A CRITICAL REVIEW OF AN IMPROVED WELL CONTROL PROCEDURE FOR THE PREVENTION OF BLOWOUTS

By

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The undersigned hereby certify that they have examined and recommended to the faculty of graduate studies for acceptance, the project entitled “A Critical Review of an Improved Well Control Procedure for the Prevention of Blowouts” by Muhammad Imran in partial fulfillment of the requirements for the degree of Master of Engineering in Petroleum Engineering.

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DEDICATION

I would like to dedicate my work to my Mother; she is the best part of my life. I would also like to dedicate my work to the workers who lost their lives at BP Macondo Well blowout on April 20, 2010.
ABSTRACT

The oil and gas industry is expanding every day and with the advancement in the offshore industry the complexity and challenges are a lot more than the past. Deeper, longer and more challenging wells are being drilled in today’s world. The phenomena of blowout prevention hold significant importance in the oil and gas industry. In the early 20th century, when the oil and gas industry was booming, drilling operations were extremely dangerous. There was an absence of technology to even determine the pressure values within the reservoir and drilling was almost a blind operation. A blowout occurs when an uncontrolled high pressure reservoir fluid enters into the wellbore. A potential of blowout in the oil and gas industry is a risk of human life/injury, state and country regulator, millions of dollars in loss, along with environmental damage. There have been many reported incidents of blowouts in the past causing grave damage to both human life and our environment. A huge capital is being invested to stop blowouts from happening all over the world or to bring the damage to minimum level.

The basic objective of this study was to promote safety and good resource management, also to draw attention of the regulators and operators to assure safety and environmental integrity during oil and gas well operations. According to this study, human error and equipment failure are the main causes of the blowouts so a wise, composed and determined management can bring the chances of a potential blowout to a minimum level. It also provides a brief summary of the basic concepts, procedures and equipment involved in the well control process to save the blowouts and what steps to take under different kick situations. Another aspect of this study is to emphasize the management role in oil and gas well operations.

Secondly, this study examines the causes of the blowout of the Macondo well that occurred in the Gulf of Mexico on April 20, 2010, and provides a series of recommendations and critical analysis about the different aspects of the Macondo well control process. The study also lists the mistakes and compromises BP and its partners were making during the drilling and well completion processes. The Macondo catastrophic failure happened because of the multiple violations of the safety and public resource development laws. This report concludes that the Macondo well blowout could have been avoided through better management of personnel, risk and communication between BP and its contractors or at least could have brought the damage to a minimum level by proper implementation of the safety laws.
Finally this report provides a brief summary of the causes of the IXTOC-1 blowout that occurred in the Gulf of Mexico on June 3, 1979. The IXTOC-1 blowout ended up by producing the world’s 2nd largest oil spill which added almost 3.5 million barrels of oil into the Gulf of Mexico. It also provides brief information about the environmental and economic damage of the IXTOC-1 blowout on the Gulf area. Finally this report concludes that human error was not a big contributor in this horrific blowout. The response to the spill was immediate and effective; the workers followed the company’s safety rules and policies.
ACKNOWLEDGEMENTS

Many thank to my advisor Dr. Michael Pegg, for his continuous kind support throughout my studies at Dalhousie University.

My special thanks to Mr. Kevin, Scotty and Joan McLean for their continuous support and encouragement in my life.

Many thank to Dr. Jan Haelssig for reading my project and being the part of my advisory committee.

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I would like to thank my brothers and sisters for believing in me and praying for a huge success in my life.
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CHAPTER NO 1

BASIC WELL CONTROL CONCEPTS

The history of oil and gas industry has been very proactive and well established. Since the time of its evolution many technical and theoretical changes have been brought into this vast industry. The involvement of the technology has paved the ways for the discovery of more reserves all over the world. One of the main reasons for such advancement in this particular industry is the demand of energy all across the world; this demand is pushing the oil companies and the scientists to implement more and more new technologies to achieve their goals and to meet the demand. Compared to early days the well control patterns are not as significant as present, although they used drilling fluid to balance the formation pressure but it was not as efficient as today.

Because of the high damage a blowout can cause economically and catastrophically, a lot more research is going into the well control procedures to make sure a safe drilling process. A blowout in an average producing well can cause damages ranging from 1 million to 10,000 million USD.

1.1-DIFFERENT PHASES TO EXTRACT OIL OR GAS FROM A RESERVOIR

Basically there are three phases to safely extract hydrocarbons from a reservoir. The first phase is the drilling phase, in this phase companies drill into a reservoir structure hoping to end up discovering a large amount of hydrocarbon reservoir at the end of the drilling process. During drilling the most important job is to prevent hydrocarbons from entering into the wellbore. The 2nd phase is the safe completion of a drilled well. In this phase the rig crew open the wellbore to allow hydrocarbons to flow into it and install equipment at the wellhead that allows controlling the flow and collecting the hydrocarbons.

The 3rd phase is the production phase, in this phase the operator actually extracts hydrocarbons from the well. In all of three phases drilling is the most complex and risky phase. Safety should have the highest priority.
1.2-WHAT IS A BLOWOUT

A blowout is an uncontrolled release of oil or gas from the well after the failure of pressure control equipment. During drilling process the formation pressure should be kept under control, to achieve this goal drilling fluids of higher densities are used to push hydrocarbons back into the formation. Equipment failure and human errors can cause a blowout as well. Blowouts can be of different types like surface blowouts, subsurface blowouts and underground blowouts. Surface blowouts are the most dangerous one and they can cause a huge damage to life, property and environment (Grace, 2003).

1.3-DRILLING MUD AND ITS FUNCTIONS

As drilling technology is emerging and improving day by day. Deeper, longer and more challenging wells are being drilled in today’s world. Drilling fluids also referred as drilling mud are added to the wellbore to facilitate the drilling process by suspending cuttings, stabilizing formation, cleaning wellbore, cooling and lubricating drill bit (Jamal, 2013). As drilling progresses one of the biggest challenge engineers are facing is to balance the formation pressure. Drilling mud plays the most important role in achieving this goal by providing a primary barrier against formation fluids. As long as the column of drilling mud inside the wellbore exerts pressure on the formation that exceeds the pore pressure, hydrocarbons should not flow into the wellbore from the formation (Mohamed, 2010).

Drilling mud for an oil and gas well drilling can be classified into three main categories, Water Based Drilling Fluids (WBDF), Oil based Drilling Fluids (OBDF) and Gas Based Drilling Fluids (GBDF). Different elements can be added to adjust the density and viscosity of a drilling mud according to the requirements. Bentonite is a one kind of element widely used in the industry to increase the density of the drilling mud (SPE 14955, 2012).
1.4-PRESSURE IN RESERVOIRS

As pressure control is a basic element of a successful drilling process, if engineers lose control on the formation pressure the result is a potential blowout. The following table provides a brief description of various pressures in reservoir which are responsible for formation of kick and well control problems (Ahmed, 2006).

**TABLE 1.1: Basic Pressures in Reservoir**

<table>
<thead>
<tr>
<th>No</th>
<th>Name</th>
<th>Brief Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hydrostatic Pressure</td>
<td>Hydrostatic Pressure is the force per unit area exerted by a body of fluid at rest.</td>
</tr>
<tr>
<td>2</td>
<td>Overburden Pressure</td>
<td>Over burden pressure is the combined effect of the formation material and the fluid in the formation at a particular depth of interest. The over burden pressure is directly related to the compressibility of the formation.</td>
</tr>
<tr>
<td>3</td>
<td>Pore Pressure</td>
<td>Pore pressure is the pressure of the fluid within the pore spaces of the formation rock. It depends upon the weight of overlying rock which exerts the pressure on both the rock material and the fluid present in the pores of the rock.</td>
</tr>
<tr>
<td>4</td>
<td>Fracture pressure</td>
<td>Fracture pressure is the amount of pressure required to permanently deform the formation.</td>
</tr>
<tr>
<td>5</td>
<td>Hydraulic pressure</td>
<td>The hydraulic pressure is the pressure required to circulate the drilling fluid into the drilling system. It is the pressure generated by the mud pump to move the drilling fluid from the mud pump passing thorough the drill pipe and back to the surface through the annulus.</td>
</tr>
<tr>
<td>6</td>
<td>Bottom-hole Pressure</td>
<td>The bottom-hole pressure is the sum of all the pressures exerted at the bottom of the wellbore</td>
</tr>
</tbody>
</table>
1.5-HYDROCARBONS FLOW PATHS

In order to understand the well control procedures and the relating problems it is very important to know the possible flow paths from where hydrocarbons can enter into the wellbore. After setting the production casing the hydrocarbons can enter into the wellbore from two locations listed below (Chief Council, 2011).

- Flow up the annulus and through seal assembly
- Flow from the inside of the production casing

Hydrocarbons can flow up the annulus and through the seal assembly. There are small flow passages through the casing hanger connecting the annulus to the inside of the wellhead. The flow passages permit mud in the annulus to flow into the wellhead and up into the riser. The flow passages remain open prior and during the final cement job. These flow passages can also allow hydrocarbons to enter into the riser during kick situation.

Hydrocarbons can also travel from the production casing in two different ways. First the cement in the shoe track can fail which will allow hydrocarbons to enter into the wellbore. In this case hydrocarbons would also have to bypass two mechanical float valves (Mechanical valves which allow only one way flow, discussed latter in BP case study) to flow up through the production casing as shown in the figure below.

Figure 1.1 shows the possible flow paths for the hydrocarbons to enter into the wellbore. The left hand side of the figure is showing the entrance of the hydrocarbons from the annulus and seal assembly. The right hand side of the figure is showing the entrance of the hydrocarbons from the bottom and from few possible flow paths in the production casing.
1.6-PRIMARY AND SECONDARY BARRIERS TO THE FLOW OF HYDROCARBONS

The main goal during drilling process is to ensure that hydrocarbons do not enter into the wellbore from the formation. To achieve this goal engineers use different barriers to stop the flow. Following is a brief description of the primary and secondary barriers being used in the industry to stop the flow of hydrocarbons into the wellbore.

**Primary Barriers**

To ensure well control, rig personnel must create and maintain barriers inside the well that will control subsurface pressure and prevent hydrocarbons flow into the wellbore. Drilling mud is the main inside primary barrier; as long as the column of the drilling mud inside the well exerts pressure on the formation that exceeds the pore pressure, hydrocarbons should not flow into the wellbore. Physical components of the well also help to create well integrity and in stopping the
hydrocarbon flow. Casing strings are installed at frequent intervals to provide stability to the wellbore. After installing the production casing, cementing is done which also provides a strong barrier to the flow of hydrocarbons in the annular space and in the shoe track. Above all careful monitoring of the well is another critical factor in the well control procedure (Grace, 2003).

**Secondary Barriers**
BOP stack on the wellhead acts as a secondary barrier during kick situations by closing various individual rams installed into the BOP stack. These BOP rams can seal the well against high pressure of the hydrocarbons. It takes almost 40 to 50 seconds to close these rams so early recognition of the kick is key component in the well control procedures (Grace, 2003).

Figure 1.2 shows the possible barriers in the well to stop the hydrocarbons from entering into the wellbore.

![Fig 1.2-Barriers in a Well to stop Hydrocarbons from entering (Chief Council 2011, p. 21)](image-url)
CHAPTER NO 2

WELL CONTROL EQUIPMENT AND PROCEDURES

2.1-WELL CONTROL EQUIPMENT

Well control is the process of controlling the flow rate with respect to casing, drill string, tubing design and preventing the well from blowouts. This is the most important aspect of drilling; companies are spending billions of dollars to make sure a safe drilling process.

Well control procedures vary slightly from rig to rig and also on the company policy as well but four simultaneous operations are normally considered.

2.1.2-Rig Control

The rig control unit includes the blowout preventer equipment, pumps, draw works and other rig equipment. This is the responsibility of drilling engineers or supervisors to assign suitable persons on different jobs to control different aspects of rig and to ensure the safety of every worker (Baker Hughes INTEQ, 1995).

2.1.2- Choke Control

Choke control is very important in drilling and the most experienced employee on the rig should be assigned to control the choke operations. Normally the duties include correct calculation of pressure and time relationships as well as operating the choke and monitoring the pump rate. The choke control person should be given guidance and complete coordination from the other rig units during the kill operations (Baker Hughes INTEQ, 1995).

2.1.3- Mud Control

Mud control is one of the main aspects of drilling process. The main responsibility of the mud control crew is to make sure that the mud pressure is balancing the formation pressure and no hydrocarbons are entering into the wellbore from the formation. The crew must make sure that
the density of the drilling mud is more than the density of the pore fluids. If the density of the drilling mud is decreasing they should add weighting material most commonly barite to increase its density. The mud control crew also have to make sure the correct operation of the mixing system and chemical additions (Baker Hughes INTEQ, 1995).

2.1.4-Supervision

Supervision is the final element of the well control system and supervisors have the responsibility to ensure that all of the above three elements of rig control are functioning properly. Decisions made under kick situations are based upon the knowledge, attitude and the judgement of the supervisors. The supervisors are also responsible of making policies and procedures for the company they work for (Baker Hughes INTEQ, 1995).

2.2-PURPOSE OF THE WELL CONTROL EQUIPMENT

Blowout prevention equipment should be designed to (Timothy, 2010):

- Close the top of the hole
- Control the release of fluids
- Permit pumping into the hole
- Allow movement of the drill pipe

The hydrostatic pressure of the drilling fluid is the primary barrier in preventing the well from blowing out. When the formation pressure becomes higher than the hydrostatic pressure, BOPs and related equipment are used as a secondary barrier to seal and to kill the well (Timothy, 2010). In addition to BOPs other equipment is used to assist in the well control procedure, for example chokes and chokes manifold are used for the controlled removal of the intruded formation fluid from the wellbore. It is very important that all well control equipment should meet the requirements of the drilling installation (Guo et al. 2007).

The following table lists the main components of the basic well control equipment with a brief description (Timothy, 2010).
# TABLE 2.1: Basic Well Control Equipment

<table>
<thead>
<tr>
<th>No</th>
<th>Name</th>
<th>Brief Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Casings</td>
<td>Casings are used to prevent the borehole from falling in during drilling; it also provides means of controlling fluids encountered during drilling.</td>
</tr>
<tr>
<td>2</td>
<td>Wellhead</td>
<td>The wellhead sits between the BOP stack and the subsequent strings of casings. The wellhead typically rests on a base plate supported by the conductor pipe that is used to start the well.</td>
</tr>
<tr>
<td>3</td>
<td>Annular Preventers</td>
<td>Annular preventers are the part of the BOP system and they seal the annular space during kick situations to stop further flow of hydrocarbons from the annulus.</td>
</tr>
<tr>
<td>4</td>
<td>Ram Type Preventers</td>
<td>Ram Preventers are also part of the BOP system and they seal the wellbore during kick situations by cutting through the drill pipe.</td>
</tr>
<tr>
<td>5</td>
<td>Drilling Spools</td>
<td>A drilling spool is designed to connect BOP and wellhead. A drilling spool has side outlets for kill and chokes lines fitted between the BOP stack and wellhead.</td>
</tr>
<tr>
<td>6</td>
<td>Operating equipment</td>
<td>The operating and control equipment, are basically the control panels to control the blowout prevention assembly</td>
</tr>
<tr>
<td>7</td>
<td>Choke</td>
<td>Choke is equipment used to control the flow rate it is one of the most important parts in well control equipment. The oil production rate can be altered by adjusting the choke size. Chokes can be surface or subsurface.</td>
</tr>
<tr>
<td>8</td>
<td>Mud Pit Level Indicator</td>
<td>It informs about the mud level in the mud tank, if the well is flowing its level will start rising up and will alert the crew members to take necessary steps to stop the kick.</td>
</tr>
<tr>
<td>9</td>
<td>Degasser</td>
<td>A degasser is used to extract entrained gas in the drilling fluid, it is installed in the mud control facility and the returning mud is passed through the degasser.</td>
</tr>
</tbody>
</table>
2.3-CAUSES AND DETECTION OF KICK

A kick is an occurrence during oil or gas well drilling when the bottom-hole pressure drops below the formation pressure, as a result formation fluid flows into the wellbore. A kick once uncontrolled can result in a blowout that can cause a large damage to the rig equipment and the well or even a loss of life during eruption (Timothy, 2010).

Some of the main reasons that can cause the kick are following (Grace, 2003):

- Lost circulation
- Low density drilling fluids
- Abnormal reservoir pressure
- Swabbing

2.3.1-Lost Circulation

During circulation of drilling fluid, the most expensive problem encountered is lost circulation. The lost circulation is the loss of drilling mud to pores or fractures in the rock formation. Lost circulation can be very expensive if it’s happening in frequent intervals and it can be an important factor for the formation of kick and latter for blowouts (Bourgoyne et al. 1986).

2.3.2-Low Density Drilling Fluids

If the density of the drilling fluid is not sufficient to keep the formation pressure away from the borehole, then a kick can occur. There are several ways that can reduce the density of the drilling fluid, like excessive dilution of the mud, heavy rain in the pit, spotting low density pills in the pit or trying to use underbalanced drilling for certain zones in the formation.

If the density of the reservoir fluid exceeds the density of drilling fluids, buoyancy force will be produced in the borehole and because of the buoyancy force the low density drilling fluids will be pushed upwards by the reservoir fluids, which pave the way for kick and later for blowout.
The various types of drilling fluids used in the drilling process are Oil Based Mud, Water Based Mud and Air Drilling (Grace, 2003).

2.3.3-Abnormal Reservoir Pressure

Abnormal pressure zones can also be one of the main factors that can cause kick. Abnormal pressure zones can be under pressures and over pressures. In under pressure abnormal systems the formation pore pressure gradient is less than hydrostatic pressure gradient 0.45 psi. They are less common and not very dangerous with respect to the kick production although they exist in some gas reservoirs (Ahmed, 2006).

Over pressure systems are wide spread in the world and they exist in all variety of basins type. They are the dangerous one with respect to the kick production. In the moderate over pressure zones the formation pressure gradient varies between 0.5-0.75 psi. In the hard over pressure zones they vary between 0.75-1.0 psi, which is lot more than the hydrostatic pressure gradient. Dealing with a high over pressure zone, there is a possibility of fracturing the reservoir that can easily produce kick (Aberdeen Drilling School, 2002).

Abnormal pressure can be caused by the following factors (Ahmed, 2006):

- Compressibility of formation
- Compressibility of reservoir fluids
- Compaction due to over loading
- Earthquakes
- Folding and Faulting

2.4-DETECTION OK KICK

It was a tough challenge in the old days to detect kicks but thanks to the new advanced technology such as highly sensitive sensors which are being used to detect mud volume level, flow rate of circulating fluid and also the flow rate of producing fluids. There is never a lack of indication that a kick is occurring. In most of the drilling practices the borehole and mud pit
tanks are acting as a closed circulating system. The addition of any fluid from the formation will result in a change in return flow and will change the mud pit volume as well (Timothy, 2010).

Figure 2.1 is shows a mud circulating system, if a kick occurs the mud pit level would increase and the well should shut-in immediately.

Fig 2.1-Shematic of a Mud Circulating System (Oil and Gas Well Drilling and Servicing e Tool, 2007).

2.4.1-Positive Indicators of kicks

In most of the drilling practices the following series of events can lead to a kick while drilling. Each crew member holds an equal responsibility to understand and interpret these signs correctly and to take proper actions accordingly. All signs do not positively indicate the occurrence of kick some of them warn the crew of a potential kick situation.
• The first indication is a drilling break, the pumps are pumping at a constant rate but drilling rate is more than normal. The increased rate is interpreted as the formation aiding the rig pumps by moving fluid up the annulus and forcing formation fluid into the bore hole. The best thing that can be done is to stop the pumps and lift up the Kelly and observe the fluid level in the annulus to see if the well is flowing.

• The second indication or the 1st confirmation if the well is flowing or the kick is taking place is an increase in the return flow rate at the flow line. The flow of formation fluid into the bore hole will increase the flow rate of drilling fluid in the annulus and it commonly occurs after the drilling break. The invading fluid is lighter than the mud, its addition in the mud will lighten the density of the drilling mud which will further reduce the bottom-hole pressure and will allow more formation fluid to enter in the bore hole. The rate of flow is directly proportional to the drilling depth and rate of penetration.

• A gain of fluid in the mud pit is an indication that well is flowing, it happens due to the intrusion of formation fluid into the borehole. If the kick contains gas its expansion in the annulus will increase the flow rate and pit volume.

• A pump pressure will decrease but the pump stroke rate will increase and it will be noticeable only when the kick fluid has travelled some distance up towards the surface in the annulus.

• One of the major indicators is the reduction in the density of the drilling fluid. As formation fluids are lighter than the drilling mud so a reduction in flow line mud density occurs as the invading fluid reach the surface. This reduction in the density is severe if the kick is gas since large amounts of gas can be dissolved in the kick fluid and as the kick fluid reaches the surface, high gas shows will occur.

• Change of the drilling fluid composition is also caused due to the intrusion of the formation fluid into the borehole. The composition varies with the type of the drilling fluids. For example if water enters into an oil based mud it will cause a change in the composition of the drilling fluid. Similarly if oil enters into a water based mud, it will change its composition as well.

• An increase in the temperature of the drilling fluid is the result of the addition of hot formation fluid. This results in a large increase of drilling fluid temperature. The frequency of this happening to other indicators is much less.
During drilling as many sensors as possible are used to confirm if the well is flowing (Grace, 2003; Timothy 2010; Goins 1983).

2.5-WELL CIRCULATION METHODS

Within the oil and gas industry there are three kick control procedures being used which have constant bottom-hole pressure. These three methods are very similar in principal and differ only in respect of when kill mud is pumped down. The names of these three methods are:

A. Driller’s method.
B. Weight on weight method or Engineer’s method.
C. Concurrent method

As soon as a kick is recognized the drill crew should shut-in the well immediately by closing the BOP system. The crew should then investigate the problem and the amount of the kick and next step is to circulate out the influx using one of the above circulation methods. Once the well integrity is established again the drill crew can proceed with the further drilling (Grace, 2006).

2.5.1- Factors Involved in the Selection of an appropriate Circulation Method

The selection of which method should be used depend on the amount and type of kick that have entered the borehole, fracture pressure of the reservoir, the rig’s equipment capabilities and the operating companies well control policies (Timothy, 2010).

Determination of the most suitable and safest method involves several important considerations (Baker Hughes INTQ, 1995):

- The time required to execute any complex kill procedure
- Surface pressure that will arise from circulating out the kick fluid
- Down hole stresses are employed to the formation during kill procedure
- The complexity of the procedure itself relative to the implementation, rig capability and crew experience
2.5.1.1-The Time Factor

The total amount of time required to execute the kill procedures is very important especially if the kick is gas because the gas bubble can increase annular pressure to very high extent. Pipe sticking can also be the issue if a fresh water mud system is in use. If it takes longer to complete the kill procedure chances are that more formation fluid can enter into the borehole which can lead to a blowout.

The driller’s method and the Engineer’s method are the least time consuming methods because in these procedures pumping begins after the shut-in pressure is recorded. Driller’s method require two circulations of drilling fluid into the well bore to complete the kill procedure while the Engineer’s method require only one circulation of drilling fluid to complete the kill procedure (Baker Hughes INTQ,1995).

2.5.1.2-Surface Pressure

The 2nd important parameter to consider while choosing an appropriate circulation method for a particular kick situation is surface pressure. If a gas kick is taking place the annular pressure near the surface can be very high due to gas expansion and this high pressure have very bad impact on the BOP equipment and also very dangerous if it goes uncontrolled.

The kill procedure that involves the least surface pressure must be used if the kick tolerance is minimal (Baker Hughes INTQ, 1995).

2.5.1.3-Down-hole Stresses

Down-hole stresses are important to be considered while selecting the kill procedure. If the extra stresses in the borehole caused by additional kick are greater than the fracture pressure of the reservoir then the situation is very hard to control and have to be very careful in killing such a kick.
So the procedure whose implementation places high stresses on the wellbore should not be used preference to the others which impose comparatively less stresses. One circulation method places fewer amounts of stresses on the wellbore and surface equipment as compare to the other methods (Baker Hughes INTQ, 1995)

2.5.1.4-Procedural Complexity

The suitability of any procedure also depends on the ease of its execution. If a kill procedure is difficult to execute in the given circumstances its reliability is negated.

The one and two circulation methods are simple in both theory and execution so the choice between the two is dependent upon the other parameters such as time factor, surface pressures, and down-hole stresses. The concurrent kill method is relatively complex in operation and its reliability can be reduced through its execution (Baker Hughes INTQ, 1995).

2.5.2-The Driller’s Method

In the driller’s method the kick is circulated out of the hole using the existing mud weight. The mud weight is then raised to the required level and circulated around the well. To execute this method two complete circulations of drilling fluid are required. It deals separately with the removal of the kick and the addition of kill weight mud. It is generally considered the simplest kick killing method. However in this method the well remains under pressure for comparatively longer time and also the annular pressures produced during the first circulation are higher than any other method (Lyons and Plisga, 2005).

This method is mostly used on small land rigs where the drillers have limited facilities and limited information about the well. It is also used on highly deviated horizontal wells as well.

First circulation

The first circulation of driller’s method is performed using the original mud. The choke is opened slightly and the pumps are started up to the kill rate. When the pumps have reached the kill rate the choke is manipulated to maintain the initial circulating pressure (ICP) on the drill pipe.
The initial circulating pressure can be calculated as:

\[
\text{Initial circulating pressure} = \text{slow circulation rate pressure} + \text{shut – in drill pipe pressure}
\]

\[
ICP = P_{scr} + SIDP
\]

The initial circulation pressure is kept constant during the circulation time by adjusting the choke simultaneously until all the kick is circulated out. Once the influx has been circulated out the pumps are stopped and the choke closed. At this time the two surface pressures, shut-in drill pipe pressure (SIDP) and the shut-in casing pressure (SICP) should be the same.

During the first circulation the mud density in the pit tank is raised to the kill mud density, when the kill mud volume is achieved the well is circulated again (Baker Hughes INTQ, 1995; Aberdeen Drilling School 2002).

The following formula is used to calculate the kill mud density:

\[
\text{Kill mud weight (ppg)} = \text{original mud weight} + \frac{SIDP}{TVD \times 0.052}
\]

Figure 2.2 shows a relief well used for drillers method to send kill mud into the wellbore.
Fig 2.2 - A Relief Well (Drilling Contractor, 2009)

2\textsuperscript{nd} – Circulation

After the first circulation the pressure should still be present on the well because the mud weight has not been changed. Once the kill mud is ready, open the choke about one quarter and start the pump and bring it to the kill rate. Meanwhile when the pump circulations are being brought up to the kill rate, the choke operator must keep the casing pressure constant as when closed in. Once the 2\textsuperscript{nd} circulation is started the drill pipe pressure will go down because the existing mud is being replaced by heavier mud. If all kick is being removed during the first circulation the choke should not need to be touched to keep the casing pressure constant during the 2\textsuperscript{nd} circulation once pumps are steady at the kill rate until kill mud reaches the bit.

Once the kill mud is reached the bit, the pressure kept on the drill pipe is the one required to circulate the kill mud and it is called the final circulating pressure it can be calculated as following.
The final circulating pressure is kept constant at the bit by controlled opening of the choke as the kill mud moves up the annulus (Baker Hughes INTQ, 1995; Aberdeen Drilling School, 2002).

When the kick fluid and the original mud have been displaced the choke should be wide open, the pump should be shut down and the SIDP and SICP both should read zero. Then the pump should be observed for flow. The kick is now killed and mud should be circulated to condition the hole and at the same time the trip margin should be added.

Figure 2.3 is a brief description of the 2\textsuperscript{nd} circulation of the driller’s method. During the first half of the 2\textsuperscript{nd} circulation the casing pressure will be holding constant by adjusting the choke, while the drill pipe pressure will decrease because of the increase in hydrostatic pressure.

During the second half of the 2\textsuperscript{nd} circulation, when kill mud would reach the bit, the drill pipe pressure would be kept constant while the casing pressure should decrease to zero. At the end of the 2\textsuperscript{nd} circulation both drill pipe pressure and casing pressure gauges should read 0.

\[
\text{final circulating pressure} = \text{slow circulating pressure} \times \frac{\text{kill mud weight}}{\text{original mud weight}}
\]
Fig 2.3- Different Stages in 2\textsuperscript{nd} Circulation (Drilling Formulas)

2.5.3-The Engineer’s Method or Wait-and-Wait Method

The wait-and-wait method is based on the idea that while the well is maintained in the shut-in condition the necessary weight of drilling fluid can be prepared in a short time. The method is to wait before circulating the well until the required mud weight is ready to circulate.

Once the well is shut-in and the pressure in the borehole stabilizes the shut-in drill pipe pressure (SIDP) is used to calculate the kill mud weight. When the mud of required weight is made up in the mud pits and when ready the kill mud is pumped down the drill pipe while keeping the annular pressure constant. The choke is adjusted in such a way as to decrease the drill pipe pressure until the kill mud reaches the bit at which point the final circulating pressure is reached. The pumping is continued holding the drill pipe pressure constant by adjusting the choke. When the kick fluid has been displaced and further volume have been displaced equal to the pipe volume the SIDP should be zero the kick should be killed and the well checked for flow.

The wait-and-wait method uses the same calculations as the driller’s method,

\[
\text{Initial circulating pressure} = \text{slow circulation rate pressure} + \text{shut – in drill pipe pressure} \\
ICP = P_{scr} + SIDP \\
Kill \text{ mud weight (ppg)} = \text{original mud weight} + \frac{SIDP}{TVD \times 0.052}
\]

Some advantages of the wait-and-wait method are lowest wellbore pressure and lowest surface pressure which means less equipment stress.

Considerable waiting time while weighting up the mud can be an issue and if influx is gas its migration can cause serious problems, also if large amount of mud wait is required it is very difficult to complete the entire procedure successfully in once circulation (Baker Hughes INTQ, 1995; Aberdeen Drilling School, 2002).
2.5.4 - The concurrent method

This is the most complicated and unpredictable method basically it combines both the driller and engineer’s method so that the kill operation may be initiated immediately upon receipt of the shut-in pressures. Pumping mud begins immediately at the kill rate with an increased density mud. The rate at which the mud density is raised is dependent upon the mixing facilities available and the capabilities of the crew.

The main issue adopting this method is that the borehole can be filled with different densities fluids making calculations of the bottom-hole hydrostatic pressure difficult.

When all of the information has been collected the pumps are initiated until the initial circulating pressure has been reached at the designated kill rate. The mud should be weighted up as soon as possible and as the mud density is changes in the suction pit the choke operator should be informed. The total pump strokes are checked on the drill pipe chart when the new density is pumped and the choke is adjusted to suit the new drill pipe conditions (Timothy, 2010).

2.6 - SPECIAL PROBLEMS IN KICK CONTROL

The majority of the problems occur in the kick control procedure are caused by the equipment failure, formation breakdown and improper operating procedure. Some of the main problems encountered in the kick control procedure are as follow (Baker Hughes INTQ 1995; Timothy, 2010).

- Stuck pipe.
- Shallow gas formations.
- Lost circulation.
- Kicks with the drill pipe out of the hole.
- Snubbing operation (a snubbing unit is a specialized piece of equipment used to overcome the pressure-area force on a pipe in order to force the pipe into the well).
- Surging and swabbing
- Underground blowout
• Bullheading (it is pumping fluid into the well without circulation back to the surface; it can cause fracturing at the weakest point of the reservoir).

2.7-BLOWOUTS AND TECHNOLOGY

Prevention is better than cure and it applies to the blowouts as well. As the world evolves, human brain also evolves. Due to the introduction of supercomputers and various other technologies, monitoring the well is easier than it was earlier. The increase in technology can be used to prevent blowouts in various ways. The various technologies at present which can be used directly or indirectly for the prevention of blowout by managing the well are (Fanchi, 2001):

• Reservoir modeling
• Logging techniques
• Production tests
• Underbalanced drilling

2.7.1- Reservoir Modeling

Reservoir modeling is the process of modeling the reservoir with the help of various improved techniques such as 3-D seismic surveys. A good reservoir modeling can provide all the information about subsurface formation such as (Fanchi, 2001):

• High pressure areas
• Low pressure areas
• High and low permeability areas
• High and low saturation areas
• It can show the areas having abnormal formation pressures
• Kick possibility zones can be identified before drilling and precautionary measures can be taken accordingly (Fanchi, 2001).
2.7.2-Logging Techniques

There are two main types of advanced logging techniques used to measure the subsurface properties at the time of drilling itself, which is more efficient. The Techniques are (Darling, 2005; Lyons and Plisga, 2005).

1. Logging while drilling (LWD)
2. Measurement while drilling (MWD)

Logging while drilling (LWD) is a method used to calculate the reservoir parameters such as porosity, permeability, formation pressure, formation temperature, fluid saturation etc.

Measurement while drilling (MWD) is a method used to measure the depth of drilling reached while drilling progresses. By knowing the exact depth of drilling depth of kick possibility zone, kick can be solved by circulating high pressure, high density drilling fluids into the borehole (Lyons and Plisga, 2005).

2.7.3-Production Tests

Production tests can provide up to date information about formation pressures. If the bottomhole pressure increases suddenly then it will be a possible identification for kick.

2.7.4-Underbalanced Drilling

Underbalanced drilling is opposite to the conventional drilling. In underbalanced drilling the wellbore pressure is kept less than the formation pressure by reducing the drilling fluid circulation pressure. This allows more formation fluid to enter into the well. When it reaches the surface a rotating head will redirect the flow to the separator, although it is more costly than the conventional method, the chances for blowouts are almost nil. The formation damage caused by the drilling fluid will be less. Figure 6.3 fluids flow in conventional and underbalanced drilling borehole (Lyons and Plisga, 2005).
Conventional Drilling                                 Underbalanced Drilling

Fig 2.4 - Shows difference in fluid flow between conventional and underbalanced drilling (Air Drilling Associates, 2006).

2.8-MANAGEMENT ROLE IN WELL CONTROL AND BLOWOUT PREVENTION

As oil and gas well drilling is a very complex process and at every step important decisions are required which are not possible without a strong and an effective management. Human error has been a big cause of the blowouts in the past as it happened in case of the BP Macondo Well blowout in 2010 in the Gulf (BP, 2010). Management of the BP took poor decisions and they compromised on the safety rules which resulted into one of the biggest blowouts in the history. A wise, composed and determined management is the most important aspect of the well control procedures. Following are few aspects of the drilling where management can improve their ability and safety procedures.

- Making mandatory to follow API standards during drilling especially while isolating potential flow zones.
- Selection of the casing and the cement design should be appropriate according to the situation and the wellbore conditions.
• Making sure that the wellbore has enough barriers against each flow path.
• Making sure the blowout prevention system (BOP) is working properly and testing the functionality of the BOP system after regular intervals.
• If possible install two blind shear rams (BSR) in BOP system in case if one fails to seal the well during emergency situation there is another one available as a backup.
• Making sure every rig personnel is completely trained and well equipped with the technology and theoretically.
• By implementing an effective communication system with in the drilling rig unit.
• By having a better relationship with its drilling co-partners and an effective communication with each other.

2.9-FLOWSHEET EXPLAINING WELL CONTROL PROCEDURE DURING A DRILLING PROJECT

Following flow sheet explains a basic well control mechanism during a drilling project. Once the seismic surveys are done and the operator has the pore pressure and fracture pressure values, operator then can proceed with drilling. If during drilling kick is confirmed the rig crew must shut-in the well immediately and then act according to the situation as shown in the flow sheet below.
Flow Sheet Explaining Basic Well Control Mechanism

1. DRILLING PROJECT
2. SISMIC SURVY
3. PORF PRESSURE
4. FRACTURE PRESSURE
5. DRILLING PROGRESSES
6. KICK INDICATORS
   - REDUCTION IN MUD DENSITY
   - MUD PIT VOLUME INCREASES
   - MUD FLOW RATE INCREASES
   - DRILLING BREAK
7. KICK CONFIRMED
8. SHUT-IN WELL IMMEDIATELY
   - PREPARE KILL MUD
   - CALCULATE AMOUNT OF INFLUX
   - NOTE WELL SHUT-IN PRESSURE
9. SELECTION OF AN APPROPRIATE CIRCULATION METHOD
CHAPTER NO 3

BP MACONDO WELL BLOWOUT APRIL 20, 2010

Case Study 1: BP Macondo Well Blowout Technical Aspects

3.1-INTRODUCTION

This case study is about examining the root causes of the British Petroleum (BP) Macondo Well blowout and highlights few technical aspects which could have been performed better to avoid this catastrophic incident in the history of oil and gas industry. This catastrophic failure appears to have resulted from multiple violations of the safety and public resource development laws. BP was the main operator and they knew the fact that deep water drilling is an inherently complex and hazardous activity, but they made wrong choices to save time and a little money. They opted to risk the life of the entire crew working on the rig and the environment. Their system failed to achieve the goal of maximum safety and they showed the attitude of being not afraid of taking the risks. BP was changing its plan over and over even up to the very last minute causing confusion and frustration among the workers. Transocean did not adequately train their employees to deal with emergency situations like kick detection. There was a lack of real leadership at the rig and no one was taking responsibility of what was happening.

Finally the negligence and an unprofessional attitude lead Macondo Well to suffer one of the worst blowouts in the history of the oil and gas industry. On the April 20, 2010 hydrocarbons were able to enter into the wellbore resulting in explosions and fire on the Deepwater Horizon drilling rig. Eleven people lost their lives and 17 others were injured. The fire which was fed by Hydrocarbons was continued for 36 hours until the rig sank in the Gulf. Hydrocarbons continued to flow from the reservoir for 87 days and it proved to be one of the largest spills in the oil and gas history (BP, 2010). This oil spill badly affected the environment and the economy of the Gulf and its impacts are still being assessed.
3.2-The MACONDO WELL

In March 2008, BP exploration and production Inc leased the Mississippi Canyon Block 252 for oil and gas exploration and designated it the Macondo prospect. BP subsequently sold its share to Anadarko [25%] and MOEX [10%] but kept the 65% of the total shares. As the main operator in the field, BP was responsible for all the aspects of well design and development of the Macondo Well (Transocean, 2011). BP paid a little more than $34 million to the Mineral Management Services (MMS) for the lease of a nine square mile plot in the Gulf of Mexico. Macondo would be its first well on the new lease. Based on the geological information and the environmental conditions BP planned to drill the Macondo Well up to the depth of 20,200 ft (National Commission, 2011). BP drilling engineer Brian Morel and Mark Hafle had the responsibility of making the well design. After having discussions with the geological department they provided the information about the pore pressure and presented the initial plan. Macondo Well was an exploration well designed so that it could later be completed for production if significant amount of hydrocarbons were found down hole (Chief Council Report, 2011).

3.3-MACONDO WELL DESIGN

The well design and the construction are the complex stages of the drilling process. The operator must consider site specific factors including flows, pressurized formation flows, reservoir structure and the anticipated volume of the hydrocarbons. In the well design process engineers use all available data to determine the planned total depth of the well, pre-determination of the pore pressure and fracture pressure of the formation, casing point selections, required casing specification and risk factors particularly to the well (BOEMRE, 2010). In case of the Macondo exploratory well the BP and the partners have a limited offset data available. As a result the Macondo well design was subject to changes as the drilling proceeded. Using seismic imagery BP had a high degree of confidence that the formation contained a significant amount of hydrocarbons (BP, 2010).

Unfortunately they still made few wrong choices or they neglected the consequences of the wrong decisions they were making to meet their goals. This section of the case study explains the
basic Macondo well design and the changes that were made to the original well plan in response to geological conditions encountered while drilling progressed.

### 3.3.1-Pore Pressure and Fracture Pressure

The pore pressure is the pressure exerted by the fluid such as hydrocarbons in the pore space of the rock. If the pore pressure exceeds the hydrostatic pressure exerted by the mud inside the well, the fluid in the pore spaces can flow into the well and the phenomenon of entering an unwanted influx of fluid or gas into the well is called Kick (Timothy, 2010). The fracture pressure is the pressure at which the geological formation will break down or permanently deform. When fracture occurs the drilling mud can flow into the formation and the mud returns are lost. It can be very costly and it involves a high risk of blowout (Timothy, 2010). Drilling engineers must design a well to manage the pore pressures and fracture pressures at different depths. During the design process a graphical representation of the estimated pore pressure, mud weight and fracture pressure is made to decide an appropriate drilling margin. BOEMRE [Bureau of Ocean Energy Management, Regulations and Enforcement] regulations require that while drilling, companies must maintain a safe drilling margin and it must be identified in the approved APD [Application for Permit to Drill]. To obtain a safe drilling margin companies have to ensure that the mud weight remain between the kick tolerance or kick margin, which is typically 0.5 pounds per gallon below the fracture gradient and the swab margin which is 0.2 above the pore pressure (BOEMRE, 2010).

Figure 3.1 represents the pore pressure and fracture pressure gradients for the Macondo well. It is clear from the figure that BP had a very small drilling margin at few points the margin was even much less than the MMS regulations. Especially at the depth of around 18000 feet the difference is very small.
Experts and most industry practices including BP explain that if mud is lost during drilling, this event is equivalent to open-hole integrity test and it requires immediate actions to maintain the safe drilling margin. BP had lost circulation events a few times and they knew that they were running very low in drilling margin but they still opted to continue the drilling without informing MMS (Experts Report, 2011). During drilling at the depth of 18,250 feet another lost circulation event occurred because the kick margin at this depth was 0.1% which is unacceptable but luckily they got control on it by adding lost circulation material (Macondo Well Blowout, 2011).

In the gulf’s deep water environment it is very hard to maintain a safe drilling margin but still companies cannot go below a certain limit. BP should have informed the MMS about the low drilling margin and should have gained re-approval to continue the drilling and should have shown more professionalism.
3.3.2-BP Casing Plan for Macondo Well

It is a common industry practice that at some points during drilling the pore pressure in the bottom of an open-hole section exceeds the fracture pressure of the formation. In this situation the mud is unable to control the pore pressure because, if driller increases mud density it can fracture the formation and if driller continue the underbalanced drilling the pore fluid may enter into the borehole causing kick. In this situation the driller must set a casing string in that particular section of the borehole. The casing protects the most fragile sections of the hole and it also stops the formation fluid to enter into the borehole (ENCO, 2012).

BP submitted its original casing plan to MMS, explaining approximate depths to install subsequent casings. Once it was approved by MMS, BP used it to serve as the basis for all the decisions during the construction of the well (BP, 2010).

BP’s original casing plan consisted of 8 casing strings at different depths as shown below in the figure 3.2.

Fig 3.2-Original Macondo Well Plan (Macondo Well Blowout, 2011)
The conditions encountered during drilling can drive changes in the casing program. As lost circulation events occurred during drilling of the Macondo Well forced BP to change their original plan. BP had to use nine casing strings based on the actual conditions encountered during drilling to reach the total depth of 18,360 feet. BP submitted its revised casing plan to MMS and gained approval (BOEMRE, 2010).

Figure 3.3 shows the final wellbore architecture for Macondo Well which consist of 9 casing strings at different depth intervals.

![Fig 3.3-Final Macondo Well Plan (Macondo Well Blowout, 2011)](image-url)
3.3.4-Long String Production Casing VS Liner

When it came to install the final production casing BP and Halliburton had two options available. One was to install a “long string” production casing throughout the well stretching from the bottom of the well all the way to the wellhead. The other option was to install a “Liner” a shorter string of casing hung from a casing hanger lower in the well. In order to connect the liner back to the wellhead, BP would eventually have had to install a “tieback” (BP, 2010). After having several discussions and running the cement model in the computer again and again BP finally decided to use a long string production casing instead of the Liner arrangement. BP’s decision to use a long string production casing was suitable economically because it saved almost 7 to 10 million dollars and it was also providing a good well integrity case for the future well completion processes (Chief Council, 2011).

3.3.5-Critical Analysis of the Macondo Well Design

- At various points in February, March and April during drilling the Macondo well, BP encountered lost circulation events because the mud weight crossed the fracture limit and drilling mud started to flow into the formation instead of coming back to the surface. The Deepwater Horizon crew responded right away according to the industry standards and pumped lost circulation material into the borehole and plugged the fractures in the formation.

- The idea of using nine casing strings instead of eight and to stop the drilling at a total depth of 18,360 feet was a wise decision. BP knew that they had penetrated into a sufficient amount of hydrocarbons bearing zone. They were also well aware with the fact that they were running very low in drilling margin so they did not want to risk further. The additional casing string also gave integrity to the hydrocarbon bearing zone.

- At one point during drilling, the drilling margin was even less than 0.1%. BP was supposed to inform MMS about it and they were required to obtain a new approval to continue drilling in that zone. However, BP showed unprofessionalism and they continued drilling without informing MMS about the low drilling margin. They broke the law but they paid the price latter.
BP and its partners knew about the low drilling margins throughout the Macondo Well drilling. They should have been more careful about every decision but they did not do it instead they showed negligence and carelessness which turned out to be a devastating end.

3.4-MACONDO WELL BLOWOUT PREVENTER SYSTEM

BOP system is one of the most important parts of a drilling unit. If during drilling hydrocarbons flow into the wellbore the blowout preventer system acts as a secondary barrier in the well control process. In deep water drilling it is a massive piece of equipment and it is attached to wellhead to seal an open wellbore. It can close the annular portion of the well around the drill pipe or casing or cut through the drill pipe using steel shearing blades. A typical BOP system for a deep water project has five to six ram type preventers and one or two annular type preventers well (Transocean, 2011).

This section of the case study discusses the BOP system that was part of the Deepwater Horizon drilling unit and it also highlights the attempts that were made to activate the blind shear ram to seal the Macondo Well after explosions.

3.4.1-BOP System for Deepwater Horizon

The BOP system for the Deep Water Horizon was Cameron manufactured and it was a massive 57 foot tall, approximately 400-ton located at the well head. A riser pin was attached to the BOP system and was extended to the drilling platform to permit the circulation of the drilling fluids. The bottom of the BOP system rests on the remotely detachable connection to the wellhead, which allows the BOP to be released after well completion (Macondo Well Blowout, 2011).

The Deepwater Horizon BOP assembly consisted of three major sections as shown in the figure 3.4 below (Transocean, 2011)

- Main BOP Stack
- Lower Marine Riser Package (LMRP)
- The Control System
Fig 3.4-Deepwater Horizon BOP System (Chief Council, 2011, p. 209)
3.4.1.1-Main BOP Stack

Table 3.1 list the components of main BOP stack of the Deepwater Horizon drilling unit at the time of the blowout (Transocean, 2011).

Table 3.1: Basic Components of the Main BOP Stack at Macondo

<table>
<thead>
<tr>
<th>No</th>
<th>Name of the Component</th>
<th>Function Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Well Head Connector</td>
<td>Connect the BOP stack to the Macondo Wellhead.</td>
</tr>
<tr>
<td>2</td>
<td>Variable Bore Rams (VBRs)</td>
<td>Two VBRs, designed to seal around several different sizes of drill Pipe but these rams were not designed to shear.</td>
</tr>
<tr>
<td>3</td>
<td>Test Ram</td>
<td>Test ram was an inverted VBR and it was designed to hold the pressure from the top down.</td>
</tr>
<tr>
<td>4</td>
<td>Casing Shear Ram (CSR)</td>
<td>CSR was designed to cut through the drill pipe or casing, it consisted of cutting elements only and was not designed to seal.</td>
</tr>
<tr>
<td>5</td>
<td>Blind Shear Ram (BSR)</td>
<td>BSR consisted of both a cutting and sealing element and has the ability to cut the drill pipe and seal the well.</td>
</tr>
<tr>
<td>6</td>
<td>Choke and Kill lines</td>
<td>They were high pressure pipes; they led from an outlet on the BOP stack to the rig pumps.</td>
</tr>
<tr>
<td>7</td>
<td>Remotely Operated Vehicle (ROV) Panels</td>
<td>Operating panels that allow ROV lowered to the sea floor to activate certain functions on the BOP stack.</td>
</tr>
<tr>
<td>8</td>
<td>Accumulator Bottles</td>
<td>They provided hydraulic fluid used to operate the various BOP elements.</td>
</tr>
</tbody>
</table>
3.4.1.2-Lower marine riser package (LMRP)

Table 3.2 list the components of LMRP of the Deepwater Horizon drilling unit at the time of the blowout (Transocean, 2011).

Table 3.2: Basic Components of the LMRP at Macondo

<table>
<thead>
<tr>
<th>No</th>
<th>Name of the Component</th>
<th>Function Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Annular Preventers</td>
<td>Two annular preventers which were rubber metal composite elements capable of closing around the drill pipe to seal the annulus</td>
</tr>
<tr>
<td>2</td>
<td>Blue and yellow Pods</td>
<td>Two blue and yellow control boxes attached to LMRP. They were used to operate the BOP components and they were capable of activating the BSR.</td>
</tr>
<tr>
<td>3</td>
<td>Multiplex Connector</td>
<td>The point at which the multiplex lines connect to the BOP stack</td>
</tr>
<tr>
<td>4</td>
<td>ROV Hot Stab Panels</td>
<td>Operating panels that allow an ROV lowered to the sea floor to activate certain function on the BOP stack</td>
</tr>
<tr>
<td>5</td>
<td>Accumulator Bottles</td>
<td>They provided hydraulic fluid used to operate the various BOP elements</td>
</tr>
</tbody>
</table>

3.4.1.3-The control system

The Deepwater Horizon BOP system had one primary and four secondary methods of controlling the subsea BOP stack. Table 3.3 lists these methods to activate the BOP especially the blind shear ram (BSR) with a brief description (Transocean, 2011; Chief Council, 2011).
Table 3.3: Basic Methods to Activate BOP at Macondo

<table>
<thead>
<tr>
<th>NO</th>
<th>NAME</th>
<th>DESCRIPTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Elector/Electric/Multiplex Control System (MUX)</td>
<td>The MUX control system transmits electrical command signals from the rig to the control pods located at LMRP through cables. These pods convert these signals into hydraulic signals that operate control valves.</td>
</tr>
<tr>
<td>2</td>
<td>Emergency Disconnect System (EDS)</td>
<td>The EDS system is managed by the surface MUX control system. It is a single button activation which initiates pre-defined functions at the BOP stack. It can disconnect the LMRP from the other half of the BOP stack to save the wellhead and BOP equipment from damaging.</td>
</tr>
<tr>
<td>3</td>
<td>ROV Intervention Panel</td>
<td>The ROV intervention panel provides direct input for a ROV to apply hydraulic pressure to perform different functions on main BOP stack and LMRP.</td>
</tr>
<tr>
<td>4</td>
<td>Auto-Shear Function</td>
<td>The auto-shear mechanically activates the high pressure shear circuit to close the blind shear rams if the LMRP is unexpectedly disconnected from the BOP stack.</td>
</tr>
<tr>
<td>5</td>
<td>Automatic Mode Function (AMF)</td>
<td>The AMF is an emergency backup system located in the subsea control pods that activates the high pressure shear function to close the blind shear ram and lock if the hydraulic pressure and power are lost to the BOP stack.</td>
</tr>
</tbody>
</table>

It is hard to say if the blind shear ram was activated through one of the above activation mechanisms but preliminary information from recovered BOP stack of the Deepwater Horizon suggests that the blind shear ram may have been closed. They found erosion in BOP Stack on either side of the recovered ram; this suggests that one of these mechanisms may have successfully activated the blind shear ram, but failed to seal the flowing well because of the high pressure of hydrocarbons coming out of the well (Chief Council, 2011).
3.4.2-Deepwater Horizon Diverter System

The diverter is a very important part of the mud control system, its function is to direct the mud returning from the well into the mud processing unit. During the kick situations or when required the diverter is closed and flow from the well is directed either to the mud gas separator (MGS) or through flow lines overboard away from the drilling rig (Timothy, 2010).

The Deepwater Horizon diverter is rated for a maximum working pressure of 500 psi with a 14-in diameter line to the MGS, as well as a 14-in diameter port and starboard overboard flow lines (Transocean, 2011).

3.4.3-Annular Preventer Could not Seal the Annulus

The LMRP had two sealing components the upper annular preventer and the lower annular preventer. Annular preventers were installed so that the well could be sealed to perform negative pressure test or potentially to stop any unwanted flow up or down the annulus. Investigation and witnesses suggest that after 7 minutes from the explosion the lower annular preventer of the Deepwater Horizon rig was closed (BP, 2010). Tries were made to activate the upper annular preventer as well but because of the high flow rate the drill pipe was lifted up a little bit which changed the position of the tool joint. The tool joint came across the upper annular preventer. The annular preventers were not designed to cut through the larger diameter tool joints so the upper annular preventer could not seal the annulus because of the tool joint position. The position of the tool joint was confirmed from the pipe sections recovered with the riser joint at the NASA Michoud facility (Transocean, 2011).

The lower annular preventer failed to seal the annulus because of the following reasons:

- High flow and pressure conditions
- Lack of hydraulic pressure
3.4.3.1-High flow and pressure conditions

After the explosions the flow and pressure conditions in the borehole were worst. Hydraulic analysis of the BOP control system supports that these conditions prevented the lower annular preventer from fully closing and sealing the annulus (BP, 2010). When the lower annular preventer was closed the flow rate in the annulus was almost 100 barrels per minute. The normal flow rate during kick situations is 10-15 barrels per minute.

\[1 \text{ barrel} = 42 \text{ gallons}\]

\[100 \text{ barrel} = 42 \times 100 = 4200 \text{ gallons per minute}\]

A typical backyard swimming pool normally takes 10,000-20,000 gallons to be filled. Thus a flow of 100 barrel per mint would fill a backyard swimming pool every 2.5-5 minutes. The Deepwater Horizon annular preventers were not designed to handle such a big flow rate (Transocean, 2011).

3.4.3.2-Lack of hydraulic power

After the explosions BP and the Transocean employees had lost control on the well and they were trying to activate all possible elements of the BOP system to bring the situation under control. It required a lot more hydraulic pressure than was available at that moment. This could be a possible contributor towards the inability of the annular preventer from closing and sealing the well (Chief Council, 2011).

BP representatives claim that a large hydraulic supply was continuously provided by rigid conduit line; however it is quite possible that leaks in the hydraulic flow line and leaks in ST-lock may have reduced the hydraulic pressure (BP, 2010).

3.4.4-Blind Shear Ram (BSR) Activation

Blind shear ram is one of the main components of the BOP equipment and its function is to cut through the drill pipe in the well and shut-in the well in an emergency well control situation. Deepwater Horizon BOP stack had one blind shear ram. Blind shear ram must cut through the
drill pipe in well control situations, but in some tough situations they are unable to perform this critical function (Transocean, 2011). As Table 3.3 states that the BOP system or the blind shear ram (BSR) of the Deepwater Horizon could have been activated in five different ways.

Following is a brief summary of the attempts that were made to activate the Deepwater Horizon blind shear ram after the explosions (BP, 2010; Transocean, 2011; Chief Council, 2010).

- The Elector hydraulic/Multiplex Control System (MUX) and the Emergency Disconnect system (EDS) were controllable from the rig but the explosion and fire damaged the multiplex cables and hydraulic lines. As a result the communication link between the control box attached to the BOP and the rig was lost. Hence the efforts made from the rig to activate the BOP through the EDS were unsuccessful. Rig person also had the option to press the high-pressure BSR close button but there is no evidence available if that happened, but most likely any effort to activate the BOP through MUX would have also gone unsuccessful because of the loss of hydraulic supply pressure.

- Automatic Mode Function (AMF) or the Deadman system is designed to activate BSR automatically if; there is no electrical power between the rig and the BOP stack, there is no communication between the rig and the BOP stack and there is no hydraulic pressure supply between the rig and the BOP stack. It seems that after the explosions these three conditions were met. According to the BP investigation report the AMF system also failed to activate the BSR. The activation of AMF system was depending on two blue and yellow control pods attached to the LMRP. Post explosion examination says that there was a low battery charge in the blue pod; these batteries power a series of relays that cause the pod to close the BSR, because of low charge in the battery the blue pod could not perform its intended function. During post examination of the yellow pod they found a faulty solenoid valve, which is one of the main components to activate the BSR. There is no evidence available that proves that these faults were happened after the explosion. If these faults were present before the explosion and they went unnoticed, it put a big question mark on functionality and safety procedures of these big companies.

- Rig crew also tried to activate the BSR using a ROV to pump hydraulic fluid in to a hot stab port on the exterior of the BOP stack. The hot stab port is connected to the blind shear ram hydraulic system; fluid flowing into the port actuates the ram directly,
bypassing the BOPs control system. Hot stab port must have been activated the BSR when other methods of activation were failed. MMS study through west engineering suggested that the activation of the BSR through ROV intervention failed due to the lack of hydraulic pressure.

- It appears from the investigation reports and according to BP that the BSR was closed by ROV activation of the autoshear function but unfortunately it failed to seal the wellbore. The autoshear function is designed to close the BSR in the event that the rig moves off position. The autoshear is activated when a rod linking to the LMRP and BOP stack is severed. Some investigation reports say that due to the rig movement after the explosions the autoshear rod was severed which activated autoshear function and few investigation reports say that the crew sent a ROV to cut the autoshear rod to activate the BSR. But the bottom line is the BSR was unable to seal the well even if it was closed.

3.4.5-Critical Analysis of the Macondo BOP System and its Activation

- BOP activation was one of the most important factors to avoid this catastrophic incident but the rig crew could not recognize the kick at early stages and they delayed its activation. The hydrocarbons coming to the surface overwhelmed the surface facilities which resulted into the explosions and fire.
- The decision to divert the flow to mud gas separator proved to be a wrong decision because hydrocarbons were vented directly to the rig floor which added to the fire and explosions
- Once the mud was overflowing on the rig floor the crew activated the lower annular preventer but it did not close completely, because it was not tested for the integrity for a long time and also the flow pressure was too high to control. Transocean and BP should have tested the BOP system after regular intervals because emergencies can come anytime.
- When the attempts were being made to activate the upper annular preventer, a tool joint came across which prevented the annular preventer to close properly. The annular preventers were not designed to cut through the larger diameter tool joints. The presence of the tool joint across the annular preventer is another example of the poor well monitoring.
• After the explosions attempts were made to active BSR through EDS but fire and explosions destroyed the MUX communication cables. Early recognition of kick would have allowed EDS to activate BSR in time.

• Once the rig lost hydraulic and electric power the AMF system should have activated the BSR. But the low charge in blue control pod and a miss wired solenoid valve in the yellow control pod might have prevented the activation of the BSR. This is another big example of the negligence and poor well monitoring at Macondo.

• Six leaks were identified in the BOP hydraulic system, but still it is unclear whether these leaks affected the ability of the blind shear ram to seal the well.

• Finally when the BSR was activated in later tries, the elastic buckling of the drill pipe forced the drill pipe to the side of the wellbore and outside of the BSR cutting surface (Transocean, 2011). It was another major contributing cause towards the failure of the BOP system to seal the wellbore.

• Deepwater Horizon BOP system had only one BSR which was still according to the MMS regulations. But modern industry practices recommend companies to have two BSRs, in case if one is unable to activate (as happened at Macondo) there is another one available as a backup.

3.5-CEMENTING THE MACONDO WELL

Cementing is one of the necessary steps in the completion of an oil or gas well. It performs several important functions. It fills the annular space between the outside of the casing and the formation. It structurally strengthen the casing, protect the casing from corrosion and seals off the annular space protecting oil or gas from flowing up or down through that space. A proper cement job should be able to seal the annular space around casing, it’s called zonal isolation. Cement should also be able to displace the entire drilling mud out of the hole so that no gas or un-cleared channel of mud remains behind. Mud channels can be dangerous if they are left behind after the completion of cement job, because later they can provide a path for oil or gas to flow from the formation into the borehole (Blowout Prevention, 2011).

3.5.1-Lost Returns a Threat to Macondo Cement Job
BP had suffered some lost return events while drilling the Macondo Well and it was one of the most crucial parameters in cement job as well. Based on the lost return events and the low drilling margin BP had to stop drilling at the total depth of 18360 feet while the planned drilling depth was 20200 feet. To perform a safe cement job at Macondo Halliburton and BP engineers had to prepare cement slurry having density of 14.3 ppg in the pay zone which is much less than normal industry practices. If they would have tried to go beyond this limit they could have ended up with another lost return event. Probably that’s why the Macondo Well crew used to call it “A well of Hell” (Chief Council, 2011).

Lost return event was a big threat to Macondo cement job which kept BP and Halliburton disturbed and frustrated throughout the process.

3.5.2-Logging and Mud Conditioning

After finishing drilling process the next stage was to condition and log the wellbore respectively. To perform this job mud is circulated throughout the well and let it to homogenize its properties then a series of electric, sonic and radiographic logs are run to obtain as much information they can about the wellbore especially about the hydrocarbon zone. BP hired Schlumberger to perform this job at Macondo Well. On April 16, 2010, before running the production casing, the Schlumberger engineers circulated the open wellbore bottoms up (A complete circulation). Then they ran a series of logs to obtain information about the wellbore. From logging results they found lots of gas units mixed in the mud but they ignored them and paid no attention (Chief Council, 2011).

3.5.3-Production Casing and Centralizers

Once conditioning and logging process was done the next stage was to lower the production casing in the wellbore. Production casing for the Macondo well was a $9\frac{7}{8}\text{-inch} \times 7\text{-inch}$ long and heavy steel pipe, going into the well from the wellhead all the way to the bottom. To lower such a heavy and long casing safely BP and Halliburton required 21 centralizers (BP, 2010). During cementing process centralizers play a very important role, they keep the casing close to the center which is very important for a good cement job. At the time of the Macondo
cementing BP and Halliburton had only 6 centralizers available instead of 21. They decided to go ahead with 6 centralizers without waiting for the remaining 15 to come which was another big mistake they made (Glen, 2011).

### 3.5.3-Float Valves and Float Valves Conversion

Float valves are very important during the drilling process; they are one way valves installed near the interior bottom end of the casing string. They permit fluid such as mud or cement to flow down through the inside of the casing while preventing fluids from flowing in the reverse direction back up the inside of the casing (Glen, 2011). Float valves can also be harmful by interfering with the process of lowering the casing string. As the casing string is lowered, it is recommended that mud be able to flow both direction up and down the casing string. Otherwise the casing can exert a lot of pressure on the formation while it is being lowered. To achieve both side flow from the float valves engineers typically use an auto-fill tube which is a hollow tube. It extends through and props open the two float valves, allowing mud to flow up through the casing while casing is being run into the well. Figure 3.5 shows float valves assembly with auto-fill tube.

![Float Valves Conversion](image)

Fig 3.5-Float Valves Conversion (Chief Council 2011, P. 70)
Once rig crew finish lowering the casing, the next step is to convert the float valve assembly by pushing the auto fill tube down and out of the float valves. This allows the float valves to close converting them into one way valves before cementing begins. Float valve conversion is a very important step and it should be done carefully (Glen, 2011).

At the Macondo Well after lowering the casing rig crew started to convert float collars. They started to generate the flow by using the flow rate of 1 bpm. At that flow rate the drilling fluid did not flow through the float assembly and pressure began to build up which was not normal. BP should have stopped the process and should have investigated the matter but they kept on trying with higher flow rates and finally during 9th attempt they succeeded to generate the flow but the pressure was built up 3142 psi which exceeded the manufacturer pressure limit of the float valve assembly. It was unclear whether float valves were converted or not but BP decided to move forward (Transocean, 2011).

3.5.4-Wellbore Conditioning

After converting the float valves the drilling engineers prefer to condition the wellbore again by circulating mud through the newly installed casing. Well condition at this stage has three benefits as follow:

- It cleans the casing, drill pipe and wellbore of cuttings and other debris that can interfere with the good cement placement and performance.
- The mud flow conditions the mud itself by breaking its gel strength, decreasing its viscosity and increasing it mobility.
- It also provides information to the crew at the surface if there are any hydrocarbons are already present in the borehole.

Under optimum conditions the operator prefer to circulate enough drilling mud through the casing after landing it to achieve a full bottoms up, which means that the crew pump enough mud down the well so the mud return back up to the surface through annulus (BP, 2010).
3.5.5-Two Plug Method to Pump Cement in Borehole

Once it comes to pump the cement into the borehole the engineers face difficulties to make sure that the oil based drilling mud does not contaminate the water based cement. In companies various techniques are being used to keep both fluids separate to stop contamination. At the Macondo well the drillers used “two- plug method”. The two plug method uses rubber darts and wiper plugs to keep both fluids separate. The rig personnel starts the cement pumping process by pumping a water-based spacer followed by the bottom dart into the drill pipe, then a top dart and more spacer fluid. After pumping final spacer fluid rig personal push the spacer fluid by drilling mud until the spacer-dart-cement-dart-spacer train sits at its accurate location in the borehole. When the bottom dart reaches at the end of drill pipe it fits into and launches the bottom wiper plug from the running tool that attaches the drill pipe to the production casing. It prevents the contamination of the cement behind it from spacer and mud fluid ahead of it. Similarly when top dart reaches at the end of drill pipe it launches the top wiper plug that sits on the float valves. It prevents the contamination of the cement from spaced and mud behind it. The rig crew continuously pumping mud down the drill pipe to displace the cement into position. Eventually spacer fluid reaches the float valves. The bottom plug lands on the float valves where it stops, circulating pressure behind it causes the bottom plug to rupture allowing the cement to pass through the plug into the shoe track. After all cement passed through this ruptured bottom plug, the top plug comes down and sits on the top of float valves. It cannot be ruptured and it also stops further fluid going down the well. The rig crew stops pumping drilling mud and allow cement to set for some time and this process is called wait on cement. Once bottom wiper plug is pushed down the float valves convert automatically and prevent any flow back into the production casing (Chief Council, 2011).

3.5.6-Macondo Well Cement Design

Cementing of the Macondo Well was not an easy job it was full of challenges and restrictions. BP’s major concern in cementing was the risk of fracturing the formation and losing returns because the kick margin was very low. This concern lead BP team to make few major
compromises in cementing the Macondo, which proved to be very costly decisions at the end. One of the main contributors towards the loss of well integrity was the failure of the cement job. As the primary function of the cement is to provide the first barrier to flow from the formation into the wellbore, to achieve this purpose the use of higher density slurries around 16.4 ppg in pay zones is a common and recommended practice in the industry as long as the density of the slurry does not exceed the fracture limit of the formation (Blowout Prevention, 2011).

As the basic concern BP and Halliburton had was the 14.3-ppg fracture point of the formation in the pay zone. Considering this narrow window between the pore pressure and fracture pressure, Halliburton engineers recommended pumping nitrified foam cement slurry across the main pay zone. To prepare nitrified foam cement slurry tiny bubbles of nitrogen gas were injected to the cement slurry just before it was sent down the well. Foamed slurry cement was used to lighten the resulting slurry from 16.7 ppg to 14.5 ppg (BP, 2010).

Cement placement was conducted by pumping the sequence of base oil, spacer, bottom wiper plug, cap cement, foamed cement, tail cement, top wiper plug and spacer.

One main purpose of the spacers and cap cement was to isolate the nitrified foam cement slurry from contaminants in the wellbore. Its contamination with the mud could make it unstable and could also break the nitrogen. The purpose of the nitrified cement was to isolate the formation, preventing migration of hydrocarbons either upward to the open casing annulus or downward to the shoe track. The purpose of the tail cement was to fill the shoe track to prevent the hydrocarbons to enter into the casing from the bottom (BP, 2010).

BP was supposed to wait for the final slurry stability tests from the Halliburton lab but they rushed to the cement job without making sure the slurry stability. Latter lab results proved that cement slurry was unstable (National Commission, 2011).

Figure 3.6 shows the consequences of the bad cement job at Macondo.
3.5.7- Macondo Well Cement Evaluation

Once the cementing job was done the next important step was the evaluation of the cement job whether it went according to the plan or it needed modifications. Any change or cementing process, after the primary cement job is called remedial cementing (Stein, 2013). BP contacted Schlumberger to provide cement evaluation services. Therefore a cement evaluation team from the Schlumberger was available on the Macondo Well cementing day. The Schlumberger team was going to run a full suite of logs including a cement bond log, isolation scanner, and variable density log. The total cost for the complete cement evaluation job was 128,000 dollars. BP had already told Schlumberger that they would use their services only if there was another lost circulation event during cementing. The Schlumberger team waited more than a day to see if BP would require their services or not (Chief Council, 2011).

In the April 20th morning Macondo team discussed that the cement job went well, everyone from the BP team agreed to send Schlumberger team home without evaluating the cement job. They decided to move on to the temporary abandonment. This decision defiantly saved some money
and time but it proved to be a very expensive decision at the end. If BP and Halliburton would have allowed the Schlumberger to evaluate the cement job, they could have found out the actual problem long ahead. But their minds were off from work that day; it looks like they were unable to take any responsible, solid and wise decision that day. Finally they moved to the next stage of the well completion process without evaluating the cement job which was one the most critical factors in this blowout.

3.5.8-Compromises BP and Halliburton made for Macondo Cement Job

- The first main compromise the cementing crew made was to limit the circulation of drilling mud through wellbore before cementing. To achieve “full bottoms up” (A complete circulation) BP needed 2760 barrels of mud but they limited it to 350 barrels only because they were scared that longer the rig crew circulated mud through the casing before cementing, the greater the risk of another lost return event (National Commission, 2011).

- The 2nd main compromise the cementing crew made was to pump cement at relatively low rate of 4 barrels or less per minute (Glen, 2011). To achieve a good cement job it is recommended to use higher flow rates like 6 barrels per minute or more, because with higher flow rates cement can displace mud from annular space properly leaving no channels. In case of the Macondo higher flow rate meant more pressure on the formation and an increased risk of lost return. Therefore BP had to pump cement at relatively lower flow rate to avoid another lost return event.

- The 3rd main compromise BP made that they pushed Halliburton engineers to reduce the volume of cement. This decision was even against to BP’s own policies (Presidential commission, 2010). Again BP team was scared that higher cement column in annulus would exert more pressure on the formation which could lead to another lost circulation event.

- BP’s original plan was to use 21 centralizers to perform the cement job at Macondo but they made another compromise by limiting the centralizers to six in total. This compromise indirectly affected the cement job (Glen, 2011).
3.5.9-Critical Analysis of the Macondo Cement Job

- It can be a little unfair to blame BP about all the compromises they were making in cementing the Macondo well because there was no other better option available at that moment. The kick margin was very low in the pay zone and their goal was to avoid another lost circulation event. But still these compromises proved very costly at the end because BP ended up with a very bad cement job, which was a big contributor to this horrific incident.

- The cement in the annular space may not have replaced mud completely which might have left mud channels in the annulus. Mud channels represent a poor and weak cement job, BP should have made sure that there were no mud channels.

- BP and Halliburton chose to use nitrified foamed cement slurry to perform cement job at the Macondo well. It was already a risky decision, they should have made sure the stability of the slurry before sending it in down-hole but the latter investigation on the cement slurry concludes that the Macondo cement slurry was very unstable and the companies involved did not take any steps to make sure the stability of the cement slurry.

- BP should not have made compromise on centralizers because they play an important role to perform a proper cement job. BP should have waited for the other 15 centralizers to arrive but they rushed to perform the cement job as a result they ended up with a really bad cement job.

- BP decided to bring Schlumberger (BP’s sub-contractor) to perform cement evaluation job once they would finish the cement job at Macondo. But after the completion of the cement job they assumed it went very well and they sent Schlumberger’s engineers home without performing cement evaluation tests. This decision definitely saved them some money but it proved to be a very poor decision. If they would have allowed Schlumberger to perform evaluation tests they would have recognized poor cement job long before the blowout and would not have moved to the temporary abandonment.

- BP could have added lost circulation material in the cement slurry but they should not have made any compromise on the flow rate and they also should not have reduced the quantity of the cement because a successful cement job was very important in case of the Macondo Well.
3.6-TEMPORARY ABANDONMENT AND WELL INTEGRITY TESTING

Once the drilling and cementing processes were done at Macondo, the next stage was to temporarily abandon the well. Temporarily abandonment refers to the procedures that rig crew use to secure a well so that a rig can safely remove its blowout preventer and riser from the well and leave the well site. BP was responsible of making the temporarily abandonment plan (Transocean, 2010).

Since deepwater drilling requires a bigger and expensive rig to perform drilling successfully, many operators once drilling is done bring a smaller and less expensive rig to finish well completion stages. It was exactly what BP was planning to do, to remove Deepwater Horizon and to bring a smaller rig to complete the well. There are no industry standards available for the temporarily abandonment procedures it depends upon the companies technical facilities and capabilities and also the needs of a particular well.

In case of the Macondo Well MMS did impose any extra requirements on BP to execute in their temporarily abandonment procedure. They advised them to set a retrievable or permanent-type bridge plug or a cement plug at least 100 feet long in the inner most casing and also the top of the plug must be no more than 1000 feet below the mud line. This plug in layman language is known as surface plug (Chief Council, 2010).

BP’s temporary abandonment procedure for the Macondo Well had the following basic sequence (Chief Council, 2010):

- Run the drill pipe into the well 8367 feet below sea level or 3300 feet below mud line.
- Displace 3300 feet of mud in the well with sea water, lifting the mud above the BOP and into the riser.
- Perform a negative pressure test to assess the integrity of the well.
- Displace the mud in the riser with sea water.
- Set the surface cement plug at 8367 feet below sea level.
- Set the lock down sleeve (LDS) in the well head to lock the production casing in place.
3.6.1-Implementation of the Lockdown Sleeve

A lockdown sleeve is a piece of equipment that is installed in the wellhead to guard against uplift forces that may be generated during the production of hydrocarbons at a well. Lockdown Sleeve needs not to be set during temporary abandonment. Macondo team originally planned to leave this job for the completion rig which is a normal industry practice. BP acted very unprofessional in taking steps towards the completion of the well. They changed temporarily abandonment plan almost every day before the final plan. Finally after many discussions and calculations BP engineers decided to install the Lockdown Sleeve using the Deepwater Horizon because it was going to save them almost 2.2 million dollars and 5.5 days of rig time. The Lockdown Sleeve decision leads them to take many of the wrong decisions that were never the part of the temporarily abandonment plan (Chief Council, 2011).

3.6.2-Establishing the Well Integrity at Macondo Well

After installation of the production casing and the primary cement job, the next stage in the temporary abandonment process was to generate the Macondo Well integrity. It is a proven fact that Macondo Well integrity was not done properly and the crew ignored and misinterpreted the well integrity test result. This negligence contributed a lot in the Macondo Well horrific incident (BP, 2010).

According to the plan BP was trying to move Deepwater Horizon to another location and was bringing a smaller rig for the completion purpose which is a common industry practice. To do so they had to make sure that during the intervening time well is stable enough to be on it’s on and no hydrocarbons are leaking into the well from the formation. Therefore as a part of the temporary abandonment procedure, the rig crew conducted several tests to check the well’s integrity. The crew conducted three different tests; a seal assembly test, a positive pressure test and a negative pressure test (Chief Council, 2011).
The right conduction and interpretation of the results of these tests was one of the most important aspects of the temporary abandonment procedure. A brief explanation about each test is given below.

### 3.6.2.1- Seal assembly test

Seal assembly test is conducted to check the integrity of the ‘casing hanger seal assembly’ the casing hanger supports the casing and seals off the annular space outside the top of the casing. To perform this test at Macondo, crew installed a plug or packer on the bottom of the drill pipe and lowered it beneath the seal assembly. The crew then closed a variable bore ram of the BOP system above the seal assembly, around the drill pipe. The rig crew pumped additional fluid in that enclosed space to increase the pressure. They noted the pressure for a predetermined amount of time and pressure did not drop, which meant that no fluid is leaking from the seal assembly into the formation; this test was considered as a success. In the morning hours of April 20, 2010 the rig crew conducted this test twice and both of them passed (Chief Council, 2011).

The success of the seal assembly test was a positive sign for BP and they felt little bit relieved after this. They next stage was to conduct the positive pressure test.

### 3.6.2.2- Positive pressure test

The next test which Macondo rig crew conducted was the positive pressure test. The procedure is almost the same as seal assembly test, but it is conducted over a larger area of the well. To conduct this test the rig crew took the drill pipe out of the well and closed the blind shear ram (BSR) of the Macondo BOP system. Then the crew added additional fluid in the well below the BOP to increase the pressure. Then they shut off the pumps and monitored the well pressure for a predetermined time, it remained constant which meant that well head, seal assembly and BOP are not leaking and they are sustaining in higher pressures. Between 10:30 am and noon the rig crew conducted a positive pressure test to 250 psi for five minutes and then a second to 2700 psi for 30 minutes. In both cases pressure inside the well remained constant (Chief Council, 2011).
The success of the positive pressure test was another positive sign for BP and it gave BP engineers a lot of confidence. Probably it made them to think that everything was right and they did not take the next stage of the tests as serious as should have taken it.

3.6.2.3-Negative pressure test

The negative pressure test is the reverse of the positive pressure test. Both seal assembly and positive pressure test does not provide any information about the integrity of the cement in the shoe track or in the annulus. To conduct this test, the well is being put in underbalanced state for a certain period of time, by replacing the mud with a lighter density fluid like sea water. In that certain period of time the crew monitor the well pressure gauge carefully. If the crew notice any increase in the well pressure, it means that hydrocarbons are leaking into the well from the formation (Chief Council, 2011). The crew should take immediate actions to stop that leakage by shutting-in the well and circulating the flux out of the well, using engineer’s or driller’s method of well circulation. Remedial cementing should be done to stop those leaks. After sealing the leaks the crew should conduct another negative pressure test to make sure there are no more leaks and no hydrocarbons are entering into the well before they move to the next stage.

At Macondo, negative pressure test results were very confusing and the results were entirely different than they expected. To perform negative pressure test at Macondo, the crew had to replace the drilling mud with sea water to a depth of 8367 feet below the sea level to bring the well in underbalanced condition. To stop the contamination between the drilling mud and sea water BP used a spacer fluid (BP chose to use fluid composed of leftover lost circulation material as spacer fluid). Once the required amount of mud was displaced the crew closed an annular preventer from the BOP system around the drill pipe (BP, 2010; Chief Council, 2011).

The next step was to bleed off any pent-pressure inside the drill pipe. To do so the crew opened a valve at the rig to allow the fluid to flow outside from the drill pipe until it stopped flowing itself and the pressure at the drill pipe fell to zero. Then they shut-in the well for a predetermined time and monitored the well. Unfortunately after shutting in the Macondo Well for the negative pressure test they noticed a rise in drill pipe pressure. They repeated the procedure several times but had the same results. After the third attempt the crew noticed that the drill pipe pressure rose up to 1400 psi. This was a clear indication that the cement was not isolating the hydrocarbons in
the pay zone and they were leaking into the well from the formation. Instead of shutting in the well and circulating the flux out of the borehole they requested and got approval to perform the negative pressure test on the kill line (BP, 2010; Chief Council, 2011).

Once the crew started the negative pressure test on the kill line the drill pipe pressure was already reading 1400 psi. To conduct the test on the kill line, rig personal opened the kill line bled the pressure down to zero psi and monitored the line for 30 minutes. This time there was no flow or pressure built up in the kill line. The well site leaders considered it as a successful negative pressure test and moved on to the next stage of the temporary abandonment. The crew knew it that the drill pipe pressure was reading 1400 psi but they did not adequately address that issue and decided to move forward (BP, 2010; Chief Council, 2011).

The drill crew completed the well integrity tests stage without making any sense. They were not sure if the well integrity was established or not but they decided to move forward. The pressure of 1400 psi at the drill pipe was a clear indication that hydrocarbons are entering into the well but they done nothing about it. Misinterpretation of the negative pressure test was a big contributor in this horrific incident.

### 3.7-KICK PRODUCTION AND LOSS OF THE WELL CONTROL

After the negative pressure test the crew moved forward to the next stage of the temporary abandonment procedure. The crew would displace mud and spacer from the riser with sea water. This process is done in several steps; first of all rig personal would pump sea water down the drill pipe to displace mud from the riser until the spacer fluid behind the mud reached the rig floor, then the rig personal would shut down the pumps and conduct a sheen test (A test to confirm that all of the oil based mud is been displaced from the riser), then the rig personal change the lineup of valves to send the spacer fluid overboard rather than to the mud pits and would resume the displacement until all of the spacer fluid is out of the wellbore and the riser was full of nothing but sea water (Chief Council, 2011).

During mud and spacer displacement procedure the rig crew should have monitored continuously for flow of the hydrocarbons. The driller, assistant driller and the mud-logger were responsible
for detecting kicks. Their job was to monitor two main parameters. One of them was the volume of the mud in the active pits; the volume of the mud going into the well should be equal to the volume of the mud coming out of the well. An increase in the pit volume is a powerful indication that something is flowing into the well. The 2nd main indicator was to monitor the volume and rate of flow coming out of the well, the volume and rate of flow of fluid coming from the well should be equal to the volume and rate of flow of fluid pumped into the well. If flow out of the well is greater than flow into the well, it is a strong indicator that a kick may be underway. Finally another main factor which was to be monitored carefully was the drill pipe pressure. During entire displacement procedure the drill pipe pressure should have remained constant. Any increase or decrease in the drill pipe pressure is interpreted as a sign of the production of kick (National Commission, 2011).

### 3.7.1-Macondo Well Monitoring System

The Deepwater Horizon had two separate systems for collecting and displaying real-time data. The “Hitec” system owned by the Transocean was the main source on which the Deepwater Horizon typically relied for monitoring the well. The “Sperry Sun” system-installed and operated by Halliburton Subsidiary at BP’s request was another source to monitor the well. Some investigation reports are relying on the “Sperry Sun” data as well (BP, 2010).

In spite of having all the high tech machinery and sensitive sensors to monitor the well, the rig personnel took their job easy and ignored or failed to read the signs of the kick on time. The numerical values obtained from the “Sperry Sun” and “Hitec” system reports shows the abnormality in the graphs and abrupt changes in the pressure values which should have alerted the crew, but unfortunately it did not happen. By the time they realized and detected the kick it was too late and it resulted as one of the horrific blowout followed by one of the biggest oil spill in the history of the oil and gas industry.
Figure 3.7 shows a typical Macondo Well monitoring and circulation system.

Fig 3.7-Macondo Well Monitoring System (Chief Council 2011, P. 170)
3.7.2-Main Activities on April 20th 2010 at Deepwater Horizon just before Explosions

On April 20, 2010 simultaneous operations were taking place. Table 3.4 describes a brief summary of the operations during the mud and spacer fluid displacement process on April 20, 2010 prior to the Explosions (BP, 2010; Transocean, 2011).

Table 3.4: Main Activities at Macondo before Explosions

<table>
<thead>
<tr>
<th>No</th>
<th>Time</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>8:02 PM</td>
<td>The crew started to displace mud and spacer in the riser with seawater.</td>
</tr>
<tr>
<td>2</td>
<td>8:50-8:52 PM</td>
<td>The pumps were slowed at 8:50 PM in anticipation of the returning spacer.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Post explosion flow analysis by OLGA proves that hydrocarbons started to flow</td>
</tr>
<tr>
<td></td>
<td></td>
<td>in the wellbore at 8:52 PM.</td>
</tr>
<tr>
<td>3</td>
<td>9:01 PM</td>
<td>Drill pipe pressure increased from 1250 psi to 1350 psi at the constant</td>
</tr>
<tr>
<td></td>
<td></td>
<td>pump rate.</td>
</tr>
<tr>
<td>4</td>
<td>9:08-9:14 PM</td>
<td>Rig crew shut off the pumps and conducted the Sheen Test.</td>
</tr>
<tr>
<td>5</td>
<td>9:20 PM</td>
<td>Senior tool pusher called his colleague and asked him about the negative</td>
</tr>
<tr>
<td></td>
<td></td>
<td>pressure test and the mud and spacer displacement. His colleague replied</td>
</tr>
<tr>
<td></td>
<td></td>
<td>that everything is going fine so far.</td>
</tr>
<tr>
<td>6</td>
<td>9:30 PM</td>
<td>The Mud pumps were shut down again because there was a problem with pump</td>
</tr>
<tr>
<td></td>
<td></td>
<td>no 2 and also responding to the return of the remainder of the spacer fluid.</td>
</tr>
<tr>
<td>7</td>
<td>9:39 PM</td>
<td>Drill pipe pressure started to decrease.</td>
</tr>
</tbody>
</table>

3.7.3-Critical Analysis of the main Activities on April 20, 2010

1: The driller repeatedly rerouted the mud returns from one pit to another during the displacement process to accommodate the incoming volume. They also sent mud from other
locations into the active pit system. Rerouting the Mud in different pits would have made difficult to monitor the pit’s volume changes accurately.

2: As at 8:52 PM the pumps were slowed down to displace the spacer fluid it put Macondo Well in underbalanced state which allowed hydrocarbons to enter into the well. The poor cement job could not stop hydrocarbons from entering into the wellbore. A good cement job could have saved this horrific incident.

3: At 9:01 PM the pressure of the drill pipe increased from 1250 psi to 1350 psi at constant pump rate. At this point the drill pipe pressure should have been decreased instead, due to the replacement of 14.6 ppg Mud with 8.6 ppg sea water. Analysis shows that 39 bbl of fluid gain took place in those ten minutes from 8:58 PM to 9:08 PM. This abnormality should have been noticed right away and they should have shut-in the well to stop the further flow of hydrocarbons in the well. But unfortunately it could not happen (BP, 2010).

4: At 9:08 PM the rig crew shut off the pumps and conducted the Sheen Test. This test verified that no oil was present in the spacer fluid before discharging it overboard. The test started at 9:10 PM when they closed a valve on the flow line that had been carrying fluids from the well to the pit tanks. So after 9:10 PM “Sperry Sun” data was no more available but it was sensing the flow of hydrocarbons just before it closed. During that short period of time the drill pipe pressure should have remained constant but it was continuously increasing, the reading went up from 1017 psi to 1263 psi in six minutes. Unfortunately no one noticed again the rise in the drill pipe pressure with pumps off. This increase in pressure was clear in “Sperry Sun” and Transocean “Hitec” system but it went undetected or ignored (BP, 2010).

5: It is very hard to believe how the senior tool pusher could rely on his colleague report about negative pressure test and mud and spacer displacement. Senior tool Pusher should have relied on the actual facts from “Sperry Sun” and Transocean “Hitec” data. It looks like no one was interested to know the actual readings of the abrupt pressure changes during that critical point of the well completion process.

6: The crew shut down the pumps again, with this shut down the well would have gone in underbalanced state again and would have allowed more hydrocarbons to enter in the wellbore.
The OLGA well flow modeling indicated that from 8:52 PM to 9:31 PM, 300 barrels of hydrocarbons were already entered in the wellbore and they were still undetected (BP, 2010).

At 9:39 PM drill pipe pressure started to decrease. It was a very bad sign which meant that lighter-weight hydrocarbons were now pushing heavy drilling mud out of the way up the casing past the drill pipe.

### 3.8-MACONDO WELL EXPLOSION AND RESPONSE

The “OLGA” well modeling indicated that hydrocarbons had been continuously flowing into the well since 8:52 PM and a 300 barrels gain had been taken by 9:30 PM. Sometime between 9:40 and 9:43 PM drilling mud began flowing from rotary table onto the rig floor. This appears to be the first moment when the rig crew realized that a Kick has occurred. Their response was very immediate but unfortunately they were not ready to handle such a big flow of hydrocarbons. A representative from Transocean was explaining the flow by saying “a 550-ton freight train hitting the rig floor followed by a jet engine’s worth of gas coming out of the rotary table” (Transocean, 2011).

The first defensive action the crew took was the diversion of the flow coming from the riser into the mud-gas separator rather than overboard into the sea (which was another option). The first explosion occurred at approximately 9:49 PM on the drilling floor and the Macondo Disaster claimed its first victim (BP, 2010).

Table 3.5 briefly explains the immediate response of the crew to bring the situation under control after they saw the kick on the rig floor (BP, 2010).
Table 3.5: Immediate Response of the crew at Macondo after Explosions

<table>
<thead>
<tr>
<th>NO</th>
<th>TIME</th>
<th>EVENT DESCRIPTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>9:40</td>
<td>Mud over flowed the flow-line and onto the rig floor.</td>
</tr>
<tr>
<td>2</td>
<td>9:43</td>
<td>Diversion of the flow to the Mud gas separator (MGS); BOP activated believed to be annular preventer.</td>
</tr>
<tr>
<td>3</td>
<td>9:44</td>
<td>Mud and water exited the MGS vents; Mud rained down on the rig. Tool pusher called well site leader and informed him about the returning mud.</td>
</tr>
<tr>
<td>4</td>
<td>9:45</td>
<td>Assistant driller called senior tool pusher and informed him that “well is blowing out” and tool pusher is trying to shut-in.</td>
</tr>
<tr>
<td>5</td>
<td>9:46</td>
<td>Gas discharged from MGS towards deck</td>
</tr>
<tr>
<td>6</td>
<td>9:47</td>
<td>Drill pipe pressure increased from 1200 psi to 5730 psi</td>
</tr>
<tr>
<td>7</td>
<td>9:48</td>
<td>Main power generation meters were reading over speed.</td>
</tr>
<tr>
<td>8</td>
<td>9:49</td>
<td>Rig power lost, Sperry Sun real time data transmission lost. First explosion occurred an estimated 5 sec after the power lost and 2\textsuperscript{nd} explosion occurred 10 seconds after the first explosion.</td>
</tr>
</tbody>
</table>

3.8.1-Critical Analysis of the Macondo Well Explosion and Response

- The Deepwater Horizon crew showed the poor performance in recognizing the kick. They did not notice or paid any attention towards the abrupt pressure changes throughout and allowed the hydrocarbons to enter into the riser up to the rig floor. If they could have recognized the kick before entering the hydrocarbons into the riser they could have avoided this blowout by shutting-in the well or at least could bring the damage to the minimum level.
- The crew took the decision to diverter the flow towards the MGS instead of diverting it overboard. It proved to be a wrong decision because the diversion of the flow to overboard could have delayed the explosion and could have given more time to the crew to react. One can say that they took this decision in rush and they were also not aware
with the amount of flux coming behind. It still does not justify their mistake, even the Transocean manual recommend to divert the high flow overboard.

- If the crew could have tried to activate the blind shear ram (BSR) through the emergency disconnect system (EDS) few minutes before the explosion the BSR could have possibly sealed the well. But unfortunately they were trying to activate BSR after the explosion when it was too late.

- Finally the Deepwater Horizon crew showed lack of knowledge and professionalism. There was a lack of real leadership and communication. It looks like they were not adequately trained to handle the emergency situations.

3.9-FACTORS OR DECISIONS THAT INCREASED THE RISK OF THE MACONDO BLOWOUT

This case study briefly explain that BP and its drilling partners at Macondo were making mistakes and taking wrong decisions almost at every stage of the drilling process. Few of the decisions proved to be very costly at the end and they contributed directly or indirectly in this horrific incident. Table 3.6 shows a summary of the events or decisions that BP and its partners were taking to finish the drilling process at Macondo Well. This table also shows if these events or decisions directly or indirectly contributed in the Macondo Well blowout.
Table 3.6: Factors or Decisions that increased the risk of Macondo Blowout

<table>
<thead>
<tr>
<th>No</th>
<th>Activity/Decision</th>
<th>Description</th>
<th>Saved Time</th>
<th>Saved Money</th>
<th>Management or Technical Failure</th>
<th>Responsible</th>
<th>Good or Bad Decision</th>
<th>Contributed towards Blowout</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Lost circulation events</td>
<td>BP suffered few lost circulation events during drilling but they acted professionally and got control on them.</td>
<td>N/A</td>
<td>N/A</td>
<td>Technical</td>
<td>N/A</td>
<td>Good</td>
<td>Yes</td>
</tr>
<tr>
<td>2</td>
<td>Kick Margin</td>
<td>Kick Margin was very low even below from MMS requirements at few stages but they did not inform MMS about it.</td>
<td>yes</td>
<td>yes</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>Reduction in total drilling depth</td>
<td>BP’s original planned depth was 20200 feet but they limited it to 18360 feet</td>
<td>yes</td>
<td>yes</td>
<td>N/A</td>
<td>BP</td>
<td>Good</td>
<td>No</td>
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<tr>
<td>4</td>
<td>Long string VS Liner Production Casing</td>
<td>BP opted to use long string production casing instead of Liner with a tie back arrangement</td>
<td>yes</td>
<td>yes</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>5</td>
<td>Nitrified Foam Cement Slurry</td>
<td>BP and HB used nitrified foam cement slurry to cement the Macondo Well</td>
<td>N/A</td>
<td>N/A</td>
<td>Management</td>
<td>BP and HB</td>
<td>Unclear</td>
<td>Yes</td>
</tr>
<tr>
<td>6</td>
<td>Unstable cement Design</td>
<td>HB cement design could not handle high temperature and pressure in borehole</td>
<td>N/A</td>
<td>N/A</td>
<td>Management</td>
<td>HB</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>7</td>
<td>Reduction in No of Centralizers</td>
<td>BP original cement plan included 21 centralizers but they limited the quantity to 6 at the end</td>
<td>Yes</td>
<td>Yes</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>8</td>
<td>Reduction in Flow</td>
<td>BP and HB pumped</td>
<td>N/A</td>
<td>N/A</td>
<td>Management</td>
<td>BP and HB</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
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<tr>
<td></td>
<td>rate to Pump Cement</td>
<td>cement at reduced flow rate of 4 bpm, higher flow rates are recommended</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Reduction in Cement Volume</td>
<td>BP reduced the total volume of the cement to be pumped in Macondo</td>
<td>N/A</td>
<td>Yes</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>10</td>
<td>Sending Schlumberger Team Home</td>
<td>BP assumed a good cement job and did not allow Schlumberger team to perform cement integrity evaluation tests</td>
<td>Yes</td>
<td>Yes</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>11</td>
<td>Float Valve Conversion</td>
<td>BP and HB assumed float valves were converted but they were not</td>
<td>N/A</td>
<td>N/A</td>
<td>Management</td>
<td>BP and HB</td>
<td>Bad</td>
<td>yes</td>
</tr>
<tr>
<td>12</td>
<td>Installation of the Lockdown Sleeve</td>
<td>BP installed lockdown sleeve very earlier at the beginning of the well completion process which is not recommended</td>
<td>Yes</td>
<td>Yes</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>Negative Pressure Test Results (NPT)</td>
<td>BP assumed NPT went well but actually it did not at all</td>
<td>Yes</td>
<td>Yes</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
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</tr>
<tr>
<td>13</td>
<td>Sperry Sun and Hitec System Data</td>
<td>BP crew ignored abrupt pressure change readings that’s why could not recognize kick at early stages</td>
<td>N/A</td>
<td>N/A</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>14</td>
<td>Hydrocarbon entered Wellbore</td>
<td>Hydrocarbons entered wellbore undetected</td>
<td>N/A</td>
<td>N/A</td>
<td>Management</td>
<td>BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>15</td>
<td>Diversion of Flow to MGS</td>
<td>Rig crew diverted flow to MGS instead overboard</td>
<td>N/A</td>
<td>N/A</td>
<td>Management</td>
<td>TR and BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>16</td>
<td>Tool Joint Location</td>
<td>Tool joint came across the upper annular preventer which prohibited annular preventer to perform its intended function</td>
<td>N/A</td>
<td>N/A</td>
<td>Management &amp; Technical</td>
<td>TR and BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>17</td>
<td>Lack of Hydraulic Pressure</td>
<td>Because of the lack of hydraulic pressure BOP components could not</td>
<td>N/A</td>
<td>N/A</td>
<td>Management &amp; Technical</td>
<td>TR and BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>Function</td>
<td>Reason</td>
<td>Status</td>
<td>Responsibility</td>
<td>Condition</td>
<td></td>
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</tr>
<tr>
<td>19</td>
<td>Low Battery Charge in Blue Pod</td>
<td>AMF could not activate BSR because of the low battery charge in blue control pod</td>
<td>N/A</td>
<td>N/A</td>
<td>Management &amp; Technical</td>
<td>TR and BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>20</td>
<td>Faulty Solenoid Valve</td>
<td>AMF could not activate BSR because of the faulty solenoid valve in yellow control pod</td>
<td>N/A</td>
<td>N/A</td>
<td>Management &amp; Technical</td>
<td>TR and BP</td>
<td>Bad</td>
<td>Yes</td>
</tr>
<tr>
<td>21</td>
<td>Leaks in BOP Hydraulic System</td>
<td>Six leaks were identified in BOP hydraulic system</td>
<td>N/A</td>
<td>N/A</td>
<td>Management &amp; Technical</td>
<td>TR and BP</td>
<td>Bad</td>
<td>Unclear</td>
</tr>
</tbody>
</table>
3.10-KEY FINDINGS

The accident of the April 20, 2010 involved a well integrity failure, followed by a loss of hydrostatic control of the well. This was followed by a failure to control the flow from the well with the BOP equipment. The following are few main key findings relating to the casual chain of events, a better performance in the respective areas could have saved this catastrophic incident from happening.

1. The negative pressure test results were accepted although the well integrity was not established.
2. The annulus cement failed to isolate the hydrocarbon zone and allowed hydrocarbons to flow from the formation into the wellbore.
3. Hydrocarbons entered the wellbore undetected; the rig crew ignored the abrupt pressure changing readings from the Macondo Well monitoring system.
4. The shoe track cement could not provide a strong barrier to the hydrocarbons and allowed them to enter into the production casing.
5. Float valves were not converted, which allowed hydrocarbons to rise up in the production casing.
6. BOP system completely failed to seal the wellbore.
7. Delay in the recognition of the hydrocarbons influx. The crew could not realize the influx until it entered into the riser.
8. Well control actions after explosions failed to regain the control on the well.
9. Diversion of the flow towards MGS resulted in gas venting to the surface of the rig.
10. Lack of real leadership and unprofessionalism was another big contributor to this incident.
CHAPTER NO 4

IXTOC-1 BLOWOUT JUNE 3, 1979

CASE STUDY 2: IXTOC-1 BLOWOUT JUNE 3, 1979

4.1 INTRODUCTION

The IXTOC-1 blowout is one of the biggest disasters in the history of oil and gas industry. This blowout was happened on 3 June, 1979 in the Bahia de Campeche, 600 miles south of Texas in the Gulf of Mexico. The water depth at the well head site was 50 meters which is 164 feet. The total depth of the well at the time of the disaster was 2 miles. The IXTOC-1 was an exploratory well and it was being drilled by the SEDCO 135F, a semi-submersible drilling platform on lease to Petroleos Mexicanos (PEMEX) (IXTOC-1 Mexico, 1979). The IXTOC-1 blowout ended up producing the world’s 2nd largest oil spill into the marine environment, after the Deepwater Horizon 2010. By the time the flow was stopped months later about 3.5 million barrels of oil were released into the Gulf of Mexico. PEMEX had to hire control experts from all over the world to bring the situation under control. The spill not only took millions of dollars but also destroyed much of the Gulf plants and animals; furthermore it badly affected the economy in the area. The IXTOC-1 blowout was caused by a mud lost circulation event, the oil and gas blowing out of the well ignited, causing the platform to catch fire. The burning platform collapsed into the wellhead area hindering any immediate attempts to control the blowout. Finally the flow was stopped on March 23, 1979.

4.2 COMPANIES INVOLVED

At the time of the blowout, three companies were participating in the drilling process of the exploratory IXTOX-1 oil well. Sedco a Texas run American company and two Mexican Governmental Agencies Permargo and Petroleos Mexicanos (PEMEX). Drilling at this
exploratory well was initiated by PEMEX six months prior to the spill on December 10, 1978. PEMEX was utilizing the Sedco 135F semisubmersible drilling platform for this project (IXTOC-1 Mexico, 1979).

After the blowout the efforts of these companies were not enough to stop the leak that’s why they had to hire experts from the companies all over the world to deal this horrific incident.

4.3-MAJOR CAUSES OF THE IXTOC-1 INCIDENT

The major elements that caused the IXTOC-1 blowout are following,

- Lost circulation event
- Swabbing pressure

4.3.1-Lost Circulation Event

Lost circulation is one of the major drilling problems geologists and drilling engineers are struggling with. It is equally dangerous in oil or gas wells. The IXTOC-1 blowout was happened after a mud loss circulation event. Lost circulation events are normally caused when hydrostatic pressure of mud exceeds the breaking strength of the formation. During lost circulation event a complete or partial flow of mud is lost into the formation instead of coming back to the surface. That particular zone where mud is being lost sometimes referred as a “thief zone”. Lost circulation events normally happen where formations are inherently fractured or have high permeability. Excessive down-hole pressure is another contributing cause of the lost circulation (David, 1996). Figure 4.1 explains the concept of partial and complete lost circulation during a drilling process.
Different additives can be added in drilling mud to reduce or eliminate mud loss by sealing porous subterranean formations. A method and composition for controlling the lost circulation event in a wellbore during drilling process is sending a pelletized combination of water-insoluble, water-absorbent polymer and bentonite to the lost circulation site. After sending this mixture into the wellbore these pellets maintain their original size until they hit the area where mud is being lost. At the site of the lost circulation these pellets accumulate, absorb water and swell to form an essentially fluid-tight plug. The porous subterranean formation thus is sealed and further loss of drilling mud is prevented (William, 1989).

4.3.2-Swabbing Pressure

Swab and surge pressure are notorious to cause formation fracture, lost circulation and well control problems. Accurate prediction of these pressures is very important in estimating the maximum tripping speeds to keep the wellbore pressure within limits of the pore and fracture pressures (Freddy, 2012). Swabbing pressure was one of the contributors in the IXTOC-1 blowout. During tripping out process the drill string is picked up to make a connection or to do some remedial work in the wellbore. The mud in the annulus must fall to replace the volume of
the drill string removed because there is a decrease in the bottom-hole hydrostatic pressure because of the upward movement of the pipe in the well. It can be dangerous if the hydrostatic pressure suddenly falls below a certain limit that can produce kick. This phenomenon of falling down the hydrostatic pressure momentarily is called swabbing (Timothy, 2010). The following figure explains the concept of the swabbing and surging in a formation.

Fig 4.2-Swab and Surge Pressure in Formations (Oil and Gas Drilling Updates, 2013)

When the drill string or casing is lowered or run into the well, mud is displaced from the well and due to the frictional pressure losses from the flow of mud in the annulus there is a sudden increase of pressure in the annulus area, this sudden increase in pressure is called Surging. It can be dangerous if the pressure has increased enough to fracture the formation (Timothy, 2010).

4.4-IXTOC-1 ACCIDENT ANALYSIS

One day before the blowout on June 2, 1979 the Sedco 135F was drilling at a total depth of 11800 feet below the seafloor. The drill bit hit a soft formation zone and all of a sudden rate of penetration of the drill bit increased while the mud pumps were pumping mud at the same rate, this phenomenon in drilling is known as drilling break. The increased drilling rate caused a fracture in the formation and resulted in complete loss of mud in the formation. PEMEX official decided to stop further drilling for that day. Both PEMEX and Sedco officials were arguing about
the best possible solution, meanwhile oil started to build up in the wellbore. Finally both companies agreed to remove the drill bit from the wellbore, run the drill pipe back into the hole and pump lost circulation material down this open ended drill pipe in an effort to seal off the fractures that were causing the loss of circulation. Pressure in the wellbore kept increasing while they were preparing to perform remedial actions to plug lost circulations sites in wellbore (IXTOC-1 Mexico, 1979).

The next morning on June 3, 1979 they started to pull out the drill string, in drilling terminology this process is known as tripping out. Since hydrocarbons were already entering into the formation and pulling out the drill pipe caused a sudden decrease in the hydrostatic pressure, which allowed more hydrocarbons to enter into the wellbore from the formation. By removing the drill string the well was swabbed leading to a kick. The hydrocarbons coming out from the formation had a very high pressure which pushed drilling mud to move upward towards the surface (Mayer, 1984).

In this situation the Sedco and PEMEX crew tried to activate the blowout preventer (BOP) system to seal the well by activating shear rams contained in the blowout preventer. These rams were designed to sever and seal off the well on the ocean floor. But unfortunately in this case drill collars came across the BOP rams which prevented rams to perform their intended function because BOP rams were not designed to cut through these thicker diameter drill collars. Finally the drilling mud which was followed by a high flow of hydrocarbons hit the rig floor at 3:30am on June 3, 1979 and caused a big blowout (Mayer, 1984).

![IXTOC-1 Blowout](IXTOC-1., 1979)
The fire and explosion led to the collapse of Sedco 135F drilling tower. The collapse caused damage to the underlying well structures. The damage to the well structures led to the release of significant quantities of oil into the Gulf.

4.5-RESPONSE TO THE SPILL

PEMEX had to hire blowout control experts from all over the world to bring the spill under control. The attempts were being made to activate the BOP system by sending ROV and sea divers but nothing was working because of the poor visibility and debris on the seafloor including derrick wreckage and 3000 meters of drill pipe. Divers were eventually able to reach and activate the BOP system but high pressure of the oil and gas coming out of the well caused rupturing. They had to reopen the BOP system to avoid complete destruction (Cutler, 2010).

In the initial stages of the spill almost 30,000 barrels of oil per day was flowing from the well into the Gulf of Mexico. The frustration level of the Governments and the companies involved was increasing with every passing day. In July 1979 they pumped a high density mud into the well and the flow was reduced to almost 20,000 barrels per day. In early August 1979 PEMEX and its partners pumped thousands of steel, iron and lead balls into the well. This technique did work and the flow was reduced to 10,000 barrels per day. Finally when the flow from the well was reduced enough by the end of February 1980, PEMEX and the Mexican authorities drilled two relief wells into the main well to lower the pressure of the oil and gas. The New York time reported on March 5, 1980 that the flow rate was negligible and capping operations were nearly completed (Mayer, 1984).

Finally when the flow from the IXTOC-1 well was stopped on 23 March 1979 almost nine and half months later about 3.5 million barrels of oil was released into the Gulf of Mexico. The IXTOC-1 spill was the 2nd largest spill in the history of oil and gas industry after Deepwater Horizon 2010 spill.
4.6-ENVIROMENTAL DAMAGE

The environmental damage caused by IXTOC-1 blowout and spill was huge because almost 3.5 million barrels of oil was entered into the marine ecosystem of the Gulf of Mexico. It was one of the largest oil spills in the history. Beaches mostly in the Mexico but to some extent in the United States were badly hit and birds succumbed in large numbers. Initially populations of fish either died off or moved on to different areas (IXTOC-1 Mexico, 1979). The following figure shows the fatal impact of oil contamination on various species.

Crabs and other beach infauna were reduced significantly, as well as causing the near extinction of the female population of kemp’s Ridely sea turtle species and tumors infesting the surveyed shrimps and fish in the Mexican coastal waters the spill. Severe drop in the marine populations and heavy oil layer on the Gulf waters showed little hope for recovery from the potential decades of catastrophic effects. Also when scientists came to survey the Gulf and assessed the damage to the ecosystems and environment, it was believed that everything hit by the oil would die and crucial parts of the marine food chain, as well as populations of organisms dependent on for the anthropogenic needs would be destroyed. However due to relatively short period of heavy oiling as well as help from the environmental conditions and deployed clean–up efforts damage to marine wildlife from IXTOC 1 was lighter than was expected (Mayer, 1984).

4.7-ECONOMIC DAMAGE

As the Gulf of Mexico have a very warm climate which attracts people from all over the world to its coastline. Recreational activities such as water sports, swimming and snorkeling in the reefs give an incentive to visit and vacation in such a warm location along the Gulf, which supports a 20 billion tourists industry. Various local communities depend upon the diverse marine life (Cutler, 2010).

When the IXTOC-1 disaster occurred and oil leaked out for months was spread along the area of the Gulf of Mexico, leaving tourism and local economics severely affected. Oil and tar covered stretches of sandy beaches and coral reefs, such environmental conditions kept tourists away from this beautiful place   In addition to a significant drop in tourists’ income, the local
communities also suffered from reduction of their major marine food sources and thus a further loss of income. Officials reported that tourism along the Texas beaches dropped by 65% during the course of the spill (Mayer, 1984).

The estimated cost of the IXTOC-1 oil spill to the industry and government made it as one of the most expensive spill in the history. The oil it released spread across Mexican and Texan coastlines. As beaches, beautiful animals and birds were covered in thick tar and oil. Contamination of food supplies forced many birds to leave their habitats for the duration of the spill.

At the same time the local people were having economic breakdown because of the reduction in the big tourist industry. However due to good weather conditions and with the industry and government efforts the climate bounced back quickly and the effects of the spill were not as disastrous as they were expected. The commercial fishing industry showed economic reduction during the first few months but recovered eventually to the normal.

4.8-RECOVERY FROM THE SPILL

As the oil and tar covered most of the Mexican beaches, some oil on the beaches was bulldozed under but long stretches of beach in the Gulf of Mexico were left alone where the oil soon weathered to tar and then to asphalt (IXTOC-1 Mexico, 1979).

As the oil hit the Texas shoreline as well in August 1979, but fortunately a tropical storm added a lot to reduce the damage. It was reported that tropical storm removed 80 percent of the oil that was on the shore of Texas (IXTOC-1 Mexico 1979). Also on August 8, the United States fish and wild life service began training volunteers for the handling of oiled birds. One thousand four hundred twenty one birds were recovered with oiled feathers or feet (Cutler, 2010).

The environment recovered from the spill, nature fought the oil with waves and petroleum eating bacteria. Most of the problems caused by IXTOC-1 spill were gone very quickly and most of the offshore populations came back to the normal. Within five years the effects of this huge spill were undetectable on the environment.
4.9-CRITICAL ANALYSIS of the IXTOC-1 Blowout

- Human error factor (misjudgement and a lack of skill) in this horrific blowout is not a too big contributor. The workers followed emergency control procedure as they were trained by the respective companies.

- Once the workers found out that mud was being lost in the formation, they should have acted right away and should have shut-in the well. Instead they were arguing to have an agreement to come up with the possible solutions to plug the lost circulation zone. They delayed a little bit before they started their defense mechanism which allowed hydrocarbons to build up pressure and they travelled quite a distance upward towards the wellhead.

- As after the lost circulation event they were taking entire drill string out of the wellbore to remove the drill bit from the drill string. This was a very risky decision especially in that formation where fracture point was already very lower. The decrease in the hydrostatic pressure was sure but they did not take any precautionary measure to overcome this problem before they started the tripping out process. The decrease in the hydrostatic pressure allowed hydrocarbons to enter into the wellbore causing kick which lead to a big blowout afterwards. They should have been prepared and should have sent mud into the wellbore equal to the volume of the solid drill string which was being removed.

- The position of the tool joints in the blowout preventer area is another big contributor to this horrific blowout. The tool joints have relatively thicker diameters than drill strings and shear rams are not designed to cut through thicker diameter tool joints. In IXTOC-1 blowout tool joint came across the shear ram which prevented the shear ram to seal the well. The rig crew must make sure the positions of the tool joints during drilling process because they can cause a big trouble if they are not at the right spot.

- The decisions of pumping higher density mud, steel, iron and lead balls into the wellbore to reduce the flow rate were the right decisions because they brought the flow rate down from 30,000 barrels to 10,000 barrels per day which was a big relief. Also the idea of drilling two relief wells was a wise decision too because it brought the flow rate under a negligible amount.
• The companies should not have taken the decision to remove the entire drill string out of the hole instead they should have tried to plug the lost circulation zone, leaving the drill string and drill bit into the wellbore. They could have sent lost circulation material in the wellbore to generate a little bit well integrity first. Once a little bit well integrity would have been established then they could have taken the drill string out of the hole carefully.

• The response to the spill was impressive and fast, weather condition in the Gulf helped a lot to get rid of the oil, higher temperature added in the evaporation process. In Texas the tropical storm proved to be a saviour because it removed 80% of the oil layer from the water.

• Oil and gas leading companies and the governments should get together and should come up with a combined comprehensive plan explaining how to fight with potential oil and gas spills in future to bring damage to the minimum level.
CHAPTER NO 5

CONCLUSIONS AND RECOMMENDATIONS

Well control is a very sensitive and a systematic process. It is a team work and it requires a complete dedication to the job from each member of the team. Most of the blowouts are caused by either human error or equipment failure. Human errors are mostly because of the carelessness, unawareness and miscommunication between the workers. Equipment failure can also be a part of human unawareness. If the goal is a safe and successful drilling process then every single detail should be considered and should be given enough attention from the management. A complete coordination between the workers is mandatory and a comprehensive and reliable communication system is an essential part of drilling process.

5.1-CONCLUSIONS

At the completion of this study I came up with the following few important points which can be improved to make sure a safe drilling process.

- Human errors and equipment failures are the main causes of the blowouts in an oil and gas well drilling process, as demonstrated in the BP, 2010 and IXTOC-1, 1979 case studies.
- MWD and LWD are very helpful tools in the drilling process because they provide very helpful information about reservoir conditions.
- This study concludes that drilling mud is the primary barrier to stop hydrocarbons from entering into the wellbore so a careful monitoring of the well is very important. It is the foremost duty of the rig crew to make sure that the density of the drilling mud is more than the density of the reservoir fluid.
- This study emphasize that the rig crew should make sure that there are enough barriers in the wellbore to stop hydrocarbons from entering into the wellbore. For example apart from the drilling mud there should be blowout prevention equipment installed at the wellhead to seal the well if kick occurs.
Blowout prevention (BOP) equipment at the wellhead act as a secondary barrier during kick situations by sealing well from the wellhead. A careful monitoring and testing of the BOP equipment before and during drilling process is very important. As demonstrated in the BP case study that Macondo BOP system was not tested and checked for a long period of time.

If possible companies should install two blind shear rams (BSR) in BOP system in case if one fails to seal the well during emergency situation there is another one available as a backup.

A careful check on the tool joint position is very important and the rig crew should make sure that tool joint is not coming across the BSR because BSRs are not designed to cut through a thicker diameter tool joint during emergency kick situations. As mentioned in the BP and IXTOC-1 case study that tool joint positions prevented BOP rams to close.

As mentioned in this study that a safe drilling margin is another important parameter to consider while drilling and companies should never proceed drilling if this margin falls below a certain limit.

According to this study, early recognition of kick is the key factor in well control defensive mechanism. It helps the rig crew to take defensive steps in advance so that the hydrocarbons cannot reach to the surface.

During lost circulation event, drilling process should be stopped and lost circulation sites should be plugged before resuming the drilling process. The decisions how to stop the lost circulation sites should not be delayed as happened in the IXTOC-1 blowout, it allowed hydrocarbons to travel quite a distance up to the wellbore.

Driller’s method and Engineer’s method are widely used in the industry to circulate out the influx of hydrocarbons from the wellbore after a successful well shut-in during kick situations.

According to this study, it is the foremost duty of the management to make sure that the rig crew is adequately trained and have enough knowledge and experience of working on a drilling rig. They should be well trained to handle emergency situations properly and calmly. As mentioned in the BP case study that Transocean employees were not adequately trained to handle emergency kick situations.
• Cementing of a well should be done carefully and companies should never move to the
next stage unless the well integrity is established. Once cementing is done companies
should run well integrity tests to make sure a successful cement job. As BP sent
Schlumberger team home without performing cement integrity tests which proved to be a
wrong decision.
• Cement slurry design should be according to the wellbore conditions and its stability and
integrity should be tested before sending it into the wellbore. As BP did not want to wait
for the cement slurry integrity results instead they rushed to cement the Macondo Well.
As a result they ended up with a very poor cement job.
• After completion of a cement job the positive and negative pressure tests to establish the
well integrity should be done and read very carefully. Misinterpretation of their results
can lead to a blowout as happened at the BP Macondo well.
• There should never be a lack of real leadership at the rig because drilling a well is a team
work and a team cannot succeed without a great captain.

5.2-RECCOMENDATIONS

• The oil and gas companies across the globe should never make any compromise on the
safety of the workers and environment during oil and gas exploration process.
• A lot more research is required to improve the predictive capabilities of drilling
abnormalities.
• A lot more research and investment is required to provide for multiple control systems to
detect undesired events and to deploy last-resort BOP system.
• There should never be a last minute change in plan regarding to any aspect of oil and gas
well exploration process.
• It is very common in the oil and gas industry to focus on increasing efficiency to save
time and a little money. But management decisions and processes should make sure that
measures taken to save time and money are not affecting the safety of the workers and
environment
• The companies and the governments should use the best available and safest drilling technology to monitor and evaluate well conditions and to minimize potential for a kick.

• Mud level in the pit should be monitored hourly. The sensors in the mud pit will give readings every second. These readings should be monitored carefully for any sudden increase in mud pit level.

• As soon as rig crew recognizes kick, they should shut-in the well right away without any unnecessary delay so that hydrocarbons cannot make it to the surface.

• All the equipment should be regularly checked for damages and corrosion. If any damage is found they should be replaced.

• The choke and BOP equipment should always be designed with the consideration of subsurface pressure and according to API standards. All the companies that design choke should follow API specifications because it is very helpful for the engineers working in the field.

• A special attention should be given to the BOP equipment testing before and during drilling process. If possible companies should install two BSR in BOP equipment just to stay on the safer side.

• Well integrity tests should be performed carefully and their results should be read carefully as well.

• There should always be a backup plan ready in case if rig lost power, like another hydraulic pump of almost equal capabilities as the main pump to provide power to the entire rig.

• The response to an oil spill should be immediate and fast and there should be a complete collaboration between the governments and the companies to deal with such a disaster. Also planning is required to deal with the potential oil spills in timely and professional manner.
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