operators to submit documentation showing that the shear rams that they used in their BOP were capable of shearing pipe in the hole under maximum anticipated surface pressures." **[5]**
	GAP Analysis: *It should be noted that the MMS regulation specifies w.r.t. maximum anticipated surface pressure and not the maximum working pressure (in the newer regulations following Macondo blowout, maximum working pressure is used, for example in NORSOK D-010 rev 4, 2013, Annexure A, Table 38, the casing shear rams are to be tested to a maximum of 70% working pressure).*	

Table 3: Summary of GAP assessment of base MMS Regulations

3.3 GAP assesement of base BP design w.r.t API Regulations

The last Gap assessment was the BP design with respect to the API regulation (API RP 65). The items considered here were, tail cement, cement job, and drilling fluid displacement

#	Base design followed in the Macondo Well	GAP w.r.t API Regulations
13	The tail cement had 16.74 ppg (nitrogen foam cement) and the rat hole had been filled with 14.0 pgg (synthetic oil based mud). **[5]**	**API RP 65-2 Section 5.8.4 Rathole** says "Rathole beneath the casing shoe can lead to contamination of cement during placement, or drilling fluid can swap with the cement after placement. These can result in poor strength development, pockets of drilling fluid, or a wet shoe. Rathole length should be minimized or filled with densified drilling fluid." [**6**]
	GAP Analysis*: Since the rathole was filled with a lighter fluid, the heavier tail cement could have been mixed with the drilling mud in the rathole, this could have led to the contamination of the cement in the casing shoe and the production liner annulus.*	
14	BP proceeded to perform the primary cement job and other succeeding operations (float collar conversion, negative pressure test etc.) even without the compressive strength analysis report from Halliburton. [**5**]	**API RP 65-2: Section 4.6.3 WOC Guidelines Prior to Removing a Temporary Barrier Element** says **"**If design and operational parameters indicate isolation of potential flow zones, cement **shall** be considered a physical barrier element only when it has attained a minimum of 50 psi compressive or sonic strength. The 50 psi compressive or sonic strength threshold exceeds the minimum static gel strength value needed to prevent fluid

		influx. Local regulations **shall** be adhered to with regards to WOC. However, caution should be exercised when the specified WOC time is less than the time required for the cement to reach a strength of 50 psi." **[6]**
	GAP Analysis: *Only a compressive strength analysis of the cement job would give information on Waiting on Cement (WOC), the time required to achieve minimum 50psi compressive strength. As seen from the API regulation, the cement job can only be considered as a well barrier element, only if it had achieved at least 50psi compressive strength, without the report from Halliburton BP could not have known the current compressive strength of the cement job.*	
15	BP had instructed Halliburton to perform OptiCem models for the primary cement job, with 6 centralizers at 'varying spacing' but the Halliburton's OptiCem model used incorrect data, it had used 7 centralizers as well as centralizer spacing to be 45feet. **[5]**	**API RP 65-2 Section 5.4.2 Centralizers** says "Appropriate casing centralization is important to successful cement placement and zonal isolation. Casing centralizers exist in many models and designs and are generally categorized as either rigid, solid or bow-spring models. Auxiliary functionalities such as flow diversion and mechanical friction-reduction are also available. Custom-built centralizers are available for either slimhole or extremely large annular clearances." **[6]**
	GAP Analysis: *It is not known why Halliburton used incorrect information, either way the Halliburton OptiCem report had not reached BP prior to the blowout, BP still choose to proceed to subsequent operations following cementing.* [5]	
16	BP and Transocean attempted the float collar conversion following primary cementing of the production liner, which was followed by temporary abandonment sequence.	**API RP 65-2** **Section 5.10.2 WOC** says "Operations on the well following cementing should be done in such a way that they will not disturb the cement and damage the seal or cause the cement to set improperly." **[6]**
	GAP Analysis: *Following the pumping of primary cement mix, BP proceeded to convert float collar even without the compressive strength analysis from Halliburton, the float collar should have converted at 500-700 psi at optimal flow rate. But the float collar was assumed to be converted at 3142 psi. It is possible that this high pressure could have disturbed or damaged the cement barrier and contributed largely to the blowout.*	
17	BP performed a partial displacement of the drilling mud prior to cementing.	"Consistent with API RP 65, Halliburton's internal cementing best practices document also advises that full well circulation be performed prior to cementing". **[5]**
	GAP Analysis: *With concerns of lost circulation events prior to cementing, BP decided to perform only a partial drilling mud displacement, which means that not all of the drilling mud (which was used to drill the open hole internal from ~17000ft to ~18000ft) were removed. There is a possibility that drill cuts might still be suspended in the annulus and this had a serious consequence on cement slurry channelling i.e. cement slurry flows on the wider side of the wellbore with stagnant drilling mud on the other side (contamination of cement).*	

Table 4: GAP assessment of base API Regulations

4 DISCUSSION

To be able to understand the Deepwater Horizon incident, it is necessary to start with the complexity of the well. The stuck pipe incident on the 8th April 2010 set the foundation for the major technical challenges that the companies would face in the future. The incident caused BP to side track the well, pushing them behind schedule. This was followed by many lost circulation events that the companies faced until they had reached the ~17000 feet towards the sandstone reservoir. From 17000ft onwards the well turned out be increasingly problematic.

Following the revision of the total well depth, BP had to choose between a 'long string' production casing versus a 'short string' production liner tie-back casing. BP had decided to use the long string based on concerns that the short string would cause mechanical integrity problems at the tie back junction along with annular pressure built up. It is vital to note that the short string would have given BP two additional well barriers, but BP chose a long string on the balance of possibilities. The long string casing gave Halliburton (cementing contractor) serious challenges via reduced annular tolerance for cementing.

Given the fact of the lost circulation events along with the reducing drilling margin from 14.1 ppg (PP at ~17000ft) to 12.6 ppg (PP at ~18000ft) and the reduced annular tolerance, the companies had very few choices and decided to use an unproved nitrogen foam cement slurry with reduced density, which was considered to be just as strong as any other conventional cement slurry.

Additionally, BP chose to ignore the Halliburton's report that said with seven centralizers, the cement job would cause gas flow problems, which is even discussed as a main requirement in NORSOK D-010 standard. BP had performed a partial displacement of the drilling mud prior to cement job instead of a full displacement to the rig. The full displacement could have effectively cleaned the hole by removing the debris and providing smooth wellbore contact. It is possible that the partial displacement had suspended debris and led to channeling of the cement job that followed. This was a compromise against API 65 Recommended practices.

By this time, BP was behind schedule and any subsequent problems would just add fuel to fire, but the Macondo well was unforgiving, it kept throwing challenges to BP who were way behind schedule and increasingly drifting away from the budget. Furthermore, BP proceeded to convert the float collar of the casing shoe without receiving a compressive strength analysis from Halliburton that they had ordered. But before they were in actual possession of the report they proceeded forward, the compressive strength report would have given valuable information on the current state of the cement column (i.e. thickening time, Waiting on Cement etc.) which is a requirement in API 65. Also, if there had been any contamination of the cement slurry from the lighter drilling mud in the rat hole, it could have been inferred from the report. It is also unknown why BP did not follow the API 65 regulation, which clearly directs the companies to use higher weight fluid in the rat hole. It is possible that BP, given the state of the complex well bore issues (lost circulation events, zero drilling margin, uncertain cement slurry etc.), were worried about the formation damage. In addition to this, it is also crucial to remember that the wiper plug disc burst at 2900psi instead of 900psi-1100psi.

The float collar conversion at the end of the cement job did not go as planned, BP compromised on multiple parameters here as well. According to Weatherford specifications the float collar was supposed to convert at 500-700 psi at an optimal flow rate of 5-7 bpm but BP noticed to have converted at a staggering 3142psi at just 4 bpm. It is also not confirmed whether the float collar had indeed been converted. Interestingly, BP did not use higher flow rate, perhaps in view of increased ECD damaging the formation, which was in effect a compromise from the API 65 Regulations as well as Weatherford specification. Pressuring the casing at 3142 psi could have also damaged the annular cement.

Following the primary cementing, BP performed temporary abandonment sequence, which mainly included the setting of the cement plug, negative pressure test and placing a lock down sleeve. According to MMS regulations, the cement plug should be set not more than 1000 feet below the mudline during temporary abandonment. But BP chose to place the cement plug at 3300 feet below the mudline, which also meant displacing 3300 feet of heavy drilling mud with seawater. BP, according to its original plan, could have chosen to place the lock down sleeve before displacing the drilling mud. This could have acted as an additional well barrier.

The negative pressure test (NPT) was one of the most important symptoms that the well was in fact flowing. Since there wasn't any concrete regulatory clarification on the procedure or even on how to verify the results of the negative pressure test, BP had no means to benchmark its negative pressure test.

Finally, when the kick started moving above the BOP as a result of the BOP failure, BP tried to discharge the kick through the mud gas separator instead of overboard in to the sea. This led to gas cloud built up and ignition followed by explosion. BP's internal guideline instructs rig crew to discharge large kick size overboard. Although the working pressure of the diverter packer is 500psi, much lower than the 1400psi formation pressure, it could have provided sufficient time to evacuate the rig crew. Eleven people could have been saved.

5 MAJOR INVESTIGATIONS PRESENTED IN THE GAP ANALYSIS

Table 5 shows the major investigations performed in this paper. It highlights the item number of the GAP analysis presented in section § 3 (Tables 2-4) and the operations that were performed in the respective item number along with the GAP Analysis Impact. It also highlights the Operations Impact that caused the blowout. Only the items 1-17 of the GAP analysis were the direct causes of the Macondo blowout.

Item number of the GAP Analysis above	Operations	GAP Analysis Impact
1	Revised total depth and choice of casing string	Low
2	Cementing (Cement evaluation, CBL)	High
3	NPT (Negative Pressure Test)	Medium
4	Cementing (Centralizers, cement slurry design)	High
5	Cementing (annular tolerance)	Medium
6	Cementing (Float collar conversion)	Medium
7	NPT	High
8	Diverter system	High
9	Temporary abandonment (Placement of cement plug)	High
10	NPT	Medium
11	Cementing (OptiCem analysis report)	High
12	BOP (Function testing)	High
13	Cementing (high density fluid in the 'rathole')	High
14	Cementing (Compressive strength analysis)	High
15	Cementing (OptiCem analysis report)	Medium
16	Cementing (Float collar conversion)	Medium
17	Cementing (Partial displacement)	High

60% High Impact GAPs	35% Medium Impact GAPs	5% Low Impact GAPs
60 % due to Cementing	17% due to NPT	23% due to Others

Table 5: Summary of Gap analysis major investigation.

6 SUMMARY

From this paper, it is possible to see the serious of events that led to the Macondo disaster and the worst case scenarios of such events, in spite of the various safety systems employed to prevent such a disastrous blowout. BP and its service companies took many major decisions which involved a lot of risks, assumptions and non-compliance of regulatory guidelines, including in-house recommended policies. Each such event snowballed with the subsequent event and resulted in the eventual blowout.

The Macondo well gave many signs and symptoms of the blowout, but the lack of oversight and preparedness of the decision makers contributed greatly to the blowout. It can be seen that the companies involved compromised greatly on the safety and made decisions on uncertainty. They did not follow the standards and code on many occasions. Even though Post-Macondo many of the standards & codes, guidelines and recommended practices were revised and updated significantly, the blowout could have been avoided if the companies had followed the guidelines, Standards & Codes that existed Pre-Macondo.

The Macondo blowout could have been avoided. The most important cause of the blowout is ‘Human Errors’. The various regulatory guidelines, standards and codes exist to keep the petroleum industry in view with health, safety and environment. Although they exist, they are only a minimum benchmark. It is in the hands of the operators and service companies to follow Best Available and Safest Technology.

From the Major Investigations, it is evident that 60% of the technical GAPs that caused the Blowout were of HIGH Impact, followed by medium impact GAPs at 35% and low impact GAPs at 5%. Additionally, 60% of the technical GAPs were due to Cementing, followed by 17% due to Negative Pressure Test and 23% for other activities.

From this paper, it is evident that BP and its service companies made substantial compromises with respect to regulations and guidelines, some of which were their own internal recommended practices. We would like to remind this famous internet quote “Hope for the best, plan for the worst”.

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