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Option: forage

Evaluation of the Managed Pressure Drilling technique in overcoming HQ formation challenge in NEZLA and its Feasibility in HAMRA FIELD

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Dedication :

What's more than being able to share the joy of success with the loved ones. At the end of my studies, I have the great pleasure to dedicate this modest work to my family and many friends:

A special feeling of gratitude to my loving parents, Djamila and Salah whose words of encouragement and push for tenacity ring in my ears.

My sister Amel, and my brother Seifeddin have never left my side and are very special.

I also dedicate this dissertation to my many friends each with his name and lovely family who have supported me throughout the process. I will always appreciate all they have done.

I dedicate this work and give special thanks to my colleagues in the drilling department and to all those I love or know from near or far.

ILYAS DRAREDJA

Dedication :

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My two sister Asma, and Romaissa have never left my side and are very special.

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Ben M'hidi

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NOMOMCLATURE

AFP :	Annular Friction Pressure
AFL :	Annular Friction Loss
API :	American Petroleum Institute
APWD :	Annular Pressure While Drilling
BH :	Bottom Hole
BHA :	Bottom Hole Assembly
BHP :	Bottom Hole Pressure
BOP :	Blow Out Preventer
BP :	Back Pressure
CBHP :	Constant Bottom Hole Pressure
CCS :	Continuous Circulation System
CCV :	Continuous Circulation Valve
CMC :	Controlled Mud Cap
CMCD :	Controlled Mud Cap Drilling
CPD :	Controlled Pressure Drilling
DDV :	Downhole Deployment Valve
DG :	Dual Gradient
DEA :	Drilling Engineer Association
ECD :	Equivalent Circulating Density
ECD-RT :	Equivalent Circulating Density Reduction Tool xviii
EDS :	Emergency Disconnect System
EMW :	Equivalent Mud Weight
ER :	Extended Reach
ERD :	Extended Reach Drilling
ERRCD :	External Riser Rotating Control Device
FP :	Fracture Pressure
HP :	High Pressure
HPHT :	High Pressure High Temperature
HSE :	Health, Safety and Environment
IADC :	International Association of Drilling Contractors
IPM :	Integrated Pressure Manager
LOT :	Leak-off Test
LRR :	Low Riser Return

MPD :	Managed Pressure Drilling
MW :	Mud Weight
MWD :	Measurement While Drilling
NGU :	Nitrogen Generation Unit
NPT :	Non-Productive Time
NRV :	Non-Return Valve
OB :	Over Balanced
OBD :	Over Balanced Drilling
PMC :	Pressurized Mud Cap
PMCD :	Pressurized Mud Cap Method
PP :	Pore Pressure
PWD :	Pressure While Drilling
RCD :	Rotating Control Device
RCH :	Rotating Control Head
ROP :	Rate of Penetration
SAC :	Semi Automated Choke
SBP :	Surface Back Pressure
SMD :	Subsea Mudlift Drilling
SSBP :	Subsea Back Pressure
TD :	Total depth/Target Depth
TVD :	True Vertical Depth
UB :	Under Balanced
UBD :	Under Balanced Drilling

INTRODUCTION

World energy demand is increasing continuously to meet the need of energy of the developing countries. Increase in the energy consumption rates forces the scientists and engineers to discover another ways of gathering energy or better ways to recover the sources that we have been already using for years.

Most of the world's remaining prospects for hydrocarbon resources will be more challenging to drill than those enjoyed in the past. In fact, many would argue that the easy ones 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 could not be more important[1].

Considering all these, MPD should now be regarded as a technology that may provide a noteworthy increase in cost-effective drill-ability by reducing excessive drilling-related costs typically related with conventional offshore drilling, if most of the world's remaining vision for oil and gas being economically un-drillable with conventional wisdom casing set points and fluids programs are taken into account[2].

Since the cost of NPT (Non-productive time) has much more economic impact upon offshore drilling and due to offshore operators' portfolios having higher percentages of otherwise un-drillable prospects than those onshore, offshore is the environment where the technology has potential to have greatest overall benefit to the industry as a whole[3].

In addition, as the predominant strengths of MPD are; reducing drilling-related non-productive time and enabling drilling prospects that are technically and/or economically un-drillable with conventional methods, it is inevitable to utilize from the advantages that MPD presents in several conditions and environments.

The abnormally risk-adverse mindset of many drilling decision-makers has contributed to the industry being seen by other industries as laggards in accepting new technology. Relative to the basic hydraulics applied to drilling a well, this is particularly the case. For instance, drilling with weighted mud, open-to-atmosphere annulus returns, and relying upon gravity flow away from under the rig floor was developed over a century ago (Spindletop, Beaumont, Texas, 1901) and remains status quo "conventional-wisdom" in the way we look at the hydraulics of drilling[3].

To date and as one may expect, operators who have practiced MPD for their first time, onshore and offshore, the applications have mostly been on the most challenging and/or otherwise un-drillable prospects, i.e., where conventionally drilled offset wells failed or grossly exceeded their budgets[3].

Beyond these proven strengths of MPD's root concepts, this body of work will strive to address applications that have yet to be fully recognized, appreciated, and practiced. And, in doing so, will further the vision that MPD is the way most wells should be drilled today and will likely have to be drilled at some point in the future due to depletion, overburden and water depths.

This work is composed of four chapters where:

In chapter I: we represent a general overview on the geology of the NEZLA where the MPD technique was taken place in order to have a better idea about the challenges that could be encountered when drilling.

In chapter II: We explain the concept of the Management Pressure Drilling, and the motivation for its usage.

In Chapter III: The different techniques of “MPD” are highlighted by presenting its variations and the usage of each one.

In Chapter IV: We shed light on the outcomes of MPD in the region of NEZLA by taking the example of the most recent wells drilled (NZ20, NZ27, NZ28 & NZ29).

Chapter I

OVERVIEW ON THE NEZLA FIELD GEOLOGY

FIELD AND WELL OVERVIEW

I.1. GEOGRAPHICAL SITUATION

The Nezla field is located 120 km SE of the Hassi Messaoud field and 100 km North of the Rhourde Nouss Central Field in the Triassic Basin in Algeria.

Coordinate:

UTM	X = of 265 200 to 267 165	Y = of 3 415 275 to 3 410 249
Geographical	X = of 630' 00 " to 637'00"	Y = of 3052' 00" to 3048'00"

Altitude: approximately 190 m.

Climate: Hot and dry.

Temperature: max (summer) = 50c and min (winter) = -5c.

Type of landscape: sand plates with cords of dunes.

Dominant winds: North Is - Southern West.

Periods of sand wind: February, Mars and April.

Pluviometry: very weak during the Winter, null during the remainder of the year.

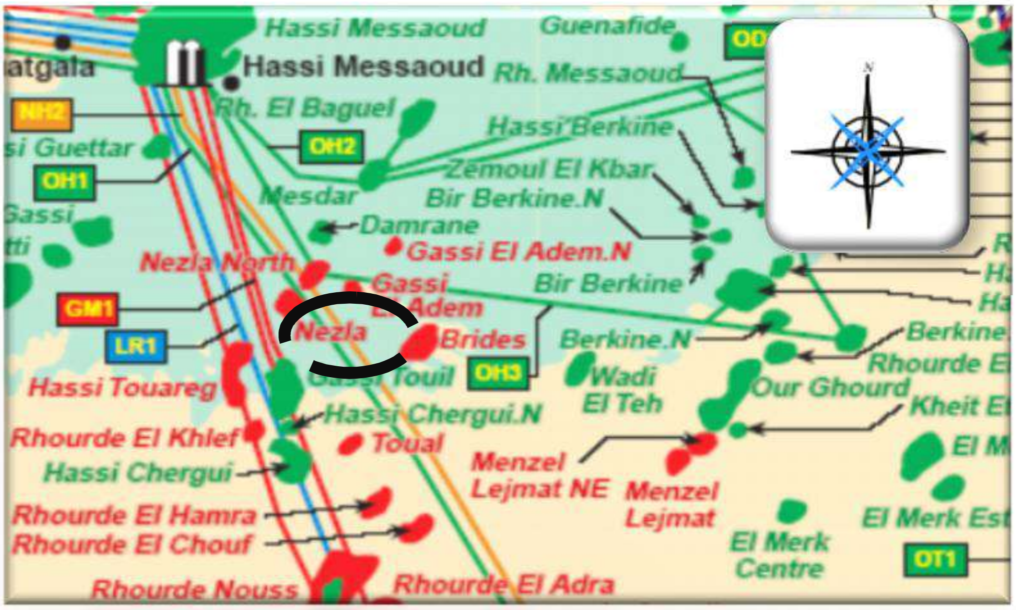


Fig I.1: situation of Nezla field

I.2 HISTORICAL REVIEW

Nezla structure was discovered in 1958 and the first well was drilled in 1960 to the Ordovician formation (NZ-1). The Nezla Field is a faulted anticline with two isolated culminations, Nezla North and Nezla South. Nezla North has proved oil in the Triassic (TAGI) and Ordovician reservoirs (Ouargla sanstone and Hamra Quartzites).

Nezla South has proved oil and gas in TAGS and TAGI Triassic reservoirs as well as the Ordovician reservoirs (GO and HQ).

Seismically, Nezla South appears as an anticline flanked to the West by a main reservoir fault with a significant throw. To the south this main reverse fault starts bending towards the East before disappearing progressively.

The following survey, NZ-2 drilled in 1967, had as the objective main thing the TAGI where it had presumption of existence of an oil ring on the side Is following the results obtained with NZ-1.The secondary objective was the quarzites of Hamra and the structural configuration of the layer. After the interesting results obtained on this well, it was decided to develop the part Is field. Thus three other wells were drilled in three years: NZ-2 (1968), NZ- 3 (1970) and NZ-4 (1970).

The wells were laid out in North-South alignment for NZ-2, NZ-2 and NZ-4 and into East-West for NZ-1, NZ-3 and NZ-4.

The development of the field was stopped in 1970 to begin again only in 1980 with the drilling of two other wells NZ-5 and NZ-6 in the Southern part, these wells are envisaged as gas producers in the TAGS. The other tanks were without much interest on this date.
Another well NZ-7, was then drilled in 1981 on periclinal North with as objective the TAGI where it was possible to meet the oil ring. However, the well did not give anything and it was abandoned.

The well NZ-8 drilled in (1982) was envisaged as gas producer in the TAGS.
A total of 25 wells have been drilled in Nezla South. There are 20 wells which have been producing from TAGS since 1980. The well NZ-18 had a very good commingled gas-condensate production, however it is not clear from which reservoir this production is coming (TAGI, GO and/or HQ).

I.2.1. Exploitation

I.2.1.1 Oil: (TAGI and Ordovician)

The exploitation of Ordovician and the TAGI began in Mars 1966 and September 1967 respectively by the intermediary from a well for each horizon. After it develops with drilling and the startup of three other wells, between 1968 and 1970, of which two produced at the same time in the TAGI and Ordovician (NZ-2 and NZ-4).The sixth well drilled in 1981 had not achieved its goal and was abandoned.
Ordovician was closed in 1978 and the TAGI in 1982 following primarily which had operational difficulties:

- With the damage of the tanks following an initial exploitation with at flows (without nozzle per moment).This had caused the production of mud, sand, and stones.
- With very frequent stoppings of the perforations and tubings by salt, requiring almost daily washings.
- With a formation of barytine due to the incompatibility of water of injection and layer.
- With difficult starlings, after each closing, which are the result of the simultaneous production of the TAGI and Ordovician on certain wells, which complicates the adaptation of a completion for each horizon.
- With the salt deposit at the bottom of the wells.
- With the Ordovician tank covered with a slotted liner in all the wells with share well NZ-1 what facilitated the sand arrivals because of the exploitation with great flow, which causes filling.
- With the corrosion of the equipment because of the significant production of salted water.

I.2.1.2. Gas: (TAGS)

Three wells drilled between 1980 and 1982 aiming at the tank of the TAGS never were not connected and were exploited because of their very low potential (poor petro-physic characteristics).

These wells are currently neutralized by safety measure, following the pressurization of the annular ones installed for this purpose.

I.3. STRATIGRAPHIC SECTION

The stratigraphy of the field of NZ is represented by the tertiary sector, the cretaceous, the Jurassic one, sorted it and the silurien. The tertiary sector is represented by the miopliocene which rests on the cretaceous in discordance. The Oligocene one, the Eocene, the paleocene one of the tertiary sector do not appear in the cut which is with the influence of the discordance miocénienne. The Austrian discordance makes disappear the bases from the lower cretaceous. The higher Silurian, the carboniferous one and the Permian one do not appear in the cut. (See Appendix 1)

I.4. LITHOLOGY AND MINERALOGY

Hamra Quartzite (Ordovician): thickness > 175 Mr. It consists of quartzite with sandstone quarzitic, siliceous cement, seldom silico-argillaceous. Pyrite traces.

Ouargla Sandstone (Ordovician): thickness = 60 Mr. It consists of quartzite with siliceous likings very consolidated with pyrite inclusions. Presence of tigillites.

Clay of Azel: thickness=95 Mr. It consists of pyritous clay and shale clay. Intercalations of likings and clay. Presence of anhydrite cryptocrystalline, quartz and of gypsum. Pyrite traces.

Sorted argilo sandy inferior (TAGI): thickness = 100 Mr. It consists of micaceous, pyritous clay with intercalation of likings, clay and silt. Presence of rollers, quartz of gypsum and anhydrite traces.

Sorted argilo-carbonated: thickness = 170 Mr. It consists of brown irregular clay intercalations, variegated, pasty with plastic, of black andesite, compacts cryptocrystalline, of translucent calcite and limestone tender, argillaceous, some pulverulent white anhydrite and argillaceous crystalline beige dolomite beaches. Limestone bench white, tender, chalky, argillaceous crystalline with dolomite, crystalline, argillaceous as well as a bench made up of an irregular alternation of likings, clay and argillaceous silt.

Sorted argilo sandy superior (TAGS): thickness = 125 Mr. It consists of clay silted, tender, pasty, silted with silto-sand spreader or sandy by place, becoming sometimes hardened with intercalations of argillaceous likings friable, likings consolidated with argilo-carbonated cement, the many last ones of silt white, argillaceous, tender and of salt and fibrous gypsum nodule, roaster, some coarse, angular quartz elements.

Sorted argillaceous: thickness = 90 Mr. It consists of clay brown, brown-red, silted, tender with plastic, seldom hardened, with beaches of argillaceous likings, argillaceous, tender and of white, pasty anhydrite and salt roaster intercalations, argillaceous silts at the top.

Sorted saliferous (TS3): thickness = 295 Mr. It consists of rock salt massive, translucent, argillaceous with intercalation of clay brown-red benches, saliferous, tender with pasty.

Sorted saliferous (TS2): thickness = 255 Mr. It consists of rock salt massive, translucent, colorless, yellowish, argillaceous by place. Intercalations of white, pulverulent anhydrite benches and of variegated, tender clay with pasty, sometimes saliferous, becoming gray and plastic.

Sorted saliferous (TS1): thickness = 50 Mr. It consists of rock salt massive, translucent, yellowish, sometimes rosâtre or white. Clay intercalations light gray, gray-white, sometimes brown, tender with pasty, of pulverulent white anhydrite.

Dolomitic lias (LD3): thickness = 25 Mr. It consists of dolomite-limestone white, white beige, saccharoid or gray-white, argillaceous, tender with intercalation of a marl bench light gray, plastic, of two slightly carbonated levels of clay, last of rock salt, roaster, argillaceous and of thin last of white, pasty anhydrite.

Saliferous lias (LS2): thickness = 75 Mr. It consists of salt hyaline, translucent, white, sometimes yellowish or roaster, with intercalations of clay brown-red to saliferous red-brick.

Dolomitic lias (LD2): thickness = 35 Mr. It consists of irregular dolomite alternations beige, microcrystalline, lasts, argillaceous, of white, pasty anhydrite with pulverulent, of light gray, variegated, tender clay with pasty, slightly dolomitic and of colorless salt.

Saliferous lias (LS1): thickness = 105 Mr. It consists of salt translucent, tender, intercalation of gray-brown, pasty clay with tending, sometimes hardened, finely dolomitic or saliferous. Some pulverulent, argillaceous, pasty anhydrite levels white at the top.

Dolomitic lias (LD1): thickness = 35 Mr. It consists of microcrystalline, tender anhydrite white gypseous pulverulent downwards. Clay intercalation, hardened with tending, slightly dolomitic with presence of beige, crystalline dolomite.

Dogger lagunaire: thickness = 40 Mr. It consists of irregular anhydrite alternation white, pasty with opaque, crystalline, tender, of clay gray, tender, often hardened, carbonated, of white, tender limestone with pasty and of compacted dolomite marble.

Argillaceous dogger: thickness = 35 Mr. It consists of clay brown-red pasty, sometimes hardened, finely silted or carbonated, with last of likings white, is consolidated, argillaceous to argilo-siliceous and presence of anhydrite, dolomite, limestone and the angular coarse quartz elements with round-off.

Gault: thickness = 100 Mr. It consists of likings gray-white, end with coarse, friable, well classified, argillaceous, sometimes consolidated, argilo-carbonated or translucent, siliceous, with clay intercalations green with blanchâtre, sometimes variegated, silto-sand spreader, sandy by places, tender, carbonated and significant presence of silt white to tend and traces lignite.

Cénomanien: thickness = 100 Mr. It consists of irregular clay blanchâtre alternations, variegated, tender with plastic sometimes hardened, carbonated, of white anhydrite to translucent, tender, sometimes gypseous, of dolomite with calcareous dolomite white-beige with white, sometimes gray-white, argillaceous, tender with compact.

Turonien: thickness = 80 Mr. It consists of dolomite beige, gray-beige, microcrystalline with cryptocrystalline compacted with sometimes calcareous or argillaceous microphone-vaciolaire or saccharoid, with limestone intercalation white, tender, sometimes pulverulent or pasty, argillaceous.

Sénonien lagunaire: thickness = 245 Mr. It consists of irregular gray clay, limestone, dolomite, white anhydrite alternations with anhydrite and marl intercalations. There are also traces of quartz, pyrite and gypsum.

Carbonated Sénonien: thickness = 150 Mr. It consists of dolomite blanchâtre, compacts, microcrystalline, sometimes beige, cryptocrystalline, marly, with the rare last ones of anhydrite.

Miopliocene: thickness = 260 Mr. It consists of sand coarse, ochre, badly consolidated with rare clay intercalations ochre, plastic, sandy, with the last ones of white limestone. And the presence of flint and white gray gravel.

I.5. RESERVOIRS

I.5.1. Superior clay-sandstone Trias (TAGS)

It is composed of three reservoirs groups:

- Basic reservoir group, named Sandy, is constituted of silty clay in which
  Numerous past metrical Sandstones are noticed.
- Median reservoir group, is composed of two past metrical Sandstones separated with a stratum of silty clay. In NZ-23, it is interpreted as compact (according to the correlation of details with the wells NZ-2, NZ-21, NZ-24, NZ-12).
- Sommital reservoir group, is more homogeneous. In NZ-23, it is interpreted compact (according to the correlation of details with the wells NZ-2, NZ-21, NZ-24, NZ-12).

I.5.2. Inferior clay-sandstone Trias (TAGI)

The Sandstone of TAGI reservoir are partitioned into many horizons separated with clay and clay-sandstone strata. The Sandstone levels are not regulars; they neither have constant thickness nor expanded: the lenticular view character is the rule for the Sandstone as for the clay.

Only the three (03) inferior meters of TAGI represent good reservoir characteristics in the well NZ-24.

Correlations of details in this formation prove that the well NZ-23 meets the TAGI with the same characteristics.

I.5.3. Ordovician Ouargla Sandstone (Grés d'Ouargla)

These are fine to medium quarzitic sandstone, rather classified as clay cement and secondary feeding is rather frequent, presence of numerous tigillites and rare white micas. The absence of the feldspaths is noticed.

The matrix characteristics of this series are not well known. This composition of very poor physical characteristics is attributed, especially because of the clay cement of Sandstone. However, we continue to think that the favorable characteristics of the series, proved by the tests and the mud losses, are because of the fissures.

I.5.4. Ordovician Hamra Quartzite

This homogeneous group of fissured quartzite constitutes the principal reservoir, gas producer to condensate. It seems logical to think that the group of Hamra Quartzite does not represent good matrix physical characteristics, and that the good characteristics proved by the tests come only from the fissures.

It is worth reporting that the reservoirs: TAGI, Ouargla Sandstone, and Hamra Quartzite communicate vertically.

Chapter II

Managed Pressure Drilling Basics

MPD BASICS

II.1. MANAGED PRESSURE DRILLING CONCEPT

The international Association of Drilling Contractors (IADC) defines managed pressure drilling (MPD) as follows: “MPD is an adaptive drilling process used to precisely to control the annular pressure profile throughout the wellbore.” IADC further states that “The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process. ” The purpose of managed pressure drilling is to create a pressure profile in the annulus within the operating window guided by pore and fracture pressures

Technical Notes:

- MPD employs a collection of tools and techniques that may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.
- MPD may include control of backpressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.
- MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects. A condition where the pressure exerted in the wellbore is less than the pore pressure in any part of the exposed formations
- MPD techniques may be used to avoid formation influx. Any flow incidental to the operation will be safely contained using an appropriate process.

According to DEA, Managed Pressure Drilling continues to demonstrate its bright future. There has not been any recorded incident of a kick while applying the techniques of managed pressure drilling, despite the fact that MPD can be used to briefly characterize a reservoir by allowing a small momentary influx. This is not to say that there have been no problems, sometimes pipe still gets stuck and lost circulation problems still exist, but not as the same magnitude as in conventional drilling. The most impressive aspects of Managed Pressure Drilling are it is as safe or safer than current conventional drilling techniques and problem wells are being drilled and completed instead of abandoned either with cement plugs or in a file labeled “TOO RISKY TO DRILL – TECHNOLOGY NOT AVAILABLE”. MPD is a sophisticated form of well control and deserves a balanced quality appraisal of risks – positive and negative[5].

II.2 CATEGORIES OF MPD

The MPD subcommittee of IADC separates MPD into two categories -"*reactive*" (the well is designed for conventional drilling, but equipment is rigged up to quickly react to unexpected pressure changes) and "*proactive*" (equipment is rigged up to actively alter the annular pressure profile, potentially extending or eliminating casing points). The reactive option has been implemented on potential problem wells for years, but very few proactive applications were seen until recently, as the need for drilling alternatives increased[14].

II.2.1 Reactive MPD

Typically, engineers plan the well conventionally, and MPD equipment and procedures are activated during unexpected developments[6].
The conventional-wisdom well construction and fluids program is planned, but the rig is equipped with at least an RCD, choke, and drillstring float(s) as a means to more safely and efficiently deal with, unexpected downhole pressure environment limits (e.g., the mud in the hole at the time is not best suited for the drilling window encountered). As a means of preparing for unexpected developments, the drilling program is equipped or *tooled up* from the beginning to deal more efficiently and safely with downhole surprises. This, in part, explains why some underwriters require that wells must be drilled with a closed and pressurizable mud-return system[11].

II.2.2 Proactive MPD

The proactive MPD[6] uses MPD methods and equipment to control the pressure profile actively throughout the exposed wellbore. This approach uses the wide range of tools available to

- Better control placement of casing seats with fewer casing strings

- Better control mud density requirements and mud costs
- Provide finer pressure control for advanced warning of potential well control incidents.

All of these lead to more drilling time and less NPT time. Briefly, proactive MPD drills:

- operationally challenged wells
- economically challenged wells
- “undrillable” wells

II.3 UBD VS MPD

A comparison of the two methods can be performed by considering the objectives for the project, the equipment requirements and potential benefits/risks of each method. It has been established that MPD is used primarily to resolve drilling-related problems, although some reservoir benefits also may be achieved. This is not surprising as any effort to decrease the degree of overbalance, and thus, the impact of drilling fluid on virgin formations usually will initiate some positive reservoir benefits. UBD, on the other hand, has long been employed to provide solutions to both drilling-related and reservoir-related problems. Thus, one can deduce that the critical difference between UBD and MPD lies in the degree of resolution attainable with each method for both the drilling-related and reservoir / production related problems[15].

MPD is designed to maintain bottom hole pressure slightly above or equal to the reservoir pore pressure (overbalanced or at balanced drilling), UBD is designed to ensure that bottom hole pressure (BHP) is always below the reservoir pore pressure and thus, induces formation fluid influx into the wellbore, and subsequently, to the surface[15].

Unlike underbalanced drilling, MPD does not actively encourage influx into the wellbore. The primary objectives of MPD are to mitigate drilling hazards and increase operational drilling efficiencies by diminishing NPT[6].

MPD cannot match UBD in terms of minimizing formation damage, allowing characterization of the reservoir, or identifying productive zones that were not evident when drilled overbalanced. Nonetheless, when the objective is simply to mitigate drilling problems, MPD can often be as effective and more economically feasible.

MPD is also preferable where wellbore instability is a concern, when there are safety concerns due to high H2S release rates, or when there are regulations prohibiting flaring or production while drilling[15,16].

Two of the primary reasons cited[15] for selecting MPD over UBD are:

1. Wellbore instability concerns during UBD,
2. Desire to reduce equipment requirements to improve cost efficiency.

However, basing the decision only on these criteria ignores the possibility that significant reservoir benefits also could be realized with UBD and that equipment requirements really depend on the reservoir to be drilled, since MPD may require an almost equivalent setup as UBD.

MPD is often seen as easier to apply compared with full UBD operations. Often in non reservoir sections, MPD design requirements may determine that a simpler equipment package will satisfy safety considerations for the well, and therefore, the day rate would be reduced compared to using full under balance. In many instances, the same equipment setup is necessary for UBD as well as MPD methods. The distinguishing difference concerns the fact that smaller-sized separation equipment can be used for the MPD setup, as large fluid influx is not expected during drilling[15].

Furthermore, some level of automation of the surface systems is needed for quick, uninterrupted reaction to changes in downhole conditions, owing to the fact that wellhead pressure changes are used to control MPD operations. This type of automation could be required to enhance UBD operations as well[15].

It is important to mention here that while UBD has the potential to eliminate formation damage; MPD can be designed only to reduce it compared to conventional overbalanced drilling. Nonetheless, residual damage in the near-wellbore area after drilling is still likely. Residual formation damage of a MPD well can be as high as that of a conventionally-drilled overbalanced well[15].

The reservoir-related or production-related benefits of UBD (and to a much lesser extent MPD) are significant when compared with conventional OBD. Primarily, these benefits are seen through higher productivity of UBD wells[15]. See Fig II.9

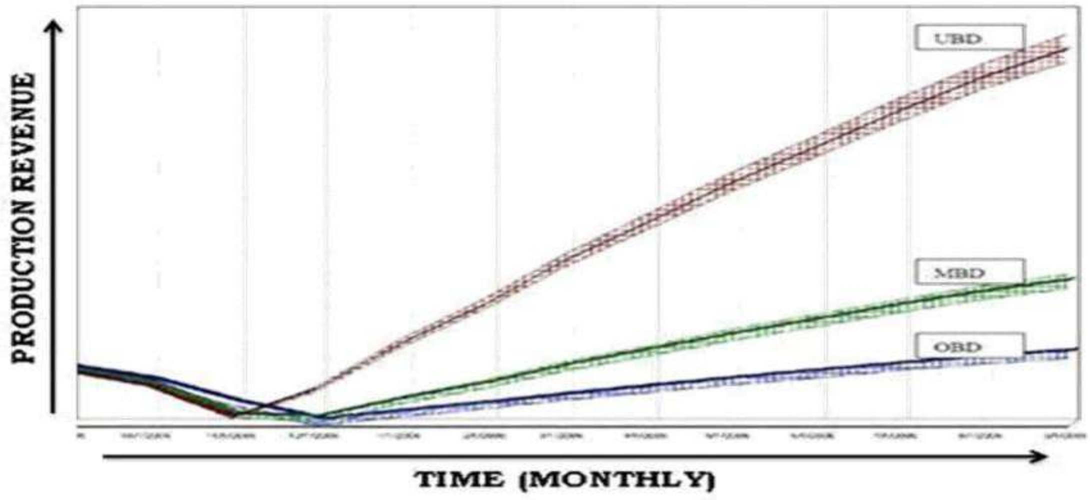


Figure II.9 Production Revenue Comparison: UBD, MPD, OBD[15]

In fact, reduction in damage to the reservoir compared with conventional OBD in some MPD wells has been recognized in the industry only recently. UBD, on the other hand, has had a much longer track record for maximizing well productivity, thereby ensuring higher sustained production rates compared to conventional wells.

II.4 THE MOTIVATION FOR MPD

It is important, almost vital that MPD become widely and comfortably used in the offshore market. This technology can, and will, lead to many resources becoming available. With the techniques and equipment that are addressed in the index (see Appendix A) more and more of the world hydrocarbon resources will become available in an economic sense. Therein lies the importance of the MPD, without this technology much of the world resources will be neglected.

About one-half of the remaining offshore resources of hydrocarbons, gas hydrates excluded are economically un-drillable with conventional tools and methods[10]. The percentage "un-drillable" increases with water depth. Drilling related obstacles to greater economic viability include:

- Loss circulation/differentially stuck pipe
- Slow ROP
- Narrow pore-to-fracture pressure margins necessitating excessive casing programs and requiring larger, more expensive drill ships to buy
- Failure to reach TD objective with large enough hole

The cost of the well increases as a result of longer drilling time and the higher cost of casing and accessories[6]. Owing to the requirement for a large number of protective intermediate casing strings in the well, the size of the production casing becomes very small in a conventional well design with a narrow PP-FP window. The lower production rate consequent to the small production casing size may be uneconomical in a high capital and operating cost environment.

High circulating pressure, difficulties in drill bit torque transmission, high drag in the open hole, susceptibility to drill string sticking etc. are among the various technical and operational limitations, for the reason that drilling a small diameter hole is difficult. Additionally, operations such as wireline logging, running and cementing casing, and running completion equipment also experience great difficulties in small size holes.

II.5 DRILLING HAZARDS

The alleviation of the drilling hazards and increase drilling operations efficiencies by reducing non-productive time (NPT) are the principal objectives of Managed Pressure Drilling[5]. The operational drilling problems mostly related with non-productive time include:

- Lost Circulation
- Stuck Pipe
- Wellbore Instability
- Well Control Incidents

Figure II.10 Drilling Hazards[5]

Making the correct decisions while drilling is a matter of recognizing, integrating, and correctly interpreting all the drilling dynamics including but not limited to weight on bit, revolutions per minute, vibration, downhole pressure, temperature, hole cleaning, shale shaker cuttings, etc. The downside of this is well understood.

Misinterpreting any of these dynamics has broad ranging repercussions. Interpreting them singularly, outside the context of the other dynamics, carries the danger of actually contributing to instability and inducing further hazards.

II.5.1 Well Control Incidents

Kick tolerance is an important concept that can be applied both in drilling operations and in casing program design. For the wells currently drilled by oil industry, more multifaceted planning and execution are required. Application of kick tolerance concept is especially helpful in. Taking kick tolerance into consideration made drilling execution safer and more economical by reducing the probability to have an incident. It is crucial to keep an eye on the kick tolerance in real time, by updating the calculation every time there is a variation of parameters which influence its value. In deepwater, choke and kill line friction is an important factor, particularly when the threshold between mud density and casing shoe fracture gradient is really narrow[17].

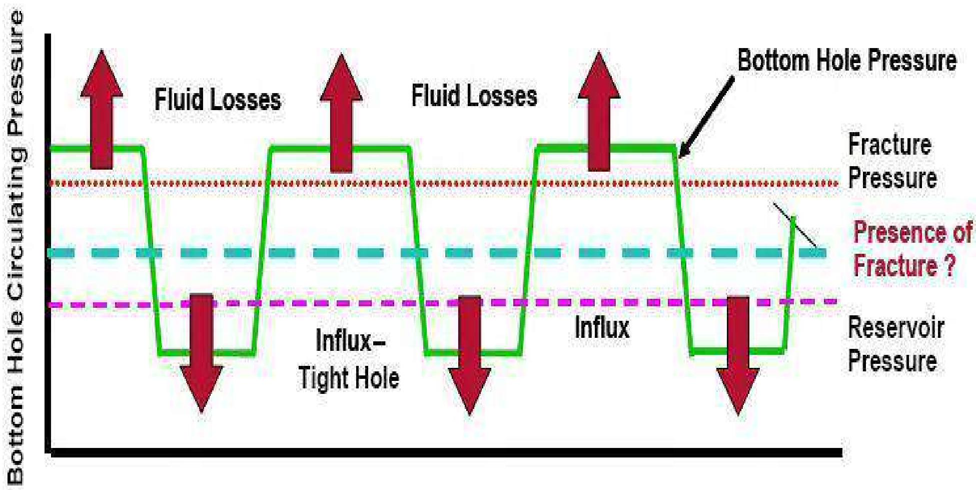


Figure II.11 Kick Occurrences due to Narrow Drilling Window[18]

This figure illustrates that taking kick is faced while stopping the pumps to make connection in conventional wells which have narrow drilling window. Dynamically overbalance system turns statically underbalanced which allows kicks to the well.

Malloy and McDonald[5] stated disadvantages of conventional drilling while dealing with kicks by emphasizing that annular pressures cannot be adequately monitored in an open vessel unless and until the well is shut in. Well control incidents during conventional drilling are predicated on increased flow, where precious time is often wasted pulling the inner bushings to “check for flow”. In that time the influx volume becomes larger. The larger the influx volume becomes, the more difficult it is to manage the kick. Correspondingly, during conventional drilling operations it is required to cease the drilling and shutting in the well. While the influx volume is being circulated out of the wellbore and the drilling fluid is more adequately weighted to compensate for the increased bottomhole pressure, the hole is not being drilled and casing is not being run. The non-productive time is mounting, exposing time sensitive formations to drilling fluids that will cause other problems leading to increased nonproductive time. The effects of non-productive time are iterative and costly.

II.5.2 Lost Circulation

Continued loss of drilling mud to the formation not only damages future production potential, but could also lead to a well control issue. The hydrostatic pressure throughout the wellbore decreases when the (static) mud column in the annulus decreases in height, hence the loss of drilling mud in the wellbore will have to be refilled. The decreased height of the mud hydrostatic column sets the stage for a pressure imbalance between the hydrostatic mud column and the fluid contained in the exposed rock formation. An influx of some magnitude will arise once the bottomhole pressure exceeds the hydrostatic pressure created by the static mud column. On condition that there is not an intervention that influx can grow in volume leading to a kick and if it is not monitored it may result in a blow-out[5].
Smith[18] stated the importance of casing in conventional operations by suggesting the only way of extending the drilling window by running casing to isolate the potential hazard section, in order to prevent these kinds of preceding drilling hazards that might occur in tight margins. This is one of the common ways of conventional drilling. The figure below illustrates the situation.

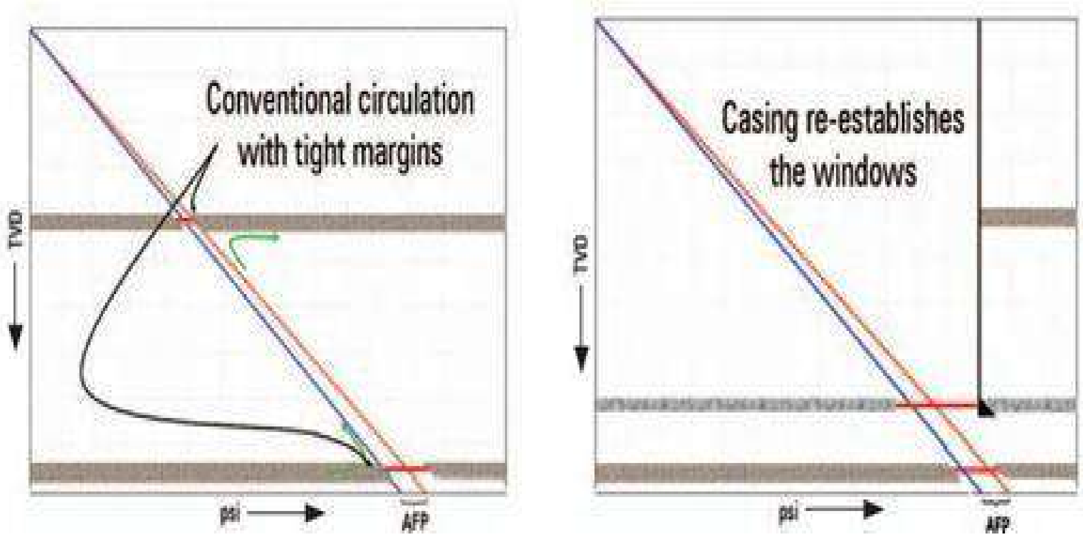


Figure II.12 Traditional Response to Extend Tight Margins[18]

II.5.3 Stuck Pipe

As it is published in the underbalanced drilling and completion manual of DEA, the most common sticking mechanism in conventional drilling is the differential sticking. When drilling fluid leaks into the formation, leaving a fairly impermeable layer of solids on the wellbore, differential sticking occurs. If the drill pipe or tubing is in contact with the wellbore, the filtrate can leak away from behind the pipe and create a low-pressure zone. Pressure sticking or differential sticking of the pipe is seen when the differential pressure over the area involved creates forces. This cannot happen if the well is underbalanced. Stuck pipe can be freed by changing the well condition to underbalance[8].

Figure 13 is an example of differential sticking due to the pressure difference between wellbore and formation. Overbalance of the static mud column can be reduced by using the back pressure instead of using a dense mud. In addition, this situation occurs mostly in static conditions because of not having circulation and rotation.

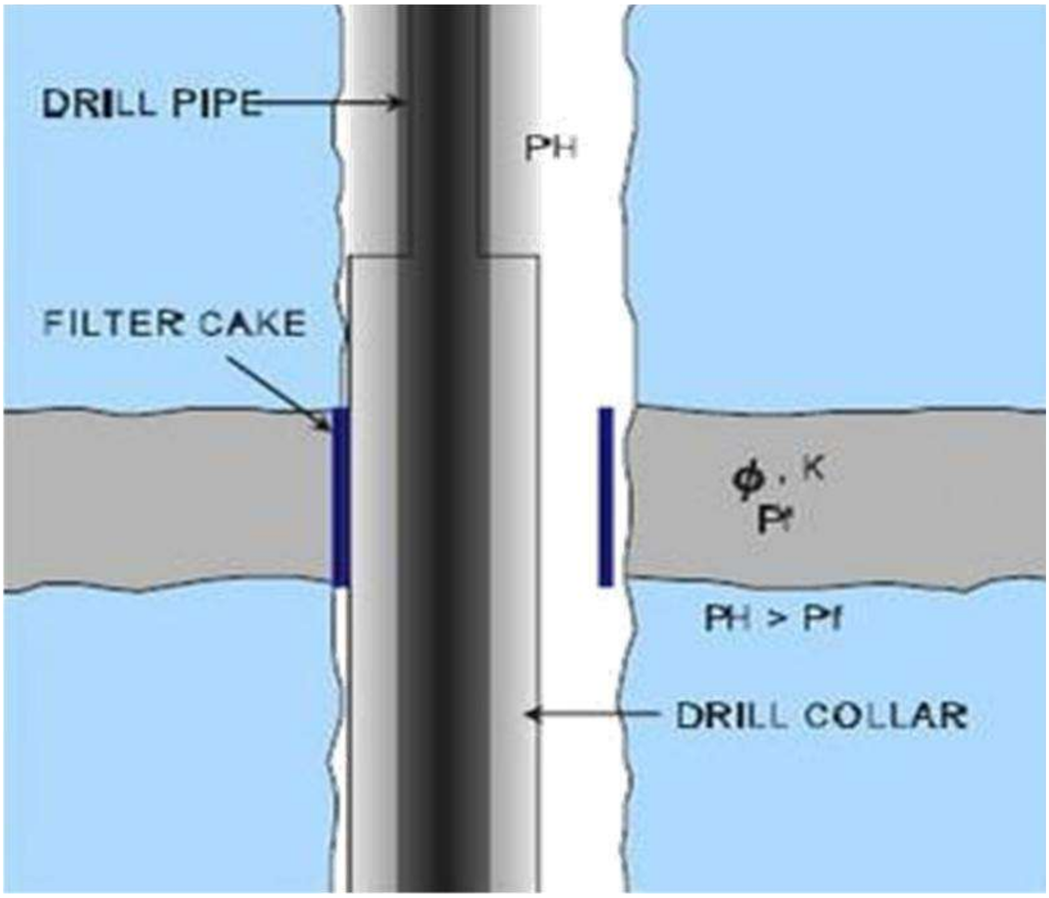


Figure II.13 Illustration of Differential Sticking[8]

II.5.4 Wellbore Instability

Once the mud column pressure against the formation is reduced there are important setbacks to consider. In order to function as a close up against well kicks or blowouts, heaving shales (geo-pressured shale), broken or fractured formations, general borehole instability due to tectonic stresses or weak formations and salt, most of the drilling procedures exploit the mud column pressure[11]. The wellbore pressure differential should be controlled very accurately to mitigate wellbore instability problems. MPD methods and tools are used to manage the pressure profiles in the wellbore to reduce the likelihood of the unwanted pressure differential. The effect of the differential pressures is clearly shown in the following figure

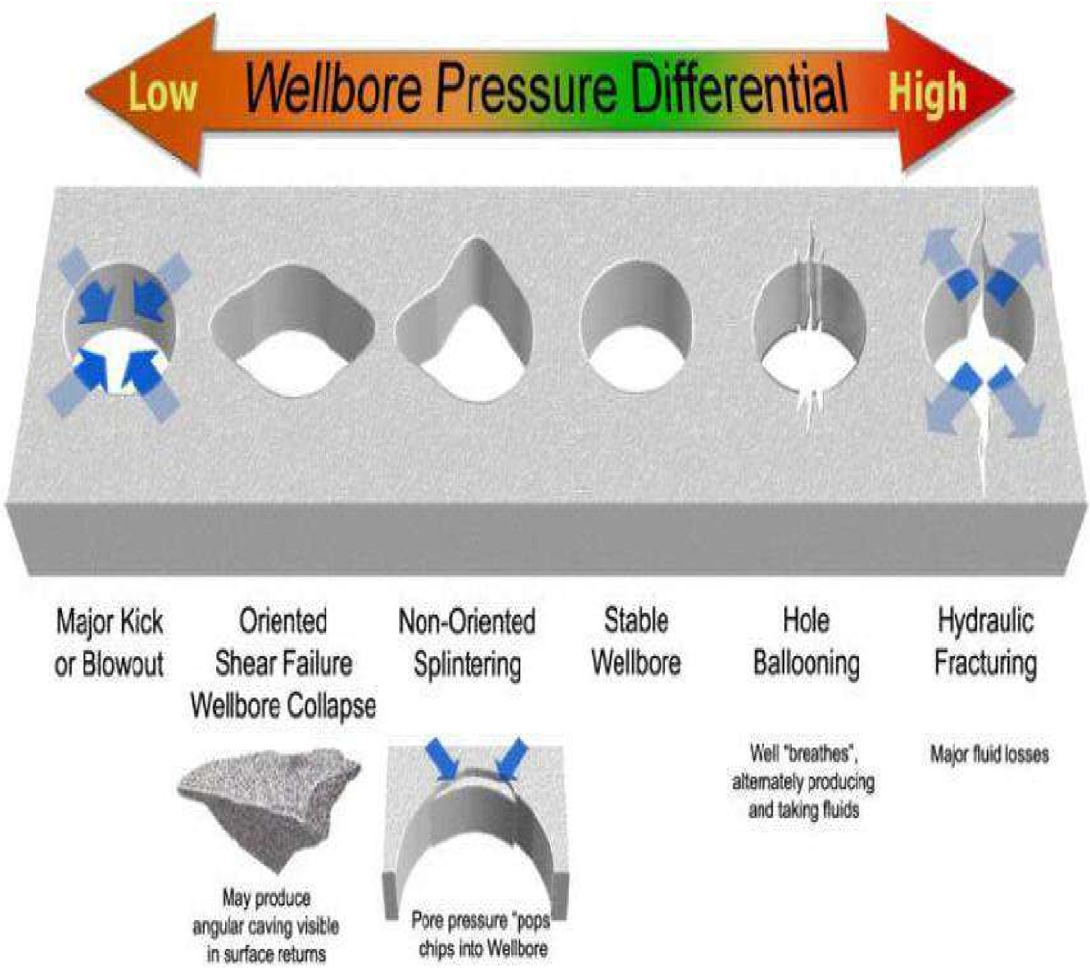


Figure II.14 Effect of Wellbore Pressure Differential[19]

Figure 14 is an illustration of the wellbore behavior due to the differential pressures across the well. Increase in wellbore pressure causes hole ballooning and hydraulic fracturing, then again a decrease in the wellbore pressure causes well collapse and kicks.

Chapter III

Managed Pressure Drilling Techniques

MPD TECHNIQUES

III.1 MPD VARIATIONS

The key variations of MPD according to their application areas and different strengths they have are listed as below:

- Constant Bottom Hole Pressure (CBHP)
  - Friction Management Method
  - Continuous Circulation Method
- Mud Cap Drilling (MCD)
  - Pressurized Mud Cap Drilling (PMCD)
    - Controlled Mud Cap Drilling (CMCD)
- Dual Gradient Drilling (DGD)

Although there are lots of emergent combinations, the ones added to the list are expected to be used in near future along with the commonly used ones.

III.2 CONSTANT BOTTOM-HOLE PRESSURE (CBHP)

CBHP is the term generally used to describe actions taken to correct or reduce the effect of circulating friction loss or equivalent circulating density (ECD) in an effort to stay within the limits imposed by the pore pressure and fracture pressure[4]. In order to reduce the effect of AFL or ECD, the need for backpressure (BP) is to be understood[7].

CBHP is very important due to their advantages which include:

- Less drilling non-productive time
- Enhanced control of the well
- More precise wellbore pressure management
- Increased rate of penetration
- Less invasive mud and cuttings damage to well productivity
- Deeper casing set points
- Fewer mud density changes to total depth objective
- Increased recoverable assets[7]

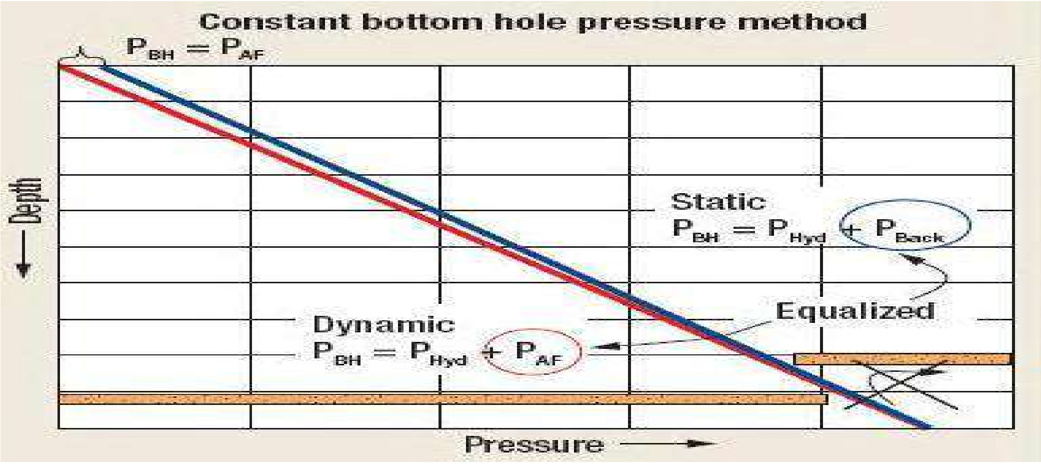


Figure III.1 CBHP when BP usage only in connection[6]

In this variation, the objective is to “walk the pore pressure line” with a nearer-balanced-than-conventional wisdom fluids program as a means of overcoming kick-loss issues associated with narrow margins between formation pore pressure and fracture gradient. When drilling ahead, surface annulus pressure is near zero. During shut-in for jointed pipe connections, a few hundred psi backpressure is required[20]. Using of backpressure shows the industry the capability to use a less dense mud.

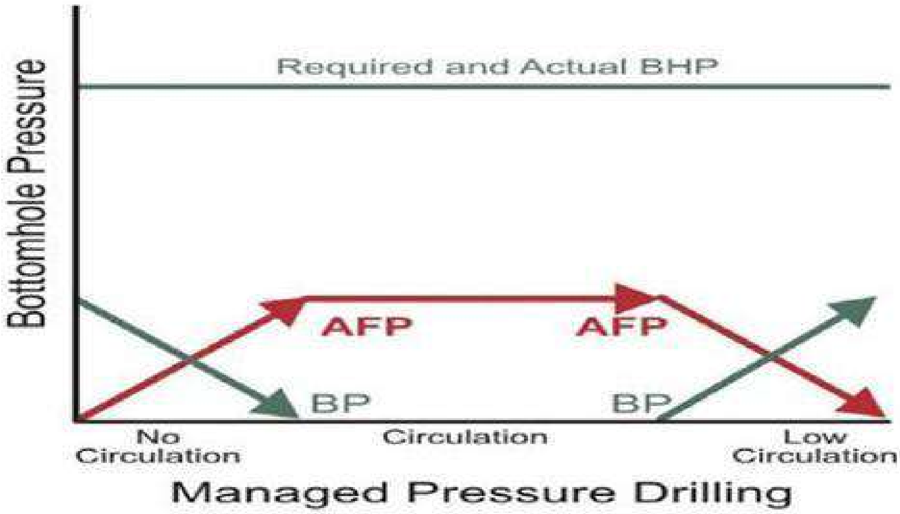


Figure III.2 The usage of Back Pressure in CBHP Method[7]

Figure 16 is a simple illustration of how ECD or AFL can be compensated. Theoretically, compensation of decreasing amount of AFL with the same amount of increasing BP is possible while stopping circulation which allows the control of BHP.

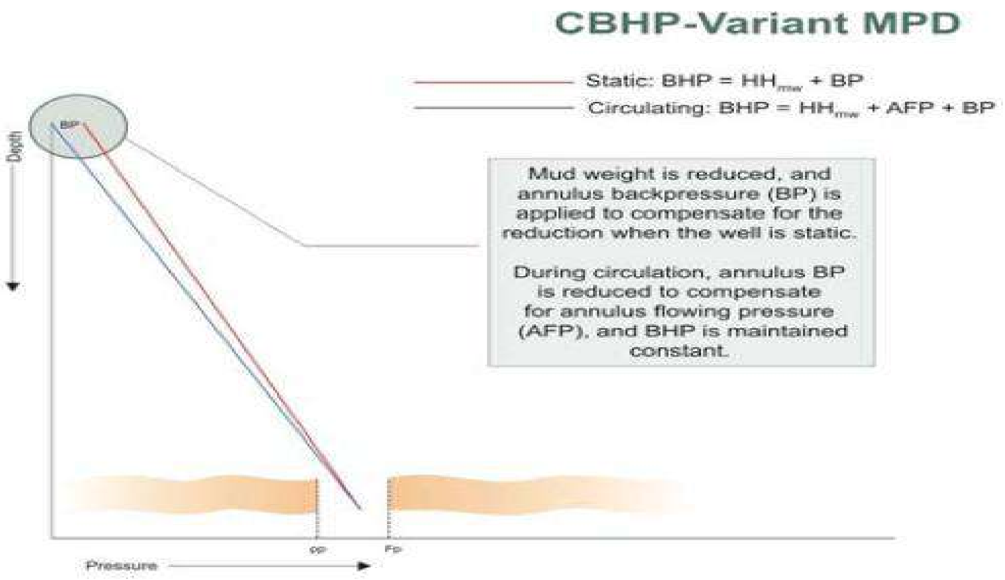


Figure III.3 CBHP - BP usage both in connection and drilling[7]

The purpose that this method[11] is distinctively applicable to drilling in narrow or relatively unknown margins between the pore and fracture gradients. Whether the rig's mud pumps are on or off, the objective is to maintain a constant EMW.

The first issue that must be addressed is how to go from static balance to dynamic (circulating) balance without either losing returns or taking a kick. This can be done by gradually reducing pump speed while simultaneously closing a surface choke to increase surface annular pressure until the rig pumps are completely stopped and surface pressure on the annulus is such that the formation "sees" the exact same pressure it saw from ECD while circulating. It has to be taken into consideration that the bottom hole pressure is constant at only one point in the annulus[13].

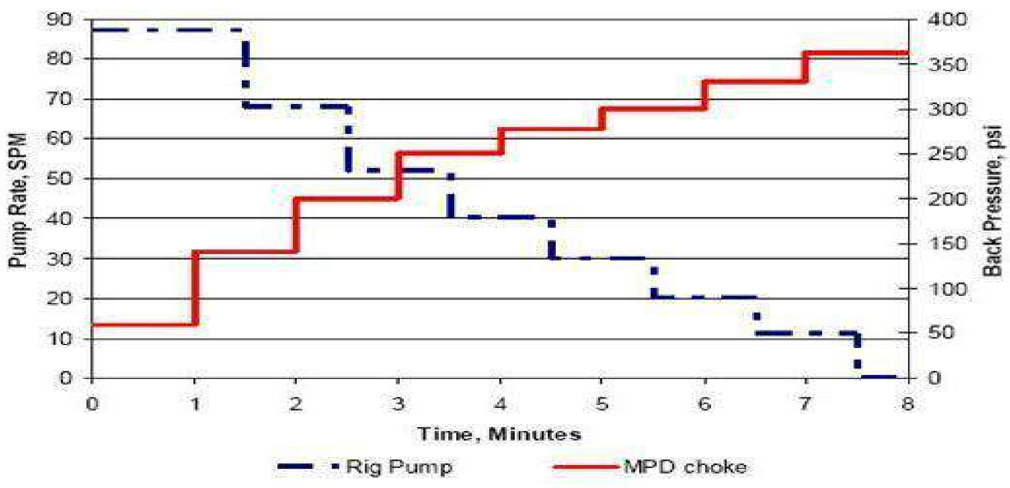


Figure III.4 Back Pressure/Pump Speed Curve for Connection[1]

In an attempt to ensure that any influx can be detected early, a mass flow meter is often installed as an integral part of the choke manifold in critical CBHP operations. The rig up for a CBHP set-up is shown in Figure 19[12]

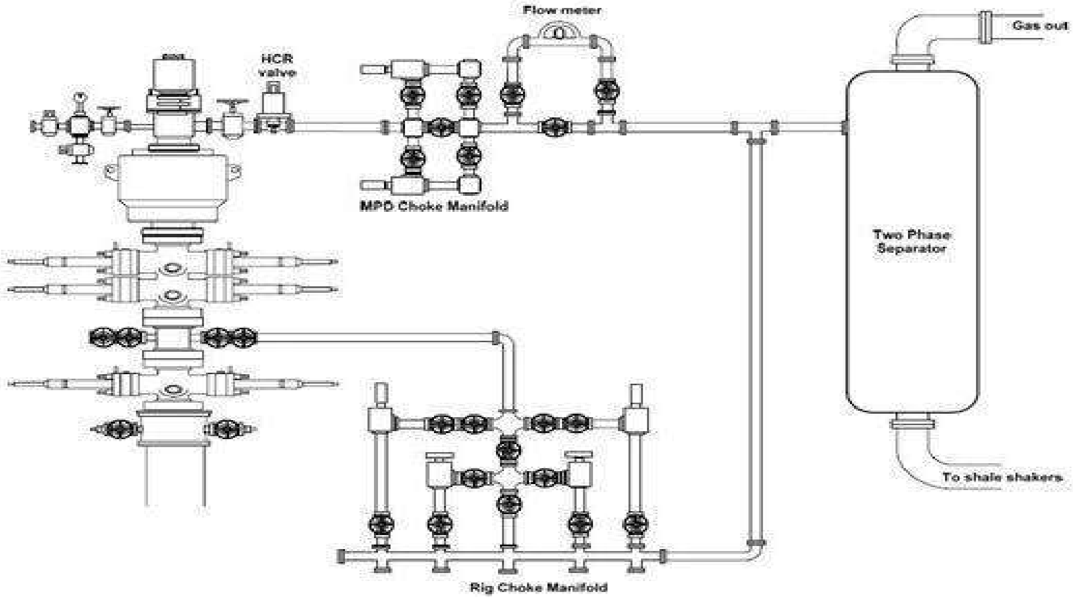


Figure III.5 Rig up for CBHP applications[12]

Equipment used in CBHP:

1. FiRotating Control Device (RCD): an excellent supplemental safety device and adjunct to the BOP stack above the annular preventer.
2. Non Return Valve (NRV): or one way valve; installed in the drill string above the bit to hold up pressure and prevent the backflow when the pumps goes off.
3. Choke Manifold Systems: installed in the return flow line to allow back pressure to be applied during the drilling process. They can be controlled manually or automatically.
4. Auxiliary pressure pump: It maintains the pressure in the annulus with a low flow rate when drilling pumps are stopped.
5. PWD: real time pressure reader tool in the bottom of the hole. (Detailed tools in Appendix 3).

III.1.1 Friction Management

Friction management techniques are used in HPHT or in Extended Reach wells, where the annular pressure is maintained to keep the bottom hole pressure as constant as possible.

In HPHT wells, this is done by maintaining some kind of annular circulation through the use of a concentric casing string. In ERD wells, the annular pressure loss often needs to be reduced to achieve the required length and reach of the well. This can now be achieved through the use of an annular pump. The pump is placed in the cased section of the well and pumps annular fluid back to surface thus reducing the annular friction pressures. These friction management techniques are considered part of the CBHP variation[12].

III.1.2 Continuous Circulation Systems

Continuous Circulation Systems technique keeps the ECD constant by not interrupting circulation during drilling operations. The method is used on wells where the annular friction pressure needs to be constant and to prevent cuttings settling in extended reach horizontal sections of the wellbore. The circulation can be maintained during connections or other interruptions to drilling progress by using a special circulating BOP system or via continuous circulating subs being added to the drill string[12]. (see Appendix A)

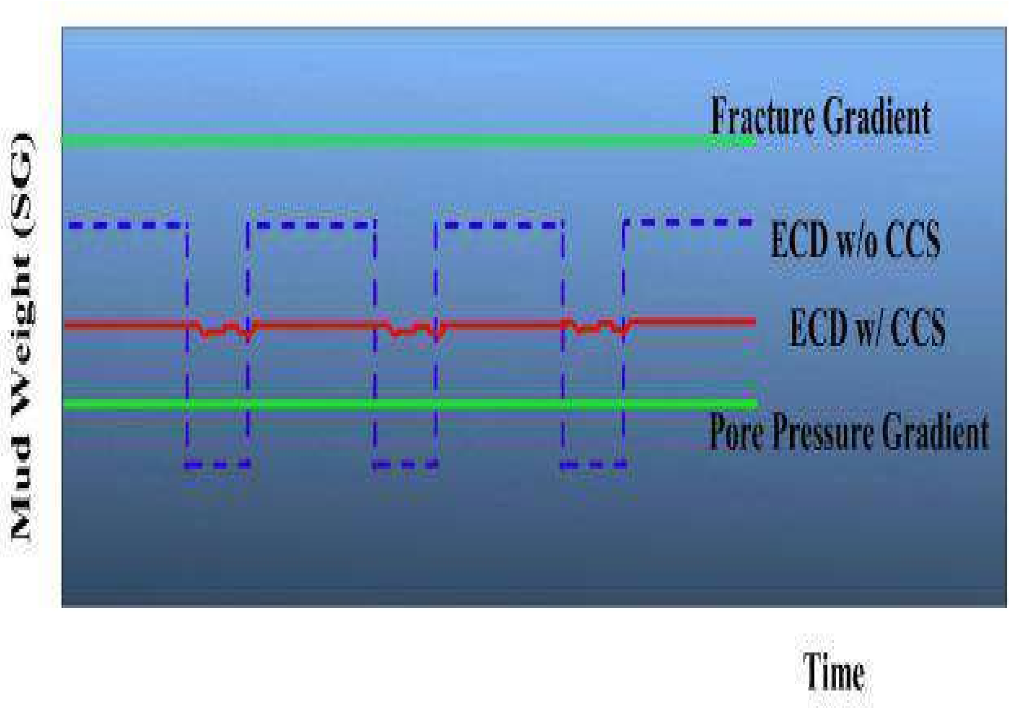


Figure III.6 Continuous Circulation System used under CBHP[20]

Figure 20 is an illustration of controlling the BHP without interrupting the circulation by using the advantages of Continuous Circulation Systems. Some slight fluctuations are seen while making up connections. BHP maintained nearly constant by keeping the ECD constant in the same way.

III.2 MUD CAP DRILLING (MCD)

III.2.1 Pressurized Mud Cap Drilling (PMCD)

A technique to safely drill with total loss returns, PMCD refers to drilling without returns to the surface and with a full annular fluid column maintained above a formation that is taking injected fluid and drilled cuttings. The annular fluid column requires an impressed and observable surface pressure to balance the downhole pressure[4].

This method also addresses lost circulation issues, but by using two drilling fluids. A heavy, viscous mud is pumped down the backside in the annular space to some height. This "mud cap" serves as an annular barrier, while the driller uses a lighter, less damaging and less expensive fluid to drill into the weak zone.

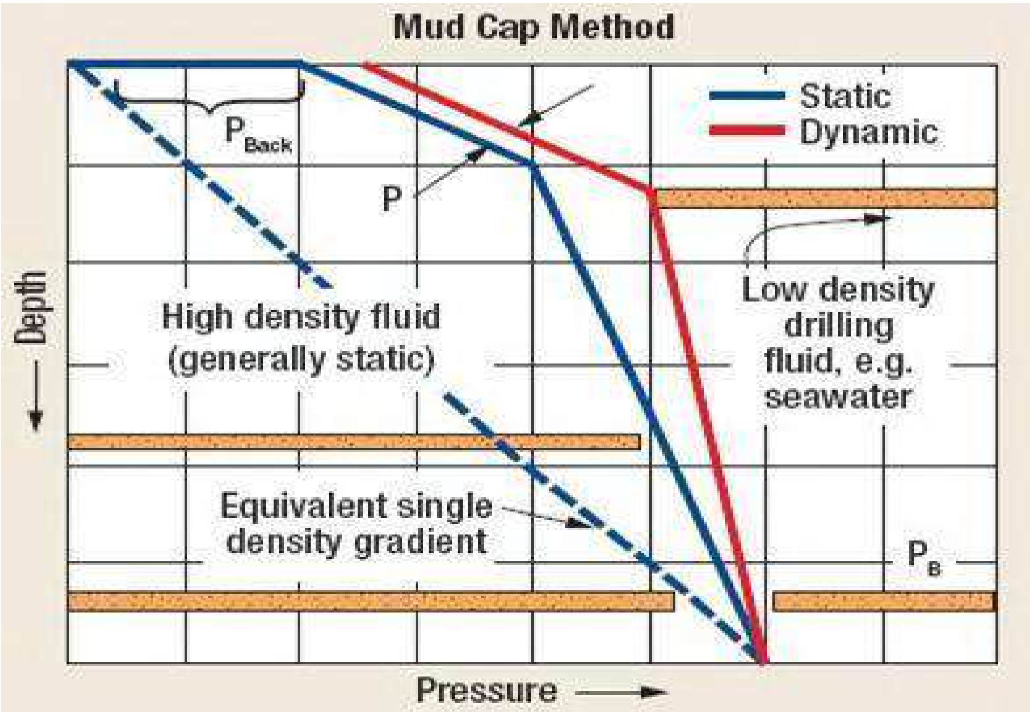


Figure III.7 Pressurized Mud Cap Method[6]

Figure 21 is an illustration of PMCD method. The driller pumps the lightweight scavenger fluid down the drill pipe. After circulating around the bit, the fluid and cuttings are injected into a weak zone up hole below the last casing shoe. The heavy, viscous mud remains in the annulus as a mud cap above the weak zone. The driller can apply optional backpressure if needed to maintain annular pressure control. The lighter drilling fluid improves ROP because of increased hydraulic horsepower[6].

PMCD is applicable in zones with a proven ability to readily accept mud and cuttings, and where offset wells have indicated depleted pressure like in deep water where heavily depleted old pay zones must be drilled to reach deeper pay zones of virgin pressure

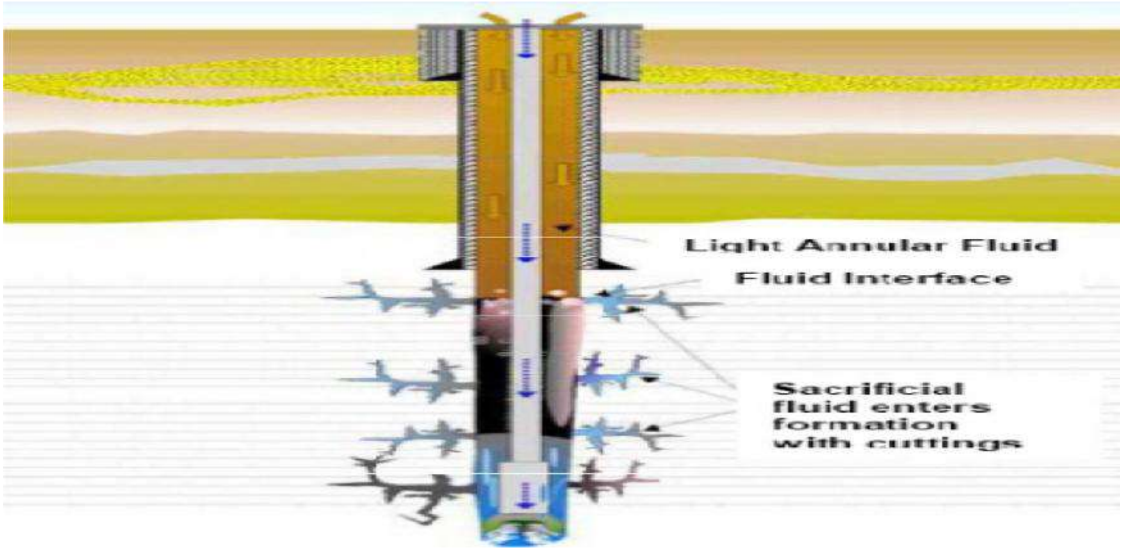


Figure III.8 Illustration of how PMCD works[21]

Considering the restrictions to use PMCD[12], total losses must be experienced. The losses must be large enough to take all of the fluids pumped down the drill string and all of the cuttings generated during the drilling process to use this technique. If circulation, even partial circulation, was to be established, the mud cap would be circulated out of the well. If circulation is possible, a well cannot use the PMCD method, and the CBHP method will have to be used[20].

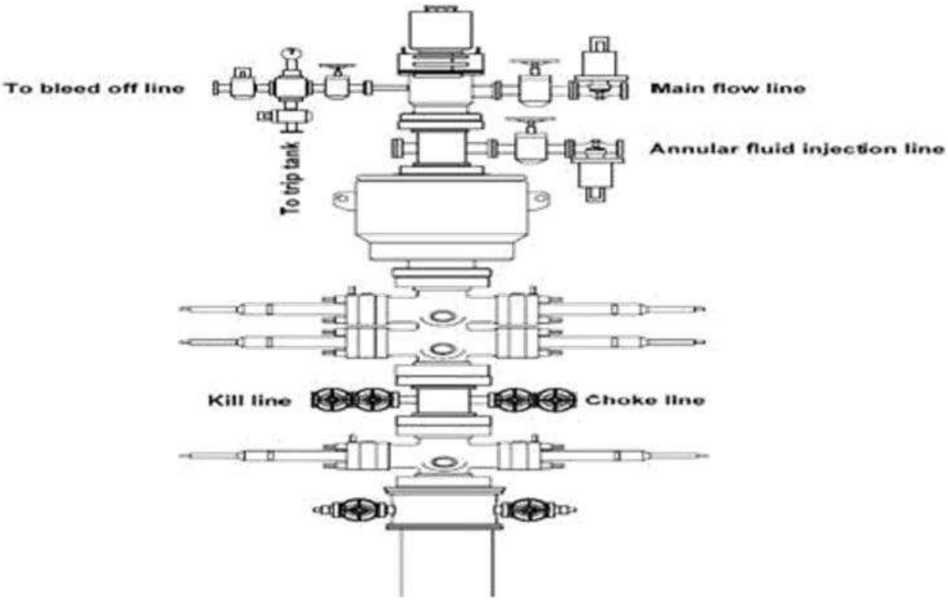


Figure III.9 Rig up for Pressurized Mud Cap Drilling Operations[12]

For PMCD operations, a flow spool must be installed below the RCD to allow fluid to be pumped into the annulus. The rig up for this set up is shown in Figure 23. The manifold on the left hand side of the RCD is the bleed off manifold that is used to be able to keep the well full from the trip tank. It also allows any pressure to bled off from the stack should this be required when changing RCD packers[12].

III.2.1.1 Controlled Mud Cap Drilling (CMCD)

Another method that uses pumps below sea level to bring the returns to the surface is the Low Riser Return and Mud-Lift System (LRRS). The principle behind LRRS is to use a smaller high pressures riser combined with surface and subsea BOPs.

A mud cap situation is created, where the mud level in the riser can be adjusted with the pump, by connecting a subsea pump to the riser below sea level and taking returns from the lower parts of the riser. See Figure 25.

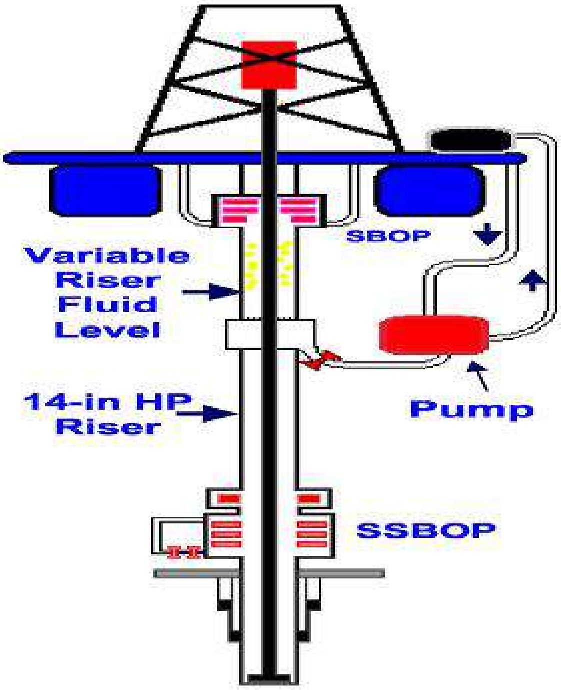


Figure III.10 CMCD Low Riser Return and Mud-Lift System[22]

The Deep Ocean Riser System with a Low Riser Return System (DORS w/ LRRS) is able to adjust the mud level in the high-pressure riser, thus adjusting the bottomhole pressure accordingly[22].

The advantages of the Controlled Mud Cap (CMC) method as cited in Grottheim's study[22] are given below:

- Unlike in conventional drilling, with LRRS it is possible to drill ultra deep water well underbalanced, and still have a riser margin. This is beneficial in that an emergency disconnect would actually increase the bottomhole pressure of the well, and help minimize the consequences of the blowing formation fluids.

- The use of heavier mud at a lower level in the riser will in fact reduce the pressure at the mud line as the top part of the riser will be filled with air and gas. Hydration formation is dependent on temperature and pressure, and because of this pressure reduction, the probabilities of hydrates forming are reduced.
- The use of heavier drilling fluid with a lower level in the riser enables kicks to be circulated out of the well without experiencing added frictional pressures.

Additionally, the mud level in the riser will be monitored, and it will in fact serve as a very accurate trip tank when pumps are shut off, and flow can be detected easier than in a conventional scenarios.

III.3 DUAL GRADIENT DRILLING (DGD)

DG[11] has been utilized successfully in primarily offshore applications, it is a drilling method with two density gradients of deferent fluids to produce the overall BHP in order to reduce the effect of deep water overburden, which avoids exceeding the fracture gradient and breaking down the formation. This saves drilling operations from spending NPT addressing lost circulation issues and associated costs[9].

To realize the DG; drilling fluids will be balanced by reducing mud density in the upper parts of marine riser or filling the marine riser with sea water or dividing the system at the sea bed into two parts through:

- Injecting less-dense media, such as inert gas, plastic pellets or glass beads, into the drilling fluid within the marine riser.
- Or to fill the marine riser with salt water, while diverting and pumping the mud and cuttings from the seabed floor to the surface[6]. In this case, the drilling riser may be filled with seawater to prevent collapse.

Figure 27 is an illustration of comparison of pressure profiles between dual gradient method and the conventional method.

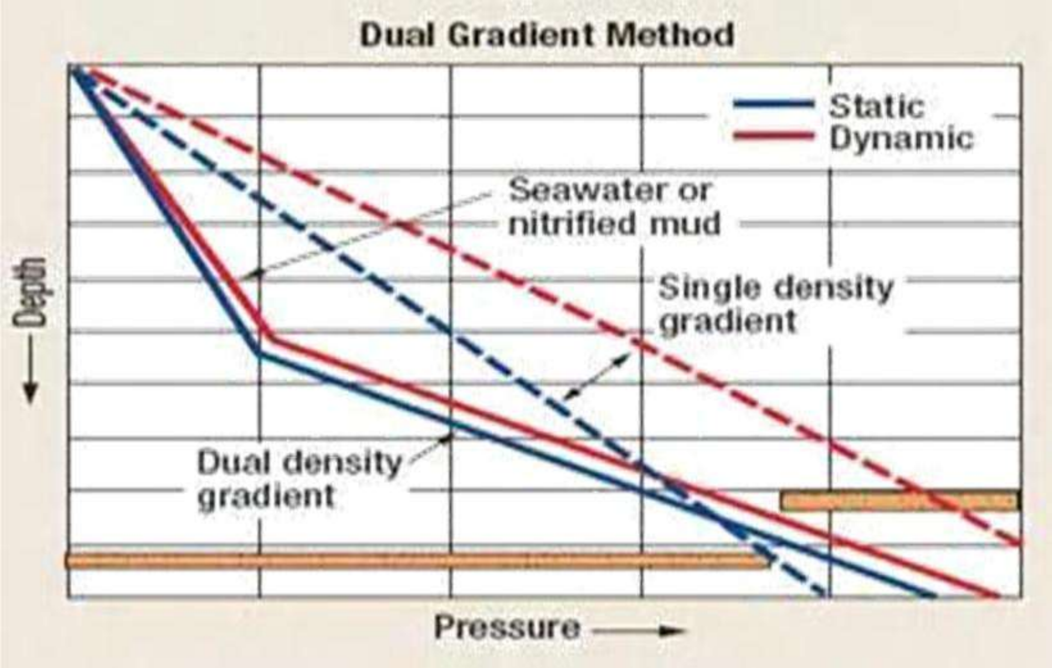


Figure III.11 Dual Gradient Method Pressure Profile[6]

III.4 INTENTIONS OF THE VARIATIONS

If the challenge is a narrow or a relatively unknown drilling window, constant bottom hole pressure (CBHP) MPD is used. This variation includes two subcategories – friction management, used in HPHT or extended-reach wells, and continuous circulation methods for wells where the annular friction pressure must be constant and to prevent cuttings settling in extended-reach horizontal wellbore sections.

CBHP MPD is uniquely applicable for subsalt and other drilling prospects where formations and fracture pressures are a relative unknown.

Pressurized mud cap drilling (PMCD) is the most common MPD method used in Asia Pacific. It is used to control wells that experience, or have a likelihood of, total losses and kicks in the same wellbore. To use this technique, the losses must be large enough to take all of the fluids pumped down the drill string and all of the cuttings generated during the drilling process. If even partial circulation is possible, the CBHP method should be used instead.

Ultimately, this variation is expected to be used in deepwater where heavily depleted old pay zones must be drilled to reach deeper pay zones of virgin pressure[1].

The dual gradient (DG) concept is most applicable to deepwater drilling because all but the most robust of pay zones would be grossly overbalanced from the tall column of heavy mud and cuttings in a marine riser.

Chapter IV

Case study on Managed Pressure Drilling in NEZLA Field and its feasibility in the field of El-HAMRA

MANAGED PRESSURE DRILLING IN NEZLA FIELD

IV.1 OBJECTIVE OF THE STUDY

This study will shed light on the outcomes of MPD in the region of NEZLA by taking the example of the most recent wells drilled (NZ20, NZ27,NZ28 & NZ29). Those wells account for the 2nd MPD campaign, since the first campaign involved (NZ22, NZ23, NZ24, NZ25 & NZ26).

Drilling in this area was performed conventionally, despite the operational difficulties and risks.

IV.2 SAMPLE OF CONVENTIONALLY DRILLED WELLS

INZ-18 (1996): total losses after drilling 30m into GO (2236m), Mud Weight was reduced from 1.58sg to 1.52sg, then total losses at the base of GO (2246m) healed with LCM and MW reduced to 1.45sg. At 2276m (24m into HQ) total losses followed by a kick, pipe got stuck while pulling out led to Side Track. TD was reached after drilling 70m into HQ with partial losses.

NZ-19 (2006): Total losses while drilling into GO (2278m), MW reduced 1.40sg to 1.34sg. Drilling was resumed with partial losses until 2600m where total losses then a kick were recorded. Drilling string got stuck during the well control. 11 days of continuous attempts to control the well, eventually, a blowout and fire at surface. The well was controlled with special well control techniques (capping & diverting) and then abandoned.

NZ-21 (2008): total losses after drilling 5m into HQ (Top 2411m), a kick of 2600 psi in the annulus was taken. The well killed by bull-heading technique.

By introducing of the MPD technique, drilling records show an improvement in dealing with unknown and narrow formation environment.

MPD in the NEZLA field was performed by WEATHERORD, Secure Drilling Services (SDS).

IV.3 MPD WELLS SUMMARY

IV.3.1 Summary of MPD at NEZLA NZ29 (Dec 2014-Jan 2015)

NZ29 was the most recent MPD well, the 8th in NEZLA campaign. The 6” section with a total length of 159m was drilled thru the 3 zones (TAGI, GO & HQ).

The mud window of this section, and referring to the onsite lower losses limit and lower inflow limit, was ranged between 1,21 sg and 1,30 sg.

Table IV.1: 6" section formation tops and relative Mud Weight data (NZ29).

Zone	Formation	TVD m	Width m	Mud Window	As Drilled
1	TAGI	2458-2503	45	1.21-1.45	1.28-1.29
2	GO	2503-2579	76	1.22-1.44	1.27-1.28
3	HQ	2579-2604	12	NA	1.27-1.28

IV.3.1.1 Mud window (as tested):

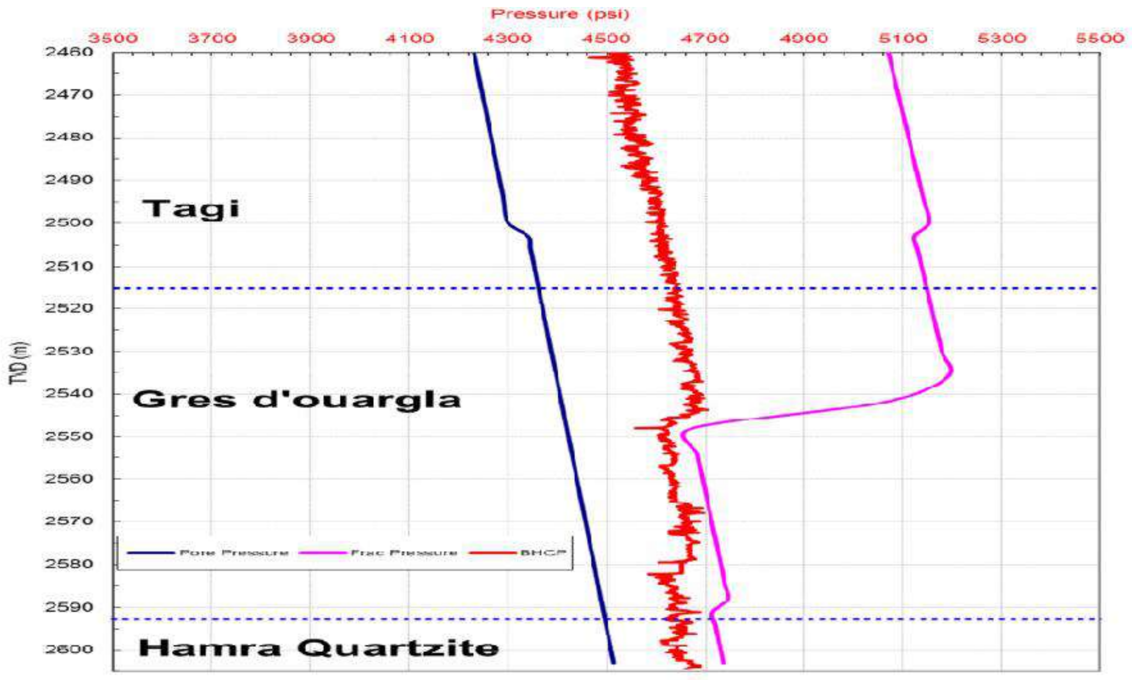


Figure IV.1 Drilling Window (NZ29)

IV.3.1.2 Operations overview:

Drilling this section was achieved in 32 days. Initially, MPD equipment were installed and tested, finger print procedure was applied. Start Hi-Speed-motor-drilling (with impregnated bit) from 7'' casing shoe @ 2445m, performed SBT (EMW 1.55sg) and drilling ahead to Top of TAGI 2458m. Lower/ upper limit tested with no gain or losses recorded (1.22-1.44 sg).

Losses (7m3/h to 12m3/h) occurred while drilling thru GO at 2545m cured by pumping LCM. While drilling, BHP was held constant by RCD, but when tripping, mud had to be changed (1.14 to 1.28sg) in static mode.

Drilling to 2579m (Top of HQ), logging & DST was performed and a decision for further drilling was taken as the main reservoir was not confirmed. Drilling resumed to final TD 2604m.

Final open hole DST, followed by running, cementing 4”1/2 tubing liner at 2597m and completion.

IV.3.1.3 Drilling curve:

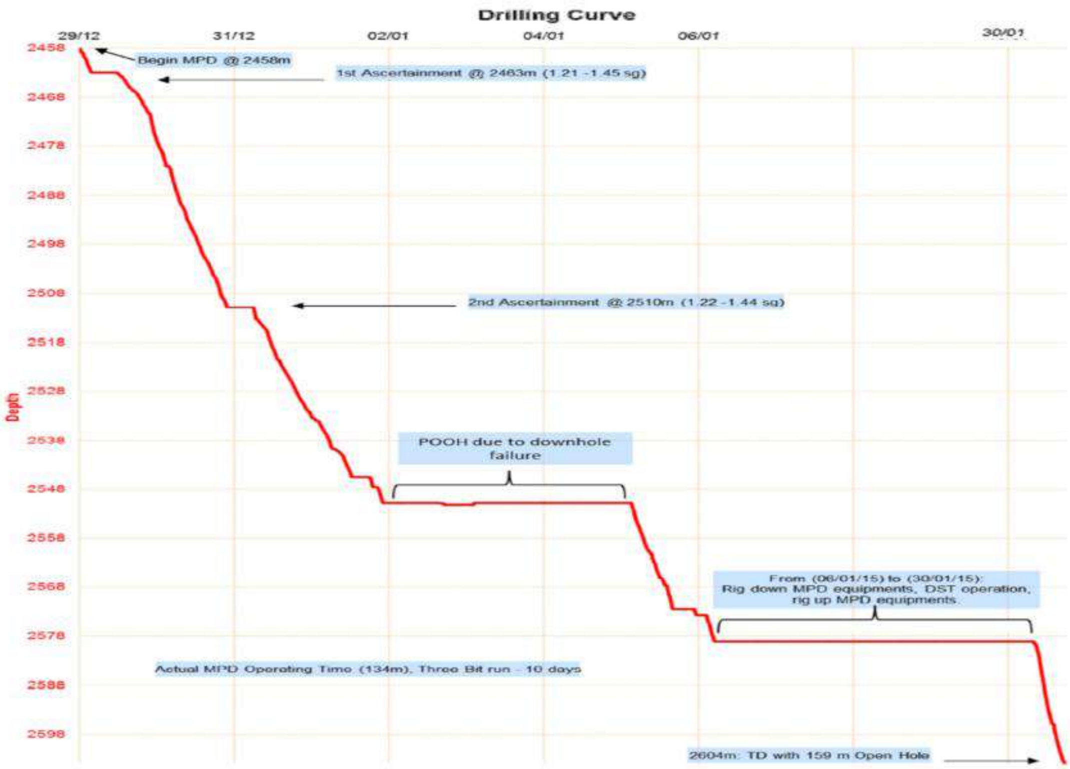


Figure IV.2 Drilling Curve (NZ29)

IV.3.1.4 Drilling Bits & ROPs:

Table IV.2: 6” Drilling Bits & ROPs Table (NZ29)

Bit	Dia	Type	Manuf	Nozzles	TFA	Formation	In	Out	Prog.	BTime	ROP	WOB (Min-Max)	Avg. Rpm	Spp	Flow	MW	Remarks
n°	in		32 of in		in2		m	m	m	hr	m/h	T	rpm	Psi	l/mn	S.G	(Reason pulled)
1	6	Impreg	Baker		1.09	Tagi - GO	2445	2579	134.0	90.64	1.48	2 - 4	40	2100	900	1.14	TD
1	6	Impreg	Baker		1.09	GO - HQ	2579	2604	25.0	8.91	2.81	2 - 4	40	2150	900	1.14	TD

Total meters	Total Hours	Av. ROP (m/hr)
159	99.55	1.60

IV3.1.5 Time Breakdown:

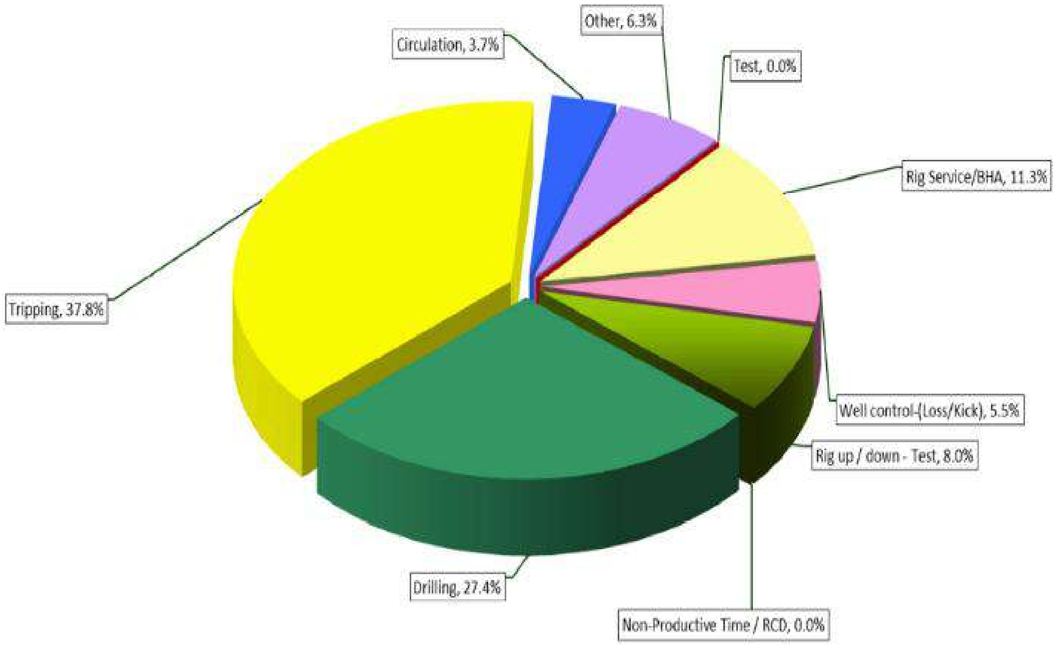


Figure IV.3 NPT Chart (NZ29)

IV.3.1.6 Final Well architecture as drilled:

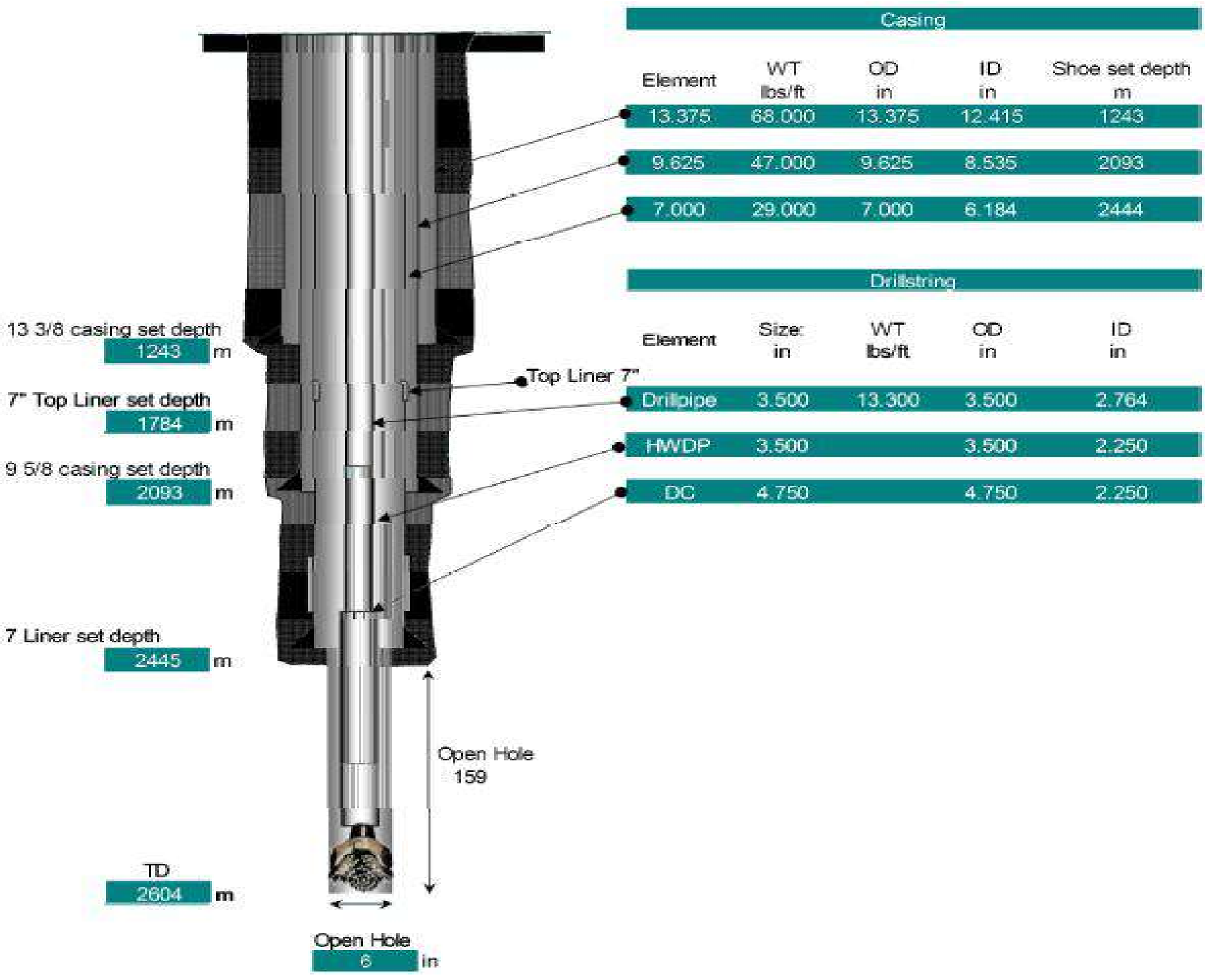


Figure IV.4 Final Well Schematic as Drilled (NZ29)

IV.3.2. Summary of MPD at NEZLA NZ28 (Aug 2014-Sept 2015)

NZ28 is the 6th in MPD well in NEZLA campaign. The 6” section with a total length of 175m was drilled through the 3 zones (TAGI, GO & QH). The mud window of this section, and referring to the onsite lower losses limit and lower inflow limit, was ranged between 1,24 sg and 1,38 sg. This range allows a good BHP control using the MPD technique.

Table IV.3: 6” section formation tops and relative Mud Weight data (NZ28)

Zone	Formation	TVD m	Width m	Mud Window	As Drilled
1	TAGI	2370-2394	24	1.20-1.45	1.29-1.30
2	GO	2394-2414	20	1.22-1.43	1.30-1.31
3	HQ	2414-2515	101	1.24-1.38	1.30-1.31

IV.3.2.1 Mud window (as tested):

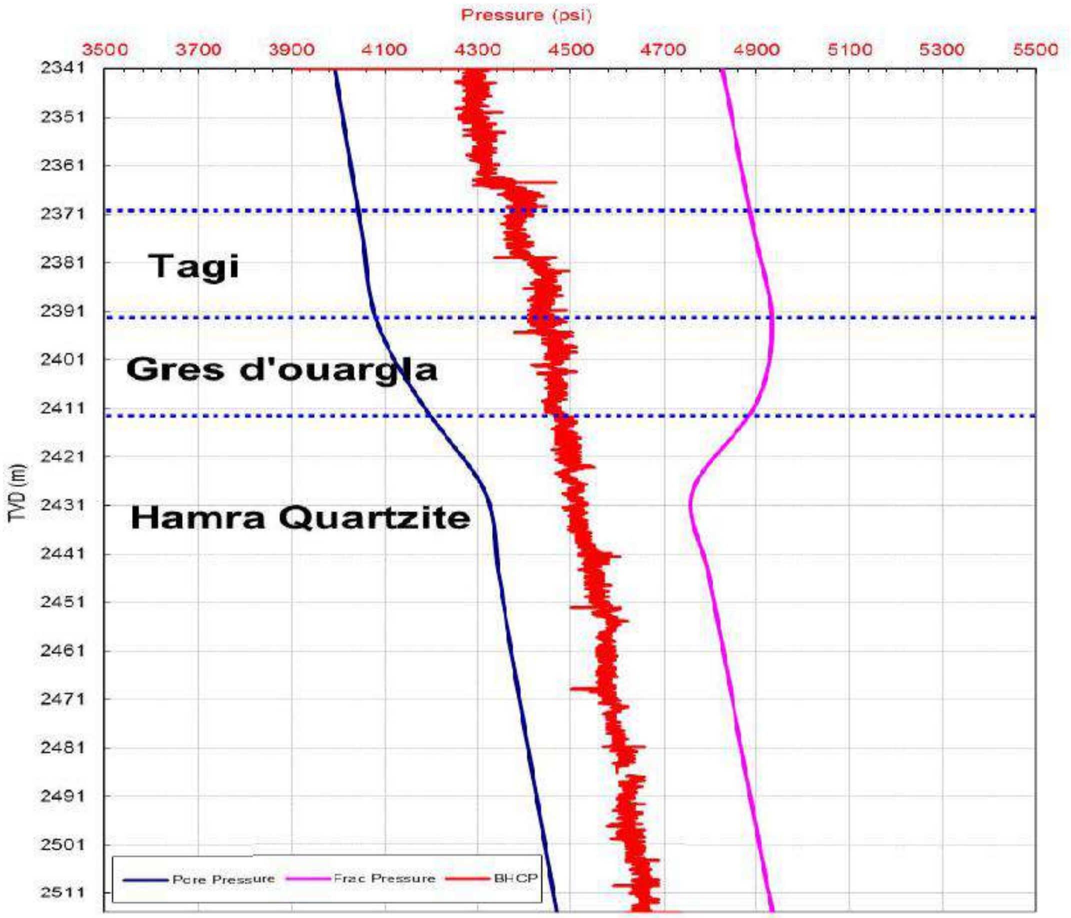


Figure IV.5 Drilling Window (NZ28)

IV.3.2.2 Operations overview:

After installing MPD related equipment and performing the required tests, drilling started from 7” casing shoe @ 2340m, SBT was performed (EMW 1.45sg), and drilling resumed to top of TAGI @ 2370m. Upper / lower tests resulted in a BHP range of (1.20-1.45sg). Gas gain was circulated out. Drilling ahead to Top of GO, HQ and to final TD @ 2515m with no recorded incidents. Logging and 4”1/2 liner tubing was set and cemented, then the well was completed.

IV.3.2.3 Drilling curve

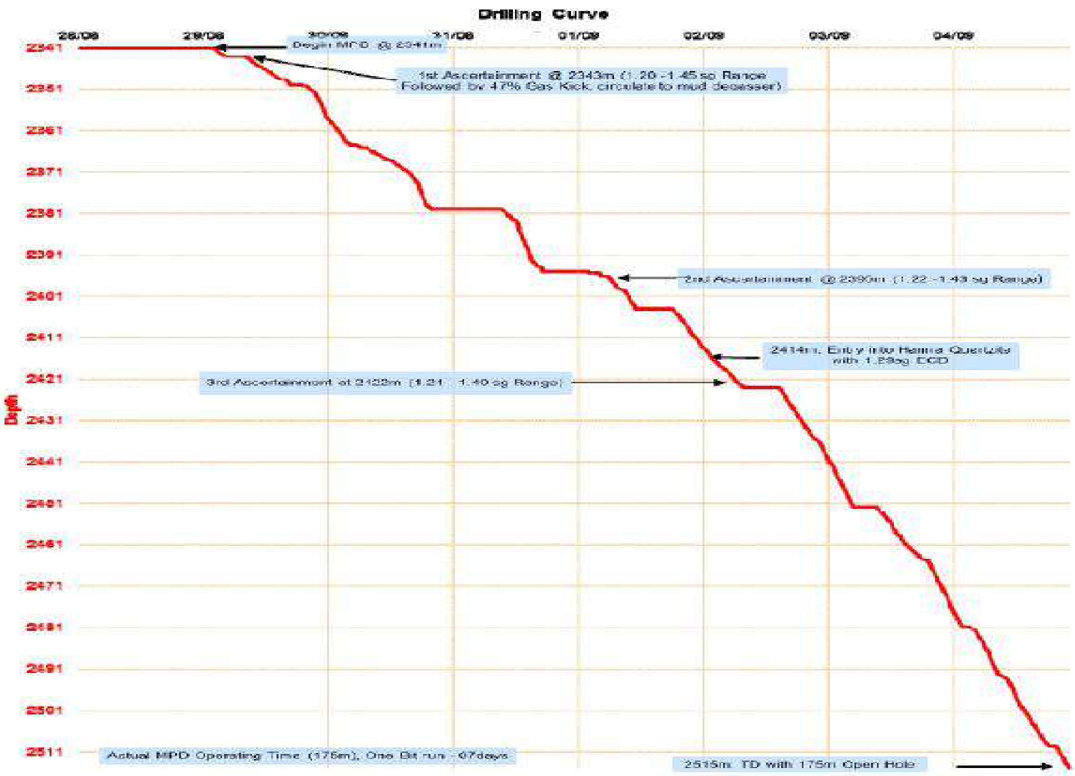


Figure IV.6 Drilling Curve (NZ28)

IV.3.2.4 Drilling Bit ROPs:

Table IV.4: 6” Drilling Bits & ROPs Table (NZ28).

Bit #	Size (in)	Made by	Type	TFA/Jets Size	MD In	MD Out	Total M Drilled	Hours	Average ROP	Dull Grading
1	6	Baker inteq	HHS352	1.09 Fixd nozzles	2328	2515	187	100	1.87	3-1-WT-X-I-CT-TD

IV.3.2.5 NPT / Time break down:

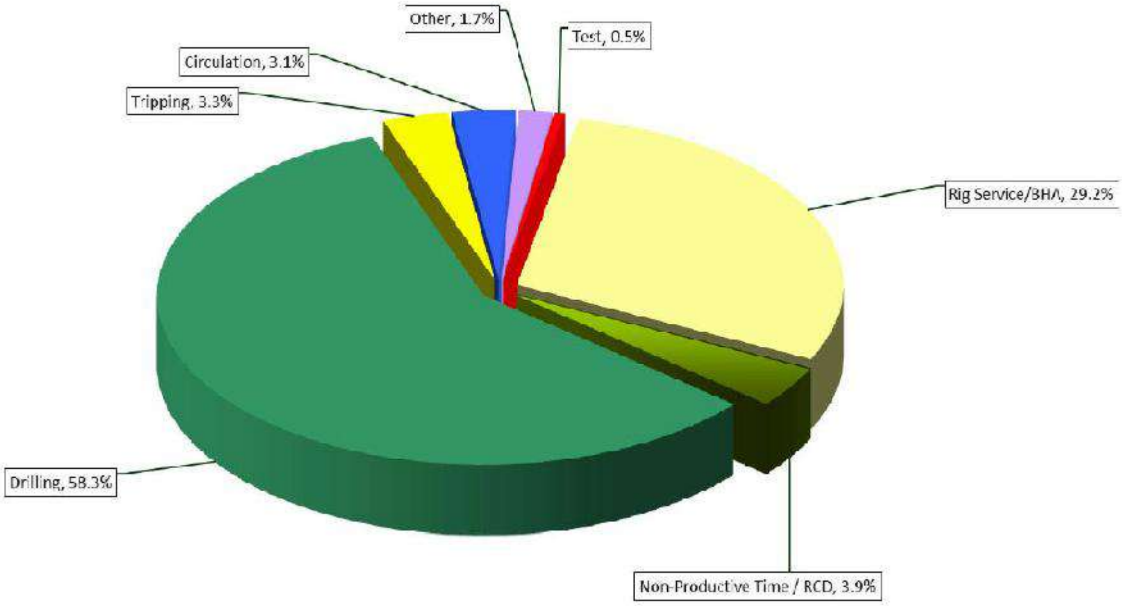
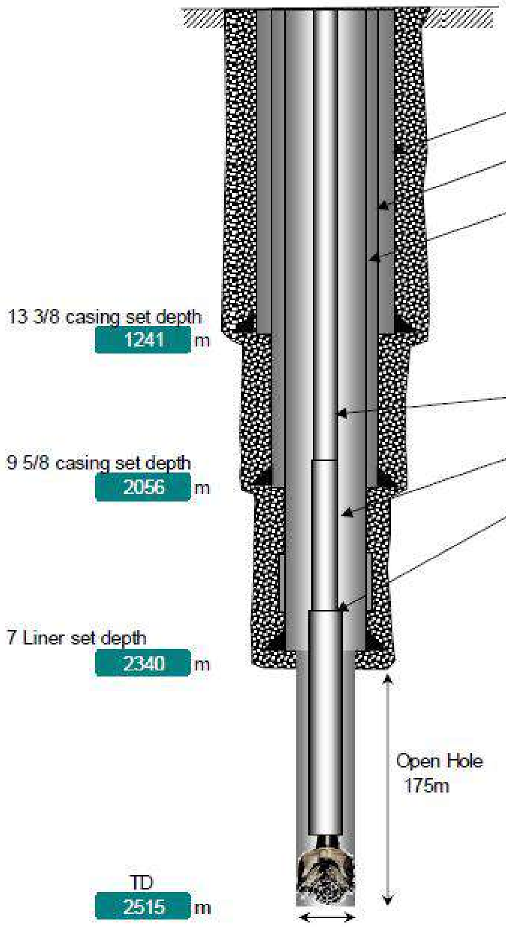


Figure IV.7 NPT Chart (NZ28)

IV.3.2.6 Final Well architecture as drilled:



Casing				
Element	WT lbs/ft	OD in	ID in	Shoe set depth m
13.375	68.000	13.375	12.415	1241.000
9.625	47.000	9.625	8.861	2056.000
7.000	29.000	7.000	6.184	2340.000

Drillstring				
Element	Size: in	WT lbs/ft	OD in	ID in
Drillpipe	3.500	14.040	3.500	2.992
HWDP	3.500		3.500	2.125
DC	4.750		4.750	2.250

Figure IV.8 Well Schematic as Drilled (NZ28)

IV.3.3 Summary of MPD at NEZLA NZ27 (Oct 2014-Nov 2014):

NZ27 is the 7th in MPD well in NEZLA campaign. The 6" section of a total length of 183m was drilled thru the 3 zones (TAGI, GO & QH).The mud window of this section, and referring to the onsite lower losses limit and lower inflow limit, was ranged between 1,30 sg and 1,31 sg. This winder was narrower than any well window had been drilled in the field.

Table IV.5: 6" section formation tops and relative Mud Weight data (NZ27).

Zone	Formation	TVD m	Width m	Mud Window	As Drilled
1	TAGI	2252-2282	30	1.24-1.45	1.30-1.32
2	GO	2282-2322	40	1.25-1.43	1.30-1.32
3	HQ	2322-2412	90	1.30-1.31	1.31

IV.3.3.1 Mud window (as tested):

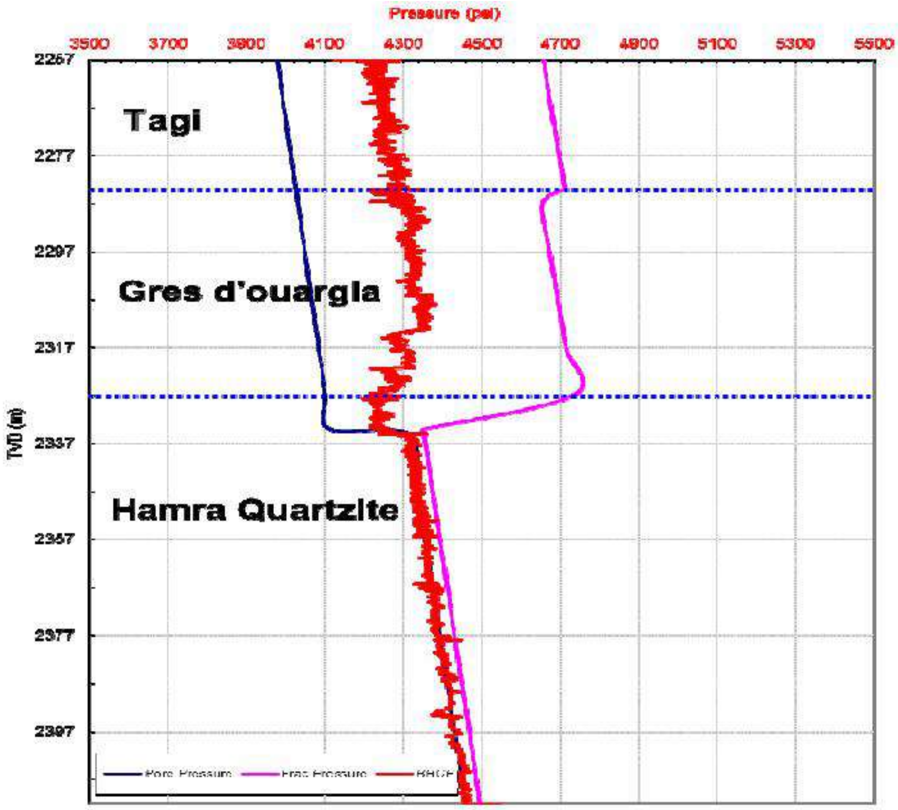


Figure IV.9 Drilling Window (NZ27)

IV.3.3.2 Operations overview:

After installing MPD related equipment and performing the required tests, drilling started from 7" casing shoe @ 2229m, SBT was performed by MPD with an ECD 1.55sg, and drilling resumed to top of TAGI @ 2252m. Upper test with MPD back pressure pump a limit of 0.45sg, and lower test to 1.24sg resulted in gaining 140litres circulated out through poor-boy degaser. Drilling ahead with equivalent density to 1.33sg to top of GO, upper / lower test to (1.24-1.43sg). Partial losses occurred and equivalent mud weight reduced to 1.30sg, with spotting LCM to cure the losses, but no result 4 more meters drilled to top HQ and losses increased, a lower test was conducted though it was impossible to monitor the gain level due to the losses. Later during drilling the equivalent mud weight was reduced to 1.29sg, 6 meters ahead, a long duration (50mins) connection and rig service had let to a kick of 32m3/WHP3000 psi/SPP 548 psi due to a delay in closing the BOP.

This event was controlled but gas level indication was 10%, when proceeding to divert to the RDC, another kick was taken, eventually controlled by driller's method for 17hrs. Drilling was resumed with controlled parameters and with continuous losses. LCM was circulated.

TD was called at 2412m. Mud weight increased for a static system (1.31sg), Hi-vis pill was pumped to clean the hole, then the well start flowing, ESD was activated and the BOP was closed at total gain of 1.2m3, then proceeded to kill the well. 4"1/2 tubing was run, set and cemented, and the well was completed.

IV.3.3.3 Kick demonstration:

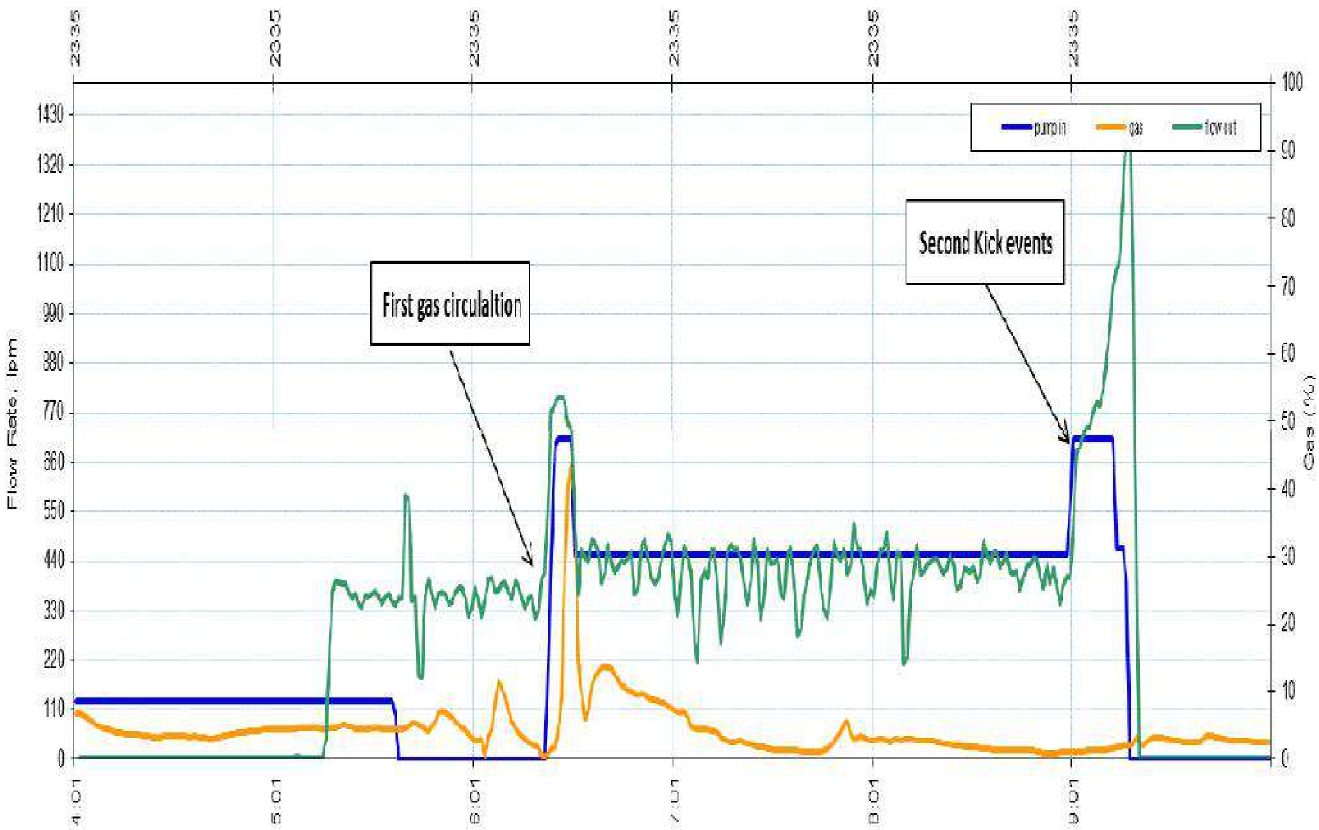


Figure IV.10 Kick Illustration Chart (NZ27)

IV.3.3.4 Drilling curve:

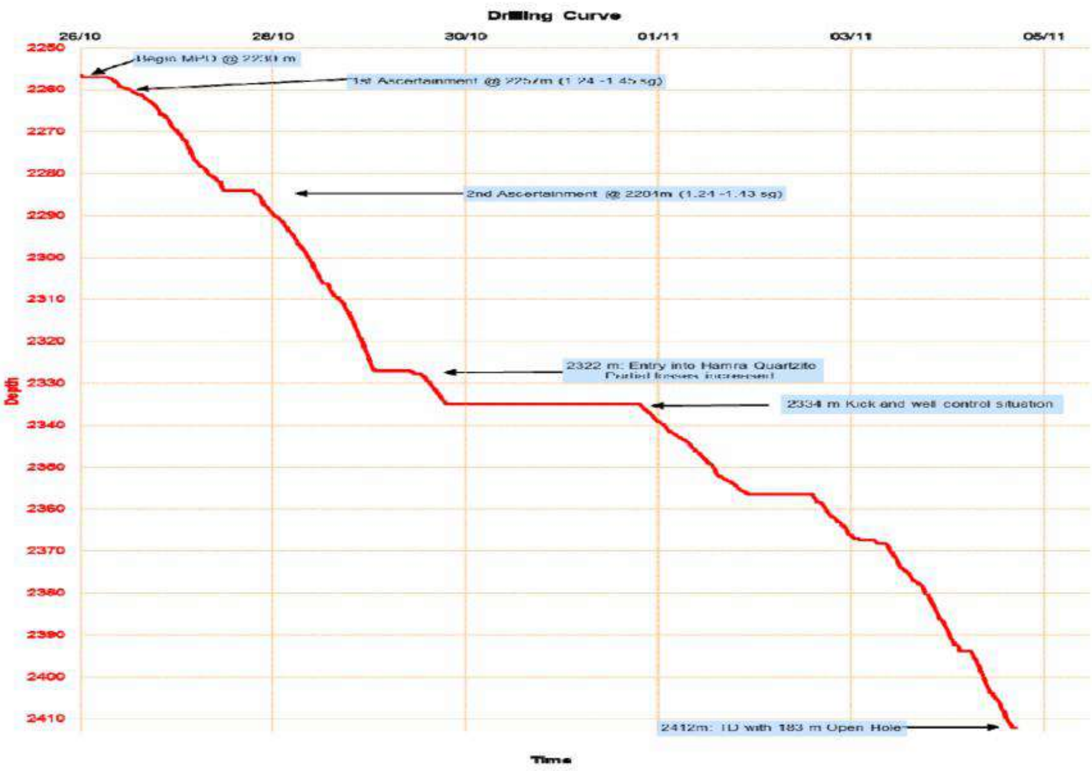


Figure IV.11 Drilling Curve (NZ27)

IV.3.3.5. Drilling Bit & ROPs:

Table IV.6 :6" Drilling Bits & ROPs Table (NZ27).

Bit	Dia	Type	Manuf	Nozzles	TFA	Formation	In	Out	Prog.	BTime	ROP	WOB (Min-Max)	Avg. Rpm	Spp	Flow	MW	Remarks
n°	in		32 of in		in2		m	m	m	hr	m/h	T	rpm	Psi	l/mn	S.G	Conditions
1	6	Impreg	Smith		1.09	Quartz	2229	2412	183.0	159.90	1.14	5 - 7	40	2380	900	1.14	2-1-WT-A-X-CT-TD

IV.3.3.6 NPT / Time break down:

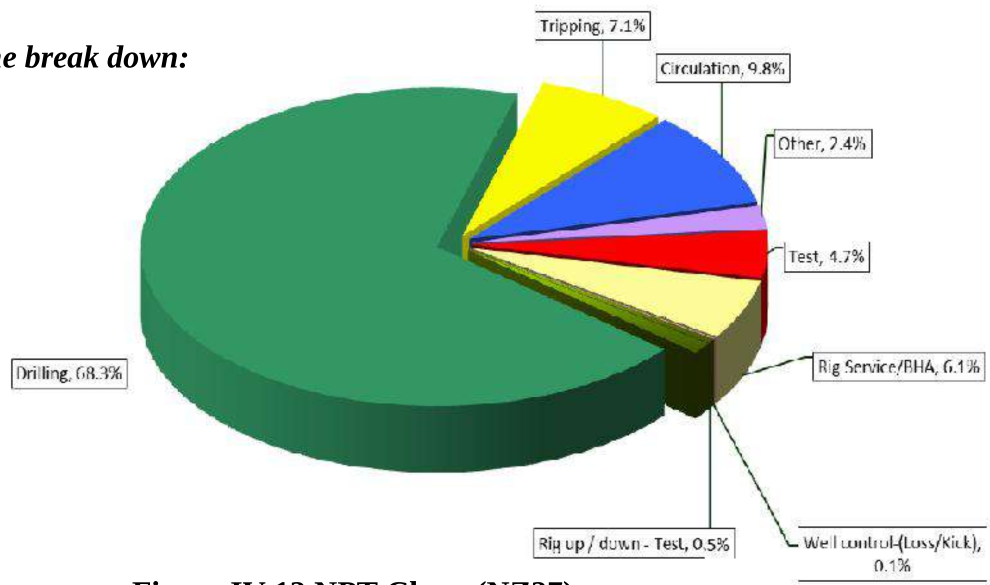


Figure IV.12 NPT Chart (NZ27)

IV.3.3.7 Final Well architecture as drilled:

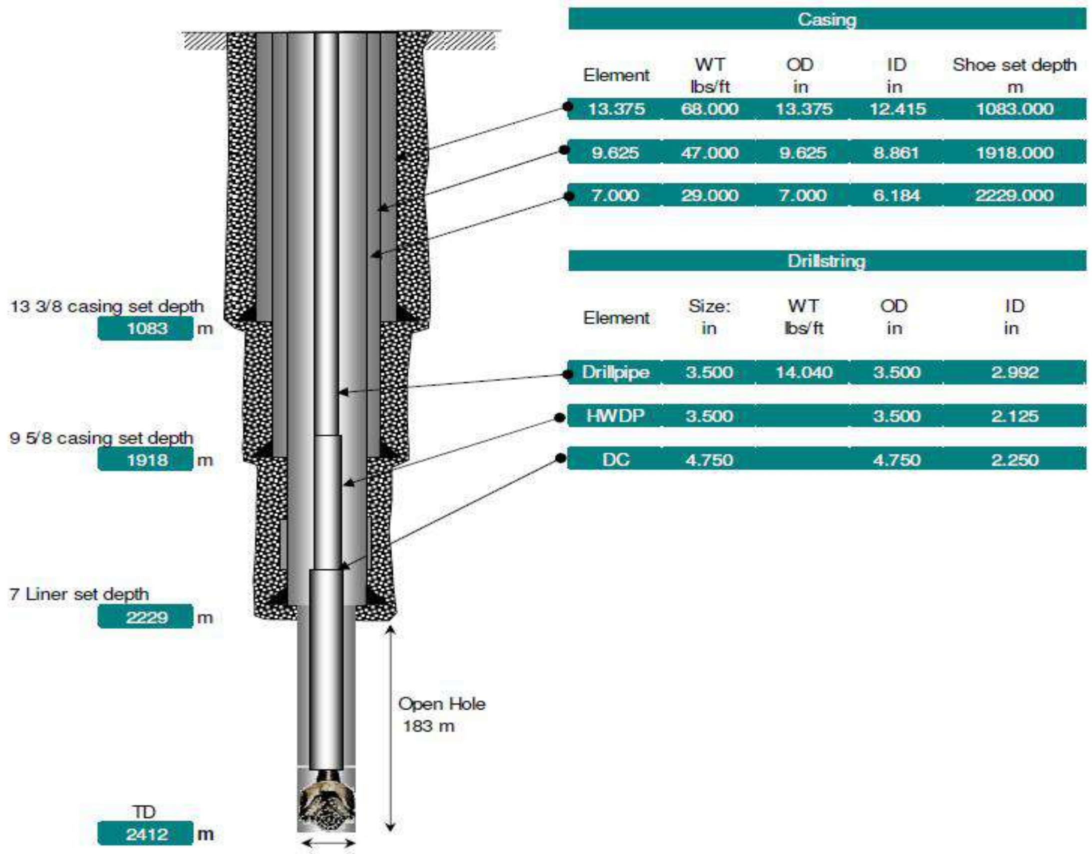


Figure IV.13 Well Schematic as Drilled (NZ27)

IV.3.4 Summary of MPD at NEZLA NZ20 (Aug 2014-Sept 2015):

NZ20 is the 9th and last in MPD well in NEZLA campaign. The 6" section with a total length of 184m was drilled through the 2 zones (GO & QH)

The mud window of this section, and referring to the onsite lower losses limit and lower inflow limit, was ranged between 1,18 sg and 1,37 sg. This range allows a good BHP control using the MPD technique.

Table IV.7: 6" section formation tops and relative Mud Weight data (NZ20)

Zone	Formation	TVD m	Width m	Mud Window	As Drilled
1	GO	2355-2400	45	1.18-1.37	1.28-1.29
2	HQ	2400-2539	139	1.19-1.32	1.24-1.25

IV.3.4.1 Mud window (as tested):

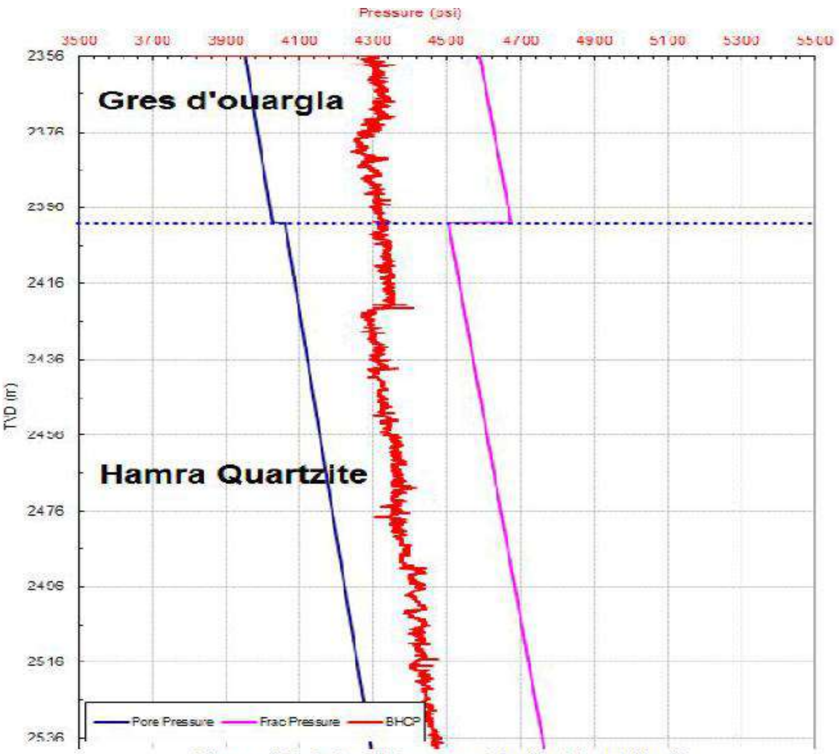


Figure 15: Actual Pressure Profile "As Drilled"

Figure IV.14 Drilling Window (NZ20)

IV.3.4.2 Operations overview:

After installing MPD related equipment and performing the required tests, and since the original well was temporarily abandoned, operations stared by drilling out the cementing plug. Drilling into the new formation started from 2355m to 2358m with ECD 1.29sg. Upper/Lower tested performed (1.18sg – 1.37sg) and drilling was resumed.

Drilling with an ECD of 1.29sg led to partial losses (3m3/h), then ECD reduced to 1.27sg with spotting LCM. At top of QH (2400m), an Upper test resulted in upper limit of 1.38sg which led to considerable mud loss that was not healed by reducing the ECD to 1.25, nor by LCM. However drilling continued to TD 2539 m with monitoring daily losses. Eventually, the well was delivered with the final completion operation.

IV.3.4.4 Drilling Bit & ROPs:

Table IV.8: 6" Drilling Bits & ROPs Table (NZ20).

Bit	Dia	Type	Manuf	Nozzles	TFA	Formation	In	Out	Prog	BTime	ROP	WOB (Min-Max)	Avg. Rpm	Spp	Flow	MW	Remarks
n°	in			32 of in	in2		m	m	m	hr	m/h	T	rpm	Psi	l/mn	S.G	(Reason pulled)
1	6	Impreg	Smith		1.09	Sandstone	2355	2539	184.0	121.00	1.52	2-11	60	2200	900	1.14	TD
									Total meters	Total Hours	Av. ROP (m/hr)						
									184	121.00	1.52						

IV3.4.3 Drilling curve:

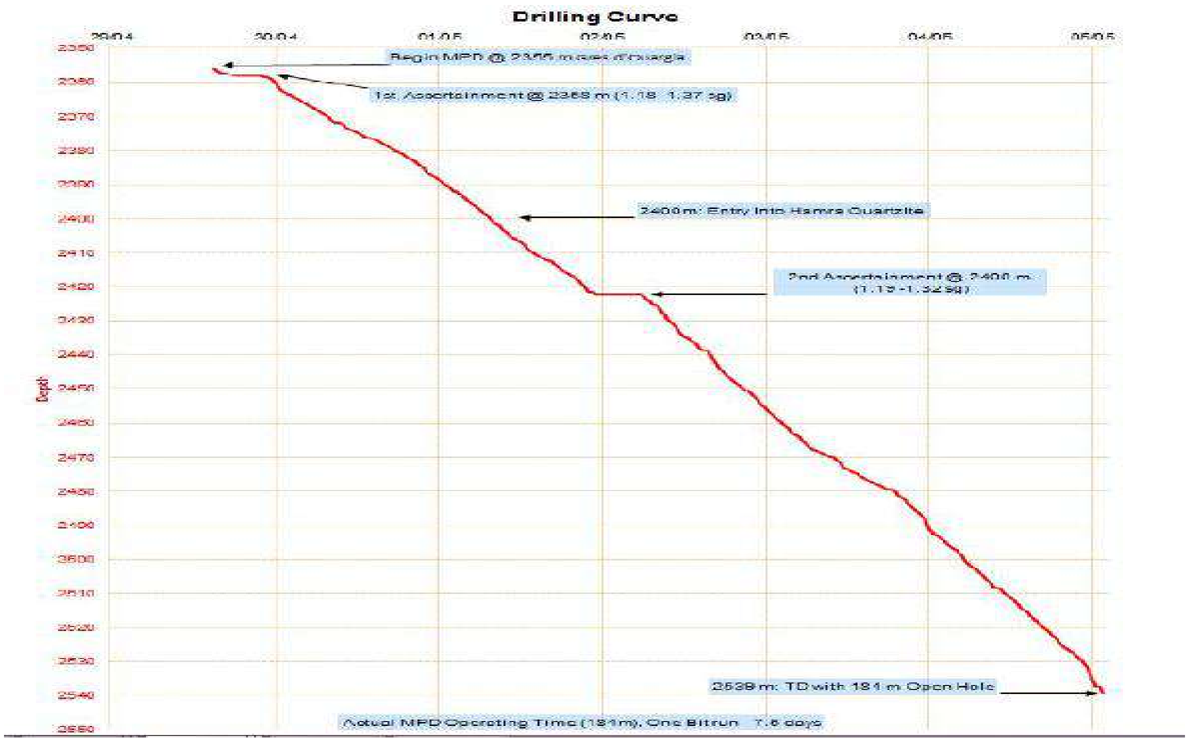


Figure IV.15 Drilling Curve (NZ20)

IV.3.4.5 NPT / Time break down:

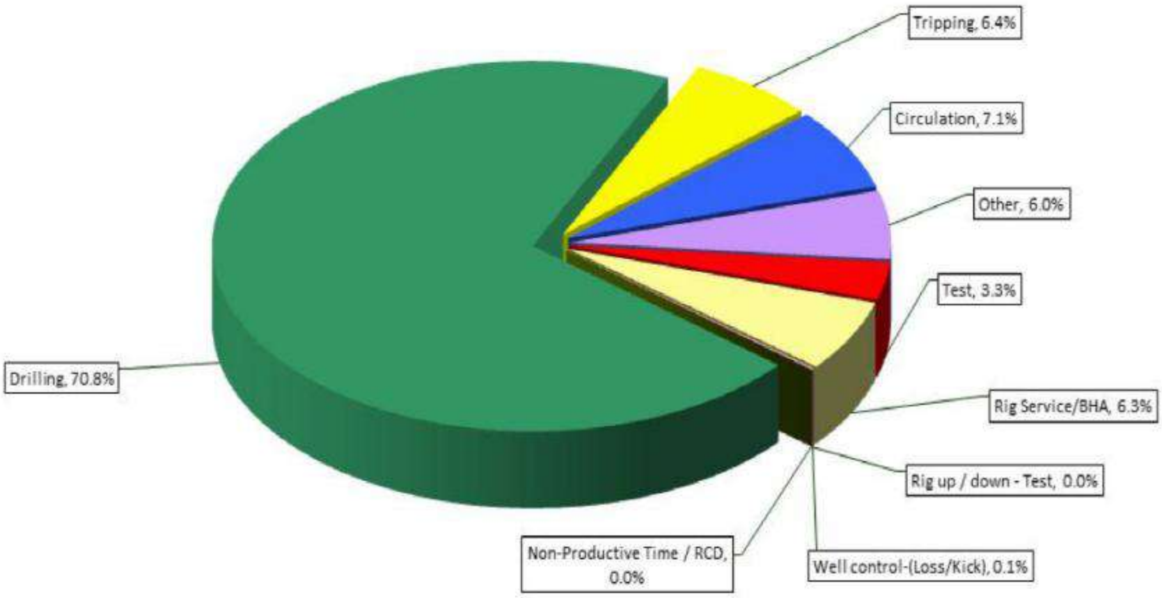


Figure IV.16 NPT Chart (NZ20)

IV.3.4.6 Final Well architecture as drilled:

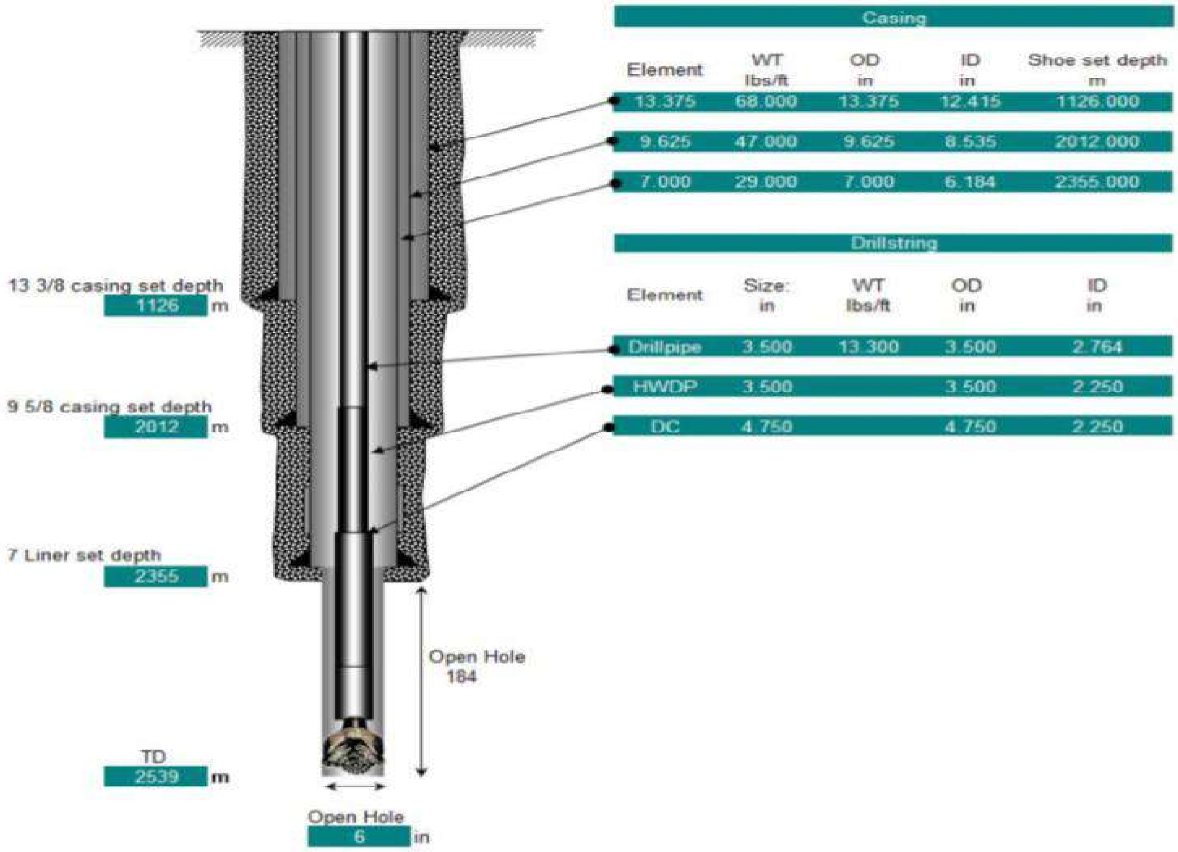


Figure IV.17 Well Schematic as Drilled (NZ20)

FEASIBILITY STUDY OF MPD ON THE WELL HAZ-104

IV.5 OBJECTIVES OF MPD APPLICATION IN HAZ-104 WELL

Managed Pressure Drilling technology is proposed to be applied on 6”hole section of HAZ-104 well to get the flexibility of increase or decrease ECD to mitigate operational problems and perform eventual Dynamic FIT and Reservoir Pressure tests to know the limits and be able to take decisions to redesign the MW to reduce formation damage and drill within operative window. Primary MPD objectives for HAZ-104 well are as follow:

6” hole section obectives:

Drilling the 6” hole section to the target depth of 4000m MD utilizing MPD-CBHP techniques throughout the expected losses and gas influx zones of Hamra Quartzites in alignment with SH objectives, minimizing the potential of losses and influx event testing the upper and lower limits of the well .

The objectives of using MPD techniques include:

- Minimize Influx/loss issues in 6” hole section where loss or gas influx may be observed Quartzites de Hamra changing the ECD by application of SBP at Weatherford choke.
- Perform dynamic FIT and Reservoir Pressure tests in order to redesign the MW according operative window; this will also determine potential of reservoir, potential prior to DST; if possible.
- Cross formation fractures with minimum M.W, hence reducing chances of losses Keep Constant BHP during connection or Rig Pump stops same than during drilling and circulation.
- As result of all above, drill 6” hole deviated section well at 80° to improve the hydrocarbon production of HAZ-104 well.

Well data and Schematics:

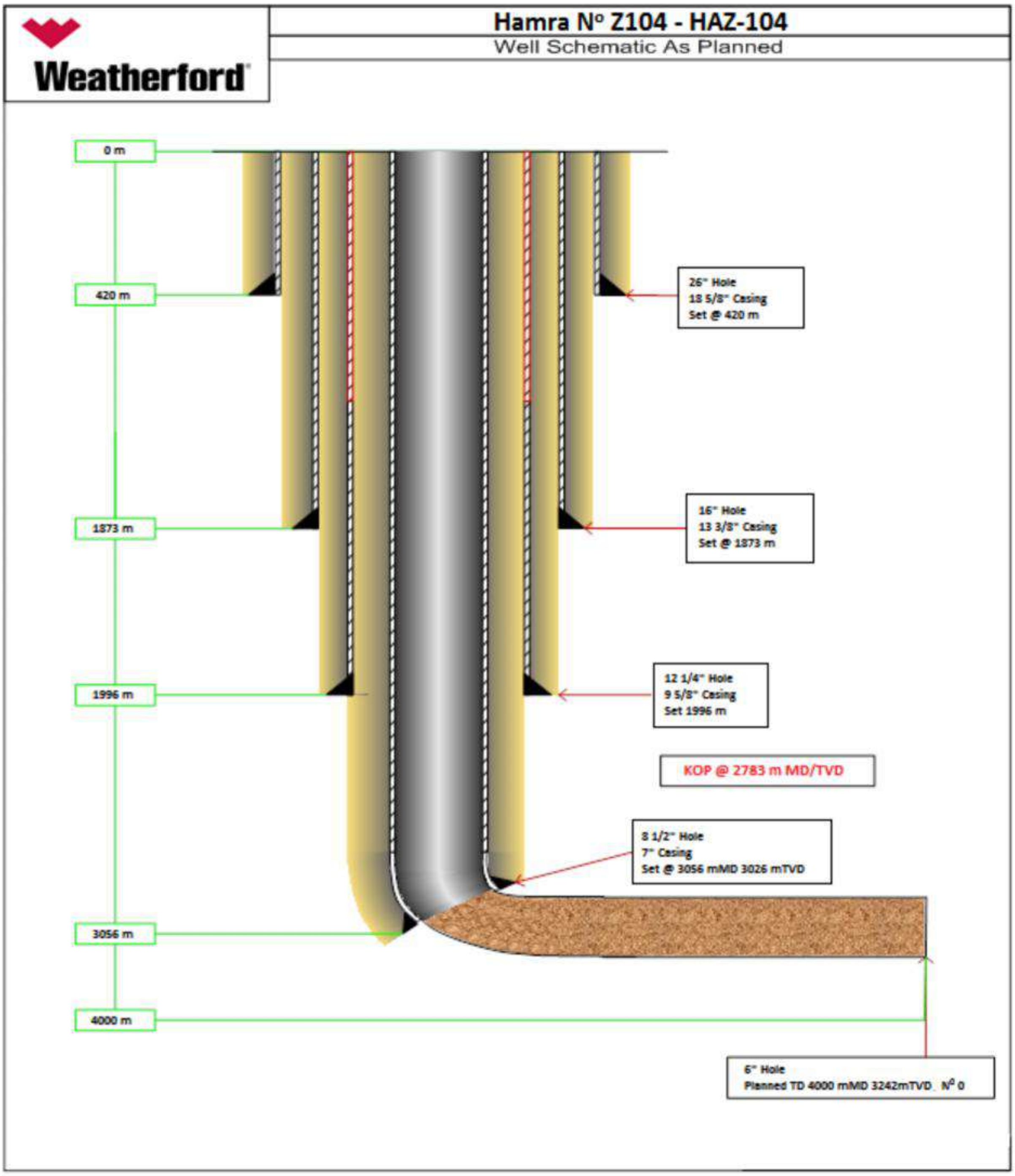


Figure IV.18 well design

IV.5.1 6" HOLE SECTION POTENTIAL DRILLING PROBLEMS

The expected interval of fractures is between 3056 – 4000 m MD with risk of partial losses and gas influx from, Hamra Quartzite formations. Offset wells HA101 and HA102s were drilled with 1.27 sg MW and 850-900 lpm OBM flow rate keeping estimated ECD of 1.40 sg. Additionally mechanical stuck was found at 3135 m MD (TVD) in HA-101 leaving unrecoverable fish and spotting a cement plug to continue with ST. Same mechanical stuck was observed at 3276 m MD (TVD) on HA-102 well but string was freed by jarring up and continued drilling until TD. Back ground gas with poor ROP observed while drilling on both wells. Performed DST (barefoot) and found non-productive wells. Isolated well with bridge plug @ 3052 m and cement plugs were spotted.

HAZ-103 is the first development deviated well in Hamra field drilled non-conventionally with MPD from 3225 to 3775 m MD where different MW‟s and ECD were held to overcome the losses zones. Two ascertainments tests were conducted at the Hamra Quartzites and the matrix window was defined between 1.14 sg and 1.17 sg of EMW ECD. HAZ will be taken as offset well reference to drill HAZ-104

HAZ-104 well will be drilled at 80° inclination thus drilling problems will be increased due to the deviated trajectory and crossing more fractures in the open hole hence more formations will be exposed.

Considering the above it is expected that operative window will be gradually becoming narrower according with the length of the openhole (944 m) and exposed formation area.

- Vast difference in ECD/BHP between static and dynamic regime (connection and drilling).
    - ✓ Uncertain operative window.
    - ✓ Losses and gas influxes.
    - ✓ Reservoir damage with losses.
- Low Productivity (No production on DST).
- Mechanical Stuck.
- Back Ground Gas.
- Narrow Operative Window.

IV.5.2 MPD Approach – Constant Bottom Hole Pressure Technique

The variant of MPD that will be applied to the **HAZ-104** well is called Constant Bottom Hole Pressure (CBHP). Having a narrow pore and fracture pressure gradient window or high annular frictional losses and temperature effect on the drilling fluid can cultivate into drilling hazards. In this situation, the bottom hole pressure is not kept constant and fluctuates depending on sudden changes as the well gets drilled. When the hole is being drilled or circulated, the additional circulating friction losses to the annular space can result in formation fracture. When circulation is ceased, the effect of absence of annular frictional losses or effect of high temperature can make the hydrostatic pressure below the formation pore pressure due to its inversely proportional effect with the density and viscosity of the fluid. A kick-loss situation ensues, nonproductive time (NPT), lost fluid cost, formation damage, well control situations arise and HSE risk escalates.

This variation is applicable to avoid changes in Equivalent Circulating Density (ECD) by applying appropriate levels of surface backpressure. The application of MPD technology using a surface annular backpressure choke will permit to maintain constant (dynamic vs. static drilling fluid conditions) annular pressure at any fixed desired depth. This desired depth is usually called anchor or pivot point. Since the pore pressure and fracture diverge with depth the anchor points are defined near to the casing shoe for each hole sections.

An initial mud density was designed from hydraulics modeling considering equipment capability at surface, adequate hole cleaning conditions and MPD strategy. The use of proper MPD application is necessary to safely manage all uncertainty inherent to an exploratory well compared with conventional drilling equipment because the MPD system is provided by a flow meter to detect changes in flow out and semi auto choke to keep the desirable SBP.

IV.5.3 Hydraulics Modeling Consideration

Input variables that are considered for hydraulic flow modeling to determine optimum ECD are:

Fluid Density: Responsible for controlling Hydrostatic Pressure.

Pump Rate: Controls Annular Friction Pressure. It should also be adequate to satisfy Mud Motor and down hole tool limits.

Surface Back Pressure: To increase BHP and compensate for Annular Friction Pressure. (**Note**: Increase in SBP has a direct impact on SPP and should be carefully noted during modeling so as to not to exceed pressure limits of mud pumps and surface equipment).

Fluid Rheology: Has an influence on Annular Friction Pressure.

IV.5.4 6” Hole Section Hydraulics Modeling & Drilling Strategy

A comprehensive analysis has been carried out considering drilling hazards and data studied of the offset wells in in similar location:

MPD Strategy

MPD system will help to reduce the drilling hazards. The MPD variants applicable to this section are as follows:

- Constant Bottomhole Pressure (CBHP): Reduce NPT generated on conventional wells during well control events, reduce the size of formation influxes, and enable the ascertainment of pressure gradients with dynamic lower limit test and dynamic upper limit test. This technique will enable to navigate through narrow drilling windows.

This will require the installation of complete MPD system (RCD, Choke Manifold, Flow Meter, Auxiliary Pump, MGS and NRV on drill string).

The best option to drill this hole section is the application MPD CBHP.

The correlation study of HAZ-104 well in 6” hole section with HA-101, HA-102 and mainly with HAZ-103 shows the existence of natural fractures, losses, low gas influxes and back ground gas however the two first wells were drilled with vertical profile. HAZ-104 well will be drilled at 80° inclination and above mentioned problems will be increased due to this deviated trajectory as it will cross more fractures and the open hole will be very much longer than in the vertical wells.

Considering the above, is expected that the operative window will be gradually becoming narrower according with the length of the open hole and exposed fractured formation area.

Once approaching TD the operative window will decrease and losses will be expected. The key to overcome this challenge is to use minimum MW possible (helped with MPD Constant Bottom Hole Pressure Technique) to avoid differential stuck since the open hole length is around 944 m and the exposed fractures area against the drill pipe surface is too large.

Once TD is called and trip to surface is required it is recommended to perform upper and lower limit tests to calculate the Control MW to make the trip to surface with minimum over balance. If the operative window is not enough to increase the MW until safe values, then could be selected the stripping MPD method like tripping technique.

IV.5.5 6” Hole Section Considerations and Assumptions

Table IV.9: MPD fluid properties

MPD Fluid Properties			
MPD Density [sg] :	YP (Ibf/100 ft2)	Mud Type " Oil Base Mud"	Oil Percent : 80%
Oil Specific Gravity	0.82	Solids Percent: 14%	Water Percent: 6%
YP (Ibf/100 ft2)	12	PV (c P) : 10	

Table IV.10: MPD drilling parameters

Drilling parameters	
OBM Injection Rate [lpm]:	700 lpm
Annular Frictional Losses [psi]:	240 psi
Min. Acceptable CTR :	0.7
Min Acceptable Annular Velocity [m/min]- :	65 m/min
ROP [m/h] :	1.5 m/hr

Table IV.11: MPD other considerations

Other considerations	
Dynamic - Circulating (SBP) [psi]	0 to 800 psi
Static - Connection (SBP) [psi]	200 to 1200 psi
Plan trajectory	Deviated at 50° at Casing depth
Bit Nozzles Size / TFA	1.25 in2 TFA
RCD Max Allowable Pressure [psi]	1500 (Dynamic) - 3000 (Static)
Rig Pump Injection Pressure thru SPP	700 lpm
Cuttings density [Ib/US gal] :	23.66

Table IV.12 : BHA estimation

pos	Type	Length (meter)	OD(inch)	ID(inch)
1	6” PDC BIT (1.25 In2)	0.18	6	N/A
2	Motor	8.14	5	3.75
3	Float Sub	0.69	4.63	2.25
4	4 ¾” Pony Non-Mag DC	2.5	4.75	2.25
5	Slim Pulse 475 Batt	9.45	4.75	3.25
6	4 ¾” Non-Mag	9.01	4.63	2.25

7	Circulating Sub	2.49	4.75	2.25
8	Drill Pipe 13.3 G105	837	3.5	2.76
9	Heavy Weight	195.3	3.5	2.06
10	Drilling Jar	9.3	4.75	2.25
11	HWDP	74.4	3.5	2.06
13	Drill Pipe 13.3 G105	2851.47	3.5	2.76

IV.5.6 6" Hole Section Hydraulics at Casing Shoe with 1.05 sg MW

Hydraulic simulations were carried out at 7"" casing shoe (3056 m MD / 3026 m TVD) to initiated drilling in MPD mode. The following operating windows depict pore pressure of 1.14 sg and 1.17 sg fracture pressure with 1.05 sg MW and different combinations of SBP in static and dynamic condition.

A recommended scenario with the selected pump rate of 700 lpm has been chosen to illustrate the MPD operating window by plotting the surface backpressure to be applied versus different mud weights scenarios at casing shoe of the 6" hole section in both static and dynamic conditions. In the below graphs it is presented that;

- The mud weight recommended to drill this section is 1.05 sg with 700 lpm and 270 psi of SBP to get 1.17 sg ECD; however the SBP will depend on the upper/lower limit dynamic tests.
- If some seepage or partial losses observed then SBP will be reduced until flow in/out be the same.
- During drilling/circulation at 700 lpm the frictional losses are 240 psi, while connections/rig pump stops then the annular frictional losses plus the actual SBP (270 psi) must be added. Calculated connection pressure is 510 psi for the recommended parameters (1.05 sg MW, 700 lpm, 270 psi and 1.17 sg ECD).
- As per the last upper/lower limit test results the mud weight and SBP can be redesigned if needed.

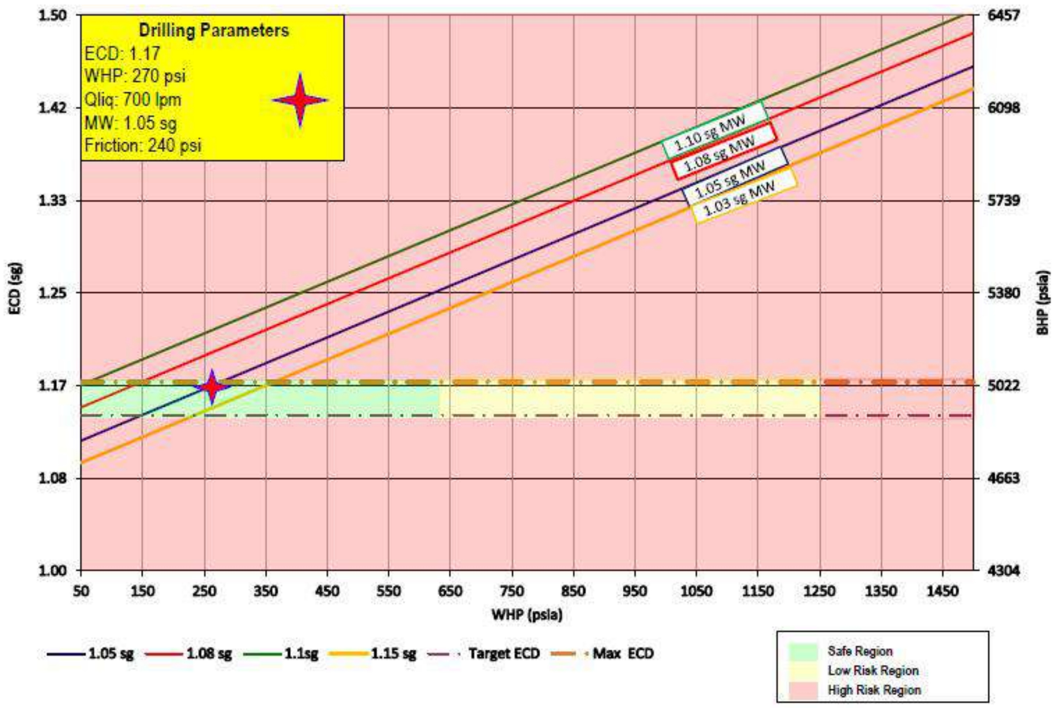


Figure.IV.19:MPD Operating Parameters at Casing Shoe with 1.05 sg MW at (Dynamic)

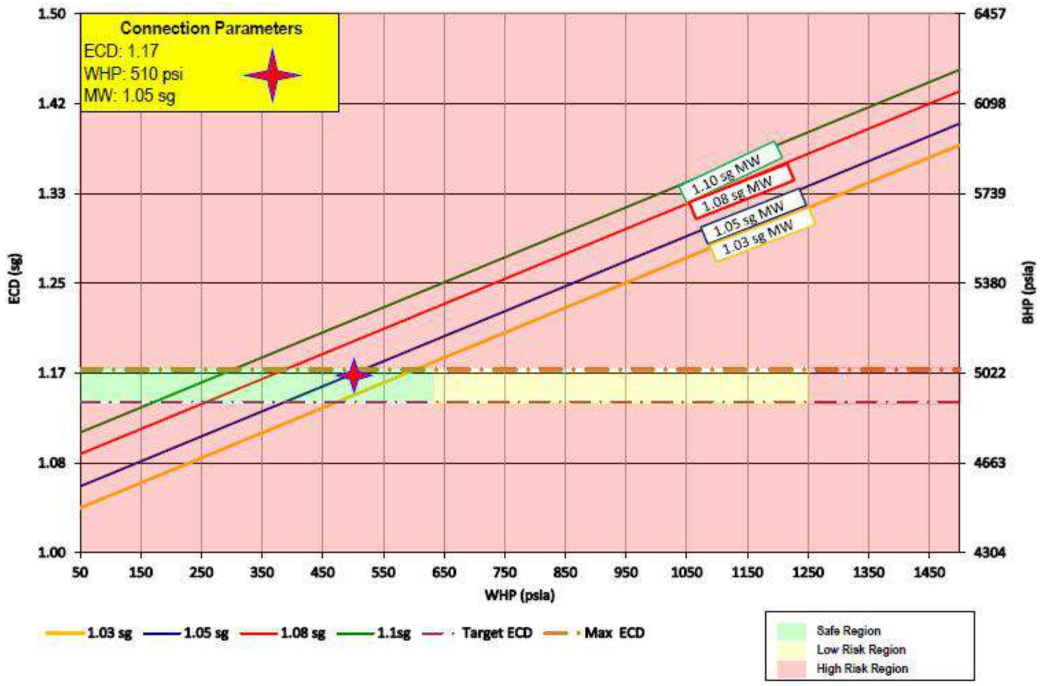


Figure IV.20 MPD Operating Parameters at Casing Shoe with 1.05 sg MW at (Static)

- **Pore Pressure:** The pore pressure 1.14 sg was defined from HAZ-103 offset well low limit test.

This must be confirmed by low limit test on the field once the top of Hamra Quartzites is confirmed.

- **Fracture Gradient:** The Fracture gradient 1.17 was defined from HAZ-103 offset well upper limit test and will be validated on the field once the top of Hamra Quartzites is confirmed.

- **Surface Back Pressure:** Dynamic surface back pressure during drilling (270 psi) was selected considering the estimated ECD 1.17 sg.
- **Handling Influx:** additional surface back pressure ranged between **350-1350 psi** could be added to handle any influx. Also 1350 psi is the Maximum Dynamic Working Pressure Rating for the RCD Bearing Assembly. Before to reach this value the well must be closed and controlled with conventional Sonatrach equipment.

IV.5.7 6" Hole Section Hydraulics at Planned TD with 1.05 sg MW

Hydraulic simulations were carried out at planned TD (4000 m MD / 3242 m TVD) to initiated drilling in MPD mode. The following operating windows depict pore pressure of 1.14 sg and 1.17 sg fracture pressure with 1.05 sg MW and different combinations of SBP in static and dynamic condition.

A recommended scenario with the selected pump rate of 700 lpm has been chosen to illustrate the MPD operating window by plotting the surface back pressure to be applied versus different mud weights scenarios at planned TD in both static and dynamic conditions. In the below graphs it is presented that:

- The mud weight recommended to drill this section is 1.05 sg with 700 lpm and 230 psi of SBP to get 1.17 sg ECD; however the SBP will depend on the upper/lower limit dynamic tests.
- If some seepage or partial losses observed then SBP will be reduced until flow in/out be the same.
- During drilling/circulation at 700 lpm the frictional losses are 320 psi, while connections/rig pump stops then the annular frictional losses plus the actual SBP (230 psi) must be added. Calculated connection pressure is 550 psi for the recommended parameters (1.05 sg MW, 700 lpm, 230 psi and 1.17 sg ECD).
- At TD it highly recommended to perform another test to calculate the control MW to make the trip to surface, perform loggings and cementing.
- As per the last upper/lower limit test results the mud weight and SBP can be redesigned if needed.
- Must be noted while drilling more fractures will be opened and the operative window could be reduced then must be pending until what depth can continue drilling to avoid get an scenario with operative window completely closed with no margin to make trips or cementing; if this situation is reached, SH must take the decision to stop drilling.

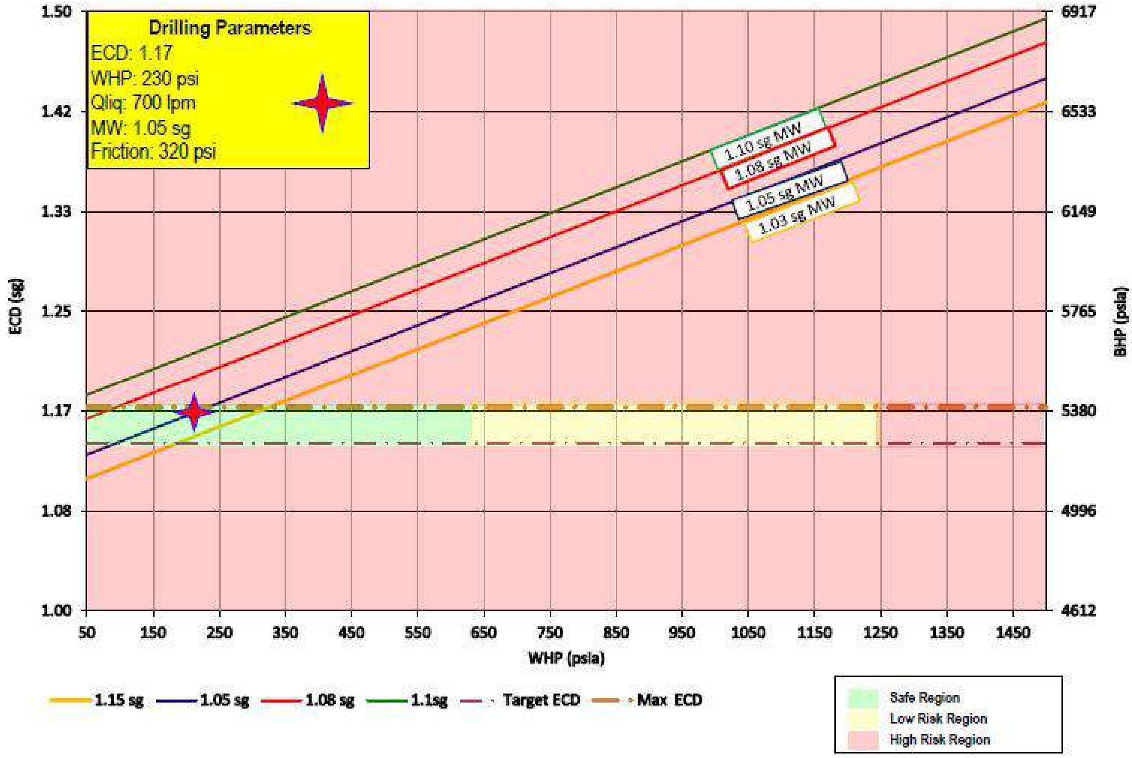


Figure IV.21 MPD Operating Parameters at Planned TD with 1.05 sg MW (Dynamic)

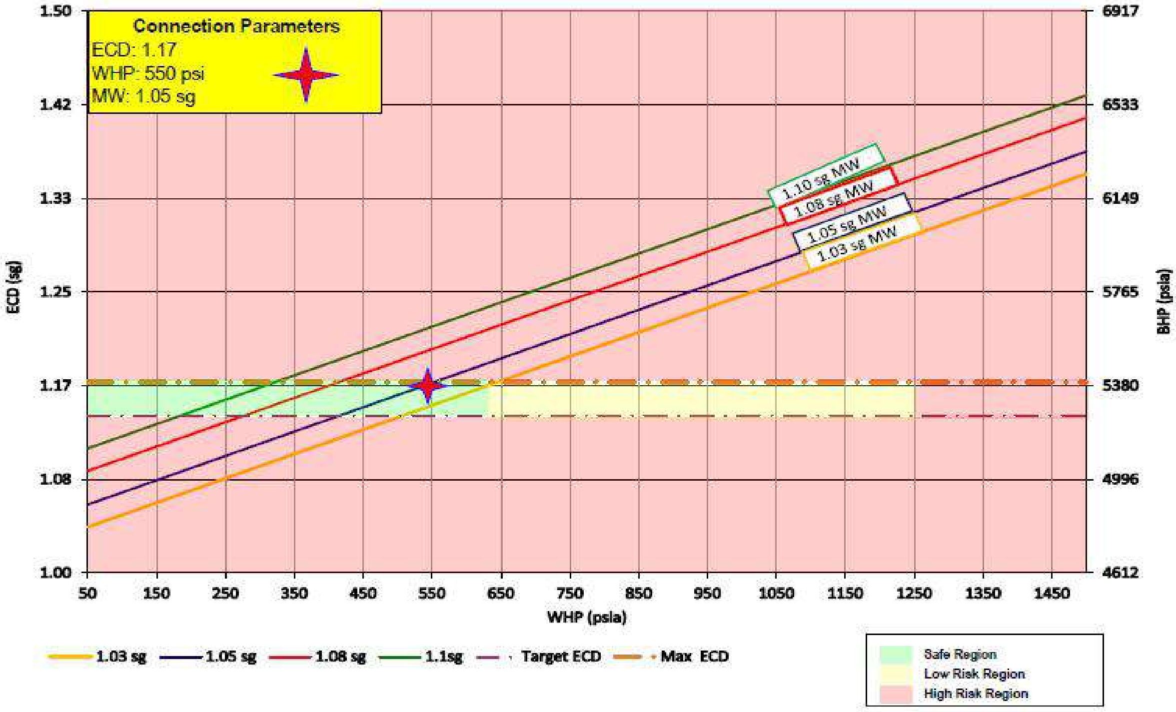


Figure IV.21: MPD Operating Parameters at Planned TD with 1.05 sg MW (Static)

- **Pore Pressure:** The pore pressure 1.14 sg was defined from HAZ-103 offset well low limit test.

This must be confirmed by low limit test on the field once the top of Hamra Quartzites is Confirmed.

- **Fracture Gradient:** The Fracture gradient 1.17 was defined from HAZ-103 offset well upper limit test and will be validated on the field once the top of Hamra Quartzites is confirmed.
- **Surface Back Pressure:** Dynamic surface back pressure during drilling (270 psi) was selected considering the estimated ECD 1.17 sg.
- **Handling Influx:** additional surface back pressure ranged between **350-1350 psi** could be added to handle any influx. Also 1350 psi is the Maximum Dynamic Working Pressure Rating for the RCD Bearing Assembly. Before to reach this value the well must be closed and controlled with conventional Sonatrach equipment.

NB:

- Must be noted while drilling more fractures will be opened and the operative window could bereduced then must be pending until what depth can continue drilling to avoid get an scenario with operative window completely closed with no margin to make trips or cementing; if this situation is reached, SH must take the decision to stop drilling.
- The Swab/Surge effect to be highly considered therefore a tripping speed needs to be defined and respected.
- A continuous fill up while tripping out needs to be implemented to avoid any influx scenarios.

IV.5.8 Hole Cleaning Criteria

The CTR defines the ability of the flowing fluid to transport the cuttings. Similar to the slipping action which occurs between the gas and liquid velocities, a slip also exists between the solid particle (cutting) velocity and the liquid velocity. It is imperative for hole cleaning design to ensure that this slip is not high enough that the cuttings would slip and accumulate behind any cross sectional area from bit to surface. CTR more than 0.7 for vertical wells and more than 0.9 for horizontal wells are the recommended values to ensure good hole cleaning.

Table IV.13: Industry Acceptable CTR

Well Trajectory	Cuttings Transport Ratio (CTR)
Horizontal	0.9
Vertical	0.7

In order to compute the CTR, Equation (1) given below is used:

$$\text{CTR} = 1 - \frac{\text{VSC}}{\text{Vmean}} \quad (1)$$

Where:

CTR: cuttings transport ratio.

VSC: cuttings slip velocity estimation, ft/s.

Vmean: mean velocity of the fluid.

The equations used to compute VSC are given the following table.

Table IV.14: Cuttings Slip Velocity (VSC) Estimation

Re_C	V_{SC}
$Re_C < 3$	$V_{SC} = 82.87 \times (\rho_s - \rho_f) \times \left({d_s}^2 / \mu_f \right)$
$3 = Re_C < 300$	$V_{SC} = 2.90 \times \frac{(\rho_s - \rho_f)^{0.667}}{(\rho_f \times \mu_f)^{0.333}}$
$300 = Re_C < 4000$	$V_{SC} = 1.54 \times \left[\frac{d_s \times (\rho s - \rho f)}{\rho f} \right] 0.5$
$Re_C = 4000$	$V_{SC} = 1.06 \times \left[d_s \times \frac{(\rho s - \rho f)}{\rho f} \right]^{0.5}$

Where:

Rec: cuttings Reynolds Number

Vsc: cuttings slip velocity estimation, ft/s

ds: diameter of the cuttings, in

ρs: density of the solid cuttings, lbm/US Gal

ρf: mean density, lbm/US Gal

μf: mean viscosity, Centipoises

$$Rec = \frac{\rho f \times Vsc \times \rho s}{\mu f} \quad (2)$$

As seen from the table above, the choice of the equation used to compute Vsc is dependent on Rec.

Therefore, it is necessary to determine which equation to use to compute Vsc such that the resulting calculated value of Rec satisfies the corresponding Rec requirement(s) for that equation. All calculations are being made by a computer flow model.

Unlike the 6” hole section (or bigger), the annular fluid velocity is defined as the determined criteria to ensure a good hole cleaning for the 6” hole section, the below table is considered as guide to ensure the a sufficient hole cleaning for this section.

Table IV.15: Industry Acceptable Annular Velocity

Well Trajector	Min. acceptable Annular velocity (ft/min)
Horizontal	55 m/min
Vertical	65 m/min

IV.5.9 ECD Management Plan

The below table depicts the process will be deployed to obtain the required ECD at the target depths.

As drilling will be progressed the applied surface back pressure (SBP) will be adjusted to maintain the pressure down the hole slightly overbalanced to avoid or minimize any influx. Also contains the plan to increase the mud density if the Working Pressure Limits for the Rotating Control Device (RCD) are reached in order to control the well.

Table IV.16: ECD Management Table

	Drilled Interval		Formation	Pore Pressure	MPD MW	Drilling Window		Pump Rate	Target ECD/ESD	Applied SBP		ECD at Applied SBP		ESD at Applied SBP	
	(m)			(sg)		(sg)		(lpm)	(sg)	(psi)		(psi)		(psi)	
	From	To				Lower	Upper			Drilling	Connection	TD	Shoe	TD	Shoe
1	3056	3303	Gres d'Ourgla	1.14	1.05	1.14	1.17	700	1.17	270	510	1.16	1.17	1.16	1.17
2	3303	4000	Quartzites de Hamra	1.14	1.05	1.14	1.17	700	1.17	230	550	1.17	1.18	1.17	1.18

IV.5.9.1 Definitions

Target ECD: Required ECD to reach a planned depth with a minimum of overbalance compared to the expected pore pressure.

Drilling Window Limits: The lower limit will be the maximum predicted pore pressure. The upper limit will be the fracture pressure either at the casing shoe depth or deeper if losses are experienced.

Max SBP: Drilling = 350 psi - Connections = 856 psi (Safe Working Pressure). Pressure limit will be based on API 16RCD as maximum operating pressure of the RCD bearing assembly sealing elements.

IV.5.9.2 MPD Operational Sequence

Operative general sequence to start drilling HAZ-104 prepared to apply CBHP MPD technique and fingerprinting tests.

Current status of the well is:

- 8-1/2” hole drilled to +/- 3037 m MD (2973 M TVD).
- 7” Casing shoe at +/- 3037 m MD(2973 M TVD).
- Mud: Displacement 1.05 SG OBM for MPD Operations, as agreed with SH.
- Casing pressure tested to as per SONATRACH guidelines.

The following operations sequence will be carried on:

1. R/U and pressure test the MPD Equipment.

2. Function test and Commission Semi-Automatic MPD Choke system.

3. P/U and M/U Directional Company motor assembly with MWD / APWD and RIH.

4. Perform shallow test (function test) of motor, record Stand Pipe Pressures at different rates.

5. Install RCD Bearing, Line up MPD System and start Displacing well to 1.05 MW as agreed with SH.

6. Perform the MPD casing trials.

7. Perform the MPD Finger Printing Procedure.

8. Set the circulation parameters at drilling rates for an ECD of 1.17 sg with 700 lpm; 270 psi WHP for 1.05 sg MW.

9. Drill-out casing shoe and circulate 2 bottoms up to drag all debris and cement in the fluid stream to the shakers until Confirm shoe debris observed on shakers.

Note: Coriolis flow meter should be kept bypassed until debris free returns are observed on shakers.

10. Continue drilling 3-4 m of new formation (TC).

11. Circulate hole clean until homogenize the mud

12. Perform SBT/FIT. Do not exceed Maximum Dynamic Working Pressure of the Bearing Assembly (90% OF RCD Dynamic Pressure Rating-1,350 psig).

13. Take Slow Circulation Rate following MPD procedure.

14. Continue drilling hole to 3-4 m inside new formation with 1.17 sg ECD as discussed with SH.

15. Circulate for sample to confirm formation.

16. Perform the Window Ascertainment Test following the MPD procedure if required:

- **a)** Upper Limit to no higher than 1.60 SG EMW at casing shoe depth. This test defines the pressure integrity of the casing shoe and this is taken as the initial Upper Limit of the window.
- **b)** The Lower Limit inflow test is performed by taking a small volume of formation influx. Maximum volume of influx should be taken as per Well Control Matrix limits.

17. Circulate influx by the First Circulation of the Drillers Method (FCWHP = SIDPP).

18. Adjust WHP to obtain an ECD on the APWD tool to keep the balance with the pore pressure obtained in the test.

19. Continue drilling the 6” hole following the below ECD Management plan:

Note 2: Follow the MPD Connections procedure for pipe connections.

Note 3: A formation kick can be taken while drilling; in this event follow the well control procedure.

20. As drilling goes deeper, fluid Losses into formation could be experienced, then follow the Fluid Losses Control procedure.

21. Fluid losses OR formation kicks scenario can occur, the decision should be taken according to Decision Trees Approved by FORAGE and PED to continue drilling to planned TD.

22. If a bit trip is required before TD, the well will be displaced to heaver mud at casing shoe to have EMW similar to ECD while drilling (MPD engineer will calculate the required MW).

23. Once section TD is reached, for either wire line logging operations or casing running; the well should be balanced to allow the operations mentioned being conventionally performed.

24. POOH BHA.

25. Perform Wire line logging as per the logging program.

26. RIH with Rotary Assembly to check hole condition before running liner. This step may be omitted depending on the duration of the logging operations and the hole condition.

27. Proceed for completion as per Sonatrach program.

Table IV.17 Consideration to be taken while tripping

MW 1.05 SG . ECD: 1.17 SG . 62 spm pressure loss 280 psi

Step (up/down) chart down		
Rig pump "spm"	Kill pump "spm"	Choke pressure "psi"
62	0	330
40	25	360
20	25	400
0	25	610

IV.5.10 UPPER/LOWER TEST LIMIT TEST HAZ 104 AT 3371 m MD/3184.57 m TVD ON 21 APR 2017

Table IV.18: Upper limit test

TVD atbottom (m)	TVD Shoe (m)	Base MW (SG)	Target ECD (SG)	Target Pressure at Bottom (psi)	Head (psi)	SBP (psi)	Start Time	End Time	Duration	Tot Vol (m3)	Final (m3)	Gain/Loss (m3)	Gain/ loss Rate (m3/hr)	Comments
3184.57	3105.3	1.05	1.18	5329	4735	594	21:28	21:31	0:03	13.10	13.10	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.19	5375	4735	640	21:31	21:36	0:05	13.10	13.10	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.20	5420	4735	685	21:36	21:40	0:04	13.10	13.10	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.21	5465	4735	730	21:40	21:44	0:04	13.07	13.07	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.22	5510	4735	775	21:44	21:48	0:04	13.05	13.05	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.23	5555	4735	820	21:48	21:52	0:04	13.03	13.03	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.24	5600	4735	865	21:52	21:56	0:04	13.03	13.03	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.25	5646	4735	911	21:56	22:00	0:04	13.02	13.02	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.25	5691	4735	956	22:00	22:04	0:04	13.00	13.00	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.27	5736	4735	1001	22:04	22:08	0:04	13.00	13.00	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.28	5781	4735	1046	22:08	22:12	0:04	12.97	12.97	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.29	5826	4735	1091	22:12	22:16	0:04	12.97	12.97	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.30	5871	4735	1136	22:16	22:20	0:04	12.95	12.95	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.31	5917	4735	1182	22:20	22:25	0:05	12.94	12.94	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.32	5962	4735	1227	22:25	22:30	0:05	12.92	12.92	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.33	6007	4735	1272	22:30	22:35	0:05	12.90	12.90	0.00	0.00	Losses
3184.57	3105.3	1.05	1.34	6052	4735	1317	22:35	22:45	0:10	12.87	12.87	0.00	0.00	Losses
3184.57	3105.3	1.05	1.35	6097	4735	1362	22:45	22:55	0:10	12.81	12.76	-0.05	-0.12	Losses

Table IV.19: Lower limit test

TVD atbottom (m)	TVD Shoe (m)	Base MW (SG)	Target ECD (SG)	Target Pressure at Bottom (psi)	Head (psi)	SBP (psi)	Start Time	End Time	Duration	Tot Vol (m3)	Final (m3)	Gain/Loss (m3)	Gain/ loss Rate (m3/hr)	Comments
3184.57	3105.3	1.05	1.25	5646	4735	911	23:17	23:22	0:05	12.83	12.83	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.23	5555	4735	820	23:22	23:27	0:05	12.83	12.83	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.21	5465	4735	730	23:27	23:32	0:05	12.85	12.85	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.19	5375	4735	640	23:32	23:37	0:05	12.86	12.86	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.17	5284	4735	549	23:37	23:47	0:10	12.90	12.90	0.00	0.00	NO losses
3184.57	3105.3	1.05	1.16	5239	4735	504	23:47	23:53	0:06	12.91	12.91	0.00	0.00	NO Gain
3184.57	3105.3	1.05	1.15	5194	4735	459	23:53	23:58	0:05	12.91	12.91	0.00	0.00	NO Gain
3184.57	3105.3	1.05	1.14	5149	4735	414	23:58	0:03	0:05	12.94	12.94	0.00	0.00	NO Gain
3184.57	3105.3	1.05	1.13	5104	4735	369	0:03	0:08	0:05	12.94	12.94	0.00	0.00	NO Gain
3184.57	3105.3	1.05	1.12	5058	4735	323	0:08	0:13	0:05	12.96	12.96	0.00	0.00	NO Gain
3184.57	3105.3	1.05	1.11	5013	4735	278	0:13	0:23	0:10	12.97	12.97	0.00	0.00	NO Gain
3184.57	3105.3	1.05	1.10	4968	4735	233	0:23	0:33	0:10	12.97	12.97	0.00	0.00	NO Gain

Results:

Upper limit test starts form 1.17 to 1.35 (loss was occurred)

Lower limit test starts from 1.17 to 1.10.It is done to confirm the existence of fracture that can produce hydrocarbons.

No gain means that there is no fracture yet so the drilling process will continue until they reach the target (4000m).

GENERAL CONCLUSION

In conclusion, MPD is not only a tooled up technology but also ultimate way of getting ready to challenge “Mother Nature” in all aspects. As she reveals the problems, the solutions should be found out to reach the target. Recently, pressure management - MPD- can be defined as one of the ultimate problem solvers until a better way is discovered.

Since Managed Pressure Drilling (MPD) is still evolving to adapt its strengths to deal with challenges, the process requires an extra effort to find out the missing parts of the concept. Once, the missing parts of different variations in a range of applications are revealed, the next step is to minimize the effect of gaps with the adaptation of available technology to MPD and/or discovering a new technology to lead to the usage of MPD. One of the major technology gaps on the way of adapting MPD should be clarified in order to speed the adaption process of MPD up to deep water applications.

RECOMMENDATIONS

- MPD should be practiced stepwise rather than jumping to the more challenging well with more sophisticated methods.
- The strengths of each method should be understood clearly since MPD is application specific.
- At first, Reactive MPD should be practiced with conventional programs to be more familiar with the concept. Reactive usage of CBHP can be a good the starting point.
- After practicing enough to understand the fundamentals of Reactive MPD, the usage of Proactive MPD should be practiced with enhanced casing programs and mud designs.
- Proactive MPD should not be practiced without a contingency plan in order to be ready for probable or less expected incidents.
- Different combinations of the available or upcoming technologies with MPD should be examined to maintain ultimate control.

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1. RCDs:

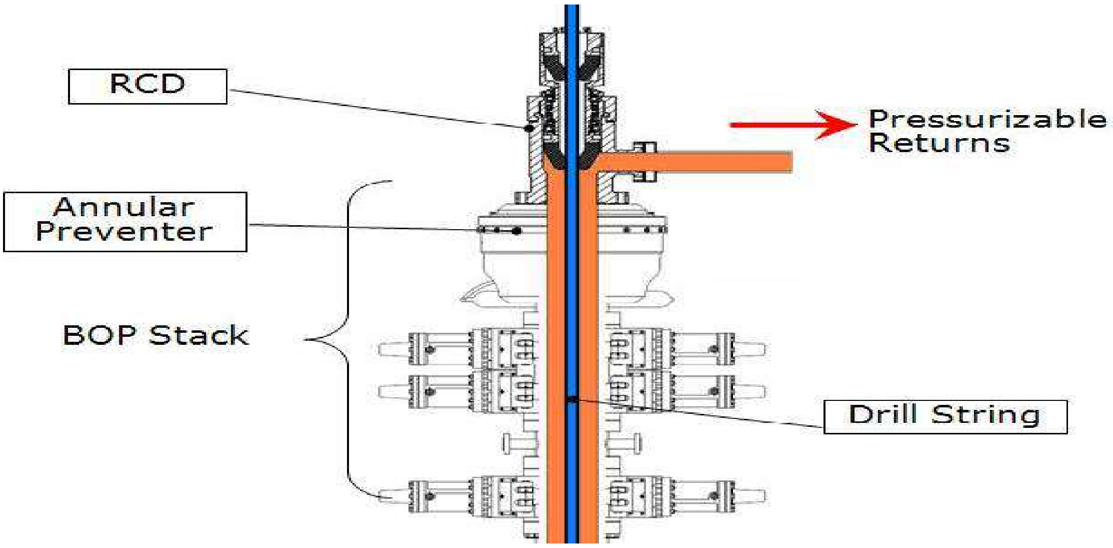


Figure 1 Typical Alignment of RCD[29]

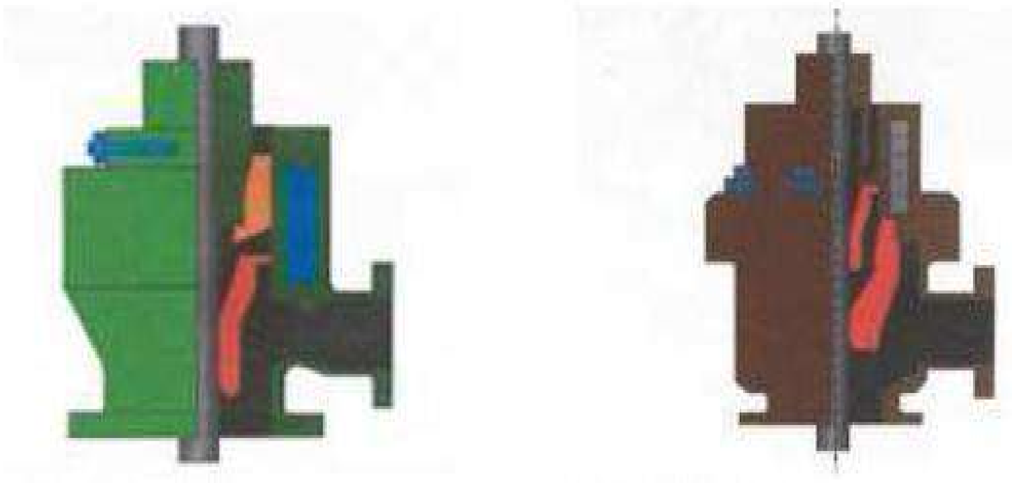


Figure 2 Single element RCD and Dual element RCD[5]

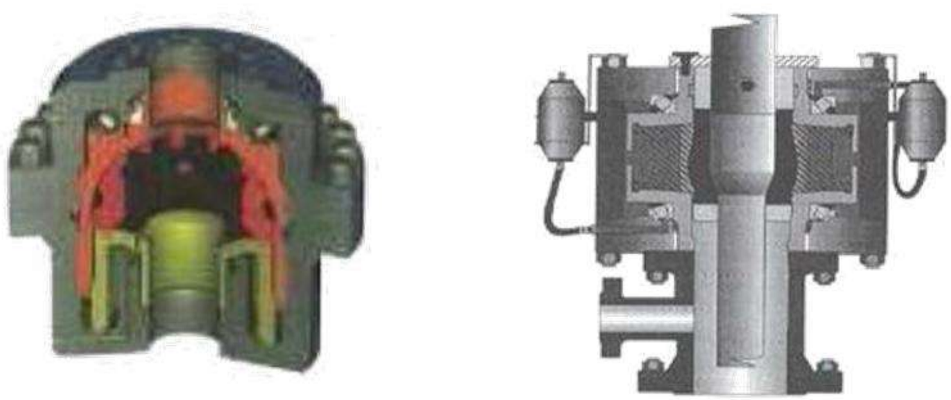


Figure 3 Rotating Annular Preventer and Rotating BOP[5]

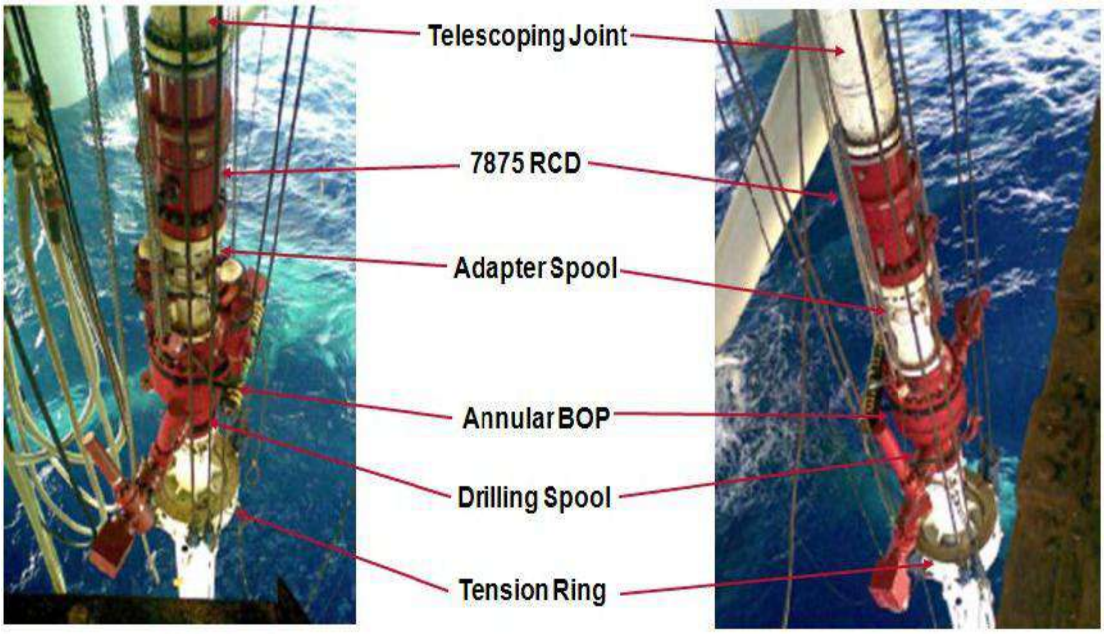


Figure 4 RCD Docking Stations installed in semi-subs[29]

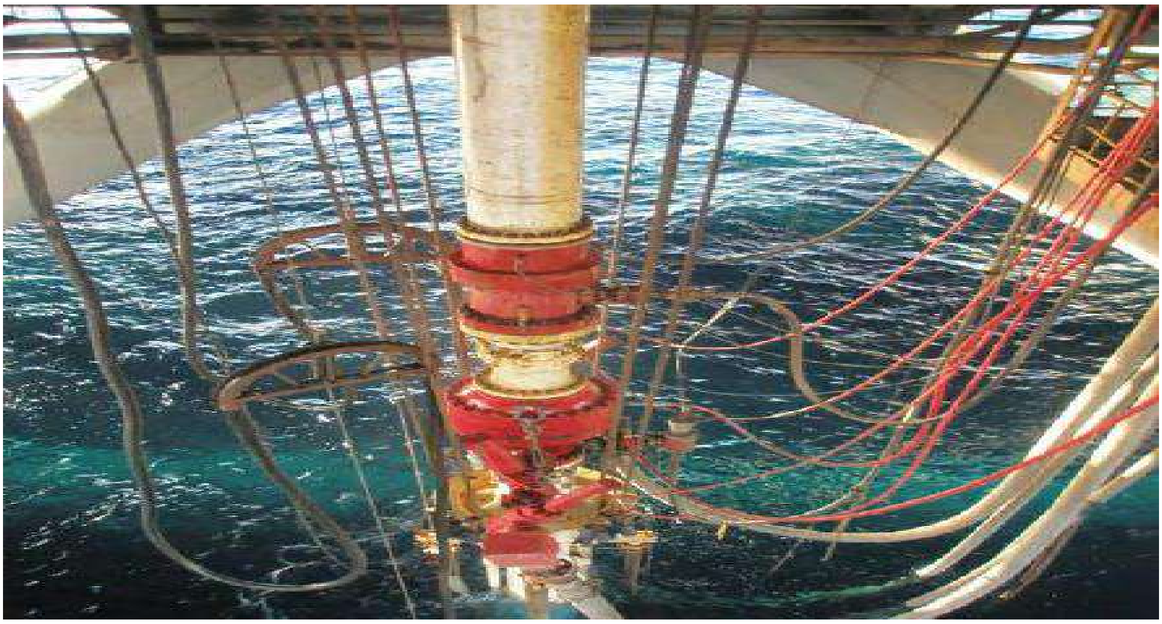


Figure 5 RCD Docking Station with flexible flowlines[29]

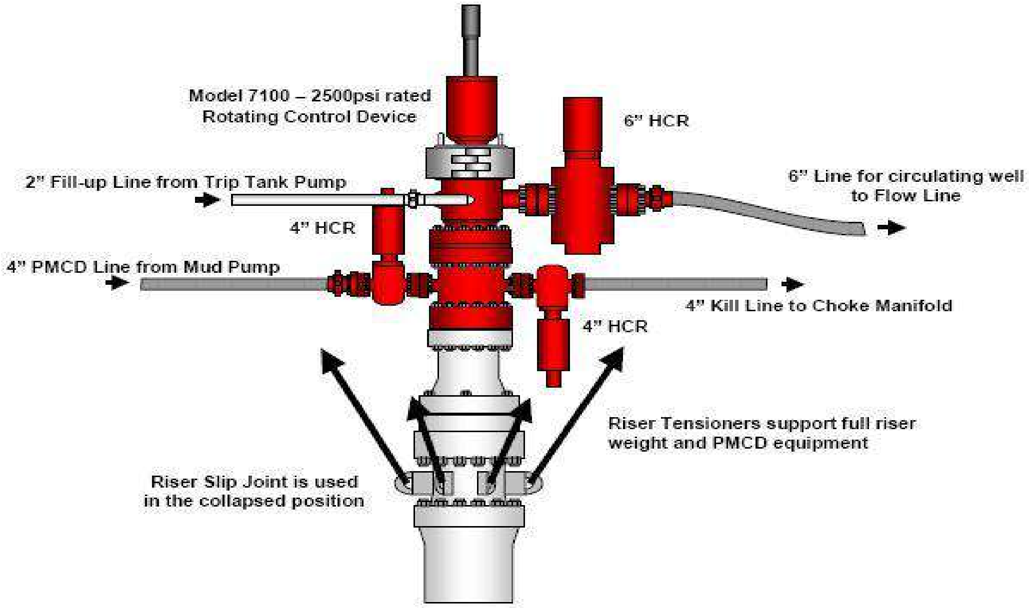


Figure 6 External Riser RCD (ERRCD) on a Riser Cap[25]

Figure 6 is an illustration of External Riser RCD. ERRCD is a part of Riser Cap which enables the applications of PMCD. With the usage of Riser Cap, high viscous fluids can be pumped down to the annulus with the purpose of creating a mud cap condition

Figure 7 Subsea RCD (SSRCD) installation in moon pool[25]

Figure 7 is an illustration of Subsea RCD or External Riser RCD with Subsea BOP installation in the moon pool area. The name is derived from the usage of the RCD with Subsea BOPs

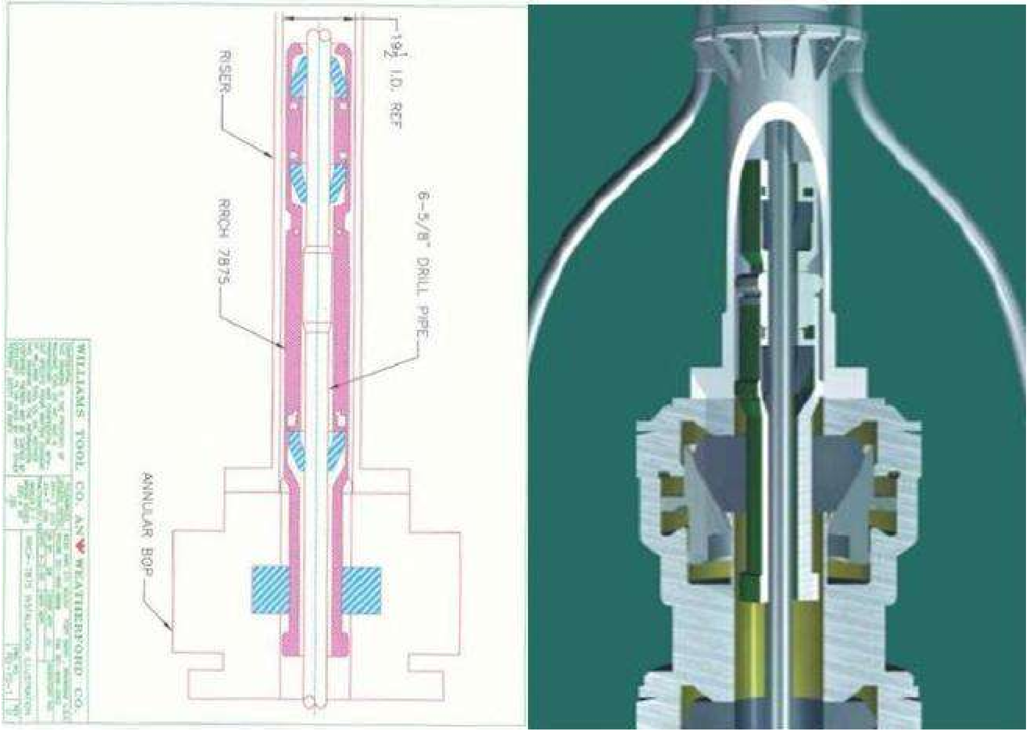


Figure 8 Alignment of Internal Riser RCD[30,10]

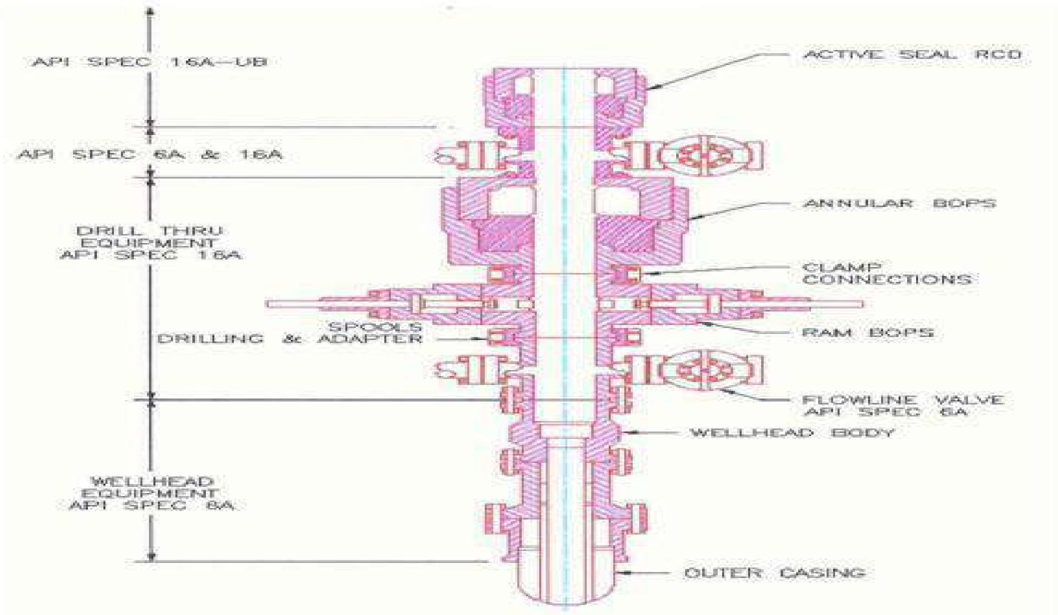


Figure 9 Active RCD in Typical Surface Stack[30]

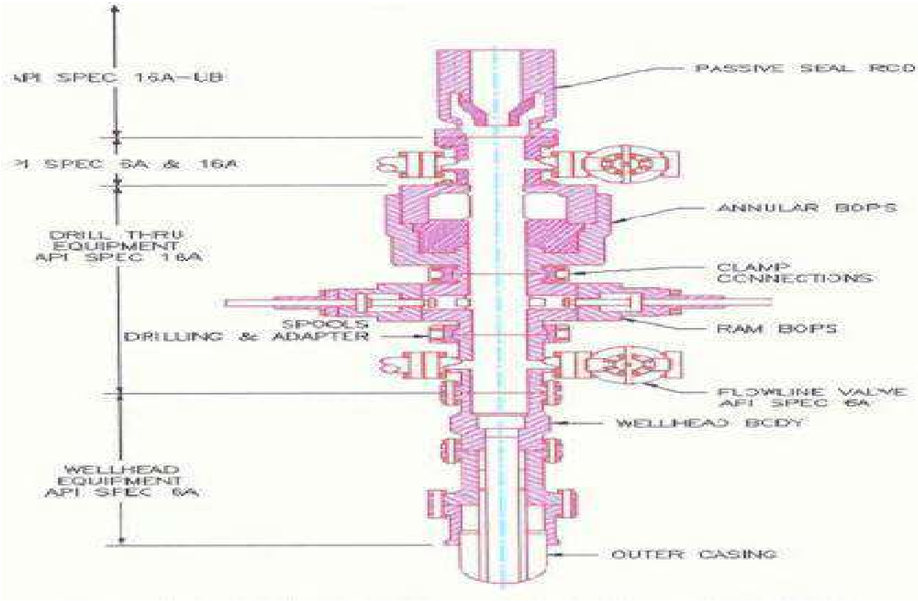


Figure 10 Passive RCD in Typical Surface Stack[30,28]

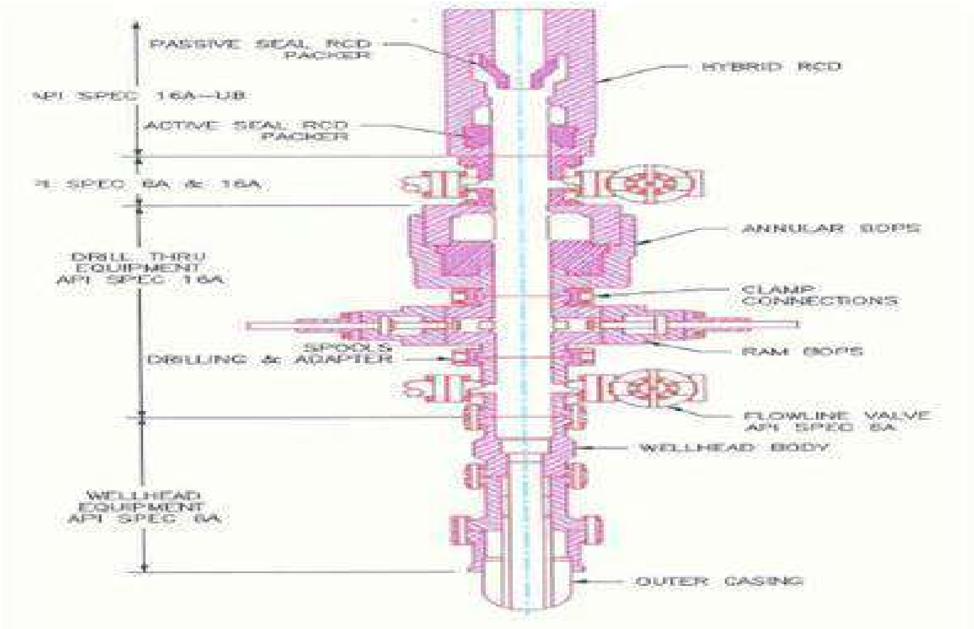


Figure 11 Passive over Active Design Hybrid RCD[30]

RCD is installed in a marine diverter which enables diverting of any influx effectively while drilling. Commonly, the usage of this type of RCD is limited to the fixed rigs.

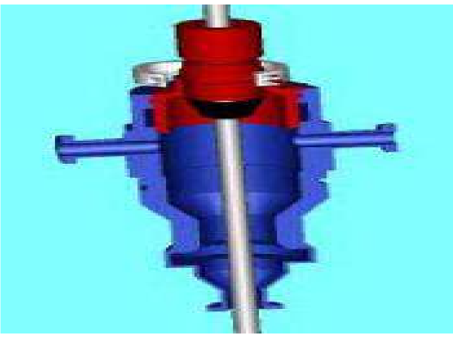


Figure 12 Marine Diverter Converter RCD[30,28]

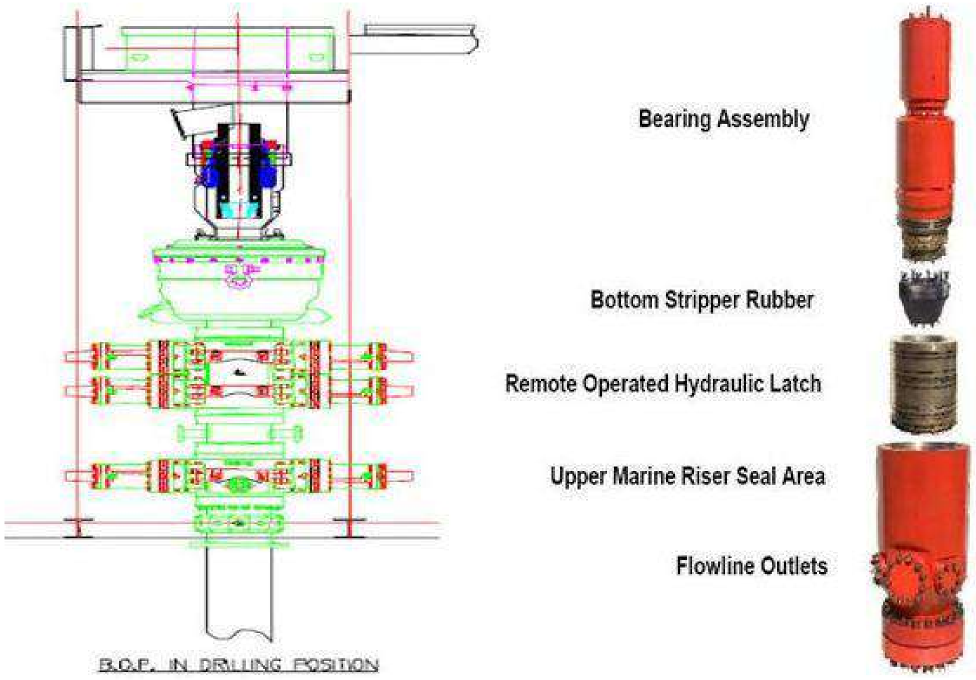


Figure 13 Alignment & Components-Bell Nipple Insert RCD[30,28]

Figure 13 is an illustration of Bell Nipple Insert RCD in a typical BOP stack in drilling position (left side) and components of Bell Nipple Insert RCD (right side) of which pressure ratings are 5000 psi static/2500 psi dynamic.

2. VALVES:

Figure 14 The Baker Model "G" and "F" Type NRV[26]

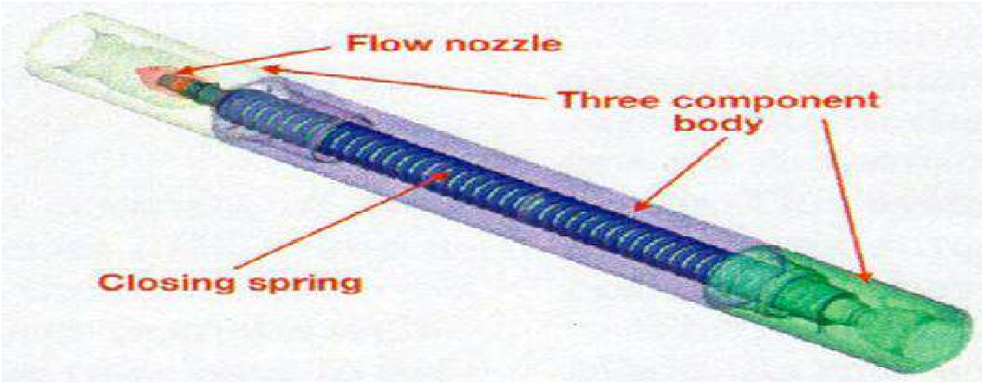


Figure 15 Hydrostatic Control Valve (HCV)[32]

Figure 15 is an illustration that displays HCV is made up of three body components; bottom body, middle body with closing spring and top body with flow nozzle.

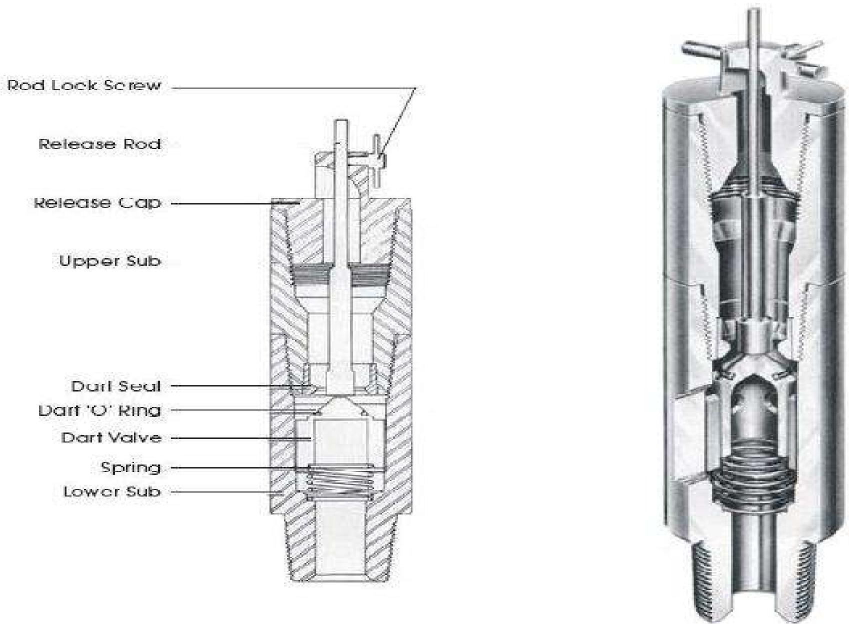


Figure 16 Pump-Down Check Valve (IBOP)[4]

Figure 16 is an illustration of the components of the Inside BOP with the optional release tool that consists of release cap, release rod and rod lock screw.

Figure 17 Wireline Retrievable Non-Return Valve[32]

Figure 17 is an illustration of Weatherford's Gateway Wireline Retrievable Non-Return Valve which can be used in Managed Pressure Drilling applications.

3. CHOKES:

Figure 18 Semi-Automatic Choke Manifold System[26]

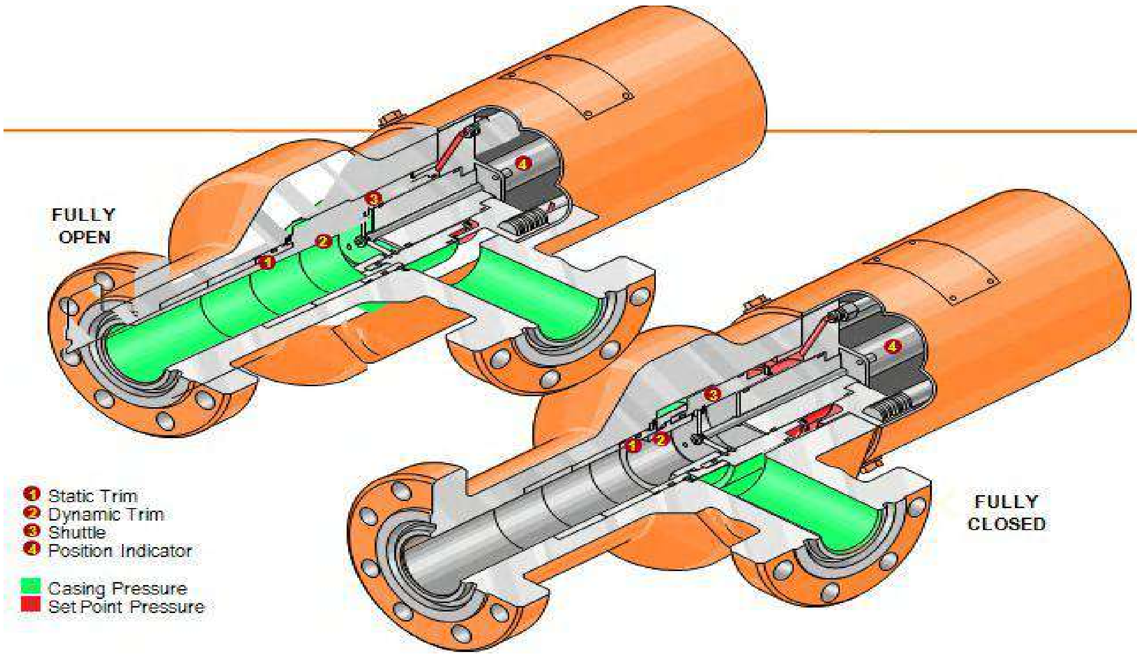


Figure 19 Operation Principle of Semi Auto Choke[26]

Figure 19 is an illustration of operational schematics of semi-automated choke valve both in fully open and fully closed position. Position of the static trim, dynamic trim and shuttle is shown in the figure for better understanding and visualizing the inside of the choke valve. According to the position of the dynamic trim, application of set point pressure can be seen.

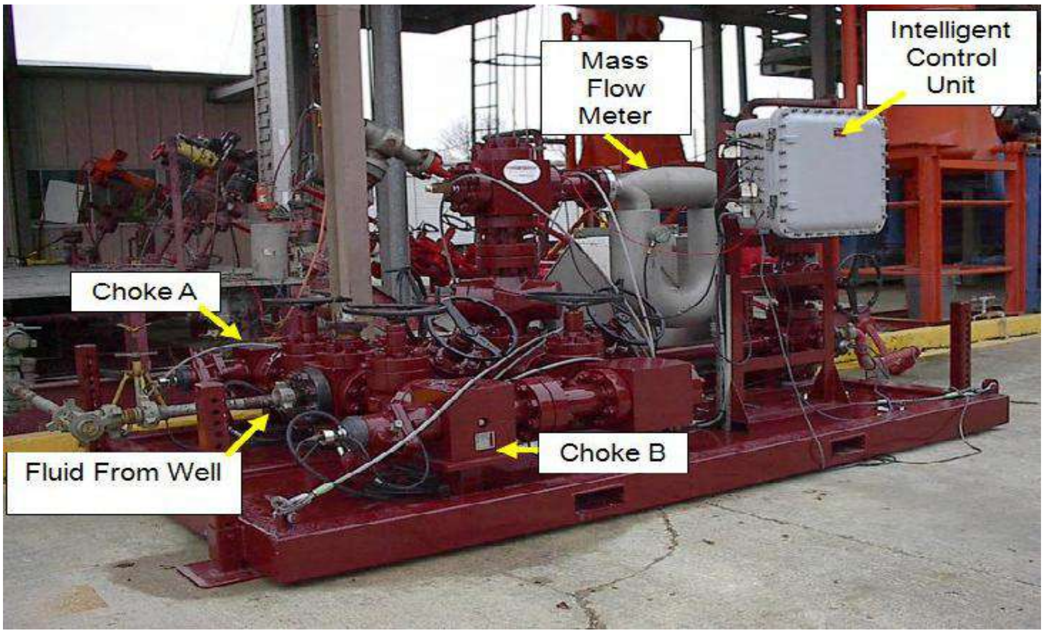


Figure 20 PC Controlled Automated Choke Manifold[26]

Figure 20 is an illustration of Secure Drilling's automated choke manifold. It is different from the semi-automated MPD chokes since the manifold has integrated mass flow meter and intelligent control unit together which enables early detection of any influx or any BHP variations.

Other Tools of MPD

In addition to the key tools of MPD, some applications of the MPD require additional or supplementary equipment which makes different variations of control possible. Other tools of MPD are listed below[8]:

A. Downhole Casing Isolation Valve (Downhole Deployment Valve):

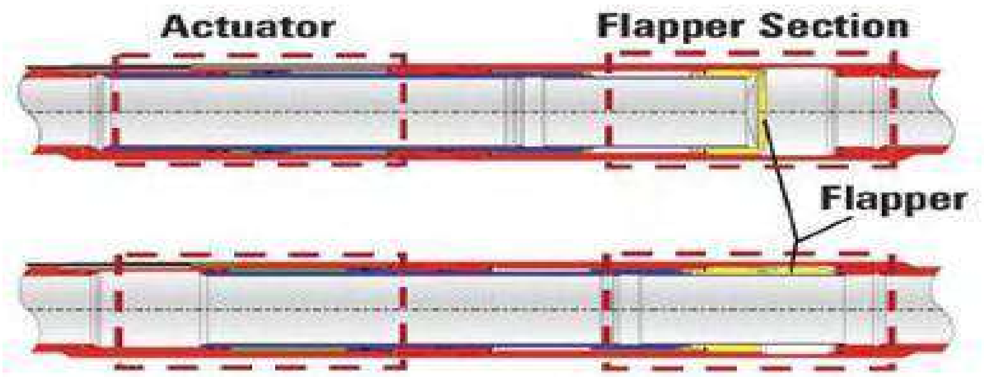


Figure 21 Downhole Isolation Valve (DIV)[34].

Figure 21 is an illustration of Downhole Isolation Valve (DIV) which is designed for safe tripping especially in underbalanced conditions. The top part of the tool has an actuator controlling the flapper movement in the flapper section which is the bottom part of the tool.

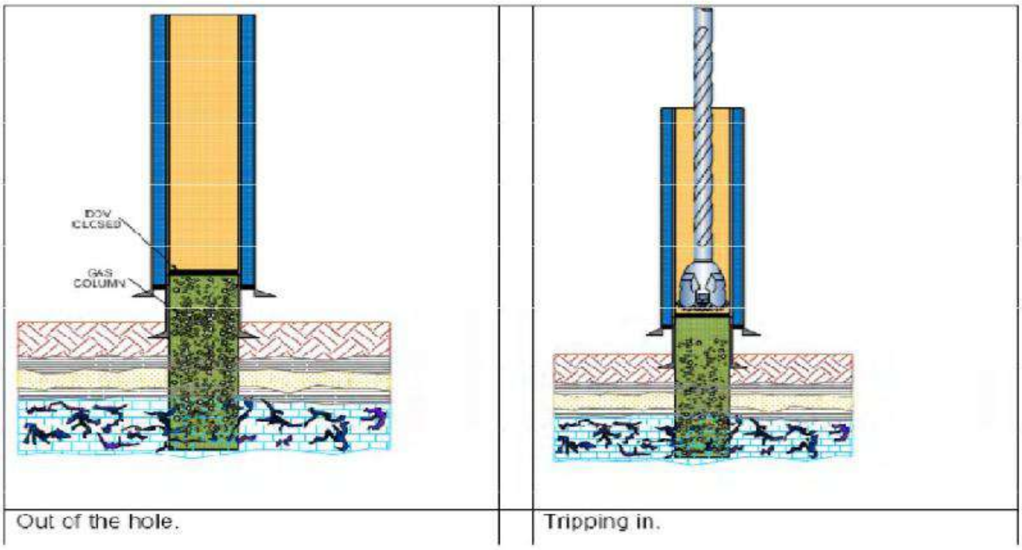


Figure 22 Tripping with Downhole Deployment Valve (DDV)[5]

Figure 22 is an illustration of the usage of DDV in MPD applications. Since DDV is a kind of down hole isolation tool, it is opened and closed by equalizing the pressures below and above the tool.

B. Downhole Air Diverter:

Figure 23 Downhole Air Diverter (DHAD)[26]

Figure 23 represents the DHAD which has been able to increase the efficiency of the compressed air system improving drilling performance in most drilling situations where pneumatic fluid is used for cuttings removal by a more efficient use of the compressed air’s energy[26]. Since the tool reduces the losses in BHA by diverting the flow, the efficient use of energy is gained.

C. Nitrogen Generation Unit:

The primary usage of the NPU (see Figure 24) is in DG MPD applications where there is a need for continuous supply of nitrogen to reduce the upper riser mud density.

Figure 24 Nitrogen Generation/Production Unit (NGU/NPU)[35]

D. Separation System:

Figure 25 is a photo of Multiphase Separation System for MPD purposes, taken in an offshore platform. The use of the separators is a need especially in DG MPD applications where the separation of gas is an obvious issue or can be used in case of any influx to condition the mud.

Figure 25 Multiphase Separation System for MPD[33]

E. Coriolis Flowmeter:

Coriolis Flowmeter is one of the important tools in MPD applications since measurements provide a supplementary data while using with automated pressure control systems.

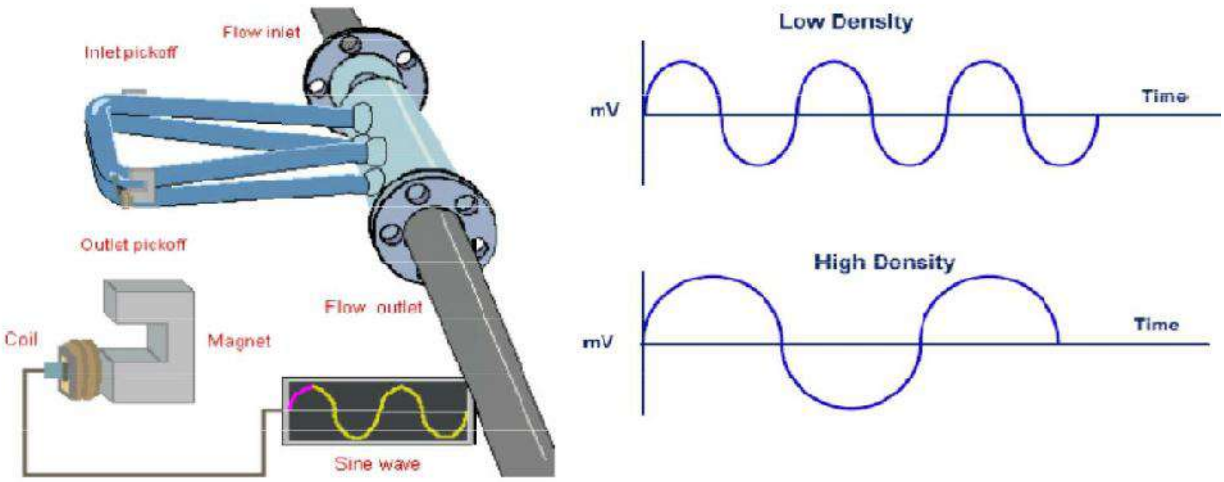


Figure 26 Working Scheme of Coriolis Flowmeter[5].

F. ECD Reduction Tool (ECD-RT)

The ECD reduction tool is expected to have application in deepwater drilling (where drillers are historically forced to run several casing strings to reach target depth, therefore progressively reducing the hole size) and extended-reach wells (where the length of the well increases frictional pressure loss)

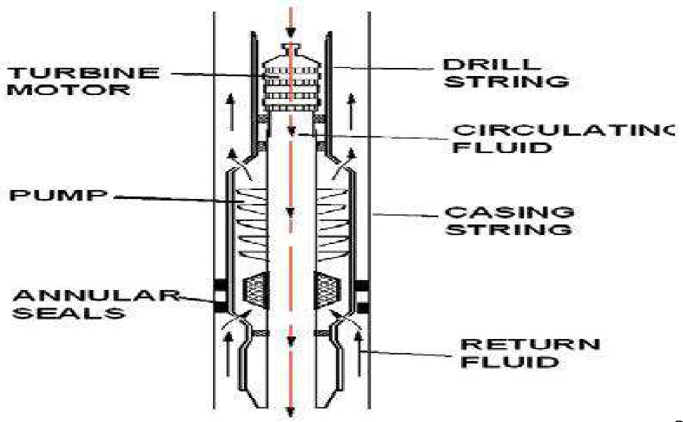


Figure 27 Flow path and Components of ECD RT[36]

G. Continuous Circulating Valve (CCV):

Continuous Circulation Valve (CCV) is also known as Continuous Circulation Device (CCD). CCV is one of the tools enabling Continuous Circulation Method which is a sub category mentioned under CBHP MDP.

Figure 28 Continuous Circulation Valve (CCV)[24]

Figure 28 is an illustration of CCV. As it is cited in Rasmussen and Sangesland's study[27], short drill pipe joints with a valve arrangement are integrated in the drill string. During drill string connection, the valve arrangement allows drilling fluid to be injected through a side port in the drill string joint and into the drill string[27].

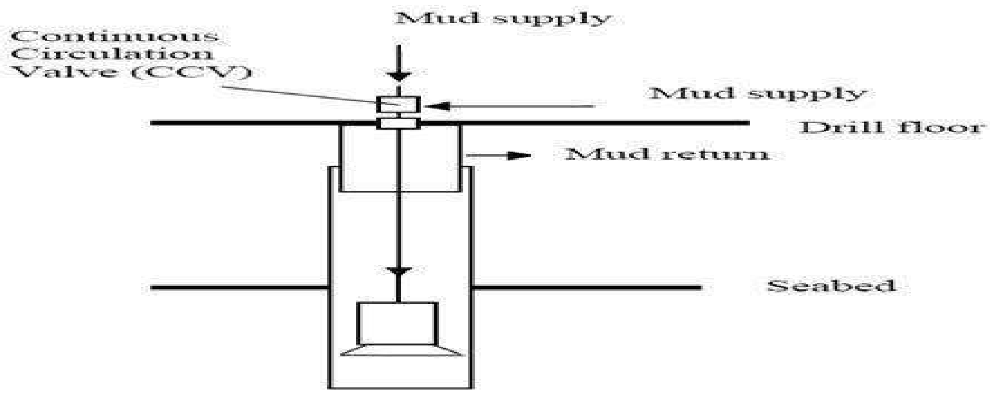


Figure 29 Continuous Circulation Method with CCV[27]

Figure 29 is an illustration of Continuous Circulation Method considered under CBHP MPD with the usage of CCV. It is possible to circulate through the valve from the top drive down the drill string or through a side port and down the drill string. Such a valve must be installed at the top of each drill pipe stand before the continuous circulation operation starts.

H. Continuous Circulation System:

Continuous circulation system (CCS) which is shown in Figure 29 permits full circulation during drill pipe connections. In HPHT wells, it is only by maintaining full circulation at all times that we can control the impact of downhole temperature changes.

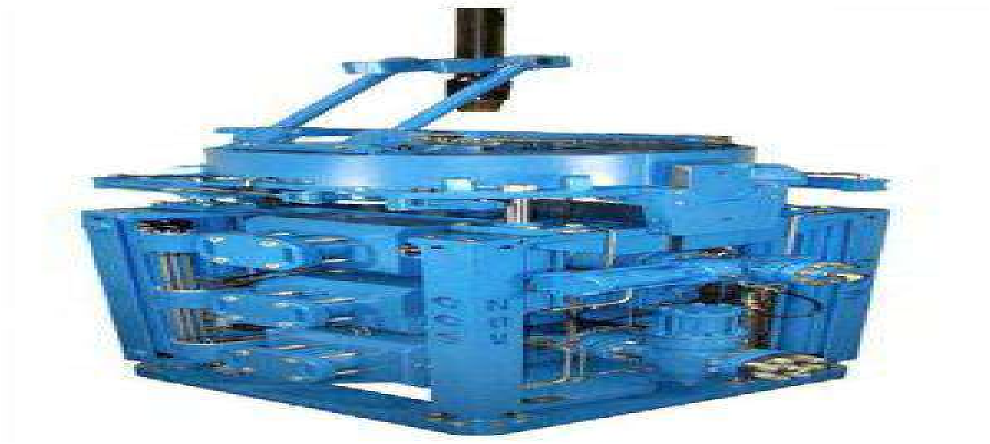
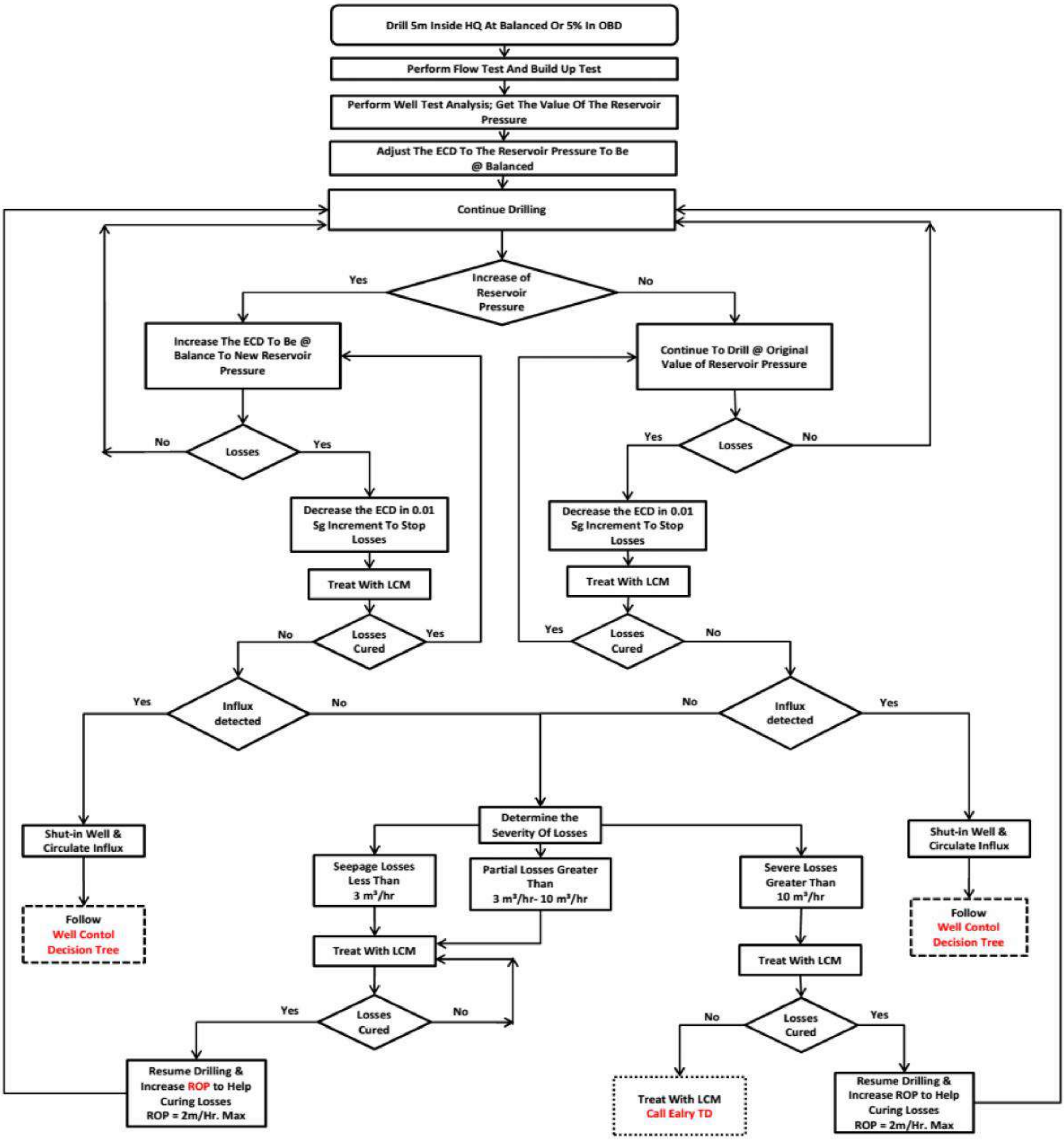


Figure 30 Continuous Circulation System[5]

Losses Decision Matrix



The usage of these equations are to be required :

$$ECD = \frac{\text{BHCP}}{\text{TVD}\times 1.428} \quad \text{.............(3)}$$

$$HP(psi) = TVD(m) \times MW(sg) \times 1.4228 \quad \text{................(4)}$$

$$Fr = BHCP - [TVD \times 1.4228 \times MV\ \ ]WHP \quad \text{..............(5)}$$

$$SBP = [(ECD - MW) \times TVD \times 1.4228] - Fr \quad \text{..................(6)}$$

HAZ-104 well design data :

Sonatrach
Activité E P
Division PED
Direction Gisements EST
Département Pôle Centre-Est

Résultats :

Coordonnées définitives
L: 29°16'31,6438"N M: 6°27'25.0036"E
X = 252916 Y = 3240932 (UTM)
Zs=285,765m Zt = 295m
Appareil : ENF-32
Remarques :

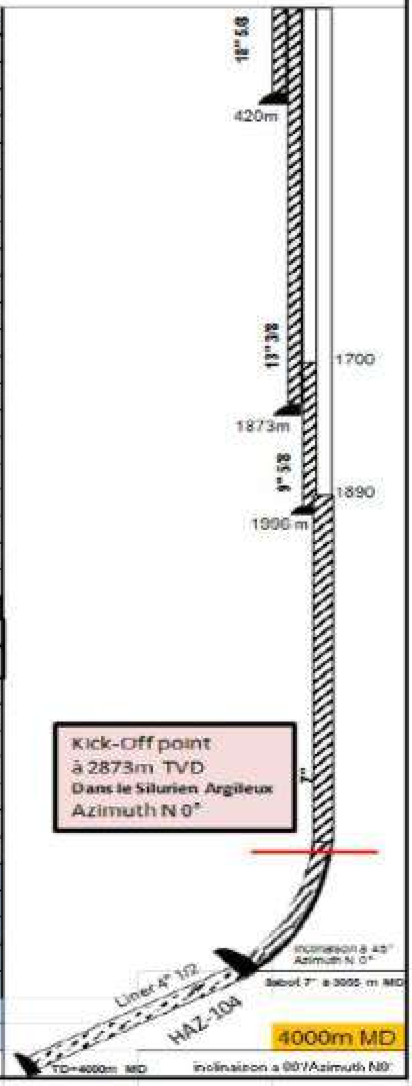
Prévisions Géologiques de Forage

Rhourde Nouss **HAZ-104**

But : Grès d'Ouargla Quartzites de Hamra

Début forage ....
Fin forage..................
Fin sondage..... (DTM)
Fond éléctrique.......... m
Fond sondeur................. m

STRATIGRAPHIE	MD	TVD	TVDSS	Epaisseurs
Mio-pliocene	9	9	286	197
Senonien Carbonaté	206	266	89	177
Senonien Lagunaire	383	383	-88	215
Senonien Salifere	598	598	-303	43
Turonien	641	641	-346	92
Cenomanien	733	733	-438	94
Albien	827	827	532	86
Aptien	913	913	-618	5
Barremien	918	918	-623	378
Neocomien	1296	1296	-1001	191
Malm	1487	1487	1192	90
Dogger Argileux	1577	1577	-1282	90
Dogger Lagunaire	1667	1667	-1372	130
Lias Arg-Dolomitic	1797	1797	-1502	75
Lias_Niveau H	1872	1872	-1577	19
Lias_LS1	1891	1891	-1596	7
Lias_Niveau B	1898	1898	-1603	18
Lias_Salifère	1916	1916	-1621	45
Lias_Argileux	1961	1961	-1666	40
TAGS	2001	2001	-1706	106
Trias Int. II	2106	2106	-1811	19
Trias Arg-Moyen	Erodé			
Trias Int. I	Erodé			
TAGI	Erodé			
Silurien B2	2126	2126	-1831	160
Silurien B1	2286	2286	-1991	118
Silurien A2	2404	2404	-2109	100
Silurien A1	2504	2504	-2209	24
Silurien M2	2528	2528	-2233	90
Silurien M1	2618	2618	-2323	45
Silurien Argileux	2663	2663	-2368	212
Ordo-DMK	2875	2874	-2580	27
Argiles Micro	2902	2899	-2607	20
Grès d'Oued Saret	2922	2917	-2627	84
Argiles d'Azzel	3006	2988	-2711	49
Grès d'Ouargla	3055	3025	-2760	64
Quartzites de Hamra	3119	3060	-2824	881
TD	4000	3242	-2947	



Epaisseurs en MD (blue)
Horizons réservoirs (yellow)
Liner Crépiné
Liner cimenté

STRATIGRAPHICAL SECTION

EON	ERE	PERIODE	AGE	LITHOSTRAT.		ABREVIATED MARKER NAME
PHANEROZOIQUE	CZ	QUATERNAIRE - TERTIAIRE	HOLOCENE-MIOCENE			HOLO_PLEISTOCENE
			OLIGOCENE PALEOCENE	Mio-Pliocene		MIO_PLIOCENE
	MESOZOIQUE	CRETACE	SENONIEN	Carbonate		SENONIEN_CARB
				Lagunaire		SENONIEN_LAG
				Salifere		SENONIEN_SAL
			TURONIEN			TURONIEN
			CENOMANIEN			CENOMANIEN
			ALBIEN			ALBIEN
			APTIEN			APTIEN
			BARREMIEN			BARREMIEN
			NEOCOMIEN			NEOCOMIEN
			Autrichienne Unc.			D_AUT
		JURASSIQUE	MALM			MALM
			DOGGER	Argileux		DOGGER_ARG
				Lagunaire		DOGGER_LAG
			LIAS	DOLOMITIQUE - SALIFERE	LD1	LIAS_ARGILO_DOL
					LS1	LIAS_ANHYD 1
					NIVEAU_H LD2	LIAS_NIVEAU_H
					LS2	LIAS_ANHYD 2
					NIVEAU_B LD3	LIAS_NIVEAU_B
				SALIFERE	S1	LIAS_S1
					S2	LIAS_S2
					S3	LIAS_S3
				ARGILEUX		LIAS_ARG
		TRIAS		Argilo-greseux superieur	TAGS	TAGS
					TAGS_SANDY	TAGS_SANDY
				TRIASSIC CARBONATE	TRIAS CARBONNATE 1	TRIAS CARBONNATE 1
					REPERE_DOL	REPERE_DOL
					TRIAS CARBONNATE 2	TRIAS CARBONNATE 2
				Argilo-greseux inferierur		TAGI
		CARBONIFERE			SUPERIEUR	
					INFERIEUR	
		DEVONIEN			SUPERIEUR	
					MOYEN	
					INFERIEUR	
		SILURIEN	GOTHLANDIEN	SILURIEN ARGILO-GRESEUX	UNITE B2	SIL_B2
					UNITE B1	SIL_B1
					UNITE A2	SIL_A2
					UNITE A1	SIL_A1
					UNITE M2	SIL_M2
					UNITE M1	SIL_M1
					ARGILEUX	SIL_ARG
					DOLERITE	
		ORDOVICIEN		UNITE IV	Dalle de M'Kratta	ORDO_DMK
					Arggiles Micro-	ARG_MICRO
				UNITE III-3	Gres d'Oued Saret	G_O_SARET
					Argiles d'Azzel	ARG_AZZEL
					HERCYNIEN	
					Gres d'Ouargla	G_OUARGLA
				UNITE III-2	Quartzites de Hamra	Q_HAMRA
				UNITE III-1	Gres d' El Atchane	G_EL_ATCH
					Argiles d'El Gassi	ARG_EL_GASSI
					Gres DE Miribel	G_DE_MIRIBEL
					Alternances	ZONE_ALTERNANCE
		CAMBRIEN		UNITE II	SUPERIEUR	CAMBRIEN_Ri
					MOYEN	CAMBRIEN_Ra
						CAMBRIEN_R2
				UNITE I	INFERIEUR	CAMBRIEN_R3
[illegible]	PRECAM	SOCLE PRECAMBRIEN				SOCLE
						TD

ملخص

إن تقنية الحفر بالضغط المتحكم فيه هو تكنولوجيا جديدة و التي ترتكز على التحكم بخسائر الضغط الحلقي مما يسمح لنا بالتغلب على مختلف المشاكل المتعلقة بالحفر منها لصق أنبوب الحفر و فقدان طين الحفر و كذلك التزايد المفرط للوقت غير المنتج والتكاليف لاسيما في الحقول التي تعرف ضغط مسامي و ضغط تشقق جد متقارب و هذا ما يسمى بنافذة الحفر الضيقة.

في هذا العمل :

- قمنا بتقييم تقنية الحفر المتحكم فيه التي طبقت في حقل نزلة في الجزائر كما قمنا بعرض أكبر المشاكل التي ووجهت اثناء الحفر عبر الخزانات الأردوفيسية.
- سلطنا الضوء على التجربة الناجحة لتقنية الحفر بالضغط المتحكم فيه اعتمادا على آخر الآبار المحفورة باستعمال هذه التقنية.

كلمات مفتاحية: الضغط المتحكم فيه, ضغط متواصل لأسفل البئر, الوقت غير المنتج, خسائر الاحتكاك الحلقي .

ABSTRACT

Managed Pressure Drilling (MPD) is a new technology which control the annular frictional pressure losses and allows us to overcome different kinds of drilling related problems including stuck pipe, lost circulation and excessive non productive time and costs especially in the fields when pore pressure and fracture pressure gradient is too close which is called narrow drilling window.

In this work:

- We evaluate the application of the MPD technology in NEZLA field in Algeria, and we present the major difficulties encountered when drilling through the Ordovician reservoirs (*Trias Argileux Gréseux, Grés d'Ouargla & Hamra Quartzite*).
- We highlight the successful experience of the MPD technique based on the recent drilled wells using MPD technology.

Key words: Managed Pressure Drilling, Continuous Bottom Hole Pressure, Non Productive Time, Annulus Frictional Losses.

RESUME

La technique de la pression contrôlée durant le forage est une nouvelle technique qui sert à gérer et contrôler les pertes de charges annulaires et permet de surmonter les différent problèmes reliés au forage y compris le coincement des tiges, la perte de la circulation et le temps non productif excessif notamment dans les champs où le gradient entre la pression de pore et la pression de fracture est très réduit et c'est ce qu'on appelle la fenêtre réduite de forage.

Dans ce travail :

- On évalue l'application de la technique du MPD sur le champ de NEZLA, et on présente les difficultés majeur rencontrées durant le forage dans les réservoirs de l'Ordovicien *(Trias Argileux Gréseux, Grés d'Ouargla & Quartzite Hamra).*
- On met en évidence le succès de l'expérience de la technique du MPD en basant sur les derniers puits forés avec la technique MPD.

Mots clés : Gestion de la pression de forage, Pression de fond continue, Temps non productif, Pertes de charge annulaire.