



University of
Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Master of Science in Petroleum Technology, Drilling Specialization	Spring semester, 2015 Open access
Writer: Trine Lillenes Midtun (Writer's signature)
Faculty supervisor: Dan Sui External supervisor(s): Svein Hovland, NOV	
Thesis title: Rig Integrated Managed Pressure Drilling	
Credits (ECTS): 30	
Key words: Managed Pressure Drilling (MPD) Management Drilling Control System (DCS) Standards Organization Constant Bottom Hole Pressure (CBHP)	Pages: 97 Stavanger, 5 th of June, 2015 Date/year

ABSTRACT

The complexity and challenges related to drilling of wells shows an increasing trend, and there is a demand for new technology and/or methods. Managed pressure drilling (MPD) is gaining more and more attention on the market, giving the possibility to drill the operationally challenged, to drill the economically challenged and to drill the un-drillable.

The principles of the MPD technique are not new, but further development of equipment and methods makes it a better choice compared to conventional drilling. Narrow pressure window is an increasing challenge on the North Continental Shelf (NCS), as result of both geological and induced (i.e. drilling and injection) factors.

Still, several challenges must be managed in order to drill the wells with respect to Health, Safety and Environment (HSE), and cost effectiveness.

The report is based on the constant bottom hole pressure (CBHP) technique, considering a fixed installation on the NCS.

The main objective of this Thesis is to improve the execution of MPD, by enhancing the working process and organizational aspects. Effectiveness and performance is not only result of the technique applied, the method is at least of equally importance. The key to success is to connect the three elements in a proper way.

Through research from previous operations, interviews with rig personnel and cooperation with NOV, the proposed step to fully integrate MPD include

1. MPD equipment permanently installed on the installation
2. Advanced control system integrated into drilling control system
3. Drilling contractor performing the MPD operation

Rig integrated MPD will lead to an increased HSE level, continuous performance and a reduced overall cost.

ACKNOWLEDGEMENT

Firstly, I want to thank my dad for encouraging me into the petroleum industry, and the rest of my family for being supportive during the entire education. The thanks also apply for my fellow students, and friends, which have contributed to an exciting journey.

I would like to thank Archer for including me in the company, and giving me the possibility to work in the oil industry, providing me both offshore – and onshore experience.

A special thanks to Svein Hovland, my supervisor at NOV, for a wider understanding of the MPD technique, and helpful assistance through the last year.

And last but not least, I would like to thank my supervisor at the University of Stavanger, Dan Sui, for reviewing and giving me constructive feedback on my Thesis.

Trine Lillenes Midtun, 05.06.15

TABLE OF CONTENTS

Abstract.....	I
Acknowledgement	II
List of Figures	V
List of Tables	VI
List of Abbreviations	VII
1 Introduction	1
2 Background	3
2.1 Drilling Window.....	3
2.2 Regulations and Standards.....	8
2.3 Conventional Drilling.....	10
2.4 Managed Pressure Drilling.....	10
2.5 Drilling Hazards [1].....	13
2.6 Why MPD?.....	16
2.7 Challenges Of MPD.....	19
3 Drilling System and Equipment.....	22
3.1 Drilling Equipment Structure.....	22
3.2 Hoisting and Rotary System	25
3.3 Power System.....	26
3.4 Drill String.....	26
3.5 Pipe Handling Equipment.....	27
3.6 Well Control System.....	29
3.7 Circulation System.....	45
3.8 Maintenance and Testing Of Equipment	51

4	Well Barriers and Well Control	53
4.1	Well Barriers.....	53
4.2	Well Control	56
4.3	Discussion.....	59
5	Drilling Operation and Personnel	61
5.1	Offshore Personnel	61
5.2	Training of Drilling Crew Personnel.....	64
5.3	Management System	65
5.4	Operational Sequence.....	68
6	Case study: Gullfaks C	76
6.1	Gullfaks Field [31].....	76
6.2	Summary Of Well C-06 A [32] [33].....	77
6.3	Drilling Of Well C-06 A [33]	77
6.4	Comments	81
7	Interviews with Personnel	82
7.1	MPD in the future.....	83
8	Rig Integrated MPD.....	85
8.1	Platform Design/Construction	86
8.2	Integrated Control System	88
8.3	Drilling Contract	89
8.4	Other Considerations	90
9	Conclusion.....	92
	References	93

LIST OF FIGURES

Figure 1-1 Process, Technique and Organization	2
Figure 2-1 Drilling Window [2]	3
Figure 2-2 Illustration of Large versus Narrow Drilling Window	4
Figure 2-3 UBD, MPD and Conventional Drilling [9]	12
Figure 2-4 Drilling Hazards [2]	13
Figure 2-5 Illustration of ECD exceeding Formation Fracture Gradient	16
Figure 2-6 Illustration of Pressure Variations caused by the Rig Pump	17
Figure 2-7 Pressure Uncertainty (Courtesy of NOV)	19
Figure 3-1 Illustration of Drilling Equipment Structure [13]	23
Figure 3-2 Illustration of Hoisting System [13]	25
Figure 3-3 Simple Illustration of Pipe Handling	28
Figure 3-4 BX Elevator, NOV [15]	28
Figure 3-5 Iron Roughneck, NOV [16]	29
Figure 3-6 Simple Illustration of the BOP-stack	30
Figure 3-7 Simple Illustration of the BOP-stack for MPD Operations	31
Figure 3-8 Installation and Operation of the PCD (Courtesy of Siem WIS) [17]	32
Figure 3-9 Seal Cartridge (Courtesy of Siem WIS) [17]	33
Figure 3-10 MPD choke manifold, NOV [18]	36
Figure 3-11 Mud Gas Separator, NOV [19]	38
Figure 3-12 Cyberbase operator station [20]	40
Figure 3-13 Simple Illustration of DCS Display	41
Figure 3-14 Illustration Of MPD Control System	42
Figure 3-15 Illustration Of MPD Workflow	43
Figure 3-16 Illustration of Choke and Pump Interaction	44
Figure 3-17 Simple Illustration of Open Circulation system [4]	46
Figure 3-18 Open Circulation System [13]	47
Figure 3-19 Simple Illustration of Closed Circulation System [4]	47
Figure 3-20 Generic MPD Rig-Up (Courtesy of NOV)	48

Figure 3-21 Back Pressure Pump, NOV [23].....	50
Figure 5-1 Simple Illustration Of Risk Matrix	66
Figure 5-2 Illustration of BHP During Connections	71
Figure 5-3 Illustration of BHP lower than Formation Pore Pressure	72
Figure 5-4 Illustration of CBHP during connection	73
Figure 5-5 Illustration of LOT [1].....	74
Figure 6-1 Gullfaks C [31]	76
Figure 8-1 Rig Integrated MPD.....	85
Figure 8-2 Balanced Process, Technique and Organization.....	91

LIST OF TABLES

Table 2-1 Hydrostatic Pressure	6
Table 2-2 Equivalent Circulating Density (ECD)	7
Table 3-1 Pressure Testing [6, p. 220]	52
Table 4-1 Well Barriers for Conventional Drilling [7, p. 48].....	54
Table 4-2 Well Barriers for MPD [7, p. 145].....	55
Table 4-3 Flow Check Procedure	58
Table 5-1 Annular Clearance.....	68
Table 5-2 Operational Sequence for Making Connections.....	70
Table 5-3 Operational Sequence for Making Connections (pressure terms)	71

LIST OF ABBREVIATIONS

AFP – Annulus Friction Pressure

BHA – Bottom Hole Assembly

BHP – Bottom Hole Pressure

BOP – Blow Out Preventer

BP – Back Pressure

BPP – Back Pressure Pump

CBHP – Constant Bottom Hole Pressure

CRI – Cutting Re-Injection

DCDA – Drilling Control and Data Acquisition

DCS – Drilling Control System

DES – Drilling Equipment Structure

DG – Dual Gradient

DP – Drill Pipe

ECD – Equivalent Circulating Density

EMW – Equivalent Mud Weight

FBP – Formation Breakdown Pressure

FIT – Formation Integrity Test

HC – Hydrocarbon

HMI – Human-Machine Interface

HPHT – High Pressure High Temperature

HSE – Health, Safety and Environment

HTV – Horizontal to Vertical

IADC – International Association of Drilling Contractors

IR – Iron Roughneck

IWCF – International Well Control Forum

LCM – Lost Circulating Material

LOT – Leak Off Test

MODU – Mobile Offshore Drilling Units

MPD – Managed Pressure Drilling

MPO – Managed Pressure Operation

MWD – Measurement While Drilling

NCS – Norwegian Continental Shelf

NOV – National Oilwell Varco

NPT – Non Productive Time

NRV – Non-return valve

P&A – Plug & Abandonment

PCD – Pressure Control Device

PM – Preventive Maintenance

PMCD – Pressurized Mud-Cap Drilling

SG – Specific Gravity

POOH – Pull Out Of Hole

TD – Target Depth

PRV – Pressure Relief Valve

UBO – Underbalanced Drilling Operation

PSA – Petroleum Safety Authority

UPS – Uninterruptible Power Supply

PWD – Pressure While Drilling

WB – Well Barrier

RCD – Rotating Control Device

WBE – Well Barrier Element

RIH – Run In Hole

WDP – Well Design Pressure

ROP – Rate of Penetration

WH – Wellhead

RPD – Rig Pump Diverter

WOB – Weight on Bit

RPM – Rotation per Minute

WOW – Wait On Weather

SDP – Section Design Pressure

WP – Working Pressure

1 INTRODUCTION

Since the first discovery of oil in the Norwegian Continental Shelf (NCS), the oil industry has been an adventure for the Norwegian country. Hundreds of wells have been successfully drilled and completed, with an enormous profit. Norway has been a leading part on the market.

After the top period, during the 1980s and 1990s, the challenges started to arise. The result of drilling all these wells, is depleted – and damaged formations. The reservoirs are nearly drained (from the viewpoint of the current technologies), more considerations are required in the planning of the wells, and the drilling operations are more complex. In addition, cost is a major factor. During the past years, several wells have been drilled, turning out to be more costly than profitable. For achieving an economically profit today, new technology is required.

Production and injection has led to changes in the formation pressures, and seismic – and logging execution – and interpretation is required ahead of the drilling operation, in order to know which pressure and other formation parameters that applies. The operational drilling window is narrower, as result of the pressure changes.

“Managed pressure drilling (MPD), as a discipline or drilling technique, is the result of the high costs of non-productive time (NPT) caused by the close proximity between pore pressure and fracture pressure”. [1, p. 1]

MPD has been applied on several fields during the past years, including Gullfaks and Kvitebjørn. Experience indicates, however, that the technique is far from optimal.

The main objective of this Thesis is to improve the execution of MPD, by enhancing the working process and organizational aspects. Effectiveness and performance is not only result of the technique applied, the method is at least of equally importance. The key to success is to connect the three elements in a proper way.

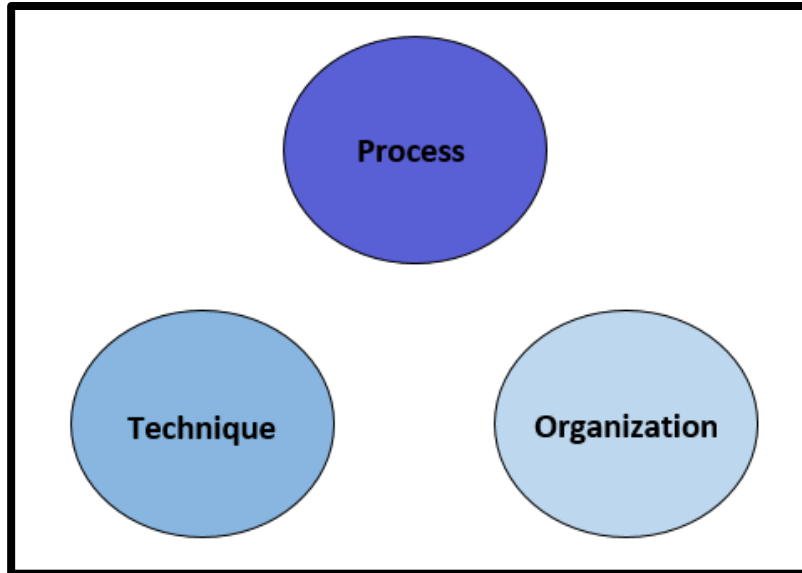


FIGURE 1-1 PROCESS, TECHNIQUE AND ORGANIZATION

To understand the MPD technique, knowledge about the various pressures defining the operational window, and well bore pressures is essential. The various methods of MPD and underbalanced drilling (UBD) are included, in order to avoid confusion and repetition, and clarify which aspects are valid for this Thesis.

The regulations and standards are used as a red line throughout the Thesis, as it is important to always have in mind what requirements apply for the different equipment and operations.

The drilling structure is included for providing a visual understanding of the platform, as well as basic elements regarding the drill string and pipe handling sequence.

Control – and circulation systems play a major role during drilling operations, and is included for both conventional drilling, and the additional equipment and system introduced by MPD.

Well control and drilling operational sequence is included for highlighting the differences, and present why MPD should be chosen in the first place.

A case study about Gullfaks is included, with the purpose of giving a realistic view of the operation. Operational details will not be included in the Thesis, as the main objective is to highlight what elements could be improved. At last, interviews with relevant rig personnel are included, ahead of approaching to Rig Integrated MPD.

2 BACKGROUND

Considering conventional drilling and managed pressure drilling, several common terms applies. This chapter covers the basic concepts of various pressure and drilling window, a short introduction about conventional drilling operation, and the MPD concept. Benefits and challenges related to MPD are presented, and should be kept in mind throughout the Thesis. Further description of equipment and systems are covered in chapter 3.

2.1 DRILLING WINDOW

Drilling window, also known as operational window or drilling margin, defines the operational pressure boundaries during drilling operations. Prediction and estimation of pressures, and the related drilling window, is critical during the entire life cycle of the well.

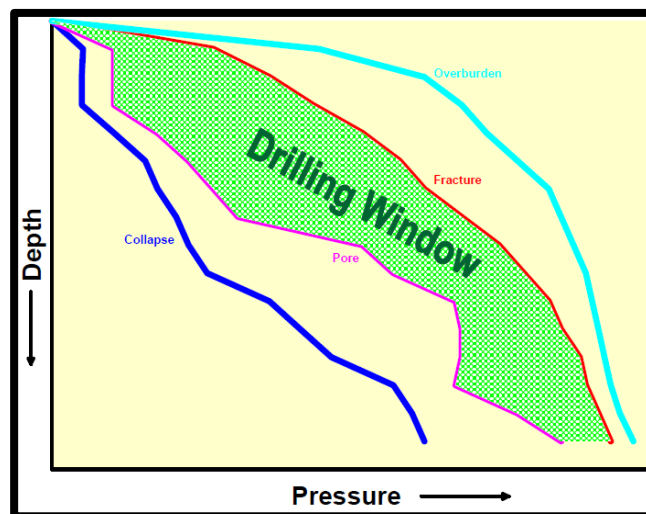


FIGURE 2-1 DRILLING WINDOW [2]

Pressure, P , is commonly defined as the amount of force exerted on a unit area.

In the oil industry, one primarily focuses on fluid pressure, and what pressure the fluid exerts under various conditions, such as down hole pressure – and temperature variations.

The metric unit for pressure is Bar or Pascal [Pa], or pressure per unit depth [Pa/m] when expressed as pressure gradient. The latter one expresses change of pressure with depth, and is a useful tool when interpreting the direction and rate of pressure.

In addition, one commonly express pressure in terms of fluid density – or mud weight gradient, which is the mass per unit volume of a drilling fluid. The metric unit is kilograms per cubic meter [kg/m^3], or specific gravity [sg]. Specific gravity, also known as relative density, is a dimensionless unit, and is the ratio of the density of any substance to the density of a reference substance, usually water.

There is no standard pressure range presented in terms of drilling window. The window is a result of various parameters, including the pressure, temperature and the formation itself. An undrilled formation usually has a large drilling window, meaning that there is a large pressure range between the lower – and upper limit, if not influenced by geological phenomena, such as faults or depletion.

The challenges arises when changes in the formation has occurred, for example due to drilling of neighboring wells in the same formation/reservoir, depleted formations, high pressure high temperature (HPHT) wells etc. The result is a narrow drilling window, where the pressure range is significantly reduced. Figure 2-2 illustrates the challenges. See Chapter 2.6.1 for more details.

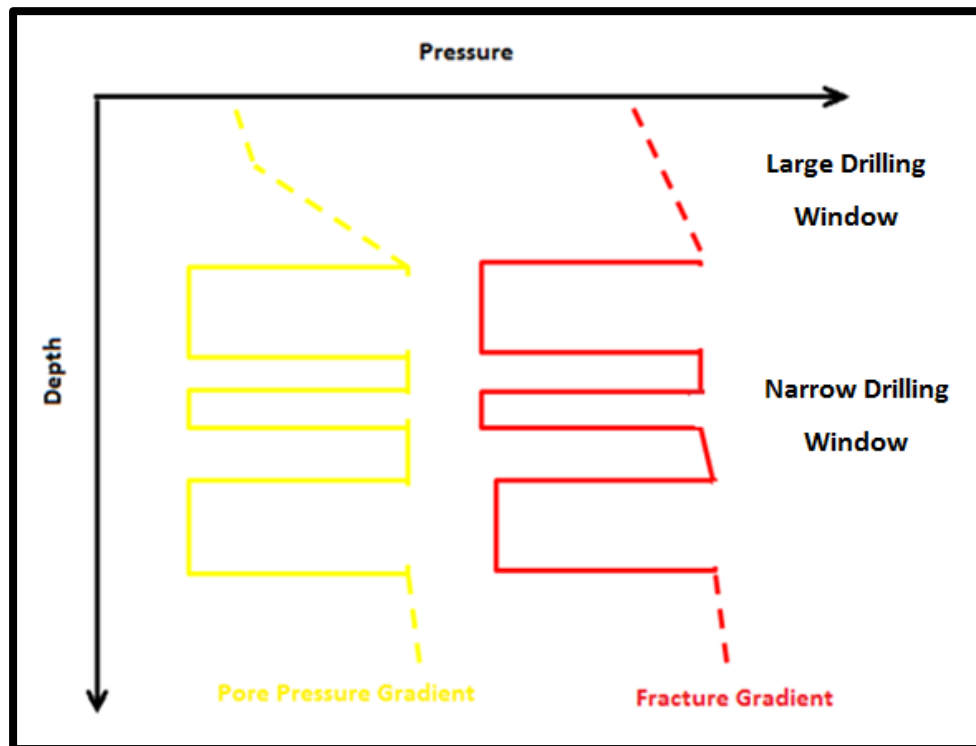


FIGURE 2-2 ILLUSTRATION OF LARGE VERSUS NARROW DRILLING WINDOW

2.1.1 FORMATION PRESSURE

The formation pore pressure and fracture pressure usually represents the lower – and upper operational limit, respectively.

In general, operating below the lower limit may lead to an influx scenario. Operating above the upper limit may lead to fracturing of the formation, and losses of drilling fluid. Either way, the event may develop into a blowout (worst-case scenario).

The formation pore pressure, P_p , is the pressure exerted by the fluids within the pores of a formation. In theory, this pressure is considered as the normal pressure gradient, exerted by the formation water gradient. In reality, the pressure term is not usually seen as a straight line, because of various influences. See abnormal pressure.

The fracture pressure, P_f , is “the amount of pressure a formation can withstand before it fails or splits”. [1, p. 23] In general, the fracture pressure gradient is higher in deep formations compared to shallow offshore fields, because of the impact from the overburden pressure.

There may be certain cases where the well bore stability forms the lower boundary, and/or the overburden pressure defines the upper boundary. Well bore stability is a function of, among others, stress and well direction, and particularly in directional wells, it may exceed the formation pore pressure. The overburden pressure is the pressure exerted by the weight of the overlying rocks and contained fluid.

For this Thesis, lower – and upper limit refers to pore – and fracture pressure, respectively.

2.1.1.1 ABNORMAL FORMATION PRESSURE [1]

Pressures are often hard to predict correctly, as changes in the formation and/or the reservoir contributes to large pressure variations. When the pressures differ from the normal, predicted pressures, one refers to abnormally low – and abnormally high pressures.

- **Abnormally low pressure:** The actual pressure is lower than the normal, expected pressure. This phenomenon is commonly seen in produced or drained reservoir, where the fluids have been drained, leaving a lower pressure.

- **Abnormally high pressure:** The actual pressure is higher than the normal, expected pressure. From a geological point of view, abnormally high pressure may occur because of faults, compaction of sediments, tectonic effect or salt domes. The abnormally high pressure may also be a result of leaks from neighboring wells, such as hydrocarbons and/or gas injection.

2.1.2 WELLBORE PRESSURE

During conventional drilling operations, the basic pressure terms for the operator are the hydrostatic – and annulus frictional pressure, commonly expressed in terms of bottom hole pressure (BHP) or equivalent circulating density (ECD). Including MPD, the back pressure term is introduced.

2.1.2.1 HYDROSTATIC PRESSURE, P_H

The hydrostatic pressure is “the normal, predicted pressure for a given depth, or the pressure exerted per unit area by a column of freshwater from sea level to a given depth.” [3]

In theory, hydrostatic pressure covers both formation fluid and well bore fluid, but related to well control and drilling operations, one refers to the hydrostatic pressure as the force exerted by the drilling fluid in the well bore. The pressure increases with depth, and is easily calculated by the following formula:

$$P_H = MW \cdot TVD \cdot 0,00981 \quad [2.1.1]$$

TABLE 2-1 HYDROSTATIC PRESSURE

Term	Parameter	Unit
P_H	Hydrostatic pressure	Bar
MW	Mud weight / Drilling fluid density	Specific Gravity (SG)
TVD	True Vertical Depth or height of fluid/ gas	Meters (m)
0.00981	Gravity constant	SI units

Seen from the formula, one can only manipulate the hydrostatic pressure by altering the weight of the drilling fluid.

2.1.2.2 ANNULUS FRICTIONAL PRESSURE, P_A

The annulus frictional pressure is a result of the circulating drilling fluid, and depends on well geometries and fluid rheology. In addition, the fluid – and pipe movement affect it. The pressure term is present during the pumping sequences (for example while drilling), but not when the pumps are stopped (for example when making connections).

2.1.2.3 BOTTOM HOLE PRESSURE, BHP [1] [4]

The bottom hole pressure is the pressure seen at the bottom of the hole, and is the sum of the pressures involved in the process, in other words $BHP = P_H + P_A$. Increasing the hydrostatic pressure (by for example increasing the mud weight) leads to an increase in bottom hole pressure, and vice versa.

The BHP is also referred to as the Equivalent Circulating Density (ECD), Equivalent Mud Weight (EMW) or Mud Weight Equivalent. The ECD expresses the effective density that is exerted by a circulating fluid against the formation and that accounts for the annulus pressure drop above the point being considered. It can easily be calculated by the following formula:

$$ECD = MW + \frac{P_A}{TVD \cdot 0,0981} \quad [2.1.2]$$

TABLE 2-2 EQUIVALENT CIRCULATING DENSITY (ECD)

Term	Parameter	Unit
ECD	Equivalent Circulating Density	Specific Gravity (SG)
P_A	Annulus Frictional Pressure	Bar
MW	Mud weight / Drilling fluid density	Specific Gravity (SG)
TVD	True Vertical Depth	Meters (m)
0.00981	Gravity constant	SI units

The ECD is important for avoiding kick and losses, particularly in wells with narrow drilling window.

2.1.2.4 BACK PRESSURE, P_{BP} [4]

The back pressure is the surface or applied (back) pressure component, responding to a pressure source on the annular side. All MPD automated drilling systems uses this back pressure to control the BHP.

2.2 REGULATIONS AND STANDARDS

The regulations comprise the framework for all petroleum activities. All operations must be performed in compliance with these, from the planning phase to the closure of the well.

Petroleum Safety Authority (PSA) is “an independent government regulator with responsibility for safety, emergency preparedness and the working environment in the Norwegian petroleum industry.” [5] PSA provides an overview and access to the various regulations, acts, standards, guidelines and interpretation. These documents are available for everybody on their website. Some of the regulations accounting for the Norwegian Continental Shelf (NCS) are referred to during the thesis, including the following HSE regulations and NORSOK standards.

2.2.1 HSE REGULATIONS

Health, safety and the environment (HSE) regulation consist of five sets of regulations:

- The framework regulations
- The management regulations
- The activity regulations
- The facilities regulations
- The technical and operational regulations

For Norway’s offshore petroleum sector, the framework -, management -, activity -, and facilities regulations applies. The technical and operational regulations apply to land-based facilities, and are not included in this Thesis.

These regulations cover different aspects about HSE, consisting largely of risk – and performance-based requirements. The regulations define the requirements the offshore personnel are imposed to follow.

2.2.2 STANDARDS

The purposes of the standards are to fulfil the functional requirements in the regulations. Several standards exist, both national – and international.

NORSOK standards accounts for the NCS, and have been developed as, among other, a supplement to the international standards. Particularly NORSOK D-001 and NORSOK D-010 are central during this thesis.

2.2.2.1 NORSOK D-001 [6]

NORSOK D-001 “Drilling facilities” (Rev.3, December 2012) “describes the functional requirements, design outline, installation and testing requirements for the drilling facilities and their systems and equipment on fixed installations and mobile offshore drilling units (MODUs).” [6, p. 6]

The standard is important during the planning phase of an installation, as well as for existing installations, to ensure that the platform complies with the requirements, in means of design and equipment.

2.2.2.2 NORSOK D-010 [7]

NORSOK D-010 “Well integrity in drilling and well operations” (Rev.4, June 2013) “focuses on well integrity by defining the minimum functional and performance requirements and guidelines for well design, planning and execution of well activities and operations.” [7, p. 7]

Chapter 4, “General principles”, accounts for all operations (drilling, pumping, completion, etc.) and include well barriers, well design and risk assessment, among others.

Chapters 5-14 consist of requirements accounting for the specific operation, e.g. drilling activities, completion activities, etc. Additional requirements yielding for MPD, is covered in Chapter 13, “Under balanced and managed pressure drilling and completion activities”.

Chapter 15, “Well barrier elements acceptance tables”, define the requirements that must be met for the specific equipment or parameter (e.g. fluid column) in order to be valid as a well barrier element.

2.3 CONVENTIONAL DRILLING

The term drilling is generally describing the process of making a hole into the ground, preparing the well for oil – or gas production. Conventional drilling during this Thesis relies on equipment and operations that are common on the NCS today, and experiences related to the normal drilling operation performed in many years. The operation is common knowledge for personnel working in the oil industry; the operator, the contractor and service companies.

For well control purposes, the primary objective is to keep the BHP within the drilling window at all times, defined by the formation pore pressure (P_P) and the fracture pressure (P_F);

$$P_P < \text{BHP} < P_F$$

Where the bottom hole pressure (BHP) is the sum of the hydrostatic pressure (P_H) and annulus frictional pressure (P_A):

$$\text{BHP} = P_H + P_A$$

The hydrostatic pressure must be higher than the formation pressure to avoid influx

$$P_H > P_P$$

Conventional drilling relies on a sufficient drilling window due to ECD, swab, kick margin and uncertainty in pore pressure.

2.4 MANAGED PRESSURE DRILLING

International Association of Drilling Contractors (IADC) defines Managed Pressure Drilling (MPD) as “an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.” [8]

MPD is not one single technique, but a general term with pressure control as the common objective. Basic techniques include (defined by IADC):

- **Constant Bottom Hole Pressure (CBHP):** “Methodology within MPD, Proactive Category; whereby bottomhole pressure is kept constant during connections to compensate the loss of AFP when mud pumps are off.” [8]
- **Pressurized Mud Cap Drilling (PMCD):** “Variation of MPD, drilling with no returns to surface where an annulus fluid column, assisted by surface pressure, is maintained above a formation that is capable of accepting fluid and cuttings. A sacrificial fluid with cuttings is accepted by the loss circulation zone. Useful for cases of severe loss circulation that preclude the use of conventional wellbore construction techniques.” [8]
- **Dual Gradient (DG):** “Two or more pressure gradients within selected well sections to manage the well pressure profile.” [8]

In addition, one distinguishes between reactive – and proactive MPD.

- **Reactive MPD:** “Using MPD methods and/or equipment as a contingency to mitigate drilling problems as they arise.” [8]
- **Proactive MPD:** “Using MPD methods and/or equipment to actively control the pressure profile throughout the exposed wellbore.” [8]

Either way, the equipment and system will be the same.

This Thesis will cover the CBHP concept, the common application for narrow pressure window. “Managed Pressure Drilling”, written by Bill Rehm et al. (2008), has been a useful book for understanding of MPD, and is a central reference related to equipment and system introduced by the MPD technology.

2.4.1 CONSTANT BOTTOM HOLE PRESSURE (CBHP) [1]

Similar to conventional drilling, MPD operates with a wellbore pressure within the pore – and fracture pressure:

$$P_p < BHP < P_f$$

Where the bottom hole pressure (BHP) for MPD operations, is the sum of the hydrostatic pressure (P_H), the annulus frictional pressure (P_A), and in addition, the back pressure (P_{BP}):

$$BHP = P_H + P_A + P_{BP}$$

Unlike conventional drilling, MPD operates with an underbalanced (UB) drilling fluid, meaning that the hydrostatic pressure term is lower than the actual formation pore pressure, providing an opportunity to perform drilling operations even with small pressure range between pore – and fracture pressure.

The BHP is controlled by the use of a rotating control device (RCD), a flow spool and a MPD choke. The back pressure ensures BHP within the drilling window, and avoids influx.

2.4.2 MANAGED PRESSURE DRILLING AND UNDERBALANCED DRILLING

Underbalanced drilling operation will not be included in the Thesis, but a short introduction is given in order to avoid misunderstanding and confusion of the two concepts. Figure 2-3 illustrates the pressure concepts of underbalanced -, managed pressure – and conventional drilling operations.

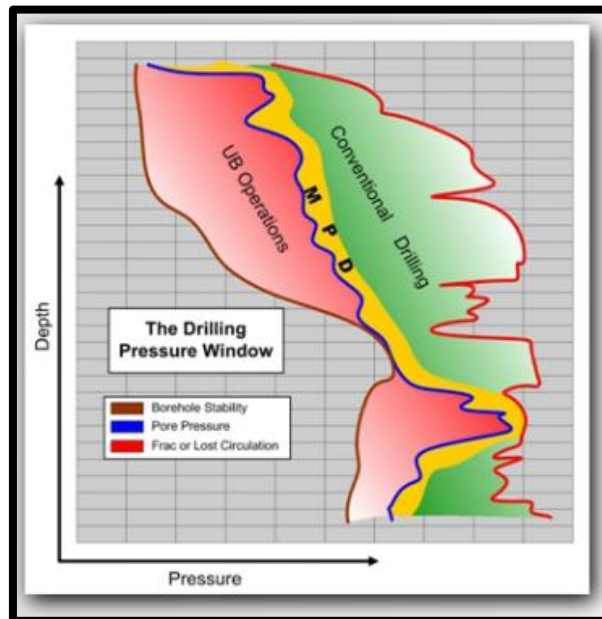


FIGURE 2-3 UBD, MPD AND CONVENTIONAL DRILLING [9]

IADC defines underbalanced drilling (UBD) as “a drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.” [8]

Manipulation of annular pressure is a central element in both MPD and UBD, and some of the equipment used is common for the two operations. What one must be aware of, however, is that UBD plan for producing formation fluid while drilling. MPD uses underbalanced drilling fluid, but do not plan for influx, as the BHP is kept constant above the formation pore pressure.

2.5 DRILLING HAZARDS [1]

Drilling hazards includes various scenarios where control of the well is lost. The term blow out was mentioned, and is the worst-case scenario. Drilling hazards exposes the personnel for danger, and many lives has been lost in the oil industry as a result. In addition, drilling hazards is a large contributor to non-productive time (NPT), in terms of cost and economy.

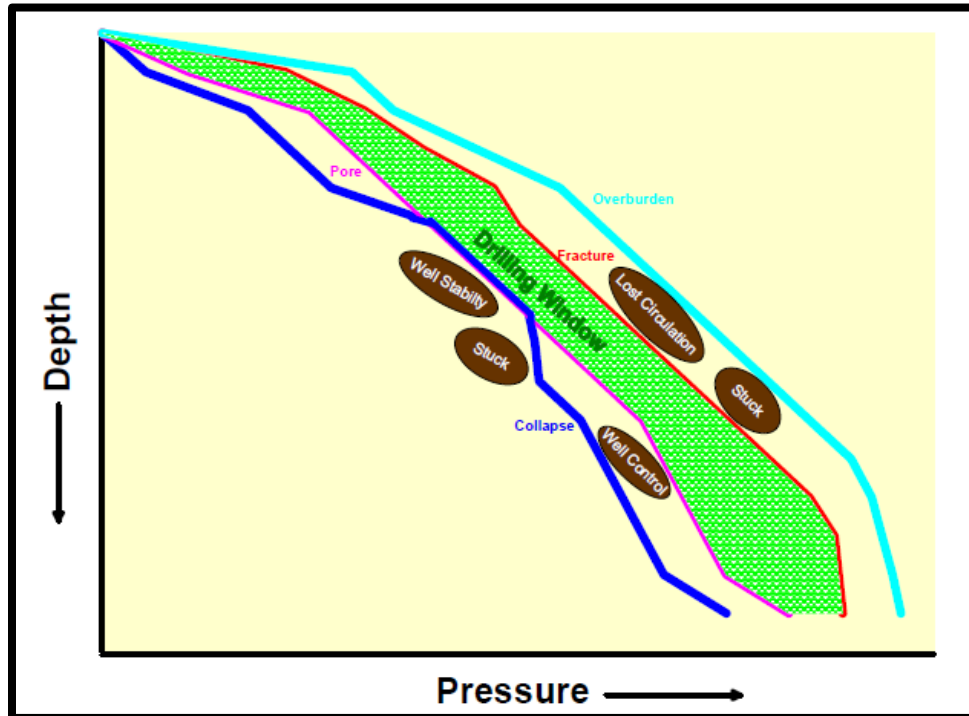


FIGURE 2-4 DRILLING HAZARDS [2]

2.5.1 LOST CIRCULATION

Lost circulation can occur in naturally fractured or unconsolidated formations, or when the hydrostatic fluid column pressure and ECD exceeds the formation fracture gradient; $BHP > P_F$. The latter one is a result of drilling with too high drilling fluid density. The result is loss of drilling fluid, as it flows into the formation.

2.5.2 STUCK PIPE

Stuck pipe can be classified as either differential sticking or mechanical sticking. Differential sticking is caused by a differential pressure between the wellbore and a permeable zone, and is a major cost issue during conventional drilling. It is a time consuming process, and can in worst case contribute to a kick scenario. Mechanical sticking is a result of geological factors, including wellbore collapse, hole pack-off and shale.

2.5.3 WELLBORE INSTABILITY

Wellbore instability is a complex phenomenon, as it is a function of stresses in the formation (magnitude and direction) and formation characters (pore pressure and permeability), as well as parameters controlled by the driller (ROP, pump rate and rotary speed). "It occurs when the hydrostatic pressure of the mud column is insufficient to maintain wellbore wall competency."
[2]

2.5.4 SURGE AND SWAB [10]

Movement of the drill string generates pressure variations, called surge and swab.

- **Surge:** When running the drill string into the hole, the well bore fluid is displaced, leading to an increase in bottom hole pressure.
- **Swab:** When pulling the string out of the hole, so-called negative pressure is generated, leading to a decrease in bottom hole pressure.

The reduction – or increase in bottom hole pressure, exposes the well bore to well control situations, particularly when operating with narrow drilling window.

2.5.5 WELL CONTROL INCIDENTS [10]

Well control incident is the scenario where formation fluid flows into the well, also known as a well kick.

- **Well Kick:** “Unplanned, unexpected influx of liquid or gas from the formation into the wellbore, where the pressure of fluid in the wellbore is insufficient to control the inflow. If not corrected can result in a blowout.” [8]

A well kick occur when the two criteria are met:

1. $P_H < P_p$: The hydrostatic pressure exerted by the drilling fluid is less than the pressure exerted by the formation pore fluid, and
2. The formation is porous and permeable, creating a flow path for the formation fluid.

The most common causes for a well kick, include

- Insufficient mud weight
- Swabbing
- Surging
- Lost circulation
- Abnormal pressure

2.5.6 BLOW OUT [10]

A blow out is an uncontrolled flow of fluid from the formation to the well bore. One distinguishes between a surface blow out, and an underground blow out.

An underground blow out is the situation where fluid flows from one formation/reservoir, along the well bore, and into another formation, without reaching the surface. In addition to being an expensive problem, the consequences of underground blow out may include dangerous to existing or future wells, weaker formation, and worst case, the potential for a surface blow out.

A surface blow out may either occur as a result of an underground blow out, if the formation consist of an open hole interval, leading the fluid up to the surface, or directly to the surface through the drill string.

2.6 WHY MPD?

The various techniques of MPD have a wide range of applications, including HPHT wells, deep water drilling with lost circulation and narrow drilling window. The latter one is considered in this Thesis, showing an increasing challenging trend on the NCS.

2.6.1 NARROW DRILLING WINDOW

Operating with a small pressure difference between the pore – and fracture pressure (or the pressures defining the lower – and upper pressure limit) is a challenge for conventional drilling, as the formation might not be able to withstand the large pressure variations provided by the operation. Narrow drilling window increases the chances for drilling hazards, if not handled carefully. Figure 2-5 illustrates the challenge, where the ECD ($P_H + P_A$) exceeds the formation fracture gradient due to circulation in the system.

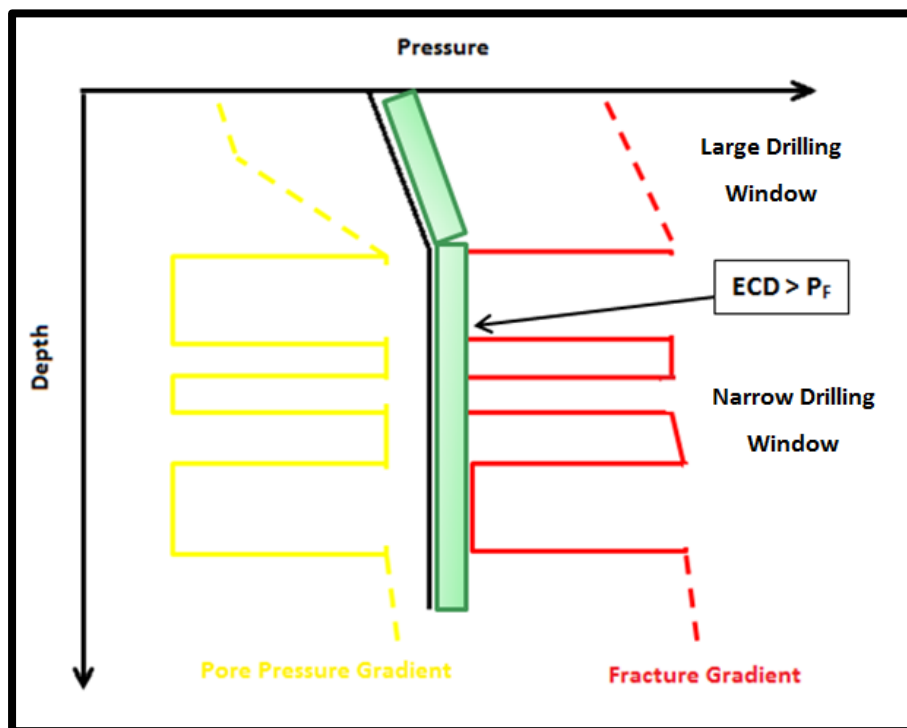


FIGURE 2-5 ILLUSTRATION OF ECD EXCEEDING FORMATION FRACTURE GRADIENT

In this context, MPD offers the possibility to drill the un-drillable, giving the reservoir a second chance, instead of the alternative of closing the field. The technique also limits non-productive time (NPT), and reduces the chance for drilling hazards.

2.6.2 DRILLING HAZARDS AND NPT

The largest contributors to the NPT include lost circulation, stuck pipe, wellbore instability and well control incidents. During conventional drilling operation, the formation is exposed to large pressure variations. Particularly when starting and stopping the rig pumps, the chance for a well control scenario increases. Figure 2-6 illustrates how the action of stopping the pumps may result in a wellbore pressure lower than pore pressure, or higher than the fracture gradient.

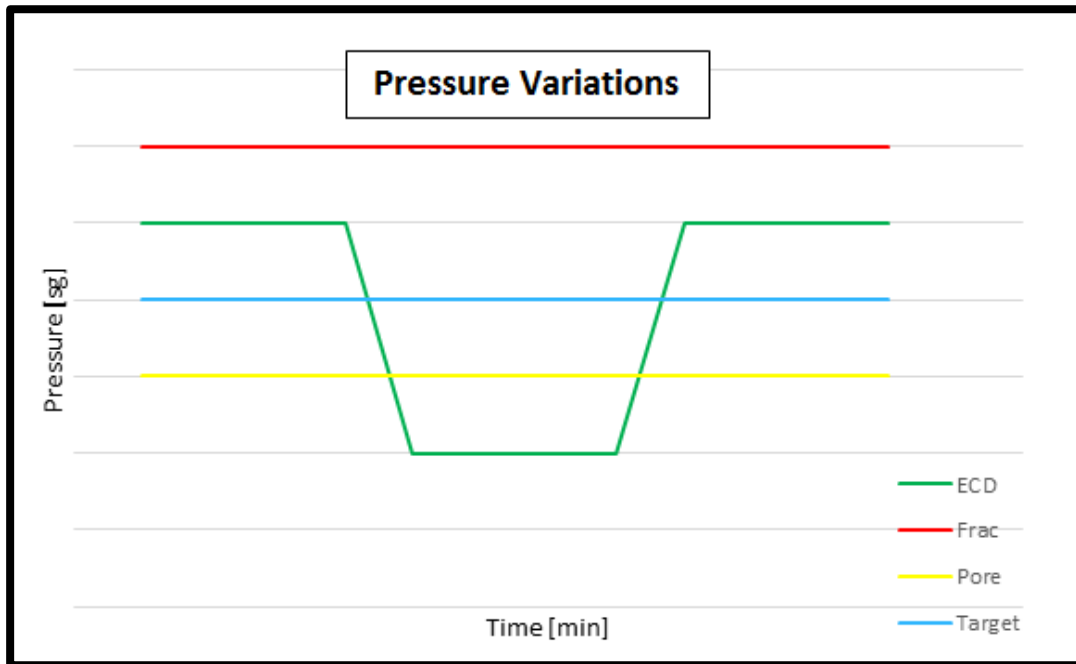


FIGURE 2-6 ILLUSTRATION OF PRESSURE VARIATIONS CAUSED BY THE RIG PUMP

The chance for differentially stuck pipe and wellbore instability is also increased, as the formation experiences large differential pressure between the wellbore and formation.

Not only do drilling hazards expose dangerous for the personnel working on the platform, but also handling of the drilling hazards is a time consuming process. For example, in case of a lost circulation scenario, the procedure is to pump down lost circulating material (LCM). The time estimation is illustrated in chapter 2.6.3.

By the use of MPD, having the ability to operate safely within the pressure limits, NPT related to well control incidents is significantly reduced, and thus related cost. Managed pressure drilling plan to avoid drilling hazards, by keeping a constant bottom hole pressure. The chances for lost

circulation and well control incident are reduced, and the formation is less exposed for differential pressure, avoiding stuck pipe wellbore instability, surge and swab. In addition, the hydraulic models and accurate measurements provided by the MPD technology, allow for earlier detection for kick and loss situations. If a well control scenario should arise, active pressure regulations make it possible to handle the situation quickly. [11]

2.6.3 HEALTH, SAFETY AND ENVIRONMENT (HSE)

MPD is preferred with respect to health, safety and environment (HSE), as it mitigate the drilling hazards described above, and consists of a closed loop system. By the use of a closed loop (circulation) system, the personnel are less exposed to the transfer of drilling fluid (and potential gas), compared to an open (atmospheric) system. In addition, the driller will see pressure changes immediately when a flow meter is installed, and have the possibility to respond rapidly.

HSE is the first priority during all drilling operations, and plays a major role, as there is always room for improvements. “Zero injury” is a common philosophy among oil companies, with the basic principles of zero injuries on humans, zero injuries on environment, and zero injuries on materials.

With the possibility to control the bottom hole pressure, safety is increased and the personnel working on rig are less exposed to the consequences related to well control accidents.

Figure 2-7 illustrates the precision of pressure control during conventional vs MPD operations.

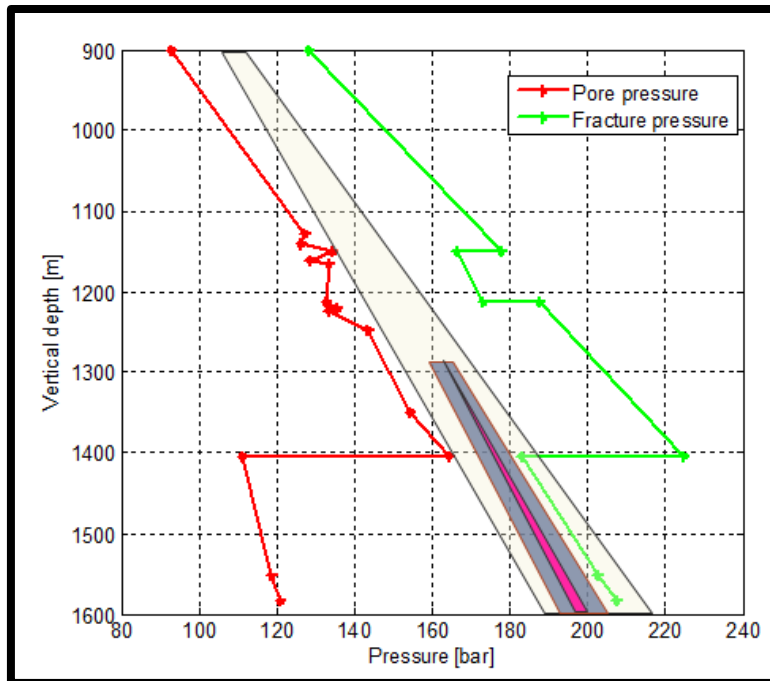


FIGURE 2-7 PRESSURE UNCERTAINTY (COURTESY OF NOV)

Experiences have shown that the pressure uncertainty conventional drilling is ± 20 bar, with hours required for changing the pressure down hole, i.e. a time consuming process. The precision of pressure control is improved to ± 10 bar for manual MPD (blue line), requiring minutes to respond, and further $\pm 2,5$ bar for automated MPD (pink line), where the pressure can be regulated in seconds.

2.7 CHALLENGES OF MPD

Even though MPD has several advantages, experiences indicate that the goal is far from accomplished. For improving the MPD operation, one must use experience from previous operations, and analyze and point out how one can overcome these challenges. The challenges reported are a result of both human – and technical factors. The MPD operation performed at Gullfaks C in 2009, resulting in a well control incident, is an example of the outcome of lack of sufficient planning and risk evaluation. The defects reported by PSA are presented in chapter 6.

2.7.1 AUTOMATION

It is important to understand the meaning of automation. The use of the term in this thesis will refer to automated equipment and control systems, not an automated drilling operation. Even though the equipment and control systems are automatic, the conventional drilling crew still needs to be in place to perform the drilling operation.

When depending on fully automated computer-controlled system, it exist several events that may occur causing failure of system and equipment. The failure may be a result of the software, or imposed by human action. Either way, the challenges arises if there is insufficient knowledge about the automation level, or how to handle the situation manually.

2.7.2 NEW TECHNIQUE

When introducing a new technique, there will always be new risks added. The term hazard is not a new concept considering drilling operations, but understanding of hazards is important, and particularly when new operations apply. Hazards in general may not be a challenge, but if not identified, the outcome can be catastrophic.

According to IADC, examples of hazards introduced by a MPD operation include, but are not limited to

- "Change in barrier philosophy
- Drilling fluid medium
- New equipment
- New or modified procedures
 - o Well Control
 - o Normal operating
- High pressure lines at surface
- Personnel training and competence" [12]

Even though MPD reduces NPT in the means of eliminating drilling hazards, the technique may contribute to NPT by other elements, such as the hazards listed above.

The risk of equipment failure or other technical problems is present during all activities. Some of the situational challenges experienced includes the

- RCD: The rotating control device has caused many hours of NPT during previous operations because of the lifetime of the packer element. Leakage of the RCD is critical for well control purposes, and changing of the element is a time consuming process.
- Back Pressure: Loss of back pressure leads to decreased BHP, exposing the well bore for an influx. This could be a result of for example failure of back pressure pump, plugging, etc.
- Software: Failure of software and hydraulic model contributes to NPT. Computer “lock-up” and failure to calibration are examples of challenges related to the software.

In addition, experience has shown that the user friendliness regarding hydraulic model needs to be improved. Failure of software and hydraulic model contributes to increase in NPT, particularly if the support team is located onshore.

2.7.3 HUMAN FACTORS AND COMPETENCE

Failure of equipment may be hard to predict, but it is possible to avoid, or reduce, NPT by responding quickly and resolving the problem. The NPT in such cases depends largely on the knowledge and training among personnel.

Personnel competence and experience is another critical factor, and common challenges addressed during MPD operations relates to human being. Management, standards, knowledge, experience and understanding of operation are key words for obtaining a successful MPD operation. Experiences have shown that all these factors need to be improved.

3 DRILLING SYSTEM AND EQUIPMENT

For understanding of the drilling operation, one must know what equipment and system that is present on the platform. Requirements and definitions provided by NORSOK D-001 (2012) are used as a red line during the chapter, with the purpose of giving a basic overview over the equipment and system, and what requirements that applies for the various components.

A drilling rig consists of six major systems, including the

- hoisting system
- rotary system
- power system
- well control system
- well monitoring system
- circulation system

Firstly, the drilling equipment structure (DES) for a fixed installation is presented with the purpose of giving a visual picture of the drilling facility.

3.1 DRILLING EQUIPMENT STRUCTURE

Included in the drilling equipment structure (DES) is the substructure, drill floor, derrick/hoisting structure and mast, illustrated in the figure below.

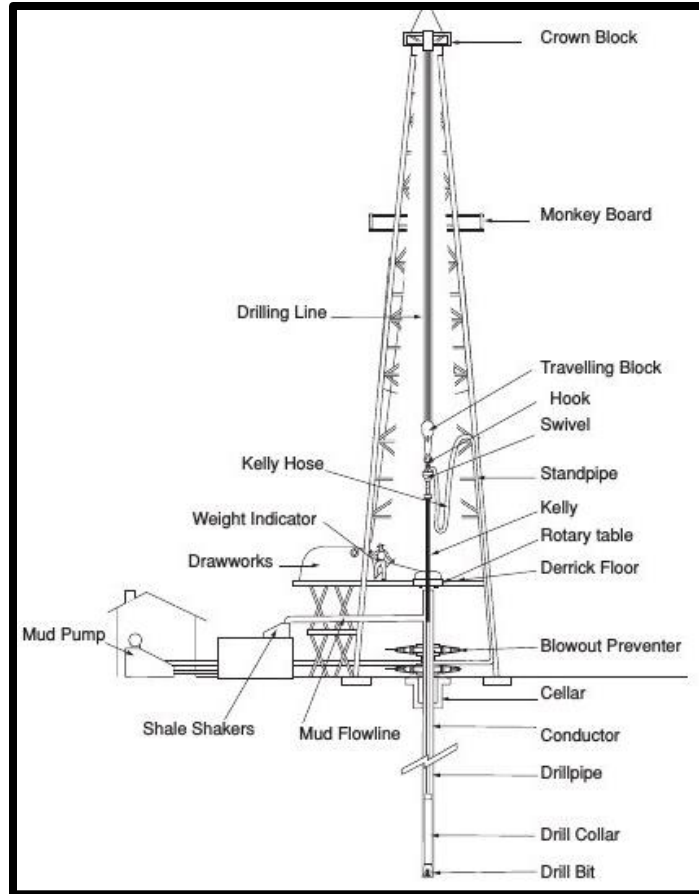


FIGURE 3-1 ILLUSTRATION OF DRILLING EQUIPMENT STRUCTURE [13]

In addition to the elements illustrated in Figure 3-1, the drilling equipment structure consist of walkways, access ladders, work platforms and associated equipment within the area.

During the construction phase of a drilling rig, it is important to consider what operations may be relevant in the future (for example MPD), in additional to the general handling of various pipe and equipment.

3.1.1 DERRICK

The derrick is the highest structure on the platform, supporting the traveling – and crown blocks, and providing sufficient vertical clearance for raising and lowering of the drill string.

3.1.2 DRILL FLOOR

The drill floor is the main working area for the drilling crew for executing the drilling operation, or other similar activities (such as wireline, coiled tubing, etc.). The driller's cabin is located at the drill floor, as well as the pipe handling equipment, draw work, work winches, etc.

3.1.2.1 DRILLER'S CABIN

The driller's cabin is located at the drill floor, and is the driller's work place for executing the drilling – and well operations. Specific requirements apply, including ergonomic design, operators view, and easily access to the control panels. [6, p. 19]

Beside the driller's workstation, there may also be present other control panels and systems in the driller's cabin. For example when running or pulling casing, the casing tong is commonly operated from the driller's cabin, by use of a dedicated workstation for operation and monitoring of the equipment. This may also be the case for other operations provided by 3rd parties (i.e. service companies).

In addition, several drillers' cabin includes workstations for both driller and roughnecks. See Chapter 3.5 and 3.6.7.

3.1.3 OTHER DECK/LEVELS

The construction of platforms varies, and the location of deck and equipment may differ. One commonly refers to the BOP-deck and the wellhead (WH) area (cellar deck in Figure 3-1). The BOP-stack can either be located just below the drill floor, or at a lower level with an additional riser¹ connected. The wellhead area is the location for the wellhead, positioned at a lower level than the BOP-stack.

¹ A riser is a large diameter bore (pipe) functioning as an extension from the wellhead to the BOP-stack (high pressure riser). When there is a large distance between the BOP-stack and the drill floor, an additional riser is installed (low pressure riser).

3.2 HOISTING AND ROTARY SYSTEM

A hoisting and rotary system must be in place in order to lower, hoist and rotate tubulars or other tools in and out of the well. Included in the system is equipment such as crown block, travelling block, draw work, drilling hook/adaptor, top drive, guide dollies, drill line spool and anchor, and rotary table. [6, p. 16] The equipment is illustrated in Figure 3-2.

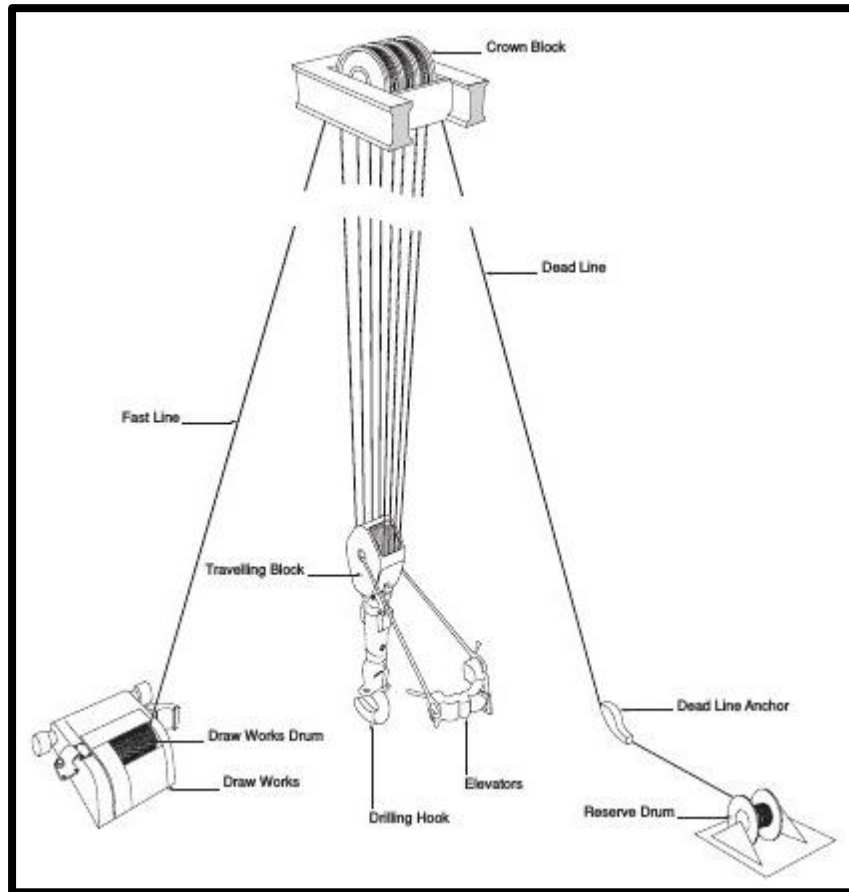


FIGURE 3-2 ILLUSTRATION OF HOISTING SYSTEM [13]

The crown – and travelling block are sets of pulleys, stationary and movable respectively, with the purpose of raising and lowering the drill string. The draw work is the primary hoisting machinery, located at the drill floor, providing the drill line (wire). The drill line spool (reserve drum in Figure 3-2) is the opposite connection point.

3.3 POWER SYSTEM

A drilling facility requires enormous amount of power to be able to function, both in terms of equipment and general power distribution such as lightning. The power system includes drilling power systems, emergency -, essential -, and UPS (uninterruptible power supply) power.

Particularly in means of handling of critical equipment, the drilling power system is of major importance, and the integrity of the system shall be based on risk assessment. It shall also be ensured that part of systems can be used in case of unforeseen well control situations. [6, p. 13]

On the specific installations, local procedures are available for how to react in case of a shutdown situation, depending on the actual activity and operation.

3.4 DRILL STRING

The drill string, or drill stem, includes the bottom hole assembly (BHA), pipe and other tools that is run into the hole.

The BHA is the lower part of the drill string, usually consisting of, from bottom to top

- bit and bit sub for crushing the rock
- mud motor for steering the bit by the use of drilling fluid
- stabilizers
- drill collar for providing weight on the bit (WOB)
- heavy weight drill pipe for providing weight
- jar in case of stuck pipe scenario
- necessary crossovers for various threads

There may also be included logging tools, measurement while drilling (MWD) tools and other equipment depending on the operation (i.e. drilling, completion, etc.).

For well control purposes, a float or check valve is often run as an integral part of the drill string. When including the valve near the bottom part of the drill string, the valve prevents fluid from

flowing from the well bore, through the drill string and up to the surface. In other words, the valve allows for flow only in one direction, and is typically a dart – or flapper type.

For MPD operations, there is a requirement for a minimum of two non-return valve (NRV), similar as the float or check valve, in the drill string, constituting one well barrier element. [7, p. 206]

A Pressure While Drilling (PWD) tool may also be included in the BHA, providing accurate down hole ECD measurements, improved kick detection, and accurate formations test, among others. These parameters are important for the MPD control system, which must be updated on a continuous basis. [14]

The upper part of the drill string is drill pipe (DP) jointed together by threads. Each joint is approximately 9 meters long with threaded ends. The size (outer diameter) of the pipe depends on the diameter of the well bore, but 3 ½” and 5” drill pipe are common.

Three single drill pipe jointed together (approximately 30 meters) contributes to a so-called stand. Pre-made stands are often stored at the set back (area at drill floor), if the same DP are to be run several times.

3.5 PIPE HANDLING EQUIPMENT

The purpose of the pipe handling equipment is to transfer DP and other drill string components from the pipe deck to the well center. Basic equipment and operational sequence, include

- Horizontal pipe handling crane (provide pipe to the drill floor level)
- Horizontal to vertical (HTV) pipe handling crane (lifting the drill pipe from horizontal to vertical position, making it ready to be run into the hole)
- Vertical pipe handling crane²
- Elevator (for sealing around the drill pipe, just below the tool joint)
- Iron roughneck or similar equipment for making up connections

² During tripping operations, where the same DP are run several trips, the vertical pipe handling crane, for example a star racker, easily lift the stands from the set back to the well center. The elevator then latches on the DP.

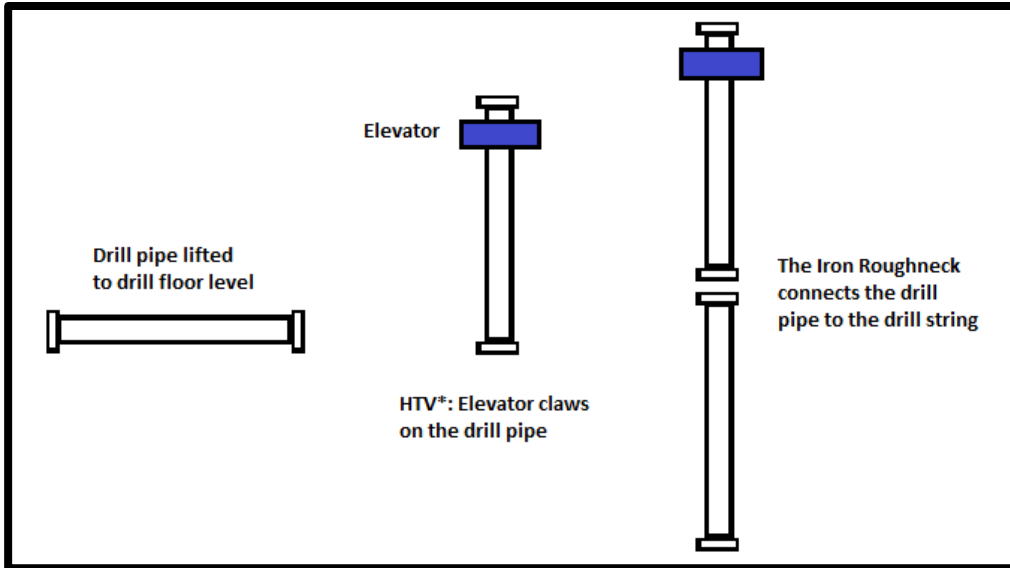


FIGURE 3-3 SIMPLE ILLUSTRATION OF PIPE HANDLING

Figure 3-3 illustrates the basic working sequence of pipe handling. Eagle and tail/conveyor are examples of HTV handling equipment.

The elevator can be equipped with different insert sizes, depending on the outer diameter of the drill pipe. The elevator is the lowest part of the top drive, and when attached to the drill pipe, the drill string can be lowered/raised in/out of the hole. The outer diameter of the tool joint is larger than the outer diameter of the pipe body; hence, the tool joint prevents the pipe from slipping.

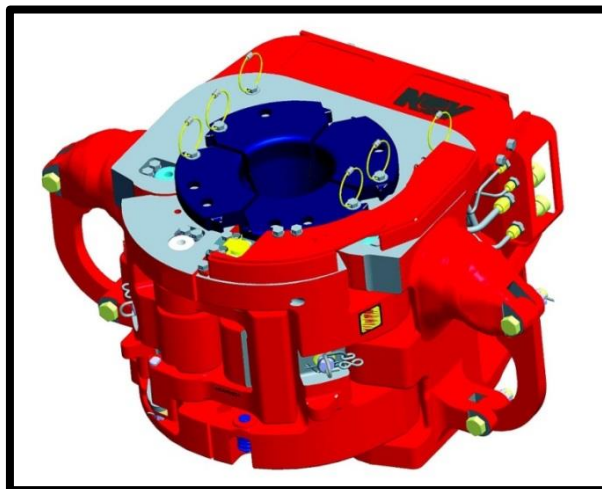


FIGURE 3-4 BX ELEVATOR, NOV [15]

The Iron Roughneck (IR) is located on a rail, and is steered forward to the well center, when connections are to be made. Depending on the pipe type – and size, the drill pipe is connected to the drill string, by applying a pre-defined torque. The iron roughneck is also used when pulling the drill string out of the hole, by “breaking out” the pipe. The machinery can either be manually operated, or remotely from the driller’s cabin. See Cyberbase.

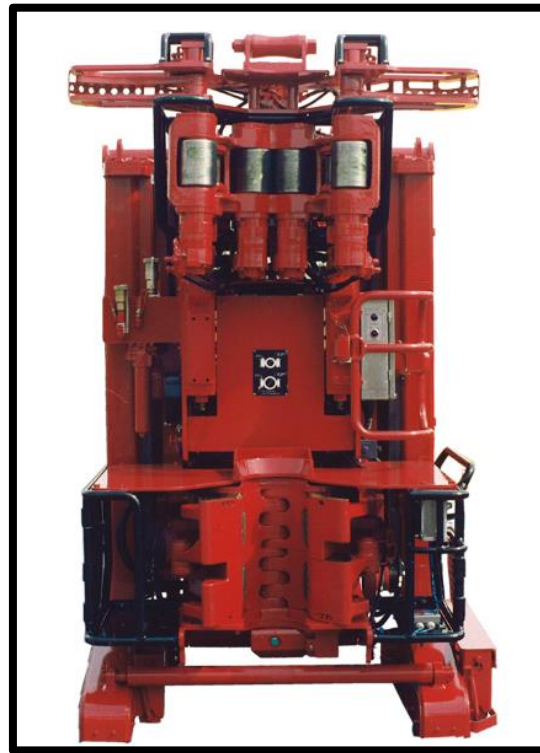


FIGURE 3-5 IRON ROUGHNECK, NOV [16]

3.6 WELL CONTROL SYSTEM

A well control system must be in place in order to monitor the well during various operations, and for preventing uncontrolled fluid of formations, i.e. well control situations, by establishing and maintaining a secondary well barrier system.

The well control system include well control equipment and control systems, such as the blow out preventer (BOP), choke and kill system, mud gas separator, diverter system, trip tank system, and control systems, among other. [6, p. 34]

3.6.1 BLOW OUT PREVENTER (BOP)

The blow out preventer (BOP) stack is installed on top of the riser/wellhead with the purpose of ensuring pressure control of the well. The BOP can be equipped with different components, but shall as minimum consist of

- one annular preventer
- one shear and seal ram preventer
- two pipe ram preventers

in addition to the kill – and choke outlets (minimum one of each), remote – and manual gate valves (minimum two of each), and wellhead coupling or connector (minimum one). [6, p. 35]

The pipe rams are shown as lower pipe ram (LPR) and upper pipe ram (UPR) in Figure 3-6, whereas the K and C refers to kill – and choke outlet, respectively.

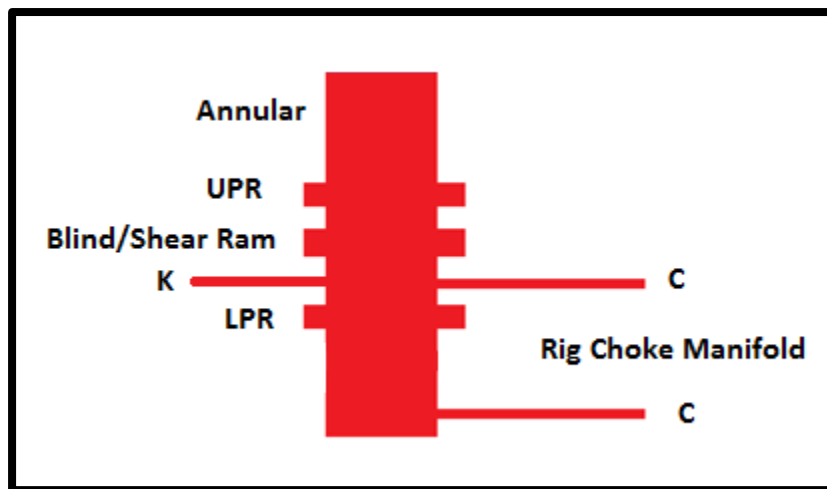


FIGURE 3-6 SIMPLE ILLUSTRATION OF THE BOP-STACK

Depending on the situation, the different rams can be activated with various functions. The pipe rams seals around the drill pipe/drill string, whereas the shear ram is activated as a last option, shearing the drill string. The BOP is operated by the BOP control system.

During MPD operations, the conventional BOP stack is in use, including additional elements. Figure 3-7 below gives a general overview, where the additional rig up elements is marked with blue color.

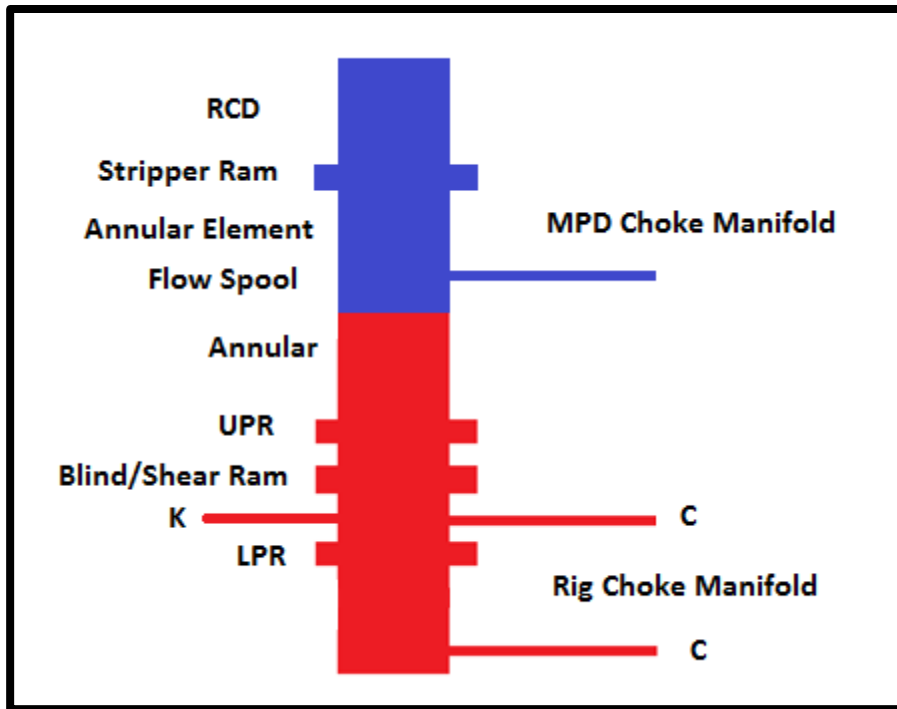


FIGURE 3-7 SIMPLE ILLUSTRATION OF THE BOP-STACK FOR MPD OPERATIONS

3.6.1.1 ROTATING CONTROL DEVICE (RCD) [17] [1]

The rotating control device (RCD)³ is installed above the conventional BOP stack (as illustrated in Figure 3-7) with the purpose to maintain pressure tight barrier in the annulus section, to divert flow from the well bore through the choke, and to allow rotation of drill string while performing the other functions.

The RCD is the primary pressure seal during a MPD operation, and is required to be present due to the annulus packing off at the surface while tripping, drilling, and making connections. [1, p. 228]

Several variations of the RCD are available on the market, where the selection of size and pressure rating depends on required surface pressures and available spacing on the BOP deck. In addition, one distinguishes between passive (well pressure actuation) and active (hydraulic actuation from external source) systems. [1]

³ Rotating control device are also known as Rotating Control Head, Rotating BOP and Pressure Control Device (PCD), among others.

The Pressure Control Device (PCD) provided by Siem WIS, is an example of a sealing solution. The purpose of the PCD and RCD is the same, however the construction, sealing and manufacturing differs. [17]

Unlike the RCD, the PCD technology uses non-rotating sealing elements. It provides several advantages, including real-time monitoring of seal performance and long lifetime of the seal due to less wear and multiple seals (pressure distributed evenly). Even though the PCD seals are stationary, rotation of the drill string is ensured by direct lubricant injection during operation, a sealing solution patented by Siem WIS.

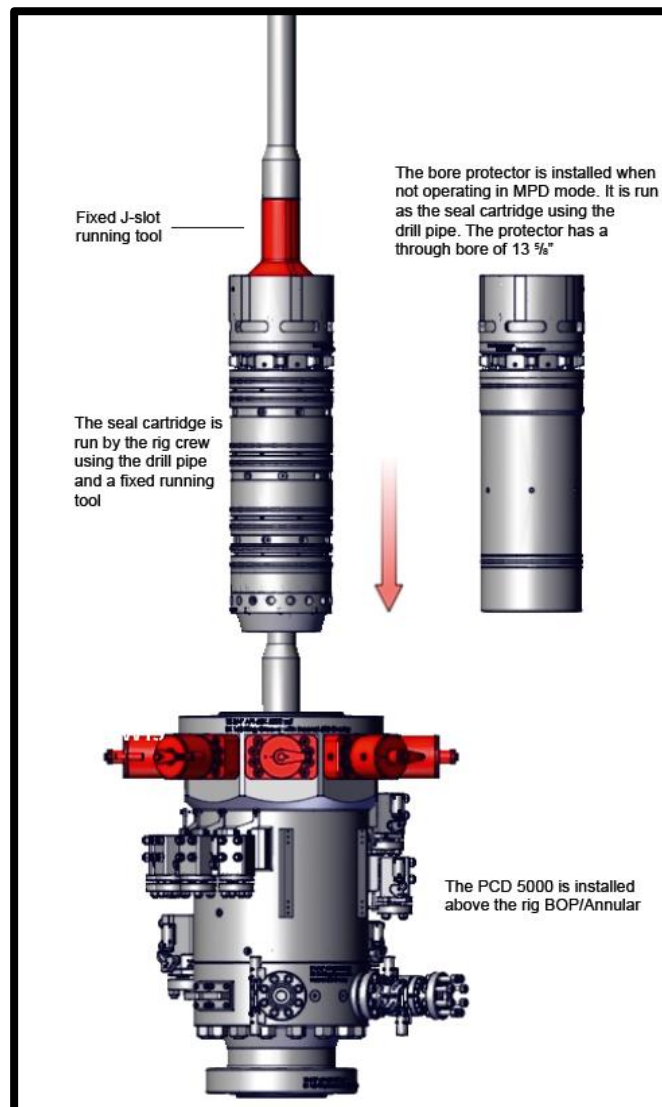


FIGURE 3-8 INSTALLATION AND OPERATION OF THE PCD (COURTESY OF SIEM WIS) [17]

Figure 3-8 shows the PCD package, including the PCD, cartridge and running tool, in addition to a control system (for controlling hydraulic functions) and a HMI system (for monitoring and trend data).

The seal cartridge consists of four sealing elements (see Figure 3-9), which are pressurized by the well bore pressure using a gradient chamber system. If there should occur leakage in one of the seal, the pressure can easily be re-distributed to the functional seals. When changing the seals, a running tool is run on drill pipe for retrieving the seal cartridge, and a new pre-loaded seal cartridge is installed. [17] “This is a fast, safe and simple operation done by the rig crew, and has a direct positive impact on non-productive time”. [17]

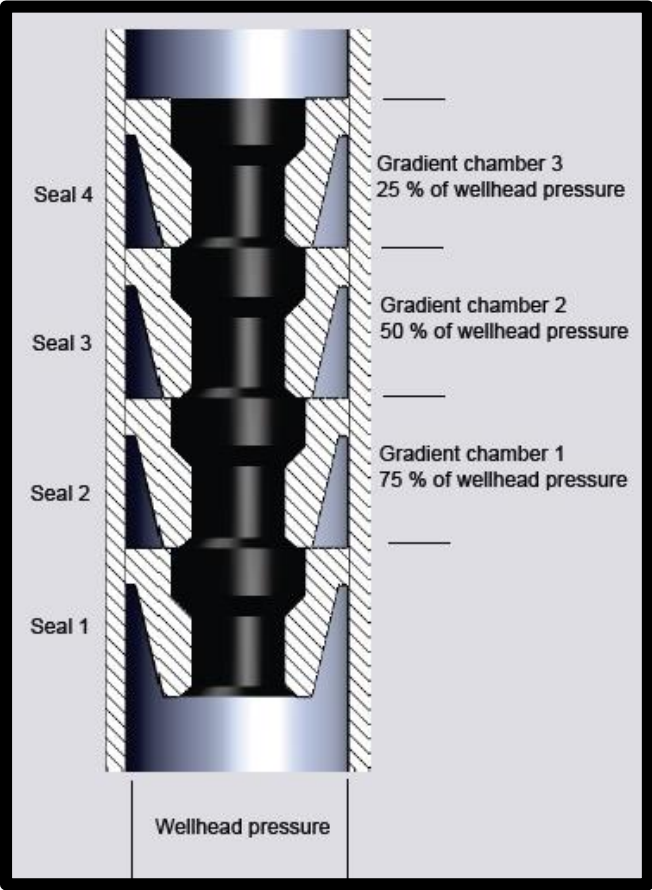


FIGURE 3-9 SEAL CARTRIDGE (COURTESY OF SIEM WIS) [17]

3.6.1.2 STRIPPER RAM

Stripper ram and additional annular element, or similar components, are commonly included in the rig up, providing a secondary flow path. For example, if the element in the RCD needs to be changed, the stripper ram is closed, preventing pressure above the ram. Alternatively, the rig annular can be used for well isolation, provided acceptable risk level.

3.6.1.3 FLOW SPOOL

The flow spool is positioned below the RCD, with the purpose to directing the return fluid from annulus to the MPD choke manifold.

3.6.2 BOP CONTROL SYSTEM

For operating and controlling the various BOP stack functions, a BOP control system is required. The system is also important for monitoring the status of the BOP stack – and control system functions.

Activation of the BOP shall be possible from three locations on the facility, including the driller's location, a safe accessible area with an independent activation panel (usually the toolpusher's office), and directly on the main unit, i.e. the BOP stack. [6, p. 42]

The remote control panels consist of lightening system that clearly indicates the position of the various functions (i.e. closed or open), in addition to

- manometers showing pressures (standpipe and accumulator)
- flow meter readings for volumes
- various alarms (including low accumulator pressure, loss of power supply, etc.)

In case of an emergency, for example a shutdown of the platform, there is a further requirement of a back-up system, called accumulator unit. The accumulator unit consists of a number of accumulator bottles, which store hydraulic fluid under pressure. In case of a shutdown situation on the platform, the accumulator unit provide hydraulic pressure to the BOP, in order to effective closure of the BOP and securing of well.

3.6.3 CHOKE AND KILL SYSTEM

A choke and kill system must be in place in order to control and monitor the pressure, allowing controlled circulation of the well under various pressure conditions. The system includes manifolds with associated valves and chokes, and piping. The choke and kill system is also connected to other equipment and systems, such as poor boy degasser and standpipe and cement manifold. [6, p. 37]

According to IADC (UBO & MPD Glossary, 2011), a choke can be defined as “a device with a fixed (positive) or variable (adjustable) orifice installed in a line to restrict the flow and control the rate of production from the well.” [8] Whereas the manifold is “a system of pipe and valves that serves to convert separate flows into one flow, to divide one flow into separate parts, or to re route a flow to any one of several possible destinations.” [8]

The purpose of the choke manifold is to maintain well control in case of loss of pressure control. Having the scenario of formation fluid flowing into the well, chokes can be adjusted in order to obtain control over pressure, by applying back pressure.

NORSOK D-010 (2013) states that a minimum of three chokes shall be present, where minimum two chokes shall allow for remote control (commonly drillers’ location and toolpushers’ office), and minimum one choke for manual operation. [6, p. 37] These chokes are connected to the BOP stack through arrangement of calves, fittings, and lines (as illustrated in Figure 3-6).

As the rig choke manifold always shall be available for well control operations, an additional, dedicated choke manifold is required during MPD operations. The well barrier acceptance criteria for MPD include [7, p. 138]

- MPD manifold and flow path independent of rig choke manifold
- Dedicated MPD manifold for
 - control of well bore pressure, and
 - reduce pressure at surface ahead of fluid entering the shakers

The principles of the choke manifolds are the same, with the purpose of controlling the flowing pressure from the well. However, if the choke system shall be valid as a well barrier element (required if drilling with UB fluid), a high accuracy flow meter and a pressure relief valve (PRV) must be included (among others) in order to meet the MPD specific requirements. [7, p. 209]

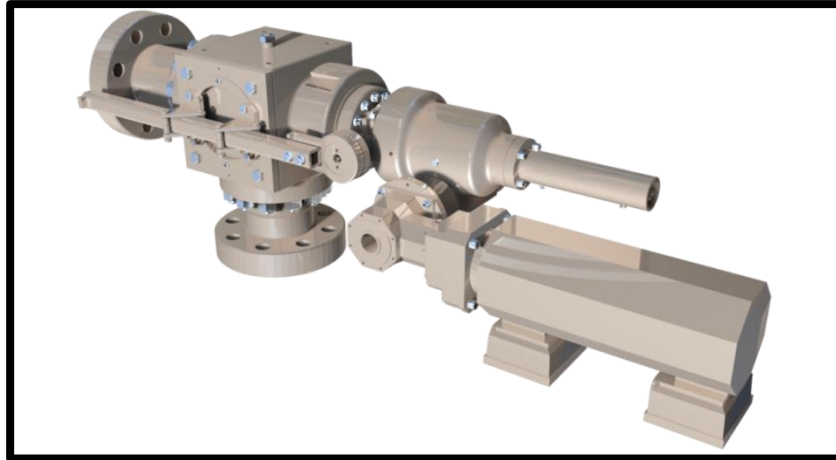


FIGURE 3-10 MPD CHOKE MANIFOLD, NOV [18]

Figure 3-10 is an example of a MPD choke manifold, provided by NOV. During MPD operations, the choke is commonly delivered as a choke skid, including the flow meter.

3.6.3.1 FLOW METER [1]

Flow meter is an instrument used for measuring volume and velocity of various fluids or other medium.

Flow control is extremely important in order to maintain well control, during all drilling operations. For conventional drilling, the flow is measured by calculations from the pump strokes, in other words when the fluid is pumped into the well. The flow meter gives the possibility to measure the flow out of the well in addition, providing more accurate flow control.

The Coriolis flow meter is a very accurate method for measuring drilling fluids, and plays an important role in MPD operations. The Coriolis meter measures and calculates the mass flow, volumetric flow, density and temperature.

3.6.3.2 PRESSURE RELIEF VALVE (PRV) [1]

The pressure relief valve (PRV) is a safety device for protecting the system against high pressure, and is particularly important when operating with a closed loop system.

Defined by IADC (UBO & MPD Glossary, 2011), a PRV is “a valve that opens automatically to relieve the line pressure that is above the safe operating limit.” [8]

Ahead of the operation, the PRV is set to a pre-determined set pressure, based on the pressure rating of the system, usually limited by the RCD.

3.6.4 MUD GAS SEPARATOR (POOR BOY)

The mud gas separator, commonly called “Poor boy degasser”, is a device (tank) located after the choke manifold, with the principle to separate gas from mud during a kick situation.

After the drilling fluid has been pumped down the well, up the annulus and through the choke manifold, it is routed through the poor boy. From the poor boy, the gas is directed to a safe area, while the fluid returns to the active mud system.

For MPD operations, one usually does one of the following

1. Routes the MPD choke manifold to the mud gas separator through a tie-in solution
2. Install a separate MPD mud gas separator, independent of the rig mud gas separator

Figure 3-11 is an example of a separate mud gas separator, provided by NOV, designed for continuous drilling in underbalanced conditions. [19]



FIGURE 3-11 MUD GAS SEPARATOR, NOV [19]

3.6.5 DIVERTER SYSTEM

A diverter system must be in place in order to close off the well below the drill floor and for directing uncontrolled flow from the well away from the drilling rig. Various systems exist, whereas annular BOP or rotating heads are commonly used as diverter system on fixed installations, included in the BOP-stack.

It shall be possible to operate the diverter system remotely from the driller's position and from the main BOP control unit. [6, p. 40]

3.6.6 TRIP TANK SYSTEM

During tripping operations (see 5.3.2) volume differences will occur, whether it is tripping in or out of hole. In order to maintain volume control, a trip tank system is required, for monitoring volume changes in the well during tripping of pipe in and out of the well, or in situations when circulation is halted. [6, p. 40]

For example during tripping out of the hole, a pump provides flow from the trip tank for ensuring that the well is replaced with fluid, as the drill string is removed from the well. For rapid and

accurate response, the location of trip tanks shall be as close to the well center/flow line as possible. [6, p. 40]

During MPD operations, a tie-in solution to the trip tank has commonly been used, with the purpose of detecting potential leakage in the RCD. When connected to the system, an increase in trip tank volume level could indicate a leakage in the RCD.

3.6.7 DRILLING CONTROL SYSTEM (DCS) [6, p. 47]

The drilling control system (DCS) is a generic term, including instrumentation such as drilling control and data acquisition (DCDA), cutting re-injection system (CRI), BOP, etc. [6, p. 47]

The DCDA is the specific drilling control system, located in the driller's cabin and operated by the driller, consisting of specific drilling data information.

It is important for the operator to achieve specific information from the well during operations, and functionalities including real time data acquisition, data processing, display/monitoring, recording/storage, alarm handling, and change in selected parameters, shall as minimum be integrated in the DCDA and available for the operator. [6, p. 52] See Annex B "Drilling parameter requirements", NORSOK D-001 (2012), for full overview.

3.6.7.1 NOV CYBERBASE [20]

The Cyberbase provided by NOV, is an example of a drilling control system common on the NCS. According to NOV, the "Cyberbase operator station systems are designed to increase productivity by improving the operator's ability to control machinery and processes." [20]

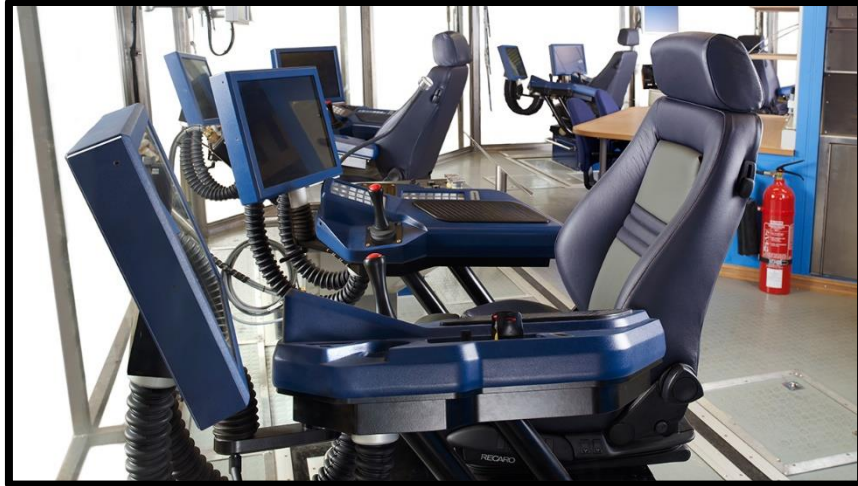


FIGURE 3-12 CYBERBASE OPERATOR STATION [20]

The system uses integrated controllers, and provides quick access to menus, easy adjustments of parameters with throttle wheel, etc.

Cyberbase is easy to use, and the operator can choose various modes depending on the operation, such as tripping and drilling, and what parameters to be visible on the screens. The alarm system and operational settings can also be modified or adjusted by the operator, for example max weight on bit (WOB).

New functions can be implemented and control of new machines can be performed remotely from the Cyberbase station, without adding new hardware.

For understanding the Cyberbase, one can consider a general drilling operation, where the following general equipment is involved:

- Top drive/draw work for hoisting and lowering the drill string
- Rig pumps for providing flow to the system
- Pipe handling equipment

The top drive and rig pumps are operated by the driller's chair, while the pipe handling equipment (i.e. vertical pipe handler, IR, HTV) is operated by the roughnecks. The driller's cabin commonly consist of two operator chair, the driller's chair and the so-called "roughneck chair".

The Cyberbase control station may be similar for both, where the roughneck operates with a different mode (i.e. roughneck / pipe handler mode).

Important parameters during a drilling operation include, but are not limited to:

- Weight on bit (WOB)
- Rate of Penetration (ROP)
- Hook Load
- Rotation per minute (RPM) provided by the rig pumps
- Pressure in the system, including standpipe pressure (manifold)
- Volume (trip tank, active tank providing mud)

Commonly two screens are connected to the driller's chair, including the above parameters.

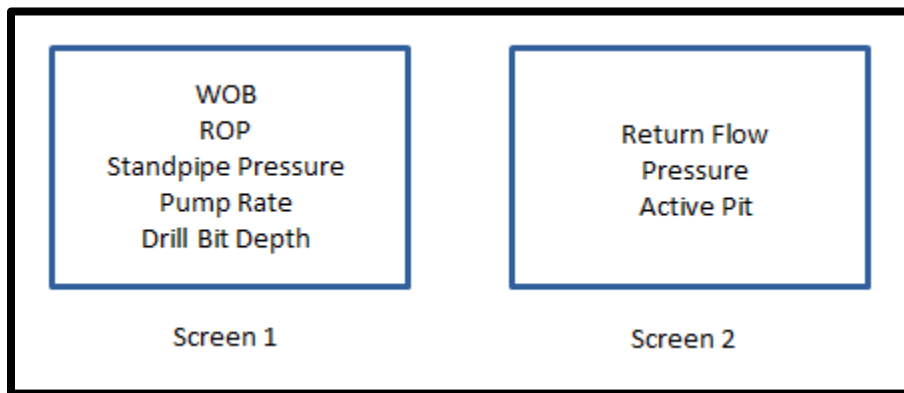


FIGURE 3-13 SIMPLE ILLUSTRATION OF DCS DISPLAY

Screen 1 includes specific parameters, such as WOB, ROP, standpipe pressure and drill bit depth. When the driller starts the pump or increases the RPM, the standpipe pressure will increase correspondingly.

Screen 2 is for monitoring of volume – and pressure changes. These parameters are calculated and displayed as a graph, and one can easily see if changes occur (for example increase or decrease in pressure).

Summarized, the driller hoist – and lower the drill string, while controlling the pressure – and volume in the system. The roughneck provide pipe to the drill string, and makes the connection.

3.6.8 MPD CONTROL SYSTEM

For automatic processes, an additional control system is required to operate the system. The main objective of the MPD control system is to maintain the pressure in the well. Various systems exist, but the basic system consists of two components:

- Hydraulic model
- Choke controller

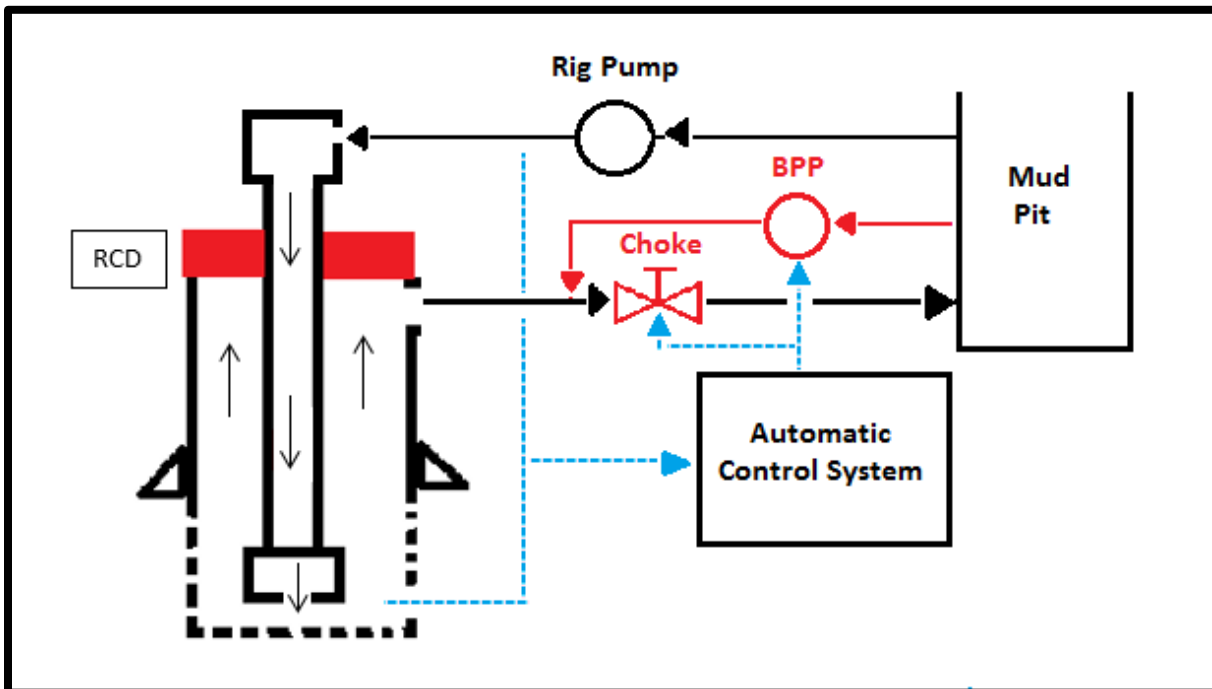


FIGURE 3-14 ILLUSTRATION OF MPD CONTROL SYSTEM

3.6.8.1 HYDRAULIC MODEL [11]

The hydraulic model computes the necessary surface pressure the choke must apply to the well, in order to maintain a constant BHP in the well. The model is based on the frictional pressure loss in the well, and requires specified input parameters related to well geometry, BHA, mud properties, etc. In addition, the model continuously calculates important parameters, like temperature, ECD, down hole pressure, etc., which are available for the driller.

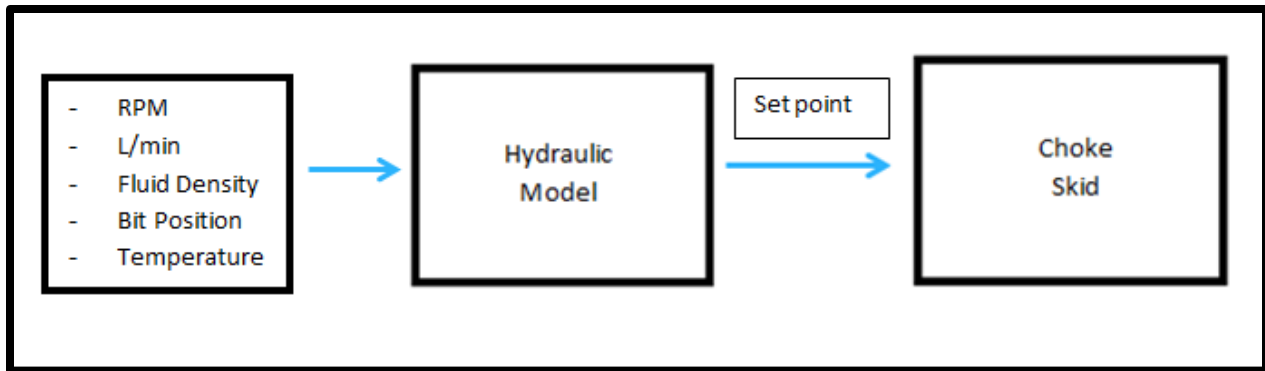


FIGURE 3-15 ILLUSTRATION OF MPD WORKFLOW

The system consists of a reference value for the back pressure, computed by the hydraulic model, for achieving the desired pressure in the well. The choke controller will then automatically open or close the choke in order to bring the back pressure to the reference value.

Regarding the hydraulic model, one must be aware of that the measurements are normally only taken near the bit, and not the entire well section. However, the ECD is automatically calculated at specified depths and is visible for the driller at all times. Typical depths includes the casing shoe, target depth, the PWD (if included) position and at the bottom hole.

3.6.8.2 CHOKE CONTROLLER

The function of the choke is to respond to the reference value generated by the hydraulic model, and can be manual, automatic or semi-automatic. The semi-automatic system is a mix of manual – and automatic choke, and is not further discussed here.

3.6.8.2.1 MANUAL CHOKE

With a manual choke control, the operator is a human being that manually adjusts the choke. A pre-defined BHP is set, and the operator adjusts the choke when necessary. This could be either during connection, or due to other pressure variations in the well. When considering a connection, we know ahead of the operation that the BHP will reduce, as the frictional pressure is lost when the pumps are stopped. Having this scenario, it is simple for the driller to inform the choke operator that he must be prepared to adjust the choke, accordingly as the driller ramps down on the pumps. Figure 3-16 illustrates the ideal performance of this operation:

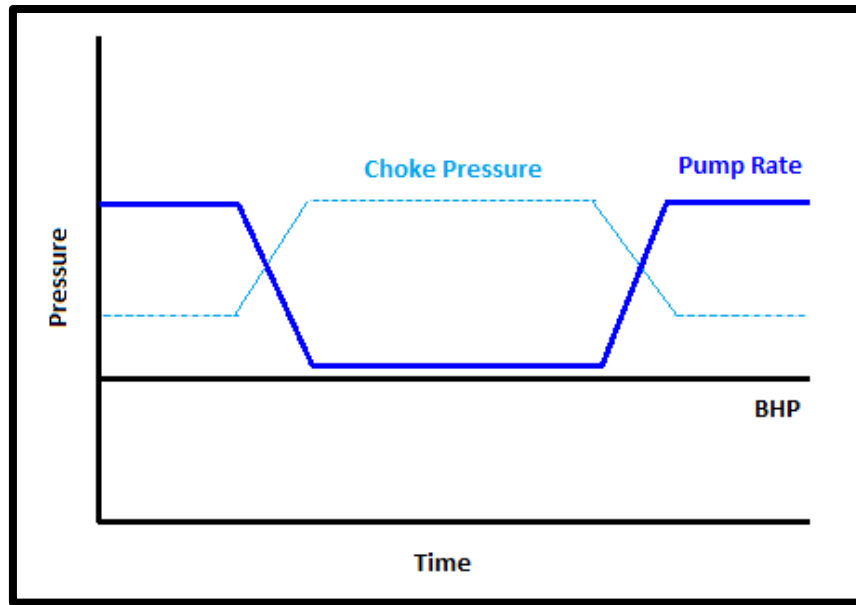


FIGURE 3-16 ILLUSTRATION OF CHOKE AND PUMP INTERACTION

In reality, the BHP will fluctuate, as the operations of ramping down the pumps and adjusting the choke will not happen accurately in most cases. There is also a potential risk of failure, as this is a manual system, depending on the operators involved. Communication is extremely important, and disturbance and/or miscommunication will have large consequences.

In addition, general variations in BHP are hard to predict before the pressure actually drop or increase and the choke operator must be prepared to adjust the choke at all times.

One must also be aware of the fact that the manual MPD choke system do not qualify as a part of the primary well barrier. [7, p. 138]

3.6.8.2.2 AUTOMATIC CHOKE

With the use of an automated MPD system, the risk related to communication and human failure is reduced, as the choke will automatically correspond to a pre-defined ramp sequence. The automated choke consists of an advanced hydraulic model of the well, which calculates the required back pressure.

3.7 CIRCULATION SYSTEM

The circulation system plays a major role in drilling – and well activities. Mud properties and flow rate is important for safe drilling operations related to pressure, hole cleaning, etc. Ahead of the specific operation, the mud is prepared in mixing tanks to obtain the correct weight and fluid properties (viscosity, temperature, etc.), by adding weighting material or other chemicals.

The circulation system can be considered as a loop, where the circulation start and ends at the main rig pumps.

3.7.1 RIG PUMPS

Rig pumps are a general term including transfer -, mixing - , and mud pumps. The latter one is commonly referred to as the main rig pump.

The function of the mud pump is to ensure that the drilling fluid is circulated to the bottom of the hole, and further up through annulus. It plays a critical role in drilling operations, and is essential in optimizing cutting transportation, volume and pressure control.

There are various types of pumps available on the market, but traditionally duplex pump (double acting, two cylinders) or triplex pump (single acting, three cylinders) are common. The flow and pressure provided from the pumps depends on types of liners and pistons used, in addition to the speed of the pumps (stroke/min). Required flow and pressure are listed in drilling programs, and liners are changed according to these values, ahead of operation.

3.7.2 OPEN CIRCULATION SYSTEM [1] [21]

During conventional drilling operations, one operates with an open circulation system, where the drilling fluid flows out of the wellhead and through surface piping open to atmospheric pressure.

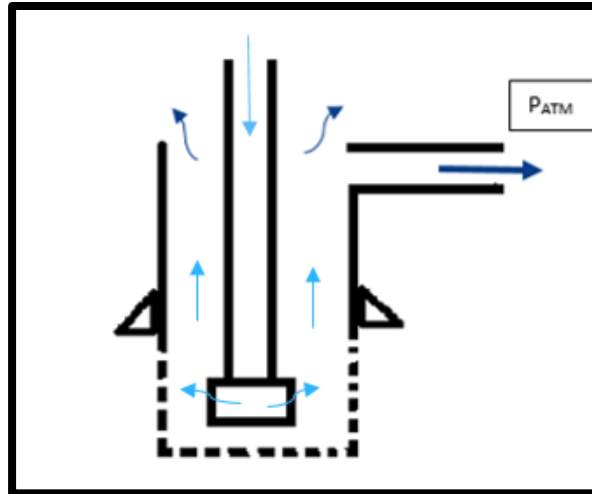


FIGURE 3-17 SIMPLE ILLUSTRATION OF OPEN CIRCULATION SYSTEM [4]

The rig pumps transfer the fluid through the surface piping, the standpipe, and the Kelly hose (rotary), the Kelly, the drill pipe and the BHA. After flowing out through the drill bit, the fluid flows up the annular, through the bell nipple, the (open) flow line, the mud-cleaning equipment, the mud tanks, the centrifugal pre-charge pumps, and in the end; the positive displacement of the main rig pumps. The circulation path is illustrated in Figure 3-18.

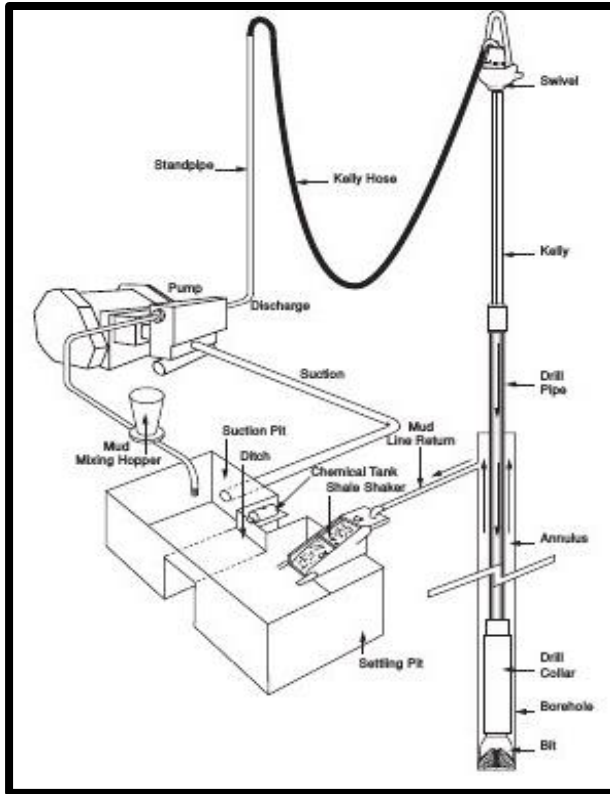


FIGURE 3-18 OPEN CIRCULATION SYSTEM [13]

3.7.3 CLOSED CIRCULATION SYSTEM [4]

MPD operates with a closed circulation system, where the fluid flows out of the wellhead under pressure, illustrated in Figure 3-19.

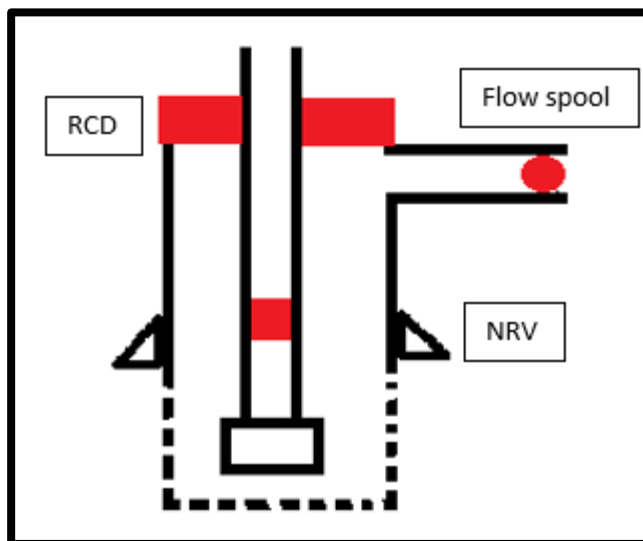


FIGURE 3-19 SIMPLE ILLUSTRATION OF CLOSED CIRCULATION SYSTEM [4]

The closed loop system differs from the open, using a RCD for sealing off the annulus. The RCD seals around the drill string and redirects the return fluid through a flow spool, to the MPD choke manifold. Figure 3-20 illustrates a generic MPD rig-up, including various flow paths.

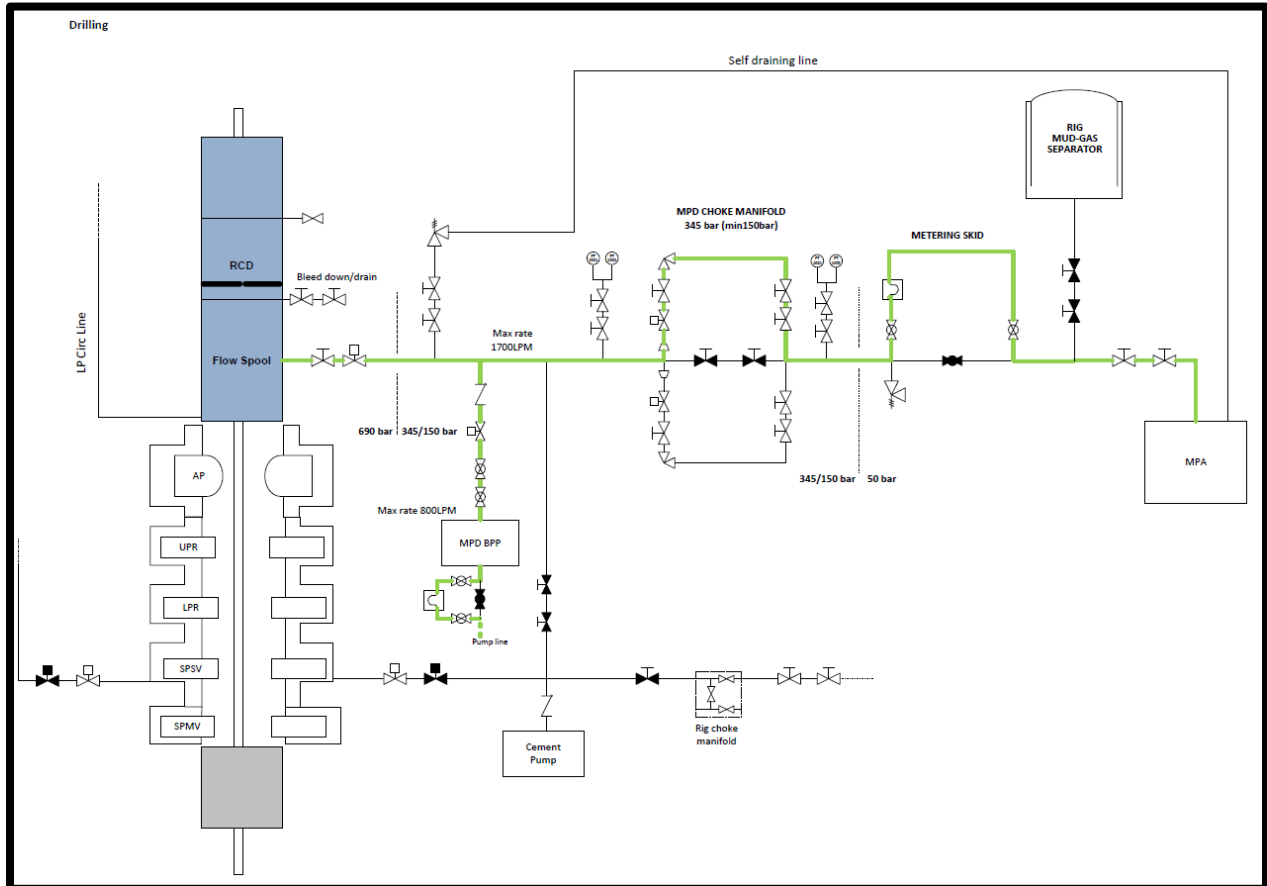


FIGURE 3-20 GENERIC MPD RIG-UP (COURTESY OF NOV)

Using a closed loop system, one can apply back pressure to the annulus by restricting the fluid flow through the operative chokes. As long as there is sufficient flow through an open choke, back pressure is present, and the conventional rig pumps can be used for this purpose. The challenges arise when the flow decreases, or is completely lost, as the amount of back pressure depends on the operator – or systems response time. [22]

When the flow decreases, for example during connections, the choke must be closed to provide the same amount of back pressure. If the flow is stopped, or lost, the choke must be closed completely for trapping the remaining back pressure.

In case of an immediately loss of pressure, for example due to pump failure, the response time will unlikely be sufficient. Failure of maintaining back pressure, leads to a decrease in BHP, which may have large consequences when operating with narrow drilling window.

To overcome these challenges, one of the following components has usually been present during MPD operations:

- Back Pressure Pump (BPP)
- Rig Pump Diverter (RPD)

3.7.3.1 BACK PRESSURE PUMP [1] [4]

A dedicated pump has commonly been included during the MPD operations, with the purpose of providing flow of fluid, and thereby pressure, to the system. When needed, for example during connections, fluid is pumped into the annulus, maintaining the pressure in the well bore.

The back pressure pump (BPP) is connected to the choke manifold, and is automatically controlled by the system. If the pressure manager senses that the well flow is insufficient in order to maintain the BHP, the back pressure pump automatically responds.

Several alternatives exist, including

- Continuously running BPP
- Simple BPP in use during connections
- Speed control from MPD control system, where BPP ramps up when rig pump rams down and vice versa

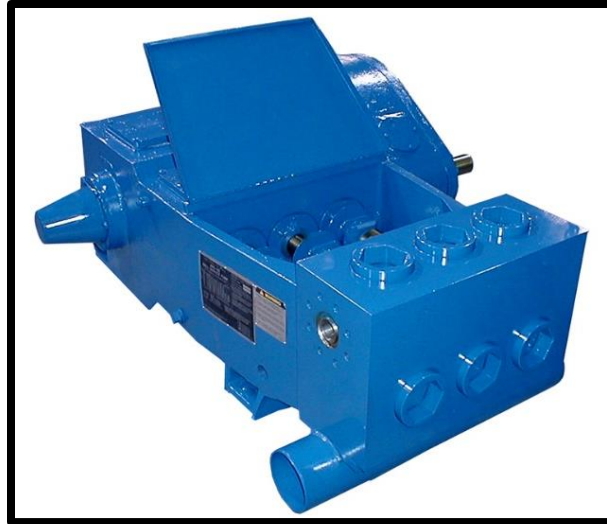


FIGURE 3-21 BACK PRESSURE PUMP, NOV [23]

Even though there are several advantages by using a back pressure pump, it contributes to an increased complexity of control into the system. Particularly when starting and stopping the pumps, the actions can lead to unacceptable fluctuations of the BHP.

3.7.3.2 RIG PUMP DIVERTER (RPD) [4]

With the purpose of achieving more accurate control during no circulation periods, the rig pump diverter was devised. By use of the RPD, the flow can be diverted from the standpipe manifold to the return line, replacing the separate back pressure pump.

Diverting the flow from the existing rig pumps, enables continuous flow during connection, and similar situations where circulation is stopped.

“The RPD is a dedicated skid, which using a combination of coordinated valves and chokes diverts flow from the drill string to the annulus (upstream of the choke) in a completely automated manner”. [4]

By replacing the separate back pressure pump, one eliminates the challenges that arise during connections and tripping operations.

3.8 MAINTENANCE AND TESTING OF EQUIPMENT

Functional equipment is important during all drilling operations, particularly when operating with narrow drilling window, where failure of equipment may lead to a well control situation. For preventing failure and unexpected events, periodically pressure testing of equipment and maintenance is required.

Daily maintenance of equipment, such as lubrication of for example the top drive, are maintained by general routines, performed by the drilling crew personnel.

In addition, maintenance program are established, including periodical inspections, pressure and function tests, in accordance with NORSOK D-010 (2013), Chapter 4.7.3: “Maintenance program and procedures”. Preventive maintenance (PM) routines are maintained in data systems with defined interval between maintenance of the various equipment. The maintenance leader follow up these routines, handing the tasks to the relevant personnel (i.e. technical department, or other), with specific time limit for the maintenance to be performed. The same equipment may have general maintenance for example each month, and extended maintenance each year (i.e. verification of certified parties). Both cases are covered through the PM routines.

For the specific maintenance activity, procedures are available describing how to perform the actual test and important specifications such as valve positions and test medium. Examples of procedures include “testing of BOP and equipment”, “testing of kill and choke manifold”, etc.

Well control equipment permanently installed on the rig shall be periodically function – and pressure tested, according to NORSOK D-010 (2013). The BOP (including annular preventers, pipe rams, shear rams, etc.) shall be function tested weekly, and pressure tested each 14th day to maximum section design pressure (SDP). [7, p. 220] See NORSOK D-010 (2013), “Annex A – Test pressures and frequency for well control equipment”, for overview of the requirements for the various components.

The pressure test is performed in two sequences, low pressure – and high pressure test (Table 3.-1), respectively. It is of major importance to perform the low pressure test before pressuring up the system further, for verification of no leaking in the system, or plugging (of for example the choke manifold). The duration period is important for stable values, throughout the test sequences.

TABLE 3-1 PRESSURE TESTING [6, P. 220]

Test	Test Pressure	Minimum Duration
Low pressure test	15 to 20 bars	5 minutes
High pressure test	WP, WDP, or maximum SDP ⁴	10 minutes

The high pressure test value is either the working pressure (WP), well design pressure (WDP) or maximum section design pressure (SDP). NORSOK D-010 (2013) specify what pressure the various components shall be tested to. [7, p. 220]

For documentation, volumes pumped/bled-off and time to open/close the various function (for example pipe ram) are recorded and plotted in a graph. The graph clearly indicate a successful test (i.e. stable trend), or deviations from the expected pressure.

Introducing new equipment on the rig, temporarily or permanent, the equipment must be included in the testing routines. The equipment must also pass various tests onshore.

The RCD shall be pressure tested prior to delivery, leak tested upon installation on location, and pressure tested after installation. When in operation, the RCD shall, according to NORSOK D-010 (2013), be periodical leak – and functional tested with the same frequency as the drilling BOP. [7, p. 204]

In other words, when included in the rig-up, testing is ensured by the general routines.

⁴ Working Pressure (WP), Well Design Pressure (WDP), Section Design Pressure (SDP)

4 WELL BARRIERS AND WELL CONTROL

Achieving a safe drilling operation relies on functional systems and knowledge among personnel. In case of an unexpected event, one must know how to react and how to handle the situation, with the primary objective to re-establish control of the well. Various well control equipment exist on the rig, including the BOP and choke manifold. Introducing MPD, additional equipment is required, shown in the well barrier schematic.

This chapter will present both conventional drilling and MPD regarding well barriers and well control, with the intention of getting a clear overview and understanding of the differences that occur between the two concepts.

NORSOK D-010 (2013) is used for definitions and principles during the chapter, as it contains the main requirements applicable to the NCS.

4.1 WELL BARRIERS

Knowledge about well barriers is of critical importance, as it is the best tool available for avoiding catastrophic outcome during drilling (and other) operations, and if a well control situation should occur.

A well barrier (WB) is not one particular object or equipment, but an envelope including different elements, that alone or in combination with other elements, prevents uncontrolled flow of fluid from the formation. These elements are referred to as well barrier element (WBE). [7, p. 15]

Considering drilling operations in general, a minimum of two well barriers is required, as it normally includes hydrocarbon (HC) bearing formations. [7, p. 22] One distinguishes between primary – and secondary WB, where the primary WB is the barrier closest to the pressurized – or hydrocarbon bearing formation, i.e. the first barrier preventing uncontrolled flow of fluid. In case of failure of the primary well barrier, the secondary well barrier is activated, preventing influx from the formation.

For a conventional drilling operation, the fluid column is the primary well barrier, with the purpose of preventing influx of formation into the well, operating with a hydrostatic pressure higher than the expected formation pore pressure; $P_H > P_P$.

Secondary well barrier for conventional drilling include, according to NORSOK D-010 (2013), in-situ formation, casing cement, casing, wellhead, high pressure riser and the drilling BOP, listed in Table 4-1.

TABLE 4-1 WELL BARRIERS FOR CONVENTIONAL DRILLING [7, P. 48]

Primary Well Barrier	Secondary Well Barrier
Fluid column	In-situ formation
	Casing cement
	Casing
	Wellhead
	High pressure riser
	Drilling BOP

Ahead of all operations, well barrier schematics (i.e. illustration of the well) are developed defining the primary – and secondary well barriers. In general, blue color defines the primary well barrier (elements), while red color defines the secondary well barrier (elements). The primary well barrier, the fluid column for conventional drilling, is shown in its normal working stage, where the WBE’s are exposed to the wellbore pressure. In case of a failure of the primary well barrier, for example taking in a kick, the secondary well barrier is activated to avoid a well incident scenario, for example a blowout.

In MPD operations, primary well barrier is maintained by a statically underbalanced fluid⁵ column with applied surface pressure. In other words, the BHP is controlled by use of a close loop system (chapter 3) and back pressure pump (or similar equipment).

⁵ One can also perform MPD operations with the use of overbalanced fluid, where the schematic for conventional drilling will apply regarding primary well barrier, but this scenario is not discussed here.

Compared to conventional drilling, the fluid column changes from a primary well barrier to a primary well barrier **element**, meaning that it forms a primary well barrier only in combination with other elements. The reason is that “a well barrier element can only be considered as a well barrier if it can be documented that the element will solely prevent a well incident within both expected and verified operational limits. Otherwise, a combination of several well barrier elements is required.” [24]

The secondary well barrier remains the same as for conventional drilling, listed in Table 4-2.

TABLE 4-2 WELL BARRIERS FOR MPD [7, P. 145]

Primary Well Barrier	Secondary Well Barrier
Statically underbalanced fluid column	In-situ formation
Casing*	Casing cement
Wellhead*	Casing*
High pressure riser*	Wellhead*
Drilling BOP*	High pressure riser*
Rotating control device	Drilling BOP*
UBO/MPD non-return valve	
Drill string or completion string	
UBO/MPD choke system	

In addition, the concept “common well barrier element” is introduced (marked with * in Table 4-2), meaning that the element is shared between the primary – and secondary WB. [7, p. 10]

Operating with common well barrier elements require a risk analysis and risk reducing measures to be applied. One must also be aware that a failure of a common well barrier element means failure of both primary and secondary well barrier element. During the MPD operation at Gullfaks, a leakage in the 13 3/8” casing occurred, leading to failure of both primary and secondary well barrier. See chapter 6.

4.2 WELL CONTROL

Establishing and maintaining control of the well is of major importance during all drilling – and well activities. Well control is a collective term, expressing all measures (including procedures, practices, equipment, etc.) that can be applied for preventing a well control scenario, i.e. uncontrolled release of well bore fluids. [7, p. 15]

In order to maintain well control, monitoring of pressure and volumes is required. As described in Chapter 2, the result of operating with pressure below the formation pore pressure or above formation fracture pressure is an uncontrolled flow situation, i.e. control of the well is lost.

4.2.1 WELL CONTROL ACTION PROCEDURES [7]

Procedures shall be available for all drilling – and well activities (see chapter 5.3). The purpose of well control action procedures is to provide a plan for activating well barriers, and how to react in case of a well control situation. Ahead of any operation, the operator and contractor shall ensure that all involved personell are familiar with the well control action procedures, and a well control bridging document shall be prepared between the disciplines.

According to NORSOK D-010 (2013), the well control bridging document shall define roles and responsibilities related to well control during the operation, shut-in procedures, various methos for how to re-establish well barriers (including activation of alternative WBEs, kill procedures and normalization), and specific well control conficuration for the well activity. [7, p. 29]

Well control action procedures shall be developed for potential incident scenarios related to the specific operation. For conventional drilling operations, potential incident scenarios include, among others, shallow gas influx and influx containing H₂S. [7, p. 42]

In addition, there must be developed action procedures depending on the position of the pipe or tools if an influx should occur (i.e. shearable pipe, non-shearable pipe or no pipe through the BOP). It is of major importance that the operator (i.e. driller) of the BOP system is aware of the position of the various drill string components in relation with the various BOP rams. For example, activation of the pipe ram (designed for sealing the dimension of the drill pipe body), will most likely fail if a tool joint is positioned in the closure area.

Introducing MPD, with related equipment and operation, the main operational risk shall be identified, and included in the well control action procedures. The additional elements are primarily due to the use of common well barrier element, leaking or plugging of MPD equipment, and failure of keeping constant bottom hole pressure. Loss of rig power is critical for all drilling activities, but particularly when operating with narrow drilling window.

4.2.2 WELL CONTROL ACTION DRILLS

Preventive measures include action drills performed by the drilling crew. Action drills are of major importance for familiarizing the involved personnel with techniques and procedures that may be relevant in case of a well control scenario.

For conventional drilling operations, the action drills that should be performed includes kick drill while drilling or tripping (depending on the operation), choke drill and H₂S drill, among others. The frequency depends on the drill to be performed, where for example kick drill while tripping (common operation) shall be performed once per week per crew, whereas the H₂S drill shall be performed prior to drilling into a zone/reservoir that may contain H₂S (i.e. depending on the formation and fluids). [7, p. 43]

These action drills are performed by simulating the various well control incidents, for example taking in a kick while drilling. Local procedures are available for execution, and involved personnel have different tasks during the drills (e.g. driller, roughneck).

The additional well control action drills for MPD operations are in large degree a result of introducing new equipment. Examples of action drills that should be performed include leaking NRV and leak in RCD. In addition, practice related to transferring between conventional and MPD is of major importance, and should be performed once prior to start the MPD operations with the crew on location. [7, p. 141]

In addition to well control action procedures and well control action drills, a well control matrix shall be prepared ahead of MPD operations, defining criteria for stopping the operation and how to respond to the situation.[7, p.141] It is important to develop review and update the matrix ahead of each operation, as new elements (for example downhole pressure conditions) or

equipment may be present. All personnel involved in the operation must be well familiar with the MPD matrix, for ensuring a safe execution.

4.2.3 WELL CONTROL SCENARIO

Typical indicators for taking in a kick, include, but are not limited to [10]

- Well flowing with the pumps off
- Changes in drilling rate
- Increase in the mud flow from the well
- Pit gain
- Decrease in pump pressure and increase in pump speed
- Increase in rotary torque

If changes in drilling parameters should occur or a suddenly increase in ROP (known as drilling break), it is normal procedure for the driller to perform a flow check in order to verify if the changes is caused by “false alarm” or small fluctuations, or if it is actually a well control scenario.

- **Flow check:** “A test performed to ensure stable well conditions or the integrity of a plug, valve or flow-control device. In most cases, the flow check involves observing stable fluid levels or conditions for a prescribed period.” [25]

Table 4-3 illustrates the procedure for performing a flow check, either conventionally or during MPD operation.

TABLE 4-3 FLOW CHECK PROCEDURE

Step	Conventional	MPD
1	Pull bit of bottom	Stop drilling
2	Stop pumps and operation (rotation)	Continue rotation and circulation
3	Monitor pit volumes for 15 minutes	Monitor flow meter, pit volumes and system pressure for 15 minutes

If no change in pit level is observed, then the well condition is stabilized, and the drilling operation can continue. If an increase or decrease in pit level volume is experienced, action is required.

In case of an influx scenario (i.e. positive flow check), the situation shall be handled conventionally⁶, specified in MPD well control matrix. Several methods for killing the well exist, whereas the most common is the “Driller’s Method” and the “Wait and Weight”. Common for both methods, the first step is to shut in the well (close the BOP). Gathering of parameters, implemented in so-called kill sheets, shall also be prepared in advance, independent of kill method. These kill sheets includes such as drill string – and annulus volumes, pressures and depths, and shall be filled out prior to drilling out of the casing shoe. The latter part consist of formulas for calculating necessary pressures and kill mud weight, which shall be filled out after shutting in the BOP, i.e. a kick situation is confirmed.

4.3 DISCUSSION

The purpose of well barriers and well control is the same, but high attention must be paid to the new concepts. For example the change in barrier philosophy, listed as a hazard in chapter 2, must be managed, and understood, by the involved personnel.

Arne Handal and Sondre Øie, DNV, have presented an analysis to address this challenge, “Safety Barrier Analysis and Hazard Identification of Blowout using Managed Pressure Drilling Compared with Conventional Drilling” [26]. The result presented states that MPD systems do have significant advantages both in terms of safety and productivity, but the risks related to implementation of what they define as safety critical equipment need to be managed through reliable and efficient control system. The meaning behind the term “safety critical equipment” is that failure of the equipment may lead to loss of well control, and yields for the dynamic and static MPD pressure control equipment and the MPD control system. Further, it is stated that the degree of criticality depends on the individual system and operation procedures.

⁶ Several articles and publications present ideas for how to kill the well with MPD. An example is the automatic kick control (AKC) procedure, by the use of PWD technology. The method will not be further discussed here, see “Automatic kick control reduces kick size, time to establish control of well” provided by IRIS (International Research Institute of Stavanger) for details.

On the other side, MPD may be a better choice, as presented in chapter 2. Summarized, advantages include:

- MPD do not plan for influx
- In case of influx, the amount and size can be limited by rapid pressure adjustment
- Standard flow check is replaced by a dynamic flow check, where BHP is kept constant
- Earlier detection in case of an influx scenario, operating with closed loop system and a high accuracy flow meter installed

Most importantly when introducing a new technique is that all personnel involved in the operation, both onshore and offshore, understand the differences and new requirements introduced by the technique. Special attention should be put on operating with underbalanced fluid, and the use of common well barrier element.

5 DRILLING OPERATION AND PERSONNEL

Several disciplines and companies are present during drilling operations. Ahead of executing a drilling operation, involved personnel must be trained and qualified to participate. This chapter consists mainly of the drilling crew personnel, as it is the discipline performing the actual drilling operation.

The drilling operation includes various sequences, where pressure testing of formation is an important part for achieving a safe operation.

The content in this chapter is largely based on experience from offshore personnel, working in Archer – the well company, a global oilfield service company.

5.1 OFFSHORE PERSONNEL

The personnel present on a platform represent various companies, whereas one distinguishes between the following disciplines/roles:

- Operator: The operator company has the overall responsibility for the drilling projects, and shall ensure that activities are carried out in accordance with the regulations. Examples of operator companies include Statoil, Shell, BP, etc.
- Contractor: The contractor company owns and operates the drilling rig. The contractor offshore personnel are commonly referred to as “drilling crew”. Examples of contractor companies include Archer, KCA, Odfjell, etc.
- Service: The service companies provide a large range of products and services for the specific activities. Examples of service companies include Schlumberger, NOV, Halliburton, etc.

Assuming a normal drilling operation, the offshore drilling crew (commonly) consists of the following positions with related responsibility and tasks:

- Tool pusher: The tool pusher is the offshore leader for the drilling crew, responsible for achieving a safe drilling operation, and that the operations are performed according to requirements and local procedures.

- Driller: The driller is the operator of the control system, described in chapter 3, and the actual drilling operation.
- Assistant Driller: The assistant driller is in place to assist the driller, and is usually responsible for the line-up of BOP and manifolds, the equipment on the platform used during the operations, and that the roughnecks are competent for the operation.
- Roughnecks: The number of roughnecks varies, but a minimum of three are common practice. The roughnecks work at the drill floor, preparing the drill string components at the drill floor before run in hole. In addition, they usually operate the shakers during operations.
- Derrick man: The derrick man is responsible for the operation and maintenance of the rig pumps, and the different tanks providing drilling fluid, water, etc.
- Roustabout: Two or more roustabouts are common, working in the pipe deck area. The roustabouts are involved in the logistics on the platform, and prepare the drill pipe and similar pipe or components at the pipe deck, before transferred to the drill floor.
- Technical personnel: The technical department consists of electrical and mechanical personnel, and is responsible for the maintenance of the technical equipment. In case of failure of equipment or systems, the technical department is present.
- Material man: The material man is responsible for transferring and logistics of equipment, and shall know what equipment that is present on the location.

The Rig Manager is the onshore leader for the contractor drilling crew, responsible for one specific installation.

The operator – and service companies provide the following offshore positions:

- Drilling Supervisor: The drilling supervisor is the operator representing, with the responsibility for drilling – and well operations.
- Engineer: During specific operations, for example drilling – or completion activities, a well engineer (from the operator company) is present at the rig, for preparing procedures and follows up equipment, among others.

- Mud engineer: A mud engineer (provided by a service company) is usually present on the rig, with the purpose of mixing correct mud weight according to the pressure limits.
- Cementer: The cementer (provided by a service company) is present during cementing operations.
- Directional Driller: The directional driller (provided by a service company) is present during drilling operations, assisting and supervising the driller for example when changing the drilling direction.
- Casing operator: The casing operator (provided by a service company) is present when running or pulling casing, for operating the casing tong (similar tong as the iron roughneck).
- Geologist: A geologist (from the operator company) is usually present when drilling into the reservoir.

The number of personnel in each position can vary within the same company and/or different companies. There might also be other positions provided by service companies in special cases, for example during well intervention or pulling of plugs; Wireline (WL), Coiled Tubing (CT), etc.

During previous MPD operations, additional positions have been present on the platform, provided by the MPD contractor, on an external third party.

- MPD supervisor: A MPD supervisor has been present on each shift (day and night), responsible for the MPD operation offshore, meetings, reporting, etc.
- MPD operators: One or two MPD operators have been in place, responsible for operation of the MPD system (software, maintenance, ensures accuracy of the hydraulic model calculating choke pressure, etc.)
- RCD operator: One or two RCD operator has been in place, responsible for operating and monitoring the RCD, including maintenance.

5.2 TRAINING OF DRILLING CREW PERSONNEL

The Activities Regulations, Chapter VI “Operational Prerequisites for Start-up and Use”, Section 21 “Competence”, state: “The responsible party shall ensure that the personnel at all times have the competence necessary to carry out the activities in accordance with the health, safety and environment legislation. In addition, the personnel shall be able to handle hazard and accident situations, cf. Section 14 of the Management Regulations and Section 23 of these regulations.” [27]

The regulations do not specify the exact meaning of competent personnel (i.e. training and courses required), but relies on the operator -, contractor -, and service companies to fulfil the requirement. Depending on the working position and tasks, trainings program are developed, including courses, practical tests or similar.

When working in a drilling company, one usually starts the offshore career as a roustabout, working on the pipe deck area. After gaining knowledge about pipe – and equipment handling, lifting and other deck relevant operation, the next position is roughneck. Working as a roughneck, the activities shifts from “prepare for drilling operation” at the pipe deck to “perform drilling operation” at the drill floor. Knowledge about lifting and handling equipment operations is of major importance, and understanding of well control and related equipment is critical. As a roughneck, you also learn about the function and maintenance of the rig pumps and thereby circulation system, which leads you to the next position; derrick man.

In order to move further up in the system, and work as an assistant driller, education is required among many companies. Common education is technical school, which is an “extended education” for people having a “certificate of apprenticeship”. Alternatively, relevant university education is accepted, showing an increasing trend today.

In addition, personnel operating the critical well control equipment are required to complete a course called “Drilling Well Control”.

5.2.1 IWCF DRILLING WELL CONTROL

“International Well Control Forum (IWCF) is the only independent body focused on oil and gas well training and accreditation”. IWCF provide various programme and training standards, including “Drilling Well Control”. [28]

The programme is designed for personnel working with critical well control on drilling installations, and consists of various levels, depending on the position.

Personnel attending the course must pass both written – and practical exams, where the latter one is a simulation task. After completing and passing the course, the certificate is valid for two years.

5.2.2 TRAINING OF PERSONNEL AHEAD OF MPD OPERATION

Ahead of MPD operation, involved personnel shall complete a basic MPD course. According to NORSOK D-010 (2013) this apply for the rig crew personnel operating well control equipment (i.e. assistant driller, driller and toolpusher), the drilling supervisor, the MPD supervisor, the MPD operator, the drilling engineer, the drilling superintendent, the rig manager, and the platform/site manager. [7, p. 144]

The personnel (except the platform/site manager) shall in addition [7, p. 144]

- complete an installation specific course (refresh every second year)
- perform on site training ahead of MPD operation, including planned operations and contingencies

5.3 MANAGEMENT SYSTEM

The Framework Regulations, Chapter III “Management of The Petroleum Activities”, Section 17 “Duty to establish, follow up and further develop a management system”, state: “The responsible party shall establish, follow up and further develop a management system designed to ensure compliance with requirements in the health, safety and environment legislation.” [29]

The related guideline, Re Section 17 “The content of management systems”, state: “Management systems shall cover the organisation, processes, procedures and resources necessary to ensure

compliance with requirements stipulated in the health, safety and environment legislation. More detailed provisions regarding management systems, including the content, are stated in the supplementary Management Regulations.” [30]

5.3.1 OPERATOR

The operator has a management system including technical requirements and guidelines. These are built upon the regulations, and apply for all operations within the company.

For the specific well, for example “Drilling of well A”, activity programs are made in advance, including scope, operational risks, pressure prognosis, casing setting depths, etc. The risks elements with related impact are presented in a risk matrix, including actions for limiting the risk.

5.3.1.1 RISK MATRIX

For a visual understanding, Figure 5-1 illustrates the general principles of a risk matrix, defined in terms of probability and impact/consequence. If one can rule out the probability or impact of an event, the risk is significantly reduced.

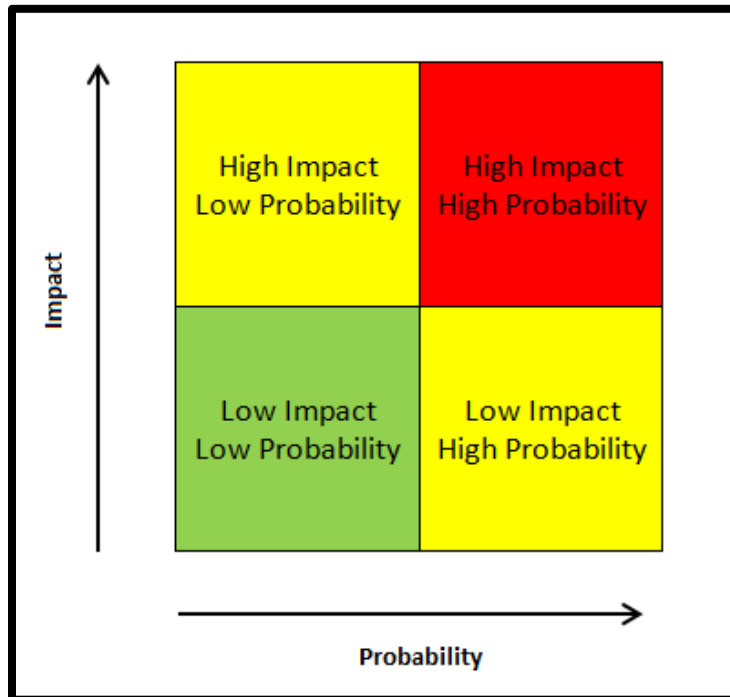


FIGURE 5-1 SIMPLE ILLUSTRATION OF RISK MATRIX

There will always be a risk for accidents to occur (for example well kick during drilling operations), but identifying the possible hazards in advance, will contribute to reducing the probability and/or the consequence, and thereby the risk. Well barriers are examples of risk management, with the purpose to reduce the probability, or the consequence.

5.3.1.2 DETAILED PROCEDURES

Introduced briefly, procedures shall be present during all drilling – and well operations. Procedures are living documents, meaning that they are under continuous improvement. A procedure is a result of regulations, experience and knowledge. The regulations define the requirements that apply, whereas the operator company uses the requirements as a foundation for the company specific procedures.

In addition to the activity program, more detailed procedures are prepared by the drilling engineer, for example “Drilling 8 ½” section”. These procedures includes specific parameters (depth, pressure, etc.) and main operational risk (for example drilling into a reservoir) for the specific well section, and is reviewed by the leader personnel before delivered to the drilling crew ahead of the operation.

The drilling – and service companies usually have their own management system including procedures on a more detailed level, within the frame provided by the regulations and the operator. These procedures may include equipment – and operational specific procedures, or other relevant services provided by the companies.

The principle of procedures will be similar for conventional drilling and MPD, but the conventional procedures must be enhanced in order to account for MPD operations. Particularly the new hazards introduced by MPD must be identified by a risk analysis, for example through a HAZID (Hazard Identification Study), and be handled carefully during the planning phase. The purpose of the HAZID is to quickly identify and describe the potential hazards associated with an operation.

Every analysis undertaken should be documented, and be available for all relevant personnel. General hazard, such as change in barrier philosophy and drilling with underbalanced fluid, should also be included in the coursing and training program.

5.4 OPERATIONAL SEQUENCE

The drilling hazards described in chapter 2, are primarily a result of pressure variations during the drilling – and tripping operations. The actual pressure seen depends on the activity, including the hydrostatic -, annulus frictional -, bottom hole – and back pressure.

A normal operation consist of handling of bottom hole assembly, tripping of drill pipe, drilling and making connections. Formation testing is performed when required.

5.4.1 HANDLING OF BOTTOM HOLE ASSEMBLY (BHA)

Handling of bottom hole assembly (BHA) is usually a time consuming process as it often consist of several components with various sizes (i.e. might have to change the pipe handling grip size).

The size of the components also influences the frictional pressure loss, as it determine the annular clearance, i.e.

$$A = \frac{\pi}{4} (ID_W^2 - OD_P^2) \quad [5.4.1]$$

TABLE 5-1 ANNULAR CLEARANCE

Term	Parameter	Unit
A	Annular Clearance (Area)	m ²
ID _W	Inner Diameter of Wellbore Wall	M
OD _P	Outer Diameter of Pipe/Drill String	M
π	Pi, constant 3.14	dimensionless

Too small annular clearance may induce high friction pressures, while too large annular clearance may result in insufficient hole cleaning. The frictional pressure loss is influenced both during conventional mode and MPD mode, but MPD has the advantage that the pressure can be easily adjusted.

5.4.2 TRIPPING

After the handling of BHA is complete, the next step is to run in hole (RIH) with drill pipe.

Tripping of drill pipe is the act of running in hole (RIH) or pulling out of hole (POOH). Introduced in chapter 3, the operation commonly involved handling of pre-made stand from the set back to the well center.

The action of tripping creates large pressure variations in the well bore. When running in hole, the well bore pressure (hydrostatic pressure) increases as the drill string displaces the fluid. When pulling out of hole, the well bore pressure (hydrostatic pressure) decreases as the fluid level drops when removing the drill string.

During conventional tripping, the drill string is not rotated, but the pumps are run when “filling the hole”, in order to maintain sufficient hydrostatic pressure to control the formation pressure.

For MPD operations, the wellbore pressure is kept constant by the use of conventional mud. When tripping out of hole, various methods are available; including bottom kill, balanced mud pill and rig assisted snubbing. Balanced mud pill and rig assisted snubbing has less negative impact on the bottom hole pressure, but is a more complex operation. Having a sufficient drilling window, bottom kill is the preferred method, where overbalanced fluid is displaced at TD to compensate for the frictional pressure loss.

5.4.3 DRILLING

After reaching the pre-drilled depth (i.e. previous section) with the drill bit, the operation shift from tripping of pipe to the actual drilling operation. The rotation of the drill string starts, and the pumps are continuously running, i.e. continuous circulation of the wellbore fluid. The drilling sequence is finished when the pre-determined target depth (TD) is reached.

Well control is critical during drilling operations, particularly if drilling into the reservoir. It is hard to obtain accurately information about the formation, and geological interpretations always include a various degree of uncertainty in down hole conditions.

During conventional drilling, large pressure variations are imposed by the driller’s actions, damaging the formation and worst case leading to a well control scenario, or fracturing of the formation. MPD reduces the probability for well control incidents, operating with constant BHP within the pressure window.

5.4.4 MAKING CONNECTIONS

The different pipe, and tools, has connections on the lower and top part. These can be either threaded or non-threaded, connecting two components. The term “making connections” describes the operation of adding drill pipe/stand to the top of the drill string. In other words, connections must be made up every time elements are added to the drill string, both during BHA handling, tripping and drilling operation.

Table 5-2 illustrates the procedure for making connections, both during conventionally and during MPD operation.

TABLE 5-2 OPERATIONAL SEQUENCE FOR MAKING CONNECTIONS

Step	Conventional	MPD
1	Stop rotation of drill string	Stop rotation of drill string
2	Stop pumps in a controlled manner	Pumps are ramped down, while the choke is adjusted correspondingly to maintain constant BHP
3	Add a new pipe/stand to the drill string and make the connection	Add a new pipe/stand to the drill string and make the connection
4	Start pumps in a controlled manner	Pumps are ramped up, while the choke is adjusted correspondingly to maintain constant BHP

Converting Table 5-2 in the means of pressure terms:

TABLE 5-3 OPERATIONAL SEQUENCE FOR MAKING CONNECTIONS (PRESSURE TERMS)

Step	Conventional	MPD
1	$BHP = P_H + P_A$	$BHP = P_H + P_A$
2	$BHP = P_H$	$BHP = P_H + P_{BP}$
3	$BHP = P_H$	$BHP = P_H + P_{BP}$
4	$BHP = P_H + P_A$	$BHP = P_H + P_A$

As shown in Table 5-3, the frictional pressure is lost during step two and three. This is a result of stopping the pumps, and thereby the circulation. The action leads to a reduction in the BHP, shown in Figure 5-2 and 5-3. The numbers corresponds to step 1-4 in Table 5-2 and 5-3.

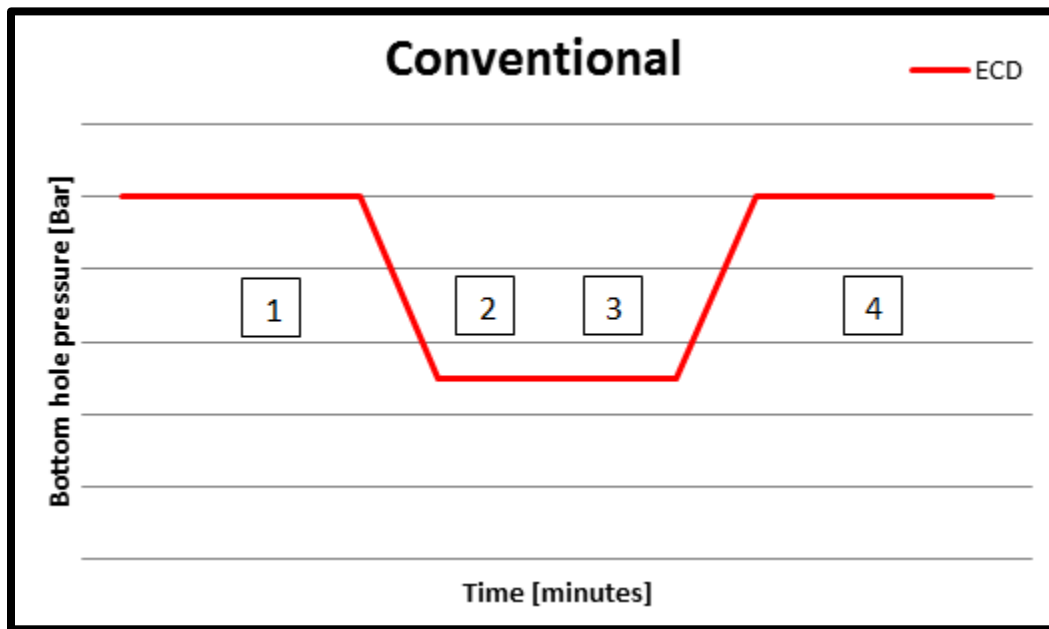


FIGURE 5-2 ILLUSTRATION OF BHP DURING CONNECTIONS

Operating with small pressure limits, this action could lead to an influx scenario, as the BHP is lower than the formation pore pressure.

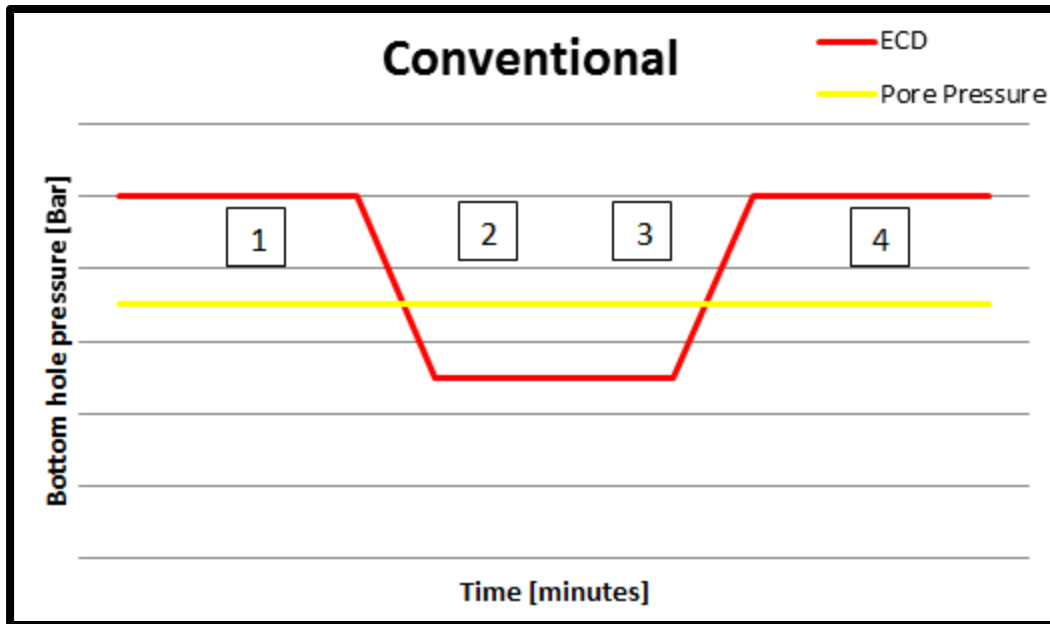


FIGURE 5-3 ILLUSTRATION OF BHP LOWER THAN FORMATION PORE PRESSURE

Another challenge is to ensure volume control after connections. When starting the pumps after a connection, it will take some time for the flow to circulate through the system. Hence, it is difficult to register if there is any decrease or increase in the active volume.

The MPD choke manifold makes it possible to hold a constant BHP during connections by adjusting the choke correspondingly as the pumps is ramped down. The frictional pressure is lost, but is replaced by a pressure provided by the back pressure. Maintaining a constant BHP during connections avoids the potential of taking in a kick caused by the reduction in the BHP.

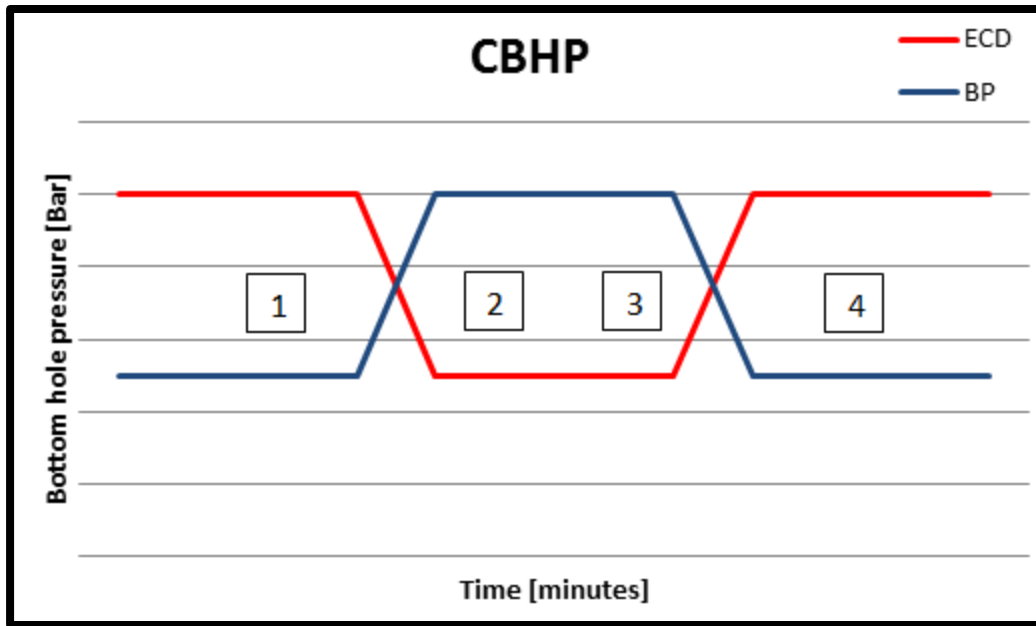


FIGURE 5-4 ILLUSTRATION OF CBHP DURING CONNECTION

5.4.5 FORMATION TESTING [1]

Ahead of drilling into a new formation, verification of sufficient formation integrity is crucial. The purpose of formation testing is to confirm or investigate the strength of the formation.

Several methods exist for determining formation integrity, including pressure/formation integrity test (PIT/FIT), leak-off test (LOT) and extended leak-off test (XLOT). [7, p. 26]

Formation testing is usually conducted at the casing shoe immediately after drilling a few meters into the new formation. The casing shoe is in most cases expected to be the weakest point in the open hole.

During the leak-off test (LOT), the well is shut in (rams closed) and fluid is pumped into the wellbore. The pressure is gradually increased, and at some pressure, the fluid will enter the formation, fracturing the rock. Injected volume is plotted versus surface pressure, and is presented in graph. The result controls the maximum pressure that can be applied to the well during drilling operations. Figure 5-5 illustrates the test sequence, where the LOT point is the yield point where fluid starts to leak off into the formation.

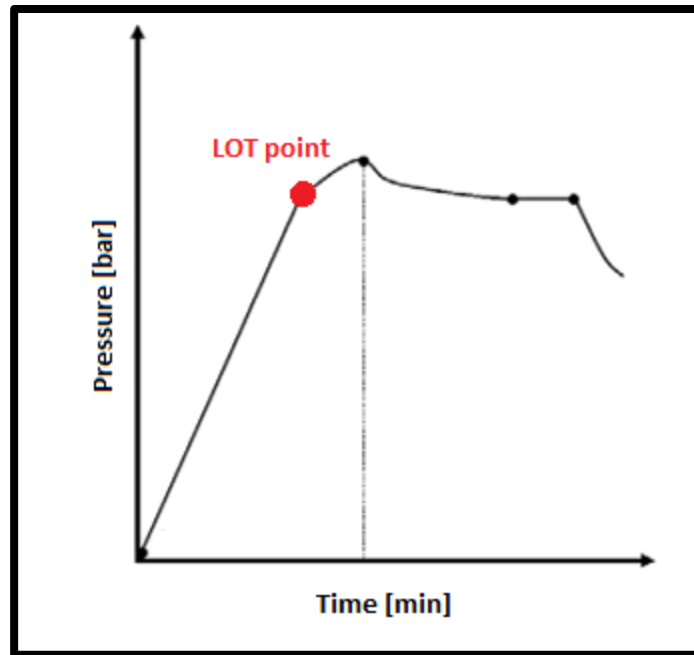


FIGURE 5-5 ILLUSTRATION OF LOT [1]

The highest pressure point on the graph is known as formation breakdown pressure (FBP), depending on various factors such as the tensile strength of the rock, the stress concentration surrounding the well bore, and the frictional losses due to fluid moving through the fractures. [1, pp. 32-33]

Performing a LOT induces the risk of weakening the well bore walls, as one actually break down the formation. In case of a brittle permeable zone, the result may be major losses to the formation.

To prevent formation damage, only formation integrity test (FIT) is usually conducted when operating with narrow drilling window. During the FIT one apply pressure until a pre-determined maximum value is reached, avoiding the formation to break down (i.e. lower pressure than LOT point in Figure 5-5). The values obtained cannot be used for evaluation of true formation fracture gradients, but gives a verification of sufficient strength.

MPD offers dynamic formation pressure tests while drilling, by increasing the back pressure in steps while monitoring the flow in and out of the well. The pressure can rapidly be increased or decreased, which reduced the chances for loss of well control.

MPD also provides the possibility to test the formation pore pressure, by reducing the bottom hole pressure. During conventional drilling, one cannot perform pressure testing of the pore pressure, as the drilling fluid is overbalanced at all times. As mentioned, the only way to reduce the hydrostatic pressure is to altering the mud, which is a time-consuming process. The primary well barrier would be lost, and the well exposed to an inflow scenario.

6 CASE STUDY: GULLFAKS C

Experiences and lesson learned during previous operations, is a useful tool when evaluating a technique, considering both positive and challenging experiences. Gullfaks C is an example of the latter one, resulting in a well control situation. The PSA's audit report and Statoil's investigation report are open documents, available at the internet, and are used during the case study.

6.1 GULLFAKS FIELD [31]

Gullfaks is an oilfield located in the northern part of the North Sea, known as the "Tampenområdet" (Tampen area). The field consists of three platforms, Gullfaks A, B and C, which started up in December 1986, February 1988 and November 1989, respectively.



FIGURE 6-1 GULLFAKS C [31]

From a geological point of view, the reservoirs consist of sandstone, located at 1700-2000 meters true vertical depth, and are characterized by unconformities and faults, which can be seen as cracks or fracture in the formation. The driver mechanisms for oil recovery are water-, gas- and water-altering gas injection, with water injection as the primary strategy.

The combination of faults and injection has contributed to complex and difficult drilling operations on the Gullfaks, as the field consist of over pressured areas. This was one of the reasons for Statoil applying MPD on Gullfaks C in 2009.

6.2 SUMMARY OF WELL C-06 A [32] [33]

The planning of well C-06 A started in 2008. In the autumn of 2009, the original well path was plugged⁷, and a sidetrack was drilled in December 2009. Statoil decided to apply managed pressure drilling technique for the last section, based on measured formation strength. Abnormal pressure caused by injection from neighboring wells increased the risk of drilling the well conventionally. During the drilling operation, several events of instability occurred, and in May 2010, the result was loss of well control.

Petroleum Safety Authority (PSA) Norway conducted the audit with the purpose of clarifying the reasons for the event. The conclusion states serious defects during the planning of well C-06 A. Several aberrations from the management -, activity – and framework regulations was proven, including risk management, knowledge and compliance of management system, competence and handover, among others.

Statoil investigation report is based on PSA's audit, with the purpose of preventing similar events in the future, and to contribute to learning for achieving a general improvement at the HSE-level.

6.3 DRILLING OF WELL C-06 A [33]

It was planned to drill the sidetrack (C-06 A) of the original wellbore C-06 conventionally, and the drilling program was approved 30.09.2009. The main risk identified in the drilling program included narrow window between pore – and fracture pressure, drilling into a high pressure zone and unexpected pore pressure, among others. [33]

The conventional drilling operation of well C-06 A, during the period from 21.11.09 to 19.03.09, included plug and abandonment (P&A) of well C-06 A, new sidetrack (C-06 AT2) of the original wellbore which had to be plugged back as a result of loss when drilling out of the shoe, and a third sidetrack (C-06 AT3). The drilling operation of C-06 AT3 is ended 19.03.09.

⁷ Plugging is the action of securing the well with required well barriers. Plug and abandonment describes a well that is secured and left, temporarily or permanent. A sidetrack is when a new well path is drilled from an original wellbore, often noted by a number behind the original well number (e.g. C-06 AT2)

After a challenging period, it is considered to drill the well with alternative solutions, based on new pressure prognosis. The decision of MPD is made.

According to the investigation report, the transition from conventional drilling to MPD involve changes related to: [33]

- New drilling method
- New requirements due to common well barrier element
- Changed assumptions for relief well
- New safety margins
- Change in kick margin
- New requirements to training

6.3.1 MPD OPERATION [33]

The 20th of March, it is decided to drill a 2300 meters long reservoir section. The operational details will not be discussed here, but the starting point for the operation, included

- MPD margin for loss and influx: +/- 0.85 bar
- Operational window, defined by pore – and fracture pressure: +/- 2.5 bar

The first section of C-06 AT4 is drilled conventionally, leading to loss of fluid and influx in the well. The 24th of March Statoil request for a dispensation for exception of the “two independent well barriers”-requirement for the transition from conventional drilling to MPD. The MPD equipment is rigged up 28th of March, and the dispensation is approved the 31th.

The 13th of April, the sidetrack of C-06 AT4 (i.e. C-06 AT5) is started with MPD mode.

In addition to the operator and drilling contractor, two additional companies were present at Gullfaks C during the operation: the MPD supplier and the PCD operator.

The additional equipment for the MPD operation included

- Pressure Control Device (PCD)
- Back Pressure Pump (BPP)

- MPD choke
- Flow meter

The period from 05.05 to 19.05, when drilling to target depth (TD), is characterized by several challenges, including

- Several events with loss of fluid and influx
- Pressure increase in annulus
- Change of PCD packing element, while leakage in stripper annular
- Problems with back pressure -, feed – and cement pump.
- Periods with underbalance
- Leakage in mud system

6.3.2 THE INCIDENT [33]

The drilling operation of C-06 AT5 to 4800 m (TD) is completed. During the final circulation and clean-up of the well section, a hole occurs in the 13 3/8” casing, leading to loss of drilling fluid to the formation. As casing was a common well barrier element, shown in chapter 4, the hole in the casing led to loss of both primary and secondary well barrier.

Due to insufficient/loss of back pressure, the reservoir fluid started to flow into the well, until the 9 5/8” shoe were packed off as a result of soils and cuttings. Fortunately, this pack-off restricted further inflow of hydrocarbons to the well.

The drill string was pulled off bottom during the event, in conjunction with changing the packing element of the PCD. In order to maintain constant bottom hole pressure, circulation is provided by the cement pump. The stripping annular (described in chapter 3) is closed for sealing off the pressure in the well.

6.3.3 CONSEQUENCE [33]

The event led to gas leakage, impairment of safety and lost reputé. Production at the platform was stopped for almost two months, resulting in a loss (delayed) of 1084 MNOK. Other economic losses were estimated to 677 MNOK. Based on this, the event was classified with actual seriousness level 1.

6.3.4 CAUSES [33]

The immediate causes include insufficient technical integrity of the 13 3/8" casing and insufficient drilling window between the pore – and fracture pressure.

The underlying causes include

- Insufficient risk evaluation of the casing as a common WBE due to insufficient technical integrity of the casing, and lack of monitoring and follow-up of the annulus pressure
- Operation carried out with insufficient drilling margin due to insufficient risk assessment during the planning phase, insufficient risk evaluation during the operation and insufficient transfer of experiences from previous operations

“Other causes are related to insufficient planning of the operation, knowledge to and compliance with requirements, MPD-knowledge and involvement of the Company’s technical expertise.” [33]

6.3.5 OBSERVATION

The observations reported by PSA, include [32]

- Risk management and change control
- Experience transfer and use of expertise
- MPO (Managed Pressure Operation)
- Governing documents
- Documentation of implemented planning and decision-making processes
- Management responsibilities

6.3.6 ACTIONS [33]

For preventing similar incidents in the future, the investigation report presents

- Short-time actions, including update of pressure prognosis
- Actions related to management system (verify and clarify requirements)
- Other actions, including, among others
 - o Improve lifetime of the PCD packing element
 - o Improve running tool for the PCD packing element

- Find a technical solution that does not expose the back pressure pump for damaging pressure shock

6.4 COMMENTS

The purpose of including the case study is not to evaluate what did go wrong or criticize the performance, but to highlight the elements that could be improved in the future. Some of the elements are included in interviews with relevant personnel.

7 INTERVIEWS WITH PERSONNEL

As part of this Thesis, personnel working in Archer have been interviewed. The personnel are well familiar with conventional drilling operations, and some of these have participated in previous MPD operations. The main topics through the interviews included

- Planning
- Training and coursing
- Equipment
- Responsibility

The experiences from the personnel introduced to MPD indicate insufficient planning, information and training. MPD was not accounted for in the planning phase, and the decision was made too quickly.

Even though the personnel had been working in the oil industry for many years, the drilling crew had no experience or knowledge about MPD in advance, and the whole process, from introduction of MPD to execution, happened too rapidly.

It is important to highlight the fact that an experienced drilling crew is unfamiliar with managed pressure drilling, which most likely indicates that this applies for other personnel as well.

Ahead of the operation, involved personnel completed a basic e-learning course about MPD, introducing the general concepts and equipment, common for the operation. In addition, relevant personnel attended an onshore course, on a more detailed level. The feedback from the onshore course is that equipment played the major role, compared to well control and change in barrier philosophy.

Except from the introduction given at the course, the personnel had no experience with the additional equipment introduced by MPD. The additional equipment and rig up requires sufficient space availability, which existing platforms may not have. Typical limitations may be the height of the BOP deck (due to the RCD, stripper ram and annular ram), and space for placing additional equipment, including the back pressure pump and choke manifold. The rig up of

equipment is also a time consuming process, depending on the activities on the platform, and other conditions, such as wait on weather (WOW). The reliability of the additional equipment is also mentioned, particularly the life time of the RCD seal.

As several disciplines are included in the execution, the competence is spread among the personnel. The driller has experience with conventional drilling, and knows how to work the drill string into the hole. The choke operator is trained to respond to the pressure variations, and the RCD operator is familiar with the RCD and related maintenance. Each discipline has their own specialties and activities as focus, but neither the driller nor the choke operator are completely competent in each other ask. The responsibility is influenced as no one has the overall 100% responsibility. Another drawback with including several disciplines is that one must learn to know each other and how to ensure communication, as well as the external parties may have a different shift rotation compared to the rig contractor, meaning that new personnel are included in the operation every time.

Early in the planning phase, MPD must be presented to personnel, having in mind that this is a new operation. The personnel have experience and knowledge about common terms like well control, well barriers, pressure, etc., applying for conventional drilling. However, they do not have any experience, most likely, with drilling with underbalanced fluid, for example.

After discussing previous operations and experiences, the latter part of the interview focuses on MPD in the future.

7.1 MPD IN THE FUTURE

Two subjects are central when discussing improvement of the MPD execution

- Planning
- Training and competence

Early integration between involved parts is important when introducing new techniques. Creating a forum for questions and discussion, will improve both planning and execution. The personnel will be informed and prepared early in the project, and may contribute with important

inputs. Training of personnel should also be started as soon as the decision of MPD is settled, or even just a contingency plan.

The basic MPD course (ref. NORSOK D-010) could be an e-learning course, or one day onshore course. As the personnel already are familiar with conventional drilling operation, the primary objective of the e-learning course should be to highlight the differences that occur when introducing MPD. The hazards listed in chapter 2 are a good starting point for what should be presented during the course. Key elements should include

- What is MPD?
- Additional equipment
- Regulations
- Well control and action procedures
- Operations and new hazards

Considering the onshore course, the well control course provided by IWCF is an example of how the course could be set up, either as a module of the course, or a separate course.

Curriculum similar to conventional drilling should be given, including control systems, well control, equipment, etc. A test should be given the last day, with a minimum percentage passed. Simulation should also be a part of the course, giving practical training and visualization of the operation. Simulation is mentioned as the best tool for training, particularly when operating with automatic systems, giving the opportunity to “try and fail”.

The course should be a requirement for the personnel working directly with MPD, in sufficient time advance of the operation. The course may be divided into several modules, depending on the position (driller, technical department).

Increasing the competence among the personnel will contribute to better planning including quality assurance of detailed procedures, risk identification and mobilizing of equipment.

The interviewed personnel find the MPD technology interesting, and are positive for similar operations in the future.

8 RIG INTEGRATED MPD

In the preceding chapters, the main operations and equipment involved in MPD operations have been discussed. In addition, a case study has been presented, and key drilling contractor personnel have been interviewed. Based on these learnings, it is apparent that significant improvements can be made by having MPD operations more integrated with the normal drilling operations. This chapter will present a proposed path towards a fully integrated MPD operation.

Proposed steps to fully integrate an MPD system, include

1. MPD equipment permanently installed on the installation
2. Advanced control system integrated into drilling control system
3. Drilling contractor performing the MPD operation

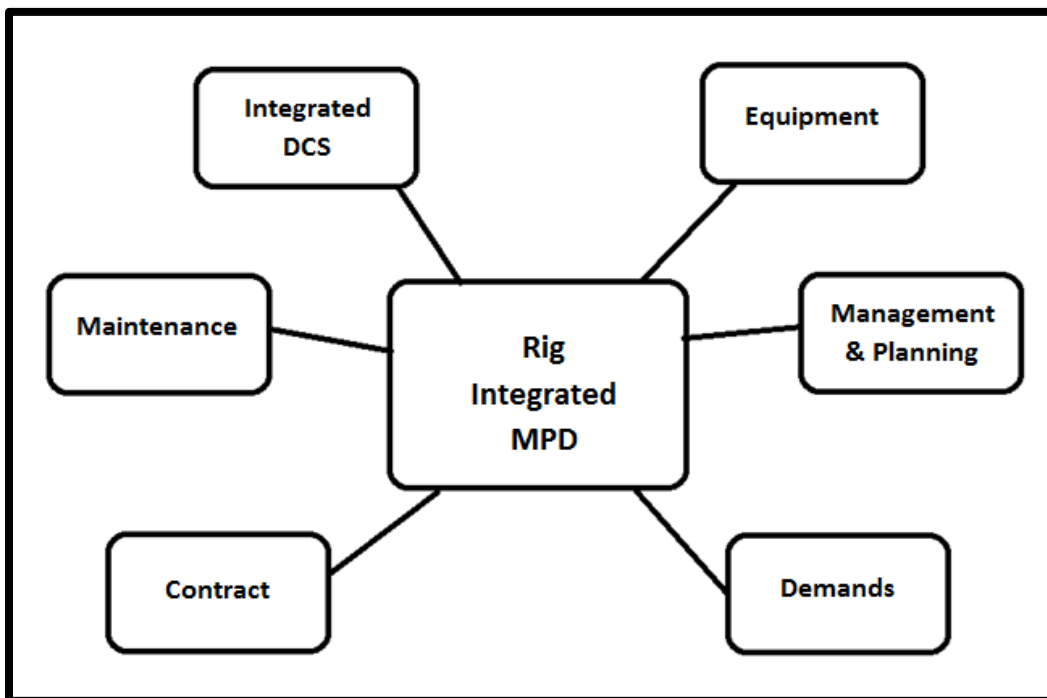


FIGURE 8-1 RIG INTEGRATED MPD

8.1 PLATFORM DESIGN/CONSTRUCTION

Considering new building projects, or reconstruction of existing platforms, MPD should be included from the start. Two alternatives should be considered, depending on the frequency of MPD operations:

1. Equipment permanently installed on the rig, including the MPD choke manifold, PRV, flow meter and RCD.
2. An improved MPD equipment package.

The benefits of equipment permanently installed, include, but are not limited to

- Reduced overall cost (one time cost, and not influenced by events such as WOW)
- Included in already existing maintenance routines
- Personnel familiar with the equipment
- Avoid problem with space availability

8.1.1 MPD CHOKE MANIFOLD

Introduced in chapter 3, the MPD choke manifold shall be dedicated (in means of controlling and reducing pressure) and independent (in means of well control situations), however, no requirements for a separate choke manifold applies.

Combining the rig – and MPD choke manifold will lead to reduced risk for failure, as fewer components are included in the line-up, and the manifold will be included in the general rig maintenance program. Specific construction principles that must be met, in compliance with the requirements:

- Tie-in from flow spool to MPD choke manifold
- Tie-in from kill line MPD to choke manifold
- It shall always be possible to shift from conventional well control to MPD mode, and vice versa
- PRV installed upstream the choke
- Flow meter installed

The flow meter should be included in the rig up, independent of drilling technique, ensuring volume control both in – and out of the well.

8.1.2 RCD

Including the RCD body in the conventional BOP-stack will ensure maintenance and testing of the component. Demands that must be met includes

- Sufficient size for handling of various dimensions, for example 18 ¾" OD
- Pressure rating of the RCD must be similar to the other equipment included in the rig-up

Various sizes of packer elements should be available on the installation, and installed ahead of the actual operation. The rig crew personnel will easily have the possibility to change the element (for example ahead of drilling a new section) by the use of a running – and retrieval tool.

For avoiding the extended height of the BOP-stack, the RCD should

1. Be designed to last for required drilling section, or
2. Implement one or two sealing mechanisms beneath the packer element, replacing the additional annular element and stripper ram.

8.1.3 BACK PRESSURE PUMP

For ensuring sufficient back pressure, one of the following alternatives should be considered:

1. One of the rig pumps dedicated for MPD operation
2. Rig pump diverter
3. Back pressure pump

Alternative one is preferable, as the pump is already on location and personnel are familiar with the operation and maintenance.

8.1.4 IMPROVED EQUIPMENT PACKAGE

For older installations, where re-construction is not planned for, or there is large time interval between each MPD operations, a standard MPD equipment package should be developed.

The package should include MPD choke manifold, including PRV and flow meter, and the RCD. A back pressure pump should be included as an option, depending on the capacity and availability of the rig pumps on location.

A more standardized package will reduce the rig-up time of equipment, as personnel already are familiar with the components.

Either way, the equipment configuration should be implemented in the drilling control system.

8.2 INTEGRATED CONTROL SYSTEM

The choke controller and hydraulic model should be implemented in the drilling control system, compared to operating with a separate MPD control system. With full integration of equipment, sensors and drilling control system, the driller can perform the operation from the driller's cabin.

The benefits of integrated control system, include, but not limited to

- High accuracy of real-time data
- Defined roles and responsibilities
- Cost effective
- Normal/routine operation
- Personnel already familiar with current control system (for example Cyberbase)
- Clearer overview
- Reduced risk for human failure (miscommunication)
- Improved well control

Considering the Cyberbase (chapter 3), an additional MPD mode should be included. The driller will decide which mode and parameters to be visible. The MPD mode should include

- Manual Control
- Down hole Control
- Choke Control
- Overview of the circulation path

Real-time data displayed continuous on the screen for the driller, shall include [7, p. 144]

- Pressures (annulus/choke, standpipe, down hole)
- Volume (active surface system fluid volume, returned liquid rate, gas injection rate)
- Drilling fluid pump rate
- Temperature (surface, down hole)

The driller is already familiar with the Cyberbase, and knows how to change and modify parameters. Including the hydraulic model and choke controller will provide a better overview for the driller, giving the possibility to see the pressure variations directly. In case of a well control scenario, the driller can easily switch from MPD mode to conventional.

8.3 DRILLING CONTRACT

Extending the contract between the drilling contractor and operator, including operation and maintenance of MPD equipment, will have several benefits, including, but not limited to

- Defined roles and responsibilities
- Personnel familiar with each other and the working area in general
- Faster operation (controlled by one operator)
- Less cost related to logistics, as the personnel is on site
- Improved effectiveness in means of continuity

If the drilling crew (contractor) performs the MPD operation, there is no doubt about roles and responsibility, the personnel are coordinated and the risk of miscommunication between several disciplines is reduced.

MPD has the large advantage that the foundation is already in place. The offshore personnel have good experience with operation and well control, and the conventional requirements regarding pressure – and volume control still applies. The operational aspect is the same, even though the performance includes some modifications.

The contractor already have established routines, and are well familiar with both well control action procedures and well control action drills. The additional elements related to MPD will be maintained through these routines. With that said, training and coursing is of critical importance when introducing new concepts and operations.

With the equipment permanently installed on the platform, pressure testing and maintenance will be covered by periodically routines performed by the drilling crew.

The equipment introduced by MPD, such as back pressure pump and MPD choke manifold, functions the same way as the rig pump and rig choke manifold. The requirements accounting for the conventional choke manifold (replace each 5th year), will yield for the MPD choke manifold.

8.4 OTHER CONSIDERATIONS

Practical considerations must be taken, including

- Increased daily rig rate, particularly during MPD operations (risk)
- Suppliers of equipment, permanently or temporarily
- Sufficient training
- Additional rig crew members on location during MPD operations
- MPD supervisor on location

These considerations are also confirmed through an interview with a Rig Manager in Archer, which sees the advantages of the drilling contractor performing the operation, related to both cost and HSE. The operator and contractor already have an established culture, working towards a common goal.

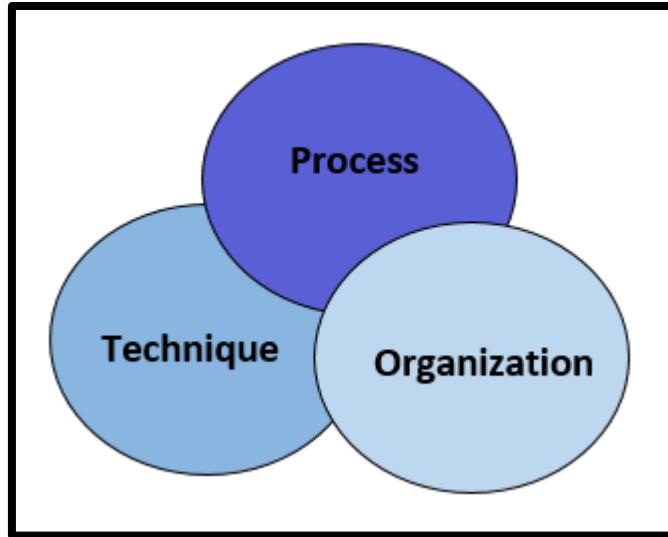


FIGURE 8-2 BALANCED PROCESS, TECHNIQUE AND ORGANIZATION

For ensuring correct input and operating of the integrated control system, a MPD supervisor should be present on the rig, similar to as a directional driller is present during drilling operations.

Summarized, the advantages of Rig Integrated MPD include

- Avoid problem with space availability
- Safer operation
- Simpler operation by means of integrated DCS
- Improved competence
- Improved management and planning as result of more coordinated teamwork
- Lower cost (long term site)

9 CONCLUSION

Related to HSE, human beings are often the limiting factor. Sufficient planning and management set the standard for the operation. Coursing is important for achieving knowledge about the operation, and what risks one must be aware of.

Rig integrated MPD will lead to a continuous performance, where the contractor personnel are familiar with both the operation and the equipment and rig-up included. The operations will be more coordinated, and maintenance and testing of equipment will be ensured.

The overall cost will be reduced, both in terms of logistics of equipment and logistics of personnel.

With the equipment and personnel on the location, rig integrated MPD may also contribute to less damage to the formation. Instead of applying MPD as a “last option”, one can use the technique, preventing high pressure variations to the formation and reservoir. This may lead to improved production.

REFERENCES

- [1] B. Rehm et al., *Managed Pressure Drilling*, J. Schubert, A. Haghshenas, A. S. Paknejad and J. Hughes, Eds., Texas: Gulf Publishing Company, 2008.
- [2] Mohr Engineering Divison, "A Probabilistic Approach to Risk Assessment of Managed Pressure Drilling in Offshore Applications," [Online]. Available: <http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Reports/500-599/582AC/>. [Accessed 19 February 2015].
- [3] Schlumberger, "Oilfield Glossary - Hydrostatic Pressure," [Online]. Available: http://www.glossary.oilfield.slb.com/en/Terms/h/hydrostatic_pressure.aspx. [Accessed 10 February 2015].
- [4] S. Saeed, R. Lovorn and K. A. Knudsen, "Automated Drilling Systems for MPD - The Reality," in *IADC/SPE Drilling Conference and Exhibition*, California, 2012: IADC/SPE 151416.
- [5] PSA, "Petroleum Safety Authority," PSA Norway, [Online]. Available: http://www.psa.no/?lang=en_US. [Accessed 22 February 2015].
- [6] NORSOK D-001, "Drilling facilities," December 2012. [Online]. [Accessed January 2015].
- [7] NORSOK D-010, "Well integrity in drilling and well operations," June 2013. [Online]. [Accessed January 2015].
- [8] IADC, "UBO & MPD Glossary," December 2011. [Online]. Available: <http://www.iadc.org/wp-content/uploads/UBO-MPD-Glossary-Dec11.pdf>. [Accessed February 2015].

- [9] K. P. Malloy et al., "Managed-Pressure Drilling: What It Is and What It Is Not," in *IADC/SPE Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition*, Texas, 2009: IADC/SPE 122281.
- [10] R. Baker, *Practical Well Control*, Texas: The University of Texas at Austin - Petroleum Extension Service, 1998.
- [11] A. Pavolov and G.-O. Kaasa, "Statoil: Automatic MPD a coming reality," Statoil Research Center, 14 July 2011. [Online]. Available: <http://www.drillingcontractor.org/statoil-automatic-mpd-a-coming-reality-9927>. [Accessed 18 February 2015].
- [12] IADC, "Underbalanced and Managed Pressure Drilling Operations - HSE Planning Guidelines," IADC, 2012.
- [13] Oil & Gas Drilling Engineering, "Rig Components," [Online]. Available: <http://www.oilgasdrilling.com/category/rig-components>. [Accessed 6 April 2015].
- [14] Halliburton, "Pressure-While-Drilling (PWD) Services," Halliburton, [Online]. Available: <http://www.halliburton.com/en-US/ps/sperry/drilling/measurement-while-drilling/pressure-while-drilling-pwd-services.page>. [Accessed 18 May 2015].
- [15] NOV, "BX-4-50 Hydraulic Actuated Elevator," NOV, [Online]. Available: http://www.nov.com/Segments/Rig_Systems/Offshore/Handling_Tools/Hydraulic_Elevators/BX-4-50_Hydraulic_Actuated_Elevator.aspx. [Accessed 15 May 2015].
- [16] NOV, "AR3200 Automated Iron Roughneck," NOV, [Online]. Available: http://www.nov.com/Segments/Rig_Systems/Offshore/Handling_Tools/Hydraulic_Elevators/BX-4-50_Hydraulic_Actuated_Elevator.aspx. [Accessed 19 May 2015].
- [17] Siem WIS, "13 5/8" Pressure Control Device - PCD 5000," [Online]. Available: http://www.siemwis.com/publish_files/pcd_5000_brochure.pdf. [Accessed 12 May 2015].

- [18] NOV, "MPD Choke Manifold," NOV, [Online]. Available:
https://www.nov.com/Segments/Wellbore_Technologies/Dynamic_Drilling_Solutions/Systems/Managed_Pressure_Drilling/MPD_Choke_Manifold.aspx. [Accessed 20 May 2015].
- [19] NOV, "H2S Mud-Gas Separator," NOV, [Online]. Available:
https://www.nov.com/Segments/Wellbore_Technologies/WellSite_Services/Solids_Control/Mud-Gas_Separator.aspx. [Accessed 20 May 2015].
- [20] NOV, "Cyberbase Operator Station," NOV, [Online]. Available:
https://www.nov.com/Segments/Rig_Systems/Offshore/Control_and_Advisory_Systems/Operator_Workstations/Cyberbase_operator_station.aspx. [Accessed 12 February 2015].
- [21] Schlumberger, "Oilfield Glossary - Circulation System," [Online]. Available:
http://www.glossary.oilfield.slb.com/en/Terms/c/circulation_system.aspx. [Accessed 12 February 2015].
- [22] P. D. Fredericks and D. Reitsma, "MPD automation addresses drilling challenges in conventional, unconventional resources," November/December 2006. [Online]. Available:
http://www.drillingcontractor.org/dcp/dc-novdec06/DC_Nov07_fredericks.pdf. [Accessed 10 May 2015].
- [23] NOV, "JWS-185," NOV, [Online]. Available:
https://www.nov.com/Segments/Wellbore_Technologies/Dynamic_Drilling_Solutions/Systems/Managed_Pressure_Drilling/JWS-185.aspx. [Accessed 20 May 2015].
- [24] A. Handal, S. Øie and M. A. Lundteigen, "Risk Assessment Targets Well Control Functions Of MPD Operations," Det Norske Veritas AS, 11 July 2013. [Online]. Available:
<http://www.drillingcontractor.org/risk-assessment-targets-well-control-functions-of-mpd-operations-24046>. [Accessed 15 March 2015].

- [25] Schlumberger, "Oilfield Glossary - Flow Check," [Online]. Available: <http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=flow+check>. [Accessed 15 February 2015].
- [26] A. Handal and S. Øie, "Safety Barrier Analysis and Hazard Identification of Blowout Using Managed Pressure Drilling Compared With Conventional Drilling," in *Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition*, Texas, 2013: IADC/SPE 164564..
- [27] PSA Norway, "The Activities Regulations," 16 December 2014. [Online]. Available: <http://www.psa.no/activities/category399.html>. [Accessed 27 May 2015].
- [28] IWCF, "International Well Control Forum," [Online]. Available: <http://www.iwcf.org/>. [Accessed 20 May 2015].
- [29] PSA Norway, "The Framework Regulations," 24 May 2013. [Online]. Available: <http://www.psa.no/framework-hse/category403.html>. [Accessed 27 May 2015].
- [30] PSA Norway, "Guidelines Regarding The Framework Regulations," 16 December 2014. [Online]. Available: <http://www.psa.no/framework/category408.html>. [Accessed 27 May 2015].
- [31] Petro Media News, "Gullfaks feltet," [Online]. Available: <http://oljefakta.petro.no/felt/gullfaks>. [Accessed 16 April 2015].
- [32] PSA Norway, "Audit of Statoil's planning for well 34/10-C-06A," 8-15 October 2010. [Online]. Available: http://www.psa.no/getfile.php/Tilsyn%20p%C3%A5%20nett/P%C3%A5legg_varsel%20om%20p%C3%A5legg/2009_1626_Rapport%20etter%20tilsyn%20med%20planlegging%20av%20boring%20-%20Gullfaks%20C%20-%20engelsk.pdf. [Accessed March 2015].

- [33] Statoil, "Granskingsrapport - Brønnhendelse på Gullfaks C," 4 November 2010. [Online]. Available:
http://www.statoil.com/no/NewsAndMedia/News/2010/Downloads/5Nov_2010_%20Rapport_broennhendelse_Gulfaks%20C.pdf. [Accessed March 2015].