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Improved Regulatory Oversight using Real-Time Data Monitoring Technologies in the Wake of Macondo

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Improved Regulatory Oversight using Real-Time Data Monitoring Technologies in the Wake of Macondo

by

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Thesis

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Dedication

To the Holy Trinity, Stella Maris, and to my family.

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Abstract

Improved Regulatory Oversight using Real-Time Data Monitoring Technologies in the Wake of Macondo

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As shown by the Macondo blowout, a deepwater well control event can result in loss of life, harm to the environment, and significant damage to company and industry reputation. Consistent adherence to safety regulations is a recurring issue in deepwater well construction. The two federal entities responsible for offshore U.S. safety regulation are the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) and the U.S. Coast Guard (USCG), with regulatory authorities that span well planning, drilling, completions, emergency evacuation, environmental response, etc. With such a wide range of rules these agencies are responsible for, safety compliance cannot be comprehensively verified with the current infrequency of on-site inspections. Offshore regulation and operational safety could be greatly improved through continuous remote real-time data monitoring.

Many government agencies have adopted monitoring regimes dependent on real-time data for improved oversight (e.g. NASA Mission Control, USGS Earthquake Early Warning System, USCG Vessel Traffic Services, etc.). Appropriately, real-time data monitoring was either re-developed or introduced in the wake of catastrophic events within those sectors (e.g. Challenger, tsunamis, *Exxon Valdez*, etc.). Over recent decades, oil and gas operators have developed Real-Time Operations Centers (RTOCs) for continuous, pro-active operations oversight and remote interaction with on-site personnel. Commonly seen as collaborative hubs, RTOCs provide a central conduit for shared knowledge, experience, and improved decision-making, thus optimizing performance, reducing operational risk, and improving safety. In particular, RTOCs have been useful in identifying and mitigating potential well construction incidents that could have resulted in significant non-productive time and trouble cost.

In this thesis, a comprehensive set of recommendations is made to BSEE and USCG to expand and improve their regulatory oversight activities through remote real-time data monitoring and application of emerging real-time technologies that aid in data acquisition and performance optimization for improved safety. Data sets and tools necessary for regulators to effectively monitor and regulate deepwater operations (Gulf of Mexico, Arctic, etc.) on a continuous basis are identified. Data from actual GOM field cases are used to support the recommendations. In addition, the case is made for the regulator to build a collaborative foundation with deepwater operators, academia and other stakeholders, through the employment of state-of-the-art knowledge management tools and techniques. This will allow the regulator to do “more with less”, in order to address the fast pace of activity expansion and technology adoption in deepwater well construction, while maximizing corporate knowledge and retention. Knowledge management provides a connection that can foster a truly collaborative relationship between regulators, industry,

and non-governmental organizations with a common goal of safety assurance and without confusing lines of authority or responsibility. This solves several key issues for regulators with respect to having access to experience and technical know-how, by leveraging industry experts who would not normally have been inaccessible. On implementation of the proposed real-time and knowledge management technologies and workflows, a phased approach is advocated to be carried out under the auspices of the Center for Offshore Safety (COS) and/or the Offshore Energy Safety Institute (OESI). Academia can play an important role, particularly in early phases of the program, as a neutral playing ground where tools, techniques and workflows can be tried and tested before wider adoption takes place.

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Chapter 1

Introduction

In the wake of Macondo, many efforts have been undertaken by industry and regulators to update standards, improve company best practices, and revise regulatory requirements to address the weaknesses exposed by the incident. Macondo highlights the complexity of operating in deepwater drilling environments and the associated exposure to occupational and process safety risks, even with some of the most sophisticated industrial systems available and a rig crew with a seven-year record without a lost-time incident (Deepwater Horizon Study Group, 2011). Challenges that will need to be addressed in the coming years include:

1. The drilling of deeper, more complex wells in deeper water and high temperature/high pressure (HPHT) geological environments that leave increasingly less room for error. Examples are the high-complexity wells that are now being planned and drilled in the Lower Tertiary and Jurassic Norphlet Plays in the offshore Gulf of Mexico.
2. The accelerating pace of technology development and application required to construct such complex wells, with standards covering such technology and their adoption into regulation lagging far behind. An example of such acceleration is seen in the progressive adoption of managed pressure drilling (MPD) techniques in the offshore environment, with the timescale from conception to application typically on the order of a few years or less. Standards development (carried out by highly credible but slow-acting entities such as API) and adoption of standards into

legislation and regulation, by contrast, take place on the timescale of a decade or more.

3. Regulators stretched by increasing offshore activity, which is buoyed by a relatively stable and high price of oil. Despite considerable (and ultimately unsustainable) cost escalation in the market place for offshore goods and services in the past decade, large offshore discoveries coupled with a high oil price are allowing deepwater operators to contract for additional deepwater drilling rigs and plan expanding drilling campaigns, thereby creating almost insurmountable resourcing challenges for the regulator charged with maintaining oversight.
4. The ongoing "Big Crew Change" and the loss of valuable deepwater well construction knowledge and expertise, which will further complicate access by regulators to scarce subject matter experts, who are also much better financially compensated when working for industry.
5. Finding a collaborative environment between regulators and operators where the goals and objectives of both parties are met and antagonism and mistrust between the parties are minimized. A balance needs to be found where the regulator can effectively oversee offshore well construction in a "trust-but-verify" approach with a combination of effective prescriptive and performance-based guidelines that prevent train wrecks such as Macondo, while the operator can demonstrate compliance with the regulations but avoid being "over-regulated" with intrusive measures that may lack the perspective, expertise and experience of industry experts.

In this thesis, the argument will be made that progressive adoption of real-time monitoring and communication technologies by the regulator in collaboration with deepwater operators offers (at least partially) a solution to these challenges, a solution that also makes optimum use of available resources and thereby is sustainable in the longer term. Moreover, this thesis is aimed to show that adoption of real-time technologies for regulatory oversight progressively addresses the prevention and mitigation of severe offshore well problems. Two main aspects are tackled:

1. Remote oversight through real-time monitoring and analysis technologies. A variety of reports have been written analyzing the sequence of events leading up to the Macondo blowout. Overarching themes that emerge from those reports show that breakdowns in process safety occurred in the following areas:
    - Adherence to approved programs
    - Barrier testing and validation
    - Blowout preventer (BOP) condition validation and operational readiness assessment
    - Anomaly detection and event mitigation
    - Management of change
    - Knowledge management

    This thesis will show that new real-time tools, systems and workflows have become available in recent years that can help avoid such breakdowns, and that real-time monitoring can itself be inserted as an additional barrier to avoid well construction hazards from turning into catastrophic events.

2. Effective knowledge management, facilitated by the latest tools and techniques that provide regulators with access to the necessary subject matter expertise. As already indicated, with the Big Crew Change, the industry has a large amount of brainpower and experience on the brink of retirement. The responsibilities of these individuals will progressively fall upon less experienced and less knowledgeable personnel. In the competition for the best talent, the regulator has great difficulty to compete, and BSEE has continually been challenged to fulfill its needs for manpower while struggling at the same time to provide its personnel with the necessary offshore well construction experience. Rather than pit the regulator against the operator, it is proposed here that they instead join forces in a knowledge sharing network facilitated by state-of-the-art knowledge management tools.

In an exemplary response to the Macondo blowout, great strides were made towards improving secondary and tertiary well control measures associated with improving BOP reliability, deployment of spill response measures, use of capping stacks, etc. It can be argued, however, that such measures are largely reactive and more could be done to augment the progressive adoption of Safety Cases on pro-active risk mitigation and prevention. The Macondo/*Deepwater Horizon* Case Example below demonstrates what the author has in mind in this regard, and introduces the main theme that will be explored further throughout the thesis.

1.1 MACONDO/*DEEPWATER HORIZON* CASE EXAMPLE

The Macondo blowout resulted in the loss of 11 lives on the *Deepwater Horizon* drilling rig and the largest offshore oil spill in American history (Chief Counsel's Report, 2011). A deepwater well, Macondo was drilled in 4,992 ft. of water in the Gulf of Mexico, with an expected total depth of 20,600 ft. (Chief Counsel's Report, 2011). Drilling was commenced in October, 2009 by the rig *Marianas*; however, in November, 2009, *Marianas* was damaged by a nearby passing hurricane (Deepwater Horizon Study Group, 2011). *Deepwater Horizon* replaced *Marianas* and recommenced drilling Macondo in February, 2010 (Deepwater Horizon Study Group, 2011). Already behind schedule, crews experienced multiple adverse drilling events, including multiple losses of circulation and a wellbore influx (kick) at 13,305 ft. that went undetected for 33 minutes (Deepwater Horizon Study Group, 2011). Drilling was terminated at 18,360 ft. after identifying a 123-ft. thick pay sand in the well and determining that the well had "run out of drilling margin" (Deepwater Horizon Study Group, 2011).

Temporary plugging and abandoning procedures were commenced, with a primary cementing plan that called for foam cement and 21 centralizers on a long string production liner (Deepwater Horizon Study Group, 2011). An insufficient number of centralizers were available on the rig, but the decision was eventually made to run the production liner with 6 of the required 21 centralizers (Deepwater Horizon Study Group, 2011). After placing the production liner, an attempt was made to close the flapper valves in the float collar that are kept in an open position to fill the liner with wellbore fluids during placement (Deepwater Horizon Study Group, 2011). Converting the valves should have taken one attempt with a pressure between 400 and 700 psi; however, nine attempts were made, reaching a final pressure of 3,142 psi, with no certain determination that the valves had converted to a closed position (Deepwater Horizon Study Group, 2011).

Upon cement placement of a compressible foam cement slurry across the pay zone, with a lead and tail slurry of heavier conventional cement, it was deemed by decision makers that a cement bond log was unnecessary to confirm proper placement and bonding of the cement (Deepwater Horizon Study Group, 2011). Lab tests of the proposed slurry performed by the service company showed a minimum wait time of 48 hours prior to conducting the required positive and negative pressure tests (Deepwater Horizon Study Group, 2011). Crews waited 10.5 hours before conducting positive pressure test, confirming pressure integrity of the production liner and potentially compromising the integrity of the slurry (Deepwater Horizon Study Group, 2011).

To confirm isolation of the hydrocarbon bearing zone, crews performed a negative pressure test. The test failed, as there was more fluid flowback than expected (Deepwater Horizon Study Group, 2011). A second test occurred with similar results, and after deliberation, an onsite decision was made that the unexpected pressure observed was due to "bladder effect" (Deepwater Horizon Study Group, 2011). After determination of positive zonal isolation, which was an incorrect determination, procedures for abandonment were continued, including displacement of wellbore fluids with lighter seawater (Deepwater Horizon Study Group, 2011). The well was put into an underbalanced situation, allowing a hydrocarbon influx at the bottom of the well (Deepwater Horizon Study Group, 2011). The influx migrated up the well and blew out at surface, causing the explosion and spill that forever changed the offshore oil and gas industry (Deepwater Horizon Study Group, 2011).

Figure 1.1 shows recorded data from the Macondo well operation approximately 1 hour before gas came to surface, first and second explosions occurred and rig power was lost at 21:49 on April 20th, 2010 (Deepwater Horizon Study Group, 2011). Mud displacement operations are underway, with 14.7 ppg drilling mud being displaced by much lighter 8.6 ppg seawater. The operation removed the primary barrier, i.e. the hydrostatic pressure generated by the weighted mud column, which, coupled with a compromised well cementation and failing float system allowed gas and oil to come to surface. Even though this simple time-based graph only shows the limited information of standpipe pressure, flow- in and out of the well, and trip tank volume, sufficient information was present for the event to be detected and possibly contained (e.g. using controlled shut-in of the BOPs and proper diversion of the gas in the riser) prior to it escalating to its catastrophic impact. The circulation of the less dense seawater into the well at constant pump rate should have reflected in the standpipe pressure (orange line) as a net decrease in pressure (due to a reduction in fluid frictional pressure loss), when instead, the opposite is observed. Around 21:00 the standpipe pressure begins to increase and continues to do so even after circulation pumps are shut off around 21:08. This trend continues for a substantial amount of time. Additionally, for a short period of time, it can be observed that the flow out of the well (green line) exceeds the flow in the well (blue line). It is understood that during this time, flow data was somewhat unreliable due to simultaneous operations taking place (mud being pumped off the rig to supply boats for return to shore). However, as noted in Figure 1.1, a small window of time with no simultaneous operations directly shows that the well was flowing, and the increases observed in the standpipe pressure are a direct indication that the well was not under control. Note that the value of the data is not in the absolute numbers that are reached at any point in time, but instead in the relative trend over time that provides clues to underlying causes.

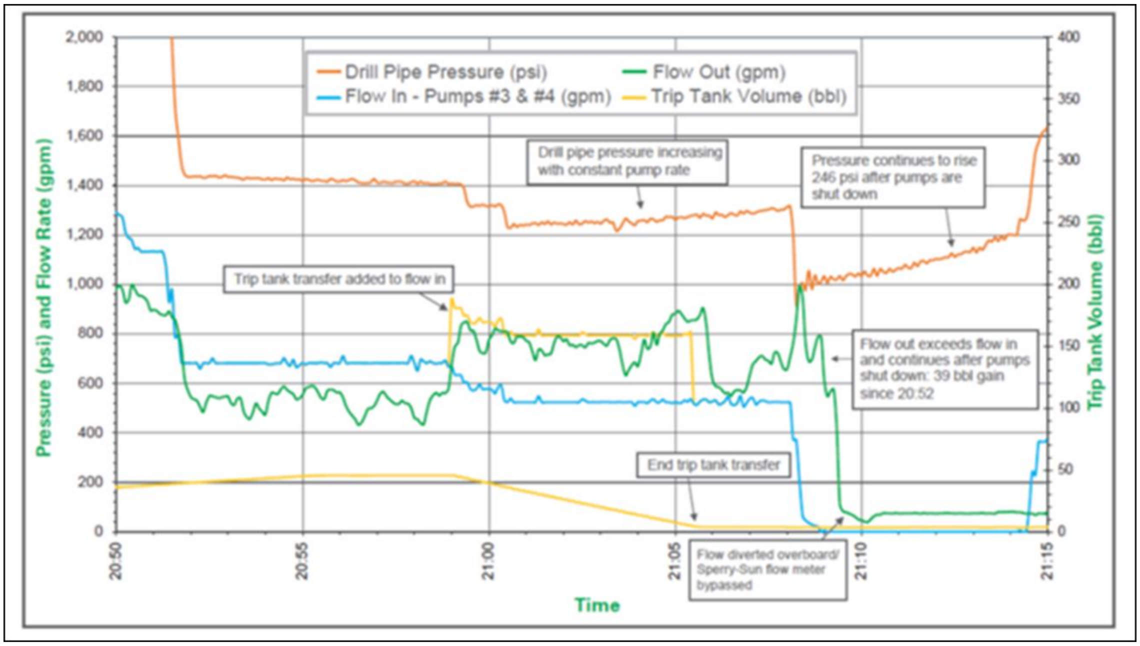


Figure 1.1: Real-time data from the Macondo blowout indicates symptomatic conditions of well flow could have been identified (from Deepwater Horizon Study Group, 2011).

The primary lesson from Figure 1.1 is that had this data and its trend over time been actively monitored, whether by a company RTOC and/or regulator, and whether by human observers or an automated real-time system able to detect adverse data trends, these anomalies could have been identified and flagged, allowing decision makers at the rig site to take corrective action. From the first noticeable 'symptom' in the real-time data around 21:00, there was approximately a 50 minute window before fluids were ejected at the drill floor. Even identifying symptoms right after circulation was suspended could have allotted approximately a 30 minute window for mitigating actions to be attempted. Even if the BOP was not able to shut-in the flow from the well, an emergency disconnect could have been attempted to separate the rig from the well. While it may not have been possible to stop the hydrocarbon flow, the window of time could have permitted proper alignment of the diverter, evacuation of the crew from the rig, etc.

This example also highlights the potential for smart real-time technology to aid humans in detection of adverse events. Judging from the Macondo real-time sensor data, a straightforward relationship between the constant pump rate, the changes in standpipe pressure, the change in density of fluid pumped in and out of the well, as well as flow rate could have been utilized to automatically detect well flow symptoms and alert relevant stakeholders. Even simpler and more direct measurements are currently available to measure relevant pressures, flow and volumes, temperatures etc. associated with well barriers evaluated in pressure tests (e.g. leak-off tests, and positive and negative pressure tests after cementing), monitoring of well flow during connections and other flow checks, etc. Moreover, the possibility exists to port this data instantaneously across data-communication and data-visualization systems to remote stakeholders for analysis and oversight purposes.

The key point here is that such technology, at various levels of sophistication, does not need to be invented but is already available and can be leveraged to great effect for oversight purposes, by the operators themselves as well as the regulator. Regardless of certain unique characteristics of a well, there are universal characteristics with inherent benefit that, if monitored, can be exploited from commonly acquired data to prevent and mitigate potentially unsafe events. This, then, sets the theme for the remainder of the thesis.

1.2 THESIS OUTLINE

There are seven chapters in this thesis. The first chapter is an introduction to the current and future challenges deepwater operators and regulators must address to ensure safe drilling and completion practices. Additionally, a brief introduction to the events and analysis of the data related the Macondo blowout are provided to show the motivation and reasoning behind this thesis. The second chapter provides a literature review of the employment of real-time data monitoring technologies in both the oil and gas industry as well as agencies within the U.S. government. In the third chapter, insight is provided on the U.S. offshore regulatory structure and focuses the discussion on the areas in the well construction process in most need of improved regulatory oversight. The third chapter also summarizes the current regulatory requirements related to these areas. In the fourth chapter, current real-time data monitoring capabilities are presented in relation to the areas in most need of improved regulatory oversight. Field examples of real-time data monitoring are also presented in this chapter. The fifth chapter presents the case for regulators to employ various knowledge management concepts to improve in-house expertise, operational capabilities, and regulation development. In the sixth chapter, recommendations for implementation of real-time data monitoring technologies as well as future work related to addressing other technology and safety matters in deepwater drilling and completion operations are presented. The seventh chapter provides a list of final key conclusions drawn from this research.

Chapter 2

Literature Review

Since the advent of the digital age, operations have become more and more dependent upon analysis of relevant data. The utilization of data allows for both optimization of performance as well as insight into potential safety hazards. Maturation of real-time data monitoring capabilities over the decades has resulted in successful implementation spanning a variety of sectors, both in industry and government.

2.1 INDUSTRY EXPERIENCE WITH REMOTE DATA MONITORING CENTERS

Oil & Gas RTOCs have a well-documented history dating back to the 1980s (Booth, 2009, Booth, 2010). As technology has advanced, these centers have played a vital role in understanding downhole operations, as well as disseminating data to an audience no longer limited to on-site monitoring. While some RTOCs within the first "generation" played an active role in project execution, much of the mission of these earlier centers was data collection and future optimization (left of center in Figure 2.1) (Booth, 2009). The speed of data transmission and the ability to apply faster, more advanced modelling catalyzed the advent of the second "generation" of RTOCs (2000s), capable of playing a more pro-active role in both planning and execution of drilling programs (right of center in Figure 2.1). Booth (2010) outlines many of the initiatives by these international oil companies in establishing RTOCs for the North Sea and Gulf of Mexico, as well as Saudi Aramco's RTOC initiative.

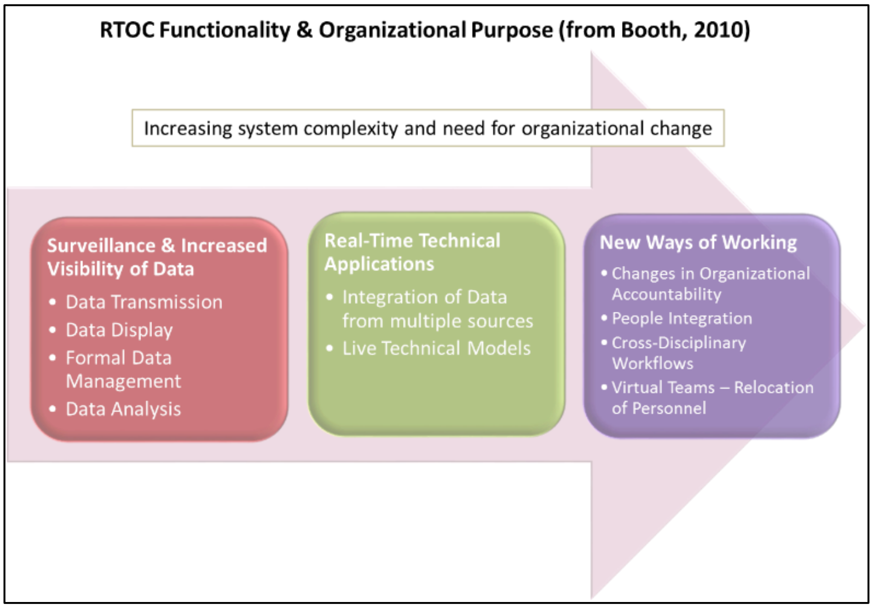


Figure 2.1: Scale of the functionality and purpose of RTOCs (from Booth, 2010).

These new data centers' effectiveness improved with advancements in data acquisition and telecommunications, and became the solution for the gap in quick decision-making in remote and complex drilling environments, such as the offshore deepwater environment. The second generation of RTOCs has demonstrated the ability to remotely monitor distant drilling operations and aid in improved decision-making process for reduced trouble time and improved process safety.

The establishment of RTOCs has dominantly been a private venture, with some of the more notable state-owned petroleum companies following suit in more recent years (Khudiri et al., 2008, Khudiri et al., 2009, Pérez-Téllez et al., 2012). Shell has been at the forefront of the development of RTOCs in the 21st century and has a documented history of implementing continuous remote real-time monitoring on a global scale (van Oort et al., 2005, Hamed et al., 2007). Additionally, Shell's large presence in deepwater, particularly the Gulf of Mexico, has positioned the company to apply many new methods and technologies for improved deepwater drilling performance (Greenwood et al., 2005, van Oort et al., 2005, Hamed et al., 2007).

The best characterization for RTOCs in the modern era would be "remote support for improved decision-making," facilitating effective collaboration while maintaining operational responsibilities as traditionally assigned (van Oort, et al., 2005). With respect to collaboration, the global networking capability of RTOCs naturally make them "hubs" where expertise can virtually meet and discuss critical issues with wells located around the world. By fostering a pro-active well design and execution approach with a primary goal of reducing non-productive and lost time, not only is operational efficiency increased, but there is an increased situational awareness that, with the right culture, can lead to improved safety.

2.2 GOVERNMENT EXPERIENCE WITH REAL-TIME REMOTE MONITORING

In the U.S., the term "government monitoring" is often seen as synonymous with Orwellian "Big Brother" control. It is often met with a negative sentiment and immediate rejection of such a concept. The Big Brother anxiety is not new to the oil & gas RTOC paradigm, and effective mitigation of these concerns has been documented in at least one RTOC implementation (van Oort et al., 2005). It is the author's belief that through careful and collaborative use of real-time technologies for well construction oversight in offshore waters, the needs of both the regulator, representing the government of the U.S and thereby its citizens, as well as industry can be met and that the Big Brother concern can be effectively addressed. Note that there are precedents. With general welfare and safety of the public in mind, multiple government agencies have developed real-time data monitoring capabilities with highly sophisticated data processing and analysis algorithms in order to increase decision-making and response time and prevent catastrophic incidents. Examples are given in the following.

2.2.1 National Aeronautics & Space Administration (NASA)

Arguably the foundational institution with regards to developments and advancements in real-time systems technology is the National Aeronautics and Space Administration (NASA). NASA would be unable to safely conduct space missions without the availability of ample data transmission in real-time. Real-time data monitoring has existed hand-in-hand with the advent of U.S. manned space flight. Mercury, the first NASA manned space flight program ushered in the era of truly real-time data telemetry, and computers had to process data simultaneously from multiple locations for decision-making within a 10 second window (James, 1981). Advancement of NASA's real-time data technologies have continued to mature with the introduction of more complex spacecraft and more demanding mission objectives (James, 1981). However, the purpose of real-time data acquisition still remains to provide Mission Control "with the information needed to ensured crew safety and mission success" (James, 1981).

Within hours prior to the launch of Space Shuttle Challenger, engineers for the manufacturer of the solid rocket boosters (SRB) expressed concerned that abnormally cold weather could have possibly compromised the integrity of the O-rings on the SRBs (Hall, 2003). Following the Challenger disaster, NASA relied more heavily on real-time data processing, improving the decision-making process for subsequent shuttle missions (Muratore, 1990). The integration of knowledge-based real-time intelligent decision support systems within the Mission Control Center construct further enabled the ability to quickly process and interpret data and aid in decision-making (Tavana, 2004). With the progression of complexity in missions, a reflective growth in real-time data monitoring and assessing technologies, and thus safety assurance, could be observed. Since the advent of these systems, NASA has effectively ensured safely executed manned spaceflight missions for decades.

2.2.2 U.S. Geological Survey (USGS)

In the past decade, the world witnessed stark reminders of the severe impact seismic activity can have on human life. Since it is impossible to stop an act of nature, the most prudent measures that can be taken are preparation and prediction. The use of real-time data for earthquake severity and propagation prediction has been an undertaking in recent decades in Japan, Taiwan, Mexico, Romania, Turkey, and more recently California (Böse et al., 2009). The United States Geologic Survey (USGS) is responsible for issuing earthquake alerts in California, and has led the development of an Earthquake Early Warning (EEW) system for the state (Böse et al., 2012). The system makes use of the existing site monitoring infrastructure of the California Integrated Seismic Network (CISN), monitoring and processing real-time data with the introduction of three parallel detection algorithms (Böse et al., 2012).

Due to the high speed at which seismic waves propagate, this system must receive and process data, then make predictions and warnings within seconds in order to provide any legitimate window of time for reaction (Böse et al., 2009). The Onsite algorithm processes data input from P-wave detection of two nearby stations to estimate the size, severity, and ground velocity of the earthquake. This algorithm provides very fast although arguably less accurate predictions. The Virtual Seismologist algorithm applies a Bayesian approach which assesses the likelihood that the incoming real-time data is in fact an earthquake. The algorithm is also employed to estimate magnitude, location, and time of origin. Requiring a minimum of four stations detecting activity, estimates are made at an average of 20 seconds after earthquake onset at the epicenter. The ELarmS algorithm is network-based, employing data from multiple sources within a large area, thus resulting in more accurate, but slower, estimations. The earthquake hypocenter is estimated by searching 965 square miles of land area, comparing predicted P-wave speed and actual P-wave detection at stations. The three algorithms are then processed through a decision module that finalizes the prediction and issues warnings to users. While the final implementation of this monitoring system is still in need of funding development and funding (Böse et al., 2009), the EEW shows promise for reliable earthquake alerts to maximize the window of opportunity for preparation.

2.2.3 U.S. Coast Guard (USCG)

The USCG is charged with facilitating safe and efficient transit of commercial traffic in federal ports and waterways. Established in the 1970s in eight ports, USCG Vessel Traffic Services (VTS) originally primarily relied on radio communications for facilitation of safe waterways (Pietraszewski, 1996). After the passing of the Oil Pollution Act of 1990 in the wake of the *Exxon Valdez* oil spill, VTS technological advancements became seen as vital to ensuring pro-active real-time traffic management for improved safety and environmental protection (Pietraszewski, 1996).

The advent of the marine Automatic Identification System (AIS) in the 1990s has made efforts to achieve this mission significantly more efficacious as compared to the days of just verbal radio transmission and radar (Schwer, 2011). AIS facilitates VTS to establish a structure in which a VTS operator can monitor speeds and headings of multiple vessels in real-time to effectively coordinate traffic via VHF data transmissions from vessels (Schwer, 2011). AIS can also transmit vessel-to-vessel, improving mariner situational awareness and critical decision-making for collision avoidance (Schwer, 2011). VTS operators can also intervene by notifying vessels that deviate from safe headings, as well as arrange traffic schemes when certain areas of a waterway may be shutdown. The adoption of real-time technology such as AIS has significantly advanced the ability of VTS to perform traffic management pro-actively and to aid in preventing hazards to human life and the environment. To date, VTS now has operations in 12 major ports through the U.S., utilizing radio communications, radar, waterway cameras, and AIS to ensure safe transit of commodities vital to the U.S. economy (U.S. Coast Guard Navigation Center, 2014).

2.2.4 Federal Aviation Administration (FAA)

Similar to the USCG, the Federal Aviation Administration (FAA) has been responsible for the surveillance and safe coordination of air traffic throughout U.S. airspace. As close to 7,000 aircraft occupy U.S. airspace at any given time, efficiency related to all-time high delays as well as safety become an ever-growing concern (Kovell et al., 2012). It is anticipated that air traffic density will only increase in the coming decades, increasing traffic controller workloads (Federal Aviation Administration, 2013). The traditional method for air traffic surveillance has been the use of both conventional radar and a beacon system employing transponders on aircraft (Kovell et al., 2012). These dated tracking technologies provide a limited set of data (position, velocity, altitude) (Kunzi et al., 2011, Kovel et al., 2012) to air traffic controllers, thus relying on the controller to interpret and communicate via radio to the respective aircraft. Modern day aircraft are equipped with much more advanced avionics, capable of providing a greater and more accurate quantity of information to air traffic controllers (Kunzi et al., 2011)

A new initiative underway by the FAA is the implementation of NextGen Air Transportation System. NextGen is a “comprehensive overhaul of the National Airspace System” for improved air traffic efficiency and safety (Federal Aviation Administration, 2011). One of the major efforts in this undertaking is the transition from the conventional air traffic surveillance systems to the employment of the Automatic Dependent Surveillance-Broadcast (ADS-B) system (Federal Aviation Administration, 2011). The ADS-B system entails multiple facets of information broadcasting, transmitting data from aircraft-to-air traffic control (ATC), ATC-to-aircraft, as well as aircraft-to-aircraft (Estes et al., 2010). ADS-B as a whole provides a larger and more accurate operational picture to both controllers and pilots, with more frequent transmission rates than radar, providing “higher position and velocity accuracy, direct heading information as well as geometric and barometric altitude (Kunzi et al., 2011).” Multiple aircraft in vicinity of one another can also utilize data transmissions to calculate relative range and bearing for collision avoidance (Kovell et al., 2012). FAA regulations mandate that aircraft in most U.S. airspace be capable of ADS-B broadcasting by 2020 (Federal Aviation Administration, 2011). ADS-B has been successfully employed in multiple regions of U.S. airspace, including helicopter traffic in the Gulf of Mexico (Federal Aviation Administration, 2011). This advancement in air traffic management enables traffic controllers to minimize aircraft separation, coordinate more efficient traffic patterns, in addition to reducing risks of collision (Kovell et al., 2012).

A common theme within these examples is the relationship between efficiency and safety. Better-informed critical decision-making can translate into fewer mistakes, which relates to improved efficiency and increased safety. The use of advancing data transmission as well as intelligent processing systems by these agencies has enabled greater situational awareness by government agents and in return greater situational awareness by those that fall under the agents' responsibilities, such as astronauts, persons residing in earthquake-prone areas, commercial vessel traffic, and the commercial and general aviation communities. This improved situational awareness yields better decision-making and mitigated risk by data-monitoring government agencies. Many facets of these real-time data monitoring capabilities could be employed by offshore regulators, such as utilization of the already established data transmission architecture in the Gulf of Mexico, artificial intelligence and simple algorithms to establish relationships between data parameters and previous well experiences, and identification of situations needing immediate intervention to prevent disastrous consequences.

Chapter 3

Offshore Regulatory Structure and Requirements

There are many parameters and variables associated with offshore well construction. Not all will be of interest to the regulator, even though they may be of great interest to the operator (especially parameters associated with performance, well construction time and cost optimization). This chapter will attempt to delineate what well construction information should be of interest to the regulator. This requires an investigation into offshore regulatory structure and requirements.

3.1 REGULATORY AUTHORITIES AND RESPONSIBILITIES

The Outer Continental Shelf Lands Act (OCSLA) primarily designates the Secretaries of the Interior and of the department in which the USCG is operating (currently Homeland Security) with the authorities to "promulgate and enforce" regulations for offshore exploration and production operations in the United States ("Outer Continental Shelf Lands Act", 2000). While retained by the respective Secretaries, these authorities are delegated to such agencies as BSEE and the USCG. There are a few areas of pertinence to this research worth noting in the act. First, regarding public interest, OCSLA emphasizes the value of natural resources possessed by the OCS, with the Federal Government as its custodian for the public. Additionally OCSLA mandates that OCS operations should be conducted "using technology, precautions, and techniques sufficient to prevent or minimize the likelihood of blowout, loss of well control (…) or other occurrences which may cause damage to the environment or to property, or endanger life or health." Regarding safety regulations, both agencies are mandated to require the utilization of the best available and safest technologies (BAST) on new and existing (when practicable) drilling and production operations.

With respect to safety inspections, OCSLA requires that the lease/permit holder give access to BSEE and USCG inspectors to any requested records or information of onsite operations relevant to health, safety, or environmental stewardship ("Outer Continental Shelf Lands Act", 2000). BSEE and the USCG must independently or jointly conduct a scheduled onsite safety inspection once per year with additional unannounced, periodic inspections. For investigations, the act mandates that either BSEE or the USCG shall investigate incidents involving a major fire, major oil spill due to OCS operations, death or serious injury, as well as allegations regarding violations of OCSLA safety regulations. The act also gives BSEE and the USCG the authority to require any evidence necessary for proper investigation of an incident.

BSEE is responsible for the promulgation and enforcement of Title 30, Chapter II of the U.S. Code of Federal Regulations (CFR). Derived from OCSLA, this set of regulations, particularly part 250, applies to oil, gas, and sulfur operations related to exploration, development, and production on the OCS. The USCG is responsible for the promulgation and enforcement of regulations within both Title 33 and 46 with respect to OCS safety of life at sea and environmental protection related to commercial vessels, including mobile offshore drilling units (MODUs) and fixed and floating facilities. When discussing the use of real-time data monitoring for regulation, BSEE would likely be the primary beneficiary of such an implementation; however, it is important to keep the USCG included in the discussion. While both have defined regulatory responsibilities, many of these areas of regulation are intricately interrelated and are vital for both agencies to have an understanding.

The primary objective in ensuring safety in drilling and completions is to minimize loss of well control events and prevent blowouts, thus preventing injury, loss of life, and damage to the environment. One study of U.S. OCS exploration from 1992 to 2006 identified the top contributing factors for blowout events (Izon et al., 2007), as can be seen in Figure 3.1. Within this time frame, almost half of the recorded incidents involved an improperly cemented well. Note that this study only considered incident data up to 2006, not including the Macondo incident in 2010, in which a major contributing factor was the lack of proper zonal isolation by the cement job on the production casing. Along with cementing, these statistics give the direction and motivation as to where regulatory oversight could be improved using real-time data monitoring. Four areas of real-time data monitoring that would encompass the majority of contributing factors to uncontrolled well control events are:

- BOP reliability (equipment failure)
- Formation strength (formation fracture)
- Zonal isolation (cementing)
- Drilling event detection (swabbing, stuck pipe, drilling into other well etc.)

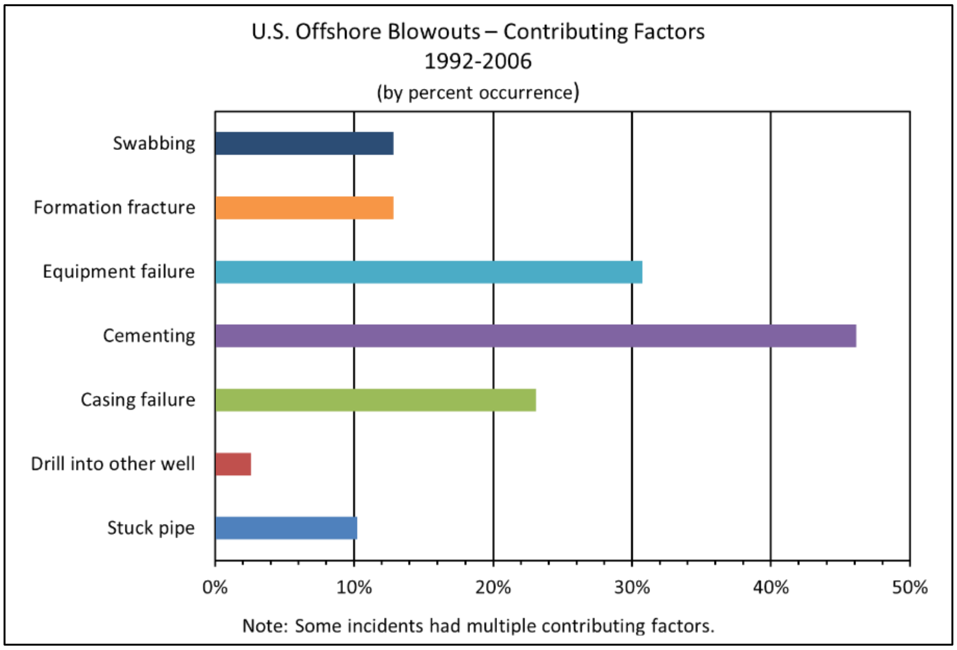


Figure 3.1: Contributing factors to blowouts in the U.S. OCS from 1992 to 2006, expressed as percentage of total occurrence. Note the prominent position of cementing as a contributing factor (from Izon et al., 2007).

These categories not only encompass many of the contributing factors to blowouts, but they also are critical points in the drilling and completions process. As stated by Wassel (2012) regarding regulation of offshore drilling:

> The Macondo well blowout demonstrated the need for a pro-active approach to offshore drilling in U.S. waters that integrates all aspects of operations that could affect occupational and system safety.

Focusing on these areas, utilizing real-time data monitoring technologies, regulators could accomplish a pro-active approach that integrates critical drilling and completion operations. The current regulations surrounding these subjects must first be understood, upon which an implementation of regulatory oversight using real-time data monitoring can be proposed.

3.2 BOP REGULATION

BSEE regulations outline requirements and frequency for testing BOPs. Basically put, the BOP system and associated components must be pressure tested (30 CFR 250.447):

- When installed.
- Within 14 days of the previous test.
- Before drilling out each casing or liner.

In this thesis, only subsea BOPs will be considered. In theory surface BOP stack oversight is a less complicated matter in comparison to subsea BOPs. The intent of BOP pressure tests is to verify that there are no leaks in the system. The basic requirements for pressure testing are that all components must be tested with first a low pressure test between 200 and 300 psi (30 CFR 250.448). Following a satisfactory low pressure test of components, a high pressure test for ram components must be conducted to the maximum working pressure of the equipment or to 500 psi greater than the calculated maximum anticipated surface pressure (MASP) (30 CFR 250.448). Additionally, annular components must be tested to 70 percent of the rated working pressure of the equipment or to a pressure approved in the application for permit to drill (APD) (30 CFR 250.448). The duration of these tests must be for at least five minutes for subsea components (30 CFR 250.448).

In addition to the basic requirements, 30 CFR 250.449 outlines additional requirements regarding BOP testing, including:

- Stump testing subsea BOP systems with water before installation at the mudline.
- Alternation of tests between control pods.
- Function testing annular and ram BOP every 7 days between pressure tests.
- Variable bore ram test requirements.
- ROV intervention requirements.

Along with satisfying these requirements, 30 CFR 250.449 also requires notification of BSEE at least 72 hours prior to stump testing and subsea installation testing and recording of all results to make available to BSEE upon request. This portion of the regulations is quite detailed and prescriptive, but rightly so: BOPs are a critical system that must function when needed. However, these requirements result in very frequent testing that can take many hours out of a critical operations window and is a disruptive and costly repeat exercise to the operator. Also, BSEE requires testing and maintaining records for inspection upon request. This indicates that every test of this critical safety component, while required, is not witnessed by BSEE. Therefore it can be assumed that many of these tests are only audited after the fact.

3.3 FORMATION STRENGTH TEST REGULATION

BSEE regulations require that a formation strength test be performed after drilling out every intermediate casing (or liner) shoe (30 CFR 250.427). Depending on the circumstances, an appropriate test between a leak-off test (LOT) or formation integrity test (FIT) must be selected. A FIT is more likely to be undertaken where it is undesirable to compromise the integrity of the wellbore or formation, or a well-established fracture gradient is known for the strata (van Oort and Vargo, 2007). The formation is tested up to a predetermined pressure (based on maximum desired mud weight), and it is expected the formation will not break down. The pressure selected should remain within the realm of linear elasticity of the formation strength. Once the desired pressure is achieved without fracture, the test is successful, and the pressure in equivalent mud weight is capable of being utilized without damaging the shoe.

A LOT is intended to more accurately identify characteristics of the wellbore and formation. In doing so, the strength of the shoe is permanently weakened. The pressure at which the fracture induced by the LOT closes, known as the fracture closure pressure (FCP), is the best estimate of the minimum principal stress of the formation (most likely the minimum horizontal stress in the normal faulting environment predominating the GOM offshore environment, see van Oort and Vargo, 2007). The minimum horizontal stress provides important geomechanical information about the formation, and can aid in appropriate development of geomechanics models and fracture gradient plots (van Oort and Vargo, 2007). An important note is that fracture reopening pressure (FRP), which is near or equal to FCP, is now the upper threshold regarding formation fracture in a well that a LOT has been performed (van Oort and Vargo, 2007). Thus, drilling fluids and equivalent circulating densities must reflect the lower strength of the wellbore, with the most accurate value for the “fracture gradient” provided by the fracture propagation pressure (FPP). The expected mud weight tolerances or selected mud weights should be identified for every shoe point in the APD, and test results are subject to BSEE audit. As with BOP test data, it can be assumed that many of these tests are only audited after the fact, with few if any FIT/LOT data reaching BSEE in real-time.

3.4 CASING AND CEMENTING REGULATION

Casing and cementing programs must, as required by BSEE regulations, be developed and certified by a professional engineer with sufficient expertise regarding the subject matter. The certification must be submitted with the APD and the approved casing and cementing program must be followed without deviation. Cementing design and execution must meet the minimum requirements of cement being placed in the annular space behind the bottom 500 ft. of casing and achieve 500 psi compressive strength before drilling out or conducting completion operations (30 CFR 250.420). More specific cement placement requirements are prescribed for the various casing types (30 CFR 250.421). Regarding wait-on-cement (WOC) times, BSEE prescribes a minimum required 12 hours of wait time under pressure prior to continuing drilling (30 CFR 250.422) for intermediate and production casing strings.

With respect to pressure test requirements in the regulations, operations cannot be resumed until an acceptable positive pressure test has been performed. The parameters to meet requirements are that the string holds pressure for at least 30 minutes with no less than a 10 percent decline in pressure (30 CFR 250.423). For intermediate and production casing strings, this pressure must be at least 70 percent of the minimum internal yield of the string (30 CFR 250.423). For negative tests, a negative test will at least be required for the final casing string or liner (30 CFR 250.423). Negative test procedures must be submitted for approval with the APD, and successful test results must be documented. The American Petroleum Institute (API) provides guidance on recommended practices for properly installing and verifying flow barriers. To verify zonal isolation, the positive and negative pressure tests are the surest method in verifying cement and casing are properly isolating the well from formations that have flow potential. Some of the criteria for interpreting acceptable or unacceptable test results include (API RP 96):

- Pressure change during hold time
- A visual observation of leak
- A difference between pressure-up volume and bleed-back volume
- A visual observation of fluid level

Discussed later, API RP 96 provides guidance on alternative methods of verifying zonal isolation should pressure testing not be feasible. In the case of any failed negative pressure test, BSEE must be notified and must approve the remedial actions.

3.5 DRILLING EVENT REGULATION

Currently there is no regulation prescribing specific requirements regarding drilling event detection. However, BSEE regulations do require that wells must be kept under control at all times, in particular using BAST "to monitor and evaluate well conditions and to minimize the potential for the well to flow or kick (30 CFR 250.401)." Additionally, operators must "use and maintain equipment necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment (30 CFR 250.401)." With this charge to the operators, it could be argued that the application of intelligent drilling event detection software would be in the interest of applying BAST to the industry. As will be argued in the following, it is quite apparent that the pro-active use of adverse drilling event detection software would greatly benefit the industry from a safety improvement standpoint, and should therefore be of interest to both operators and regulators.

Chapter 4

Current Real-Time Data Capabilities

In the following sections, an overview is provided of the state-of-the-art in real-time monitoring capabilities that can be readily leveraged to facilitate remote oversight that addresses all the regulatory requirements discussed in the previous chapters. The treatment of these capabilities in this thesis is neither exhaustive nor complete: it mainly serves to illustrate to those less familiar with real-time technologies and RTOCs what is already readily available in terms of enabling capabilities in the hope to lend credence to the idea that remote regulatory oversight of offshore operations is not a far-fetched as it may sound when hearing about it for a first time.

4.1 BOP RELIABILITY

BOPs are frequently referred to as the last line of defense regarding total loss of well control. It is a very costly proposition to pull a BOP from the seafloor for repairs, while it is potentially even more costly to neglect a component failure. While company policies tend to put safety at the front of the minds of personnel, the decision to pull carries a hefty cost. Therefore, this decision must be made with as much pertinent information as possible. In order to have a sound picture of BOP reliability, certain areas must be covered:

- Usage (cycles)
- Failure impact
- Testing

Modern-day BOPs, especially subsea BOPs, have a vast array of working components. A common BOP stack configuration that might be used would include two annular preventers, four ram-type preventers, a casing shear ram, and multiple choke and kill line outlets (Holand, 2001). Current subsea BOP control systems are predominantly multiplex-controlled for fast activation in deepwater applications (Holand, 2001). In an extensive series of studies, subsea BOP system reliability data was collected, the second phase of which particularly focused on Gulf of Mexico deepwater wells (Holand, 2001). Between July 1997 and May 1998, data was recorded for 83 wells with water depths ranging from 1,335 to 6,725 ft. (Holand, 2001). Table 4.1 outlines the results of the study with an overview of recorded BOP failures. Additionally, Table 4.1 shows the relatively long periods of time (mean time to failure) these components are employed until failure. It should be noted that over 50% of failures were associated with control systems (Holand, 2001). However, only three rigs employed a multiplex control system at the time (Holand, 2001).

Table 4.1: BOP failures from Holand (2001) study of deepwater Gulf of Mexico wells.

BOP Failures (from Holand, 2001)

BOP Subsystem	**BOP-Days in Service**	**No. of Failures**	**Mean Time to Failure (BOP-Days)**
Annular preventer	4,009	12	334
Connector	4,009	10	401
Flexible joint	4,009	1	4,009
Ram preventer	4,009	11	364
Choke/kil valve	4,009	13	308
Choke/kill lines, all	4,009	8	501
Main control system	4,009	60	67
Unknown*	4,009	2	2,005
Total	4,009	117	34

*Unknown due to poorly described report of failure

A later Gulf of Mexico BOP reliability study from 2004 to 2006 confirmed failure statistics very similar to previous studies, including Holand (Sattler and Gallander, 2010). This would validate the hopes that these are certainly robustly built machines. However, even though the likelihood of failure may be low, the consequences of failure still dictate a high risk involved with BOP reliability. Over time, these components are cycled potentially hundreds of times. Therefore it is important to have a clear record, in real-time, of total component cycles since the last maintenance period, in particular with the control system. Capability is becoming available to monitor BOP control system function in real-time (Chapman and Brown, 2009). Thus, a more pro-active vision of real-time function data can accurately identify when a certain component may be more likely to fail.

Upon failure or malfunction of a BOP component, an investigation must be performed to assess the operational and safety impact the failure may have on BOP reliability. It is inevitable that in the field components will fail, and it would be naïve to assume major operators do not have teams of experts to conduct such assessments. However, with no discredit to this expertise, these assessments may take extended periods of time to research failure effects, remedies, and any regulatory compliance involved. When BOP components fail at 6,000 ft. of water depth, 200 nautical miles from shore, with an 18,000 ft. well with a narrow pore pressure fracture gradient, at a rig rate of over $1M per day, assessing the reliability of a BOP becomes a very critical exercise, and convincing regulators of its soundness could be an equally tolling task. Current technologies can provide an accurate failure effects analysis of BOP reliability based on failed components in a matter of minutes (Huse and Alme, 2013). This type of software is commonly found in the nuclear industry to assess risk based on failed components. There are some limitations to this software. Currently, manual troubleshooting must be undertaken in order to first identify the failure point. Then the failure must be manually entered into the software to then receive a final assessment of BOP reliability. If this technology were to be automated to assess, in real-time, BOP reliability based on sensor data connected to BOP components, this would become a much more valuable tool. There has been a similar effort as of recent to provide an assessment of BOP "health" integrating existing alarms and data in real-time (McKay et al., 2012). Regulatory oversight and safety in the industry could benefit from requirements for a technology capable of this type of performance.

Based on BSEE regulations alone, there is a significant amount of testing required to validate BOP stack operability and reliability. The intent of these tests is to verify each BOP component's ability to hold pressure. As discussed earlier, BSEE requires both high and low pressure (between 200 and 300 psi) tests to be conducted. Historically, pressure data and leak detection has been verified with an analog circular chart recorder (CCR) (Winters et al., 2007). It can be observed from the example in Figure 4.1 that the CCR has a relatively poor resolution, particularly in the case of the low pressure test. This can lead to a fairly subjective judgment as to whether or not the leak test was passed. Based on the resolution of the CCR, acceptable "flat-lines" typically reflect a pressure change/decline rate of –4 to –3 psi/min (Winters et al., 2007). One study found in over 100 sets of BOP pressure tests (10 to 25 tests per set), flat-lines determined as "acceptable" by personnel witnessing the tests ranged from 4 to over 20 psi/min (Franklin et al., 2011). By recording tests digitally, resolution can be improved, typically on the higher order of –3 psi/min or better, and data can also be transmitted in real-time to remote locations for better interpretation (Winters et al., 2007).

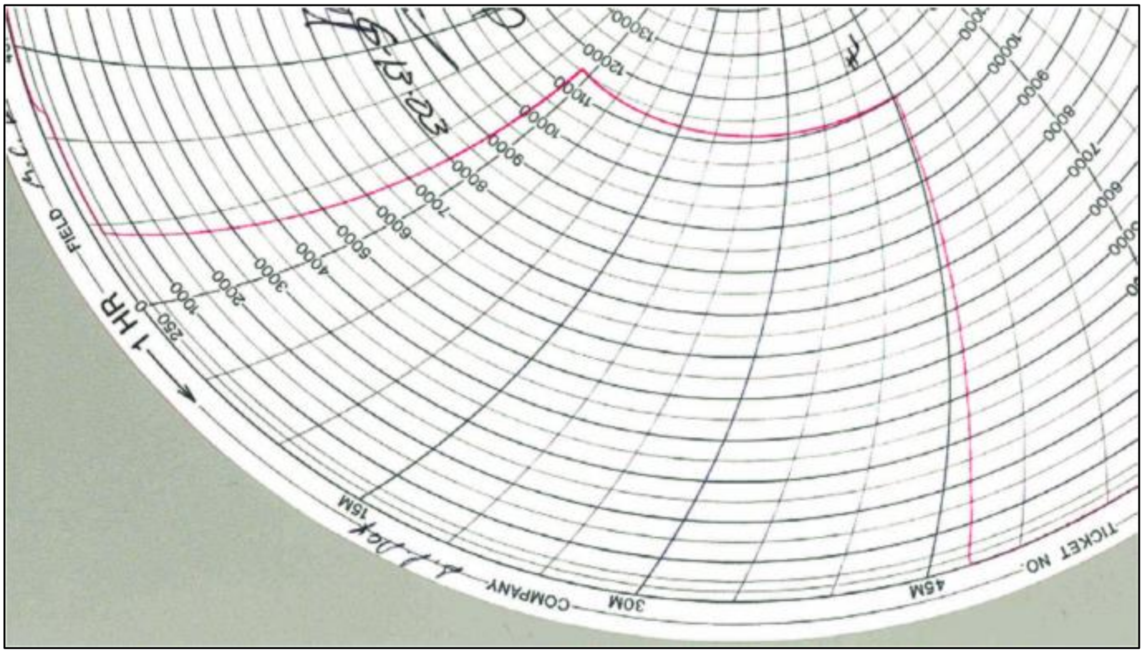


Figure 4.1: Example of a low and high pressure BOP test as recorded on a CCR (from Franklin et al., 2004). The red line is indication of test pressure “flat-lines.” Note the relatively poor resolution for low pressure testing in the vicinity of 250 psi.

Additionally, as deepwater and ultra-deepwater drilling become more commonplace, the combination of the use of relatively compressible synthetic-based drilling fluids, their ability to dissipate heat more slowly than water-based counterparts, and the temperature profile of extreme water depths greatly affect pressure readings at surface (Franklin et al., 2004). As required by regulation, subsea BOP component test pressures must be held constant for at least five minutes to be considered passing. Thus, an extensive period of time must transpire during the leak test in order for pressure to equilibrate and more confidently discern between fluid compressibility and temperature effects versus an actual leak. Figure 4.2 provides an example of the amount of time each series of required BOP tests consumes. In this case, almost 14 hours are dedicated to completed pressure tests for all BOP components with a significant portion of downtime as well as time waiting for pressure decay to dissipate during tests. Combined with the required recurrence of these tests, this leads to a large portion of operational time devoted to tests on rigs with expensive day rates, potentially adding haste to operations.

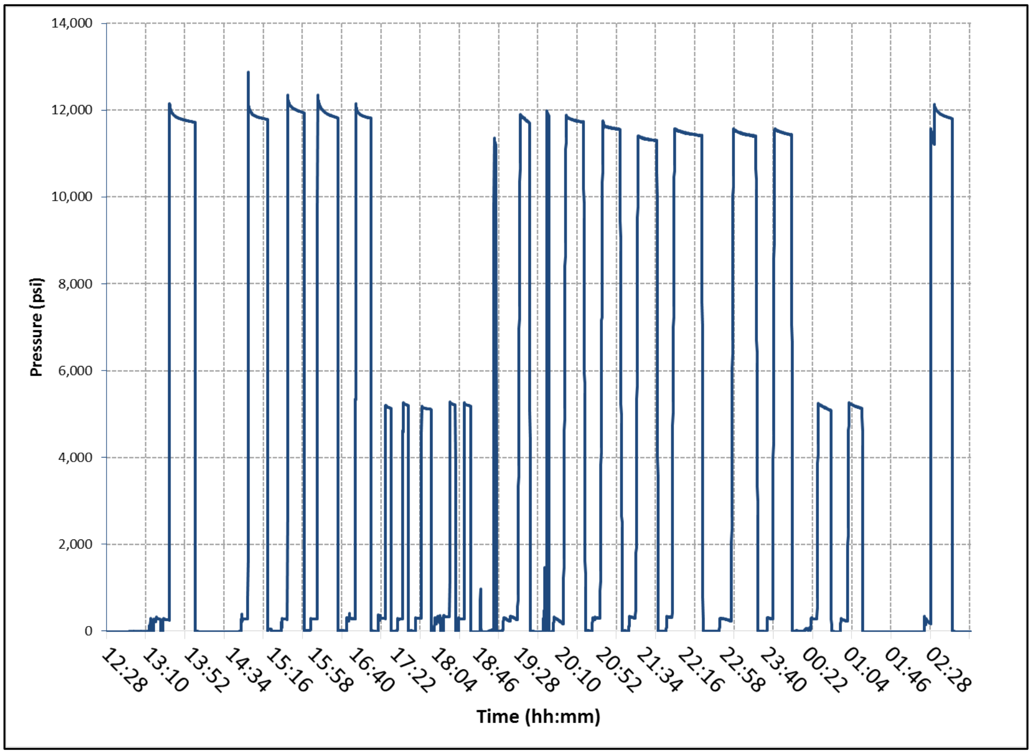


Figure 4.2: Example of a single series of component pressure tests for a deepwater Gulf of Mexico subsea BOP, as required by regulation. Note in this case, the complete series of tests consumes roughly 14 hours of operational time, a common occurrence for subsea BOP testing.

Since these tests are required to be conducted at least every 14 days, this accumulates to be a significant amount of operational time and associated cost. Studies have shown that using more accurate digital data, pressure decay and pressure leaks can be more easily differentiated (Franklin et al., 2004, Winters et al., 2007). The significant advantage to this is the development of relationships in real-time data to accurately predict the success of leak test without performing full tests for every component (Franklin et al., 2004, Franklin et al., 2011). This facilitates reduced downtime without sacrificing the improved accuracy of real-time digital data.

For this thesis, a commercially available software and BOP testing service was used to investigate capabilities of more accurate test validation and remote oversight. A visit was made to the service company's RTOC where BOP testing is monitored and verified. RTOC personnel were readily available to provide technical support for field personnel in analyzing test data. The particular software used employs a thermal compensation leak detection (TCLD) algorithm, which establishes the expected pressure and temperature behavior for the particular system being tested and the fluid being used based on a "benchmark test." The BOP tests are broken down into systems based on relative volumes being tested. For example, all tests that include the test manifold have a small volume and are therefore associated with that system. The benchmark test is simply a BOP component pressure test taken to a rate of decay less than 3 psi/min (flat-line) on a system. With relatively little volume change between subsequent tests, the TCLD algorithm can then predict in a much shorter time frame that the test underway will pass.

The user interface for this software can be seen in Figure 4.3. In this particular case, while passing the test according to the TCLD, a discrepancy was observed in the volume pumped based on previous test volumes associated with the same system. The alignment was checked, and it was discovered an in-line valve was closed, which restricted testing to only the components upstream of the valve. The valve was opened and the subsequent tests passed, and all required components in that particular procedure were properly tested according to the schematic (Figure 4.4). Figure 4.5 displays the history for this particular test of components on a subsea BOP for a deepwater operator. It should be noted that this information is all available in an automatically generated report based on the recorded data from the software, a convenient application for regulators to access online at any time after the test with applicable permissions from the operator. Additionally recorded in these reports are the control pod function tests, which are regulatory requirements by BSEE as well (Figure 4.6). Two important notes should be made. First, this discrepancy was not discovered by rig personnel, but the service technician, which emphasizes the need for technically competent remote oversight. Second, comparing the digital output in Figure 4.3 to the CCR output such as in Figure 4.1, this discrepancy would have most likely never been caught. Higher quality digital real-time data enabled a closer eye to be kept on a small, but very critical detail in testing vital safety equipment.

12:37 Ram Single Line 1.30 bbl

6 Annular x 6.625 in, Kelly Hose, IGV-L, LIK-L, Lo...
Ram Two Line 5,600

15:00 Ram Two Line 2.00 bbl

7 Annular x 6.625 in, Lo Torq-T, Lo Torq-L, Lo Tor...
Ram Single Line 5,600

15:39 Ram Single Line 4.30 bbl

8 MPR x 6.625 in, KIV-B, Lo Torq-L, Lo Torq-B, L...
Ram Single Line 5,600

16:35 Ram Single Line 1.60 bbl

9 MPR x 6.625 in, IGV-R, Lo Torq-L, Lo Torq-R, L...
Ram Two Line 5,600

16:59 Ram Two Line --.-- bbl
a) 17:15 Ram Two Line 2.90 bbl

10 LPR x 6.625 in, Lo Torq-R, Lo Torq-L, Lo Torq-...
Ram Single Line 5,600

17:53 Ram Single Line 1.70 bbl

11 Lo Torq-L, Lo Torq-R, Lo Torq-L, Lo Torq-L, LO...
Ram Single Line 5,600

18:27 Ram Single Line 1.10 bbl
a) 19:08 Ram Single Line 0.80 bbl
b) 20:13 Ram Single Line 2.20 bbl

12 CIV-T, KIV-T, Lo Torq-L, Lo Torq-R, Lo Torq-L,...
Ram Two Line 5,600

Reviewing completed test

Figure 4.3: BOP component testing user interface. Displayed is the test in which an incorrect valve alignment according to the procedure was mistakenly tested. While passing the TLCD test, it was noticed that the volume pumped was relatively lower than volumes in previous tests (left column). With the aid of the user display and digital real-time data, this mistake was identified and corrected, and the subsequent test with the correct alignment passed. (Courtesy of IPT Global)

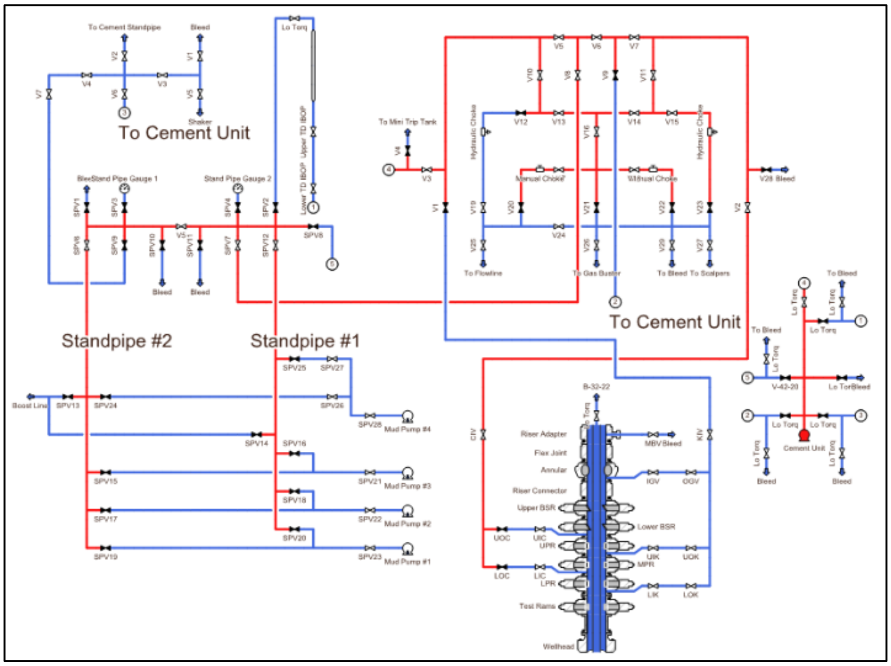
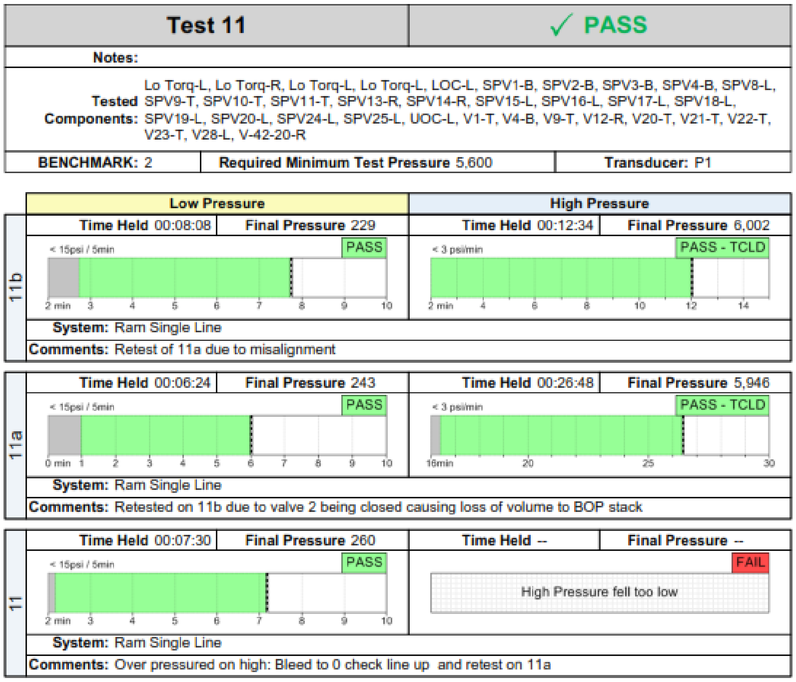


Figure 4.4: The BOP component test valve alignment for the discussed test 11 according to the company's test procedure. This schematic is both constructed and presented in the software, as well as provided in the automatically generated report, available electronically 24 hours a day. Red indicates pressured lines testing that respective side of a component that isolates the pressure, while blue indicated the non-pressured side. The software is a "smart schematic" in which it tracks along the pressured line component ratings and required test pressures, preventing overpressurization of components and ensuring every component is accounted for in testing. (Courtesy of IPT Global)



Test 11 ✓ PASS

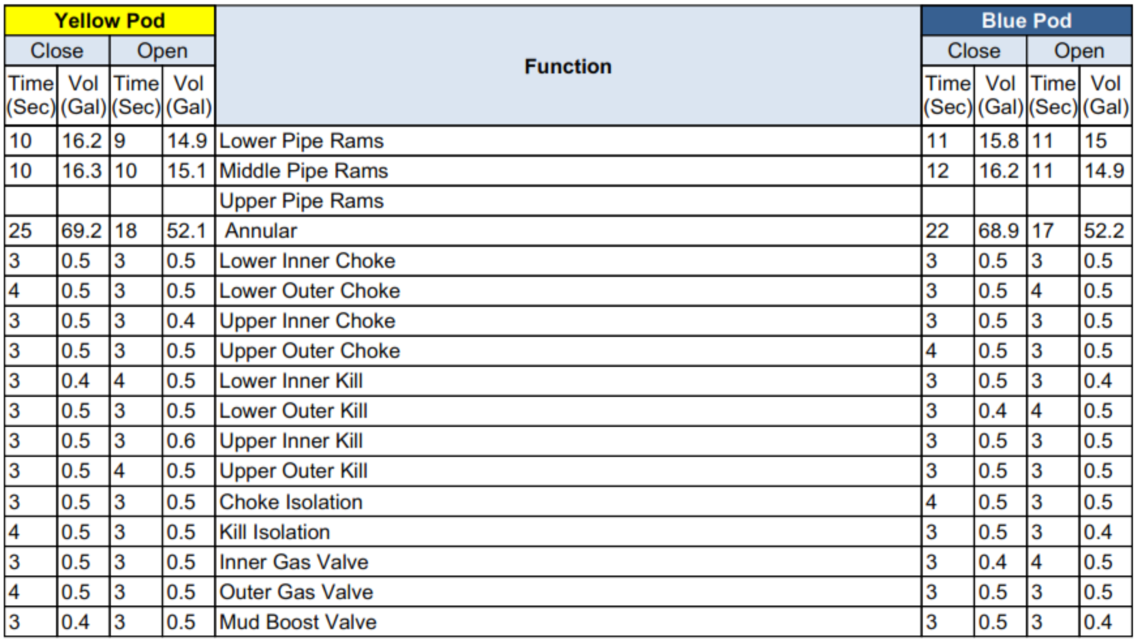
Notes:

Tested Components: Lo Torq-L, Lo Torq-R, Lo Torq-L, Lo Torq-L, LOC-L, SPV1-B, SPV2-B, SPV3-B, SPV4-B, SPV8-L, SPV9-T, SPV10-T, SPV11-T, SPV13-R, SPV14-R, SPV15-L, SPV16-L, SPV17-L, SPV18-L, SPV19-L, SPV20-L, SPV24-L, SPV25-L, UOC-L, V1-T, V4-B, V9-T, V12-R, V20-T, V21-T, V22-T, V23-T, V28-L, V-42-20-R

BENCHMARK: 2 | **Required Minimum Test Pressure** 5,600 | **Transducer:** P1

	Low Pressure		High Pressure	
11b	**Time Held** 00:08:08	**Final Pressure** 229	**Time Held** 00:12:34	**Final Pressure** 6,002
	PASS		PASS - TCLD	
	System: Ram Single Line			
	Comments: Retest of 11a due to misalignment			
11a	**Time Held** 00:06:24	**Final Pressure** 243	**Time Held** 00:26:48	**Final Pressure** 5,946
	PASS		PASS - TCLD	
	System: Ram Single Line			
	Comments: Retested on 11b due to valve 2 being closed causing loss of volume to BOP stack			
11	**Time Held** 00:07:30	**Final Pressure** 260	**Time Held** --	**Final Pressure** --
	PASS		FAIL	
	System: Ram Single Line			
	Comments: Over pressured on high: Bleed to 0 check line up and retest on 11a			

Figure 4.5: The pressure test history for test 11, as presented in the automatically generated report. Test 11 failed due to an immediate pressure spike that exceeded the pressure test limitations. 11a proceeded and technically passed the TCLD test, albeit an incorrect valve alignment. Due to a volume discrepancy displayed in the digital real-time data, the incorrect alignment was discovered and the components were subsequently retested (11b). Volumes pumped for 11, 11a, and 11b were 1.10, 0.80, and 2.20 bbl., respectively. (Courtesy of IPT Global)



Yellow Pod				Function	Blue Pod			
Close		Open			Close		Open	
Time (Sec)	Vol (Gal)	Time (Sec)	Vol (Gal)		Time (Sec)	Vol (Gal)	Time (Sec)	Vol (Gal)
10	16.2	9	14.9	Lower Pipe Rams	11	15.8	11	15
10	16.3	10	15.1	Middle Pipe Rams	12	16.2	11	14.9
				Upper Pipe Rams				
25	69.2	18	52.1	Annular	22	68.9	17	52.2
3	0.5	3	0.5	Lower Inner Choke	3	0.5	3	0.5
4	0.5	3	0.5	Lower Outer Choke	3	0.5	4	0.5
3	0.5	3	0.4	Upper Inner Choke	3	0.5	3	0.5
3	0.5	3	0.5	Upper Outer Choke	4	0.5	3	0.5
3	0.4	4	0.5	Lower Inner Kill	3	0.5	3	0.4
3	0.5	3	0.5	Lower Outer Kill	3	0.4	4	0.5
3	0.5	3	0.6	Upper Inner Kill	3	0.5	3	0.5
3	0.5	4	0.5	Upper Outer Kill	3	0.5	3	0.5
3	0.5	3	0.5	Choke Isolation	4	0.5	3	0.5
4	0.5	3	0.5	Kill Isolation	3	0.5	3	0.4
3	0.5	3	0.5	Inner Gas Valve	3	0.4	4	0.5
4	0.5	3	0.5	Outer Gas Valve	3	0.5	3	0.5
3	0.4	3	0.5	Mud Boost Valve	3	0.5	3	0.4

Figure 4.6: As displayed in the automatically generated report, a record of control pod function testing, also a requirement in BSEE regulations. (Courtesy of IPT Global)

As can be seen, there are many available technologies and developing capabilities that improve awareness of BOP reliability and ensure proper execution of tests using real-time data. All of these could be – or already are – fully virtualized for remote data communication and monitoring. This remote monitoring technology could be implemented by the regulator with relative ease and would significantly improve oversight while potentially minimizing delays in offshore operations. While there are currently no concrete regulatory requirements for such provisions, mandating real-time data to monitor and assess such information could be addressed through 30 CFR 250.440. This rule requires that BOP systems and associated components must be maintained to ensure proper well control: a broad requirement, but these topics certainly would fit under its scope. The BOP testing software validates the concept of remote real-time data monitoring for improved regulatory oversight on many fronts including 24-hour remote access, improved data resolution, and an automated process by which safety and efficiency are improved.

4.2 FORMATION STRENGTH

Formation strength tests are performed with a number of intended objectives (van Oort and Vargo, 2007):

- To verify the strength and integrity of the cement bond located at the casing shoe.
- To determine the wellbore's ability and limitations for enduring a formation fluid influx (i.e. kick tolerance).
- To determine minimum and maximum equivalent pressures the wellbore will permit prior to failure.

Verifying the strength and integrity of the cement bond provides assurance that the cement properly isolated the previous hole section and no channels exist for formation fluids or gas to leak past the cement. Determining wellbore strength provides important information to prevent fracturing at the casing shoe when trying to control and circulate out well influxes. Determining the minimum and maximum tolerable pressures ensures wellbore stability and prevention of unintended fracturing. With better knowledge surrounding these serious operational hazards, a safer drilling program can be followed. Van Oort and Vargo (2007) give a thorough explanation of formation strength tests and recommendations for more accurate tests and interpretations.

There are, however, certain factors that can contribute to improperly interpreted test results, namely fluid compressibility, fluid expansion due to the downhole temperature profile, barite sag, and gel strength (van Oort and Vargo, 2007). Additionally, the location of the gauge of the cementing unit can affect the test data. While it is possible to account for these conditions, it has been verified that downhole pressure sensors can provide much more accurate pressure measurements at the shoe, thus preventing overestimation of shoe strength due to poorly interpreted tests (van Oort and Vargo, 2007). Figure 4.7 shows pressure data from a deepwater Gulf of Mexico well FIT in which the formation was to be tested to a desired equivalent mud weight of 13.0 ppg with a synthetic-based mud. A large discrepancy was observed between surface pressure and downhole recorded PWD data, attributed to the effect of mud gel strength. The difference in measurements equates to a 0.36 ppg mud weight for this particular test, a considerable value when the typical industry standard for a mud window is 0.5 ppg. This shows the value in downhole real-time data being applied for critical formation strength measurements.

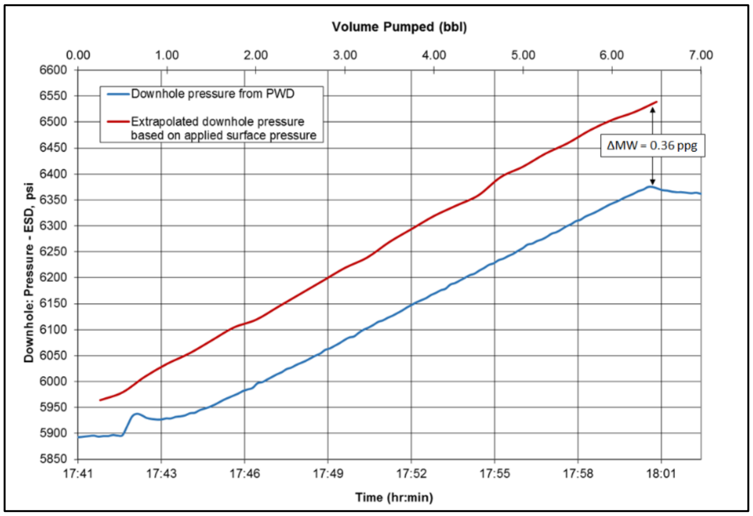


Figure 4.7: Observed difference between downhole PWD data measurements and extrapolated downhole pressure from surface measurements (from van Oort and Vargo, 2007).

Real-time data acquisition of critical tests such as formation strength tests provides continuous measurement recording of test conditions. Accuracy in test interpretation can be lost if these tests are manually recorded, as seen in Figure 4.8. Software is available to provide remote real-time witnessing of these tests and have been employed in the industry (van Oort et al., 2005). Additionally, geomechanical data from LOTs has been successfully integrated with real-time downhole pressure data update the pore pressure-fracture gradient (PPFG) profile of the well (Greenwood et al., 2005). These capabilities could be adopted by regulators to verify test interpretation and similarity to predictions in the approved APD as well as ensure the required safe drilling margin is being used according to the approved APD. Implementing real-time data monitoring at this critical stage in drilling can provide another snapshot that contributes to an overall continuous oversight without excessive intrusion or interruption. Regulators can witness tests in real-time and verify that the kick tolerance and tolerable mud weight according to the FIT or LOT is concurrent with the predicted mud weight in the approved APD. If a continuous real-time update is implemented, the regulator can have 24-hour access to a live PPFG window to verify a safe drilling margin.

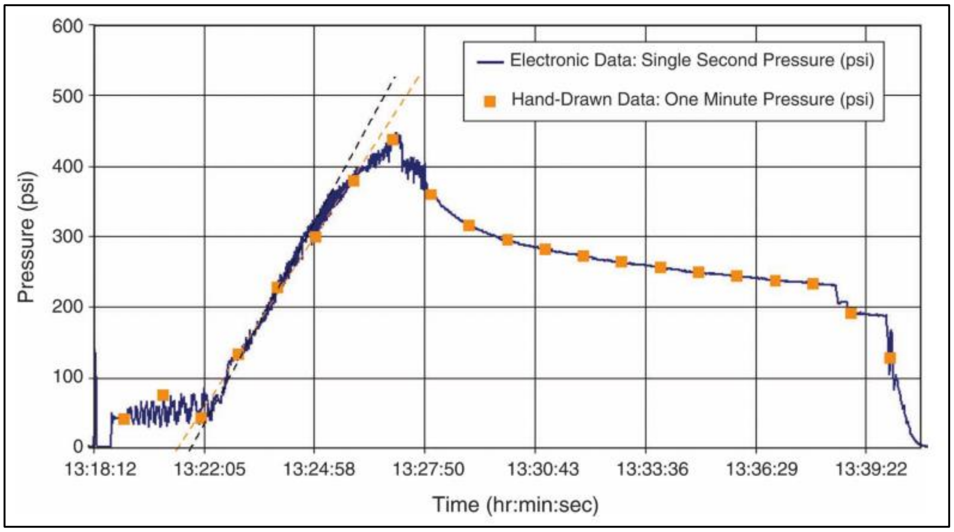


Figure 4.8: Comparison of electronic recorded data versus manually hand recorded data and the accuracy of data interpretation (from van Oort and Vargo, 2007).

4.3 ZONAL ISOLATION (CEMENTING)

Arguably one of the most critical procedures in well construction is zonal isolation, particularly isolation of zones capable of flowing to surface. With the drastic technological advancements of offshore drilling, cementing has remained relatively unchanged in practice versus the increase in depth and complexity of offshore drilling and completions. As seen in Figure 3.1 cementing is by far the most common contributing factor to blowouts. The complication of cementing in deepwater and achieving proper cement placement is compounded by the well temperature profile, pressures experienced, placement challenges, and wait-on-cement (WOC) time (Ravi et al., 1999).

Much preparatory work is undertaken to ensure the best slurry additives, densities, and volumes are selected to accomplish the cementing job. These slurries are similarly constrained in static and dynamic densities by the PPFG window of the well. Thus, attention must be paid to the pressures exerted on the formation during cement placement.

Additionally, spacer fluid must effectively prevent contamination of the cement slurry. Cement compressive strength can be significantly degraded due to contamination from improper displacement of drilling fluids or influx of formation fluids into the wellbore. In addition to appropriate spacer fluid volumes, care must be taken to complete full circulation of wellbore fluids prior to cementing in order to further prevent any contamination by debris. WOC time is also a critical value to accurately predict and adhere to.

Accurate placement of cement slurries across hydrocarbon bearing zones is critical to ensuring proper zonal isolation. The significant majority of zonal isolation problems can be avoided by achieving successful placement of cement. Placement of cement can be appropriately monitored utilizing real-time data from the rig and/or cementing service company. Figure 4.9 is cementing real-time data from a 5-½ inch production liner for a deepwater well in the Gulf of Mexico. From this data being observed in real-time, reasonable verification of adherence to the approved cementing program can be performed, particularly when actual vs. planned data is compared: the real-time data can be compared to the cementing program spacer and slurry volumes, densities, and pressures to ensure proper placement with associated top-of-cement (TOC), an accurate beginning of WOC time, etc. This practice of cement placement verification can also be found in API Standard 65-2, suggesting that data such as "rates, volumes, densities, pressures, fluid rheologies, etc." can be used to monitor proper cement placement or to identify discrepancies in a failed job (API Standard 65-2).

In the particular case of the well in Figure 4.9, when comparing the data to the approved cement program (Table 4.2) some discrepancies were identified. The spacer actually used is of a lower density (14.9 ppg) and a lower quantity is pumped than prescribed (71 bbl.). The lead cement slurry can be observed in the increase of fluid density to around 15.5 ppg, but only 54 bbl. are pumped before the tail slurry, near the prescribed density (16.4 ppg) is introduced. This tail slurry has a lower volume (47 bbl.) which carries the risk of either improperly isolating the hydrocarbon bearing zone(s) or being either contaminated to a higher extent or over-displaced, leaving the shoe improperly isolated. While no adverse effects may have been experienced in this case, the example illustrates that remote oversight may help in executing cement programs in accordance with approved plans.

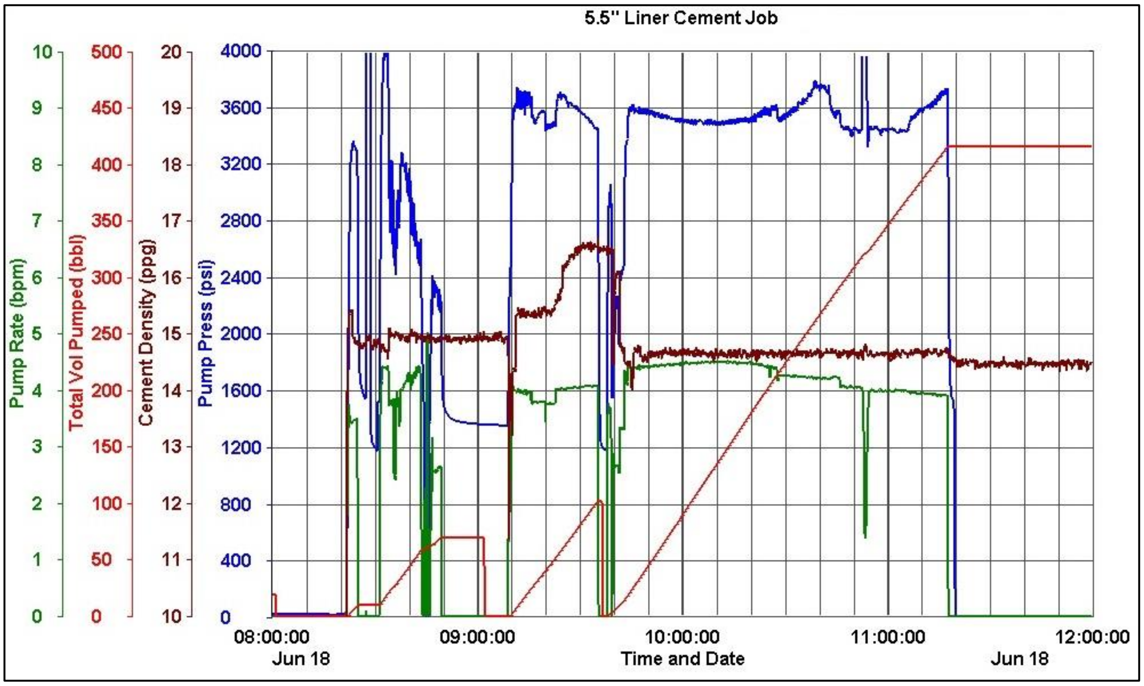
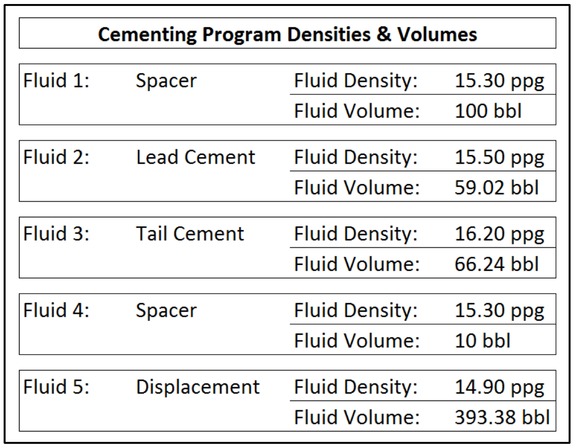


Figure 4.9: Real-time cementing data from a 5-½ inch liner cement job in the Gulf of Mexico.

Table 4.2: Fluid and slurry densities and volumes according to the approved cementing program for the 5-½ inch liner cement job in Figure 4.9.



Cementing Program Densities & Volumes			
Fluid 1:	Spacer	Fluid Density:	15.30 ppg
		Fluid Volume:	100 bbl
Fluid 2:	Lead Cement	Fluid Density:	15.50 ppg
		Fluid Volume:	59.02 bbl
Fluid 3:	Tail Cement	Fluid Density:	16.20 ppg
		Fluid Volume:	66.24 bbl
Fluid 4:	Spacer	Fluid Density:	15.30 ppg
		Fluid Volume:	10 bbl
Fluid 5:	Displacement	Fluid Density:	14.90 ppg
		Fluid Volume:	393.38 bbl

Once the estimated WOC time is observed, a minimum compressive strength of 500 psi should be present as the cement hardens. From this point two tests are undertaken to verify the quality of hydraulic isolation that the cement job has achieved. The first test, the casing test, is a positive pressure test, exerting pump pressure inside the casing or liner for an extended period of time. This test is performed to verify both that there are no leaks in the cement job and that the casing (or liner) and wellhead seal assemblies can withstand pressures from the well (Deepwater Horizon Study Group, 2011). It is very important that this test is performed only after the prescribed WOC time. If the cement is still in a dormant phase, expansion of the casing or liner from the internal pressure will put the cement around the outside of the casing in tension, plastically deforming the cement. This hinders a satisfactory bond between the cement and casing and can result in a micro-channel for hydrocarbons to leak by. If the positive casing test yields successful results, a negative pressure test is performed to likewise verify effective prevention of hydrocarbon flow by the cement job.

By putting the well in an underbalanced scenario by decreasing the pressure inside the string, it can be verified whether or not the cement is capable of keeping flow zones in check (Chief Counsel's Report, 2011). When this is performed, either measurements in flow or pressure can be used to verify whether or not the well is flowing. This is a very critical stage in the construction of the well. By inducing a net "negative" pressure in the well, it has been intentionally put in an underbalanced scenario with a yet-to-be validated cement job. As witnessed with the Macondo blowout, if the negative test is poorly executed and improperly interpreted, the consequences can be disastrous. If it is not possible to perform the negative test or should test results be inconclusive, API RP 96 provides recommendations for alternative verification of zonal isolation. Figure 4.10 provides a categorization of barrier verification. It should be recalled that the most certain method to verify effective isolation by the cement job is through pressure testing. Confirmation methods (as shown in Figure 4.10) should be assessed within the appropriate context. For example, acoustic measurement data from a cement bond log (CBL) can be used to observe a satisfactory bond between the casing and cement as well as the location of the cement placement. Beyond this, the CBL is unable to be used to verify hydraulic isolation of flow zones. Thus, it would be inferred (possibly with other supplemental data) that zonal isolation has been achieved.

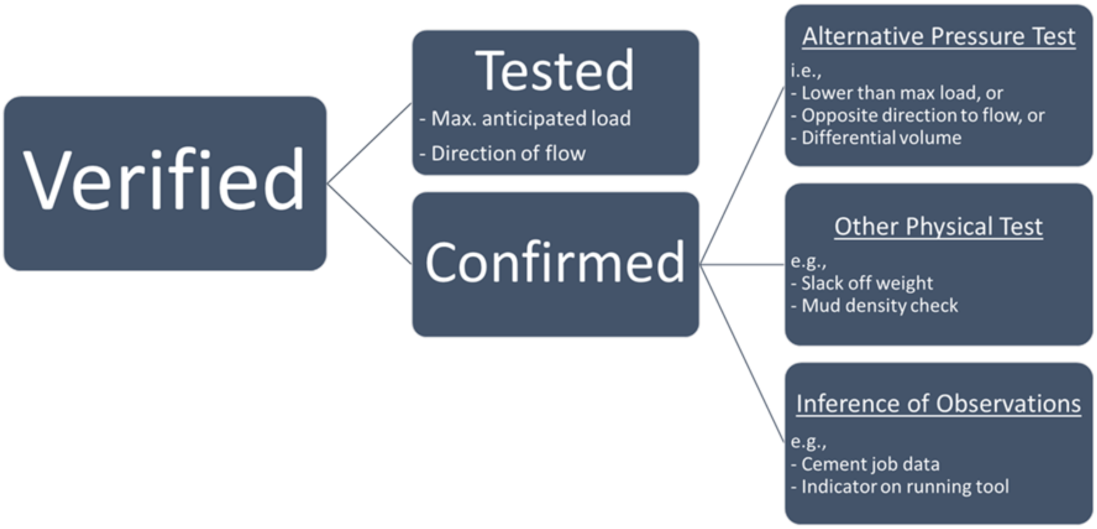


Figure 4.10: According to API RP 96, categories of verifying effective formation barriers by either testing or confirmation (from API RP 96).

With these very dynamic operations, it becomes quite a challenge for the regulator to ensure proper adherence to what has been approved. Without data, this cannot be effectively accomplished. Without real-time data, especially related to cementing operations, a realization that improper adherence to the approved program is a costly fix if discovered after the job has been completed. As noted in one of the Macondo reports, there was no requirement to supply the regulator with evidence of a successful test result (National Academy of Engineering, 2011). Had the regulator been able to witness tests via real-time data, the anomalous results may have been brought under greater scrutiny. The regulator can employ software to monitor the real-time data of these placement operations in real-time and identify whether operations are executed in accordance with what the operator outlined in the program and even compare to original simulations (Creel et al., 2006). After verification of cement placement based on the operator's preparatory work and analysis of real-time data, the regulator can then ensure an accurate timeframe is respected for the WOC time. Once WOC time is observed, the regulator can then also witness positive and negative tests in real-time to verify casing integrity and hydraulic isolation of the well and formation fluids. Should the operator decide to run a CBL after the WOC time, this could be supplementary evidence witnessed in real-time to verify successful TOC placement and cement bond.

Real-time data is a very valuable asset to the regulator to ensure compliance with what has been proposed and approved. WOC cement time can be properly recorded and monitored, and the respective positive and negative pressure tests can be witness remotely to ensure appropriate hydraulic isolation of pressured zones. It is believed by the author that effective remote cementing and zonal isolation monitoring by itself yields great benefits to improving safe offshore deepwater well construction.

4.4 DRILLING EVENT DETECTION

All of the areas previously discussed provide what could be referred to as a continuous "snapshot" of operations. However, an important gap in oversight is verification of safe practices while drilling. Real-time data could provide significant value in ensuring some level of oversight is maintained by the regulator, as to intervene when critical. This is also certainly the most contentious subject to consider with respect to regulatory real-time data monitoring. Many of the contributing factors to blowouts listed in Figure 3.1 can be prevented with the aid of effective real-time drilling data monitoring (stuck pipe, formation fracture, swabbing, and even equipment failure to an extent). The question to ask is how the regulator can maximize effective oversight without an inspector standing on the drill floor 24 hours a day.

A common concern related to regulator use of real-time data monitoring for drilling event detection is the in-house technical competence and experience to properly manage and interpret the required data. Government inspectors and petroleum engineers do not have the operational opportunity provided by oil and gas operators. Additionally financial compensation for such occupations within the government cannot rival that of the industry, and quite often better knowledge and experience follows the better salary (U.S. Government Accountability Office, 2014). Within oil and gas industry real-time monitoring operations, in-house experience is developed over decades before a person is entrusted to then interpret real-time data streams. This expertise is challenging to come by, and as the largest portion of the industry expertise approaches retirement, replacing this talent will become even harder. The Big Crew Change will prove to challenge the industry in replacing old expertise with new personnel in frontiers that are accelerating in difficulty and complexity at a rapid pace.

In this sense, both industry and the government face a similar serious challenge: accelerating the learning curve and maximizing experience in a short time period. In part motivated by the future loss of much industry experience, efforts in recent years have been undertaken to implement artificial intelligence to aid in monitoring well data. Using an approach such as case-based reasoning (CBR), knowledge and experience can be digitally captured from trouble scenarios, stored, and retained for future use in new wells.

Currently, oil and gas RTOCs rely heavily on highly skilled and experienced personnel to interpret real-time data. Based on their training and experience over the years in the oil and gas industry, they have retained a great base of knowledge upon which to draw. When even the slightest inflection on a data stream occurs, they can recall a situation that occurred in the past that had a similar behavior. They can then reason how closely a past experience matches the current scenario, diagnose the problem, and attempt mitigation. The person draws upon recollections of past experiences to handle new situations.

Case-based reasoning is essentially the use of intelligent computer systems to emulate human reasoning (Gunderson et al., 2011). The basic application of CBR is "to identify the current problem situation, find a past case similar to the new one, use that case to suggest a solution to the current problem, evaluate the proposed solution, and update the system by learning from this experience (Aamodt and Plaza, 1994). As seen in Figure 4.11, the general steps in the process are (Aamodt and Plaza, 1994):

1. Retrieve the most similar case or cases
2. Reuse the information and knowledge in that case to solve the problem
3. Revise the proposed solution
4. Retain the parts of this experience likely to be useful for future problem solving

By following this process, the program can be designed to mimic human learning experience. A new scenario is met with past experience, similarities are weighed, and intelligent decision support is provided based on the best available knowledge. This new 'case' can then be stored in the case-base for future retention, essentially improving the knowledge and experience of the program. Just as a human has been trained and educated on certain subject, knowledge of the relationships between the fundamentals learned and conditions faced in a problem is then tested. The more a person is challenged with new problems, the more experience a person will attain. The same is true for CBR programs, except that a CBR system continuously retains the stored experience whereas personnel change outs might vary the levels of expertise.

Still a relatively young technology in the oil and gas industry, CBR is increasing in visibility and credibility. It has been employed in the industry to identify symptoms of adverse conditions in the drilling process to then diagnose or predict a problem (van Oort and Brady, 2011, Raja et al., 2011). The CBR system used in this research employed symptom detection "agents." These agents are developed algorithms that utilize well characteristics with universal relationships in well symptoms. Once an agent successfully identifies a symptom to a drilling problem, it is presented as an event (e.g. flowback, max torque) (Gunderson and Shokouhi, 2012). As real-time data is transmitted, agents continuously monitor and interpret the data and flag events (Gunderson and Shokouhi, 2012). The CBR program uses the accumulation of events to then search the case base for similarities in the current symptoms to any stored case. If there is a similarity, the stored case is then displayed along with a percentage of similarity to the current scenario. Each stored case provides a summary of the actions taken in that particular instance, the detailed outcome, and any recommended actions for similar cases in the future. If the current scenario becomes increasingly similar to a certain stored case, recommendations in the historical case can be employed to avoid the same problem. While performance improvement usually leads to improved safety, a current primary motivator for employing CBR is the reduction of NPT. However, this technology can also be effectively used for the goal of improved safety and compliance while drilling. As indicated in Figure 3.1, many

NPT incidents can also be contributing factors to losses of well control and blowouts. Among others, this software is currently capable of identifying events related to stuck pipe, pore pressure change, and lost circulation using primarily surface data. An additional advantage to using an artificial intelligence system such as this is the ability for quick reference to a likely solution to the suspected problem with the well (Gunderson and Shokouhi, 2012). Depending on the experience of the drilling engineer, a fast response to a time critical problem may not occur; however, similar historical events being presented by the system provide a quick and ready guide for mitigating actions (Gunderson and Shokouhi, 2012).

Assuming the regulator has less expertise in the area of data interpretation, CBR could aid in accelerating this learning curve. Additionally, if a CBR system is automated to notify regulators of a potential incident, there is not necessarily a need for the regulator to scour through data streams 24 hours a day.

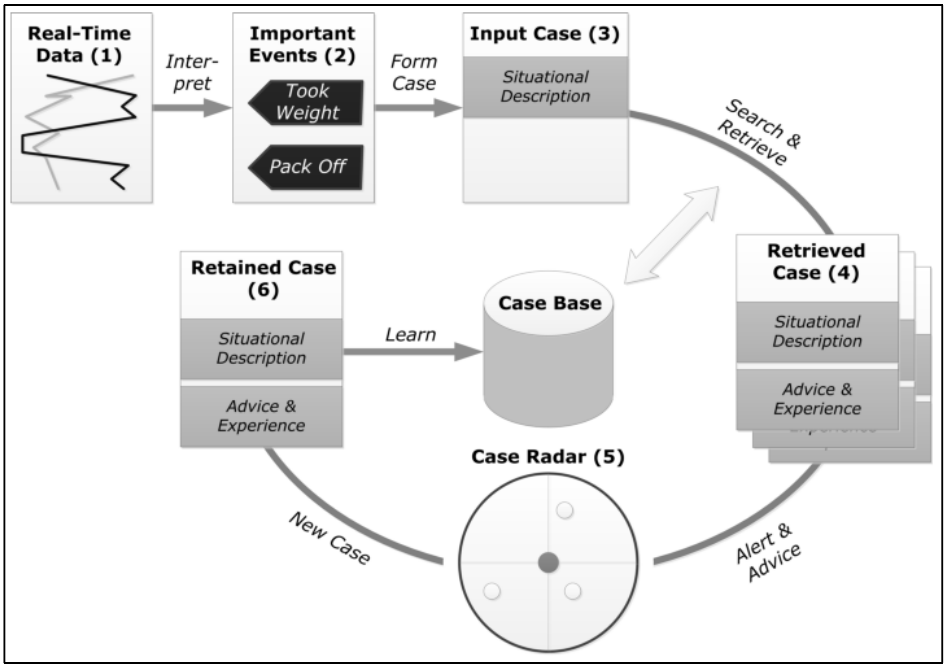


Figure 4.11: The case-based reasoning cycle applied to drilling (from Gunderson et al., 2011).

The challenge with monitoring real-time drilling data is that every well is unique. Fixed alarm parameters for one well will be of no relevance to a different well. In fact, those parameters may not even be relevant for the next section of hole being drilled. However, there are certain universal relationships between well characteristics that can be applied to most wells, if not every well, to detect symptomatic conditions (van Oort and Brady, 2011). Additionally monitoring data trends and ensuring proper context are much more valuable than just spot-checking data points. Trend measurements such as mechanical specific energy (MSE), d-exponent, flowback fingerprinting, and surface pressures provide an adaptable approach to monitoring and improving drilling performance and safety. Regarding data context for example, a standpipe pressure of 1,766 psi means nothing unless it was placed into the context that it should be expected to be decreasing, and three minutes earlier it was 1,210 psi (Deepwater Horizon Study Group, 2011). Understanding the relationship that a less dense fluid is displacing a heavier fluid should be decreasing the standpipe pressure reading is one that a trained eye could analyze in the data, if that trained eye is continuously monitoring the data and has the proper situational awareness. The above example, taken straight from the Macondo blowout, was a trend that was not identified, even with personnel on board that were likely experienced enough to identify the problem. Contributing confusion around the well conditions such as bladder effect, an incorrectly confirmed negative pressure test, simultaneous operations of transferring tanks and discharging overboard, all led to not having the proper context of the situation (Deepwater Horizon Study Group, 2011). Well condition relationships and data trends are relatively simple to develop and implement in a CBR system and the symptomatic conditions in the Macondo incident would be easy to recognize in a CBR system continuously monitoring data.

Figure 4.12 shows historical data analyzed by the CBR software. According to drilling reports, a stuck pipe event was experienced at approximately 9:00 am. As seen, events are flagged prior to the pipe becomes stuck and indicates such as the pipe has been identified as stuck in the hole. As shown in Figure 3.1, stuck pipe is a contributing factor in approximately 10 percent of blowout events. It may prove to be very challenging to identify symptoms that caused this event prior to its occurrence, particularly to the less experienced eye. However, referring to Figure 4.13, the CBR “radar” identified these symptoms much earlier. The radar indicates the magnitude of the current drilling state’s similarity to cases in the case base, the outer rim of the radar being 50 percent similarity and the center being 100 percent similarity. In this instance, a stuck pipe case appeared on the CBR radar approximately 8 hours prior to the incident. This sort of "prediction" reflects previous experiences with this CBR software (van Oort and Brady, 2011, Raja et al., 2011). This technology could be valuable in aiding to identify symptomatic conditions of potential well control incidents well in advance, giving operators and regulators sufficient reaction time.

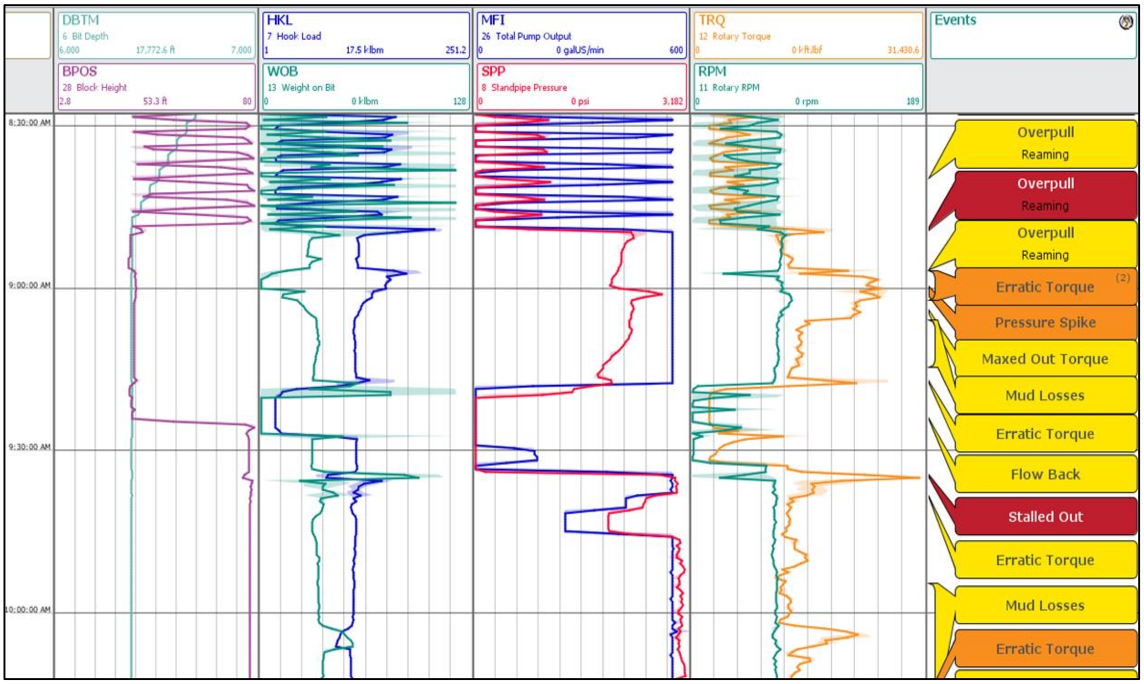


Figure 4.12: Drilling data analyzed by the CBR software, flagging events symptomatic of a stuck pipe case. As can be seen just before 9:00 am, hookload spikes with little block position movement, with additional symptoms of pressure spike and high torque leads. It can be observed that minutes before the stuck pipe incident, overpull events began to flag the symptoms.

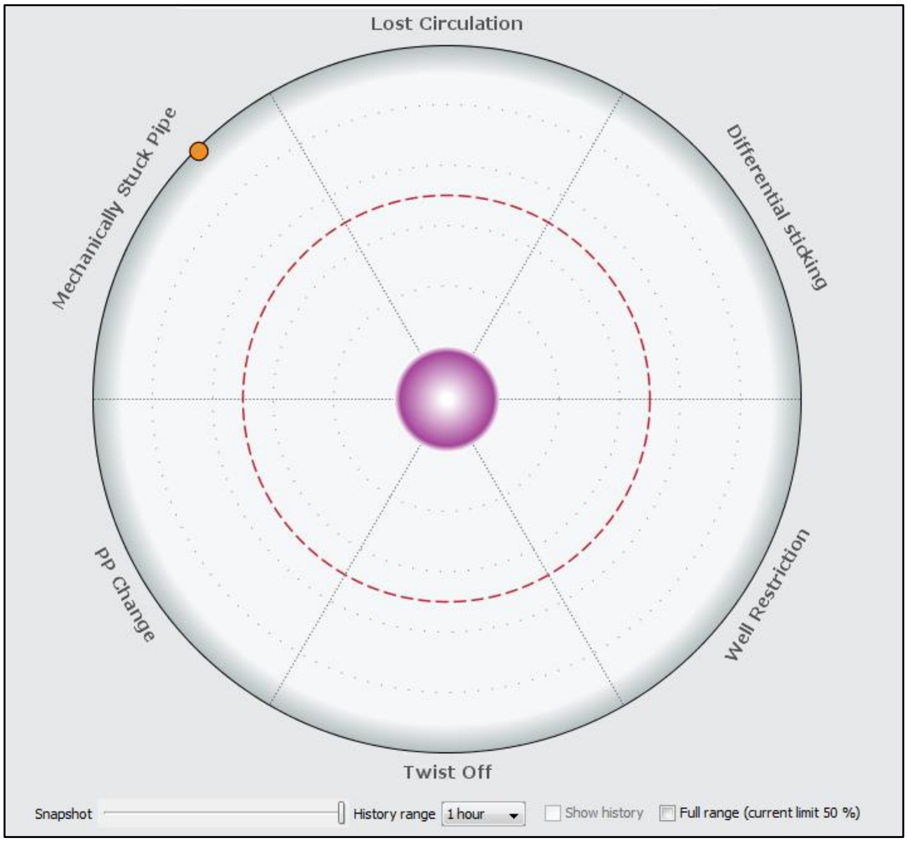


Figure 4.13: The CBR radar showing the initial appearance of a stuck pipe case approximately 8 hours before the stuck pipe incident occurred.

In addition to CBR, there have been developments in more focused areas of anomaly identification. For the purposes of this research, the primary adverse event detection needed for improved safety regulation is influx detection. Multiple well symptoms from real-time data can be utilized to verify a suspected fluid influx. For kick detection, commonly monitored parameters are the mud pit volume, return mud flow or mud flow out of the well, and standpipe pressure, all taken from sensors at surface (Anfinsen and Rommetveit, 1992). Under normal operating conditions, the volume of drilling fluid flowing out of the well should equal the volume of fluid that was pumped into the well. In the case of a kick, expected responses would be a gain in pit volume, increased return flow, and a decreased standpipe pressure (Anfinsen and Rommetveit, 1992). Due to the continuing trend of drilling deeper wells and the compressibility of commonly utilized synthetic- or oil-based muds in deepwater, the ability to manually identify positive kick symptoms in a timely manner is complicated. Too much time transpiring between influx and identification can result in a lengthy and costly kill operation, sidetracks, or even total loss of the well. Thus, there is opportunity for more automated approach to utilize real-time data in identifying provides a much closer watch on time critical information.

Some work has been done to develop early kick detection using what is known as flowback fingerprinting (Ali et al., 2013). By fingerprinting the change in volume in the mud pits, particularly during connections when there is no flow into the well, a method can be developed to determine whether or not the well is taking a kick. Fluid flowback after shutting off mud pumps is typically expected to be between 20 and 50 barrels, usually displaying a "repeatable profile" in the data (Ali et al., 2013). Thus, this repeatable profile can be "fingerprinted" and repeatedly compared to the new flowback data of the well. In deepwater applications, weak formations may display wellbore "ballooning" or "breathing," where drilling fluid is actually opening fractures into the formations. Once the dynamic pressure from the pumps is shut off, the formation returns the volume of drilling fluid back to the well, observed as a gain in the mud pits. It is important to be able to differentiate between wellbore breathing and kicks, as improper diagnosis could lead to erroneously weighting up fluid and exacerbating the breathing problem, and eventually leading to uncontrolled fracture propagation, lost circulation, and potentially a real kick. Wellbore breathing can also be differentiated by an automated system through fingerprinting. Figure 4.14 shows real-time data from a well being monitored by an RTOC and the use of flowback fingerprinting to appropriately identify anomalous flowback and differentiate between breathing and a kick. However, when analyzing the kick flowback in Figure 4.14, it should be noted that it takes just short of six minutes to visually identify a significant deviation from the previous fingerprints.

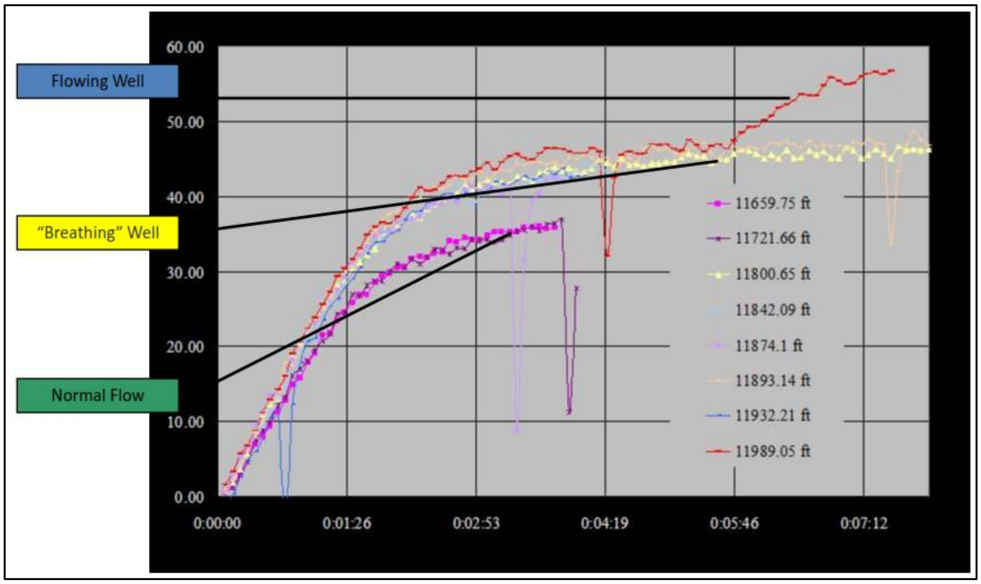


Figure 4.14: Flowback fingerprinting performed by RTOC personnel in order to identify anomalous well flow (from van Oort et al., 2005).

By using an intelligent process, kicks could be identified much more quickly, leaving a larger window for reaction time and minimizing safety impacts. Work has been done to automate the flowback fingerprinting process in real-time, statistically analyzing flowback data (Ale et al., 2013). Figure 4.15 represents historical data from a kick that was not detected by manual alarm settings, resulting in 31 days of NPT (Ali et al., 2013). This data set was then run through an automated smart flowback fingerprinting program (Ali et al., 2013). By maintaining a continuous running average of flowback response and comparing that to the current state, limitations were set within one standard deviation of the running average, resulting in abnormal flowback detection within one minute of monitoring (Ali et al., 2013). Expanding the window to two standard deviations was also successful in identifying abnormal flowback in a relatively short time (Ali et al., 2013). With the development of a simple intelligent relationship, an automated detect process was able to be employed and real-time monitoring was less dependent on human eyes, attention, and experience.

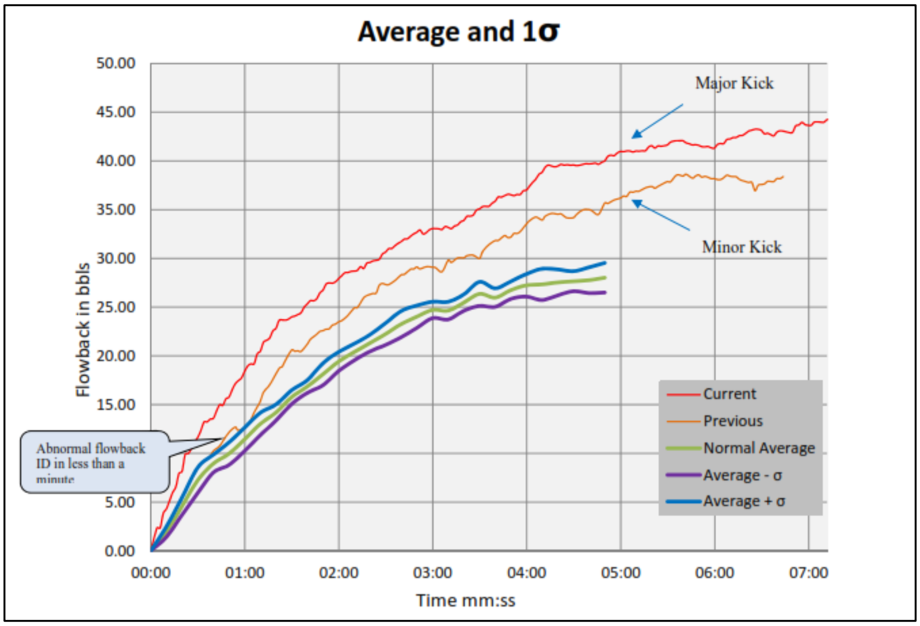


Figure 4.15: Automated flowback fingerprinting identifying abnormal flowback within one minute of monitoring data (from Ali et al., 2013).

While flow and volume parameters are frequently used in kick detection efforts, these data readings can be subject to much variation due to the quality of the sensors, or as seen in the Macondo blowout, simultaneous operations. Another method in early kick detection avoids the dependence on analyzing flow and utilizes real-time pressure readings at surface (Reitsma, 2010, Reitsma 2011, Mills et al., 2012). Primarily tested with dynamic annular pressure control managed pressure drilling (MPD), the use of standpipe and annular discharge pressures and their relationship has proven to be an effective method in kick detection, applicable to conventional drilling methods as well (Reitsma, 2010). As had already been demonstrated, standpipe pressure is a reliable parameter for identification, but additional validation is required. While ultimately downhole data provided by PWD would give the most accurate information for detection of influxes, current downhole data telemetry such as mud-pulse telemetry has limitations. Due to the amount of data collected downhole and limited bandwidth capability, a relatively long span of time can transpire before pressure readings are relayed to surface. Additionally, during connections when there is now fluid flow, data cannot be transmitted.

Typically, as previously mentioned, flow and volume data of drilling fluid is utilized to verify influx. However, it has been proven that using sensor data from annular discharge pressure provides comparable results in detecting influxes with significant lower cost (Reitsma, 2011). Additionally, with respect to limited deck space on offshore rigs, pressure sensors require significantly less space than flow sensing equipment such as Coriolis flow meters and are not as sensitive to conditions such as two phase flow (Reitsma, 2010). Figure 4.16 shows the similar trend in kick detection between monitoring annular discharge pressure and the change in flow rate using a Coriolis flow meter. This automated kick detection method shows positive results in its capability to detect influxes in a relatively short period of time.

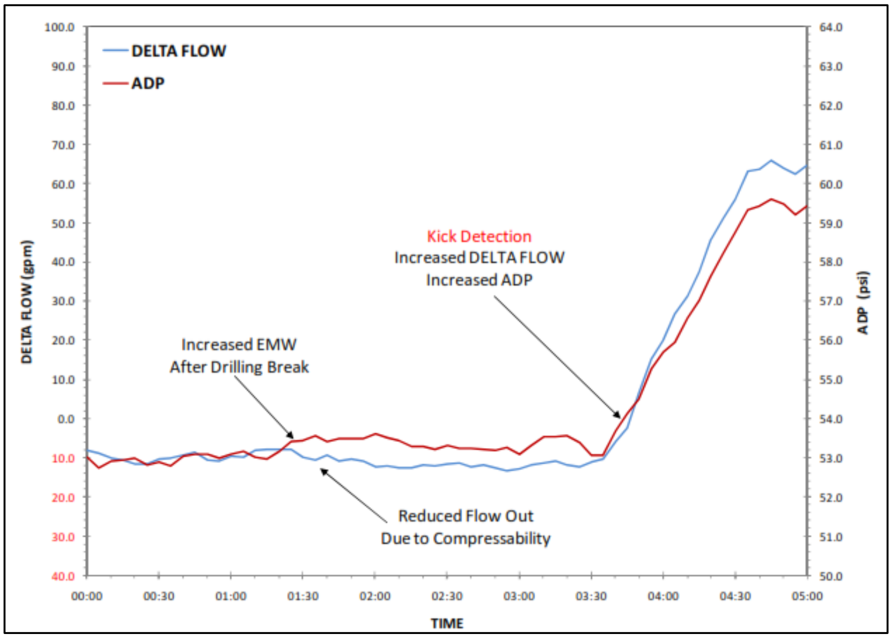


Figure 4.16: Comparison of change in fluid flow rate (Delta Flow) and annular discharge pressure (ADP) readings in kick detection (from Reitsma, 2010).

Chapter 5

Knowledge Management

Beyond the employment of real-time data for improved regulatory oversight, there are organizational challenges that the regulatory agencies must overcome for more effective oversight. The exhaustive attempts to keep rulemaking from lagging too far behind the rapid advancement of technology, compounded with the struggle to hire and retain personnel exposes the need for agencies to be capable of doing “more with less” with regards to in-house knowledge and expertise.

5.1 CASE FOR ACTION

Always present in rulemaking is the debate to identify what is too prescriptive versus what might be too “laissez-faire.” It’s certainly understood that the majority of people are simply trying to do their job the best they know how. In some cases regulation can be left to goal-based incentives, while at other times rules need to be more prescriptive. It is frequently perceived that the regulator is an enemy to industry and more than anything just gets in the way of efficiency. The reality is that the offshore oil and gas industry is regulated, and there are cases in which violations of safety occur. Another reality is that industry harnesses the vast majority of experience and knowledge on virtually any subject that might be regulated offshore. For truly effective regulation the two entities, industry and regulators, must work together. The same is true for standards. While this is a slightly different dynamic, it is vital for all parties to participate in identifying best practices. There are three areas that impact the effectiveness of regulation:

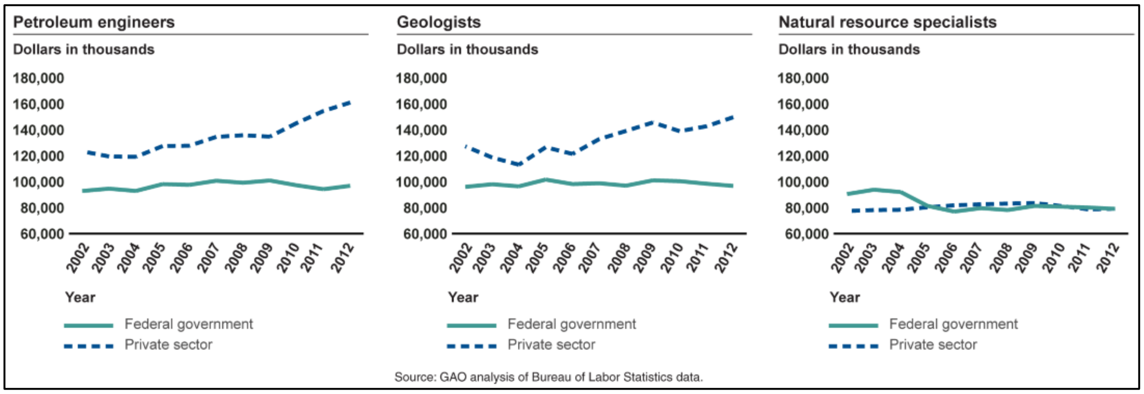
- Timely development of sound regulations and standards.

- Personnel staffing and retention.
- Personnel knowledge and experience.

Development of safety rules can be a lengthy process. For example, some of the regulations inspired by Macondo, an incident of much significance, were not finalized until years after the blowout. Likewise standards can experience the same sort of lag time. Certainly standards and regulations should not be developed and implemented hastily, but certain avenues within KM can facilitate more timely development and possibly ensure more effective methods of compliance.

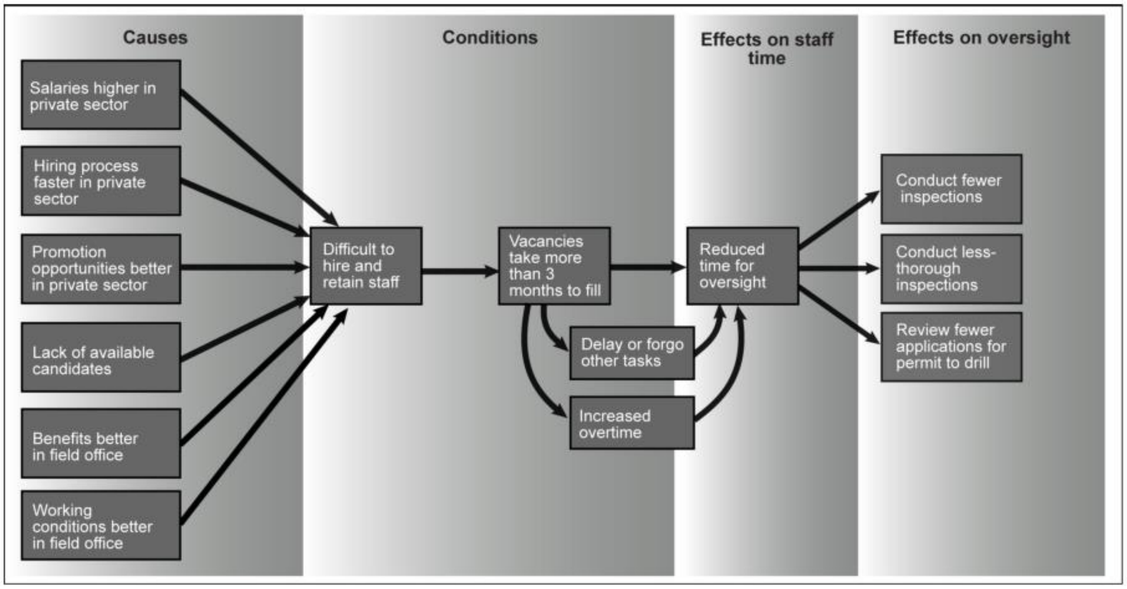
BSEE continues to be challenged by a lack of personnel staffing and retention. It is no secret that the industry is currently undergoing a boom. Likewise industry salaries are reflecting that as well. In a 2014 audit performed by the U.S. Government Accountability Office (GAO), officials within BSEE, the Bureau of Offshore Environmental Management (BOEM), and the Bureau of Land Management (BLM), were surveyed regarding employee hiring and retention. One of the primary difficulties in hiring and retention of personnel referenced was the difference between industry and federal salaries (Figure 5.1) (U.S. Government Accountability Office, 2014). In an attempt to address workforce issues after the Macondo blowout, Congress approved funding for BSEE to increase Gulf of Mexico unsupervised inspector positions to more than twice the amount at the time of the incident in 2010, from 52 to 129 (U.S. Government Accountability Office, 2014). However, by October 2012 BSEE had only increased its inspector workforce to 71 (U.S. Government Accountability Office, 2014). Figure 5.2 provides an insightful look into the effects of an insufficiently manned regulatory workforce. The USCG faces similar challenges, but from a different perspective. Being a military service, offshore regulators are frequently rotated out and transferred every few years, often to offices that have no involvement in OCS regulation. As far as personnel demand, the OCS regulatory mission for the USCG is a relatively small piece of the larger puzzle of the multi-mission service. Very few personnel are employed for OCS regulation, thus the loss of one person due to rotation can have a large impact.

The challenges of hiring and retention quite frequently impact the agencies' in-house knowledge and experience. As noted in the GAO audit, "top applicants are typically hired by the petroleum industry, leaving Interior [BSEE] with less-skilled applicants." Thus, regulators are doubly challenged to effectively perform duties understaffed and with typically less knowledgeable individuals compared to the industry bodies being regulated. To make the issue more challenging, the attrition rate of BSEE inspectors is above the Federal Government average (U.S. Government Accountability Office, 2014), assuming trained personnel are leaving the bureau for industry jobs. Additionally in the forecast, over 30 percent of BSEE petroleum engineers will be retirement eligible by 2017 (U.S. Government Accountability Office, 2014). Considering all of these conditions, BSEE has a formidable task of ensuring it maximizes its management of in-house talent and captures personnel experience before it may be lost. The USCG again has a similar challenge in that OCS regulatory personnel are sparse and spread thin geographically. In addition, most USCG inspectors are not strictly dedicated to OCS regulation, thus the knowledge is one of a many required skills for job performance. Providing an easily navigable network to retain corporate knowledge is essential for more efficient use of manpower.



Source: GAO analysis of Bureau of Labor Statistics data.

Figure 5.1: The trend in salaries (average) of oil and gas related specialties in industry versus federal employment (from U.S. Government Accountability Office, 2014).



Source: GAO analysis of survey data.

Figure 5.2: Causes and effects of insufficient regulatory workforce hiring and retention (from U.S. Government Accountability Office, 2014).

The traditional paradigm for both agencies' inspections is the use of paper checklists that are then documented and archived electronically. Additionally the same can be said for incident investigations. Everything is performed on paper, then electronically documented. Some analyses of these statistics are performed that provide some beneficial use to focusing inspections or communicated common non-compliances. However there are available knowledge management capabilities that could significantly advance the use of such data, catapulting agencies and industry into a much more effective use of the information at hand. This topic is explored in more detail in the remainder of this chapter.

5.2 DEFINITION

Knowledge management (KM) often is interpreted in many different forms. In its truest form the focus of KM is the ability to capture, share and improve organizational knowledge within an organization or between organizations. It is key to align KM not only with and organization's internal strategy but also with its day-to-day business activities. When implementing correct KM a wide range of concepts are addressed related to knowledge capture and sharing. These include concepts such as information management, data management, virtual working and organizational collaboration.

Each of these elements though not considered to be KM are key to provide foundational elements to create the right environment to share. For example, if information is not correctly managed, the right information would not be shared which would render sharing itself moot. If the foundational quality of information is ensured then the organization puts itself in a position to share and build on this knowledge. Five main areas of focus are considered when implementing KM:

- Context

- People and Culture
- Technology
- Process
- Compliance

Not all of these elements are considered enablers for KM. Some may be blockers but need to be addressed to have a successful KM implementation.

5.3 CONTEXT

When it comes to implementing a knowledge solution, context is everything. If one is looking to improve the knowledge of a team, organization or company, the context in which the entity operates must be understood. For example, with the regulatory environment, elements such as the agency’s mandate, focus, and long term vision must be properly understood. Also, the collaborative environment in which the agency works related to partners, customers and support elements, must be understood.

Once full insight is attained regarding the context of an organization’s KM needs, key factors can be identified for enhanced collaboration and sharing.

5.4 PEOPLE

The biggest challenge for any KM initiative is the change element, the ability to change behaviors within the organization and to the outside world. Change management should not be taken lightly especially within the regulatory environment. Many years of set behaviors and beliefs live within the organization which would need to be changed to embrace an improved sharing culture. Within KM, creating a sharing and learning organization is key and does not happen overnight. In many KM implementations change can take 3-5 years. This is not only focused on the existing staff but enabling the change within new staff as they are brought on board.

5.5 TECHNOLOGY

Selecting the right technology to support and enable the KM initiative is often critical. The biggest mistake many organizations make, however, is that technology is seen as the only enabler of change. Cultural change is often more important than the technologies implemented. That being said, it is vital to employ technologies that are easily understood and require a minimal learning curve. If large amounts of time are needed to train staff on the technology, it quickly becomes a burden and will lose organizational support for implementation. When selecting the right technological tools, another important factor is integration. It is not useful to have multiple tools that do not work in an integrated fashion. This too can alienate organizational staff and prevent new concepts from being adopted.

5.6 PROCESS

Process management is often mistaken for KM. Since many organizations have corporate processes and workflows, enabling change is seen to be a process. Though process is important and helpful from an enforcement mechanism it shouldn't be confused with enabling a sharing environment. Process should always be in support of describing how people work together, but more importantly, should be making sure that people are willing to collaborate. In practice, if a process is forced rather than having personnel display the willingness to collaborate, the result will be very different. If an activity is forced, it will tend to always be done to the minimum required standard and nothing more.

If personnel are invested and wanting to do an activity, consequently better value results will be produced. For example personnel are asked to share their experiences, it will likely result in open and honest feedback. If it is dictated they must share at least once a month, they will collaborate but purely as a "check the box" exercise.

5.7 COMPLIANCE

One might find it strange to see compliance in a knowledge sharing model, but it becomes important when it might block knowledge sharing initiatives. Many knowledge sharing initiatives fail or are halted due to compliance. What starts out as a great idea and initiative can easily be slowed down if compliance is not addressed early in the KM program. Compliance in this context means where focus is needed on information security, records management compliance and any export of information limitations.

5.8 APPLICATION AREAS

In this section, the focus is on key enablers for knowledge sharing. Some of these might not be considered pure knowledge capture and sharing but certainly help to reach out and create an improved platform for collaboration. The concepts discuss in the following sections have been identified which would be of the most value based on a collaboration maturity model in Figure 5.3. This model has been developed after extensive KM experience with major offshore oil and gas operations. The maturity model is meant as a method to identify areas of improvement. Each box defines the maturity level of collaboration an organization has and what the desired improvement would be.

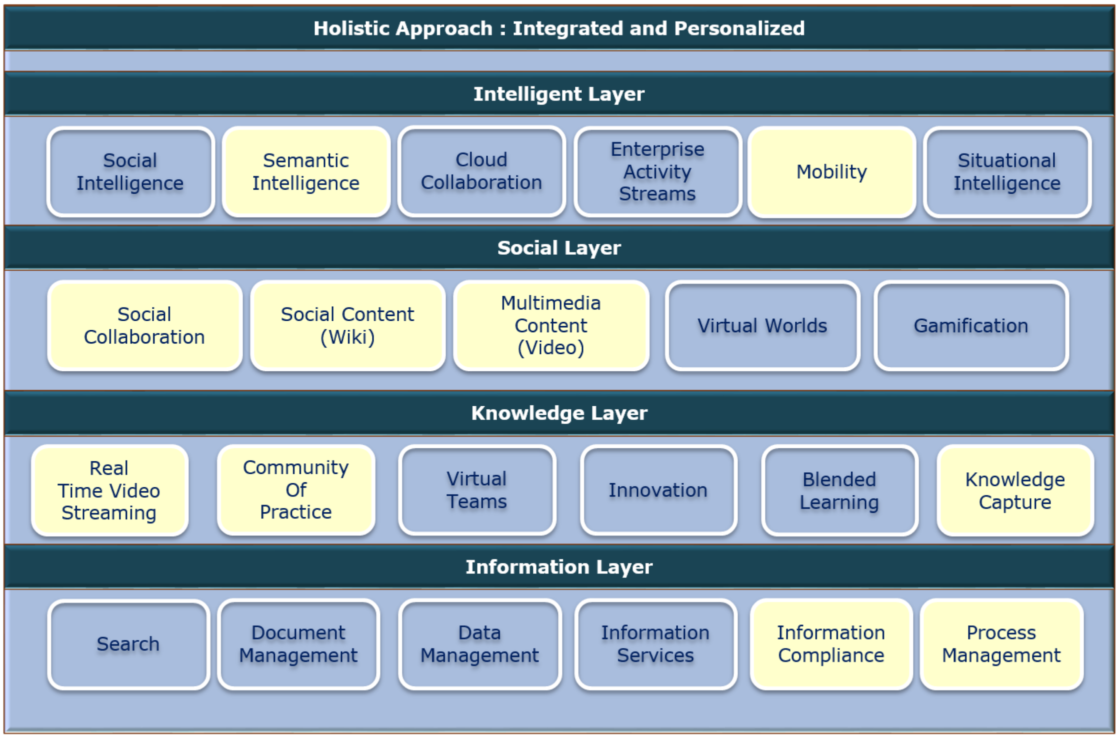


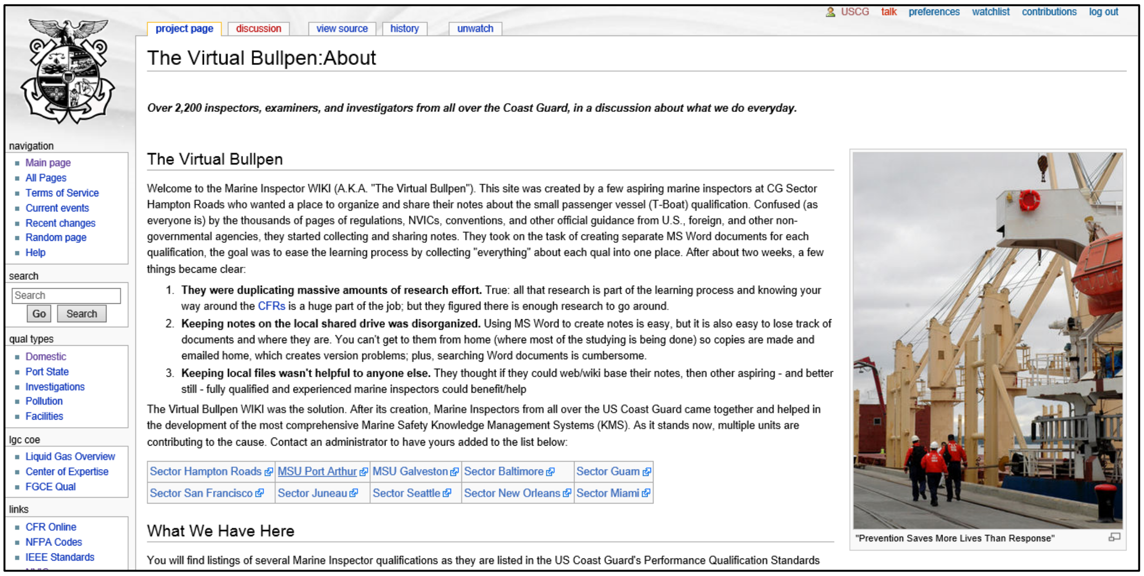
Figure 5.3 The collaboration maturity model. Highlighted areas (white) are concepts believed to have the greatest potential impact on offshore regulation KM.

5.8.1 Knowledge Capture

In KM there are two sides to knowledge: explicit and tacit knowledge. Explicit knowledge is knowledge or information that is documented and captured. Tacit knowledge is the experience in people's minds.

When focusing on knowledge capture, it is desired to capture and share tacit knowledge to a wider audience. There are many ways to enable knowledge capture. Traditionally knowledge capture would be done through structured interviews after which a report would be created and often sent to a few people and then lost in the archives. More recently knowledge capture has moved to embrace social media concepts such as Wikipedia, video lessons learned and storytelling.

Wikipedia within an organization is becoming more and more important to share information. An example of this is the SPE's PetroWiki. SPE has transferred its engineering handbooks to an electronic, web-based Wiki site. The primary motivator in this venture is the ability to provide focused content to users without having to provide large paper manuals. Also, this provides the opportunity to have multiple people involved in updating the content year-round and to provide information in context when it is needed. In fact, the USCG has already seen a grassroots movement in establishing a marine inspections and investigations Wiki (Figure 5.4). This knowledge capture tool was established and is still managed by USCG inspectors for inspectors. While an extremely powerful knowledge repository, its employment has been significantly underutilized.



The Virtual Bullpen:About

Over 2,200 inspectors, examiners, and investigators from all over the Coast Guard, in a discussion about what we do everyday.

The Virtual Bullpen

Welcome to the Marine Inspector WIKI (A.K.A. "The Virtual Bullpen"). This site was created by a few aspiring marine inspectors at CG Sector Hampton Roads who wanted a place to organize and share their notes about the small passenger vessel (T-Boat) qualification. Confused (as everyone is) by the thousands of pages of regulations, NVICs, conventions, and other official guidance from U.S., foreign, and other non-governmental agencies, they started collecting and sharing notes. They took on the task of creating separate MS Word documents for each qualification, the goal was to ease the learning process by collecting "everything" about each qual into one place. After about two weeks, a few things became clear:

1. **They were duplicating massive amounts of research effort.** True: all that research is part of the learning process and knowing your way around the CFRs is a huge part of the job; but they figured there is enough research to go around.
2. **Keeping notes on the local shared drive was disorganized.** Using MS Word to create notes is easy, but it is also easy to lose track of documents and where they are. You can't get to them from home (where most of the studying is being done) so copies are made and emailed home, which creates version problems; plus, searching Word documents is cumbersome.
3. **Keeping local files wasn't helpful to anyone else.** They thought if they could web/wiki base their notes, then other aspiring - and better still - fully qualified and experienced marine inspectors could benefit/help

The Virtual Bullpen WIKI was the solution. After its creation, Marine Inspectors from all over the US Coast Guard came together and helped in the development of the most comprehensive Marine Safety Knowledge Management Systems (KMS). As it stands now, multiple units are contributing to the cause. Contact an administrator to have yours added to the list below:

Sector Hampton Roads	MSU Port Arthur	MSU Galveston	Sector Baltimore	Sector Guam
Sector San Francisco	Sector Juneau	Sector Seattle	Sector New Orleans	Sector Miami

What We Have Here

You will find listings of several Marine Inspector qualifications as they are listed in the US Coast Guard's Performance Qualification Standards

Figure 5.4: The USCG marine inspections and investigations Wiki (from The Virtual Bullpen). The "Virtual Bullpen" is a knowledge capture tool where all USCG inspectors and investigators can provide input and experience regarding various sections of regulatory requirements and USCG inspector and investigator qualifications.

Video lessons learned are considered an extension to traditional after action reviews (AAR). AARs are used to capture learning after an activity or audit is performed. AARs include the following main elements:

- What was the intent?
- What actually happened?
- What could be improved?
- What will we do different next time?
- Who will we share this with?

This is a very powerful tool originally used by the U.S. Army and has made its transition into the oil and gas industry. As learnings are captured through reviews, anything that can be documented through short video lessons can aid future personnel in applied learning. With new technologies, it is now possible to utilize voice recognition and index information provided within videos. This makes finding a section regarding specific information in a video easy to retrieve.

Within an organizational environment, applying Wiki provides the ability to show relevant, contextual information based on intelligent search recommendations. An example of a new technology that enables this is semantic recommendation. Semantic recommendations use factors such as context, location, and information needs and provide content (be it Wikis or documents) relevant to a specific problem. Semantics can also be used to track new technology concepts in oil and gas through advantage external indexing of third party material.

When it comes to capturing lessons and sharing them, it has been found that the use of stories vs. reports often help to drive a better, more simply understood lesson. By interviewing seasoned professionals and capturing their stories, it provides an easy and effective vehicle for new staff to understand issues and challenges. Throughout time a story often does bring more context and appreciation for why things should happen or be operated in a certain way. The so-called storytelling methods have started to become popular within the oil and gas industry, and combined with video, provide an effective delivery method to teach and mentor the next generation of oil and gas personnel and inspectors/regulators.

A valuable application of knowledge capture is data collected by the regulatory organizations around HSE incidents. Data captured from these investigations can then be utilized to analyze commonly occurring incidents and anticipate needs for regulatory and standards development or modification. This will help ensure lower incident and a pro-active focus on safety based on regulatory captured information.

5.8.2 Knowledge Sharing

Once knowledge is captured, it is ready to be shared. Sharing knowledge can be done in many different ways, but the primary mechanism is through so called Communities of Practice (CoP). A CoP is a group of people who share a common goal or interest collaborating together to supply knowledge to each other. Many oil and gas companies are actively employing CoPs. When implementing CoPs, it is important to have organizational support for knowledge sharing and a strong focus on enabling behavior change. To move from ad hoc email discussions to structured conversation can be a challenge. A new development in this area is to leverage social media as a collaboration platform. The reasoning behind this is that one can easily exploit mobile collaboration. Additionally, training needs are lower due to it being relatively easy to use, and the concept is already understood by most if not all users. When developing new concepts and innovation, the use of crowdsourcing and idea brainstorming has become popular. New innovations often come from a collaboration of various parties including operators, service companies, government, standards organizations, and universities to bring a wide range of experience and styles to a specific problem. This is based on the so-called open innovation concept (Chesbrough, 2005).

CoPs together with Wiki and knowledge capture become very powerful in sharing ideas and capturing lessons. Once someone has shared and discussed a specific issue it is important to close the loop on the discussion to capture conclusions. This is where the use of Wikis becomes a powerful learning mechanism for organizations.

Although sharing knowledge within a CoP is important, other applications can be of value when focusing on social collaboration. CoPs certainly can become of great value to promote dialogue between all involved parties in the development of new rules. Social collaboration would ensure that ideas are not trapped in strings of email conversations. Instead, any party that may be new to the dialogue can refer to the history and provide input as needed. The social collaboration area becomes the central conduit of information and discourse. Secondly, emails can become obtrusive mixed with routine day to day email communications. A more efficient way to handle these conversations is by leveraging social collaboration where all communications are stored and separated through an app on a mobile device. Another example, which is interrelated to the virtual collaboration section, is in the CBR automated alerting software or any applications that create email alerting (Figure 5.5). Traditionally, when alerts are generated in an application these are sent through email. Again, emails can become mixed with more routine correspondence. The concept would be that an alert is sent into a collaboration space and any parties associated or "tagged" in this space can, in a virtual environment, discuss the course of action and a historical log of discussions, decisions, and events are retained.

Figure 5.5: The implementation of an app-based social collaboration tool for standards and regulation development, as well as real-time alerts, could provide a more efficient means of addressing challenges and involving all necessary parties in real-time collaboration.

5.8.3 Virtual Collaboration

A final focus area in KM is the ability to leverage intelligent technologies to reduce dependence on deploying personnel out in the field and share information more effectively in real-time. This includes technologies focused on:

- Mobile technology
- Real-time alerting
- Augmented reality
- Remote drone support

Mobile technology and specifically technology that is overall intrinsically safe on the rig to enable individual personnel are an interesting development in the oil and gas industry. Mobile support devices such as tablets and smartphones can now feature Class

1/Division 1 specifications, preventing ignition of hydrocarbons that might be present. This provides users with the ability to share information in the field to and from the rig floor. An example where mobile technology could help is through live streaming from the rig (Figure 5.6). Video can be streamed from any cameras on the rig and from the intrinsically safe devices to the office or other locations.

Figure 5.6: An example of the use of mobile technology for remote oversight, utilizing an intrinsically safe mobile device that can be taken anywhere on the rig without ignition risk (from Mobile Smart Worker Solutions).

This helps to reduce the need for deploying office staff to the field for on-site compliance and quality assurance inspections, as any personnel on the rig can use the device to show any equipment that needs to be inspected.

Another developing technology is augmented reality. A comparable example of this technology would be Google Glass. An augmented reality environment gives the user the ability to use the camera of his or her mobile device and move over specific technologies on a rig and relevant information and instructions can overlaid on top of the camera view. This is a great way to train and teach new staff how to perform specific actions in the field.

Finally, while having an intrinsically safe device on the rig, there is always the capability to leverage other remote concepts such as inspection drones on each of the rigs. Although currently more on the outer periphery of recommendations to be considered for adoption, this could eventually help reduce personnel work time and physical presence in hazardous environments.

5.9 APPLICATION TO BSEE AND USCG CHALLENGES

Referring back to the presented challenges for BSEE and USCG KM, many of the above-mentioned concepts can be applied to help address these agencies' knowledge gaps and ultimately improve performance in oversight.

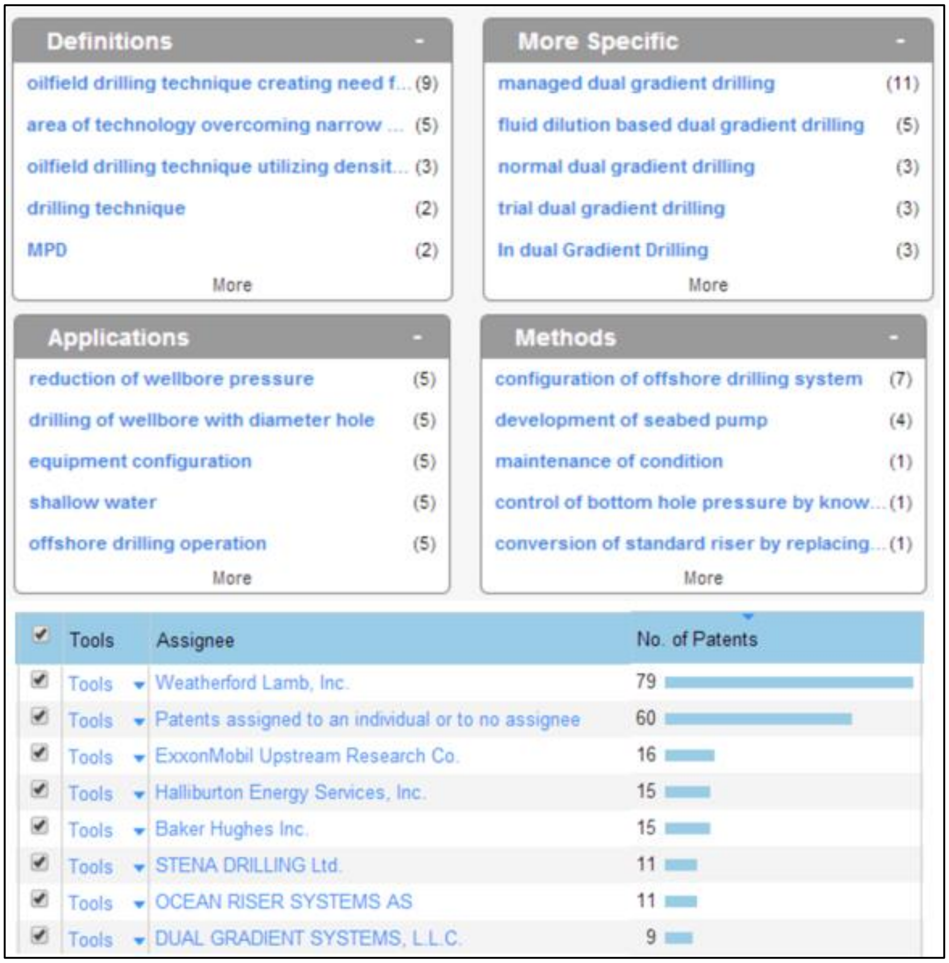
5.9.1 Timely Development of Sound Regulations and Standards

The first area of focus when it comes to regulation and standards creation and development is actually understanding and tracking changes in new developments. It can be a challenge to keep pace with new technologies and associated standards application in the industry. An example of this time gap is the maturation and implementation of manage pressure and dual-gradient drilling (MPD/DGD) technologies without timely development of rules or standards. While a simple concept, MPD/DGD technologies push the technical envelope further than what the industry thought possible. However, application is relatively complex compared to conventional techniques. Thus, a vacuum in standards around such technology leaves both the regulator and industry with a sound guideline or rule for safe implementation. Through the use of externally focused semantic search engines, development changes can be tracked in specific areas of technology, and standards and regulatory bodies can be made aware in advance to start work on any associated requirements (Figure 5.7). Through use of technology that understands and interprets the information through natural language processing, organizations have the ability to flag relevant information rather than having to sift through long laundry lists of non-applicable information. This capability is currently being applied by an oil and gas operator in order to track new developments and innovations in deepwater technology.

Once the areas of importance around which standards development is needed become clear, the experience within the organization must certainly be leveraged, but even more so experience from within the industry must be tapped. This is where professional organization communities of practice come into play, such as API, SPE, IADC, etc. These organizations, if able to participate with the regulatory organizations, can provide insight into any other innovations and can help problem solve what standards development would be best.

The advantage in leveraging these communities is to make use of the large membership and still be able to track the conversations. Again, the use of a semantic-based search engine to index these communities and provide recommendations becomes important.

After employing the industry CoPs for scope and direction, the actual creation and deployment of a standard becomes very important. Rather than updating one large document being printed and sent to organizations, utilizing Wiki's in such a way that specific sections can be edited and are more frequently and easily able to provide in-context material to the industry, e.g. one has no need to send a whole guide but just a specific reference page. As the professional organizations also are moving towards Wiki this can be used for reference as well.



Definitions	-
oilfield drilling technique creating need f...	(9)
area of technology overcoming narrow ...	(5)
oilfield drilling technique utilizing densit...	(3)
drilling technique	(2)
MPD	(2)
More	

More Specific	-
managed dual gradient drilling	(11)
fluid dilution based dual gradient drilling	(5)
normal dual gradient drilling	(3)
trial dual gradient drilling	(3)
In dual Gradient Drilling	(3)
More	

Applications	-
reduction of wellbore pressure	(5)
drilling of wellbore with diameter hole	(5)
equipment configuration	(5)
shallow water	(5)
offshore drilling operation	(5)
More	

Methods	-
configuration of offshore drilling system	(7)
development of seabed pump	(4)
maintenance of condition	(1)
control of bottom hole pressure by know...	(1)
conversion of standard riser by replacing...	(1)
More	

☑	Tools	Assignee	No. of Patents
☑	Tools ▾	Weatherford Lamb, Inc.	79
☑	Tools ▾	Patents assigned to an individual or to no assignee	60
☑	Tools ▾	ExxonMobil Upstream Research Co.	16
☑	Tools ▾	Halliburton Energy Services, Inc.	15
☑	Tools ▾	Baker Hughes Inc.	15
☑	Tools ▾	STENA DRILLING Ltd.	11
☑	Tools ▾	OCEAN RISER SYSTEMS AS	11
☑	Tools ▾	DUAL GRADIENT SYSTEMS, L.L.C.	9

Figure 5.7: An example of the use of semantic intelligence. In this case, a search was performed for dual gradient drilling. From this, much information is brought to the fingertips of the user, including definitions, methods, even trends in patents by year and by patent registrants (from IHS Goldfire).

The advantage in leveraging these communities is to make use of the large membership and still be able to track the conversations. Again, the use of a semantic based search engine to index these communities and provide recommendations becomes important. After employing the industry CoPs for scope and direction, the actual creation and deployment of a standard becomes very important. Rather than updating one large document being printed and sent to organizations, Wiki's can be used in such a way that specific sections can be edited and are more frequently and easily able to provide in-context material to the industry (e.g. one has no need to send a whole guide but just a specific reference page). As the professional organizations also are moving towards Wiki this can be used for reference as well.

5.9.2 Personnel Staffing and Retention

As there is a limit on staffing, and no one can be everywhere at the same time, it becomes important to be able to leverage experience and connections between the regulatory staff. In this way, one person need not know all the answers, and a network of personnel can actually support multiple companies and assets at one time. This becomes easier through the use of mobile technology where reviews can happen through rig-safe devices and remote communication can happen together with video back to the shore, including from the rig floor. Either deployed regulators can relay questions or concerns back to shore for additional input, or the rig can relay information back to the regulators on shore, all in real-time. Combine this with a drone on the rig that can be steered remotely by the reviewer this becomes a very powerful tool and cuts down on not only manpower needs but travel costs.

Drone technology has been successfully applied in the United Kingdom with various offshore oil and gas companies. Though the application of this technology is still under review within the U.S. it is expected that in 2015 clarity will be provided to the use of drone technology in U.S. airspace. Once regulation regarding commercial drones is implemented in U.S. airspace, it can be anticipated that commercial drone usage on offshore installations will become a commonplace inspection tool from the industry perspective, removing personnel from harm’s way. Regulators should be prepared to embrace this technology as a means to enhance remote inspection capabilities. An example of this might be a supply vessel allision with a tension leg platform. Upon notification, regulators could remotely witness the extent of structural damage suffered and determine response/investigation needs before planning and procuring a costly helicopter flight.

Though augmented reality is becoming more applicable in the industry it will take a significant effort to relate this to the wide range of diverse rigs and environments. However, once this has been done being able to pull up specifics on any technology on the rig makes it a very powerful tool.

5.9.3 Personnel Knowledge and Experience

As there is a limit on experienced personal every opportunity must be taken to share knowledge of more experienced staff. When implementing video capture, interviews can be a powerful way to capture knowledge even of staff leaving the organization or retiring. By providing a video-on-demand library that can be accessed out in the field, learning can be accelerated. This is important especially for younger staff coming in who are much more accustomed to video learning, e.g. by using YouTube. It is important to make the lessons compelling and help create a bond between the experienced staff and new hires so the use of stories creates a stronger bond and makes a lesson harder to forget.

Finally, by embedding AAR's into the daily routine a library of experience becomes available for current and future staff. This is important to build a routine around this with new staff so it become second nature on every activity done. An example of how to apply the AARs is to have a regular meeting virtual or together where each of the field personnel can highlight challenges in the field. By performing AAR's and capturing the learnings and actions, the distribution of knowledge will be accelerated.

5.10 RECOMMENDED KM APPROACH

When it comes to the implementation of solutions in the Knowledge management space, the five focus areas and their associated key activities would be utilized. In implementing the various knowledge concepts previously described, specific questions should be asked relevant to each concept. Appendix A1 provides a checklist has been provided as an example for mobile technology implementation. KM provides a most cost-effective avenue to ensuring timely development of worthwhile standards and regulations and promotes an all-encompassing inclusion of expertise. However, as with any implementation of new concepts, they must be strategically introduced so as to have the optimum cultural acceptance. Therefore, this thesis recommends a three phase approach to regulatory agencies in implementing KM concepts.

5.10.1 Phase I

The first phase of KM concepts implementation addresses ideas that can most easily be implemented within an organization, both in infrastructure and corporate culture.

- Wiki – The fastest way to embrace Wiki concepts and its value is to focus on information within standards that are repeatedly used in the field. By separating these sections into an easily retrievable Wiki the ability to react to specific standard activities is accelerated. This would be a fast easy win to do within the regulatory organizations. Members within the USCG have taken an important first step in developing a Wiki for this purpose, however, much can be done to further foster and develop this capability, particularly related to offshore regulation. Also, integrating BSEE and its respective knowledge within a Wiki will improve knowledge capture and sharing in both camps.
- Semantics – By leveraging technologies that already have pre-indexed multiple sources relating to technology (SPE, IEEE, global patents) together with semantic intelligence the knowledge on new concepts will become easily and readily available. This will give the regulators clear insight into the range and concepts out in the industry vs. waiting to be educated or have to self-discover the range of regulatory implications. This can easily be done now through online subscription services.
- Lessons Learned – Initiating a lessons learned initiative is reasonably straight forward. By including this in a weekly close out practice even between two field staff, the learning and capture can quickly create a valuable reference library of lessons. Many times best results are seen when veteran personnel are paired with less experienced personnel.

5.10.2 Phase II

To one extent or another, second phase concepts involve a greater degree of either infrastructure development or cultural transition.

- Storytelling – Recording experiences of knowledgeable/transitioning personnel provides a user-friendly interface to learn from past challenges. Many times, particularly with geographical challenges, different regulatory offices of the same organization might come to different conclusions. However, the implementation of storytelling can provide an additional element of experience to help provide uniformity in regulation. Once developed and adopted, storytelling archives can be rolled into the organization Wiki.
- Collaboration space/CoPs – CoPs can provide a significant advantage in taking input in policy/regulation/standard development from multiple parties identified as having integral experience and value in the industry. However, a significant cultural barrier must be overcome both internally and externally. While still maintaining enforcement bounds, regulatory and industry parties must begin to look at each other from the perspective of being collaborators together in an effort to ensure safe, efficient delivery of offshore wells. Additionally, regulatory agencies must foster a more cooperative and participatory relationship with sister agencies (e.g. between USCG and BSEE) and utilize CoPs to maximize understanding of responsibilities and collaboration.
- Mobile Technology – Mobile technology could be seen as a far-fetched concept for regulatory purposes, but the world is in an accelerated transition to providing anything and everything through the screen of a tablet or smartphone. Inspections

at a far distance offshore provide a good example of how regulators can benefit from having instantaneous access to regulations, standards, electronic checklists, Wikis, lessons learned, storytelling videos, collaboration space, and even video chat for supplemental support and better on-site decision-making. Simply put, intrinsically safe mobile technology can be where KM capabilities all come together for the regulator.

5.10.3 Phase III

Third phase concepts focus on long-term implementation of new practices and procedures with sufficient cultural change. These represent technologies "on the horizon" – very powerful capabilities, but requiring more painstaking integration with corporate culture and development of new infrastructure.

- Real-time Alerting – In reality, real-time alerting technology is akin to a phase II concept. The idea of real-time alerting could be implemented with relative ease; however, the complication is what the alerting is actually linked to. In this context, real-time alerting associated with drilling events requires the acceptance and development of an infrastructure utilizing artificial intelligence, such as CBR, and subsequently linking such alerts to a collaboration space.
- Drone Support – Dependent on future regulatory requirements, the forecast is promising for employment of drone support by the offshore industry in the Gulf of Mexico. However, offshore regulators may be far from developing policy relying on such technology to supplement or augment inspection criteria.
- Augmented Reality – Augmented reality provides a clear opportunity into identifying "hot spots" when entering into a working environment of an operator.

> By having the ability to visualize past hot spots at a glance on a mobile device not only highlights areas of focus but teaches new staff what past experience has captured as relevant. For regulators, having this capability directly tied to incident and non-compliance statistics, even as particular as a specific rig history, can help ensure the hot spots do not go overlooked. Extensive infrastructure would need to be established for this technology to be implemented in the future, but could provide significant value to offshore safety.

As the current offshore climate seems to forecast that the industry will continue to increase its deepwater (and eventually Arctic) presence and develop more remotely located offshore fields, regulatory agencies will need to keep pace with the trend. The furthering of field development in harsher conditions will also push the need for advanced technological methods for more efficient and safer performance. In order to avoid lagging behind appropriately overseeing and regulating these changes in the industry, agencies will need to maximally exploit their in-house expertise as well as collaborative industry, non-governmental, and academic partners.

Chapter 6

Recommendations and Future Work

A case has been presented here that currently available real-time data acquisition and monitoring technologies can be employed by the regulator to the benefit of offshore safety and compliance. It has been shown that a regulator monitoring data can witness required tests throughout the entire well construction process from the convenience of a computer virtually anywhere in the world. In real-time communication with the operator, drilling contractor, and involved service company, the regulator can identify key measurements that ensure that operations are being performed in accordance with what was proposed and approved.

6.1 REAL-TIME DATA MONITORING REGULATORY STRUCTURE

A significant hurdle in the implementation of such technology is that of promulgating regulation. Completely restructuring a regulatory regime is not an overnight change-out. However, if the currently regulatory regime were utilized with minimal introduction of new regulations, it might be more easily embraced and implemented. It should be clarified that the lines of responsibility should not be blurred when integrating the regulator into remote oversight. The objective is ensuring consistent, continuous compliance with already existing safety regulations and performance in accordance with the plan that has been vetted and approved. The operator is still ultimately responsible for decision-making regarding planning and execution of well construction; however, integrating the regulator into execution and even to some extent planning, will certainly provide more continuous and informed oversight, but has the potential of providing a more efficient manner in regulating and performance.

The current set of rules lends itself well to establishing requirements for providing regulators access to real-time data, particularly with respect to BOP, formation strength, and cementing/casing tests. In one form or another, information from these tests is already required to be provided upon request of the regulator. Providing access to real-time data could fit entirely within this requirement. However, in an effort to minimize the burden on companies to provide real-time data, what is the minimum data set needed to effectively regulate remotely with real-time data? Simply put, this type of regulation could be performed with data that most, if not all, deepwater operators already acquire for these tests. Specifically, regulators would need to require, minimally:

- Pump pressures
- Volumes
- Pump/Flow rates
- Fluid densities (and corrections for downhole effects)
- Standpipe pressure
- Health monitoring on key equipment, e.g. BOPs

The use of downhole pressure data would prove to benefit the accuracy of tests and ultimately the safety of well operations. However, the minimal set of data requirements could be attained from surface measurements.

The subject of event detection could be expected to be a more challenging, but very important transition to regulatory oversight through remote real-time data monitoring. As written now, the regulations provide for a loose interpretation that could justify requirement of drilling event detection capabilities and regulator real-time data monitoring capability in accordance with the requirement to keep wells under control using BAST (30 CFR 250.401). However, being that this requirement would necessarily require much more data on a more continuous basis, and would additionally bring with it the potential for interrupted operations, a clear expectation and procedure would need to be laid out. Also, the extent of drilling activities suitable/fit for oversight would need to be determined. The case-based reasoning software used in this research provides monitoring of not only pore pressure changes and losses of circulation, but many other NPT issues that could also be contributing factors to well control incidents. However, if the scope of oversight would just be limited to pore pressure/fracture gradient, and influx monitoring through flowback fingerprinting or SPP/ADP measurements, the data requirement would not be as substantial. At a minimum, automated influx monitoring employing technologies such as flowback fingerprinting and/or SPP/ADP should be implemented. These technologies only require provision of data that is already utilized for kick detection, which includes fluid flow rates, standpipe pressure, and mud pit volume (Ali et al., 2013). SPP/ADP, however, would require one additional pressure sensor somewhere along the annulus discharge line (Reitsma, 2011). These two capabilities alone could flag anomalous conditions, notify regulators of potential catastrophe, and allow them to contact the rig to ensure they are aware of the unsafe situation. It would still be up to rig personnel and their respective shore-based leadership to determine the best and safest remedy to satisfy the regulator that it is safe to continue downhole operations.

With respect to case-based reasoning and related artificial intelligence/pattern recognition technologies, it is the opinion of the authors that this provides a very promising future in the industry as an automated, fairly objective monitoring system that can make its users safer and better drillers. This technology is the preview into the future of drilling and completions, and its advancement and maturity should be embraced by both regulators and industry as a very valuable aid to safer drilling operations. The application of the technology itself is very effective in its current state, but will become an even better asset in the future and also assist in maximizing learning experiences of regulators and drilling engineers.

6.2 IMPLEMENTATION

Like the phased approach outlined in the KM section, developing a regulatory structure for real-time data monitoring adoption would need to mirror such implementation and is recommended as such. This phased implementation could easily be trialed under the auspices of the OESI and COS, minimizing much overhead cost that would otherwise be shouldered independently by regulatory agencies. Additionally, these organizations coupled with academic partners could provide a "neutral party" testing ground, mitigating any concern regarding conflicts of interest.

6.2.1 Phase I

The first phase of implementation would necessarily be a small scale pilot program, utilizing already established infrastructure in a cooperative setting UT-Austin (a partner in the OESI) provides a unique opportunity in this partnership with its Remote Collaboration Center, an RTOC capable of monitoring up to nine drilling and completion operations concurrently. This facility is also "vendor neutral," providing virtually any commonly employed data software in well design and execution. In this phase, basic implementation of essential tools would be undertaken, utilizing simpler softwares for real-time monitoring (BOPs, LOTs/FITs, casing, slurry placement, etc.). Real-time drilling data could also be visualized for purely educational purposes to begin grooming regulators to recognize suspect data patterns. This exercise in monitoring real-time data would, in reality, be in need of one or a few cooperating offshore operator(s) willing to provide real-time data and two way communications with the rig and operator's RTOC. The overall goal of this phase would simply be proof of concept and staging for phase II.

6.2.2 Phase II

Upon proof of concept and validation in the value of regulatory real-time data monitoring, regulators would look to establish a small-scale, war room-like RTOC, implementing lessons learned and adopted software usage from phase I. An increase in data volume could be undertaken, soliciting for operator voluntary compliance. A goal-based approach could be developed at this point. In response to satisfactory remote compliance via real-time data, regulators could trial the approach of decreasing onsite visits to rigs cooperating with voluntary compliance. Workflows could be matured as well as development and maturation of more defined rules and regulations. While utilizing the software implementations from phase I, more complex software such as CBR for drilling event detection/prediction, could be employed. This phase would validate independent management of real-time data and a RTOC by regulators.

6.2.3 Phase III

Mature implementation of RTOC concepts would be adopted in phase III. Voluntary compliance would eventually transition to mandatory compliance with data provision for regulatory real-time data monitoring. Regulators would have real-time data monitoring covering all offshore operations, utilizing the matured software developments from previous phases. To accomplish this, agencies would need to establish one central RTOC. However, dependent on the number of offshore well operations underway, it may be beneficial to also employ satellite RTOCs at the agencies' field offices that would report to the central RTOC for discrepancies. Ultimately, rules and regulations will have reached full maturity, and dependent on the final implementation of real-time technologies, including KM capabilities, onsite visits could be employed at a minimum or phase out completely.

6.3 WORKFLOWS

Procedural workflows for testing requirements could be fairly straightforward. In fact, BSEE notification is already required for BOP stump tests and initial installation tests. 30 CFR 250.449 requires that the operator notify BSEE a minimum of 72 hours in advance of these two BOP tests. With this as a template, advance notice could be required for all the previously mentioned tests. Based on weather or operational demands regulators may either delay the test or prevent regulators from witnessing tests. Implementing a 72-hour notice requirement for all tests may be too burdensome, particularly since the predictability of some of these waypoints in well construction can be in flux. However, with real-time capabilities, a 72-hour advance notice may not be required for all tests, since regulators could simply access tests live from their desks or retrieve the data or reports if operational demands prevent them from witnessing in real-time. Upon completion of the tests to satisfaction, and the regulator verifying positive test results in accordance with the approved well plans, operations could continue. If some adversity is met, for example a LOT that results in a lower mud weight requirement than originally predicted, the operator could then address and modify the program for approval.

Workflow becomes slightly more involved when it comes to drilling event detection. With respect to drilling events, 30 CFR 250.188 requires immediate oral notification of:

- Any loss of well control, meaning surface or underground blowout,
- Flow through a diverter, and
- Uncontrolled flow resulting from a failure of surface equipment or procedures.

While prudent to establish reporting requirements for incidents, this does not outright prevent an incident from occurring. Now rightly, prevention of well control incidents is the responsibility of the operator, and by delegation, personnel contracted by the operator. However, as witnessed with the Macondo blowout, sometimes these actions and the current oversight provided by the regulator is not enough. The advantage that intelligent, automated real-time data monitoring software provides is to quickly identify trouble events before uncontrolled development, or in the case of case-based reasoning, essentially predict the event before it even occurs. Thus, in the use of this capability, the regulator could be given the ability to be automatically notified of a potentially serious event, and proceed with informing involved parties and collaborating in a solution, and potentially ordering a shut-in after the situation is brought safely under control.

6.4 INVESTIGATIONS

With varying focuses, both USCG and BSEE have investigation authorities on mobile offshore drilling units and offshore facilities. While incident investigations are undertaken for the purpose of both identifying violations and ensuring justice, the overarching idea behind investigations is to identify what went wrong, and how it might be prevented in the future. Incident investigations provide the 20/20 hindsight to ask the question related to every decision made leading up to the incident, "Why did they decide to do that?" In answering that question throughout an incident investigation, new barriers to ensure safety can be developed. Implementing requirements for operators to provide and record real-time data could provide a significantly better avenue to finding the answers in investigations more accurately, thereby helping to promote a safer industry. In the maritime industry, chapter V, regulation 20 of the Safety of Navigation of the International Convention for the Safety of Life at Sea, 1974 (SOLAS), requires that vessels to which SOLAS is applicable must have on board an operating voyage data recorder (VDR). A likeness to the commercial aviation industry's "black box," the VDR records data from critical ship systems that would be integral to identifying causal factors in an incident, including voice recording. Noting that some mobile offshore drilling units are subject to SOLAS, the idea of a requirement for an offshore drilling industry "black box" should not seem far-fetched, and in fact would yield better identification of causal factors and aid in preventing future incidents more effectively.

6.5 SIMULTANEOUS OPERATIONS

Some of this discussion on recommendations for improved regulatory oversight and offshore safety should be directed toward the subject of simultaneous operations. Relatively little work or discussion has been done with respect to developing standards or requirements surrounding the risk involved with conducting certain operations simultaneously. However, in almost any incident, particularly an incident of national and international significance, there is a loss of situational awareness due to a lack of maintaining the full operational picture. Simultaneous operations were a significant contributor in personnel on the *Deepwater Horizon* losing situational awareness and failing to identify the symptomatic conditions of a hydrocarbon influx. The systems and associated operations on board mobile offshore drilling units and offshore floating facilities are vastly more complex than what is commonly seen in the maritime industry. Likewise these vessels and facilities are vastly more complex than what is commonly seen in the land drilling industry. The combination of maritime and drilling operations leads to a significant need for communication and oversight. A primary example of a conflict of this synergy is the offloading of displaced fluids from the well to a supply boat, thus making it difficult to detect anomalous flowback from the well (Deepwater Horizon Study Group, 2011).

6.6 SOFTWARE

The oil and gas industry certainly does not have a shortage of commercial software available for purchase. However, some are much more capable and respected than others. The landscape of software using data and real-time data is more or less partitioned into very specific applications, be it geomechanics, BOP testing, geosteering, hydraulics modeling, etc. For the application of regulatory oversight using real-time data monitoring, regulatory agencies could by all means solicit for a contract to develop a custom software suite capable of employing a full gamut of services needed by the regulator. While providing a "one-stop shop" this would most likely not be cost effective, and it could possibly be difficult to update and keep pace with the ever-evolving industry technologies. Instead, as this thesis has shown, commercial software is readily available for the regulator to implement with relative ease. Currently BOP tests can be witnessed and validated in real-time by a web-based, automated leak test software with fluid thermal compensation (Franklin, et al., 2004, Franklin et al., 2011). This software is widely used in the in the deepwater Gulf of Mexico community. Pressure tests verifying formation strength, casing shoe integrity, and cement and casing integrity can be witnessed in any real-time data visualization software. A variety of this particular type of software are available and also in a web-based format, accessible from virtually any computer with an internet connection. Early kick detection using automated flowback fingerprinting or SPP/ADP may require more specialized software; however, the benefit in detecting anomalous flows would certainly outweigh costs.

6.7 BAST RECOMMENDATIONS

In 2013, at the request of BSEE, the National Academy of Engineering and National Research Council released a report with recommendations and options for implementation of BAST. Many points and recommendations reflect similar revelations in this thesis, but some are important to note. In order to address the agency's competency and hiring challenges, the report recommended utilizing industry expertise in aiding assessment of technologies (National Academy of Engineering, 2013). In particular, BSEE should maximize use of its newly established Offshore Energy Safety Institute (OESI) to aid in research and maturation of technologies that can advance industry safety. "OESI could serve BSEE as a competent, trusted, conflict-free agent if it is given the appropriate resources (National Academy of Engineering, 2013)."

Regarding the collaborative effort needed to develop effective BAST implementation, the report made a very important note:

> BSEE has an opportunity to redefine the relationship between it and industry more as a partnership – one that recognizes that the final authority remains with the federal agency but in which the agency acknowledges that industry has much more technological expertise to offer (National Academy of Engineering, 2013).

While it shouldn't be doubted that BSEE makes a concerted effort to develop a fruitful relationship, both industry and BSEE must come to a level of trust in collaborating together to develop BAST requirements in a common vision for offshore safety. This relationship must be fostered not only in parties involved with BAST determinations, but also with respect to field personnel.

This thesis has made mention of the value that an operator's RTOC can have on the performance and safety of a well and the value that real-time monitoring could have for regulators to have improved oversight and awareness of compliance and safety. Similarly, the BAST report addresses and makes recommendations considering the value and use of RTOCs for well planning, monitoring, and simulating adverse conditions in time-critical situations (National Academy of Engineering, 2013). When looking into the potential for RTOC implementation, there are three possibilities:

1. Requiring a data set that all operators must monitor in an RTOC, where upon regulators would then inspect and audit the RTOC itself. This lends itself to a

simpler rule implementation, as much infrastructure is already in place. However, this would not accomplish the continuous oversight that is needed and possible.

2. Requiring a data set that all operators must provide to the regulator, to the respective government RTOC depending on the geographic location of the well. This would ensure continuous oversight by the regulator, but would likely confuse the lines of responsibility between regulator and operators. Additionally, the infrastructure cost would be significant. This option may be a reasonable thought for a national incident "war room."
3. Requiring a data set that all operators must provide and monitor, providing web-based access of real-time data to regulators. This provides the regulator continuous access to monitor the well construction process at any point, while not requiring the 24/7 manpower of a regulatory RTOC. Also, this minimizes any additional infrastructure cost, as regulators could simply access the data from workstation computers.

The third scenario is an optimum scenario for continuous regulatory oversight while still minimizing interruption and intrusion into the drilling schedule. It is strongly recommended that BSEE consider implementation of real-time monitoring regulation and monitoring to improve awareness and safety.

Furthering recommendations for BAST implementation, there are emerging and maturing technologies in the industry today that should be given particular attention by BSEE for BAST consideration. Two technologies that in particular can both improve offshore well performance and safety are pressure management drilling methods, namely dual gradient drilling, and wired drillpipe.

The first venture into dual gradient drilling use in the Gulf of Mexico occurred in the early 2000s (Eggemeyer et al., 2001). Since then, the concept has grown in popularity and application, and multiple techniques now exist. At a point in which the industry foresaw the technical limit being reached on these highly complex deepwater wells, DGD introduced a new era in deepwater drilling. By lowering the hydrostatic pressure in the annulus, PPFG windows can be better navigated, reducing the number of casing strings needed. Also, DGD provides the capability of drilling at a higher mud weight, possibly even kill mud weight, allowing for speedy well control operations. Being that the industry is seeing frequent issues with dynamic positioning (DP) systems, heavier mud used for DGD purposes could provide riser margin should a drive off occur and emergency disconnect needed. Multiple techniques of DGD have been developed and are in use today, some certainly more effective than others. It is recommended BSEE focus standards and regulatory development for this technology, in order to establish requirements for safe implementation of DGD methods.

Wired drillpipe is a relatively new development in data telemetry, and by far exceeds the capabilities of the current methods (McNeill et al., 2008). With the implementation of multiple sensor packages along the drillstring, wired drillpipe can monitor conditions throughout the well, as compared to only knowing conditions near the BHA (Veeningen, 2012). With this feature, wired drillpipe can also aid in faster and more accurate identification of hydrocarbon influxes, as well as monitor hydrocarbon movement up the annulus for well control response purposes (Veeningen, 2012, Karimi, et al., 2013).

However, it is currently a much more expensive technology that the industry has trouble finding justifiable purpose in its implementation. Based on historic trends in technology, this capability will one day be determined justifiable by offshore operators, particularly as its latent benefits become more apparent. It is recommended regulators explore this technology and its potential implementation as BAST for improved drilling safety.

Chapter 7

Conclusions

It was apparent from the Macondo incident in hindsight that the available real-time data could have provided insight into the unsafe conditions. The culture that fostered the Macondo scenario should not be shouldered by one individual, by one company, or by even just the oil and gas industry. More than just specific problems that the incident exposed, it appears to represent the culmination of years of passive regulatory oversight of dynamic operations, small sacrifices/negligences in safety to complete operations that accumulate into big problems, and an environment in which the regulator and operator are more or less pinned against one another in achieving safety compliance. Key conclusions from this research are:

- Current real-time data monitoring technology is readily available and lends itself to be effectively integrated with regulations to maintain pro-active, continuous oversight in drilling and completion operations for measurable improved safety. Regulators can, in fact, build on long traditions and experience that has been obtained with real-time monitoring at NASA, USGS, USCG and FAA to name a few.
- From the recent memory of the Macondo incident, the more recent well control incidents, as well as the continuing issues with DP station keeping failures in the Gulf of Mexico, there are compelling reasons for developing a new regulatory dynamic now.
- The offshore industry, particularly in deepwater drilling, relies heavily on the use of real-time data. As systems become more digitized and automated, reliance on

and proper interpretation of data will only grow in the Gulf of Mexico. Regulators likewise should embrace this movement for more efficient and effective safety compliance.

- With the relative ease of access to real-time data through commercial software and web-based applications, regulators can maintain continuous oversight of rig operations without setting foot on board. This negates the question of whether or not compliance is maintained between the relatively infrequent annual, at best monthly, visits onsite.
- There are tangible benefits to both operators and regulators in the adoption and standardization of real-time data regulatory requirements and oversight. Regulators can ensure a more holistic, continuous vision of operations and safety compliance. Likewise, with the proof of safety compliance and improved communications via real-time systems, operators can benefit from reduced interruption of unscheduled onsite inspections and potentially the elimination of onsite visits altogether.
- A secondary effect of the adoption of real-time data for regulation may be the accelerated transition from antiquated, less reliable measurement methods, such as the CCR or manually recorded LOTs, to the industry adopting high quality data to ensure accurate measurements and objective interpretation.
- The prevention measures in this thesis prove a more holistic view on oversight, not dedicated to a single cause of potential problems. They are a pro-active approach that aims to prevent events that are not a carbon-copy of the Macondo experience.

- These implementation concepts are compatible with –and independent of – the industry strides forward on recovery measures. They are also fully aligned with the shift from heavily prescriptive regulation toward performance-based rules.
- Building a collaborative foundation, particularly through KM employment, regulatory agencies can embrace and achieve a “more with less” paradigm when addressing the fast technological pace of deepwater drilling, maximize corporate knowledge and retention. KM provides a connection that can foster a truly collaborative relationship between regulators, industry, and non-governmental organizations with a common goal of safety assurance and without confusing lines of authority or responsibility. This solves several key issues for regulators with respect to having access to experience and technical know-how, by leveraging industry experts that could not have normally been accessible or afforded.
- The recommendations provided herein fall in line with many of the recommendations made in previous reports where BSEE could improve regulations and oversight.

It is expected that many of the suggestions and recommendations presented in this thesis will find criticism and resistance, both from long-term industry insiders as well as more conservative forces on the regulatory side. Please note that it is argued in this thesis for a gradual, phased approach to testing and trialing the proposed real-time technology and KM approach in true collaborative fashion, under the auspices of such newly created industry-government collaboration entities such as the Center for Offshore Safety (COS) and/or the Offshore Energy Safety Institute (OESI), as well as the National Offshore Safety

Advisory Committee (NOSAC). Only after recommended practices and workflows would have been validated and vetted, with input from all parties (regulator, industry, academia) involved, would a recommendation for implementation in actual well construction practice and associated oversight be made. Academia in particular can play a useful role here, by presenting a "neutral playing ground" where tools, techniques and workflows can be objectively tested without bias and/or invoking scrutiny and criticism by the public at large. The implementation of real-time data monitoring for improved regulatory oversight of offshore wells in the wake of Macondo will provide a promising future in ensuring offshore safety.

Appendix

A1 KNOWLEDGE MANAGEMENT MOBILE TECHNOLOGY APPLICABILITY AND IMPLEMENTATION CHECKLIST

Table A.1 provides checklists for implementing concepts within the five focus areas of knowledge management. These same checklist items can be addressed for any of the knowledge management concepts that are to be implemented.

Table A.1: An example of checklist considerations for knowledge management implementation of mobile concepts.

Category	Checklist	Mobile Concepts
Context	What is the organizational scope of the project?	When it comes to mobile concepts the scope probably should start with the BSEE organization as a first adopter in the field.
	Which specific challenge has the highest priority and needs to be address first?	First priority is to understand in which regulatory areas mobile technology will have the most value.
	Governance and ownership of the KM initiative?	Governance must be defined to include senior staff with BSEE and USCG and advisors from some operators.
	Overall agreed funding method and support	Funding specifically for the mobile portion should be set based on a multi-year agreement to ensure success and embedment.
People and Culture	Key stakeholders and supporters of the initiative	Review BSEE and USCG and identify blockers and champions mainly with those having a passion around mobility.
	What the change effort must be – what are we trying to accomplish?	The change in behavior is ensuring that use of mobile and video streaming and capture technology is embedded as part of the daily activities.
	Longer term support for the change management elements and not just a limited exercise	Focus will be on the new hires as they are circled into the organization. The change will happen through correct onboarding.
	Current behaviors and culture within the organizations	Identify specific areas of contention between BSEE and USCG.
Technology	Which technology will bring the highest value?	This would be a combination of infrastructure requirements and choosing the right safe devices to use in the field.
	Which technology is ready now and which needs to be developed?	Identify current state in the mobile devices and associated applications and prioritize as part of the implementation plan.
	What is affordable to be leveraged?	Include cost and benefit analysis to ensure that the costs don't out way just offering better working wages to field staff.
	Ensuring there is sufficient support and training	When supplying the mobile device a strong support structure is to be in place to correctly use the technology.
Process	Where having a formal process is valuable from a regulatory point of view	Ensure that in specific inspection activities it is mandatory to use the mobile device to capture video.
	Where is providing less formal forms of collaboration would be more useful, e.g. community collaboration	Ensuring that collaboration on the device and sharing experience and knowledge is more voluntary than an obligatory activity.
Compliance	The use of cloud based environments to share information and knowledge from records management compliance point of view.	Agree up front if information is only accessible within the organization or can be stored security external to the organization. This specific as it relates to video captured information and social collaboration on the mobile device.
	Ensure that information security is addressed on specific information	Clear regulatory agreements should be in place around information stored on the mobile device and how this is managed.
	Ensure that any copyrighted material is addressed correctly	Ensure that any information that is used or shared through the mobile device is not subject to copyright.

List of Acronyms and Symbols

AAR: After action report
ADP: Annular discharge pressure
ADS-B: Automatic Dependent Surveillance-Broadcast
AIS: Automatic Identification System
APD: Application for permit to drill
API: American Petroleum Institute
ATC: Air traffic control
BAST: Best available and safest technologies
BLM: Bureau of Land Management
BOEM: Bureau of Offshore Environmental Management
BOP: Blowout preventer
BSEE: Bureau of Safety and Environmental Enforcement
CBL: Cement bond log
CBR: Case-based reasoning
CCR: Circular chart recorder
CFR: Code of Federal Regulations
CoP: Community of practice
COS: Center for Offshore Safety
DGD: Dual gradient drilling
DP: Dynamic positioning
EEW: Early Earthquake Warning System
FAA: Federal Aviation Administration

FCP: Fracture closure pressure

FIT: Formation integrity test

FPP: Fracture propagation pressure

ft: feet

GAO: Government Accountability Office

GOM: Gulf of Mexico

HPHT: High pressure, high temperature

IADC: International Association of Drilling Contractors

IEEE: Institute of Electrical and Electronics Engineers

km: kilometer

KM: Knowledge management

LOT: Leak-off Test

MASP: Maximum anticipated surface pressure

MODU: Mobile offshore drilling unit

MPD: Managed pressure drilling

MSE: Mechanical specific energy

NASA: National Aeronautics and Space Administration

NOSAC: National Offshore Safety Advisory Committee

NPT: Non-productive time

OCSLA: Outer Continental Shelf Lands Act

OCS: Outer continental shelf

OESI: Offshore Energy Safety Institute

PPFG: Pore pressure-fracture gradient

ppg: pounds per gallon

psi: pounds per square inch

psi/min: pounds per square inch per minute

PWD: Pressure while drilling

RP: Recommended practice

RTOC: Real-time operations center

SOLAS: Convention for the Safety of Life at Sea

SPE: Society of Petroleum Engineers

SPP: Standpipe pressure

TCLD: Thermal compensation leak detection

TOC: Top-of-cement

U.S.: United States

USCG: United States Coast Guard

USGS: United States Geological Survey

UT: University of Texas

VDR: Voyage data recorder

VTS: Vessel Traffic Service

WOC: Wait-on-cement

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