A COMPARATIVE STUDY OF MANAGED PRESSURE DRILLING AND CONVENTIONAL DRILLING

BY
ISAAC EMENA RAMSY
ENG2006430

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FACULTY OF ENGINEERING
UNIVERSITY OF BENIN
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CERTIFICATION

This is to certify that this project was carried out by **ISAAC EMENA RAMSY** of the Department of Petroleum Engineering with matriculation number **ENG2006430** in partial fulfillment of the requirements for the Award of the Degree, Bachelor of Engineering (B.ENG)

ENGR. ISAAC OMOREGBEE
(PROJECT SUPERVISOR) **DATE**

DR. O. A. TAIWO
(PROJECT COORDINATOR) **DATE**

ENGR. DR. IKPONMWOSA OHENHEN
(HEAD OF DEPARTMENT) **DATE**

PROF. KEVIN CHINWUBA IGWILO
(EXTERNAL SUPERVISOR) **DATE**

DEDICATION

This work is dedicated to Almighty God for his love, grace, wisdom, and strength given to me, to my wonderful and loving parents Mr. and Mrs. Isaac for their unending support.

ACKNOWLEDGEMENT

I would like to express my sincere gratitude to my project supervisor, Engr. Isaac Omoregbee for his tireless efforts towards the completion of this work, for the knowledge impacted and experience shared throughout my undergraduate studies. I could not have been able to cope without his support.

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I wish to express my gratefulness to and every lecturer in the department for impacting greatly and positively in me.

I also want to thank my lovely family, the family of Mr and Mrs Isaac, for their support and prayers. . Special thanks to my aunty Mrs Stella Akele for her support and prayers.

I also want to thank my friends and course mates for every little way they supported me.

Last but not the least, I wish to show my unending gratitude to Almighty God for everything.

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ABSTRACT

In most drilling operations, it is evident that a considerable amount of money is spent when faced with drilling related problems such as stuck pipe, lost circulation and excessive mud cost which in turn leads to an increase in non-productive time especially in deep-water environment where the pore pressure and fracture pressure gradient is very close (narrow drilling window). Managed pressure drilling (MPD) has been found to be effective when compared with conventional drilling method to eliminate or reduce these hole problems. The MPD technique is of two types: Reactive MPD (where MPD equipment is rigged up in cases of drilling hazards) and Proactive MPD (MPD equipment is rigged up from the onset). There are four variations of MPD and each variation used must suite the drilling hazard to be mitigated.

In this review, three case studies in the deep-water environment (Bolontiku Field in the Gulf of Mexico, Tarim Basin in China and Kristin Field in the Norwegian sea in the haltenbanken area) were taken, to comparatively analyze the challenges, methods used and the drilling hazards encountered when drilling conventionally and with MPD technique, using indices of comparison such as: Cost of drilling, target depth attained, number of drilling days and mud losses seen. In all the three cases considered, the drilling hazards were encountered while drilling conventionally, which were not able to be mitigated. However, with the application of the constant bottom hole managed pressure drilling technique, in the Bolontiku and Tarim Basins, the wells were drilled safely, reduced the number of drilling days by 50% when compared with the conventional drilling technique. Application of the pressurized mud cap drilling was done on the Kristin field and it shows that MPD enabled drilling in highly depleted reservoirs with the application of a static drilling fluid weight below the original pore pressure.

CHAPTER ONE

INTRODUCTION

1.0 Background of Study

With the ever-increasing demand for petroleum products (domestic and industrial) and the fewer onshore fields available, it becomes essential to explore and exploit deep and ultra-deep fields. In doing this, we evaluate possible measures to be used in making these ventures technologically, economically, and environmentally feasible, hence the need for managed pressure drilling (MPD). Most of the world's remaining prospects for hydrocarbon resources will be more challenging to drill than those enjoyed in the past. Infact, many would argue that the easy oil have already been drilled. And with oil prices where they are today, drilling safely and cost effectively while producing a good well in the process can never be over emphasized. From the studies carried out by the Association for the study of Peak oil and gas, many countries have passed their peak rate of oil production, suggesting that the world's peak production is now imminent. As a result, oil and gas firms are looking to squeeze every last drop of reserves from the nook and crannies of the ocean, in hard to reach ultra-deep places, safely and cost effectively. Having these in mind, the concept of Managed Pressure Drilling (MPD) should be regarded as a technology that can provide a noteworthy increase in cost-effective drill-ability by reducing excessive drilling-related costs typically related with the conventional offshore drilling, if most of the world's remaining vision oil and gas being economically undrillable with conventional wisdom casing set points and fluids programs are taken into account.

1.1 Statement of Problem

Narrow drilling margins presents great challenge mainly in deep-water environment. in deep water environment, it is a major practice to set numerous casing strings at shallow depths to avoid extensive lost circulation when practicing the conventional drilling operation and this leads to much cost of operation.

Since the budget spent on onshore applications is considerably lower than that spent on offshore application, of recent, the use of MPD variations in offshore applications is increasing rapidly in order to increase drilling performance, mitigating drilling hazards, und enhancing the production rates. In order to achieve a precise control of bottom hole pressure, the usage of back pressure from the surface is a vital deal".

Drilling the "undrillables" in deep-water using conventional means has been proven to be problematic in terms of downhole pressure management, hence leads to drilling hazards and even nonproductive time. .Most undrillables do not get to their target reservoir using conventional drilling techniques to the difficulty in balancing the bottom-hole pressure with the reservoir pore pressure in highly depleted fields with narrow drilling window.

1.2 Objectives

In this study the primary aims are to:

- To review managed pressure drilling technique

- To analyze the cost effect for Managed pressure drilling and conventional drilling
- To proffer other solutions on how to mitigate drilling hazards apart from using a better drilling technique.

1.3 Research Questions

- How does choke control, mud weight and pump rate affect the point of constant annular pressure?
- What are the advantages of MPD over conventional well practices?
- What do drilling companies think about MPD and how has it helped them to drill safely?
- What is the minimum back pressure required to mitigate drilling hazards:

1.4 Justification of Study

It is important, that MPD become widely and comfortably used in the offshore market. As stated by Coker, this technology can, and will, lead to the availability of many offshore resources. It has been seen and quoted by some industry professionals that as much as 70% of current offshore hydrocarbon resources are economically undrillable, with the use of conventional drilling methods. Utilizing the right techniques and equipment more and more of these offshore resources will become available from an economic standpoint. Therein lies the importance of the MPD, without this technology much of the world resources will be neglected. To further buttress the importance of MPD to the industry, Hannegan stated highlighting the drawbacks that about one-half of the remaining offshore resources of hydrocarbons, gas hydrates excluded are economically undrillable with conventional tools and methods. Amongst other drilling environment, MPD is even more useful in deep water and ultra-deep water as the percentage ”undrillable” increases with water depth. There are various drilling related obstacles which cannot be totally covered by conventional drilling methods and these includes:

- Loss circulation/differentially stuck pipe,
- Slow Rate of Penetration (ROP),
- Narrow pore-to-fracture pressure margins necessitating excessive casing programs and requiring larger, more expensive drill ships to buy.
- Shallow geohazards when drilling top holes riserless.
- Flat time spent circulating out riser gas, kicks, etc.
- Failure to reach Target depth (TD) objective with large enough hole.

1.4 Scope of Work

Though MPD can be used for both onshore and offshore fields, the scope of study is limited to offshore fields. This is due to available information, time and funds constraints. The most appropriate candidates for MPD are offset wells, which are characterized by wellbore instability and excessive drilling fluid losses or those that will be drilled through pressured, virgin zones and depleted or otherwise underpressured zones. However, these parameters alone suggest that the number of wells that are good MPD candidates is quite considerable.

1.5 Definition of Terms

1.6.1 Overburden Pressure

This is the pressure at any point in the formation exerted by the total weight of the overlying sediments. It may be sometimes referred to as ”lithostatic load”. It is dependent on the density of the rock column and the rock column itself. Overburden pressure is also defined as the weight of the rocks and fluid contained in the rocks above the zone of interest. It has a range which varies between 18 and 22 pounds per gallon (ppg equivalent density). This can be converted to about 1psi/ft. Although for shallow marine environment and massive salt deposit, the value of 1psi/ft. is not applicable. The concept of overburden pressure during drilling operations can never be overemphasized. This is due to the variation of this concept depending on the assumptions made while predicting the pressures. Worthy of note is that the exact value of overburden pressure can never be predicted since the distributions of the overlying rocks are not homogeneous in real sense as made in the assumptions.

1.6.2 Formation Pore Pressure

The formation pore pressure is also referred to as ”formation fluid pressure”. It is the pressure exerted by the fluid within the formation being drilled. Formation pore pressure varies depending majorly on the area and depth of deposition. The deposition of sediments in sedimentary rocks leads to the compaction and squeezing out of the originally deposited sea water which of course contains some quantity of salt. As deposition and compaction continues, more squeezing is expected, leading to the remnant of larger salt molecules from.

.

1.6.3 Fracture Pressure

This is the minimum lateral stress which must be overcome for hydraulic fracturing to occur. When fracturing occurs, the orientation of the fracture is usually parallel to the maximum stress which most times, is the overburden pressure. This is indicative of a vertical fracture. Fracture pressure may also be defined as the upper boundary of the drilling window and it is treated as the secondary control variable while designing the hydraulics of the well. It has common units such as psi/ft, kg/m, ppg and kPa. Formations at very great depths are usually highly compacted because of the high overburden pressure and the also have high fracture gradients. In shallow offshore fields, because of the lower overburden pressure resulting from the sea water gradient, lower fracture gradients are encountered.

1,6,4 Collapse Pressure

In order to maintain a gun barrel hole and keep the formation intact, to avoid potential collapse, a minimum mud weight is usually used. This minimum mud weight is referred to as the collapse pressure. In every drilling operation, this parameter is necessary because approaching the collapse pressure results in the popping in of large splinters of formation into the wellbore which in turn results to a stuck pipe.

1.6.5 Conventional Drilling

Conventionally drilled wells are open to atmosphere. Conventional drilling practices are known as traditional drilling practices. They rely on maintaining hydrostatic pressure in the annulus to prevent formation fluids from entering the borehole. Ideally, when drilling fluid or mud is circulated down the string, and up the annulus, an equivalent circulating density (ECD) is created.

1.6.6 Equivalent Circulating Density (ECD)

This is the effective density exerted by circulating fluid against the formation. It is a function of mud weight, pressure drop and true vertical depth. Problems associated with drilling can be solved using:

Constant bottom hole pressure (CBHP)

Pressurized mud cap drilling (PMCD)

Dual Gradient Technique (DG)

Return flow control/ HSE method

Constant Bottom Hole Pressure (CBHP)

The equivalent mud density (EMW) and the effective bottom hole pressure are constantly under pressure control, when the pump stops, the system can apply an hydraulic back-pressure at the surface to make up for the difference from the loss of Annular frictional pressure (AFP). When the pump is brought back to function, the system can dial back on pressure to compensate because the AFP now becomes a part of the equivalent mud weight. Drilling a well with constant bottom hole pressure solves the problem of having kicks when not circulating, losses when not circulating and gives a more constant wellbore pressure profile.

Pressurized Mud Cap Drilling (PMCD)

This type of drilling technique eliminates disposal problems and dangerous gases such as shallow gases reaching the surface. It also eliminates losses into thief zones (Thin zones of high permeability).

Dual Gradient Technique

The uphole annular pressure is controlled. It is used mainly in offshore environment where the water provides a significant amount of overburden. However, the liquid overburden is less dense than the typical formation overburden. Drilling window is small because the margin between the pore and fracture pressures is small. Due to weak formation strength, deep water conventional drilling applications usually require multiple casing strings to avoid severe lost circulation at shallow depth. To reduce the effect of deep water overburden, the drilling system should be balanced by reducing mud density in the upper parts of marine riser or filling marine riser with sea water. The intent here is to mimic the salt water overburden with a lighter fluid density. Less dense media such as inert gas, plastic palate or glass beads are injected within the marine riser and the risk of fracturing the weak zone is reduced.

Return Flow Control Method/ HSE Method

Tooling up to securely and more efficiently react to down hole surprises is involved here. This technique does not control any annular pressure. Annular returns are diverted away from the rig floor to prevent any gas especially H_2S from spilling to the rig floor.

1.6.7 Primary Well Control

Maintaining hydraulic pressure above pore pressure of the exposed formation.

1.6.8 Under Balanced Drilling (UBD)

This is a drilling technique in which the formation pore pressure is greater than the pressure exerted by the annular fluid or gas column. UBD is a closed drilling system unlike conventional drilling technique. UBD is done only when the mud is static and there is no pipe movement. Reasons for underbalanced drilling amongst others are:

To improve drilling rate

Limit lost circulation

Protect the reservoir formation

CHAPTER TWO
LITERATURE REVIEW

2.0 Introduction

This segment seeks to evaluate the collection of research related to the current inquiry. A thorough review or summary of applicable literature was undertaken to obtain a complete understanding of the notion of managed pressure drilling, together with its various methods like the constant bottom-hole pressure technique, mud cap drilling, continuous circulation system, equivalent circulating density reduction tool, dual gradient drilling method linked to managed pressure drilling, and its applications.

2.1 History and Evaluation of Managed Pressure Drilling Technology

Managed Pressure Drilling (MPD) technique first emerged in land drilling projects in the mid-1960s, but it was criticized by drilling decision makers before being adopted as a way to address common problems in conventional drilling processes. A review of prior research indicates several methods designed to solve different issues in drilling operations.

Various reports of safe operations have been recorded by operators who implemented this technique, resulting in its increasing acceptance among drilling decision makers, unlike its initial introduction to the oil and gas industry. Balancing wellbore pressure is a crucial factor that affects whether a well succeeds or fails.

Wells can be drilled using conventional overbalanced drilling, underbalanced drilling, or managed pressure drilling. Recently, discussions have arisen about the precise definition of Managed Pressure Drilling, often mistaken for underbalanced drilling. To clarify this confusion, two definitions were offered by the International Association of Drilling Contractors (IADC).

According to IADC, Underbalanced drilling is a drilling activity using 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.

Managed Pressure Drilling (MPD) is also defined by this association as an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the down hole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. MPD intends to avoid continuous influx of annular fluids to the surface.

Conventional overbalanced drilling maintains a down hole pressure greater than the pore pressure of the formation that the wellbore penetrates.

Understanding the challenges encountered in conventional drilling is essential for comprehending the pressure profile of a reservoir and thus for the successful implementation of managed pressure drilling technique. Managed pressure drilling has been found to be more cost effective than conventional drilling in some fields in Australia, United States of America etc.

Operators have shown that MPD provides solutions to many undrillable wells. As stated by Malloy (2007), MPD does not actively encourage fluid influx and the main aim of this new technology is to mitigate the drilling hazards encountered and increase the operational drilling efficiency by reducing the non-productive time. Non-productive time (NPT) are lost time which are encountered during conventional drilling techniques in the cases of kicks, differential sticking, loss circulation etc.

A drilling company in 1998, Weatherford acquired and developed key technologies, from proprietary Rotary control Devices (RCDs) to advanced self-generation units to patented fluid and foam technology.

Many of the ideas on which MPD is predicated were first formally presented in three abnormal pressure symposia at Louisiana State University between 1967 and 1972. These symposia looked at the origin and extent of abnormal pressures and how to predict pressures and fracture gradients from available data.

2.2 Historical Methods and Developments

The Equivalent Circulating Density (ECD) was effectively used in well control practices developed in the 1970's. The present technology combines and formalizes new techniques with those historically used to deal with some of the most common drilling problems, such as kicks and lost circulation.

Rotating heads were described in the 1937 shaft tool company catalog. In the 1960's, Rotating Control devices(RCD) enabled the practice of drilling with compressible fluids (gas, air, mist and foam) to flourish. Now referred to as performance drilling (PD) or simply air drilling, its value is primarily realized in the form of improved penetration rates, longer life of drilling bits, and reduced overall costs of drilling the prospects.

At first reluctant, the industry finally accepted the practice of horizontal drilling in the 70's and 80's. This spurred an exciting and beneficial perspective to drilling technology, however brought unanticipated surprises. The fluid column, the primary well control barrier designed to prevent a blowout, fell downward into the fractures encountered and a significant number of well control incidents occurred as high pore pressure hydrocarbons entered the wellbore then flowing to the surface.

Mud cap drilling (MCD) was common for years as "drilling dry" or "drilling with no returns". A more formalized version of MPD was tried in Venezuela in the 1980's, in the Hibernia field of Nova Scotia in the 1990's and later in Kazakhstan in the former Soviet Union.

Over time, other uses of the RCD evolved. Uses other than air drilling and underbalanced operations. The industry learned to use the RCD to more precisely manipulate the annular hydraulic pressure profile when drilling with a conventional mud system. It also enabled one to drill safely with an Equivalent Mud Weight (EMW) nearer the reservoir pore pressure to drill safely with an Equivalent Mud Weight (EMW) nearer the reservoir pore pressure. Although an influx of hydrocarbon during the drilling process is not invited,one is better prepared to safely and efficiently deal with any that may be incidental to the operation. In 2003, the assemblage of techniques was recognized as a technology within itself and given the label managed pressure drilling.

It was not until 2003 that the enabling characteristics of the technology began to be more fully appreciated by offshore drilling decision makers. MPD is a technology that addresses a litany of drilling related issues or barriers to conventional methods. The encounter of drilling related issues or barriers to conventional methods. The encounter of trouble zones is undeniably on the increase. This is due in part to a requirement to drill in greater water depths and through depleted zones or reservoirs. Many would argue most of the easy prospects in shallow and deep waters have already been drilled. Those remaining are more likely to be hydraulically challenged requiring more precisely controlled management of the wellbore pressure profile to be drilled safely and efficiently.

In the year 2003, the Weatherford/SURE process offered clients both quick screening tools and detailed evaluation. And today, Weatherford continue to strengthen MPD engineering and well planning services through the application of two MPD techniques:

2.3 Categories of Managed Pressure Drilling

Reactive MPD

In reactive MPD, the well is designed for conventional drilling, but equipment are put in place, which is rigged and quickly reacts to an unexpected pressure change. Reactive MPD is used as a contingency plan to mitigate drilling hazards.

The equipment used here are the rotary control device (RCD), choke and drill string float.

Proactive MPD

In proactive MPD, it is designed at initial stage with a casing, fluid and open hole drilling plan or alternate plans that take full advantage of the ability to precisely manage the wellbore plan or alternate plans that take full advantage of the ability to precisely manage the wellbore pressure. This application involves working in advance to plan for MPD, engineering the pressure profile best suited for the specific needs of your well and drilling program. Proactive MPD radically reduces drilling NPTalong with costs by enabling fundamental changes to fluid, casing and open hole programs. As wells become deeper, hotter, higher pressured or more depleted, many will require some form of proactive MPD. It determines if there will be a success or failure.

Hoyer stated that another technology can be used to mitigate drilling hazards along with MPD by emphasizing that a technique known as drilling-with-casing or liner technology can provide an effective means of dealing with well instability and lost circulation which are encountered during the conventional drilling systems.

His technique has been demonstrated in such demanding applications at the Banuwati field offshore Sumatra, Indonesia, which is a limestone reservoir. This Lower Baturaja limestone is infamous for severe lost circulation conditions. It was seen that in this difficult environment, the drilling-with-casing system overcame severe wellbore instability and lost circulation challenges that had resulted in three side-tracks in just one well.

In the economic standpoint, the system saved three days of rig time equating to almost one million USD. This achievement was attributed to the technology's smear effect, in which the close proximity of the casing wall to the borehole spreads ground cuttings against the formation to create an impermeable filter cake.

Hoyer also did a research on the other technology referring to the necessity of MPD in reducing drilling problems. He further explained that solid expandable casing or liner being a proven method of isolating trouble zones with no loss or minimal loss of hole size compared to conventional telescoping casing designs. Wellbore stability is often critical in reaching the target depth with optimal hole size for evaluation and completion.

Malloy and Mac Donald (2009) stated that the starting point of MPD can be found by the utilization of a few specific technology developed by underbalanced drilling technique, which is considered as the forbearer of managed pressure drilling.

There are several studies about different aspects of MPD modelling (e.g. Landet et al. (2012a, 2013); Petersen et al. (2008); Mahdianfar et al.(2013); Kaasa et al. (2012). Estimation and control design in MPD has been investigated by several researchers (e.g. Zhou et al. (2011); Godhaven et al. (2011); Zhou and Nygaard (2011);

Breyholtz et al. (2010); Zhou et al. (2011); Godhaven et al. (2011). These studies are mainly focused on pressure control during drilling from a fixed platform without any heave motion.

Medley and Reynolds in their study, buttressed on the benefits of doing an efficient and accurate wellbore management and discovered that doing this can overcome about eighty percent of the problems encountered during conventional drilling.

Rasmussen and Sangesland (2007) compared and evaluated different MPD methods for compensation of surge and swab pressure. In Nygaard et al. (2007a), it is shown that surge and swab pressure fluctuation in the bottom hole pressure during pipe connection can be suppressed by controlling the choke and main pump. Nygaard et al. (2007b) used a nonlinear model predictive control algorithm to obtain optimal choke pressure for controlling the bottom hole pressure during pipe connection in a gas dominant well. Pavlov et al. (2010) presented two nonlinear control algorithms based on feedback Linearization for handling heave disturbances in MPD operations. Mahdianfar et al. (2012a, b) designed an infinite-dimensional observer that estimates the heave disturbance. This estimation is used in a controller to reject the effect of disturbance on the downhole. In all the above mentioned papers, the controllers are designed for the nominal case disregarding the uncertainty in the parameters, though several parameters in the well could be uncertain during drilling operations. In addition, the heave disturbance, which is inherently stochastic and contains many different harmonics, is approximated by one or a couple of sinusoidal waves with known fixed frequencies throughout controller design and simulations.

Model predictive Control (MPC) is one of the most popular controller design methodologies for complex constrained multivariable control problems in industry and has been the subject of many studies since 1970s (e.g see Mayne et al. (2000); Morari and Lee (1999); Garcia et al. (1989); Maciejowski (2002). At each sampling time, a MPC control action is acquired by the on-line solution of a finite horizon open-loop optimal control problem. Only the first part of the optimal control trajectory is applied to the system. At the next sampling tome, the computation is repeated with new measurements obtained from the system.

Research carried out by Kozicz in 2008 suggests that 50% of the total non-productive time during drilling is related to wellbore pressure. By controlling the annular pressure profile, MPD technique can overcome the technical challenges that are related to MPD, decrease NPT, increase the rate of penetration and enables wells which have been considered to be undrillable to be drilled economically.

To further emphasize on the advantage of Managed Pressure Drilling, which is a relatively new drilling technique, Brainard stated that MPD techniques can influence many pressure related drilling challenges, stated previously.

Operators over time have come to realize that in their budget, about twenty percent of the time spent on the rig, is on corrective measures when losses and kicks occur. This increases drilling cost and non-productive time, which is undesirable because the main objective of every business is to maximize profit.

Generally speaking, Managed pressure drilling is designed to maintain bottom hole pressure slightly above (overbalanced) or equal to the reservoir pore pressure. It involves drilling through a narrow pressure window, in which a low density fluid is used and a backpressure is added at the surface via the choke in order to contain the formation pore pressure.

Further advantages in managing and mitigating drilling hazards are coming from recent advances in high-collapse resistant expendables and more technologies that help prepare for trouble (proactive managed pressure drilling) rather than react to it (reactive managed pressure drilling).

Hannegan(May 2004) was the first to speak on managed pressure drilling and its application. He explained the several variations of MPD, such as Constant Bottom hole Pressure (CBHP) method of MPD, pressurized mud cap drilling (PMCD), dual gradient drilling (DGD), HSE MPD, riserless MPD, and zero discharge riserless MPD.

Terwoogt defined Pressurized Mud Cap Drilling (PMCD) as an advanced technique used to manage wells encountering drilling fluid losses. When fluid is lost into the formation, the hydrostatic pressure in the annulus decreases. The hydrostatic pressure must be put to a check, so as to avoid formation fluid flow when it drops below the formation pore pressure. The well is then controlled by filling the annulus at a higher rate than the flowing gas.He named this method 'mud cap drilling'.

Borre Fossli, Sigbjorn (Oct 2004) described controlled mud cap (CMC) MPD technology for deepwater offshore applications. The system utilizes an engineering simulator to calculate the dynamic pressure losses in the wellbore during drilling and controls the speed of the mud lift pump at the sea floor in real time to maintain the required mud level in the riser to control the BHP. In this system, during pipe connection, the effect of losing friction during pipe connection is compensated by varying the level of fluid in the riser to maintain the same BHP as during drilling.

Drilling challenges like differential sticking and severe drilling fluid losses can result from a large pressure differences between wells and formation. It is an expectation that these incidents will be reduced with the application of MPD. Furthermore, an increase in the rate of penetration may be an additional benefit. (Miller 2006).

A system known as the "Dynamic Annular Pressure Control" (DAPC) is used to calculate in real time, the backpressure or set point required to maintain a described downhole pressure.

The DAPC system comprises of five major components known which includes:

- Single phase hydraulic model
- Data communication interface and historical data base
- Graphical user interface
- Proportional, Integral, Derivative (PID) device controller
- Programmable Logic controller (PLC) sensors and control

These various components have their specific functions, for instance, drilling engineers use the single phase hydraulics model to calculate the surface pressure set point that will deliver the required downhole pressure.

There are various inputs to this model. This includes frequently changing data, static data and slowly changing data. The frequently changing data include the pump rate, the slowly changing data are the viscosity and mud density while the static data is the well drill string geometry.

2,4 Research Publications in MPD

Managed pressure drilling has been in existence before 1996. Though at this time, not much work had been done on it. Research on MPD was more prominent between the year 2005 and 2006.

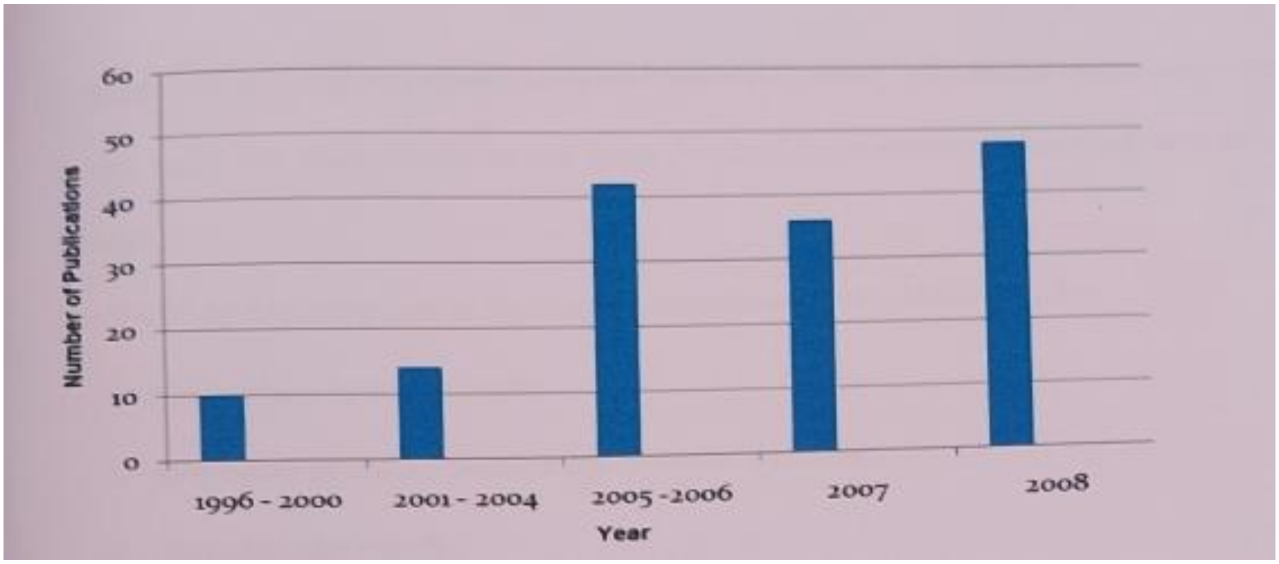


Figure 2.1: Research publications related survey on Managed Pressure Drilling

From the literature review carried out, it can be concluded that managed pressure drilling is a new and adaptive drilling process hence more work and research will be done to further improve the technique. It is also seen from the literature review carried out, that rheology and hydraulics models has rarely been published.

Table 2.1 Classification of research publications.

Name of category	**Percentage of papers**
MPD techniques	30%
Field experience	25%
MPD development	10%
Application	15%
Case studies	20%

2.5 Objectives of the Research

The main Objectives of this research are:

- To review the MPD technique
- To compare the results of the application of conventional drilling and managed pressure drilling, using three case studies.

CHAPTER THREE
METHODOLOGY AND APPROACH

3.0 TECHNIQUES AND STRATEGIES

Managed pressure drilling as outlined previously, represents a flexible drilling method that permits a driller to drill within tight drilling intervals or functional boundaries. Forecasting of hole pressure plays a crucial role in secure boring operations. Certain storage areas experience excessive pressure, whereas others face insufficient pressure, and some remain inside constrained pressure variations (0.46 psi/ft)[10].

The focus of this section is to examine three case studies where managed pressure drilling was applied to address various drilling issues like unproductive periods, influxes, and fluid loss, among others.

3.0.1 CASE STUDY ONE

The drilling operation was performed by a drilling service provider, navigating through unusually elevated and reduced pressure zones in the BOLONTIKU MARINE AREA[20].

3.1 SUMMARY OF THE BOLONTIKU FIELD

The Bolontiku field lies at sea on the mainland ledge of the northern Gulf of Mexico, next to the shoreline of Tabasco Province. This field consists of calcified carbon rocks from the later Jurassic Kimmeridgian layer, producing a petroleum API density of 39 degrees.

The original base-hole pressure observed was 8159 pounds per square inch, but it has now dropped to 5600 pounds per square inch. This notable decrease in base-hole pressure resulted from exhaustion. The area features a typical functional interval of 0.07 grams per cubic centimeter, viewed as limited. The area's extent measures 5 kilometers in length and 2.3 kilometers in width.

For this area, the 9 7/8 inch tubing was intended to extend to the lower Paleocene layer, right over the Cretaceous layer, while a 7 5/8 inch tubing was scheduled to encompass the lower Paleocene and Cretaceous layers.

the Cretaceous and Upper Tithonian Jurassic (UTJ). The goal of the 7 5/8 inch tubing was to separate the Upper Tithonian Jurassic and the Cretaceous storage from one another.

The main storage situated in the upper Jurassic is covered by a Cretaceous layer that also contains hydrocarbons.

An evaluation of the 8 1/2 inch segment bored for six wells in this field has been conducted. Various approaches were employed for drilling these wells:

The initial pair of wells (well 13 and well 31) were bored utilizing traditional approaches.

- The following pair of wells (well 32 and well 43) were bored using traditional approaches initially, then switched to controlled pressure boring methods because of the difficulties faced.

- The final pair of wells well 43 and well 47) were bored applying the steady base-hole pressure method, assisted by an automatic restrictor right from the beginning of the segment.

The illustration beneath displays the position of the Bolontiku field.

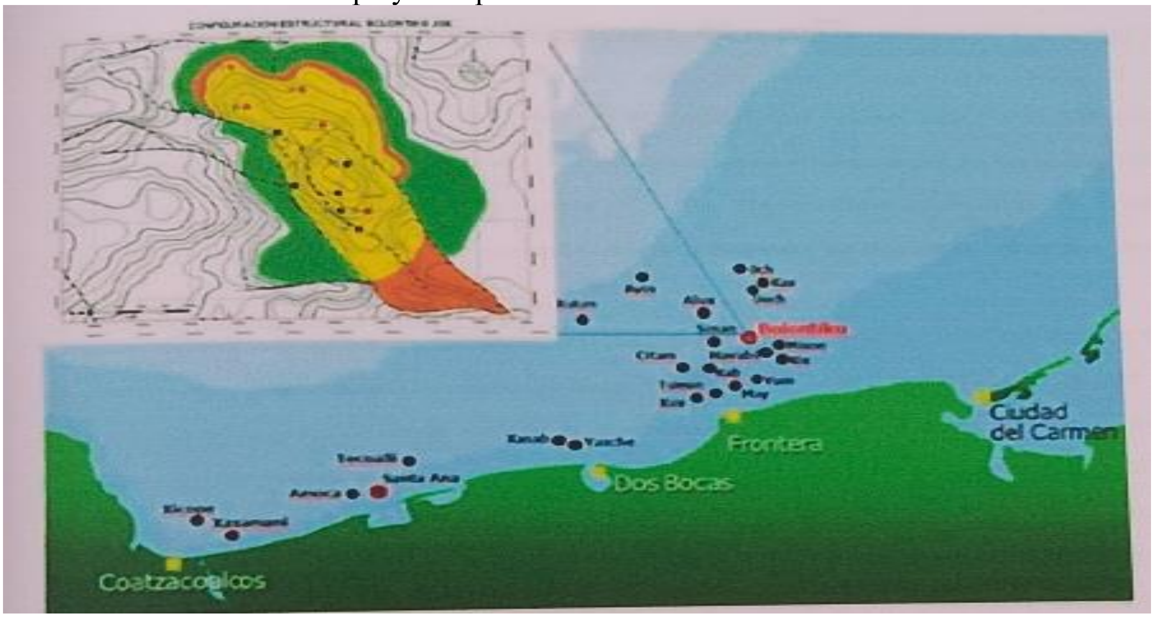


Figure 3.1: Chart depicting the earthly position of the Bolontiku field, illustrating its placement in the Gulf of Mexico[20]

3.2 MOTIVATIONS FOR EMPLOYING MPD IN THE FIELD

- A restricted functional interval of 0.07 grams per cubic centimeter

- Difficulty in properly regulating the borehole pressures with standard approaches

- Rise in Unproductive Duration, leading to extended periods and expenses

3.3 DIFFICULTIES AND APPROACH APPLIED FOR WELLS 13 AND 31

Standard boring approach was utilized for well 13, employing a slurry density of 1.94 grams per cubic centimeter.

Standard drilling approach relies on slurry density and circulation speed as means of pressure regulation. Slurry density and circulation speed are elevated when there appears to be an entry into the well, whereas the opposite occurs during influx events. This approach is comparatively sluggish in contrast to controlled pressure boring due to the duration required for the updated fluid thickness to circulate.

Owing to the tight pressure gap between the break pressure and the hole pressure, fluid disappearances occurred. The drilling service providers faced obstacles when applying the standard approach because of this tight pressure gap, and they experienced multiple influxes and slurry disappearances. As a reaction to the heightened influxes, the slurry density was raised to suppress the well.

For well 31, standard boring approach was applied. The obstacles faced in well 13 and well 31 are identical. In well 31, the gap between the hole and break variation was 0.05 grams per cubic centimeter. The issues were linked to pressure and lacking a way to modify the static and dynamic pressures to fit inside the boring gap[29].

3.4 DIFFICULTIES AND APPROACH APPLIED FOR WELLS 32 AND 43

The wells were originally intended to be bored using standard methods with a slurry density of 1.86 grams per cubic centimeter; nevertheless, nearby boreholes had been bored in the upper Cretaceous region, thus exhaustion was anticipated in well 32. During the drilling of this well, a reduced slurry density was selected because of the exhaustion in the upper Cretaceous region. An elevated prediction of the original storage pressure was made, so fluid disappearances persisted. The slurry density was additionally lowered to 1.55 grams per cubic centimeter as a measure against the fluid disappearances for a brief period, but subsequently, MPD was implemented. It was found that the layers around the storage remained at original pressure, thus resulting in a tight drilling gap.

Due to the sequence of slurry disappearances and influxes faced, luckily, the borehole was equipped with a spinning regulation mechanism (RCD). The RCD assisted in redirecting the stream to the platform restrictor via the gas divider, without an automatic MPD setup. Since the borehole was not originally equipped with the MPD setup, the influxes persisted but were redirected and directed to the exterior. In other words, the influxes did not halt the boring activity thanks to the RCD that was already installed.

A fluid-operated restrictor was installed to manage the rear pressure. An automatic restrictor was selected to constrict the pressure gap. The restrictor was equipped with a unique tip to prevent early deterioration during boring, and an additional restrictor served as a reserve in case the main restrictor malfunctioned.

Automatic restrictors are utilized in regulating the ring-shaped pressure outline; they manage the setup rear pressure that will align to a pressure target point depending on the boring factors.

Manual restrictors are applied for instances of intense influxes, aiding the operator in sustaining command over the setup and securely removing borehole entries. The installed RCD was employed to redirect the stream to the platform restrictor and via the basic mud gas divider without an automatic MPD setup added to the platform. This, however, did not halt the slurry disappearances, but gas was regularly directed to the exterior.

A triple-phase upright divider was set up after the restrictor to allow secure removal of the gas from the borehole to the release zone on the platform. To sum up, the boreholes achieved their intended depth, which was the upper Jurassic region of the storage. This became feasible with the assistance of the RCD.

Based on the insights from well 32, the starting slurry plan for well 43 was adjusted to consider the exhausted Cretaceous storage pressure. The original strategy was to bore using standard methods while managing the disappearances. A tight drilling gap was faced, and there were gas influxes, which were redirected to the basic divider, following the application of rear pressure to the platform restrictor. The difficulties faced in well 43 mirrored those in well 32.

The application of MPD succeeded in accessing the main storage in well 43. Nonetheless, there was a requirement for hazard evaluation because of safety issues related to subjecting the platform restrictor to severe conditions of boring slurry, filled with bored fragments, which worsens when the layer gas is being removed from the borehole. Because of these factors, the hand-operated controlled pressure boring formerly used in well 43 was altered to automatic controlled pressure boring method.

Following all the issues faced, the borehole was not positioned at the main storage but was positioned in the Cretaceous region[29].

3.5 DIFFICULTIES AND APPROACH APPLIED FOR WELLS 43 AND 37

These represent the concluding two boreholes examined in this area. With a sensible level of expertise, the boring specialists opted to apply the steady base-hole pressure controlled pressure boring (CBHP MPD) method to bore the boreholes.

CBHP MPD refers to the expression commonly applied to outline measures implemented to rectify or lessen the impact of moving dynamic loss or comparable moving thickness in an effort to remain within the boundaries set by the hole pressure and break pressure. To diminish the impact of ring-shaped dynamic pressure (AFP) or comparable moving thickness (ECD), there will be a necessity for rear pressure from the exterior via the utilization of restrictors. While boring forward, the

Exterior ring pressure is close to nothing. During closure for connected pipe linkage, a small number of hundred pounds per square inch rear pressure is necessary. Employing a rear pressure suggests that there exists an ability to utilize a less thick slurry. The aim of this method is to sustain borehole pressure amid the hole pressure of the most pressurized layer and the break pressure of the least strong. This is typically achieved by drilling with a slurry density whose static variation is lower than necessary to equalize the highest hole pressure, with the gap compensated by employing dynamic while moving. This method is highly specialized because of the obstacles encountered in shifting from stationary to active equilibrium without incurring an influx. This method entails choosing a base-hole pressure and preserving it throughout boring activity and even when the circulators are deactivated. Circulators might be deactivated due to pulling out or forming a linkage.

The CBHP method was implemented with a stationary under-equilibrated slurry so that if it were in active condition, with the support of a rear pressure, it would lead to a minor over-equilibrated state. A benefit of this minor over-equilibrated state is that it permits the preservation of the static pressure as minimal as feasible along with possessing the capacity to lower the base-hole pressure by reducing or removing the rear pressure to bore through intense slurry disappearance regions.

Nevertheless, removing the rear pressure at times is insufficient to cease the slurry disappearances in an exhausted region. In such a scenario, the slurry thickness could be decreased more but constantly bearing in mind that this part is an exhausted petroleum storage with a tight boring gap. Additionally, the lowering of the base-hole pressure ought to be performed gradually and constantly confirmed with stream verifications.

The strategy for well 37 was to position the 9 7/8 inch tubing base at 4406 meters measured depth or 4280 meters true vertical depth and bore the subsequent part. Nonetheless, relying on earth science data, the tubing base was not positioned at the preset depth, but at a depth of 4460 meters measured depth. The slurry density applied was

smaller than that applied for boring well 43 by 0.12 grams per cubic centimeter. Owing to this reduced slurry thickness, after boring through roughly 50 meters, the rock in the Paleocene turned extremely unsteady, which nearly caused the boring tool to become stuck in the borehole. One of the remedies for this would have involved raising the slurry thickness to avert failure of the unsteady rock layer. Nonetheless, this remedy might have posed a difficulty because the Cretaceous area was exhausted. This led to the application of a contingency liner and the 7 5/8 inch tubing base was positioned at a calculated depth of 4562 meters. The strategy was to bore the next part with a tool of 6 1/2 inch, applying steady base-hole MPD method, with a heightened slurry density of 1.20 grams per cubic centimeter and a static base-hole pressure of 7547 pounds per square inch at the tubing base.

The fluid dynamics simulation on the updated borehole shape was revised and boring was performed using standard methods, with MPD gear installed and prepared for application (Responsive MPD). After boring approximately 226 meters, there were slurry disappearances. The static base-hole pressure needed to interrupt the movement was smaller than the real amount by 589 pounds per square inch and a variance of 0.09 grams per cubic centimeter in slurry density. When the denser slurry was being substituted, an influx from the borehole was accepted with a closure pressure of 600 pounds per square inch and 36 cubic meters capacity growth in the reservoir.

A responsive controlled pressure boring was applied to manage the influx and boring continued with a rear pressure of 200 pounds per square inch and a slurry density of 1.12 grams per cubic centimeter for a comparable moving thickness of 1.16 grams per cubic centimeter. The target for the rear pressure was modified by the boring service providers to monitor the underground pressure outline, which led to no slurry disappearances or entries. Because of the exhaustion procedure that took place, the boring gap was additionally narrowed and there was intrusion of water into the borehole and there was likewise a change in the petroleum water proportion from 80/20 to 52/48. Steady base-hole pressure was preserved during linkages by a technique referred to as the pressure capturing method. The dynamic pressure disappearances were computed to specify the quantity of rear pressure required to maintain the comparable moving thickness steady at the base of the borehole.

Each time the tool was lowered and then movement tried, serious slurry disappearances happened. This slurry disappearance was managed by prompting the borehole to influx and regulating it on the exterior with the MPD restrictor.

The MPD stream gauge was utilized for the prompt identification between regular movement and start of influx, thereby a rapid rear pressure growth was swiftly implemented to regulate the borehole until stream entering and exiting the borehole would balance and boring promptly restart.

The intended depth was effectively attained, departing the conclusion of the borehole into the UJT layer[29].

3.6 EQUIPMENT UTILIZED FOR MPD

The arrangement of the gear applied for MPD differs based on the traits of the storage and the goals of the task (IADC). The gear applied for the controlled pressure boring activities are as listed[29]:

- Spinning regulation mechanism at the borehole top

- Automatic restrictor unit

- Exterior tubing triple-phase divider
- Information gathering setup
- Bulk stream gauge

Rotating Control Device (RCD)

The RCD serves as a stationary MPD pressure regulation tool that is employed to separate rear pressure and seal the borehole setup or hold liquid. An RCD acts as an outstanding additional security tool that supports the explosion prevention stack over the ring-shaped preventer. Its role is to securely lessen petroleum compounds leaking from the borehole to the platform surface.

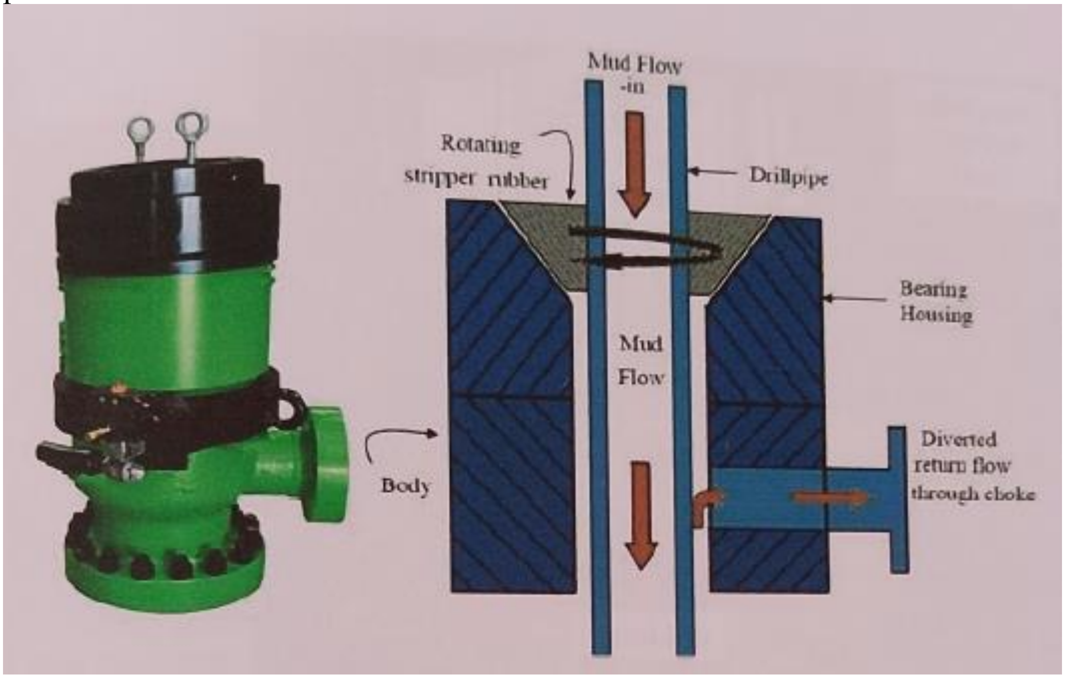


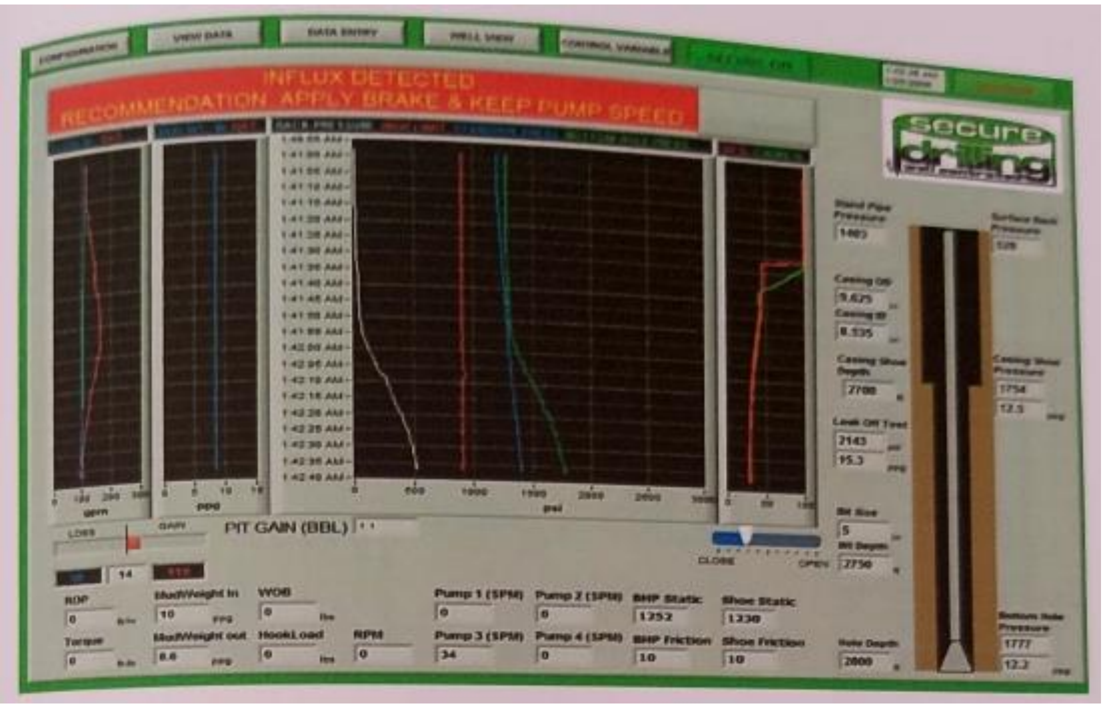
Figure 3.2 Spinning Regulation Tool[28]

Automatic Restrictor Unit

The automatic restrictor unit is employed to control the ring-shaped fluid rear pressure and the slurry return stream. The restrictor is set up in the return stream path to permit rear pressure to be implemented during the boring procedure. During linkages, to activate the restrictor, it is circulated over the borehole top[29].

Mass Flow Meter

This device is employed to quickly spot any gains or losses, allowing for immediate corrective steps to reduce downtime that is not productive.



INFLUX DETECTED
RECOMMENDATION: APPLY BRAKE & KEEP PUMP SPEED

PIT GAIN (BBL)

Stand Pipe Pressure 1403
Surface Back Pressure 329
Casing OD 9.625 in
Casing ID 8.535 in
Casing Shoe Depth 2700 ft
Casing Shoe Pressure 1754 / 12.5 ppg
Leak Off Test 2143 psi / 15.3 ppg
Bit Size 5 in
Bit Depth 2750 ft
Hole Depth 2800 ft
Bottom Hole Pressure 1777 / 12.2 ppg
ROP 0
Torque 0
MudWeight In 10 ppg
MudWeight out 8.6 ppg
WOB 0
HookLoad 0
RPM 0
Pump 1 (SPM) 0
Pump 2 (SPM) 0
Pump 3 (SPM) 34
Pump 4 (SPM) 0
BHP Static 1252
BHP Friction 10
Shoe Static 1230
Shoe Friction 10

Figure 3.5: Prompt recognition and supervision of influx

The red indicator shows an increase in the returning flow, while the blue and green indicators represent an elevation in the pressure at the bottom of the hole.

Automated Choke Manifold

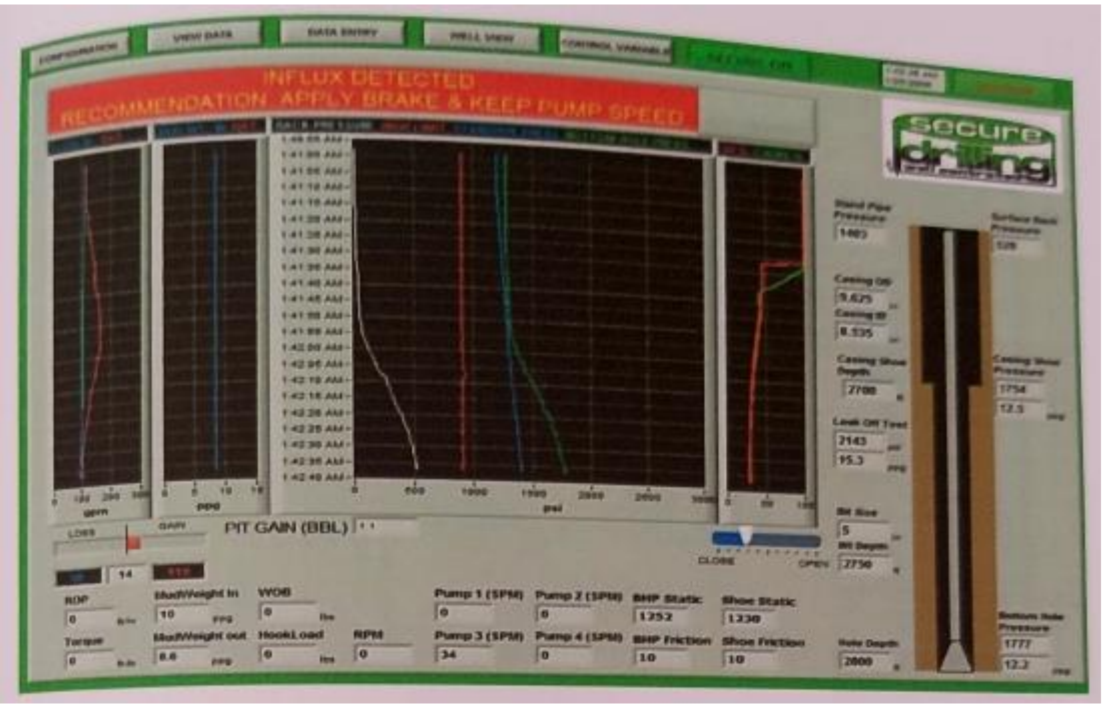
The automated choke setup is utilized to manage the pressure in the annular space and the flow of returning mud. It is positioned along the return line to enable the application of back pressure throughout the drilling process. When making connections, the choke is activated by pumping fluid from the surface across the wellhead.

Figure 3.3: Managed automated choke system

Surface Three-Phase Separator

The incorporation of separators in managed pressure drilling is essential. They are used when separating gas presents an issue. They can also be applied in scenarios involving fluid influx to condition the drilling fluid. The design of these separators depends on their intended purpose. Vertical types are used for isolating gas from liquids, while horizontal ones are for separating fluids of different densities.

Figure 3.4: Three-phase separation device



INFLUX DETECTED
RECOMMENDATION: APPLY BRAKE & KEEP PUMP SPEED

PIT GAIN (BBL)
14
ROP 0
Torque 0
MudWeight In 10 ppg
MudWeight out 8.6 ppg
WOB 0
HookLoad 0
RPM 0
Pump 1 (SPM) 0
Pump 2 (SPM) 0
Pump 3 (SPM) 34
Pump 4 (SPM) 0
BHP Static 1252
BHP Friction 10
Shoe Static 1230
Shoe Friction 10
Stand Pipe Pressure 1403
Surface Back Pressure 528
Casing OD 9.625 in
Casing ID 8.535 in
Casing Shoe Depth 2700 m
Casing Shoe Pressure 1754, 12.5 ppg
Leak Off Test 2143 psi, 15.3 ppg
Bit Size 5 in
Bit Depth 2750 m
Hole Depth 2800 m
Bottom Hole Pressure 1777, 12.2 ppg

Figure 3.5: Real time detection and monitor of influx

3.0.2 CASE STUDY TWO

This examination focuses on the application of managed pressure drilling conducted in the Tazhong area, situated in the middle of the Taklimakan Desert within the Tarim Basin in Xinjiang, China.

3.7 SUMMARY OF THE TARIM BASIN

The area is positioned in the Tarim Basin, amid the vast Taklimakan desert in the Xinjiang Uyghur Autonomous Region in northwestern China, at an approximate height of 900 meters, encircled by large mountain chains. Exploration activities in this basin began in 1952, with large-scale development commencing in 1989. The Tarim represents China's biggest hydrocarbon-containing basin, spanning 560,000 square kilometers. It features a slightly over pressured, fractured limestone deposit that yields sour oil and gas from depths between 4,000 and 6,500 meters. The basin's production in 2002 reached five million tons of oil equivalent, rising to twenty million tons by 2008. Wells drilled using traditional methods in this region often suffered from serious circulation losses. Consequently, a novel managed pressure drilling system was created to address the difficulties in this critical pressure setting. An automated managed pressure drilling setup was implemented to alleviate the drilling risks faced in the area.

The Tz1 formation in this region includes four production zones, specifically:

- Tz 82

- Tz62

- Tz 24

- Tz 83

This formation is a marginally overpressured gas deposit with an equivalent density ranging from 1.11 to 1.2 specific gravity. The temperature in the formation varies from 130°C to 140°C. The gas has a density between 0.61 and 0.64 specific gravity, including carbon dioxide levels from 1.6% to 3.2%, and hydrogen sulfide concentrations from 11 ppm to 33,000 ppm. The illustration below depicts the position of the Tarim in China.

Figure 3.7: Location of the Tarim Basin within China

3.8 DIFFICULTIES FACED IN THE FIELD USING CONVENTIONAL DRILLING

Performing drilling operations in a confined pressure range demands significant expertise to keep the process within the operational limits. In this area, tracking the pore pressure of the formation proved challenging due to the extensive fracture network encountered. This created issues in maintaining well control since a mud weight even marginally above the formation's pore pressure could lead to lost circulation, contaminating or harming the reservoir. A slightly lower mud weight might cause influxes or even uncontrolled releases if not managed. In this location, establishing the formation pore pressure during drilling was tough because of the highly developed fracture systems. Horizontal wells amplified these challenges even further.

While drilling with standard techniques in this field, lost circulation occurred, which hindered the transmission of measurement while drilling and logging while drilling signals to the surface, making it effectively impossible to sustain directional control during drilling.

3.9 JUSTIFICATIONS FOR IMPLEMENTING MPD IN THE FIELD

- To penetrate and finalize the Ordovician limestone deposit with minimal fluid losses and without any well control incidents.

- To extend horizontal wells to their full planned depth in less time, with the potential to advance further.

- To shorten the duration of well construction and cut down on non-productive periods by preventing issues like fluid losses, influxes, and stuck tubing.

- To enhance output and recover more reserves through drilling that maximizes links with the fracture networks while reducing damage to the formation.

- To uncover new deposit systems by advancing deeper into the Ordovician limestone using MPD methods.

- To identify losses and influxes sooner with the MPD setups and possess the capability to manage both without needing to close the well and resort to standard well control methods.

3.10 EQUIPMENT USED

The goal was to comprehend the working conditions so that appropriate protocols could be established and suitable gear selected. Solid understanding of the operational range is crucial for picking the correct equipment for the task, as the kind of gear utilized relies on the objectives of the technique.

Automated Choke Regulation

The automated choke serves as a pressure controller mainly for closed-loop drilling operations. The accuracy of the choke is critical for regulating the pressure at the hole's bottom. This accuracy relies on prior well planning and establishing the operational factors. One key purpose of the auto choke is to calculate a surface or wellhead pressure target based on measured data to achieve the desired bottom-hole pressure aligned with the reservoir's hydraulic profile. Computations occur in real-time (at minimum every second) to assess the well's dynamic state.

The automated choke regulation also guarantees secure management of all returning fluids. It includes a mass flow meter for ongoing measurement of the rate and density of the returning fluids.

Rotating Control Device (RCD)

A 500 psi RCD was utilized for pressure management above the rig's blowout preventer stack to redirect the returning flow to the automated choke regulation equipment.

Continuous Choke Flow Mechanism

The continuous choke flow mechanism sustains the back pressure and steady bottom-hole pressure when the rig pumps are deactivated during connections or trips.

Drill String Floats and Non-Return Valves

The assembly at the bottom of the hole incorporated both dual and single flapper-style float valves to act as a barrier and stop backflow through the drill string once circulation ceases.

Pressure While Drilling Tool (PWD)

A positive pulse PWD device was employed to offer real-time monitoring of bottom-hole pressure and was combined with the automated choke control's hydraulic model for precise bottom-hole pressure management.

Programmable Logic Controller (PLC)

The PLC acts as the connection between the hardware and software. It is an industrial computer applied in numerous industrial operations. It offers resistance to electrical interference, broad temperature tolerance, durability against vibrations and shocks, and protection for memory storage. The primary functions of the PLC include monitoring, controlling, and regulating. It observes data from sensors like flow rates and temperatures. It also manages automated elements such as solenoids used for operating chokes and valves. Additionally, it facilitates communication by translating data between hardware and software.

Non-Return Valves

A non-return valve, as defined in API specification 7NRV, refers to drill string valves that block reverse flow upward through the drill string. Various models exist. Two examples are illustrated below (Malloy K.P., 2008).

Flapper Type   Plunger Type

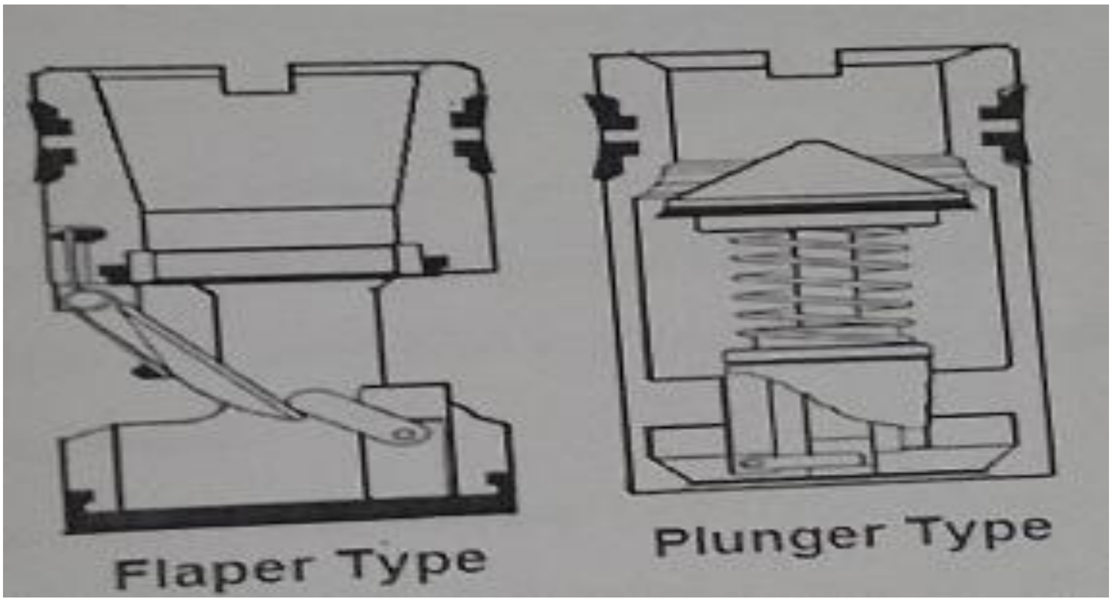


Figure 3.8: Non-Return Valves

Back Pressure Pump

The back pressure pump is a low-volume triple pump linked to the choke manifold and automatically regulated by the system. When the pressure controller detects insufficient flow from the well to sustain the needed back pressure, it activates the back pressure pump automatically (Malloy K.P., 2008).

Figure 3.9: Pump for Applying Back Pressure

3.11 METHOD USED

The configuration for Managed Pressure Drilling (MPD) in this initiative presented significant difficulties due to the horizontal orientation of the wells, combined with a limited operational range between the formation's pore pressure and its fracture threshold. The primary issue involved regulating the pressure at the well's heel while avoiding fluid losses at the opposite end. To address this, the drilling service provider implemented a combination of specialized software and equipment capable of accurately managing the pressure at the bottom of the hole. This setup included an automated MPD arrangement comprising a Rotating Control Device (RCD), an automated choke mechanism for flow regulation, a Pressure While Drilling

(PWD) instrument, a system for gathering data, and a unified hydraulics simulation.

The strategy developed by the drilling operator for these MPD wells involved a technique known as Balanced Mud Cap Drilling (BMCD) for positioning. This method took into consideration the effects of swab and surge pressures and guaranteed that pipe trips could be performed securely without the need to suppress the well or manage pressures at the surface. Every time a trip was necessary, the borehole was cleaned through circulation, and the drill pipe was withdrawn under controlled conditions to the upright portion of the well, utilizing the automated choke system to sustain a steady pressure at the hole's bottom.

For each individual trip, a fresh computation was required to determine the placement depth for the balanced mud cap. This step was taken to establish a particular pressure at the bottom of the hole while ensuring no pressure at the wellhead.

The pressure level was engineered to extend deeper than the depth where the pipe becomes buoyant, serving as an extra precautionary step.

In order to attain zero pressure at the wellhead, a specialized MPD mud formulation (a viscous separating agent) was utilized to create a barrier that stopped the mixing of fluids with varying specific gravities. Subsequently, the well was converted to the BMCD mud, and the pressure at the wellhead was gradually reduced automatically to reach zero.

Once the RCD's bearing component was taken out, a customized trip nipple was fitted following verification that the well showed no flow. The pump from the trip tank was then employed to circulate fluid across the well's top as the bit was retrieved to the surface in a standard manner. This approach required careful planning and adjustments to properly handle swab and surge pressures while also enhancing the speed of tripping operations.

It is critically essential to maintain a uniform weight for the BMCD to guarantee that the mud cap is positioned accurately, thereby preserving an exact and unchanging bottom hole pressure (BHP) throughout tripping activities.

Up to now, a sum of five wells using MPD have been completed in this location. These wells were bored laterally across the Ordovician limestone formation, employing a 6-inch drill bit. The MPD fluid setup applied across all these wells was intended to remain statically underbalanced, with mud densities varying from 1.05 specific gravity (SG) to 1.1 SG.

3.0.3 CASE STUDY THREE

This examination explores the ways in which managed pressure drilling mitigated the issues related to reservoir depletion in the KRISTIN FIELD.

3.12 SUMMARY OF THE KRISTIN FIELD

The Kristin field represents a reservoir under extreme pressure and temperature conditions, reaching 911 bar (equivalent to 13213 psi) and 342 degrees Fahrenheit.

The swift reduction in reservoir pressure poses a significant issue, as it leads to a progressively tighter drilling margin and associated operational difficulties. During the initial stages of field development, the practical drilling margin existed between a pore pressure of 1.9 SG and a fracture pressure of 2.14 SG.

As depletion advances, its impact on the fracture threshold results in an increasingly constrained fracture pressure.

This location features a highly overpressured storage area holding hydrocarbons within three distinct productive layers, namely:

- The Tofte layer

- The Ile layer

- The Garn layer

The hydrocarbon mixtures in these layers consist of highly undersaturated, rich gas condensates featuring a dew point pressure of 500 bar (7250 psi). These layers are divided by a shale barrier.

The Tofte layer is composed of a single unit with a typical thickness of 130 meters. The Ile layer averages 87 meters in thickness, whereas the Garn layer has an average thickness of 110 meters.

3.13 JUSTIFICATIONS FOR ADOPTING MANAGED PRESSURE DRILLING IN THE KRISTIN FIELD

The motivations for introducing managed pressure drilling in the Kristin field include the following:

- MPD facilitates prompt identification of kicks through heightened responsiveness to incoming fluids.

- It provides enhanced regulation of the pressure at the bottom of the hole amid well control situations.

- It permits a quick decrease in bottom hole pressure when dealing with loss events.

- It offers the capacity to elevate back pressure on the well, thereby restricting additional fluid entry while the subsea Blowout Preventer (BOP) is being shut. This marks a key distinction from traditional drilling methods. In standard drilling practices, there is no cap on fluid inflow during BOP closure, whereas MPD allows for such a restriction by boosting the back pressure at the surface.

Within this field, a solution involving a pressurized riser was applied. Typically, marine risers in offshore operations serve to transport drilling fluids and extra solids back to the surface. The traditional setup functions under atmospheric pressure, directing the drilling fluid flow as an overflow from the riser into the rig's mud handling system. Riser segments are generally constructed to endure loads like those from ocean currents.

3.14 IMOLEMENTATION OF MANAGED PRESSURE DRILLING IN THE KRISTIN FIELD

The application of managed pressure drilling here was organized into two stages: stage 1 and stage 2.

3.14.1 STAGE ONE (Initial Test Well)

During this stage, implementation included a pressurized riser setup, incorporating a multi-part slip joint (MPSJ), an RCD, and a hydraulic coupling. The role of the MPSJ is to allow secure MPD operations from a semi-submersible platform.

The well in stage one was targeted in a zone with minimal depletion. The MPD apparatus was positioned after the RCD and flow spool, comprising a hose for drilling fluid connected back to the flow conduit.

Additionally, it was arranged that fluid returns would be directed straightforwardly from the choke to the shaker units.

3.14.2 STAGE TWO (Subsequent Test Well)

In this well, the MPSJ and RCD were combined with a riser sealing mechanism, along with a more durable and precise MPD assembly further along the line. In contrast to stage one's focus on validating the pressurized riser, the objective of the stage two test well extended beyond qualifying the semi-submersible riser setup; it also aimed to validate the automated MPD approach for drilling in depleted sections of the Kristin reservoir, characterized by tight operational margins. The components in the second stage of the MPD setup encompass:

- A system for automated choke management

- A pair of pumps for back pressure to sustain counter pressure by pumping down the booster line of the riser.

- A setup for separating mud and gas located after the choke.

- A couple of relief valves plus a junk trap, similar to those in stage one before the choke, supplemented by an extra backup relief valve for operations.

- An adaptive MPD well management circuit that permits returns to be captured before the automated choke, sourced from either the RCD or flow spool, or alternatively from the rig's choke conduit, and kept under control.

Back pressure pumps specific to MPD were omitted in stage one. Instead, one of the rig's three mud pumps will be utilized to pump steadily through the riser using the booster line. This method enables the retention of back pressure before the choke even without injection down the drill pipe. It further supports near-constant maintenance of Constant Bottom Hole Pressure (CBHP) amid pipe connections and trips. Meters for flow were placed on the standpipe as well as the riser booster conduit to track the rates of drilling fluid injection along each path.

CHAPTER FOUR

4.0 RESULT,ANALYSIS AND DISCUSSION

In this chapter of the work, the effects of the application of managed pressure drilling over conventional drilling method is analyzed for the three case studies taken.

4.1 ANALYSIS OF CASE STUDY ONE

WELL 13

Well 13 was drilled conventionally. The data and plot for the drilling depth versus drilling days is shown below

Table 4.1; Drilling days and depth for well 13

DRILLING DAYS	DEPTH
1.40304	12.1901
2.10505	18.6453
2.80707	25.1006
3.16357	32.2905
3.17356	39.4947
3.18354	46.6989
3.54004	53.8888
5.37547	128.021
5.73198	135.211
6.08848	142.401
6.09846	149.605
6.045496	156.795
7.15598	162.53
7.854	166.103
9.93809	169.62
10.9866	176.061
13.0847	189.663
16.5518	190.961
17.2538	197.416
17.9569	204.592
19.3499	209.578
19.7064	216.768
20.4184	230.427
21.1214	237.603
23.8955	238.93
23.8955	238.93
27.0162	240.242
27.0162	240.242
30.1638	241.555
30.1638	241.555

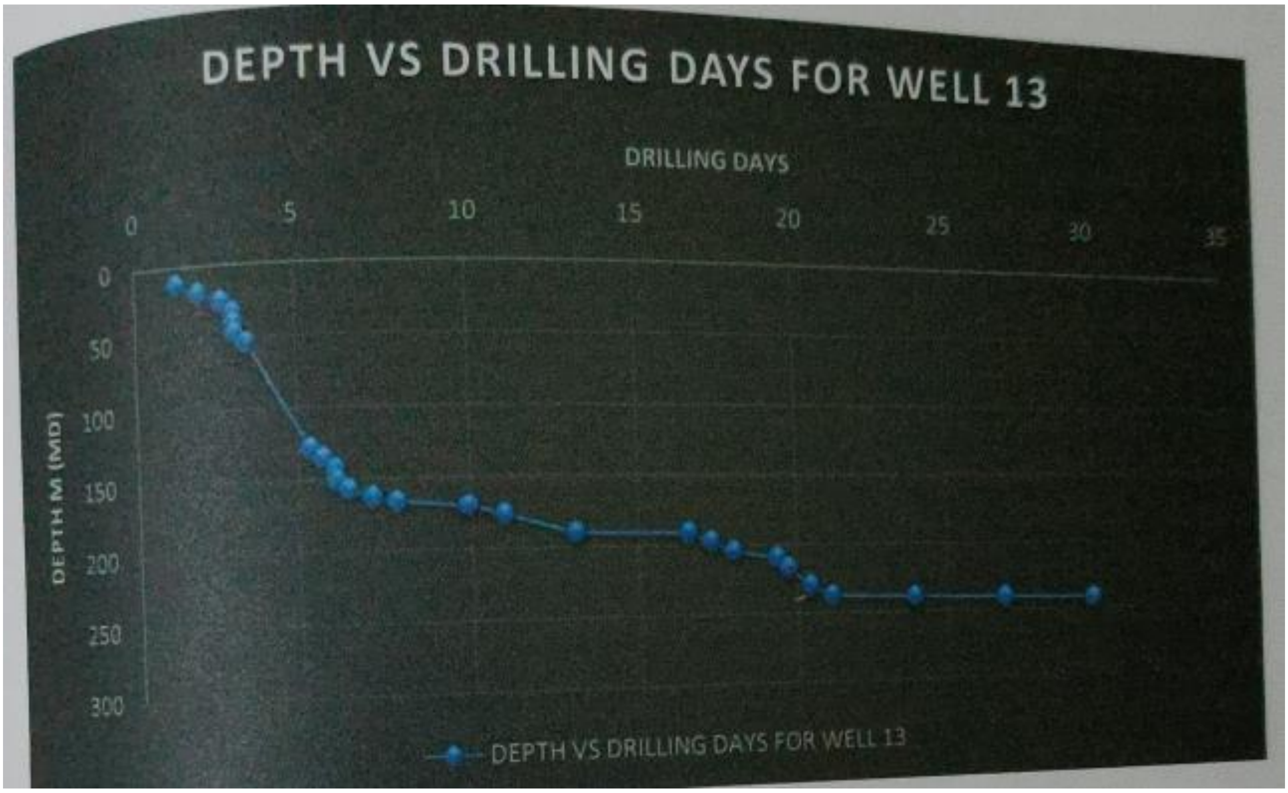


Figure4.1; plot of drilling days vs depth for well 13

The table for the relationship between the bottom hole pressure and depth is shown in the table below

Table 4.2: shows the relationship between the bottom hole pressure and depth for well 13

HYDRAULIC BHP (PSI)	DEPTH (M)
205.97	19.9691
268.657	67.2473
331.343	101.139
367.164	130.068
456.716	173.854
519.403	215.496
564.179	242.322

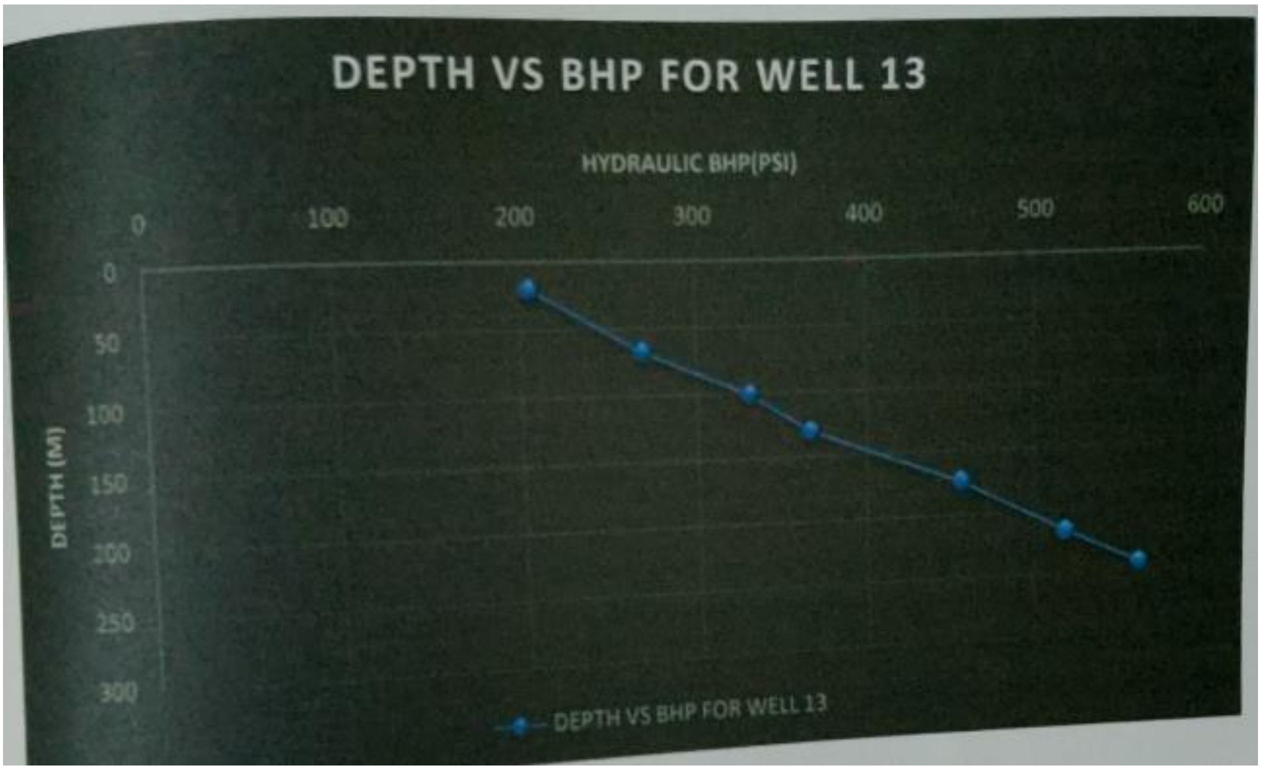


Figure 4.2 plot of depth and hydraulic bottom hole pressure for well 13

For this well, a historical analysis was carried out to determine the number of drilling days, kicks, mud losses, gas influxes and hydrostatic bottom hole pressure. Fig 4.1 is indicative of an increase in the number of drilling days with depth. Due to the series of mud losses and kicks encountered in the well, the well was landed in a secondary reservoir, above the primary reservoir, caused by the narrow drilling window between the pore pressure and fracture gradient. The hydrostatic bottom hole pressure, as expected for conventional drilling technique, also increased with depth, due to the increase in the pressure and temperature as depth increased.

Due to the narrow drilling window, the mud losses were encountered, which led to the reduction in the hydrostatic pressure and led to a kick. The table below shows the depth in which mud losses and kicks occurred during the drilling process.

Table 4.3 showing the depth in which mud losses, kicks and gas influxes occurred in the drilling of well 13

DEPTH FOR MUD LOSSES (M)	DEPTH FOR KICKS (M)	DEPTH FOR GAS INFLUX (M)
4457	4462	4362
4470	4467	4397
-	-	4462
-	-	4467

From the table above, the total drilling days for well 13 is approximately 30 days, while the length section for the well is approximately 242 days, hence the average depth drilled per days can be calculated using the formula

Average length drilled per day = $\frac{\text{total length section (M)}}{\text{No. of days taken to drill the section}}$

Average length drilled per day for well 13 = $\frac{242}{30}$ = 8.0887m/day

This is indicative that an average of approximately 8.1 meters were drilled per day in well 13, The total mud lost has been calculated for this well to be 3006m^2

WELL 31

Well 31 was also drilled conventionally like well 13. Similar challenges encountered in well 13 was encountered in this well. The increase in in depth led to an increase in pressure and temperature as the well was drilled. The relationship between the drilling depth and the number of days taken to drill the hole section for well 31 is given in the table below

Table 4.4: shows the drilling days and depth for well 31

DRILLING DAYS	DEPTH (M)
0.006879	1,43721
1.53056	7.27815
3.72494	90.7466
4.05857	97.9511
4.3922	105.156
4.7258	112.36
5.05601	118.846
5.82989	155.531
7.35358	161.372
7.35358	161.372
7.983	167.877
9.95037	203.917
9.95037	203.917
11.7664	208.339
14.7622	209.242
14.7622	209,242
17.4656	211,564
20.4614	212.467
20.4614	212.467
20.795	219.671
21.4244	226.176
21.4244	226.176
21.7581	233.38
23.5707	237.084
23.5707	237.084
26.563	237.268
29.5553	237.452
29.5553	237.452
32.5477	237.636
35.2408	237.802
35.2408	237.802

The plot of the depth vs the number of drilling days is shown below

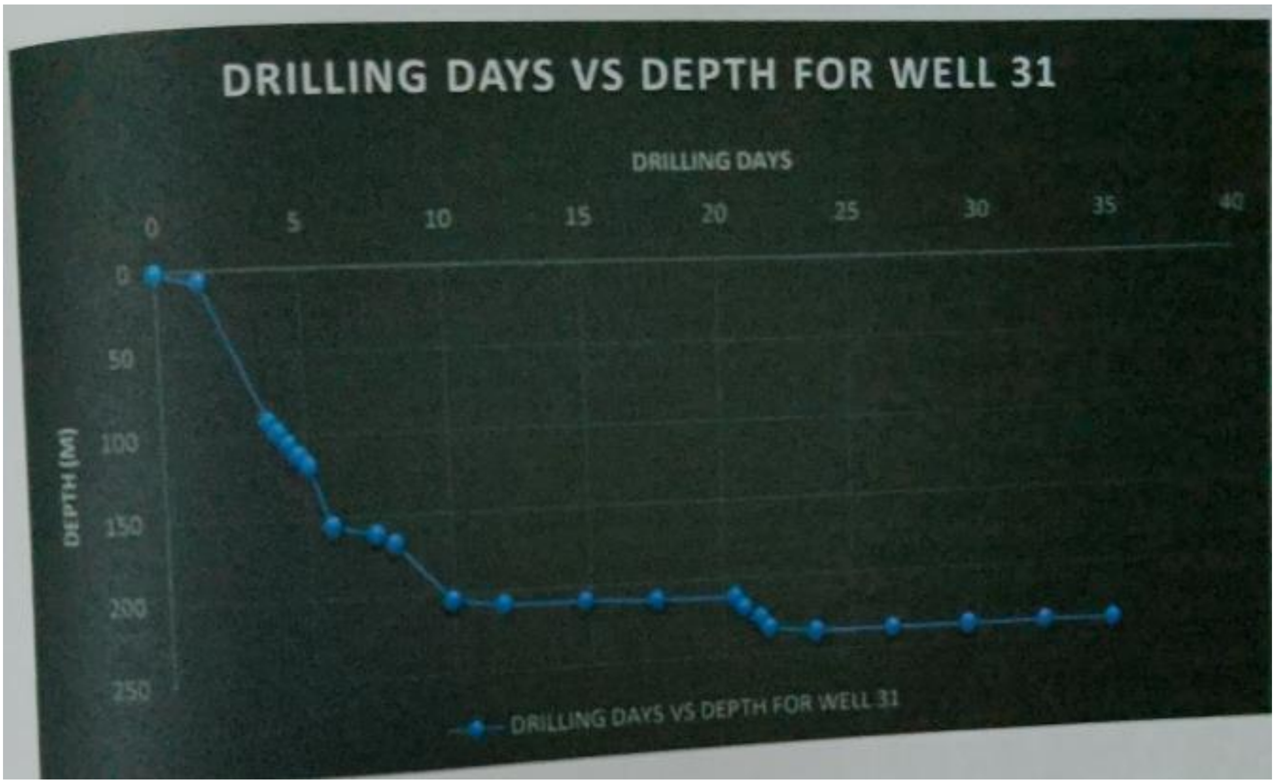


Figure 4.3 plot of depth vs drillings for well 31

The total length for this well is 238m and the total time taken to drill this section is approximately 35 days, applying equation one above to determine the average length drilled per day for this well results to a value of 6.8m/day. the total mud lost 1405m^3

The data and plot of the depth vs the hydrostatic bottom hole pressure for this well is given in the table below

Table 4.5 showing the relationship between the hydrostatic BHP taken to drill 8$^{1/2}$ in the section of well 31

HYDROSTATIC BHP (PSI)	DEPTH (M)
323.792	15.8898
337.225	39.4068
473.007	64.1949
484.746	70.5508
496.485	76.9068
508.223	83.2627
531.073	89.6186
553.923	95.9746
576.773	102..331
588.449	108.051
611.299	114.407
623.038	120.763
634.777	127.119
657.627	133.475
669.366	139.831
681.205	146.186
703.955	152.542
715.694	158.898
727.433	165.254
739.171	171.61
750.910	177.966

762.649	184.322
774.325	190.041
786.064	196.398
797.803	202.754
809.542	209.11
821.281	215.466
844.131	221.822

The plot showing the relationship between the hydrostatic bottom hole pressure and depth is shown below

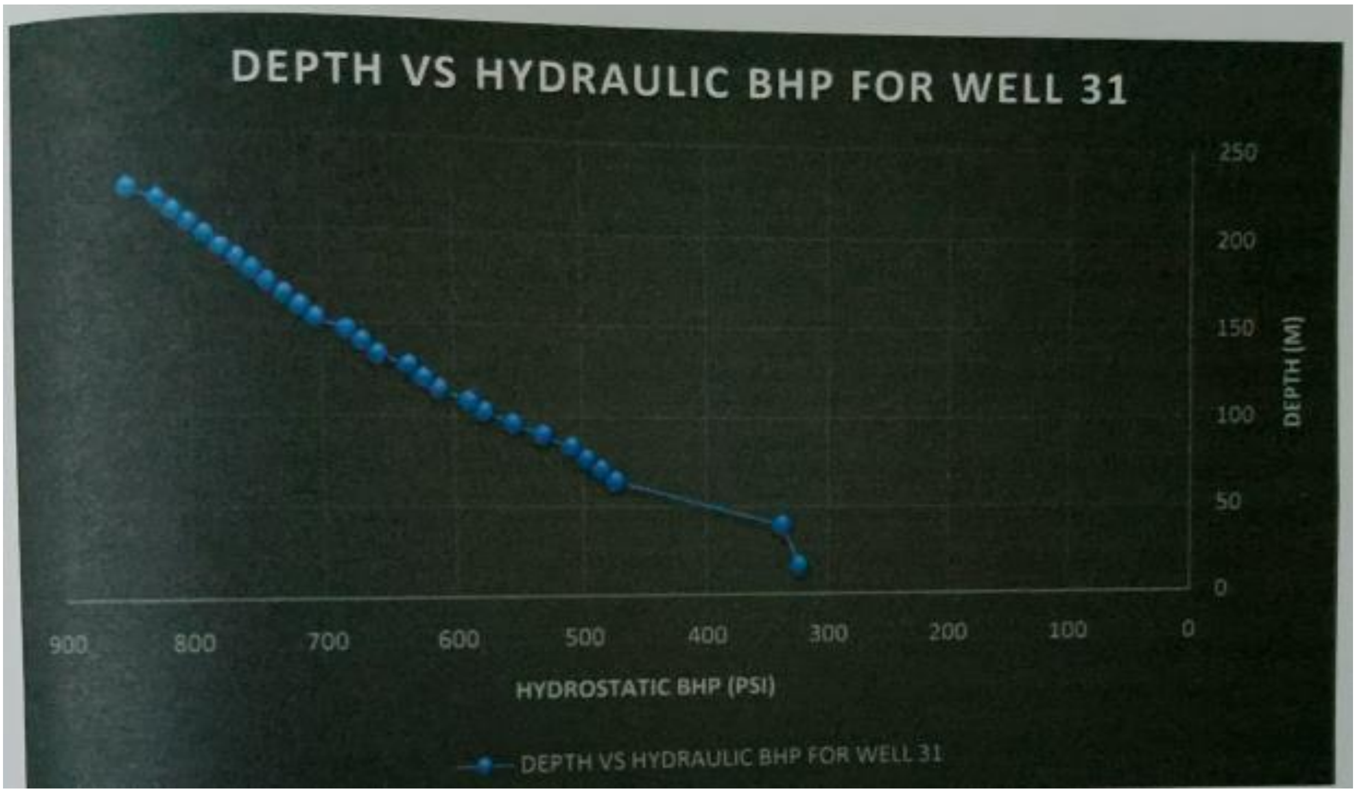


Figure 4.4 plot of depth vs hydrostatic BHP for the $8^{1/2}$ inch hole section of well 31

Because the pressure increases with depth, while drilling there should also be a pressure that counterbalances the formation pressure. As seen in figure 4.4, the hydraulic bottom hole pressure increased with depth during the conventional drilling. However, due to the narrow pressure window of the reservoir, the annular pressure profile was not kept constant which in turn led to a series of kicks and mud losses. These drilling hazards resulted to non productive time, which directly affect the operational cost.

Table 4.6 shows the different drilling hazards in which they occurred in well 31

DEPTH FOR MMUD LOSSES (m)	DEPTH KICKS (m)	DEPTH FOR GAS INFLUX (m)
4400	4410	4375
4410	4415	4445
4430	4450	4465
4460	-	-

Making an analysis of the data above, it is clearly indicative that the drilling window of this reservoir is very narrow, because the intervals in which kicks and mud losses were observed in the process of drilling is a very short one. For instance, for the case of mud losses in the well, mud loss was observed initially at a depth of 4400mnand drilling only 10m away, a kick was observed. In this scenario, having a kick means that the hydrostatic pressure is low to contain the formation pressure, hence the during the circulation of the kick, a heavier mud has to be pumped down the hole through the drill pipe. This kick circulation method is rather slow, hence increasing the non productive time and cost of drilling.

WELL 32

Well 32 was planned to be drilled conventionally at first with anticipated mud weight of 1.86g/cm^3, the table below shows the number of days taken to drill at different depth.

Table 4.7; Relationship between the depth and drilling days for the 8$^{1/2}$inch section of well 32

DRILLING DAYS	DEPTH (M)
1.06818	62.3864
1.86713	88.4266
2.66608	114.467
6.33392	200.533
7.73951	226.652
9.1451	252.771
11.7255	273.855
13.1311	299.974
17.7238	347.255
20.3042	368.339
24.0402	381.792
24.8392	407.832
29.2203	426.556
34.7185	432.456
34.7165	432.456
37.3182	456.136
40.4668	472.107
40.4668	472.107
41.8724	498.226
43.278	524.344
43.278	524.344
45.8392	542.832
52.5594	631.888
53.9458	655.411
55.4668	698.107
56.8724	723.226
57.6713	749.266
60.8199	765.236
63.9878	783.802
64.7867	809.843
66.1923	835.962
66.9913	862.002
68.3969	888.121

The plot below graphically represents the table of values in table 4.7

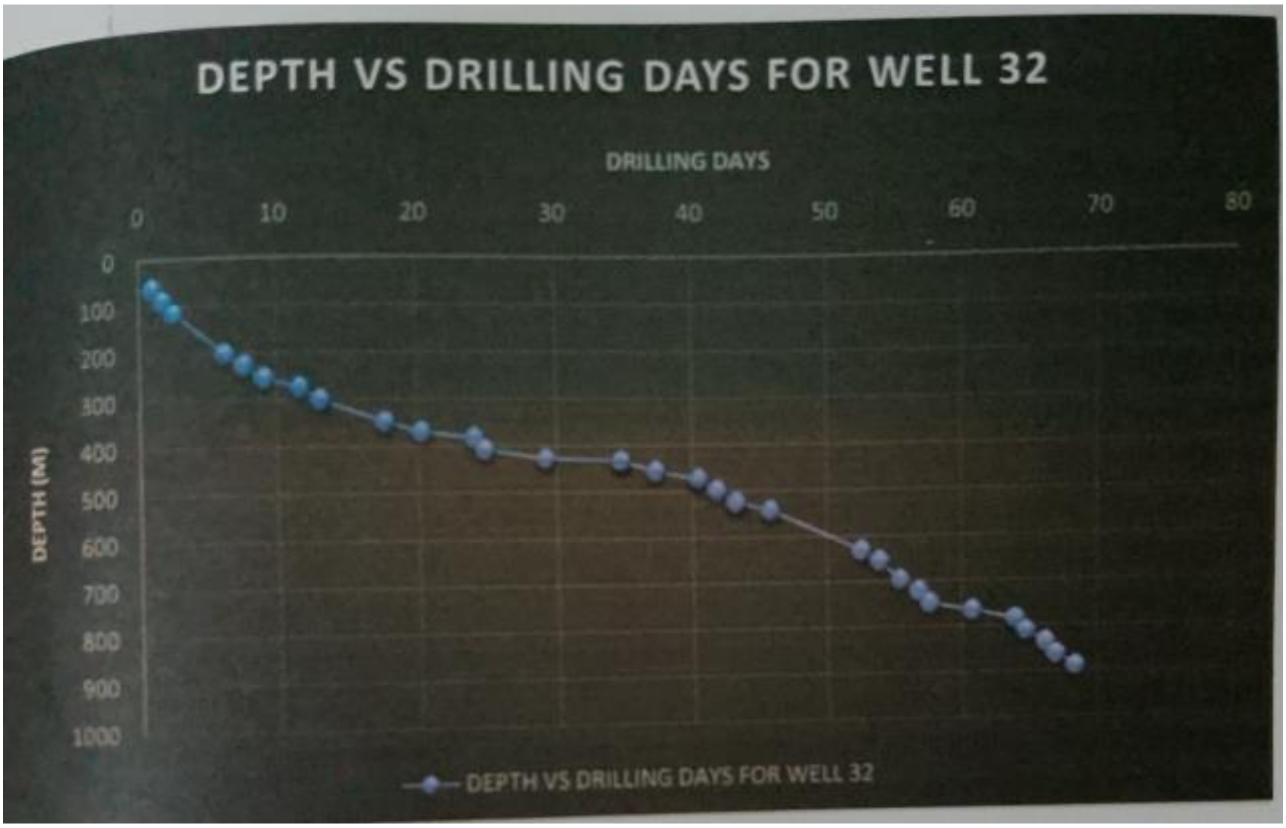


Figure 4.5: Plot showing the relationship between the depth and the number of drilling days on well 32

Using equation4.1above, we can determine the average length drilled per day. The total length section from the table is approximately 888m, while the total number of days taken to drill through this hole section 68 days. applying equation 4.1 therefore, the average length drilled per day is 12.98m/day and the total mud lost for this well is 3705m^3.

Table 4.8: Relationship between the hydraulic BHP and depth for well 32

DEPTH (M)	HYDRAULIC BHP (psi)
4330	10100
4370	10250
4470	10400
4490	10600
4490	11000
4510	11500
4530	11600
4540	10500
4560	11000
4630	10800
š4710	10500

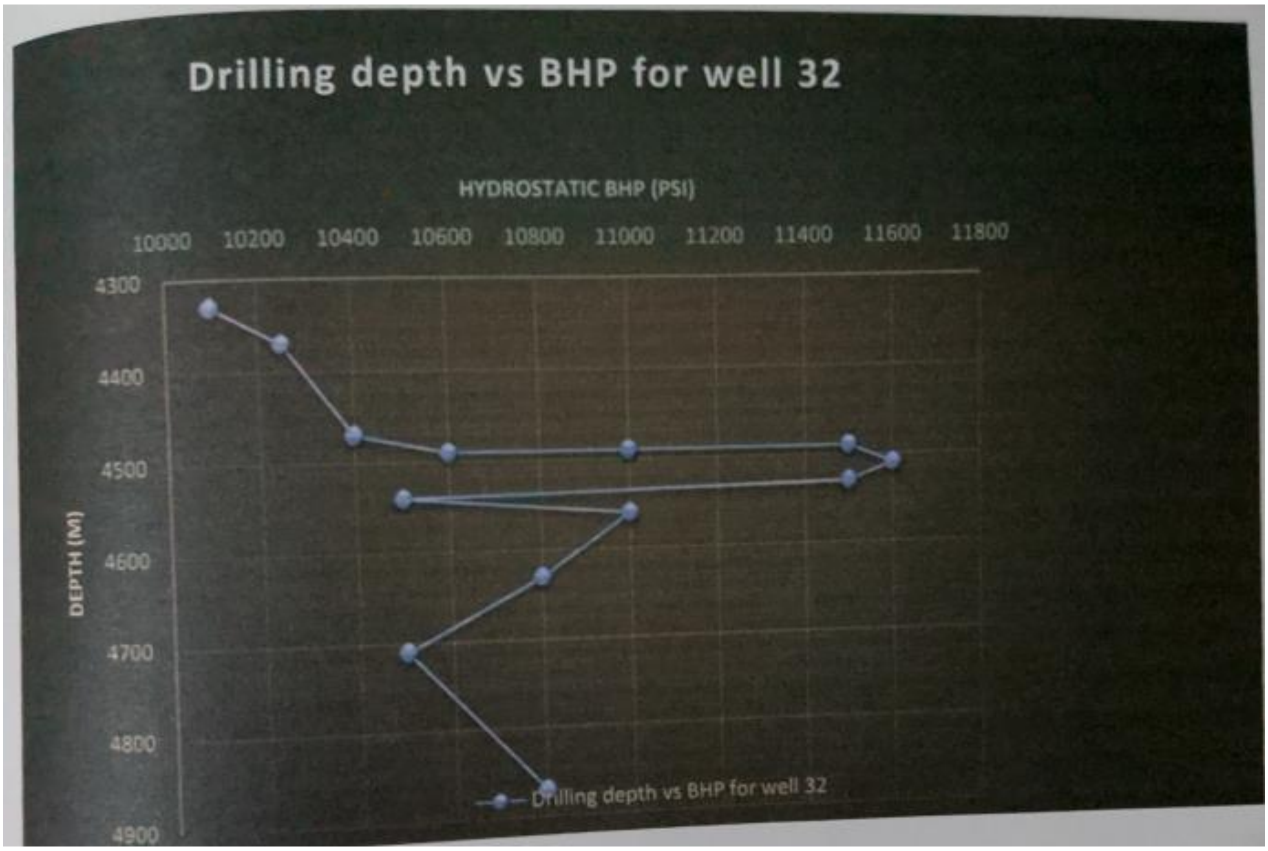


Figure 4.6: Plot of the depth and hydraulic variation in well 32

Conventionally, there is pressure increase with depth, which in turn calls for an increase in the hydrostatic bottom hole pressure. The hydrostatic bottom hole pressure was managed by the drilling engineers, but due to the unpredictable pore pressure gradient in the reservoir, there were still series of kicks and losses. As seen in the figure above, between the depth of 4500meters and about 4550meters, the hydrostatic bottom hole pressure was increased drastically. This drastic increase is indicative of a high pore pressure. This high pressure is due to the surrounding reservoir, which was at virgin pressure. Although series of kicks occured during the drilling of this well, the kicks were managed by diverting them to the RCD, without a pause in drilling operation.

The table below illustrates the drilling hazards that occurred in the drilling of the 8 1/2 inch section of the well being considered.

Table 4.9: illustrating the drilling hazards that occurred during the drilling of well 32

DEPTH FOR MUD LOSSES (m)	DEPTH FOR KICKS (m)	DEPTH FOR GAS INFLUX (m)
4475-4875	4510-4515	4510-4515
-	4545	4525
-	4595	4535
-	-	4545

As in the case of well 31, this table is indicative of a narrow drilling window, in which as at the depth of 4475meters, there were mud losses and at a few more depth ahead, kicks were encountered. The advantage of this well over the others is that the non productive time was reduced due to the fact that an RCD was put in place, which allowed for the divertion of the reservoir fluid flow while drilling continued till the target depth was encountered.

WELL 43

Well 4 was planned initially to be drilled with the managed pressure drilling technique, however, there were safety concerns on exposing the rig chokes to some harsh conditions such as drilling mud loaded with drilled cuttings, which even worsens in the presence of formation gas. The tables below shows the drilling event for well 43.

Table 4.7: relationship between the number of drilling days and depth for the 8 ½ inch section of well 43

DRILLING DAYS	DEPTH (M)
1.15385	11.9857
2.30769	33.2737
2.69231	56.6488
4.23077	78.0561
5.76923	94.8122
6.15385	118.187
6.53846	141.562
6.92308	188.193
7.69231	209.362
8.07692	232.737
12.3077	271.258
13.0769	294.753
14.2308	316.041
14.6154	339.416
15.7692	358.378
16.5385	381.872
19.6154	389.803
20	413.178
27.6923	589.982
28.4615	611.151
28.4615	611.151
28.4615	611.151
28.4615	657.782
29.2308	709.064
29.2308	709.064
30.7692	788.611

The figure below shows the graphical representation of the data points in the above table

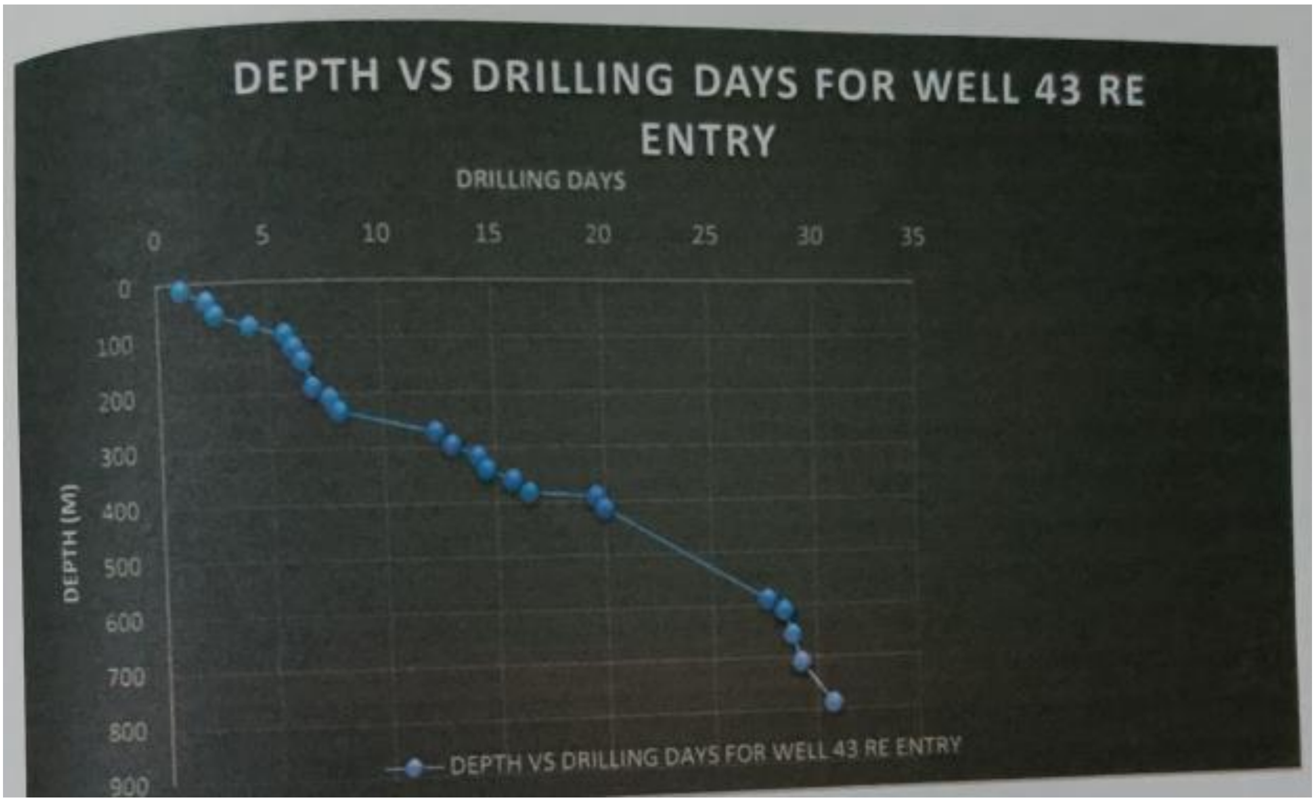


Figure 4.7: Plot of depth vs number of drilling days for the 81/2 inch section of well 43

From the plot above, as expected,, the number of drilling days increases with depth. The total drilling length is approximately 789meters while the total time taken to drill the section lengths approximately 31 days. Employing equation 4.1 above, the average length of well drilled per day is 25.5m/day. and the total mud lost was $653m^2$

A plot of the hydrostatic pressure and depth is also shown below

Table 4.11: Drilling hazards associated with well 43

DEPTH FOR MUD LOSSES (m)	DEPTH FOR KICKS (m)	DEPTH FOR GAS INFLUX (m)
4400	4500	4390-4400
4410	4602	4495-4500
4425-4500	4610	4575
4525-4600	4790	4605
4605-4700	-	4610
4720	-	4700
4800-4830	-	4710
4850	-	4795
4880	-	4800
4900	-	4820

The interpretation of this table is same as that for the other wells previously drilled. However, in this case, since the automated managed pressure drilling was used, there were mudlosses and kicks which did not affwet the drilling operations and therefore there were no from o non productive time or excessive cost of operation.

WELL 37

This was the last well drilled in the field. It was drilled with the constant bottom hole pressure managed pressure drilling technique. The table below shows the relationship between the depth and number of days taken to drill this well.

Table 4.12 Table showing the relationship between the drifting days and the depth for

the 81/2 inch settings for well 37

DRILLING DAYS	DEPTH (m)
1.26222	24.2216
2.09241	46.288
2.48971	68.4187
2.8474	112.744
2.886	90.5494
3.2437	134.875
4.07874	154.722
5.35255	172.285
5.74884	194.416
6.14514	216,547
6.97633	238.613
8.25013	256.176
10.8325	271.327
14.7349	277.406
16.4475	292.685
17.7174	312.468
18.5139	354.51
18.9102	376.641
19.3065	398.771
19.7028	420.902
21.4076	440.62
23.9436	482.405
24.7748	504.471
25.1364	546.577
25.1711	526.602
25.5327	568.708
25.929	590.839
31.8013	714.231
32.1976	736.361

The figure below also shows the plot of depth and number of drilling days for the drilling of the hole section for this well.

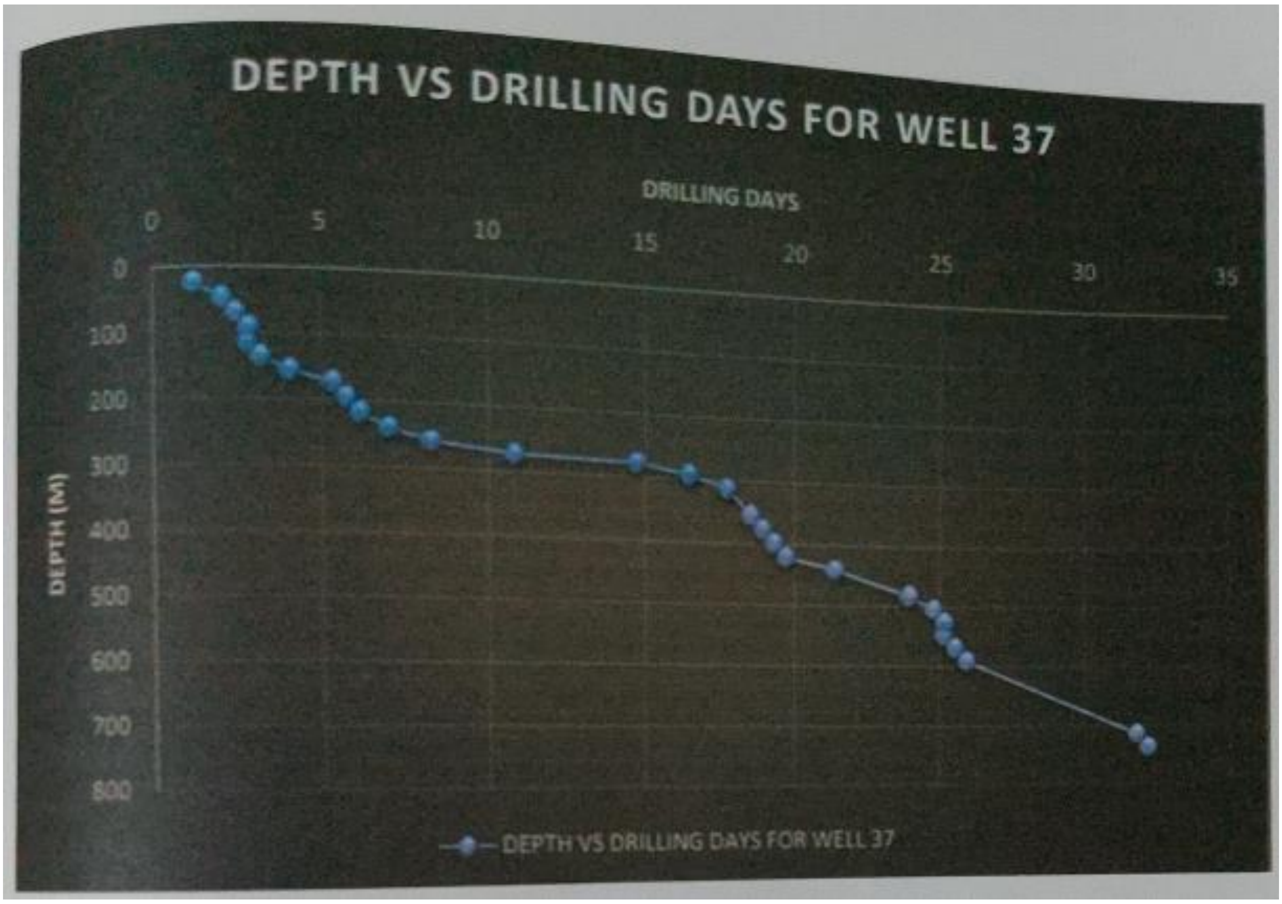


Figure 4.8: Plot of depth and number of drilling days for the 81/2 inch hole section for well 37

Using equation 4.1, the average depth taken to drilled per unit time in days of the section can be calculated. In this well, the total length is approximately 736m, which was drilled in approximately 32 days, hence the average depth drilled per unit time is 23m/day. The total mud loss seen was 1256m².

The figure below is a plot showing the number of drilling days and depth for all the wells in the Bolontiku field.

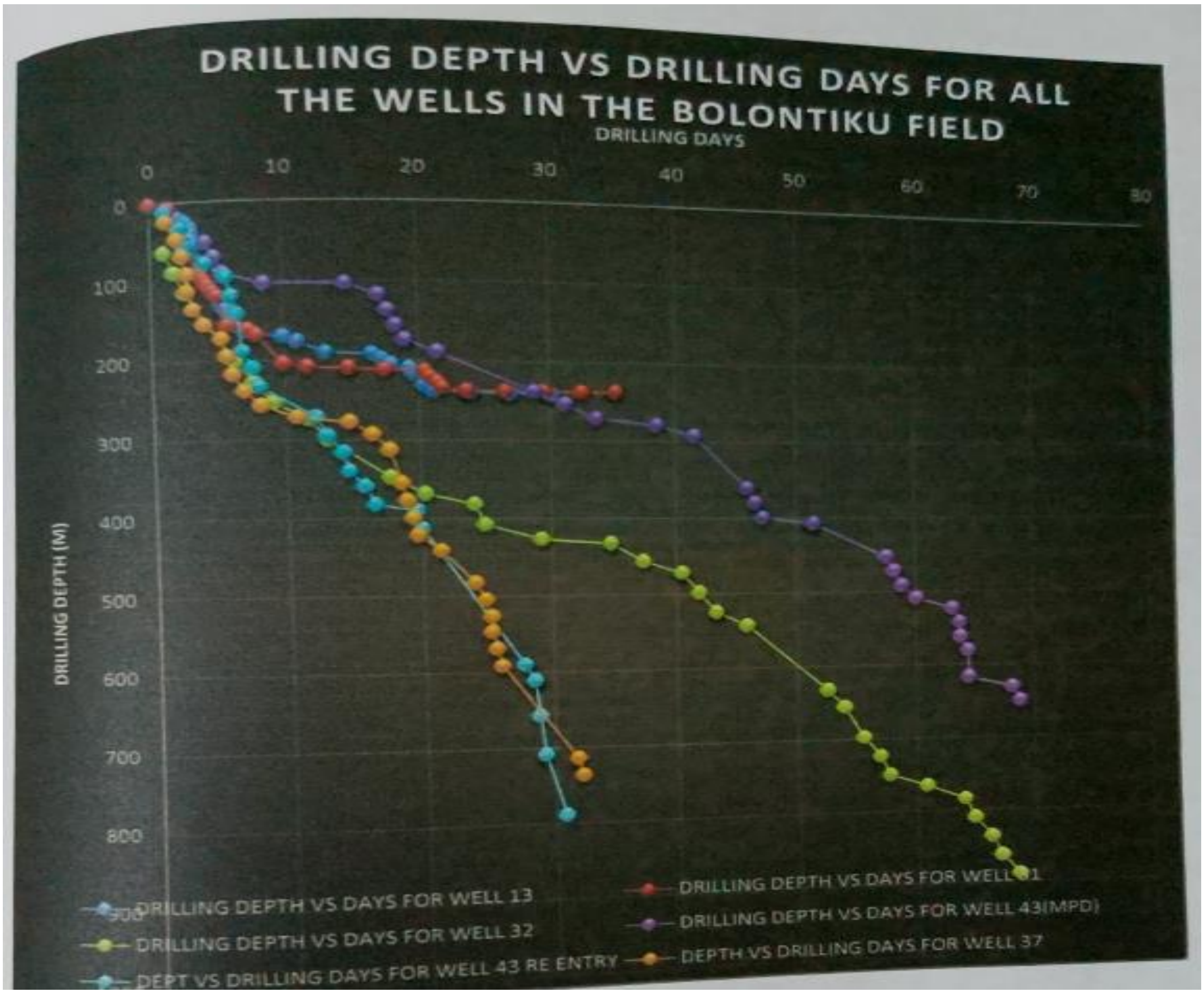


Figure 4.9: A plot of all the wells in the Bolontiku field showing the relationship between the drilling days and depth

In the figure above, it is evident that only wells drilled with MPD technique were successful at reaching the target depth. The table below shows the summary of the results gotten from this case study.

Table 4.13: Summary of the results for all wells in case study one

Well number	**Drilling technique**	**Section length**	**Drilling Time (d)**	**Average meters drilled per day(m/d)**	**Total mud lost (m^3)**
13	**Conventional**	242	30	8.0667	3006
31	**Conventional**	238	35	6.8000	1405
32	**MPD**	888	68	12.9800	3705
43	**Automated MPD**	789	61	13.11	2208
43	**Automated MPD**	813	31	25.5	653
37	**Automated MPD**	736	32	23	1256

: The conventionally drilled wells could not reach their target depth and were left to produce at the secondary reservoir (the cretaceous reservoir). However, the four wells drilled with MPD technique were successful in reaching their target depth. From table 4.13 above the wells drilled with the automated MPD approach gave better results, drilling a more section length in lesser number of days compared to those drilled conventionally and with the Manual MPD approach.

From the foregoing of this case study, it can be said that MPD is suitable for fractured and depleted reservoirs in which loss circulation and well control may pose a challenge.

When drilling conventionally through a depleted zone with an ovelying high pressure formation in a typical pore pressure and fracture pressure window, there are likely cases of lost returns due to high wellbore pressure against the depleted zone, while overbalanced is maintained at high pressure formation.

This challenge may be mitigated through the use of constant bottom hole pressure MPD technique, which precisely controls the wellbore pressure, so that the fracture pressure at the depleted zone is not exceeded, while overbalance at the high pressure zone is still maintained.

4.2 ANALYSIS OF CASE STUDY TWO

Analysis of the five wells drilled in this field are shown below

TZ:62-11H

This was the first well drilled with MPD technique in this field. The well was drilled to a depth of 5452 meters, with a horizontal displacement of 591 meters. With the automated MPD technique, there were minimized losses and influxes from the well. The longest horizontal well previously drilled in the field was done conventionally, reaching a horizontal displacement of 360 meters. The MPD drilled well was drilled further to an additional displacement of 391 meters, beyond the predetemined target depth

The overall drilling time from the date of spud was reduced from the initial pla of 151 days to 131 days, thereby saving operational cost.

TZ 26-211

This was the second MPD well drilled in this field. However, the well was initially planned and drilled with the conventional drilling technique through the 7 inches liner shoe and 145 meters was drilled. This however posed a well control problem because there were series of kicks and lost circulation. To curtail these problems, the well was bull headed and a low circulation mud treatment was used to attempt to get the well stabilized and under control. The problems led to an MPD system being rigged up (Reactive MPD) which was unsuccessful also in gaining stability and drilling operations were discontinued.

TZ 62-10H

This was the third MPD well dilled in this field. It was drilled to a depth of 5690 meters (600 meters displacement) with the automated managed pressure drilling technique. There were minimal losses and kicks from the well. However, the well was not drilled to the target depth because there was a junk which was suspended in the hole. The target depth was called at a depth of 5690 meters instead of the planned depth of 6728 meters.

TZ 26-411

Before rigging up the MPD equipment, the 6-inch hole was drilled conventionally from the 7 inch liner shoe and a depth of 257 meters was drilled. There were well control problems du to the kicks and losses that were experienced. The well was bulheaded, and the an LCM treatment was used as an attempt to get the well stabilized and MPD operations were commenced, but only 5 meters of new formation was drilled due to severe fluid losses and influxes encountered and the drilling operation was discontinued.

TZ 162 1H

This was the fifth MPD well drilled in the field and it was drilled to a set depth of 6778 meters with a displacement of 685 meters, with minimal losses and influxes from the well.

The tables below gives a summary of the operational results of the MPD drilled wells, in comparison to the conventionally drilled wells.

Table 4.14: comparative horizontal lateral displacement of previous conventional wells vs MPD wells drilled in the Tarim basin.

CONVENTIONAL WELLS				MPD WELLS		
WELL	**PLANNED LATERAL LENGTH (m)**	**ACTUAL LATERAL LENGTH (m)**		**WELL**	**PLANNED LATERAL LENGTH (m)**	**ACTUAL LATERAL LENGTH (m)**
TZ62-7H	780	360		TZ62-11H	591	982
TZ62-6H	900	187		TZ26-2H	834	146*
TZ1-1H	830	227		TZ62-10H	623	600**
TA62-2H	811	146		TZ26-4H	719	261*
TZ62-4H	518	159		ZG152-1H	685	685

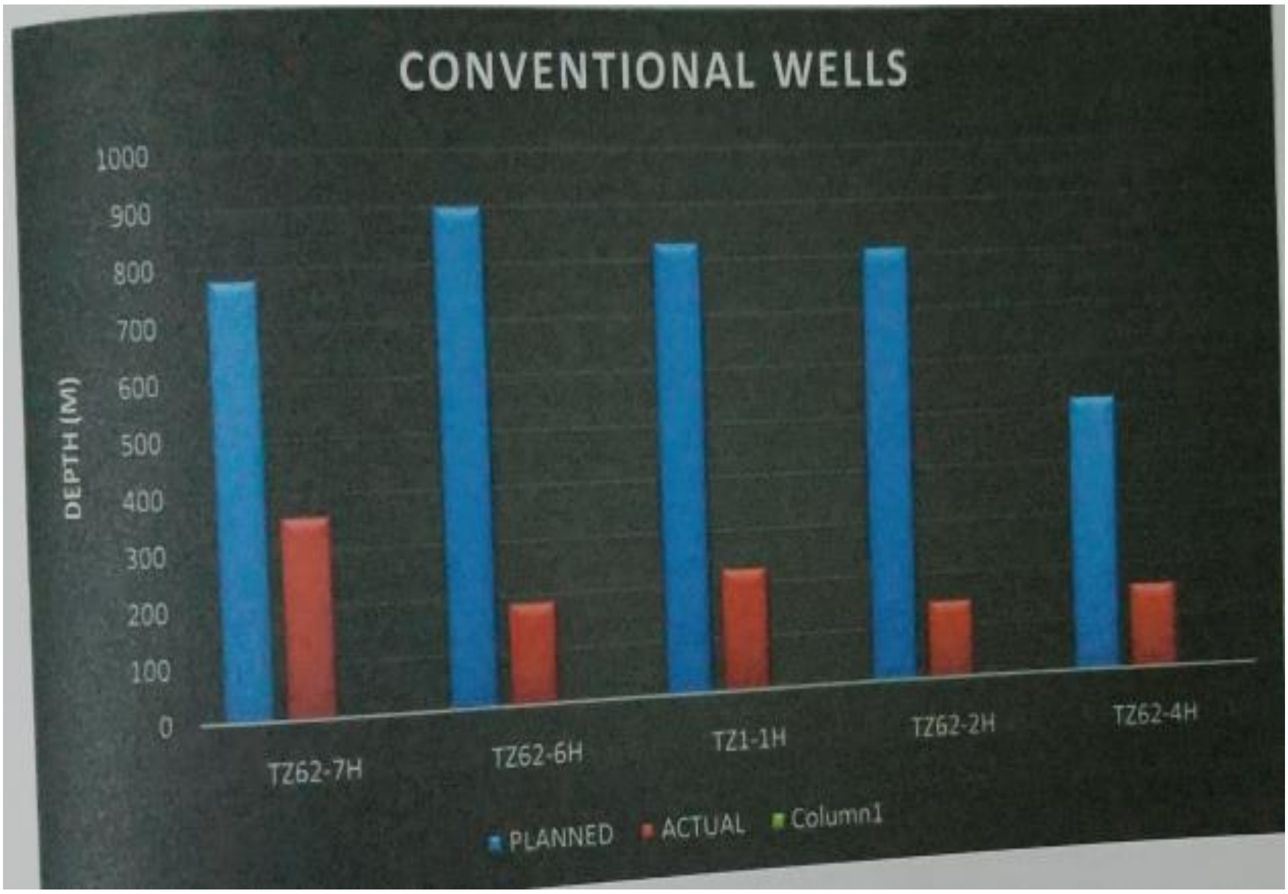


Figure 4.1o: Comparison between the planned and actual length drilled for the wells planned with MPD

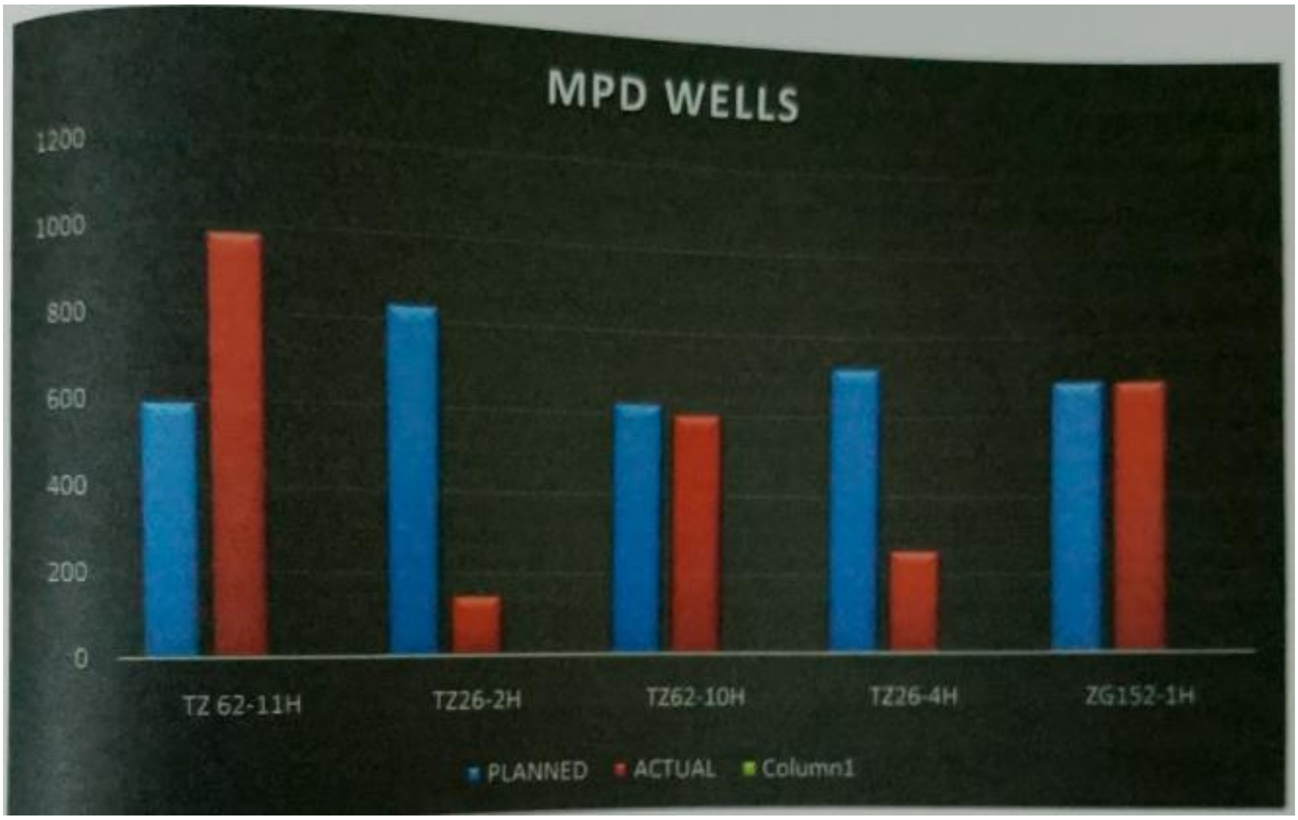


Figure 4.11: comparison between the planned and actual length drilled for the wells planned with MPD

Where:
*Partially drilled conventionally, experienced well control problems rior to attempting MPD operations.
*Well was landed early due to the suspected junk in the hole.
The table above is indicative that the wells drilled with MPD technique are more successful and reached their target depth (except three wells, due to the above mentioned reasons) compared to the conventionally drilled wells.

Table 4.15: Total losses on conventionally drilled horizontal wells

WELL	TOTAL LOSSES-CONVENTIONAL HORIZONTAL WELLS DRILLED IN 2008 (m^3)
TA62-7H	3750
TZ62-6H	3400
TZ1-1H	1738
TZ62-2H	3356
TZ62-4H	1472

: The MPD objectives were successful on TZ62-11H, TZ62-10H and ZG162-1H The well issues were limited due to the use of the automated MPD system. Also, there were minimal toss and kick events which reduced the non productive time, there by making the technique more cost effective.

The total mud losses reduced from 18000bbls to minimal with the MPD technique. Also, with the use of the BMC technique, trips were conducted safely and efficiently. In the course of drilling, there were no reported HSE incidents, this is attributed to the proper use of the risk assessment systems, safety meetings, drills and pre MPD classroom and live rig floor training for all rig crews.

The MPD technique were not met on the TZ26-2H and TZ26-411 wells, because the MPD system was unable to establish or maintain a stable circulating system du to fluid losses and influxes from the formation encountered after the section had been drilled conventionally initially.

It should be recalled that the wells in consideration are highly deviated wells, drilled into a high pressure and high temperature reservoir with narrow operating window. The effect of well deviation on the drilling window can never be overemphasized. In horizontal wells, collapse gradient becomes more important than the pore pressure gradient. In fact, for some cases, the collapse pressures are bigger than the pore pressure, hence making the collapse pressure a means of determining the lower boundary of the drilling window. Usually, collapse gradient increases, since the effect of gravitational forces on the upper side of the wellbore is increasing with the increasing well deviation, hence making the drilling of highly deviated wells more challenging.

4.3 ANALYSIS OF CASE STUDY THREE

Table 4.16: Table showing the relationship between the pore pressure and time for an example well in the Kristin field.

TIME (days)	PORE PRESSURE (bar)
52.5904	899.8
78.1065	888.784
129.528	873.21
162.446	860.892
199.064	847.923
232.079	837.22
265.094	826.516
301.713	813.547
334.631	801.229
371.054	785.031
400.174	771.75
432.994	757.818
462.016	742.922
494.934	730.604
527.754	716.671
560.769	705.968
732.759	643.076
765.774	632.372
798.692	620.054
835.505	610.314
941.855	575.287
974.870	564.583
1007.79	552.265
1297.42	455.622
1330.63	448.147
1425.78	413.459
1502.92	390.098
1803.36	286.658
1876.7	262.334
1931.72	244.495
2012.56	220.483

2089.69	197.123

Table 4.17: table showing the relationship between the fracture pressure and time for an example well in the Kristin field.

TIME (days)	FRACTURE PRESSURE (bar)
77.6195	1004.71
198.383	960.622
235.391	954.111
264.9	947.287
298.012	938.198
331.027	927.495
474.287	884.342
511.101	874.602
544.116	863.898
687.473	822.359
720.488	811.656
753.503	800.952
900.464	757.148
933.479	746.445
970.195	735.090
1113.55	693.552
1146.57	682.848
1183.38	673.108
1366.96	616.335
1403.77	606.594
1752.72	501.147
1785.74	490.443
1822.55	480.703
2182.5	371.688
2211.82	361..635

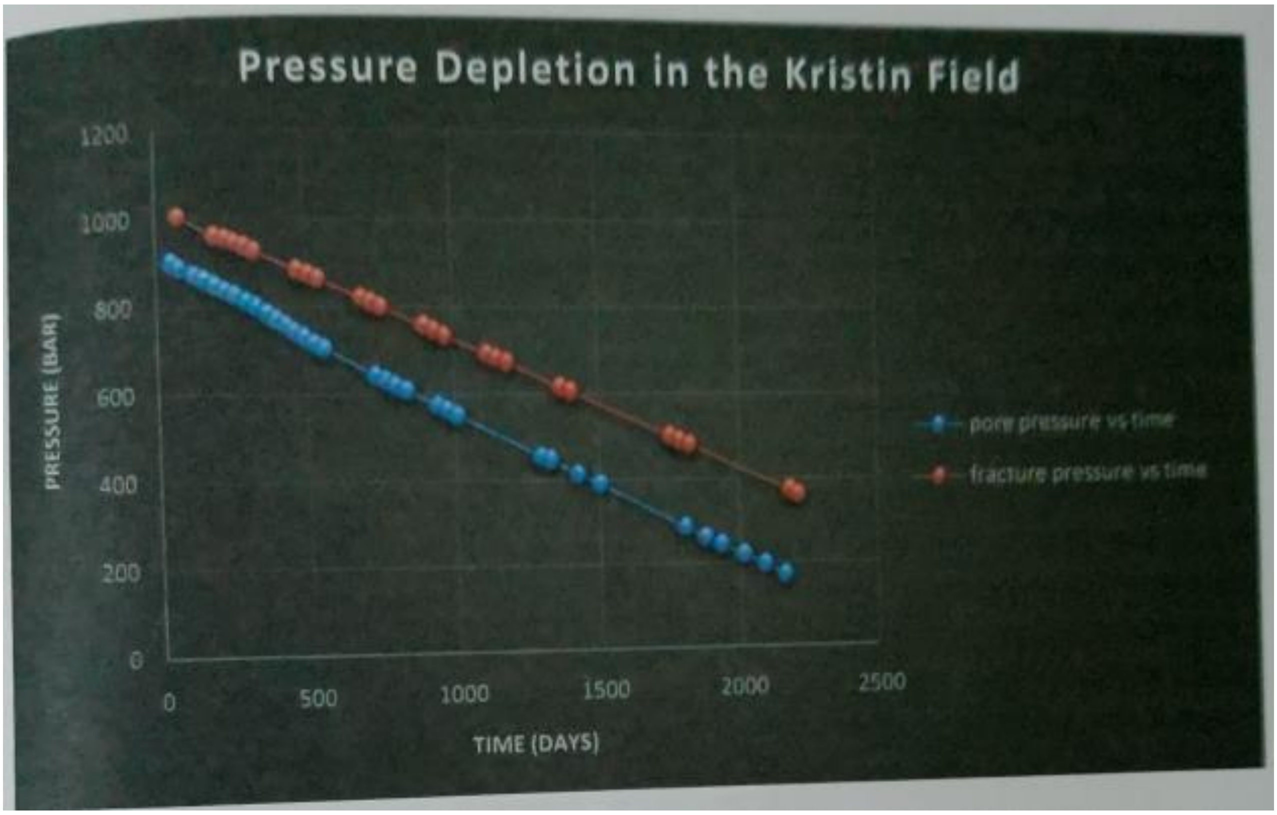


Figure 4.12: Depletion limit drillable for the MPD well.

The table above shows the relationship between pore pressure, fracture pressure and time for managed pressure drilling trial well(phase two well). The corresponding figure shows how the depletion limit drillable with MPD is extended with the riser capable of holding 130 bar and 165 bar applied at the surface for a typical scene. Currently the well head pressure is 130 bar, based on the 2500 psi rated lower flex joint and using a wall thickness riser of 0.625". This pressure is further expanded by using a 3000psi or a higher rated lower flex joint, which allows full use of the steel riser working limit when installing 0.685" riser sections at the bottom of the riser assembly.
This enables drilling in depleted sections of the kristin reservoir up to an initial limit of 220 bar to 260 bar.

4.4 DISCUSSION

For a successful drilling operation, apart from choosing the right drilling technique, the brilling engineer must understand or acknowledge other factors that may lead to poor drilling such as:
*The type of bit used for that particular reservoir
*The properties of the drilling mud
*Formation characteristics etc
Understanding these factors and the mechanism behind them enables him to always make the right choice of tools and equipment to be used for drilling so as not to incur more cost and less productivity.

BIT TYPE SUITABLE FOR VARIOUS FORMATION TYPE

A bit is the most basic tool used by the drilling engineer. The major challenge the engineer faces is the challenge of selecting the best bit and bit operating conditions.
According to design, bit type may be classified as:

*Drag bits

*Rolling cutter bit

DRAG BIT

Drag bits have fixed cutter blades/stones that are integral with the body of the bit and rotates as a unit with the drill string. Examples of this type of bit are bits with steel cutters, diamond bits, poly crystalline diamond bits (PCD)".

Drag bits with steel cutter element such as fishtail bit perform best relative to other bit types in uniformly soft, unconsolidated formations. As the formation becomes harder and more abrasive, the rate of bit wear increases rapidly and the drilling rate decreases rapidly. This problem can be resolved by changing the shape of the cutter element and reducing the angle at which it intersects the hole.

Also, in soft formations that may be gummy, the cuttings may stick to the blades of the drag bit and reduce their effectiveness. To resolve this problem, a jet can be placed so that the drilling fluid impinges on the upper surface of the blade. Due to the problem of rapid dulling harder rocks and bit cleaning in gummy formations, drag bits with steel cutting element largely has been displaced by other types of bits in all areas.

Diamond bits perform best relative to other bit types in non- brittle formations that have plastic mode of failure. Diamond bits for hard formations have many small stones (0.07-0.125 carat), while bits for large formation have a few large stones (0.75-2 carat) stones. The diamond bit is designed to be operated at a given flow rate and pressure drop across the face of the bit. Experiments conducted by bit manufacturers have indicated the need for approximately 2.0 to 2.5hhp/sq in of hole bottom, with approximately 500 to 1000 psi pressure drop across the face of the bit, to cool the diamond adequately. The pressure drop across the face of the bit as a given flow rate can be established as the difference between the pump pressure measured with the bit off bottom and the pump pressure measured while drilling".

The polycrystalline diamond bit (PCD) is has a polycrystalline diamond drill bank as the cutter element. The drill blank consists of a layer of PCD. PCD performs best in soft, firm and medium hard non abrasive formations that are not gummy.

They have been reported to be the best bit size drilling uniform sections of carbonates or evaporites that rae not broken up with hard shale stringers. Successful use of these bits also has been accomplished in sandstone, siltstone and shale. However, bit balling is a serious problem in very soft gummy formations, rapid cutter abrasion and breakage are serious problems in hard abrasive formations

4.4.1.2 ROLLING CUTTER BIT

The three cone rolling cutter bit is the most common bit type currently used in rotary drilling operations. The drilling action of a rolling cutter bit depends to some extent on the offset of the cones. The offset of the cones is a measure of how much the cones are moved so that their axis do not intersect at a common point of the centerline hole. Offsetting causes the cones to stop rotating periodically as the bit is turned and scrape the bottom of the hole like das bit. The action tends to increase the drilling speed in most formation types. Though in promotes faster tooth wear in abrasive formations.

The shape of the bit teeth also has an effect on the drilling action of the rolling cutter bit. Long widely spaced steel teeth should be used for drilling soft formations. As the rock type gets harder, the tooth length and cone offset must be reduced to prevent tooth breakage"

BIT SELECTION AND EVALUATION

The selection of the best available bit for the given job is unfortunately by trial and error method. However, the most valid criterion for comparing the performance of various bits is the drilling cist per unit interval drilled. Comparisons must be made between succeeding bits

in a given well or between bits used to drill the same formations in different wells.
The initial selection of bit type in a wild cat area can be made on the basis of what is known about the formation characteristics and the drilling cost in an area".

DRILLING FLUID PROPERTIES

Various drilling fluid properties affect the rate of penetration (ROP). These are:
*Fluid density
*Rheological flow properties
*Filtration characteristics
*Solid content and size distribution
*Chemical composition

Penetration rate tend to decrease with increasing fluid density, viscosity and solid content and increases with increasing filtration rate.
The chemical composition of the fluid has an effect on the penetration rate, in that the hydration rate and bit balling tendency of some clays are affected by the chemical composition of the drilling fluid.
According to Maurer's experiment, which were conducted using a single bit tooth under simulated borehole conditions, have provided some insight into the mechanism by which an increase in drilling fluid density causes a decrease in penetration rate for rolling cutter bits.
An increase in the drilling fluid density, causes an increase in the bottom hole pressure beneath the bit and thus n increase in the pressure differential between the pore hole pressure and the formation fluid pressure. The pressure differential between the bottom hole and the formation fluid pressure is known as the overbalance"

FORMATION CHARACTERISTICS

The elastic limit and ultimate strength of the formation are important formation properties affecting penetration rate.
Permeability of the formation also has a significant effect on the penetration rate. In permeable rocks, the drilling fluid filtrate can move into the rock ahead of the bit and equalize the pressure differential acting on the chips formed beneath each tooth.
The mineral composition of the rock also has some penetration rate. Rocks containing hard abrasive minerals causes rapid dulling of the bit teeth. Rocks with gummy clay minerals can cause the bit to ball up and drill in a very inefficient manner

4.5 INDICIES OF COMPARISON BETWEEN MANAGED PRESSURE DRILLING AND CONVENTIONAL DRILLING TECHNIQUE

*Depth drilled per day
*Mud losses
*Depth reached
*Drilling Cost

Table 4.18: comparative between MPD and conventional drilling (case one)

	Conventional drilling	**Manual MPD**	**Automated MPD**
Avg drilling days	32.5	64.5	31.5
Avg depth drilled per day	7.435m	13.045m	24.25m
Avg mud lost	2205.5m^3	2957m^3	954.5m^3

% difference in drilling days = $\frac{64.5-32,5}{64.5} \times 100 = 50\%$

This is indicative that 50% less drilling days is required to drill with MPD compared to conventional drilling.

4.6 COST ANALYSIS

Analysing the cost for managed pressure drilling and conventional drilling, the following can be deduced:

Avg cost of an offshore rig per day = $300000

Comparing the cost between conventional and manual MPD drilling

7.435m/day = $300000

13.045m/day = $X

X = $526361 (This implies that if the well was drilled conventionally, the avg. cost of he drilling rig would have been $526361)

$$\%\ \textit{difference in cost} = \frac{526361-300000}{526361} \times 100 = 43\%$$

43% cost of drilling is saved using MPD compared to conventional drilling method

Using the same computational procedure, 69% of cost is saved using automated MPD instead of the conventional drilling technique

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations can be drawn from the work done:

1. From the three case studies highlighted, it has been proven that MPD is a better and safer way of drilling through the use of equipment such as the rotating control device and surface chokes compared to the conventional drilling technique.

2. MPD technique was applied with both manual and automatic choke. However, the use of automatic choke system resulted in less lost to the formation.

3. Rigging up MPD at the initial stage of drilling is more effective than when a corrective MPD measure is used, as seen in case two(Tarim Basin).

4. It is more cost effective to use MPD technique rather than the conventional drilling technique. From the cost analysis carried out in this work, about 43% of the drilling cost is saved when using MPD compared to conventional drilling technique.

5. Using MPD technique reduces the number of drilling days by 50% hence reducing the non productive time associated with conventional drilling.

6. As discussed previously in this work, for a successful drilling operation, apart from choosing the right drilling technique, the drilling engineer must understand or acknowledge other factors that may lead to poor drilling and an increase in non productive time. Factors such as the following should be taken into consideration:

The type of bit used for that particular reservoir

The properties of the drilling mud

Formation characteristics etc

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