THE UNDERESTIMATED VALUE OF SAFETY IN ACHIEVING ORGANIZATIONAL GOALS: CAST ANALYSIS OF THE MACONDO ACCIDENT

By

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To God, my lord, my shepherd.

No oil is worth a life!

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ABSTRACT

On April 20, 2010, an explosion in the rig Deepwater Horizon performing drilling operations on the Macondo Prospect Well, in the Gulf of Mexico, led to the largest oil spill in the history of the petroleum industry. Eleven crewmembers lost their lives and around 4.9 million barrels of oil were discharged into the ocean until the continuous subsea blowout of the well was contained in September 19, 2010.

Given the magnitude and the complexity of the accident, several safety analyses have been proposed by the international community at different levels of the system involved in the accident. Most of these studies use accident analysis techniques based on chain-of-event models, whose main objective is to identify root-causes. However, while this approach describes physical phenomena accurately, it does not explain the role of organizational and socio-economical factors, human decisions, or design inaccuracies in accidents in complex, adaptive, and tightly coupled systems like Macondo. In response to this need, N. Leveson developed the new accident-analysis technique Causal Analysis Based on System Theory (CAST), based on her model System-Theoretic Accident Model and Processes (STAMP). In STAMP accidents are not treated as chain of failure events, but as complex processes that result from a large variety of causes including component failures and faults, system design errors, unintended and unplanned interactions among system components, human operator errors, flawed management decision-making, inadequate controls and oversight, and poor safety culture.

This thesis presents management recommendations based on a CAST analysis of the Macondo Accident. The goal is to help the oil and gas offshore drilling community achieve safer operations and understand the value of systems safety in achieving organizational goals.

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María F. Tafur

Cambridge, MA, May 2017

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1. INTRODUCTION

1.1 MOTIVATION

"Most managers do care about safety. The problems usually arise because of misunderstandings about what is required to achieve high safety levels and what the costs really are if safety is done right. Safety need not entail enormous financial or other costs."[13]

This is exactly the case in a significant amount of oil and gas operations. Managers in the oil and gas industry, especially mid-level managers, do not deliberately ignore safety; actually they spend substantial efforts firefighting safety related issues in many fronts at a time. They perceive their working environment as an intrinsically hazardous system and accept "superficial" hazard management as a natural task. In consequence, they consider safety management as an everlasting and expensive burden that they often bypass when external forces demand performance efficiency. They rarely use safety management as an instrument to enhance productivity and achieve organizational goals.

At higher management levels, executives commonly measure organizational goals through profit metrics and system safety is not regarded as a strong contributor to achieving these goals. System safety is simply not perceived as a basic operational requirement; it is often confused with personal safety and included as a marginal cost to improve the perception of the company in the eyes of the world. Nevertheless, safety management can be used as an insurance tool that not only frees systems from losses, but that if done right can clarify and structure systems interactions, systematic gaps and flaws, stakeholders roles, and efficient paths towards profit increase and a sustainable existence of the company.

The Macondo disaster portrays the underestimation of safety in achieving organizational goals. In this case, profit and performance pressures implicitly excluded system safety from the core priorities of the parties involved and led the project to a high-risk state long before the accident, until the catastrophic blowout took place. Therefore, the study of this accident from a managerial perspective serves to identify the key elements that placed system safety in a secondary plane before the accident. It also serves as a motivation to explore the factors that applied to the different levels of management within the system, and to establish the bases of safety recognition as a core corporate competency beyond unpredictable and temporary profit and performance demands.

1.2 Analyses of the Macondo Accident

On April 20, 2010, an explosion in the rig Deepwater Horizon performing drilling operations on the Macondo Prospect Well, in the Gulf of Mexico, led to the largest oil spill in the history of petroleum industry. Eleven crewmembers lost their lives and around 4.9 million barrels of oil were discharged into the ocean until the continuous subsea blowout of the well was contained in September 19, 2010.[21]

Given the magnitude and the complexity of the accident, several safety analyses have been proposed by the international community to prevent more events of this nature by identifying the relevant factors that led to the disaster. Most of these analyses focus on the technical shortcomings. The ones that go beyond the technicalities of the accident tend to limit their analysis to the recognition of the same systematic conditions identified by the U.S. government in its investigation. Surprisingly, even the analyses that model the disaster combining social and cognitive skills with safety culture theory under a system-thinking perspective do not reach different conclusions, let alone propose alternative recommendations, regarding management. These authors are able to find human and organizational factors that are essential causes of the accident yet do not define the applicability of their model or introduce tools to overcome the existing weaknesses of the system. Moreover, unlike typical formal hazard analysis techniques, these analyses succeed in considering human behavior but then omit humans in their models to the extent of not even recognizing them as components of the system.

None of these studies offer a clear view of the safety roles and requirements of the people making safety-related decisions, which hinders the identification of the management indicators contributing to unsafe states and ultimately interferes in the definition of genuine and acceptable human actions that could lead to safer environments.

1.3 Thesis Objectives and Outline

The first objective of this thesis is to present to the managers in oil and gas offshore systems recommendations based on the analysis of the Macondo Accident that would hopefully help them achieve safer operations. Different stakeholders have different safety requirements; in complex systems, in which not even the interaction between components is entirely clear, defining safety requirements is crucial to identify and overcome system design errors in an effective manner. This need demands a sociotechnical approach, where organizational, financial, environmental, regulatory and cultural factors that are relevant to safety managers are addressed, so that each stakeholder understands and integrates safety in the system as early as possible.

To achieve this objective, the accident analysis technique Causal Analysis Based on System Theory (CAST) is used. Developed by Professor Nancy G. Leveson, this technique is based on her System-Theoretic Accident Model and Processes (STAMP). STAMP is a systems-theory-based model that includes "not only component failure and faults but system design errors and unplanned and unanticipated interactions among components that have not failed. … It also includes causal factors involving social, human, and organizational factors. In STAMP, accidents result from a large variety of causes including component failures and faults, system design errors, unintended and unplanned interactions among system components, human operator errors, flawed management decision making, inadequate controls and oversight, and poor safety culture. Accidents are treated as complex processes and not just chains of failure events. Analysis methods built on STAMP can identify potential hazards resulting from any of these causal factors."[14]

Considering the scope of STAMP, the second objective of this thesis is to determine if a CAST analysis of the Macondo Accident leads to alternative management recommendations beyond the existing ones. To answer this question, the analysis is based on several investigation reports to include different points of view and findings. Its first iteration was reviewed with managers associated with the system and complemented with their input. Then, the recommendations from the revised result are compared to recommendations from existing analyses.

This document is divided in five chapters: Chapter 1. Introduction. Chapter 2. CAST, which introduces CAST and STAMP. Chapter 3. CAST Analysis of the Macondo Accident, that contains the revised causal analysis of the accident and management recommendations. Chapter 4. Comparison to Other Analyses, which presents three published analyses, their recommendations, and their difference with the CAST analysis.   Chapter 5. Conclusions of the CAST analysis process and the results.

2. CAST

CAST is an accident analysis technique that uses the accident causality model STAMP to:

1. Identify the questions that need to be answered to understand **why** an accident occurred,
2. Establish the basis for maximizing learning from events,
3. Find voids in the structure of the system where the accident happened,
4. Propose changes that will eliminate not only symptoms and but also causal factors.[13]

Many industries primarily use accident analysis techniques based on chain-of-event models, whose main objective is to identify a root-cause. This approach works well when system failure is dictated by physical component failure. However, it can overlook subtle and complex interactions among failure events, completely miss no-component-failure accidents along with the entire accident process, and limit the identification of systematic causal factors.[13]

Essentially, event-based models that describe physical phenomena accurately are inadequate to explain accidents caused by organizational and socio-economical factors, human decisions, and software design inaccuracies in complex, adaptive, and tightly coupled systems.[13] In fact, events are the result of inadequate control and dysfunctional interactions in the system, therefore they must be part of any accident analysis; but, they are not the most fundamental component of the analysis nor do they represent the entire environment of the accident. In response to this need, STAMP (System-Theoretic Accident Model and Processes) incorporates event-based models into system-based analysis that allows the examination of the sociotechnical complexity of an accident.

2.1 STAMP Basics

STAMP is based on Systems Theory, which arose in the 1930's and 1940's to overcome the limitations of traditional analysis in modeling increasingly complex systems. This theory studies the system as a whole and is based in two concepts: hierarchy and emergence and control and communication, which determine the nature of STAMP and its components.[13]

Hierarchy and emergence deal with different levels of complexity characterized by having emergent properties, such as safety, that do no exist at low (physical component) levels of complexity in the system. A general model of a system can be expressed in these terms to identify the structure of the system and to explain the relationships between its different levels.

Control and communication deal with the imposition of constraints upon the tasks performed by subordinate levels of the system's structure and the communication between levels to ensure the enforcement of constrains. Active feedback loops allow the controller to implement actions upon the process and ascertain its status.

STAMP considers safety as a control problem, in which the control (physical, logical, cultural, political, legal, etc.) enforces safety constraints within the system and between the system and its environment, and the loss results from inadequate implementation of these safety constraints in design and/or operations.[13] In this sense, systems in STAMP are a group of interrelated components that stay in dynamic equilibrium through feedback loops and continuously adapt to achieve their goals while reacting to internal and external changes over time.[13]

In contrast with event-based models, the three main components of STAMP are safety constraints, hierarchical safety control structures, and process models. These components are the basis for any prospective (hazard analysis, like STPA) and retrospective (accident analysis, like CAST) studies based on STAMP. Events are no longer the basic unit, root causes do not exist anymore, and accidents causes are not merely due to human errors, but are the result of inadequate safety control structures that under certain circumstances lead to the violation of behavioral safety constraints.[31]

Safety Constraints. Safety constraints are the most basic concept in STAMP; losses occur when safety constraints are not enforced. The evolution of systems into highly automated ones has shifted the nature of hazard controls from passive (physical principles and limited materials) to active (actions required to provide protection, such as monitoring, measurement, diagnosis, and response). While safety engineering still focuses on avoiding failures, imposing constraints on system behavior to avoid hazards offers a higher-level approach that covers unsafe events and conditions in all levels;[13] it enables a holistic view to ensure safety through the synthesis of general controls that the whole system can satisfy and that all components can define as safety responsibilities according to their rank.

Hierarchical Safety Control Structure. Based on the systems theory concept of hierarchy, safety control structures represent systems in which each level imposes constraints on the activity of the level beneath. This control happens through communication channels that aim to prevent accidents when control processes between levels are inadequate and safety constraints under their responsibility are violated. Specifically, at each level of the safety hierarchical structure, inadequate control may result from: missing constraints (unassigned responsibilities in regards to safety), inadequate safety control commands, commands not executed (or executed incorrectly) at lower-levels, and inadequately communicated or processed feedback about constraint enforcement.[13]

To implement effective communication between levels, safety control structures must include two types of interactions: downward, as reference channels providing information on the enforcement of safety constraints on the lower level, and upward, as measuring channels providing feedback to the upper level on the implementation of safety constraints [Figure 1.].[13]

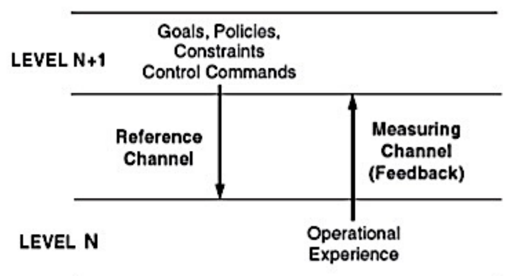

Figure 1. Communication channels between control levels [13].

Process Models. Process models, whether human mental models or embedded in automated logic, must contain the relationship among the system variables, the current state of such variables, and the ways the process can change state.[13] Usually, a controller has a formal or informal model of the process (Figure 2); however, the process model might not match the activity being controlled and the control action issues unsafe commands causing undesired outcomes (Figure 2).

In STAMP, there are four types of inadequate control actions:[13]

1. Incorrect or unsafe control command given.
2. Required control actions (for safety) are not provided.
3. Potentially correct control commands are provided at the wrong time (too early or too late).
4. Control is stopped too soon or applied too long.

Process Models are crucial to understand **why** accidents occur and why humans provide inadequate control over safety-critical systems, and design safer systems.[13]

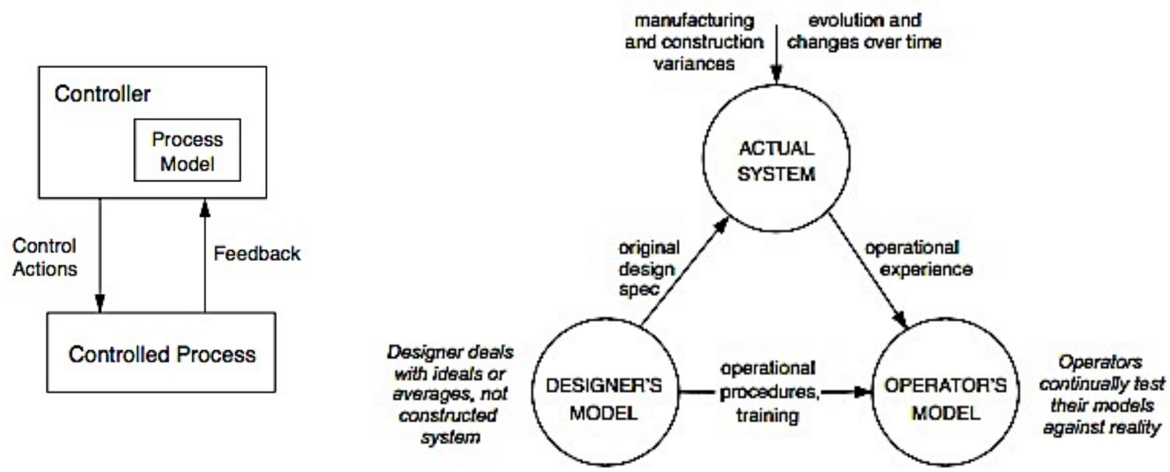

Figure 2. Right: Controllers contain process models of the processes being controlled.[13] Left: Relationship between mental models.[13]

Old Assumption	New Assumption
Safety is increased by increasing system or component reliability; if components do not fail, then accidents will not occur.	High reliability is neither necessary nor sufficient for safety.
Accidents are caused by chains of directly related events. We can understand accidents and assess risk by looking at the chains of events leading to the loss.	Accidents are complex processes involving the entire sociotechnical system. Traditional event-chain models cannot describe this process adequately.
Probabilistic risk analysis based on event chains is the best way to assess and communicate safety and risk information.	Risk and safety may be best understood and communicated in ways other than probabilistic risk analysis.
Most accidents are caused by operator error. Rewarding safe behavior and punishing unsafe behavior will eliminate or reduce accidents significantly.	Operator error is a product of the environment in which it occurs. To reduce operator "error" we must change the environment in which the operator works.
Highly reliable software is safe.	Highly reliable software is not necessarily safe. Increasing software reliability will have only minimal impact on safety.
Major accidents occur from the chance simultaneous occurrence of random events.	Systems will tend to migrate toward states of higher risk. Such migration is predictable and can be prevented by appropriate system design or detected during operations using leading indicators of increasing risk.
Assigning blame is necessary to learn from and prevent accidents or incidents.	Blame is the enemy of safety. Focus should be on understanding how the system behavior as a whole contributed to the loss and not on who or what to blame for it.

Figure 3. The basis for a new foundation for safety engineering.[13]

Assumptions. Finally, as any model, STAMP is based on some assumptions. These are presented in Figure 3 under **New Assumption,** in comparison to the traditional foundations for safety engineering under **Old Assumption.**[13]

2.2 CAST Process

In practice, CAST uses STAMP as its foundation and is applied following the process hereunder:[13]

1. Identify the system(s) and hazard(s) involved in the loss.
2. Identify the system safety constraints of each hazard and the system requirements associated with them.
3. Document the safety control structure in place to control the hazard and enforce the safety constraints. This includes: the roles and responsibilities of each component in the structure as well as the controls and feedback to execute them.
4. Determine the events leading to the loss.
5. Analyze the loss at the physical level. This step entails:
    - Identifying the contribution of: physical and operational controls, physical failures, dysfunctional interactions, communication and coordination flaws, and unhandled disturbances.
    - Defining why these physical controls were ineffective in preventing the loss.
6. Analyze each level of the safety structure bottoms-up. Determine how and why each level contributed to the inadequate control. Starting with the controller immediately above the physical process, identify the controller's:
    - Responsibilities related to the prevention of the loss.
    - Unsafe or absent control actions.
    - Process model flaws and contextual factors.
7. Examine the overall coordination and communication contributors to the loss such as industry and organizational safety culture and safety information system,
8. Define the dynamics and changes (voids and weakening over time) in the system and safety control structure that led to the loss.
9. Generate recommendations that will eliminate or reduce unsafe behavior.

3. CAST Analysis of the Macondo Accident

3.1 Context of the Accident

On the evening of April 20, 2010, hydrocarbons escaped from the Macondo well onto Transocean's Deepwater Horizon (DWH) offshore platform, resulting in explosions and fire on the surface. Of the 126 workers on board, 11 lost their lives, and 17 were injured. The fire, which was fed by 700,000 gallons of oil on board and a continuous flow of hydrocarbons from the well, continued for 36 hours until the rig sank on April 22, 2010 along with the riser and components of the blowout preventive system.[30] Hydrocarbons continued to flow from the reservoir for 87 days, causing the largest marine oil spill ever to occur in U.S. waters. By the time the well was capped on July 15, 2010, nearly 206 million gallons of oil (five million barrels) had been spilled into the Gulf of Mexico (GoM). Federal commissions and engineering groups around the world estimated that from April 20 until July 15, around 210 million barrels were spilled into the Gulf.[30] This estimate is around 20 times the amount spilled in the 1989 Exxon Valdez disaster, which held the record for the largest spill in U.S. waters before Macondo.[17]

On the technical side, the accident involved a well integrity failure, followed by a loss of hydrostatic control of the well that resulted in the release of pressurized oil and gas into the rig. The Blowout Preventer (BOP) at the seabed was unable to seal the well and the blowout became an uncontrollable disaster.

On the managerial side, the accident involved a series of regulatory and corporate culture omissions motivated by the lucrative offshore drilling business that placed the Macondo project in a high state of risk since its very conception.

British Petroleum

British Petroleum (BP) was founded in 1909 as the Anglo-Persian Oil Company (APOC) by Englishman William Knox D'Arcy following his discovery of oil in Iran, the product of an eight-year exploration venture. In its early years, APOC struggled to stay profitable and was rescued from bankruptcy in 1914 by the British government. Winston Churchill, who by that time was head of the British Navy, believed Britain needed a dedicated oil supply and convinced the government to buy 51% of APOC.[17]

The British government retained BP's majority until the late 1970s when, under the privatization policy of Prime Minister Margaret Thatcher, the government began selling off national companies shares in an attempt to reduce state intervention and promote free markets. After the government sold its final 31% stake in 1987, BP's performance as a new private company was declining; in 1992, BP reported losses for $811 million. On the verge of bankruptcy, the company had to drastically reduce operating costs.[17]

The landscape started to improve in the mid-1990s. BP's new CEO John Browne began implementing an aggressive growth strategy, highlighted by entering the Russian market and mergers with rivals Amoco (formerly Standard Oil of Indiana) in 1998 and ARCO (formerly Atlantic Richfield) in 2000. Along with focusing on growth (by 2000 it was the third largest oil corporation in the world), BP began repositioning itself as an energy company; it entered the 21st century investing in renewables by launching the Alternative Energy Division and adopting the new sunburst logo and name BP "Beyond Petroleum" plc. For a period, BP became the largest manufacturer of solar cells in the world and Britain's largest producer of wind energy, investing $4 billion in alternative energy between 2005 and 2009.[17]

However, BP's new alternative energy focus changed in May 2007, when Tony Hayward, head of Exploration and Production (BPX), became CEO. In response to the negative press on poor safety standards for two highly publicized accidents, Hayward announced that safety was BP's new "number one priority".[1] Hayward also emphasized his determination to simplify management and improve financial performance, assuring that BP was "far too complex and fragmented causing duplication and lack of clarity" and that its performance was "dreadful".[18] Hayward's restructuring plan included significantly shrinking the Alternative Energy division, reducing BP's workforce in 18%, strict cost cutting measures, numerous mergers and acquisitions, and a drastic transformation of BP's organizational structure.[17]

BP's Organizational Structure

In the 1980s BP's organizational structure had several layers of management that interacted through a slow and rigid decision-making web. As the MIT Sloan 2012 case, BP and the Deepwater Horizon Disaster of 2010, explains it:

"In some cases, simple proposal changes required 15 signatures. Simultaneously, the company was overleveraged and its overall performance was suffering. Robert Horton, who was appointed CEO in

1989, started a radical turnaround program in an effort to cut $750 million from BP's annual expenses. He removed several layers of management and slashed the headcount at headquarters by 80. Horton also intended to increase the speed of managerial decision-making and, thereby, the pace of business in general. Horton transformed hierarchically structured departments into smaller, more flexible teams charged with maintaining open lines of communication.

Horton transferred decision-making authority away from the corporate center to the upstream and downstream business divisions. While deep cuts were made to capital budgets and the workforce, employees at all levels were encouraged to take responsibility and exercise decision-making initiative. In 1992 David Simon was appointed CEO replacing Robert Horton. Simon continued Horton's policy of cost cutting, especially in staffing.

The biggest changes during this period occurred in BPX, which was led by John Browne. Building upon his predecessors' efforts, Browne, who envisioned creating a spirit of entrepreneurship among his staff, extended decision-making responsibilities to employees at more levels in the organization. Under the new strategy, decision-making authority and responsibility for meeting performance targets was no longer held by BP's regional operating companies, but by onsite asset managers. Asset managers contracted with BP to meet certain performance targets and extended this practice among all employees working on a given site. Employee compensation was tied to asset performance and the overall performance of the site. The model, which was known as an "asset federation," was later applied across the company after Browne took over as CEO in 1995.

One tradeoff with the asset federation model was that because each site manager managed their "asset" autonomously and was compensated for its performance. There was little incentive to share best practices on risk management among the various BP exploration sites. There were also downsides to a system in which a centralized body had little oversight over the setting of performance targets, particularly in an industry where risk management and safety were essential to the long-term success of an oil company. And BP had had its shares of safety breaches."[17]

When Tony Hayward assumed as CEO in 2007, he focused on creating consensus within the company's management structure and speeding decision-making processes, following BP's well-established style of cost cutting and reduction of management layers. His strategy stemmed in a near-50-percent rise in profits in the first year. It also resulted in an unconsolidated safety management system, resembling the asset federation model, split into BP's business units, ignored by BP's executives, and unable to address the existing problems in time to avoid the Macondo accident.[16][17]

BP's Safety Issues prior the Deepwater Horizon Disaster

Although safety was touted to be important at Macondo, BP's approach focused on easily measured personal safety metrics, such as injuries, rather than system safety risks of events like a blowout. BP put "safety first" on individual employees' performance evaluation forms, but the metrics for safety encompassed only a subset of the risks of drilling. For example, the evaluation of the Wells Team Leader of GoM in 2009 had personal safety at the top of the list of his key performance indicators, measured in the form of recordable injuries. GoM Wellsite Leaders had similar objectives that emphasized recordable injuries and safety meetings, while Executives Managers did not have safety-specific goals at all.[16]

It is not clear whether and to what extent BP has or assesses safety metrics regarding drilling procedure or well design.[21] BP expected full compliance with its mandatory engineering policies, but it seems that BP lacked a systematic way to assess whether engineers complied with those policies, especially after the design review process was complete and the well entered the execution phase. [21] BP did not appear to have tracked how employee decisions impacted process safety or risk.

Major catastrophes were not new to BP. In the mid-2000s, disaster struck the company twice. First, on March 23, 2005, BP's Texas City Refinery exploded, killing 15 people, injuring 170, and accounting for a financial loss of $1.5 billion.[16] A year later, on March 2, 2006, an oil spill was discovered on BP's exploration pipeline in western Prudhoe Bay, Alaska. During the five-day leak, around 260,000 gallons of oil poured into 1.9 acres (two football fields) of the bay, making it the largest oil spill in Alaska.[8]

Following the recommendation of the U.S. Chemical Safety and Hazard Investigation Board, BP commissioned James Baker, a former U.S. secretary of state and oil industry lawyer, and a team of experts to investigate the Texas City Refinery tragedy. The main findings exposed in the Baker Report state that:

- [BP did] not provide effective process safety leadership and [did not] adequately establish process safety as a core value across all its five U.S. refineries. BP mistakenly interpreted improving personal injury rates as an indication of acceptable process safety performance at its U.S. refineries. BP's reliance on this data, combined with an inadequate process safety understanding, created a false sense of confidence that BP was properly addressing process safety risks.[16]

- [BP did] not establish a positive, trusting, and open environment with effective lines of communication between management and the workforce.[16]
- [BP did] not always ensure that adequate resources were effectively allocated to support or sustain a high level of process safety performance. In addition, BP's corporate management mandated numerous initiatives that applied to the U.S. refineries and that, while well intentioned, had overloaded personnel at BP's U.S. refineries.[16]
- [BP did] not effectively incorporate process safety into management decision-making. BP tended to have a short-term focus, and its decentralized management system and entrepreneurial culture have delegated substantial discretion to managers without clearly defining process safety expectations, responsibilities, or accountabilities. [BP did] not instill a common, unifying process safety culture among its U.S. refineries. Each refinery has its own separate and distinct process safety culture. [BP did] not ensure timely compliance with internal process safety standards and programs, nor timely implementation of external good engineering practices that support and could improve process safety performance at BP.[16]
- [BP did] not ensure an appropriate level of process safety awareness, knowledge, and competence in the organization. First, BP did not effectively define the level of process safety knowledge or competency required by the executive management, line management above the refinery level, and refinery managers. Second, BP did not adequately ensure that its personnel and contractors have sufficient process safety knowledge and competence.[16]
- [BP did] not implement an integrated, comprehensive, and effective process safety management system.[16]
- [BP did] not effectively use the results of its operating experiences, process hazard analyses, audits, near misses, or accident investigations to improve process operations and process safety management systems. The principal focus of the audits was on compliance and verifying that required management systems were in place to satisfy legal requirements.[16]
- [BP did] not effectively evaluate the steps towards actually improving the company's process safety performance. Neither BP's executive management nor its refining line management ensured the implementation of an integrated, comprehensive, and effective process safety management system.[16]

Before The Baker Report was published and BP had time to act upon its recommendations, the Alaska oil spill happened. Crude spilled over the bay for five days before it could be discovered through a quarter inch hole in an above ground 34-inch diameter pipeline. For many years, warnings from employees and state inspectors concerning corrosion of the pipeline were ignored. As Rep. Tammy Baldwin highlighted from a 2005 BP report, the company's corrosion-fighting process was based on a specific budget instead of local demands. BP managers did not expect to have corrosion problems in those lines.[8] BP had to pay $66 million to the state of Alaska, yet the entire world suffered the financial impact due to the shutdown of the Trans-Alaska Pipeline; the price of crude per barrel jumped $2.22 overnight.[8]

After this chain of unfortunate disasters, BP **proposed** several actions in regards to safety. According to the Appendix F of The Baker Report, at the corporate level these measures included:

- **Leadership Visibility.** BP's Group Chief Executive met with the company's top 200 leaders to stress BP's commitment to safety and communicate his expectations regarding safety.[16]
- **Learning Culture.** BP initiated various efforts to review management systems, safety culture, and process safety performance at its U.S. refineries.[16]
- **Review of Employee Concerns.** BP appointed retired United States District Judge Stanley Sporkin to hear and review BP employees concerns[1].[16]
- **Support for, or Checks on, Line Management.** BP enhanced the role of the Chairman and President of BP America, who started reporting directly to the Group Chief Executive. This position was granted the authority to address and correct issues related to safety[2], operations integrity, compliance, and ethics within all U.S. operations.[16]
- **Engineering Technical Practices and Refining Process Safety Minimum Expectations.** BP continued developing engineering technical practices and process safety minimum expectations, which served to standardize BP operating practices. BP also started developing a group-level engineering technical practice for risk assessment and hazard identification. [16]
- **Integrity Management and Control of Work Group Standards.** BP started the implementation of new group standards on integrity management and control of work.[16]
- **Board of Directors Oversight.** The Board of BP received presentations from senior management on process safety matters more frequently than in the past. The Board also started tracking a new set of process safety metrics. In addition, Board members planned visits to operational sites to increase their awareness of local issues.[16]
- **Review of Safety and Operations.** BP announced it would conduct a ten-year review of safety operations across the company.[16]

[1] However, BP ignored the results. In fact, many employees refused to talk to the Baker's Report Commission, or did it only with their lawyers present because BP was firing people who criticized their safety efforts. [16]
[2] Neither BP's Chairman, nor anyone from BP's Executive Level, addressed system safety issues in the following years. [16]

However, none of these motions made substantive changes in BP's safety management system. To the amazement of the world, five years later the Macondo accident left the Gulf severely damaged and the public questioning BP's safety and risk management style once again.

The Macondo Well Project

On March 19, 2008, BP acquired a 10-year lease to Mississippi Canyon Block 252 in the Central Gulf of Mexico where the Macondo well is located [Figure 4], 48 miles from the nearest shoreline.[6][21]

The Macondo well proved to have great potential for oil extraction, but with high gas content and the crude reserves at nearly 5000 ft below sea level, drilling was challenging. When BP submitted the Application for Permit to Drill, it also submitted several Applications for Permit to Modify due to the outstanding conditions of the well.[6]

BP started drilling in October of 2009 with Transocean's rig Marianas, but had to interrupt operations due to Hurricane Ida. BP resumed operations on February 3, 2010 with Transocean's rig Deepwater Horizon.[6]

Transocean charged BP approximately $1M per day ($500,000 for leasing the rig and around the same amount in contractors fees). BP originally estimated that drilling the Macondo well would take 51 days and cost approximately $96 million. By April 20, 2010 the rig was already on its 80th day on location and had far exceeded its original budget.[6][21]

BP's primary objective for the Macondo well was to evaluate a Miocene geological formation (M56) for commercial hydrocarbon-bearing sands [6]. However, during the project development the well was conceived as an infrastructure-led development. This means that the exploration well was drilled so that it could later be completed to become a production well if sufficient hydrocarbons were found [6].

To drill the Macondo well, there was a Macondo Engineering team that worked in liaison with BP's Subsurface experts and specialist contractors such as Halliburton and MI-Swaco to develop the design of the well. By late June 2009, the teams had: a detailed engineering design, a shallow hazard assessment, and a design peer review completed. The original well plan included all elements of the well design and equipment, along with a preliminary sequence of operations (including cementing and pressure testing plans).[21]

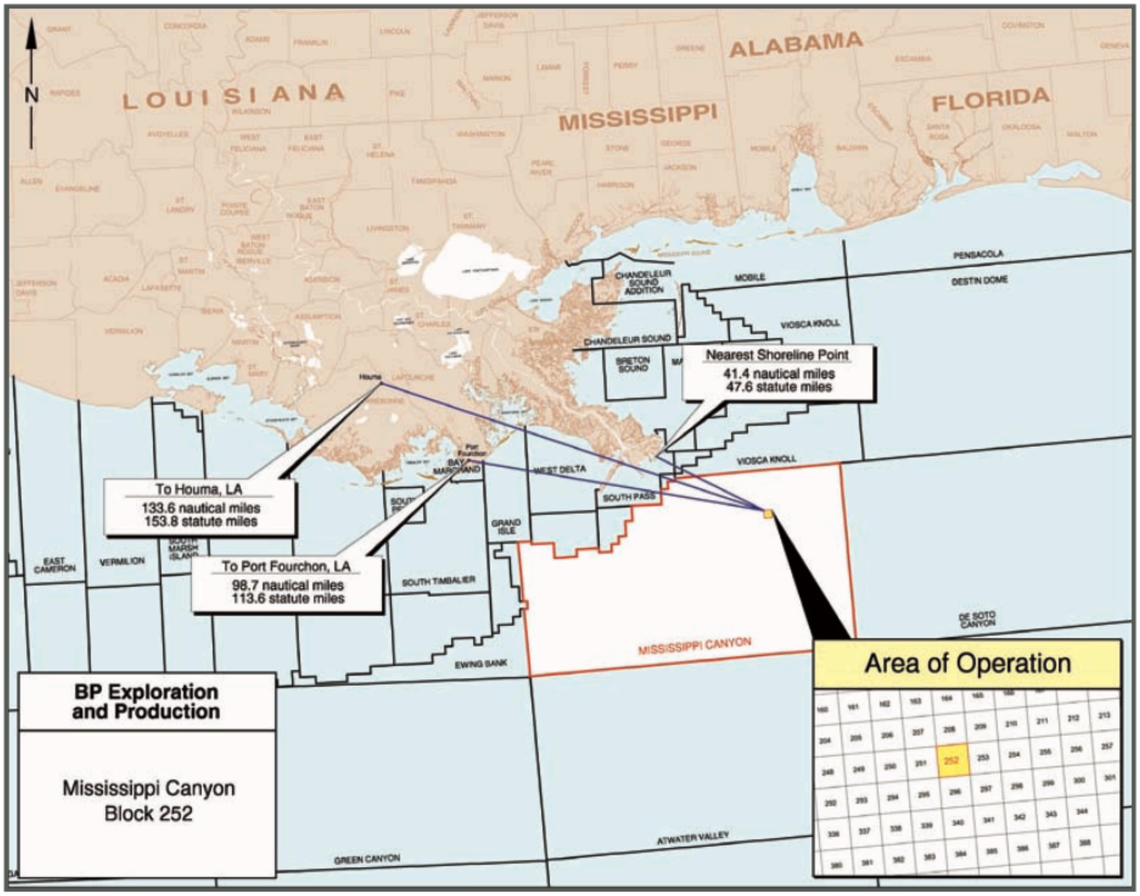

Figure 4. Geographic location of the lease and the well [6].

The Deepwater Horizon Rig and the Subsea Equipment

The Deepwater Horizon was a dynamically positioned, semi-submersible mobile offshore drilling unit that entered service in April 2001 and went to work for BP in the Gulf of Mexico the same year in September. With the exception of one well drilled for BHP Billiton in 2005, the Deepwater Horizon worked exclusively for BP.[29] The Deepwater Horizon Crew drilled more than 30 wells on the U.S. outer continental shelf (OCS) during the course of the rig's career without relevant safety incidents.[29]

The U.S. Coast Guard (USCG), the Mineral Management Service (MMS), the Marshall Islands (the flag state inspection) and the American Bureau of Shipping (ABS) regularly inspected and certified the Deepwater Horizon.

On July 27, 2009, the USCG renewed the Deepwater Horizon *Coastal State Certificate of Compliance*, which was valid through July 27, 2011.[29]

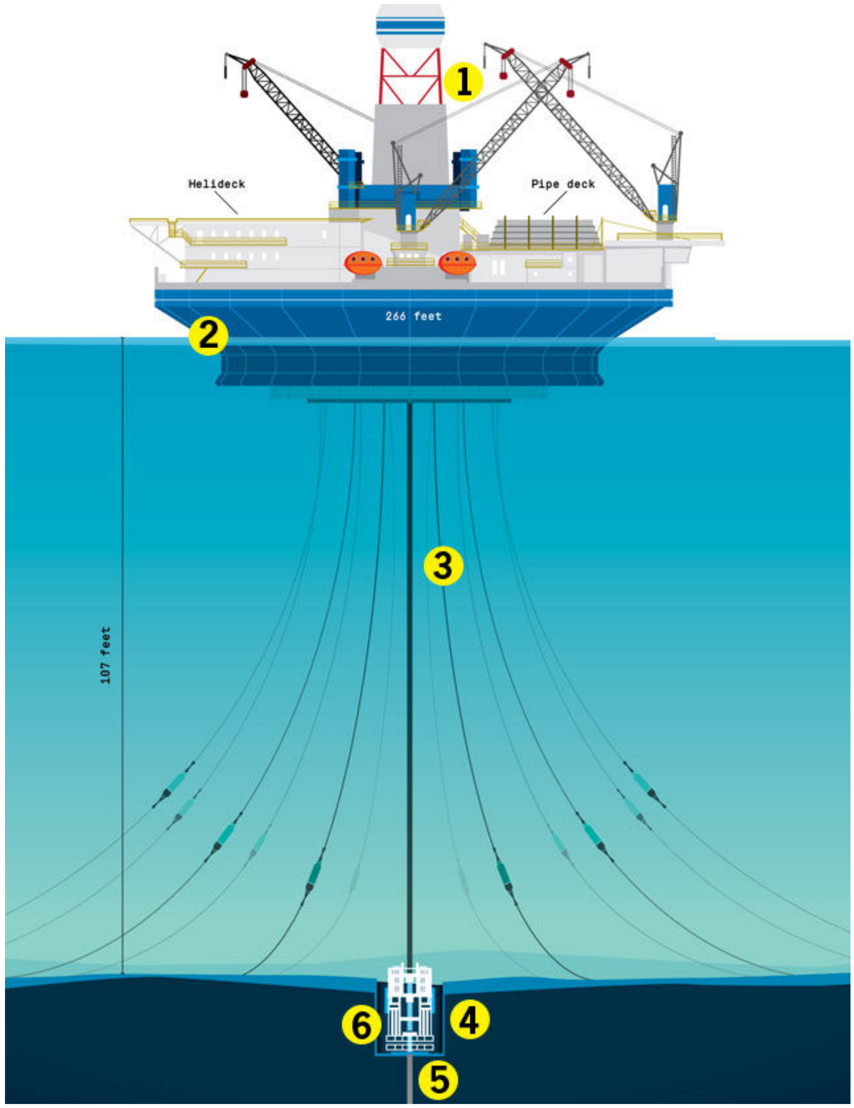

Figure 5. The Macondo well drilling set-up. 1-Rig, 2-Platform, 3-Riser, 4-Formation, 5-Well, 6-BOP.

The Deepwater Horizon also passed its Marshall Islands flag inspections in December 2009, and had its ABS Class Certificate renewed on Oct. 19, 2009, which was valid through Feb. 28, 2011.[29] In addition, the MMS inspected the Deepwater Horizon three times in 2010. During its last inspection of on April 1, 2010 though, the inspectors made no findings that required action by the rig crew.[29]

However, and in spite of having all its certifications and inspections up to date, by the time of the accident the Deepwater Horizon rig was operating with numerous maintenance issues. In September 2009 for example, BP conducted a safety audit on the rig before it headed to the Macondo well. The audit team identified 390 repairs that needed immediate attention and would require more than 3,500 hours of labor to fix and some downtime onshore. Yet, the Deepwater Horizon never stopped working between the audit and the accident.[29]

As Transocean's Chief Electronics Technician Mike Williams declared: "the crew had to be adept at developing workarounds in order to maintain the function of the rig".[16] For instance, one of Williams's recurrent tasks was to service the Drilling Chairs — the three oversight computers that controlled the drilling equipment. These computers, operating on a mid-1990s era Windows NT operating system, would frequently freeze. If Chair A went down the driller would have to go to Chair B to keep control of the well. If all three chairs went down at once, the drill would be completely out of control. Williams frequently reported the software problems and the need to have them fixed.[16]

In regards to the subsea equipment, during the investigation the most controversial component was the Blowout Preventer (BOP), a routine drilling tool located on ground level (in this case on seabed level) and designed to shut in the well in case of blowout.[21] As the operator, BP had specified the configuration of the BOP and had delegated to Transocean its operation and maintenance since it started operating in 2000.[21]

In contrast to the rig, this BOP was not certified at the moment of the accident. According to BP's September 2009 rig audit and April 2010 assessment, the BOP's bodies and bonnets were last certified on December 2000, so their recertification was at least five years overdue. The recertification process entails complete disassembly of the BOP on surface, which can take up to 3 months or longer and generally requires time in dry dock. As a result, industry common practice suggests "the best time to perform major maintenance on a complicated BOP control system [is] during a shipyard time of a mobile offshore drilling unit (MODU) during its five-year interval inspection period".[21] Nevertheless, the Deepwater Horizon never stopped working since its commission, and neither did its BOP.

In addition, the April 1st, 2010 MMS inspection of the rig did not find incidents of noncompliance and did not identify any problems justifying stopping the drilling, contrary to its regulations, and to the recommendations of industry associations and manufacturers, which demand a comprehensive inspection of the BOP every three to five years.[21]

Together with omitting the outdated recertification, the MMS also approved the testing of the BOP at lower pressures than required by their regulation. Though testing at lower pressures is also in accord with industry practice to avoid unnecessary wear or damage of the tool while in operation, most tests did not establish the ability of the equipment to perform during blowout conditions with large volumes of gas moving at high speed and high pressure.[21]

3.2 CAST OF THE ACCIDENT

CAST Step 1. The System

CAST starts by identifying the system in which the accident took place. In this case, the system is comprised of the well, the barriers that contained it, the rig, the drilling equipment, and all the organizations involved in the drilling, along with their personnel and safety policies and standards. It also includes the environment and public impacted by the uncontrolled discharge of hydrocarbons in the Gulf of Mexico and its surroundings.

As mentioned in the introduction, the focus of this analysis is on the management level of the operator of the well, which is BP. Nevertheless, the fundamentals of the analysis are defined for the accident *per se* and include the entire system.

CAST Step 2. System Hazards and Safety Constraints

In system safety engineering, and therefore in CAST, accidents and hazards are defined as follows:

Accident: An undesired or unplanned event that results in a loss, including loss of human life or human injury, property damage, environmental pollution, mission loss, etc. [13].

Hazard: A system state or set of conditions that, together, with a particular set of worst-case environmental conditions will lead to a loss (accident or incident) [13].

System Hazard: Poor engineering and management decision-making leading to a loss [13].

Based on these concepts and the nature of the accident, two main system hazards have been defined. The first one addresses the well integrity and the second one the emergency response to the oil spill. Figure 6 presents the division of the analysis.

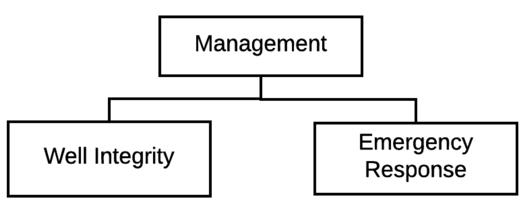

Figure 6. Basic division of the analysis.

Macondo System Hazard 1. Uncontrolled release of hydrocarbons from deepwater wells.

Safety Constraints associated to Hazard 1:

The safety control structure must ensure that:

- All well designs and well operations decisions must ensure well integrity.
- At least one of the three principal barriers must be operational at any given time.
- Means must be provided to control the well at all times: effective mechanisms (equipment and trained personnel) must detect and control changes in the well at all times.
- Response means must be provided to handle and contain any uncontrolled release of hydrocarbons from deepwater wells.

Macondo System Hazard 2. Underwater hydrocarbon spill.

Safety Constraints associated to Hazard 2:

The safety control structure must ensure that well operators and governmental agencies have the means to:

- Avoid underwater spills.
- Contain these spills when they occur in the shortest possible time.
- Minimize the environmental, economic and societal impact of these spills when they cannot be contained as soon as they occur.

CAST Step 3. The Safety Control Structure

A simplified high-level safety control structure of the Macondo Accident is provided in Figure 7. This structure shows the system at a very high-level of abstraction and divided in two major subsystems in accordance with the two main hazards identified for the system: The Well Integrity Structure in the left, and The Emergency Response Structure in the right. The Well Integrity Structure models the drilling of the well from the planning phase until the blowout. Above it are the U.S. regulatory agencies that control safety regulations for oil and gas extraction in U.S. territory. The Emergency Response Structure models the emergency after the blowout until the well was capped and the affected communities and ecosystems were repaired. Due to the magnitude of the accident, in this structure the U.S. government is included as head of the system.

Both structures are connected through BP's executive managers at the time of the accident and the federal agencies directly involved in oil and gas regulations and operations, in this case the MMS and the U.S. Coast Guard.

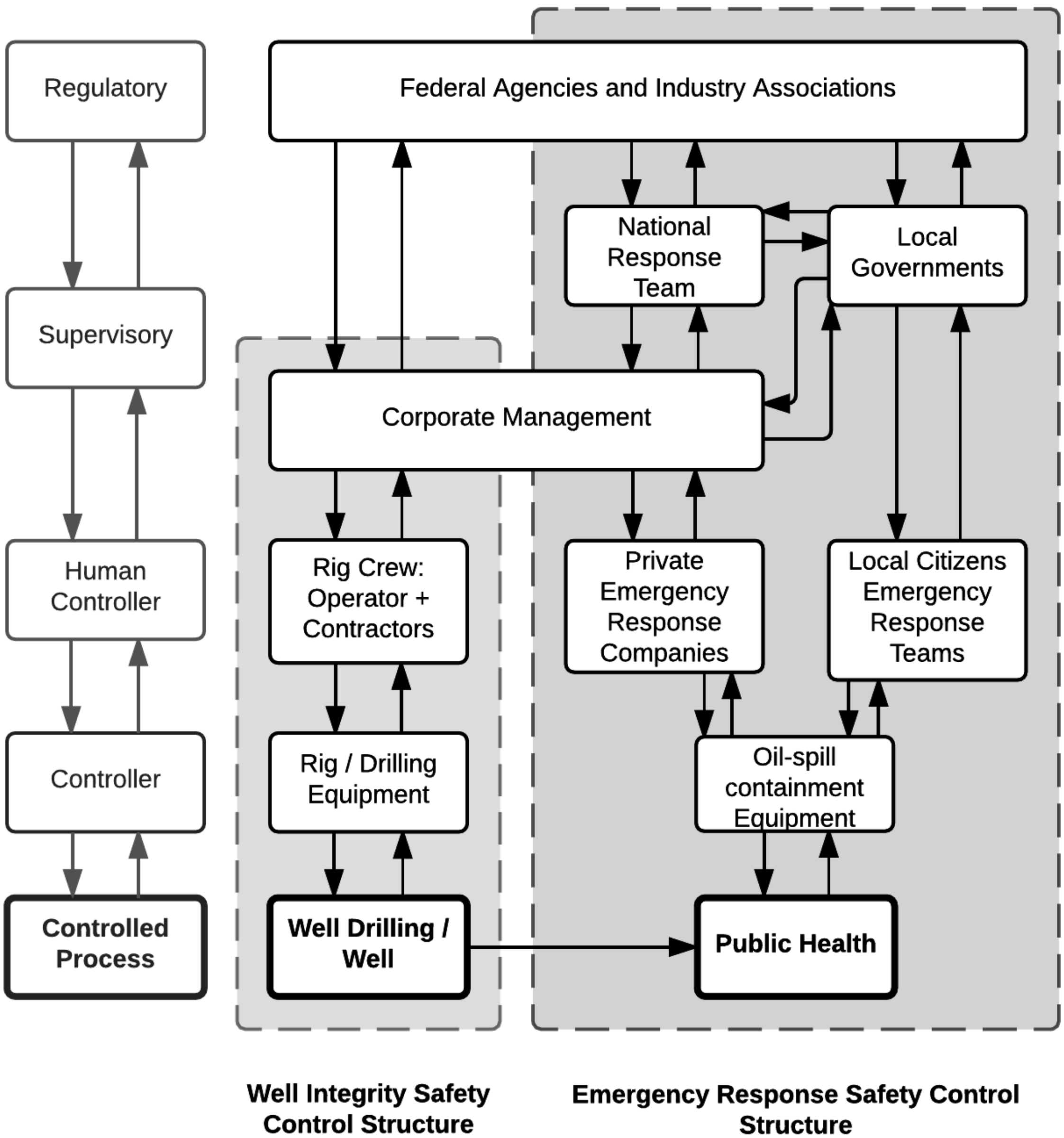

Figure 7. High-Level safety control structure of the Macondo accident.

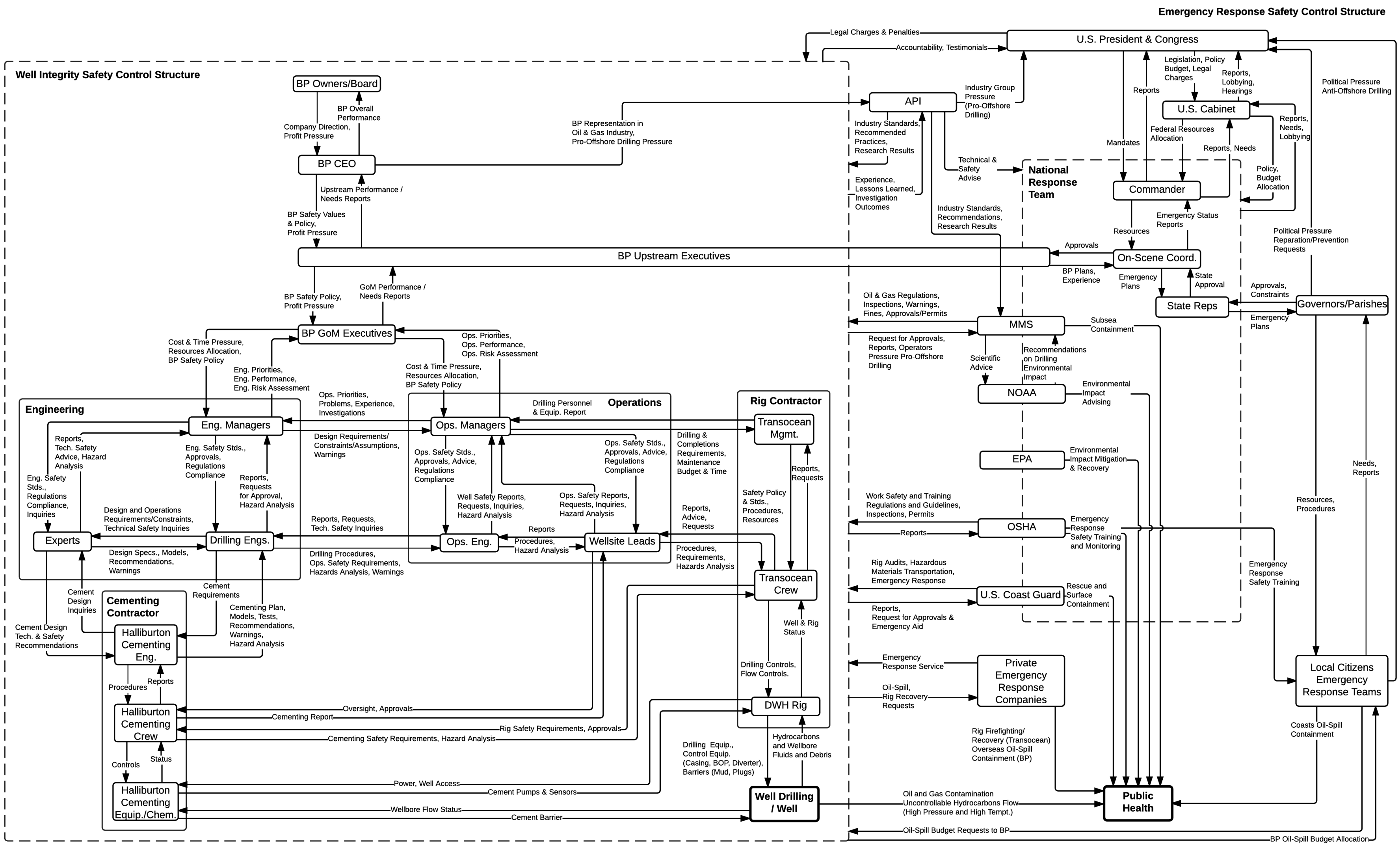

Figure 8. Detailed safety control structure of the Macondo accident.

Figure 8 shows a detailed version of the high-level structure. This structure is based on the investigation reports of BP and Transocean; the Chief Counsel's Report and the Report to the President prepared by the National Commission of the BP Deepwater Horizon Oil Spill and Offshore Drilling; the report of the Bureau Of Ocean Energy Management, Regulation And Enforcement; the report of the U.S. Chemical Safety and Hazard Investigation Board; the report of the U.S. Coast Guard; the Multidistrict Litigation Documents 2179 Phase 1, 2, 3 containing the testimonials of some of the people involved in the accident (mainly BP and Transocean personnel); and interviews with BP and Transocean personnel currently affiliated with the companies. This control structure focuses on the management level of the system; it starts at the level of the crews in the rig and ascends all the way up to the President and the Congress of the U.S. and the owners and shareholders of BP, contemplating in that way all the management hierarchies of the system.

Considering the vast amount of information available, this structure still does not include all the components of the system, like the other six contractors involved in the drilling of the well [21] or the other dozen of federal agencies that participated in the emergency response [22]. The goal of this structure is to represent the components whose safety controls played a leading role in the accident and thus had the greatest impact in its outcome. It is important to highlight that a careful examination of the safety responsibilities within the system was carried out, and that some components were merged to include their responsibilities in the model. Discrepancies with the exact and very complex system of the Macondo Accident are not expected to affect the analysis, since the objective is to find the safety weaknesses in the system to propose plausible improvements and not to blame specific individuals. In line with this goal, the model of the safety control structure is based on roles and not the actual people involved in the accident; however, an organizational structure with names and positions was built to facilitate the collection of data and general understanding of the system. The entire organizational structure is shown in Appendix A; Figure 9 and Figure 10 display the emergency response and the well integrity subsystems accordingly.

Since the scope of this thesis is the study of safety management in corporations drilling deepwater wells offshore, from now on the analysis is going to revolve around BP, Transocean and Halliburton. The previous steps intentionally covered the whole system to emphasize the complexity and scale of the accident and underline that its emergency response is also worth studying. In this case, the emergency structure evolved along with the magnitude of the disaster and only its analysis could tell if perhaps a pre-established structure could have minimized the spill.

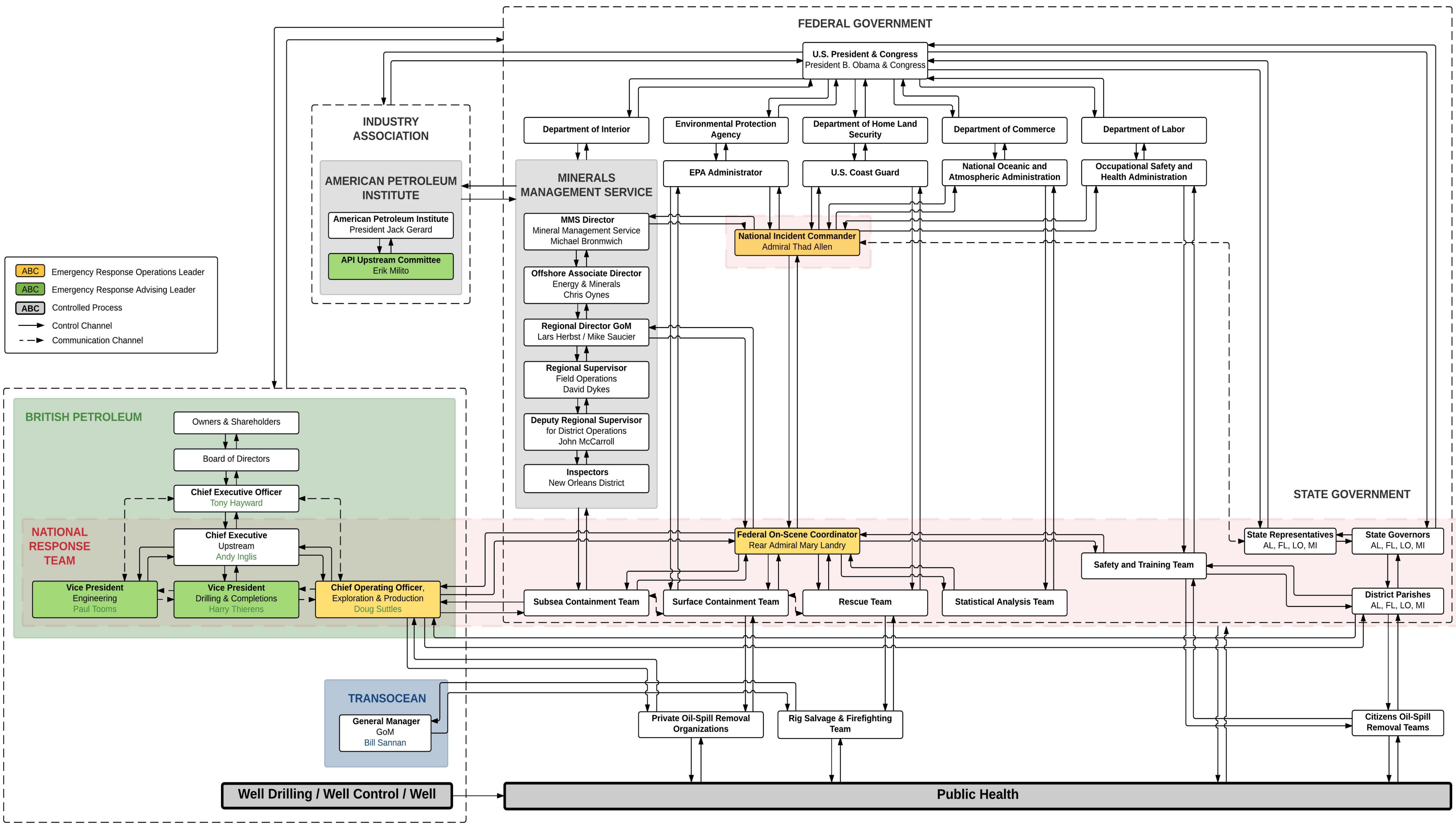

Figure 9. Emergency Response Organizational Structure of the Macondo Accident.

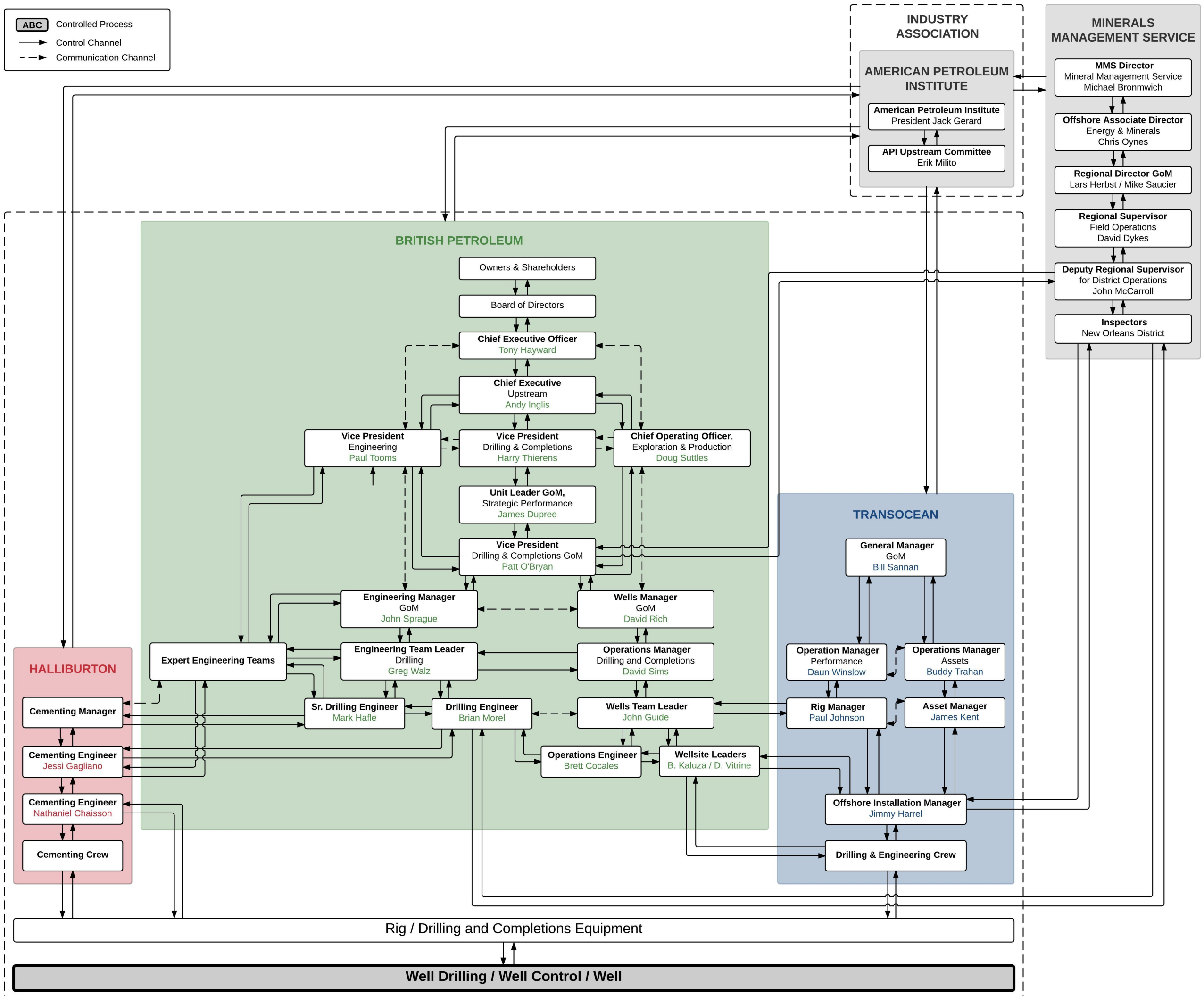

Figure 10. Well Integrity organizational structure of the Macondo accident.

Figure 11 presents the safety control structure concerning the well integrity of Macondo. It focuses on BP, but includes the management levels of Transocean and Halliburton directly related to the well. It also includes the MMS, the U.S. Coast Guard and the American Petroleum Institute (API), which also had a relevant impact in the integrity of Macondo.

Like the detailed structure of the whole system, this one starts at the level of the crews in the rig, but stops at the level of the regulators. The doted box contains all the components following the industry safety standards established by the API, which also includes the MMS and the U.S. Coast Guard [22]. The boxes in grey represent the components on the rig.

There are four subsystems in this structure, Engineering, Operations, Rig Contractor, and Cementing Contractor.

Engineering refers to the BP team responsible for the design of the well. In this model it is formed by three subsystems:

- The Engineering Managers, which under BP's organizational structure were the Engineering Manager of the GoM and the Engineering Team Leader (Figure 10). Between both roles they were responsible for disseminating BP's safety policy and standards throughout the team, managing the project level risk assessment, approving changes in the design and ensuring compliance with regulatory and corporate safety requirements.
- The Experts, regarded as the Design Team in several reports, refer to five BP teams specialized in different areas of oil and gas exploration and extraction. They were responsible for determining how best to achieve the well's objectives while managing potential drilling hazards (high pore pressures and hydrocarbon deposits) and man-made hazards (nearby oil & gas development infrastructures (wells, platforms, pipelines and ship traffic). They also had to design to maintain the integrity of the well over its lifetime, considering the environmental and mechanical stresses that the well would experience throughout its existence.
- The Drilling Engineers, in this case the Junior and Senior Drilling Engineers (Figure 10). Both were responsible for leading the well design and supporting its drilling and control, preparing the risk assessment of the project and delivering to Operations drilling procedures, design specifications and assumptions, safety requirements and hazard analyses.

Operations refers to the BP team responsible for drilling of the well. Like the Engineering team, it is formed by three subsystems:

- The Operations Managers, which under BP's organizational structure were the Engineering Manager of the GoM, the Engineering Team Leader and the Wells Team Leader (Figure 10). The Engineering Manager and Team Leader were responsible for disseminating BP's safety policy and standards throughout the team, approving changes in operations, wellsite related HSE decisions, simultaneous operations plans, and ensuring operations adherence to regulatory and corporate safety requirements.

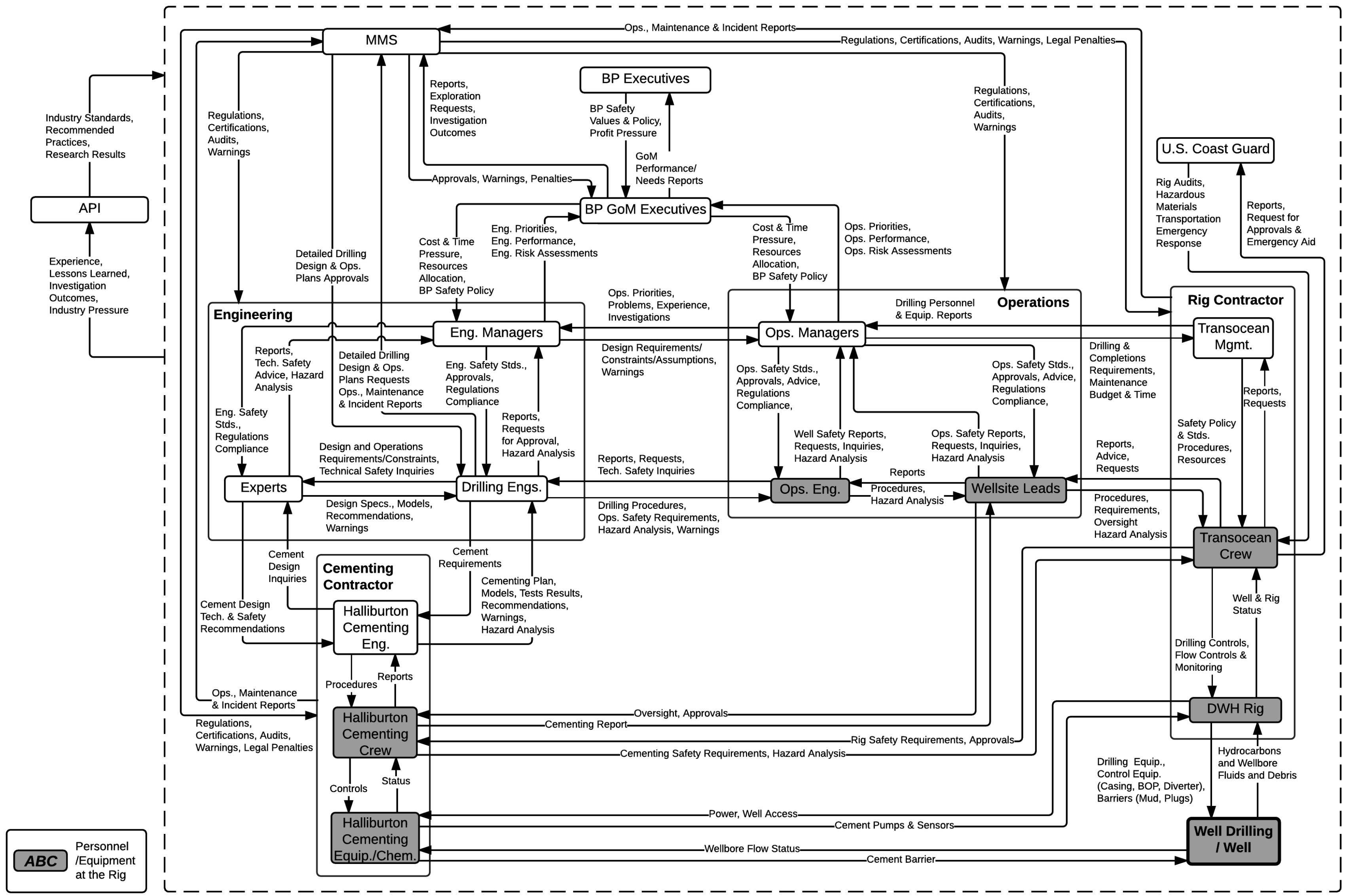

Figure 11. Detailed control structure of the Macondo Well integrity.

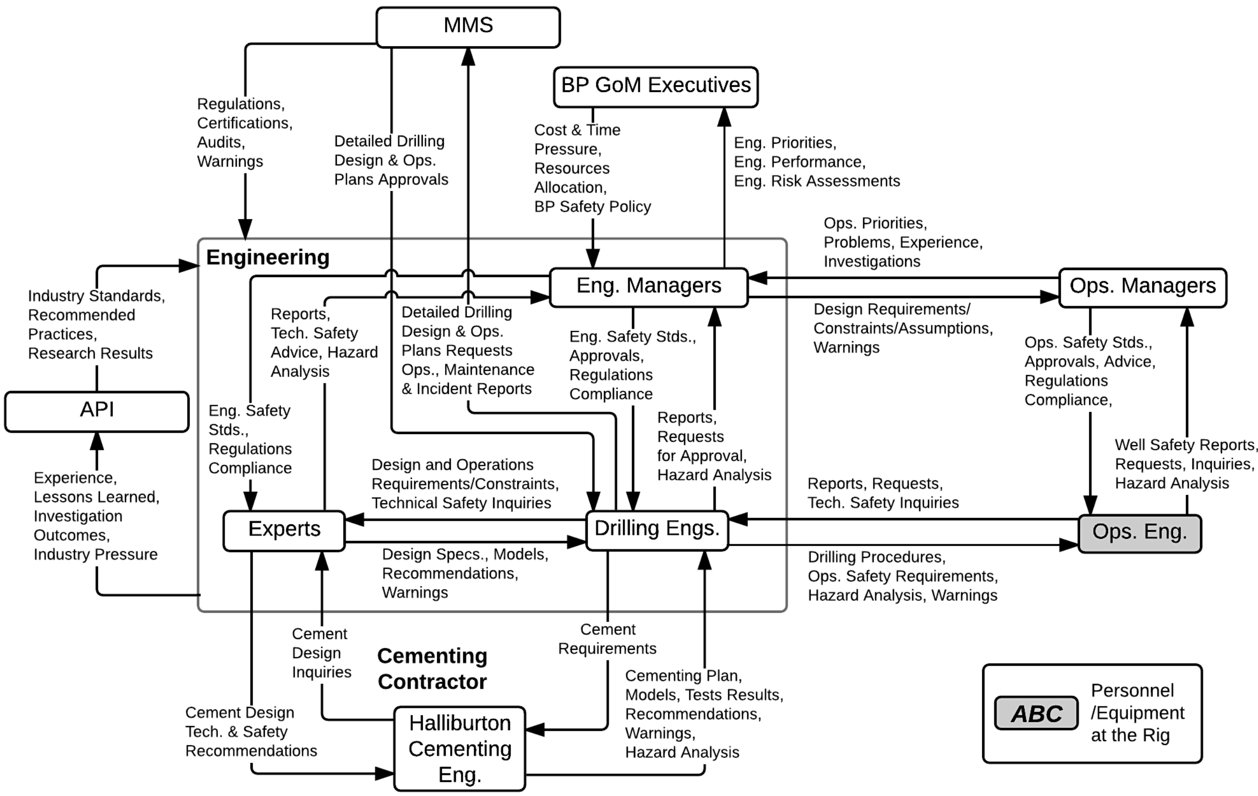

Figure 12. Engineering safety control structure.

The Wells Team Leader, a key manager in operations with a high load of safety requirements, was accountable for safety and operations at the drilling rig, well control and contingency procedures, and rig inspection and maintenance programs.

- The Operations Engineer working at the rig, was responsible for preparing Deepwater Horizon drilling and completion procedures in accordance to engineering designs, assuring well control at all times and assisting the Wells Team Leader in his tasks related to the Macondo Well.
- The Wellsite Leaders were BP's representatives at the rig, informally referred as Company Men in the industry. They were the company's eyes and ears and were responsible for implementing the design and operations procedures in accord with BP's safety policies and standards. They were also responsible for making recommendations and decisions regarding the course of several drilling operations and reporting any anomalies and incidents with the well, the rig, and the personnel onboard.

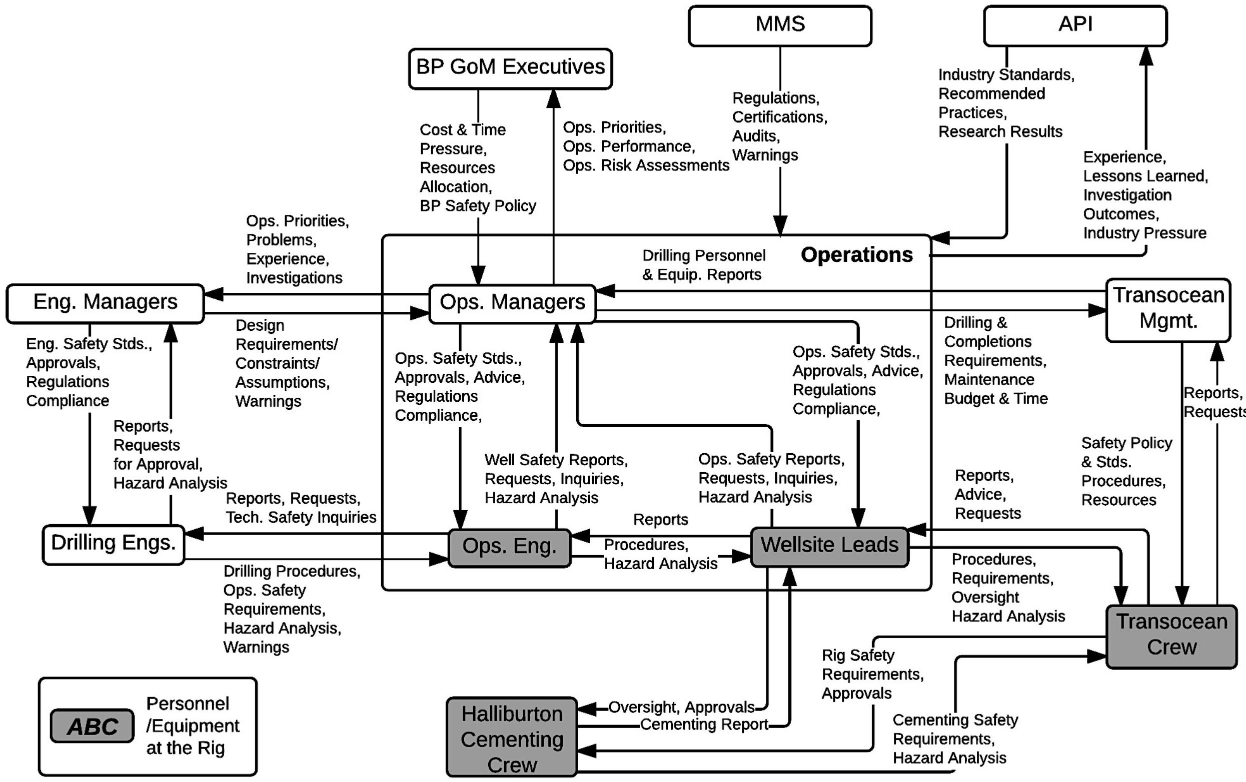

Figure 13. Operations safety control structure.

Rig Contractor refers to Transocean, the company that owned and operated the Deepwater Horizon rig. For drilling operations of the Macondo Well, BP interacted with Transocean's Managers onshore and with Transocean's Rig Crew offshore, the two management subsystems of this group.

- The Managers were responsible for complying with BP's rig and personnel safety requirements, adhering to offshore drilling federal regulations, and providing the rig crew with safety policies and standards.
- The Rig Crew was responsible for maintaining safe operations on the rig, monitoring the well, investigating and reporting any anomalies with the integrity and control of the well, and executing BP's and Transocean's contingency plans in case of emergency.

Cementing Contractor refers to Halliburton, the company providing the cementing service for Macondo. BP counted with a designated engineering from Halliburton for its Gulf of Mexico wells. This Cementing Engineer worked at BP offices with the Engineering team and was responsible for preparing the cementing design and execution plan, ensuring the feasibility of the design and presenting laboratory results and simulations that backed it up. For cementing operations onsite, Halliburton sent a Field

Cementing Engineer and an Operator, referred as the Halliburton Cementing Crew, to implement the plan designed by the Cementing Engineer onshore. The main responsibilities of the Cementing Crew were to comply with Halliburton's, BP's and Transocean's safety requirements, provide a hazard analysis of the cementing operation to the entire rig crew and ensure the correct pouring of the cement into the well.

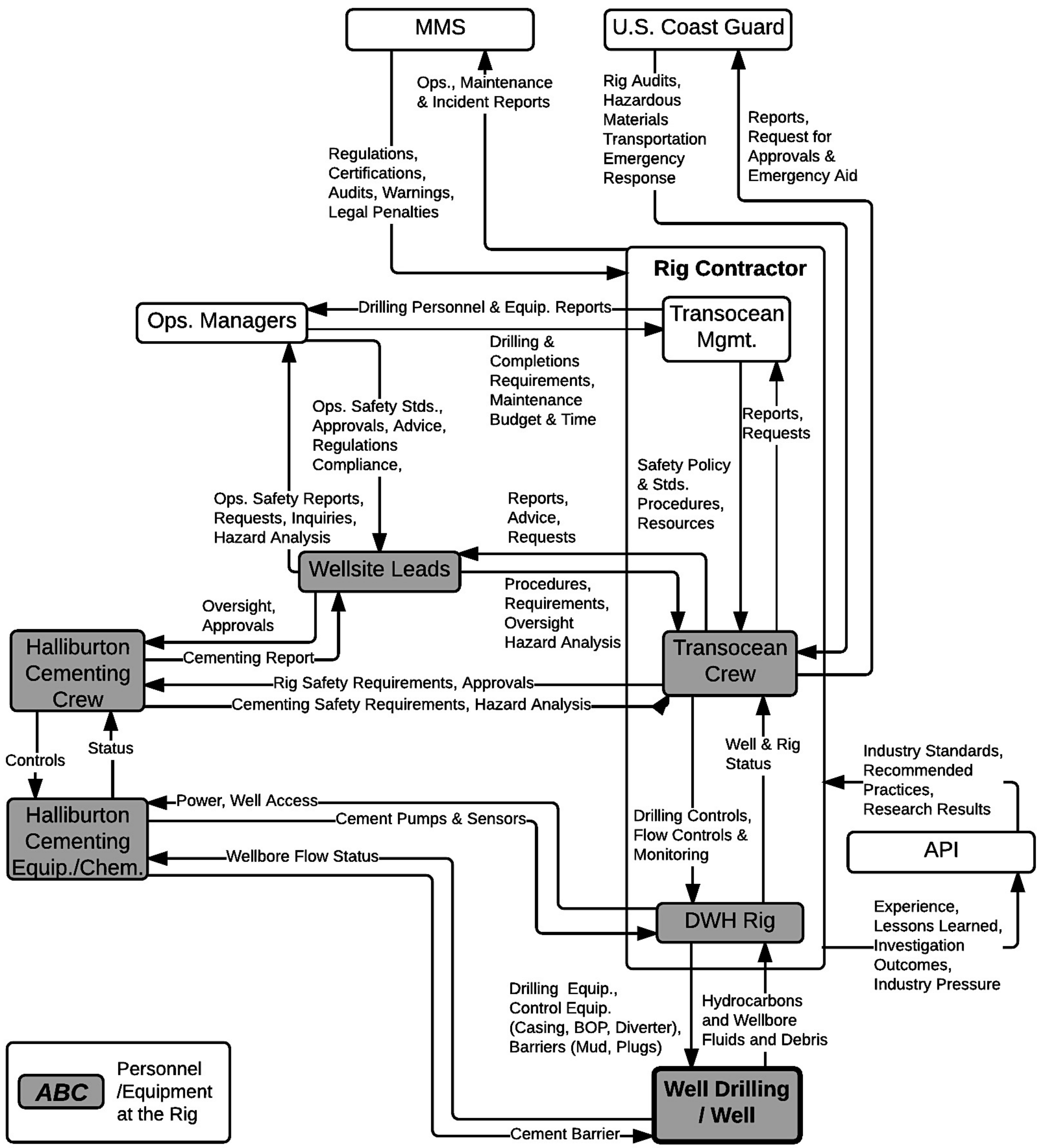

Figure 14. Rig contractor safety control structure.

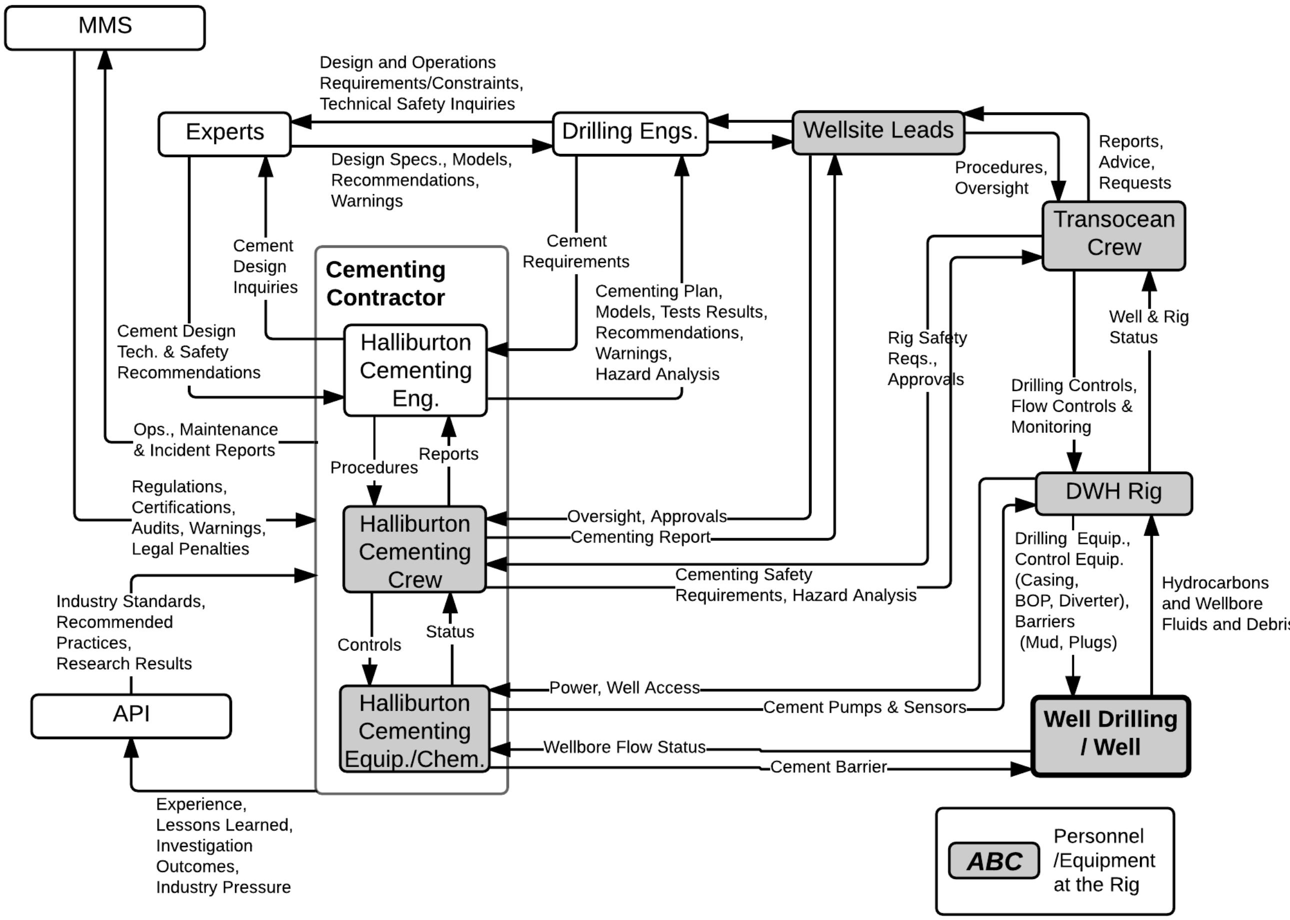

Figure 15. Cementing contractor safety control structure.

CAST Step 4. Proximate Events Leading to the Accident

The table below contains the sequence of events leading to the blowout. It is based on the Chief Counsel's Report and Transocean Investigation Report, which contained the most complete chronology of the accident.

Table 1. Chronology of the Macondo Accident as presented in the Chief Counsel's Report [21] and Transocean Investigation Report [30].

Time	Event
03.19.2008	BP pays $34 million for an exclusive lease to drill in Mississippi Canyon Block 252.
10.06.2009	Transocean's Marianas arrives on location and begins the drilling of the Macondo well.
11.08.2009	The Marianas drills for 34 days, reaching a depth of 9,090 feet. It then stops drilling and moves off-site to avoid Hurricane Ida. Hurricane Ida nevertheless damages the rig badly enough that it can no longer drill the well.

Time	Event
01.31.2010	Transocean's Deepwater Horizon arrives on location. Its first task is to lower its giant blowout preventer (BOP) onto the wellhead that the Marianas had left behind. The BOP is a stack of enormous valves that rig crews use both as a drilling tool and as an emergency safety device. Once it is put in place, everything needed in the well—drilling pipe, bits, casing, and mud—passes through the BOP.
02.10.2010	The Deepwater Horizon resumes the drilling of the Macondo well.
03.08.2010	Halliburton personnel send BP the results of a foam stability test it ran in February on the cement blend it plans to use at Macondo. To the trained eye, the data showed that the cement slurry design was unstable. Halliburton personnel did not comment on the evidence of the cement slurry's instability, and there is no evidence that BP examined the foam stability data in the report at all.
04.09.2010	After numerous instances indicating fractures in the formation over the past few weeks, BP elects to call total depth at 18,360 feet, short of the 20,200 feet initially planned. BP informs its lease partners Anadarko and MOEX that "well integrity and safety" issues require the rig to stop drilling further.
04.1-15.2010	BP and its contractors spend five days logging the open hole with sophisticated instruments. Based on the logging data, BP concludes that it has drilled into a hydrocarbon reservoir of sufficient size (at least 50 million barrels) and pressure that it is economically worthwhile to install a final production casing string that BP will eventually use to recover the oil and gas.
04.13.2010	Halliburton personnel run a second set of tests on the now-slightly-altered cement blend they plan to use at Macondo. The foam stability test showed that the cement slurry would be unstable.
04.14-15.2010	After going back and forth, BP engineers choose a "long string" production casing—for a single continuous wall of steel between the wellhead, on the seafloor, and the oil and gas zone at the bottom of the well. The other option considered, a "liner," would result in a more complex—and theoretically more leak-prone—system over the life of the well. But it would be easier to cement into place at Macondo.
04.15.2010	A Halliburton engineer informs BP engineers that computer simulations suggest that the Macondo production casing would need more than six centralizers (used to keep the casing string centered) to avoid channeling in the cement job. BP engineers order 15 additional centralizers—the most BP could transport immediately in a helicopter.
04.16.2010	A helicopter delivers 15 additional centralizers to the rig. BP engineers decide the centralizers are the wrong kind and do not run them.
04.18.2010	Halliburton personnel run yet another set of tests on the cement slurry they plan to use at Macondo. The test would normally take 48 hours to complete. It is unclear whether Halliburton had results from the test in hand before it pumped the job. Halliburton did not send the results of the final test to BP until six days after the blowout.
04.18-19.2010	The Deepwater Horizon crew installs the long string production casing. The leading end of the casing, the "shoe track," began with a "reamer shoe"—a bullet-shaped piece of metal with three holes designed to help guide the casing down the hole. The reamer shoe was followed by 180 feet of seven-inch-diameter steel casing. Then came a Weatherford-manufactured "float collar," a simple arrangement of two flapper (float) valves, spaced one after the other, held open by a short "auto-fill tube" through which the mud in the well could flow. As the long string was lowered down the wellbore, the mud passed through the holes in the reamer shoe and auto-fill tube that propped open the float valves, giving it a clear flow path upward.

Time	Event
04.19.2010	In preparation for cementing, the crew attempts to convert the float valves by pushing the tube downward. After nine attempts, the crew establishes circulation. Circulation pressure is lower than predicted, but the crew decides the pressure gauge is broken.
04.19.2010	The first compromise in BP's plan was to limit the circulation of drilling mud through the wellbore before cementing. Optimally, mud in the wellbore would have been circulated "bottoms up"—meaning the rig crew would have pumped enough mud down the wellbore to bring mud originally at the bottom of the well all the way back up to the rig. There are at least two benefits to bottoms up circulation. Such extensive circulation cleans the wellbore and reduces the likelihood of channeling. And circulating bottoms up allows technicians on the rig to examine mud from the bottom of the well for hydrocarbon content before cementing. But the BP engineers feared that the longer the rig crew circulated mud through the casing before cementing, the greater the risk of another lost-returns event. Accordingly, BP circulated approximately 350 barrels of mud before cementing, rather than the 2,760 barrels needed to do a full bottoms up circulation.
04.19-20.2010	The crew pumps cement into the well for the shoe track cement job. BP decides to pump the cement down at the relatively low rate of 4 barrels or less per minute. BP also decides to limit the volume of cement pumped to approximately 60 barrels—a volume that its own engineers recognized would provide little margin for error.
04.20.2010 5:45am – 7:30am	BP and Halliburton personnel declare the cement job a success. BP decides to send home a team of Schlumberger technicians who had been standing by on the rig to perform a suite of cement evaluation tests.
04.20.2010 10:30am	BP moves on to prepare the well for temporary abandonment. A BP engineer sends out an "Ops Note" to the rest of the Macondo team listing the temporary abandonment procedure for the well. The temporary abandonment procedure had undergone numerous modifications over a short period, none of which appear to have been subject to any formal risk assessment. The morning of April 20 was the first time rig personnel had seen the procedure they would use that day.
04.20.2010 10:55am – 12:00pm	The crew conducts a positive-pressure test to evaluate, among other things, the ability of the casing in the well to hold in pressure. The pressure inside the well remained steady, showing there were no leaks in the production casing through which fluids could pass from inside the well to the outside.
04.20.2010 3:00pm – 4:57pm	The crew prepares to conduct a negative-pressure test, and displaces mud from a depth of 8,367 feet to above the blowout preventer. The negative-pressure test checks not only the integrity of the casing but also the integrity of the bottomhole cement job. At the Macondo well, the negative-pressure test was the only test performed that would have checked the integrity of the bottomhole cement job.
04.20.2010 4:57pm – 6:40pm	The crew conducts a negative-pressure test on the drill pipe. For a successful negative-pressure test, the drill-pipe pressure must remain at zero psi after the pressure is bled off and the pipe is closed. The crew attempts to bleed drill-pipe pressure down to zero three times, but each time drill-pipe pressure builds back up. At the end of the test, drill-pipe pressure is 1,400 psi. BP and Transocean personnel discuss the pressure, apparently explaining it as a result of "the bladder effect." BP's Well Site Leader Don Vidrine insists on running a second negative-pressure test, this time on the kill line.
04.20.2010 8:02pm	The crew opens the annular preventer and begins displacing mud and spacer from the riser.

Time	Event
04.20.2010 9:01pm	After steadily decreasing for much of the displacement, drill-pipe pressure changes direction and begins increasing. This is an anomaly that apparently went unnoticed.
04.20.2010 9:08pm – 9:14pm	The crew shuts down the pumps to perform a sheen test. With the pumps off, the drill-pipe pressure should have stayed constant or gone down. Instead, it went up by approximately 250 psi. Had someone noticed it, he would have recognized this as a significant anomaly that warranted further investigation before turning the pumps back on.
04.20.2010 9:14pm	The crew turns the pumps back on and continues the displacement.
04.20.2010 9:18pm	The pressure-relief valve on Pump No. 2 blows, and the driller organizes a group of crewmembers to go to the pump room to fix the valve.
04.20.2010 9:20pm	The senior toolpusher calls the rig floor and asks about the displacement. The toolpusher responds, "It's going fine . . . I've got this."
04.20.2010 9:30pm	The driller notices an odd and unexpected pressure difference between the drill pipe and the kill line. The crew shuts off the pumps to investigate.
04.20.2010 9:36pm – 6:40pm	The driller orders a floorhand to bleed off the drillpipe pressure, in an apparent attempt to eliminate the difference. The drillpipe pressure initially dropped off as expected, but immediately began climbing again. Despite the mounting evidence of a kick, neither the driller nor the toolpusher performed a visual flow check or shut in the well.
04.20.2010 9:40pm – 9:43pm	Drilling mud begins spewing from the rotary onto the rig floor. The crew closes one of the annular preventers to shut in the well and routes the flow to the mud-gas separator (rather than overboard into the sea). The flow continues and quickly overwhelms the mud-gas separator system.
04.20.2010 9:45pm	The assistant driller calls the senior toolpusher and tells him the well is "blowing out."
04.20.2010 9:46pm	The crew activates a variable bore ram to shut in the well.
04.20.2010 9:49pm	The first explosion occurs. On the drilling floor, the Macondo disaster claims its first victims. A short time later, a second explosion occurs.
04.20.2010	Sometime after the first explosion, Transocean personnel on the bridge attempt to activate the Emergency Disconnect System. Although the panel indicators lit up, the rig never disconnected.

CAST Step 5. Analysis of the Loss at the Physical System Level.

Although this analysis is focused on the management level of the accident, an important step in CAST and in the study of any incident involving physical components is the examination of the physical system level. This section contains the overview of the physical controls at the Macondo well that did not keep it under control.

During drilling operations, the whole rig crew must ensure that hydrocarbons do not migrate from the reservoir into the well. This is achieved by monitoring the well and containing any hydrocarbon influxes before they reach the pipe that connects the rig to the well (riser), this is known as Well Control.

The Macondo well had a series of systems in place to contain the hydrocarbons in the reservoir and in the worst-case scenario in the well. This Well Controls are considered as the physical controls of this system and include:

- **Cement** at the bottom of the well.
- **Mud** in the well and the riser.
- **Blowout Preventer (BOP)** at the top of the well, at the seabed.

Each of these physical controls is linked to the flawed drilling processes at Macondo and from which the next levels of the system are analyzed.

The first process is **cementing** the casing into the well to control its further production and avoid undesired migration of hydrocarbons from the reservoir to the well.

The second process is **displacing the mud** to prepare the well for a change of rigs to transition from drilling to production. The mud serves as a debris remover but also keeps the well's pressure above that of the reservoir, in this way it helps to keep the well overbalanced to also avoid the migration of hydrocarbons into the well.

The third process is a drilling contingency procedure: **shutting in the well** to control unexpected inflows of pressurized hydrocarbons into the well, or kick. When hydrocarbons exit the well and cannot be contained, a kick is considered to become a blowout. Blowout preventers are a stack of rams on top of the well (in this case at the seabed) that seals the well in the event of kicks and blowouts.

Cement. As stated above, the goal of the cement control and ultimately of the cementing job was to provide a physical barrier to contain the hydrocarbons in the reservoir.

The cementing process involves pumping cement and other chemicals down the inside of a casing string placed inside the well until it flows out the bottom and back up into the annular space between the casing string and the borehole.

In order to achieve hydrocarbons isolation the following safety requirements need to be fulfilled:

- The cement must fill the annular space in the zone containing the hydrocarbons as well as the zones above and below to ensure safe isolation. At Macondo, the volume of cement poured into the well has been declared to be insufficient as per regulatory and corporate standards [21]. The reason behind this decision was to avoid damaging the formation with excessive fluids circulation, a questionable choice considering its implication in the integrity of the well [21].

- The cement flowing into the annular space must displace all the drilling mud, so that the cement remaining in the well does not get contaminated and losses its sealing capacity. If mud channels remain after the cement is pumped, they can become flow path for gases or liquids from the formation. There is no certainty that at Macondo cement actually flowed from the bottom of the well to fill the annular; lower flow rates than required and potentially clogged valves downhole seemed to have impeded this process.
- **The cement slurry must be formulated so that it sets and cures properly under wellbore conditions.** Additives, like Nitrogen to foam the cement, must be carefully planned to achieve the desired isolation. The design of the cement for Macondo has been largely criticized; the choice of foamed cement, lighter than required for the conditions of the well, apparently contributed to the failure of the cement barrier too.

Beyond these requirements, the cement barrier might not seal the hydrocarbons zone in a well with a deviated geometry or a poor centralization of the casing string, since the slurry sets on one side of the annular only. The centralization of the casing has also been discussed as a cause of failure of the cement barrier at Macondo, considering that less than half of the centralizers needed to keep the casing in place were used.

Mud. Drilling mud is used in the process to carry away cuttings and to keep the well overbalanced. The mud column inside the well exerts downward hydrostatic pressure that rig crews can control by varying the mud weight. Drillers pump mud down through the drill pipe and for most of the drilling process keep it circulating back to the rig through the annular space between the drill pipe and the borehole.

In Macondo, some investigations allege that the mud did not achieve either of its purposes at two stages of the operation. The first case, and usually overlooked due to its indirect relation to the blowout, affected the cementing job. Mud was pumped at a lower rate than planned which might have not activated Weatherford's valves downhole in order to let the cement slurry pass through, or might have not removed the debris at the bottom of the hole, impeding the activation of the valves and contributing to the contamination of the cement, or both. In any case, these scenarios jeopardized the cementing job and serve as partial explanation of its failure. The second case, and most studied one, is the mud displacement the day of the blowout. To transition from drilling to production, the well had to be abandoned temporarily to change rigs. A series of plugs had to be installed to seal the well and BP's plan involved changing the drilling mud for seawater, which meant replacing a heavier hydrostatic column for a lighter one. This left the well underbalanced, and without a strong cement barrier, pressurized hydrocarbons made their way out.

Considering the imminent impact of maintaining hydrostatic overbalance through the mud column to avoid loss of well control, the following safety requirement is considered:

- **The drilling mud pressure should exceed the pressure of the formation.** As long as the column of drilling mud in the well exerts higher pressure than that of the formation, hydrocarbons are not expected to migrate into the well. If the pressure of the formation exceeds the mud pressure, the well is underbalanced, meaning that the mud column is no longer sufficient on its own to prevent hydrocarbon flow.

In consequence, because the effectiveness of the mud was compromised during the temporary abandonment procedure and directly resulted in the blowout, this process is further studied in the next sections and the mud flow-rate and debris removal is addressed as part of the cementing process.

Blowout Preventer. The Blowout Preventer (BOP) is a routine drilling tool whose main goal is to shut in the well in case of a kick, to prevent a blowout, or during a blowout to mitigate the uncontrolled release of wellbore fluids.

The BOP as a whole is called the "BOP stack". It consists of a series of annular seals and rams stacked in vertical sequence on top of one another. By closing various individual rams in the BOP stack, rig personnel can shut in the well, preventing hydrocarbon flow up the well once it has migrated from the reservoir. When a BOP ram is closed, it becomes a well control barrier. BOP rams can be activated in several ways: manually from the rig, robotically using remotely operated vehicles (ROVs), and automatically when extreme certain conditions are met, such as disconnection from the platform. Each ram is activated separately. If a kick evolves beyond the point where the driller can safely shut in the well with an annular seal or a pipe ram, he or she can cut the drill pipe activating a blind shear ram. Considered as the last resource in a well control emergency, BOP's are usually designed so that blind shear rams can be activated in as many as five different ways. The following were available at the Deepwater Horizon:

1. Direct activation of the ram by pressing a button on a control panel on the rig.
2. Activation of the Emergency Disconnect System (EDS) by rig personnel.
3. Direct subsea activation of the ram by a Remotely Operated Vehicle (ROV).
4. Activation by the Automatic Mode Function (AMF) or deadman system due to emergency conditions or initiation by ROV; and

5. Activation by the autoshear function if the rig moves off location without initiating the proper disconnection sequence or if initiated by ROV.

In order for the BOP to effectively contain a kick or a blowout, the following safety requirements need to be fulfilled:

- Power supply and hydraulic pressure from the rig and from the back-up systems embedded in the BOP must feed its rams at all times. The BOP installed at Macondo was found with insufficient battery charge to activate the rams and some investigations report that the BOP activation systems were all connected to the same energy supply at the rig, without any back up.
- The BOP must be tested at a pressure such that well containment can be guaranteed, as suggested in some reports at the same pressure at which the casing is tested. Among the most controversial findings is the fact that BP and Transocean, with the MMS authorization, never tested the BOP to ensure it could withstand a blowout under Macondo's conditions. The industry defends its positions of not abrading the equipment unnecessarily, but studies published by the same MMS before the Macondo accident show than more than half of the BOPs in service were not be able to control a blowout, so accurate testing was recommended and described as essential as installing the BOP to ensure well control.
- The blind shear activation modes must be tested and operational under expected blowout conditions (pressure, temperature, power supply, signal communications). It is unclear what failed in the BOP and when, but some reports stay that none of the five activation modes worked. The forensic analysis of the BOP shows that it failed because it could not cut the pipe to shut in the well. This analysis shows that the embedded activation systems lacked sufficient charge, that a previous modification had interchanged some connections of the blind rams preventing their activation robotically, and that the BOP had some leaks and lacked maintenance and recertification; all potential contributing factors to the BOP's inability to cut through the drill pipe.

CAST Step 6. Analysis of the Loss at the Control System Level.

Starting with the human controllers immediately above the three physical processes presented in the previous section, each subsystem (Engineering, Operations, Rig Contractor and Cementing Contractor) of the well integrity safety structure was analyzed. Additionally, the intervention of the MMS was also analyzed, since it played a main role in the system and there are numerous questions about its role as regulatory party.

For each controller four categories were determined:

- Safety-Related Responsibilities
- Context
- Unsafe Decisions and Control Actions
- Process Model Flaws

In turn, the unsafe decisions and control actions were divided in the following management aspects:

- Risk
- Communication
- Procedures
- Personnel
- Leadership
- Equipment

Finally, for each of these aspects the process involving the unsafe decision or control action is highlighted. The actions referring to the cementing job are in grey, the ones related to the temporary abandonment are in brown, and the ones referring to the kick response are in red.

The following tables contain the information for each human, or group of humans, controller within each subsystem. The content is based in the same sources of the safety control structure with the difference that the Process Model Flaws were complemented with the input of BP and Transocean personnel that generously clarified the rationale behind most of the unsafe decisions and control actions identified in a first iteration of this CAST analysis. Appendix B contains more details on these interviews.

The synthesis of the unsafe decisions and control actions along with a complementary analysis of them is presented at the end of the tables.

Engineering. The following charts contain BP's Engineering team formed by the Drilling Engineers, the Experts or Design Team, the Engineering Team Leader, and the Engineering Manager.

Table 2. Analysis of BP's Drilling Engineers.

DRILLING ENGINEERING (BP)

Safety-Related Responsibilities

- Design wells and shepherd designs through BP's processes and experts, ensuring that they comply with internal and external engineering, operations and safety guidelines and regulations.
- Request design specifications, models, laboratory tests form BP experts and specialist contractors.
- Present procedures and equipment deviation/concession requests to BP management and MMS approval.
- Prepare Project Level Risk Assessment and Well Specific Risk Assessment and Implementation.
    (i) Develop safety procedures.
    (ii) Determine and implement effective well-control procedures.
    (iii) Advise and consult well containing procedures and pollution avoidance/mitigation plans.
- Advise and consult with BP and Transocean Rig Crew on key decisions in heightened-risk circumstances; in general, assist with overall safety on the rig.
- Facilitate real time performance monitoring as a measure to support operations performance and well control.
- Report safety lessons learned into future procedures.

Context

- Planned the Macondo casing program and set out the steps to drill the well.
- Team consisted of a Sr. Drilling Engineer and a Junior Drilling Engineer.
- The Junior Drilling Engineer was relatively new to drilling engineering and BP. He was assigned to the exploration team two years before the blowout, where he helped to plan two wells before being transferred to Macondo to help the Sr. Drilling Engineer.
- The Sr. Drilling Engineer had been involved with deepwater drilling for 17 years and had personally been involved in between 20 and 50 wells.
- BP charged the Junior Drilling Engineer with critical design decisions. BP relied heavily on him to design not only the well itself, but also the cement program and temporary abandonment procedures at Macondo.
- The Junior Drilling Engineer was perceived as being overworked by other members of the team and by the haste in his decision-making process days before the blowout.
- The Junior Drilling Engineer expressed preference towards high workloads, nevertheless expressed frustration and desire to leave his position due to the numerous last-minute changes and time and cost pressures.
- By the time of the blowout, the Macondo well had taken longer to drill and cost much more than what had been anticipated. The original price for the well was $96 million; by the time of the accident the price was already $142 million.
- BP's guidance on well design and operations placed a premium on drilling quickly. It emphasized the achievement of the technical limit for drilling a well, meaning what drilling times might be possible if everything works perfectly.

Cementing:

- Together with Halliburton decided to use foamed cement technology to minimize the risk of annular pressure increase.
- Requested Halliburton's lead cement engineering change weeks before the blowout.
- Communicated to managers the risk that the primary bottom-hole cement would not act as a barrier.

Temporary Abandonment:

- Sr. Drilling Engineer had been away on vacation while the team had put together the temporary abandonment procedures. He was concerned that the final plan was not approved by the MMS.
- BP had no consistent or standardized temporary abandonment procedures across its GoM operations, and the formal written guidance was minimal. For example, the guide available did not specify the location of those barriers or the procedure by which they should be set. This left the Macondo engineers to determine such issues for themselves on an ad hoc basis.
- Neither BP nor Transocean had pre-established standard procedures for conducting a negative pressure test.

Unsafe Decisions and Control Actions

RISK

- Never assessed the overall likelihood of the success of each main activity, either on their own or in consultation with experts or contractors. For example: Did not consult in-house cement expert to check Halliburton's foamed cement formulas and tests.
- Junior Drilling Engineer did not effectively use the input from technical experts. For example:
  (i) Did not consider in-house cement expert cautions about foamed cement stability or his recommendations to increase the foamed cement stability.
  (ii) Never asked subsea expert about the wisdom of setting a surface cement plug three times deeper than usual below the mudline to accommodate setting the *lockdown sleeve*, or displacing mud with seawater without first installing additional physical barriers; both decisions affected the mud barrier and compromised the control of the well.

Cementing:

- Used a decision tree with a simplified linear approach in which complex risks (such as the risk of failed cementing) can be forgotten or ignored on the basis of simple and incomplete indicators (such as partial returns or lift pressure) Appendix E.
- Focused heavily on reducing the risks of further lost returns and annular pressure increase, ignoring overarching risks such as well integrity.
- Focused excessively on volume and pressure indicators of cementing success, omitting its location and quality (foam stability and casing coverage).
- Decided to pump just as much cement above the hydrocarbons zone as the MMS required without verifying the quality of the cement, bypassing BP standards.
- Omitted running cement evaluation tests (logs). Did not consider the cement was a well control barrier during the subsequent temporary abandonment.

Temporary Abandonment:

- Did not re-evaluate well integrity risks associated with the *lockdown sleeve* installation, a determining piece for the entire temporary abandonment plan.
- Did not subject any last-minute changes to a formal risk assessment.
- Did not consider the risks of clogging the flow lines with lost of circulation material (high viscosity fluid to control lost returns) during the cementing job. The presence of this fluid could have directly affected the pressure readings during the negative pressure test.
- Did not use the real-time online data available to him to help the Well Site Leaders find out the cause for the anomalous pressure reading during the negative pressure test.
- Did not confirm the Well Site Leaders conclusions on the negative pressure tests with the real-time online data he had available.

Emergency Response:

- Did not evaluate lowering the testing regime of the BOP. The tests performed to the BOP did not prove its ability to contain pressures in a worst-case blowout scenario.

COMMUNICATION

- Did not clarify the communication plan between offshore and onshore despite being aware that it was not comprehensive.

Cementing:

- Did not provide current and accurate parameters for Halliburton's simulation.
- Did not involve the individuals monitoring the well in discussions about how to mitigate the risks of cement failure.

Temporary Abandonment:

- Did not emphasize well integrity and control risks to the offshore crew. For example:
  (i) Never emphasized to rig personnel the particular importance of the negative pressure test as the only way to assure the cement was working as the exclusive well control mechanism during the mud change.
  (ii) Did not evaluate the negative pressure test risks and details with the Wellsite Leaders.

(iii) Did not mention monitoring the well for kicks during the mud displacement to them Transocean and Sperry Drilling personnel.

- Sent more than four procedures to rig crew with last-minute changes and unclear instructions.

PROCEDURES

- Did not use an organized process to assess risks and settled, classify and prioritized regulations and recommendations.

Cementing:

- Did not order enough centralizers in time, even though original well designs required 11-16 centralizers.
- Deviated from the centralizers placement plan based on Halliburton's simulation. Placed the centralizers based on his own criteria and never requested a simulation check from Halliburton.

Temporary Abandonment:

- Did not develop the temporary abandonment procedure in a timely manner. Even though Macondo was considered as a production well from the start, the drilling program did not include temporary abandonment procedures.
- Did not adhere to the approved MMS procedure, made last-minute changes to it.
- Did not specify negative pressure test details nor highlighted which parameters had to be monitored.

PERSONNEL

- Sr. Drilling Engineer did not closely review Junior Engineer work in the last few weeks before the blowout.

Temporary Abandonment:

- Did not check if the Transocean Rig Crew was familiar setting a lock-down sleeve.

LEADERSHIP

Cementing:

- Did not actively reviewed Halliburton's progress or lab results on the foamed cement design.
- Did not insist that Halliburton's Cement Engineer deliver the cement lab results in a timely manner.
- Did not asked in-house expert or Sr. Halliburton personnel to double-checked Halliburton's Cement Engineer cementing plan.

Process Model Flaws

- Inadequate risk assessment. Unable to identify and evaluate all risks and then consider their combined impact. Believed addressing risks as isolated events, without a full appreciation of their impact on entire operation, was an intrinsic part of drilling operations.
- Did not know who was accountable for ensuring compliance with BP's standards on drilling safety.

Cementing:

- Believed their cementing design decisions were minimizing risks when they were in fact increasing them.
- Assumed that risks associated with remedial cementing (well barriers) were preferred than risks associated with drilling operations.
- Did not believe that inadequate centralization might increase the chance of a blowout.
- Believed Halliburton's simulation was not reliable, without realizing that BP was not providing current and accurate inputs to the model.
- Did not believe the foamed cement tests were critical.

Temporary Abandonment:

- Believed that notifying the MMS and asking for their approval when changes in the procedure where made was unnecessary, as long as the changes made the procedure more rigorous than the original.
- Believed that executing simultaneous activities (displacing mud and testing the cement) was acceptable in order to safe time (and money).
- Believed the rig crew, BP and Transocean, knew how to conduct and interpret a negative pressure test.
- Did not realize that severely under-balancing the well while the mud was displaced from the riser would let the

well relying solely on the cement as the exclusive barrier in the wellbore.
- Believed that Wellsite Leaders were going to report anomalies during all tests and operations.
- The Junior Drilling Engineer prioritized costs and efficiency while designing the temporary abandonment procedures, accepted not focusing on well control or integrity.

Table 3. Analysis of BP's Experts or Design Team.

EXPERTS or DESIGN TEAM (BP)
Safety-Related Responsibilities
• Provide design specifications, technical safety advice and recommendations to Drilling Engineers and contractors based on design and operations requirements. • Deliver hazard analysis of critical projects to Engineering managers. • Determine how best to achieve the well's objectives while managing potential drilling hazards (high pore pressures and hydrocarbon deposits) and man-made hazards (nearby oil & gas development infrastructures (wells, platforms, pipelines) and ship traffic). That is: (i) Specify drilling fluids and casing strings to maintain balance and contain formation pressures without fracturing the rock. (ii) Because drilling conditions often differ significantly from predictions, must design and redesign the deepwater well as the well progresses to ensure well integrity and control at all times. (iii) Include effective wellbore barriers like: cemented casing, mechanical and cement plugs, and BOP in the design. (iv) Design the well drilling so that two verified barriers are operative to contain any potential flow path at all times. (v) Ensure well integrity over the well's lifetime: must consider the environmental and mechanical stresses that the well will experience throughout its existence.
Context
• Forecasted that the well might encounter a substantial hydrocarbon reservoir. • Recognized that it might also encounter a number of hazards compromising the well integrity: fragile rock, gas zones (hard to predict and control), overpressures, and under-pressures. • Was primarily concerned about annular pressure increase due to a significant loss that was attributed to this cause in the Marlin Platform in 1999. • The entire Macondo team encountered a series of complications while drilling the well: lost mud into the formation, coped with uncontrolled (kicks) and controlled influx of fluids from the formation, faced difficulties determining well pressures, and fractured the rock. • BP Drilling Engineers had the primary responsibility for the Macondo well design. They worked with five teams in the design: 1. Geologists and Petro-Physicists. In charge of developing a pore pressure profile for the well. 2. Casing and Tubular Designers. In charge of independently reviewing the well design. 3. Fluid Experts and Rock Strength Experts. In charge of checking the geo-mechanical aspects of the well. 4. Completion Engineers. In charge of providing input during the design process for the completion process. 5. Subsea Wells Experts. In charge of advising over deepwater offshore drilling and operations. • Their most notable decision contributing to the blowout was the use of a long string production casing, which had been the plan all along. However, it was not until the lost circulation event and declaration of early total depth that the team identified many of the risks associated with using a long string. • By the time of the blowout, the Macondo well had taken longer to drill and cost much more than what had been anticipated. The original price for the well was $96 million; by the time of the accident the price was already $142 million.

- BP's guidance on well design and operations placed a premium on drilling quickly. It emphasized the achievement of the technical limit for drilling a well, meaning what drilling times might be possible if everything works perfectly.

Unsafe Decisions and Control Actions

RISK

- For the Casing choice focused on long-term reward and not in short-term risks. In fact, casing design decisions were motivated by the desire to: save $3M, keep original and approved design, ensure feasible production in the future, and avoid annular overpressures. Well integrity and control based on effective barriers and containment operations was not considered.
- Focused primarily in avoiding annular pressure increase, effectively de-emphasized other risks (like cementing complications) and discouraging certain well design approaches.
- The team disregarded other casing choices that would have helped to maintain well integrity (pressure balance and cementing simplicity and effectiveness) and minimize post-blowout containment complications (the decision to include rupture disks and omit a protective casing from the well design hindered the efforts).

Cement:

- Did not run casing and cement models with current parameters, so could not rely on them to make decisions.

Temporary Abandonment:

- Allowed equipment availability to drive design and procedure decisions. Design teams normally begin by considering their objective and the attendant risks, and developing a well design and procedures that are efficient and safe. They then arrange for the equipment and materials necessary to execute the design. The opposite happened at Macondo.
- Decided to set the *lockdown sleeve* during temporary abandonment because the Deepwater Horizon could do that job more quickly and efficiently than a completion rig. Having decided this, the team planned to install the sleeve last to avoid its damage with other operations. These restrictions hindered the abandonment procedures and compromised the integrity of the well.

Emergency Response:

- Did not consider the risk of having a BOP with only one blind shear ram. BOP's with two blind shear rams have better chances of cutting the drill pipe and shutting down the well in case a pipe joint is across one of the rams which they cannot cut, or one of the rams simply fail.
- Did not assess the risk of having the electric and hydraulic powers activating the BOP shear ram fed by the same source and not fire isolated.

COMUNICATION

Cement:

- Did not consult completion engineers before reaching a decision on whether to run a long string or a liner.

PROCEDURES

Cement:

- Design decisions were finalized too late. This generated discomfort and demanded extra efforts in operations.

EQUIPMENT

Emergency Response:

- Did not assess if the hydraulic power of the backup systems in the BOP was enough to activate the shear ram under high-pressure events such as a blowout.
- Did not incorporate kick detection instruments during cementing and temporary abandonment procedures. The rig's drilling equipment only had kick detection sophisticated instruments during the course of actual drilling.

Process Model Flaws

- Did not know who was accountable for ensuring compliance with BP's standards on drilling safety.
- Inadequate risk assessment. Unable to identify and evaluate all risks and then consider their combined impact.
- Focused in latest major risk in the company, ignoring the overarching risks of the project; based design on management priorities.

Cementing:

- Believed Halliburton's expertise was sufficient, and did not see the need to review their design.

Temporary Abandonment:

- Did not believe that the impact of setting a *lockdown sleeve* could compromise the mud barrier and the integrity of the well.
- Did not believe that the risks of setting a *lockdown* sleeve with the Deepwater Horizon could be more "expensive" than the risks associated with a blowout.
- Believed the operations team had the expertise to implement the temporary abandonment plan installing the *lockdown sleeve*.

Emergency Response:

- Believed the BOP was capable of dealing with a blowout of the Macondo well.
- Did not see the need to review the BOP's design.
- Did not assess if the hydraulic power of the backup systems in the BOP was enough to activate the shear ram under high-pressure events such as a blowout.

Table 4. Analysis of BP's Drilling Engineering Team Leader.

DRILLING ENGINEERING TEAM LEADER (BP)
Safety-Related Responsibilities
• Develop and approve safety procedures. • Manage the project level risk assessment and Implementation and approve drilling and completions primary designs accordingly. • Manage well specific risk assessment and implementation. • Approve plans and procedures sent for regulatory authorization. • Approve equipment deviation/concession requests. • Manage real time performance monitoring as a measure to support operations performance and well control. • Embed safety lessons learned into future procedures.
Context
• A month before the accident (March, 2010) G. Walz replaced D. Sims in this position. • New to the position. Assumed the role one month before the blowout. • By the time of the blowout, the Macondo well had taken longer to drill and cost much more than what had been anticipated. The original price for the well was $96 million; by the time of the accident the price was already $142 million. **Cementing:** • Approved the use of foamed cement technology. • Was not aware of BP's 2007 audit of Halliburton's capabilities regarding lab support, cement tests clarity and interpretation, and data transfer.
Unsafe Decisions and Control Actions
RISK • Did not check the Macondo's MOC process in time, he realized that it was not in place and unclear after the blowout. • Adopted Macondo's team culture of following regular procedures without customized planning or execution details.

Cementing:

- Approved the cement plan aware of its likelihood of failure as a barrier.
- Did not guide the design team to identify and evaluate all cementing risks and then consider their combined impact. For example:
  - (i) Disregarded the impact of poor centralizations on gas hydrocarbons flow, focusing only in annular pressure increase.
  - (ii) Did not ask the team to question the overall value of pressure and volume parameters as indicators of cementing success.

Temporary Abandonment:

- Did not request the design team to re-evaluate well integrity risks associated with the *lockdown sleeve* installation.

COMMUNICATION

Cementing:

- Did not request the team to provide current and accurate parameters to Halliburton's simulation.

Temporary Abandonment:

- Did not make clear to the Wellsite Leaders that they had to call back to shore when confronted with unexpected results during critical tests.

PROCEDURES

- Delayed engineering decisions.

Temporary Abandonment:

- Did not ask the Well Team Leader to follow the approved abandonment procedure neither evaluated his reasoning for not doing so.

PERSONNEL

- Did not realize that the Junior Drilling Engineer was making critical design decisions and was not effectively seeking input from technical experts. Relied heavily on him for the design not only the well itself, but also the cement program and temporary abandonment procedures.

EQUIPMENT

- In the most recent rig audit, he ignored equipment needs that would have increased the well's monitoring quality and accuracy. For example: personnel had to perform basic well monitoring calculations by hand, instead of having automated systems to help monitor the well, there were inadequacies in the sensors and instrumentation for detecting kicks, and there was no camera installed on the rig to monitor flow on the overboard line.

Process Model Flaws

- Thought Macondo's team culture of following regular procedures without customized planning or execution details was acceptable, and did not have time to question it due to schedule delays.
- Unsure about his authority over operations, thus believed he could not stop or delay the drilling to minimize risks.
- Believed his delays on planning did not allow him to demand the entire team to reevaluate risks in on-going operations.

Cementing:

- Believed that minimizing annular pressure increase was by far more important than maintaining the wellbore isolated, among other well integrity risks.
- Did not believe that inadequate centralization might increase the chance of a blowout.

Table 5. Analysis of BP's Engineering Manager.

ENGINEERING MANAGER (BP)
Safety-Related Responsibilities
• Approve Management of Change (MoC) to Drilling and Completion Operations, ensuring full compliance with BP and MMS safety requirements. • Ensure BP and MMS policy and standards adherence and dissemination among the engineering team. • Deliver engineering risk assessment and performance reports to BP GoM executives.
Context
• BP's 2010 robust risk assessment procedures were not in place for Macondo. • By the time of the blowout, the Macondo well had taken longer to drill and cost much more than what had been anticipated. The original price for the well was $96 million; by the time of the accident the price was already $142 million. • Was primarily accountable for the time and cost performance of the Macondo Well. • Had drilling efficiency in his performance contract for 2010. **Cementing:** • Approved the use of foamed cement technology.
Unsafe Decisions and Control Actions
RISK • Was aware that risk assessment process in the GoM had flaws, but acted too late to remedy the gap. For example: did not raise awareness of the new requirement to evaluate the effectiveness of each barrier BP requirement, noting that it was ready only by the time of the incident. • Did not prevent ad hoc decision-making. • Did not required or even promoted robust risk analysis and mitigation during the execution phase. Limited its emphasis during the planning phase of the well only. **Cementing:** • Approved the cement plan aware of its likelihood of failure as a barrier. **COMMUNICATION** **Emergency Response:** • Did not ensure the team applied their well control training and certification. • Did not promote the use of the risk assessment tools for loss of well control available since 2009. **PROCEDURES** • Did not ensure the Macondo team allocated enough time to write detailed procedures. • Did not act upon his manager's request to avoid just in time delivery of well plans, contributing to problems on other rigs. **PERSONNEL** • Sent a Wellsite Leader from another rig out to the Deepwater Horizon without properly determining if he was capable of substituting for one of the rig's veterans and bypassing BP's formal MoC for this. • Did not take active actions to aid the team with the lack of clear authority, reporting lines, and management of change procedures.
Process Model Flaws

- Did not fully understand safety major hazards and risks.
- Did not believe the reorganization had affected the decision making structure neither the safety control structure.
- Was not fully aware of the Wellsite Leader's report of unsafe operations, frustrated personnel, and lack of clarity in procedures.
- Believed everyone is accountable for process safety, without accounting for the diffusion of personal responsibility in this approach.
- Did not know who was accountable for important practices associated with safety.
- Was always thinking about how to drill wells faster.
- Believed the team under his supervision had discretion whether to subject a particular decision to the MOC process.

Operations. The following charts contain BP's Operations team formed by the Wellsite Leaders, the Operations Engineer, the Wells Team Leader, and the Drilling and Completions Operations Manager.

Table 6. Analysis of BP's Wellsite Leaders (offshore).

WELLSITE LEADERS ON THE DRILLING RIG (BP)
Safety-Related Responsibilities
• Act as the company's eyes and ears: report in a timely manner any operations safety anomalies to operations managers and engineering (usually through the drilling engineer onboard). • Act according to BP's safety policies and standards in case of any eventuality and confirm details with the onshore team when in doubt. • Make recommendations and decisions regarding the course of drilling operations to maintain well control and integrity. • Ensure the well is safely prepared for each operation without compromising well control and integrity. For example, for cementing, they must ensure the team circulates and conditions fluids in the wellbore, check that all downhole equipment settings complies with the cement pumping plan, make efforts to leave the casing as centered as possible. • Assist with overall safety on the rig. • Advise and consult with Transocean Rig Crew on key decisions in heightened-risk circumstances. • Review, codetermine and implement effective well-control procedures. • Direct the containing of hydrocarbons and any pollution coming from the wellbore.
Context
• The two Wellsite Leaders onboard at the time of the blowout were replacing the regular ones: M. Sepulvado and E. Lee, not on the rig at the time of the blowout. • B. Kaluza was onboard as a temporary replacement for R. Sepulvado, an experienced wellsite leader who had worked on the DWH since it set sail in 2001, but was onshore attending a training program. • Kaluza was assigned to the project without a MOC and a proper assessment of his capabilities for the job as required by BP standards. • A 3rd engineer onboard was training to become a wellsite leader. • Two wellsite leaders served on the rig at the same time, splitting responsibility according to 12-hour shifts. • The two-man team worked on the rig for several weeks at a time and then returned to shore for a similar period. • One wellsite leader remarked that the cost of the Macondo well was a concern and that he was aware the rig

was running behind. But stated that cost and time pressure was not an issue and that he did not feel more pressure to hurry to get things done than would otherwise be the case.

Temporary Abandonment:

- BP policies did not require the Rig Crew to report the results of tests to shore.
- By the time of the blowout, the MMS regulators did not require operators even to conduct negative pressure tests, let alone spell out how such tests were to be performed. Nor had the oil and gas industry developed standard practices for negative pressure tests.
- The wellsite leaders were concerned that the final plan was not approved by the MMS.
- Both displayed troubling unfamiliarities with negative pressure test theory and practice. Neither calculated expected pressures or volumes before running the negative pressure test even though other BP wellsite leaders routinely do so.
- Nobody else in the offshore team believes the "the bladder effect" is a real phenomenon, hence did not believe this was a justification for the anomalies in pressure during the negative test.

Emergency Response:

- Neither of the two Wellsite Leaders had been present in the previous kick of the well.

Unsafe Decisions and Control Actions

RISK

Temporary Abandonment:

- Did not question or raise awareness of the risk of executing simultaneous activities (displacing mud and testing the cement).
- Did not request expert assistance to run and interpret the negative pressure test.
- Did not consider the risks of clogging the flow lines with lost of circulation material (high viscosity fluid to control lost returns) during the cementing job. The presence of this fluid could have directly affected the pressure readings during the negative pressure test.

Emergency Response:

- Did not confirm that the Transocean Rig Crew was trained and ready to response to low frequency, high-risk event such as a blowout.
- Did not guarantee that a section of drill pipe, and not a pipe joint, was across the BOP blind shear ram. BOP's blind shear rams cannot only cut drill pipe.
- Did not question lowering the testing regime of the BOP. The tests performed to the BOP did not prove its ability to contain pressures in a worst-case blowout scenario.

COMUNICATION

Cementing:

- Never communicated the cementing risks to its other contractors, primarily the Transocean rig crew.

Temporary Abandonment:

- Did not examine Transocean's Toolpusher interpretation of the negative pressure test pressure values.
- Never contacted BP onshore personnel to discuss their inability to bleed off drill pipe pressure during the negative pressure test. They did not seek a second opinion from their managers, both of whom are engineers and were on the rig during the negative pressure test as part of the VIP visit.

PROCEDURES

Cementing:

- Did not check if the downhole valves (float collars) settings were adequate for the new cement pump rates.

Temporary Abandonment:

- Did not inspect the final fluid blend (*spacer*) for the mud displacement.
- Neither calculated expected pressures or volumes before running the negative pressure test even though other BP wellsite leaders routinely do so.
- Were not at the rig floor during most of the preparations for the negative pressure test and missed part of the test on the drill pipe.

- Did not examine Transocean's Toolpusher interpretation of the negative pressure test pressure values.
- Did not request detailed instructions to perform the negative pressure test nor asked for the parameters that had to be monitored.

LEADERSHIP

Temporary Abandonment:

- Did not question or further consulted the Well Teams Leader decision to deviate from the procedure prepared by the Drilling Engineers.

Emergency Response:

- Neither of the two Wellsite Leaders made efforts to review and improve the kick response process of the team.

Process Model Flaws

- Kaluza usually refused to consult onshore. "He attempt[ed] to have all the answers to any questions that [arose]".

Cement:

- Did not believe that inadequate centralization might increase the chance of a blowout.
- Refused to consider the possibility that the downhole valves (float collars) had failed.
- Believed that measuring instruments were not working to justify anomalous well conditions. For example: stated that mud pressure gauges were failing to justify anomalous pressure values before the cementing job. Omitted the change in cement pump rates affected the activation of the downhole valves (float collars).

Temporary Abandonment:

- Believed that executing simultaneous activities (displacing mud and testing the cement) was acceptable in order to save time (and money).
- Believed in the "*bladder effect*" justification of the negative pressure tests anomalies, ignoring the possibility of well integrity risks.
- Believed the Transocean Rig Crew along with the MI-Swaco Mud Engineer were not only competent to conduct and interpret a negative pressure test, but experienced and worthy of consultation.
- Believed they themselves knew how to conduct and interpret a negative pressure test. But, both displayed unfamiliarities with negative pressure test theory and practice.
- Did not realize that severely underbalancing the well while displacing mud from the riser let the well relying solely on the high-risk bottomhole cement as the exclusive barrier in the wellbore.
- Did not consider that reporting detailed anomalies of the negative pressure test to shore was necessary.

Emergency Response:

- Neither of the two Wellsite Leaders was fully aware of the flaws in kick responses of the team.
- Fell into a *culture of denial* mindset over imminent kick signals.
- Believed Transocean Crew had the knowledge and equipment necessary to detect kick signals, control kicks to prevent blowouts and avoid explosions on the rig.

Table 7. Analysis of the Operations Engineer (offshore).

OPERATIONS ENGINEER ON THE RIG (BP)

Safety-Related Responsibilities

- Prepare Deepwater Horizon's drilling and completions operations in an efficient and safe manner, assuring well control at all times.
- Develop and implement hazard analysis (complementary to those from Engineering) inspection programs.
- Report safety issues and lessons learned in a timely manner.
- Provide support to critical operations at the rig.
- Develop and review drilling and completions re-design compliance with BP and MMS safety requirements.

- Advise and consult with BP and Transocean Rig Crew on key decisions in heightened-risk circumstances.
- Review, and codetermine effective well-control procedures.
- Advise and consult well containing procedures and pollution avoidance/mitigation plans.
- Develop correct use of contingency procedures.

Context

- Reported to Wells Team Leader informally (in operations), although his direct manager was the Drilling Engineer Team Leader (design).
- Temporarily replaced the Wells Team Leader right after the kick in March 2010. Became in charge of the investigation of the incident.

Temporary Abandonment:

- Neither BP nor Transocean had pre-established standard procedures for conducting a negative pressure test.
- By the time of the blowout, the MMS regulators did not require operators even to conduct negative pressure tests, let alone spell out how such tests were to be performed. Nor had the oil and gas industry developed standard practices for negative pressure tests.

Unsafe Decisions and Control Actions

RISK

Temporary Abandonment:

- Did not requested expert assistance from the onshore personnel to run and interpret the negative pressure test, even though he was aware of his lack of expertise of the Wellsite Leaders.

COMMUNICATION

Cementing:

- Did not explicitly communicate to Halliburton or Weatherford the decision to use less centralizer than needed.
- Never communicated the cementing risks to other contractors, primarily the Transocean Rig Crew.

PROCEDURES

Cementing:

- Did not properly manage design changes and procedural modifications. For example: changed mud circulation rates without adjusting downhole valves settings for the cementing job. It is still unknown how much was the cementing flow affected by the inadequate operation of these valves.
- Did not check the type of centralizers Weatherford was sending to the rig. They were not adequate for the job and were not used.

Temporary Abandonment:

- Did not request detailed instructions to perform the negative pressure test nor asked for the parameters that had to be monitored.
- Delegated the negative pressure details to the MI-Swaco Mud Engineer.

Emergency Response:

- Did not check equipment modifications done by Transocean. For example: Transocean converted one of the pipe rams into a test ram as per BP's request 6 years before the blowout But, by mistake also connected one of the emergency activation mechanisms to the test ram which delayed the accident efforts significantly.
- Did not question condition-based maintenance system through which critical equipment, such as the BOP and rig gas and fire sensors, were improperly maintained despite MMS recommendations, API and manufacturers recommendations.

PERSONNEL

Temporary Abandonment:

- Did not check if the Transocean Rig Crew was familiar setting a lock-down sleeve.

LEADERSHIP

Temporary Abandonment:

- Did not actively revise the temporary abandonment plan in terms of safety and efficiency even though that was one his main responsibilities, along with is overall planning.

Process Model Flaws

Cementing:

- Believed that risks associated with remedial cementing (primary well barrier) were preferred than risks associated with drilling operations (stuck drillbits or casing).
- Did not believe that inadequate centralization might increase the chance of a blowout.

Temporary Abandonment:

- Believed that executing simultaneous activities (displacing mud and testing for isolation) was acceptable in order to safe time (and money).
- Believed in the "bladder effect" justification of the negative pressure tests anomalies, ignoring the possibility of well integrity risks.
- Believed the Transocean Rig Crew along with the MI-Swaco Mud Engineer were not only competent to conduct and interpret a negative pressure test, but experienced and worthy of consultation.
- Did not realize that severely underbalancing the well while displacing mud from the riser let the well relying solely on the high-risk bottomhole cement as the exclusive barrier in the wellbore.
- Did not consider that reporting detailed anomalies of the negative pressure test to shore was relevant.

Emergency Response:

- Fall into a *culture of denial* mindset over imminent kick signals.
- Believed Transocean Crew had the knowledge and equipment necessary to detect kick signals, control kicks to prevent blowouts and avoid explosions on the rig.

Table 8. Analysis of BP's Well Team Leader.

WELLS TEAM LEADER (BP)

Safety-Related Responsibilities

- Accountable for the safety and operations of the drilling rig.
- Implement drilling and completions safety procedures.
- Develop and approve inspection programs.
- Implement Rig Crew safety performance incentive mechanics.
- Ensure rig's effective communication on safety procedures, issues, and lessons learned.
- Provide support to critical operations at the rig.
- Approve drilling and completions re-design compliance with BP and MMS safety requirements.
- Prepare drilling and completions MoC's for management approval.
- Ensure the correct use of contingency procedures.

Context

- A month before the accident (March, 2010), his manager changed from I. Little to D. Sims. Sims was his counterpart in engineering and then became his direct supervisor in operations.
- Championed the every-dollar-counts culture.
- Had drilling efficiency as his number one priority in his contract for 2010.
- Questioned (and seemed to disagree with) most of his superior's decisions about the rig operation.
- Considered that it was easier and faster to make decisions under the old structure.
- Was concerned about not having a dedicated figure responsible for concealing between engineering and

operations under the new structure.

- Was perceived as being overworked by other members of the team and by the haste in his decision-making process tight before the blowout.
- Replaced the Drilling and Completions Operational Manager right after the kick in March 2010. Became in charge of the investigation of the incident at point, but soon delegated it to the Operations Engineer.
- Had lost his father weeks before the blowout.

Unsafe Decisions and Control Actions

RISK

Cementing:

- Did not examine whether the mechanical risks of running additional centralizers outweighed the cementing risks of not using them.
- Did not offer any alternative to the centralizers issue and refused to compromise operations over quality (casing centralization and cementing success).

Emergency Response:

- Did not ensure the Rig Crew response to kicks efficacy improved after the kick in March 2010.
- Did not request prove that the Transocean Rig Crew was trained and ready to response to low frequency, high-risk events such as a blowout.
- Did not emphasize to the Rig Crew that a section of drill pipe, and not a pipe joint, had to be across the BOP blind shear ram. BOP's blind shear rams cannot only cut drill pipe.
- Did not evaluate lowering the testing regime of the BOP. The tests performed to the BOP did not prove its ability to contain pressures in a worst-case blowout scenario.

Emergency Response:

- Did not check equipment modifications done by Transocean. For example: Transocean converted one of the pipe rams into a test ram as per BP's request 6 years before the blowout But, by mistake also connected one of the emergency activation mechanisms to the test ram which delayed the accident efforts significantly.

COMUNICATION

- Did not report incidents on the rig in timely manner.
- Did not clarify the communication plan between offshore and onshore.

Temporary Abandonment:

- Did not ask the Rig Crew to request detailed instructions to perform the negative pressure test.
- Did not emphasize to the Wellsite Leaders the importance of supervising critical tasks, such as the negative pressure test.
- Did not ask the Rig Crew to keep the vigilant mindset during mud displacement operations.

PROCEDURES

Cementing:

- Did not properly manage design changes and procedural modifications. Approved mud circulation changes without requesting the adjustment of downhole valves (float collars) critical for the cementing job. It is still unknown how much was the cement flow affected by the inadequate operation of these valves.

Temporary Abandonment:

- Did not follow the procedure prepared by the Drilling Engineers and approved by the MMS.

Emergency Response:

- Did not question condition-based maintenance system through which critical equipment, such as the BOP and rig gas and fire sensors, were improperly maintained despite MMS recommendations, API and manufacturers recommendations.

PERSONNEL

- Did not ensure that the Wellsite Leaders exercised independent judgment to understand the test results or to resolve uncertainties before proceeding.

Process Model Flaws
• Did not take safety performance to the same level as drilling performance. • Believed that drilling efficiency in costs and time where more important than last-minute changes in pro of well integrity and safety. Applied the "risk/reward equation" to support his arguments. • Considered the Drilling Engineer Team Leader last-minute safety precautions were paranoiac. • Was confused about his authority and accountability after the reorganization. • Did not believe Engineering and Operations Managers could easily resolve issues. **Cementing:** • Believed that risks associated with remedial cementing (primary well barrier) were preferred than risks associated with drilling operations (stuck drill-bits or casing). • Did not believe that inadequate centralization might increase the chance of a blowout. • Believed BP in-house expert had vetted the cement program, but nobody on the Macondo team consulted the expert after April 14, and he never saw any laboratory testing data for the cement until after the blowout. **Temporary Abandonment:** • Believed that executing simultaneous activities (displacing mud and testing the cement) was acceptable in order to safe time (and money). • Believed the Rig Crew, BP and Transocean, knew how to conduct and interpret a negative pressure test. Thought that Transocean personnel were in fact capable and competent to recognize problems with the well during the negative pressure test. • Did not know that the BP Rig Crew had delegated the detailed procedure of the negative pressure test to the MI-Swaco Mud Engineer. • Did not realize that severely under-balancing the well while displacing mud from the riser would let the well relying solely on the cement as the exclusive barrier in the wellbore. • Believed that the Wellsite Leaders were going to report anomalies during tests and operations. **Emergency Response:** • Believed Transocean Crew had the knowledge and equipment necessary to detect kick signals, control kicks to prevent blowouts and avoid explosions on the rig.

Table 9. Analysis of BP's Drilling and Completions Operations Manager.

DRILLING AND COMPLETIONS OPERATIONS MANAGER (BP)
Safety-Related Responsibilities
• Approve wellsite related HSE decisions. • Approve rig/field simultaneous operations plans compliance with BP and MMS safety requirements. • Ensure BP and MMS policy and standards adherence. • Approve Management of Change (MoC) to Drilling and Completion Operations, ensuring full compliance with BP and MMS safety requirements. • Deliver operations risk assessment and performance reports to BP GoM executives.
Context
• A month before the accident (March, 2010) D. Sims, coming form Engineering, replaced I. Little in this position. • In the old organizational structure I. Little was the only person integrating engineering and operations and reconciling their interests. Little left the Macondo Team after the reorganization. • Under the new structure, to find an individual who had responsibility for both engineering and operations, the Macondo team had to go all the way up to P. O'Bryan, the Head of Drilling and Completions for the GoM, three level of hierarchy above theirs. • Sims was the Wellsite Leader's counterpart in the engineering team and with the reorganization became his

superior.
- Sims had expressed concerned about the Wells Team Leader due to his bad attitude towards the project, his issues listening to others' opinions and collaborating with them, and his unwillingness to make decisions and accept accountability.
- Sims was aware of the family loss of the Wells Team Leader and attributed to this reason part of his disagreements with him.
- Had drilling efficiency in his performance contract for 2010.

Unsafe Decisions and Control Actions

RISK
- Did not stop the job despite the imminent alarm of the Wells Team Leader due to unsafe operations, frustrated personnel, and lack of clarity in procedures. In fact, asked the Wells Team leader to make an effort to continue the job under these conditions.
- Did not fully investigate the causes of the kick that took place in March 2010, a month before the blowout.

Cementing:
- Did not properly manage design changes and procedural modifications. Approved mud circulation changes without requiring the adjustment of downhole valves (flow collars) critical for the cementing job. It is still unknown how much was the cement flow affected by the inadequate operation of these valves.
- Approved cement plan aware of its likelihood of failure as a barrier.
- Did not request the team to carefully review the impact of centralizing the casing on the well's integrity; favored operations efficiency instead.

Temporary Abandonment:
- Did not request the Drilling Team to evaluate the impact in well integrity and operations associated with the abandonment plan proposed by the Design Team.

PROCEDURES
- Did not allow planning to catch up with operations.

Emergency Response:
- Did not question condition-based maintenance system through which critical equipment, such as the BOP and rig gas and fire sensors, were improperly maintained despite MMS recommendations, API and manufacturers recommendations.

PERSONNEL
- Did not take active actions to aid the Wells Team Leader and the Operations Engineer with the lack of clear authority, reporting lines, and management of change procedures.

LEADERSHIP
- Did not provide clear accountability and authority guidelines to Wells Team Leader.
- Did not assume Little's role of reconciling design and operations.

EQUIPMENT
- Did not adequately encourage the team to use the data displays and monitoring equipment they did have onshore.

Process Model Flaws

- Did not believe the reorganization had affected the decision making structure neither the safety control structure.
- Was not concerned by the Wellsite Leader report of unsafe operations, frustrated personnel, and lack of clarity in procedures.
- Believed everyone is accountable for process safety, without accounting for the diffusion of personal

responsibility in this approach.

- Did not know who was accountable for important practices associated with safety.
- Was always thinking about how to drill wells faster.
- Believed that that except for changes to the well plan, the Wells Team Leader had discretion whether to subject a particular decision to the MoC process.
- Believed that constantly monitoring data and other information from onshore tended to disempower personnel on the rig.

Cementing:

- Did not believe that inadequate centralization might increase the chance of a blowout.
- Believed Wells Team Leader did not accept accountability.

Rig Contractor. The following charts contain Transocean's Rig Crew and Managers Onshore.

Table 10. Analysis of Transocean's Rig Crew.

RIG CREW (TRO)

Safety-Related Responsibilities

- Maintain safe operations at the rig.
- Determine and report anomalies regarding well stability to BP and Transocean's Managers.
  - (i) Monitor and report the presence and quantity of gas in drilling mud.
  - (ii) Investigate well flow issues.
- Respond to well control events and shut in the well and shut down the rig upon loss of well control.
- Report well control issues to the U.S. Coast Guard in case of emergency.
- Request U.S. Coast Guard approval for Hazardous Material transportation and deviations from maritime regulations.
- Prepare for audits related to the rig and platform safety status from the MMS and the U.S. Coast Guard.
- Provide technical support to the Well Site Leader onboard.
- Maintain the platform in place and shut in the well when upon risk of disconnection from the riser.
- Keep all emergency alarms and sensors operative at all times.
- The senior toolpusher has overall responsibility for implementing the well control operation and ensuring that the drill crew are correctly deployed during the well control operation and that all rig floor personnel is notified and evacuated.

Context

- The Transocean Rig Crew included the drill, marine, and maintenance crews.
- Transocean senior personnel involved in day-to-day operations were the Offshore Installation Manager (OIM) and the Captain.
- The OIM was the Sr. Transocean Manager onboard who coordinated rig operations with BP's well site leaders and generally managed the Transocean Crew.
- The Captain was responsible for all marine operations and was the ultimate command authority during an emergency and when the rig was underway from one location to another.
- The Transocean drill team was led by a senior toolpusher, who supervised two toolpushers responsible for coordinating round-the-clock drilling operations. The toolpushers supervised the drillers and assistant drillers, who operated the drilling machinery and monitored the rig instruments.
- Transocean Managers deliberately decided not to train their personnel in the conduct or interpretation of negative pressure tests. The rig workers were supposed to learn about these procedures through general work experience.

- Transocean Managers were unable to conclude whether its Deepwater Horizon rig crew had enough experience to conduct and interpret the negative pressure test at the time of the blowout.
- Transocean policies did not require their personnel to report the results of well integrity tests to shore.
- Transocean was not notified about the risks of a poor bottomhole cement job, the importance of the negative pressure test, and the risk of underbalancing the well during the mud displacement.
- Transocean did not have a detailed plan with the temporary abandonment activities.

Unsafe Decisions and Control Actions

RISK

- Never undertook any risk analysis to establish mitigation plans regarding their performance of simultaneous operations during the mud displacement after the negative pressure test.
- Did not immediately shut in the well upon observing unexpected pressure readings.

Emergency Response:

- Agreed to perform simultaneous activities without a formal risk assessment. Simultaneous activities can interfere with well monitoring by obscuring kick signal and confusing the crew, therefore decreasing the team's emergency response efficacy.
- Did not prepare emergency response procedures for low frequency, high-risk events such as a blowout.
- Did not guarantee that a section of drill pipe, and not a pipe joint, was across the BOP blind shear ram. BOP's blind shear rams cannot only cut drill pipe.
- Did not question lowering the testing regime of the BOP. The tests performed to the BOP did not prove its ability to contain pressures in a worst-case blowout scenario.
- Did not properly assess the risk of sending high flow rates of hydrocarbons to the mud gas separator and not overboard in response to imminent kicks.

COMMUNICATION

- Did not report the complications in the maintenance routines and monitoring that the maintenance system on the rig was causing.
- Did not keep the Mudlogger apprised of all pit changes and fluid movements and do not appear to have monitored data more closely in his absence.

Emergency Response:

- Did not report continuous pressure anomalies to BP Crew the hours before the blowout.
- Did not report Transocean Senior Crew Member, BP Crew, or the Mudloggers the shut down of the pumps to investigate the pressure anomalies right before the blowout.
- Did not communicate to the Mudloggers, who were also responsible for monitoring the well, about the numerous activities taking place along with the mud displacement during the temporary abandonment process.

Temporary Abandonment:

- Did not communicate to the BP Crew that they were unfamiliar setting *lockdown sleeves*.

PROCEDURES

- Destroyed test records at the end of each well, creating unnecessary information gaps in maintenance and safety processes.

Temporary Abandonment:

- Did not calculate expected pressures and volumes during the mud displacement, relied only in visual inspections that proved to be insufficient and incorrect as per the accident investigation.
- Did not make efforts to continuously and reliably monitor return volumes during the displacement prior to sending the spacer overboard.

Emergency Response:

- Ignored all signs of hydrocarbons flow into the well and kick that arose since the negative pressure test.
- Did not identify a mistake in the BOP modification 6 years before the blowout. Transocean converted one of the pipe rams into a test ram as per BP's request, but by mistake also connected one of the emergency

activation mechanisms to the test ram, this delayed the accident efforts significantly.

- Applied condition-based maintenance. Under this system, equipment is not disassembled and inspected as per recommended practices and regulations, but only “if [the crew] feel[s] that the equipment is beginning to wear, then [they] make...the changes that are needed”.

LEADERSHIP

- Did not insist in having fixed the duplicate and erroneous maintenance instructions that the maintenance system was issuing.

Process Model Flaws

- Were confused about the maintenance system implemented on the rig. They were not sure about the maintenance routines and instructions.
- Did not think that condition-based maintenance systems were problematic or inferior to regulations or recommendations.

Cementing:

- Believed measuring instrumentation was not working to justify anomalous well conditions. For example: stated that mud pressure gauges were failing to justify anomalous pressure associated with inadequate operation of the downhole valves due to change in circulation rates before the cementing job.

Temporary Abandonment:

- Believed the BP rig crew knew how to conduct and interpret a negative pressure test.
- Believed that the well was not under risk of a kick during temporary abandonments procedures (controlled testing and mud displacement).
- Had confidence on the wellbore barriers in place (mud and cement).
- Incorrectly concluded the negative pressure had proven the wellbore was properly isolated.
- Concluded prematurely that well control risks had receded after the negative pressure test.
- Believed they were competent to interpret negative pressure tests.
- Addressed abandonment activities with hasty mindset and loss of focus. Thought the job was already finished and successful.
- Did not believe that reporting detailed anomalies of the test to shore was relevant.
- Were unaware of the five parameters to prevent a well control event due to a failure of a tested mechanical barrier, as mandated by Transocean after the North Sea near-blowout:
  (1) the volumes to be pumped, (2) the planned displacement rate(s), (3) the position of the fluid interface(s) at all times, (4) the resultant U-tube pressures in the well at all times and, (5) most importantly the point at which the completion fluid will become under- balanced with respect to formation pressure.
- Did not know that monitoring the displaced volume alone is insufficient and does not satisfy the requirement for a known monitored column of fluid.
- Were unaware of the major risks associated with the abandonment operations at the time of the blowout.

Emergency Response:

- Fell into a *culture of denial* mindset over imminent kick signals.
- Believed BP Crew was in charge of detecting kick signals.
- Based on the condition-based maintenance system, the Transocean Rig Crew did not feel:
  (i) The batteries in the death-man backup activation system in the BOP did not have enough charge to power the blind shear ram.
  (ii) The leaks in the BOP might have diminished the hydraulic power of the accumulators activating the blind shear ram.
  (iii) The BOP needed recertification on dry dock as per the manufacturer recommendations and the MMS regulations.

Table 11. Analysis of Transocean's Managers Onshore.

MANAGERS ONSHORE (TRO)
Safety-Related Responsibilities
• Provide rig equipment and rig personnel in compliance with BP's requirements, MMS regulations, and API recommendations for drilling operations. • Provide adequate instrumentation and procedures for well control operations to Transocean Crew. • Provide alarms, sensors, systems and procedures for loss of control events. • Report rig incidents and investigations outcomes to MMS. • Train rig personnel in offshore emergency response.
Context
• An April 2010 internal Transocean assessment showed that it did not believe that the rig crews could identify and mitigate all risks on their own, and that the rig crews did not fully understand the companies maintenance system. • Transocean decided not to take the Deepwater Horizon platform to dry dock because of disagreements with the BP's Wells Team Leader on the daily rate pay during repairs. BP representatives refused to pay this non-operational time.
Unsafe Decisions and Control Actions
RISK **Emergency Response:** • Required regular well control drills, but none focused specifically on emergency situations—how to recognize an emergency and what steps to take immediately upon recognizing it. • Documented the near-blowout as a Completions accident despite the fact that it applied equally to Drilling operations (particularly to temporary abandonment procedures). • Inadequately assessed the diverter activation procedure in response to kicks. Did not fully consider the risks of explosion when sending high flow rates of hydrocarbons to the mud gas separator and not overboard in response to potential blowouts. **COMMUNICATION** **Temporary Abandonment:** • Did not have procedures in place for reporting test results to shore. **Emergency Response:** • Did not communicate to BP and its rig crew lessons learned from a similar near miss on one of its rigs in the North Sea four months prior to the Macondo blowout. • Did not ensure all operative rig crews were aware of the near-blowout in the North Sea. **PROCEDURES** • Did not encourage Rig Crews to keep test records at the end of each well, creating unnecessary information gaps in maintenance and safety processes. **Emergency Response:** • Did not ensure equipment modifications were checked afterwards or reviewed in regular basis. For example: Transocean converted one of the pipe rams into a test ram as per BP's request 6 years before the blowout But, by mistake also connected one of the emergency activation mechanisms to the test ram which delayed the accident efforts significantly. • Established a condition-based maintenance system through which critical equipment, such as the BOP and rig gas and fire sensors, were improperly maintained despite MMS recommendations, API and manufacturers

recommendations.

PERSONNEL

Temporary Abandonment:

- Did not adequately train its rig personnel regarding kick monitoring during end-of-well, non-drilling activities, such as temporary abandonment (including displacing mud and testing the cement).
- Could not evaluate the level of training of the rig crew, particularly for specific tasks such as a negative pressure test.

Emergency Response:

- Did not adequately train its crews on how to respond to emergency situations such as those that occurred on the night of the blowout.
- Did not adequately train its Dynamic Positioning Officers (DPOs) on how to respond to emergency situations.
- Did not initiate the emergency disconnect system until after the hydrocarbons were past the BOP stack.

EQUIPMENT

- Did not make efforts to improve the inadequate well monitoring equipment on the Deepwater Horizon. For example:
  (i) The data displays depended not only on the right person looking at the right data at the right time, but also that the person understood and interpreted the data correctly.
  (ii) The Rig Crew did not have systems with automated alarms, similar to those in airline cockpits, to call attention to potential kick indicators. Such systems should also inform Mudloggers of crucial events—such as a change to the active pit system or a change in fluid routing. On the Deepwater Horizon, the Mudlogger depended on direct communication or guesswork to learn what was happening elsewhere on the rig.

Emergency Response:

- Did not incorporate kick detection instruments during cementing and temporary abandonment procedures. The rig's drilling equipment only had kick detection sophisticated instruments during the course of actual drilling.
- Did not asses the capacity of the flow-out lines from the riser, the mud gas separator, and the overboard packer to handle high flow rates of hydrocarbon and debris typical of a blowout emergency.
- Did not consider the addition of an automated system to aid with the detection of kicks, gas in the riser and timely activation of the diverter to avoid or at least delay explosions on the rig due to loss of well control.

Process Model Flaws

- Believed Transocean Rig Crew was going to report anomalies during tests and operations.
- Believed that making the Rig Crew aware of hazards was not sufficient: "You can tell them what the hazards are, but until they get used to identifying them their selves, they are only following your lead".
- Thought that condition-based maintenance systems were better than the MMS regulations and recommendations, API and manufacturers recommendations.

Temporary Abandonment:

- Believed Transocean Rig Crew was able to recognize signs of a kick during complex drilling operations, but did not believe they were able to do so during well testing procedures since that was not their responsibility.
- Did not believe well testing procedures needed formal training, even less so their interpretation. Believed these procedures could be learned through general work experience.
- Believed Transocean Rig Crew was aware of the North Sea near-blowout four months ago.

Emergency Response:

- Assumed the Transocean Rig Crew checked the online advisory platform regularly.
- Believed that alerting the Transocean Rig Crew about online advisory on the North Sea was unnecessary because it simply restated good well control practice already known to the crew.
- Believed that drilling and completions operations are significantly different, therefore sharing lessons learned between both processes is irrelevant.
- Believed BP Crew was in charge of detecting kick signals.

- Believed Transocean Crew had the knowledge and equipment necessary to detect kick signals, control kicks to prevent blowouts and avoid explosions on the rig.

Cement Contractor. The following chart combines Halliburton's Cementing team into a single controller. Little information regarding the crew that performed the cementing job at the well was available, so the safety aspects related to these roles were included under the cementing engineer onshore role.

Table 12. Analysis of Halliburton's Lead Cementing Specialist Engineer and Cementing Crew.

LEAD CEMENTING SPECIALIST ENGINEER AND CEMENTING CREW (HAL)

Safety-Related Responsibilities

- Design and pump the cement for all of the casing strings in the Macondo well, ensuring the slurry becomes a stable barrier able to maintain well integrity.
- Provide a comprehensive hazard analysis of the cementing job to on the design onshore and offshore.
- Deliver simulations and laboratory tests of the cement design, and provide technical safety advice to the operator based on the results.
- Review cement design with BP Experts team.

Context

- Lead Cementing Specialist for the Macondo Well was working in BP's offices with the Engineering team.
- BP requested Lead Cementing Specialist replacement claiming poor job performance weeks before the blowout.
- BP recognized that if the formation fractured again during the cementing job, it could compromise the cement barrier quality and force the rig crew to conduct remedial cementing operations. Thus, BP engineers focused particularly on ensuring the integrity of the formation by: reducing the volume of cement pumped into the well, reducing the rate at which the cement was pumped, and using nitrogen foamed cement, a less dense slurry.
- Jointly with BP decided to use foamed cement technology.
- Ran a model with the poor centralization plan, and made BP aware of severe gas flow potential and bad cement quality. However, was not aware of BP's final decision to use only the six centralizers.
- Ran simulations with imperfect inputs due to poor communication with BP.

Unsafe Decisions and Control Actions

RISK

- Did not adequately assess and inform BP of the cementing risks or suggest design alternatives.
- Did not recommend additional indicators of cementing success aside volume and pressure.
- Did not highlight the well integrity issues modeled in the simulations right before the cementing job.
- Began pumping the Macondo job without carefully reviewing laboratory foam stability data and without solid evidence that the foamed cement design would be stable.
- Recommended a foamed cement design without conducting any formal internal review with BP or Halliburton experts.

COMMUNICATION

- Reported the cement job was a success, without communicating his concerns on the quality of the cement downhole.

- Did not emphasize the importance of foam stability testing to the Macondo team.

PROCEDURES
- Reported foamed cement tests to BP selectively, choosing not to report the unfavorable results, and without a comprehensive interpretation.
- Had a habit of waiting too long to conduct crucial cement slurry tests

Process Model Flaws

- Did not believe that inadequate centralization might increase the chance of a blowout, but after the blowout believed that the centralization of the casing string was the only cause of the poor cement quality.
- Did not believe cement evaluation logs were necessary.
- Did not think that consulting experts in the design was needed.
- Believed his risk assessment was sufficient.
- Did not consider the laboratory results were critical to ensure the stability of the slurry design.
- Believed that foamed cement in the conditions that was poured at Macondo could potentially result in an effective cement barrier.

MMS. The chart below describes the MMS in a similar way as the controllers presented above. The unsafe decisions and control actions focus on the aspects that its regulations did not cover by the time of the blowout.

There was no input from MMS personnel in this chart, the information displayed is based on the investigation reports already mentioned and the interviews held with BP and Transocean personnel.

Table 13. Analysis of the MMS.

MMS

Safety-Related Responsibilities

- Responsible for enforcing regulations governing drilling operations contained in the Code of Federal Regulations, 30 CFR Part 250. Subpart D covered many aspects of drilling operations, including permitting, casing requirements, cementing requirements, diverter systems, BOP systems, drilling fluids requirements, equipment testing, and reporting.
- Audit and enforce regulations upon BP and all the contractors involved in the drilling of Macondo.
- Review and approve Application for Permit to Drill [APD] submitted by BP, to determine whether it was complete, satisfied the relevant regulatory requirements and contained no errors, and allowed BP to complete the drilling in a safely manner. This review include an assessment of:
  (i) well casing setting depths determined by formation strength;
  (ii) predicted formation fluid pressure; drilling mud weight limits;
  (iii) any anticipated subsurface hazards;
  (iv) effectiveness of well casing strength for pressure containment at its specified depth;
  (v) effectiveness of cementing the well casing after successfully securing and isolating the hydrocarbon zones or
  (vi) any encountered subsurface hazards;
  (vii) and maintaining well control by adjusting drilling mud properties and the use of well control equipment such as diverters and BOP stacks.
- Assess whether BP oil spill financial responsibility coverage was current.

Context

- The MMS had a built-in financial incentive to promote offshore drilling that conflicted with its mandate to primarily ensure safe drilling and environmental protection.
- The revenue increase dependent on deepwater drilling came with increased safety and environmental risks, however those risks were not matched by greater, more sophisticated regulatory oversight.
- The MMS was unable to maintain up-to-date technical drilling-safety requirements to keep up with industry's rapidly evolving deepwater technology. As drilling technology evolved, many aspects of drilling lacked corresponding safety regulations.
- At the time of the blowout, MMS systematically lacked the resources, technical training, or experience in petroleum engineering that is critical to ensuring that offshore drilling is being conducted in a safe and responsible manner.
- Operators routinely gathered information and formulated drilling programs that were much more detailed than the information required in the APD submitted to the MMS. For example, the drilling prognosis submitted with the Macondo Application Permit for Drilling (APD) was condensed to a single page, while the full BP drilling program was more than 100 pages long.

Unsafe Decisions and Control Actions

- Did not impose special requirements for deepwater drilling water conditions.
- Granted exemptions from regulatory requirements on a routine basis, without studying each case in detail.
- Rarely questioned any statements or predictions contained in permit applications for deepwater drilling.
- Did not question BP about the numerous changes in their design and operations.
- The MMS well control training received by BP and Transocean covered initial kick response during drilling operations, but did not included kick detection and indicators, or emergency response to full-scale blowouts.
- Regarding the design, MMS regulations did not addressed:
  (i) The use of long string production casings. They did not specify any minimum number of annular barriers to flow.
  (ii) Issues related to Annular Pressure Buildup (APB), nor authorize or prohibit any particular APB mitigation approaches.
  (iii) Design measures that would facilitate containment or capping measures in the event of a blowout.

Cementing:

The MMS regulations did not:

- Require the use of casing centralizers, nor specify minimum standoff percentages or other centralization criteria.
- Address the possibility of cement contamination, nor specify any measures to reduce the likelihood of contamination (such as the use of wiper plugs or spacer fluids).
- Specify whether or how to evaluate float valve conversion or performance.
- Require BP to conduct or report cement slurry tests, nor specify any criteria for test results.
- Address the use of foamed cement (or any other specialized cementing technology) at all. Did not even require BP to inform MMS of its use.
- Specify practical indicators of an inadequate cement job, and comprehensive measure for a remedial cementing.
- Require a negative pressure test before temporary abandonment.

Temporary Abandonment:

The MMS regulations did not address:

- The fact that BP relied on a single wellbore barrier during temporary abandonment.
- The extent to which BP had underbalanced the well during temporary abandonment activities.
- Whether BP could or should set its surface cement plug in drilling mud, or whether BP should satisfy additional requirements before displacing drilling mud from the wellbore in order to set its surface cement plug in seawater.

- Whether the BOP could be open during riser displacement operations or plug cementing.
- Whether alternatives besides a deep surface plug could accommodate lockdown sleeve setting requirements.

Emergency Response:

- Approved lowering the testing regime of the BOP. The tests performed to the BOP did not prove its ability to contain pressures in a worst-case blowout scenario.
- Did not identified the need to require (not only suggest) BOP's with two blind shear rams in high-profile, high-risk deepwater wells; let alone demanded BP and Transocean to ensure that the one blind shear ram in place had drill pipe across it at all times.
- Did not checked if the BOP was in compliance with disassembling and inspection regulations during their rig inspection in April 2010.

Process Model Flaws

- Inspectors believed that requiring changes to the well design after recognizing risks associated with might have held them responsible if their suggestions caused problems.
- Inspectors believed BP's design and operations had undergone proper risk assessment.
- Inspectors were not aware of any problems with the well during their inspection in April 2010 or until the blowout.
- Did know their limitations regarding deepwater drilling operations by the time of the blowout, and did not act upon that.

Synthesis. Figures 16 through 18 contain generic unsafe control actions for each human controller analyzed.

Figure 16 relates BP Engineers and Wellsite Leaders (BP's lowest level of management studied in this analysis).

The most common unsafe control actions in this group include:

- De-emphasis on overarching risks related to well control and blowout prevention, in exchange for local and simplified risk assessments, unorganized system safety analyses and prioritization of tasks and trade-offs, mostly influenced by costs and reservoir integrity-related hazards that greatly affected BP in the past. There was no hazard analysis for simultaneous activities or proper check of critical equipment.
- Underestimation of risks, and denial when problems occurred, as well as loss of vigilant mindset during non-drilling, yet critical, operations.
- Constant deviation from regulations and standards and selective implementation of their specifications. Frequently, the people in the team would apply the less demanding regulation or standard addressing the same requirement.
- Poor cross-functional communication and peer review throughout all the stages of the project.

- Unclear, incomplete, late and absent exchange of information (procedures, risks, counsel, anomalies and inquiries), aggravated by a partial implementation of approved plans without a formal management of change (MoC).
- Inadequate contractor supervision and assessment of skills to handle non-routine operations and hazards, along with informal assignment of safety responsibilities to third parties.
- *Ad hoc* decisions and plan deviations based on personal judgement without enough information, expert's input, or formal hazard analysis.

The rationale for these unsafe control actions is based on an unclear definition of system safety accountability. Most controllers in this level thought they had no responsibility, nor accountability, for several critical tasks.

They also assumed that others could take full autonomy on procedures in which they shared responsibility, making them neglect such procedures later in the project.

The mindset of the group was also biased by BP's mandates on time and cost reduction and the avoidance of specific hazards that had caused great losses in the past. This mindset limited project-specific risk assessments and encouraged the standardization of worst-case scenarios that proved to be far from standard for all the wells.

Moreover, this approach led to a strong resistance to believe that something could go wrong, even after the omission of regulations, standards, and procedures and the presence of unsolved issues from previous activities.

Figure 17 relates BP Managers and Team Leaders (BP's highest level of management studied in this analysis).

The most common unsafe control actions in this group include:

- Absence of a system safety assessment plan, combined with underestimation of isolated risks identified by the personnel under their supervision. These unsafe control actions are grounded on poor enforcement of BP's MoC procedures and standards, questionable adherence to regulations and industry practices, lack of dissemination of formal risk analysis tools and minimum use of alternative resources to reinforce well monitoring. For instance, there was no official risk assessment plan for the implementation phase (in particular for non-drilling operations), and there was a deficient audit and maintenance of critical equipment.
- Bias towards cost-driven drilling, in which "the operation" was always priority regardless of safety circumstances.

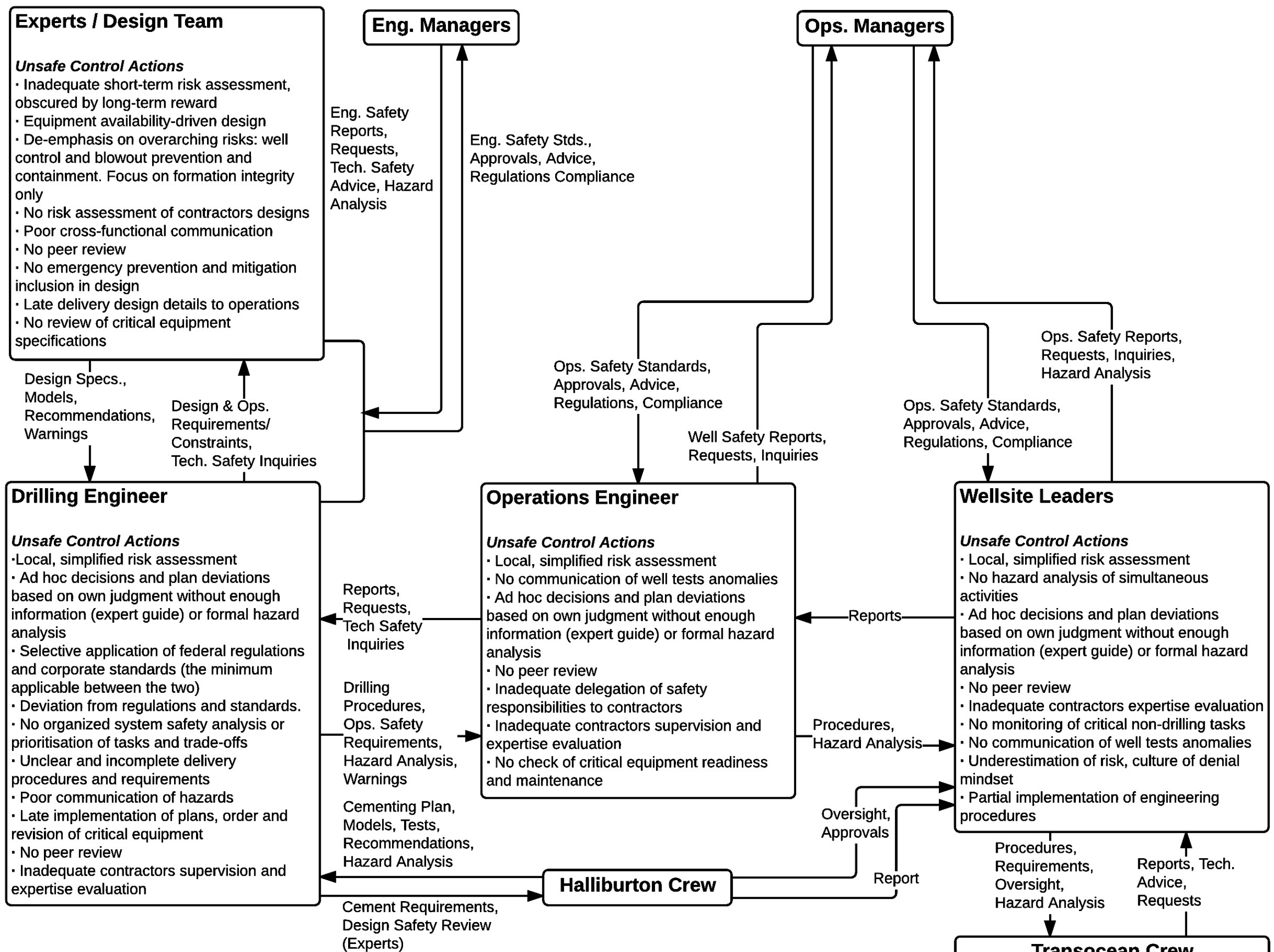

Figure 16. Unsafe control actions of BP Engineers and Well Site Leaders (BP's lowest level of management analyzed).

- Poor understanding of their own safety responsibilities and those of their personnel under supervision, which generated confusion and resulted in tensions within the team. There was no clear and timely dissemination of BP's new and improved risk analysis procedures, investigation of incidents, nor team collaboration and peer review schemes.
- Inadequate personnel assignment and contractors supervision. There was not an effective skill-proficiency evaluation that would ensure that the human controller was prepared for his or her technical and safety role. Similarly, there was no policy to support the team on the rig using alternative procedures such as monitoring the well in real time from shore.

The rationale behind these unsafe control actions is based on a strong believe that faster drilling is better, which can be true for flawless, completely safe projects with cost-reduction objectives.

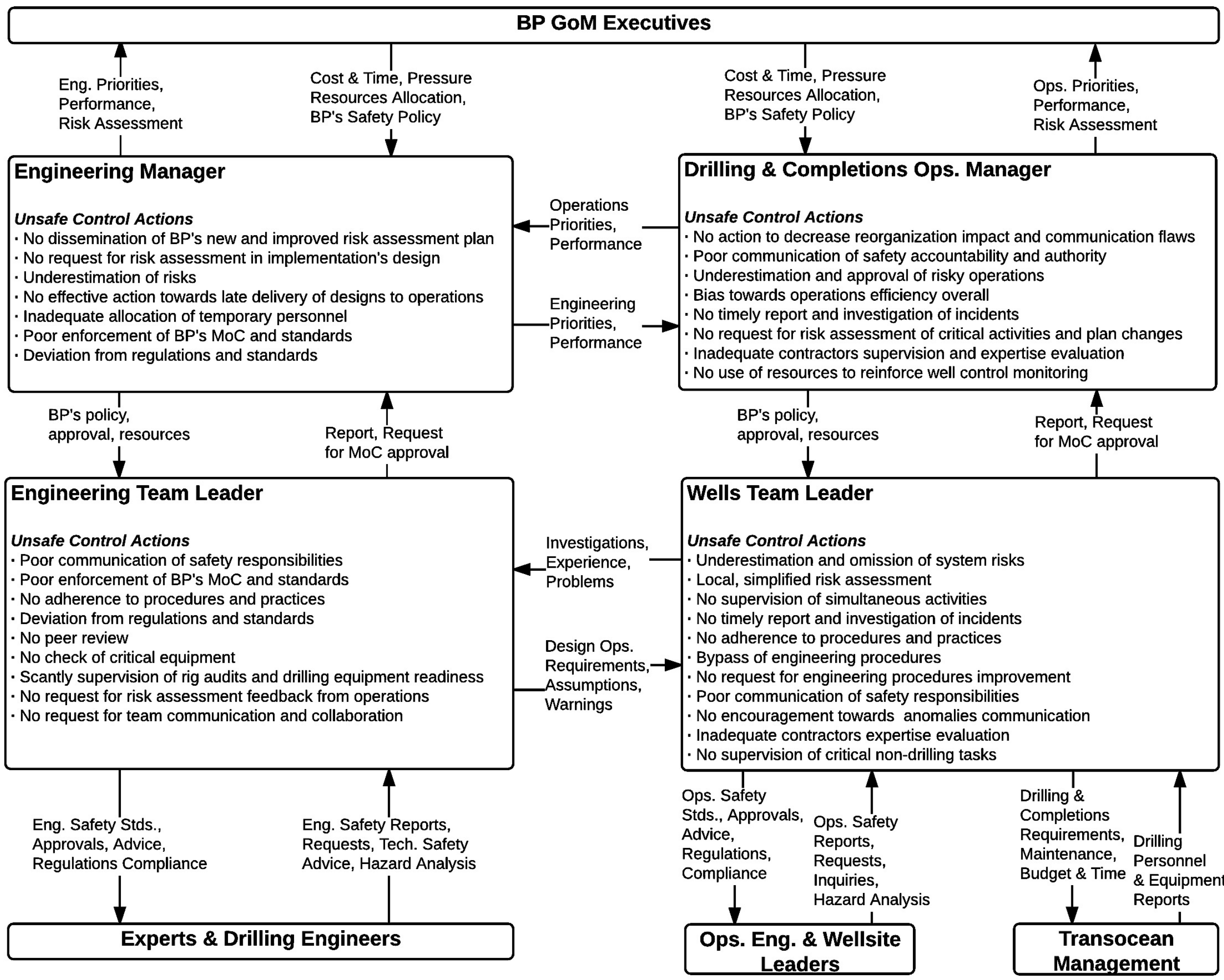

Figure 17. Unsafe control actions of BP Managers and Team Leaders (BP's highest level of management analyzed).

Moreover, managers at this level also assumed that the personnel and the equipment were operating as per regulatory and corporate standards, and that BP's reorganization had not changed anything.

BP Manager and Team Leaders also thought that everyone was accountable for system safety[3], which they tended to confuse with personal safety (the only quantifiable safety in the metrics of the project).

[3] Saying that everyone is responsible is a wide spread belief and statement throughout the oil and gas industry and many others. The issue with this approach is that when everyone is responsible for safety (and resolving conflicts between it and other goals), then nobody is responsible for safety. This point is further discussed in the section of Reorganization, page 84.

When new members had a conflict with the lack of MoC procedures or the new structure, the rest ignored them or demeaned their requests for action. Both team leaders expressed discomfort for the delays and not knowing the extension of their authority, but no team effort seemed to have addressed these or any tensions in their dynamics, except for a promise from the managers that these challenges were going to be addressed as soon as the project was finished.

Figure 18 presents contractors and regulators.

For Transocean the main unsafe control actions include:

- Lack of risk assessment of non-drilling operations, critical equipment, and simultaneous activities, and no emergency response for low frequency, high-risk events.
- Misinterpretation and underestimation of loss of well control signals (particularly during non-drilling operations and blowouts) followed by *ad hoc* decision based on own judgment without enough information (expert guide) or formal hazard analysis.
- Absence of communication channels and support policies to report well control and maintenance issues to shore. In addition to unattended software (for drilling and maintenance) flaws.
- A maintenance policy that deviated and bypassed maintenance regulations and recommended practices for critical equipment.
- Poor dissemination of lessons learned between teams and no record keeping of rig and equipment modifications and maintenance histories.
- Inexistent skillset, not even training, for non-drilling and special testing activities and low-frequency, high-risk emergencies.

The rationale for Transocean's Crew unsafe control actions is based on their believe that all drilling accountability was the responsibility of BP, and that BP was taking sufficient measures to maintain the well under control without their proactive input. Transocean's crew was also unaware of the integrity status of the well, which seems to have led them to assume that post-drilling activities were safe from a loss-of-well-control event.

Furthermore, Transocean's Managers believed that their experience-based training and condition-based maintenance was superior to industry practices and regulations. They supported these claims with their outstanding performance and personal safety records that did not reflect incomplete maintenance registers, poor communication of lessons learned across the company, and uneven automation efforts.

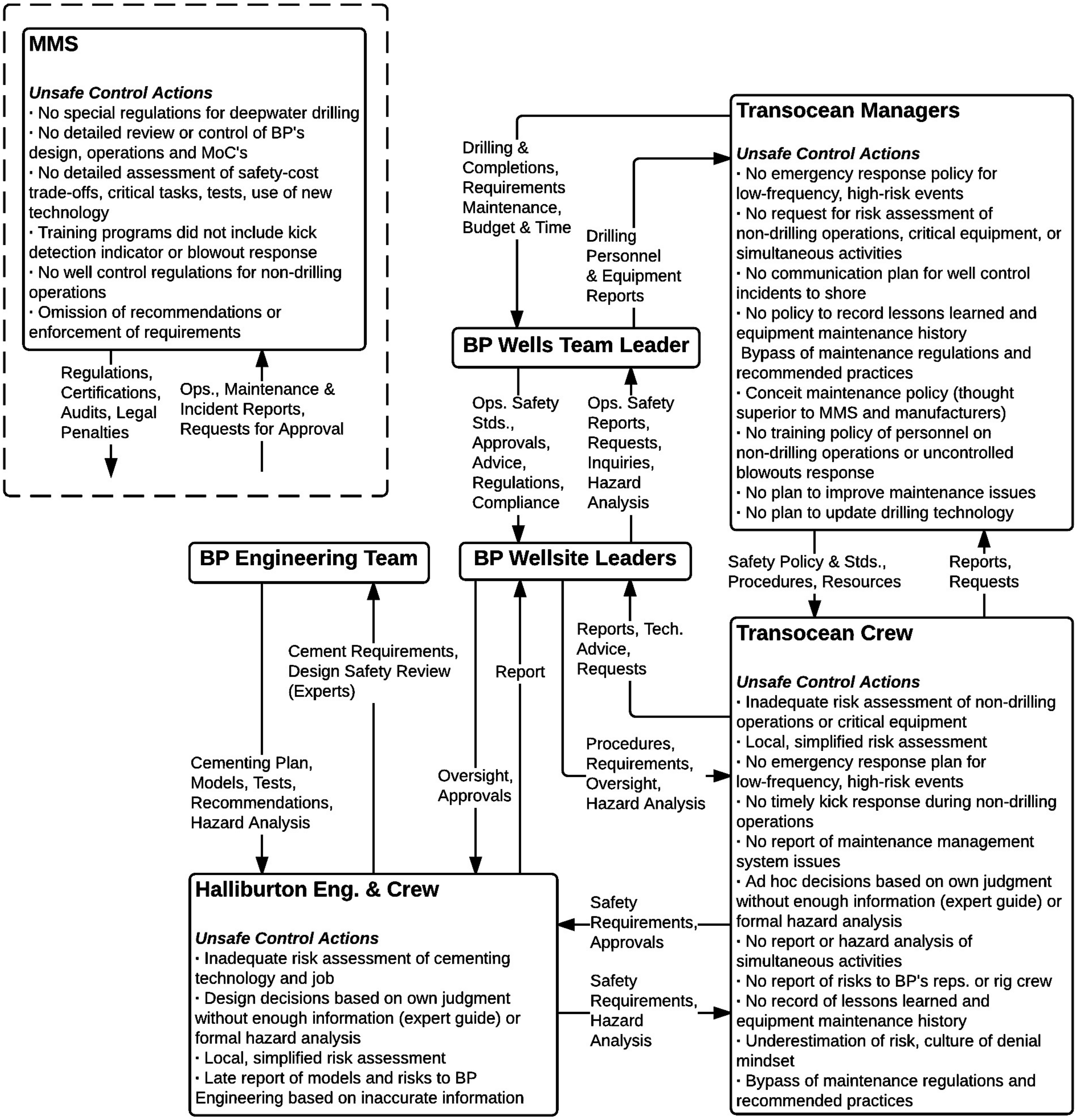

Figure 18. Unsafe control actions of contractors and regulators (MMS).

For example, while the platform had state of the art geo-location technology, the drilling software and monitoring system was outdated, but since both were "working" as per their standards, the disparity and need for improvement was not visible to them.

For Halliburton the main unsafe control actions include:

- Inadequate risk assessment of new cementing technology for specific applications.
- Design decisions based on own judgment without enough information (expert guide) or formal hazard analysis.
- Isolated and simplified risk assessment accompanied by late report of models and risks based on incomplete information.

The rationale for the Halliburton crew's unsafe control actions is based on their assumption that the design and the technology they offered was safe for Macondo and that their approach to reach that conclusion was sufficient, even after laboratory tests and simulations (which by the way lacked accurate inputs from BP) were showing unsuitable results. This seems to have being influenced by BP's preference towards a reservoir integrity-driven design and partial involvement of Halliburton with the project.

The cementing engineer also believed that BP valued his simulations and models, the tools that he used to validate his recommendations. He was not fully aware, though, that the lack of accuracy and timely delivery of this information had deteriorated his credibility within BP.

There is no clarity around the decision to delay and selectively report test results, rather than believing that this method was not critical to confirm the effectiveness of the cement.

For the MMS the main unsafe control actions include:

- Lack of special regulations for deepwater drilling and well control regulations for non-drilling operations.
- No detailed review or control of BP's design, operations, and MoC's, as well as no assessment of safety-cost trade-offs, critical tasks, tests, or use of new technology.
- Insufficient training programs that omitted kick detection indicators and blowout response.
- Omission of recommendations and enforcement of federal regulations.

The rationale behind the MMS's actions is based on the lack of resources, lower level of specialized knowledge and unawareness of the conditions of the well. Besides, the inspectors in charge of Macondo believed their advice could bring them legal consequences, for which they opted for not sharing any non-solicited counsel, even when they had doubts about the design and the numerous changes in operations.

In higher levels of hierarchy of the MMS, there seems to have been interest in facilitating any offshore exploration due to the profitability of the business.

CAST Step 7. Communication Contributors to the Loss.

"Inadequate communication and excessive compartmentalization of information contributed to the Macondo blowout" [21]. While the Engineering team was making decisions regarding one aspect of the well, Wellsite Leaders were making decisions about other aspects at the same time. There was no effective communication of critical information across teams, and apparently no one seemed to be analyzing the risks of these simultaneous actions at a system level. For example, there is no evidence that the Wellsite Leaders communicated their decision to circulate the mud at a lower flow rate than planned before the cementing job, a decision that might have impacted the entire quality of the cement and a strong hypothesis that it did.

Hidden in the high-level of management is also the poor and sometimes nonexistent communication of BP's safety policy. Since Hayward took over as CEO, three years before the blowout, he had claimed that safety was BP's new number one priority and the executives in charge of the Gulf of Mexico were aware of it. They took charge of personal safety metrics and made sure they reflected an operation without incidents. However, although they knew about several initiatives to address system safety that were launched early in 2010, they did not spend much effort in deploying them. They argued that these plans were pilots, did not impact safety metrics, and therefore decided to postpone their dissemination across their teams for months, as late as the very day of the blowout (Appendix G, Exhibit 4235).

Another communication flaw of this kind was present in the lack of sharing lessons learned. Months before the Macondo accident, a Transocean rig in the North Sea faced a similar event during completion operations. The cement barrier failed to contain the reservoir influx after also being tested and considered reliable. In this case the BOP was able to seal the well and no one was injured. However, no one related to Macondo knew about this incident.The most common communication contributor was the lack of counsel between subsystems. When faced with anomalous data, decision-makers did not seek advice from others with expertise, instead opted to carry on with the operation with incomplete or inaccurate information. For example, the Drilling Engineers along with the Cement Engineer proceeded with the foamed cement design without a formal risk assessment. The input of experts from BP and Halliburton from different specialties could have resulted in a better evaluation of the impact of this new technology in the integrity of the well. Likewise, after the cementing job, neither BP nor Transocean crewmembers sought counsel to investigate the myriad anomalies during the negative pressure test and the subsequent mud displacement; instead both crews regarded the kick signals as normal drilling phenomena using questionable theories such as the "bladder effect". As one of the Transocean employees interviewed for this analysis stated, “Sometimes we can’t accept that things are going wrong, so we justify they’re fine with illogic explanations ”.

It is important to stress though, that for none of these individuals on the rig was it clear when and why they had to ask for help or call back to shore. In addition, two important cultural aspects of the oil and gas industry worsen communications and could have influenced Macondo’s interactions too: (1) it is not the most common practice in the industry to seek counsel, since it tends to be perceived as sign of incompetence, and (2) offshore platforms are perceived as highly automated, flawless rigs which encourages a culture of denial about any type of incidents and anomalies with the drilling operation, even more during final activities when the operation is normally considered a success.

Figure 19 (Bottom) reflects the state of the safety control structure of the well integrity at the time of the blowout. The doted lines with descriptions in grey and italicized words represent the feedback loops that were absent, insufficient or wrong controls. As is evident, the majority of the structure lacked effective communication of safety control actions; the remaining ones, in black and non-italicized words, show a safety structure governed by cost and time pressures, approvals, and penalties.

This version of the safety structure is based in the management level analysis and was revised by the BP personnel interviewed.

CAST Step 8. Dynamics and Changes in the System Over Time.

Aside from ineffective communication and isolation of information between subsystems and controllers, there were other dynamics in place that contributed to the accident. Constantly fed by cost and time pressures, the reorganization of BP’s Macondo team, late and risky procedures, poor management of personnel and equipment, and inadequate risk management led to a false sense of safety, underestimation of risks, and incentives that mainly prioritized performance (faster and cheaper drilling).

Reorganization. BP’s Macondo team underwent a considerable change a month before the blowout as part of the reorganization of the entire Exploration Business Unit (BPX). Figure 20 shows the structure up until March and Figure 21 shows the new structure established in early April. The impact of the change highly affected the decision scheme of the team. As can be seen in the diagrams the leader conciliating the engineering and the operations of the well was completely removed from the team.

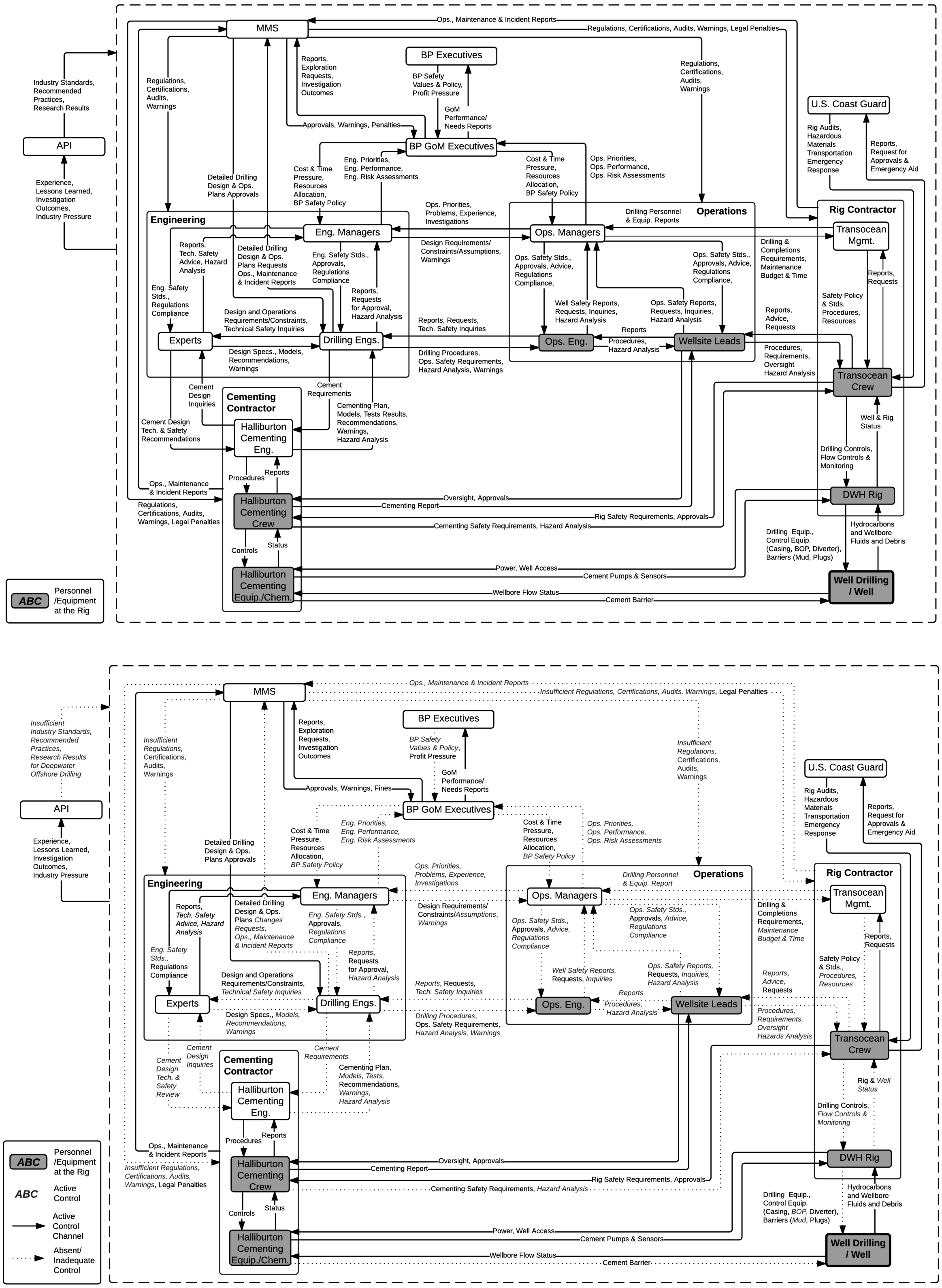

Figure 19. Theoretical safety control structure of the Macondo well integrity (Top). Existing safety control structure the Macondo well integrity at the time of the blowout (Bottom).

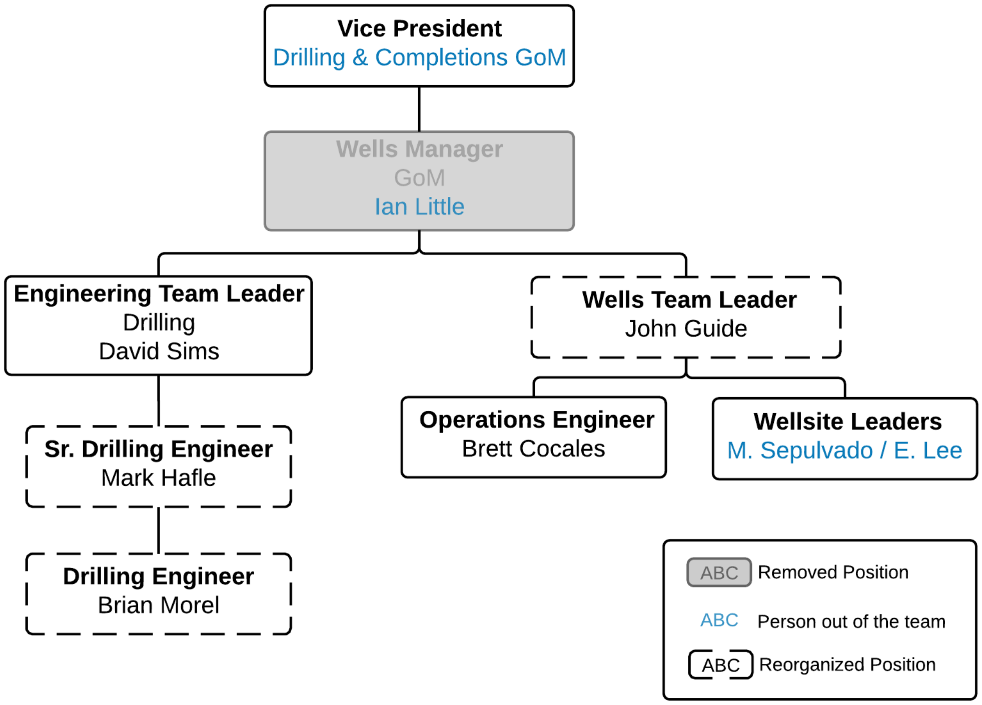

Figure 20. Old Organization of the Macondo Drilling Team.

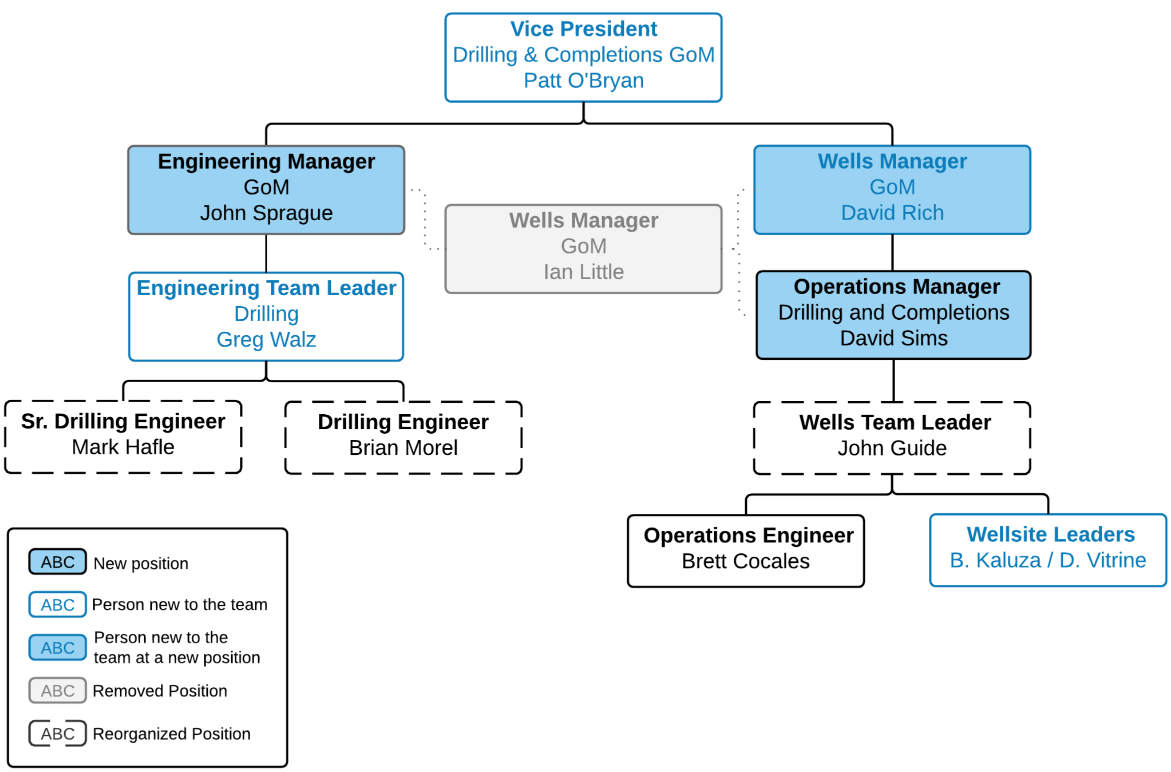

Figure 21. New Organization of the Macondo Drilling Team.

After a careful study of this role, it is not clear who took over several of his safety-related responsibilities, including:

- Communication of best practices between Engineering and Operations.
- Definition of project priorities between Engineering and Operations.
- Investigation of major failure incidents.
- Critical equipment supervision and compliance.
- Testing of system integration equipment.

The person that received the handover of this position, the new Wells Operation Manager, did not acknowledge inheriting these responsibilities and admitted not being sure who was accountable for them in the team, but believed that everyone on the team was more likely to be accountable. This reflects the common confusion between personal safety and system safety coming from higher levels of management in BP, since suggesting that everyone is accountable for system safety can lead to evasion of personal safety-related responsibilities.

"For example, BP [representatives] admitted that its internal engineering standards required the Macondo team to conduct a formal risk assessment of the annulus cement barriers in the well, and that such an assessment might have led the team to run a cement evaluation log. Yet nobody on the team appears to have brought up the relevant Engineering Technical Practice (ETP) on zonal isolation. There also appears to have been confusion about who was accountable for ensuring the adequacy of the cement slurry design, determining the risks attendant to changes in operations, and assessing the competence of personnel assigned to perform the negative pressure test" [21]. Nobody was taking ownership of the responsibilities of the former Wells Manager.

Moreover, the Wells Team Leader expressed discomfort for losing this integrating position in the new structure, arguing that the next integrator figure between the groups was too far up in the organization to be reached out for specific well issues and that he did not consider the new managers were reconciling Engineering and Operations priorities adequately.

Prior to the change, the Wells Team Leader had the integrator role as his direct supervisor, but after the change that position was three hierarchy levels above his. The change also placed the Engineering Team Leader as the Operations Manager and new supervisor of the Wells Team Leader. Unsure of his authority, the Wells Team Leader engaged in several arguments with his old equal in the structure.

Although unrelated to the new structure, but equally relevant, BP's Macondo team also had a constant flow of personnel. The boxes in blue in Figure 21 show the roles occupied by people that had less than 6 months in the team (Table 14). Coincidentally, both Wellsite Leaders were temporary replacements at the moment of the blowout.

Risk Management and Procedures. The Deepwater Horizon accident is framed under the highly competitive market of deepwater drilling. The delicate balance between safety and cost management is a constant challenge for operators.

Table 14. New staff in the Macondo team [16],[20].

Position	Time in Position
Drilling & Completions Vice President, GoM	3 months
Wells Manager	6 months
Drilling & Completions Operations Manager	18 days
Engineering Manager	6 months
Drilling Engineering Team Leader	18 days
Wellsite Leader (R. Kaluza)	4 days

For Macondo, Engineering made critical decisions driven by cost pressures. Immersed in a savings culture, the team labeled several safe operations as inefficiencies (like the cement evaluation logs, the cement and temporary abandonment rigorous safety analysis and risk assessment, and the BOP preventive and timely maintenance). It seems like the team never considered the possibility of a catastrophe and throughout the project indulged bypassing several regulations, corporate standards and industry recommendations.

The team also perceived cost-efficient changes at the component level as overall improvements, Table 15 presents some examples.

They never evaluated the impact of these changes in the system and did not realize that they were actually decreasing the integrity of the well, like installing a non-critical sleeve during the temporary abandonment procedure to reduce rig costs, or decreasing the mud flow circulation rate to protect the formation but jeopardizing the cementing job.

Appendix D contains the Official Risk Register for Macondo prepared during the design phase by Engineering. All the risks are defined to have an impact on cost, schedule and production; yet not a single one considers health and safety or environment threats.

The migration to a state of higher risk driven by cost and time demands was even more evident during the last ten days before the blowout, when Operations significantly changed the initial procedures to transition into production. Under time pressures, *ad hoc* decisions were made and last-minute adaptations did not undergo formal risk assessment. In addition, these decisions were not consulted with experts within or outside BP and did not fully adhere to regulations and standards. For example, "the engineering and operations team never asked BP experts … about the wisdom of setting a surface cement plug 3,000 feet below the mudline to accommodate setting the lockdown sleeve or displacing 8,300 feet of mud with seawater without first installing additional physical barriers. [In addition,] it never provided rig personnel a list of potential risks associated with the plan or instructions for mitigating those risks."

However, BP's management system did not prevent such *ad hoc* decision-making. BP's project development practices required a relatively robust risk analysis and mitigation during the planning phase of the well but not during the execution phase. BP's Beyond the Best Common Process set forth BP's procedures for selecting, designing, and drilling wells in the Gulf of Mexico. It laid out a five-stage process: (1) Appraise, (2) Select, (3) Define, (4) Execute, and (5) Review.

The first two stages consisted of identifying and selecting a wellsite. BP planned and permitted the well during the Define stage. During the Execute stage, BP and its contractors drilled and completed the well. Finally, once drilling and completion was done, there was a Review stage to evaluate the project and to identify areas for improvement. Engineering became accountable for performance and safety during the Define stage, although Operations was involved. Then Operations took over primary accountability during the Execute stage, with Engineering continuing to support planning and design decisions.

Before proceeding from one stage to the next, a well had to satisfy certain requirements. For the Engineering part for example, before moving from Select to Define and from Define to Execute stages, the well concept, design, and plan had to undergo a rigorous peer review process, which consisted of a multi-disciplinary group of experts assessing how the balance between risk and value was being managed and was led by a member of the BP's drilling and completions excellence team.

There was no equivalent peer review process during the Execute stage though. The decision to perform any formal risk analysis was left to the team's discretion, specifically the Wells Team Leader. For example, in case Operations decided to prepare a formal risk analysis they had to present a Management of Change (MoC) request, along with a mitigation plan for management approval. But a MoC was optional and applied mainly to decisions to deviate from the well plans approved during the Define stage, not to drilling procedures such as the temporary abandonment of the well.

During the legal hearings, the Engineering Team Leader declared that he had observed that the MoC process "was not clear for the Macondo team" but that the culture was to "do what we have been doing”. None of the drilling processes considered in this analysis, the cementing (the cement slurry design and the casing string centralization) and the temporary abandonment (including the simultaneous rig activities that increased its risk), went through a MoC process.

It is important to highlight that BP was aware of the weaknesses in its risk assessment process; in fact, BP’s 2008 internal review found that risk assessment required improvement (stronger major hazard awareness and integration of assessment processes/results).

Table 15. Examples of unsafe decisions that potentially saved operations time.

Decision	Was There a Less Risky Alternative Available?	Less Time Than Alternative?	Decision Maker
Not waiting for more centralizers of preferred design.	Yes	Saved Time	BP Onshore
Not waiting for foam stability test results and/or redesigning slurry.	Yes	Saved Time	Halliburton (and perhaps BP) onshore
Not running cement evaluation log	Yes	Saved Time	BP Onshore
Using spacer made from combined lost circulation materials to avoid disposal issues.	Yes	Saved Time	BP Onshore
Displacing mud from riser before setting surface cement plug.	Yes	Unclear	BP Onshore
Setting surface cement plug 3,000 feet below mudline in seawater	Yes	Unclear	BP Onshore (approved by MMS)
Not installing additional physical barriers during temporary abandonment procedure.	Yes	Saved Time	BP Onshore
Not performing further well integrity diagnostics in light of troubling and unexplained negative pressure test results.	Yes	Saved Time	BP (and perhaps Transocean) on rig
Bypassing pits and conducting other simultaneous operations during displacement.	Yes	Saved Time	Transocean (and perhaps BP) on rig

Nowadays, BP has more robust risk assessment procedures established after Macondo in 2010, and under continuous improvement. In an interview with BP personnel, the Gulf of Mexico Executive

Managers, aware of this new rigorous risk assessment plan, were already discussing the need to establish new requirements to evaluate the effectiveness of each barrier days before the accident.

The contractors' contribution to risk assessment in Macondo was no better. It appears that they focused only on their tasks without providing important information to the decision-makers at BP, sharing valuable lessons with them, or raising awareness of the imminent danger of the operation.

For example, Transocean did not report any risk analysis or mitigation plan regarding their performance of simultaneous operations during critical steps (such as the negative pressure test) and omitted sharing with BP their incident in the North Sea. Nor is there evidence that someone from Halliburton performed a comprehensive hazard analysis of the foamed cement design and job for the specific conditions of Macondo.

Personnel. The operations at Mocondo heavily relied on human judgement. For instance, verifying the quality of the cement barrier was led by the interpretation of the negative pressure test done by the Wellsite Leaders and the Transocean Crew. The detection of kicks, thereby the prompt activation of the BOP, was led by the Transocean Crew.

Beyond doubt, the human controllers of the Macondo system were unfairly expected to make decisions *in situ* to keep themselves and the system safe. The problem with this approach is that at their hierarchical level, right above the physical components, they do not have access to the whole system and a decision that seems perfectly safe within their level can be the most dangerous one for the system. Then, if BP, Transocean and Halliburton executives pretended to operate in this manner, they must have had provided a safe system for the human controllers to rely in their human judgement to make system-safe decisions. This could have been translated into providing the Rig Crew and Wellsite Leaders exercising their judgment with adequate training, information, procedures, resources, and support to do their jobs effectively.

For instance, before the blowout, both the Wells Team Leader and the Junior Drilling Engineer may have been overworked, as suggested by some of their rushed decisions, and as perceived by their colleagues. During the legal hearings, the Operations Engineer Brett Cocales testified: "I would say with the kind of load that a wells team leader is undertaking, … additional resources would be of benefit to that person, including additional people to handle the multitasking areas that that person has to undertake. Testimony of Brett Cocales, 268- 69. In addition, there was no safety engineering structure or safety engineer on the rig. All responsibility for safety was placed on managers and workers with conflicts in their responsibilities. Well-managed projects have responsibility for assisting with safety-critical decisions assigned to people who specialize in and are responsible for providing the information to managers so they can make better decisions.

Equipment. Despite the complexity involved in deepwater drilling, comparably to that space travel, the drilling equipment in Macondo was not extensively automated. Drilling Operators had to perform basic well monitoring calculations by hand, such as calculating the net flow from the well, instead of having automated systems calculating it for them. Similarly, many of the sensors in the platform available for kick detection did not work properly and provided unreliable data due to tidal movement, not to mention that there were not enough cameras installed to monitor flow from the wellbore at critical points, like the overboard line. Floorhand Operators had to physically measure volume levels with hand-made levels and visually confirm the direction of the flow.

In addition, there was no equipment in place to detect the presence of hydrocarbons during non-drilling operations. While the operation used sophisticated sensors in the drilling tools to detect kicks while actively drilling, there were no sensors downhole capable of detecting kicks when no drilling was being done. As a matter of fact, it seems that nowhere in the oil and gas industry do such sensors exist.

BP and Sperry Drilling (Halliburton's Drilling Company) were able to gather and transmit real time data from the well. BP even allocated a large room in its Houston Headquarters to monitor the data from the wells in the Gulf of Mexico. At the time of the blowout, however, no one was assisting the monitoring of the well onshore. BP had no plans to benefit from this resource *in pro* of the integrity of the well alleging that doing so "tended to disempower personnel on the rig". It should be noted though that the only personnel in the rig monitoring the well at the time of the kick was the Transocean Toolpusher. No one from BP, despite having access to the data at their offices and rooms on the rig, was monitoring the well.

As has been already addressed in this analysis, the maintenance of the equipment at Macondo was also questionable. As per Transocean's condition-based maintenance philosophy "…the equipment shall define the necessary repair work, if any", the BOP had its certification pending and the Deepwater Horizon had never been in dry dock for a full onshore maintenance. In addition, Transocean's Rig Management System II (RMS) seemed to have complicated the maintenance onboard. Apparently the RMS delivered duplicated and erroneous maintenance orders leaving unattended relevant equipment, such us the computers in the driller's room, which operated intermittently and had outdated software.

CAST Step 9. General Recommendations.

BP - Technical Recommendations

Cement. The cement control did not provide a physical barrier to contain the hydrocarbons in the reservoir.

General Recommendations:

- Early in the well design, run an exhaustive risk review of potential cement technologies and slurry designs specific for the reservoir to be intervened; involve the Engineering and Operations, in house experts and contractor's specialists in this process.
- Request tests and simulations that accurately represent downhole conditions, and allocate time for prototyping iterations to ensure constant communication and evaluation of results.
- Avoid last minute changes of critical parameters of the design and keep track of changes through rigorous risk assessment.
- Even in straight wells, assess the risks associated with poor centralization of the casing string as potential contributors of a bad cementing job. Rigorously assess the trade-offs between a remedial cement job and a stuck drill pipe downhole, prioritizing well integrity and well control.

The cement did not fill the annular space in the zone containing the hydrocarbons as well as the zones above and below to ensure safe isolation.

Recommendations:

- Run rigorous risk assessments addressing pumping flow rates and volumes to avoid uncovered zones, poor isolation issues, and gas instability.
- Adhere to regulations, corporate standards and industry practices.
- Formalize deviation from regulations and standards through Management of Change and risk assessment procedures.

The cement flowing into the annular space did not displace all the drilling mud, then the cement remaining in the well most likely got contaminated and lost its sealing capacity.

Recommendations:

- In preparation for the cementing job, ensure that downhole equipment such as valves that could impede the flow of debris out of the well or the flow of the cement into the annular are properly set-up.

- Review previous mud circulation rates and valves settings, and validate their status prior to the cementing job.
- Establish procedures to confirm full displacement of mud and cement.
- Do not rely on negative pressure tests and visual inspection to validate the success of the cementing job and the quality of the cement as a well control barrier, complement this process with other methods, such as electric logs for cement evaluation.

The cement slurry was not formulated so that it set and cured properly under wellbore conditions.

Recommendations:

- Carefully assess the compatibility of different design choices, such as the use of foamed cement with long casing strings in deepwater wells, considering well integrity and control risks constantly.
- Allocate sufficient resources to test the cement before using it in wells with challenging conditions.

Mud. The drilling mud control did not act as a physical barrier that maintained the well overbalanced.

General Recommendations:

- Design well-specific temporary abandonment procedures complemented by a risk assessment of the changes in the mud column.
- In general, avoid underbalancing the well, and if needed ensure other well barriers are effective. Consider mud displacement as a critical non-drilling operation in which one of the well barriers is altered and sometimes disabled.
- Keep a vigilant mindset during mud displacement operations and notify the entire crew of the activity and the contingency plan in case well control is lost.
- Adhere to the plans approved by federal regulators and request their re-approval in case of changes; regulators must be aware of the risks and consequences of underbalancing the well and losing its control.

The drilling mud pressure did not exceed the pressure of the formation during the temporary abandonment.

Recommendations:

- Except for deliberately seeking to underbalance the well, constantly control the weight of the mud so that it contains the migration of hydrocarbons into the well without damaging the reservoir.

- Plan mud displacement and mud circulation operations taking into account the pressures of the well and the reservoir; monitor these pressures closely, especially when heavy mud is going to be replaced. Consider the incorporation of automated monitoring systems for mud displacement procedures and enhance the existent ones; in particular, improve the monitoring methods during open system displacements, in which the mud quantity is not conserved.
- Avoid mud displacements without prior confirmation of the characteristics of the mud in the well, the pits, and the pipelines. Plan for an accurate flow tracking during its displacement.
- Avoid simultaneous activities that could distract the rig crew and alter flow meters or other instruments tracking the mud displacement. Find ways to mitigate the risks associated with inevitable simultaneous tasks, and ensure that flow-tracking instrumentation is appropriate and reliable for open sea operations and is not affected by tidal movements.

Blowout Preventer. The Blowout Preventer (BOP) did not shut in the well during the blowout.

General Recommendations:

- Keep BOP's certified and adequately maintained in accord to regulations and vendor recommendations.
- Implement procedures to verify the status of BOPs after kicks and establish contingency plans in case they are damaged beyond repair to continue operating while drilling.
- Ensure that BOP's can be promptly activated from different points on the rig, and that there is personnel trained and authorized to do it under pre-established conditions. Include BOP's activation procedures during emergency drills.
- Ensure the design of each BOP is appropriate for well-specific conditions; reconsider the complexity of an equipment-dependent well design and its consequences.
- Evaluate alternatives to rotate BOPs for onshore maintenance and recertification, such as a back-up BOP; plan this in liaison with contractors and manufacturers.

Power supply and hydraulic pressure from the rig and from the back-up systems embedded in the BOP did not feed the rams after the blowout.

Recommendations:

- Ensure BOPs have different sources of power and hydraulic supply connected to them, and that these sources are reliable, properly maintained and independent from each other. Consider their protection from fire or explosion by isolating them or locating them in places with low risk of ignition.

The BOP was not tested at a pressure such that well containment was guaranteed.

Recommendations:

- Design and implement tests to ensure that BOPs can withstand real blowout conditions. Develop procedures to regularly test the equipment without wearing it out; collaborate with manufacturers and industry associations to determine feasible protocols and testing frequencies.

The blind shear activation modes were not tested and operational under blowout conditions (pressure, temperature, power supply, signal communications).

Recommendations:

- Since some of the rams can be activated in test mode or real mode, ensure that the blind shear rams are tested in real mode (not only in test mode) at a convenient stage of the process, for example before each well begins; if this damages the equipment, contemplate modifications accordingly. Similarly, ensure that test modes and real modes are properly connected after any intervention to the BOPs.
- Ensure the rams' activations modes are operating at all times, including in the routinely checks automated and remote modes too.

BP - Management Recommendations

Engineers and Wellsite Leaders.

- Did not determine how best to achieve the Macondo's objectives while managing potential drilling hazards and man-made hazards.
- Did not shepherd Macondo's designs through BP's processes and experts, ensuring that they complied with internal and external engineering, operations and safety guidelines and regulations.
- Prepared risk assessments without including considering overall system safety. Developed hazard analyses for specific activities of the project, and implemented them depending on scheduling convenience. Selectively requested MoCs and regulatory permits for critical procedures.
- Ensured the well was prepared for each operation without safety considerations on well control and integrity, but a focus on Operations scheduling.

- Reported safety issues and lessons learned late and did not finish high-impact investigations like the analysis of the kick a month before the blowout.
- Prepared contingency procedures for low-level risk emergencies, but not for high-level risk, infrequent emergencies like a blowout.
- Inadequately supervised contractors and wrongly assumed their proficiency to carry out non-routinely operations. Informally assigned them safety responsibilities.
- Made *ad hoc* decisions and deviated from procedure based on personal judgement and without enough information, expert's input, or formal hazard analysis.

<u>Recommendations:</u>

- Focus on overarching risks related to well integrity and control and blowout prevention, not in individual risks. Review risk assessment procedures (Appendix D) and improve over-simplified decision-making protocols (Appendix E). Structure system safety analyses and prioritization of tasks and trade-offs basing it on well integrity and not costs and reservoir integrity-related hazards only.
- Prepare adequate hazard analyses for simultaneous activities in which all the parties involved participate.
- Identify the critical equipment and establish proper check and maintenance plans for it as per regulations and vendors recommendations.
- Avoid underestimating risks and denial of loss of control signals, on the contrary look for those constantly and investigate them thoroughly. Keep a vigilant mindset during non-drilling, yet critical, operations, and be aware of the active barriers of the well at all times.
- Avoid constant deviation from regulations and standards and selective implementation of specifications and procedures based on personal judgement and incomplete information. Do not apply the less demanding regulation or standard addressing the same requirement to be in compliance, instead run a proper risk assessment for each decision and equally adhere to regulations and standards.
- Prepare and request complete Management of Changes (MoCs) in compliance with BP and MMS regulations and standards when: deviations in Enginnering or Operations plans occur, simultanoues activities are considered, and *ad hoc* decisions lack formal riks assessments.
- Improve poor cross-functional communication and peer review throughout all the stages of the project. Establish back-up monitoring plans and agile counsel channels in times of crisis.

- Consult with the team test results, assumptions and decisions before proceeding, and keep everyone informed of issues and decisions made at each stage of the process.
- Report and investigate incidents in a timely manner. Share lessons learned frequently with the entire team, including contractors and suppliers.
- Review the guidelines in place for the supervision and skillset evaluation of contactors. Similarly, avoid the informal transference of safety responsibilities to contractors. Define roles and responsibilities clearly since the beginning of the project to avoid confusion.
- Prepare contingency plan for all types of emergencies, disseminate them and review them regularly. Include these plans in the rig drills and assign responsibilities to the personnel on the platform.

Team Leaders and Managers.

- Managed project level risk assessments without detecting flaws in system safety analyses, underestimation of individual risks, confusion with safety responsibilities, critical equipment without maintenance and risky operations that jeopardized the well's integrity and control.
- Did not provided support to solve tensions within the team, clarify organizational, counsel between Engineering and Operations priorities, and maintain overall project progress while securing well integrity.
- Approved Management of Change (MoC) to Drilling and Completion Operations and simultaneous operations without compliance with BP and MMS safety requirements.
- Did not ensure audits, investigations and lessons learned were concluded and shared within the team and throughout BP.
- Underestimated the tension that the reorganization created within the team, but was not certain about the safety accountability distribution under the new structure.
- Managed onshore support and monitoring poorly. Did not use the resources available (BP risk assessment tools, real-time onshore monitoring, expert teams input) to make safer critical decisions and validate well integrity.
- Managed personnel and supervisors without assessing their preparedness or guaranteeing their proper training and experience.

Recommendations:

- Implement a system safety assessment plan, carefully examining the relation between isolated risks.

- Review the well development process, and include risk assessments and cross-functional, peer reviews for the Execution stage of the process, just like they exist for the Design stage.
- Enforce the use of MoC procedures and standards and clarify how, when and why management of change must be used. Review existent assumptions in the current process.
- Approve designs and procedures that adhere to regulations and corporate standards.
- Disseminate formal risk analysis tools and establish plans to use alternative well monitoring technology. Improve over-simplified decision-making protocols used by Engineers.
- Change personnel assignment and contractors supervision guidelines. Develop effective evaluations of skills proficiency to facilitate the accurate placement of new and temporary personnel and define clear contractor supervision roles and responsibilities within the team. Ensure contractors have well defined safety responsibilities and review contractual compliance measures.
- Improve the audit process. Include maintenance policies of contractors on critical equipment, historical records of critical equipment, software used for drilling monitoring and reporting systems onboard.
- Improve the report, support scheme within the team. Encourage the interaction between Well Site Leaders and technical experts onshore. Assign responsibilities and reporting protocols for these tasks.

Executive Level. There was not an effective safety management system in place for the Macondo Well.

Recommendations:

- Reconsider the integration of the Safety Management System (SMS) and the Business Management System (BMS). The SMS is under the BMS and therefore the conflict between cost and safety prioritization and the confusion for the managers. This could explain why the implementation of the company's number one priority, safety, was not clear to them and why they where hesitant to disseminate new risk assessment plans and existent tools within the teams.
- Eliminate cost-driven drilling bias regarding well integrity decisions, in which "the operation" is always priority regardless of safety circumstances.
- Define clear safety responsibilities throughout the company.
- Examine the confusion between personal safety and system safety. Ensure the methods to validate both are clearly defined and differentiated from one another.

- Rigorously plan organizational changes; avoid impacts on unfinished projects and provide resources to ensure proper handover of safety responsibilities, in particular when positions are eliminated.
- Consider exclusive Project-Specific Management positions, independent of Engineering and Operations, through which performance priorities can be easily settled *in pro* of the project and the integrity of the well.
- Evaluate if the Safety Business Unit created after the accident is facilitating and improving the implementation of system safety within the company or is dangerously removing system safety responsibilities from decision makers. The abdication of responsibilities was present in mid-level managers at the time of the accident, and the division of Safety, Engineering and Operations might be encouraging that.

Transocean. Did not provide rig equipment and rig personnel in compliance with BP's requirements, MMS regulations, and API recommendations for drilling operations and well control emergencies.

<u>Recommendations.</u>

- Clarify safety responsibilities and communication channels with the operator since the beginning of each project, to assure the rig crew is fully aware of the status of the operation, the well, and the contingency plans in case of emergency.
- Examine the improvements on their condition-based maintenance policy after the blowout, and continue improving it accordingly. Avoid maintenance operations without bypassing regulations or manufacturer's recommendations.
- Keep updating the automation of drilling monitoring systems and flow tacking instrumentation for offshore applications.
- Continue strengthening personnel training in well control emergency response. Ensure proper coaching in the interpretation of kick signals, particularly during non-drilling operations and blowouts is complemented with practical training. Encourage the preparation of formal hazard analysis and the investigation and consultation with the operator and Transocean Senior personnel of any anomalies with the well.
- Maintain clear and official communication channels with contractors and operators. Ensure lessons learned are promptly shared within the company and the industry regardless of their segment of origin.

Halliburton. Provided inadequate cementing services that resulted in an inadequate cement barrier.

Recommendations:

- Run rigorous risk assessments of new cementing technologies for specific applications. Confirm compatibility with well design and formation conditions.
- Ensure cement slurries are tested stable before cementing jobs.
- Cement simulations and laboratory tests must take into account well conditions and must be performed using onsite fluids values and samples. Avoid pouring cement formulations that have not achieved stability during laboratory tests.
- Validate cement design with in-house and operator's experts. Determine the impact in well integrity and the causes of a potential remedial cementing job depending on the well and warn the client in a timely manner.

U.S. Oil and Gas Regulatory Agencies (Former MMS). Did not enforce sufficient drilling regulations and thorough inspections in the Macondo Well.

Recommendations:

- Allocate sufficient resources to carry out inspections in deepwater oil and gas rigs, wells, fields and related projects. This entails more and better-trained personnel for these purposes, capable of detecting unsafe procedures and equipment involved in the operation.
- Enforce timely and complete report regulations.
- Strengthen knowledge of deepwater high-profile oil and gas services in order to: provide appropriate guidance in the implementation of regulations; adequately review and update regulations; run accurate review of permit applications for oil and gas services, particularly when deviations from regulations and industry practices are requested; avoid relying in operators and contractors approach and procedures, particularly regarding critically safety-related decision; provide sufficient training programs that include kick detection indicators and blowout response.

4. Comparison to Other Analyses

The following recommendations have been collected from three published safety analyses of the Macondo accident. The purpose of this information is to compare it with the recommendations from the CAST analysis and determine if alternative recommendations were identified in this analysis.
The material selected focused also on the human controllers in the system, and therefore serves as point of reference for comparison.

4.1 Other Analyses

Developing safety indicators for preventing offshore oil and gas deepwater drilling blowouts.

By Jon Espen Skogdalen[a], Ingrid B. Utne[b], and Jan Erik Vinnem[a] (Safety Science 49 (2011) 1187–1199).
[a]Department of Industrial Economics, Risk Management and Planning, University of Stavanger, NO 4036 Stavanger, Norway; [b]Department of Marine Technology, Norwegian University of Science and Technology (NTNU), NO 7491 Trondheim, Norway

In this paper, published in the Safety Science Elsevier journal, the authors present an extension of the indicators from the Risk Level Project (RNNP) in the Norwegian oil and gas industry to the Macondo Accident. The RNNP indicators determine strong contributors to deepwater production risk in relation to safety, barriers and undesired incidents. The authors show the application of such indicators to deepwater drilling in areas related to schedule and cost, well planning, operational aspects, well incidents, operators' well response, operational aspects and status of safety critical equipment.
Figure 22 presents the safety indicators identified on Skogdalen's study.[27]

Recommendation on Schedule and Costs. Based on the two indicators identified for this area:

- Comparison between planned and actual total costs.
- Comparison between planned and actual time used.

The recommendation is to refine these indicators and ensure the inclusion of safety-related issues in budget and time allocation.[27]

Rationale: *"A review of investigation reports issued by the MMS about LWC and blowouts in the period of 2000–2010, showed that schedule and cost issues were not covered. This might be due to a seeming lack of understanding between schedule, cost, and risky behavior. As a result of a cascade of deeply flawed failure and signal analysis, decision-making, communication, and organizational – managerial processes, safety was compromised to the point that the blowout occurred with catastrophic effects''. The Deepwater Horizon rig was 43 days overdue on 20 April, and the total costs had reached about $139 million dollars in the middle of March. The original costs were estimated at $96 million dollars (DHJIT, 2010) indicating more than $40 million dollars in additional costs".[27]*

Recommendation on Well Incidents. Based on the indicators identified for this area:

- Too low mud weight
- Gas cut mud
- Annular losses
- Drilling break
- Ballooning
- Swabbing
- Poor cement
- Formation breakdown
- Improper fill up

The recommendation is to actively report to the authorities, for proper dissemination of the incident, well integrity and well incidents, and the crew's response if incidents occur.[27]

Rationale: "All these contributors can be analyzed as undesired incidents, even though they do not necessarily lead to a kick if handled by proper well response measures. The precursor incidents can form the basis for developing relevant safety indicators. Stuck string, lost circulation, and shallow gas influx were experienced by the Deepwater Horizon rig in March 2010 (DHJIT, 2010). Investigation of the crew's response to those incidents could have revealed if the status of the procedures, competence, skills and management of the crew to handle well incidents were sufficient."[27]

Recommendation on Operators' Well Response. Based on the indicators identified for this area:

- Time from first indication of well incident to first response
- Evaluation of well response action (proper action taken?)

- Evaluation of follow-up action
- Time before normal conditions are established

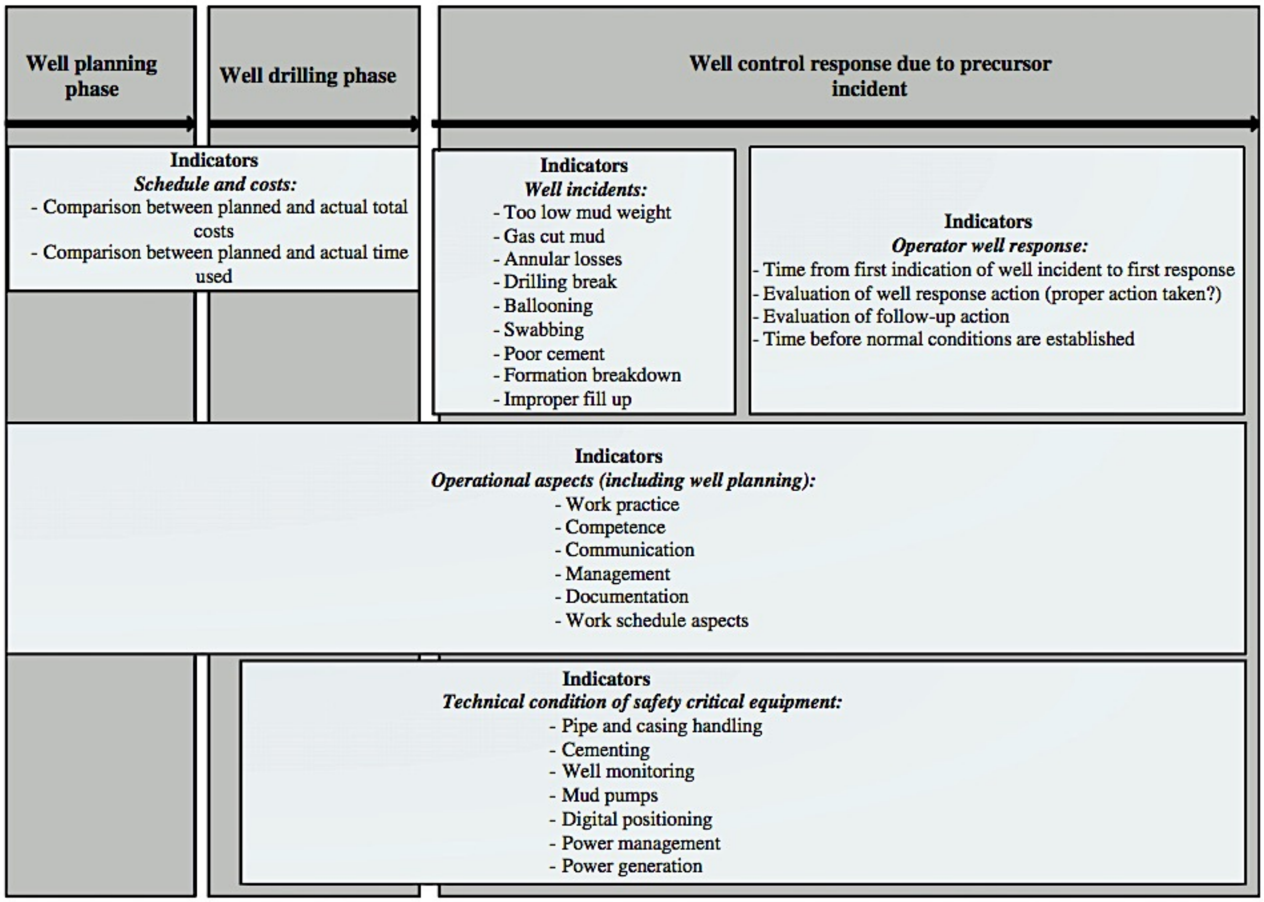

Figure 22. Suggested indicators for deepwater drilling presented by Skogdalen et al [27].

The recommendation is for the drillers to gain improved understanding of these indicators.[27]

Rationale: *"The time between the first ''signals'' of an undesired incident and subsequent well control actions is an indication of the crew's situation awareness, training, competence, and management. Data is recorded real time during drilling and it is therefore possible to analyze the time from the incident occurred until actions were taken and control of the well achieved. According to BP (2010), flow indications started approximately 51 minutes before the blowout on 20 April. The influx was not detected until the hydrocarbons had entered the riser, 40 min after the first influx. Real time data was available to the drilling crew (BP, 2010) who should, according to recommended practice, monitor changes to pit volume, flow rate, and pressures in order to identify potential flows and losses (API,* *2010a). During the afternoon, mud was offloaded to the nearby supply vessel, and some pits were being cleaned and emptied. These operations reduced the ability to monitor changes to the pits' levels. In addition, preparations for the next completion operations were carried out, such as preparing for setting the plug in the casing after replacing with seawater. BP's own investigation report (BP, 2010) states that apparently pit volumes were not effectively monitored for the rest of the evening.*

The key operator skills are the operators' abilities to recognize patterns (relationships and trends) at the system level, and at the same time formulate specific contingency scenarios for what they are doing. Without these skills, the control room cannot tell what is abnormal or unusual. It is therefore of importance to reveal the precursor zone. In this zone the operators are not longer clear on what actions of theirs could lead to accidents and failure (Roe and Schulman, 2010). Sometimes new software or hardware itself can limit their control options and thus their ability to cope with the unforeseen (Roe and Schulman, 2008). The principles of the precursor zone can be compared to other theories like Resilience Engineering (Hollnagel et al., 2006, 2008) and High Reliability Organizations (Roberts and Bea, 2001) in terms of revealing the limits and fundamental principles for safe operations."[27]

Recommendations on related to Operational Aspects. Based on the indicators identified for this area:

- Work practice
- Competence
- Communication
- Management
- Documentation
- Work schedule aspects

The recommendations are:

- To enable an operator to do the proper well response (within the incidents and undesired events zone), the technological system must be designed and function according to intention. [27]
- Use the Operational Conditional Safety (OTS) as a means for measuring the changes over time in the level of operational safety as the result of actions taken. The results can be recorded over time, and used as a basis for developing safety indicators.[27]
- Recognize that the operational aspects are also very much determined by the well design. Deepwater wells in the GoM require a high degree of investigation, conceptualized during the planning and design, and communication with a larger team for longer periods of time.[27]

Rationale: *"Typical problems that occur if time is not spent on well design and planning are, for example, lack of knowledge of overall geology and basin mechanics, not understanding the production profile of the target zone, the design philosophy of previously drilled wells, or reasons for why previous wells got in trouble, and cost sensitivity mentality (Shaughnessy et al., 2003)."[27]*

- Extensive data should be documented during the drilling process, such as current well status, purpose of well, temperature, pore pressure and formation strength prognosis, and design life requirements.[27]

Rationale: *"This is important data that can be used for well planning of following wells in the same area. The current situation is that critical operational issues for managing these fields are stored on a large volume of Excel files, disorganized acquisition, and that there is minimal sharing of the different sources of available data (Velazquez et al., 2010). The Macondo well was originally planned as an exploration well, but the well turned out to be so successful it was decided to transform it into a keeper well for later production. This requires a different well completion procedure, such as installation of a production casing (DHJIT, 2010). The original well design consisted of eight casing strings, but with the production casing, the total number became nine (BP, 2010)."[27]*

- Uncertainty is a critical issue that should be addressed during well planning, and a review upon completion reveals to which extent the uncertainties were sufficiently attended to during the planning phase. In addition, a collection of data on well planning across companies may indicate if the well design, assumptions, and uncertainties for similar types of wells are encountered differently between the operators, and are sufficiently described.[27]

Recommendations on the Technical Condition of Safety Critical Equipment. Based on the indicators identified for this area:

- Pipe and casing handling
- Cementing
- Well monitoring
- Mud pumps
- Digital positioning
- Power management

- Power generation

The recommendation is to actively assess and communicate the conditions of critical safety technical barriers and the Technical Safety Condition Systems TTS. Reviewing maintenance, inspection and design.[27]

Rationale: *"On the Deepwater Horizon rig, the BOP did not isolate the well before and after the explosions. The BOP may have been faulty before the blowout or it may have been damaged due to the accident. According to BP, several maintenance jobs of the BOP were overdue, and leaks from the hydraulic control system had been discovered at the time of the accident (BP, 2010). The BOP on the Deepwater Horizon was not re-certified in accordance with federal regulations because the certification process would re- quire full disassembly and more than 90days of downtime (DHJIT, 2010). According to a testimony (DHJIT, 2010) the crew onboard the rig was struggling with the chairs used for controlling the drilling functions. There were three chairs: A–C. These chairs control everything, such as top drive, mud pumps, and hydraulics, but the computers had locked up so no data could go through the system. A new system was ordered, but they could not make the old software run correctly on the new operating system. This means that at times they would lose track of what was going in the well."[27]*

Learning from the BP Deepwater Horizon accident: risk analysis of human and organizational factors in negative pressure test.

By Maryam Tabibzadeh and Najmedin Meshkati (Environment System Decision (2014) 34:194–207 DOI 10.1007/s10669-014-9497-2).

The authors of this paper introduce a three-layer, conceptual risk analysis framework used to assess the critical role of human and organizational factors in conducting and interpreting a negative pressure test, although they assure that the framework can be applied for the risk analysis of any high-risk operation. The result of the analysis establishes that organizational factors are root causes of accumulated errors and questionable decisions made by personnel or management. It also identifies procedural issues, economic pressure, and personnel management issues as the organizational factors with the highest influence on misinterpreting a negative pressure test, and leading to accidents in offshore drilling in general. The risk analysis framework consists of three main layers (Figure 23). The bottom layer, the physical states of the system, shows the system-related factors influencing the misinterpretation of a negative pressure test. The second layer indicates decisions or actions made by crew or management, which affect the results of the NPT directly or indirectly. And, the top layer includes the root organizational factors influencing the decisions or actions displayed in the middle layer.[29]

Recommendations at the Organizational Level

- All the parties involved in engineering and operations activities should follow the management of change (MoC) processes.[29]

Rationale: "BP developed a systematic, risk-based process called MoC as part of its operation integrity and risk management program in order to document, evaluate, approve, and communicate changes. This process was part of the BP golden rules, which requires that ''work arising from temporary and permanent changes to organization, personnel, systems, process, procedures, equipment, products, materials of substances, and laws and regulations cannot proceed unless a MoC process is completed.'' (Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) report 2011, pp. 179 and 192).

Despite the company careful documentation for the MoC processes, the DWH team did not use this process as their change management tool for the day- to-day changes in the drilling operations (BOEMRE report 2011, p. 179). Two of the main examples regarding not considering the MoC processes, which are related to the negative pressure test results, are last minute changes to the negative pressure test procedure and last minute changes of the personnel.

Although the referenced instances in failure to follow management of change processes are related to the conducted negative pressure test in the Deepwater Horizon, this category of organizational factors can be influential in analysis of any NPT. In addition, management of change has been introduced as one of the main management system practices for offshore drilling safety in a comprehensive study based on analysis of several offshore drilling accidents (de Morais and Pinheiro 2011). Therefore, failure to follow MoC processes can be a generalized organizational factor, which contributes to system failure."[29]

Recommendation on Economic Pressure

- BP should revaluate the production versus safety organizational emphasis.[29]

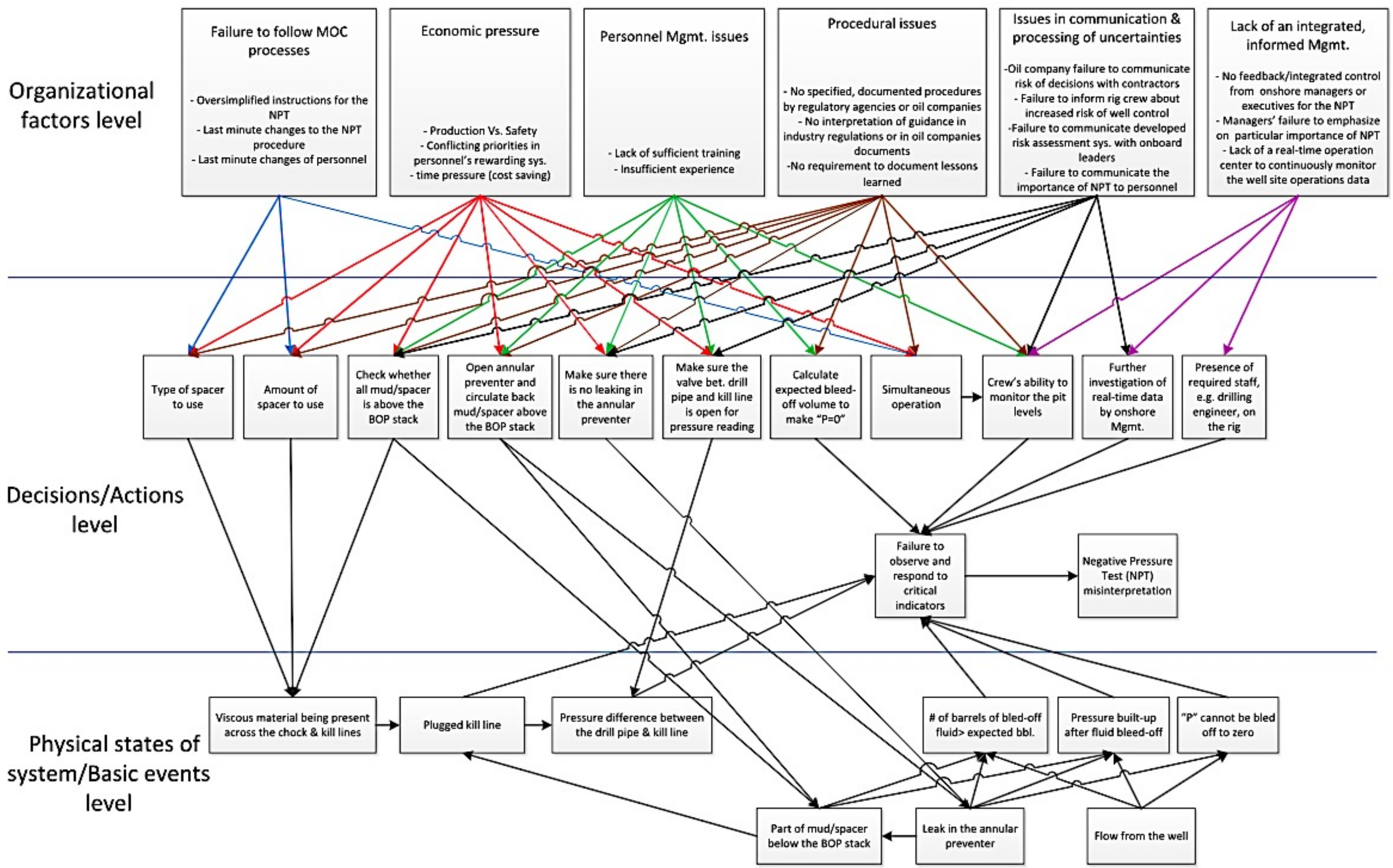

Figure 23. Three-layer conceptual framework to analyze the contributing causes of a negative pressure test misinterpretation.

Rationale: *"According to the BOEMRE report (2011, p. 184), there is evidence showing that the performance of BP personnel was reviewed, at least in part, based upon their ability to control or reduce cost, and they were compensated based on that. This issue existed while there was no comparable performance measure for the occupational safety achievements."[29]*

- Transocean should redefine their personnel's rewarding system to avoid conflicting priorities. [29]

Rationale: *"According to the BOEMRE report (2011, p. 189), Transocean policy of rewarding personnel introduced conflicting priorities when it tried to maintain safe operations. In addition, it created risk of compromising safety in making operational decisions."[29]*

- BP should have appropriate contingencies and mitigations (BOEMRE report 2011, p. 199) for cost and time saving plans.[29]

Recommendations on Personnel Management

- Both BP and the Transocean training programs should include sufficient well controlling issues to address situations such as negative pressure tests and displacement operations.[29]
- The MMS (Mineral Management Service) should specifically require trained personnel on well control procedures in oil and gas operations at all times.[29]

Recommendations on Procedures

- The MMS should provide a documented procedure with clear regulations for negative pressure tests in offshore oil prospects.[29]
- BP and Transocean should also establish standard procedures for the negative pressure tests. In addition, such standard should include interpretation guidance.[29]
- The MMS should require a detail documentation and divulgation of lessons learned.[29]

Recommendations on Communication and Processing Uncertainties

- BP should improve its communication channels with Transocean to reduce operational risks.[29]
- BP and Transocean should inform the rig crew about the increased risk of the well control.[29]
- BP should communicate its developed risk assessment system with the onboard leaders.[29]
- BP should communicate the importance of the negative pressure test to the rig personnel.[29]
- BP and Transocean should actively encourage an effective communication between the driller and the mudlogger to properly monitor the well.[29]

Recommendations on Integrated and Informed Management

- BP and Transocean should establish systematic feedback component from onshore managers or executives to onboard crew in order to inform them about the risk of specific decisions regarding critical operations, like the Negative Pressure Test, or to monitor the progress of conducting such test in a real-time manner. Existence of such integrated management system is crucial to safety of any other high-risk operation as well.[29]

Rationale: *"This issue was the main cause of actions like no further investigation of real-time data by the onshore management. Any of these issues could have had a positive effect on recognizing the anomalies of the negative pressure test and evaluating the results in a more appropriate way."*

- BP should consider the implementation of a real-time operation center to continuously monitor the well site operations data.[29]

Rationale: *"According to the NAE/ NRC report (2011, p. 28), the data from the rig was being recorded onshore, but there was no continuous monitoring of those stored data. Had BP arranged a continuous monitoring of the real-time data, the management would have high likely recognized failure in the negative pressure test and taken appropriate control actions."[29]*

The Deepwater Horizon explosion: non-technical skills, safety culture, and system complexity.

By Tom W. Reader[a] and Paul O'Connor[b] (Journal of Risk Research, 2014 Vol. 17, No. 3, 405–424)

[a]London School of Economics, Institute of Social Psychology, London, UK; [b]Department of General Practice, National University of Ireland, Galway, Ireland.

In this paper published in the Journal of Risk Research, the authors systematically address the operational and underlying safety management issues that led to the Macondo Accident within a human factors framework. First, they apply non-technical skills (NTS) (social and cognitive skills that underpin safe performance in complex work environments) theorem to understand operational activities in the lead-up and occurrence of the well blowout. NTS research is used to develop interventions for training and observing safety behaviors (e.g. decision-making, teamwork). Then, they apply safety culture theory to understand how the organizational and industry environment shaped the management of risk. Safety culture research is used to understand and change the socio-technical constraints and enablers of safety activity in high-risk workplaces. Finally, to integrate these perspectives, they take a systems-thinking approach to understand the accident. Their findings are presented in the model in Figure 24.[25]

Recommendations on Cognitive/individual Factors

- Interventions to improve decision-making, risk awareness, and situation awareness problems offshore could focus on improving the decision-making skills of operators (e.g. through systemizing thinking, or refining communication skills), and information collection and presentation techniques. They could also focus on improving formal risk assessment procedures, and training for staff to recognize problematic patterns and trends indicating uncertainty (Skogdalen, Utne, and Vinnem 2011). However, considering the highly social nature of work offshore, it is unlikely that interventions will be individual-focused, and they must reflect social influencers of activity. Specifically, team social awareness research shows the importance of considering social dynamics in group assessments of risk (Reader et al. 2011).[25]

Recommendations on Team Factors

- Crew Resource Management style-training is used to train control-room operator decision-making competences during emergencies (Flin 1995), teamwork skills in offshore production teams (O'Connor and Flin 2003), and group decision-making in deepwater exploration teams (Crichton 2009). Yet, these focus on quite specific problems and situations, and mishap research shows that problems in team and leadership communication often reflect aspects of safety culture.[25]

Rationale: *"The finding that teamwork and leadership problems contributed to the DH mishap is highly consistent with offshore safety research. The Cullen (1990) report highlights similar issues leading to the Piper Alpha explosion in the North Sea in 1988, with effective communication and leadership within teams and across shifts (and companies) recognized as essential for preventing mishaps. Teamwork was influenced by professional and social barriers (e.g. operational and contract, management and technical staff) that created divergent perceptions on risk and unclear lines of responsibility (Mearns, Flin, and O'Connor 2001)."[25]*

Recommendations on Production/Cost-Savings Pressure

- Revise and improve overall safety culture.[25]

Rationale: *"The DH investigation identifies production vs. safety pressures as underlying decision-making and operational behavior. This is the classic indicator of safety culture (Flin et al. 2000), and although the Macondo well was not active, the deep-sea drilling operation was highly expensive and pressure to ensure progression existed. Many of the riskier operational decisions were made due a desire to save time, costs, or ensure long-term viability of the well, and "without full appreciation of the associated risks" (National Oil Spill Commission 2011, 223). It was believed by crew members that operations could only be stopped if there was deemed to be an immediately threat to their own personal safety, rather than a threat to the integrity of the drilling operation itself (Hopkins 2011). Furthermore, a survey of the Transocean crew prior to the incident found some employees to fear reprisals for reporting unsafe situations, and others felt staff shortages were limiting work completion. This reflects safety culture research in the offshore oil and gas industry, with the risk assessment and safety behaviors of offshore workers being shaped by beliefs regarding organizational prioritization of safety, training, knowledge of safety, the regulatory environment, and organizational culture (Mearns, Whitaker, and Flin 2001). Along- side the typical production-safety pressures found in safety culture investigations, the report also identifies a number of other manifestations of poor safety culture."[25]*

Recommendations on Industry Standards and Regulation

- Introduce safety cases in the United States in a manner similar to the BP North Sea (National Oil Spill Commission 2011). Ideally, this would result in organizations outlining their safety management systems and procedures in greater detail, alongside changing perceptions on the prioritization of safety and production.[25]

Rationale: *"The role of the regulator is critiqued by the DH investigation. Effective regulation shapes offshore safety culture through creating expectations and norms on safety management (Cox and Cheyne 2000; Taylor 1979). The MMS lacked the staff, resources, technical expertise (e.g. growing awareness on the increased likelihood of blowout preventer failures in Deepwater conditions (National Oil Spill Commission 2011, 74)), decision-making autonomy, and political influence to regulate safely. Senior officials focused on maximizing 'revenue from leasing and production'. This impacted upon safety culture through the following mechanisms. First, the quality of external inspections were often less rigorous than internal safety audits, focusing on quantity rather than quality (National Oil Spill Commission 2011, 78). Inspectors did not ask 'tough questions' and avoided reaching conclusions that would increase regulation or costs (National Oil Spill Commission 2011, 126). Second, contingency planning for DH disaster scenarios was inadequate (National Oil Spill Commission 2011, 84), and there were 'no meaningful' regulations for testing cement, managing well-cementing, or conducting negative-pressure tests (National Oil Spill Commission 2011, 228). Where guidelines were available (e.g. depths for installing cement plugs), exclusions were accepted. The above issues in regulation are seen as contributing to an environment where production was prioritized over safety; an underlying cause of the DH mishap.*

The lack of 'safety cases' is seen as emblematic of the poor industry-wide safety culture within which the DH operated. Safety cases involve operating companies validating the effectiveness of their installation safety management systems through demonstrating that hazards have been mitigated to 'as low as reasonably practicable'."[25]

Recommendations on Communication Culture between Operational, Management, and Contract Staff

- Relevant organizations must share or emphasize information on previous near-misses to reduce the likelihood of future blowout. Regulators should encourage and aid companies in this process.[25]

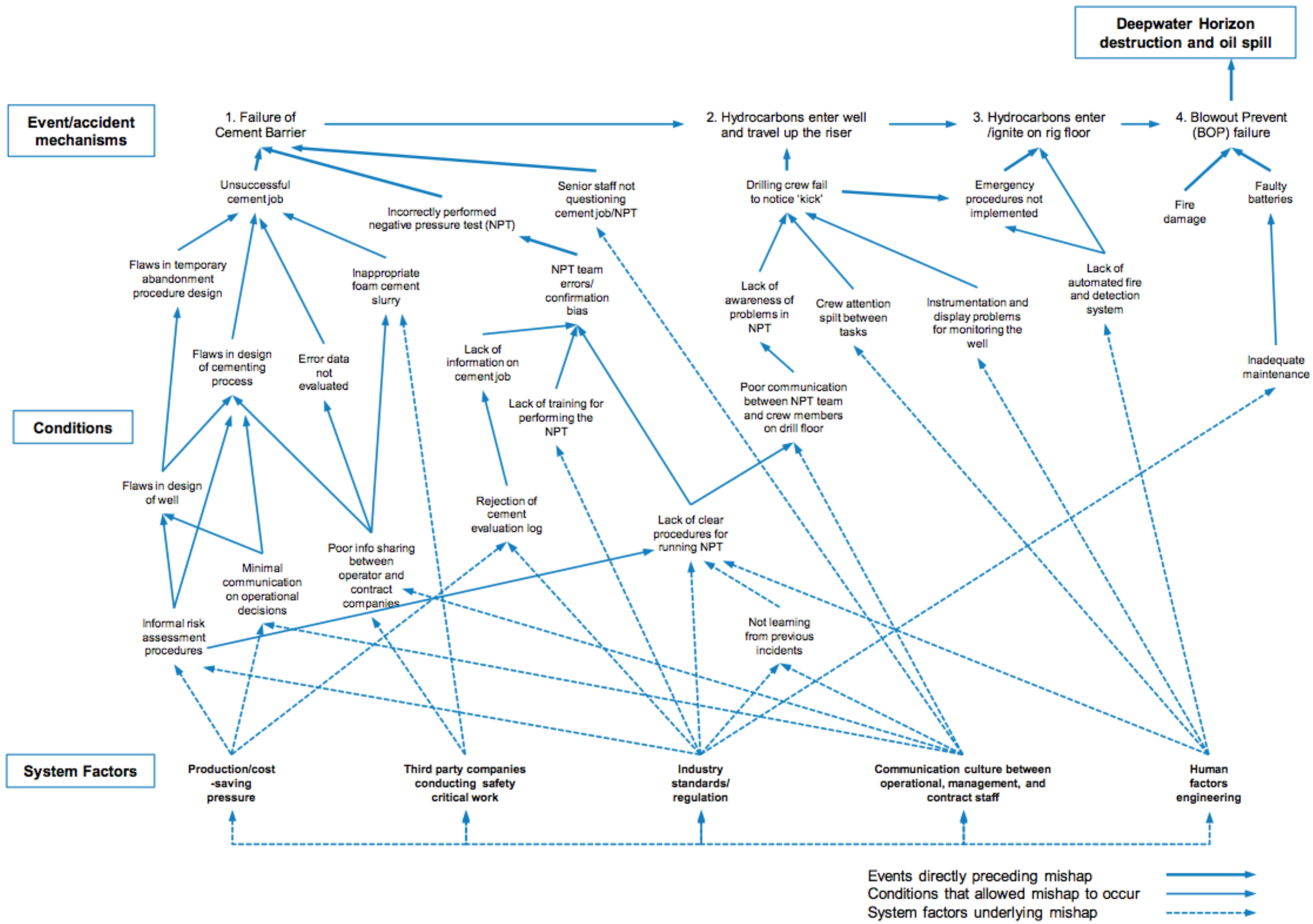

Figure 24. Model of the interactions, conditions and system factors leading to the Macondo accident, by Reader et al.

Rationale: *"Learning from incidents is key to safety culture (Mearns et al. 2013), and several directly relevant incidents from within BP and Transocean were not learned from or incorporated into best practice guidelines for operator staff (National Oil Spill Commission 2011, 219). For example, a gas line rupture on a North Sea BP platform, and the focus on lost-time-incidents (rather than process safety) prior to the Texas City refinery explosion. Crucially, a similar failure on a North Sea Transocean rig (involving condensate release after a 'successful' NPT) was not taken into account on the DH (National Oil Spill Commission, 2011, 124). Regulators play a key role in aiding companies to learn from cross-industry failures (e.g. through inspection), and the Minerals Management Service (MMS) is critiqued for its lack of effectiveness."[25]*

Recommendations on Human Factors Engineering

- There must be adequate staff training for enabling staff to manage and respond to emergency and safety-related situations.[25]
- Safety-critical tasks requiring vigilance for long shifts must be covered by sufficiently rested personnel. Safety manuals must be understandable and reflective of the working environment, and must provide adequate guidance for safety-critical tasks (e.g. negative-pressure-test).[25]
- Systems engineering must be considered in the improvement and design of human-computer interfaces for monitoring equipment, and automated emergency response systems.[25]

Rationale: "The DH investigation highlights the problems in human factors engineering underlying the incident. The extent to which organizations consider and engineer systems to cope with human factors problems is highly symptomatic of safety culture. Human factors management in a number of areas on the DH was seen as poor. First, in terms of training, there was inadequate staff training for enabling staff to manage and respond to emergency and safety-related situations. Second, in terms of human performance limitations, operators performed safety-critical tasks requiring vigilance for long shifts, despite the effects of fatigue and unfavorable comparisons with safety regulations in other national environments (National Oil Spill Commission 2011, 225). Safety manuals were overly complex and unreflective of the working environment, and did not provide adequate guidance for safety-critical tasks (e.g. negative-pressure-test). Third, systems engineering was not optimal in a number of areas, in particular the design of human-computer interfaces for monitoring equipment, and automated emergency response systems."[25]

4.2 Comparison to CAST

While the focus of these approaches is the identification of leading indicators, CAST focuses in understanding the system and finding its weaknesses. CAST provides a safety control structure with defined safety responsibilities and control interactions, which results in much more detailed role-specific recommendations. From this approach, leading indicators and general recommendations can also be identified and can be compared to those of other studies, although no framework to backtrack and model the origin of these indicators is used.

Table 16 contains a summary of the recommendations presented in the three analyses picked for comparison. Common recommendations across the CAST of the Macondo accident and these analyses include: the use of automated monitoring and emergency systems, adequate training on well control and emergency response, sharing of lessons learned, improvement in regulations coverage and enforcement, reconsideration of cost vs. safety prioritization, adherence to formal risk assessment and management of change procedures, and a revision of the safety culture of the companies involved in the accident.

In this case, the majority of the recommendations from the three analyses were covered by CAST, with the exception of the use of federal and public pressure to make organizations improve their safety management systems and change their perceptions on the prioritization of safety and production, the allocation of rested personnel for safety-critical tasks requiring vigilance for long shifts, and the improvement of safety manuals and guidelines. The last two recommendations were addressed in this analysis in a different way. The lack of personnel was identified more strongly within BP Engineers and Team Leaders in Operations, who appeared to have been overworked by the time of the accident, as opposed to the Transocean crew monitoring the mud displacement who had been working for three hours after a 12-hour rest when the blowout happened. As for the manuals and guidelines, while the continuous improvement of them is key, their absence was the issue in Macondo; there were no regulation, standards or procedures for certain non-drilling yet critical operations that highly contributed to the blowout. The suggestion on public pressure was not considered.

For its part, this CAST analysis identified recommendations that none of the other three analyses did, such as:

- Reconsidering the integration of the Safety Management System (SMS) and the Business Management System (BMS). The SMS is under the BMS and therefore the conflict between cost and safety prioritization and the confusion for the managers. This could explain why the implementation of the company's number one priority, safety, was not clear to them and why they were hesitant to disseminate new risk assessment plans and existing tools within the teams.

- Examining the confusion between personal safety and system safety. Ensuring the methods to validate both are clearly defined and differentiated from one another.
- Avoiding the underestimation of risks and the denial of loss of well-control signals; instead, looking for these signals constantly and investigating them thoroughly. Keeping a vigilant mindset during non-drilling, yet critical, operations, and being aware of the active barriers of the well at all times.
- Rigorously planning organizational changes; avoiding impacts on unfinished projects and providing resources to ensure proper handover of safety responsibilities, in particular when positions are eliminated.
- Considering exclusive Project-Specific Management positions, independent of Engineering and Operations, through which performance priorities can be easily settled *in pro* of the project and the integrity of the well.
- Validating designs with in-house and contractors' experts, to determine the impact in well integrity and the risks associated with the input of cross-functional teams.
- Examining condition-based maintenance policies used by contractors and assuring their compliance with regulations and standards.

Table 16. Summary of other analyses.

Type of Recomm.	Skogdalen et al.[27]	Tabibzadeh & Meshkati [29]	Reader & O'Connor [25]
Technical	· Technological system must be designed and function according to intention. · Actively assess and communicate the conditions of critical safety technical barriers and the Technical Safety Condition Systems TTS. Reviewing maintenance, inspection and design.	· BP should consider the implementation of a real-time continuous monitoring.	· Systems engineering must be considered in the improvement and design of human-computer interfaces for monitoring equipment, and automated emergency response systems.
Management	· Refine the comparison between planned and actual total costs and time, and include safety issues in allocation of these	· All the parties should follow the MoC processes. ·BP should have contingencies and mitigations for cost and time	· Improve: the decision-making skills of operators, the information collection and presentation techniques, formal

	resources. · Improve the understanding of well control indicators. · Use the Operational Conditional Safety (OTS) to measure the changes over time in the level of operational safety. · Minimize uncertainty through well planning and industry collaboration.	saving plans. · Both BP and Transocean trainings should include well control issues. · BP and Transocean should establish standard procedures and interpretation guidance for non-regulated ops. BP should improve its communication channels with contactors. · BP and Transocean should establish systematic feedback components between onshore to offshore for decision-making processes.	risk assessment procedures, and training for staff to recognize problematic patterns and trends indicating uncertainty. · Use Crew Resource Management style-training. · Relevant organizations must share and emphasize information on previous near-misses to reduce the likelihood of future blowout. · Provide adequate staff training for enabling staff to manage and respond to emergency and safety-related situations. · Provide sufficiently rested personnel for safety-critical tasks requiring vigilance for long shifts. · Safety manuals must be understandable and reflective of the working environment, and must provide adequate guidance for safety-critical tasks
Regulation	· Actively report to the authorities.	· The MMS should require trained personnel on well control procedures. · The MMS should provide documented procedure with clear regulations for non-regulated ops. · The MMS should require detail documentation and divulgation of lessons learned.	· Use federal and public pressure to accelerate the migration to organizations outlining their safety management systems and procedures in greater detail, alongside changing perceptions on the prioritization of safety and production. · Regulators should encourage and aid companies to actively share lessons learned.
Safety Culture		· BP should revaluate the production versus safety organizational emphasis. · Transocean should redefine their personnel's rewarding system to avoid conflicting priorities.	· Revise and improve overall safety culture.

5. CONCLUSIONS

A CAST analysis of the Macondo accident was carried out and reviewed with input and review from current members of similar systems. The outcome was a series of management recommendations for oil and gas offshore systems based on the blowout.

The quality of the CAST analysis improved significantly after the second iteration. It was beneficial to base the first CAST analysis on the most comprehensive investigation report available, in this case the Chief Counsel's Report, and then complement it with other reports and interviews. Including several reports helped to clarify the technical aspects of the accident, while interviewing people with understanding of the system complemented the unsafe control actions and the process model flaws sections.

The first iteration of the CAST analysis was successfully reviewed with managers currently associated with BP and Transocean. It is important to highlight though, that around 25 people were contacted and only six agreed to collaborate with this analysis; no one from U.S. regulatory agencies contributed.

The scope of the analysis was delimited based on the resources available, nevertheless the fundamentals of the CAST analysis were defined for the entire accident in hope that further study of the subsystems are studied too.

The vast amount of information proved to be a challenge in avoiding redundancy and assuring clarity in this final document. Having an organizational structure of the companies and organizations involved and combining some roles with equal or equivalent safety roles proved to streamline the process; nevertheless actions to continue facilitating the processing of information should be considered in the future.

Through the comparison to three published analyses focused on the management system of the Macondo accident, it was possible to determine that this CAST analysis indeed led to alternative management recommendations. The points that it was able to exclusively cover were mainly related to the safety management system and the organizational structure of the company at the time of the blowout. None of the listed recommendations in Chapter 4 were contemplated by the other analyses and are considered of vital importance for the improvement of the overall safety system of BP.

Leading indicators and general recommendations were easily gathered after synthetizing the analysis of each human controller defined in the safety structure. The indicators derived from the concurrent unsafe control actions and decisions of the controllers in the same level of hierarchy and the general recommendations were developed based on them.

In general, CAST analyses offer a comprehensive approach to complex accidents and results in applicable recommendations for the parties involved. During the interviews, what collaborators found most useful were the safety control structure and the definition of safety roles. These system-theory-based tools, as opposed to system dynamic loops, were easily understood and more appealing to the uneducated eye. Just seeing them and without extensive education or training resulted in their being able to identify points for improvement.

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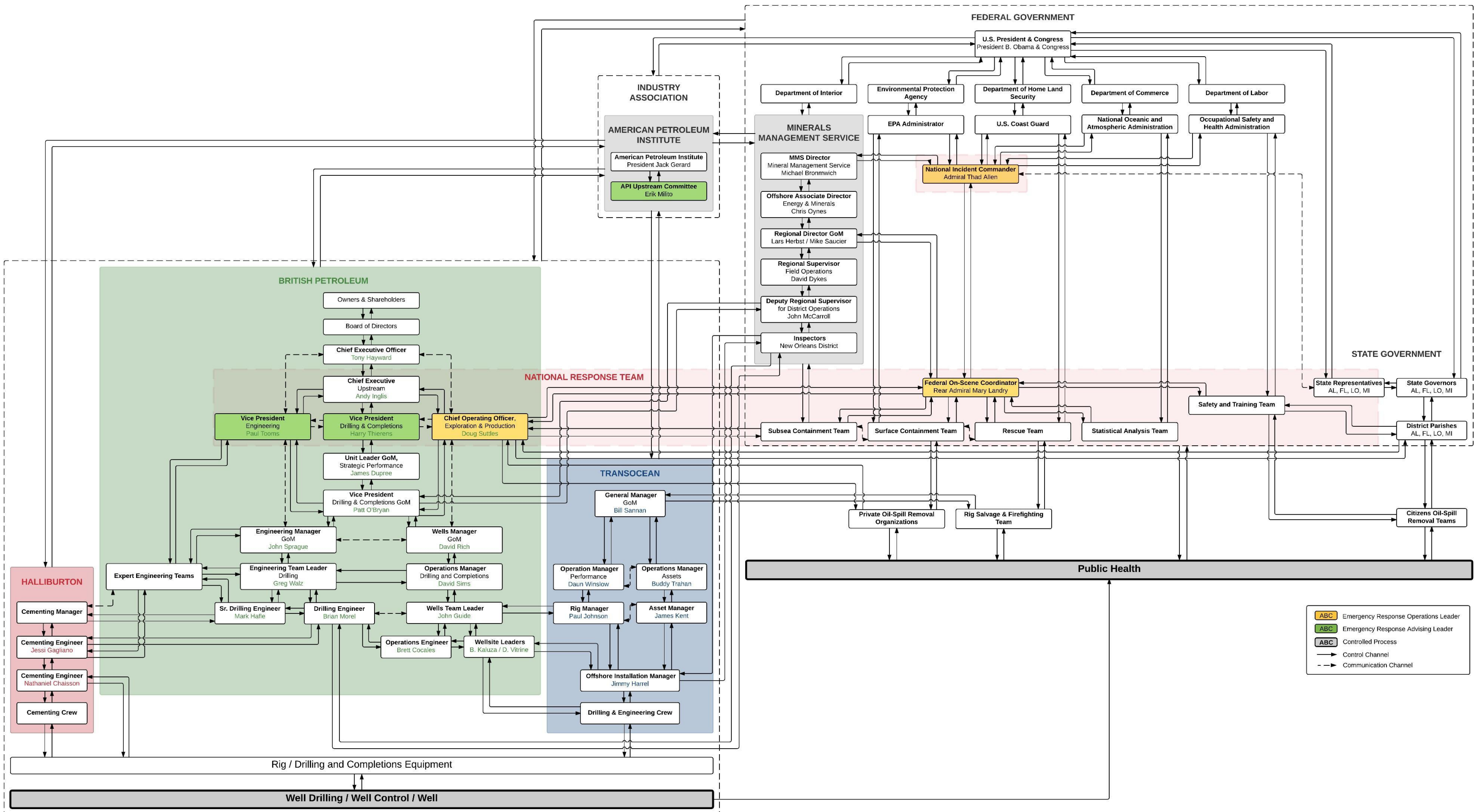
APPENDIX A

Organizational Structure of the Macondo Accident



FEDERAL GOVERNMENT
U.S. President & Congress
President B. Obama & Congress
Department of Interior
Environmental Protection Agency
Department of Home Land Security
Department of Commerce
Department of Labor
EPA Administrator
U.S. Coast Guard
National Oceanic and Atmospheric Administration
Occupational Safety and Health Administration
National Incident Commander
Admiral Thad Allen
MINERALS MANAGEMENT SERVICE
MMS Director
Mineral Management Service
Michael Bromwich
Offshore Associate Director
Energy & Minerals
Chris Oynes
Regional Director GoM
Lars Herbst / Mike Saucier
Regional Supervisor
Field Operations
David Dykes
Deputy Regional Supervisor
for District Operations
John McCarroll
Inspectors
New Orleans District
STATE GOVERNMENT
State Representatives
AL, FL, LO, MI
State Governors
AL, FL, LO, MI
District Parishes
AL, FL, LO, MI
NATIONAL RESPONSE TEAM
Federal On-Scene Coordinator
Rear Admiral Mary Landry
Safety and Training Team
Subsea Containment Team
Surface Containment Team
Rescue Team
Statistical Analysis Team
Private Oil-Spill Removal Organizations
Rig Salvage & Firefighting Team
Citizens Oil-Spill Removal Teams
Public Health
INDUSTRY ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
American Petroleum Institute
President Jack Gerard
API Upstream Committee
Erik Milito
BRITISH PETROLEUM
Owners & Shareholders
Board of Directors
Chief Executive Officer
Tony Hayward
Chief Executive
Upstream
Andy Inglis
Vice President
Engineering
Paul Tooms
Vice President
Drilling & Completions
Harry Thierens
Chief Operating Officer,
Exploration & Production
Doug Suttles
Unit Leader GoM,
Strategic Performance
James Dupree
Vice President
Drilling & Completions GoM
Patt O'Bryan
Engineering Manager
GoM
John Sprague
Wells Manager
GoM
David Rich
Expert Engineering Teams
Engineering Team Leader
Drilling
Greg Walz
Operations Manager
Drilling and Completions
David Sims
Sr. Drilling Engineer
Mark Hafle
Drilling Engineer
Brian Morel
Wells Team Leader
John Guide
Operations Engineer
Brett Cocales
Wellsite Leaders
B. Kaluza / D. Vitrine
TRANSOCEAN
General Manager
GoM
Bill Sannan
Operation Manager
Performance
Daun Winslow
Operations Manager
Assets
Buddy Trahan
Rig Manager
Paul Johnson
Asset Manager
James Kent
Offshore Installation Manager
Jimmy Harrel
Drilling & Engineering Crew
HALLIBURTON
Cementing Manager
Cementing Engineer
Jessi Gagliano
Cementing Engineer
Nathaniel Chaisson
Cementing Crew
Rig / Drilling and Completions Equipment
Well Drilling / Well Control / Well
ABC Emergency Response Operations Leader
ABC Emergency Response Advising Leader
ABC Controlled Process
Control Channel
Communication Channel

APPENDIX B

After a first iteration of the CAST analysis presented in this thesis, personnel from BP and Transocean were contacted in order to clarify the organizational structure, unsafe control actions and potential process model flaws that were not clear from the information available in the investigation reports. To protect the identity of the collaborators only their roles are mentioned along with the questions that they answered. Their input is presented in Chapter 3: Steps 6 through 9 of the CAST analysis.

BP Personnel Interviewed

Health and Safety Team Leader – BP Offshore

Interview Date: March 14th, 2017

Interview Duration: 45 minutes

Material Review Questions:

- Could you please verify the organizational structure prepared in this analysis?
- Could you please read and comment on the unsafe control prepared in this analysis?

Analysis Questions:

In the Macondo context:

- How were safety responsibilities assigned in BP? When? By whom? What happened when they changed? Who controlled that? How were they assigned to contractors? Why?
- What were the roles of the teams on the rig? What were their safety responsibilities?
- What were the roles of the managers onshore? What were their safety responsibilities?
- What was the difference between personal safety and system safety?
- Was everyone accountable for safety?
- How was the training for special operations, such infrequent tests or blowouts response, planned? Who was accountable for that? Were there certifications for these operations? Who provided them? Who approved them?

- How were lessons learned shared? How was that transference across different segments and business units? Why? How fast was the process? What communication channels were more effective? Why?
- What was considered the worst catastrophe for BP in 2010? For the Macondo team?
- How were hazards identified? What method was used for hazard analysis? Did all teams follow the same approach? Why or why not?
- How was the risk assessment process? What method was used? Who dis it? How big was the team and why?
- How were simultaneous operations handled in offshore platforms? Why were they allowed at all? Why were they allowed during non-drilling operations?

Safety Team Lead – Operations and Health

Interviews Dates: March 25th, 2017

Interviews Duration: 60 minutes

Material Review Questions:

- Could you please verify the organizational structure prepared in this analysis?
- Could you please read and comment on the unsafe controls prepared in this analysis?

Analysis Questions:

In the Macondo context:

- How were safety responsibilities assigned in BP? When? By whom? What happened when they changed? Who controlled that? How were they assigned to contractors? Why?
- What were the roles of the teams on the rig? What were their safety responsibilities?
- What were the roles of the managers onshore? What were their safety responsibilities?
- Who determined adherence to regulations and corporate standards and procedures? Which ones were mandatory? Which ones were optional? Why?
- What was the difference between personal safety and system safety?
- Was everyone accountable for safety?
- How did BP handle personnel not reporting incidents? What were their motives? Why?

- How did BP handle leaders with aversion to consult others? What were their motives? Why?
- How were drilling performance and safety performance related? Why were they depending on one another?
- What was the "risk/reward equation"? Was it a common practice? Was it a formal standard? Who used it? Why?
- How was training for special operations, such infrequent tests or blowouts response, planned? Who was accountable for that? Were there certifications for these operations? Who provided them? Who approved them?
- How were lessons learned shared? How was that transference across different segments and business units? Why? How fast was the process? What communication channels were more effective? Why?
- What was considered the worst catastrophe for BP in 2010? For the Macondo team?
- Who was in charge of detecting a kick? Why?
- How were hazards identified? What method was used for hazard analysis? Did all teams follow the same approach? Why or why not?
- How was the risk assessment process? What method was used? Who did it? How big was the team and why?
- How were simultaneous operations handled in offshore platforms? Why were they allowed at all? Why were they allowed during non-drilling operations?
- What happened when Engineering was delayed and Operations had already started?
- Was there a project manager for each well? Why or why not? Who assumed this role?
- How often did Engineering and Operations met?
- How was new technology assessed? How was it incorporated into projects? How was the validation process? Who decides what tests were necessary? What was the contractor's role and expected input?

Safety Process Superintendent – Gulf of Mexico Unit

Interview Date: March 2nd, 2017; March 23rd, 2017; April 13th, 2017

Interviews Duration: 45 minutes, 60 minutes, 60 minutes

Material Review Questions:

- Could you please verify the organizational structure prepared in this analysis?
- Could you please read and comment on the unsafe controls prepared in this analysis?

Analysis Questions:

In the Macondo context:

- How were safety responsibilities assigned in BP? When? By whom? What happened when they changed? Who controlled that? How were they assigned to contractors? Why?
- What were the roles of the teams on the rig? What were their safety responsibilities?
- What were the roles of the managers onshore? What were their safety responsibilities?
- Who determined adherence to regulations and corporate standards and procedures? Which ones were mandatory? Which ones were optional? Why?
- What was the difference between personal safety and system safety?
- Was everyone accountable for safety?
- What did it mean to have safety as the number one priority? How was that implemented in BP? Why did this approach not help avoid Macondo?
- How were reorganization managed? Who decided the timing for them? Who decided which units were being restructured?
- How were teams with high personnel rotation handled?
- How was temporary personnel selected? What was done when no one had the necessary skillset?
- How was drilling performance measured? Why? Why not in terms of other metrics? What could have those metrics been?
- Who decided if a MoC was necessary or not? Why? Who should have *really* been deciding?
- Was the MoC process different in Engineering and Operations? Why?
- How were problems solved on the rig? Who had the last word? When should the Company Men have called to shore? How often should they have done it? Why?
- How did BP handle personnel not reporting incidents? What were their motives? Why?
- How did BP handle leaders with aversion to consult others? What were their motives? Why?
- How were drilling performance and safety performance related? Why were they depending on one another?

- What was the "risk/reward equation"? Was it a common practice? Was it a formal standard? Who used it? Why?
- Who led and integrated cross-functional teams in well projects?
- Did all procedures had to be planned and vetted by in-house experts at least?
- How was training for special operations, such infrequent tests or blowouts response, planned? Who was accountable for that? Were there certifications for these operations? Who provided them? Who approved them?
- How were lessons learned shared? How was that transference across different segments and business units? Why? How fast was the process? What communication channels were more effective? Why?
- What was considered the worst catastrophe for BP in 2010? For the Macondo team?
- Who was in charge of detecting a kick? Why?
- Who should have known how to control the well? Who was responsible and who was accountable?
- What happened to the personnel involved in the accident afterwards?
- How were hazards identified? What method was used for hazard analysis? Did all teams follow the same approach? Why or why not?
- How was the risk assessment process? What method was used? Who did it? How big was the team and why?
- Who reported anomalies to shore? Why?
- How were simultaneous operations handled in offshore platforms? Why were they allowed at all? Why were they allowed during non-drilling operations?
- How was onshore monitoring used? Why? Did it help? How did each team perceive it?
- Why were drilling activities at the end usually rushed?
- When was drilling considered successful?
- Was there cost and time pressure? Why or why not? How did each team perceive this pressure?
- What happened when Engineering was delayed and Operations had already started?
- How were delays in Operations handled? What had priority and why?
- Was there a project manager for each well? Why or why not? Who assumed this role?
- How often did Engineering and Operations met?

- Why did Operations not have formal design reviews with cross-functional teams like Engineering?
- How was new technology assessed? How was it incorporated into projects? How was the validation process? Who decides what tests were necessary? What was the contractor's role and expected input?
- What was riskier, getting stuck downhole or doing a remedial cementing job? Under what conditions was one scenario riskier than the other? Which one had more impact on well integrity and why? Who decided what had priority?
- Did inadequate centralization of a case string contribute to the blowout?
- What is foamed cement? How does it work? When is a reliable barrier and when not? Why did it not work at Macondo?
- Is temporary abandonment a critical operation? Why or Why not?

Transocean Personnel Interviewed

Deepwater Drilling Engineer

Interviews Dates: March 20th, 2017; April 17th, 2017

Interviews Duration: 60 minutes, 60 minutes

Material Review Questions:

- Could you please verify the organizational structure prepared in this analysis?
- Could you please read and comment on the unsafe controls prepared in this analysis?

Analysis Questions:

- How were safety responsibilities assigned in Transocean? When? By whom? What happened when they changed? Who controlled that? How were they assigned to contractors? Why?
- What were the roles of the teams on the rig? What were their safety responsibilities?
- What were the roles of the managers onshore? What were their safety responsibilities?
- Who determined adherence to regulations and corporate standards and procedures? Which ones were mandatory? Which ones were optional? Why?

- What was the difference between personal safety and system safety?
- Was everyone accountable for safety?
- How were hazards identified? What method was used for hazard analysis? Did all teams follow the same approach? Why or why not?
- How was the risk assessment process? What method was used? Who did it? How big was the team and why?
- Who reported anomalies to shore? Why?
- How were simultaneous operations handled in offshore platforms? Why were they allowed at all? Why were they allowed during non-drilling operations?
- What was riskier, getting stuck downhole or doing a remedial cementing job? Under what conditions was one scenario riskier than the other? Which one had more impact on well integrity and why? Who decided what had priority?
- Did inadequate centralization of a case string contribute to the blowout?
- What is foamed cement? How does it work? When is a reliable barrier and when not? Why did it not work at Macondo?
- Is temporary abandonment a critical operation? Why or Why not?
- Who was in charge of detecting a kick? Why?
- Who should have known how to control the well? Who was responsible and who was accountable?
- What happened to the personnel involved in the accident afterwards?
- Why during the blowout response hydrocarbons were directed to the mud gas separator and not overboard? Was that the normal procedure?
- What is condition-based maintenance? Is it still being used? Why or why not?
- How was the rig maintained? When? Where? By whom? How has that changed? Why?
- How were BOP's tested? What was tested? How often? By whom? How did they guarantee blowout control? How were they certified? What was certified? How often? By whom?
- Why did the BOP not shut in the well? What went wrong?
- Why did the rig crew wait to cut the pipe? Was that the procedure?
- How were offshore platform rigs updated? What had priority? Why? Was automated monitoring for drilling ever considered? Why or why not?

- How was instrumentation for open sea different from onshore instrumentation? Did the Deepwater Horizon had it? Why or why not?
- What happens when the rig crew is not fully aware of the operator's plans, or even worst when the crew does not know status of the well? How was that handled at Macondo?
- Why were drilling activities rushed at the end? Was that common?
- When was drilling considered successful?
- What happens when you lose a platform?

Subsea Operations Support Manager

Interviews Dates: March 17^{th}, 2017; April 25^{th}, 2017

Interviews Duration: 30 minutes, 45 minutes

Material Review Questions:

- Could you please verify the organizational structure prepared in this analysis?
- Could you please read and comment on the unsafe controls prepared in this analysis?

Analysis Questions:

- How were safety responsibilities assigned in Transocean? When? By whom? What happened when they changed? Who controlled that? How were they assigned to contractors? Why?
- What were the roles of the teams on the rig? What were their safety responsibilities?
- What were the roles of the managers onshore? What were their safety responsibilities?
- Who determined adherence to regulations and corporate standards and procedures? Which ones were mandatory? Which ones were optional? Why?
- What was the difference between personal safety and system safety?
- Was everyone accountable for safety?
- How were hazards identified? What method was used for hazard analysis? Did all teams follow the same approach? Why or why not?
- How was the risk assessment process? What method was used? Who did it? How big was the team and why?
- Who reported anomalies to shore? Why?

- How was training for special operations, such infrequent tests or blowouts response, planned? Who was accountable for that? Were there certifications for these operations? Who provided them? Who approved them?
- How were lessons learned shared? How was that transference across different segments and business units? Why? How fast was the process? What communication channels were more effective? Why?
- What was considered the worst catastrophe for BP in 2010? For the Macondo team?
- How were simultaneous operations handled in offshore platforms? Why were they allowed at all? Why were they allowed during non-drilling operations?
- What happens when the rig crew is not fully aware of the operator's plans, or even worst when the crew does not know status of the well? How was that handled at Macondo?
- Why were drilling activities rushed at the end? Was that common?
- When was drilling considered successful?
- What happens when you lose a platform?

APPENDIX C

Macondo BP RACI Chart

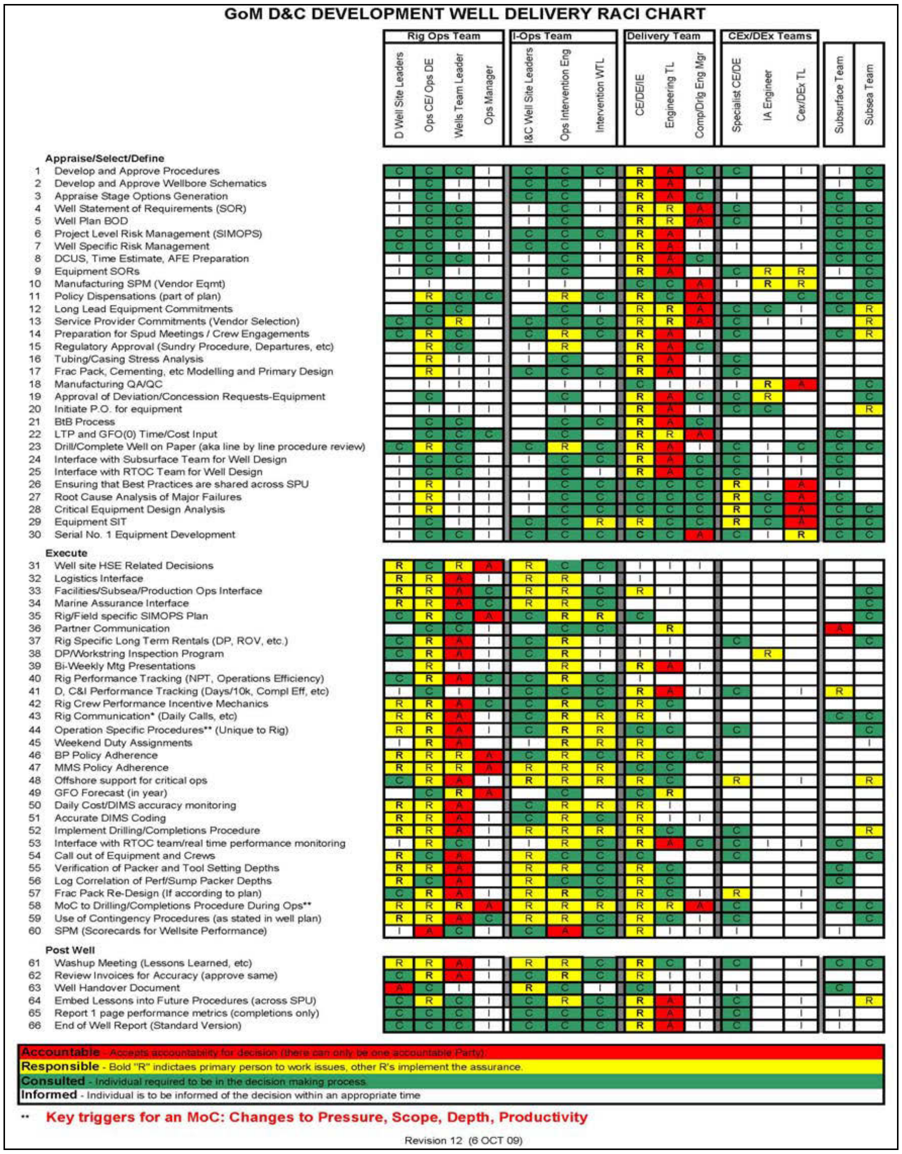


Figure 5: RACI Chart

Title of Document:	GoM D&C Operating Plan/ Local OMS Manual	**Document Number:**	2200-T2-DM-MA-0001
Authority:	Kevin Lacy	**Revision:**	0
Custodian/Owner:	Mark Webster	**Issue Date:**	11/1/2009
Retention Code:	AAA0000	**Next Review Date (if applicable):**	11/1/2010
Security Classification:	Project Confidential	**Page:**	Page 14 of 73
Warning: Check DW Docs revision to ensure you are using the correct revision.			

APPENDIX D

BP Risk-Register for the Macondo Well

- Risk-Register [33]
- Risk Rating Matrix [33]

Risk Register for Project: Macondo

Last Updated: 20-Jun-09

General									Last Update		Pre-Response					Post-Response				
R/O no.	Data Check	Risk or Opp.	Category	Risk/Opportunity Name	Event Description / Impact	Owner	Risk Status	Actions	By	Date	Impact Type	Impact Level	Prob.	Manageability	Rating	Impact Type	Impact Level	Prob.	Rating	Notes
1	OK	T	NDS	Well Control	Potential well control problem: risk of losing the wellbore in an uncontrolled situation	Mark Hafle	Accepted	0	Mark Hafle	17-Jun-09	Cost	Medium	Moderate	High	Mod.	Cost	Medium	Moderate	Mod.	Casing program design to mitigate issues.
2	OK	T	NDS	Complex overburden	Multiple shallow water flow units, faults & potential gas.	Craig Scherschel	Accepted		Mark Hafle	27-Apr-09	Cost	Medium	Low	Medium	Low	Cost	Medium	Very Low	V. Low	Picked the best location to mitigate the risk.
3	OK	T	NDS	PP/FG uncertainty	Drilling into pressure ramps unexpectedly or without proper mud weight or shoe test can cause a kick, fluid loss, and stuck pipe which lead to possible loss of hole section and/or well. Kicks identified in the offsets.	Marty Albertin	Accepted		Mark Hafle	27-Apr-09	Cost	Medium	Moderate	High	Mod.	Cost	Medium	Low	Low	
4	OK	T	NDS	Wellbore stability	Drilling through any salt/sediment interface may encounter problems with shales sloughing/slumping into the well bore	Mark Hafle	Dormant		Mark Hafle	27-Apr-09	Cost	Low	Low	Medium	V. Low					Primarily a risk with salt exit. We chose a location without salt. EPTG wellbore stability study to determine if minimum MW will cause wellbore breakout / instability
5	OK	T	NDS	Tight hole, stuck pipe	Offset well (Rigel) encountered problems with stuck pipe at 8900'.	Mark Hafle	Accepted		Mark Hafle	27-Apr-09	Cost	Medium	Low	Medium	Low	Cost	Medium	Low	Low	We are aware of it and will monitor the situation while drilling. This entails sidetracking the well. Conditioning trip will be made prior to running casing. Weight vs depth will be monitored to help decision in pulling casing. Decision tree on way for
6	OK	T	NDS	Mass Transport Deposits (MTD)	Can be shallow water flow units when buried deeper than about 500 ft in deepwater settings, may be over pressured. May have quite variable soil properties. Not ideal strata to set casing shoe. Evaluate the setting depth of csg shoes with respect to the depth of MTDs identified geophysically and in offset wells. Have pump and dump mud ready to kill SWF while drilling riserless.	Binh Van Nguyen	Accepted		Mark Hafle	13-May-09	Cost	Low	Low	Medium	V. Low	Cost	Low	Low	V. Low	Identified them and are aware.
7	OK	T	NDS	Reduced wireline program	Loss of data or limited data collection as a result of well problems or borehole environmental conditions.	Team	Accepted		Team	13-May-09	Schedule	Medium	Low	High	Low					Talking just about the M56.
8	OK	T	NDS	Lost Circulation	Lost circulation indentified in the offsets. Risk to time and cost.	Mark Hafle	Active		Mark Hafle	17-Jun-09	Cost	Low	Moderate	Medium	Low					Loss circulation is possible with narrow PPFG window. Keep mud weight on the light side and have a robust loss circulation contingency plan in place.
9	OK	T	NDS	Narrow PPFG window	Isabela had a narrow PPFG windows (Miocene): if mud weight and hole conditions are not monitored carefully the we may begin to experience substantial losses to the formation or the well may flow back	Marty Albertin	Accepted		Mark Hafle	17-Jun-09	Cost	Medium	Moderate	High	Mod.	Cost	Medium	Moderate	Mod.	Keep MW as close to PP as possible. Two contingency strings are available if necessary: 9-3/8" liner and 7" liner. Use LWD tool if possible to get real time pressure samples.
10	OK																			
11	OK	T	NDS	Hurricane	Hurricanes and storms often exceed tolerances, and the rig must unlatch and move to safer conditions.	Team	Accepted		Mark Hafle	20-May-09	Schedule	Medium	Moderate	Low	Mod.	Schedule	Medium	Moderate	Mod.	Have a Hurricane plan which is updated daily during Hurricane season with T-times and other requirements needed to secure the well. Suspending before peak hurricane season.
12	OK	T	NDS	Loop and Eddy currents	Loop and eddy conditions occur almost throughout the year in many GoM deep water areas. Delays caused by high current velocities can be very costly.	Team	Accepted		Mark Hafle	20-May-09	Schedule	Medium	Moderate	Low	Mod.	Schedule	Medium	Low	Low	Our location is further North.
13	OK	T	NDS	Hydrate buildup on wellhead / connector	Potential for hydrate buildup around connectors preventing unlatching.	Mark Hafle	Accepted		Mark Hafle	20-May-09	Schedule	Low	Low	High	V. Low	Schedule	Low	Low	V. Low	Several mitigations in place should the event occur.
14	OK	T	NDS	Shallow water/gas flows	Uncontrolled shallow water and gas flows prior to riser installation could undermine and crater the drill center. See complex overburden	Mark Hafle	Accepted		Mark Hafle	20-Jun-09	Cost	High	Low	High	Mod.	Cost	High	Low	Mod.	Set 28" for isolation, gain formation integrity to allow Fast drill process through 22" section. Set 22" casing above Horizon 50 sand package to have BOP nippled up prior to crossing sand with SGF potential. 28" and 22" will be foam cemented.
15	OK	T	NDS	Lost drill center/respud	Wellhead Subsidence, stuck pipe, surface fracture, TOS rubble zone: potential risk for collapse/squeezing of all conductors	Mark Hafle	Accepted		Mark Hafle	17-Jun-09	Cost	High	Low	High	Mod.	Cost	High	Very Low	Low	28" for added support.
16	OK	T	NDS	Gumbo Attack	Gumbo due to pump and dump.	Mark Hafle	Accepted		Mark Hafle	17-Jun-09	Cost	Low	Moderate	High	Low	Cost	Low	Moderate	Low	Gumbo in the offsets.
17	OK	T	NDS	Shallow depletion	Evaluate potential for depleted zones.	Marty Albertin	Accepted		Mark Hafle	20-May-09	Cost	Medium	Low	Medium	Low	Cost	Medium	Low	Low	Monitor pressures. Spot Stress Cage material prior to running casing. Have 16" casing patch contingency available.
18	OK	T	Planning	BOP Issue	Potential for the BOP stack to cause NPT on the well.	Trent Fleece	Accepted		Team	17-Jun-09	Schedule	High	Low	Medium	Mod.	Schedule	High	Low	Mod.	Doing some PM's while the BoP is on the surface. Good get some new equipment vesus refurbished if things go long.
19	OK	T	Planning	Zonal Isolation	Risk of a good cement job on the 9-7/8" Production String	Mark Hafle	Active		Team	17-Jun-09	Cost	Medium	Moderate	High	Mod.					Numerous simulations show expandable is only option. The sands will be stress caged and fit for purpose cementing design will be used with low circulating rates will be used to keep ECD's below fracture pressure.
20	OK	T	Planning	Shock & Vibration	Risk of down hole tool failures due to shock and vibration.	Mark Hafle	Accepted		Team	17-Jun-09	Cost	Medium	Low	High	Low	Cost	Medium	Very Low	V. Low	Fit for purpose BHA's designed for each hole section incorporating DW GoM SPU lessons learned.
21	OK	T	Planning	Annular Pressure Build-up	Risk of casing failure during the production phase of the well.	Mark Hafle	Accepted		Mark Hafle	17-Jun-09	Production	High	Low	Medium	Mod.	Cost	High	Low	Mod.	Rich Miller in EPTG did a well specific design to mitigate APB issues. This well design incorporates three 16" rupture disc subs.
22	OK	T	Planning	Compaction	Casing failure late in life due to reservoir compaction.	Mark Hafle	Active		Mark Hafle	17-Jun-09	Production	Low	Very Low	Low	V. Low					Steve Wilson does not see any compaction risk at the Isabela location. Any compaction would be late in life due to reservoir drawdown.
23	OK	T	Planning	Expendable Issues	Risk of tubular expansion failure.	Mark Hafle	Accepted		Mark Hafle	17-Jun-09	Cost	Medium	Low	Medium	Low	Cost	Medium	Low	Low	
24	OK																			
25	OK																			

Risk Rating Matrix - customize the matrix in the SETUP worksheet

Impact Level	Health & Safety	Environment: Threats	Environment: Opportunities	Reputation: Threats	Reputation: Opportunities	Cost	Schedule	Production	Reserves	NPV			
	One or more fatalities	Damage long-term and/or extensive	-	Outrage. Prosecution. Possible loss of operating license	Commended by NGO at international level. Global recognition	> 10 $M	> 12.75 days	> 0.1 of Project Production*	> 0.15 of Project Reserves*	> 0.1 of Project NPV*			Very High
	Serious injury or DAFWC. HiPo	Short-term damage within facility boundary	Long-term and/or extensive improvement	Involvement of regulator	Commended by NGO at national level. Recognition within country	3 - 10 $M	3.4 - 12.75 days	0.03 - 0.1 of Project Production*	0.04 - 0.15 of Project Reserves*	0.03 - 0.1 of Project NPV*			High
	Recordable injury, first aid, serious occurrence	Rapid on-site clean-up	Short-term improvement within facility boundary	Complaints from local community	Commended by NGO at local level. Recognition within area	1 - 3 $M	0.85 - 3.4 days	0.01 - 0.03 of Project Production*	0.01 - 0.04 of Project Reserves*	0.01 - 0.03 of Project NPV*			Medium
	No impact	No impact	Minor enhancement	Minimal impact	recognised positive contribution within BP	< 1 $M	< 0.85 days	< 0.01 of Project Production*	< 0.01 of Project Reserves*	< 0.01 of Project NPV*			Low

(Type of Impact)

Probability

Very Low	Could only occur as the result of multiple, independent system or control failures. Future occurrence is thought most unlikely. No comparable occurrence is known.
Low	Could result from a plausible combination of system or control failures. Would probably occur if the system were to be operated for long enough. Comparable events are known to have occurred in the past.
Moderate	Could result from the failure of a single system or control. Could be expected to occur if this operation were repeated regularly. Comparable events are within the team's direct experience.
High	Uncontrolled. Will occur whenever circumstances are unfavorable. Comparable events are frequent.

Prob-Impact Grid

Impact Level	Probability / Frequency: Very Low < 1%	Low 1 - 5%	Moderate 5 - 25%	High > 25%
Very High	Mod.	High	V. High	V. High
High	Low	Mod.	High	V. High
Medium	V. Low	Low	Mod.	High
Low	V. Low	V. Low	Low	Mod.

Manageability

Low	Project Management Team can only influence impact. Risk reduction measures are unlikely to be cost-effective.
Medium	Project Management Team can influence probability and / or impact. Risk reduction measures will be roughly cost-neutral.
High	Project Management Team can control probability and / or impact. Risk reduction measures will be highly cost-effective

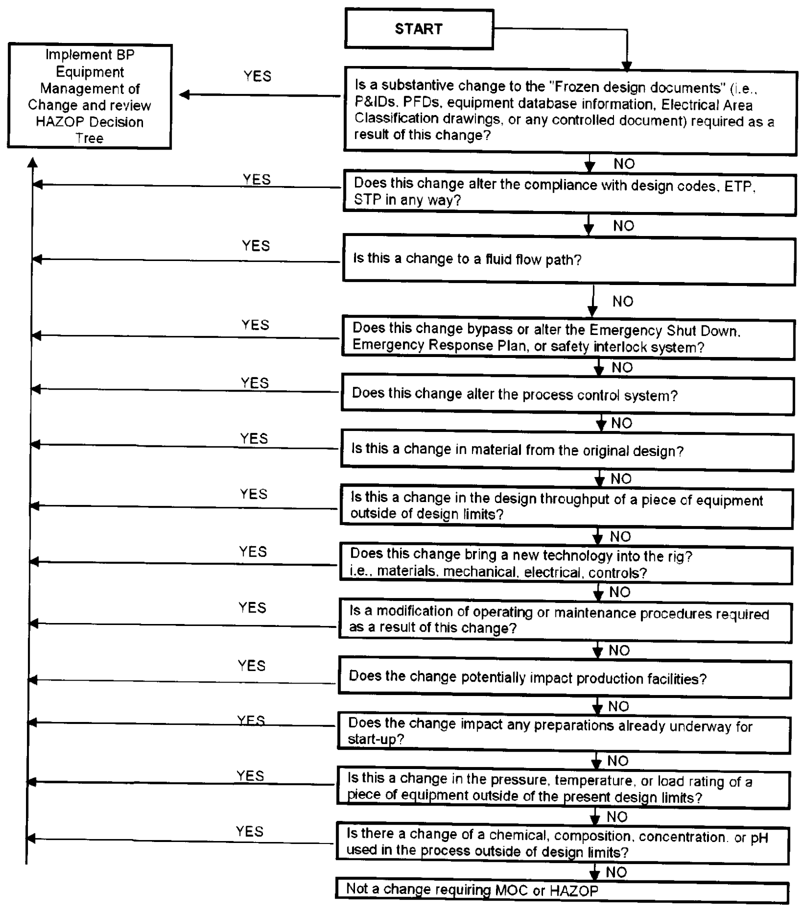
APPENDIX E

BP GoM Decision Trees

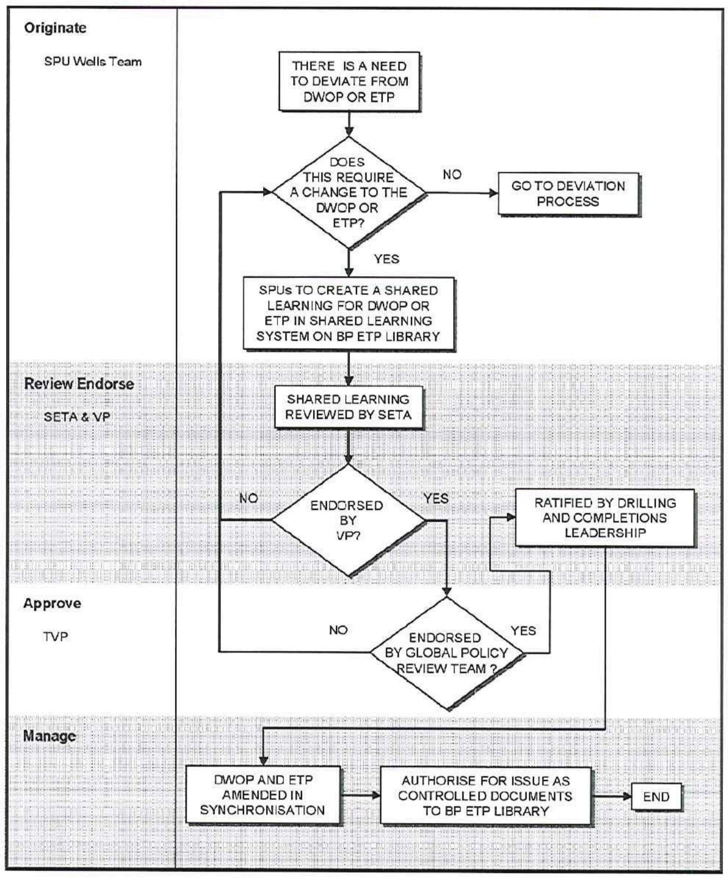
- Initiation Tree, Exhibit 6291 [20]
- Practice Amendment / Revision Flow Map, Exhibit 0093 [20]
- Practice Deviation Map, Exhibit 0093 [20]
- Barrier Verification Method, Exhibit 6237 [20]
- Complex Zonal Isolation Assessment, Exhibit 6237 [20]
- Zonal Isolation Decision Tree, Exhibit 6237 [20]
- Cement Bond Log Decision Tree [16]

7.2 Initiation Decision Tree – BP-Owned Rig Equipment

A "checklist" for initiating an MOC for BP-owned rig equipment is below.



Addendum 1
Practice Amendment/Revision Flow Map



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Addendum 3
Practice Deviation Map

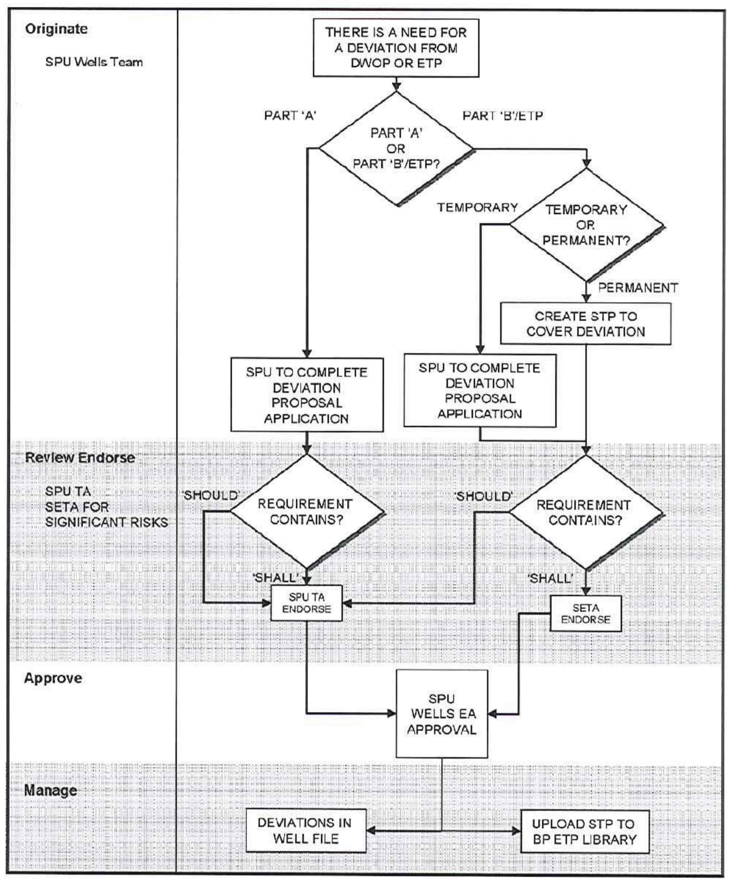

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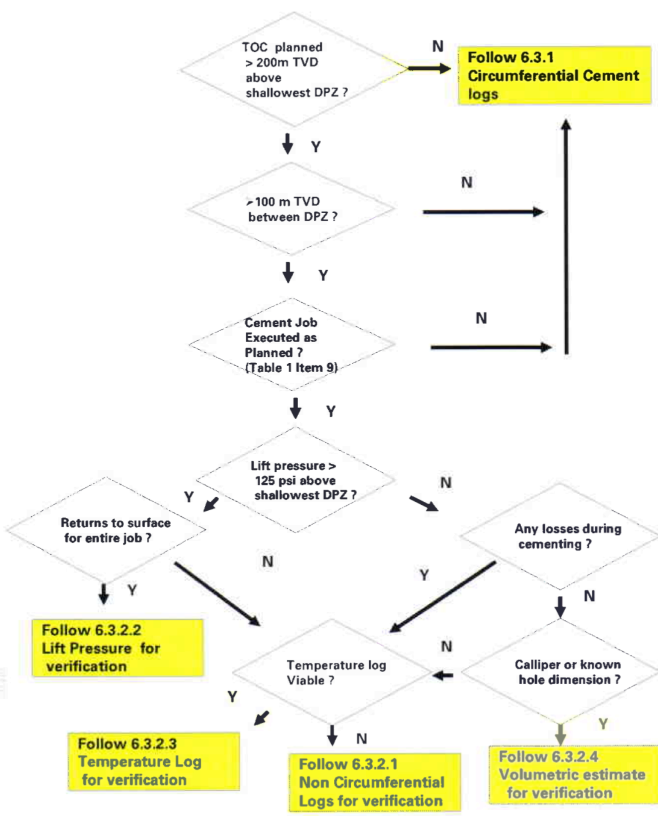
Figure 2 - Guide to selection of barrier verification method



Annex A
Normative annexes

A.1 Complex zonal isolation identification

a. If any hole section of an onshore well is identified as meeting any of the criteria in Table A.1-1, A.1-2 or A.1-3, that hole section (only the single hole section) shall be considered complex

b. If any hole section of an offshore well is identified as meeting any of the criteria in Table A.1-1, A.1-2 or A.1-3, the entire well shall be considered complex

Figure A.1-1 Complex zonal isolation assessment

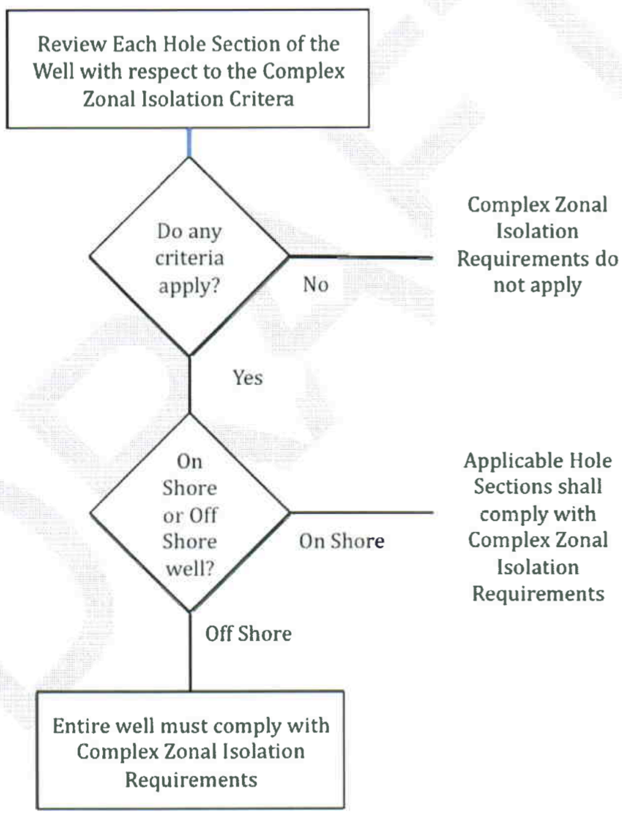


Figure B.1-1 Example of Basis of Zonal Isolation Decision Tree

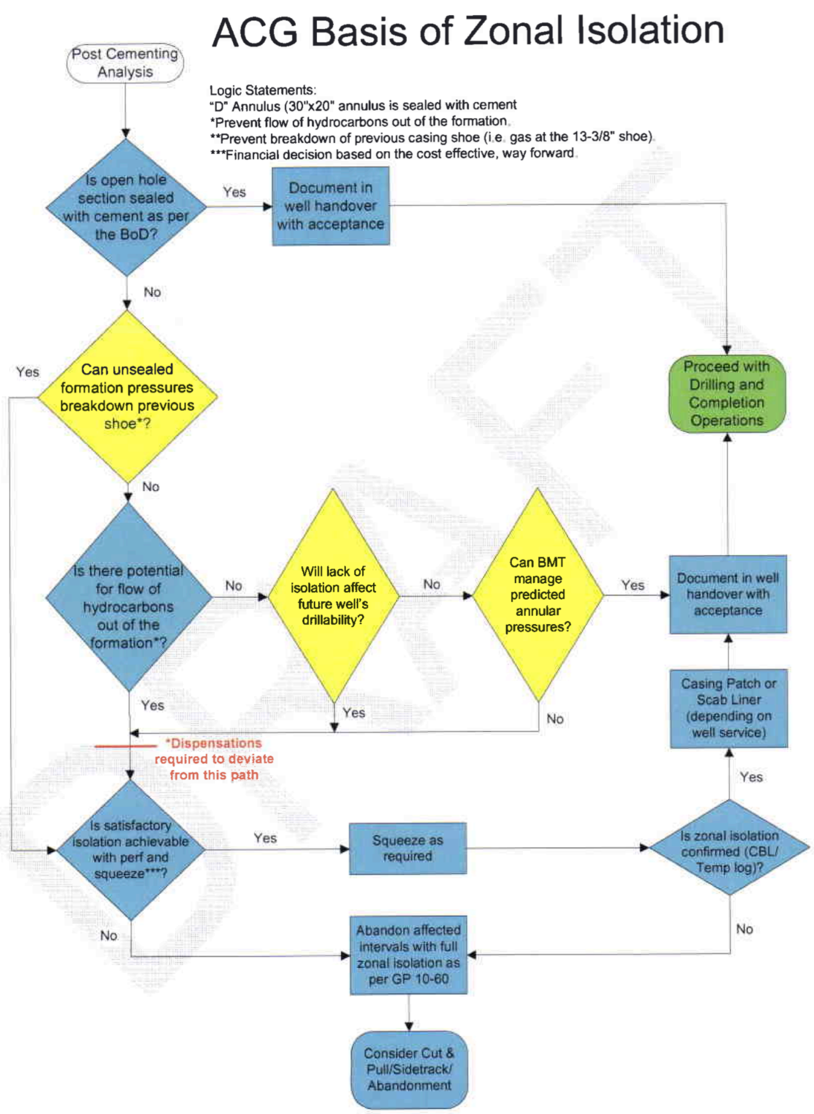
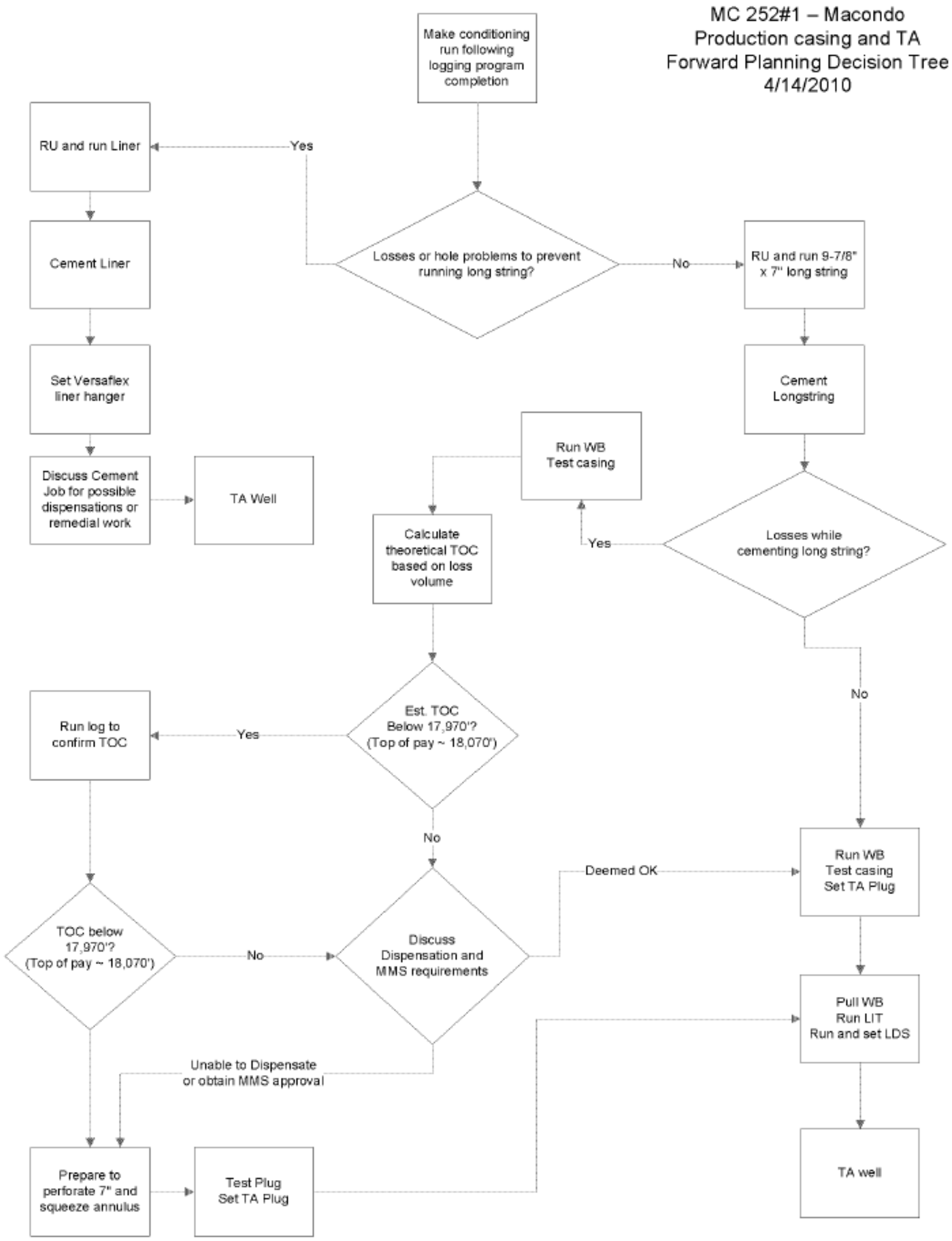


Exhibit 4 BP's Cement Bond Log Decision Tree



Source: Casewriter.

APPENDIX F

BP's Safety System Management Complements

- BP Achievable Mindset, Exhibit 4237 [20]
- BP DC&I Excellence, Exhibit 4237 [20]
- BP Conformance Requirements, Exhibit 2304 [20]
- BP GoM MoC Process Summary, Exhibit 6291 [20]

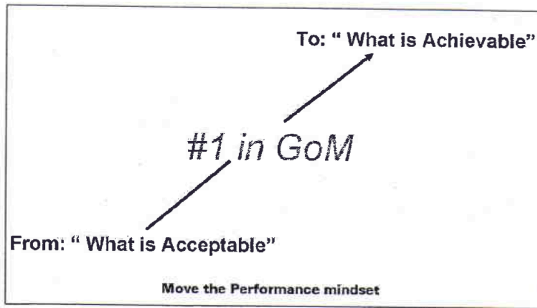


Figure 4: Moving the Performance Mindset

4.3 The "What is Achievable" Mindset

The DW GoM's current target-setting strategy is biased by the Approved for Expenditure (AFE) process.

Currently, we generate P10, P50 (mean) and P90 curves, monitoring and reporting relationships between our actual performance and the P50 curve. In essence, we are judging ourselves against an average performance; anything below the P50 line is deemed acceptable.

Now, we will challenge our teams to achieve the unachievable by:

- Using each DC&I unit's historic data
- Creating time curves based on "best time" for each task performed
- Monitoring against industry benchmarks
- Developing stronger awareness of NPT

The barrier to excellence is represented in Figure 5. As noted in the Figure, there is an 800-lb "thing" representing the barrier that has the LT pounding their collective heads at an average performance. The "thing" includes all the factors that affect performance (behaviors, expectations, results such as NPT, etc.).

There are two primary methods that will help the teams move past Average:

- Chip away/push/drag the "thing" down the performance line by focusing on improving on all the factors that we know are the barrier.
- Set what would appear to be unattainable targets and fall short of those targets.

Both result in a movement to the right. The section bullet, if managed properly, would be fun.

Draft

6 DC&I Excellence: Driving Consistency through Standardization

Team behaviors are driven largely through engineering procedures; operational guidelines; and equipment standardization (Figure 6). By standardizing these, the team becomes increasingly cohesive; and continuous improvement results as lessons learned are rolled into the guidelines utilized by every asset.

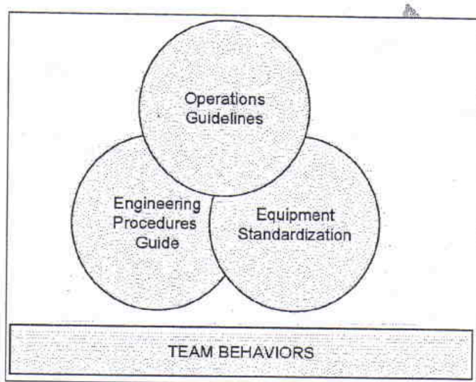


Figure 6: Standardizing through Consistency

6.1 Engineering Procedures Guide

- Performance focus
  - Every rig minute counts – ProNova, "The Geolograph"
  - TL workbook
  - NPT
- Cost estimating, monitoring, financial memorandums (FMs), AFEs
- Application for permit to drill (APDs)
- Well plans and standards
  - Casing tests
  - Leak off test (LOT) and FIT
  - Performance directional DC&I and surveying

- Casing running
- Cementing
- Crew Engagement meetings
- Engineering efficiency studies
- Final well reviews

6.2 Rig Operations Excellence Guidelines

- The Role of the Wells Team Leader and Ops Engineer
- Ownership of DC&I Excellence Plan
  - Tech Limit
  - NPT
- Standardized rig procedures
  - Reports
  - Daily planner
- Performance updates vs. plan
- Rig operations efficiency improvements
- Onsite technical support
- Operations excellence
- Rig operations planning and execution process

6.3 Equipment Standardization

- Quality Assurance/Quality Control (QA/QC)
- Use of the same equipment, such as:
  - Liner hangers
  - Liner top packers
  - Liner top polished bore receptacle (PBR)/seal assemblies
  - Float equipment
  - Surge reduction tools
  - Centralizers
  - Stop collars
  - Wellhead equipment

Draft

16 Appendix A - Conformance Requirements

There are a number of requirements GoM D&C need to conform with to ensure consistency in risk management.

The overriding requirement is conformance with OMS. Each entity must manage risk consistently with BP requirements. OMS provides the essential requirements to standardize the risk management processes across GoM D&C through conformance with group practices (defined and recommended) and procedures.

In addition, there are two processes widely used within GoM D&C that contain requirements for the management of risk - BtB and MPcp. They are specific to wells delivery and project management respectively. Each process contains sections on managing risk, and although each procedure has specific areas of focus, they are fundamentally the same when it comes to risk management. The minor differences are around risk management steps and definitions, but both procedures cover the complete Risk Life Cycle as illustrated in the Risk Management Process below.

BtB and MPcp each use a 4X4 risk matrix and have similar threshold criteria for ranking and rating risk. Neither process specifies a specific risk management tool.

The difference lies between the risk matrix and ranking approach contained within these two procedures and that contained within OMS which uses the 8x8 matrix for ranking and rating risks. Project teams, because of the varying values associated with their specific project, prefer to use BtB or MPcp as they provide the required granularity to manage their risks effectively. BtB and MPcp allows specific threshold values to be established for project based on the project's NPV, CAPEX or other impact type. OMS, on the other hand, has fixed and higher threshold values.

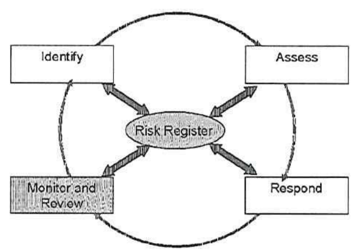
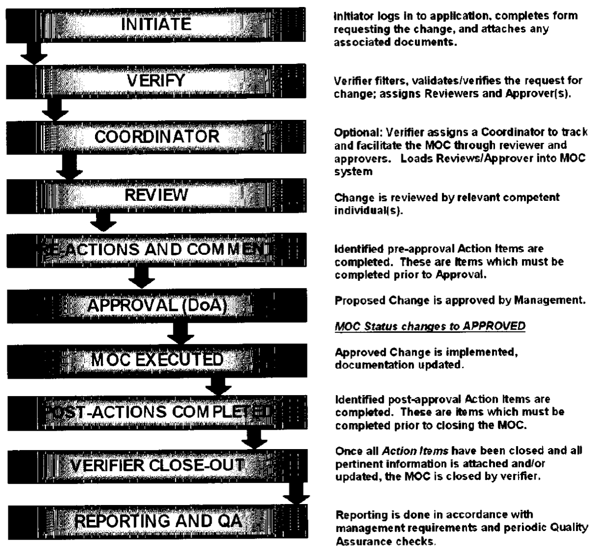


Figure 11: Risk Management Process

What is considered high risk in one project based on NPV and probability may not be ranked the same compared to another project or against the OMS ranking. The OMS matrix is better suited for managing and reporting high level risks up through the organization.

4 Process Summary

Change requests can originate from any GoM D&C team member, typically an engineer. Any proposed change should be "socialized" within the D&C team and any other applicable stakeholder team prior to the initialization of the MOC and entry of the MOC into the BizFlow® DCMOC workflow. A complete vetting of the change proposal will minimize the likelihood of MOC rejection or extended review cycles, both of which will delay actioning the MOC. The following flow chart summarizes the Drilling and Completions MOC process.



Additional process details and guidance are described in the following section.

5 Process Detail, BizFlow® DCMOC Workflow, and Roles

The BizFlow® DCMOC workflow is initiated to facilitate the MOC process and to ensure changes are properly reviewed, approved, communicated, and documented.

The following sections describe the MOC process in more detail and how the process is facilitated using the BizFlow® DCMOC workflow.

APPENDIX G

Macondo Team's Emails Cited in the CAST Analysis

- Exhibit 0595
- Exhibit 0566
- Exhibit 0759
- Exhibit 1126
- Exhibit 1694
- Exhibit 2580
- Exhibit 4230
- Exhibit 4235
- Exhibit 4243

EXHIBIT # 565

WIT:

From: Vidrine, Don J
Sent: Fri Apr 16 11:23:02 2010
To: Kaluza, Robert
Subject: FW: Modification of Permit to Bypass at Location Surface Lease: G32306 Surface Area: MC Surface Block: 252 Bottom Lease: G32306 Bottom Area: MC Bottom Block: 252 Well Name: 001 Assigned API Number: 608174116901 has been approved.
Importance: Normal
Attachments: Macondo_RBP_7addition.pdf

-----Original Message-----
From: Morel, Brian P
Sent: Thursday, April 15, 2010 9:43 PM
To: Vidrine, Don J; Sepulvado, Ronald W
Subject: FW: Modification of Permit to Bypass at Location Surface Lease: G32306 Surface Area: MC Surface Block: 252 Bottom Lease: G32306 Bottom Area: MC Bottom Block: 252 Well Name: 001 Assigned API Number: 608174116901 has been approved.

FYI - Approved permit for casing. Still working on getting permission to set deeper surface plug.

----- Original Message -----
From: Powell, Heather (JC Connor Consulting)
To: Hafle, Mark E
Sent: Thu Apr 15 15:11:56 2010
Subject: FW: Modification of Permit to Bypass at Location Surface Lease: G32306 Surface Area: MC Surface Block: 252 Bottom Lease: G32306 Bottom Area: MC Bottom Block: 252 Well Name: 001 Assigned API Number: 608174116901 has been approved.

Please tell me 3rd time's the charm! :)

Thanks!
Heather

-----Original Message-----
From: frank.patton@mms.gov [mailto:frank.patton@mms.gov]
Sent: Thursday, April 15, 2010 2:40 PM
To: Powell, Heather (JC Connor Consulting)
Subject: Modification of Permit to Bypass at Location Surface Lease: G32306 Surface Area: MC Surface Block: 252 Bottom Lease: G32306 Bottom Area: MC Bottom Block: 252 Well Name: 001 Assigned API Number: 608174116901 has been approved.

Modification of Permit to Bypass at Location Surface Lease: G32306 Surface Area: MC Surface Block: 252 Bottom Lease: G32306 Bottom Area: MC Bottom Block: 252 Well Name: 001 Assigned API Number: 608174116901 has been approved. as of 2010-04-15 14:39:39.0

Temporary Abandonment Procedure
Macondo – MC 252 #1
Deepwater Horizon

Current Status:

Making wiper trip prior to running a long string of 9-7/8" x 7" production casing

Forward Plan:

Run casing to 18,300' +/- per approved APD. Test casing to 2500 psi per approved APD.

Temporary Abandonment Procedure: *(estimated start time Sunday, April 18, 2010)*

1. Negative test casing to seawater gradient equivalent for 30 min. with kill line.
2. TIH with a 3-1/2" stinger to 8367'.
3. Displace to seawater. Monitor well for 30 min.
4. Set a 300' cement plug (125 cu.ft. of Class H cement) from 8367' to 8067'.

   The requested surface plug depth deviation is for minimizing the chance for damaging the LDS sealing area, for future completion operations.

   This is a Temporary Abandonment only.

   The cement plug length has been extended to compensate for added setting depth.
5. POOH.
6. Set 9-7/8" LDS (Lock Down Sleeve)
7. Clean and pull riser.
8. Install TA cap on wellhead and inject wellhead preservation fluid (corrosion inhibitor) below TA cap.

U.S. Department of the Interior
Minerals Management Service (MMS)

OMB Control Number 1010-0141
OMB Approval Expires 11/30/2011

Form MMS-124 - Electronic Version
Application for Permit to Modify

Lease G32306 **Area** MC **Block** 252 **Well Name** 001 **ST** 00 **BP** 01 **Type** Exploratory
Application Status Approved **Operator** 02481 BP Exploration & Production Inc.

Questions

Number	Question	Response	Response Text
3	Will all wells in the well bay and related production equipment be shut-in when moving on to or off of an offshore platform, or from well to well on the platform? If not, please explain.	N/A	
4	Are you downhole commingling two or more reservoirs?	N/A	
5	Will the completed interval be within 500 feet of a lease or unit boundary line? If yes, then comment.	N/A	
6	For permanent abandonment, will casings be cut 15 feet below the mudline? If no, then comment.	N/A	

ATTACHMENTS

File Type	File Description
pdf	Proposed Wellbore Schematic
pdf	Proposed Procedure

CONTACTS

Name	Heather Powell
Company	BP Exploration & Production Inc.
Phone Number	281-504-0984
E-mail Address	heather.powell@bp.com
Contact Description	Regulatory

PAPERWORK REDUCTION ACT OF 1995 (PRA) STATEMENT: The PRA (44 U.S.C. 3501 et seq. Requires us to inform you that we collect this information to obtain knowledge of equipment and procedures to be used in drilling operations. MMS uses the information to evaluate and approve or disapprove the adequacy of the equipment and/or procedures to safely perform the proposed drilling operation. Responses are mandatory (43 U.S.C. 1334). Proprietary data are covered under 30 CFR 250.196. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB Control Number. Public reporting burden for this form is estimated to average 11/4 hours per response, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect of this form to the Information Collection Clearance Officer, Mail Stop 4230, Minerals Management Service, 1849 C Street, N.W., Washington, DC 20240.

U.S. Department of the Interior
Minerals Management Service (MMS)

OMB Control Number 1010-0141
OMB Approval Expires 11/30/2011

Form MMS-124 - Electronic Version
Application for Permit to Modify

Lease G32306 **Area** MC **Block** 252 **Well Name** 001 **ST** 00 **BP** 01 **Type** Exploratory

Application Status Approved **Operator** 02481 BP Exploration & Production Inc.

Pay.gov Amount: $116.00	**Agency Tracking ID:** EWL-APM-125409	**Pay.gov Tracking ID:** 250MBOJJ

General Information

API 608174116901	**Approval Dt** 16-APR-2010	**Approved By** Frank Patton
Submitted Dt 16-APR-2010	**Well Status** Drilling Active	**Water Depth** 4992
Surface Lease G32306	**Area** MC	**Block** 252

Approval Comments

Correction Narrative

Permit Primary Type Abandonment Of Well Bore

Permit Subtype(s)

Temporary Abandonment

Operation Description

Procedural Narrative

Please see the attached proposed procedure.

Subsurface Safety Valve

Type Installed N/A

Feet below Mudline

Shut-In Tubing Pressure (psi)

Rig Information

Name	Id	Type	ABS Date	Coast Guard Date
T.O. DEEPWATER HORIZON	46428	SEMISUBMERSIBLE	28-FEB-2011	27-JUL-2011

Blowout Preventers

			--- Test Pressure ---	
Preventer	**Size**	**Working Pressure**	**Low**	**High**
Annular		10000	250	3500
Rams	18.75	15000	250	6500

Date Commencing Work (mm/dd/yyyy) 18-APR-2010

Estimated duration of the operation (days) 8

Verbal Approval Information

Official	Date (mm/dd/yyyy)

Questions

Number	Question	Response	Response Text
1	Is H2S present in the well? If yes, then comment on the inclusion of a Contingency Plan for this operation.	NO	
2	Is this proposed operation the only lease holding activity for the subject lease? If yes, then comment.	NO	

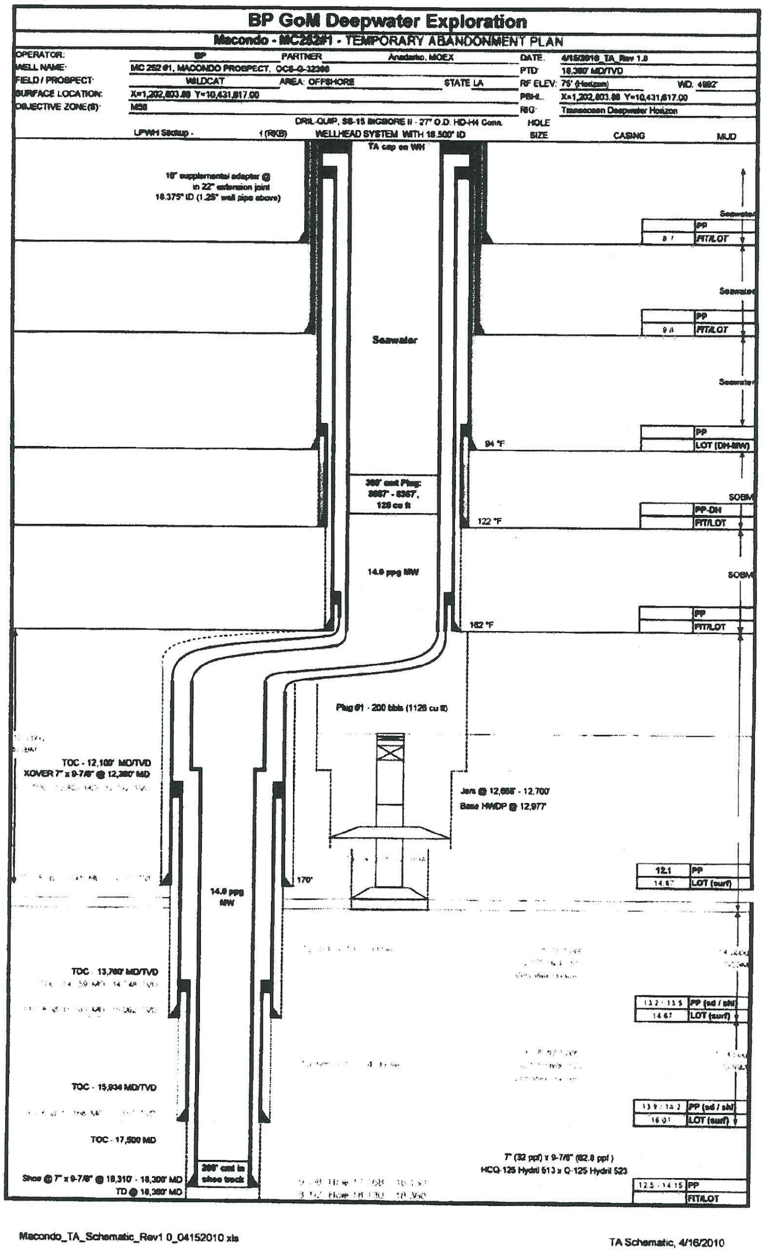

BP GoM Deepwater Exploration
Macondo - MC252#1 - TEMPORARY ABANDONMENT PLAN
Seawater
14.0 ppg MW
Plug #1 - 200 bbls (1126 cu ft)
TOC - 12,100' MD/TVD
TOC - 13,760' MD/TVD
TOC - 15,934 MD/TVD
TOC - 17,500 MD
TA Schematic, 4/16/2010

EXHIBIT # 566
WIT: ____

P

Kaluza, Robert

From: Morel, Brian P
Sent: Tuesday, April 20, 2010 10:43 AM
To: Morel, Brian P; Vidrine, Don J; Kaluza, Robert; Lambert, Lee; Lee, Earl P (Oper Svcs Dril)
Cc: Guide, John; Hafle, Mark E; Cocales, Brett W; Walz, Gregory S
Subject: Ops Note
Follow Up Flag: Follow up
Flag Status: Red

Quick ops note for the next few days:

1. Test casing per APD to 250 / 2500 psi
2. RIH to 8367'
3. Displace to seawater from there to above the wellhead
4. With seawater in the kill close annular and do a negative test ~2350 psi differential
5. Open annular and continue displacement
6. Set a 300' balanced cement plug w/ 5 bbls in DP
7. POOH ~100-200' above top of cement and drop nerf ball / circulate DS volume
8. Spot corrosion inhibitor in the open hole
9. POOH to just below the wellhead or above with the 3-1/2" stinger (if desired wash with the 3-1/2" / do not rotate / a separate run will not be made to wash as the displacement will clean up the wellhead)
10. POOH and make LIT / LDS runs
11. Test casing to 1000 psi with seawater (non MMS test / BP DWOP) – surface plug
    a. Confirm bbls to pressure up on original casing test vs bbls to test surface plug (should be less due to volume differences and fluid compressibility –seawater vs sobm)
    b. Plot on chart / send to Houston for confirmation

4/25/2010

EXHIBIT # 759

WIT: ______

From: O'Bryan, Patrick L
Sent: Tue Apr 27 19:39:27 2010
To: Zanghi, Mike
Subject: RE: Bladder effect
Importance: Normal

Mike,

??
??
??
??
??
???

Regards,
Pat

From: Zanghi, Mike
Sent: Tuesday, April 27, 2010 2:26 PM
To: O'Bryan, Patrick L
Subject: FW: Bladder effect

From: Daigle, Keith G
Sent: Tuesday, April 27, 2010 9:32 AM
To: Sigurdson, Scott; Zanghi, Mike
Subject: FW: Bladder effect

Bob Kaluza's thoughts around " bladder effect"
Thanks,
Keith

From: Kaluza, Robert
Sent: Sunday, April 25, 2010 8:23 PM
To: Guide, John; Daigle, Keith G
Cc: Vidrine, Don J
Subject: Bladder effect
John and Keith,

Please consider this suggestion in the analysis about how this happened:
I believe there is a bladder effect on the mud below an annular preventer as we discussed. As we know the pressure differential was approximately 1400 - 1500 psi across an 18 3/4" rubber annular preventer, 14.0 SOBM plus 16.0 ppg Spacer in the riser, seawater and SOBM below the annular bladder. Due to a bladder effect, pressure can and will build below the annular bladder due to the differential pressure but can not flow --- the bladder prevents flow, but we see differential pressure on the other side of the bladder.

Now consider this. The bladder effect is pushing 1400 - 1500 psi against all of the mud below, we have displaced to seawater from 8,367' to just below the annular bladder where we expect to have a 2,350 psi negative differential pressure but due to a bladder effect we may only have a 850 - 950 psi negative pressure until we lighten the load in the riser.

When we displaced the riser to seawater, then we truly had a 2,350 psi differential and negative pressure.

Something to consider in our analysis.

Bob Kaluza
WSL Thunderhorse Project
337 735 6370 (w)
702 501 8763 (c)
robert.kaluza@bp.com

From: Sims, David C
Sent: Sun Mar 14 04:53:00 2010
To: Guide, John
Subject: RE: call
Importance: Normal

John,

I have a much longer response typed, but I'm not going to send it until I'm back and we can talk. We need to talk. We cannot fight about every decision.

I listened to everything that everyone said. I heard the WSLs opinions. I did not agree with their opinions and so I made a decision to do something else. It is interesting that you think that because I did not blindly agree to what they suggested, that somehow I must not have been listening.

By the way, you said you agreed "100%" with me this morning. Bleeding with pipe off bottom and while underbalanced to a kick zone is wrong. Even if you want to argue that bleeding was justified, the volume they bled was completely arbitrary and the volume they wanted to bleed tonight was completely arbitrary.

Jimmy Adams is in Mississippi. He stated that he is a long way away and not fully familiar with the circumstances. I value his opinion, but like our WSLs, he could not offer any facts or any real argument for how we could have trapped pressure or how that would change what we ultimately have to do - weight up. When he is in the office next week and fully versed on the circumstances, you will be able to take his opinion or not.

I will hand this well over to you in the morning and then you will be able to do whatever you want. I would strongly suggest, for everyone's sake, that you make logical decisions, based on facts, after weighing all the opinions.

David

From: Guide, John
Sent: Saturday, March 13, 2010 6:04 PM
To: Sims, David C
Subject: Re: call

You did not listen. Jimmy adams a person you asked to be involved agreed with murry and ronnie. Your mind was wade up. You never asked the wsl opinions.

From: Sims, David C
To: Guide, John

EXHIBIT # 1126
WIT:

Sent: Sat Mar 13 23:20:44 2010
Subject: call

What did I do to make you mad?

From Guide, John
Sent Sat Apr 17 15.18.31 2010
To: Sims, David C
Subject: RE: Discussion - The way we wo*k with engineering
Importance: Normal

I totally concur. I told them all we will work through it together. I want to do better

---

From: Sims, David C
Sent: Saturday, April 17, 2010 10:14 AM
To: Guide, John
Subject: RE: Discussion - The way we work with engineering

John, I've got to go to dance practice in a few minutes. Let's talk this afternoon

For now, and until this well is over, we have to try to remain positive and remember what you said below - everybody wants to do the right thing. The WSLs will take their cue from you. If you tell them to hang in there and we appreciate them working through this with us (12 hours a day for 14 days) - they will It should be obvious to all that we could not plan ahead for the well conditions we're seeing, so we have to accept some level of last minute changes.

We've both in Brian's position before. The same goes for him. We need to remind him that this is a great learning opportunity, it will be over soon, and that the same issues - or worse - exist anywhere else.

I don't think anything has changed with respect to engineering and operations Mark and Brian write the program based on discussion/direction from you and our best engineering practices. If we had more time to plan this casing job, I think all this would have been worked out before it got to the rig. If you don't agree with something engineering related, and you and Gregg can't come to an agreement, Jon or me gets involved. If it's purely operational, it's your call.

I'll be back soon and we can talk.

We're dancing to the Village People!

From: Guide, John
Sent: Saturday, April 17, 2010 8:40 AM
To: Sims, David C
Subject: Discussion - The way we work with engineering
David, over the past four days there has been so many last minute changes to the operation that the WSL's have finally come to their wits end The quote is "flying by the seat of our pants". More over, we have made a special boat or helicopter run everyday. Everybody wants to do the right thing, but, this huge level of paranoia from engineering leadership is driving chaos. This operation is not Thunderhorse. Brian has called me numerous times trying to make sense of all the insanity Last night's emergency evolved around the 30 bbls of cement spacer behind the top plug and how it would affect any bond logging (I do not agree with putting the spacer above the plug to begin with). This morning Brian called me and asked my advice about exploring opportunities both inside and outside of the company.

What is my authority? With the separation of engineering and operations I do not know what I can and can't do The operation is not going to succeed if we continue in this manner.

Confidential

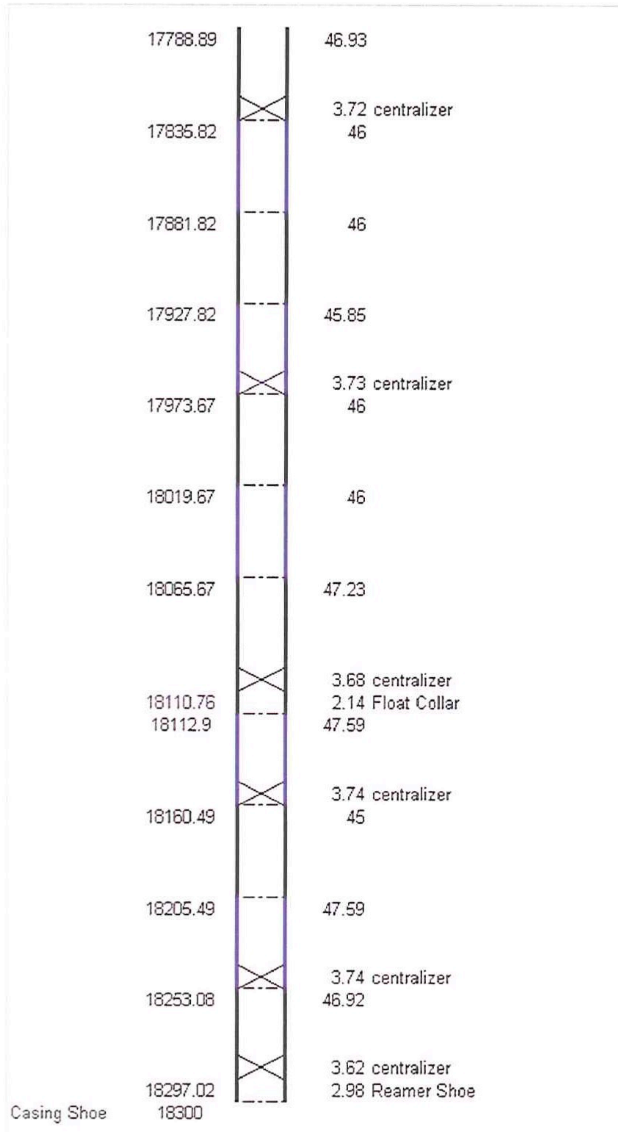
BP-HZN-BLY00069434

EXHIBIT
tabbies
1694

From: Morel, Brian P [Brian.Morel@bp.com]
Sent: Thursday, April 15, 2010 4:00 PM
To: Jesse Gagliano; Hafle, Mark E; Cocales, Brett W; Walz, Gregory S
Subject: RE: OptiCem Report
Attachments: image002.jpg; image003.jpg

We have 6 centralizers, we can run them in a row, spread out, or any combinations of the two. It's a vertical hole so hopefully the pipe stays centralized due to gravity. As far as changes, it's too late to get any more product to the rig, our only options is to rearrange placement of these centralizers. Please see attached diagram for my recommendation.

EXHIBIT
tabbies
2580



Brian

From: Jesse Gagliano [mailto:Jesse.Gagliano@Halliburton.com]
Sent: Thursday, April 15, 2010 3:35 PM

To: Hafle, Mark E; Morel, Brian P; Cocales, Brett W; Walz, Gregory S
Subject: OptiCem Report

Attached is the updated OptiCem report & lab test. The items that I updated in OptiCem are below; everything else is the same from the one we ran together yesterday.

Imported caliper data
Imported directional data
Entered in centralizer info
Updated Cement RPM data from lab test

Updating the above info now shows the cement channeling and the ECD going up as a result of the channeling. I'm going to run a few scenarios to see if adding more centralizers will help us or not.

Below is what the standoff looks like with the current centralizer plan. Let me know if you have any questions. Thanks!!

Halliburton Energy Services
OptiCem v6.4.8
Centralizer Calculations Report
This report was created 04/15/2010 15:31:57.
GetCentNumber = 10

n	Spacing ft	MD ft	Dev. °	Az. °	Stand. %	Rest. Force lbf	Tension lbf	Centralizer
10	48.0	18300.0	0.9	219.9	80.73	11	0	B 7.000x8.500
		18276.0			77.23			
9	45.0	18252.0	0.9	219.9	80.31	21	1356	B 7.000x8.500
		18229.5			79.77			
8	45.0	18207.0	0.9	219.9	80.33	20	2627	B 7.000x8.500
		18184.5			79.80			
7	45.0	18162.0	0.9	219.9	91.47	20	3899	B 7.000x8.500
		18139.5			90.86			
6	48.0	18117.0	0.9	219.9	91.44	21	5170	B 7.000x8.500
		18093.0			90.66			
5	84.0	18069.0	0.9	219.9	63.91	27	6526	B 7.000x8.500
		18027.0			59.77			
4	45.0	17985.0	0.9	219.9	45.09	25	8590	B 7.000x8.500
		17962.5			44.83			
3	84.0	17940.0	0.9	219.9	45.09	25	9696	B 7.000x8.500
		17898.0			42.29			
2	45.0	17856.0	0.9	219.9	43.95	25	11760	B 7.000x8.500
		17833.5			43.70			
1	17811.0	17811.0	0.9	219.9	13.98	3399	12865	B 7.000x8.500
		17810.0			13.98			
		17790.0			50.00			
	0.0	0.0			50.00			

Jesse Gagliano
Halliburton Energy Services
Account Representative - Cementing
Office - 281-366-6106
Cell - 281-635-4798
Fax - 713-583-9700
E-mail - jesse.gagliano@halliburton.com

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4230
Exhibit No. ______
Worldwide Court Reporters, Inc.

From: Sims, David C
Sent: Sun Mar 07 20:39:57 2010
To: O'Bryan, Patrick L
Subject: FW: Burns
Importance: Normal

Pat, I sent this to Dave Rich on Friday and not sure if it's too late wrt to next position for Tim. Our (you and me) conversation about rigs and a conversation Dave and I had about people movement and needs made me suddenly uncomfortable about our org capability. I'm sure there are things going on that I'm not aware of and my concerns may be based on a lack of context or an incomplete picture and if so, I apologize up front!

If Robert leaves and/or if the rig situation materializes as you speculated however, we will need a WTL (unless comes with the rig) and that may start a daisy chain. I've got some ideas, so if I can help, just let me know.

Thanks,

David

David Sims
Drilling Engineering Team Leader
GOM Deepwater/DeepGas Exploration and Appraisal
Work - 281-366-0360
Mobile - 713-304-5600
Home - 281-578-8653
Fax - 281-366-3835
Mailto:simsdc@BP.com

From: Sims, David C
Sent: Friday, March 05, 2010 2:40 PM
To: Rich, David A
Subject: Burns

Dave,

I've been thinking about the need we have for people and the exodus of talent from GOM and I really think we need to stop the bleeding. We are losing all our best talent. I believe that Tim Burns can step into a WTL role right now. He has been a superintendent before and I believe that he has the communication, teambuilding, and leadership skills needed to do well in this role. I've seen him fill in officially for John and he's always had a great relationship with the WSLs. He is in the top three in drilling engineering talent in the SPU. He's done a good job in his role as RTOC project manager. If we are going to lose any of our WTLs, I'd support giving Tim a chance at his first team leader role here in GOM rather than NAG. The easiest place for him to roll into would be on the Horizon - if there was a good fit for John with his completions experience say at Atlantis or drilling the Mad Dog wells with the Clarion where he has experience in that field. Not trying to get rid of John but thinking about how to set up Tim for success. Horizon is going to be drilling Kaskida and Tiber wells for the next few years and Tim is an expert there.

Thanks for listening,

David

David Sims
Drilling Engineering Team Leader
GOM Deepwater/DeepGas Exploration and Appraisal
Work - 281-366-0360
Mobile - 713-304-5600
Home - 281-578-8653
Fax - 281-366-3835
Mailto:simsdc@BP.com

4235
Exhibit No.
Worldwide Court Reporters, Inc.

From: Cooper, Steve D
Sent: Tue Jun 02 09:54:42 2009
To: Cooper, Steve D
Subject: Updated: Well Integrity Management - D&C Conference Action Items
Importance: Normal
Attachments: RE: Well Integrity; RE: Well Integrity; RE: Well Integrity; Well Integrity Strategy White Paper V1.doc; FW: Well Handover; Well Integrity and Performance Management White Paper v3.doc

Gent's,
This meeting has been rescheduled at Pat's request, to allow participation and discussion by all. We each have full calendars and this represents our best opportunity to discuss and agree the way forward within the next 2 - 3 weeks, please confirm availability.

For reference, a separate discussion with Dick (1/6), generated the following questions.

1. How well understood is the accountability for wells within the SPU's - Is there a need for a Group Defined Practice for well accountability from planning (MP or infill development) through to abandonment?
2. What is the current integrity status of BP well stock, is it improving, static or declining - how visible are trends for integrity issues/ dispensations within the SPU and within the D&C ELT?
3. What is the integrity related risk to the company - reputation, production?
4. Do SPU's include well integrity with process integrity within the Orange book - how consistent is this process - is there a need for a separate well integrity section?

Thanks

The EPT breakout session from the D&C conference (continuous improvement and SPU takeaways), generated a significant amount of discussion relating to the Central Azeri well integrity incident. This was largely relating to how few people were even aware of the incident and what the major lessons were to prevent a similar occurrence. As a result of this discussion the following actions were identified for roll-up with those from other SPU's, see attachment.

1. Have well integrity addressed by existing networks. (Brian Hay).

The topic and the Central Azeri incident were discussed during the CEx call (20th May), and a follow-up dedicated call will be scheduled for the CEx network w/c 1st June.

2. Follow up with the ELT to progress Dave Andrew's IM white paper. (Steve Cooper).
3. Have the ELT mandate compliance with the well hand over documentation requirements (common WHD format and a well operability / management scheme in place), for all wells or groups of wells, as appropriate. (Steve Cooper).
4. Utilise a global inventory management tool, which links key strategic suppliers to oversee D&C inventory, equipment and needs. (SPA not yet assigned).

I would be grateful if you would confirm your availability to discuss the ELT position with regard to 2 and 3 above, and if appropriate, how we can best move this forward.

<<...>> <<...>> <<...>> <<...>> <<...>> <<...>>

Dial up details are as follows:

Conference code: 0922458628

Reservationless-Plus UK LocalCall Dial-In Number: 08451462024

Reservationless-Plus UK Freephone Dial-In Number: 08006941555

Reservationless-Plus Std International Dial-In Number:+44 (0) 1452 584028

United States : 18666161740

Thanks and regards

Steve

From: Bowman, Mike BJ
Sent: Sun May 10 10:04:24 2009
To: Andrews, David
Cc: O'Bryan, Patrick L; Haden, Steven K; Baker, Kate H; Bedrock, Martin
Subject: RE: Well Integrity
Importance: Normal

A good starter for 10 Dave; this in the end must be owned and sponsored by Steve & Pat - if they support further working into a more polished set of segment guidelines then from SS&W, please work with Kate Baker my Director of Well Planning & Operations - this touches on a number of issues that came to light during the recent C Azeri incident

Am sure some of the Advisors could help here also but must not let that defocus the project

Mike

Mike Bowman
Vice President Geoscience & Subsurface Description
Exploration & Production Technology
BP Exploration, Sunbury
United Kingdom

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Office: + 44 1932 734570

From: Andrews, David
Sent: 20 April 2009 04:42
To: O'Bryan, Patrick L; Haden, Steven K; Bowman, Mike BJ; Braunston, Dick
Cc: Mason, Mike C; Hey, Michael-James; Adair, Paul; Cameron, Paul (ABZ); Saul, David C (D&C Aberdeen); Peacock, Ralph; Sweeney, Frank M
Subject: Well Integrity

I have attached a DRAFT white paper for your review. I have titled this paper "Strategy for Well Integrity" but it could just as easily been titled "Strategy for Wells". I'm sure that this will come as no surprise to you as you will have often heard me saying that well integrity is nothing more than an outcome of good wells practice.

I have to admit that the paper still requites a lot of work in terms of crossing the t's and dotting the i's but I see little point of spending more time on it if the proposal is deemed as "too difficult". Much more work will be required if any merit is seen within the proposal. I believe we have a great opportunity to grasp this nettle and, if we do, steal a march on the competition.

The proposal ignores personal issues. The paper is based purely on what I consider to be in the best interest of our wells. Our wells are important. Arguably, after the reservoir, our wells are our biggest single assets yet they are treated with so much indifference at a corporate level. No other asset, piece of kit or reservoir, is passed from pillar to post across the complete range of disciplines in the same way as our wells. The reservoir and its management, for example, moves from one group to another but each of those groups is made up of like minded reservoir specialists using the same metrics and drivers.

At the other end of the spectrum we have the well. Each and every one of our Functions has a finger in the well pie. Project and Engineering has an input at the early stage and this input can have a major impact on our wells life cycle. I'm sure that we can all think of instances where well performance has suffered from poor early input. The well is then handed off to Drilling and Completions who, with input from Subsurface and Wells, drill and complete the well. The construction phase is critical and our well stock has suffered from poor construction practise but at least accountability for this phase in a wells life is completely clear and there is great benefit in this. Finally a well is handed off to Operations and HSE where it will remain for the bulk of its life, with input from Subsurface and Wells, yet many who operate our well stock have little deep knowledge of our wells.

I believe that the present management structure of our wells raises two issues. 1) there is no single continuity/accountability as a well moves from inception to abandonment. Considering the immense value these wells deliver is this acceptable? And 2) each of these Functions has its own set of metrics and drivers, in relation to the well, which in some cases conflict. One could argue that it is a measure of our ingenuity that we deliver operational wells of any sort given this adversarial backdrop. Imagine what could be achieved.
<< File: Well Integrity Strategy White Paper V1.doc >>

I have recently heard it suggested that SPUs are motivated by greed and fear. I believe that this assertion is not without merit and to some extent these primeval instincts are healthy provided there is a conscience. I believe that the Functions within EPT, to a great extent, should act as the SPU conscience. We should be allowed to intervene far more than we are allowed to at the moment.

Thanks for your time,

David.

David Andrews

Advisor

Global Well Integrity Lead

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From: O'Bryan, Patrick L
Sent: Thu May 07 16:27:39 2009
To: Andrews, David
Subject: RE: Well Integrity
Importance: Normal

Dave,
I'll review on the plane this weekend and discuss with you when I return the week of 5/18.
Steve Haden and I have had some dialogue on this as well.
Pat

From: Andrews, David
Sent: Monday, April 20, 2009 4:42 AM
To: O'Bryan, Patrick L; Haden, Steven K; Bowman, Mike BJ; Braunston, Dick
Cc: Mason, Mike C; Hey, Michael-James; Adair, Paul; Cameron, Paul (ABZ); Saul, David C (D&C Aberdeen); Peacock, Ralph; Sweeney, Frank M
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Thanks for your time,
David.
David Andrews
Advisor

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From: Haden, Steven K
Sent: Tue Apr 28 00:53:26 2009
To: Andrews, David
Cc: O'Bryan, Patrick L
Subject: RE: Well Integrity
Importance: Normal

David,
I've had a chance to read and do have some thoughts. I'm in Houston this week and will visit with Pat about next steps so we can move forward. I do think we should probably get more specific on what change needs to look like. I would also like to bring the Central Azeri understandings into our forward direction.
Regards,
Steve

From: Andrews, David
Sent: 20 April 2009 04:42
To: O'Bryan, Patrick L; Haden, Steven K; Bowman, Mike BJ; Braunston, Dick
Cc: Mason, Mike C; Hey, Michael-James; Adair, Paul; Cameron, Paul (ABZ); Saul, David C (D&C Aberdeen); Peacock, Ralph; Sweeney, Frank M
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Thanks for your time,
David.

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From: Morel, Brian P
Sent: Tue Apr 13 12:13:29 2010
To: Walz, Gregory S
Subject: FW: Macondo
Importance: Normal

FYI

From: Kelley, Merrick M
Sent: Monday, April 12, 2010 11:08 PM
To: Morel, Brian P
Cc: Hafle, Mark E
Subject: RE: Macondo

Brian
I suspect there is more to your question, if so please advise but to address the below, the Macondo tree order for 3 trees is on the schedule to be placed in the 3Q 2010 with a 2Q 2012 delivery. I am going to install the LDS on Isabela at the beginning of June. I know you all are under pressure to finish Macondo so we can get Nile P&A moving and not jeopardize the Kaskida well and IFT. I can also anticipate the challenge back to us about not installing the LDS with the rig to save 24 hours rig time. If you all plan to take this stand please ensure you have it well documented that boat charges will still need to be allocated on the Macondo drilling AFE or if that is not considered part of your scope then please ensure you all do a clear job of documenting this for the completion team so we have it on the radar for the completion AFE.
Based on resources and priority we will not likely combine the Isabela and Macondo lock down sleeve jobs and will leave it until the Macondo development plan is progressed and approved.
On another note, please advise how you plan to leave the high pressure wellhead preserved, i.e. with wellhead preservation fluid and a lightweight T/A cap, etc.
Thanks
Merrick

From: Morel, Brian P
Sent: Monday, April 12, 2010 4:42 PM
To: Kelley, Merrick M
Subject: Macondo

Merrick,
Can you confirm if a tree has been ordered for Macondo and timing on that tree arriving? Do you know when the Isabella LDS is going to be set?

Thank You,
Brian Morel

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