ECONOMICAL IMPACT OF A DUAL GRADIENT DRILLING SYSTEM

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submitted by **MERTER PEKER** in partial fulfillment of the requirements for the degree of **Master of Science in Petroleum and Natural Gas Engineering Department, Middle East Technical University** by,

Prof. Dr. Canan Özgen __________
Dean, Graduate School of **Natural and Applied Sciences**

Prof. Dr. Mahmut Parlaktuna __________
Head of Department, **Petroleum and Natural Gas Eng.**

Prof. Dr. Mahmut Parlaktuna __________
Supervisor, **Petroleum and Natural Gas Eng. Dept., METU**

Examining Committee Members:

Prof. Dr. Nurkan Karahanoğlu __________
Geological Eng. Dept., METU

Prof. Dr. Mahmut Parlaktuna __________
Petroleum and Natural Gas Eng. Dept., METU

Assist. Prof. Dr. Çağlar Sınayuç __________
Petroleum and Natural Gas Eng. Dept., METU

M.Sc. H. Ali Doğan __________
TPAO, ANKARA

M.Sc. E. Doruk Tanyel __________
TPAO, ANKARA

Date: 19.06.2012

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Last Name: MERTER PEKER

Signature:

ABSTRACT

ECONOMICAL IMPACT OF A DUAL GRADIENT DRILLING SYSTEM

Peker, Merter

M.Sc., Department of Petroleum and Natural Gas Engineering

Supervisor: Prof. Dr. Mahmut Parlaktuna

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Dual Gradient Drilling (DGD) system is a promising technology that was developed to overcome the deep water drilling problems occurred due to narrow operating window between pore pressure and fracture pressure.

In conventional drilling practice, single mud weight exists from drilling unit to TVD (True Vertical Depth) which creates big hydrostatic pressure in bottom hole ,moreover, minor changes in mud weight results a big pressure changes proportional to the length of hydrostatic column increase with water depth. On the other hand, DGD allows using two different mud weights to get same bottom hole pressure; low gradient drilling fluid from drilling unit to the sea floor and high gradient drilling fluid form the sea floor to TVD, to decrease the effect of water column on mud hydrostatic pressure in TVD.

In this thesis, a conventionally drilled deepwater well was redesigned considering the DGD system and drilled virtually to determine the changes of cost of services and materials on total operation budget to prove the positive impact of system on total operation cost.

This study not only proved the technical advantages of the DGD system, but also showed economical impact of the system on total drilling cost, by decreasing around 19%.

Keywords: Dual Gradient Drilling, Subsea Mudlift Drilling (SMD) System, Deep Water Drilling, Drilling Expenditure.

ÖZ

ÇİFT BASINÇ EĞİLİMLİ SONDAJ SİSTEMİNİN EKONOMİK ETKİSİ

Peker, Merter

Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü

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Çift Basınç Eğilimli Sondaj, derin denizlerdeki sondajlarda formasyon basıncı ve formasyon çatlatma basıncı arasındaki dar operasyon alanının ortaya çıkardığı zorlukları çözmek adına geliştirilmiş umut vadeden bir teknolojidir.

Geleneksel sistemde kullanılan sondaj çamuru sondaj ünitesinden kuyu dibine kadar tek basınç eğiliminde kuyu dibine basınç uygular. Sondaj çamurundaki ufak öz kütle değişikleri kuyu dibine kuyu derinliği ile orantılı olarak etki eder ve bu derinlik su derinliği arttıkça artış gösterir. Bu durum güvenli bir operasyon yapmak için, içinde bulunulması gereken operasyonda çalışmayı zorlaştırır. Çift Basınç Eğilimli Sondaj, su sütununun kuyu dibi basıncı üzerindeki etkisini azaltmak amacıyla, iki farklı çamur ağırlığı kullanılarak aynı kuyu dibi basıncını elde etmeye olanak tanır; sondaj ünitesinden deniz tabanına kadar düşük öz kütleli sondaj çamuru kullanılırken, deniz tabanından kuyu dibine kadar ağır öz kütleli sondaj çamuru kullanılır.

Bu tezde sistemin olumlu etkisini kanıtlamak için, geleneksel yollarla kazılan bir kuyu Çift Basınç Eğilimli Sondaj sistemi ile tekrar dizayn edildikten sonra, sanal sondaj operasyonu tatbik edilmiştir. Sondaj servislerindeki ve sondaj malzemelerindeki maliyet düşüşlerinin toplam operasyon bütçesindeki etkisi ortaya konulmuştur.

Bu çalışma Çift Basınç Eğilimli Sondaj sisteminin teknik avantajlarını kanıtlamanın yani sıra, sistemin ekonomik etkisini, toplam operasyon maliyetindeki 19%'lik azalma ile ortaya koymuştur.

Anahtar Kelimeler: Çift Basınç Eğilimli Sondaj, Denizaltı Çamur Kaldıraç Pompa Yöntemi, Derin Deniz Sondajı, Sondaj Maliyeti.

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LIST OF SYMBOLS AND ABBREVIATIONS

P_f= Formation Pressure, psi

$P_{fracture}$= Fracture Pressure, psi

P_{fluid}= Fluid Hydrostatic Pressure, psi

μ = Viscosity, cp

ρ_{fluid} = Fluid density, lbm/ft3

σ= Overburden stress, psi

ROP= Rate of Penetration

AFE= Authorization for Expenditure

D=Depth, m

WD= Water Depth, m

TVD= True Vertical Depth, m

CHAPTER 1

INTRODUCTION

In order to meet the world's increasing demand for energy and petroleum need, major oil and gas companies started to search for oil and gas in new environments. Based on their evaluations of the earth, most of these companies were interested to explore for resources offshore. Oil and gas discoveries in shallow water areas encouraged them to search deep water areas. As drilling moves into deeper waters, new technologies must be developed for safe and successful operations.

Drilling in deep water is complicated and expensive compared to the onshore or shallow water exploration operations. As the search for hydrocarbons is getting deeper, new prospects are discovered where the difference between the pore pressure and the fracture pressure is decreased that in turn has a negative effect on the drilling operation. In conventional drilling, single gradient drilling, that has a single mud weight is used from surface to total depth to control bottom hole pressure (BHP). On the other hand single gradient drilling does not successfully solve the problem of narrow operation window between pore and fracture pressure in deep water drilling operations. This resulted companies to use longer casing strings with bigger sizes and wider ranges, larger wellheads, heavier risers and more expensive rigs to reach target zones.

Dual Gradient Drilling (DGD) aims to provide same BHP that is conventionally achieved with a single fluid gradient by using dual fluid gradient and to reduce pressure on the base of the riser, ideally, a pressure less than or equal to hydrostatic pressure when riser is filled only with saltwater. This technique was developed to control the pressure at the bottom of the well by manipulating two pressure gradients: one heavier, going from bottom of the well to mudline, and another gradient, equal to or less than that would be obtained with seawater, from mudline to the surface. Figure 1.1 is a schematic representation achieving same BHP by using DGD, this schematic also gives us a clear idea of advantages of this system on casing and wellhead selection. This system allows us to work with a wider drilling window and setting the casing to deeper points. Thus, some of the casing sections can be eliminated and accordingly much simpler wellhead configuration can be selected in well design.

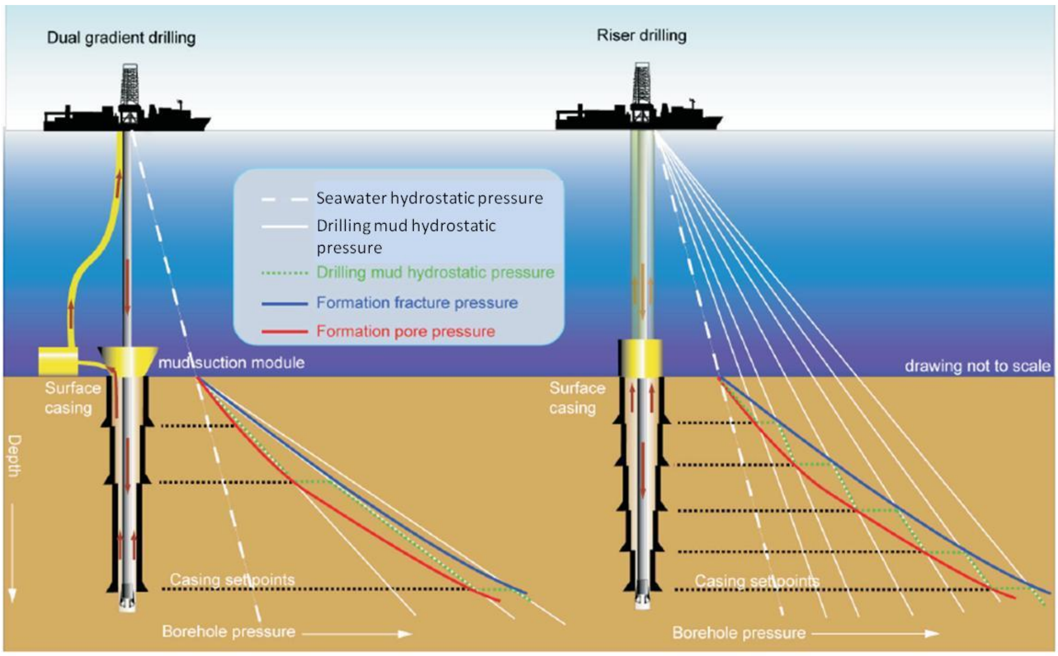

Figure 1.1 Differences between Conventional Drilling and DGD [1].

To understand the innovation of DGD system, fluid return sections should be studied carefully. Different from the conventional drilling, return fluid is diverted to pumps and lifted to surface by using return line which is small diameter line from sea floor to drilling unit. The hydrostatic head below the mud line is made equivalent as drilling unit placed on the sea floor and the hydrostatic pressure problem of the sea water is eliminated, demonstrated in Figure 1.2.

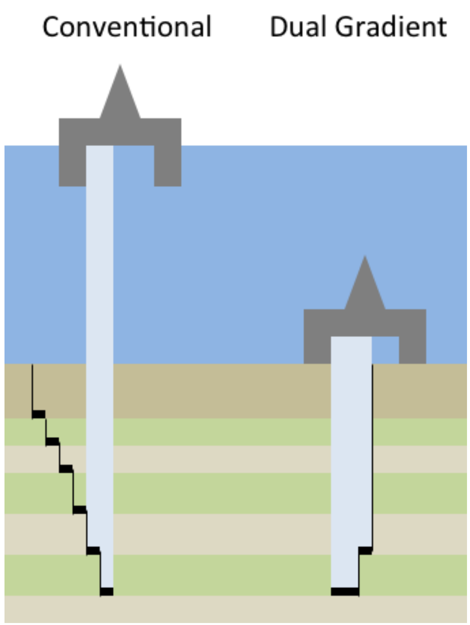

Figure 1.2 Schematic demonstration of dual gradient system effect.

It is an expensive, complex, step-change technology that the industry has been trying to develop for over a decade. A number of different strategies have been attempted with varying degrees of success. Major oil companies have efforts to commercialize this technology and bring it to fruition.

Although the technical advantages of this system were reported in many articles, there is no paper published to show the economical impact of this system on total operational cost. Therefore, this study was performed to figure out this impact by resigning the previously drilled deep water well with DGD system and simulating the drilling of the resigned well on paper. Finally, the expenditures of both wells (original and redesigned) were compared to show this impact.

CHAPTER 2

LITERATURE REVIEW

In this chapter of the study, the aim is provide more information about DGD; starting from the basic to advance. Thus it is going to be started with conventional drilling; the way that industry uses mostly today, and be continued with DGD and what kind of advantages that DGD brings to industry, then the chapter is finalized with different kinds of system to achieve DGD.

2.1 Conventional Drilling

The aim of the conventional drilling is to optimize BHP between pore pressure and fracture gradient to make a controlled drilling where pore pressure is defined as the pressure of fluids inside the pore of the formation, usually hydrostatic pressure and fracture pressure are defined as the pressure at which a formation break down, or fracture.

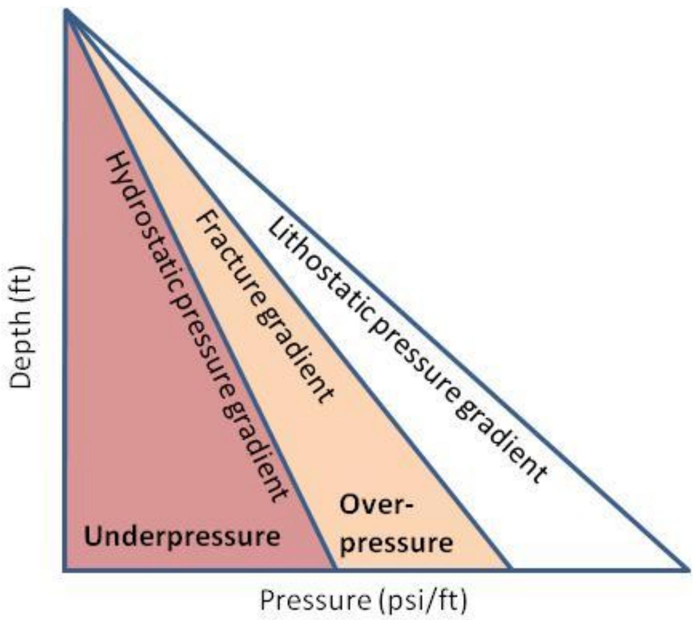

Figure 2.1 Schematic Demonstration of Pressure Behavior

In conventional drilling, the element used to balance pressure in interested depth of formation is hydrostatic pressure of drilling fluid. The pore pressure, where normal pressure gradient is in place, defined as;

$$P_f\,(psi) = \text{Formation Pressure Gradient}\,(psi/ft) * \text{Depth}(ft) \tag{2.1}$$

Based on Eaton model [2], the fracture pressure can be defined as;

$$P_{fracture} = \sigma_{min} + P_f \tag{2.2}$$

where,

$$\sigma_{min} = \frac{\mu}{1-\mu}\sigma_z \tag{2.3}$$

and

$$\sigma_z = \sigma_{overburden} - \mathrm{P_f} \tag{2.4}$$

Therefore, to perform a balanced drilling, drilling fluid hydrostatic pressure value stays between pore pressure and fracture pressure.

$$P_{formation} < P_{fluid} < P_{fracture} \tag{2.5}$$

where,

$$\mathrm{P_{fluid}} = 0.052 \times \rho_{\mathrm{fluid}} \times D \tag{2.6}$$

Considering the deep water environment, pore pressure and fracture pressure are directly affected by the water column; the hydrostatic pressure of the water is also added to the pore pressure to calculate the total formation pressure of the interested depth, from sea level.

Likewise, due to usage of the marine riser, (which is the link to conduct to drilling fluid between sea floor to drilling unit [2], figure 2.2) the hydrostatic pressure of the drilling fluid in the marine riser section, is taken into account to calculate BHP (which is demonstrated in figure 2.2).

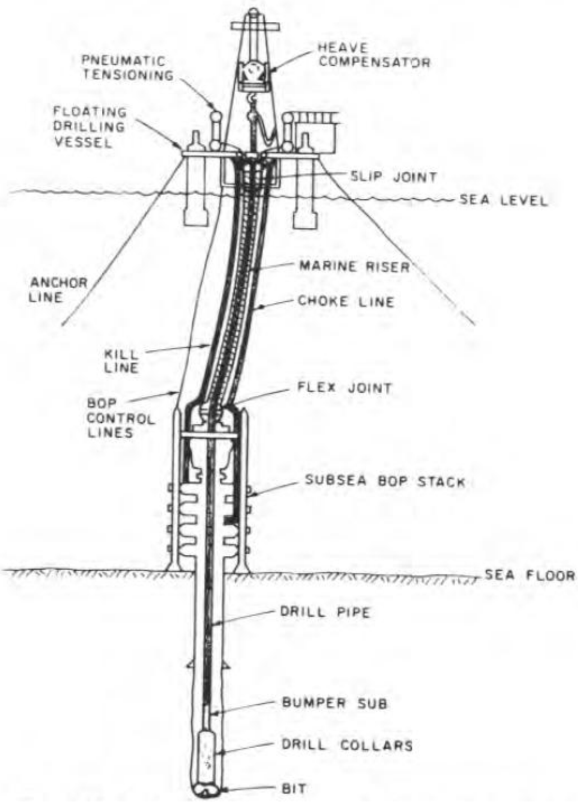

Figure 2.2 Schematic Subsea Drilling Equipment [2].

Therefore, the formation pressure is calculated like;

$$P_f = \mathrm{WaterPress.Gradient} * \mathrm{WD} + \mathrm{FormationPress.Gradient} * (\mathrm{TD} - \mathrm{WD}) \quad (2.7)$$

How to Select Casing Setting Depths

The correlation of pore-pressure gradients and fracture gradients is the main criteria to determine the number of casing string and their setting depths.

The mud weight is chosen above the formation pore pressure in interested depth (casing shoe point) and is kept constant until reaching the bottom hole pressure (mud hydrostatic) excess the fracture pressure (next casing shoe point) where both formation pore pressure and fracture pressure are expressed as equivalent circulating density. Moreover, trip margin, which is the effect of pipe movement on bottom hole pressure; commonly used 0.5ppg, is also considered during design process.

The Figure 2.3 shows the way of the selection if casing setting depths based on these pressure gradients.

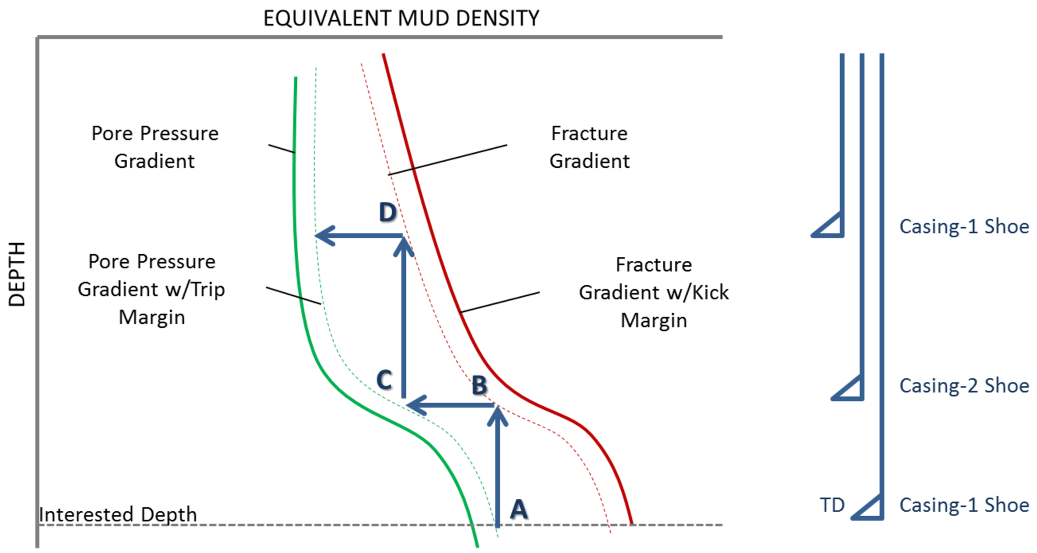

Figure 2.3 Casing Setting Points

Considering the minimum mud weight to reach objective depth at Point-A without getting an influx from formation fluid, Point-B is the maximum point that this fluid can result safe operation without fracturing the formation. Thus, the Point-B, where fracture gradient is equal to mud weight, is selected to set casing shoe depth and selected mud weight is used between Point-A and Point-B to perform operation.

After the determination of the casing shoe depth in Point-B, new mud weight is selected to figure out new casing shoe in upper section. Similarly, lowest mud weight is selected in Point-B considering the pore pressure gradient in same depth, which is Point-C. The new weight can balance the formation pressure until fracturing it until Point-D where is the casing shoe point prior casing.

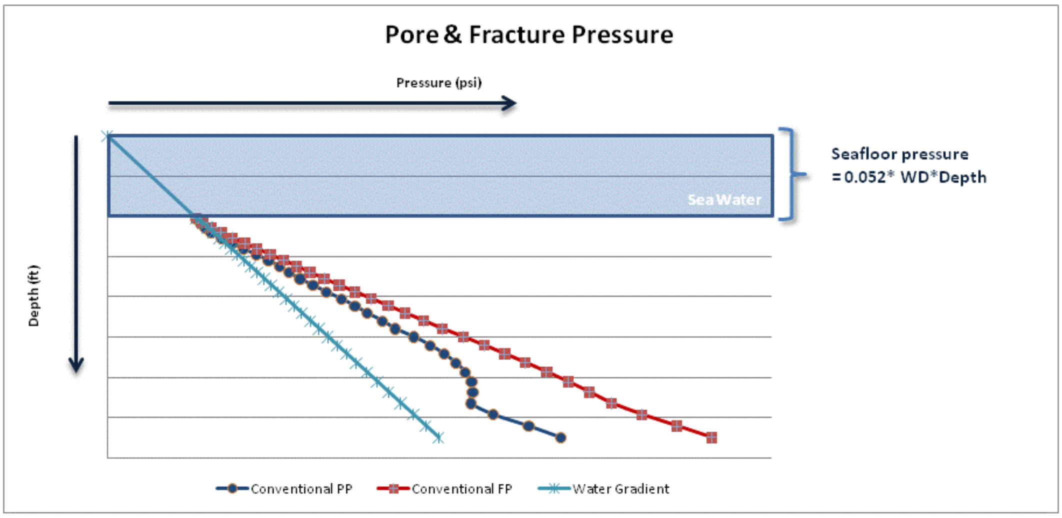

Figure 2.4 Effect of Sea Water on Formation Pressure Calculation.

The hydrostatic pressure of water column makes engineer to design more complex well architecture and drilling program. The main reason of this is the narrow operation area between pore pressure and fracture pressure which is called operating window. As it is mentioned before, to perform a safe and controlled drilling operation, hydrostatic pressure of the drilling fluid should be selected inside the operating window. On the other hand, in deep water environment due to the additional hydrostatic pressure of the water, operating window gets narrow. Thus, more complex well architecture is required with many sections and casings. In figures 2.4 and 2.5 are the demonstration of this problem; to drill down to planned depth, five sections are needed to be drilled with five different mud weight and four different casing are needed to be set.

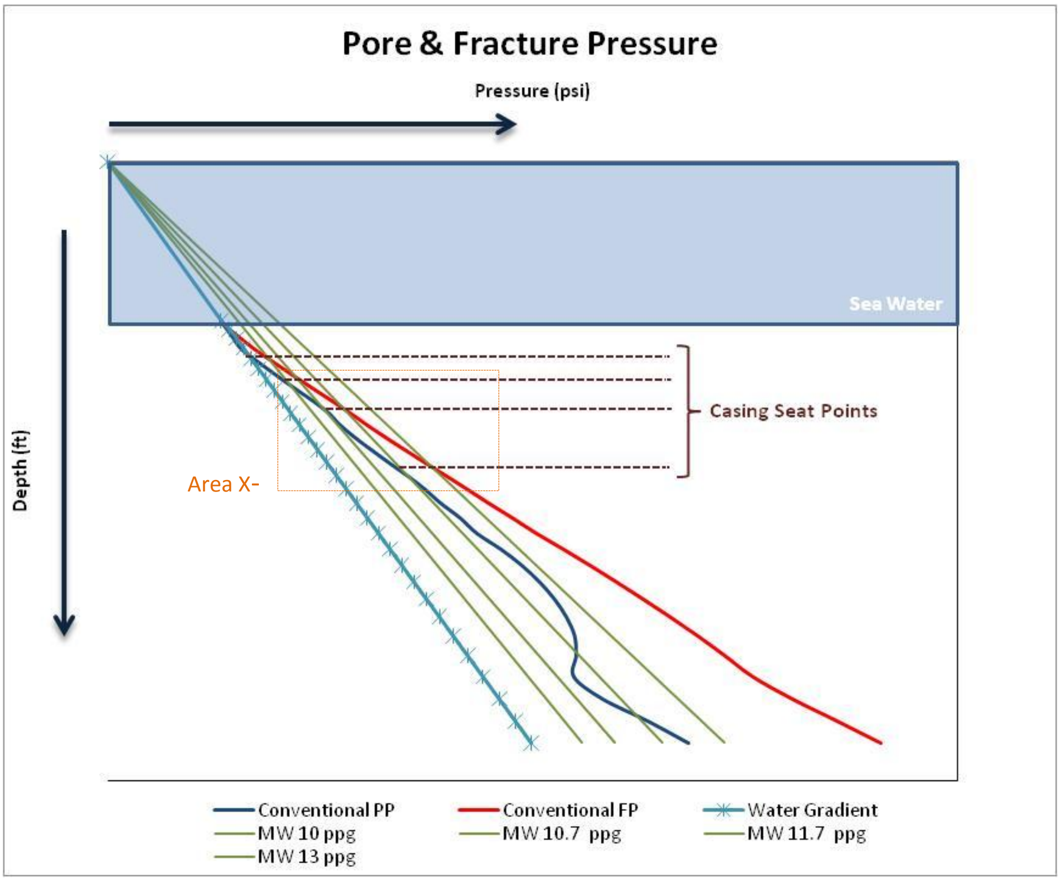

Figure 2.5 Schematic of Effect of Sea Water on Well Design.

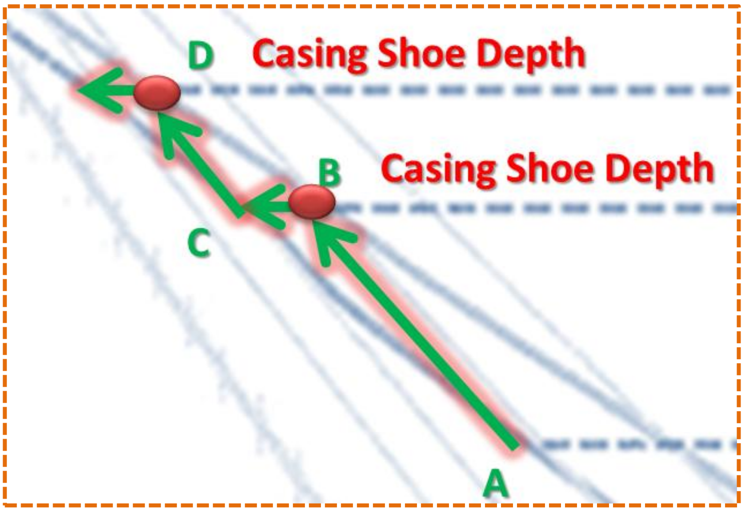

Figure 2.6 Zoom of the Area X.

The Figure 2.6 shows the zoom version of the Area X marked in Figure 2.5 with the application of the casing selection depths mentioned with Figure 2.3. The only difference between these figures; the graph in Figure 2.3 is drown in pressure gradient vs depth but; the graph in Figure 2.5 is in pressure vs depth. Thus, the vertical lines referring constant mud weight in Figure 2.3 same as the straight trendy lines. Similarly, after determining the casing setting depth in Point-B, next mud weight is calculated based on pore pressure value in same depth. The operation can be performed safely inside the operation window until reaching the depth where mud pressure is equal to fracture pressure. This is the signal of necessity of changing mud weight and setting new casing.

Other critical point that questions the conventional drilling in deep water environment, open hole section of the wellbore faces with risk of fracture due to full column of drilling fluid between drilling unit and TVD [3].

The risk of the fracturing the formation and the expensive design of well architecture due to narrow operation window make companies to search different techniques and technologies. Dual Gradient Drilling, the one of the invention, was developed to cure these problems.

2.2 Dual Gradient Drilling

Basic definition of DGD is a technique that allow us to use two different pressure gradient to maintain same bottom hole pressure as conventional drilling. The importance of the using two pressure gradient is to eliminate the effect of the hydrostatic pressure of the sea water. To achieve dual gradient, special design materials and tool designed to support, one gradient which is equal to water gradient from sea floor to mud line and second gradient from mud line to total depth.

DGD provides opportunity to work with narrow operation window than conventional drilling by replacing reference point of pore & fracture pressures calculation to mudline which is rotary table in conventional.

Wider operation window allows setting fewer casing size and going deeper sections. Thus, the simpler wellhead configuration can be used. Another benefit of working wider operation window is limitations on determining the mud weight decrease, which reduce the risk of kicks & lost circulation and increase the operational ability during well control operations.

Figure 2.7 shows the effect of dual gradient concept on operation window and casing selection. This graph was prepared with same data as figure 2.5 by simulating dual gradient concept. It is very good example to see how DGD does effective solution to well design problems due to narrow window between pore and fracture pressure.

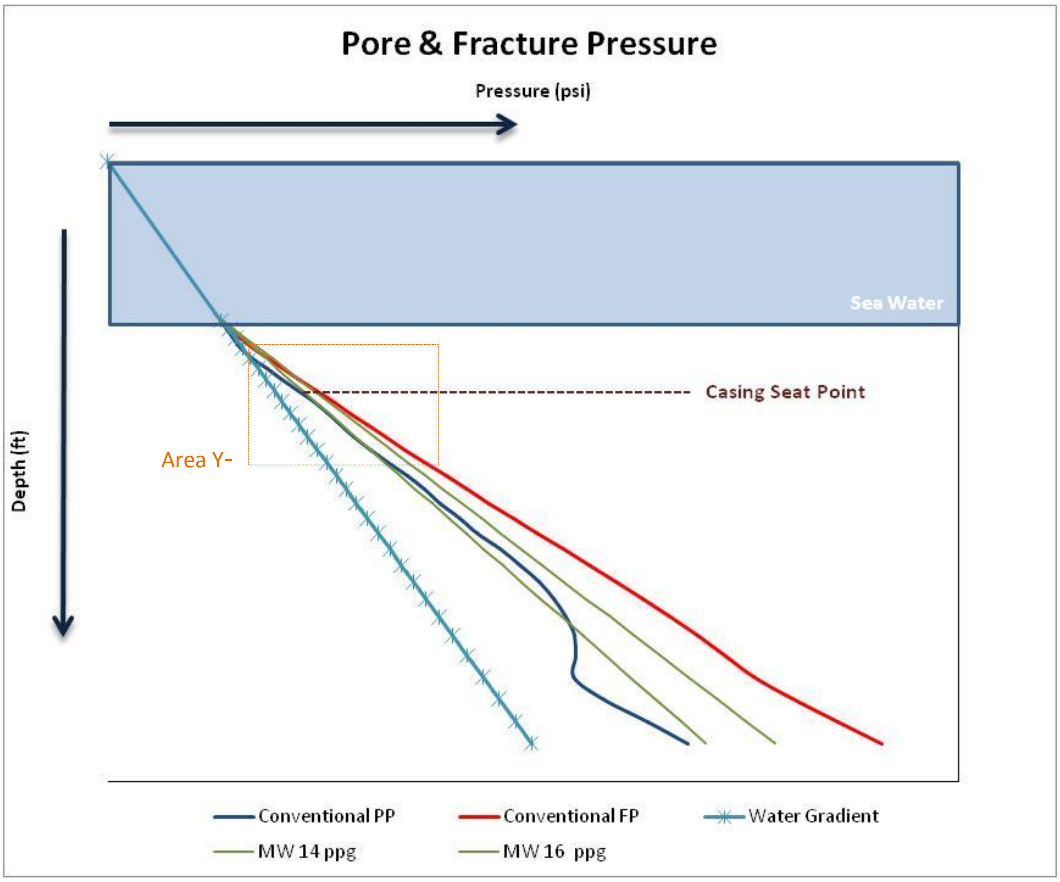

Figure 2.7 Schematic of Effect of Sea Water on Well Design.

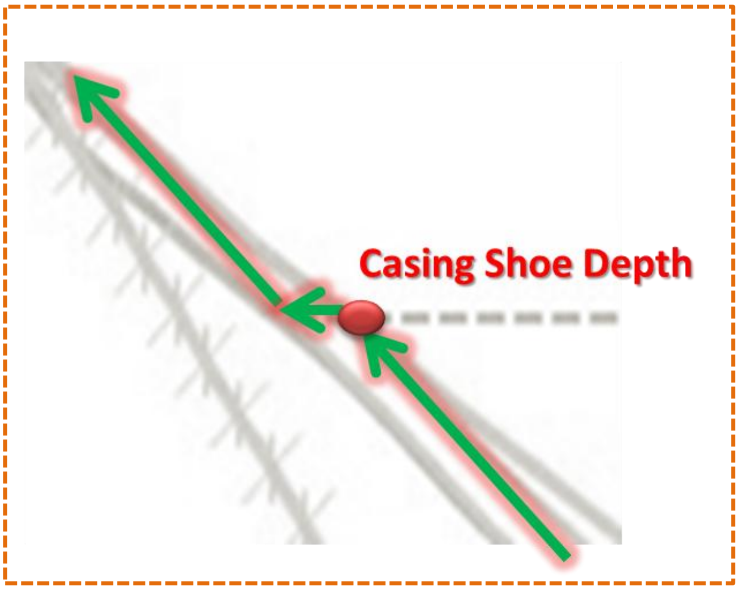

Figure 2.8 Zoom of the Area Y.

Figure 2.8 shows the Area Y with the study of casing selection point. In this case, the selected mud weight can cover longer interval after eliminating effect of extra mud pressure due to water column.

After applying the same process to the advantages and the techniques to achieve DGD are briefly explained in next chapters. Moreover, as a main goal of this study, the economic impact of the DGD is deeply investigated.

2.3 Advantages of Dual Gradient Drilling

Considering the main purpose of the DGD; eliminating drilling fluid head inside the riser, the return of this system is to improve the working interval between formation pressure and fracture pressure. This improvement actually brings advantage of the system from designing phase to completion phase.

High pore pressure and low fracture gradients leads engineer to design well with more casing points not to fracture the formation. This issue also drives many problems like selection of wellhead. The more casing size, the more complex wellhead is need to be selected which means extra money, delivery time, even larger and heavier risers and finally bigger, more expensive rigs selection.

Setting additional casing strings to reduce the operational risks, increase the well integrity and allow drilling head create a risk not to reach targeted TVD, count out your contingency options as well. Even target can be reached, mostly well is ended up with small production casing, which also limits well production design. Small wellbore at TVD precludes large production tubing - limiting production rates.

Dual Gradient Drilling is the cure of all problems mentioned above. Creating wider operational window allow using fewer casing strings, thus less complex wellhead configurations can be selected. Moreover, less casing string are required to reach planned TVD without reducing hole size which allows room for high rate completions. Reducing casing strings also means that fewer casing, cementing and logging operations which results with shorter drilling campaigns with lower cost. Reduced operation cost allows drilling wells being not commercial with conventional drilling, which makes exploring new areas and developing deeper wells possible.

In terms of subsea point of view, DGD system reduce the weight of riser system which expands capacity of existing rig fleet and mitigates effects of high currents.

Conventional deep water drilling results in longer and heavier drilling risers and well control become more difficult due to the pore pressure and fracture pressure proximity and long choke lines with high friction pressure drops. DGD also helps us to solve this issue and gives opportunity perform better well control. Also DGD safer than the conventional drilling in case of any emergency disconnect because the riser filled by sea water which allow to makes safer and more environmental friendly emergency disconnects.

2.4 Types of Dual Gradient Drilling Systems

There are three main techniques also illustrated on Figure 2.9, were developed to achieve DGD by reducing the annular mud hydrostatic pressure at riser; Mechanical Mud Lifting (mud pumps), Mud Dilution (gas lift) and Hollow Glass Spheres (lightweight solid additives).

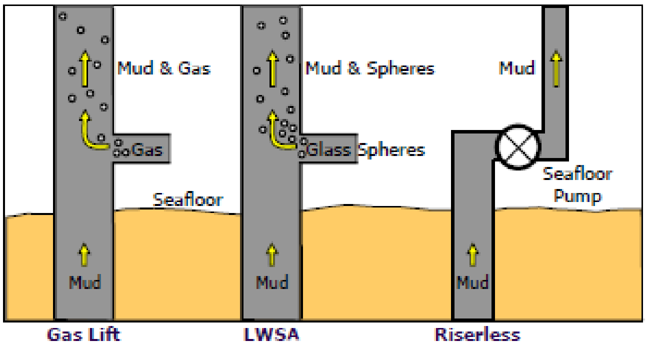

Figure 2.9 Schematic Of DGD Techniques [4].

Although, Mud Dilution and Hollow Glass Spheres techniques shown with riser, with the required mortification, both system can be used as riserless with return line [4].

In this study, three techniques will be studied under two sections;

1- Reduced Mud Weight; based on low-density components injection into riser to decease mud weight.

2- Mechanical Mud Lifting; based on installing pumps to sea floor to lift return mud from seabed to drilling unit.

2.4.1 Reduced Mud Weight

The technique consists of diluting the mud returns from the base of the riser to above sea floor with the injection of low-density components such as; nitrogen and hollow spheres. This is the way to cut the mud and reduce the mud density to sea water gradients or lower.

Mainly, there are two techniques to diluting the mud in the riser; injecting low density fluid, nitrogen or adding lightweight solid additives to mud.

2.4.1.1 Mud Dilution

Development of the Dual Gradient Drilling concept (DGD) injection of lighter fluid in the Lower Marine Riser Package (LMRP) for the purpose of avoiding drilling problems such as loss of circulation, in scenarios characterized by narrow operating margin between pore pressure and fracture.

Instead of removing mud column in the riser, this system dilutes the mud in the riser to reduce extra mud hydrostatic in the riser by decreasing mud weight. Nitrogen is injected to cut mud weight from down riser to seafloor. Low density fluid (nitrogen) reduces the weight of return mud equal or lower than mud weight.

Figure 2.10 show the basic flow line and cycle of Mud Dilution technique. Low density fluid (nitrogen) is pumped from rig floor to down riser via lower marine riser package (LMRP) then mixes with return mud to get reduced mud weight fluid. Mixed fluid goes up to separator on rig floor where mixture is separated into low density fluid and mud.

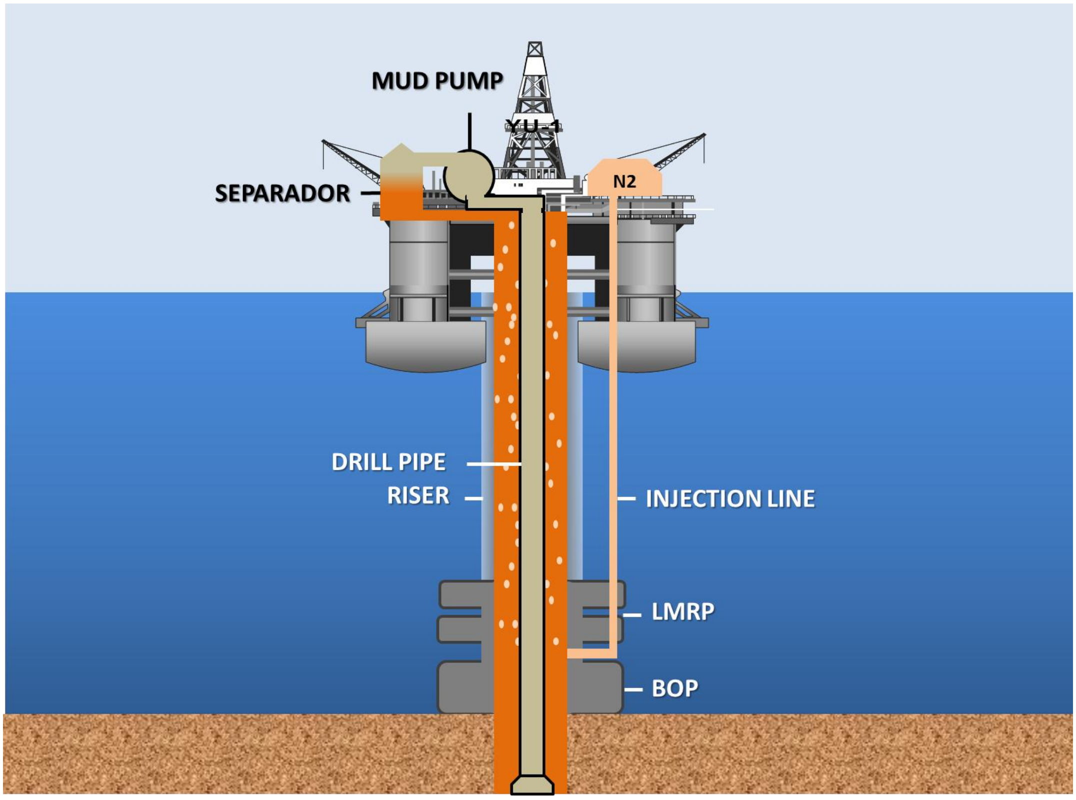

Figure 2.10 Schematic of Mud Dilution System.

Use of nitrogen, as the fluid to lower the density of the mud, needs availability of storage space on drilling unit for the tanks of nitrogen and multiphase separator to split nitrogen from mixed fluid. Moreover, compressibility factor of nitrogen causes non-linear pressure gradient inside the riser. [4]

2.4.1.2 Injection of Hollow Spheres of Low Density

The US-Maurer technology developed a new technique called Hollow Spare Dual-Gradient Drilling System, which involves the injection of high concentration of lightweight materials such as, for example, hollow spheres and solids through one or more points in the riser.

The theory is same as Mud Dilution system, to eliminate the excess pressure of annulus mud column by reducing mud weight in the riser. While injecting nitrogen in Mud Dilution system, Lightweight Solid Additives (LWSA) are pumped in Hollow Spare Dual-Gradient Drilling System.

Lightweight solid additives (plastic, composite, glass, metal, etc.) are mixed with slurry and pumped by a surface pump in drilling unit to the line in sea floor which communicates with riser connection point through valve. Then, mixed return drilling fluid, cuttings and the balls return to the surface and transferred to the separator where the gravel will be extracted. Lightweight solid additives (LWSA) are able separated from mud by conventional shale shaker. Figure 2.11 below shows the system of hollow spheres.

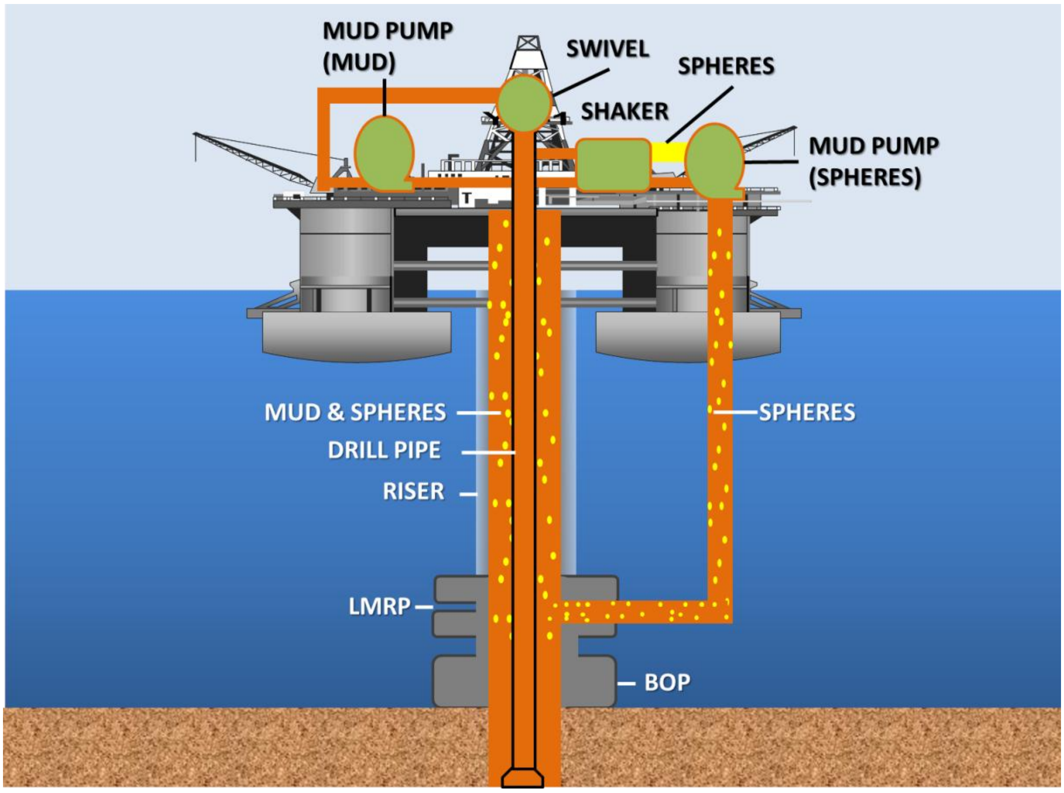

Figure 2.11 Schematic of Mud Dilution System

Although, the technique of injection in the riser is similar to the gas injection system, due to the using incompressible hollow spheres, it is possible to get linear pressure gradients inside the riser. [4]

2.4.2 Mechanical Mud Lifting

In conventional offshore drilling, drilling fluid is pumped down through drill pipe and return up through annulus and riser. In mechanical mud lift model, unlike reducing return mud weight in the riser, usage of riser eliminated by diverting return flow to alternative small diameter return line and pumping up to drilling unit by mud lift pump system installed to seabed. In this way, effect of return mud hydrostatic head in riser is eliminated as shown in Figure 2.12.

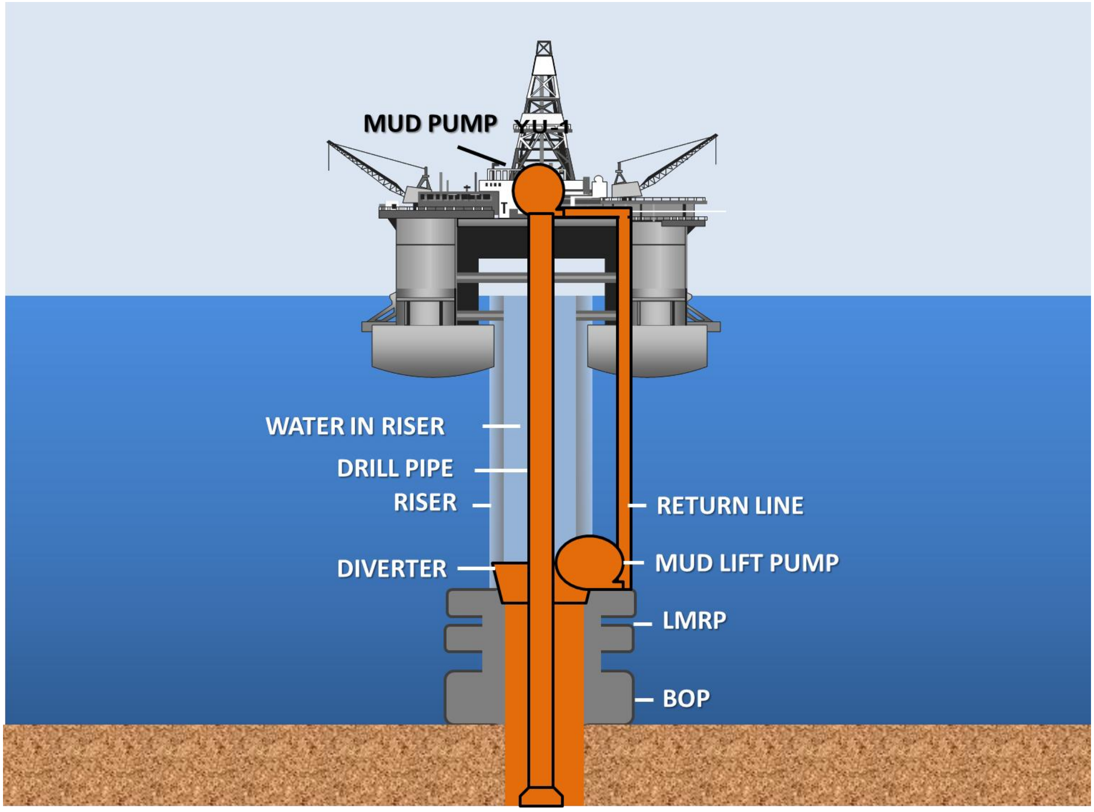

Figure 2.12 Schematic of Mechanical Mud Lifting [8].

Three different Joint Industry Project (JIP) established to develop DGD system based on this concept: Subsea Mudlift Drilling (SMD); DeepVision Project, Shell's Subsea Pumping System – SSPS and CMP (Controlled Mud Pressure) which the AGR is developing, based on RMR pump technology.

2.4.2.1 Subsea Mudlift Drilling (SMD)

Partnership project spearheaded by the companies Conoco and Hydril. It is a system with three to six pumps diaphragm positive displacement positioned in mud line, each capable of pumping 80 gpm. Pumps are hydraulically actuated by pressurized sea water through a line 6 inches, working in automatic mode according to the pressure variation at the top of the annular well as shown in Figure 2.13.

The mud is diverted from the well to cancel the pumps submerged by a rotary diverter (SRD), passing first by a crusher which reduces to 1 1 / 2 inch diameter of the annular solid returning well. To avoid the effect of U-tube is added to the BHA drilling a check valve.

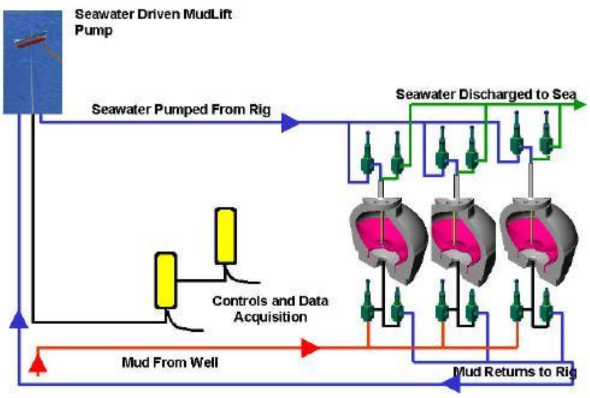

Figure 2.13 Positive Displacement Diaphragm Pumps [5].

2.4.2.2 Deep Vision

Partnership project spearheaded by companies Baker Hughes and Transocean. System works with multistage centrifugal pumps in series which are electrically driven. Drilling riser is filled with sea water and wellhead modified (Mechanical Seawater Mud- Isolation System) isolates the annular and riser.

2.4.2.3 Shell's Subsea Pumping System (SSPS)

System of electric submersible pumps (SESPs - seafloor electric-submersible pumps) operates in series. SSPS pumps are similar ESPs pumps used for pumping oil and water in oil production wells. A bed of nitrogen separates the well from submerged pumping system and ensures that the pressure in the annular space is equalized with the hydrostatic pressure of seawater. Gravels larger than 0.25, are separated from drilling mud in mud line and discharged to water.

2.4.2.4 Controlled Mud Pressure (CMP)

AGR is developing a drill system called CMP - Controlled Mud Pressure System that is targeted towards the application of the technology used in drilling equipment in riserless mud recovery (RMR) with riser and BOP submarine. The RMR is employed in the recovery of drilling fluid and cuttings in the drilling of the initial phases of offshore well, with no riser.

The CMP controls the pressure on the bottom through a pump connected to the underwater marine riser below the lower annular preventer. This is possible by adjusting the volume of drilling fluid and mattress spacer (lighter fluid) in the drilling riser. Thus the downhole pressure will be determined by the weight of the drilling fluid to the annulus of the well and the combination of drilling fluid and spacer present in the riser mattress.

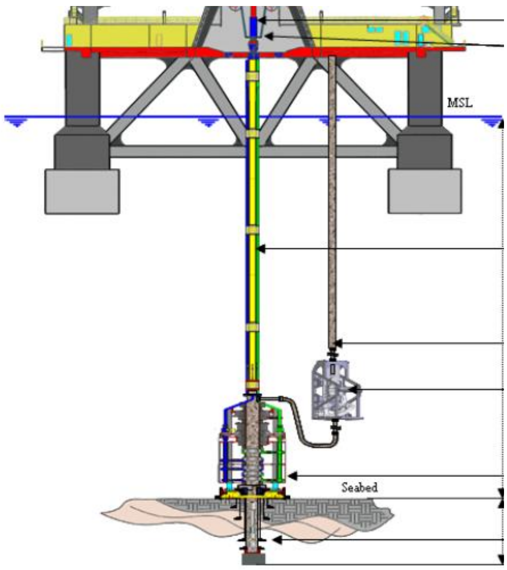

Figure 2.14 Schematic of Controlled Mud Pressure System-1.

Although, these facilities were technically success, especially Subsea Drilling Mudlift JIP was completed 90% of project goals; they were not put into operation due to commercial failure (except Controlled Mud Pressure – which System will be available for use in 2012.) which contributed by several factors; economical downturn in the industry, required costly rig modification and no single operator had suitable project in their deepwater portfolio to apply the technology. [6]

2.5 Concept of Subsea Mudlift Drilling System

Deepwater drilling is considered as a future of drilling industry, the deeper well is drilled, the more place is explored. This is why oil industry works to develop new techniques and invent new technologies to get the ability to drill deeper.

Although deepwater drilling is the big opportunity to explore new reserves, it also brings the challenges with itself. As the demand of exploring the deeper waters and drilling deeper, the challenges increase like hydrostatic head difference between water and drilling mud. Actually, this pressure difference can be pointed as a main difficulty in deepwater drilling operations, which causes operational difficulties and also brings many limitations to well design.

With the interest of exploring oil and gas in deepwater, major oil companies started to research a way to cure this pressure difference. “Dual Gradient Drilling”, also named as “Riserless drilling” concept is one of the ideas that considered as solution. Since 60’s, companies have been trying to develop this concept and make it commercial solution. There are three large scale project were conducted to develop different approaches to archive dual gradient system. [7]

In this project, one the major and most significant joint industry projects (JIPs) is selected to indicate the economical benefits of the DGD with technical capabilities; the SubSea Mudlift Drilling JIP.

In the following chapters, the SubSea Mudlift Drilling concept is studied; how it developed and how it works.

2.5.1 History

Interest of searching beneficial technologies to explore deep waters start in the early 1960s and removing riser effect is one of these technologies. On the other hand, due to the lack of technology capability, this idea could not reach the maturity.

With the increase demand in 1990's, the aim to explore increased rapidly, especially in Gulf of Mexico. However, limited number of offshore drilling rigs with weak capability with the increase the demand of new technology in dramatic way let companies to re study the riserless drilling, which system allow incapable rig to drill deeper wells in deeper water depths with required modification.

Additional to system advantages on increasing the capability of rig, system also decrease the operational costs by decreasing variety of casing sections, allowing to use simple wellhead configuration and more which are discussed in previous chapters.

It was too much effort to achieve this kind of project by one single company, although Conoco and Hydril started to investigate the way to design riserless drilling, they quickly understood that they needed contribution of others companies. In 1996, they collected other major 25 companies; operators, service companies and contractors under same umbrella by arranging one day workshop. It was a one-day workshop to share the idea with other companies and to perform brain storming on riserless drilling which was called "SubSea MudLift Drilling JIP" later.

This workshop was the beginning of big partnership called SubSea MudLift Drilling JIP (Joint Industry Project) which took almost 5 years and $45 MM was invested during this time. It can be studied in three phases [5];

- Phase I – Conceptual Engineering
- Phase II – Component design and Testing, Procedure Development
- Phase III – System Design, Fabrication and Testing

Figure 2.15 JIP Project Schedule

2.5.1.1 Phase I – Conceptual Engineering

Considering the size of the project, collecting 22 companies inside the same room and ask to work together to create new idea that changes all the operational routines was not a simple thing. Thus, during Phase I, companies mainly focused on understanding this idea and try to investigate the negative and positive aspects. Conoco was assigned as Project Administrator and Hydril Project Designer.

The aim of the participants in this stage was to investigate ways to establish dual gradient system, to search required modification on well control procedure for dual gradient system, to search the ways to apply this new technology to existing rigs.

The JIP set project target to achieve the dual gradient system working with maximum 108gpm with an unweighted mud and 800gpm with an 18.5ppg mud in an environment; 12 1/4” hole in 10,000’ water depth.

At this phase, project team selected to use positive displacement pump which was an electro-hydraulically powered diaphragm pumping system to lift return fluid from sea floor to drilling unit after reviewing a wide range of lifting system; dilution of return mud with low density material (gas or glass beads) and mud pump located sea floor with various pump design.

Two riser configurations determined; one return line designed inside the existing riser, other one return line separate from the existing riser and in both pumping system located above the BOP.

Moreover, Texas A&M University was selected to prepare simulator to understand the behavior of dual gradient system.

2.5.1.2 Phase II – Component design and Testing, Procedure Development

Due to the primary focus on Gulf of Mexico operations in Phase I, JIP participant's number decreased to 9 in Phase II.

Phase II can be considered the beginning the technology getting shapes with development system and procedures simultaneously. The designs of most critical items were concluded and related procedures were started to established.

The critical change in the project during the Phase II was the changing electro-hydraulically powered diaphragm pumping system. Although, project team was sure that changing electro-hydraulically powered pump could create enough power to achieve project goal, the long term viability of high powered cables was questionable. Thus, project team decided to use diaphragm pumps running by sea water which pumped from surface to power the system. It also decreased the complexity of electro-hydraulically powered pump, decreased the system weight 75kips and helped team to eliminate the high voltage power cables.

Moreover, since participants did not want to design and produce new riser in limited time frame, project team decide to eliminate remote riser for return flow. The riser modeling was performed based on the 5th generation drillships to make the system fitting to several rig types [5].

As it was already mentioned; creating new technology one thing, using this technology other thing. To make the people familiar to this new technology, also additional to new drilling procedure coming with dual gradient drilling, all existing conventional drilling procedures were modified. Other issue that became more clear in Phase II, specific training should be prepared during Phase III since the dual gradient drilling procedure and well control procedures for dual gradient with were defined during Phase II much more different than the conventional ones.

2.5.1.3 Phase III – System Design, Fabrication and Testing

This is the actual phase that all pieces of the puzzle came together to make meaning. During this stage, pumping system design was completed and started to fabricate, riser system modified to fit second generation semisubmersible rig which accommodate 2 ea 5” lines to the seafloor; one for return mud, other for powering diaphragm pumps in seafloor.

The main target of the project team was manufacturing system that is totally trustable and commercially applicable for deep-water drilling. Moreover, under this main target, there were more than 100 minor targets were set by project team, such as; drilling real well, prove dual gradient system and components, prove all procedures…etc.

Texaco and its prospect in Green Canyon were selected as test operator and test area. Diamond Offshore New Era semisubmersible rig was modified to perform drilling operation; additional weight, power requirements and other equipment required for mudlift system. Meanwhile, Project team designed the additional equipment based on rig’s moonpool and BOP handling equipment dimensions.

Other important step accomplished during this step was training of the rig crew. It was a big change for Diamond Offshore New Era crew, up to that moment; they just had to focus on conventional drilling and now faced with something different. With the assistance of Texas A&M University, all the drilling procedures were revised and new procedures specific for dual gradient drilling were written. These procedures were used in 3-week training held for rig crew.

Different from other operations in Texaco's portfolio, for this special case, experts re-write Texaco's conventional drilling program according to special procedures. Although, Texaco's original drilling program contained 4 casing sections, to perform a better test, project team added 1 more casing section.

Table 2.1 Casing selection for conventional well and DGD well [8].

Conventional Shasta Well	SMD Field Test Well
30" drive pipe	30" drive pipe
16" surface casing	20" surface casing
10-3/4" casing	13-3/8" casing
7-5/8" production string	9-5/8" liner
	7" production string

Texaco drilled first two sections with conventional single gradient drilling. The project team drilled two sections and cased with 13 3/8" and 9 5/8" casing. Then Texaco returned to drill last section and set 7" production casing. [8]

Considering the time and budget spent this project, it was one of the biggest projects in oil industry. Furthermore, JIP performed successful field test by drilling a well with 90% project goals achieved. Although, in terms of technical view, project team accomplished the built dual gradient drilling system, due to the several factor it could be considered as commercial failure. [6]

1- Economical turbulent in industry in 2001.
2- The huge cost required to modify existing rigs.
3- No deep-water prospect in company's portfolio.

Nowadays, Chevron is planning to drill a well by using similar system; dual derrick rig Pacific Santa Ana was selected and modified with dual gradient system when she was in shipyard in Korea other considering the oil prices. The expected date of the start operation is 1st Quarter of 2012 in GOM. Considering the increase in oil price since 2001 and new technical developments, Chevron aims to deploy first commercial dual gradient system.

2.5.2 Operational part

In SubSea Mudlift system like conventional drilling; drilling fluid is pumped from mud pumps in drilling unit to bit through the drilling string. The innovation that SubSea Mudlift system brings to industry, takes in place where the flow return back to drilling unit. Instead of conventional drilling riser, the return flow send to drilling unit through small diameter return lines by mudlift pump located on mudline. Although, the idea seems to be so easy, considering the complexity of the deep-water drilling special designed equipment required.

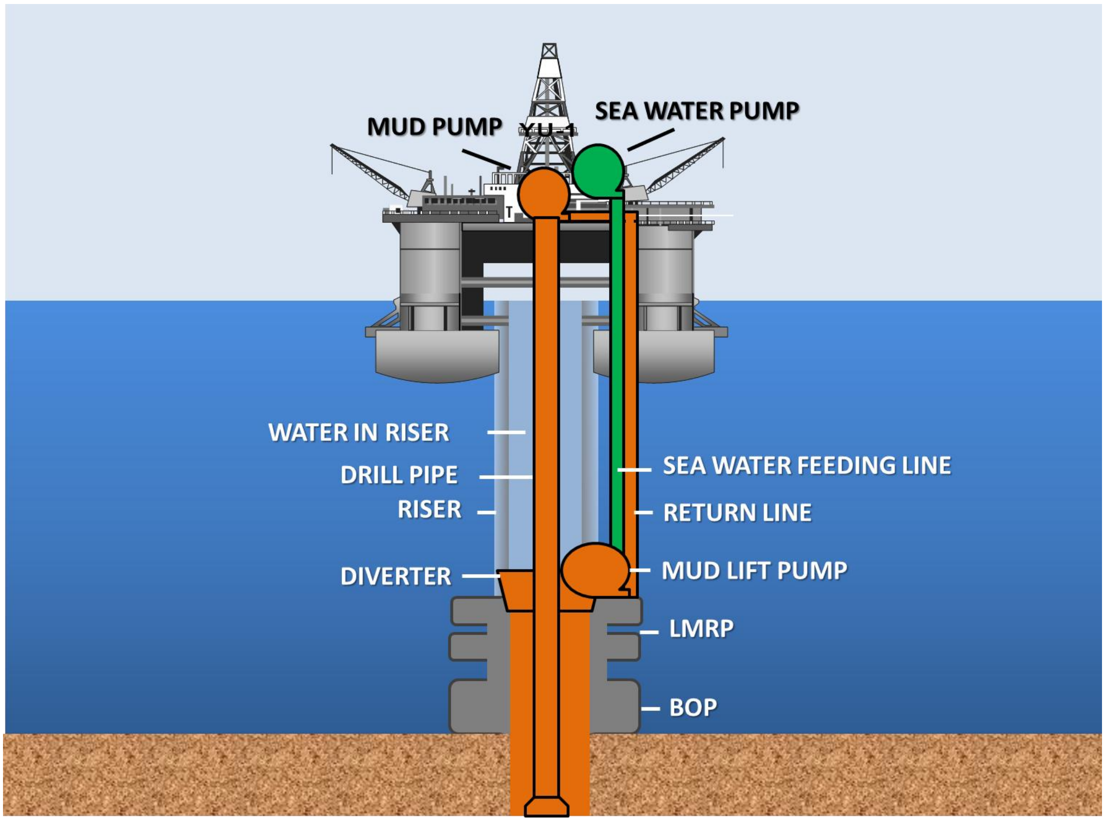

Figure 2.16 Schematic of SubSea Mudlift System.

Mudlift Pump (MLP): It is a diaphragm pump running by sea water which pumped from surface to power the system and can be considered as heart of the SubSea Mudlift system. It is positive displacement pump, works similar to booster line in conventional drilling, which adds energy to return flow and lifts it to drilling unit. [7] The MLP can be used as two triplex pumps, a quintablex, a quadraplex, a triplex, a dublex or as a single chamber pump because each chamber of MLP can be run separately. [6]

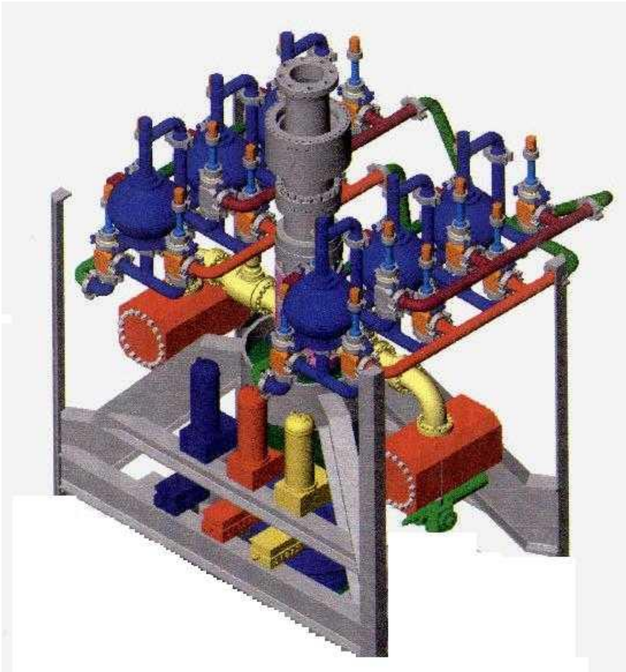

Figure 2.17 Schematic of Mudlift Pump [5].

Solid Processing Unit (SPU): Managing cuttings is one of the important issues in subsea pumping system. Cutting come in variety of size and geometry so to avoid any blockage in system cuttings have to be processed. [9] The solid processing unit was designed to avoid any cuttings bigger than 1 ½" x 1 ½" x 1 ½" enter to mudlift pump. The bigger cuttings are sheared by SPU cutters and after that send to MLP to pump up the drilling unit. SPU has a vital role to keep MLP operating without any blockage, considering the deepwater environment; even small failure in MLP is a reason to stop drilling for days. [6]

Subsea Rotating Device (SRD): It is similar to the conventional rotating heads which serves a mechanical barrier between seawater inside the riser and return mud flow. SRD is an upper part of the SubSea Mudlift system which is 60ft above the MLP. It also used to get pressure above wellhead equal to the seawater pressure, which works in pressure balance environment between riser and wellhead. Sealing element of SRD run on the drill pipe and each trip came to surface for maintenance. [6] [7]

Figure 2.18 Schematic of Subsea Rotating Device [6].

Figure 2.19 Picture of Subsea Rotating Device [10].

Drill String Valve (DSV): different from the single gradient drilling, dual gradient system hydraulic balance based on the dynamic condition. Thus when mud pumps are stopped and well stay in static condition, dual gradient system always has a potential u-tube from drill string to annulus. To avoid this potential u-tube, the valve called Drill String Valve (DSV), is installed to BHA. [2] DSV prevents the u-tube when circulation stops; like connection, tripping and surveying, makes these operations normal as conventional drilling.

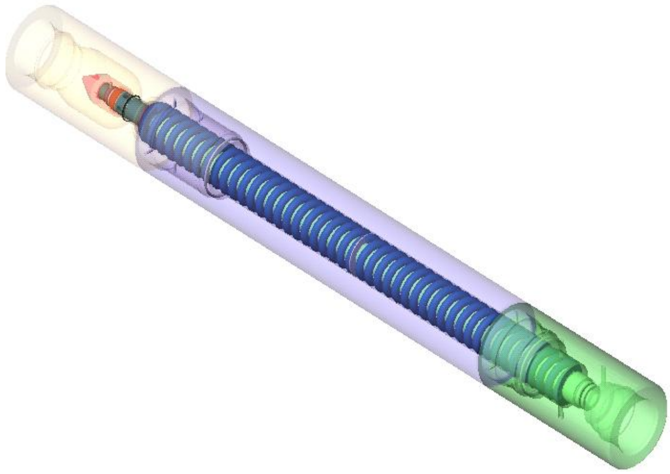

Figure 2.20 Schematic of Drill String Valve [6].

Riser Dump Joint (RDJ): Studies shows that incase of any emergency disconnect, the heavy load, inside the riser because of SRD which is trapped the sea water inside the riser, brings too much forces to subsea system. Thus, the modified riser joint, called Riser Dump Joint, is installed to riser string and during the emergency disconnect it opens and allows to free movement to sea water inside the riser.

2.5.3 U tube

Mud lift system should be considered as a dynamic close circulation system; all hydraulic calculations are made when pumps are on. On the other hand there is a possible u tube affect when pumps are off; considering the higher mud column in drill string, the u tubing phenomena must be examined carefully to perform a safe and successful operation.

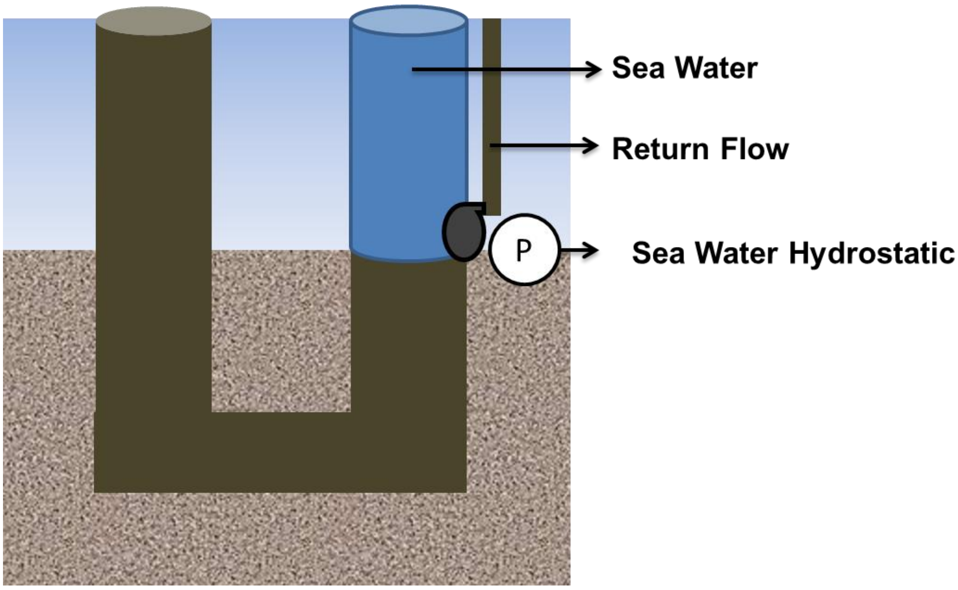

Figure 2.21 Schematic of U-Tube – Dynamic Condition

The inlet pressure of the MLP is maintained to hydrostatic pressure of the sea water. Therefore, when the circulation stops, drilling mud static pressure inside the drill string makes more pressure than MLP inlet pressure; they are not statically balanced. This differential pressure drives the system u-tubing.

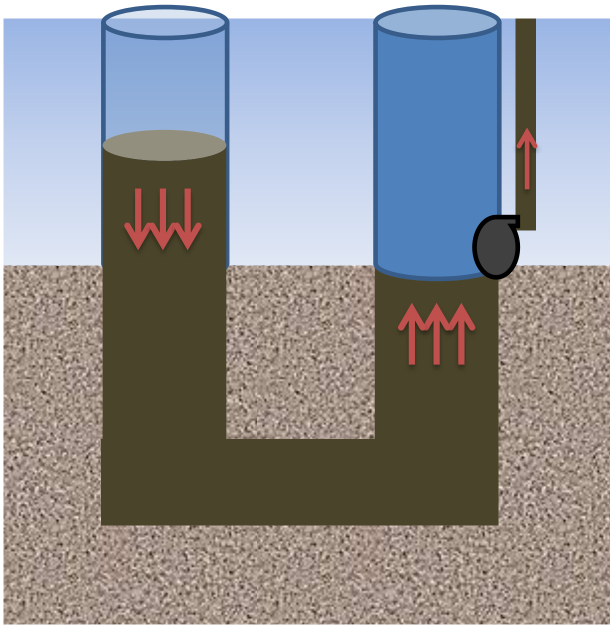

Figure 2.22 Schematic of U-Tube – Static Condition

Since U-tubing is a big challenge for rig crew to manage and makes not possible to operate; DSV was invented to eliminate u-tubing affect. Thus using DSV makes operations (connection, tripping, surveying, etc.) like conventional drilling.

CHAPTER 3

STATEMENT OF THE PROBLEM

Dual Gradient Drilling (DGD) is a new concept that allows reaching ultra deep water targets more economically and safely by eliminating the problems that occur due to the narrow operating window between pore pressure and fracture pressure. Principally, this system minimizes the effect of hydrostatic pressure of the drilling fluid inside the riser and thus on the bottom hole pressure.

The primary objective of DGD is to explore the deep water environment and to drill deeper wells. The system also decreases operational costs, which can be considered as an important primary objective by most major companies.

The main objective of this research is to determine the effect of DGD on operational costs. A first step is to prove the technical advantages of the system by redesigning a conventionally planned well using the DGD system. The new design is compared with the old design and technical advantages are presented. Then the newly designed well is drilled on paper and its performance is compared with the conventional well results. Finally, based on the new design and performance of the well, operational budgets are compared and results are presented.

CHAPTER 4

METHOD OF STUDY

Pore and fracture pressures are the most critical parameters to determine whether the prospect technically can be drilled or not. Based on pressure data of the formation, well trajectory and casing set points are calculated. This pressure information is the starting point of the well engineering phase where well design, casing types, bit types and mud program are determined. From this point of view, a link can be established between pore and fracture pressures and the total drilling operation budget; a more complex pressure behavior means the operational costs will be higher.

Technical difficulties which affect the cost and time of drilling operations can be minimized when the operating window between the pore pressure and fracture pressure is enlarged. Although it is not possible to change earth's pressure behavior, there is a way to eliminate the hydrostatic effect of the water column in the deep water environment; called Dual Gradient Drilling, which has the effect of increasing maneuverability inside the narrow operating window. Increasing the maneuverability inside the operating window decreases the number of required casing strings needed to reach deeper formations which in turn lowers operational costs.

The aim of this study is to investigate the effect of Dual Gradient System on the operational costs. According to this purpose, a deep water well; Alpha well, was studied based on Alpha well drilling history and a new well, Beta Well, is simulated based on Alpha well drilling history by using Dual Gradient System.

From now on total operation cost is called as an AFE (Authority for Expenditure) which is budgetary document, usually prepared by the operator, to list estimated expenses of drilling a well. Such expenses are cover cost of materials which planned to be used in operation, as well as the cost of the services were intended to perform in operation. Although, AFE is prepared prior or operation to get necessary approval from partners, AFE structure is used to follow up the total operation expenditure and represents the final operation cost at the end of the operation. The example AFE structure can be seen in Table 4.1.

Table 4.1 AFE Example

AFE Example	
Material	Cost ($)
Wellhead	xxx.xx
Casing	xxx.xx
Liner & Casing Accessories	xxx.xx
Fuel & Lubricants & Water	xxx.xx
Bits	xxx.xx
Cement & Chemicals	xxx.xx
…	xxx.xx
Services	Cost ($)
Well Design And Planning	xxx.xx
Well Site Supervision & Office Supervision	xxx.xx
Contract Drilling Rig	xxx.xx
Logistic Support Base	xxx.xx
Wellhead Service	xxx.xx
Drilling And Fishing Tools	xxx.xx
Casing & Tubing Running Services	xxx.xx
…	
TOTAL	XXX.XX

Basically, the AFE consists of two section; material and services. Material costs are calculated based on well design; specifications and quantity of wellhead, casing, liner hangers, usage of the fuel, cement chemicals and mud chemicals. Moreover, duration of the operation and necessary services per sections are considered to calculate service costs.

Therefore, this study continues on presenting Alpha Well in section 2.1 and simulation scenario in 2.2.

4.1 Alpha Well

Alpha well is a deep water well in 2175m water depth. Figure 4.1, illustrates depth - pressure data of the well. The yellow area represents the narrow operational window between pore pressure and fracture pressure, which is lower than 1ppg in some sections.

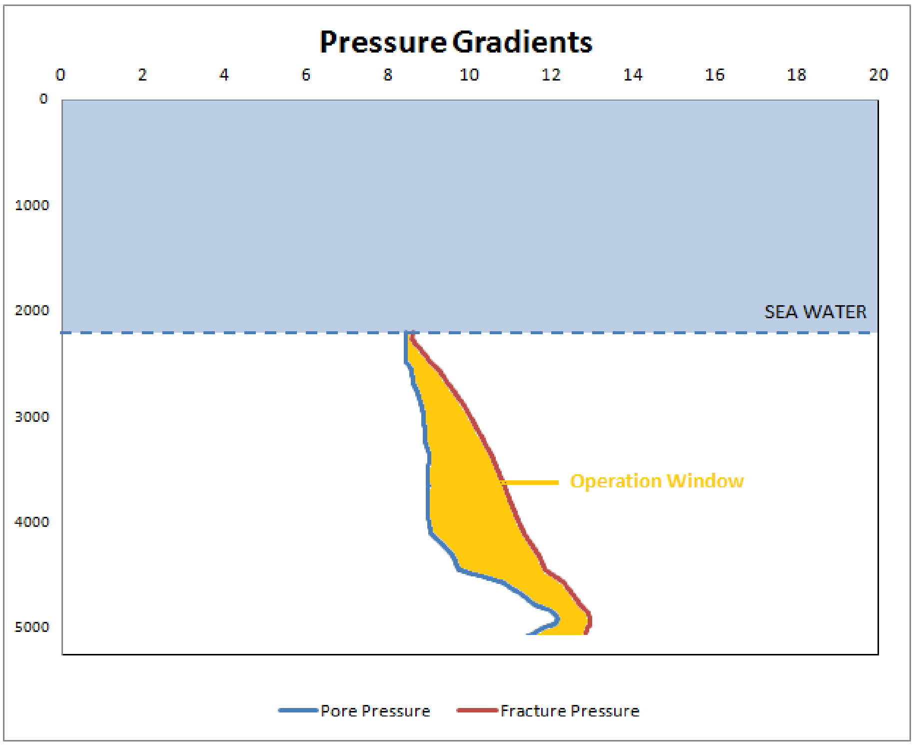

Figure 4.1 Pressure Graph of Alpha Well

Alpha well was designed with 8 sections, 7 of them were cased. The information about formation pressures, mud weights and casing setting depths is presented in Figure 4.2.

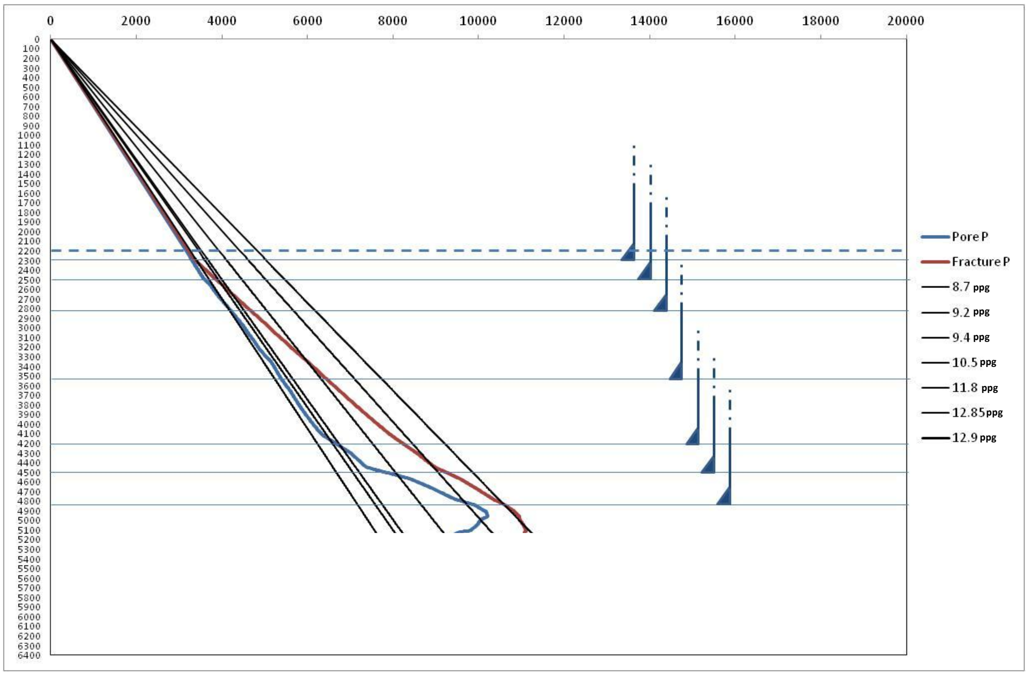

Figure 4.2 Pressure Graph of Alpha Well with mud weight.

The casings setting depths and types are tabulated hereunder;

Table 4.2 Alpha Well Casing List

Well Alpha			
Casing(inch)	**Name**	**Type**	**Shoe Depth (m)**
36	Conductor	Casing	2278.5
22	Surface	Casing	2498.7
18	Intermediate	Casing	2820.0
16	Intermediate	Casing	3527.0
13 5/8	Intermediate	Casing	4212.0
11.88	Intermediate	Liner	4510.0
9 5/8	Production	Liner	4845.0

Alpha well was drilled in 162 days, with an average of 35% NPT (Non Productive Time), shown in Figure 4.3.

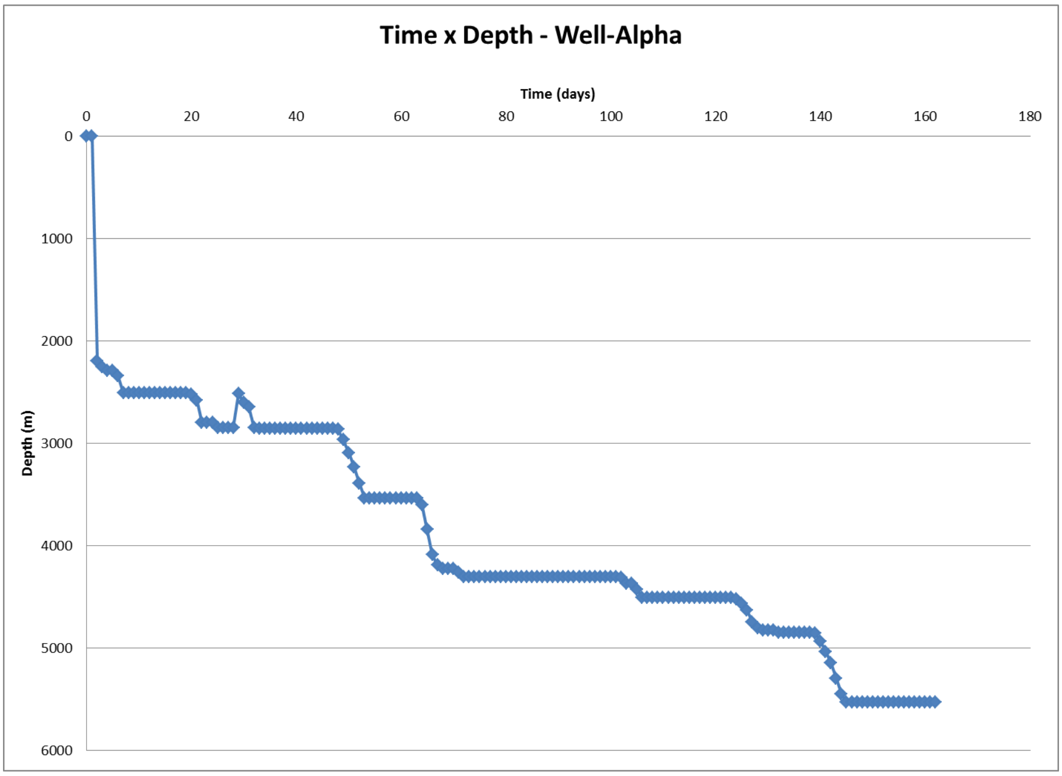

Figure 4.3 Time vs Depth Graph of Alpha Well.

The breakdown of total operation schedule is tabulated as per sections hereunder.

Table 4.3 Time Breakdown of Alpha Well Per Sections

SECTIONS	TIME (hrs)
PHASE ZERO	62
PHASE 1 – Conductor Casing	73
PHASE 2 - Surface Casing	290.5
PHASE 3 - Intermediate Casing	719.5
PHASE 4 - Intermediate Casing	370
PHASE 5 - Intermediate Casing	927
PHASE 6 - Intermediate Casing	528
PHASE 7 - Intermediate Casing	355
PHASE 8 - 8 1/2" Hole	376.5
PLUG & ABANDON	167.5
TOTAL	**3869**

4.2 Simulation Scenario

Simulation of the Alpha well is performed in 3 steps, given in Figure 4.4;

1. Designing Beta well (Re-designing Alpha well with DGD system).
2. Drilling Beta well on paper based on Alpha well's drilling timeline.
3. Establishing Beta well AFE breakdown.

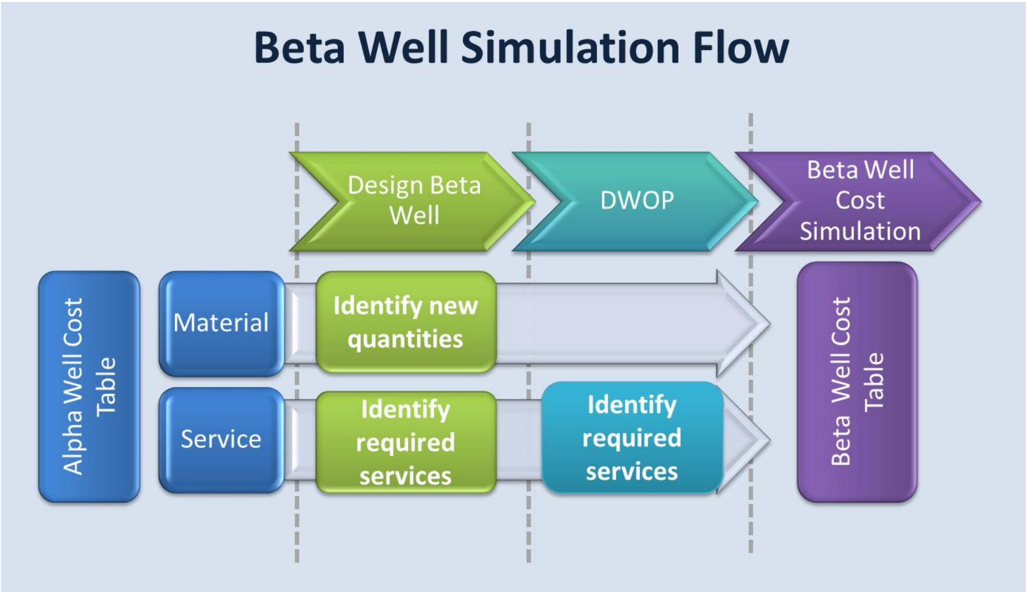

Figure 4.4 Beta Well Simulation Flow

4.2.1 Designing Beta well (Re-designing Alpha well with DGD system)

Purpose: To determine the materials and services required for Beta Well.

Pressure data of the Alpha well was re-arranged by eliminating the water column, like an onshore well operation. Principally, the pressure readings at the mud line are transferred to the sea level. This pressure transfer could be considered as a depth correction from Alpha well to Beta well.

After making the depth revision, the Beta well was designed by using software called Stress Check according to new depth and pressure data. Casing types and setting depths were determined and wellhead & bit types were selected.

4.2.2 DWOP (Drill Well on Paper) Beta well

Purpose: To determine duration of the operation (for calculating costs of services which are directly proportional with duration).

After completion of the engineering phase where well architecture was completed and required materials and services were determined, the Beta well drilling program was written. The Alpha well timeline was separated into 6 sub-operations which were identified based on industry norms. Duration requirements, identified to perform each sub-operation, were designated as PT (productive time) and NPT (non productive time), shown in Table 4.4. This data was used to simulate Beta well and to calculate the duration of the Beta well drilling operation.

Table 4.4 Operation Sub Categories

OPERATION SUB CATAGORIES	
Drilling Operation	Since the Beta well was simulated from the Alpha well, the location and formations of the Beta well are the same as the Alpha well. Thus, same ROP values were used for equivalent depths to calculate drilling time. However, since section lengths of the Beta Well are longer than the Alpha well, in some cases, one section of Beta well covers two sections of the Alpha well. In such cases, the lower ROP value of the two sections was used for the single section of the Beta well.
Enlargement Operation	As the Alpha well is ultra-deep water well, some sections required enlargement to set the required

	casing strings. However, with the technical advantages provided by DGD, enlargement was not required for the Beta well. Thus the time spent for enlargement was not taken into account for the Beta well.
Casing & Cement Operation	The time requirement was calculated based on the length of the casing.
Logging Operation	The time requirement was calculated based on the length of logged interval.
Drill Out	It is the operation in which cement is drilled out after cementing the casing, to start a new section. The time required to perform this operation was assumed the same as the Alpha well.
BOP Operation	The Blow Out Preventer (BOP) should be tested periodically. This operation refers the time required to perform BOP testing and was assumed the same as the Alpha well.

Table 4.5 Alpha Well Operation Breakdown- Detailed

APLHA WELL OPERATION BREAKDOWN	TIME (HRS)	NPT (HRS)	PT (HRS)
PHASE ZERO	**62.00**		
Preparing to Spud	62.00	5.50	56.50
PHASE 1	**73.00**		
Drilling	10.00	0.00	10.00
Casing and Cement	49.00	1.50	47.50
Drill Out	14.00	0.00	14.00
PHASE 2	**290.50**		
Drilling	16.00	0.00	16.00
Casing and Cement	98.00	47.00	51.00
BOP	132.00	21.50	110.50
Dual Gradient System Installation	-	-	-
Drill Out	44.50	4.50	40.00
PHASE 3	**719.50**		
Drilling Pilot Hole	270.00	80.50	189.50
Enlarging Pilot Hole	68.00	26.00	42.00
Logging	25.50	0.00	25.50
Casing and Cement	65.50	1.00	64.50
BOP Test	221.00	178.00	43.00
Drill Out	69.50	21.00	48.50
PHASE 4	**370.00**		
Drilling	188.50	70.00	118.50
Logging	41.50	1.00	40.50
Casing and Cement	84.50	0.50	84.00
BOP	29.00	2.00	27.00
Drill Out	26.50	0.50	26.00
PHASE 5	**927.00**		
Drilling	660.50	500.00	160.50
Casing and Cement	126.50	0.50	126.00
BOP	36.50	5.50	31.00
Logging	19.50	2.00	17.50
Drill Out	84.00	43.50	40.50
PHASE 6	**528.00**		
Drilling	179.50	54.00	125.50
Logging	0.00	0.00	0.00
Enlarging Hole	56.50	0.00	56.50
Liner and Cement	234.00	97.50	136.50
BOP	21.50	3.00	18.50
Drill Out	36.50	6.50	30.00
PHASE 7	**355.00**		
Drilling	105.00	1.00	104.00
Logging	45.00	1.00	44.00
Liner and Cement	128.00	6.50	121.50
BOP	34.50	1.00	33.50
Drill Out	42.50	16.00	26.50
PHASE 8	**376.50**		
Drilling	146.00	21.50	124.50
Logging	230.50	155.50	75.00
PLUG & ABANDON	**167.50**		
Cement Plugs	111.50	5.50	106.00
Abandon	56.00	3.00	53.00
TOTAL	**3,869**	**1,384**	**2,485**

4.2.3 Establishing Beta Well AFE breakdown

Purpose: Set benchmarks on AFE to simulate Beta well AFE.

The AFE of Alpha well was tabulated in Table 4.5; with service and material breakdowns. Since in the final stage of this research the economical benefit of DGD system will be calculated in percentages, all services and material costs of the Alpha well were converted to percentages to express their effects on total operational cost. Thus, in the following steps of this study, these percentages refer to the cost of the mentioned service or material.

Unit price of material and service in the Beta well was assumed the same as the Alpha well since the operation was performed in same location, at the same time and with the same companies. The price of any item in Beta well is taken from Alpha well.

In order to establish a link between the two wells, four benchmarks were determined.

Material Based: It is considered for the material section in AFE; wellhead, casing, bit, liner hanger, etc. The amount of material is the only factor for these items to calculate their costs. Therefore based on the Beta well design, amount of the material is determined and cost of same is calculated considering its unit price by Alpha well. *Parameters were determined based on the Beta well design.*

Time Based: There are rental services required to perform the drilling operations such as MWD (Measuring While Drilling), LWD (Logging While Drilling) tools, rental charge of the drilling unit, mud logging services, etc. Although small changes can be observed depending on the quantity of tools used in some service lines such as MWD/LWD, considering the total operation time, these changes are negligible. Thus, daily averages of these services can be used to calculate the Beta well operational costs considering the duration of the drilling campaign. For instance, as the duration of the Beta well is 1.2 times longer than the Alpha well, the rental charge of the drilling unit increases with the same ratio of 1.2. *Parameters were determined based on Beta well operation duration calculated from the DWOP.*

Section Based: Section based analysis show services and/or material requirements for specific sections or specific time requirements which are not purchased for all sections or rented for the whole operation. Thus, the ratio is dependent on the number or length of services performed. For instance; there were two liner hangers used in the Alpha well whereas there was only one used in the Beta well. Thus, the cost of liner hangers is decreased by half in the Alpha well as compared to the Beta well. Moreover, underreaming service costs depend on usage time which is 10hrs in the Beta well and 491.5hrs in the Alpha Well, which reduces the total cost of this service by almost 88%. *Parameters were determined based on the Beta well design.*

Fixed Cost: Fixed cost criterion is set for services which are the same for both the Alpha and Beta wells. For instance, as an environmental impact assessment was performed for the Alpha well; an environmental impact assessment must also be performed for the Beta well. Thus, the cost of this service must be same in both wells.

Table 4.6 Alpha Well AFE Breakdown

ALPHA WELL AFE BREAKDOWN	Weight (%)	Base of Simulation
MATERIALS		
WELLHEAD	0.43%	Material Based
CASING	2.15%	Material Based
LINER HANGER	0.30%	Material Based
CASING ACCESSORIES	0.03%	Material Based
RIG FUEL & LUBRICANTS & WATER	1.69%	Time Based
BITS	0.64%	Material Based
CEMENT & CHEMICALS	1.39%	Material Based
DRILL/COMPLETION FLUID MATERIALS	2.64%	Material Based
TOTAL MATERIAL	*9.28%*	
SERVICES		
WELL PLANNING	0.76%	Fixed Cost
SUPERVISION	4.50%	Time Based
CONTRACT DRILLING RIG	56.02%	Time Based
ROV	0.70%	Time Based
AIR TRANSPORTATION (HELICOPTER)	-	-
Helicopter Mobilization Costs	1.04%	Fixed Cost
Helicopter Operational Cost	2.81%	Time Based
Helicopter Demobilization Cost	0.14%	Fixed Cost
MARITIME TRANSPORTATION	-	-
PSV Mobilization Cost	0.75%	Fixed Cost
PSV Operational Cost	3.41%	Time Based
PSV Demobilization Cost	0.56%	Fixed Cost
LOGISTIC SUPPORT BASE	2.89%	Time Based
WELLHEAD SERVICE	0.84%	Time Based
DRILLING RENTAL AND FISHING TOOLS	0.45%	Time Based
UNDERREAMER SERVICE	0.98%	Section Based
LINER HANGER SERVICE	0.35%	Section Based
CASING & TUBING RUNNING	0.93%	Section Based
H2S SERVICES	0.15%	Time Based
DIRECTIONAL TOOLS & SERVICE	0.76%	Time Based
MWD, LWD & APWD TOOLS & SERVICE	1.53%	Time Based
DRILL/COMPLETION FLUID SERVICE	0.52%	Time Based
OPEN HOLE & CMT LOGS	7.17%	Section Based
WELL SITE LOCATION/ RIG POSITIONING	0.03%	Fixed Cost
O.S. SITE SURVEY/ ENV. BASE LINE SURVEY	0.22%	Fixed Cost
MUD LOGGING	0.28%	Time Based
CEMENTING SERVICE	0.82%	Time Based
COMMUNICATION	0.17%	Time Based
CATERING	0.07%	Time Based
OTHER RENTALS & SERVICES	1.87%	Time Based
TOTAL SERVICES	*90.72%*	
TOTAL	*100.00%*	

CHAPTER 5

SIMULATION RESULTS, ANALYSIS AND DISCUSSION

5.1 Design Beta Well

The pressure data of the Alpha well was transformed to the new depth profile considering the DGD system effect. The pore pressure of the Alpha well at 2195m is 3156psi. After elimination the water column which is 2175m, same pressure point was shifted to 20m in Beta Well. This correction was applied to all pressure data of Alpha well.

Table 5.1 Example Depth Correction

Alpha Well Depth (m)	Pore pressure (psi)	Beta Well Depth (m)
2195	3156	20
2266	3258	91

After this process, pressure vs depth graph of Beta well was establish and preliminary casing points were determined which are presented in Figure 5.1. The Beta well has six sections with five casing strings, where the Alpha well had eight sections with seven casing strings.

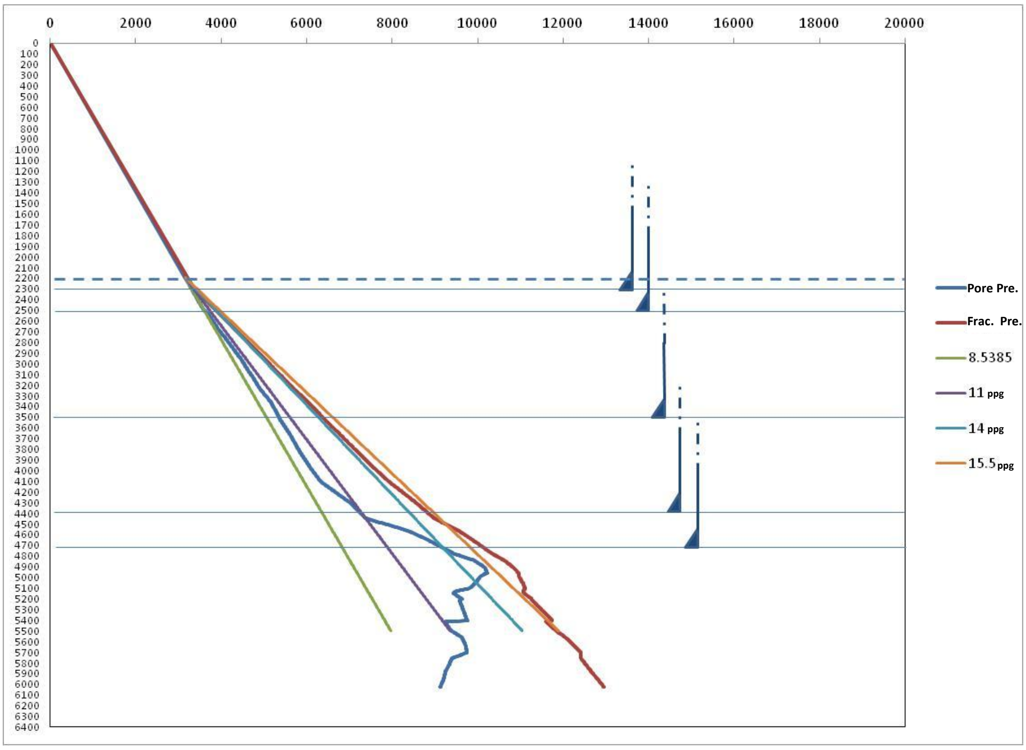

Figure 5.1 Pressure vs Depth Graph of Beta Well.

After selection of preliminary casing depths, the final well architecture was determined by Stress Check, which is casing design software. The final well design was presented in Figure 5.2 and the final casing selections are presented in the Table 5.1.

According to Beta well simulation flow in Section 2.2, new quantities of materials, which are listed hereunder and required services are determined necessary for Beta well in the following sections.

- Wellhead
- Casing Types, Casing Accessories, Liner hanger & Cement Chemicals
- Mud Chemicals
- Bit

Moreover, it was determined that all services were performed in Alpha well are also required in Beta well. Although, the duration of the services is calculated under Section 3.2 DWOP Beta well one by one, in this section well design based services are studied and results are presented.

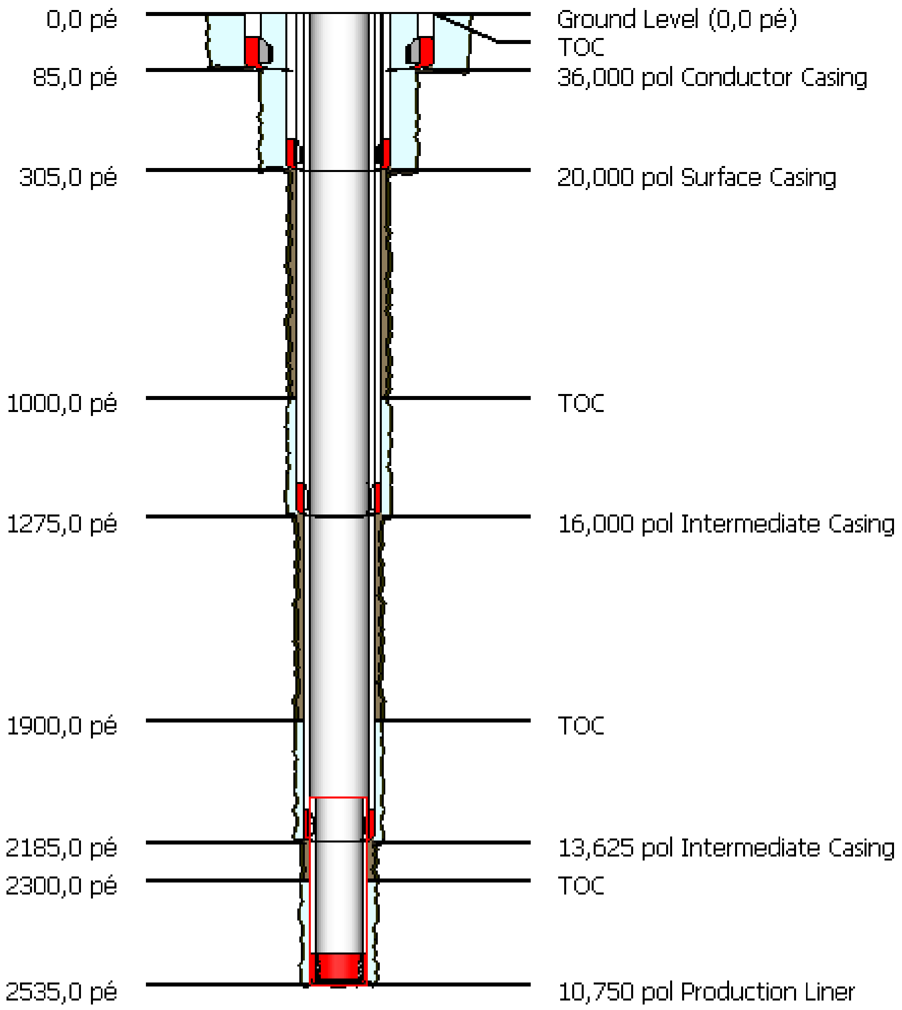

Figure 5.2 Beta Well Architecture

Table 5.2 Beta Well Casing List

Casing			Measured Depths (m)		
OD (inch)	Name	Type	Hanger	Shoe	TOC
36,000	Conductor	Casing	0,0	85,0	0,0
20,000	Surface	Casing	0,0	305,0	0,0
16,000	Intermediate	Casing	0,0	1275,0	1000,0
13,625	Intermediate	Casing	0,0	2185,0	1900,0
10,750	Production	Liner	2135,0	2535,0	2300,0

5.1.1 Wellhead Selection

The reduction in casing strings also allowed using a simpler wellhead design in the Beta well. According to market research, the simple wellhead, which complies with the Beta well requirements, is 50% cheaper than the complex wellhead used in the Alpha well.

Below is the wellhead selection of both wells;

- Alpha wellhead: 36/30 x 28/26 x 22 x 18 x 16 x 13 5/8 x 10 ¾ x 7
- Beta wellhead: 36/30 x 20 x 16 x 13 5/8 x 10 ¾ x 7

Moreover, the complex deep water wellhead used in the Alpha well had sub-mudline casing receptacles which required extra haldling attention to avoid damage while running casings or large diameter downhole tools. However, the simple wellhead used in the Beta well not only provided economical benefit, but also prevented such kinds of operational risks.

Results - *Simpler and cheaper wellhead.*

- *Easier installation.*

5.1.2 Casing Selection (Casing Types, Casing Accessories, Liner hanger & Cement Chemicals)

Although, design results allowed using low grade casings for some sections of the Beta well, to make a better cost comparison, the same grades were selected in the Beta well as in the Alpha well. Moreover, there were two assumptions made while calculating the cost of the Beta well. Even though smaller casing sizes were selected (20” and 10 3/4” casings, instead of 22” and 11 7/8” casings) higher casing prices were taken as base prices instead of lower casing prices, which was a conservative approach considering the worst case.

Table 5.2, shows the casing sizes of the Alpha well, with the related costs of the casing sections including casing, casing accessories, liner hanger and cementing chemicals.

The percentages represent the weight of each section in its material group. For instance, cost of the 13 5/8” casing is equal to 50.02% of the total casing cost; the cost of the 9 5/8” cement job is equal to 6.55% of the total cement cost of the Alpha well. These percentages were used as base values while calculating costs of the Beta well.

Table 5.3 Alpha Well Casing Summary

		COST			
SECTION	CASING LENGTH (m)	CASING	CASING ACC.	LINER HANGER	CEMENT CHEM.
36" Casing	71.5	8.44%	included casing		15.69%
22" Casing	291.7	9.25%	included casing		24.71%
18" Casing	378.4	3.12%	31.12%		8.81%
16" Casing	1155.8	11.87%	18.31%		5.75%
13 5/8" Casing	2005	50.02%	36.36%		9.84%
11 7/8" Casing	250	7.05%	8.57%	50.16%	16.14%
9 5/8" Casing	751.4	10.24%	5.64%	49.84%	6.55%
P&A					12.53%
TOTAL		**100.00%**	**100.00%**	**100.00%**	**100.00%**

Table 5.3 represents the calculation of the costs based on the Beta well. Casing costs were calculated proportional to the length of the casing; if the length of casing increases in Beta well, cost of the casing also increases by the same ratio.

Cost of the casing accessories does not change with the length change; the cost is fixed for each section. Thus, the cost of the accessories were taken directly from the Alpha well and used in the Beta well, otherwise this cost was not reflected in the Beta well cost. This approach was also used for liner hanger and cement chemical cost calculations.

Table 5.4 Beta Well Casing Summary

		COST			
	CASING LENGTH	CASING	CASING ACC.	LINER HANGER	CEMENT CHEM.
36" Casing	85	9.54%	included casing		15.69%
20" Casing	305	9.69%	included casing		24.71%
16" Casing	1275	13.10%	31.12%		5.75%
13 5/8" Liner	2185	54.51%	36.36%		9.84%
10 3/4" Liner	400	7.72%	8.57%	50.16%	16.14%
P&A					12.53%
TOTAL		94.56%	76.05%	50.16%	84.65%

Table 5.4 shows the comparison between Alpha well and Beta well.

Table 5.5 Comparison Table Alpha – Beta

	CASING	CASING ACC.	LINER HANGER	CEMENT CHEM.
Well Alpha	100%	100%	100%	100%
Well Beta	95%	76%	50%	85%
Difference	94.56%	76.05%	50.16%	84.65%

Results - *Fewer casing variety.*

- *Less casing string, casing accessories and cement material.*

5.1.3 Mud Chemicals

Two criteria were used to make the comparison; maximum section volume and mud losses. Assuming drilling the same formation, mud losses were same and equal in the Beta well as in the Alpha well. Then ration between the amounts of mud generated and mud lost, projected to Beta well were proportional to the maximum section volumes of the Beta and Alpha wells.

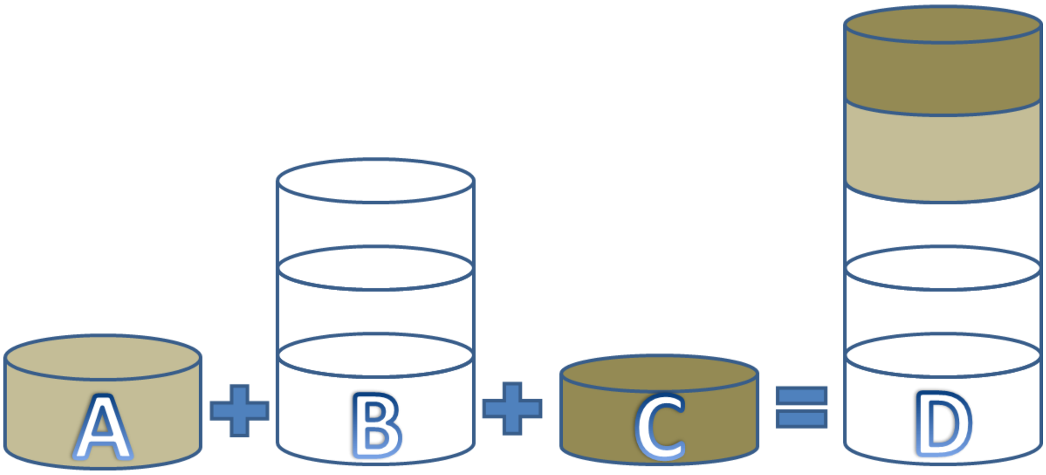

Figure 5.3 Relation To Calculate Mud Consumption

To estimate the Beta well mud chemical cost (based on the Alpha well consumption), the basic relation is established; total volume is summation of “max. well volume”, “volume required to condition the drilling fluid” and “volume of drilling fluid losses”.

According to section volumes and final mud report tabulated in Table 5.5, maximum volume (A) and generated mud volume (D) is summarized in Table 5.6.

Table 5.6 Alpha Well Volume Summary

SECTIONS	VOLUME (bbl)	TOTAL VOL. (bbl)	MUD VOL. (bbl)	MUD LOSSES (bbl)
SECTION I + II				
42" Hole	402	1185	5650	
28" Hole	783			
SECTION III				
Riser	2605	3522	14201	8527
22" Casing	372			
22" Open Hole	546			
SECTION IV				
Riser	2605	3855	14245	8114
18" Casing	338			
20" Open Hole	912			
SECTION V				
Riser	2605	4092	7895	7895
16" Casing	812			
17 1/2" Open Hole	676			
SECTION VI				
Riser	2605	3790	3204	2412
13 5/8" Casing	978			
14 3/4" Open Hole	207			
SECTION VII				
Riser	2605	3831	1918	713
13 5/8" Casing	972			
11 7/8" Casing	91			
12 1/4" Open Hole	162			
SECTION VIII				
Riser	2605	3857	1801	4553
13 5/8" Casing	920			
9 5/8" Casing	174			
8 1/2" Open Hole	158			

Table 5.7 Alpha Well Maximum Volume

Max. Volume (bbl)	Total Mud Vol. (bbl)	Total Mud Losses (bbl)
4,092	48,914	32,214

Based on this information, for the Alpha well total mud losses (C) were reported as 32,214bbl and the remaining volume was correlated with the maximum well volume. The idea is that in a perfect operation (without any losses) except for conditioning mud, the generated mud volume can be used for all sections, thus maximum mud volume is equal to the maximum hole volume. Based on that, a maximum well volume (A) and generated mud volume (without losses) (A+B) ratio was calculated as 4.08, Table 5.7.

Table 5.8 Mud – Volume Ratio

Total Mud Dilution	48,914
Total Mud Losses	32,214
Net Mud Volume -Perfect Operation (no losses)	16,700
Biggest Well Volume	4,092
Well Vol. - Mud Vol. Ratio	4.08

After calculating the maximum well volume and total mud volume generated without losses for Alpha well which is (A+B) / (A). This ratio was used to calculate total mud volume for Beta well via same relation.

Maximum hole volume (A) was calculated as 1,995 bbl based on Table 5.9 for Beta well. By using the ratio calculated for the Alpha well and assuming drilling the same formation as the Alpha well, the same losses (C) were also added to calculate the total mud (D) required to be generated for Beta well, Table 5.10. Therefore total required volume for Beta well was calculated 40,356.95 bbl.

Table 5.9 Beta Well Volume Summary

SECTIONS	VOLUME (bbl)	TOTAL VOL. (bbl)
SECTION I + II		
Return Liner 5"	176	1480
42" Hole	478	
28" Hole	827	
SECTION III		
Return Liner 5"	176	1437
20" Casing	315	
17 1/2" Hole	946	
SECTION IV		
Return Liner 5"	176	1702
16" Casing	895	
14 3/4" Hole	631	
SECTION V		
Return Liner 5"	176	1409
13 5/8" Casing	1066	
12 1/4" Hole	167	
SECTION VI		
Return Liner 5"	176	1995
13 5/8" Casing	1041	
10 3/4" Casing	195	
8 1/2" Hole	583	

Table 5.10 Beta Well Mud – Volume Calculation

Well Vol. - Mud Vol. Ratio	4.08
Biggest Well Volume	1,995
Net Mud Volume -Perfect Operation (no losses)	8,143
Total Mud Losses	32,214
Total Mud Dilution	40,356.95

Result: - *Drilling riser was eliminated and 5” return line was used for return flow, so quantity of drilling fluid in riser was eliminated. It decreases the total generated mud volume.*

- *New well design may allow to drill small hole sizes, which slightly decreases the total generated mud volume.*

5.1.4 Bit Selection

Weight of each bit cost, used in Alpha well, was calculated based on total bit cost. According to the Beta well design, the bit selection was made from the Alpha well inventory. In Table 5.10, “x” represents Alpha well bit selection and “o” represents the Beta well bit selection. Based on this study, %74.03 of Alpha well bit cost is enough to cover Beta well.

Table 5.11 Bit Selection Table

Well Alpha (x)	BIT NUMBER - COST													Well Beta (o)
SECTIONS	1	2	3	4	5	6	7	8	9	10	11	12	13	SECTIONS
SECTION I	xo													SECTION I
SECTION II	xo													SECTION II
SECTION III		xo	xo											SECTION III
SECTION IV				x	x									
SECTION V						xo	xo							SECTION IV
SECTION VI								x	x	x				
SECTION VII										o	xo			SECTION V
SECTION VIII												xo	xo	SECTION VI
100.00%	3.88%	13.99%	1.24%	12.83%	2.44%	10.47%	11.35%	1.56%	9.14%	9.07%	16.71%	6.16%	1.18%	74.03%

Result: - *Decrease in bit quantity.*

5.1.5 Section Based Service

Some of the services were not charged based on time; the cost of these services is related with the number of services provided or length of interval performed. Table 5.11, shows the 4 services with their criteria of simulation. The calculated ratio refers the cost effect of services for the Beta well.

Liner hanger quantity is decreased from 2 to 1 with new well design. Beta well has only one liner hanger.

Casing tubing services can considered as callout based services, when the service is required, the contractor team and material are mobilized to drilling unit and after completion of the service they are demobilized out of the drilling unit. Although, duration of the services proportional with the length of the casing string, in general charges per sections are close to each other; this is why in this study service cost calculated proportional to number of cased section assuming the cost of services per section is identical.

Considering the Beta well reaches same target as Alpha well and evaluate the same formation interval, wireline logging interval is not change and cost of this service remains same.

The underreamer service is required in complex well design where bit could not pass through inside the previous casing to drill next section. Simpler well design in Beta well results in fewer drilling sections, which eliminates the necessity of underreamer services. In Beta well, this service used just for first section; hole opener for 42”x 28” section.

Table 5.12 Section Based Services

Services	Criteria	Well Alpha	Well Beta	Ratio
Liner Hanger Service	Liner Hanger Number	2	1	50.00%
Casing & Tubing Running	Casing and Liner Number	7	5	71.43%
Open Hole & CMT Log	Logging Length	3024	3005	99.37%
Underreamer Service	Underream Service Time	491.5	10	2.03%

Result:

- *One liner hanger out of two was eliminated because of simpler well design. Thus, necessity of liner hanger services reduces 50%.*
- *Due to lower value of casing string, casing & tubing running services is reduced 71.43% accordingly.*
- *As total depth of the well is not changed, the wireline logging interval does not change.*
- *Due to the simpler well design, necessity of underreamer service is almost eliminated.*

5.2 DWOP Beta Well

In this section, drilling operations of the Beta well was simulated on paper. All steps of the Alpha drilling plan were revised based on the Beta well design. The main milestone of this study was determining ROP rates; considering that both wells were drilled in the same formation, based on bit performance of Alpha well transferred to Beta Table 5.12. If the section of the Beta well was longer than the Alpha well, the minimum ROP in the Alpha well was transferred to the Beta well, reference Table 5.13.

Table 5.13 Alpha – Beta Section Comparison

Well Alpha				Section Matching	Well Beta			
Hole Size (inch)	Length (m)	Casing (inch)	Length (m)		Hole Size (inch)	Length (m)	Casing (inch)	Length (m)
42	74.5	36	71.5		42	85.0	36	85.0
28	225.5	22	291.7		28	220.0	20	305.0
22	346.0	18	378.4		-	-	-	-
20	683.0	16	1155.4		17 1/2	970.0	16	1275.0
17 1/2	684.0	13 5/8	2005.0		14 3/4	910.0	13 5/8	2185.0
14 3/4	291.0	11.875	365.1		-	-	-	-
12 1/4	339.0	9 5/8	751.4		12 1/4	350.0	10 3/4	400.0
8 1/2	681.0				8 1/2	775.0		

Table 5.14 ROP Calculation

Alpha - Beta Time Relation					
Drilling	ROP Correction			Logging	Casing
	Drilling Time	ROP			
x 1.14	10.00	7.45	OK -SAME	-	x 1.19
x 0.98	16.00	14.09	OK -SAME	-	x 1.05
-	42.00	8.24		-	-
x 1.42	118.50	5.76	OK (LOWER)	x 1.42	x 1.11
x 1.33	160.50	4.26	NO (USE LOWER	x 1.33	x 1.09
-	125.50	2.32	ROP) x 2.45	-	-
x 1.03	104.00	3.26	OK -SAME	x 1.03	x 0.52
x 1.14	124.50	5.47	OK -SAME	x 1.14	-

There are 3 important assumptions that were set in this section of the study; (1) due to technical issues, the Alpha well had a pilot hole section. As the Beta well was drilled in the same location, the same technical concerns must be considered as well. (2) Because of the Alpha well design, 3 sections were drilled and simultaneously enlarged. To make a conservative simulation, although ROP values for these sections were considered to be slower than drilling operations without enlarging, during the simulation these rates were applied directly to the Beta well. (3) Installation of the Dual Gradients System was an additional operation to the revised timeline. The estimated time for installation was considered as

50% of the BOP installation time. Actually, as BOP installation also covers deploying same and DGD equipments to sea bed in single run; half of the BOP installation time could be considered more than enough to make a conservative estimation. Table 5.15 demonstrates the timeline of the Alpha operation; which is also separated by NPT (non-productive time) which occupied 35.77% of the total operation time, and PT (productive time). The simulation of the Beta well was tabulated under “Beta Opr. Time” column, which was correlated with Alpha operation PT by “Time Relation” which is the result of the studies mentioned above.

Based on DWOP results; the Beta well was drilled in 2,262 hours without any NPT, then considering the same drilling location with the same rig and crew, a 35.77% NPT was applied. The comparison of the total operation hours for both the Alpha and Beta wells are tabulated in table 5.14.

Table 5.15 Total Operation Time

TOTAL OPERATION TIME	
Well Alpha	3869
Well Beta	3072
Difference	79.39%

Table 5.16 Alpha Well Timeline

APLHA WELL OPERATION BREAKDOWN	TIME (HRS)	NPT	PT	Time Relation	Beta Opr. Time
PHASE ZERO	**62.00**				
Preparing to Spud	62.00	5.50	56.50	1.00	56.50
PHASE 1	**73.00**				
Drilling	10.00	0.00	10.00	1.14	11.40
Casing and Cement	49.00	1.50	47.50	1.19	56.53
Drill Out	14.00	0.00	14.00	1.00	14.00
PHASE 2	**290.50**				
Drilling	16.00	0.00	16.00	0.98	15.68
Casing and Cement	98.00	47.00	51.00	1.05	53.55
BOP	132.00	21.50	110.50	1.00	110.50
Dual Gradient System Installation	-	-	-		55.25
Drill Out	44.50	4.50	40.00	1.00	40.00
PHASE 3	**719.50**				
Drilling Pilot Hole	270.00	80.50	189.50	1.00	189.50
Enlarging Pilot Hole	68.00	26.00	42.00		
Logging	25.50	0.00	25.50		
Casing and Cement	65.50	1.00	64.50		
BOP Test	221.00	178.00	43.00		
Drill Out	69.50	21.00	48.50		
PHASE 4	**370.00**				
Drilling	188.50	70.00	118.50	1.42	168.27
Logging	41.50	1.00	40.50	1.42	57.51
Casing and Cement	84.50	0.50	84.00	1.11	93.24
BOP	29.00	2.00	27.00	1.00	27.00
Drill Out	26.50	0.50	26.00	1.00	26.00
PHASE 5	**927.00**				
Drilling	660.50	500.00	160.50	2.45	393.23
Casing and Cement	126.50	0.50	126.00	1.09	137.34
BOP	36.50	5.50	31.00	1.00	31.00
Logging	19.50	2.00	17.50	1.33	23.28
Drill Out	84.00	43.50	40.50	1.00	40.50
PHASE 6	**528.00**				
Drilling	179.50	54.00	125.50		
Logging	0.00	0.00	0.00		
Enlarging Hole	56.50	0.00	56.50		
Liner and Cement	234.00	97.50	136.50		
BOP	21.50	3.00	18.50		
Drill Out	36.50	6.50	30.00		
PHASE 7	**355.00**				
Drilling	105.00	1.00	104.00	1.03	107.12
Logging	45.00	1.00	44.00	1.03	45.32
Liner and Cement	128.00	6.50	121.50	0.52	63.18
BOP	34.50	1.00	33.50	1.00	33.50
Drill Out	42.50	16.00	26.50	1.00	26.50
PHASE 8	**376.50**				
Drilling	146.00	21.50	124.50	1.14	141.93
Logging	230.50	155.50	75.00	1.14	85.50
PLUG & ABANDON	**167.50**				
Cement Plugs	111.50	5.50	106.00	1.00	106.00
Abandon	56.00	3.00	53.00	1.00	53.00
TOTAL	**3,869**	**1,384**	**2,485**		**2,262**

In Figure 5.3, the graph shows the time versus depth comparison of both the Alpha and Beta wells; Alpha operations took 161days, whereas Beta well was completed in 128 days resulting in a 33 day savings.

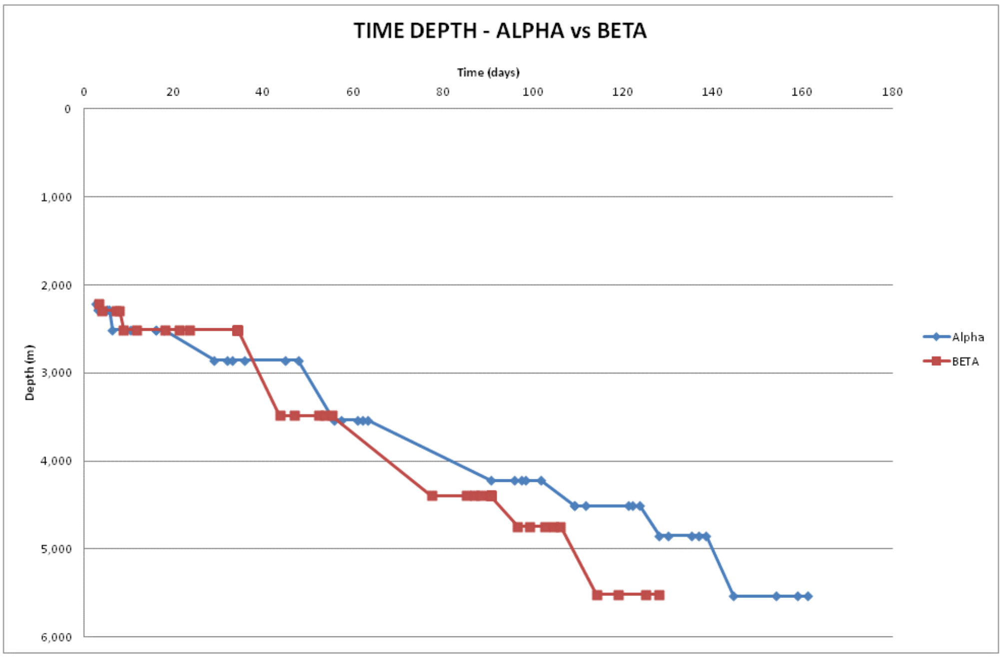

Figure 5.4 Time Vs Depth Comparison of Alpha and Beta Well

5.3 BETA WELL COST CALCULATION

Table 5.16 shows the final AFE of the Beta well with comparison to the Alpha well AFE. It was calculated based on the “ratio per service” which were calculated in 4 different criteria (material based, time based, section based, fixed cost) in previous sections.

Table 5.17 Beta Well AFE Breakdown

ALPHA WELL AFE BREAKDOWN	Weight (%)	Base of Simulation	BETA WELL Ratio per Service	BETA WELL Effective Ratio
MATERIALS				
WELLHEAD	0.43%	Material Based	50.00%	0.22%
CASING	2.15%	Material Based	98.12%	2.11%
LINER HANGER	0.30%	Material Based	50.16%	0.15%
CASING ACCESSORIES	0.03%	Material Based	76.05%	0.02%
RIG FUEL & LUBRICANTS & WATER	1.69%	Time Based	79.39%	1.34%
BITS	0.64%	Material Based	77.41%	0.50%
CEMENT & CHEMICALS	1.39%	Material Based	84.65%	1.18%
DRILL/COMPLETION FLUID MATERIALS	2.64%	Material Based	82.51%	2.18%
TOTAL MATERIAL	*9.28%*			*7.70%*
SERVICES				
WELL PLANNING	0.76%	Fixed Cost	100.00%	0.76%
SUPERVISION	4.50%	Time Based	79.39%	3.57%
CONTRACT DRILLING RIG	56.02%	Time Based	79.39%	44.48%
ROV	0.70%	Time Based	79.39%	0.55%
AIR TRANSPORTATION (HELICOPTER)	-	-	0.00%	0.00%
Helicopter Mobilization Costs	1.04%	Fixed Cost	100.00%	1.04%
Helicopter Operational Cost	2.81%	Time Based	79.39%	2.23%
Helicopter Demobilization Cost	0.14%	Fixed Cost	100.00%	0.14%
MARITIME TRANSPORTATION	-	-	0.00%	0.00%
PSV Mobilization Cost	0.75%	Fixed Cost	100.00%	0.75%
PSV Operational Cost	3.41%	Time Based	79.39%	2.70%
PSV Demobilization Cost	0.56%	Fixed Cost	100.00%	0.56%
LOGISTIC SUPPORT BASE	2.89%	Time Based	79.39%	2.30%
WELLHEAD SERVICE	0.84%	Time Based	79.39%	0.67%
DRILLING RENTAL AND FISHING TOOLS	0.45%	Time Based	79.39%	0.36%
UNDERREAMER SERVICE	0.98%	Section Based	2.03%	0.02%
LINER HANGER SERVICE	0.35%	Section Based	50.00%	0.17%
CASING & TUBING RUNNING	0.93%	Section Based	71.43%	0.66%
H2S SERVICES	0.15%	Time Based	79.39%	0.12%
DIRECTIONAL TOOLS & SERVICE	0.76%	Time Based	79.39%	0.60%
MWD, LWD & APWD TOOLS & SERVICE	1.53%	Time Based	79.39%	1.22%
DRILL/COMPLETION FLUID SERVICE	0.52%	Time Based	79.39%	0.41%
OPEN HOLE & CMT LOGS	7.17%	Section Based	99.37%	7.13%
WELL SITE LOCATION/ RIG POSITIONING	0.03%	Fixed Cost	0.03%	0.00%
O.S. SITE SURVEY/ ENV. BASE LINE SURVEY	0.22%	Fixed Cost	100.00%	0.22%
MUD LOGGING	0.28%	Time Based	79.39%	0.22%
CEMENTING SERVICE	0.82%	Time Based	79.39%	0.65%
COMMUNICATION	0.17%	Time Based	79.39%	0.13%
CATERING	0.07%	Time Based	79.39%	0.06%
OTHER RENTALS & SERVICES	1.87%	Time Based	79.39%	1.48%
TOTAL SERVICES	*90.72%*			*73.21%*
TOTAL	*100.00%*			*80.91%*

Since DGD system has not become commercial yet, daily rate of the service has not disclosed. Therefore, this data was not covered in cost comparison calculation. Also, lack of this data was not allowed to calculate the minimum operation duration to recover the cost of the system.

Moreover, the mud weight in Beta Well reached the 15.5ppg in the last phase of the well, which was 12.9ppg in Alpha Well. The cost of the required barite to increase mud weight 2.6ppg was also not calculated separately in this study, it was considered under “volume required to condition the drilling fluid” in section 5.1.3.

CHAPTER 6

CONCLUSIONS

To understand the economical impact of the Dual Gradient System, the deepwater well, which was drilled conventionally, was redesigned and simulated with Dual Gradient System. The results of this simulation were compared with the original well data. Based upon the work performed for this thesis the following conclusions were drawn.

In addition to technical advantages of the Dual Gradient System in deep-water environment;

1. Dual Gradient System increases the operation ability where a narrow operational window exists between pore pressure and fracture pressure as expected.
2. Dual Gradient System allows using less casing strings to reach planned TVD.
3. Simpler wellhead configurations can be selected in deep water environment.
4. Dual Gradient System allows reaching TVD without reducing hole size which provides an opportunity for high rate completions

Under the conditions studied in this thesis, the following conclusions were drawn;

5. Variety of casing string was decreased from 7 casings for Alpha well to 5 casings for Beta Well.
6. Simpler well design also brought the simpler wellhead configuration, which decreased the wellhead cost around 50%.
7. Beta Well reached the same target with wider casing size, 10 3/4” which was 9 5/8” in Alpha Well. It made the higher production rate possible in production phase of the well.
8. As system simplifies the well design, the necessity of some services are eliminated such as; liner hanger service and hole enlargement service.
9. Dual Gradient System decreases the operation cost around 19% considering the limitations. System also decreases the operation duration around 20%, material cost around 17%

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