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Evaluation of Slender Well Drilling

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HOVEDOPPGAVE/DIPLOMA THESIS/MASTER OF SCIENCE THESIS

Kandidatens navn/The candidate's name:	*Steven Leonardus Paulus*
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Utfyllende tekst/Extended text:

Background:

Offshore wells being constructed today have large well volume and are being drilled with large, high cost drilling units. There is an important potential for cost reduction through starting the well with a substantially smaller diameter, which imply reduced casing dimensions and cost, reduced mud volumes and cost, reduced BOP size and cost, and the possibility to use lower cost drilling units. The cost reduction potential is highest for subsea wells. The project objective is to analyze the slender well designs and concept based on enabling technologies. One key element in slender well design is casing/ liner design, hydraulic program and borehole stability. For comparison, data will be provided for three alternative slender well designs.

Tasks:

1) Make a literature survey of slender well designs including enabling technologies. Discuss potential and limitations.
2) Perform hydraulic calculations comparing three slender well designs versus the standard conventional design.
3) Perform borehole stress calculation based on static and dynamic well condition.
4) Assess the slender well designs and perform analysis for potential time and cost savings compared to conventional wells.

Supervisor	*Sigbjørn Sangesland*
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Sigbjørn Sangesland

Summary

The Slender well concept is one of the methods to reduce drilling time and cost. So, more wells can be drilled to increase the productivity of the field. The concept reduces the casing size on the top section and maintaining the production section of the well to be the same. It allows reducing the size of the riser, blow-out-preventer and well head, tubular and rig-size needed to handle all the equipment. On top of the cost reduction from using smaller equipment, there is also cost reduction from the materials used e.g. volume of drilling muds, cements and steel, etc.

There are three Slender Well designs which have been proposed. This thesis analyzes all three designs and compares these with the Standard Conventional design. The Slender Well design proposals are the FMC (medium) design, the SBBU-1 and SBBU-2 design.

The analysis in this thesis covers the potential cost savings for the different options. Also the hydraulics of each design based on the flow-rate selection for each hole-size is discussed. The hydraulic modeling provides static and dynamic well pressure that can be used to calculate the radial and tangential stresses present in the borehole.

Compared to a standard well, the Slender Well designs show that the cuttings volume can be reduced by 39% for the FMC design, 48% for the SBBU-1 design and 58% for the SBBU-2 design. The mud volume reduction is as much as 31% for the FMC design, 44% for the SBBU-1 design and 46% for the SBBU-2 design. The steel volume (weight) reduction is as much as 12% for the FMC design, 42% for the SBBU-1, 29% for SBBU-1 with tie-back liner and 63% for the SBBU-2 design.

The hydraulics study shows that the Slender Well designs have a lower pressure loss because smaller hole-size uses lower flow-rate. However, for the SBBU-1 design with 5-7/8 inch hole in the production section the annulus pressure loss becomes more dominant. The SBBU-1 with the tie-back option has the highest annulus pressure loss. It will have a higher pump pressure during drilling and will limit the flow-rate. The SBBU-2 utilizes liner and creates bigger flow area in the annulus. The annular velocity in the biggest flow area will be very low when drilling the 5-7/8 inch hole section. Which pose a risk of cuttings accumulation that might lead to hole problems.

The borehole stability study of the Slender Well design shows that the tangential stress is higher than the radial stress during static condition. At this condition, the borehole failure mechanism is borehole collapse due to shear failure. The high pressure loss during drilling of the production section increased the radial stress above the tangential stress. At this condition, the borehole failure mechanism is caused by fracturing due to tensile failure. Assessing the Slender Well design with respect to all failure conditions shows that the Slender Well design will not experience any borehole failure issue at the depth of interest. There is risk of borehole collapse when drilling the top section. But the risk can be mitigated by increasing the mud-weight and/or utilizing Managed Pressure Drilling technique. Smaller hole diameter (5-7/8 inch) will increase the radial stress at the borehole wall due to higher well pressure during circulation. But in general it will not improve the borehole stability when drilling the well as compared to larger hole diameter.

Drilling time planner estimation for each of the Slender Well designs provides an estimation of drilling time and cost to drill each well. The estimations are made by breaking down the operation sequences covering drilling, running casing / liner, cementing, etc. The total time needed to drill the well using the Standard Conventional design is 32.46 days, the FMC design needs 27.5 days, the SBBU-1 design needs 29.98 days and the SBBU-2 design needs 26.50 days.

The Slender Well design reduces the total well cost based on the total drilling time. The reduction for the FMC (medium), SBBU-1 and SBBU-2 design are 15.3%, 7.6% and 18.4% respectively. However, the Slender Well design has the potential to reduce the rig day-rate by utilizing a lower specification rig. A 25% reduction in rig day-rates will reduce the total drilling cost for FMC (medium), SBBU-1 and SBBU-2 designs as much as 36.5%, 30.7% and 38.8% respectively. The cost reduction from the mud volume, mud chemicals needed, steel weight, cuttings volume and logistics would significantly add to the total cost reduction.

Based on the Slender Well configurations, the FMC design is most suitable to drill production well and the SBBU-1 and SBBU-2 design are most suitable to drill exploration wells. This is mainly due to the smaller final hole-size at the production section for SBBU-1 and SBBU-2 design. The SBBU-1 design with Pre-Installed Liner provides additional casing setting depth that makes it suitable for a more complex geological area compared to the SBBU-2 design. But the SBBU-2 design has the highest potential cost reduction among all three Slender Well design. The current technologies that are readily available in the market could be used to complement the Slender Well design. Technology such as by-pass circulation sub could reduce the annulus pressure loss and solve cuttings accumulation problems for the SBBU design by diverting mud flow to the annulus without passing the BHA and the bit. Other technologies, such as Coiled Tubing, CoilFlat Liner, dual-gradient drilling could be used to enhance the design to be applied in various reservoir condition and complex geological area.

Further studies should be on optimizing the mud rheology to reduce the pressure loss on the available design. Expanding the Slender Well design to add hole section smaller than 5-7/8 inch by introducing coil tubing drilling. So, the Slender Well design can be used to drill deeper at an area with more geological complexities. A more in depth study on cost reduction estimates to select the technologies that are best incorporated in the Slender Well design.

Acknowledgements

I would like to express my gratitude to Professor Sigbjørn Sangesland for all of his trust, guidance, inputs and supports during the writing of this thesis. It has been a great pleasure and a wonderful experience to be working on a topic that suits my knowledge and has a potential impact for the future of oil and gas drilling.

I would like to thank my family. To my parents, Johanes Paulus and Herlina Tjondrosetio; Thank you for introducing me to the Petroleum industry, which gives me a chance to see the world, and for supporting my decisions in life. To my brother and sister, Sherwin Leonardo and Jane Sherly Stephanie; Thank you for all the supports and motivations.

I would also like to thank a special friend, Benedicta Karina. Thank you for always being there.

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Steven Leonardus Paulus

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Nomenclature

BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
DC	Drill Collar
DP	Drill Pipe
HSE	Health, Safety and Environment
ID	Internal Diameter
LCM	Lost Circulation Material
LWD	Logging While Drilling
MPD	Manage Pressure Drilling
M/U	Make Up
MW	Mud Weight
MWD	Measurement While Drilling
OD	Outer Diameter
OH	Open Hole
PIL	Pre-Installed Liner
R/D	Rig Down
RKB	Rotary Kelly Bushing
ROP	Rate of Penetration
SG	Specific Gravity
TD	Target Depth / Total Depth
TFA	Total Flow Area
XPD	Expandable Liner

1. Introduction

As time goes by, the oil and gas industry is keeps facing new challenges to fulfill the world's oil and gas demand. And as the industry progress, the "easy" reservoirs which had been found in the past are depleting. To meet up with the world's energy demand in terms of oil and gas, the industry needs to keep exploring to find new reservoirs while also maintaining the current reservoirs to keep it at optimal production rate and increase the recovery factor.

One of the solutions to increase recovery factor of a reservoir are drilling new wells to recover the un-drained oil and/or drilling injection well to improve oil recovery. For exploration, drilling exploration wells are necessary to confirm if there are hydrocarbons in the area of interest. But drilling is known to be a costly operation which tends to regulate the number of wells that should be drilled from the feasibility point-of-view. Therefore, it is one of the industry's interests to come up with means to reduce drilling cost.

Slender well design is a mean to reduce well cost by reducing the upper section size of the well and keeping the lower section the same. This reduction allows using smaller tubular for the well construction so smaller rig equipment is needed for the operations with reduced risk of handling and lifting equipment. The reduction also means less drilling fluids and cuttings volume that need to be handled. Depending on the type of well, this design would allow lower specification (modified 3rd generation) offshore rig to handle the drilling operations. The slender well design provides major savings in equipment, material and rig day-rates. From the Health, Safety and Environment (HSE) perspective, one of the major focuses in the oil and gas industry, these reductions would be an approach that is environmentally friendly.

Furthermore, exploration drilling is now reaching remote areas e.g. deep-water exploration and arctic exploration. In remote exploration, logistic is an issue of itself. Reducing the equipment size that need to be transported and the amount of materials needed for drilling, would also be a major savings in logistic cost and overall drilling cost.

Although the Slender Well concept has been implemented in some areas of the world, the problems associated with Slender Well design have to be assessed further. This thesis discuss the proposed Slender Well design by looking at the technology enabler that complements the design, the effect of reducing the size on the upper section towards well hydraulics, and looking at the effect of using a slim production section from the borehole stability perspective. The results are analysis of each technology that complements the design, predictions of pump pressure needed to drill with the Slender Well Design, the analysis of borehole stresses if the hole-size is reduced and the quantification of material and cost reductions.

The thesis aims on presenting the benefits and limitations of the three proposed Slender Well designs and provide assessments for each design to be used as feasible options for future well designs. This thesis also aims on providing a basis for developing various Slender Well designs based on development or exploration needs.

2. Slender Well Design

2.1. Background

The oil and gas industry had experienced ups and downs over time due to various events worldwide. These events caused fluctuations of oil price as shown in **figure 2.1**, which affects the feasibility of projects during those times. Therefore, various ideas were developed in order to keep projects as economic as possible with minimum reduction of its result.

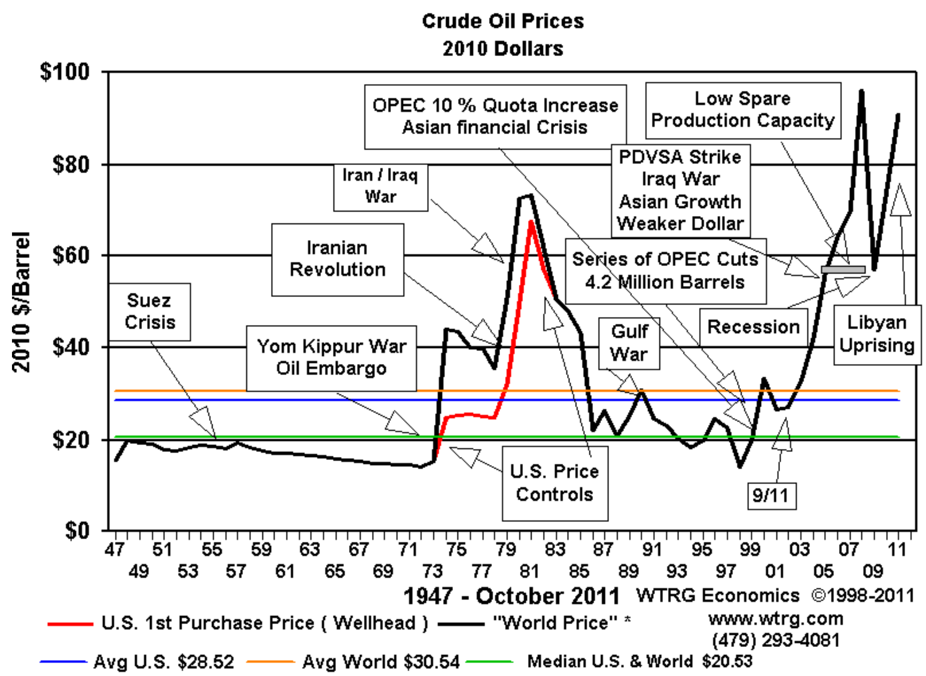

Figure 2.1 Historical Crude Oil Price. From (WTRG Economics)

In the well construction department, "slender well" concept was introduced. It is a concept of reducing the well geometry to reduce overall cost of a well. The slender well design will reduce the annular clearance for the top section casing which resulted in drilling a smaller hole for the top section, using a smaller riser size, less mud volume needed, etc. Furthermore, with smaller tubular and equipment, it means that less deck space on the rig will be used and smaller rig could be utilized. **Figure 2.2** illustrates the comparison between conventional well and slender well.

The direct effect of these reductions, are savings in many areas; Starting from rig utilization, materials and equipment for drilling and completing the well and many more. This new well construction concept has been predicted to reduce significant amount of cost up to more than 50% (Howlett et al., 2006).

This concept had been implemented in several fields and/or wells in various places. The 2003 Brazilian deep water drilling record in Campos Basin (block BMC-10) was achieved with a slender well concept (Avelar et al., 2005). This concept could be developed further with current technology improvements, also a push factor due to the increasing energy demand which leads to exploration ventures and asset maintenance.

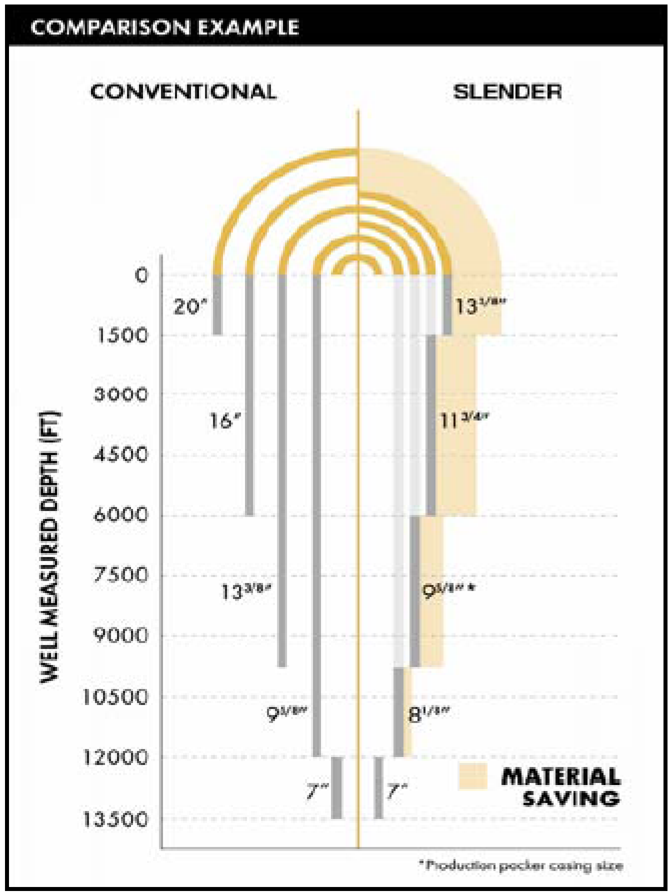

Figure 2.2 Comparison of Conventional Well with Slender Well. From (Howlett et al., 2007)

2.2. Advantage of Slender Well Design

The slender well construction concept aimed towards cost reductions, improvements in safety and environmental aspects. The benefit of this concept is stated by several key-points (Howlett et al., 2007).

- *Economic*, fewer consumables (casing, drilling fluid, chemicals, etc.), faster drilling, lower logistics and reduced rig costs.
- *Environmental*, fewer cuttings and drilling fluids to be dispose.
- *Reduced risk*, fewer operations involving big tubular that reduces the risk during transportation and handling.
- *Contingency*, taking account additional casing string that can be run without affecting the final hole size.

- *Bottom-up design*, allowing well to be designed for the required production tubular without excessively large top-hole sizes.
- *Abandonment*, simplifying the well abandonment process due to less overlapping casing and potential leak paths at the top of the well.
- *Well integrity*, using API casing and normal cementing techniques means integrity is straightforward to engineer and plan.
- *Technical*, reduction of well telescoping effect compared to conventional construction.

The slender well concept generally saves cost from reducing the size of the equipment which dictates the size of the other equipment being used. The riser size selection will dictate the size of the rig and other equipment to handle the tubular. The slender well concept proposes a reduction in riser size selection so a smaller rig and tubular handling equipment can be used. Utilizing smaller rig allows using several old generation rigs that had been upgraded. From rig availability perspective, this remove the time needed in waiting of the constructions of new rigs. From logistics perspective, smaller equipment will take less space so more equipment can be stored. This reduces the overall project cost significantly.

Smaller equipment and tubular are easier to handle, enhancing the safety aspects of the operations. The waste from the operations and chemical treatments of the drilling fluids will be reduced, and it is beneficial for the environmental and health aspect. As one of the leading industry in health safety and environment, it will proof to be important in developing this concept.

Statistical studies showed a trend between hole-size and rate-of-penetration as shown in **figure 2.3**. There is a hole-size window where drilling can be optimized in terms of rate-of-penetration, saving drilling time and in the end reducing daily rig cost. Study conducted in a field in Kuwait shows that the smaller top section has an average of 40% improvements in ROP and drilling time reduction from 9 days to 5.5 days (DeMong et al., 2003).

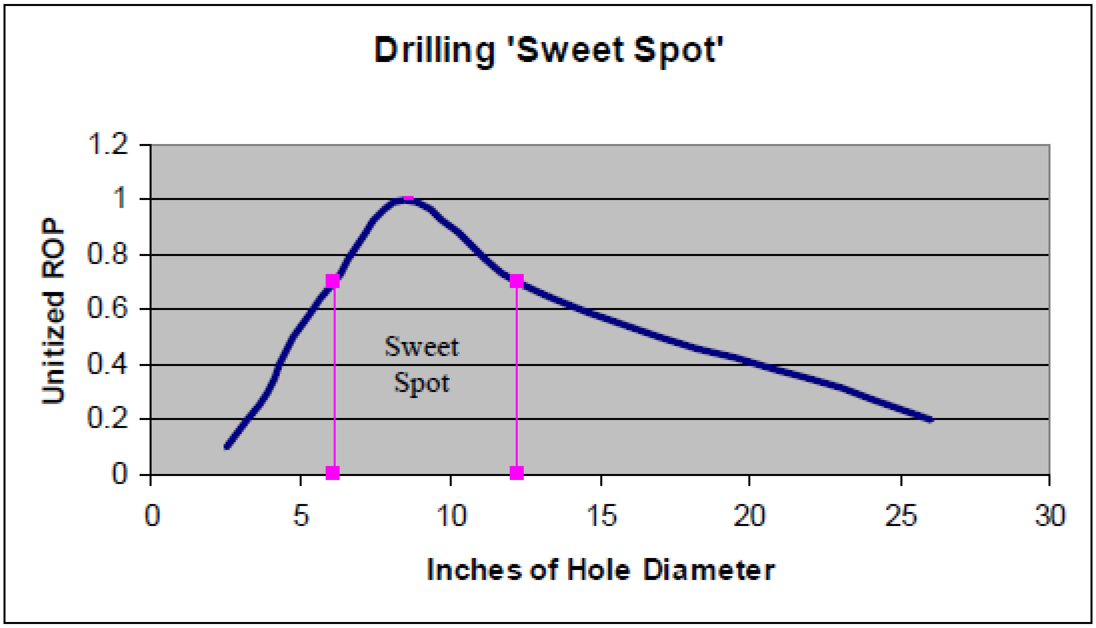

Figure 2.3 Optimum ROP Window (DeMong et al., 2003)

2.3. Limitations of Using Slender Well Design

Slender well design concept is facing several challenges from the technical perspective of well design. Slimming down the top section will have a drawback in the hydraulics, hole-cleaning, torque and drag of the well itself. These problems will affect other aspects during drilling and completing the well.

Slimming down the top section of the well causes reduction of the annulus diameter or cross section flow area, this cause an increase in pressure loss due to higher frictional loss during drilling. Another challenge arises when drilling the lower section of the well. A conventional well has the smallest hole-size of 8-1/2 inch while slender well concept may go to 5-7/8 inch "Open Hole" diameter and the casing / liner size before it will be the 9-5/8 inch. The configurations is not favoring the slender well concept as the enlargement of the cased-hole annulus would reduce the flow velocity, reducing the hole cleaning ability. The problem can be mitigated with increasing the flow, but as the flow increase so does the pressure. So, there will be a pressure limiting how much flow can be increased.

There is also a big challenge in drilling the slim lower section (5-7/8 inch) apart from the hydraulics. The equipment used tends to be less durable and more susceptible to shock, vibration and heat due to their smaller size and mass. The small size of the equipment used to construct the bottom-hole-assembly cause it to be more flexible. The flexibility of the BHA in this slim section reduces the steering control and making it susceptible to weight-on-bit variations. Applying high weight-on-bit might cause the BHA to bend and steer the wrong direction. But a low weight-on-bit will result in lower rate-of-penetration. So the challenge is finding an optimum weight-on-bit versus rate-of penetration without sacrificing the steering capability.

Mud pulse telemetry is signal transmitted by Measurement While Drilling tools in the form of pressure pulses inside the drill-string. As mentioned before, higher flow-rate is needed to optimize cutting transport in the big flow area of the cased-hole annulus. Higher flow-rate increases the flowing pressure inside the drill-string which often leads to a weak signal transmission which unable to be decoded by the surface computer. Poor signals will cause losing of valuable formation evaluation real time data and the direction and inclination data. However, there are other variables that could minimize poor signal transmission, such as the quality of the pumps pulsation dampener, quality of the sensor, etc.

Several of this challenge can be mitigated or minimized with the current development in drilling technology which will be covered thoroughly in chapter 3.

3. Technology Driver

Since the slender well concept was discussed for over a decade ago, there has been a rapid development in the oil and gas industry. Some of the technologies that could complement the slender well concept are discussed in this chapter.

3.1. Slim Riser

The industry standard for conventional deep water drilling is the utilization of 21 inch drilling riser and 18-3/4 inch Blow-Out-Preventer. Due to its size and weight, the riser dictates the size and the capability of the Mobile Offshore Drilling Unit (MODU). In general, 5^{th} generation MODU is used for the operations. The new Slim Riser concept reduces the riser size to 16 inch riser, which then will allow using 3^{rd} and 4^{th} generation rigs for the operations.

Reducing riser size to 16 inch improves the water depth capability of the rig. The improvement is contributed by the reduction in tensioner loads, lower variable deck loads, reductions in mud pit space and storage requirements due to smaller riser volume. Comparing to the conventional 21 inch riser system, the slim riser system requires 40-45% less storage space per joint, 25-30% less weight and 55-60% mud storage requirement as (Childers et al., 2004).

The configuration of the 16 inch slim riser system still retains the 18.75 inch BOP and shown in **figure 3.1**, and the wellhead system with 18-3/4 inch housing is shown in **figure 3.2**. However, there are also drawbacks in this concept. The 16 inch riser has a drift of 14-5/8 inch. This limits the number of string that can pass through it. Therefore, this slim riser concept is best used when three or less casing strings are required under the BOP, unless expandable liners are used.

This slim riser concept is important to slender well concept as the reduction of the riser size provides significant cost reductions.

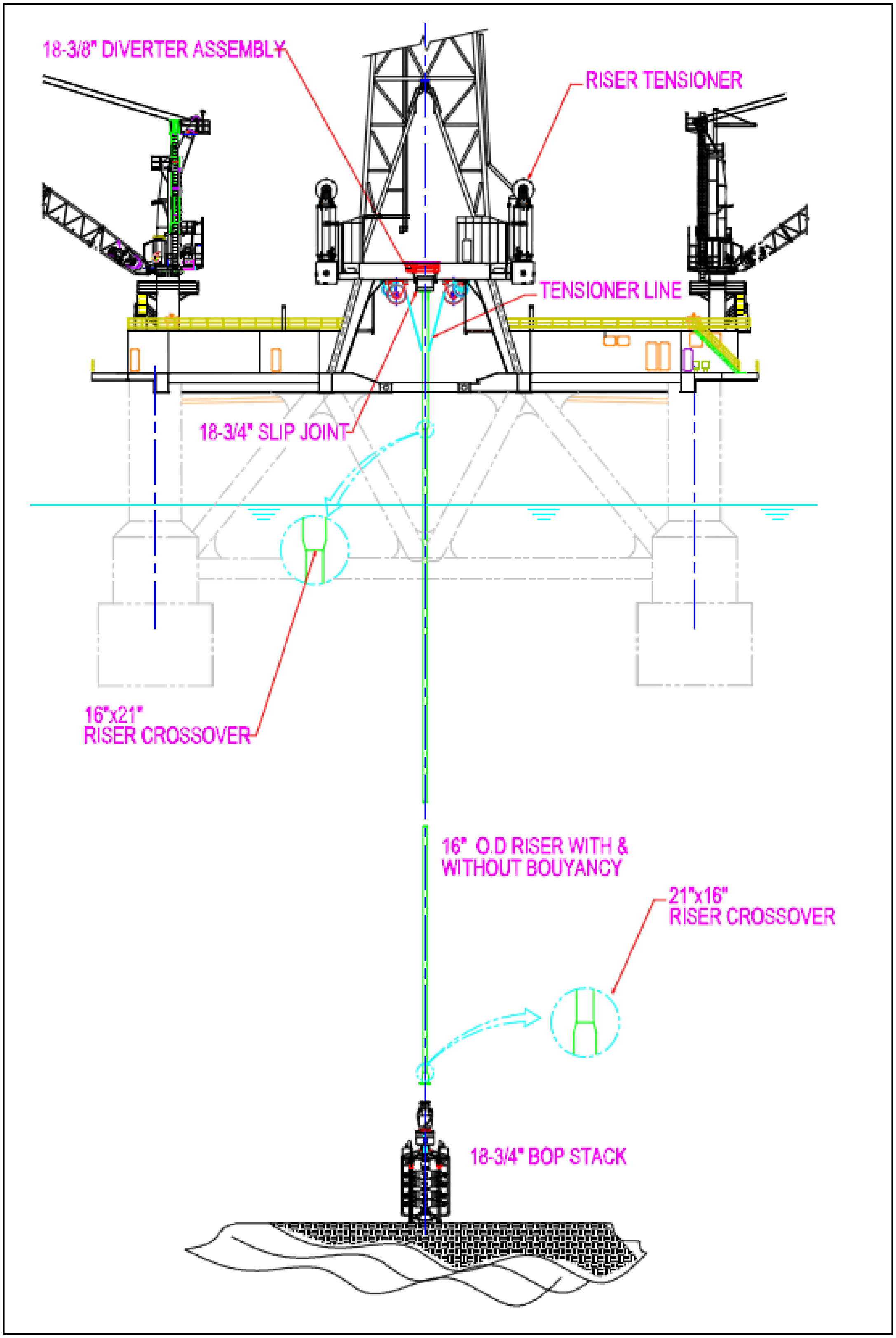

Figure 3.1 Slim Riser Concept shown with 16 inch riser system hooked to an 18-3/4 inch BOP stack and 21 inch diverter and slip joint (Childers et al., 2005)

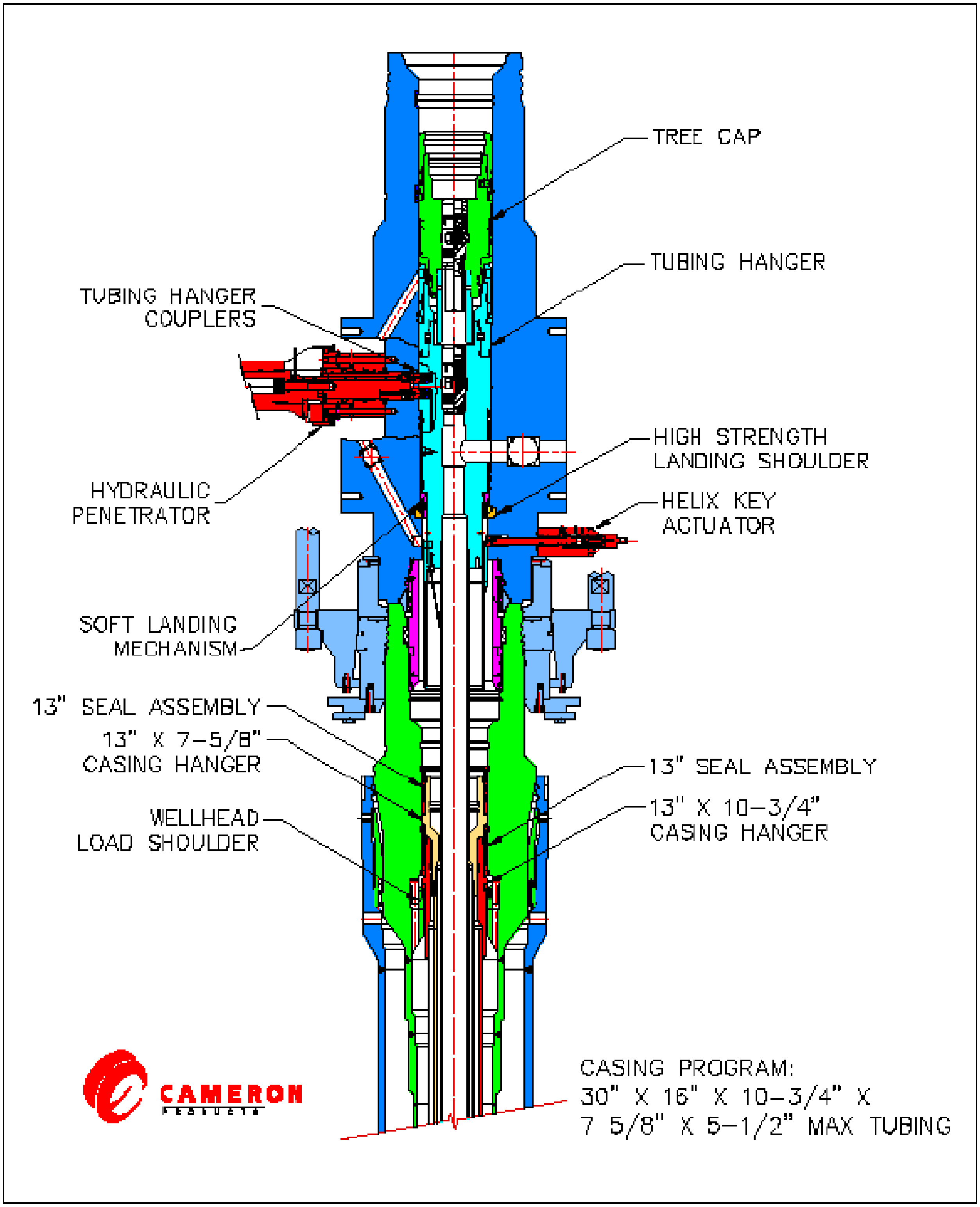

Figure 3.2 One wellhead system with 18-3/4 inch housing (Childers et al., 2004)

3.2. Expandable Tubular

Expandable tubular, generally termed expandable liner; is a liner made of specific material composition which allows it to be expanded without losing its integrity with respect to burst, collapse, tension and compression design limitations. **Figure 3.3** shows a stress-strain relationship and the expansion region of an expandable liner. The deformation in the elastic region is reversible while in the plastic region it is irreversible, resulting in the tubular to stay expanded. Exceeding the plastic region, the tubular will fracture.

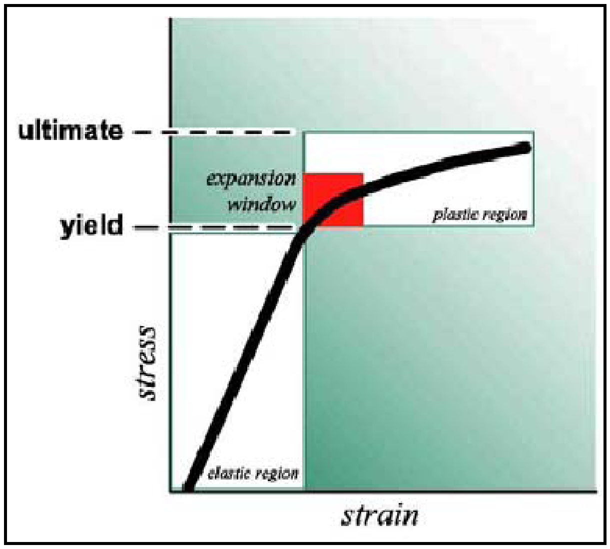

Figure 3.3 Stress-strain curve for a metallic solid (Gupta et al., 2007).

Expandable tubular minimize the loss of hole size as drilling goes deeper. In order to utilize expandable tubular, the hole-size are made bigger using an under-reamer and/or bi-center bit technology. Then the expandable tubular are run down to the required depth followed by the cementing process, and then a cone is dropped to start the expansion process. There are two methods of expansion, bottom-up expansion and top-down expansion.

The bottom-up expansion method uses an expansion cone which is run at the bottom of the liner. The drill string is used to get the liner down to its place. Once the liner is in place, cement is pumped through the drill string. After cementing, a plug is dropped down which creates a pressure barrier underneath the expansion cone. So as pumping continues, it will create pressure and expand the liner as the cone is pulled upward at a rate of 20-30 feet per minute. The cone will pass through the liner hanger and expand it to set it in place before it can be retrieved at surface. Then drilling continues by drilling out the shoe. **Figure 3.4** illustrates the step-by-step processes.

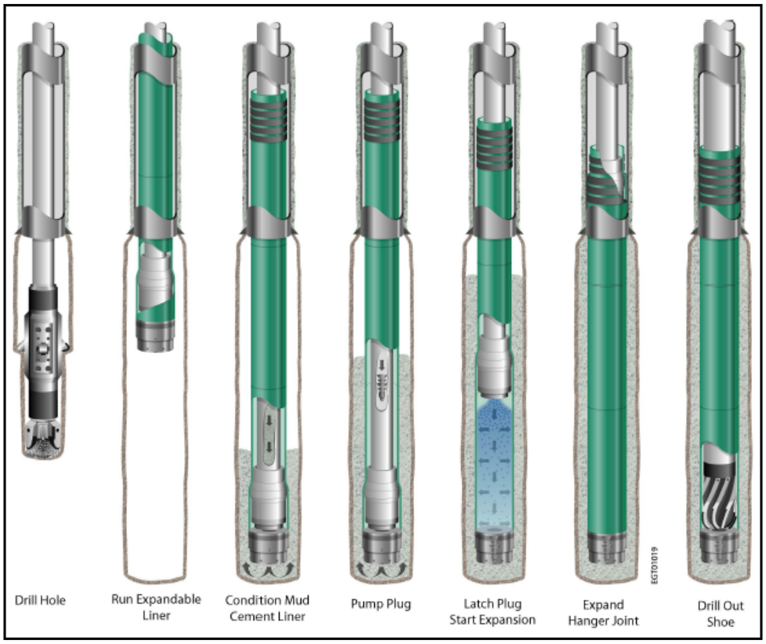

Figure 3.4 Bottom – Up Expansion (DeMong et al., 2003)

The top-down expansion method uses an expansion cone which is run after the liner had been run into the positioned depth. Once the liner is in its setting depth, the cone is then run by pressurizing the drill pipe fluid. As the pressure increase, the anchor is set against the inside of the previous casing, ensuring no upward movement of the whole assembly as the cone is pushed down. The piston will push the cone and expand the liner until it reached the full stroke. At full stroke, the pressure will be released from the system that holds the anchor. The tool can then be moved to expand the liner below it. The process continues until the whole liner is expanded. These processes are illustrated in **figure 3.5**.

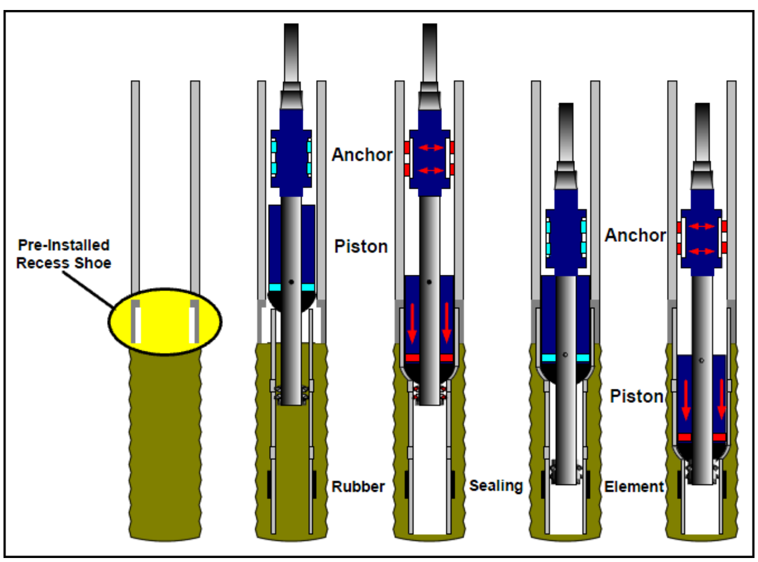

Figure 3.5 Top – Down Expansion (Jabs, 2004)

In the past, expandable tubular is used as a contingency measures just in case drilling encounter un-suspected casing point due to pore pressure uncertainties. But for the case of development wells where pore pressure uncertainties can be minimized, the use of expandable tubular as a part of the well has been proven more beneficial and cost saving than just using it as a contingency (Carstens et al., 2006).

3.3. Bi-Center Bit

The concept of bi-center bit was introduced in the 1950's and it was introduced as a reliable new technology in the industry by 1994 (Denham et al. 2000). Bi-center bit is a combination of bit and a reamer which has a one sided cutter to simultaneously drill and under-ream. The pilot bit centralizes the bi-center allowing the reamer to ream, creating an oversized hole. The advantage of the bi-center bit is the smaller pass-through diameter during trip-in, with respect to the drill-hole diameter during drilling; as shown in **figure 3.6** and **figure 3.7**.

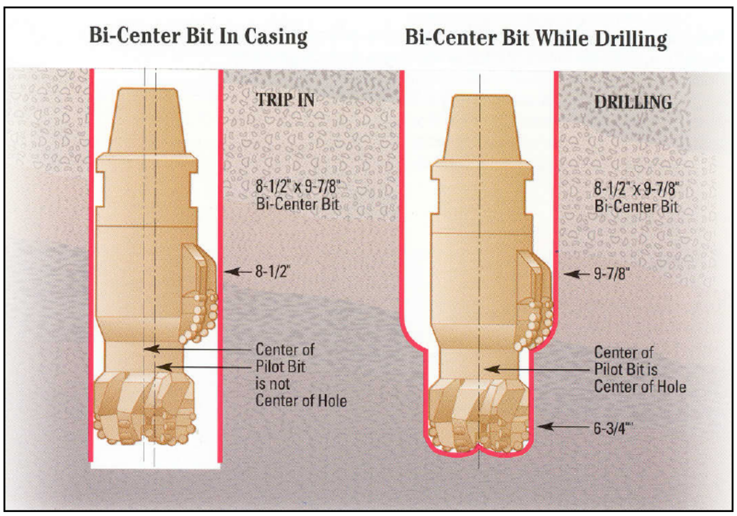

Figure 3.6 Bi-Center Bit trip-in and drilling condition (Morrison et al., 2005)

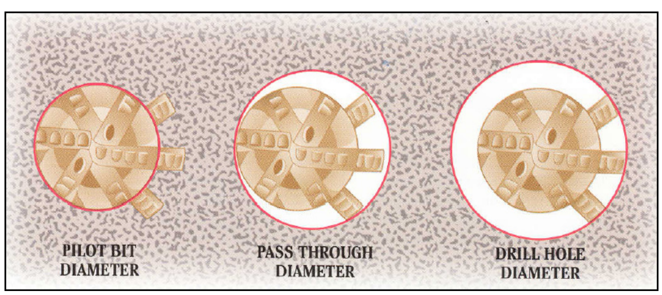

Figure 3.7 Bi-Center Bit Hole Sizes (Morrison et al., 2005)

Bi-center bit is not widely accepted back then because there are several drawbacks associated with its use. Unable to be used to drill-out cement, erratic torque, premature wear, undersized hole and poor directional control when paired with directional drilling tools were the main problems. The problems became clear as more bi-center bits were used. Nowadays, improvements in design had been made to make it better. The improvements of technology and computer, allows computational analysis of its design. The new bi-center bit could be utilized to drill-out cement, improving directional characteristics and hole quality.

3.4. Pre-Installed Liner Concept

This concept introduces smaller diameter liner which is run as a part of a bigger diameter surface casing run. After drilling or jetting the surface casing section, one or several liners are run inside the casing. This method would allow utilization of smaller BOP and riser because all the casing and liners which are bigger than the riser ID had been run before the BOP and riser are installed (Sangesland, 2005). This concept complements the slender well concept which aim in total cost reduction of the well.

Figure 3.8 shows a schematic of a pre-installed liner inside the surface casing that had been run. The liners OD are bigger than the riser and the ID of the well head installed on top of the surface casing. **Figure 3.9** shows how drilling continues and after drilling, the liners inside the casing are then extended telescopically until the setting depth.

The limitation for the liner length is dictated by the length of the surface casing. In theory, the longer the length of the surface section, the longer the liner length would be and the deeper the well can be drilled. Other considerations are the mud circulation method in which the annulus of each liner length need to be blocked to prevent mud entering the annulus before the liner is deployed.

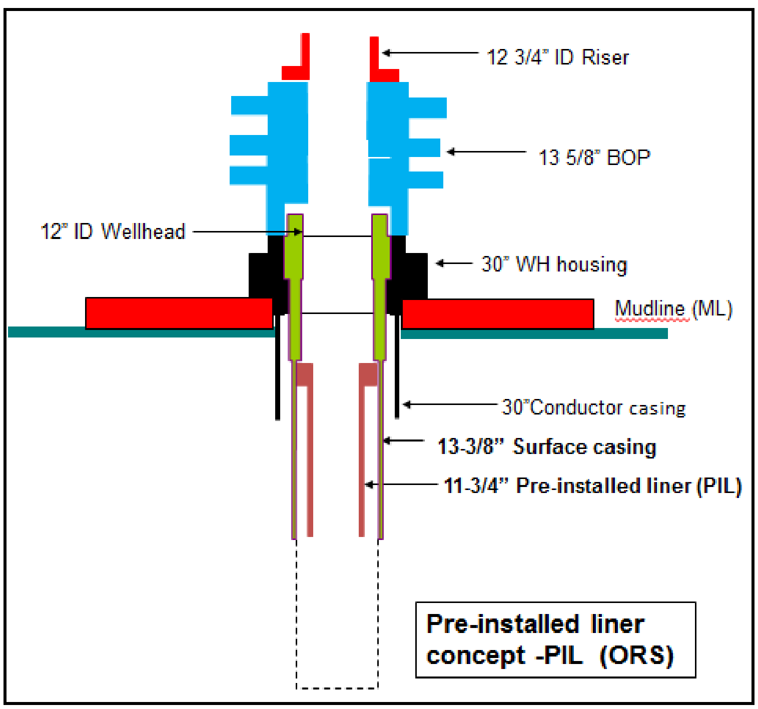

Figure 3.8 Pre-installed liner configuration before deployment (Sangesland, 2013)

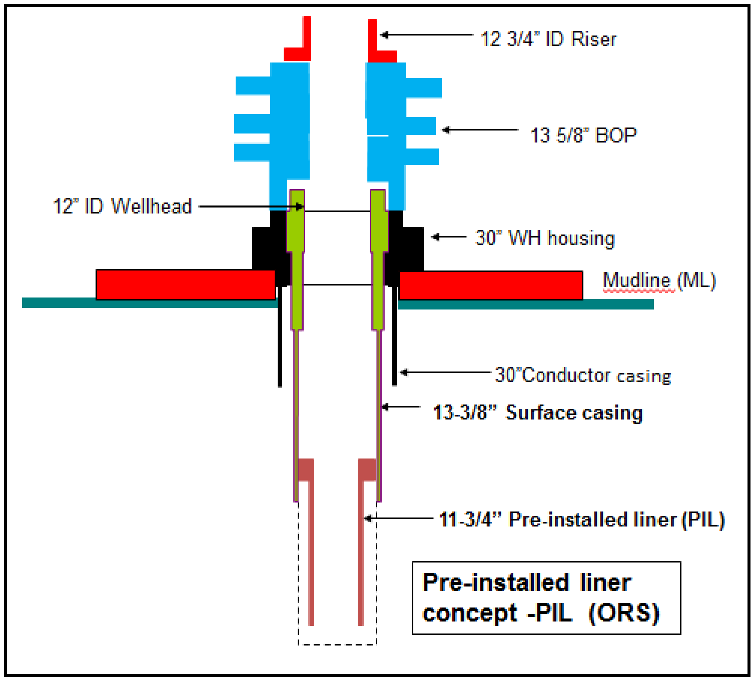

Figure 3.9 Pre-installed liner telescopic deployment (Sangesland, 2013)

3.5. Manage Pressure Drilling and Dual Gradient Drilling

Manage Pressure Drilling (MPD) is an adaptive drilling process used to control the annular pressure profile. The main aim of MPD is to minimize hole problems, extending the drilling window which will also extend the casing setting depth and/or minimize the number of casing size used. Variations of MPD include single gradient drilling and dual gradient drilling. Single gradient drilling utilize a rotating control head, choke and backpressure pump on surface creating a backpressure to manipulate the mud gradient. Dual gradient drilling utilize sea-bed pump or subsea pump to pump the mud return from the seabed to the surface, manipulating the mud return gradient and creating a dual gradient.

Figure 3.10 shows casing point with conventional drilling and **figure 3.11** shows casing points with MPD of the same pore pressure and fracture pressure profiles. These illustrations showed how MPD can be used to slim down a well construction by minimizing the casing points.

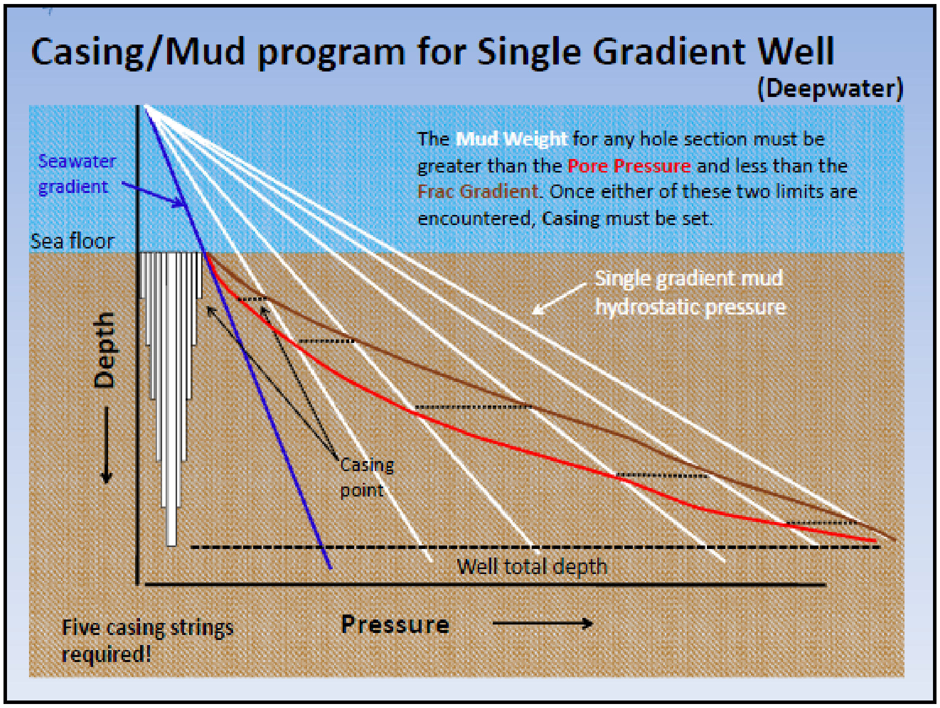

Figure 3.10 Casing points with conventional drilling (Eck-Olsen et al., 2012)

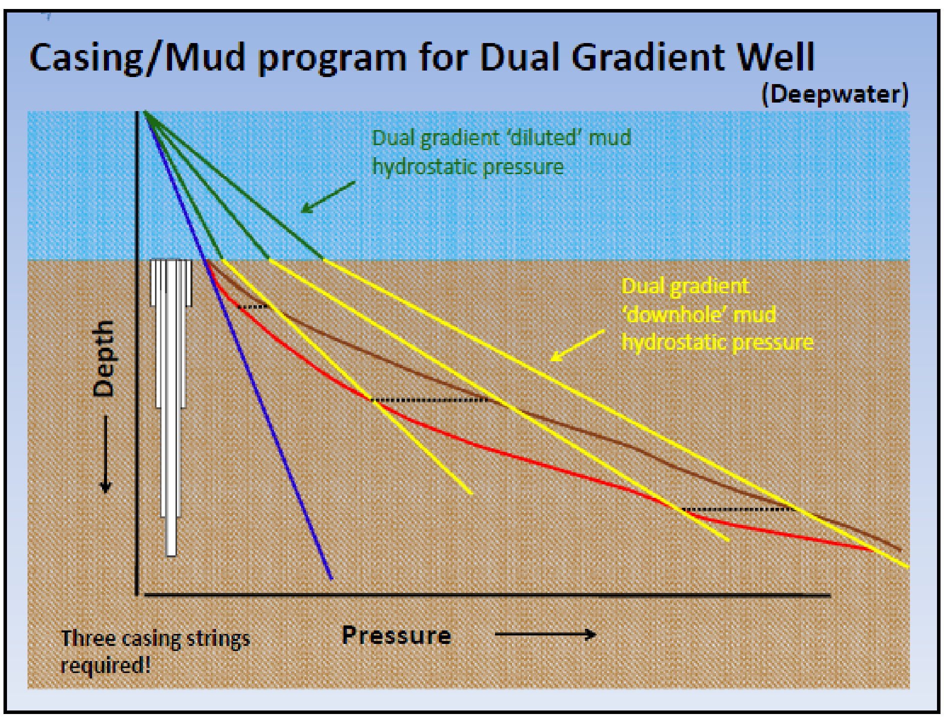

Figure 3.11 Casing points with MPD (Eck-Olsen et al., 2012)

3.6. Slim Hole Measurement While Drilling and Rotary Steerable System

The development of Measurements While Drilling (MWD), Logging While Drilling (LWD) and Rotary Steerable System (RSS) tools to be a part of the Bottom Hole Assembly (BHA) has been very extensive. The latest development answers various technical drilling problems. In the past, there are limited options of tools for drilling slim well because the smallest size of the reliable tools are only available in 6-3/4 inch tool size which can be used to drill 8-1/2 inch hole size. But the trend is towards slim hole drilling, drilling deeper, accessing High Pressure High Temperature (HPHT) reservoirs and the technology provider realizes the importance of developing tools to facilitate these trends.

Several problems encountered when drilling slim-hole section are weight transmission to the drill bit to provide sufficient WOB, poor directional control due to BHA flexibility and reliable steering tool, flexible BHA induces shock and vibration and mud pulse telemetry issue due to higher operating pressure relative to pressure pulses used to deliver telemetry signals. The new tools reduce the magnitude of the problems, or at best, remove it entirely. The signal problems are minimize with improvements in software for signal decoding and the weight transmission problems are minimize by reducing drag with full rotation when using 4-3/4 inch rotary steerable system, which also enhance steering capability compared to the conventional mud motor. Furthermore, a combination of a mud motor and rotary steerable system in the same BHA assembly can overcome torque and increases down-hole rotation per minute (RPM), leading to an increase rate of penetration (ROP). In this particular case, the mud motor termed “power section” and the real time connection can be maintained with integrated electrical connection on the power section or via additional sub that contains electromagnetic connection between the RSS and the MWD tool. **Figure 3.12** shows an example of a rotary steerable system combined with modular motor as the power section. This particular example is a product of Baker Hughes.

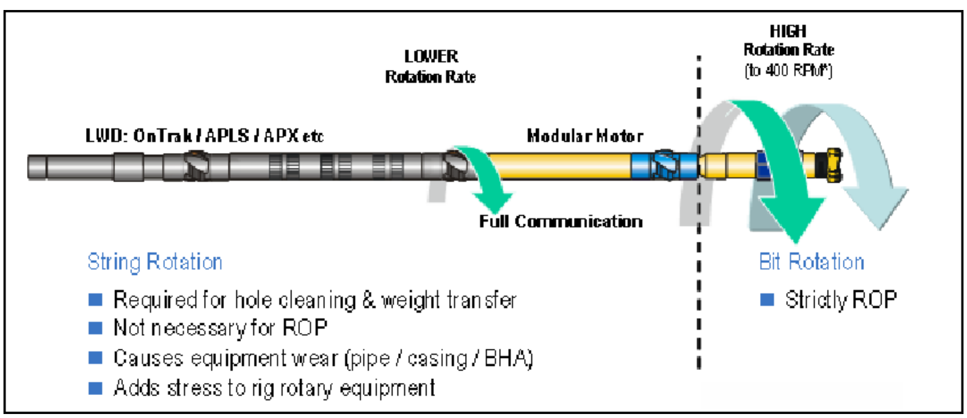

Figure 3.12 Rotary Steerable System with Modular Motor (Kellas et al., 2005)

3.7. Close Clearance Liner System

The slender well design reduces the annular distance between each casing / liner sizes. The size could be as small as 1/8 inches in the lower reaches of the well and 1/4 inches in the upper reaches (Howlett et al., 2006). This reduction in annular clearance will limit the casing / liner running speed because of the surge and swab issue. With a smaller annular clearance, the running speed must be decreased and increases the open hole duration after drilling. This condition is not preferable because of the time delayed effect that might cause borehole stability problems.

Flow diversion shoe is designed to minimize surge and swab when running casing / liner. The flow diversion shoe shown in **figure 3.13**, use an artificial inner annular space created by an inner tubing string and deployment tool with internal bypass shown in **figure 3.14**. This combination will create an inner flow area for fluid to travel inside the liner, over the top of the liner and around the outer diameter of the drill pipe deployment string as it is the path of the least resistance. Results are shown on **figure 3.15**, where the mud flows out of the deployment string.

Figure 3.13 Flow Diversion Shoe (Howlett et al., 2006)

Figure 3.14 Deployment tool (Howlett et al., 2006)

Figure 3.15 Mud flow from inner annulus (Howlett et al., 2006)

3.8. Drilling Agitator Tool

Slender well design tend to include drilling a smaller hole section as compared to conventional drilling. This slim hole section had been known to be challenging. One of the challenges is frictions and weight transfer. Slim bottom-hole-assembly has lower weight in total and the drag or friction force in the wellbore tend to hinder the weight transfer.

Drilling agitator tool uses a rotor that rotates on a stator by flowing mud through it. This movement provides excitement towards the bottom-hole assembly and helped with weight transfer to the bit and improves drilling performance. An illustration of drilling agitator tool by NOV is shown in **figure 3.16**.

Figure 3.16 Downhole Agitator Tool by NOV (NOV, 2009)

3.9 Coiled Tubing Drilling with Steerable Motor

Coiled tubing drilling has been used extensively for work-over operations such as well unloading and/or cleaning scale deposits. Advances in the coiled tubing drilling technology have allowed slim section to be incorporated as a part of the well design. Service providers are now providing measurements - logging while drilling technology and steerable system for coiled tubing drilling in 2-3/4 inch until 4-3/4 inch hole. These make coiled tubing drilling more reliable and can be incorporated as part of the well design, instead of only used for contingency in drilling or work-over operations.

Coiled tubing is also a good option because of its simplicity. The storage of the tubing in a reel system makes it easy to be run down-hole and to be stored on the rig. **Figure 3.17** shows an illustration of coiled tubing with steerable motor from Baker Hughes.

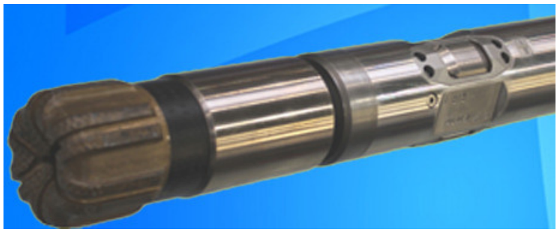

Figure 3.17 CoilTrak Rib Steered Motor (Baker Hughes, 2013)

3.10. CoilFlat CT Liner

CoilFlat CT Liner is a new liner concept by Marinovation. The liner is a continuous pipe-in-pipe casing that is reeled to a drum to be stored and transported like coiled tubing. The CoilFlat CT liner is collapsible, reducing its size during storage and deployment to the desired depth. Pressure is applied internally by pumping fluid through it, the pressure will then expand the liner to a full round shape. To increase its strength, cement are pumped down through the CoilFlat Cells (the annulus between the inner pipe and outer pipe of the liner) and up to the annulus between the liner and the formation.

The illustration of the CoilFlat CT Liner is shown on **figure 3.18**. This liner concept is introduced to solve the collapse limitation of the present MonoBore or Monodiameter well system. This new technology can complement Slender Well design in similar manner to Expandable Tubular.

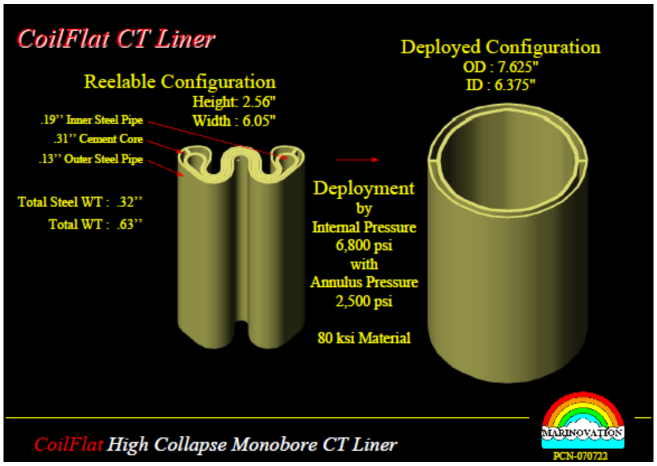

Figure 3.18 CoilFlat CT Liner (Drilling Engineering Association, 2013)

3.11. By-Pass Sub

By-pass sub allows the fluid to be partially circulated without passing the bit. It will increase the annular velocity and reduce the pressure loss at the bit. The by-pass sub is commonly used when drilling depleted zone with high lost circulation. To handle the lost circulation, Lost Circulation Material (LCM) is commonly used. These materials can be composed of cellophane flakes, cedar bark, crushed walnut shells, etc. The materials are designed to close-off the permeable zones causing the lost circulation. However, if these materials pass the BHA and/or the bit, there is a high possibility that they might clog the BHA and/or bit. Normally, depending on the tools in the BHA and/or nozzle size, the LCMs are limited in size and concentration, which reduces the effectiveness to seal the formation. With the by-pass sub, the LCM materials can be diverted via the sub to the annulus without passing the BHA and the bit.

This tool complements Slender Well design by reducing the annulus pressure loss because the flow is diverted via the sub. It will also reduce the pressure loss at the bit and increase annulus velocity to enhance hole-cleaning process. The current technology allows the by-pass sub to be open and close multiple times which gives flexibility of using it. **Figure 3.19** shows the illustration of the by-pass valve that allows multiple open-close sequence.

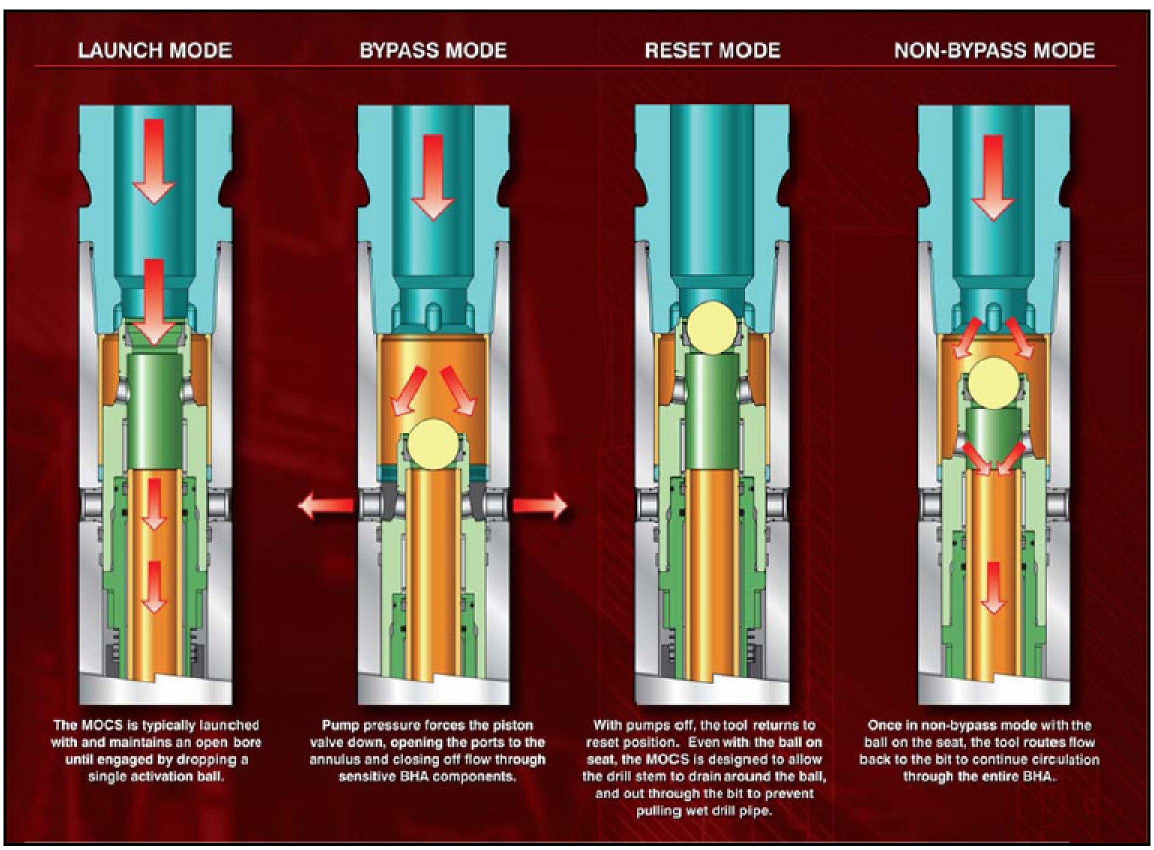

Figure 3.19 By-Pass Sub Illustration (Herrington et al., 2012)

3.12. Cementing Concept with Active Under-Reamer

The smaller the hole-size drilled, the smaller the casing and/or liner that will be used. These small tubular are more flexible in nature causing it hard to keep it centered inside the hole. If the tubular is not centered, the cementing process will not be optimum. The tubular that rest against the borehole wall will be pushed inside the borehole and the cement will not create a seal between the borehole and the tubular. The failure in sealing will create a path for hydrocarbon migration that might pose risk to the well and its production.

A concept in cementing is to under-ream sections of the well to enlarge the borehole. The tubular will not be able to rest against the borehole wall of these enlarge area because it will hold itself against the smaller area of the borehole. So when the cement is pumped through the enlarge borehole, it can fill the enlarged area where there will be no contact between tubular and the borehole wall. This will create a good cementing job that can seal properly, as illustrated by **figure 3.20**.

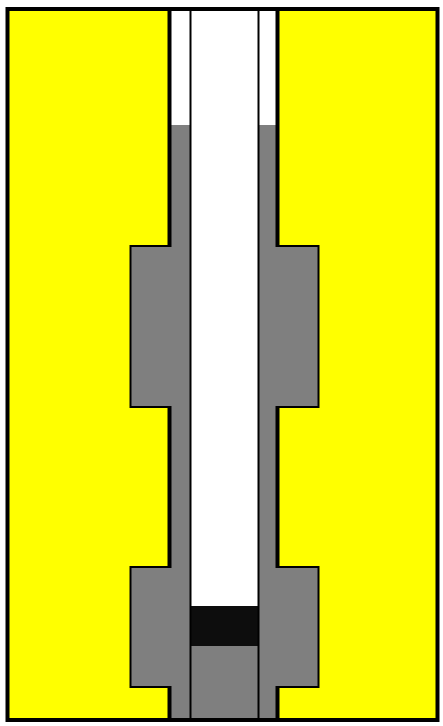

Figure 3.20 Illustration of partially under-reaming the borehole to ensure better cementing

4. Well Design

Well construction with slim design had been used for various reasons in several countries. Petrobras used a slim construction as part of their project in the Marlim Field, Campos Basin, Brasil. A new well head system allows Petrobras to eliminate the 26 inch phase (20 inch casing) and only use a three phase arrangement (30 inch, 13-3/8 inch and 9-5/8 inch). This slender design reduce total drilling time per well in three days (Cordeiro et al., 1999).

Various studies of slender well constructions in the North Sea area yielded results of slender well design as shown in the schematic in **figure 4.1**. There are three slender well designs which are compared to the standard well design in the North Sea. These three slender well designs are the FMC (medium), SBBU-1 and SBBU-2 design. The FMC designs are based on the design proposed by the FMC Technologies, while the SBBU-1 and SBBU-2 designs are based on the design proposed by Centre for Drilling and Wells for Improved Recovery, a joint project between NTNU, SINTEF, University in Stavanger and IRIS.

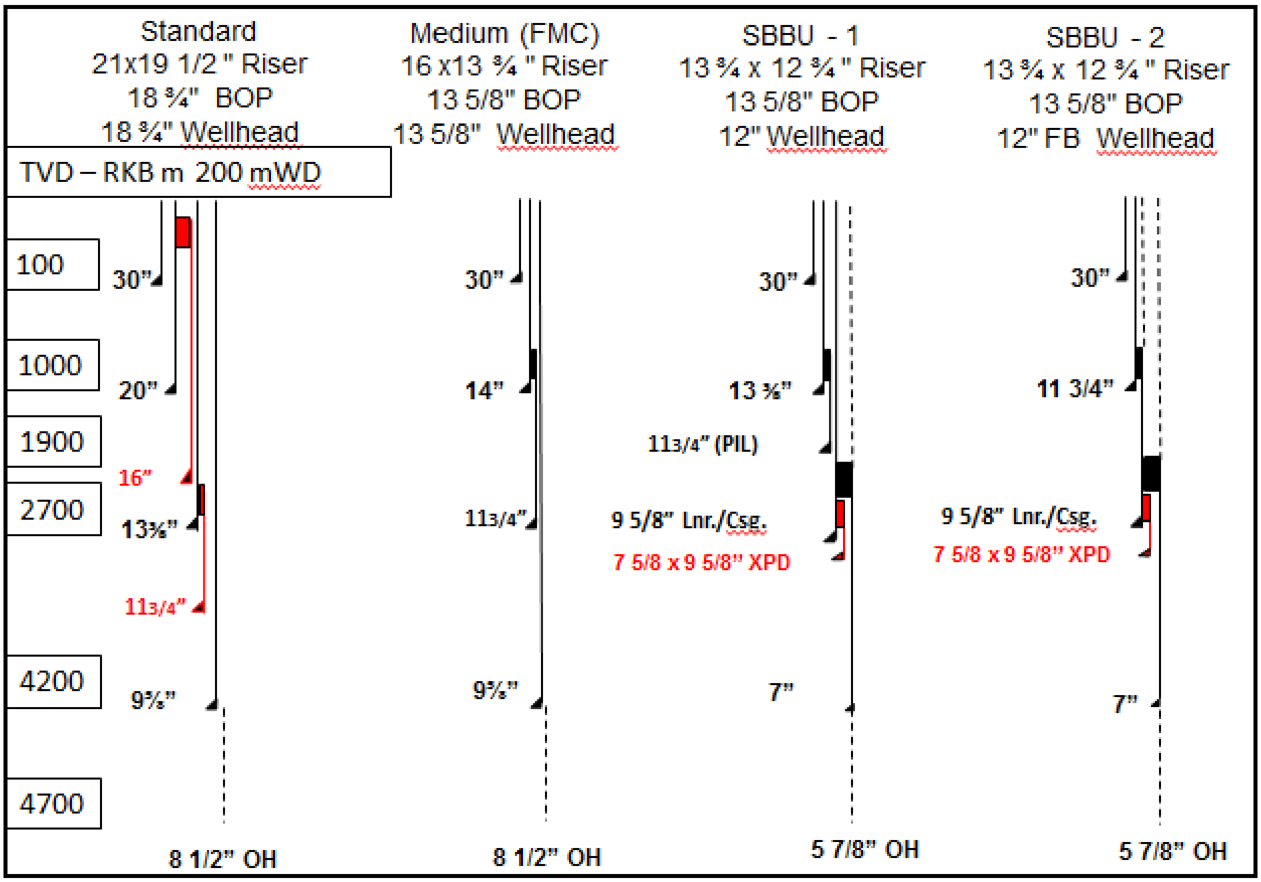

Figure 4.1 Slender Well Design Options for Exploration (Sangesland, 2012)

4.1. Standard / Conventional Design

Standard well design in the North Sea starts with 36 inch hole to install 30 inch casing followed by drilling 26 inch hole down to 1000 meter, to install 20 inch casing. These two sections are normally drilled riser-less with weighted sea water and mud returning to sea bed. After installation of the 20 inch casing, an 18-3/4 inch full bore wellhead system is installed and a 21 inch riser (19-1/2 inch internal diameter) is connected before continue drilling the next sections.

The next section to be drilled is the 17-1/2 inch hole section down to 2700 meter, to install the 13-3/8 inch casing. An optional 16 inch liner is available if the pressure complexity of the drilled section forced to call section depth earlier than planned. This section is followed by the 12-1/4 inch hole down to 4200 meter, to install the 9-5/8 inch casing. Also on this section, an optional 11-3/4 inch liner is also available if the pressure complexity forced to call section depth earlier than expected. The final section is drilling the 8-1/2 inch hole to 4700 meter, which can then be left as an open hole or utilizing a 7 inch liner, depending on the production (producing zone and rate) characteristics.

4.2. FMC (medium) Design

This medium design will allow using a smaller riser as compared to the standard design. It started with drilling the 36 inch hole to install the 30 inch casing. The next section is the 17-1/2 inch section until 1000 meter, to install the 14 inch casing. These two sections can be drilled riser-less with weighted mud returning to sea bed. After installing the 14 inch casing, a 13-3/8 inch wellhead and BOP can be installed to be connected to the 16 inch riser (13-3/4 inch internal diameter).

The next section to be drilled is the 12-1/4 inch hole until 2700 meter, to install the 11-3/4 inch liner. After that, another 12-1/4 inch section can be drilled using a bi-center bit or a reamer which can be activated down-hole after passing through the 11-3/4 inch casing. This second 12-3/4 inch hole section until 4200 meter, can be secured with 9-5/8 inch casing. The final section is the 8-1/2 inch hole section until 4700 meter that can be left as an open hole or utilizing a 7 inch liner to secure it.

4.3. SBBU-1 Design

The SBBU-1 design introduces a smaller riser compared to the standard and FMC (medium) design. After drilling the 36 inch section and installing the 30 inch casing. The next section is the 17-1/2 inch hole section until 1000 meter then a 13-3/8 inch casing is installed. This is a smaller casing size as compared to the FMC design. With this casing size, the design can use a smaller 12 inch wellhead and 13-3/4 inch riser (12-3/4 inch internal diameter). Pre-Installed Liner (PIL) concept is included in this design, it utilize an 11-3/4 inch liner that is run inside the 13-3/8 inch casing. This PIL can be extended to 1900 meter after drilling a 12-1/4 inch hole.

The next 12-1/4 inch section can be drilled down to 2700 meter using a bi-center bit or a down-hole activated reamer. This hole section can be secured with a 9-5/8 inch liner or casing. Pressure complexities may require more than one casing setting depth. Therefore, an option of an expandable liner is included in this design. The liner can be run in 7-5/8 inch diameter and expanded to 9-5/8 inch diameter. The next section to drill is the 8.5 inch hole section until 4200 meter and secure it with a 7 inch liner with tie-back option. The final section is the 5-7/8 inch hole section down to 4700 meter that can be left as an open hole or utilizing a 5 inch casing or liner.

4.4. SBBU-2 Design

The SBBU-2 design introduces a smaller surface casing as compared to the SBBU-2 design. After the 36 inch hole section and 30 inch casing, the next section is a 12-1/4 inch hole section until 1000 meter. It is then secured with 11-3/4 inch casing. This casing size is smaller than the 13-3/8 inch casing which is used in the SBBU-1 design. With this casing size, the SBBU-2 design uses 13-5/8 inch BOP and 12 inch full-bore wellhead.

The next section that follows is the 12-1/4 inch hole section until 2700 meter, which will be secured with a 9-5/8 inch liner / casing. If pressure complexities arise, an option of expandable liner (7-5/8 inch expanded to 9-5/8 inch liner) is included in the design. The next section is the 8-1/2 inch hole section until 4200 meter, to install 7 inch liner / casing. The final section is the 5-7/8 inch hole section down to 4700 meter, with an option to keep it as an open hole or utilize a 5 inch casing and or liner.

4.5. Cuttings Volume Calculations

Assessments of the economic advantages provided by slender well designs are somewhat ambiguous and complex, as there are so many parameters that can be considered. However, from the data presented in **figure 4.1**, volumetric calculations of the removed rock during well construction process can be estimated. The smaller amount of rock removed will reduced the cost of cuttings handling in the surface and its logistics.

Table-1, **table-2**, **table-3**, and **table-4** shows volume calculations for the Standard Conventional design, FMC (medium) design, SBBU-1 design, and SBBU-2 design respectively. **Table-5** shows the volume reduction in percentage with respect to the standard well design. Based on this calculation, it shows that the proposed slender well designs can reduce drilled rock volume from 39% to 57%.

Table 1 Volumetric Calculation for Conventional / Standard Well Design

Conventional Well				
Hole Size (inch)	Depth Start (meter)	Depth End (meter)	Length (meter)	Volume (cubic meter)
36	0	100	100	65.67
26	100	1000	900	308.28
17.5	1000	2700	1700	263.80
12.25	2700	4200	1500	114.06
8.5	4200	4700	500	18.30
Total Volume Removed :				**770.12**

Table 2 Volumetric Calculation for FMC (Medium) Well Design

FMC (Medium)				
Hole Size (inch)	Depth Start (meter)	Depth End (meter)	Length (meter)	Volume (cubic meter)
36	0	100	100	65.67
17.5	100	1000	900	139.66
12.25	1000	4200	3200	243.32
8.5	4200	4700	500	18.30
Total Volume Removed :				**466.96**

Table 3 Volumetric Calculation for SBBU-1 Well Design

SBBU-1				
Hole Size (inch)	Depth Start (meter)	Depth End (meter)	Length (meter)	Volume (cubic meter)
36	0	100	100	65.67
17.5	100	1000	900	139.66
12.25	1000	2700	1700	129.26
8.5	2700	4200	1500	54.91
5.875	4200	4700	500	8.74
Total Volume Removed :				**398.25**

Table 4 Volumetric Calculation for SBBU-2 Well Design

SBBU-2				
Hole Size (inch)	Depth Start (meter)	Depth End (meter)	Length (meter)	Volume (cubic meter)
36	0	100	100	65.67
12.25	100	2700	2600	197.70
8.5	2700	4200	1500	54.91
5.875	4200	4700	500	8.74
Total Volume Removed :				**327.03**

Table 5 Volume Reduction with respect to Standard Well Design

	Volume Removed	**Volume Reduction**
Conventional Well	770.12 m^3	N/A
FMC (Medium	466.96 m^3	39.37%
SBBU-1	398.25 m^3	48.29%
SBBU-2	327.03 m^3	57.54%

The reduction of the rock volume to be drilled would reduce drilling expenses in various ways. There will be less drilling fluid needed, less steel consumption for casing, less cuttings that needed treatment and transportation, utilizing smaller equipment, etc. that will lead to a cost effective and efficient operations.

4.6. Mud Volume Calculations

The cost for mud and its treatment contributes significantly towards the total drilling cost. The slender well design will reduce the volume of mud which leads to cost savings. The mud volume for each well design is the sum of the mud volume used for each section. The general formula used for volume calculation is shown in equation 4.1. Where V is volume in m^3; ID is the internal diameter in inch and L is the length of the pipe in meter.

$$V = \frac{\pi}{4} \times (ID \times 0.0254)^2 \times L \qquad (4.1)$$

The mud volume calculation assumes that a water depth of 400 meter to calculate the riser volume. The calculation result for each well design is presented in the following tables. **Table-6** shows mud volume calculation for the conventional design, **table-7** shows the calculation for FMC (medium) design, **table-8** shows the calculation for SBBU-1 design, **table-9** shows the calculation for SBBU-1 design with tie-back option and **table-10** shows the calculation for the SBBU-2 design. **Table-11** summarizes the calculation and show the mud volume reduction of each slender well design with respect to the standard conventional design.

Table 6 Mud Volume Calculation for Standard Conventional Design

Standard Conventional Design					
Section	**Well Configuration**	**ID**	**Length**	**Volume**	**Total Volume**
(inch)		**(inch)**	**(meter)**	**(cubic meter)**	**(cubic meter)**
17-1/2	Riser	19.5	400	77.07	518.07
	20 inch Casing	18.7	1000	177.19	
	Open Hole	17.5	1700	263.80	
12-1/4	Riser	19.5	400	77.07	399.79
	13-3/8 inch Casing	12.35	2700	208.67	
	Open Hole	12.25	1500	114.06	
8-1/2	Riser	19.5	400	77.07	250.59
	9-5/8 inch Casing	8.54	4200	155.21	
	Open Hole	8.5	500	18.30	
				Total Mud Volume:	**1168.45**

Table 7 Mud Volume Calculation for FMC (Medium) Design

FMC (Medium) Design					
Section	**Well Configuration**	**ID**	**Length**	**Volume**	**Total Volume**
(inch)		**(inch)**	**(meter)**	**(cubic meter)**	**(cubic meter)**
12-1/4	Riser	13.75	400	38.32	253.22
	14 inch Casing	13	1000	85.63	
	Open Hole	12.25	1700	129.26	
12-1/4	Riser	13.75	400	38.32	342.24
	14 inch Casing	13	1000	85.63	
	11-3/4 inch Casing	11	1700	104.23	
	Open Hole	12.25	1500	114.06	
8-1/2	Riser	13.75	400	38.32	211.84
	9-5/8 inch Casing	8.54	4200	155.21	
	Open Hole	8.5	500	18.30	
				Total Mud Volume:	**807.29**

Table 8 Mud Volume Calculation for SBBU-1 Design

SBBU-1 Design					
Section	**Well Configuration**	**ID**	**Length**	**Volume**	**Total Volume**
(inch)		**(inch)**	**(meter)**	**(cubic meter)**	**(cubic meter)**
12-1/4	Riser	12.75	400	32.95	234.59
	13-3/8 inch Casing	13	1000	85.63	
	11-3/4 inch Liner	11	900	55.18	
	Open Hole	12.25	800	60.83	
8-1/2	Riser	12.75	400	32.95	246.78
	9-5/8 inch Casing	8.54	2700	99.78	
	Open Hole	12.25	1500	114.06	
5-7/8	Riser	12.75	400	32.95	173.98
	9-5/8 inch Casing	8.54	2700	99.78	
	7 inch Liner	6.54	1500	32.51	
	Open Hole	5.875	500	8.74	
				Total Mud Volume:	**655.36**

Table 9 Mud Volume Calculation for SBBU-1 Design with Tie Back option

SBBU-1 Design with Tie Back					
Section	**Well Configuration**	**ID**	**Length**	**Volume**	**Total Volume**
(inch)		**(inch)**	**(meter)**	**(cubic meter)**	**(cubic meter)**
12-1/4	Riser	12.75	400	32.95	234.59
	13-3/8 inch Casing	13	1000	85.63	
	11-3/4 inch Liner	11	900	55.18	
	Open Hole	12.25	800	60.83	
8-1/2	Riser	12.75	400	32.95	246.78
	9-5/8 inch Casing	8.54	2700	99.78	
	Open Hole	12.25	1500	114.06	
5-7/8	Riser	12.75	400	32.95	165.24
	7 inch Liner	6.54	4200	99.78	
	Open Hole	5.875	500	32.51	
				Total Mud Volume:	**646.61**

Table 10 Mud Volume Calculation for SBBU-2 Design

SBBU-2 Design					
Section	**Well Configuration**	**ID**	**Length**	**Volume**	**Total Volume**
(inch)		**(inch)**	**(meter)**	**(cubic meter)**	**(cubic meter)**
12-1/4	Riser	12.75	400	32.95	223.52
	11-3/4 inch Liner	11	1000	61.31	
	Open Hole	12.25	1700	129.26	
8-1/2	Riser	12.75	400	32.95	212.00
	11-3/4 inch Liner	11	1000	61.31	
	9-5/8 inch Liner	8.54	1700	62.82	
	Open Hole	8.5	1500	54.91	
5-7/8	Riser	12.75	400	32.95	198.34
	11-3/4 inch Liner	11	1000	61.31	
	9-5/8 inch Liner	8.54	1700	62.82	
	7 inch Liner	6.54	1500	32.51	
	Open Hole	5.875	500	8.74	
				Total Mud Volume:	**633.86**

Table 11 Mud volume reduction for the Slender Well designs with respect to Standard Conventional design

Design	Total Mud Volume	% Reduction
Conventional	1168.45	N/A
FMC (Medium)	807.29	30.91%
SBBU-1	655.36	43.91%
SBBU-1 with Tie Back	646.61	44.66%
SBBU-2	633.86	45.75%

The mud volume reduction for the FMC (medium) design, SBBU-1 design, SBBU-1 with tie-back option and SBBU-2 design are 31%, 44%, 45% and 46% respectively.

The riser volume is directly related to the water depth. As the water depth increases, the more mud volume could be reduced with the utilization of smaller riser. **Table-12** shows the calculation of riser volume as a function of water depth for designs that utilize different riser ID size. The plot for the difference in volume is shown on **figure 4.2**.

Table 12 Riser Volume as a function of water depth

	Mud Volume in Riser (m^3)		
Riser ID (inch):	**19.5**	**13.75**	**12.75**
Water Depth	**Std. Conventional Design**	**FMC Design**	**SBBU design**
200	38.54	19.16	16.47
400	77.07	38.32	32.95
1000	192.68	95.80	82.37
1500	289.01	143.70	123.56

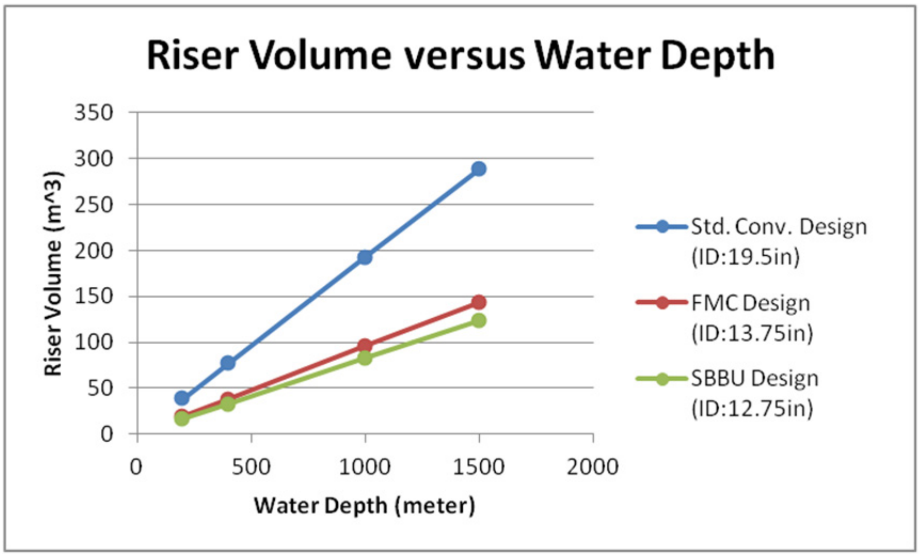

Figure 4.2 Plot of Riser Volume as a function of water depth

The plot shows a considerable volume difference between the Standard Conventional design with the Slender Well designs. The reduction of volume for the Slender Well design shows that at 1000 meter, the FMC design could reduce the mud volume as much as 251% and the SBBU design 286%. **Table-13** shows the mud volume reduction in cubic meter and percentage (with respect to the Standard Conventional design) as a function of water depth.

Table 13 Riser Volume reduction as a function of water depth

	Mud Volume Reduction			
	FMC Design		SBBU design	
Water Depth	**(m^3)**	**(%)**	**(m^3)**	**(%)**
200	19.38	50.28%	22.06	57.25%
400	38.75	100.56%	44.12	114.50%
1000	96.88	251.40%	110.30	286.24%
1500	145.31	377.10%	165.46	429.36%

4.7. Steel Volume Calculations

Slender well design with smaller borehole size will also use smaller casing size. The reduction in casing size will reduce the steel volume leading to reduction in cost of casing. In general, smaller casing size can be run faster due to easier lifting operations. The steel volume can be calculated with,

$$V = \pi \times d \times L \times t \times (0.0254)^2 \quad (4.2)$$

Where *d* is the diameter of the casing component in inch, *L* is the length of the casing component in meter and *t* is the thickness of casing in inch.

The weight of the steel is calculated with steel density of 7860 kg/m^3. The calculations of steel volume and weight for each well design are presented in tables below. **Table-14** shows the calculation for the Standard Conventional design, **table-15** shows the calculation for the FMC (medium) design, **table-16** shows the calculation for the SBBU-1 design, **table-17** shows the calculation for the SBBU-1 design with tie-back option and **table-18** shows the calculation for the SBBU-2 design. **Table-19** shows the reduction of steel volume for Slender Well design with respect to the Standard Conventional design.

Table 14 Steel Volume calculation for Standard Conventional Design

Standard Conventional Design					
Component	**Diameter**	**Thickness**	**Length**	**Volume**	**Weight**
	(inch)	**(inch)**	**(meter)**	**(cubic meter)**	**(tonnes)**
30 inch casing	30	0.625	100	3.80	29.87
20 inch casing	20	0.635	1000	25.74	202.32
13-3/8 inch casing	13.375	0.55	2700	40.26	316.42
9-5/8 inch casing	9.625	0.435	4200	35.64	280.14
Total Steel Volume & Weight :				**105.44**	**828.75**

Table 15 Steel Volume calculation for FMC (Medium) Design

FMC (Medium) Design					
Component	**Diameter**	**Thickness**	**Length**	**Volume**	**Weight**
	(inch)	**(inch)**	**(meter)**	**(cubic meter)**	**(tonnes)**
30 inch casing	30	0.625	100	3.80	29.87
14 inch casing	14	0.635	1000	18.02	141.63
11-3/4 inch casing	11.75	0.55	2700	35.37	277.97
9-5/8 inch casing	9.625	0.435	4200	35.64	280.14
Total Steel Volume & Weight :				**92.83**	**729.61**

Table 16 Steel Volume calculation for SBBU-1 Design

SBBU-1 Design					
Component	**Diameter**	**Thickness**	**Length**	**Volume**	**Weight**
	(inch)	**(inch)**	**(meter)**	**(cubic meter)**	**(tonnes)**
30 inch casing	30	0.625	100	3.80	29.87
13-3/8 inch casing	13.375	0.55	1000	14.91	117.19
11-3/4 inch pre-installed liner	11.75	0.55	900	11.79	92.66
9-5/8 inch casing	9.625	0.435	2700	22.91	180.09
7 inch liner	7	0.362	1500	7.70	60.55
Total Steel Volume & Weight :				**61.12**	**480.36**

Table 17 Steel Volume calculation for SBBU-1 Design with Tie-Back option

SBBU-1 Design with Tie Back					
Component	**Diameter**	**Thickness**	**Length**	**Volume**	**Weight**
	(inch)	**(inch)**	**(meter)**	**(cubic meter)**	**(tonnes)**
30 inch casing	30	0.625	100	3.80	29.87
13-3/8 inch casing	13.375	0.55	1000	14.91	117.19
11-3/4 inch pre-installed liner	11.75	0.55	900	11.79	92.66
9-5/8 inch casing	9.625	0.435	2700	22.91	180.09
7 inch liner	7	0.362	4200	21.57	169.55
Total Steel Volume & Weight :				**74.98**	**589.36**

Table 18 Steel Volume calculation for SBBU-2 Design

SBBU-2 Design					
Component	**Diameter**	**Thickness**	**Length**	**Volume**	**Weight**
	(inch)	**(inch)**	**(meter)**	**(cubic meter)**	**(tonnes)**
30 inch casing	30	0.625	100	3.80	29.87
11-3/4 inch liner	11.75	0.55	1000	13.10	102.95
9-5/8 inch liner	9.625	0.435	1700	14.43	113.39
7 inch liner	7	0.362	1500	7.70	60.55
Total Steel Volume & Weight :				**39.03**	**306.77**

Table 19 Steel volume reduction for the Slender Well designs with respect to Standard Conventional design

Design	Steel Volume Reduction (cubic meter)	Steel Weight Reductions (tonnes)	% Reduction
FMC (Medium)	12.61	99.14	11.96%
SBBU-1	44.32	348.39	42.04%
SBBU-1 with Tie Back	30.46	239.39	28.89%
SBBU-2	66.41	521.98	62.98%

The steel volume reduction for the FMC (medium) design, SBBU-1 design, SBBU-1 with tie-back option and SBBU-2 design are 12%, 42%, 29% and 63% respectively.

4.8. Drilling Cost as a function of On-Bottom Time

The total cost of drilling is a function of drilling time and drilling cost with respect to time. Drilling time is a function of the operational activities conducted on the rig. However, most of the activities are being done simultaneously with the drilling process itself. So simplifying the activities, drilling time are mainly a function of adding more meters to the well, thus it can be said that it is the function of Rate-Of-Penetration. While drilling cost can generally be stated with the rig day-rate with all the services cost included. The equation can be expressed as,

$$Total\ Drilling\ Cost = Drilling\ Time\ \{f(ROP)\} \times Drilling\ Cost\ \{f(Rig\ DayRate)\} \quad (4.3)$$

Economical assessment of total drilling cost is made based on the unitized ROP data presented by DeMong et al. on **figure 2.3**. The figure provides ratio factor of ROP between each hole-size, whereas the maximum value of ROP is when drilling 8-1/2 inch hole. By taking the 8-1/2 inch hole ROP of 30 meter/hour, the ROP for all the other hole size are calculated by applying the ratio factor. The ROP for all the other hole-size are presented in **table-20**. With the ROP value for each hole-size, the on-bottom drilling hour for each section of each well design can be calculated and it is presented in **table-21**.

Table 20 ROP estimation for each hole-size based on the unitized ROP data by DeMong et al.

Hole Size (inch)	Ratio Factor	ROP (m/hour)
5.875	0.7	21
8.5	***1***	***30***
12.25	0.7	21
17.5	0.5	15
26	0.2	6
36	0.2	6

Table 21 Total on-bottom drilling hour as a function of ROP, depth and hole-size

Section	Time to drill (hour)			
	Conventional	FMC	SBBU-1	SBBU-2
Conductor (0 - 100 meter)	17	17	17	17
Top (100 -1000 meter)	150	60	60	43
Intermediate-1 (1000 - 2700 meter)	113	81	81	81
Intermediate-2 (2700 -4200 meter)	71	71	50	50
Production (4200 - 4700 meter)	17	17	24	24
Sum:	**368**	**246**	**231**	**214**

The ROP values are applied for each well section based on hole-size to estimate the total drilling cost for each well design. The total drilling is a function of the rig day-rate. The result of the calculation based on ROP data are given in **table-22** and plotted in **figure 4.3**. Comparing the total drilling cost for slender well designs against the standard conventional well, the reduction in drilling hours gives a cost reduction as much as 33.25% for the FMC design, 37.13% for the SBBU-1 design and 41.79% for the SBBU-2 design.

Table 22 Total drilling cost for each well design as a function of rig day-rate

Rig Day-Rate	Total Drilling Cost (Million-USD)			
(Million-USD/ day)	Conventional	FMC	SBBU-1	SBBU-2
0.1	1.46	0.95	0.89	0.82
0.25	3.66	2.39	2.24	2.06
0.5	7.32	4.77	4.47	4.12
0.75	10.98	7.16	6.71	6.18
1	14.64	9.54	8.95	8.23

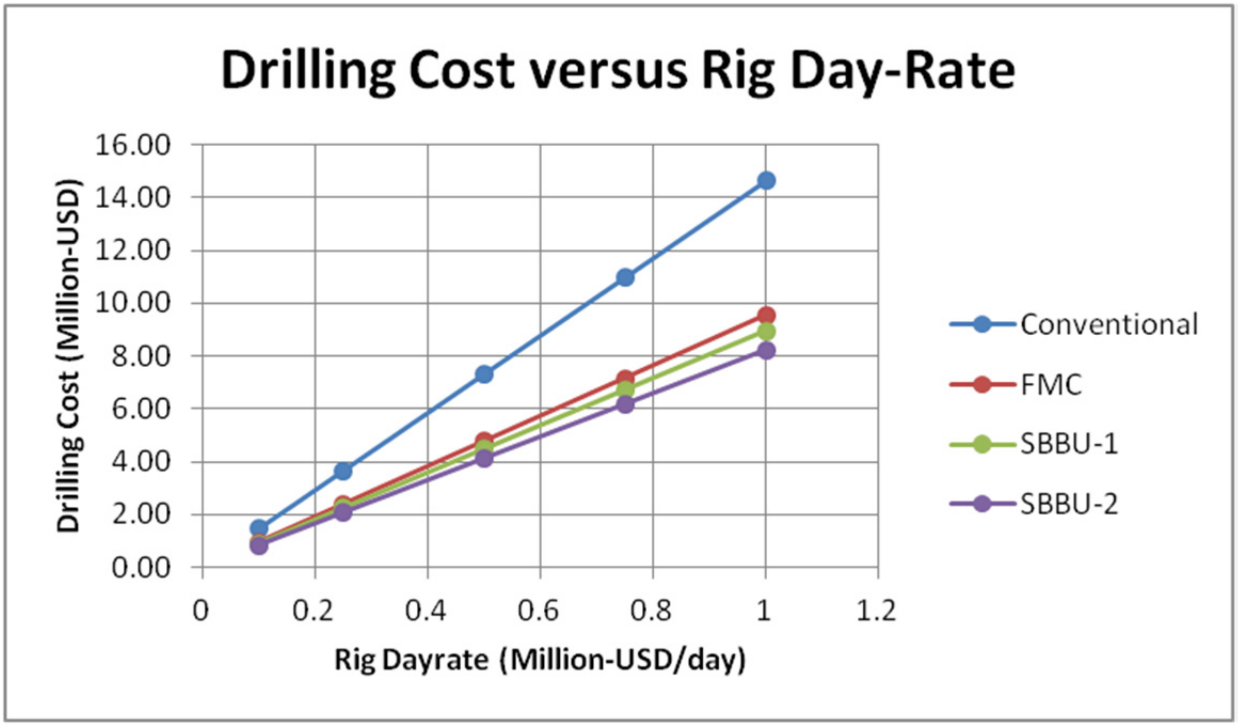

Figure 4.3 Plot total drilling cost for each well design as a function of the rig day-rate

5. Well Hydraulics

This chapter will discuss qualitatively the well hydraulics of the previously proposed slender well designs. Qualitative conclusions will be drawn from a quantitative modeling which simplifies several parameters. The interest of the simulation is to compare the pressure loss and annulus velocity of each slender well design. These two parameters are of importance because annulus velocity relates to cutting lifting capability and it is better with higher flow-rate. However, a higher flow-rate will lead to a higher pressure loss which most of the times makes it not feasible for the drilling process itself.

5.1. Fluid Rheology

Rheology modeling for the calculations presented is based on laboratory data used in real well design calculations. The data are presented in **table-23** below and plotted in **figure 5.1**. From the plot we can see that the model follows the Herschel-Buckley Model. However, it has to be noted that the Fann Viscometer used for the measurements was initially designed for the Bingham Plastic Model. The program used for this thesis will calculate based on the Bingham Model formulas.

Table 23 Fann Viscometer Data for Rheology Model

Fann RPM	Fann Readings
600	70
300	50
200	38
100	30
60	25
30	19
6	12
3	11

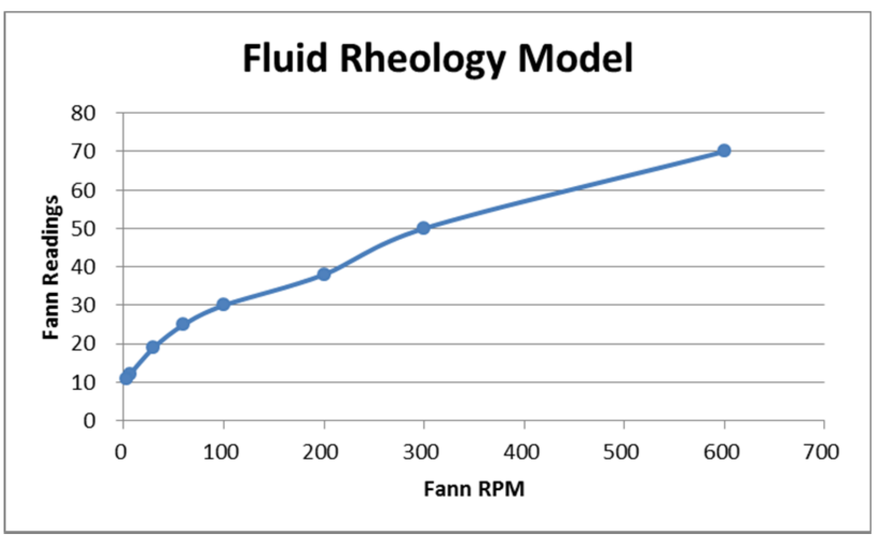

Figure 5.1 Plot of Rheology Model

Using the Bingham Model, plastic viscosity and yield point can be calculated with the simple oilfield method.

$$\mu_p = \theta_{600} - \theta_{300} = 70 - 50 = 20cP$$

$$\tau_y = (\theta_{300} - \mu_p) \times 0.48 = (50 - 20) \times 0.48 = 14.4\ Pa$$

5.2. Mud Weight

Mud weight provides hydrostatic pressure to overcome the formation pressure to ensure safe drilling, create a stable borehole and minimize hazardous potential of formation fluid entering the wellbore. The mud weight used for the model are described in **table-24** below,

Table 24 Mud Weight for each depth interval

Depth (meter)	Mud Weight (SG)
0 - 1000	1.035
1000 - 2700	1.5
2700 - 4200	1.85
4200 – 4700	2

5.3. Flow Rate and RPM

Apart from mud rheology, flow rate and drill-string rotation are important in its relation with hole-cleaning process. A higher flow rate will increase the cutting lifting velocity resulting in a better hole cleaning. A higher drill-string rotation will also improve hole cleaning because it will agitate the cuttings and allows it to be transported our by the mud flow in the annulus. These parameters became more important on high deviation well.

Various studies and field experiences had given a general rule of thumb for flow-rate and drill-string rotation as cited in *Drilling Fluid Engineering* (Skalle, 2011). **Table-25** shows recommendations for flow rate and drill-string rotations for various hole-sizes. This recommendation will be used in the modeling and calculation process.

Table 25 General Rule Of Thumb for Flowrate and RPM for each hole-size (Skalle, 2012)

	17-1/2 inch	**12-1/4 inch**	**8-1/2 inch**	**5-7/8 inch (*)**
Flow Rate (lpm)	4000-5000	3000-3500	2000-2500	750-1500
Drill-string Rotation (RPM)	140-180	130-175	120-170	120 - 180
Circulation Bottoms Up	1-3	2-4	3-4	3-4

(*) The parameters for 5-7/8 inch slim-hole section are based on the writer's working experience.

5.4. Bottom Hole Assembly

Bottom Hole Assembly is the configuration of the equipment used in the lower part of the string that improves drilling process. The pressure drop and ECD calculator provides several bottom-hole assembly options from well-known providers. A simple BHA model consisting of a motor and measurement while drilling (MWD) tool are selected. In the model, the 17-1/2 inch and 12-1/4 inch hole section are drilled with a *9-1/2 inch – 8-1/2 inch high flow INTEQ MWD* combined with *9-5/8 inch 5/6 lobe DynadrillF2000M*. The 8-1/2 inch hole-section is drilled with *6-3/4 inch INTEQ MWD* combined with *6-3/4 inch Positive Displacement Motor SperryDrill*. However, the calculation sheet does not contain library for slim tool. Therefore, the 5-7/8inch hole-section is using the same BHA configuration as the 8-1/2 inch hole-section.

In reality, although the equipment for drilling and measurements while drilling are of the same size. The stabilizer sizes attached to the equipment are different depending on the hole-size. In the model, the BHA components are kept simple by only including the motor and MWD. Because the highest pressure loss comes from these two components. The pressure loss on the motor are because the mud flow is being used to rotate the rotor inside the motor and pressure loss on the MWD tool are because the MWD tool has smaller flow-area due to the electronics installed in the MWD collar. Other BHA component such as under-reamer and stabilizer are assumed to have the same ID with drill collar.

5.5. Pressure Loss

Circulation of drilling fluid during drilling is needed for various reasons such as, hole cleaning, cooling down the bit and many more. This circulation process uses mud pump to pump the drilling fluid. In doing so, the mud pumps have to overcome frictional pressure loss inside the drill string, in the annulus and also the pressure loss at the bit.

5.5.1. Drill-String and Annular Pressure Loss

Pressure loss in the drill-string and annulus is strongly related to the flow rate, mud rheology, inside diameter of the pipe, outside diameter and the hole-size. The simulation of the model will show the plots of the pressure as a function of the flow-rate. The model simulates only the depth of interest where the design differs from one slender well to another. **Table-26** presents the depth of interest, hole-size and casing size used for each design.

Table 26 Well configuration for each design

	Conventional		**FMC (Medium)**		**SBBU-1**		**SBBU-2**	
Depth Interval	Hole Size	Casing Size	Hole Size	Casing Size	Hole Size	Casing Size	Hole Size	Casing Size
(meter)	(inch)	(inch)	(inch)	(inch)	(inch)	(inch)	(inch)	(inch)
100	36	30	36	30	36	30	36	30
1000	26	20	17-1/2	14	17-1/2	13-3/8	12-1/4	11-3/4
1900	n/a	n/a	n/a	n/a	12-1/4	11-3/4 PIL	n/a	n/a
2700	17-1/2	13-3/8	12-1/4	11-3/4	12-1/4	9-5/8	12-1/4	9-5/8
4200	12-1/4	9-5/8	12-1/4	9-5/8	8-1/2	7	8-1/2	7
4700	8-1/2	OH (7” Liner)	8-1/2	OH (7” Liner)	5-7/8	OH (5” Liner)	5-7/8	OH (4” Liner)

The pressure loss modeling and analysis will be focusing on drilling the section down to 2700 meter (Intermediate-1 section), 4200 meter (intermediate-2 section) and 4700 meter (production section). Plots of total internal and annular pressure loss for each section are shown in **figure 5.2**, **figure 5.3** and **figure 5.4**.

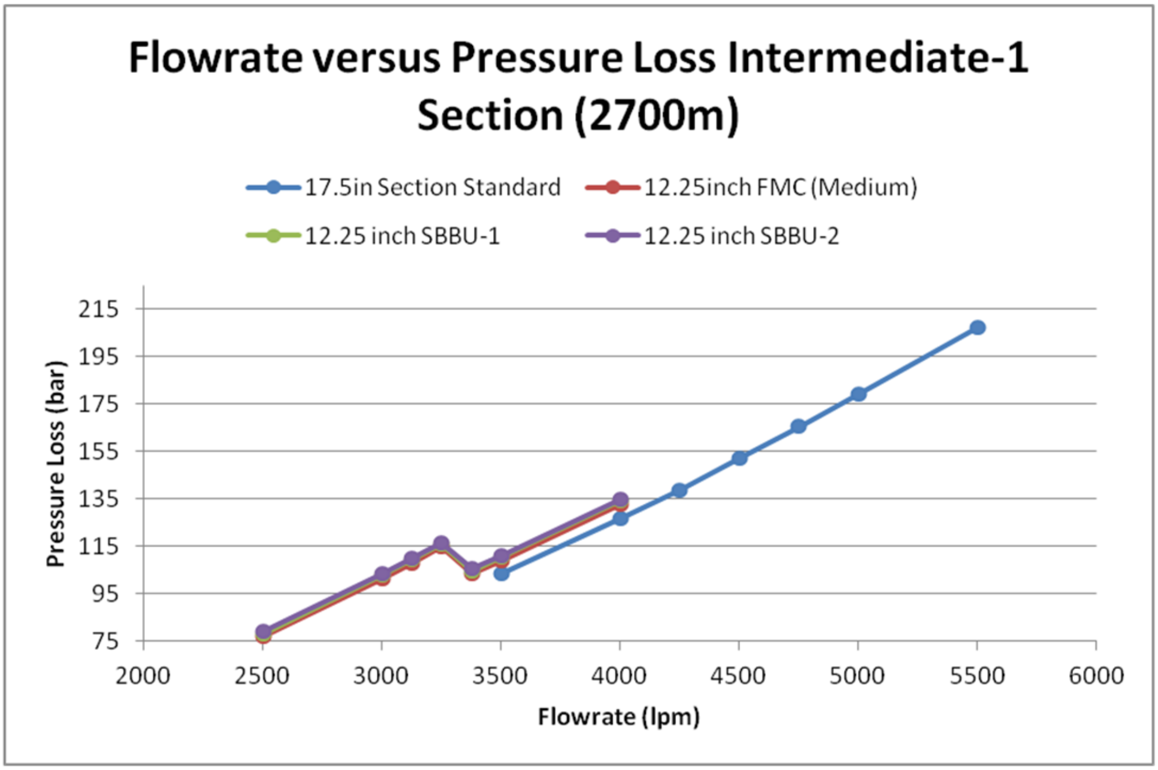

Figure 5.2 Total Internal and Annular Pressure Loss for Intermediate-1

Figure 5.2 shows that all the slender well design have a lower pressure loss when drilling the 12-1/4 inch hole-section. The FMC (medium) design with 14 inch casing until 1000 meters gives the biggest annulus clearance among all the slender well designs. This design gives the lowest pressure loss followed by SBBU-1 which uses a 13-3/8 inch casing until 1000 meters and 11-3/4 inch Pre-Installed Liner from 1000 meters to 1900 meters. The highest pressure loss of the slender well design is the SBBU-2 because it has the smallest annular clearance with 11-3/4 inch casing.

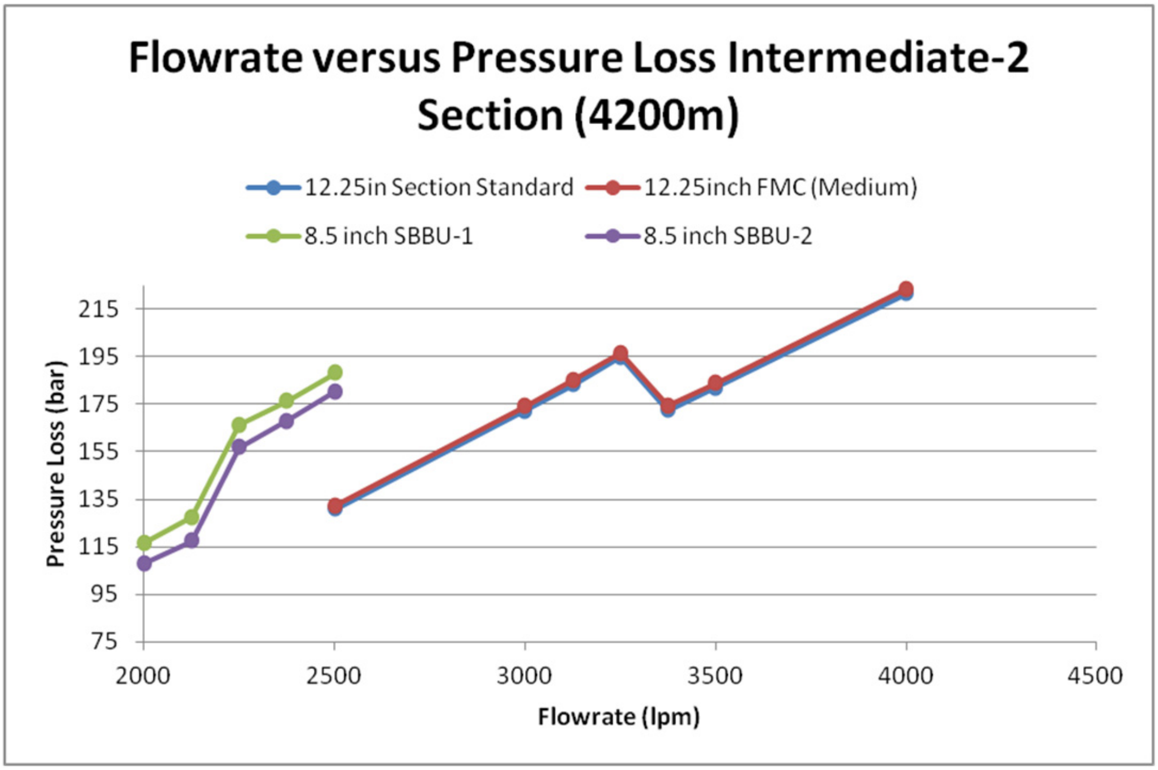

Figure 5.3 Total Internal and Annular Pressure Loss for Intermediate-2

Figure 5.3 shows that for intermediate-2, drilling down to 4200 meters, the SBBU-1 and SBBU-2 design has a relatively lower pressure loss as compares to the standard conventional well. However, the FMC (medium) design has a slightly higher pressure loss. The difference between SBBU-1 and SBBU-2 design is that SBBU-1 utilize 9-5/8 inch casing from top to 2700 meters and SBBU-2 utilize 11-3/4 inch casing from top to 1000 meters, followed by 9-5/8 inch liner from 1000 meters to 2700 meters. The 11-3/4 inch casing on SBBU-2 design provides a bigger annulus clearance that reduces the pressure loss.

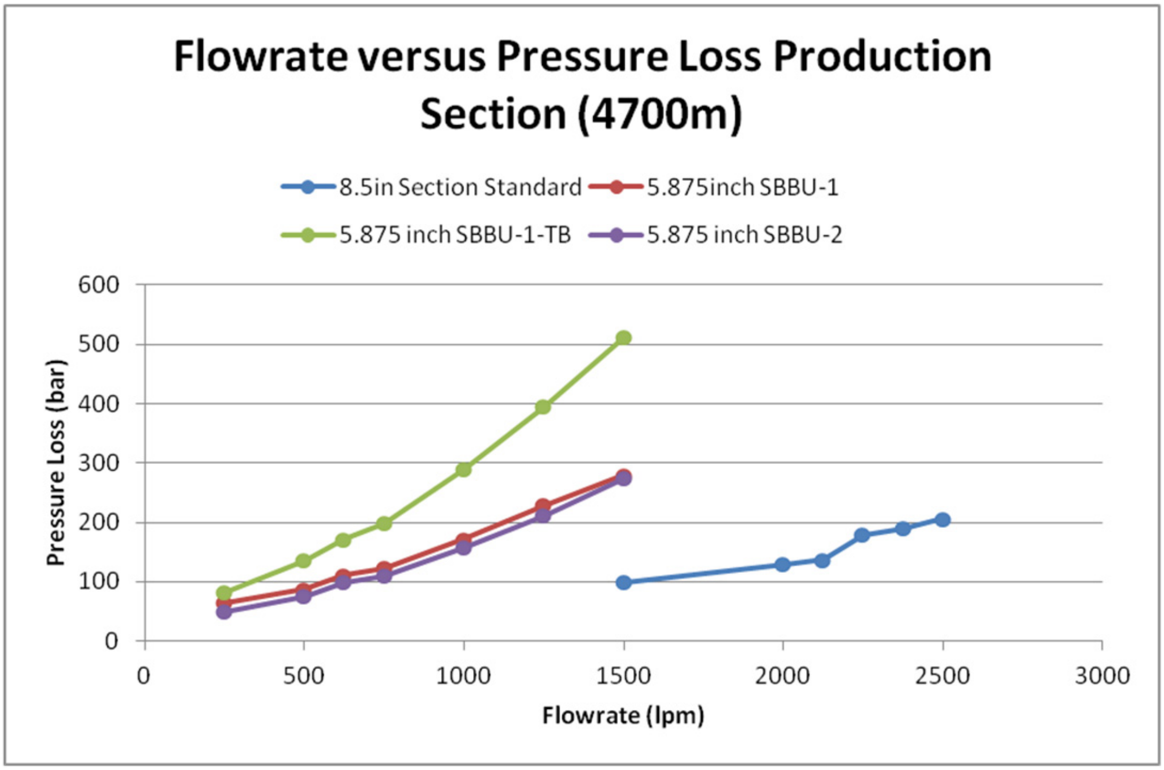

Figure 5.4 Total Internal and Annular Pressure Loss for Production

In the production section, the pressure losses are relatively equal to slightly higher between the slender designs and the standard conventional design. However, the slender designs are more sensitive to the change of flow-rate due to its smaller annular clearance. From the plot in **figure 5.4**, it can be seen that the pressure loss are relatively equal with the standard conventional well design when the flow-rate is below 750 lpm. The SBBU-1 tie back option, represented by the green line, has the highest pressure loss because of the tie back which gives small annular clearance all the way to surface.

5.5.2. Bit Pressure Loss

Pressure loss on the bit is strongly related to the mud rheology, bit type and size, model and total flow area of the bit. Pressure loss on the bit takes a major percentage of the circulating pressure loss. The pressure loss on the bit is used to create a “jetting” effect to clean the cuttings that accumulate near the cutters (for a tri-cone bit) and to create a mechanical force that helps to destroy the drilled formation. In some type of bit, the mud circulated also helps with lubricating the bearing of the bit.

The model used does not take into account the bit type and pressure loss by bit model. It uses a general bit pressure loss formula,

$$P_b = \frac{(MW \times 8.34) \times \left({}^{flow-rate}/_{3.7853} \right)}{(10858 \times TFA^2) \times 14.5} \qquad (5.1)$$

Where P_b is the bit pressure loss; MW is mud weight in specific gravity; flow rate is expressed in liter per minutes and TFA is total flow area expressed in inch^2. It shows that the bit pressure loss is dependent on mud weight, flow-rate and nozzle sizes and number of nozzles.

Figure 5.5, **figure 5.6**, and **figure 5.7** show the bit pressure loss versus total flow area for the recommended flow of each hole-size and well section. These three figures represent each well design and each well section. **Figure 5.5** shows the plot for intermediate-1 section (2700 meter), where the standard conventional well design has a relatively higher pressure loss at the bit because of the higher flow-rate for the larger hole size (17-1/2 inch) as compared to the other three slender well design (12-1/4 inch). **Figure 5.6** shows the plot for intermediate-2 section (4200 meters), where the standard conventional and FMC design have a relatively higher pressure loss at bit because the higher flow-rate for the larger hole size (12-1/4 inch) as compared to SBBU-1 and SBBU-2 design (8-1/2 inch). **Figure 5.7** shows the plot for production section (4700 meter), where the standard conventional and FMC design (8-1/2 inch) have a higher pressure loss as compared to SBBU-1 and SBBU-2 (5-7/8 inch).

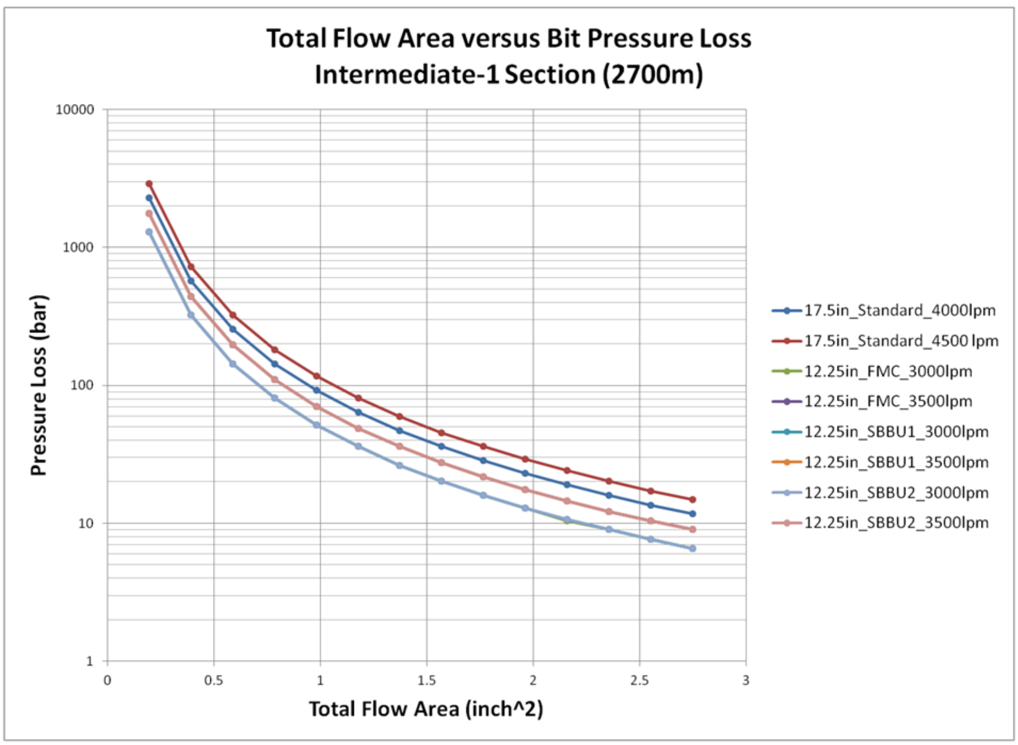

Figure 5.5 TFA versus Bit Pressure Loss for Intermediate-1 section

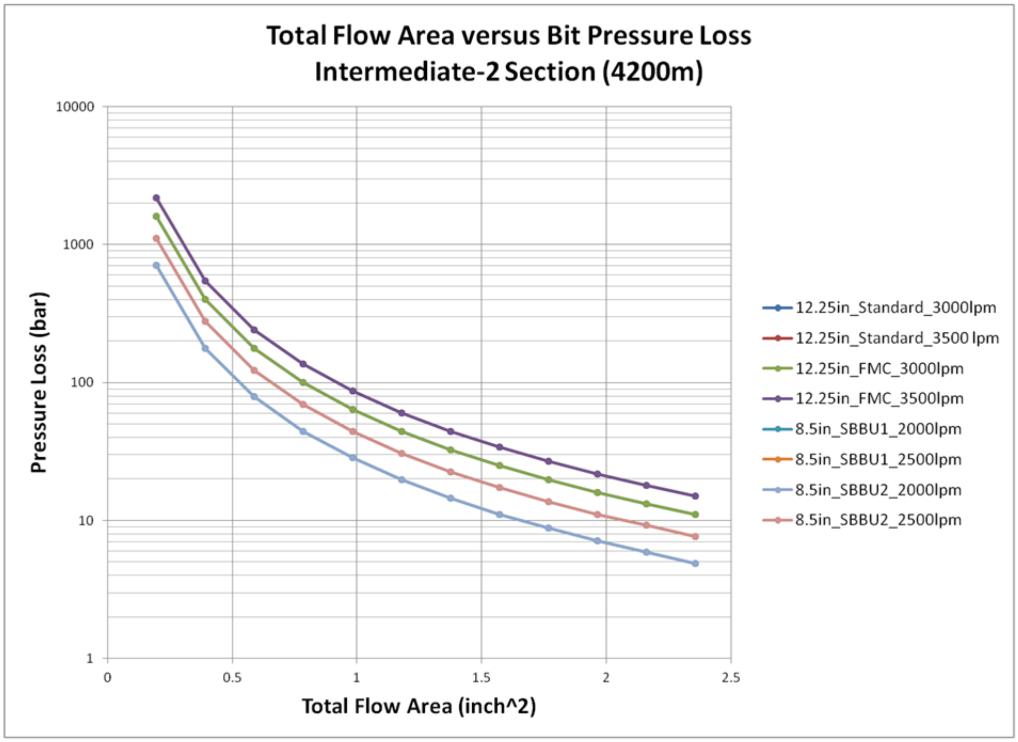

Figure 5.6 TFA versus Bit Pressure Loss for Intermediate-2 section

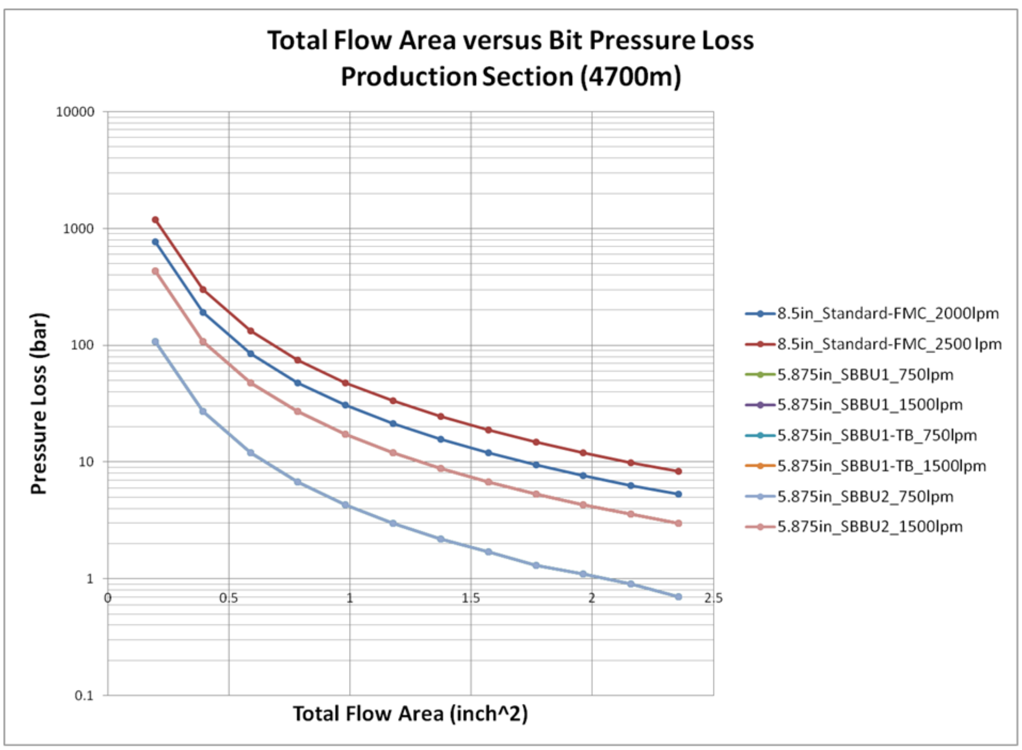

Figure 5.7 TFA versus Bit Pressure Loss for Production Section

5.5.3. Total Pressure Loss

Total pressure loss can be modeled by combining the calculated internal and annular frictional loss with the pressure loss at the bit. In field practice, total pressure loss will be reflected by the pump pressure during circulation. The pump pressure plots are presented as a function of total flow area and flow rate because the bit pressure loss calculation is dependent on those two variables. The frictional pressure loss is added to the corresponding flow rate because it is flow rate dependent.

Figure 5.8 shows a plot of pump pressure as a function of total area and flow rate for intermediate-1 section. The plot shows that the standard design has a higher pump pressure range because for this section, the standard design used the 17-1/2 inch hole-size that requires higher flow rate (4000 - 4500 lpm). The slender designs have a relatively similar pressure range between each other despite the different construction they have. It shows that the frictional pressure loss is not a dominating factor in this section. The majority of the pressure losses are dominated by the pressure loss at the bit and in the bottom-hole assembly.

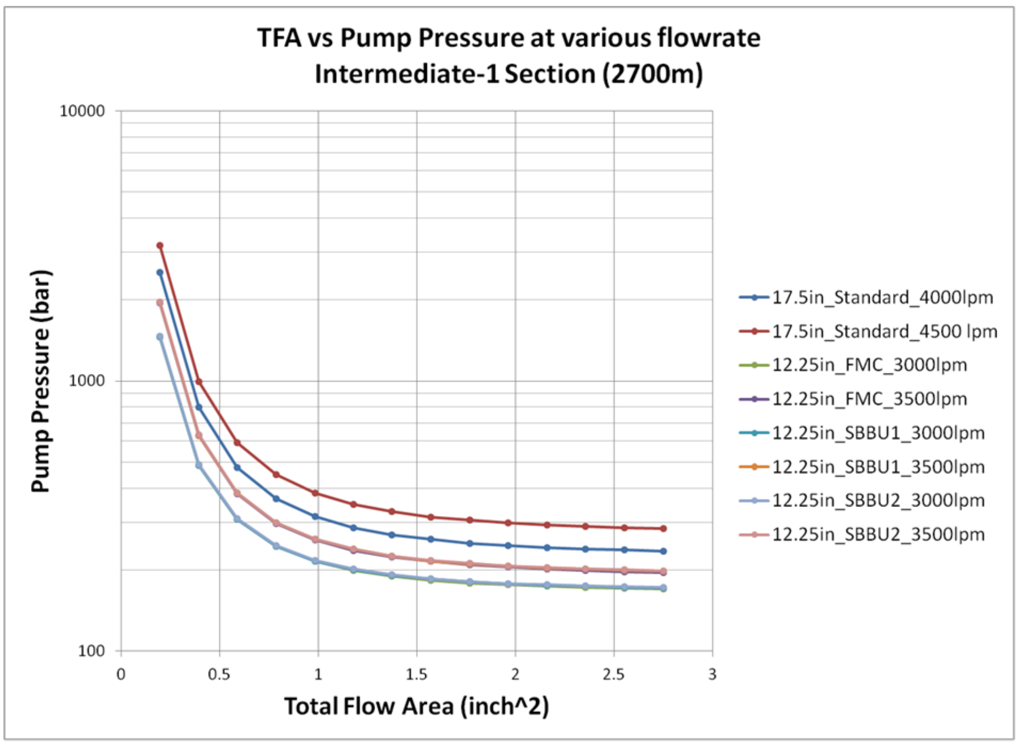

Figure 5.8 TFA versus Pump Pressure for Intermediate-1 Section

Figure 5.9 shows a plot of pump pressure as a function of total area and flow rate for intermediate-2 section. The plot shows that the pump pressure for the standard and the FMC design are relatively similar within the range of flow rate (3000 - 3500 lpm) for the same 12-1/4 inch hole size. However, the slender design SBBU-1 and SBBU-2 that drill 8-1/2 inch hole-size with the flow rate range 2000 to 2500 lpm has a slightly different pump pressure range. SBBU-1 and SBBU-2 has the same pump pressure range at a smaller TFA. But the range differs as the TFA increases because the pressure loss at the bit becomes less dominant as compared to the frictional loss due to the difference in well construction. The SBBU-1 has a higher pump pressure range because of a higher annulus pressure loss due to the utilization of 9-5/8 inch casing from top to 2700 meter. The SBBU-2 has lower pump pressure range due to smaller annulus pressure loss as it utilize an 11-3/4 inch casing to 1000 meter, followed by 9-5/8 inch liner from 1000 to 2700 meter.

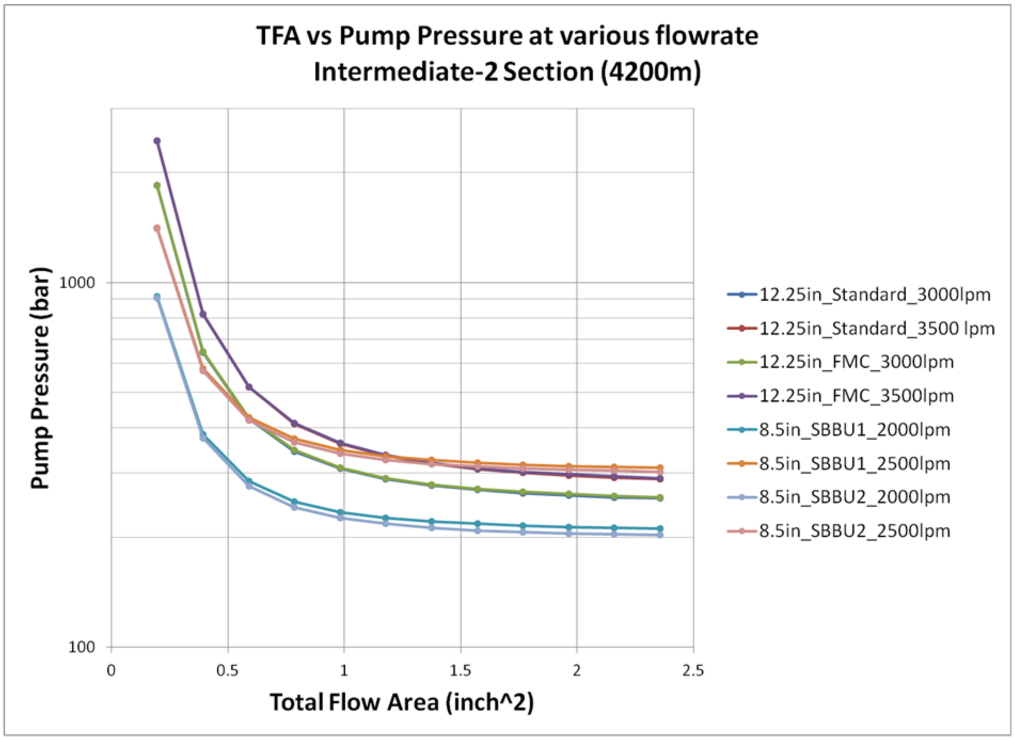

Figure 5.9 TFA versus Pump Pressure for Intermediate-2 Section

Figure 5.10 shows a plot of pump pressure as a function of total area and flow rate for production section. The plot shows a wider pressure range for each design which indicates that as the well construction becomes slimmer and annulus clearance becomes smaller; the pump pressure becomes more sensitive to the change of flow rate.

The standard conventional and FMC design are similar for this section so they are combined into the same plots of flow rate (2000 – 2500 lpm). Plotting of SBBU-1 and SBBU-2 design is the similar at higher flow rate (1500 lpm) but differs at lower flow rate (750 lpm). The SBBU-1 utilize 9-5/8 inch casing from top to 2700 meter followed by a 7 inch liner and the SBBU-2 utilize 11-3/4 inch casing from top to 1000 meter followed by a 9-5/8 inch liner from 1000 to 2700 meter and a 7 inch liner from 2700 to 4200 meter. This gives SBBU-2 a larger overall annular clearance which resulted in smaller pressure drop.

This figure includes the SBBU-1 design with a casing tie-back to the top. The "SBBU1-TB" plot illustrates pressure loss if the well construction utilizes a 7 inch casing tie-back to the top. The plot shows a large increase in pump pressure with the tie-back design due to a very long section with small annular clearance which gives higher friction pressure in the annulus. The configuration of the slender designs in the production section has to be evaluated against the burst and collapse of the casing design to check the feasibility of the casing tie-back for SBBU-1 and SBBU-2. The limiting factor for the pressure and flow rate is the mud pump in use. Thy hydraulic simulation results for annulus pressure loss, bit pressure loss and total pressure loss are shown in Appendix-A.2.

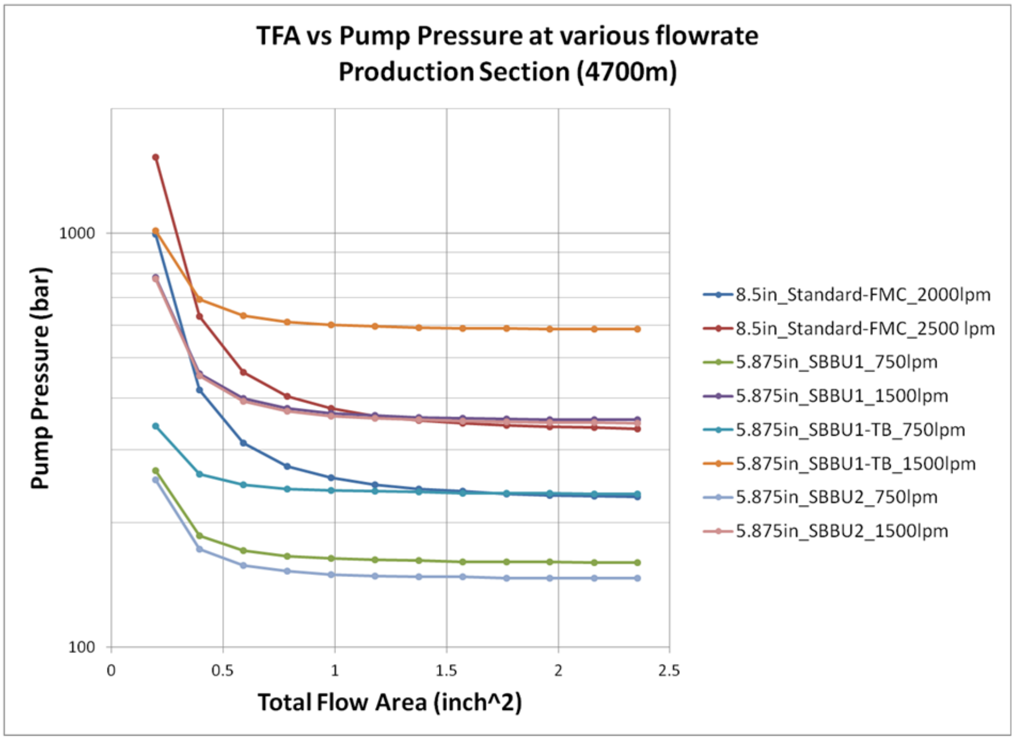

Figure 5.10 TFA versus Pump Pressure for Production Section

5.6. Annular Velocity

The annular velocity is a function of annulus clearance and flow rate and it is an important parameter related to hole cleaning aspects. In general, the higher the annular velocity, hole-cleaning will be improved. But a high annular velocity would also lead to higher annular pressure loss and higher pumping pressure required to compensate the pressure loss.

The annular velocities of each slender well design are compared to analyze which one would provide a better hole cleaning. The SBBU-1 and SBBU-2 are designed with tie-back string as an option. The tie-back option needs to be validated, to see whether the flow on the wider annulus clearance on the top section would be sufficient to lift the cuttings to surface if the tie-back string is not installed.

The analysis is made based on the hole-size and flow-rate for each section and design. The rate-of-penetration is assumed to be 30 meter/hour for drilling all sections. The cutting slip velocity used in the calculations is 0.20 meter/second, which is the slip velocity value in water (Skalle, 2011. p.71).

Cuttings concentration ($c_{cuttings}$) can be calculated by estimating cuttings volume rate ($q_{cuttings}$) and compare it with the flow-rate. The formulas for these calculations are,

$$q_{cuttings} = ROP \times A_{bit} \tag{5.2}$$

$$c_{cuttings} = q_{cuttings} \div flowrate \tag{5.3}$$

The calculations for each hole-size with the high recommended flow-rate for each hole-size are presented in **table-27** and with the low recommended flow-rate in **table-28**.

Table 27 Cuttings Concentration in dynamic condition for each hole size at high recommended flow-rate

Hole Size (inch)	Flowrate (lpm)	Flowrate (m^3/s)	q-cuttings (m^3/s)	c-cuttings
17-1/2	4500	0.075	0.00129	1.72%
12-1/4	3500	0.058	0.00063	1.09%
8-1/2	2500	0.042	0.00031	0.73%
5-7/8	1500	0.025	0.00015	0.58%

Table 28 Cuttings Concentration in dynamic condition for each hole size at low recommended flow-rate

Hole Size (inch)	Flowrate (lpm)	Flowrate (m^3/s)	q-cuttings (m^3/s)	c-cuttings
17-1/2	4000	0.067	0.00129	1.94%
12-1/4	3000	0.050	0.00063	1.27%
8-1/2	2000	0.033	0.00031	0.92%
5-7/8	750	0.013	0.00015	1.17%

The transport velocity ($v_{transport}$) is the average velocity of cuttings to be transported out of the well. This velocity is a function of annular velocity (v_{ann}) and slip velocity (v_{slip}).

$$v_{transport} = v_{ann} - v_{slip} \tag{5.4}$$

The difference in speed of annular velocity and transport velocity can be expressed as transport ratio. The transport ratio value can be used to estimate cuttings concentration at stationary condition to see the cuttings accumulation when the circulation is stopped.

$$R_{transport} = \frac{v_{transport}}{v_{ann}} = 1 - \frac{v_{slip}}{v_{ann}} \tag{5.5}$$

$$c_{cuttings-static} = \frac{c_{cuttings-dynamic}}{R_{transport}} \tag{5.6}$$

The simulation provides annular velocity calculations for each design at each segment of pipe. The maximum and minimum values of annular velocities for each design are taken and plotted together to be compared. Cuttings concentration at static condition ($c_{cuttings-static}$) can be estimated from the annular velocities and hole size. The annular velocities depends on the flow-rate and the model analyzes each design based on the higher recommended flow-rate and lower recommended flow-rate as previously shown in **table-27** and **table-28**.

Figure 5.11 compares the maximum and minimum annular velocities for each well design during drilling of Intermediate-1 section with higher recommended flow-rate. The conventional design has the lowest annular velocity values between each design because the size of the hole is bigger (17-1/2 inch hole) compared to the slender well design (12-1/4 inch hole). The lowest annular velocity for the conventional design is located at the section between the 20 inch casing and 5-1/2 inch drill pipe. The highest annular velocity for the conventional design is located at the section between the 17-1/2 inch open hole and 9-1/2 inch bottom hole assembly. **Figure 5.12** compares the cuttings concentration and it shows higher cuttings concentration when drilling the intermediate-1 section with conventional design.

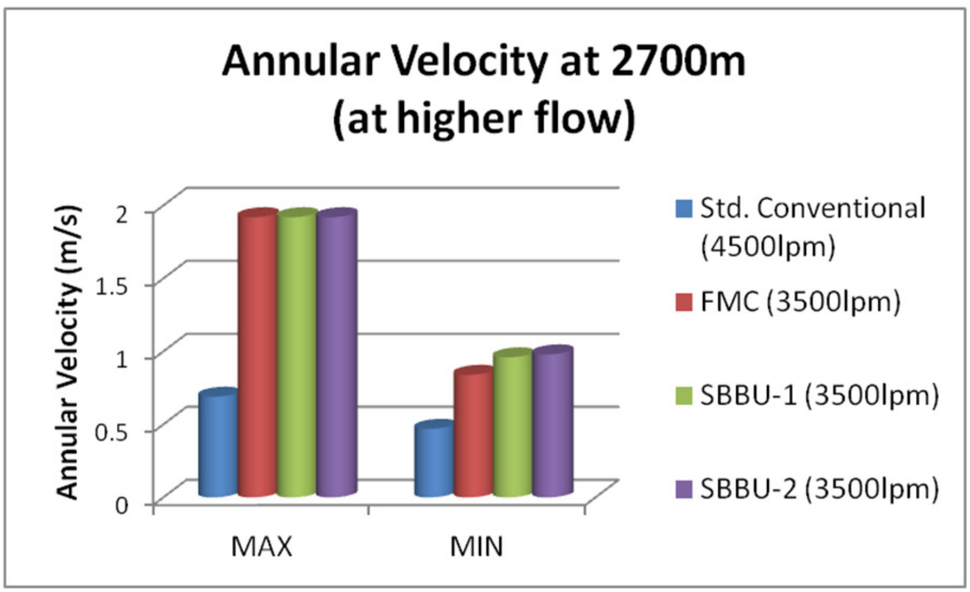

Figure 5.11 Maximum and minimum annular velocity with higher flow-rate at Intermediate-1 section

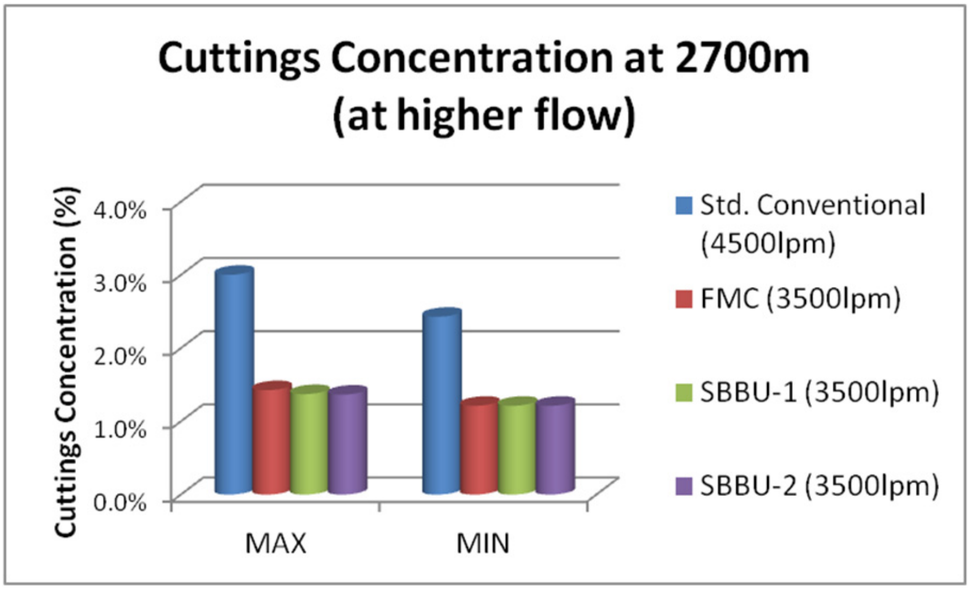

Figure 5.12 Static cuttings concentration with higher flow-rate at Intermediate-1 section

Figure 5.13 compares the maximum and minimum annular velocities for each well design during drilling of Intermediate-2 section with the higher recommended flow-rate. The conventional and FMC design has a lower maximum annular velocity compared to the SBBU designs, because the size of the hole is bigger (12-1/4 inch hole) compared to the SBBU designs (8-1/2 inch hole). The minimum annular velocity for the SBBU-2 design is relatively the same for the Conventional and FMC design. This is because design uses a 9-5/8 inch liner which is not tied back to surface. It gives a bigger annulus clearance between the 11-3/4 inch casing with the 5-1/2 inch drill pipe during drilling. **Figure 5.14** compares the cuttings concentration and it shows that the cuttings concentration at static condition is relatively equal between each design.

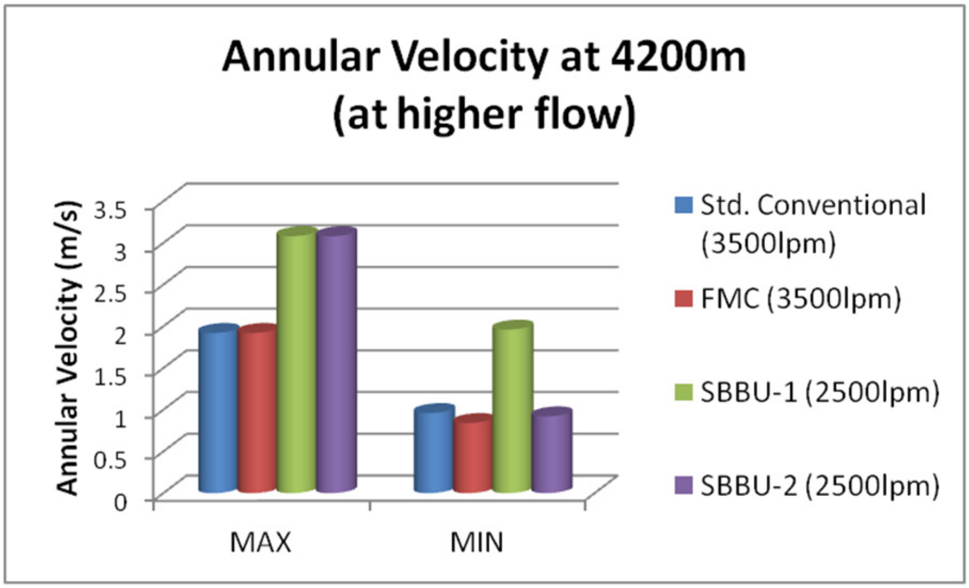

Figure 5.13 Maximum and minimum annular velocity with higher flow-rate at Intermediate-2 section

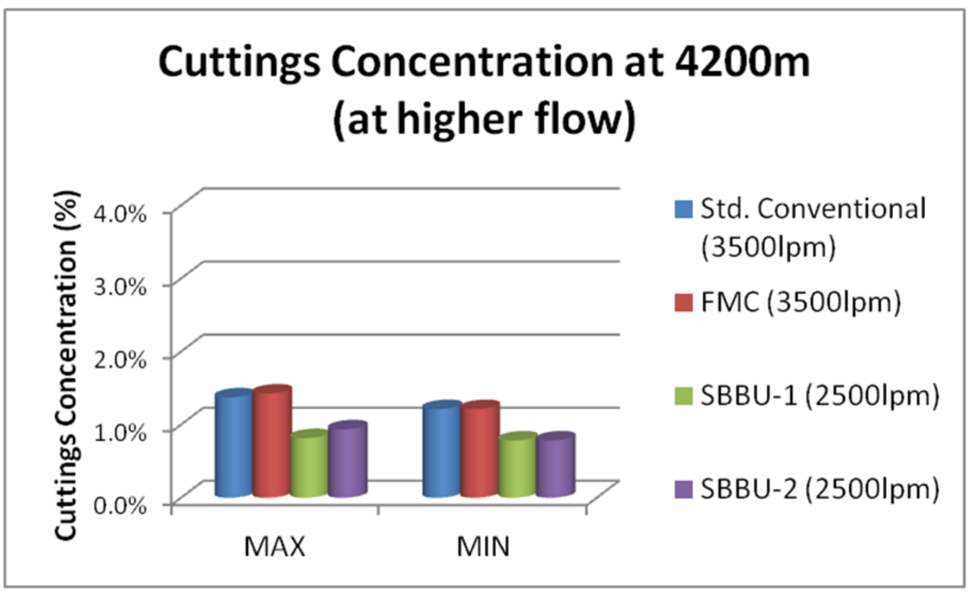

Figure 5.14 Static cuttings concentration with higher flow-rate at Intermediate-2 section

Figure 5.15 compares the maximum and minimum annular velocities for each well design during drilling of Production section with the higher recommended flow-rate. The conventional and FMC design has a lower maximum annular velocity compared to the SBBU designs, because the size of the hole is bigger (8-1/2 inch hole) compared to the SBBU designs (5-7/8 inch hole). The SBBU-2 design has the lowest value of minimum annular velocity for the SBBU-2 design because design uses a 9-5/8 inch liner and 7 inch liner which are not tied back to surface. It gives a bigger annulus clearance between the 11-3/4 inch casing with the 5-1/2 inch drill pipe during drilling. **Figure 5.16** compares the cuttings concentration and it shows that the cuttings concentration at static condition is relatively equal between each design.

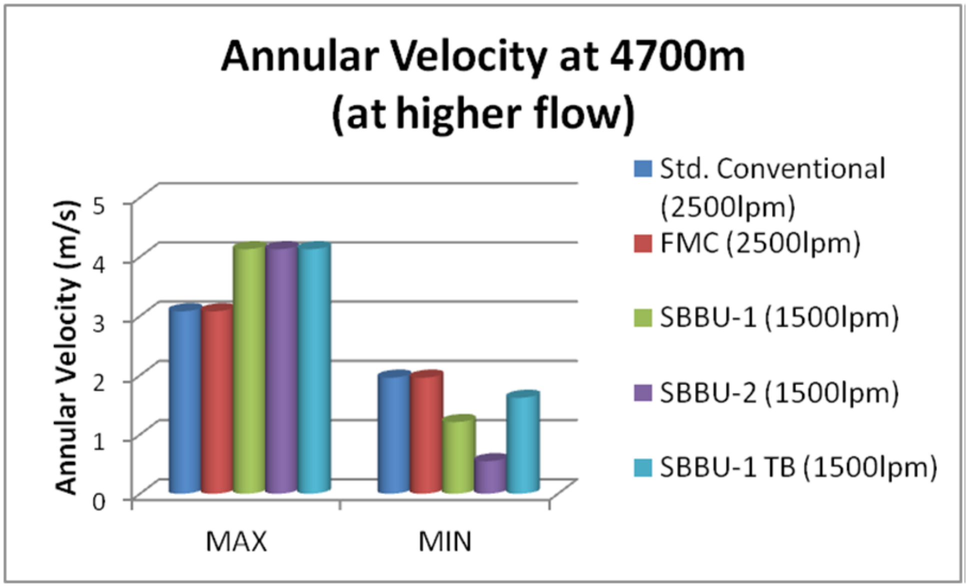

Figure 5.15 Maximum and minimum annular velocity with higher flow-rate at Production section

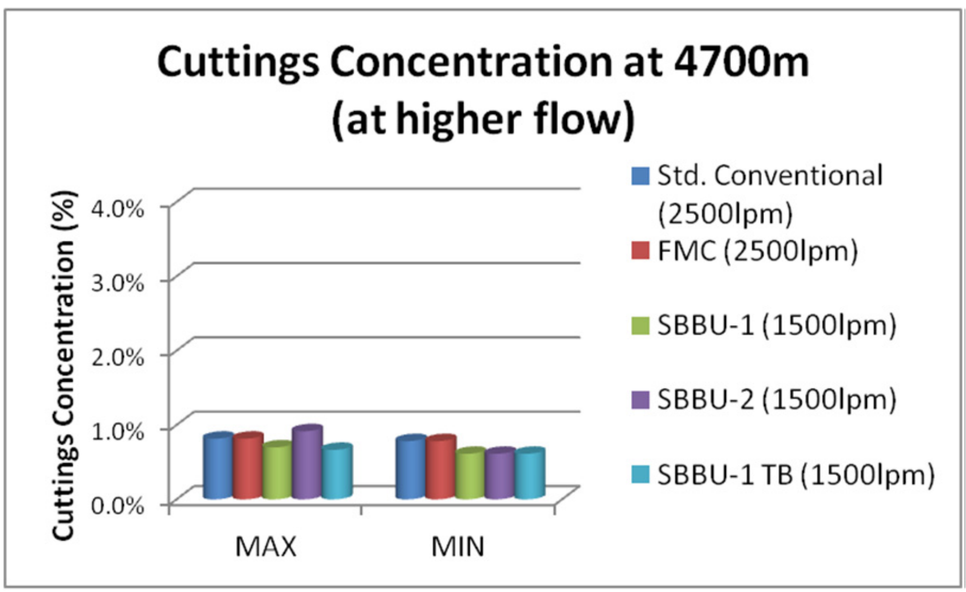

Figure 5.16 Static cuttings concentration with higher flow-rate at Production section

Figure 5.17 compares the maximum and minimum annular velocities for each well design during drilling of Intermediate-1 section with lower recommended flow-rate. The Conventional design has the lowest maximum and minimum flow-rate because the design is utilizing an 17-1/2 inch hole-size as compared to the slender well design with 12-1/4 inch hole size. **Figure 5.18** shows higher cuttings concentration when drilling the intermediate-1 section with the Conventional design as compared to the slender design. It shows higher cuttings concentration compared to the condition at higher flow-rate.

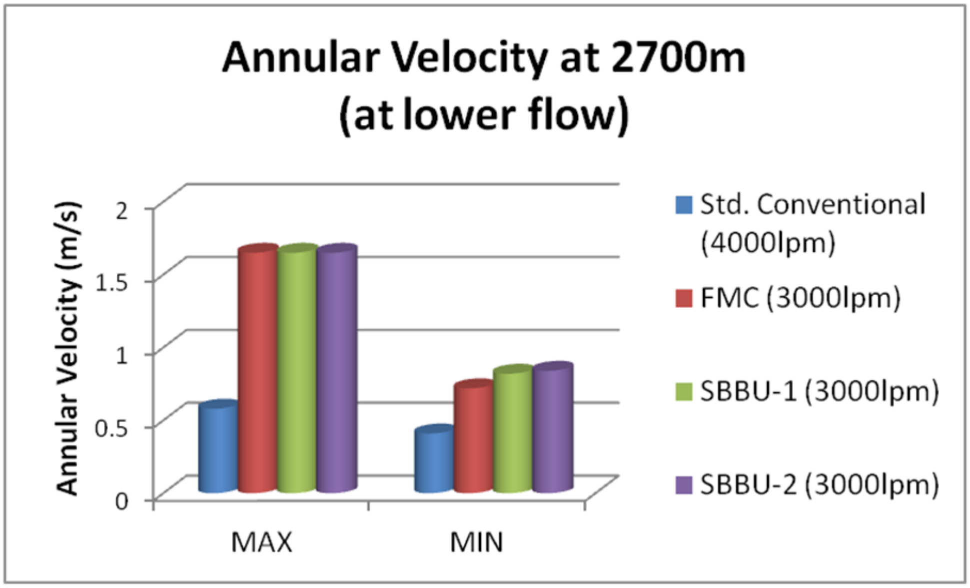

Figure 5.17 Maximum and minimum annular velocity with lower flow-rate at Intermediate-1 section

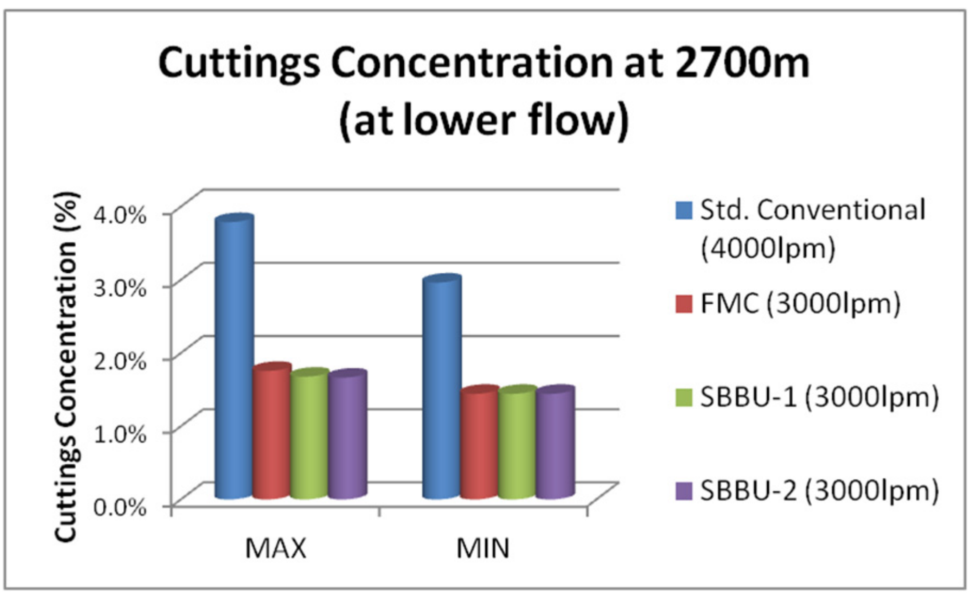

Figure 5.18 Static cuttings concentration with lower flow-rate at Intermediate-1 section

Figure 5.19 compares the maximum and minimum annular velocities for each well design during drilling of Intermediate-2 section with lower recommended flow-rate. The trends are similar to the condition at the higher flow-rate. **Figure 5.20** shows higher cuttings concentration at lower flow rate compared to the condition at higher flow-rate.

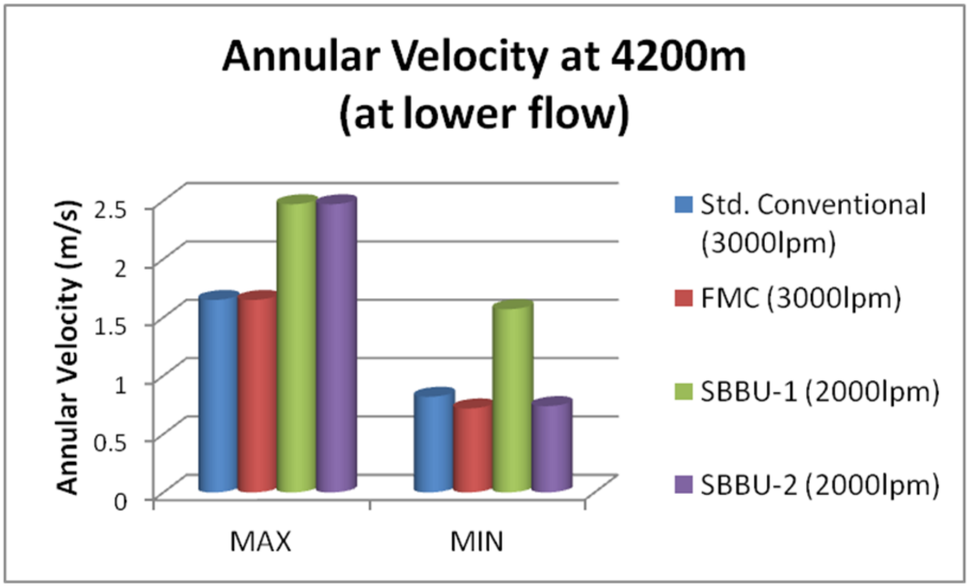

Figure 5.19 Maximum and minimum annular velocity with lower flow-rate at Intermediate-2 section

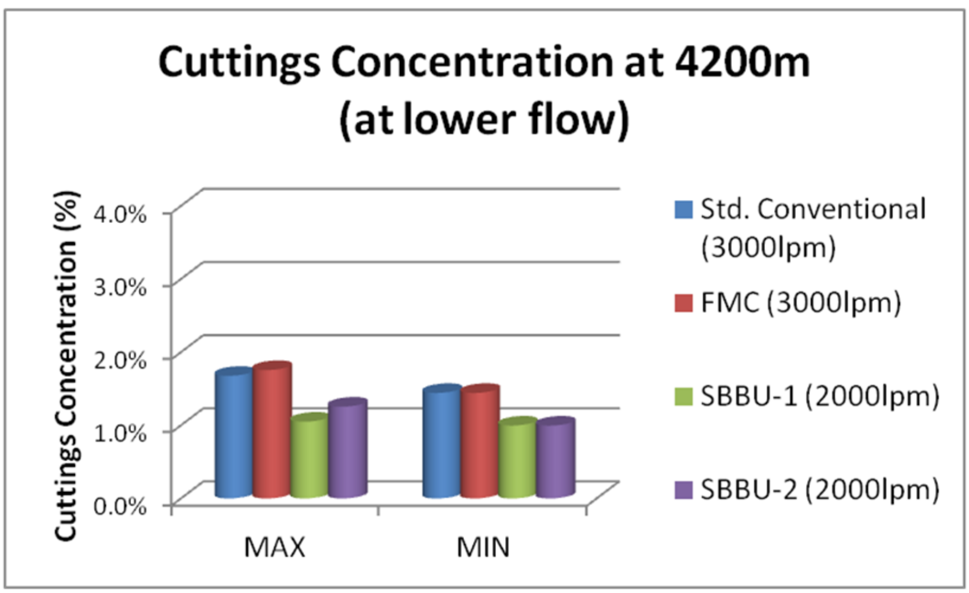

Figure 5.20 Static cuttings concentration with lower flow-rate at Intermediate-2 section

Figure 5.21 compares the maximum and minimum annular velocities for each well design during drilling of Production section with lower recommended flow-rate. The SBBU-1 and SBBU-2 design utilize a slim home size of 5-7/8 inch that has a lower flow-rate of 750 lpm. This lower flow-rate gives lower annulus velocity compared to the Conventional and FMC design which utilize an 8-1/2 inch hole and 2000 lpm flow-rate. The SBBU-2 design has the lowest minimum annular flow-rate because of its configuration. **Figure 5.22** shows higher cuttings concentration compared to the condition at higher flow-rate. The SBBU-2 design has a cuttings concentration up to 4% because of the low annular velocity. In practical, it has been proven that problems related to cuttings accumulations will become serious when the cuttings concentration reaches 4% (Skalle, 2011). The detailed data for the annular velocity and cuttings concentration are attached in Appendix-A.3.

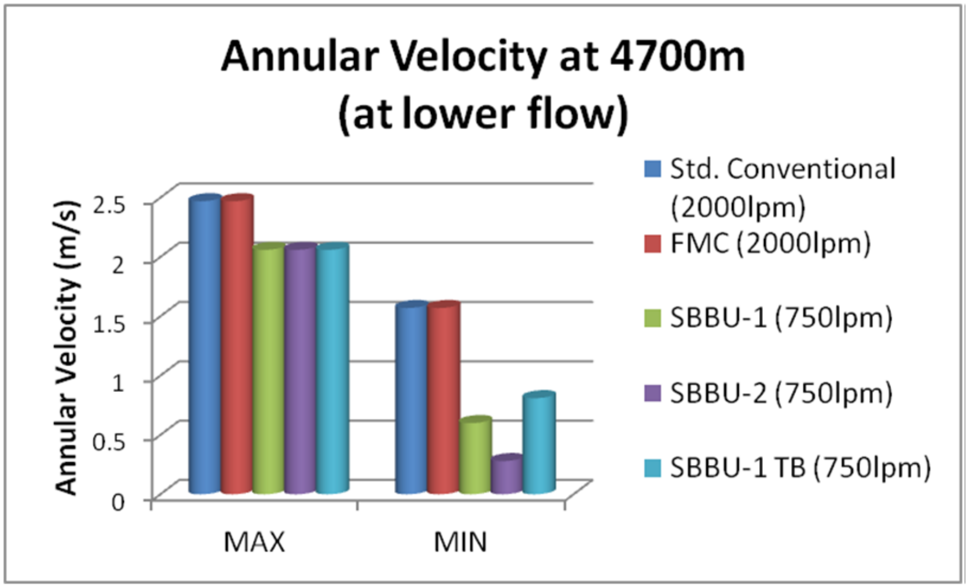

Figure 5.21 Maximum and minimum annular velocity with lower flow-rate at Production section

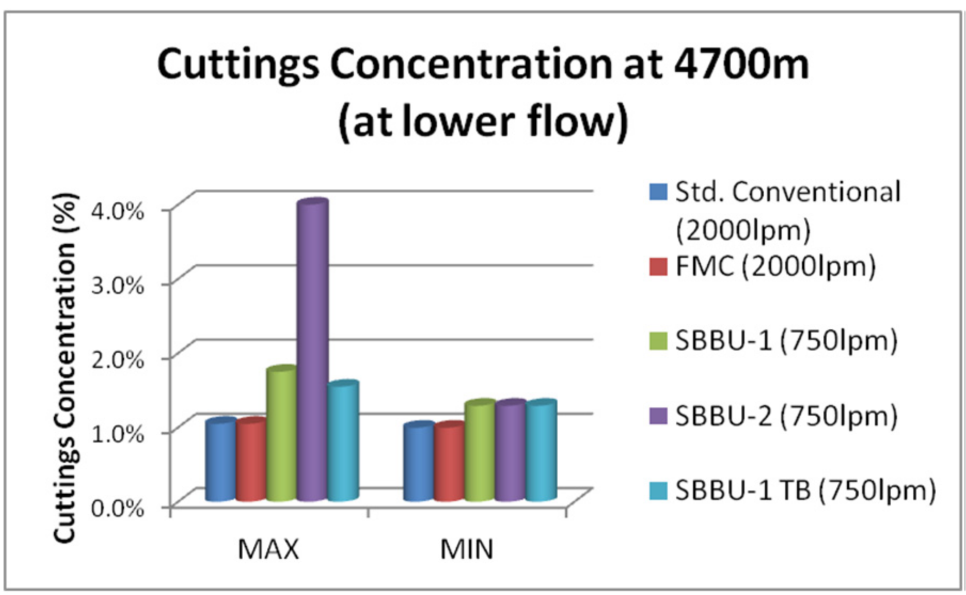

Figure 5.22 Static cuttings concentration with lower flow-rate at Production section

6. Borehole Stability on Slender Well Designs

The slender well design modeling provides annular hydrostatic and hydrodynamic pressure that relates to borehole stability issue. In general, reducing the diameter of the borehole will increase its stability. The conventional and the three slender well designs with smaller borehole diameter are assessed with respect to radial and tangential stresses. This simple assessment will provide a comparison between designs at each section depth.

6.1. Horizontal Stress, Unconfined Strength and Pore Pressure

The horizontal stresses for each section depth are calculated with Breckels and van Eekelen correlation. The correlation is based on fracturing data from the US Gulf Coast and can be used with a fair degree of confidence in other tectonically relaxed area like the North Sea (Fjær et al., 2008). The correlation derived relationships between horizontal stress (σ_h) and depth (D).

$$\sigma_h = 0.0053D^{1.145} + 0.46(P_f - P_{fn}) \qquad \text{(D < 3500 meter)} \qquad (6.1)$$

$$\sigma_h = 0.0264D - 31.7 + 0.46(P_f - P_{fn}) \qquad \text{(D > 3500 meter)} \qquad (6.2)$$

Where the horizontal stress, pore pressure (P_f) and normal pore pressure (P_{fn}) are expressed in Mega-Pascal; Depth (*D*) is expressed in meter. The normal pore pressure follows the gradient of sea water, 1050 kg/m^3. It is assumed that the pore pressure is equal to the normal pore pressure. The data for horizontal stress and normal pore pressure are presented in **table-29**.

Table 29 Pore Pressure and Horizontal Stress

Depth (meter)	Pore Pressure (Mpa)	Horizontal Stress (MPa)
100	1.03	1.03
1000	10.29	14.43
1900	19.55	30.09
2700	27.78	45.00
4200	43.22	79.18
4700	48.36	92.38

6.2. Static and Dynamic Condition

The static condition use the hydrostatic pressure based on the mud-weight used to drill the section. The dynamic condition used the annulus pressure loss value calculated at the higher recommended flow-rate for each design, based on the hole-size drilled. The value for the pressure at static condition and dynamic condition are presented in **table-30.** The circulation pressure loss for the conductor casing and the top section is not simulated. Therefore, the dynamic pressure loss is not available and it is assumed to be similar to the hydrostatic pressure.

Table 30 Well Pressure at static and dynamic condition

Depth	Mud Weight	Pw-Static	Pw-Dynamic (MPa)				
(meter)	(SG)	(MPa)	Conventional	FMC	SBBU1	SBBU-1 TB	SBBU-2
100	1.035	1.01	N/A	N/A	N/A	N/A	N/A
1000	1.035	10.14	N/A	N/A	N/A	N/A	N/A
1900	1.5	27.93	N/A	N/A	N/A	N/A	N/A
2700	1.5	39.69	40	40.54	40.70	N/A	40.75
4200	1.85	76.15	77.49	77.68	82.19	N/A	81.29
4700	2	92.12	97.83	97.83	97.35	98.55	96.8

6.3. Radial and Tangential Stress

The radial and tangential stresses are derived from hollow cylinder model. To simplify the calculations, several assumptions had to be made. In the case of drilling a well, pore pressure is not yet depleted, so it is assumed to be constant. With this assumption, the radial stress (σ_r) and tangential stress (σ_θ) are given by the following formula for the case of constant pore pressure.

$$\sigma_r = \sigma_h - (\sigma_h - P_w)\frac{R_w^2}{r^2} = \left(1 - \frac{R_w^2}{r^2}\right)\sigma_h + \frac{R_w^2}{r^2}P_w \qquad (6.3)$$

$$\sigma_\theta = \sigma_h + (\sigma_h - P_w)\frac{R_w^2}{r^2} = \left(1 + \frac{R_w^2}{r^2}\right)\sigma_h - \frac{R_w^2}{r^2}P_w \qquad (6.4)$$

$$\sigma_z = constant$$

The stresses are a function of horizontal stress (σ_h), well pressure (P_w), well radius (R_w) and distance from the well (r). The stresses are plotted with respect to the distance from the borehole. The calculation data are presented in tables in Appendix-B.2.

Figure 6.1 shows stress as a function of the distance from wellbore under static condition for the Intermediate-1 Section. The stress acting at the borehole wall are equal for all designs. But in the stress concentrated area, slightly inside the borehole wall, the conventional design has a higher tangential stress and lower radial stress compared to the other three slender designs. The difference is because the conventional design utilizes a bigger hole-size (17-1/2 inch hole) as compared to the slender designs (12-1/4 inch hole).

Figure 6.2 shows the plot of stress against distance from well bore at dynamic condition for Intermediate-1 section. The difference of annulus pressure loss between each designs slightly alter the well pressure that governs the radial stress at the borehole wall. The tangential stresses of each design are also altered because the sum of the radial and tangential stress is constant. Both tangential and radial stress converges at the far field stress of 45 MPa.

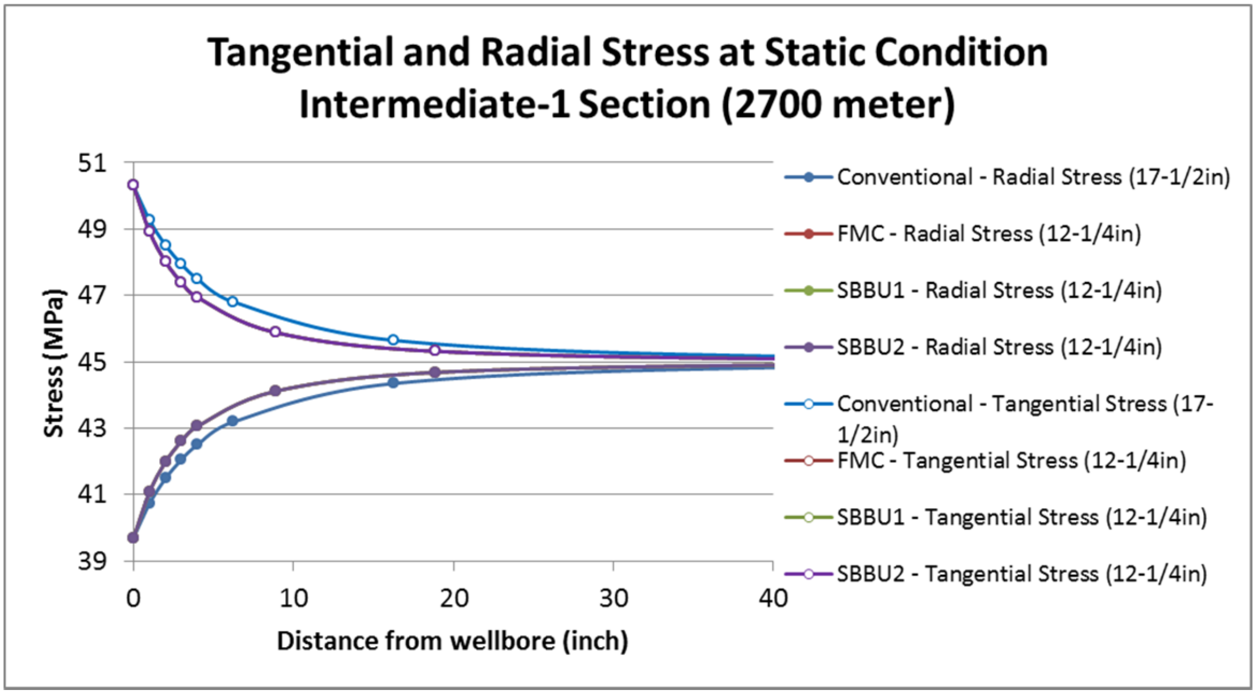

Figure 6.1 Radial and Tangential Stress at Static condition in Intermediate-1 Section

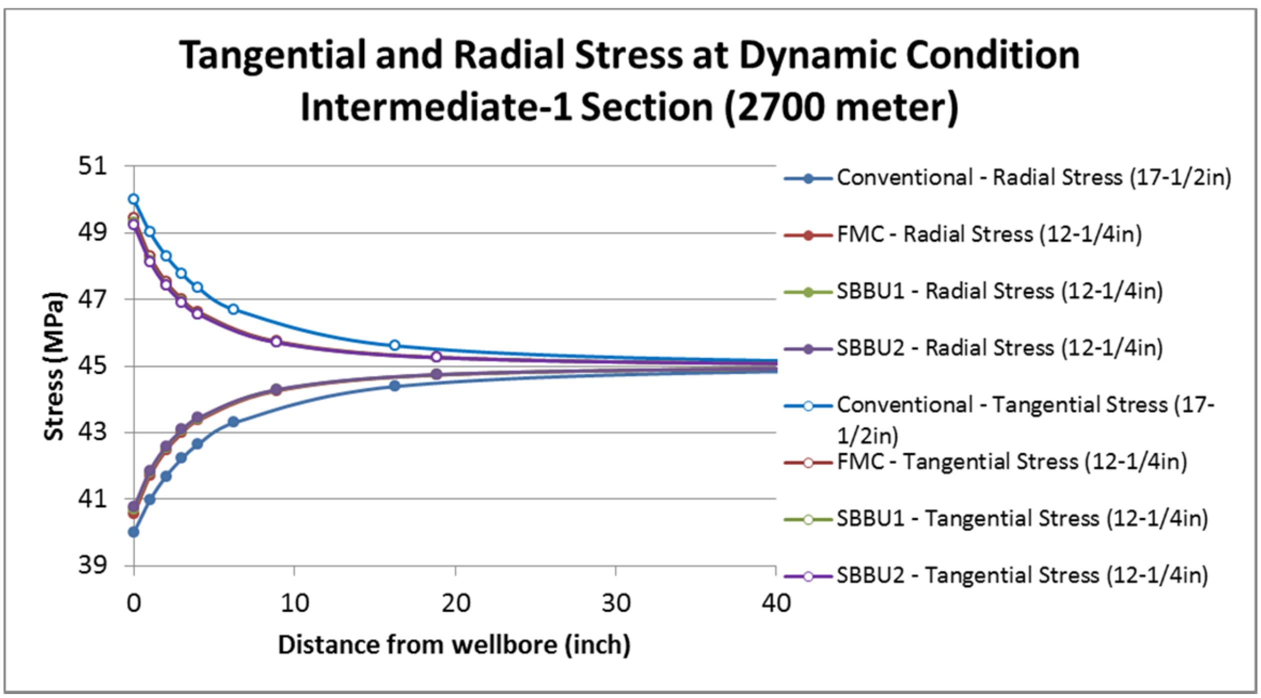

Figure 6.2 Radial and Tangential Stress at Dynamic condition in Intermediate-1 Section

Figure 6.3 and **figure 6.4** show the plot of radial and tangential stresses for the Intermediate-2 section under static condition and dynamic condition respectively. The plot shows that in the stress concentrated area (slightly inside the borehole wall), under static condition, the SBBU-1 and SBBU-2 designs which utilize a smaller borehole size (8-1/2 inch hole) have a higher radial stress and lower tangential stress. The SBBU-1 and SBBU-2 design which has a higher annular pressure loss increase the well pressure beyond the far field stress (approximately 79.2 MPa). The plot reverses; in the stress concentrated area the radial stress becomes higher than the tangential stress.

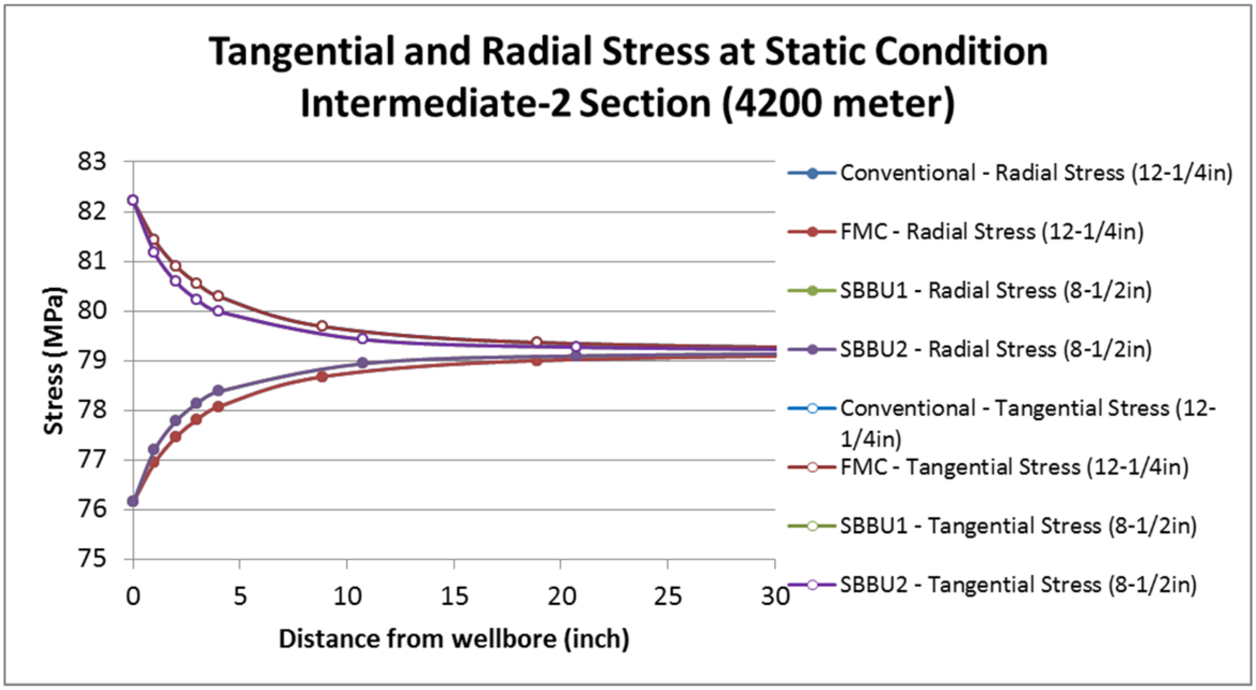

Figure 6.3 Radial and Tangential Stress at Static condition in Intermediate-2 Section

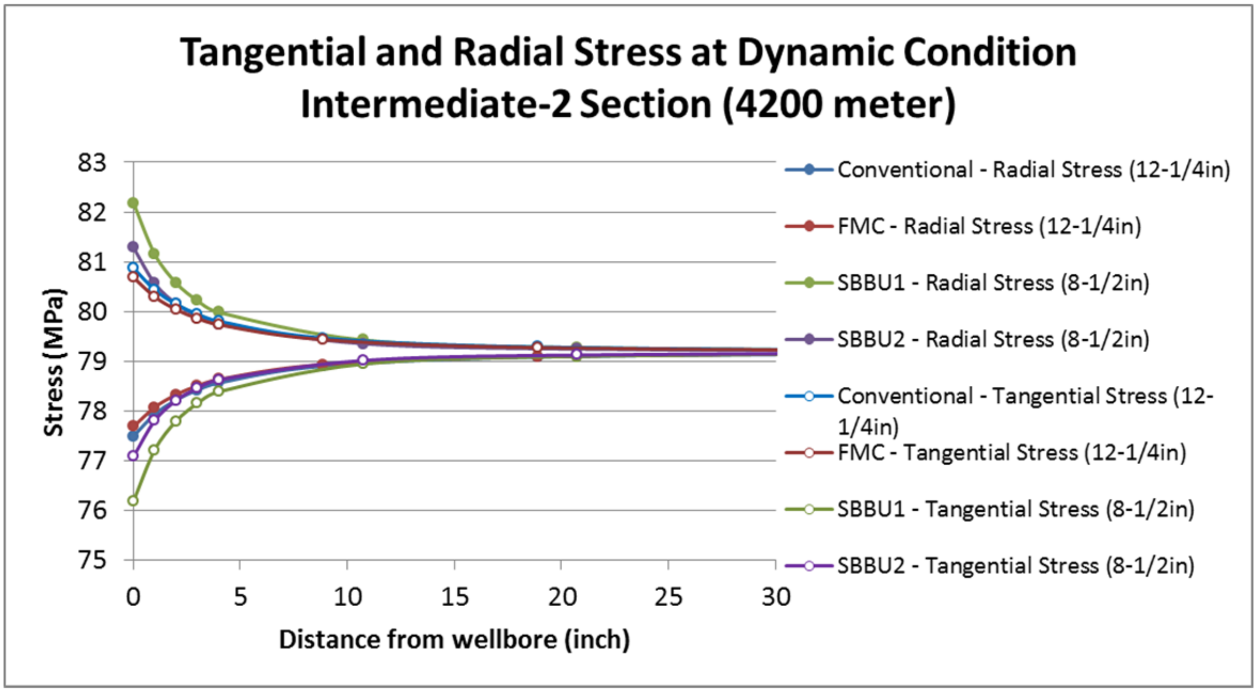

Figure 6.4 Radial and Tangential Stress at Dynamic condition in Intermediate-2 Section

Figure 6.5 and **figure 6.6** show the plot of radial and tangential stresses for the Production section under static and dynamic condition respectively. Under static condition, the SBBU-1 and SBBU-2 with smaller borehole size (5-7/8 inch hole size) have a higher radial stress and lower tangential stress in the stress concentrated area as compared to the Conventional and FMC designs (8-1/2 inch hole size). Under dynamic condition, all designs have high annular pressure loss that increases the well pressure beyond the far field stress (approximately 92.4 MPa). The dynamic condition reverses the plot, resulting in a higher radial stress and a lower tangential stress in the stress concentrated area for all designs. The SBBU-1 with Tie Back option is included in the plot. It has the highest dynamic well pressure compared to all the other design. This is because the tie back option to surface has the highest annular pressure loss.

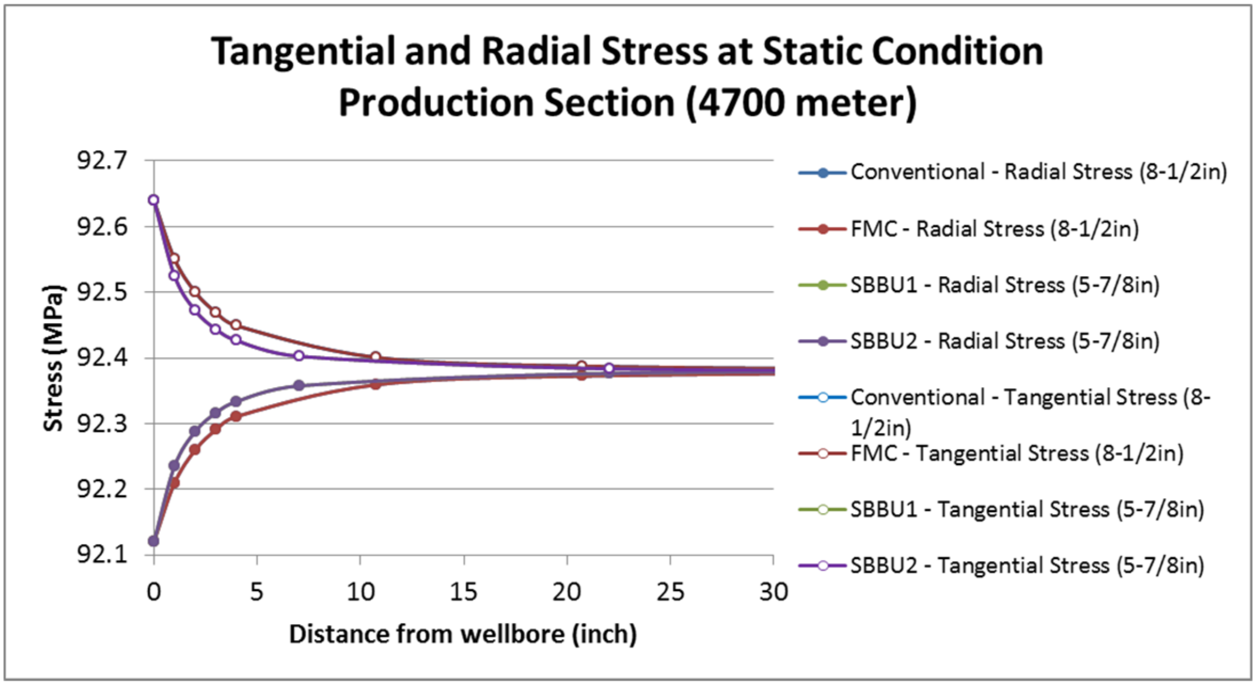

Figure 6.5 Radial and Tangential Stress at Static condition in Production Section

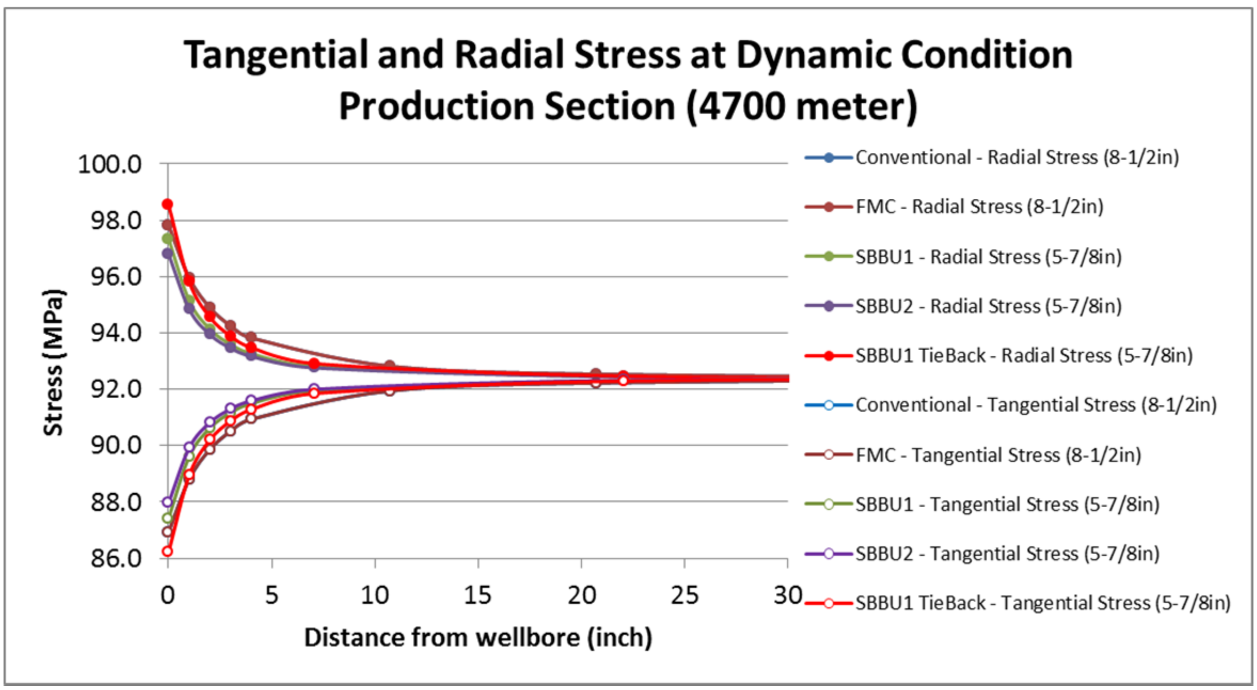

Figure 6.6 Radial and Tangential Stress at Dynamic condition in Production Section

6.4. Borehole Stability Assessments

The calculated static and dynamic well pressure could be used to assess the borehole stability against the failure criterion to check all the Slender Well designs against any borehole stability failure risk. **Figure 6.7** shows borehole shear failure conditions in vertical boreholes with isotropic far-field horizontal stresses and impermeable borehole wall.

Case	$\sigma_1 \geqslant \sigma_2 \geqslant \sigma_3$	Borehole failure occurs if
a	$\sigma_\theta \geqslant \sigma_z \geqslant \sigma_r$	$p_w \leqslant p_f + \frac{2(\sigma_h - p_f) - C_0}{1 + \tan^2 \beta}$
b	$\sigma_z \geqslant \sigma_\theta \geqslant \sigma_r$	$p_w \leqslant p_f + \frac{\sigma_v - p_f - C_0}{\tan^2 \beta}$
c	$\sigma_z \geqslant \sigma_r \geqslant \sigma_\theta$	$p_w \geqslant p_f + 2(\sigma_h - p_f) - \frac{\sigma_v - p_f - C_0}{\tan^2 \beta}$

Figure 6.7 Shear Failure condition in vertical boreholes with impermeable borehole wall. From (Fjær et al., 2008: Table 4.1, p. 156)

The shear failures critical to borehole stability are failures when then tangential stress or the axial stress along the borehole axis is the maximum and the radial stress is the minimum. These are reflected by case (a) and case (b). The solutions for borehole shear failure can be stated as,

$$P_{w,min}^{(a)} = \frac{3\sigma_H' - \sigma_h' - C_0}{\tan^2 \beta + 1} + P_{fo} \quad (6.5)$$

$$P_{w,min}^{(b)} = \frac{\sigma_h' + 2|v_{fr}|(\sigma_H' - \sigma_h') - C_0}{\tan^2 \beta} + P_{fo} \quad (6.6)$$

Shear failure may also occur when the well pressure is high, as presented by case (c). But it is not thought to be causing significant drilling problems. However, this failure mode is close to the limit for hydraulic fracturing by tensile failure. So the borehole stability has to be checked against the tensile failure limit given by,

$$P_{w,max}^{frac} = 3\sigma_h - \sigma_H - P_{fo} + T_0 \quad (6.7)$$

For drilling condition, it is assumed that the rock does not have tensile strength (T_0), the pore pressure is equal to the original pore pressure (P_{fo}). Simplifying the calculations, the horizontal stresses are similar to all directions.

Statistical observation of field data given in **table-31** provides an estimate of unconfined strength, Poisson's ratio, failure angle and vertical stress at various depths. Extrapolation of these data provides an estimate of the parameters at the depth of each section. The extrapolated data is given in **table-32**.

Table 31 Statistical observation of geo-mechanical field data at various depths (*)

Depth (m)	Co (Mpa)	Poisson's Ratio	Failure Angle (deg)	Vertical Stress (Mpa)
500	1	0.4	45	9
1000	4	0.3	50	19
2000	15	0.25	55	40
3000	25	0.2	55	63
4000	45	0.15	60	87

(*) Data provided by Erling Fjær via email correspondence (2013).

Table 32 Extrapolated geo-mechanical data for the depth of each section

Depth	Co	Poisson's Ratio	Failure Angle	Vertical Stress
meter	**(Mpa)**	**V_{fr}**	**(deg)**	**(Mpa)**
100	1	0.4	45	1
1000	4	0.3	50	19
1900	13.9	0.25	55	37.9
2700	22	0.2	55	56.1
4200	49	0.15	60	91.8
4700	59	0.15	60	103.8

The failure conditions are calculated based on the data at each section depth. The result of the calculation is presented in **table-33**. The conditions of failure are compared against the static and dynamic well pressure which has been calculated before. Based on all the failure limits, the static and dynamic well pressures for all designs do not fulfill any of the failure conditions. These show below 1500 meter, that all the Slender Well design will not experience any borehole stability failures during drilling. However, failure conditions are fulfilled for borehole collapse due to shear failure at the top section.

Table 33 Calculation result for the failure conditions

	Case-a	Case-b	Frac
Depth	**Pw-min**	**Pw-min**	**Pw-max**
meter	**(Mpa)**	**(Mpa)**	**(Mpa)**
100	0.53	0.00	1.04
1000	12.06	13.61	18.57
1900	21.91	21.73	40.63
2700	31.87	30.88	62.21
4200	48.95	43.08	115.14
4700	55.62	47.18	136.40

7. Discussion

7.1. Hydraulic and Annular Velocity

They hydraulic study based on modeling in chapter-5 provides estimate of pressure loss for each well design based on the flow-rate selection for drilling each hole section. The pressure loss is a function of the mud rheology, flow-rate, drill-string configuration, bottom hole assembly and the well configuration that determines the annulus clearance for flow.

For simplification, the same mud rheology is used for all the well sections in all well design. The rheology is assumed to be constant without changes due to temperature or other aspects. The bottom hole assembly is simplified, consisting of a mud motor and MWD collar. The selections are available in the library for modeling. However, the library does not contain the BHA selection to drill the 5-7/8 inch hole. Therefore, the BHA configuration used to calculate the pressure loss in drilling the 5-7/8 inch hole is the 6-3/4 inch BHA. This is the BHA used to drill the 8-1/2 inch hole.

The hydraulic modeling compares the circulation pressure loss against the slender well design on each section. The result shows that on the intermediate-1 and intermediate-2 sections, the slender designs have lower circulation pressure loss compared to the conventional design. While on the production section, the circulation pressure losses are relatively equal between the slender design (5-7/8 inch hole) and the standard conventional design (8-1/2 inch hole). The highest circulation pressure loss in this section is the SBBU-1 design with the tie-back option to surface (shown in figure 5.4).

The annular pressure loss are combined with the bit pressure loss and presented in a plot of total flow area versus pump pressure. The flow-rate are presented in range for each hole size. The flow-rate for the 17-1/2 inch hole is between 4000 to 4500 lpm, the 12-1/4 inch hole is between 3000 to 3500 lpm, the 8-1/2 inch hole is between 2000 to 2500 lpm and the 5-7/8 inch hole is between 750 to 1500 lpm. Based on the plots for all three sections (intermediate-1, intermediate-2 and production), the pump pressure are relatively stable after TFA is above 0.5 inch^2. However, the magnitude of the pressure depends on the hole-size and configurations. The plots shows the potential pump-pressure range for each well designs and the smaller the well configuration, the higher and wider the pressure range. The highest pressure and also the widest range is the SBBU-1 design with tie-back option. The pump pressure limits the flow-rate that can be used for drilling, which affects many factors in drilling, most important is the hole cleaning aspects.

The hole cleaning aspects are assessed by calculating transport ratio based on the annular velocity modeling. The transport ratios for each section at maximum and minimum recommended flow-rate are used to calculate the cuttings concentration. Based on statistics, major hole problems starts to occur when cuttings concentration are above 4% (Skalle, 2011). Based on the calculation for each section of each design, the only time the cuttings concentration is going to be above 4% is for the SBBU-2 design. The SBBU-2 design has an 11-3/4 inch casing on top with 9-5/8 inch liner that are not tied back to surface. This large annulus clearance result in lower annulus velocity which leads to higher cuttings concentration.

7.2. Borehole Stability

Borehole stability study assessed the effect of using a smaller hole-size with the slender well design. The data provides static well pressure from the mud weight used and the dynamic well pressure from the modeling of annulus pressure loss. The horizontal stress prediction used the Breckels and van Eekelen correlation which is a function of depth and pore pressure.

The results are plots of radial and tangential stresses for each well design at each section as a function of the distance from the borehole. The plots for static condition show that reducing the borehole size does not change the stress working on the borehole wall. However, smaller borehole size will increase the radial stress and reduce the tangential stress at the stress concentrated area (slightly inside the borehole wall). The plots for dynamic condition show that annulus pressure loss for the SBBU-1 and SBBU-2 design at the intermediate-2 section is high enough to change the radial stress to be higher than the tangential stress. At the production section, the annulus pressure loss for all the design is high enough to increase the radial stress above the tangential stress.

The change in radial and tangential stress will change the calculation for borehole failure. **Figure 6.7** shows the different formula to assess borehole stability with different stress distribution. The calculation from statistical observation of the field data shows that for the case in this thesis, the vertical stress is the maximum principal stress. It means that the vertical stress is higher than the tangential stress and radial stress, as illustrated in **figure 7.1**.

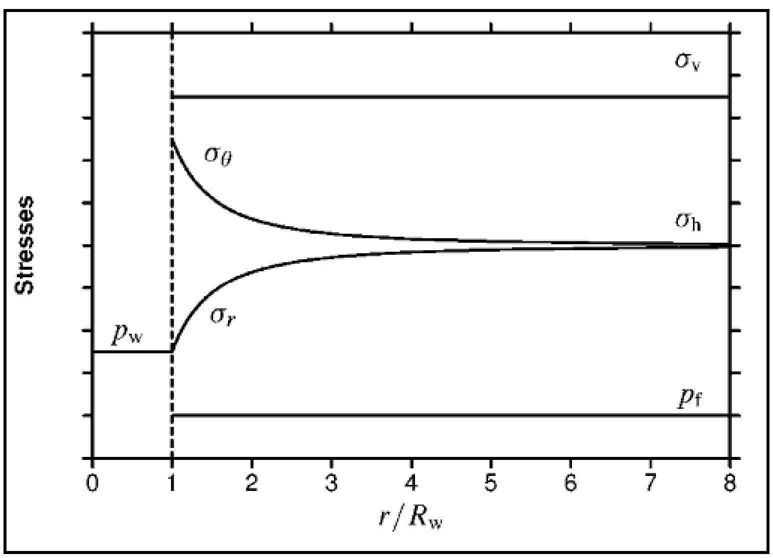

Figure 7.1 Illustration of $\sigma_v > \sigma_\theta > \sigma_r$ around a vertical borehole with an impermeable wall, elastic formation and isotropic horizontal far field stresses. From (Fjær et al., 2008: Fig. 9.2, p. 315)

The minimum well pressure for borehole stability during drilling should be check against case (b) for shear failure which is given by the equation 6.6. The maximum well pressure for borehole stability during drilling should be check against the limit for tensile failure that will cause fracturing. This is given by equation 6.7.

Figure 7.2 shows the plot of all the static and dynamic well pressure along with the borehole failure conditions. Based on the plot, all the well pressure in the area of interest (below 2700 meter) are above the Pw,min (a) and Pw,min (b); and below the Pw,max. There are no failure conditions that are fulfilled and there will be no borehole collapse by shear failure, nor fracturing by tensile failure.

However, the model suggested that there will be borehole collapse because the shear failure conditions are fulfilled when drilling the conductor and top section. The well pressure is too low with 1.035 SG gravity mud (sea-water). This suggested that the sea-water used to drill needs to be treated to increase the mud weight to around 1.4 SG. Treating sea-water with additives to increase the mud-weight to 1.4 SG could be a challenge. Another method to avoid borehole collapse is by increasing the circulation pressure using Managed Pressure Drilling Method. The MPD method could change the gradient by introducing a back-pressure pump on the surface to increase the circulating pressure to be higher than the minimum well pressure.

It needs to be noted also that the well pressure calculations neglects the water depth and the use of riser. Increasing water depth will increase the hydrostatic pressure to be above the minimum well pressure.

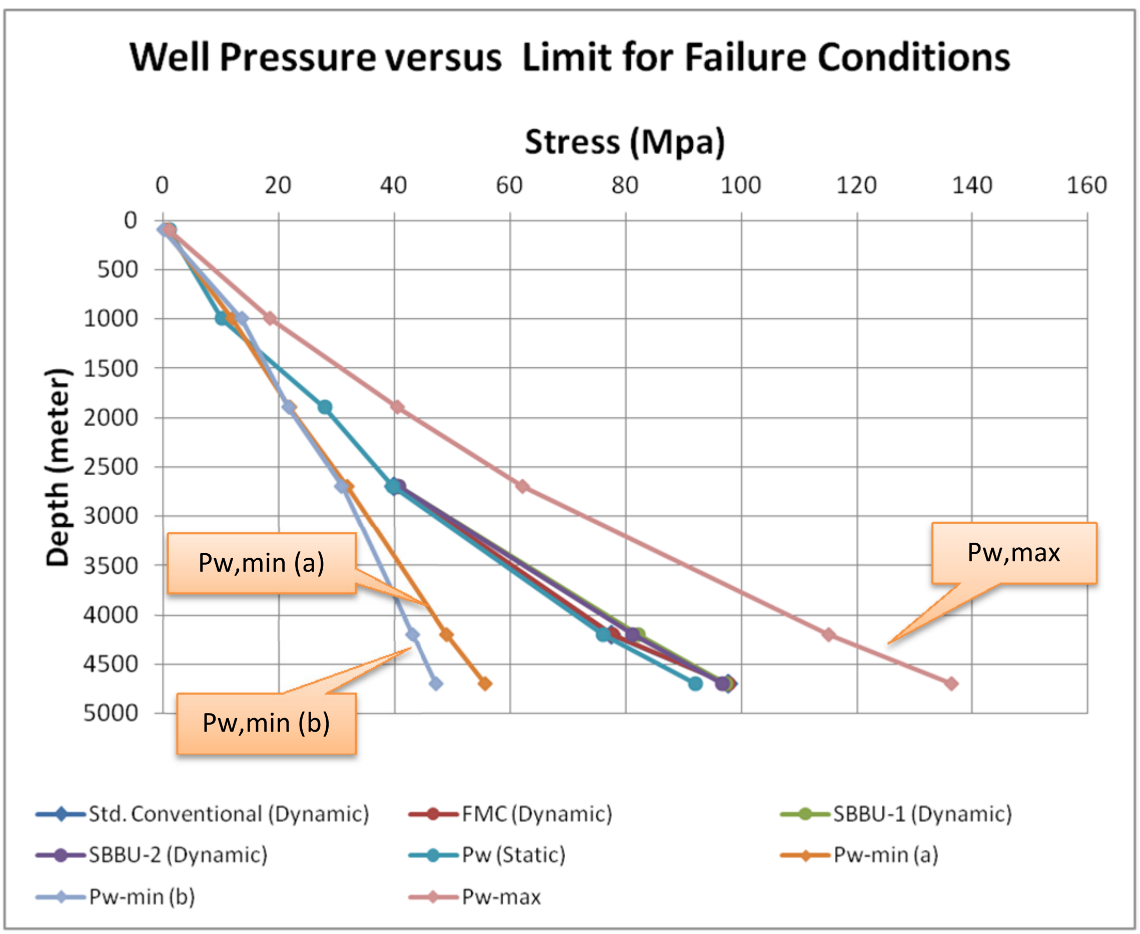

Figure 7.2 Static and Dynamic Well Pressure with Limit for Failure Conditions

7.3. Slender Well Design

The slender well design is one of the industry's solutions to reduce drilling cost. However, an overall assessment of economy would be too complex. A more simplified basis for economical assessment had been done. It estimates the reduction of cuttings volume, mud volume, steel volume and drilling hour/cost. The estimation results are presented in percentage with respect to the Standard Conventional design; it is presented in **table-34** below.

Table 34 Reduction by using Slender Well design with respect to the Standard Conventional design

Parameters	FMC (medium)	SBBU-1	SBBU-1 TB	SBBU-2
Cuttings Volume	39.37%	48.29%		57.54%
Mud Volume	30.91%	43.91%	44.66%	45.75%
Riser volume @400m WD	100.56%	114.50%		
Steel Volume	11.96%	42.04%	28.89%	62.98%
On-Bottom Drilling Hour	33.25%	37.13%		41.79%

The table shows that the FMC design has the least potential cost reduction compared to the other slender well design. But, the FMC design has an 8-1/2 inch production section, which is bigger than the other slender well designs. This bigger production section may allow installing the usual completion equipment and a feasible option for well with high productivity.

The SBBU-2 design has the highest potential cost reduction compared to the other slender well design. However, SBBU-2 design also has the highest risk for hole cleaning problems. The utilization of liners creates a large area of flow (at the top 11-3/4 inch casing) for a low flow-rate when drilling the 5-7/8 inch hole section. There is option for a 9-5/8 inch expandable liner that makes this design applicable to a more complex geology as compared to the FMC-design.

The SBBU-1 design has a higher cost reduction than FMC design but lower than the SBBU-2 design. This design utilizes the Pre-Installed Liner concept to add additional casing setting depth. Also it has an option of 9-5/8 inch expandable liner. Among all the slender well design, this design can be used for a more complex geology compared to FMC and SBBU-2 design. However, further assessment has to be made for the tie-back option. The hydraulic analysis shows that the tie-back option gives the highest pressure loss in the annulus. So, with this option, the pump-pressure limitation will limit the flow-rate.

The technologies in the market today are available to complement the Slender Well design. The high annulus pressure loss when the SBBU-1 design utilizes the tie-back liner can be reduced by using a bypass-sub. The by-pass sub, can also be used to increase annular velocity for cutting lifting capability. It can be used to solve the cutting accumulations risk for the SBBU-2 design.

Based on the Slender Well design configuration, the FMC design is most suitable for production or development well at a high productivity area. The SBBU-1 and SBBU-2 designs are most applicable for exploration wells. The SBBU-1 design has an advantage over SBBU-2 from its Pre-Installed Liner concept that allows an additional casing setting depth. The disadvantage of the SBBU-1 design is the extra hours to set the PIL that incur additional drilling cost.

7.4. Drilling Time Planner

Previously the drilling cost is based on the estimation of the on-bottom drilling hours calculated from the unitized ROP curve. Expanding the estimation by breaking down the operational sequences of each design gives a more realistic estimate of the total drilling cost. The detailed operational sequences are presented in Appendix-C.

The operational sequences include the time needed to install the BOP, making-up BHA, rigging-up and rigging down equipment to run casing / liner, etc. Based on these estimates, the total time needed to drill the well with Standard Conventional design is 32.46 days, with FMC design is 27.5 days, with SBBU-1 design is 29.98 days and with SBBU-2 design is 26.50 days. **Figure 7.3** shows the plot of drilling time (in days) needed to finish each well section. The SBBU-1 design has a relatively longer drilling time as compared to the FMC and the SBBU-2 design because the extra time needed for utilizing the Pre-Installed Liner. If the Pre-Installed Liner is not utilized the cost of the SBBU-1 design would be similar to the SBBU-2 design.

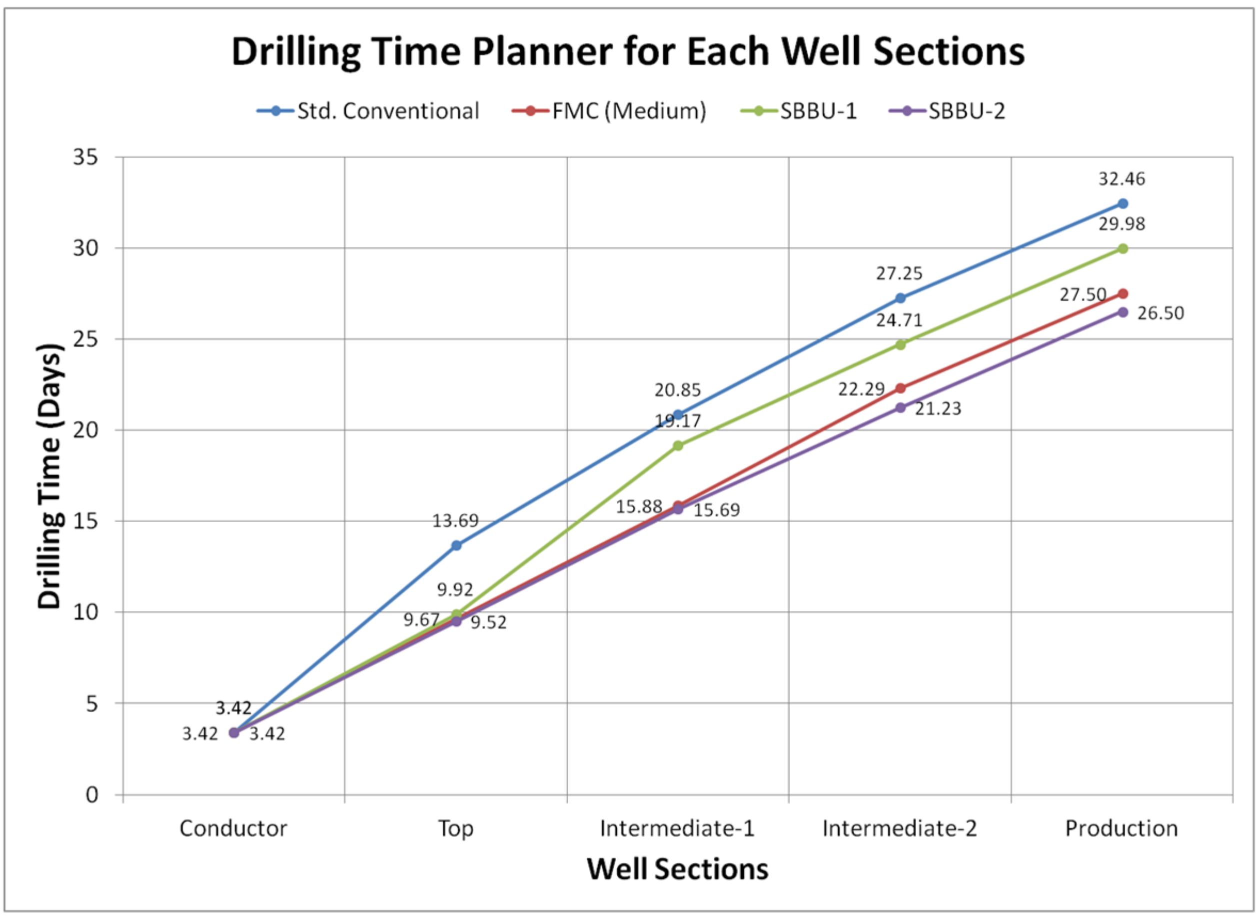

Figure 7.3 Drilling Time Planner for each well sections and well designs

Based on the total drilling time for each well design, drilling cost estimation is made by multiplying the drilling time with rig day-rates. The spread rate is included in the calculations. The spread rate is an estimate of additional cost and normally assumed by doubling the rig day-rate. **Figure 7.4** shows the plot of the total drilling cost for each well design based on the estimated drilling hours and rig day-rate. The plot shows that rig day-rates play an important part in reducing the drilling cost.

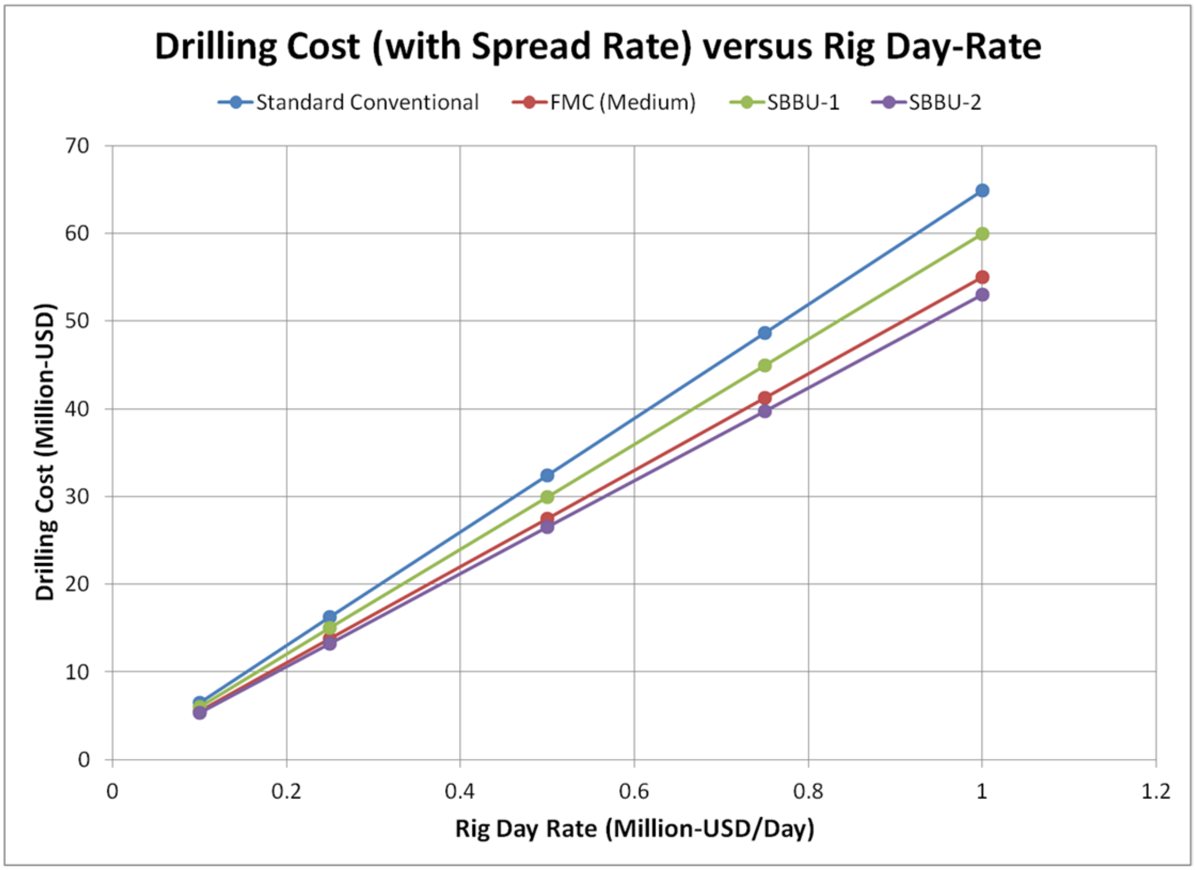

Figure 7.4 Total Drilling Cost with Spread Rate as a function of Rig Day-Rate

Comparing to the time needed to drill the well with the Standard Conventional design, the drilling time reduction for the FMC design is 15.3%, with the SBBU-1 design is 7.6% and with the SBBU-2 design is 18.4%. But the Slender Well design can utilize a smaller rig because of the reduction in the materials needed to drill the well. Assuming that the rig day-rate for drilling with Slender Well design is 25% less than the day-rate for drilling with the Standard Conventional design, the cost reduction for FMC design is 36.5%, for SBBU-1 design is 30.7% and for SBBU-2 design is 38.8%. And if the reduction of mud volume, steel weight, cuttings volume and logistics are included then the total cost reduction would be significant.

8. Conclusion

- Drilling with Slender Well design will reduce the volume of cuttings removed from the borehole. The Standard Conventional design removes 770.12m^3 cuttings volume. The FMC (medium), SBBU-1 and SBBU-2 designs give cuttings volume reduction of 39%, 48% and 58% respectively

- Drilling with Slender Well design will reduce the required volume of mud. The Standard Conventional design would require a total mud volume of 1168.45m^3. The FMC (medium), SBBU-1, SBBU-1 with tie-back and SBBU-2 designs give mud volume reduction of 31%, 44%, 45% and 46% respectively (200 meter water depth)

- Drilling with Slender Well designs will reduce the amount of steel volume in the borehole. The Standard Conventional design has a total steel weight of 828.75 tonnes. The FMC (medium), SBBU-1, SBBU-1 with tie back option and SBBU-2 designs give steel weight reduction of 12%, 42%, 29% and 63% respectively

- The smaller the hole-size the higher the pressure loss changes due to variation in flow-rate

- The SBBU-1 design with tie back has the highest annulus pressure loss that will lead to requiring a higher pumping pressure. The SBBU-2 design has the highest risk to have cuttings accumulation on the 11-3/4 inch casing section on top when drilling the production section; Because It has the biggest annulus clearance

- Reducing the hole-size with Slender Well Design does not change the stress at the borehole wall during static condition. But it will increase the radial stress and decrease the tangential stress in the stress concentrated area (slightly inside the borehole wall).

- All the Slender Well designs have been tested against borehole failure conditions and it shows that there will not be any borehole collapse by shear failure or fracturing by tensile failure in the area of interest (below 1500 meter).

- There is a high risk of borehole collapse when drilling the top section. The risk can be mitigated by increasing mud weight or utilizing MPD method with back-pressure pump to increase the well pressure above the minimum required well pressure

- The Slender Well design reduces the total on-bottom drilling hours. The Standard Conventional design needs 368 hours to drill to TD. The FMC (medium), SBBU-1 and SBBU-2 design reduces the on-bottom drilling hours as much as 33.3%, 37.1% and 41.8% respectively.

- The Slender Well design reduces the total drilling time (including all other operation) to drill the well until TD. The Standard Conventional design will need 32.46 days to finish the well. The FMC (medium), SBBU-1 and SBBU-2 would reduce the time as much as 15.3%, 7.6% and 18.4% respectively. Assuming all the variables are the same, this leads to a total cost reduction of the same percentage.

- The Slender Well design would allow utilizing a lower specification rig. Assuming the rig has 25% less day-rates, to potential cost reduction for the FMC (medium), SBBU-1 and SBBU-2 designs are 36.5%, 30.7% and 38.8%.

- The technology available in the drilling industry such as by-pass sub, Manage Pressure Drilling, etc. could complement the Slender Well designs and enhance the result for maximum cost saving

9. Future Works

- Further investigations of potential cost saving by slender well drilling with the updated pricing of rig day-rate, services cost, logistics cost, etc.
- Assess the extra cost for technology and service implementation against the potential cost savings of the Slender Well design
- Investigate the effect of changing the mud rheology to optimize the hydraulics and cross-check its effect on pressure loss and borehole stability risk
- Investigate the risk and potential to utilize hole-size smaller than 5-7/8 inch hole and coiled tubing option.

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Appendix

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A. Appendix A – Well Hydraulics

A.1. Fluid Rheology Theory

Rheological models are different models based on the fluid behaviors across a wide range of shear rates. This model provides basis for dynamic pressure (pumping pressure) measurements.

Terms used in the mud models are shear stress and shear rates which are analogous to pump pressure and rate respectively. These terms can be described by considering two plates separated by a specific distance with a fluid in between. If a force is applied to the upper plate while the lower plate is stationary, a velocity (V) will be reached and will be a function of the force (F), the distance between plates (x), the area of exposure (A), and the fluid viscosity (μ). It is expressed in the equation below:

$$\frac{F}{A} = \mu \frac{V}{x} \tag{A.1}$$

The F/A term is the shear stress (τ) while V/x is shear rate (γ) and can be written as:

$$\tau = \mu\gamma \tag{A.2}$$

Below are an explanation of several terms and parameters related to fluid rheology:

Below are an explanation of several terms and parameters related to fluid rheology:

- *Shear Rate* (sec^{-1}): The change in fluid velocity divided by the width of the channel through which the fluid is flowing in laminar flow.
- *Shear Stress* ($lb/100ft^2$): The force per unit area required to move a fluid at a given shear rate.
- *Viscosity*, μ (centipoise, cP): The ratio of shear stress to shear rate.
- *Plastic Viscosity*, PV, μ_p (cP): The contribution to total fluid viscosity of a fluid under dynamic conditions that depends on the size, shape and number of particles in the moving fluid. PV can be calculated using shear stresses measured at θ_{600} and θ_{300}on the FANN Viscometer.
- *Effective Viscosity*, μ_e (cP): Viscosity measurements that takes account of the geometry though which the fluid is flowing.
- *Yield Point*, YP ($lb/100ft^2$): The minimum force to initiate flow, used to describe the Bingham Plastic model.
- *Yield Stress* ($lb/100ft^2$): The force required to initiate flow. It is a calculated value of the fluid's shear stress when the plot is extrapolated to the y-axis at shear rate equals zero. It is equal to YP in the Bingham Plastic Model and τ_0 in the Herschel-Buckley Model.
- *Gel Strengths* ($lb/100ft^2$): Time dependent measurements of the fluid's shear stress under static conditions. It is measured after 10 seconds, 10 minutes and 30 minutes intervals.
- *Reynolds Number*, Re : Dimensionless numerical term that can be used to determine flow regime. Low Reynold's number indicate laminar flow and Re higher than 2000 indicates turbulent flow.

Several rheology models are:

Newtonian Model: Fluid that show a linear relationship between shear stress and shear rate with a slope equal to the dynamic viscosity. The plot illustration is given by figure 5.1 and can be expressed the same as equation 5.2.

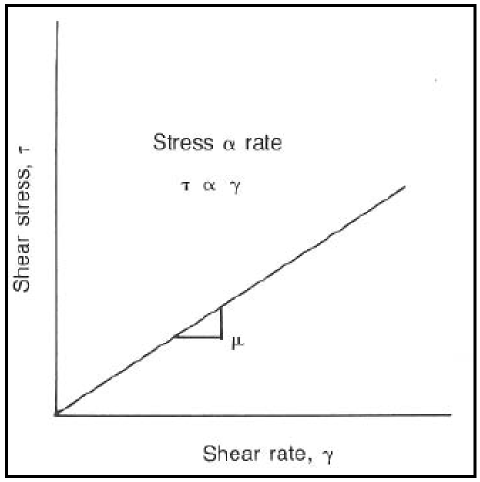

Figure A.1 Newtonian Fluid (Adams et al., 1985: Fig. 18-5)

Bingham Plastic Model: Fluid flow takes place after a minimum value of shear stress, expressed as Yield Point (YP), is exceeded. After exceeding the YP, the shear stress – shear rate relationship is linear with a constant value of viscosity known as plastic viscosity (μ_p). The plot illustration is given by figure 5.2 and can be expressed as:

$$\tau = \tau_y + \mu_p \dot{\gamma} \quad \text{(A.3)}$$

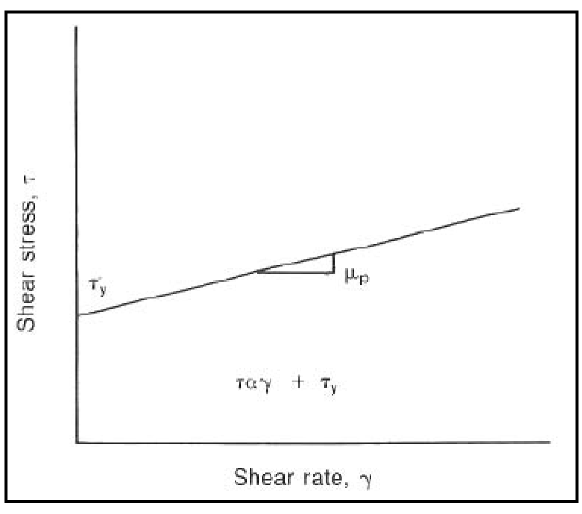

Figure A.2 Bingham Plastic Fluid (Adams et al., 1985: Fig. 18-6)

Power Law Model: This model gives better accuracy by relating shear stress and shear rate with the expression,

$$\tau = K(\gamma)^n \quad \text{(A.4)}$$

Where the term *n* is the Power Law Index and represents the behavior of the fluid. The fluid is considered Newtonian when *n* is equal to 1. As the value of *n* decreases (< 1), the fluid exhibits non-Newtonian behavior and the viscosity will decrease as the shear rate increases. The term K is the Consistency Index that represents the thickness of the mud. Higher K-value indicates a more effective hole cleaning by the drilling fluid. Figure 5.3 illustrates the plot of Power Law Model.

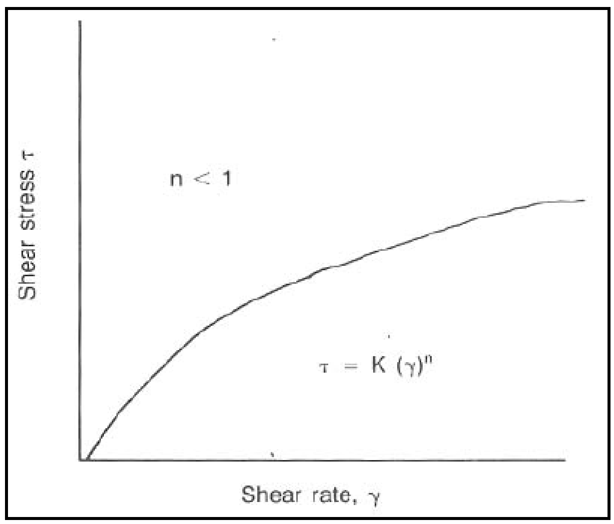

Figure A.3 Power Law Fluid (Adams et al., 1985: Fig. 18-7)

Herschel-Buckley (Yield Power Law - YPL) Model: Is a more accurate rheological behavior as compared to the Power Law Model and is given by,

$$\tau = \tau_0 + K(\gamma)^n \quad \text{(A.5)}$$

Where τ_0 is the yield stress which represents shear stress at zero shear rate. This model will reduce to Bingham Model when n equals to 1; and it reduces to Power Law Model when τ_0 equals to 0.

A.2. Hydraulic Simulation Results

A.2.1. Hydraulic Simulation for Standard Conventional Design

A.2.1.1 Simulation results for 17-1/2 inch hole-section until 2700 meter.

Table 1 Internal and Annular pressure drop data for Conventional Design 17-1/2" hole section

Flowrate	Pressure Drop (bar)												
(lpm)	20"CSG - 5 1/2"DP		17-1/2"OH - 5 1/2"DP		17-1/2"OH – 6-5/8"HWDP		17-1/2"OH - 8" DC		17-1/2"OH - 9 1/2" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
3500	29.8	0.9	44.8	1.7	0.8	0.1	11.3	0.1	13.8	0.1	100.5	2.9	103.4
4000	36.7	1	55.1	1.7	1	0.1	13.9	0.1	17	0.1	123.7	3	126.7
4250	40.3	1	60.5	1.8	1.1	0.1	15.3	0.1	18.6	0.1	135.8	3.1	138.9
4500	44.1	1	66.1	1.8	2	0.1	16.7	0.1	20.4	0.1	149.3	3.1	152.4
4750	48	1	71.9	1.8	2.1	0.1	18.2	0.1	22.1	0.1	162.3	3.1	165.4
5000	51.9	1	77.9	1.9	2.3	0.1	19.7	0.1	24	0.1	175.8	3.2	179
5500	60.2	1.1	90.3	1.9	2.7	0.1	22.9	0.1	27.8	0.1	203.9	3.3	207.2

Table 2 Annular Velocity data for Conventional Design 17-1/2" hole section

Flowrate	Annular Velocity (m/s)				
(lpm)	20"CSG - 5 1/2"DP	17-1/2"OH - 5 1/2"DP	17-1/2"OH – 6-5/8"HWDP	17-1/2"OH - 8" DC	17-1/2"OH - 9 1/2" BHA
3500	0.36	0.42	0.44	0.48	0.53
4000	0.41	0.48	0.5	0.54	0.61
4250	0.44	0.51	0.54	0.58	0.65
4500	0.47	0.54	0.57	0.61	0.69
4750	0.49	0.57	0.6	0.64	0.72
5000	0.52	0.6	0.63	0.68	0.76
5500	0.57	0.66	0.69	0.75	0.84

Table 3 Bit pressure drop data at 4000 lpm for Conventional Design 17-1/2" hole section

At 4000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	91.2	2524	85.53	526.3	1631.7	2301.4
0.393	72.1	798	21.38	263.1	815.9	575.4
0.589	53.4	479	9.5	175.4	543.9	255.7
0.785	39.2	367	5.35	131.6	407.9	143.8
0.982	29.2	315	3.42	105.3	326.3	92.1
1.178	22.3	287	2.38	87.7	272	63.9
1.374	17.4	270	1.75	75.1	233.1	47
1.571	13.9	259	1.34	65.8	204	36
1.767	11.3	251	1.06	58.5	181.3	28.4
1.963	9.4	246	0.86	52.6	163.2	23
2.16	7.9	242	0.71	47.8	148.3	19
2.356	6.7	239	0.59	43.9	136	16
2.553	5.8	237	0.51	40.5	125.5	13.6
2.749	5	235	0.44	37.6	116.6	11.7

Table 4 Bit pressure drop data at 4500 lpm for Conventional Design 17-1/2" hole section

At 4500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	91.6	3182	121.78	592.1	2065.2	2912.7
0.393	73	997	30.45	296	1032.6	728.2
0.589	54.6	592	13.53	197.4	688.4	323.6
0.785	40.4	451	7.61	148	516.3	182
0.982	30.2	385	4.87	118.4	413	116.5
1.178	23.1	350	3.38	98.7	344.2	80.9
1.374	18.1	328	2.49	84.6	295	59.4
1.571	14.5	314	1.9	74	258.1	45.5
1.767	11.8	305	1.5	65.8	229.5	36
1.963	9.8	298	1.22	59.2	206.5	29.1
2.16	8.2	293	1.01	53.8	187.7	24.1
2.356	7	289	0.85	49.3	172.1	20.2
2.553	6	286	0.72	45.5	158.9	17.2
2.749	5.2	284	0.62	42.3	147.5	14.9

A.2.1.2. Simulation results for 12-1/4" hole-section until 4200 meter.

Table 5 Internal and Annular pressure drop data for Conventional Design 12-1/4" hole section

Flowrate	Pressure Drop (bar)												
(lpm)	13-3/8"CSG – 5-1/2"DP		12-1/4"OH – 5-1/2"DP		12-1/4"OH – 6-5/8"HWDP		12-1/4"OH - 8"DC		12-1/4"OH - 9 1/2" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
2500	68.1	7.2	32.8	3.6	0.6	0.4	7.8	0.3	9.5	0.6	118.8	12.1	130.9
3000	91.8	7.6	44.2	3.8	0.8	0.4	10.3	0.3	12.6	0.6	159.7	12.7	172.4
3125	98.1	7.7	47.2	3.8	0.8	0.4	11	0.3	13.4	0.6	170.5	12.8	183.3
3250	104.6	7.9	50.4	3.9	0.9	0.4	11.7	0.3	14.2	0.6	181.8	13.1	194.9
3375	88.3	8	42.5	4	0.9	0.4	12.4	0.3	15.1	0.6	159.2	13.3	172.5
3500	93.4	8.1	45	4	1	0.4	13.1	0.3	16	0.6	168.5	13.4	181.9
4000	114.9	8.5	55.3	4.2	1.2	0.4	16.2	0.3	19.7	0.9	207.3	14.3	221.6

Table 6 Annular Velocity data for Conventional Design 12-1/4" hole section

Flowrate	Annular Velocity (m/s)				
(lpm)	13-3/8"CSG – 5-1/2"DP	12-1/4"OH – 5-1/2"DP	12-1/4"OH – 6-5/8"HWDP	12-1/4"OH - 8"DC	12-1/4"OH - 9 1/2" BHA
2500	0.68	0.7	0.78	0.96	1.37
3000	0.82	0.84	0.94	1.15	1.65
3125	0.85	0.87	0.98	1.19	1.72
3250	0.89	0.91	1.02	1.24	1.79
3375	0.92	0.94	1.06	1.29	1.86
3500	0.96	0.98	1.1	1.34	1.92
4000	1.09	1.11	1.26	1.53	2.2

Table 7 Bit pressure drop data at 3000 lpm for Conventional Design 12-1/4" hole section

At 3000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	86.7	1842	90.82	394.7	1132	1596.6
0.393	62	644	22.71	197.4	566	399.1
0.589	42	422	10.09	131.6	377.3	177.4
0.785	28.9	345	5.68	98.7	283	99.8
0.982	20.7	309	3.63	78.9	226.4	63.9
1.178	15.3	289	2.52	65.8	188.7	44.3
1.374	11.7	278	1.85	56.4	161.7	32.6
1.571	9.2	270	1.42	49.3	141.5	24.9
1.767	7.4	265	1.12	43.9	125.8	19.7
1.963	6.1	261	0.91	39.5	113.2	16
2.16	5.1	258	0.75	35.9	102.9	13.2
2.356	4.3	256	0.63	32.9	94.3	11.1

Table 8 Bit pressure drop data at 3500 lpm for Conventional Design 12-1/4" hole section

At 3500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	88.8	2447	144.22	460.5	1540.8	2173.1
0.393	66.5	818	36.06	230.2	770.4	543.3
0.589	46.8	516	16.02	153.5	513.6	241.5
0.785	33.1	410	9.01	115.1	385.2	135.8
0.982	24.1	361	5.77	92.1	308.2	86.9
1.178	18	335	4.01	76.7	256.8	60.4
1.374	13.9	319	2.94	65.8	220.1	44.3
1.571	11	308	2.25	57.6	192.6	34
1.767	8.9	301	1.78	51.2	171.2	26.8
1.963	7.3	296	1.44	46	154.1	21.7
2.16	6.1	292	1.19	41.9	140.1	18
2.356	5.2	289	1	38.4	128.4	15.1

A.2.1.3. Simulation results for 8-1/2” hole-section until 4700 meter.

Table 9 Internal and Annular pressure drop data for Conventional Design 8-1/2” hole section

Flowrate	Pressure Drop (bar)												
(lpm)	9-5/8"CSG – 5-1/2"DP		8-1/2"OH – 5-1/2"DP		8-1/2"OH – 5-1/2"HWDP		8-1/2"OH - 6"DC		8-1/2"OH – 6-3/4" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
1500	32.5	43.8	2.3	3.9	3.8	1	4.5	0.7	4.5	1.3	47.6	50.7	98.3
2000	49.7	48.3	3.6	4	5.9	1.1	7.1	0.8	7.1	1.7	73.4	55.9	129.3
2125	54.4	47.3	3.9	5.3	6.5	1.1	7.8	0.9	7.8	1.8	80.4	56.4	136.8
2250	94.3	44.1	6.7	5.9	7.1	1	8.5	1	8.5	2	125.1	54	179.1
2375	103.1	42.2	7.4	6.4	7.7	0.9	9.2	1.1	9.2	2.2	136.6	52.8	189.4
2500	112.1	45.5	8	7	8.4	1	10	1.2	10	2.4	148.5	57.1	205.6
3000	151.1	93	10.8	9.4	11.1	2	13.3	1.3	13.3	3.1	199.6	108.8	308.4

Table 10 Annular Velocity data for Conventional Design 8-1/2” hole section

Flowrate	Annular Velocity (m/s)				
(lpm)	9 5/8"CSG - 5 1/2"DP	8-1/2"OH - 5 1/2"DP	8-1/2"OH - 5 1/2"HWDP	8-1/2"OH - 6" DC	8-1/2"OH - 6 3/4" BHA
1500	1.21	1.35	1.17	1.36	1.85
2000	1.61	1.8	1.57	1.81	2.47
2125	1.71	1.92	1.66	1.93	2.62
2250	1.81	2.03	1.76	2.04	2.77
2375	1.91	2.14	1.86	2.16	2.93
2500	2.01	2.25	1.96	2.27	3.08
3000	2.41	2.7	2.35	2.72	3.7

Table 11 Bit pressure drop data at 2000 lpm for Conventional Design 8-1/2" hole section

At 2000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	77.3	993	60.43	263.1	543.9	767.1
0.393	45.9	418	15.11	131.6	272	191.8
0.589	27.4	311	6.71	87.7	181.3	85.2
0.785	17.5	274	3.78	65.8	136	47.9
0.982	12	257	2.42	52.6	108.8	30.7
1.178	8.6	247	1.68	43.9	90.7	21.3
1.374	6.5	241	1.23	37.6	77.7	15.7
1.571	5	238	0.94	32.9	68	12
1.767	4	235	0.75	29.2	60.4	9.5
1.963	3.3	233	0.6	26.3	54.4	7.7
2.16	2.7	232	0.5	23.9	49.4	6.3
2.356	2.3	231	0.42	21.9	45.3	5.3

Table 12 Bit pressure drop data at 2500 lpm for Conventional Design 8-1/2" hole section

At 2500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	78.5	1528	118.02	328.9	849.9	1198.6
0.393	47.7	629	29.5	164.5	424.9	299.7
0.589	28.8	462	13.11	109.6	283.3	133.2
0.785	18.5	404	7.38	82.2	212.5	74.9
0.982	12.7	377	4.72	65.8	170	47.9
1.178	9.2	362	3.28	54.8	141.6	33.3
1.374	6.9	353	2.41	47	121.4	24.5
1.571	5.4	348	1.84	41.1	106.2	18.7
1.767	4.3	344	1.46	36.5	94.4	14.8
1.963	3.5	341	1.18	32.9	85	12
2.16	2.9	339	0.98	29.9	77.3	9.9
2.356	2.5	337	0.82	27.4	70.8	8.3

A.2.2. Hydraulic Simulation for FMC (Medium) Design

A.2.2.1. Simulation results for 12-1/4 inch hole-section until 2700 meter.

Table 13 Internal and Annular pressure drop data for FMC (Medium) Design 12-1/4" hole section (2700 meter)

Flowrate	Pressure Drop (bar)												
(lpm)	14"CSG - 5 1/2"DP		12-1/4"OH - 5-1/2"DP		12-1/4"OH - 6 5/8"HWDP		12-1/4"OH - 8" DC		12-1/4"OH - 9 1/2" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
2500	21.7	2.3	32.5	4.1	0.5	0.4	6.7	0.3	8.2	0.6	69.6	7.7	77.3
3000	29.2	2.4	43.8	4.4	0.7	0.4	8.9	0.3	10.8	0.6	93.4	8.1	101.5
3125	31.2	2.4	46.8	4.4	0.7	0.4	9.5	0.3	11.6	0.6	99.8	8.1	107.9
3250	33.3	2.5	49.9	4.5	0.8	0.4	10.1	0.3	12.3	0.6	106.4	8.3	114.7
3375	28.2	2.5	42.3	4.6	0.8	0.4	10.7	0.3	13	0.6	95	8.4	103.4
3500	29.8	2.5	44.8	4.6	0.8	0.4	11.3	0.3	13.8	0.7	100.5	8.5	109
4000	36.7	2.6	55.1	4.9	1	0.4	13.9	0.3	17	0.8	123.7	9	132.7

Table 14 Annular Velocity data for FMC (Medium) Design 12-1/4" hole section (2700 meter)

Flowrate	Annular Velocity (m/s)				
(lpm)	14"CSG - 5 1/2"DP	12-1/4"OH - 5-1/2"DP	12-1/4"OH - 6 5/8"HWDP	12-1/4"OH - 8" DC	12-1/4"OH - 9 1/2" BHA
2500	0.6	0.7	0.78	0.96	1.37
3000	0.72	0.84	0.94	1.15	1.65
3125	0.75	0.87	0.98	1.19	1.72
3250	0.78	0.91	1.02	1.24	1.79
3375	0.81	0.94	1.06	1.29	1.86
3500	0.84	0.98	1.1	1.34	1.92
4000	0.96	1.11	1.26	1.53	2.2

Table 15 Bit pressure drop data at 3000 lpm for FMC (Medium) Design 12-1/4" hole section (2700 meter)

At 3000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	88.8	1458	73.64	394.7	917.9	1294.5
0.393	66.5	487	18.41	197.4	468.9	323.6
0.589	46.9	307	8.18	131.6	306	143.8
0.785	33.1	244	4.6	98.7	229.5	80.9
0.982	24.1	215	2.95	78.9	183.6	51.8
1.178	18.1	199	2.05	65.8	153	36
1.374	13.9	190	1.5	56.4	131.1	26.4
1.571	11	183	1.15	49.3	114.7	20.2
1.767	8.9	179	0.91	43.9	102	16
1.963	7.4	176	0.74	39.5	91.8	12.9
2.16	6.2	174	0.61	35.9	83.4	10.4
2.356	5.2	172	0.51	32.9	76.5	9
2.553	4.5	171	0.44	30.4	70.6	7.7
2.749	3.9	170	0.38	28.2	65.6	6.6

Table 16 Bit pressure drop data at 3500 lpm for FMC (Medium) Design 12-1/4" hole section (2700 meter)

At 3500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	90.4	1949	116.94	460.5	1249.3	1762
0.393	70.2	628	29.23	230.2	624.7	440.5
0.589	51.1	383	12.99	153.5	416.4	195.8
0.785	37.1	297	7.31	115.1	312.3	110.1
0.982	27.4	258	4.68	92.1	249.9	70.5
1.178	20.7	236	3.25	76.7	208.2	48.9
1.374	16.1	223	2.39	65.8	178.5	36
1.571	12.8	215	1.83	57.6	156.2	27.5
1.767	10.4	209	1.44	51.2	138.8	21.8
1.963	8.6	205	1.17	46	124.9	17.6
2.16	7.2	202	0.97	41.9	113.6	14.6
2.356	6.1	199	0.81	38.4	104.1	12.2
2.553	5.3	197	0.69	35.4	96.1	10.4
2.749	4.6	196	0.6	32.9	89.2	9

A.2.2.2. Simulation results for 12-1/4 inch hole-section until 4200 meter.

Table 17 Internal and Annular pressure drop data for FMC (Medium) Design 12-1/4" hole section (4200 meter)

Flowrate	Pressure Drop (bar)														
(lpm)	14"CSG – 5-1/2"DP		11-3/4"CSG – 5-1/2"DP		12-1/4"OH – 5-1/2"DP		12-1/4"OH – 6-5/8"HWDP		12-1/4"OH - 8" DC		12 1/4"OH - 9 1/2" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
2500	25.2	1.8	42.9	6.9	32.8	3.6	0.6	0.4	7.8	0.3	9.5	0.6	118.8	13.6	132.4
3000	34	1.9	57.8	7.4	44.2	3.8	0.8	0.4	10.3	0.3	12.6	0.6	159.7	14.4	174.1
3125	36.3	2	61.8	7.6	47.2	3.8	0.8	0.4	11	0.3	13.4	0.6	170.5	14.7	185.2
3250	38.7	2	65.9	7.7	50.4	3.9	0.9	0.4	11.7	0.3	14.2	0.6	181.8	14.9	196.7
3375	32.7	2.1	55.6	7.8	42.5	4	0.9	0.4	12.4	0.3	15.1	0.6	159.2	15.2	174.4
3500	34.6	2.1	58.8	7.9	45	4	1	0.4	13.1	0.3	16	0.6	168.5	15.3	183.8
4000	42.6	2.2	72.4	8.3	55.3	4.2	1.2	0.4	16.2	0.3	19.7	0.9	207.4	16.3	223.7

Table 18 Annular Velocity data for FMC (Medium) Design 12-1/4" hole section (4200 meter)

Flowrate	Annular Velocity (m/s)					
(lpm)	14"CSG - 5 1/2"DP	11 3/4"CSG - 5 1/2"DP	12 1/4"OH - 5 1/2"DP	12 1/4"OH - 6 5/8"HWDP	12 1/4"OH - 8" DC	12 1/4"OH - 9 1/2" BHA
2500	0.6	0.92	0.7	0.78	0.96	1.37
3000	0.72	1.11	0.84	0.94	1.15	1.65
3125	0.75	1.16	0.87	0.98	1.19	1.72
3250	0.78	1.2	0.91	1.02	1.24	1.79
3375	0.81	1.25	0.94	1.06	1.29	1.86
3500	0.84	1.29	0.98	1.1	1.34	1.92
4000	0.96	1.48	1.11	1.26	1.53	2.2

Table 19 Bit pressure drop data at 3000 lpm for FMC (Medium) Design 12-1/4" hole section (4200 meter)

At 3000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	86.6	1843	90.82	394.7	1132	1596.6
0.393	61.8	646	22.71	197.4	566	399.1
0.589	41.8	424	10.09	131.6	377.3	177.4
0.785	28.8	347	5.68	98.7	283	99.8
0.982	20.6	311	3.63	78.9	226.4	63.9
1.178	15.2	291	2.52	65.8	188.7	44.3
1.374	11.7	279	1.85	56.4	161.7	32.6
1.571	9.2	272	1.42	49.3	141.5	24.9
1.767	7.4	267	1.12	43.9	125.8	19.7
1.963	6.1	263	0.91	39.5	113.2	16
2.16	5.1	260	0.75	35.9	102.9	13.2
2.356	4.3	258	0.63	32.9	94.3	11.1

Table 20 Bit pressure drop data at 3500 lpm for FMC (Medium) Design 12-1/4" hole section (4200 meter)

At 3500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	88.7	2449	144.22	460.5	1540.8	2173.1
0.393	66.3	819	36.06	230.2	770.4	543.3
0.589	46.6	518	16.02	153.5	513.6	241.5
0.785	33	412	9.01	115.1	385.2	135.8
0.982	23.9	363	5.77	92.1	308.2	86.9
1.178	17.9	337	4.01	76.7	256.8	60.4
1.374	13.8	321	2.94	65.8	220.1	44.3
1.571	10.9	310	2.25	57.6	192.6	34
1.767	8.9	303	1.78	51.2	171.2	26.8
1.963	7.3	298	1.44	46	154.1	21.7
2.16	6.1	294	1.19	41.9	140.1	18
2.356	5.2	291	1	38.4	128.4	15.1

A.2.2.3. Simulation results for 8-1/2 inch hole-section until 4700 meter.

Hydraulic simulation result for FMC (medium) Design, 8-1/2" hole-section until 4700 meter has the same configuration with Conventional Design 8-1/2" hole section. Therefore, the data refer to those of Conventional Design 8-1/2" hole section.

A.2.3. Hydraulic Simulation for SBBU-1 Design

A.2.3.1. Simulation results for 12-1/4 inch hole-section until 2700 meter.

Table 21 Internal and Annular pressure drop data for SBBU-1 Design 12-1/4" hole section

Flowrate	Pressure Drop (bar)														
(lpm)	13-3/8"CSG – 5-1/2"DP		11-3/4"CSG – 5-1/2"DP		12-1/4"OH – 5-1/2"DP		12-1/4"OH – 6-5/8"HWDP		12-1/4"OH - 8" DC		12-1/4"OH – 9-1/2" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
2500	21.7	2.3	19.5	3.6	13	1.6	0.5	0.4	6.7	0.3	8.2	0.6	69.6	8.8	78.4
3000	29.2	2.5	26.3	3.9	17.5	1.7	0.7	0.4	8.9	0.3	10.8	0.6	93.4	9.4	102.8
3125	31.2	2.5	28.1	4	18.7	1.8	0.7	0.4	9.5	0.3	11.6	0.6	99.8	9.6	109.4
3250	33.3	2.6	29.9	4.1	20	1.8	0.8	0.4	10.1	0.3	12.3	0.6	106.4	9.8	116.2
3375	28.2	2.6	25.4	4.1	16.9	1.8	0.8	0.4	10.7	0.3	13	0.6	95	9.8	104.8
3500	29.8	2.6	26.9	4.2	17.9	1.9	0.8	0.4	11.3	0.3	13.8	0.7	100.5	10.1	110.6
4000	36.7	2.8	33	4.4	22	2	1	0.4	13.9	0.3	17	0.8	123.6	10.7	134.3

Table 22 Annular Velocity data for SBBU-1 Design 12-1/4" hole section

Flowrate	Annular Velocity (m/s)					
(lpm)	13-3/8"CSG – 5-1/2"DP	11-3/4"CSG – 5-1/2"DP	12-1/4"OH – 5-1/2"DP	12-1/4"OH – 6-5/8"HWDP	12-1/4"OH - 8" DC	12-1/4"OH – 9-1/2" BHA
2500	0.68	0.92	0.7	0.78	0.96	1.37
3000	0.82	1.11	0.84	0.94	1.15	1.65
3125	0.85	1.16	0.87	0.98	1.19	1.72
3250	0.89	1.2	0.91	1.02	1.24	1.79
3375	0.92	1.25	0.94	1.06	1.29	1.86
3500	0.96	1.29	0.98	1.1	1.34	1.92
4000	1.09	1.48	1.11	1.26	1.53	2.2

Table 23 Bit pressure drop data at 3000 lpm for SBBU-1 Design 12-1/4" hole section

At 3000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	88.7	1459	73.64	394.7	917.9	1294.5
0.393	66.3	488	18.41	197.4	458.9	323.6
0.589	46.6	308	8.18	131.6	306	143.8
0.785	33	245	4.6	98.7	229.5	80.9
0.982	23.9	216	2.95	78.9	183.6	51.8
1.178	17.9	200	2.05	65.8	153	36
1.374	13.8	191	1.5	56.4	131.1	26.4
1.571	10.9	185	1.15	49.3	114.7	20.2
1.767	8.9	181	0.91	43.9	102	16
1.963	7.3	177	0.74	39.5	91.8	12.9
2.16	6.1	175	0.61	35.9	83.4	10.7
2.356	5.2	174	0.51	32.9	76.5	9
2.553	4.4	172	0.44	30.4	70.6	7.7
2.749	3.9	171	0.38	28.2	65.6	6.6

Table 24 Bit pressure drop data at 3500 lpm for SBBU-1 Design 12-1/4" hole section

At 3500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	90.3	1951	116.94	460.5	1249.3	1762
0.393	70	629	29.23	230.2	624.7	440.5
0.589	50.9	384	12.99	153.5	416.4	195.8
0.785	36.9	299	7.31	115.1	312.3	110.1
0.982	27.2	259	4.68	92.1	249.9	70.5
1.178	20.6	238	3.25	76.7	208.2	48.9
1.374	16	225	2.39	65.8	178.5	36
1.571	12.7	216	1.83	57.6	156.2	27.5
1.767	10.3	210	1.44	51.2	138.8	21.8
1.963	8.5	206	1.17	46	124.9	17.6
2.16	7.2	203	0.97	41.9	113.6	14.6
2.356	6.1	201	0.81	38.4	104.1	12.2
2.553	5.2	199	0.69	35.4	96.1	10.4
2.749	4.6	198	0.6	32.9	89.2	9

A.2.3.2. Simulation results for 8-1/2 inch hole-section until 4200 meter.

Table 25 Internal and Annular pressure drop data for SBBU-1 Design 8-1/2" hole section

Flowrate	Pressure Drop (bar)												
(lpm)	9-5/8"CSG - 5-1/2"DP		8-1/2"OH - 5-1/2"DP		8-1/2"OH - 5-1/2"HWDP		8-1/2"OH - 6" DC		8-1/2"OH - 6-3/4" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
1500	19.8	28.2	9.6	16.9	3.6	1	4.3	0.7	4.3	1.3	41.6	48.1	89.7
2000	30.3	31.1	14.6	18.2	5.6	1.1	6.7	0.8	6.7	1.6	63.9	52.8	116.7
2125	33.2	31.7	16	21.8	6.2	1.1	7.4	0.9	7.4	1.7	70.2	57.2	127.4
2250	57.3	30.6	27.6	24	6.7	1.1	8	0.9	8	1.9	107.6	58.5	166.1
2375	62.6	28.5	30.1	26.2	7.3	1	8.7	1	8.7	2.1	117.4	58.8	176.2
2500	68.1	27.7	32.8	28.5	7.9	0.9	9.5	1.1	9.5	2.2	127.8	60.4	188.2
3000	91.8	56.5	44.2	38.4	10.5	1.9	12.6	1.2	12.6	3	171.7	101	272.7

Table 26 Annular Velocity data for SBBU-1 Design 8-1/2" hole section

Flowrate	Annular Velocity (m/s)				
(lpm)	9-5/8"CSG - 5-1/2"DP	8-1/2"OH - 5-1/2"DP	8-1/2"OH - 5-1/2"HWDP	8-1/2"OH - 6" DC	8-1/2"OH - 6-3/4" BHA
1500	1.21	1.35	1.17	1.36	1.85
2000	1.61	1.8	1.57	1.81	2.47
2125	1.71	1.92	1.66	1.93	2.62
2250	1.81	2.03	1.76	2.04	2.77
2375	1.91	2.14	1.86	2.16	2.93
2500	2.01	2.25	1.96	2.27	3.08
3000	2.41	2.7	2.35	2.72	3.7

Table 27 Bit pressure drop data at 2000 lpm for SBBU-1 Design 8-1/2" hole section

At 2000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	77.4	916	55.89	263.1	503.1	709.6
0.393	46.2	384	13.97	131.6	251.6	177.4
0.589	27.6	286	6.21	87.7	167.7	78.8
0.785	17.7	251	3.49	65.8	125.8	44.3
0.982	12.1	235	2.24	52.6	100.6	28.4
1.178	8.7	226	1.55	43.9	83.9	19.7
1.374	6.5	221	1.14	37.6	71.9	14.5
1.571	5.1	218	0.87	32.9	62.9	11.1
1.767	4.1	215	0.69	29.2	55.9	8.8
1.963	3.3	214	0.56	26.3	50.3	7.1
2.16	2.8	213	0.46	23.9	45.7	5.9
2.356	2.3	212	0.39	21.9	41.9	4.9

Table 28 Bit pressure drop data at 2500 lpm for SBBU-1 Design 8-1/2" hole section

At 2500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	78.5	1412	109.17	328.9	786.1	1108.7
0.393	47.8	580	27.29	164.5	393.1	277.2
0.589	28.9	426	12.13	109.6	262	123.2
0.785	18.6	373	6.82	82.2	196.5	69.3
0.982	12.8	348	4.37	65.8	157.2	44.3
1.178	9.2	334	3.03	54.8	131	30.8
1.374	6.9	326	2.23	47	112.3	22.6
1.571	5.4	321	1.71	41.1	98.3	17.3
1.767	4.3	317	1.35	36.5	87.3	13.7
1.963	3.5	314	1.09	32.9	78.6	11.1
2.16	2.9	312	0.9	29.9	71.5	9.2
2.356	2.5	311	0.76	27.4	65.5	7.7

A.2.3.3. Simulation results for 5-7/8 inch hole-section until 4700 meter.

Table 29 Internal and Annular pressure drop data for SBBU-1 Design 5-7/8" hole section

Flowrate	Pressure Drop (bar)														
(lpm)	9-5/8"CSG – 5-1/2"DP		7"CSG – 3-1/2"DP		5-7/8"OH – 3-1/2"DP		5-7/8"OH - 4"HWDP		5-7/8"OH – 4-1/4" DC		5 7/8"OH - 4 3/4" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
250	10	15.6	16	8.5	3.2	2.6	1.3	1.3	1.3	0.8	1.3	1.5	33.1	30.3	63.4
500	3.9	19.2	29.1	10.8	5.8	3.4	3	1.7	3.2	1.1	3.2	2.2	48.2	38.4	86.6
625	5.6	21.3	42	11.8	8.4	3.7	3.5	1.8	4.5	1.1	4.5	2.4	68.5	42.1	110.6
750	6.1	22.8	45.6	12.6	9.1	3.9	4.6	1.9	6	1.2	6	2.7	77.4	45.1	122.5
1000	9.5	25.2	71.2	14	14.2	4.3	7.2	2.3	9.3	1.5	9.3	3.3	120.7	50.6	171.3
1250	13.5	27.4	100.7	15.1	20.1	5.4	10.2	2.6	13.2	1.9	13.2	4.7	170.9	57.1	228
1500	17.9	16.9	133.7	16	26.7	7.2	13.6	3.5	17.5	2.5	17.5	6.2	226.9	52.3	279.2

Table 30 Annular Velocity data for SBBU-1 Design 5-7/8" hole section

Flowrate	Annular Velocity (m/s)					
(lpm)	9-5/8"CSG – 5-1/2"DP	7"CSG – 3-1/2"DP	5-7/8"OH – 3-1/2"DP	5-7/8"OH - 4"HWDP	5-7/8"OH – 4-1/4" DC	5 7/8"OH - 4 3/4" BHA
250	0.2	0.27	0.37	0.44	0.5	0.69
500	0.4	0.54	0.74	0.89	1	1.38
625	0.5	0.67	0.92	1.11	1.25	1.72
750	0.6	0.81	1.11	1.33	1.5	2.06
1000	0.8	1.08	1.47	1.78	2	2.75
1250	1.01	1.35	1.84	2.22	2.5	3.44
1500	1.21	1.62	2.21	2.66	3	4.13

Table 31 Bit pressure drop data at 750 lpm for SBBU-1 Design 5-7/8" hole section

At 750 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	40.3	267	6.67	98.7	76.5	107.9
0.393	14.5	186	1.67	49.3	38.2	27
0.589	7	171	0.74	32.9	25.5	12
0.785	4.1	166	0.42	24.7	19.1	6.7
0.982	2.6	164	0.27	19.7	15.3	4.3
1.178	1.8	163	0.19	16.4	12.7	3
1.374	1.4	162	0.14	14.1	10.9	2.2
1.571	1	161	0.1	12.3	9.6	1.7
1.767	0.8	161	0.08	11	8.5	1.3
1.963	0.7	161	0.07	9.9	7.6	1.1
2.16	0.6	160	0.06	9	7	0.9
2.356	0.5	160	0.05	8.2	6.4	0.7

Table 32 Bit pressure drop data at 1500 lpm for SBBU-1 Design 5-7/8" hole section

At 1500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	55.2	782	53.36	197.4	306	431.5
0.393	23.5	458	13.34	98.7	153	107.9
0.589	12	399	5.93	65.8	102	47.9
0.785	7.1	378	3.34	49.3	76.5	27
0.982	4.7	368	2.13	39.5	61.2	17.3
1.178	3.3	363	1.48	32.9	51	12
1.374	2.5	359	1.09	28.2	43.7	8.8
1.571	1.9	357	0.83	24.7	38.2	6.7
1.767	1.5	356	0.66	21.9	34	5.3
1.963	1.2	355	0.53	19.7	30.6	4.3
2.16	1	354	0.44	17.9	27.8	3.6
2.356	0.8	354	0.37	16.4	25.5	3

A.2.3.4. Simulation results for 5-7/8 inch hole-section with tie-back option until 4700 meter.

Table 33 Internal and Annular pressure drop data for SBBU-1 Design 5-7/8” hole section with tie-back option

Flowrate	Pressure Drop (bar)												
(lpm)	7"CSG - 3-1/2"DP		5-7/8"OH - 3 1/2"DP		5-7/8"OH - 4"HWDP		5-7/8"OH - 4-1/4" DC		5-7/8"OH - 4-3/4" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
250	44.5	23.7	3.2	2.6	1.3	1.3	1.3	0.8	1.3	1.5	51.6	29.9	81.5
500	81	30.2	5.8	3.4	3	1.7	3.2	1.1	3.2	2.2	96.2	38.6	134.8
625	116.7	33.1	8,4	3.7	3.5	1.8	4.5	1.1	4.5	2.4	129.2	42.1	171.3
750	126.8	35.4	9.1	3.9	4.6	1.9	6	1.2	6	2.7	152.5	45.1	197.6
1000	198.2	39.2	14.2	4.3	7.2	2.3	9.3	1.5	9.3	3.3	238.2	50.6	288.8
1250	280.3	42.4	20.1	5.4	10.2	2.6	13.2	1.9	13.2	4.7	337	57	394
1500	372.1	44.9	26.7	7.2	13.6	3.5	17.5	2.5	17.5	6.2	447.4	64.3	511.7

Table 34 Annular Velocity data for SBBU-1 Design 5-7/8” hole section with tie back option

Flowrate	Annular Velocity (m/s)				
(lpm)	7"CSG - 3-1/2"DP	5-7/8"OH - 3 1/2"DP	5-7/8"OH - 4"HWDP	5-7/8"OH - 4-1/4" DC	5-7/8"OH - 4-3/4" BHA
250	0.27	0.37	0.44	0.5	0.69
500	0.54	0.74	0.89	1	1.38
625	0.67	0.92	1.11	1.25	1.72
750	0.81	1.11	1.33	1.5	2.06
1000	1.08	1.47	1.78	2	2.75
1250	1.35	1.84	2.22	2.5	3.44
1500	1.62	2.21	2.66	3	4.13

Table 35 Bit pressure drop data at 750 lpm for SBBU-1 Design 5-7/8" hole section

At 750 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	31.5	342	6.67	98.7	76.5	107.9
0.393	10.3	262	1.67	49.3	38.2	27
0.589	4.9	247	0.74	32.9	25.5	12
0.785	2.8	241	0.42	24.7	19.1	6.7
0.982	1.8	239	0.27	19.7	15.3	4.3
1.178	1.3	238	0.19	16.4	12.7	3
1.374	0.9	237	0.14	14.1	10.9	2.2
1.571	0.7	236	0.1	12.3	9.6	1.7
1.767	0.6	236	0.08	11	8.5	1.3
1.963	0.5	236	0.07	9.9	7.6	1.1
2.16	0.4	235	0.06	9	7	0.9
2.356	0.3	235	0.05	8.2	6.4	0.7

Table 36 Bit pressure drop data at 1500 lpm for SBBU-1 Design 5-7/8" hole section

At 1500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	42.5	1014	53.36	197.4	306	431.5
0.393	15.6	691	13.34	98.7	153	107.9
0.589	7.6	631	5.93	65.8	102	47.9
0.785	4.4	610	3.34	49.3	76.5	27
0.982	2.9	600	2.13	39.5	61.2	17.3
1.178	2	595	1.48	32.9	51	12
1.374	1.5	592	1.09	28.2	43.7	8.8
1.571	1.1	590	0.83	24.7	38.2	6.7
1.767	0.9	588	0.66	21.9	34	5.3
1.963	0.7	587	0.53	19.7	30.6	4.3
2.16	0.6	587	0.44	17.9	27.8	3.6
2.356	0.5	586	0.37	16.4	25.5	3

A.2.4. Hydraulic Simulation for SBBU-2 Design

A.2.4.1. Simulation results for 12-1/4 inch hole-section until 2700 meter.

Table 37 Internal and Annular pressure drop data for SBBU-2 Design 12-1/4" hole section

Flowrate	Pressure Drop (bar)												
(lpm)	11-3/4"CSG - 5-1/2"DP		12-1/4"OH - 5-1/2"DP		12-1/4"OH - 6-5/8"HWDP		12-1/4"OH - 8" DC		12-1/4"OH - 9-1/2" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
2500	21.7	4.1	32.5	4.1	0.5	0.4	6.7	0.3	8.2	0.6	69.6	9.5	79.1
3000	29.2	4.4	43.8	4.4	0.7	0.4	8.9	0.3	10.8	0.6	93.4	10.1	103.5
3125	31.2	4.4	46.8	4.4	0.7	0.4	9.5	0.3	11.6	0.6	99.8	10.1	109.9
3250	33.3	4.5	49.9	4.5	0.8	0.4	10.1	0.3	12.3	0.6	106.4	10.3	116.7
3375	28.2	4.6	42.3	4.6	0.8	0.4	10.7	0.3	13	0.6	95	10.5	105.5
3500	29.8	4.6	44.8	4.6	0.8	0.4	11.3	0.3	13.8	0.7	100.5	10.6	111.1
4000	36.7	4.9	55.1	4.9	1	0.4	13.9	0.3	17	0.8	123.7	11.3	135

Table 38 Annular Velocity data for SBBU-2 Design 12-1/4" hole section

Flowrate	Annular Velocity (m/s)				
(lpm)	11-3/4"CSG - 5-1/2"DP	12-1/4"OH - 5-1/2"DP	12-1/4"OH - 6-5/8"HWDP	12-1/4"OH - 8" DC	12-1/4"OH - 9-1/2" BHA
2500	0.92	0.7	0.78	0.96	1.37
3000	1.11	0.84	0.94	1.15	1.65
3125	1.16	0.87	0.98	1.19	1.72
3250	1.2	0.91	1.02	1.24	1.79
3375	1.25	0.94	1.06	1.29	1.86
3500	1.29	0.98	1.1	1.34	1.92
4000	1.48	1.11	1.26	1.53	2.2

Table 39 Bit pressure drop data at 3000 lpm for SBBU-2 Design 12-1/4" hole section

At 3000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	88.7	1460	73.64	394.7	917.9	1294.5
0.393	66.2	489	18.41	197.4	458.9	323.6
0.589	46.6	309	8.18	131.6	306	143.8
0.785	32.9	246	4.6	98.7	229.5	80.9
0.982	23.9	217	2.95	78.9	183.6	51.8
1.178	17.9	201	2.05	65.8	153	36
1.374	13.8	192	1.5	56.4	131.1	26.4
1.571	10.9	185	1.15	49.3	114.7	20.2
1.767	8.8	181	0.91	43.9	102	16
1.963	7.3	178	0.74	39.5	91.8	12.9
2.16	6.1	176	0.61	35.9	83.4	10.7
2.356	5.2	174	0.51	32.9	76.5	9
2.553	4.4	173	0.44	30.4	70.6	7.7
2.749	3.8	172	0.38	28.2	65.6	6.6

Table 40 Bit pressure drop data at 3500 lpm for SBBU-2 Design 12-1/4" hole section

At 3500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	90.3	1951	116.94	460.5	1249.3	1762
0.393	70	630	29.23	230.2	624.7	440.5
0.589	50.9	385	12.99	153.5	416.4	195.8
0.785	36.8	299	7.31	115.1	312.3	110.1
0.982	27.1	260	4.68	92.1	249.9	70.5
1.178	20.6	238	3.25	76.7	208.2	48.9
1.374	16	225	2.39	65.8	178.5	36
1.571	12.7	217	1.83	57.6	156.2	27.5
1.767	10.3	211	1.44	51.2	138.8	21.8
1.963	8.5	207	1.17	46	124.9	17.6
2.16	7.1	204	0.97	41.9	113.6	14.6
2.356	6.1	201	0.81	38.4	104.1	12.2
2.553	5.2	200	0.69	35.4	96.1	10.4
2.749	4.5	198	0.6	32.9	89.2	9

A.2.4.2. Simulation results for 8-1/2 inch hole-section until 4200 meter.

Table 41 Internal and Annular pressure drop data for SBBU-2 Design 8-1/2" hole section

Flowrate	Pressure Drop (bar)														
(lpm)	11-3/4"CSG - 5-1/2"DP		9-5/8"CSG - 5-1/2"DP		8-1/2"OH - 5-1/2"DP		8-1/2"OH - 5-1/2"HWDP		8-1/2"OH - 6" DC		8-1/2"OH - 6-3/4" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
1500	7.3	2.3	12.5	17.7	9.6	16.9	3.6	1	4.3	0.7	4.3	1.3	41.6	40.2	81.8
2000	11.2	2.6	19.1	19.6	14.6	18.2	5.6	1.1	6.7	0.8	6.7	1.6	63.9	44.2	108.1
2125	12.3	1.3	20.9	19.9	16	21.8	6.1	1.1	7.4	0.9	7.4	1.7	70.1	47.3	117.4
2250	21.2	1.3	36.1	19.3	27.6	24	6.7	1.1	8	0.9	8	1.9	107.6	49.2	156.8
2375	23.2	1.2	39.4	17.9	30.1	26.2	7.3	1	8.7	1	8.7	2.1	117.4	50.4	167.8
2500	25.2	1.2	42.9	17.5	32.8	28.5	7.9	0.9	9.5	1.1	9.5	2.2	127.8	52.7	180.5
3000	34	2.4	57.8	35.6	44.2	38.4	10.5	1.9	12.6	1.2	12.6	3	171.7	83.6	255.3

Table 42 Annular Velocity data for SBBU-2 Design 8-1/2" hole section

Flowrate	Annular Velocity (m/s)					
(lpm)	11-3/4"CSG - 5-1/2"DP	9-5/8"CSG - 5-1/2"DP	8-1/2"OH - 5-1/2"DP	8-1/2"OH - 5-1/2"HWDP	8-1/2"OH - 6" DC	8-1/2"OH - 6-3/4" BHA
1500	0.55	1.21	1.35	1.17	1.36	1.85
2000	0.74	1.61	1.8	1.57	1.81	2.47
2125	0.79	1.71	1.92	1.66	1.93	2.62
2250	0.83	1.81	2.03	1.76	2.04	2.77
2375	0.88	1.91	2.14	1.86	2.16	2.93
2500	0.92	2.01	2.25	1.96	2.27	3.08
3000	1.11	2.41	2.7	2.35	2.72	3.7

Table 43 Bit pressure drop data at 2000 lpm for SBBU-2 Design 8-1/2" hole section

At 2000 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	78.2	908	55.89	263.1	503.1	709.6
0.393	47.2	375	13.97	131.6	251.6	177.4
0.589	28.5	277	6.21	87.7	167.7	78.8
0.785	18.3	242	3.49	65.8	125.8	44.3
0.982	12.5	226	2.24	52.6	100.6	28.4
1.178	9.1	218	1.55	43.9	83.9	19.7
1.374	6.8	213	1.14	37.6	71.9	14.5
1.571	5.3	209	0.87	32.9	62.9	11.1
1.767	4.2	207	0.69	29.2	55.9	8.8
1.963	3.5	205	0.56	26.3	50.3	7.1
2.16	2.9	204	0.46	23.9	45.7	5.9
2.356	2.4	203	0.39	21.9	41.9	4.9

Table 44 Bit pressure drop data at 2500 lpm for SBBU-2 Design 8-1/2" hole section

At 2500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	79	1404	109.17	328.9	786.1	1108.7
0.393	48.4	573	27.29	164.5	393.1	277.2
0.589	29.4	419	12.13	109.6	262	123.2
0.785	19	365	6.82	82.2	196.5	69.3
0.982	13.1	340	4.37	65.8	157.2	44.3
1.178	9.4	326	3.03	54.8	131	30.8
1.374	7.1	318	2.23	47	112.3	22.6
1.571	5.5	313	1.71	41.1	98.3	17.3
1.767	4.4	309	1.35	36.5	87.3	13.7
1.963	3.6	306	1.09	32.9	78.6	11.1
2.16	3	305	0.9	29.9	71.5	9.2
2.356	2.5	303	0.76	27.4	65.5	7.7

A.2.4.3. Simulation results for 5-7/8 inch hole-section until 4700 meter.

Table 45 Internal and Annular pressure drop data for SBBU-2 Design 5-7/8" hole section

Flowrate	Pressure Drop (bar)																
(lpm)	11-3/4"CSG - 5-1/2"DP		9-5/8"CSG - 5-1/2"DP		7"CSG - 3-1/2"DP		5-7/8"OH - 3-1/2"DP		5-7/8"OH - 4"HWDP		5-7/8"OH - 4-1/4" DC		5-7/8"OH - 4-3/4" BHA		Total		
	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Int.	Ann.	Circ.
250	3.7	0.7	1.3	5.6	16	8.5	3.2	2.6	1.3	1.3	1.3	0.8	1.3	1.5	28.1	21	49.1
500	1.4	0.8	2.5	7.2	29.1	10.8	5.8	3.4	3	1.7	3.2	1.1	3.2	2.2	48.2	27.2	75.4
625	2.1	0.9	3.5	7.9	42	11.8	8.4	3.7	3.5	1.8	4.5	1.1	4.5	2.4	68.5	29.6	98.1
750	2.3	1	3.8	8.4	45.6	12.6	9.1	3.9	4.6	1.9	6	1.2	6	2.7	77.4	31.7	109.1
1000	3.5	1.1	6	9.3	71.2	14	14.2	4.3	7.2	2.3	9.3	1.5	9.3	3.3	120.7	35.8	156.5
1250	5	1.2	8.5	10.1	100.7	15.1	20.1	5.4	10.2	2.6	13.2	1.9	13.2	4.7	170.9	41	211.9
1500	6.6	0.7	11.3	10.7	133.7	16	26.7	7.2	13.6	3.5	17.5	2.5	17.5	6.2	226.9	46.8	273.7

Table 46 Annular Velocity data for SBBU-2 Design 5-7/8" hole section

Flowrate	Annular Velocity (m/s)						
(lpm)	11-3/4"CSG - 5-1/2"DP	9-5/8"CSG - 5-1/2"DP	7"CSG - 3-1/2"DP	5-7/8"OH - 3-1/2"DP	5-7/8"OH - 4"HWDP	5-7/8"OH - 4-1/4" DC	5-7/8"OH - 4-3/4" BHA
250	0.09	0.2	0.27	0.37	0.44	0.5	0.69
500	0.18	0.4	0.54	0.74	0.89	1	1.38
625	0.23	0.5	0.67	0.92	1.11	1.25	1.72
750	0.28	0.6	0.81	1.11	1.33	1.5	2.06
1000	0.37	0.8	1.08	1.47	1.78	2	2.75
1250	0.46	1.01	1.35	1.84	2.22	2.5	3.44
1500	0.55	1.21	1.62	2.21	2.66	3	4.13

Table 47 Bit pressure drop data at 750 lpm for SBBU-2 Design 5-7/8" hole section

At 750 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	42.5	254	6.67	98.7	76.5	107.9
0.393	15.6	173	1.67	49.3	38.2	27
0.589	7.6	158	0.74	32.9	25.5	12
0.785	4.4	153	0.42	24.7	19.1	6.7
0.982	2.9	150	0.27	19.7	15.3	4.3
1.178	2	149	0.19	16.4	12.7	3
1.374	1.5	148	0.14	14.1	10.9	2.2
1.571	1.1	148	0.1	12.3	9.6	1.7
1.767	0.9	147	0.08	11	8.5	1.3
1.963	0.7	147	0.07	9.9	7.6	1.1
2.16	0.6	147	0.06	9	7	0.9
2.356	0.5	147	0.05	8.2	6.4	0.7

Table 48 Bit pressure drop data at 1500 lpm for SBBU-2 Design 5-7/8" hole section

At 1500 lpm flowrate						
TFA	Bit P-drop	Pump Pressure	HP/sq.in	Jet Velocity	Jet Impact Force	P-Drop at bit
(inches)	(%)	(bar)	(HP)	(m/s)	(kg)	(bar)
0.196	55.6	777	53.36	197.4	306	431.5
0.393	23.8	453	13.34	98.7	153	107.9
0.589	12.2	393	5.93	65.8	102	47.9
0.785	7.3	372	3.34	49.3	76.5	27
0.982	4.8	362	2.13	39.5	61.2	17.3
1.178	3.4	357	1.48	32.9	51	12
1.374	2.5	354	1.09	28.2	43.7	8.8
1.571	1.9	352	0.83	24.7	38.2	6.7
1.767	1.5	350	0.66	21.9	34	5.3
1.963	1.2	349	0.53	19.7	30.6	4.3
2.16	1	349	0.44	17.9	27.8	3.6
2.356	0.9	348	0.37	16.4	25.5	3

A.3. Annular Velocity and Cuttings Concentration

A.3.1 At High Recommended Flow-Rate

Annular velocity and cutting concentration at high recommended flow-rate are given in table below. The calculations are made with ROP of 30 m/hour and cuttings slip velocity in water of 0.2 m/s (Skalle, 2011).

Table 49 cuttings concentration for each hole size based on the recommended high flow rate

Hole Size (inch)	Flowrate (lpm)	Flowrate (m^3/s)	q-cuttings (m^3/s)	c-cuttings
17.5	4500	0.075	0.00129	1.72%
12.25	3500	0.058	0.00063	1.09%
8.5	2500	0.042	0.00031	0.73%
5.875	1500	0.025	0.00015	0.58%

A.3.1.1. Standard Conventional Design

Table 50 Cuttings concentration for Conventional Design's 17-1/2" hole section with 4500 lpm

Conventional	**Flow: 4500 lpm**		
2700 meter	**Ann. Vel.**		
17-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
20"CSG - 5-1/2"DP	0.47	0.57	3.00%
17-1/2"OH - 5-1/2"DP	0.54	0.63	2.74%
17-1/2"OH - 6-5/8"HWDP	0.57	0.65	2.66%
17-1/2"OH - 8"DC	0.61	0.67	2.57%
17-1/2"OH - 9-1/2"BHA	0.69	0.71	2.43%
MAX	**0.69**		**3.00%**
MIN	**0.47**		**2.43%**

Table 51 Cuttings concentration for Conventional Design's 12-1/4" hole section with 3500 lpm

Conventional	**Flow: 3500 lpm**		
4200 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
13-3/8"CSG - 5-1/2"DP	0.96	0.79	1.37%
12-1/4"OH - 5-1/2"DP	0.98	0.80	1.37%
12-1/4"OH - 6-5/8"HWDP	1.1	0.82	1.33%
12-1/4"OH - 8"DC	1.34	0.85	1.28%
12-1/4"OH - 9-1/2"BHA	1.92	0.90	1.21%
MAX	**1.92**		**1.37%**
MIN	**0.96**		**1.21%**

Table 52 Cuttings concentration for Conventional Design's 8-1/2" hole section with 2500 lpm

Conventional	**Flow: 2500 lpm**		
4700 meter	**Ann. Vel.**		
8-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
9-5/8"CSG - 5-1/2"DP	2.01	0.90	0.81%
8-1/2"OH - 5-1/2"DP	2.25	0.91	0.80%
8-1/2"OH - 5-1/2"HWDP	1.96	0.90	0.82%
8-1/2"OH - 6"DC	2.27	0.91	0.80%
8-1/2"OH - 6-3/4"BHA	3.08	0.94	0.78%
MAX	**3.08**		**0.82%**
MIN	**1.96**		**0.78%**

A.3.1.2. FMC (Medium) Design

Table 53 Cuttings concentration for FMC Design's 12-1/4" hole section (2700 meter) with 3500 lpm

FMC (Medium)	**Flow: 3500 lpm**		
2700 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
14"CSG - 5-1/2"DP	0.84	0.76	1.43%
12-1/4"OH - 5-1/2"DP	0.98	0.80	1.37%
12-1/4"OH - 6-5/8"HWDP	1.1	0.82	1.33%
12-1/4"OH - 8"DC	1.34	0.85	1.28%
12-1/4"OH - 9-1/2"BHA	1.92	0.90	1.21%
MAX	**1.92**		**1.43%**
MIN	**0.84**		**1.21%**

Table 54 Cuttings concentration for FMC Design's 12-1/4" hole section (3500 meter) with 3500 lpm

FMC (Medium)	Flow: 3500 lpm		
4200 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
14"CSG - 5-1/2"DP	0.84	0.76	1.43%
11-3/4"CSG - 5-1/2"DP	1.29	0.84	1.29%
12-1/4"OH - 5-1/2"DP	0.98	0.80	1.37%
12-1/4"OH - 6-5/8"HWDP	1.1	0.82	1.33%
12-1/4"OH - 8"DC	1.34	0.85	1.28%
12-1/4"OH - 9-1/2"BHA	1.92	0.90	1.21%
MAX	**1.92**		**1.43%**
MIN	**0.84**		**1.21%**

Table 55 Cuttings concentration for FMC Design's 8-1/2" hole section with 2500 lpm

FMC (Medium)	Flow: 2500 lpm		
2700 meter	**Ann. Vel.**		
8-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
9-5/8"CSG - 5-1/2"DP	2.01	0.90	0.81%
8-1/2"OH - 5-1/2"DP	2.25	0.91	0.80%
8-1/2"OH - 5-1/2"HWDP	1.96	0.90	0.82%
8-1/2"OH - 6"DC	2.27	0.91	0.80%
8-1/2"OH - 6-3/4"BHA	3.08	0.94	0.78%
MAX	**3.08**		**0.82%**
MIN	**1.96**		**0.78%**

A.3.1.3. SBBU-1 Design and Tie-Back Option

Table 56 Cuttings concentration for SBBU-1 Design's 12-1/4" hole section with 3500 lpm

SBBU-1	Flow: 3500 lpm		
2700 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
13-3/8"CSG - 5-1/2"DP	0.96	0.79	1.37%
11-3/4"CSG - 5-1/2"DP	1.29	0.84	1.29%
12-1/4"OH - 5-1/2"DP	0.98	0.80	1.37%
12-1/4"OH - 6-5/8"HWDP	1.1	0.82	1.33%
12-1/4"OH - 8"DC	1.34	0.85	1.28%
12-1/4"OH - 9-1/2"BHA	1.92	0.90	1.21%
MAX	**1.92**		**1.37%**
MIN	**0.96**		**1.21%**

Table 57 Cuttings concentration for SBBU-1 Design's 8-1/2" hole section with 2500 lpm

SBBU-1	Flow: 2500 lpm		
4200 meter	**Ann. Vel.**		
8-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
9-5/8"CSG - 5-1/2"DP	2.01	0.90	0.81%
8-1/2"OH - 5-1/2"DP	2.25	0.91	0.80%
8-1/2"OH - 5-1/2"HWDP	1.96	0.90	0.82%
8-1/2"OH - 6"DC	2.27	0.91	0.80%
8-1/2"OH - 6-3/4"BHA	3.08	0.94	0.78%
MAX	**3.08**		**0.82%**
MIN	**1.96**		**0.78%**

Table 58 Cuttings concentration for SBBU-1 Design's 5-7/8" hole section with 1500 lpm

SBBU-1	Flow: 1500 lpm		
4700 meter	**Ann. Vel.**		
5-7/8" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
9-5/8"CSG - 5-1/2"DP	1.21	0.83	0.70%
7"CSG - 3-1/2"DP	1.62	0.88	0.67%
5-7/8"OH - 3-1/2"DP	2.21	0.91	0.64%
5-7/8"OH - 3-1/2"HWDP	2.66	0.92	0.63%
5-7/8"OH - 4"DC	3	0.93	0.62%
5-7/8"OH - 4-3/4"BHA	4.13	0.95	0.61%
MAX	**4.13**		**0.70%**
MIN	**1.21**		**0.61%**

Table 59 Cuttings concentration for SBBU-1 Tie Back option Design's 5-7/8" hole section with 1500 lpm

SBBU-1 Tie Back Option	Flow: 1500 lpm		
4700 meter	**Ann. Vel.**		
5-7/8" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
7"CSG - 3-1/2"DP	1.62	0.88	0.67%
5-7/8"OH - 3-1/2"DP	2.21	0.91	0.64%
5-7/8"OH - 3-1/2"HWDP	2.66	0.92	0.63%
5-7/8"OH - 4"DC	3	0.93	0.62%
5-7/8"OH - 4-3/4"BHA	4.13	0.95	0.61%
MAX	**4.13**		**0.67%**
MIN	**1.62**		**0.61%**

A.3.1.4. SBBU-2 Design

Table 60 Cuttings concentration for SBBU-2 Design's 12-1/4" hole section with 3500 lpm

SBBU-2	Flow: 3500 lpm		
2700 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
11-3/4"CSG - 5-1/2"DP	1.29	0.84	1.29%
12-1/4"OH - 5-1/2"DP	0.98	0.80	1.37%
12-1/4"OH - 6-5/8"HWDP	1.1	0.82	1.33%
12-1/4"OH - 8"DC	1.34	0.85	1.28%
12-1/4"OH - 9-1/2"BHA	1.92	0.90	1.21%
MAX	**1.92**		**1.37%**
MIN	**0.98**		**1.21%**

Table 61 Cuttings concentration for SBBU-2 Design's 8-1/2" hole section with 2500 lpm

SBBU-2	Flow: 2500 lpm		
4200 meter	**Ann. Vel.**		
8-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
11-3/4"CSG - 5-1/2"DP	0.92	0.78	0.94%
9-5/8"CSG - 5-1/2"DP	2.01	0.90	0.81%
8-1/2"OH - 5-1/2"DP	2.25	0.91	0.80%
8-1/2"OH - 5-1/2"HWDP	1.96	0.90	0.82%
8-1/2"OH - 6"DC	2.27	0.91	0.80%
8-1/2"OH - 6-3/4"BHA	3.08	0.94	0.78%
MAX	**3.08**		**0.94%**
MIN	**0.92**		**0.78%**

Table 62 Cuttings concentration for SBBU-2 Design's 5-7/8" hole section with 1500 lpm

SBBU-2	Flow: 1500 lpm		
4700 meter	**Ann. Vel.**		
5-7/8" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
11-3/4"CSG - 5-1/2"DP	0.55	0.64	0.92%
9-5/8"CSG - 5-1/2"DP	1.21	0.83	0.70%
7"CSG - 3-1/2"DP	1.62	0.88	0.67%
5-7/8"OH - 3-1/2"DP	2.21	0.91	0.64%
5-7/8"OH - 3-1/2"HWDP	2.66	0.92	0.63%
5-7/8"OH - 4"DC	3	0.93	0.62%
5-7/8"OH - 4-3/4"BHA	4.13	0.95	0.61%
MAX	**4.13**		**0.92%**
MIN	**0.55**		**0.61%**

A.3.2. At Low Recommended Flow-Rate

Annular velocity and cutting concentration at lower recommended flow-rate are given in table below. The calculations are made with ROP of 30 m/hour and cuttings slip velocity in water of 0.2 m/s.

Table 63 cuttings concentration for each hole size based on the recommended low flow rate

Hole Size (inch)	Flowrate (lpm)	Flowrate (m^3/s)	q-cuttings (m^3/s)	c-cuttings
17.5	4000	0.067	0.00129	1.94%
12.25	3000	0.050	0.00063	1.27%
8.5	2000	0.033	0.00031	0.92%
5.875	750	0.013	0.00015	1.17%

A.3.2.1 Standard Conventional Design

Table 64 Cuttings concentration for Conventional Design's 17-1/2" hole section with 4000 lpm

Conventional	Flow: 4000 lpm		
2700 meter	**Ann. Vel.**		
17-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
20"CSG - 5-1/2"DP	0.41	0.51	3.79%
17-1/2"OH - 5-1/2"DP	0.48	0.58	3.33%
17-1/2"OH - 6-5/8"HWDP	0.5	0.60	3.23%
17-1/2"OH - 8"DC	0.54	0.63	3.08%
17-1/2"OH - 9-1/2"BHA	0.58	0.66	2.96%
MAX	**0.58**		**3.79%**
MIN	**0.41**		**2.96%**

Table 65 Cuttings concentration for Conventional Design's 12-1/4" hole section with 3000 lpm

Conventional	Flow: 3000 lpm		
4200 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
13-3/8"CSG - 5-1/2"DP	0.82	0.76	1.68%
12-1/4"OH - 5-1/2"DP	0.84	0.76	1.66%
12-1/4"OH - 6-5/8"HWDP	0.94	0.79	1.61%
12-1/4"OH - 8"DC	1.15	0.83	1.53%
12-1/4"OH - 9-1/2"BHA	1.65	0.88	1.44%
MAX	**1.65**		**1.68%**
MIN	**0.82**		**1.44%**

Table 66 Cuttings concentration for Conventional Design's 8-1/2" hole section with 2000 lpm

Conventional	Flow: 2000 lpm		
4700 meter	**Ann. Vel.**		
8-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
9-5/8"CSG - 5-1/2"DP	1.61	0.88	1.05%
8-1/2"OH - 5-1/2"DP	1.8	0.89	1.03%
8-1/2"OH - 5-1/2"HWDP	1.57	0.87	1.05%
8-1/2"OH - 6"DC	1.81	0.89	1.03%
8-1/2"OH - 6-3/4"BHA	2.47	0.92	1.00%
MAX	**2.47**		**1.05%**
MIN	**1.57**		**1.00%**

A.3.2.2. FMC (Medium) Design

Table 67 Cuttings concentration for FMC Design's 12-1/4" hole section (2700 meter) with 3000 lpm

FMC	Flow: 3000 lpm		
2700 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
14"CSG - 5-1/2"DP	0.72	0.72	1.76%
12-1/4"OH - 5-1/2"DP	0.84	0.76	1.66%
12-1/4"OH - 6-5/8"HWDP	0.94	0.79	1.61%
12-1/4"OH - 8"DC	1.15	0.83	1.53%
12-1/4"OH - 9-1/2"BHA	1.65	0.88	1.44%
MAX	**1.65**		**1.76%**
MIN	**0.72**		**1.44%**

Table 68 Cuttings concentration for FMC Design's 12-1/4" hole section (4200 meter) with 3000 lpm

FMC	Flow: 3000 lpm		
4200 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
14"CSG - 5-1/2"DP	0.72	0.72	1.76%
11-3/4"CSG - 5-1/2"DP	1.11	0.82	1.55%
12-1/4"OH - 5-1/2"DP	0.84	0.76	1.66%
12-1/4"OH - 6-5/8"HWDP	0.94	0.79	1.61%
12-1/4"OH - 8"DC	1.15	0.83	1.53%
12-1/4"OH - 9-1/2"BHA	1.65	0.88	1.44%
MAX	**1.65**		**1.76%**
MIN	**0.72**		**1.44%**

Table 69 Cuttings concentration for FMC Design's 8-1/2" hole section with 2000 lpm

FMC	Flow: 2000 lpm		
4200 meter	**Ann. Vel.**		
8-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
9-5/8"CSG - 5-1/2"DP	1.61	0.88	1.05%
8-1/2"OH - 5-1/2"DP	1.8	0.89	1.03%
8-1/2"OH - 5-1/2"HWDP	1.57	0.87	1.05%
8-1/2"OH - 6"DC	1.81	0.89	1.03%
8-1/2"OH - 6-3/4"BHA	2.47	0.92	1.00%
MAX	**2.47**		**1.05%**
MIN	**1.57**		**1.00%**

A.3.2.3. SBBU-1 Design and Tie-Back Option

Table 70 Cuttings concentration for SBBU-1 Design's 12-1/4" hole section with 3000 lpm

SBBU-1	**Flow: 3000 lpm**		
2700 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
13-3/8"CSG - 5-1/2"DP	0.82	0.76	1.68%
11-3/4"CSG - 5-1/2"DP	1.11	0.82	1.55%
12-1/4"OH - 5-1/2"DP	0.84	0.76	1.66%
12-1/4"OH - 6-5/8"HWDP	0.94	0.79	1.61%
12-1/4"OH - 8"DC	1.15	0.83	1.53%
12-1/4"OH - 9-1/2"BHA	1.65	0.88	1.44%
MAX	**1.65**		**1.68%**
MIN	**0.82**		**1.44%**

Table 71 Cuttings concentration for SBBU-1 Design's 8-1/2" hole section with 2000 lpm

SBBU-1	**Flow: 2000 lpm**		
4200 meter	**Ann. Vel.**		
8-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
9-5/8"CSG - 5-1/2"DP	1.61	0.88	1.05%
8-1/2"OH - 5-1/2"DP	1.8	0.89	1.03%
8-1/2"OH - 5-1/2"HWDP	1.57	0.87	1.05%
8-1/2"OH - 6"DC	1.81	0.89	1.03%
8-1/2"OH - 6-3/4"BHA	2.47	0.92	1.00%
MAX	**2.47**		**1.05%**
MIN	**1.57**		**1.00%**

Table 72 Cuttings concentration for SBBU-1 Design's 5-7/8" hole section with 750 lpm

SBBU-1	Flow: 750 lpm		
4700 meter	**Ann. Vel.**		
5-7/8" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
9-5/8"CSG - 5-1/2"DP	0.6	0.67	1.75%
7"CSG - 3-1/2"DP	0.81	0.75	1.55%
5-7/8"OH - 3-1/2"DP	1.11	0.82	1.42%
5-7/8"OH - 3-1/2"HWDP	1.33	0.85	1.37%
5-7/8"OH - 4"DC	1.5	0.87	1.35%
5-7/8"OH - 4-3/4"BHA	2.06	0.90	1.29%
MAX	**2.06**		**1.75%**
MIN	**0.6**		**1.29%**

Table 73 Cuttings concentration for SBBU-1 Tie Back option Design's 5-7/8" hole section with 750 lpm

SBBU-1 Tie Back Option	Flow: 750 lpm		
4700 meter	**Ann. Vel.**		
5-7/8" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
7"CSG - 3-1/2"DP	0.81	0.75	1.55%
5-7/8"OH - 3-1/2"DP	1.11	0.82	1.42%
5-7/8"OH - 3-1/2"HWDP	1.33	0.85	1.37%
5-7/8"OH - 4"DC	1.5	0.87	1.35%
5-7/8"OH - 4-3/4"BHA	2.06	0.90	1.29%
MAX	**2.06**		**1.55%**
MIN	**0.81**		**1.29%**

A.3.2.4. SBBU-2 Design

Table 74 Cuttings concentration for SBBU-2 Design's 12-1/4" hole section with 3000 lpm

SBBU-2	Flow: 3000 lpm		
2700 meter	**Ann. Vel.**		
12-1/4" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
11-3/4"CSG - 5-1/2"DP	1.11	0.82	1.55%
12-1/4"OH - 5-1/2"DP	0.84	0.76	1.66%
12-1/4"OH - 6-5/8"HWDP	0.94	0.79	1.61%
12-1/4"OH - 8"DC	1.15	0.83	1.53%
12-1/4"OH - 9-1/2"BHA	1.65	0.88	1.44%
MAX	**1.65**		**1.66%**
MIN	**0.84**		**1.44%**

Table 75 Cuttings concentration for SBBU-2 Design's 8-1/2" hole section with 2000 lpm

SBBU-2	Flow: 2000 lpm		
4200 meter	**Ann. Vel.**		
8-1/2" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
11-3/4"CSG - 5-1/2"DP	0.74	0.73	1.25%
9-5/8"CSG - 5-1/2"DP	1.61	0.88	1.05%
8-1/2"OH - 5-1/2"DP	1.8	0.89	1.03%
8-1/2"OH - 5-1/2"HWDP	1.57	0.87	1.05%
8-1/2"OH - 6"DC	1.81	0.89	1.03%
8-1/2"OH - 6-3/4"BHA	2.47	0.92	1.00%
MAX	**2.47**		**1.25%**
MIN	**0.74**		**1.00%**

Table 76 Cuttings concentration for SBBU-2 Design's 5-7/8" hole section with 750 lpm

SBBU-2	Flow: 750 lpm		
4700 meter	**Ann. Vel.**		
5-7/8" Hole Section	**(m/s)**	**R-Transport**	**C-Cuttings**
11-3/4"CSG - 5-1/2"DP	0.28	0.29	4.08%
9-5/8"CSG - 5-1/2"DP	0.6	0.67	1.75%
7"CSG - 3-1/2"DP	0.81	0.75	1.55%
5-7/8"OH - 3-1/2"DP	1.11	0.82	1.42%
5-7/8"OH - 3-1/2"HWDP	1.33	0.85	1.37%
5-7/8"OH - 4"DC	1.5	0.87	1.35%
5-7/8"OH - 4-3/4"BHA	2.06	0.90	1.29%
MAX	**2.06**		**4.08%**
MIN	**0.28**		**1.29%**

B. Appendix B – Borehole Stability

B.1. Borehole Stability Theory

Rock formations that are located deep under the ground will have stresses acting on it. These in situ stresses consist of the overburden stress (σ_v), minimum horizontal stress (σ_h), and maximum horizontal stress (σ_H). After drilling a well through these formations, the borehole will have stresses acting on it. These stresses acting towards the borehole consist of tangential / hoop stress (σ_θ), axial stress (σ_z), radial stress (σ_r).

Stable borehole can be achieved if the stresses acting on the borehole are below limit and does not fulfill the failure criterion. Stability during drilling can be expressed as a relation between the stress acting on the borehole with the pressure supporting the borehole itself (Fjær et al., 2008). Considering an anisotropic horizontal stress field, the relationship can be described as:

$$\sigma_r = p_w \quad \text{(B.1)}$$

$$\sigma_\theta = \sigma_H + \sigma_h - 2(\sigma_H - \sigma_h)\cos 2\theta - p_w \quad \text{(B.2)}$$

$$\sigma_z = \sigma_v - 2\upsilon_{fr}(\sigma_H - \sigma_h)\cos 2\theta \quad \text{(B.3)}$$

The angle θ will be zero in the direction of the maximum horizontal stress (σ_H).

B.1.1. Failure Types

In general, there are three types of failure mechanism that a rock can experienced based on the stresses working on. These failure types are tensile failure, shear failure and compaction failure. In addition to these is the effect off fluid towards the stresses acting on the rock itself.

B.1.1.1. Tensile Failure

Tensile failure occurs when the effective tensile stress across a plane exceeds the tensile strength (T_0) limit. Effective stress is given by stress minus the pore pressure and the tensile strength is a characteristic property of the rock. Thus the failure criterion is expressed as

$$\sigma' = \sigma - p_f = -T_0 \quad \text{(B.4)}$$

In rocks exhibiting isotropic behavior, the condition for tensile failure will be fulfilled first for the lowest principle stress, the failure criterion then becomes

$$\sigma_3{}' = \sigma_3 - p_f = -T_0 \quad \text{(B.5)}$$

Pre-existing cracks which are oriented relatively normal to the direction of tensile stress, will have higher probability to originate tensile failure. Thus, tensile strength is very sensitive to the presence of cracks (Fjær et al., 2008).

B.1.1.2. Shear Failure

Shear failure occurs when the shear stress along some plane in the sample is sufficient to initiate faulting along the failure plane. Faulting will allow the two sides of the plane to move relative to each other in a frictional process governed by the force which push the bodies against each other. So the critical shear stress (τ_{max}), that allows occurrence of shear failure, depends on the normal stress acting over the failure plane (Fjær et al., 2008). This is expressed as:

$$|\tau_{max}| = f(\sigma') \qquad \text{(B.6)}$$

Various shear failure criteria had been obtained by choosing specific forms of the function, $f(\sigma')$.

B.1.1.3. Compaction Failure

Compaction failure commonly occurs in high porosity materials. This is when a material under a hydrostatic loading (compressed) exhibits pore collapse and/or grain crushing. Pore collapse shows re-orientation of the grain which allows the grains to fill the void space within the material. The other mechanism, grain crushing, shows that the grain are crushed and split into smaller grains which then fill the small void space within the materials. This compaction process, leads to a closer arrangement of the grains within the materials, resulting in a more compact material.

The compaction failure criterion is given by

$$\frac{1}{(1-\gamma)^2}\left(\frac{\bar{\sigma}'}{p^*}-\gamma\right)^2+\frac{1}{\delta^2}\left(\frac{q}{p^*}\right)=1 \qquad \text{(B.7)}$$

Where $\bar{\sigma}'$ is the mean effective stress,

$$\bar{\sigma}=\frac{\sigma_x+\sigma_y+\sigma_z}{3} \qquad \text{(B.8)}$$

q is a deviatoric stress invariant,

$$q=\sqrt{\frac{3}{2}[(\sigma_1-\bar{\sigma})^2+(\sigma_2-\bar{\sigma})^2+(\sigma_3-\bar{\sigma})^2]} \qquad \text{(B.9)}$$

p^* is a critical effective pressure (or crushing pressure), $\gamma(\approx 0.5)$ and $\delta(\approx 0.5-0.7)$ are constants.

Assuming $\gamma = 0$ and $\delta = 1$ are acceptable for many rocks, therefore the equations can be simplified,

$$(\bar{\sigma}')^2+q^2=(p^*)^2 \qquad \text{(B.10)}$$

Compared to tensile failure and unconfined shear failure, that leads to the lost of the load carrying capacity. The load carrying capacity will increase due to a denser structure formed after compaction failure (Fjær et al., 2008).

B.1.1.4. Fluid Effects

<u>Pore Pressure</u>

Terzaghi's definition relates pore pressure with effective stress, which appears to be relevant to be used in failure criteria. Under the assumption that the rock is linearly elastics, it is expressed as

$$\sigma' = \sigma - p_f \quad \text{(B.11)}$$

The effective stress, represent the forces transmitted through the frame of the rock, while the remaining stress is transmitted through the pore fluid. The effect of increasing pore pressure and keeping the total stresses constant will move the Mohr circles to the left, closer to the shear and tensile failure lines (Fjær et al., 2008).

Partial Saturation

Partial saturation with at least two immiscible fluids, where one is a wetting phase and the other is a no-wetting phase, produces a pressure difference called as capillary effect. This effect could be defined in a generalized effective stress.

$$\sigma' = \sigma - \alpha\left(p_{nw} - S_{we}p_{cp}\right) \quad \text{(B.12)}$$

p_{nw} is the pressure in the non-wetting fluid, S_{we} is the degree of saturation of the wetting fluid, and p_{cp} is the capillary suction pressure. This effect can be related to the intergranular cohesion of the rock that may have a large impact on the strength and stiffness of the rock (Fjær et al., 2008).

Chemical Effect

Over geological time, the pore water will reach a chemical equilibrium with the solid minerals contained in the rock. Disturbance to this equilibrium, such as an introduction of different fluid during drilling, could affect the rock properties. It has been observed that typically it will be a reduction of strength due to the deterioration of the cement (Fjær et al., 2008).

B.1.2. Borehole Shear Failure

Shear failures are the most critical to borehole stability. It occurs when the tangential (hoop) stress or the axial stress along the borehole axis is the maximum and the radial stress (well pressure) is the minimum (case a and case b).

This failure mechanism will be initiated at the borehole wall as it is where the shear stress is the highest (Fjær et al., 2008). There are three realistic cases for this failure mechanism.

Case a: $\sigma_\theta > \sigma_z > \sigma_r$

$$p_{w,min}^{(a)} = \frac{2\sigma_h - C_0 + p_f\left(\tan^2\beta - 1\right)}{\tan^2\beta + 1} \quad \text{(B.13)}$$

Case b: $\sigma_z > \sigma_\theta > \sigma_r$

$$p_{w,min}^{(b)} = \frac{\sigma_v - C_0 + p_f\left(\tan^2\beta - 1\right)}{\tan^2\beta} \quad \text{(B.14)}$$

Case c: $\sigma_z > \sigma_r > \sigma_\theta$

$$p_{w,max}^{(c)} = \frac{\left(2\sigma_h - p_f\right)\tan^2\beta - \left(\sigma_v - p_f\right) + C_0}{\tan^2\beta} \quad \text{(B.15)}$$

For the case of permeable borehole wall and a steady state pressure profile, then the criterion will relate with Mohr-Coulomb criterion. This will make the minimum effective stress at the borehole wall to be zero as the pore pressure is equal to the well pressure. Therefore, for case (a) and (b) it becomes,

$$p_{w,min}^{(a)} = \frac{2\sigma_h - C_0 - \alpha\frac{1-2v}{1-v}p_{f0}}{2-\alpha\frac{1-2v}{1-v}} \quad \text{(B.16)}$$

$$p_{w,min}^{(b)} = \frac{\sigma_v - C_0 - \alpha\frac{1-2v}{1-v}p_{f0}}{2-\alpha\frac{1-2v}{1-v}} \quad \text{(B.17)}$$

B.1.3. Borehole Tensile Failure

This failure mechanism will occur by two different ways. One would be at a high well pressure which leads to a negative effective tangential stress;

$$\sigma_\theta{}' = -T_0 \quad \text{(B.18)}$$

This high well pressure will lead to opening a path known with the term "fracturing". Fracture will open parallel to the maximum in situ horizontal stress (at $\theta = 0^o$ or 180^o). The fracturing pressure is expressed as,

$$p_{w,max}^{(frac)} = 3\sigma_h - \sigma_H - p_f + T_0 \quad \text{(B.19)}$$

Another way for a tensile failure mechanism is when the well pressure becomes lower than the pore pressure, so that the radial effective stress will be negative; $\sigma_r{}' = -T_0$. This failure mechanism will lead to the forming of sharp, blade-shaped cutting which falls from the borehole, and can normally be observed at the shaker (Fjær et al., 2008). This cutting breakouts mechanism is shown in figure 4.1 and the radial tensile failure pressure is expressed as,

$$p_{w,min}^{(rad,tens)} = p_f - T_0 \quad \text{(B.20)}$$

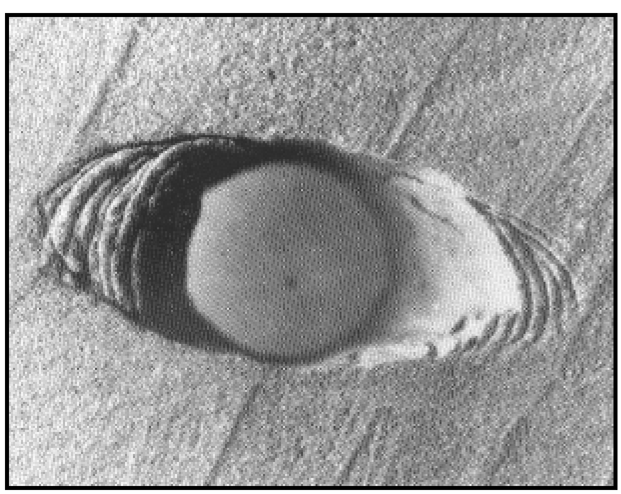

Figure B.1 Borehole breakout, as formed in a laboratory specimen of sandstone. (From Holt et al., 2008:Fig. 7.2, p.42)

B.1.4. Time Delayed Borehole Failure

Borehole failure may occur after time elapse due to various effects. Several effects discussed in this chapter are pore pressure equilibrium, temperature, creep and chemistry effect (rock-fluid interaction).

B.1.4.1. Pore Pressure Equilibrium

Overbalance drilling is generally used in to maintain the hydrostatic pressure above formation pressure. Over time, the overbalance condition and the permeability of the formation would cause gradual pressure equilibrium between the borehole wall and the well pressure. Based on the consolidation theory, the time τ_D is needed to reach pore pressure equilibrium after the well is drilled. This is given by,

$$\tau_D \approx \frac{l_D^2}{C_D} \qquad \text{(B.21)}$$

In this equation, l_D is the characteristic length and C_D is the diffusion coefficient, proportional to permeability.

Maintaining overbalance will increase the pore pressure near the borehole wall. It will reduce stability because the effective confinement (minimum effective principle stress) will approach zero as the pore pressure equilibrate. This will shift the Mohr-Coulomb circle towards the direction of the shear failure criterion, as illustrated in figure 4.2. In the case of drilling underbalance, the pore pressure will decrease over time and improve the stability with respect to borehole collapse (Fjær et al., 2008).

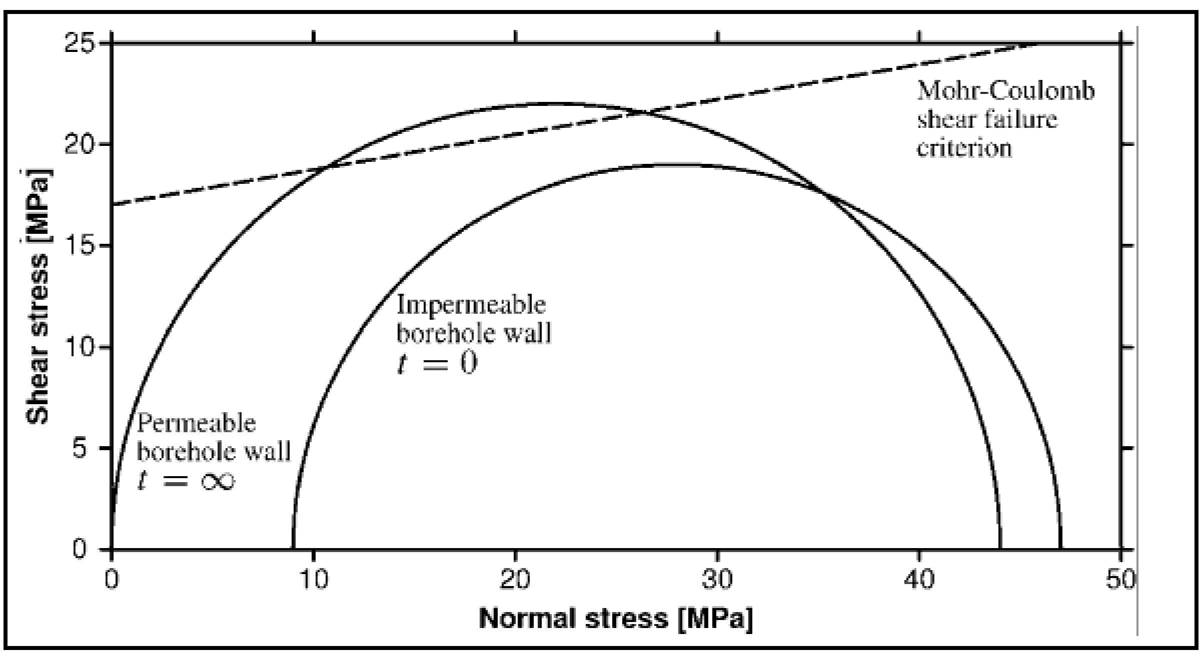

Figure B.2 Illustration of Mohr circle shifting to the left from initial condition (t = 0) until pore pressure reach equilibrium at (t = ∞). From (Fjær et al., 2008: Fig. 9.6, p. 321)

B.1.4.2. Temperature Effect

Temperature cycles occur as drilling fluid is circulating during drilling. The cool drilling fluid will help reduce the formation temperature at the borehole wall as it is in circulation (dynamic condition). But when the circulation stops, the formation temperature at the borehole wall will increase and stabilize with the in-situ formation temperature.

Decreasing the temperature will increase the strength and stiffness of the rock. Cooling will also reduce the tangential stress. Hence, reduces the risk of shear failure but promotes fracturing. For a low permeability rock like shale, cooling will influence the pore pressure. This is due to a larger thermal expansion coefficient for the fluid than for the solid part of the rock itself. The basic formula of thermoelasticity for the borehole wall is given by,

$$\sigma_r = p_w$$

$$\sigma_\theta = \sigma_H + \sigma_h - 2(\sigma_H - \sigma_h)\cos 2\theta - p_w + \frac{E_{fr}}{1-\upsilon_{fr}}\alpha_T(T_w - T_o) \qquad \text{(B.22)}$$

$$\sigma_z = \sigma_v - 2\upsilon_{fr}(\sigma_H - \sigma_h)\cos 2\theta + \frac{E_{fr}}{1-\upsilon_{fr}}\alpha_T(T_w - T_o) \qquad \text{(B.23)}$$

Measurements during drilling such as a Leak Off Test (LOT) will have to take account this cooling effect. Other advantages of this cooling effect are maintaining rheological properties of drilling mud, reduced wear and tear of equipment, extend the usage of MWD/LWD and other downhole tools to be used to drill deeper. These advantages are discussed further by Maury and Guenot (1995).

B.1.4.3. Creep

Every material which is brought above its yield point will creep to failure. Therefore, in a borehole situation, mud weight (well pressure) which kept above the lower limit (pore pressure) will cause the borehole to collapse due to creep. This phenomena is difficult to distinguish from the others are the testing for creep is time-consuming and complicated (Fjær et al., 2008).

B.1.4.4. Chemistry Effect (Shale Swelling)

Chemical interaction between drilling fluid and rock formation is a part of time-delayed failure phenomena. Shale, especially those from the smectite group, is of particular interest due to its ability to swell. Observations and statistics shows that instabilities tend to occur in association with this type of shale.

Clay swelling in shale formation will cause swelling pressure that will decrease the effective stress in shale, resulting in decreasing the mechanical stability. The swelling pressure is different from the pore pressure. The pore pressure is due to the hydrostatic pressure of the water which is located in the pores between different particles. The swelling pressure is the pressure from the interlayer water molecules inside smectite particles. These differences in pressure are illustrated in figure 5.1 and the effective stress (σ_{eff}) is given by,

$$\sigma_{eff} = \sigma_i - p_{pore} - p_{swell} \qquad \text{(B.24)}$$

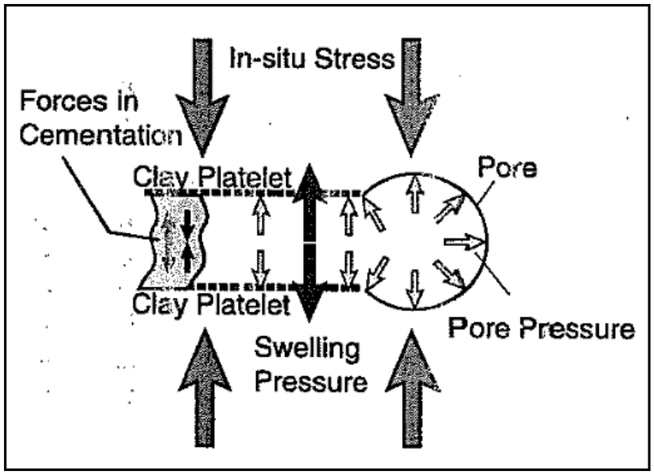

Figure B.3 A schematic representation of downhole forces acting on a shale system. From (van Oort, Eric., 2003: Fig. 2, p. 214)

Observations show that borehole will be more stable if drilled with oil based mud. This is due to a higher capillary pressure for a non-wetting fluid to enter the pores. A higher differential pressure is needed to overcome the capillary pressure to allow oil entering shale which is water wet. The capillary pressure (p_{cp}) is expressed by,

$$p_{cp} = \frac{2\gamma}{r} \qquad \text{(B.25)}$$

From the equation γ is the surface tension and r is the pore size. Fjær et al. (2008) illustrates the capillary effect by giving; $\gamma_{oil-water} = 50 \times 10^{-3}\ N/m$ and typical pore size of shale 10nm. This will give a capillary entry pressure of approximately 10MPa. However, despite the advantages, oil based mud is less preferred due to environmental reason. Therefore, the industry is pushing towards optimizing water based mud.

B.2. Radial and Tangential Stress at Static and Dynamic Condition

B.2.1. Radial Stress at Static Condition

Table 77 Radial Stress for Conventional Design under static condition

Radial Stress in Conventional Design					
17-1/2 inch Hole		**12-1/4 inch Hole**		**8-1/2 inch Hole**	
r (inch)	**(Mpa)**	**r (inch)**	**(Mpa)**	**r (inch)**	**(Mpa)**
0	39.69	0.00	76.15	0.00	92.12
1	40.72	1.00	76.94	1.00	92.21
2	41.48	2.00	77.46	2.00	92.26
3	42.05	3.00	77.81	3.00	92.29
4	42.50	4.00	78.07	4.00	92.31
6.25	43.19	8.88	78.67	10.75	92.36
16.25	44.35	18.88	79.00	20.75	92.37
41.25	44.83	43.88	79.13	45.75	92.38
91.25	44.96	93.88	79.17	95.75	92.38

Table 78 Radial Stress for FMC (Medium) Design under static condition

Radial Stress in FMC (Medium) Design					
12-1/4 inch Hole		**12-1/4 inch Hole**		**8-1/2 inch Hole**	
r (inch)	**(Mpa)**	**r (inch)**	**(Mpa)**	**r (inch)**	**(Mpa)**
0.00	39.69	0.00	76.15	0.00	92.12
1.00	41.08	1.00	76.94	1.00	92.21
2.00	41.98	2.00	77.46	2.00	92.26
3.00	42.61	3.00	77.81	3.00	92.29
4.00	43.06	4.00	78.07	4.00	92.31
8.88	44.11	8.88	78.67	10.75	92.36
18.88	44.68	18.88	79.00	20.75	92.37
43.88	44.92	43.88	79.13	45.75	92.38
93.88	44.98	93.88	79.17	95.75	92.38

Table 79 Radial Stress for SBBU-1 Design under static condition

Radial Stress in SBBU-1 Design					
12-1/4 inch Hole		8-1/2 inch Hole		5-7/8 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	39.69	0.00	76.15	0.00	92.12
1.00	41.08	1.00	77.19	1.00	92.24
2.00	41.98	2.00	77.78	2.00	92.29
3.00	42.61	3.00	78.14	3.00	92.32
4.00	43.06	4.00	78.37	4.00	92.33
8.88	44.11	10.75	78.94	7.06	92.36
18.88	44.68	20.75	79.09	22.06	92.38
43.88	44.92	45.75	79.16	47.06	92.38
93.88	44.98	95.75	79.17	97.06	92.38

Table 80 Radial Stress for SBBU-2 Design under static condition

Radial Stress in SBBU-2 Design					
12-1/4 inch Hole		8-1/2 inch Hole		5-7/8 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	39.69	0.00	76.15	0.00	92.12
1.00	41.08	1.00	77.19	1.00	92.24
2.00	41.98	2.00	77.78	2.00	92.29
3.00	42.61	3.00	78.14	3.00	92.32
4.00	43.06	4.00	78.37	4.00	92.33
8.88	44.11	10.75	78.94	7.06	92.36
18.88	44.68	20.75	79.09	22.06	92.38
43.88	44.92	45.75	79.16	47.06	92.38
93.88	44.98	95.75	79.17	97.06	92.38

B.2.2. Tangential Stress at Static Condition

Table 81 Tangential Stress for Conventional Design under static condition

Tangential Stress in Conventional Design					
17-1/2 inch Hole		12-1/4 inch Hole		8-1/2 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0	50.30	0.00	82.21	0.00	92.64
1	49.27	1.00	81.42	1.00	92.55
2	48.51	2.00	80.90	2.00	92.50
3	47.94	3.00	80.55	3.00	92.47
4	47.50	4.00	80.29	4.00	92.45
6.25	46.80	8.88	79.69	10.75	92.40
16.25	45.65	18.88	79.36	20.75	92.39
41.25	45.16	43.88	79.23	45.75	92.38
91.25	45.04	93.88	79.19	95.75	92.38

Table 82 Tangential Stress for FMC (Medium) Design under static condition

Tangential Stress in FMC (Medium) Design					
12-1/4 inch Hole		12-1/4 inch Hole		8-1/2 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	50.30	0.00	82.21	0.00	92.64
1.00	48.92	1.00	81.42	1.00	92.55
2.00	48.01	2.00	80.90	2.00	92.50
3.00	47.39	3.00	80.55	3.00	92.47
4.00	46.94	4.00	80.29	4.00	92.45
8.88	45.88	8.88	79.69	10.75	92.40
18.88	45.32	18.88	79.36	20.75	92.39
43.88	45.08	43.88	79.23	45.75	92.38
93.88	45.02	93.88	79.19	95.75	92.38

Table 83 Tangential Stress for SBBU-1 Design under static condition

Tangential Stress in SBBU-1 Design					
12-1/4 inch Hole		8-1/2 inch Hole		5-7/8 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	50.30	0.00	82.21	0.00	92.64
1.00	48.92	1.00	81.17	1.00	92.52
2.00	48.01	2.00	80.58	2.00	92.47
3.00	47.39	3.00	80.22	3.00	92.44
4.00	46.94	4.00	79.99	4.00	92.43
8.88	45.88	10.75	79.42	7.06	92.40
18.88	45.32	20.75	79.27	22.06	92.38
43.88	45.08	45.75	79.20	47.06	92.38
93.88	45.02	95.75	79.19	97.06	92.38

Table 84 Tangential Stress for SBBU-2 Design under static condition

Tangential Stress in SBBU-2 Design					
12-1/4 inch Hole		8-1/2 inch Hole		5-7/8 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	50.30	0.00	82.21	0.00	92.64
1.00	48.92	1.00	81.17	1.00	92.52
2.00	48.01	2.00	80.58	2.00	92.47
3.00	47.39	3.00	80.22	3.00	92.44
4.00	46.94	4.00	79.99	4.00	92.43
8.88	45.88	10.75	79.42	7.06	92.40
18.88	45.32	20.75	79.27	22.06	92.38
43.88	45.08	45.75	79.20	47.06	92.38
93.88	45.02	95.75	79.19	97.06	92.38

B.2.3. Radial Stress at Dynamic Condition

Table 85 Radial Stress for Conventional Design under dynamic condition

Radial Stress in Conventional Design					
17-1/2 inch Hole		12-1/4 inch Hole		8-1/2 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	40.00	0.00	77.49	0.00	97.83
1.00	40.97	1.00	77.93	1.00	95.95
2.00	41.69	2.00	78.22	2.00	94.90
3.00	42.23	3.00	78.42	3.00	94.25
4.00	42.64	4.00	78.56	4.00	93.83
6.25	43.30	8.88	78.90	10.75	92.82
16.25	44.39	18.88	79.08	20.75	92.54
41.25	44.84	43.88	79.15	45.75	92.42
91.25	44.96	93.88	79.17	95.75	92.39

Table 86 Radial Stress for FMC (Medium) Design under dynamic condition

Radial Stress in FMC (Medium) Design					
12-1/4 inch Hole		12-1/4 inch Hole		8-1/2 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	40.54	0.00	77.68	0.00	97.83
1.00	41.70	1.00	78.07	1.00	95.95
2.00	42.46	2.00	78.33	2.00	94.90
3.00	42.99	3.00	78.50	3.00	94.25
4.00	43.37	4.00	78.63	4.00	93.83
8.88	44.25	8.88	78.93	10.75	92.82
18.88	44.73	18.88	79.09	20.75	92.54
43.88	44.93	43.88	79.16	45.75	92.42
93.88	44.98	93.88	79.17	95.75	92.39

Table 87 Radial Stress for SBBU-1 Design with Tie Back option, under dynamic condition

Radial Stress in SBBU-1 Design						SBBU-1 Tie Back	
12-1/4 inch Hole		8-1/2 inch Hole		5-7/8 inch Hole		5-7/8 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	40.70	0.00	82.19	0.00	97.35	0.00	98.55
1.00	41.82	1.00	81.15	1.00	95.15	1.00	95.81
2.00	42.56	2.00	80.57	2.00	94.14	2.00	94.56
3.00	43.06	3.00	80.21	3.00	93.60	3.00	93.89
4.00	43.42	4.00	79.98	4.00	93.27	4.00	93.49
8.88	44.28	10.75	79.42	7.06	92.81	7.06	92.91
18.88	44.74	20.75	79.27	22.06	92.45	22.06	92.47
43.88	44.93	45.75	79.20	47.06	92.40	47.06	92.40
93.88	44.98	95.75	79.19	97.06	92.38	97.06	92.39

Table 88 Radial Stress for SBBU-2 Design under dynamic condition

Radial Stress in SBBU-2 Design					
12-1/4 inch Hole		8-1/2 inch Hole		5-7/8 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	40.75	0.00	81.29	0.00	96.80
1.00	41.86	1.00	80.56	1.00	94.84
2.00	42.58	2.00	80.15	2.00	93.94
3.00	43.08	3.00	79.90	3.00	93.46
4.00	43.44	4.00	79.74	4.00	93.17
8.88	44.29	10.75	79.35	7.06	92.76
18.88	44.74	20.75	79.24	22.06	92.44
43.88	44.93	45.75	79.20	47.06	92.40
93.88	44.98	95.75	79.18	97.06	92.38

B.2.4. Radial Stress at Dynamic Condition

Table 89 Tangential Stress for Conventional Design under dynamic condition

Tangential Stress in Conventional Design					
17-1/2 inch Hole		12-1/4 inch Hole		8-1/2 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	49.99	0.00	80.87	0.00	86.93
1.00	49.02	1.00	80.43	1.00	88.81
2.00	48.31	2.00	80.14	2.00	89.86
3.00	47.77	3.00	79.94	3.00	90.51
4.00	47.35	4.00	79.80	4.00	90.93
6.25	46.70	8.88	79.46	10.75	91.94
16.25	45.61	18.88	79.28	20.75	92.22
41.25	45.15	43.88	79.21	45.75	92.34
91.25	45.04	93.88	79.19	95.75	92.37

Table 90 Tangential Stress for FMC (Medium) Design under dynamic condition

Tangential Stress in FMC (Medium) Design					
12-1/4 inch Hole		12-1/4 inch Hole		8-1/2 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	49.45	0.00	80.68	0.00	86.93
1.00	48.29	1.00	80.29	1.00	88.81
2.00	47.53	2.00	80.03	2.00	89.86
3.00	47.01	3.00	79.86	3.00	90.51
4.00	46.63	4.00	79.73	4.00	90.93
8.88	45.74	8.88	79.43	10.75	91.94
18.88	45.26	18.88	79.27	20.75	92.22
43.88	45.06	43.88	79.20	45.75	92.34
93.88	45.01	93.88	79.19	95.75	92.37

Table 91 Tangential Stress for SBBU-1 Design with Tie Back option, under dynamic condition

Tangential Stress in SBBU-1 Design						SBBU-1 Tie Back	
12-1/4 inch Hole		8-1/2 inch Hole		5-7/8 inch Hole		5-7/8 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	49.29	0.00	76.17	0.00	87.41	0.00	86.21
1.00	48.17	1.00	77.21	1.00	89.61	1.00	88.95
2.00	47.44	2.00	77.79	2.00	90.62	2.00	90.20
3.00	46.93	3.00	78.15	3.00	91.16	3.00	90.87
4.00	46.57	4.00	78.38	4.00	91.49	4.00	91.27
8.88	45.71	10.75	78.94	7.06	91.95	7.06	91.85
18.88	45.26	20.75	79.09	22.06	92.31	22.06	92.29
43.88	45.06	45.75	79.16	47.06	92.36	47.06	92.36
93.88	45.01	95.75	79.17	97.06	92.38	97.06	92.37

Table 92 Tangential Stress for SBBU-2 Design under dynamic condition

Tangential Stress in SBBU-2 Design					
12-1/4 inch Hole		8-1/2 inch Hole		5-7/8 inch Hole	
r (inch)	(Mpa)	r (inch)	(Mpa)	r (inch)	(Mpa)
0.00	49.24	0.00	77.07	0.00	87.96
1.00	48.14	1.00	77.80	1.00	89.92
2.00	47.41	2.00	78.21	2.00	90.82
3.00	46.91	3.00	78.46	3.00	91.30
4.00	46.55	4.00	78.62	4.00	91.59
8.88	45.71	10.75	79.01	7.06	92.00
18.88	45.25	20.75	79.12	22.06	92.32
43.88	45.06	45.75	79.16	47.06	92.36
93.88	45.01	95.75	79.18	97.06	92.38

C. Drilling Time Planner

C.1. Drilling Time Planner for Standard Conventional Design

Table 93 Drilling Time Planner estimate for Standard Conventional Design

Planned Hours	ACTIVITY	
	36 inch HOLE SECTION (200 - 300 m) - 100 m hole	**Comments**
12	Make up 36 inch BHA.	
6	Position rig over well.	
17	Drill 36 inch hole to 300 MD.	
10	Displace to mud, disconnect suction hose, POOH.	
10	M/U PGB, 30 inch conductor, WH, RT & Guidepost.	
12	Run 30 inch conductor.	
12	Cement 30 inch conductor. POOH w/ landing string.	
3	L/D 36 inch BHA.	
82	**TOTAL DAYS 36 inch SECTIONS :**	**3.42**
	26 inch HOLE SECTION (300 - 1200 m) - 900 m hole	**Comments**
8	M/U 26 inch BHA. RIH.	
3	Drill shoe track to 300 m	
150	Drill 26 inch hole to 1200m.	
15	Circ. Hole clean. Flow check. POOH.	
9	R/U and run 20 inch casing to 1200 m MD.	
12	Cement 20 inch casing	
40	Run BOP and riser	
6	Test BOP	
3.5	L/D 26 inch BHA	
246.5	**TOTAL DAYS 26 inch SECTIONS :**	**10.27**
	17-1/2 inch HOLE SECTION (1200 - 2900 m) - 1700 m hole	**Comments**
6	M/U 17-1/2 inch BHA. RIH	
3	Displace to mud.	
8	Test casing. Drill shoe track. LOT.	
113	Drill 17-1/2 inch hole to 2900 m MD.	
10	Circ. Hole clean. Flow check. POOH.	
10	Pull Wear Bushing. Clean Wellhead.	
10	R/U and run 13-3/8 inch casing.	
12	Cement 13-3/8 inch casing. Set 13-3/8 inch S.A. Pressure test same. POOH & R/D equipment.	
172	**TOTAL DAYS 17-1/2 inch SECTIONS :**	**7.17**
	12-1/4 inch HOLE SECTION (2900 - 4400 m) - 1500 m hole	**Comments**

10	M/U 12-1/4 inch BHA. RIH.	
8	Test casing. Drill shoe track. LOT	
71	Drill 12-1/4 inch hole to 4400 m MD.	
15	Circ. Hole clean. Flow check. POOH	
8	Run logging / gyro	
10	Pull Wear Bushing. Clean Wellhead.	
14	R/U and run 9-5/8 inch casing	
14	POOH. R/D equipment. Set wear bushing	
3.5	L/D 12-1/4 inch BHA.	
153.5	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**6.40**
	8-1/2 inch HOLE SECTION (4400 - 4900 m) - 500 m hole	**Comments**
13	M/U 8-1/2 inch BHA. RIH.	
8	Test casing. Drill shoe track. LOT.	
17	Drill 8-1/2 inch hole to 4900 m MD.	
17	Circulate hole clean. Condition mud. Flow Check. POOH.	
4	L/D 8-1/2 inch BHA.	
15	R/U and run 7 inch liner. Circulate and set hanger.	
6	POOH w/ liner hanger running tool.	
5	Pull Wear Bushing. Clean Wellhead.	
40	Pull BOP	
125	**TOTAL DAYS 8-1/2 inch SECTIONS :**	**5.21**
	TOTAL WELL DAYS :	**32.46**

C.2. Drilling Time Planner for FMC (Medium) Design

Table 94 Drilling Time Planner estimate for FMC (Medium) Design

Planned Hours	ACTIVITY	
	36 inch HOLE SECTION (200 - 300 m) - 100 m hole	**Comments**
12	Make up 36 inch BHA.	
6	Position rig over well.	
17	Drill 36 inch hole to 300 MD.	
10	Displace to mud, disconnect suction hose, POOH.	
10	M/U PGB, 30 inch conductor, WH, RT & Guidepost.	
12	Run 30 inch conductor.	
12	Cement 30 inch conductor. POOH w/ landing string.	
3	L/D 36 inch BHA.	
82	**TOTAL DAYS 36 inch SECTIONS :**	**3.42**
	17-1/2 inch HOLE SECTION (300 - 1200 m) - 900 m hole	**Comments**
4.5	M/U 17-1/2 inch BHA. RIH.	
3	Drill shoe track to 300 m	
60	Drill 17-1/2 inch hole to 1200m.	
15	Circ. Hole clean. Flow check. POOH.	
6	R/U and run 14 inch casing to 1200 m MD.	
12	Cement 14 inch casing	
40	Run BOP and riser	
6	Test BOP	
3.5	L/D 17-1/2 inch BHA	
150	**TOTAL DAYS 17-1/2 inch SECTIONS :**	**6.25**
	12-1/4 inch HOLE SECTION (1200 - 2900 m) - 1700 m hole	**Comments**
8	M/U 12-1/4 inch BHA. RIH.	
3	Displace to mud.	
8	Test casing. Drill shoe track. LOT.	
81	Drill 12-1/4 inch hole to 2900 m MD.	
10	Circ. Hole clean. Flow check. POOH.	
10	Pull Wear Bushing. Clean Wellhead.	
10.5	R/U and run 11-3/4 inch liner.	
18.5	Cement 11-3/4 inch liner. Set 11-3/4 inch S.A. Pressure test same. POOH & R/D equipment.	
149	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**6.21**
	12-1/4 inch HOLE SECTION (2900 - 4400 m) - 1500 m hole	**Comments**
10.5	M/U 12-1/4 inch BHA. RIH.	
8	Test casing. Drill shoe track. LOT	
71	Drill 12-1/4 inch hole to 4400 m MD.	

15	Circ. Hole clean. Flow check. POOH	
8	Run logging / gyro	
10	Pull Wear Bushing. Clean Wellhead.	
14	R/U and run 9-5/8 inch casing	
14	POOH. R/D equipment. Set wear bushing	
3.5	L/D 12-1/4 inch BHA.	
154	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**6.42**
	8-1/2 inch HOLE SECTION (4400 - 4900 m) - 500 m hole	**Comments**
13	M/U 8-1/2 inch BHA. RIH.	
8	Test casing. Drill shoe track. LOT.	
17	Drill 8-1/2 inch hole to 4900 m MD.	
17	Circulate hole clean. Condition mud. POOH.	
4	L/D 8-1/2 inch BHA.	
15	R/U and run 7 inch liner. Circulate and set hanger.	
6	POOH w/ liner hanger running tool.	
5	Pull Wear Bushing. Clean Wellhead.	
40	Pull BOP	
125	**TOTAL DAYS 8-1/2 inch SECTIONS :**	**5.21**
	TOTAL WELL DAYS :	**27.50**

C.3. Drilling Time Planner for SBBU-1 Design

Table 95 Drilling Time Planner estimate for SBBU-1 Design

Planned Hours	ACTIVITY	
	36 inch HOLE SECTION (200 - 300 m) - 100 m hole	**Comments**
12	Make up 36 inch BHA.	
6	Position rig over well.	
17	Drill 36 inch hole to 300 MD.	
10	Displace to mud, disconnect suction hose, POOH.	
10	M/U PGB, 30 inch conductor, WH, RT & Guidepost.	
12	Run 30 inch conductor.	
12	Cement 30 inch conductor. POOH w/ landing string.	
3	L/D 36 inch BHA.	
82	**TOTAL DAYS 36 inch SECTIONS :**	**3.42**
	17-1/2 inch HOLE SECTION (300 - 1200 m) - 900 m hole	**Comments**
4.5	M/U 17-1/2 inch BHA. RIH.	
3	Drill shoe track to 300 m	
60	Drill 17-1/2 inch hole to 1200m.	
15	Circ. Hole clean. Flow check. POOH.	
6	R/U and run 13-3/8 inch casing to 1200 m MD.	
12	Cement 13-3/8 inch casing	
6	R/U to run 11-3/4 inch pre-installed liner. Liner suspended in WH.	
40	Run BOP and riser	
6	Test BOP	
3.5	L/D 17-1/2 inch BHA	
156	**TOTAL DAYS 17-1/2 inch SECTIONS :**	**6.50**
	12-1/4 inch HOLE SECTION (1200 - 2100 m) - 900 m hole	**Comments**
8	M/U 9-7/8 inch x 14 inch UR & BHA. RIH.	
3	Displace to mud.	
8	Test casing. Drill shoe track. LOT.	
43	Drill 9-7/8 inch x 14 inch hole to 2100 m MD.	
10	Circ. Hole clean. Flow check. POOH.	
10	Pull Wear Bushing. Clean Wellhead.	
25	R/U drillstring to run 11-3/4 inch pre-installed liner.	
12	Cement 11-3/4 inch PIL. Pressure test same. POOH & R/D equipment.	
119	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**4.96**
	12-1/4 inch HOLE SECTION (2100 - 2900 m) - 800 m hole	**Comments**
9	M/U 9-7/8 inch x 12-1/4 inch UR & BHA. RIH.	

8	Test casing. Drill shoe track. LOT.	
38	Drill 9-7/8 inch x 12-1/4 inch hole from 2100 to 2900 m MD.	
12	Circ. Hole clean. Flow check. POOH.	
10	Pull Wear Bushing. Clean Wellhead.	
10.5	R/U and run 9-5/8 inch casing.	
15.5	Cement 9-5/8 inch casing. Set 9-5/8 inch S.A. Pressure test same. POOH & R/D equipment.	
103	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**4.29**
	8-1/2 inch HOLE SECTION (2900 - 4400 m) - 1500 m hole	**Comments**
10.5	M/U 8-1/2 inch BHA. RIH.	
8	Test casing. Drill shoe track. LOT	
50	Drill 8-1/2 inch hole to 4400 m MD.	
15	Circ. Hole clean. Flow check. POOH	
8	Run logging / gyro	
10	Pull Wear Bushing. Clean Wellhead.	
14	R/U and run 7 inch liner	
14	Cement 7 inch liner. Pressure test same. POOH & R/D equipment.	
3.5	L/D 8-1/2 inch BHA.	
133	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**5.54**
	5-7/8 inch HOLE SECTION (4400 - 4900 m) - 500 m hole	**Comments**
13	M/U 5-7/8 inch BHA. RIH while P/U singles of 3-1/2 inch DP.	
8	Test casing. Drill shoe track. LOT.	
24	Drill 5-7/8 inch hole to 4900 m MD.	
17	Circulate hole clean. Condition mud. POOH.	
3.5	L/D 5-7/8 inch BHA.	
10	R/U and run 5 inch liner. Circulate and set hanger.	
6	POOH w/ liner hanger running tool.	
5	Pull Wear Bushing. Clean Wellhead.	
40	Pull BOP	
126.5	**TOTAL DAYS 8-1/2 inch SECTIONS :**	**5.27**
	TOTAL WELL DAYS :	**25.02**

C.4. Drilling Time Planner for SBBU-2 Design

Table 96 Drilling Time Planner estimate for SBBU-2 Design

Planned Hours	ACTIVITY	
	36 inch HOLE SECTION (200 - 300 m) - 100 m hole	**Comments**
12	Make up 36 inch BHA.	
6	Position rig over well.	
17	Drill 36 inch hole to 300 MD.	
10	Displace to mud, disconnect suction hose, POOH.	
10	M/U PGB, 30 inch conductor, WH, RT & Guidepost.	
12	Run 30 inch conductor.	
12	Cement 30 inch conductor. POOH w/ landing string.	
3	L/D 36 inch BHA.	
82	**TOTAL DAYS 36 inch SECTIONS :**	**3.42**
	12-1/4 inch HOLE SECTION (300 - 1200 m) - 900 m hole	**Comments**
4.5	M/U 12-1/4 inch BHA. RIH.	
3	Drill shoe track to 300 m	
60	Drill 12-1/4 inch hole to 1200m.	
15	Circ. Hole clean. Flow check. POOH. Rack-back BHA.	
6	R/U and run 11-3/4 inch liner to 1200 m MD.	
12	Cement 11-3/4 inch liner	
40	Run BOP and riser	
6	Test BOP	
146.5	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**6.10**
	12-1/4 inch HOLE SECTION (1200 - 2900 m) - 1700 m hole	**Comments**
8	M/U 12-1/4 inch BHA. RIH.	
3	Displace to mud.	
8	Test casing. Drill shoe track. LOT.	
81	Drill 12-1/4 inch hole to 2900 m MD.	
12	Circ. Hole clean. Flow check. POOH.	
10	Pull Wear Bushing. Clean Wellhead.	
10.5	R/U to run 9-5/8 inch liner.	
12	Cement 9-5/8 inch liner. Set 9-5/8 inch S.A. Pressure test same. POOH & R/D equipment.	
3.5	L/D 12-1/4 inch BHA.	
148	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**6.17**
	8-1/2 inch HOLE SECTION (2900 - 4400 m) - 1500 m hole	**Comments**
10.5	M/U 8-1/2 inch BHA. RIH.	
8	Test casing. Drill shoe track. LOT	
50	Drill 12-1/4 inch hole to 4400 m MD.	

15	Circ. Hole clean. Flow check. POOH	
8	Run logging / gyro	
10	Pull Wear Bushing. Clean Wellhead.	
14	R/U and run 7 inch liner	
14	POOH. R/D equipment. Set wear bushing	
3.5	L/D 8-1/2 inch BHA.	
133	**TOTAL DAYS 12-1/4 inch SECTIONS :**	**5.54**
	5-7/8 inch HOLE SECTION (4400 - 4900 m) - 500 m hole	**Comments**
13	M/U 5-7/8 inch BHA. RIH while P/U singles of 3-1/2 inch DP.	
8	Test casing. Drill shoe track. LOT.	
24	Drill 5-7/8 inch hole to 4900 m MD.	
17	Circulate hole clean. Condition mud. POOH.	
3.5	L/D 5-7/8 inch BHA.	
10	R/U and run 4 inch liner. Circulate and set hanger.	
6	POOH w/ liner hanger running tool.	
5	Pull Wear Bushing. Clean Wellhead.	
40	Pull BOP	
126.5	**TOTAL DAYS 8-1/2 inch SECTIONS :**	**5.27**
	TOTAL WELL DAYS :	**26.50**