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“LOW COST DEEP WATER WELLS”

by

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Abstract

A major cost-factor of drilling deep water wells today is associated with the high day rates of the larger rigs capable of drilling in such depths. Most subsea completions today are based on the 18-3/4" wellheads system. This wellhead size is normally required because of the number of casing strings needed to reach the down-hole target depth. Over the last two decades a number of different technologies have been developed to manage longer sections and to increase the drilling reach, especially in deep water. Some of these technologies are briefly described in this thesis, as well as a suggested alternative from the author. The Slim Wellhead Concept may be used to bring older 3^{rd} or 4^{th} generation rigs into the deep water market, achieving cost savings as well as possibilities to reach new water depths of exploration.

Questions being asked in this thesis:

- Is it possible to achieve cost saving in drilling by minor adjustments of technology?
- Is it possible to achieve new water depth records with the rigs and technology already available on the market today?

The conclusion of this thesis is that by using the slim wellhead concept with a 13-5/8" BOP and 16" marine riser can give significant savings in weight and requirement to capacities. With respect to variable deck load it is possible to achieve of up to 50% weight reduction for the BOP and 40% weight reduction for the slim drilling riser, valid for 1500 meters of water depth. The selection of a lighter BOP and a slim riser would give a total reduction of 500 tonnes or more to the deck load. The reductions of weight and requirements to capacities of the rigs can facilitate the use of smaller and less expensive drilling vessels.

The overall saving potential for a 1500 meters water depth well is found to be in excess of 40%. This number is based on a combination of lower day rate and shorter overall drilling time.

Additionally, it is demonstrated by extrapolation the present tension capacity on $5^{th}/6^{th}$ generation rigs will be sufficient to support a 16" marine riser in 4000 meter water depth.

Preface

The aim of the thesis is to provide the reader with an insight in how expensive the drilling cost of today's deep water exploration and drilling operations can be, and the alternatives to reduce this cost. The driving cost-factors of the drilling projects are associated with the rig's high day rates. Performing deep water operations, the use of a 5th or 6th generation rig is the only possible opportunity to meet the requirement to capacity needed in such depths. By modifying smaller and older rigs, it may be possible to perform drilling operations of deep water wells with a considerable lower project cost than today. Furthermore, the opportunities for exploring new water depths by using the technology presented in the thesis will be explored.

The objectives of this thesis are to:

1) Firstly, evaluate the potential of a reduced wellhead size from 18-3/4" to 13-5/8" on the requirements to riser tension capacity, variable deck load capability, mud volume and operating water depth.
2) Secondly, evaluate the potential of an increase in water depth capacity by reduction of the wellhead and riser size.

Acknowledgement

I am grateful to all the people and companies that helped me with their knowledge and expertise of the technology presented in this thesis. I owe a special debt of gratitude to Professor Arnfinn Nergaard at the University of Stavanger for using his valuable time in advising me during the process. Also, Professor Nergaard is thanked for giving me this interesting thesis. The research and study for this thesis brought me in contact with new acquaintances in several companies, where I now have a broader engineering network of people within different fields. Working with this thesis gave me a better understanding of the concept of well design and drilling technology.

I wish to thank both Heidi Kvamme and Inger Gåsemyr at the University library of Stavanger to help me financially with a licence to the online database RigLogix. Furthermore, I would like to thank David Theiss (Cameron) for contributing with his knowledge during the whole study process. Mr Theiss is an expert within BOP, drilling and casing systems. I would like to acknowledge Kurt Mikalsen, Gregor Campbell (Baker Hughes) and Harald Hufthammer (IKM Cleandrill) for contributing with their expertise within mud systems. Also, thanks to Kjetil Hausken (Trelleborg) for his contribution of information about riser joints and flotation modules. I wish to extend a thank to Kjetil Abbedissen (CEO of International Drilling Service, I-DS) for contributing from his field of experience in tensioning systems, drilling and trip time of slim wells. Thanks to my colleagues Frode Tjelta and Benjamin Lung-Tze Liew, as well as Mr Abbedissen (I-DS), for their comments and corrections of the thesis and final result.

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Stavanger

John Normann Gundersen — June 15th 2012

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Abbreviation

API	American Petroleum Institute
BHA	Bottom Hole Assembly
BOP	Blowout Preventer
C&K	Choke and Kill
DD	Drilling Depth (seabed to bottom of well)
GOM	Gulf of Mexico
HP	Horse Power
HPHT	High Pressure, High Temperature
LMRP	Lower Marine Riser Package
M/U	Make Up
MN	Mega Newton
MODU	Mobile Offshore Drilling Unit
OBM	Oil Base Mud
POOH	Pulling out of Hole
R/D	Rig Down
R/U	Rig Up
RIH	Running in Hole
RKB	Rotary, Kelly, Bushing
ROP	Rate of Penetration
SG	Specific Gravity
TD	Total Depth (WD + DD)
USD	US Dollars
WBM	Water Base Mud
WD	Water Depth (surface to seabed)
WH	Wellhead
WOC	Waiting on Cement
WP	Working Pressure

Glossary[1]

Active pit: A large tank that contains the drilling fluid on the rig. The fluid is circulating in loop into the borehole during the drilling process. Synonymous of active pit is active mud tank. The word "active" is used since it is that certain fluid or mud that is currently being circulated.

Conductor pipe: A short string of large diameter. The string is usually put into the well first, where it prevents the hole from caving into the wellbore.

Intermediate casing: Is installed after the surface casing is set in place. Provide protection against caving and seals off weak zones from abnormal formation pressures or heaving shales, as well as minimizing the hazards related to loss of circulating zones.

Liner: A relative short casing string that does not extend up into another casing string to the top of the wellbore, but is suspended from the inside of the previous casing string. The advantage of a liner is that it is a substantial saving in steel, and could therefore save capital cost of the well.

Liquid mud: A fluid that is circulated through the wellbore and bringing the drill cuttings to surface. Other functions are to provide a hydrostatic barrier, lubrication and cooling for the drill bit. Synonymous of liquid mud is drilling fluid or drilling mud.

Make up: To assemble parts by screw together two pieces to from a complete unit. I.e. connect two drill string, two riser or two casing joints.

Rotary, Kelly, Bushing**:** Kelly bushing (KB) is an adapter that serves to connect the rotary table to the kelly. The kelly bushing is designed so that it is free to move up or down the through the rotary table. Depth measured is commonly referenced to the KB, i.e. 2000m KB, meaning 2000 meters below the kelly bushing.

Sack: A sack contains cement. Sack could be synonymous with a bag, i.e. a bag of cement. A sack is a unit of measure and refers to the amount that occupies a bulk volume of 0.028 m^3 (1 ft^3). One sack weighs about 43 kilograms (94 pounds).

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[1] Source: SCHLUMBERGER. 2012. *The Oilfield Glossary: Where the Oil Field Meets the Dictionary* [Online]. Schlumberger. Available: www.glossary.oilfield.slb.com [Accessed 24.05 2012].

Stand: Two or three pipe joints screwed together during a tripping operation. The drillpipe is racked in the derrick during trip. One joint of pipe is about 9 meters. When two joints are screwed together to a stand it's called "doubles", if the stand includes three joints it's called "trebles". One usual stand length is about 27 meters (90 ft.), i.e. "trebles".

Surface casing: A string of casing set in place after the conductor pipe. Prevent the loose formations from caving in, seals off weak zones and give a firm base for installation of the BOP stack. The surface casing also provides the structural strength so that the following intermediate casings may be suspended inside the top of the surface casing.

Surge: An increase in pressure downhole that occur when the drillstring is lowered too fast in the hole. It may also occur when the mud pump is brought up to speed after starting.

Swab: When the drillstring is pulled out of the hole, the reservoir fluid has to flow downwards. If the drillstring is lifted upwards too fast, a drop in pressure would occur in the drilling mud below the bit. Swabbing is a risk factor and is harmful in drilling operation where kicks may occur.

Tripping: Hoisting the drill string out of the wellbore or replacing it in the wellbore is called tripping. Tripping is carried out when the bit is worn out and must be replaced.

Unit Conversion[2]

Multiply	Unit	by	to obtain	SI Unit
barrels	bbl.	0.1589	cubic meters	m^3
cubic feet	$ft.^3$	0.0283	cubic metres	m^3
feet	ft.	0.3048	meters	m
horsepower	hp	0.7457	kilowatts	kW
inches	in.	0.0254	meters	m
kip per square inch	ksi	6.89E+06	Pascal	Pa
kips (1000 pounds)	kips	4.45E+03	Newton	N
pound-force per square inch	psi	0.0689	bars	bar
pounds	lb.	0.4536	kilograms	kg
pounds per gallon	ppg (lb./gal)	119.82	kilograms per cubic metre	kg/m^3
pounds per gallon	ppg (lb./gal)	0.1198	specific gravity	SG (kg/l)

[2] Source: GABOLDE, G. & NGUYEN, J.-P. 1999. *Drilling data handbook,* Paris, Éditions Technip.

1.0 Introduction

1.1 Objective

1) Evaluation of reduction potential of reduced wellhead size from 18-3/4" to 13-5/8" on overall requirements to rig.
2) Evaluation of potential increase in water depth capacity by reduction of the wellhead size.

A basic assumption for the first evaluation is a water depth of 1500 meters and a drilling depth of 3500 meters, with a resulting total depth of 5000 meters.

1.2 Limitations

In this thesis the possibility of reducing the requirement to a rig has been investigated. By reducing the rig requirement one can use smaller and older rigs to perform the same drilling operations as the new and larger rigs when it comes to operations in deep water. Only semi-submersibles from 2nd to 6th generation have been considered in this thesis.

The water depth considered is 1500 meters and the drilling depth is 3500 meters. The total depth considered is 5000 meters, and the in-depth analysis will be based on these assumptions. Variations will be discussed but not thoroughly analysed.

The calculation performed on the riser is done by simplifications where the riser joints are seen as straight pipes, flanges, telescope, pup and flex joints being neglected.

There are several factors involved when it comes to storage of different equipment on the platform deck. Because of the weight and size of 1500 meters of riser equipment, it is assumed that mud and casing strings are stored and transported by supply vessels, therefore not being part of any variable deck load (VDL) analysis.

The weather situation considered is limited to normal days when the supply vessels can be operated without any problems.

The HPHT (high pressure, high temperature) wells are not considered in the thesis as they require special competence and equipment.

1.3 Background

The cost of drilling in deep water (defined by API as beyond 600 meters) is very high. The high cost of building a new generation rig which is able to drill in such water depths is associated with the high day rates. A substantial part of the VDL capacity is driven by the size of the marine riser and associated systems. Large risers for deep water require sufficient weight and riser storage capacity. These variables are dominated by the selected size of marine drilling riser.

The aim of the thesis is to present a new slim wellhead concept where a small drilling riser and a new casing program with fewer casing strings in combination with a smaller and lighter BOP stack is used. If the benefit of this concept can be realized, a lower requirement to the rig's hoisting system, tensioning system, storage space and deck load capacity could be achieved. This is all factors which will make it possible to use smaller and older rigs.

There are companies today that are proposing new technologies that bring solutions that might reduce the required capacity of the rig. Some of the technologies presented as a potential cost-reduction solution are:

- Managed Pressure Drilling
- Expandable Casing
- Dual Gradient Drilling
- Riserless Drilling

These types of technology solutions are not treated in this thesis. These are technologies that are generally developed to extend sections to be drilled, however, this also implies that many wells can be drilled with fewer casings and thereby enable the reduction of the wellhead size. This thesis deals with the rig related to potential savings related to downscaling of wellhead and riser dimensions.

The key factor of a slim wellhead concept is as mentioned the ability to use an existing available smaller rig to drill subsea wells. The smaller rig would not be capable of drilling wells in deep water with a large bore riser system because it lacks the VDL capacity and riser tensioning capacity. Use of the slim wellhead system enables the rig to drill wells in deeper water. This is a great advantage for the operators because it will increase the number of available rigs capable of drilling the deeper water wells, with a substantially lower day rate. This is also an advantage for the owners of the smaller rigs because it allows them to market their rig in the deeper water market.

1.4 Research Methodology

Because this thesis was not a straight-forward theoretical thesis, most of the information needed could not be found in text books. The research methodology required gathering information and data from three main sources: conference papers, personal communication and discussion with field experts from the industry and a database to collect up-to-date rig information. The gathered information and data was constantly compared with several experts' opinion to make sure that this was as correct as possible during the process, and then presented as a full and understanding overall picture on how it works in field practice.

1.5 State Of The Art

Subsea wells today are mostly based on 18-3/4" wellheads. This wellhead size is normally required because of the number of casing strings needed to reach the down-hole target depth. Over the last two decades a number of different technologies have been developed to manage longer sections and to increase the drilling reach, especially in deep water. These technologies might also be applied for reducing the number of casing strings for a given target depth. Aggressively using the new technologies might possibly reduce the necessary wellhead size from 18-3/4" to 13-5/8" for subsea production wells (Nergaard, 2012).

The thesis will highlight the potential advantages from reducing the subsea wellhead size from 18-3/4" to 13-5/8" by presenting and comparing technologies available, which can contribute to generally reduce cost and perhaps make it possible to explore in deeper water than what is possible today.

1.5.1 Past, Present and Future

Drilling for oil and gas has come a long way in the last 60 years. Back in the early 1950's in the Gulf of Mexico (GOM), shallow water wells were drilled from fixed structures, often with land in sight. The history of drilling technology has not been developed in a linear progression, but enormous technological advances have been done. Starting in the early 60's with drilling in shallow water with an operating water depth of 150 meter, and culminating with today's technology which is capable of drilling in ultra-deep waters with an operating water depth of 3000 meters or more (Nergaard, 2010). The latest world record for deep water drilling was set by Transocean's drillship *Dhirubhai Deepwater KG2*, April 11th 2011, with an operating water depth of 3107 meters (Transocean, 2011).

The definition "offshore" appeared in the 40's when the rig's location got beyond the sight of land. The first offshore well was drilled in the 1947, located off the Louisiana coast, and had a water depth of 3 meters (OSC, 2010).

The first generation of semi-submersible was developed in the early 60's and could drill in an operating water depth of about 150 - 200 meters. By the late 1960's the second generation started to appear, and had a water depth capacity of 300 meters and an operational displacement up to 20000 tons. Around the early 80's the third generation was developed with a water depth capability of about 500 meters. Fourth generation appeared in the 1990's and had a water depth of 1000 meters and an operational displacement of 35000 tons. In the late 1990's the fifth generation semis where developed which could reach water depths of up to 2500 meters. Sixth generation are the latest and arrived in 2008. These rigs have an operating water depth up to 3000 meters or more, with a displacement of 50000 tons. In other words, a new generation semi-submersibles was developed almost each decade (Nergaard, 2010).

Presently, the progression in water depth capability has nearly stopped. During the last ten years the record in operational water depth has been around 3000 meters. The cost of reaching these water depth records is becoming very high. So, is it possible to reach unexplored depths in the nearest future? Is it possible to even reach as far as 4000 meters of water depth within the next ten years?

1.5.2 History of the Slim Wellhead

The slim wellhead concept had its appearance already in the 60's and therefore it must not be considered as an all new concept presented in this thesis. In the late 60's and early 70's it was in fact the primary methodology used in the Santa Barbara Channel when about 80 wells were drilled by four mobile offshore drilling unit (MODU) by using a single 13-5/8" BOP stack with a 16" riser. But during the 1970's, the usage of the slim wellhead concept nearly stopped, where the large bore system that is known today became more desirable to use – the conventional wellhead system with the 18-3/4" BOP and the 21" riser. Development in maximum drilling depths slowed down with consequences for exploration (Childers and Quintero, 2004).

With today's knowledge of the slim wellhead concept, drillers may have more confidence in the selection of a slim concept of some sort, where it is generally agreed that the usage of this type of a concept is a major cost saving alternative. Perhaps it is one of few alternatives to go for in the future if one is going to be able to reduce cost on deep water operations as well as exploration and development in greater depths then today.

1.5.3 50 Years Development of Rig Capacity

Semi-submersibles have had 50 years of development. Equipment and capacity have large increase when comparing the rig specifications on those built back in the 60's and the present built 6th generation semis. The items listed in Table 1 are factors affecting the cost of drilling, and list the average capacities of the semi-sub generations of interest for this thesis. The day rates are averaged numbers valid at present.

Table 1 - Factors affecting drilling cost (RigLogix, 2012)

Semi-Submersible Generation					
	2nd	3rd	4th	5th	6th
Variable Deck Load (tonnes)	2 900	3 400	4 500	6 100	8 000
Hoisting Capacity (tonnes)	530	570	680	860	970
Tensioning Capacity (MN)	2,9	3,6	6,1	12,6	13,8
Liquid Mud Capacity (m^3)	430	460	970	1 760	2 470
Mud Pump Capacity (HP)	4 500	4 600	5 200	8 100	8 900
Sack Storage (m^3)	120	150	170	230	240
Operating Displacement (tonnes)	22 000	27 000	36 000	41 000	50 000
Day Rate (USD)	270 000	300 000	370 000	450 000	500 000

Today, drilling units able of working in deep water are generally equipped with heavy duty drilling equipment, and thereby has its cost. Comparison between the 2nd and 6th generation rig shows that the day rate is almost doubled from the 2nd generation. Of course, a 2nd/3rd generation rig cannot operate the water depth that's possible by the larger 5th/6th generation rigs, unless changes are made. The requirements of rig specification are largely driven by the marine riser and the well operation. Requirement to mud storage, riser storage and tensioning are all influencing the variable deck load, which can be reduced by introducing new alternatives for drilling operations. If new technology is possible to use, usage of smaller rigs on deep water project may be possible. Figure 1 shows some rigs from each of the generation presented in Table 1. Figure 2 illustrates the market share of rig generations.

Figure 1 - Semi-Submersibles of Generations (RigLogix, 2012)

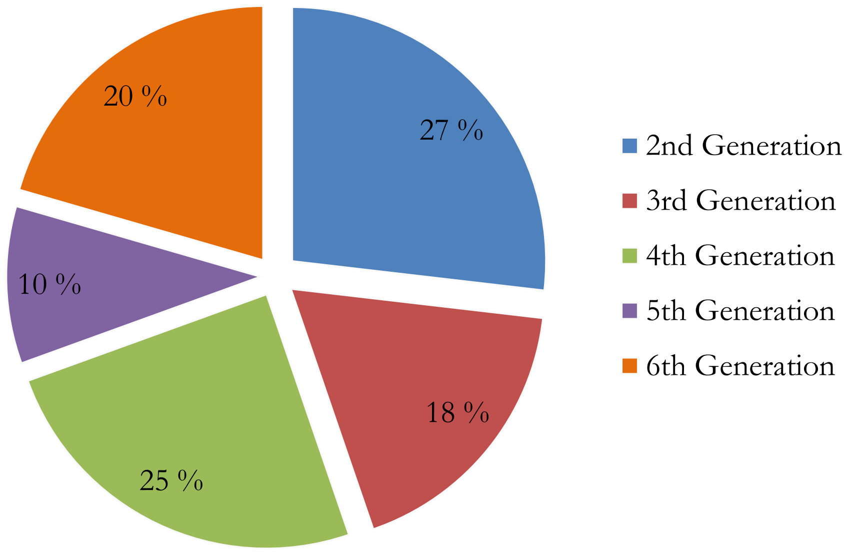

Figure 2 - Generation Share of the Market (RigLogix, 2012)

1.6 Structure of Thesis

The thesis starts out with presenting the background for the work and looking briefly at the history of drilling and development of rig capacities. In chapter 2 an evaluation of reduction potential of reduced wellhead size from 18-3/4" to 13-5/8" on overall requirements to rig is presented. A typical conventional wellhead system is presented, followed by a brief presentation of new technologies and concepts within drilling operation. Furthermore, the author's suggestion of a new concept is presented, namely the slim wellhead concept. The consequences of the concept are discussed, where it's been focused on some components and parts of the rig that may be influenced by the changes made from the new concept. In chapter 3, the potential of an increase in water depth capacity is presented, where it's been looked into what depth of exploration the oil industry may reach in the future by using one of the largest semi-submersibles available on the market today combined with the slim well concept presented in chapter 2. In the final chapters, the conclusion is given based on the result, as well as recommendation for further work on the slim wellhead concept.

2.0 Objective 1

This chapter looks into the potential of a cost reduction when reducing the conventional wellhead size from 18-3/4" to 13-5/8" on overall requirements to rig, where the conventional wellhead system is presented, followed by a brief presentation of new technologies within drilling operation, as well as the new concept named the slim wellhead concept.

2.1 Conventional Casing Program

In this chapter a conventional casing program is presented. This is the base case, and afterwards a casing program, which can lead to usage of older generation semis and thereby reduce operating costs, is presented. It is defined in this thesis as the *slim wellhead concept*, which includes usage of a 13-5/8" BOP and a 16" marine riser.

Casings are used to seal off well sections and to be structural foundations for the well. These are used to maintain integrity for the production life of the well. As a new section of the well is drilled, a new casing string that has a smaller diameter and higher pressure rating than the previous one is run. The conventional casing program used today in deep wells could include half a dozen different types of casing. Table 2 shows a conventional casing program with its typical hole and casing sizes (McCrae, 2003).

Table 2 - Typical hole and casing size

Casing string	Casing size	Hole size
Conductor	30"	36"
Surface	20"	26"
1st Intermediate	13-3/8"	17-1/2"
2nd Intermediate	9-5/8"	12-1/4"
Liner	7"	8-1/2"

The smaller strings are run through the wellhead and being hung off in the wellhead housing. The wellhead size selected for this typical casing program is the 18-3/4", and is the most common size used today. Figure 3 illustrates the casing program with a total depth of 5000 meters. With this wellhead size, the requirement to the drilling riser is that it has to have a greater inner diameter (ID) than 18-3/4", so a riser with 21" outer diameter (OD) is selected, leaving enough margin for the variable riser wall thickness that may be needed for deeper waters (Chakrabarti, 2005).

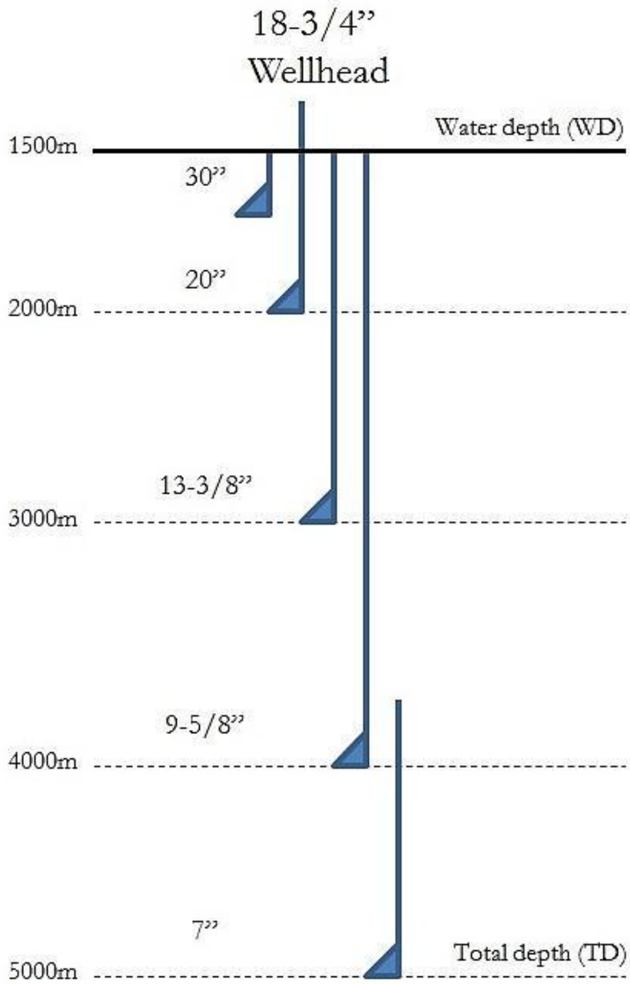

Figure 3 - Structure of a typical casing program with 18-3/4" WH

2.2 Alternative Design Solution

There are several companies today that are proposing new technologies and solutions that will require less capacity of the rig, and thereby give the opportunity to use smaller rigs, which further contributes to reducing the cost of deepwater drilling. One of the companies is Atwood Oceanics, presenting a slim riser concept. Atwood's slim riser concept is based on the modern 18-3/4" wellhead system used in a conjunction of a 16" riser string, connected with a non-standard developed component called a crossover joint. The crossover joint allows the rig to retain its standard riser assemblies.

The 16" riser connects to the rig's conventional 21" riser system by using an upper crossover joint. The upper joint is a special joint of 3 meters (10 ft.) with a 21" box looking up and a 16" pin looking down.

The lower crossover joint is then the transition between the 16" riser and the 21" riser connection in the lower marine riser package (LMRP). The lower crossover joint is similar to the upper joint, i.e. a 3 meter (10 ft.) joint, with a 16" box riser connection facing up and 21" pin riser on the bottom end to connect to the existing system (Childers and Quintero, 2004). Figure 4 shows the upper and lower crossover joint connection between the riser and existing rig assemblies.

The advantage of this slim riser concept is that it may bring older 3rd or 4th generation rigs into the deepwater market, but still maintain the usage of the conventional 18-3/4" BOP subsea system.

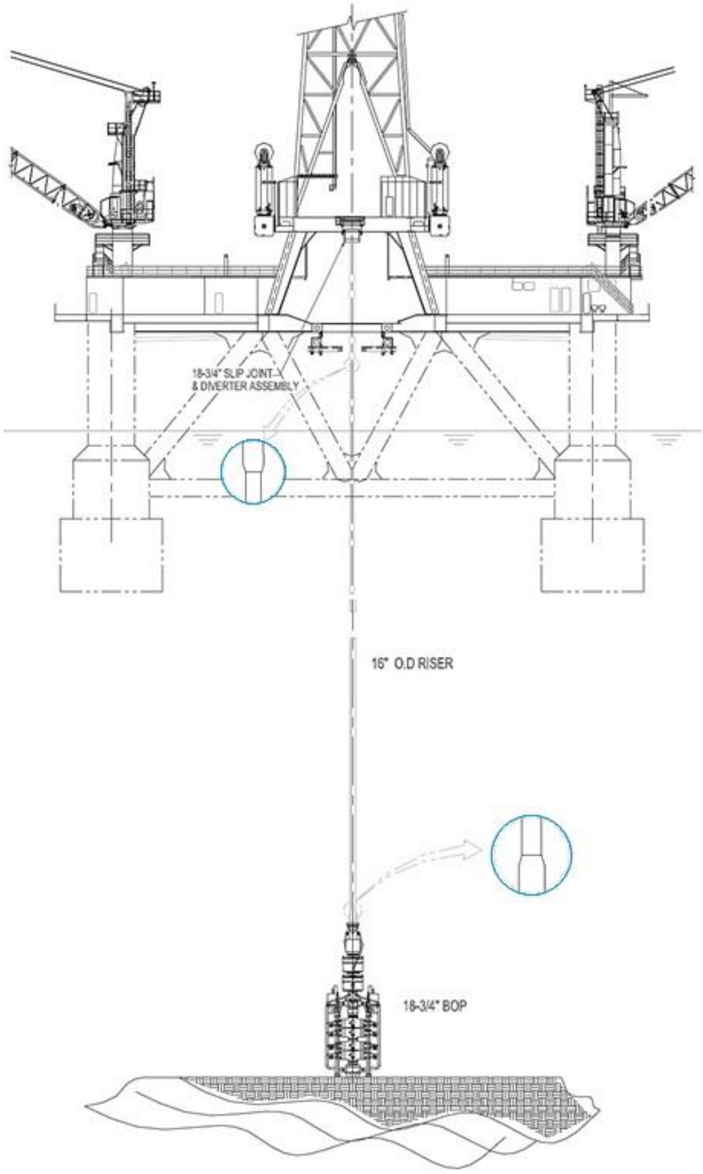

Figure 4 - Slim Riser Concept with Crossover Joints (Childers and Quintero, 2004)

2.3 The Slim Wellhead Concept

The basic of the slim wellhead concept is that it can give the opportunity for cost-savings for deepwater operations where one might bring smaller 2nd and 3rd generation rigs in to these deep water areas. The key features of the slim wellhead concept are as follows:

- Usage of a 13-5/8" BOP
- Slim casing strings
- Fewer and longer casing strings
- 16" (OD) marine drilling riser

This first part of the thesis will present the slim wellhead concept and see the significant improvement the concept can have to the rig's capacity by reducing the BOP and riser size. Improvements which are considerable:

- Reduction of mud volume required due to smaller riser volume and reduction of volume in casing program
- Reduction of riser storage due to a smaller riser
- Reduced requirement to variable deck load (VDL) due to reduction of riser tension

2.3.1 Optimized Casing Program

The possibility of being able to use smaller and older rigs depends on several factors. Optimizing the casing program is one factor, where the objectives for this is to reduce overall well cost and minimizing drilling time while still reaching total depth (TD) with adequate hole size and maintaining the same production rate as for a conventional casing program. By optimizing the casing program to a "slim bore well", the rest of the subsea equipment can be downsized, as well as the drilling unit.

The reduction of casing size and mud volume used in the drilling phase does not alone have the sufficient reduction to allow the usage of smaller rig. Focus needs to be on reduction of the overall concept - from well to rig, which can give the total reductions that will lower the requirement of the rig and furthermore make it possible to use a smaller and less expensive rig. The proposed casing program for the slim wellhead is given in Table 3.

Table 3 - Optimized casing program for the Slim WH Concept (McCrae, 2003)

Casing string	Casing size	Hole size
Conductor	20”	26”
Surface	13-3/8”	17-1/2”
Intermediate	9-5/8”	12-1/4”
Liner	7”	8-1/2”

The usage of a 13-5/8” BOP can be the main component to bring down the total project cost, where the usage of a slim riser as well as a slim casing program will be necessary. By comparing the conventional casing program one observe that there are fewer casing where it is now run only one casing string and a liner after the 13-5/8” BOP is set. It is worth mentioning that the majority of wells drilled throughout the world do not require large bore capability and can be drilled and completed with only two or three casing strings after the BOP stack is set (Childers and Quintero, 2004).

In the interest of this thesis, a base case with a total depth (TD) of 5000 meters and a drilling depth (DD) of 3500 meters has been looked at. The sections for the 20” conductor and the 13-3/8” surface casing are drilled to open sea before installing the 13-5/8” BOP stack on top. After the BOP is set, a long 12-1/4” section for the 9-5/8” casing is chosen, with an optional 11-3/4” liner. In the last section the 7” liner is installed, like on the conventional casing program. With the 7” liner at the end, conventional production tubing can be used and thereby maintain the production rate as for the conventional wellhead program. Figure 5 gives an illustrative comparison between the casing program of the slim wellhead and the conventional wellhead program.

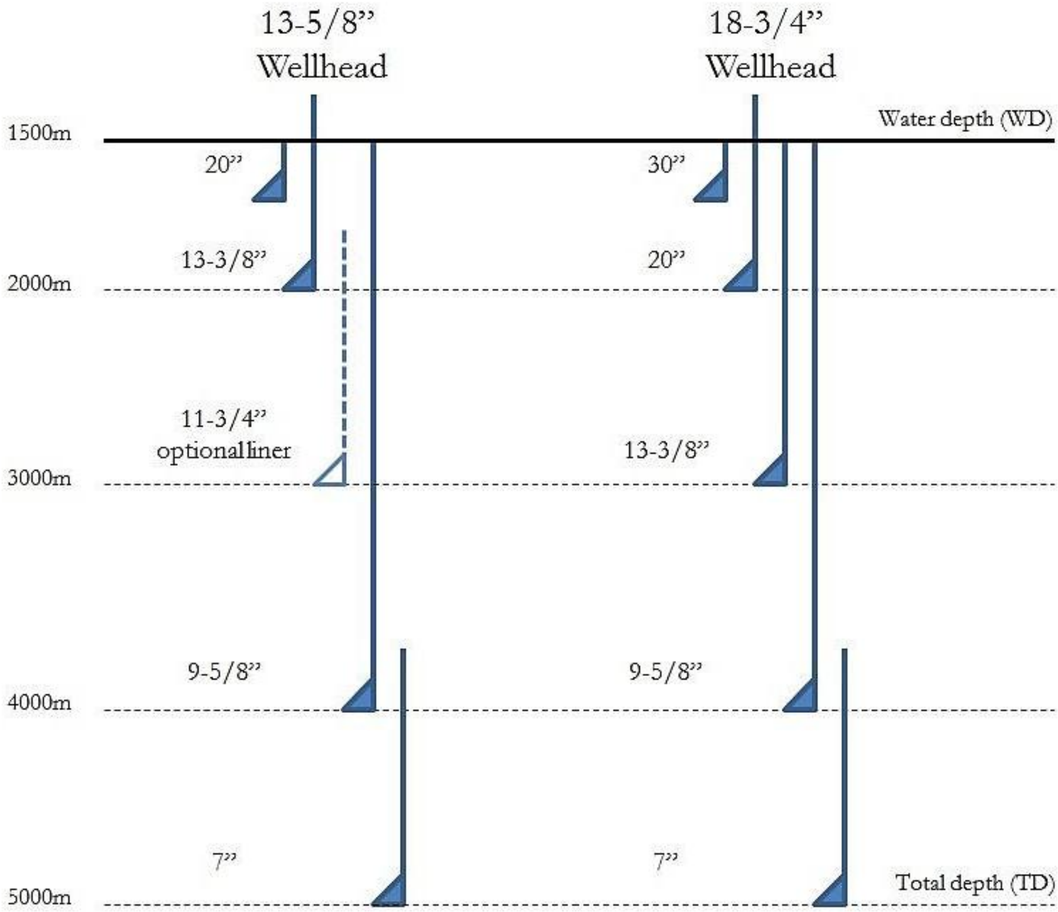

Figure 5 - Slim WH and Conventional WH

2.4 The effects of a Slim Wellhead System

By a change in the wellhead system where a slim drilling riser and BOP is used would have a potential of a decrease of several requirements to the rig and furthermore, the cost of the drilling operation. The effect of the slim wellhead concept and its influenced components are presented in the following chapters.

2.4.1 Reduction due to change in Casing Program

Casing and tubing account for about 15 to 20 per cent of the completed cost of the well and is usually the greatest single item of expense on the well (Feder, 2001). An economical saving may be achieved by reconsidering the casing program, where selection of fewer casing strings, slim casing sizes and slim sections of drilling are all to be of considerable importance to reduce cost.

By reconsidering the casing program advantages which might be achieved are:

- reduction of mud volume due to smaller section volume
- reduction in cement needed due to smaller annulus volume
- decrease drilling time
- drilling slim section results in less drill cuttings
- less cuttings need to be processed and disposed of, so fewer transportation for the supply vessels to bring the cuttings to onshore base
- fewer casing strings gives fewer crane lifts during the operation
- slim casing reduce deck space on supply vessel which results in less vessel trips to shore to reload casing strings
- fewer casing strings to purchase

The most important argument in choosing a slim casing program over the conventional casing program would be the reduction of rig cost, in terms of lower day rates and reduced drilling time.

Two approaches deserve to be mentioned related to drilling time: Reduction of trip time and reduction of the volume of formation that needs to be extracted. Both will help illustrate that it is possible to achieve reduction in drilling time.

Reduction of Trip Time

Tripping is when the drill string is pulled out of the hole and replaced by a new one. This is done when the drill bit has been worn-out so that a decrease in penetration rate occurs. The penetration rate for smaller bits is not higher than for larger bits, so by discussing the time of drilling in this chapter one can look at the physical reduction in the drilling time, and not the reduction of formation and drill cutting volumes.

A typical process on a rig would have an average tripping time will be 90 sec/stand in riser and upper sections of the well. The stand is two or three single joints of drill pipes screwed together, with an approximate length of 27 meters for a trebles stand. When entering the lower sections of the well, tripping time can be increased to about 120 sec/stand. The increase is needed to avoid getting surge while tripping (Abbedissen, 2012).

By considering the new casing program, which has one less casing string installed after the BOP is set, rig time will be reduced. Table 4 gives the typical operations and the approximate running time of the casing strings.

Table 4 - Estimated savings in trip time (Abbedissen, 2012)

Time Reduction of Trip Sequences			
	Slim Casing Program (4 strings)	Conventional Casing Program (5 strings)	Saving (hours)
R/U and R/D equipment	24	30	6
M/U casing string	42	57	15
Running in Hole (RIH)	120	150	30
Physical Cementing Job	24	30	6
Waiting on Cement (WOC)	32	40	8
Pressure Test & Disconnect	8	10	2
POOH	20	25	5
Total	270	342	21%

By reducing one casing section, rig time will be reduced. By comparing the different operations by running only 4 strings compared to 5 casing strings it is observed that there is one less rig up (R/U) and rig down (R/D) operation of the running tools (which run the casing string) and can save about 6 hours of work. RIH will of course depend on length of string and section depth, but 24-36 hours saved can be achieved. One less cement job is needed, where physical cementing job saves about 6 hours. After that, an 8 hours waiting on cement (WOC) is needed. So 13-15 hours on the total cementing job is easily saved (Abbedissen, 2012).

Furthermore, fewer casing strings will lead to more casing stored on vessels and again will lead to reduced number of required supply vessels needed for a well, included less logistic planning. Achieving great cost savings on projects requires proper planning as well as knowledge of the available options (Childers and Quintero, 2004).

A high end rig rate today for an operating company (such as Statoil) will be around 650 000 USD/day. But the total cost for the operating company with all service personnel will be approximately 1 300 000 USD/day. So to manage to save 3 - 4 days on a well will make a large impact on the total well budget (Abbedissen, 2012).

Reduction of formation volume that needs to be extracted

One of the main challenges on a 3rd and 4th generation rig is to manage to handle all the cuttings returning to the rig from the bigger sections such as the 17-1/2" and the 12-1/4" section. That can lead to reduced rate of penetration (ROP) to manage to handle the cuttings. The drill time can be extended due to higher volume of formation to be extracted. By reducing the hole size less formation and less cuttings will be extracted and transported back to the rig, and there will be no limitations on the ROP due to shaker capacities, as well as less cuttings to be processed and disposed of to the onshore base (Abbedissen, 2012). To minimize the amount of material that needs to be transferred from the rig to a supply vessel is always to be desired.

By doing a simplified calculation an approximate reduction of total drill time (physical drilling, process and disposal of cuttings) can be found. A rough assumption is that the total time to drill is proportional to the volume of formation to be extracted. If there is less formation to remove, then the cost of the well should decrease (Theiss, 2012).

The drill time reduction can be estimated by comparing the volumes of the holes to be drilled in the slim program from Table 3 with the volumes of the holes being drilled in the conventional program from Table 2. The calculation is found in Appendix A and the result is given in Table 5.

Table 5 - Formation Volume in Well

Volume of extracted Formation		
Slim Well	**Conventional Well**	**Reduction of Volume**
$V_{SW} = 303\ m^3$	$V_{CW} = 457\ m^3$	- 33 %

From the simplified calculation of the two casing programs a reduction in total drill time is found to be about 33%.

Other authors claim similar result from their slim hole technology. A presentation of a slim wellbore design by Enventure Global Technology (Tubbs et al., 2006) found that the slim hole drilling compared with a conventional program could have an average reduction in drilling time to TD of 21%, reducing from 94 to 74 days. Another slim wellhead technology presented by Shell Petroleum (Erivwo et al., 2003) found a reduction of 28% from their study.

Their results will of course have variations from the result presented in Table 5 due to the difference in section dimensions, drill depth and numbers of sections to be drilled. However, from these results one may claim that a reduction of 20 - 30% in total drilling time may be possible by considering a slim casing program.

2.4.2 Casing String and Deck Load

As mentioned while discussing trip time, the casing strings are usually stored on supply vessels and loaded on drilling deck as they are needed for the upcoming section. Large rigs could of course be able to store more than others, but in this case having 1500 meter riser stored on deck, there will be lack of deck space if the casing strings are included, even for the largest rigs. So, by reducing the numbers of casing strings will not have a reduction to the deck load capacity, since only the next casing string to be run will be stored on the deck at any time. The casings will usually arrive at the rig one week before the casing string needs to be run.

The casing strings are handled by casing companies, which transport the strings as well as crew and tools for this job. A typical company that provide this service is Odfjell Well Service (Abbedissen, 2012).

Hence, every material transfer requires more activity and adds risk to the operation. By reducing numbers of casing strings less crane lifts needs to be performed to load the casing onto the deck (Theiss, 2012).

2.4.3 Mud System

The rig is usually provided with two mud systems. This is because one can be back-up to the other. The mud systems are large and heavy, so it's difficult to have all the needed mud stored on board at all times. Also the liquid mud must be kept agitated or circulated to prevent it from settling so they do not want to keep too much mud on the rig. Thus, most rigs will then receive and store liquid mud or dry mud and cement products from a supply vessel. Different types of mud and fluid for the different drilling section are used; typical sequence after BOP is set could be as follows:

- First section drilled with water base mud (WBM)
- After this, oil base mud (OBM) is used
- Last is the completion carried out with use of brine

The active and reserve pit volumes must be back loaded onto a supply vessel when one section is finished and make room for mud for the next hole section. Hence, the drilling vessel lacks of pit capacity in either volume or weight capacity (Mikalsen, 2012).

Reduction in mud volumes are achieved by the slim casing program. By comparing the slim casing program to the conventional program the result is given in Table 6. The calculations are found in Appendix A.

Table 6 - Reduction of Mud Volume in Well

Reduction of Mud Volume in Well			
	Slim casing program	**Conventional casing program**	**Change**
Volume of Mud (m^3)	330	505	- 175

Table 6 shows a reduction of 175 m^3 of mud in the program. Table 7 illustrates an approximate cost reduction related to reduction of mud, estimated for oil base mud (OBM).

Table 7 - Cost Reduction of Mud (Holdhus, 2012)

Budget of Mud Expenditures		
Mud Reduction (m^3)	**Mud Cost (USD/m^3)**	**Savings (USD)**
175	1 800	315 000

Another achievement related to reduction of mud is that these fluids are produced at shore and are transferred to the rig. Less mud needed due to fewer sections that needs to be drilled, reduce transfer needed from the supply vessels, as well as less on loading and back loading of mud to the vessel (Hufthammer, 2012).

Considering that the required mud for the whole well is stored at deck at all times, a reduction of variable deck load is limited due to the slim casing program. It is the reduction in drilling time and final cost that gives the largest effect to the budget (Abbedissen, 2012).

Consequences of mud weights related to the marine riser are being discussed in chapter 2.5.4.

2.4.4 Liquid, Active and Reserve Pit

The liquid mud, or the drilling fluid, acts as a primary barrier. The mud transports the drill cuttings up to surface, as well as providing lubrication and cooling for the drill bit (API, 2004). The liquid mud system consists of both active and reserve pits. Active pits and reserve pits are listed in the rig specifications as total liquid mud. The rig's rated total liquid mud capacity is the maximum volume of liquid mud that the vessel can support. Using a smaller size riser and slim hole drilling will potentially allow you to not use all of the rated total liquid mud capacity of the rig (Theiss, 2012).

The mud from the active pit is the mud that is in a circulating loop during the drilling process. It is been circulated through the drill pipe down to the drill bit, bringing the drill cuttings up through the annulus of the riser pipe. The active pit would be refilled from the other pits during the drilling. The reason for using the active pits is to have accurate volume control. In case of a loss in the well one could easily read the reduction/loss of mud in the pit. Contrary will they be able to read the gain of mud when the volume in the pit increases, indicating a kick/influx (Hufthammer, 2012).

The rig must have at least reserve pit capacity to store the riser's volume when the active mud is circulated out of the riser to sea water prior to disconnect. Also the reserve pit must have capacity to contain the active mud when it is circulated out of the hole. The rig will also store some dry mud which can be mixed to make liquid mud as it is needed (Theiss, 2012).

As mention when discussing mud system, most rigs will receive and store liquid mud or dry mud and cement products from a supply vessel since the rig don't want to store too much extra mud due to preventing it from settling.

Selecting a smaller riser would cause a decrease of mud in the active pit volume as well as a decrease in the reserve pit volume. This gives a reduced requirement of the rigs' tensioning capacity due to decrease of weight of the drilling riser. Requirement of riser tensioning will be discussed in chapter 2.5.6.

2.4.5 Mud Pumps

Changing the casing program and reducing the volume of well would not have a large impact on the mud pumps, and therefore no reduction to the requirement of power. The requirement to the pump capacity is driven by factors such as:

- Size of last drilling section
- Mud type and density
- Bottom hole pressure
- Depth from RKB (drill floor) to BHA

Since both casing programs, optimized slim program and conventional program, are being compared to the same total depth as well as same section volume and liner size, one must assume that the requirements to the pump have no reduction, since both casing programs are similar when total depth is reached.

It is beyond the scope of this thesis to describe the mud pump required capacity for a rig to operate in a total depth of 5000 meters. However, a rig today operates with usually three or four mud pumps, rated between 1600 to 2200 HP each and with a working pressure from 5000 to 7500 psi, so that lack of power may not be a limitation for using smaller semi-submersibles for deep water operations (Abbedissen, 2012).

2.4.6 Sack Storage

The rig will store some dry cement which can be mixed to make cement as needed. The dry cement is stored in sacks, where one sack requires a storage space of about 0.028 m^3 (1 ft^3). The cement must be stored dry and mixed only just prior to it being circulated into the well, since cement can't be stored mixed for very long as it will start to set.

If may be difficult to claim that a reduction in volume of the well requires less storage capacity for sack materials due to reduced annulus volumes, since this will not be limited for using a smaller rig. But if a reduction of sack storage shall be illustrated it may done by a simplified statement assuming that the required storage of dry sack material could be reduced by a similar percentage as the reduction of the cemented annulus volumes. The result is given in Table 8.

Table 8 - Reduction in Cemented Annulus Volume

	Cemented Annulus Volume		
	Slim casing program	**Conventional casing program**	**Change**
Volume of Cement (m^3)	145	290	- 50 %

The volume of cement needed to fill the annulus of the slim casing program compared to the conventional program is reduced by 50 %. However, seen from a practical point of view, a rig would always desire to store some spare material. If the rig suddenly needs more material than first intended, the rig would need more frequent resupply from a supply vessel, which requires more transportation, labour and crane lifts to get the materials onto the rig. This would increase the risk of adding unnecessary costs to the budget.

However, if the sack storage capacity is a factor to be a significant limitation of using a smaller rig, one may need to use a supply vessel for the deep water operations. The limitation will then be partially offset by using the supply vessels to store the cement products for the rig.

2.4.7 BOP Stack

There are not many modern 13-5/8" BOP stacks used in any working pressure as most modern rigs have 18-3/4" drilling systems. Therefore a replacement of the 18-3/4" BOP stack to the 13-5/8" is required when considering this slim wellhead concept. Upgrading to a smaller BOP will result in weight savings to rig when stored dry on deck, and furthermore reduce requirement to the hoisting capacity when deploying the slim riser and BOP to seabed.

The weight exerted on the wellhead connector which attaches the BOP stack to the wellhead will also be reduced.

The weights of BOP components vary considerably from model to model and manufacture to manufacture. The components in one type will also vary in rated working pressure, e.g. a 15 ksi BOP stack could have 10 ksi annular BOPs at the upper section, and the rams at the lower section of the BOP stack could be rated to 15 ksi working pressure (WP). Similar with a 10 ksi BOP stack, this may consist of both 10 ksi and 5 ksi components regarding the placement to the components. The lower section of the BOP that is connected to the wellhead will have the highest rated working pressure.

There are many components included in a total BOP stack such as:

- Ram and annular BOP components
- Stack frame/guidance system
- Subsea control system
- Choke and kill stack valves and piping
- Mandrel
- Accumulator bottles
- Wellhead connector
- LMRP connector

All components add considerable weight to the BOP stack assembly, even though they are not all the main components. Most BOP stacks consist of a wellhead connector, two double ram BOP's, one single ram BOP, two annual BOP's, a lower marine riser connector, a flex joint, a riser adapter and a wellhead connection. Some BOP stacks now have six or even seven ram cavities. Deepwater BOP stacks have a large number of accumulator bottles which also would add greatly to the weight of the BOP stack.

Table 9 list some of the components and their estimated weights of a comparable 13-5/8" 10 ksi working pressure and a 18-3/4" 10 ksi working pressure BOP stack from Cameron (Theiss, 2012).

Table 9 - Estimated weight of BOP Stack

BOP Stack from Cameron			
Components	**13-5/8" 10 ksi**	**18-3/4" 10 ksi**	**Change**
2x Double Ram Type U BOP (kg)	16 800	51600	34 800
1x Single Ram Type U BOP (kg)	4 700	13 100	8 400
2x Annular Type D BOP (kg)	24 800	37 200	12 400
1x Wellhead Connector (kg)	8 200	16 300	8 100
1x LMRP Connector (kg)	8 200	16 300	8100
Flex Joint w/riser adapter (kg)	11 300	18 200	6 900
Stack Frame (kg)	20 400	31 000	10 600
Total Weight (tonnes)	94	184	- 49 %

Observe that by replacing the 18-3/4" BOP stack with the 13-5/8" BOP stack a reduction of about 90 tonnes in deck load is possible. The 13-5/8" individual components and the full BOP stack would have about 50 % weight reduction of an 18-3/4" BOP stack. Note that these numbers may fall short as they do not include the other components discussed above. The heaviest 18-3/4" 15 ksi BOPs today weighs up to 400 tons. A comparable 13-3/8" 15 ksi BOP would then probably weigh less than 200 tons (Nergaard, 2012).

Figure 6 shows the lower section of the total BOP stack and the upper section called the lower marine riser package (LMRP).

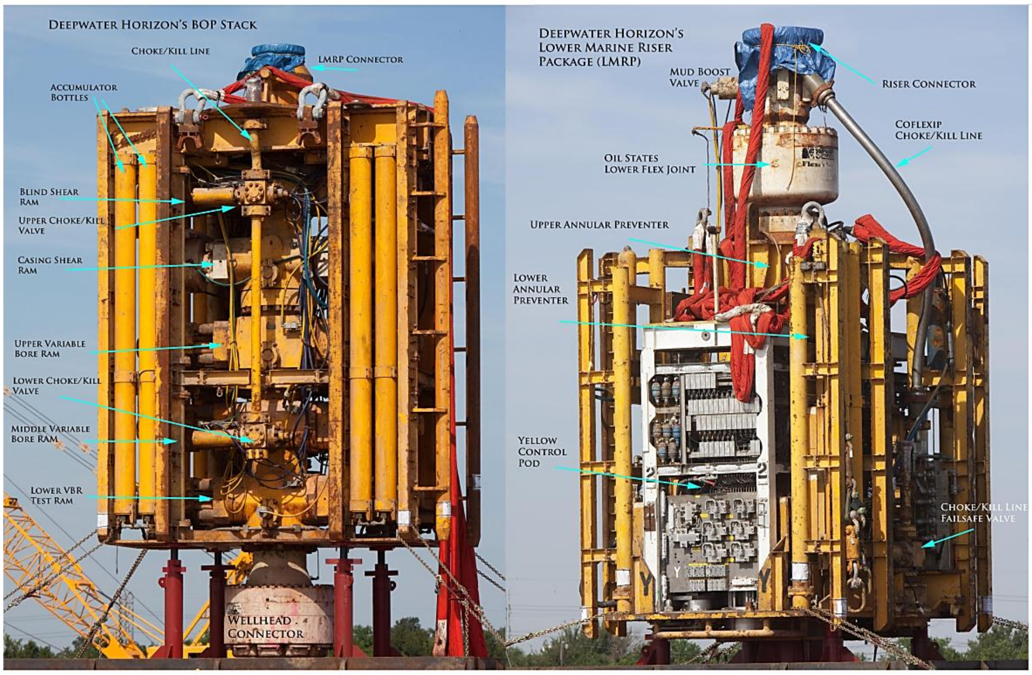

Figure 6 - BOP Stack and LMRP from the Deepwater Horizon (Konrad, 2010)

The weight of a BOP stack is a factor, but the riser size and its tensioning requirement is the largest factor for the limited usage of a 3rd generation semi for deep water operations. Requirement of tension capacity is being discussed in chapter 2.5.6.

2.5 Slim Riser in Deep Water Operations

The cost of drilling deep water wells today is high, which is associated with the day rates of the latest generation semisubmersibles as well as drilling time. The cost is mostly driven by the requirement to the well size and riser. To be capable of having a drilling riser operating in deep water sets high requirements to the rigs capacity when it comes to handle the variable deck loading, riser storage, mud storage and to riser tensioning. Changing the riser dimension will have an effect on all these factors, and further be a major cost saving factor. Selecting a slim riser instead of the conventional 21" riser will have a large reduction to the requirement of riser tension and deck load, which allows usage of a smaller and older semi-submersible when performing drilling operations of deep water wells.

To drill in a water depth of 1500 meters today, a 5th or 6th generation semi is used. By using a 16" riser as presented in this slim wellhead concept, it may be possible to use a 3rd or 4th generation rig, which will give a significant overall project cost reduction due to lower day rates. Table 10 indicate the sufficient cost savings that can be achieved if reduction of the requirements to rig storage and deck load are possible.

Table 10 - Cost difference between a 3rd and 5th generation rig

	Semi-Submersible		
	3rd	**5th**	**Change**
Day Rate (USD)	300 000	450 000	- 33 %

In this chapter the reduction of requirements to the rig when considering a slim riser instead of a conventional riser is going to be illustrated. The primary goal is to be able to use smaller rigs and then have a lower day rate and furthermore get a sufficient overall cost reduction to deep water projects. This may be possible when reducing the riser size from 21" to 16" (OD), combined with the slim casing program.

2.5.1 Deck Load Reduction due to Slim Riser

Variable deck load (VDL) is any load on the vessel which can be varied. In other word, the variable loads are loads that are not permanent parts of the vessel. These loads can include any equipment (including drill pipe, riser and casing) or any materials and supplies stored on deck or in the tanks and bins. The weight of the riser is part of the variable deck load when it is stored on deck. Variable deck loads also include the riser top tension when riser is deployed in sea as this is a variable load which must be supported by the vessel. When some materials (cement, mud below the seabed, the BOP stack) are installed and therefore supported by the well, they are no longer part of the deck load. However some of the variable deck load capacity must be reserved for items such as the BOP stack which must at some point return to the deck and be supported by the vessel (Theiss, 2012).

The lightship weight includes the weight of the hull, the decks themselves, the derrick, the draw works, the power generation equipment, the personnel quarters and helicopter pad. Basically all the items that are permanent parts of the rig which can't be varied (Theiss, 2012).

The bottom line is that older and smaller drilling rigs will have limited variable deck load capacity. The rig needs to be able to support the submerged weight of the riser when it is installed and the weight of the riser when it is stored on deck. A larger riser will weigh more both installed and when stored on the deck.

If it is desirable to use these rigs in increased water depths, attention must be paid to minimizing the loads on the vessel which consume this limited capacity. Reducing the size of the drilling riser is one of the larger factors to minimize the loads on the vessel.

2.5.2 Comparison of Deepwater Drilling Riser

The rig must have sufficient deck space and deck load capacity to support the riser when it is not deployed. A reduction of diameter in riser would decrease the weight to deck as well as storage space. Reducing the diameter of the riser will affect the diameter of the floatation modules which also reduce the weight on deck and the requirement to deck space. The floatation modules are supporting some of the riser weight when deployed in water. The force transferred to the rig by the riser and BOP is proportional to the mass of riser and BOP, and this need to be safely handled by the hoisting system. The riser tensioners needs to support the weight of riser and mud during the drilling operation, and ultimately by the vessel (Taylor et al., 2003).

By reducing the size of both the riser and BOP, a reduction of hoisting capacity is induced, as well as lower requirement of the riser tensioners due to decreased volume of mud and lighter riser.

Table 11 represent typical dimensions, weights and floatation modules used by semi-submersibles.

Table 11 - Characteristics of Riser Joint and Floatation Module (Hausken, 2012)

Riser Joint, Lines and Floatation Module		
	21" OD x 19.5" ID	**16" OD x 14.5" ID**
Length of Riser Joint	22.86 m (75 ft.)	19.81 m (65 ft.)
Joint weight w/lines (dry) (tonnes/joint)	11.1	5.9
Length of Floatation modules	21.7 m (71-1/4 ft.)	18.8 m (61-3/4 ft.)
Weight of floatation modules (dry) (tonnes/joint)	10.3	5.4
Buoyancy of floatation modules (tonnes/joint)	13.3	6.8
C&K line	6-3/4" x 4-3/4" (0.17 x 0.12m)	5" x 4" (0.13 x 0.10m)
Hydraulic line	4" x 3.5" (0.10 x 0.09m)	2-5/8" x 2" (0.07 x 0.05m)
Boost line	5" x 4" (0.13 x 0.10m)	-

A typical riser joint is 95% covered by a floatation module, given in Table 11 from the difference in length of the riser joint and the flotation module. Usually one or two joints at the lower end of the riser, which is connected to the BOP, are not covered by these floatation modules. This is to provide better control when deploying the riser and BOP to seabed, where the modules have larger OD than the bare riser joints so the modules are more affected by currents. This gives more stability and thereby easier to set the BOP (Hausken, 2012).

Furthermore, a typical 21" riser joint is outfitted with one kill line and one chock line for well control, two hydraulic lines used to charge the BOP control system accumulator and one boost line to increase the fluid velocity inside the riser to lift cuttings. On a 16" riser, the use of a boost line will not be required. Using the slim riser, the mud velocity in the riser is higher than for the conventional riser for a given volume flow rate. A larger riser will require a higher volume flow rate to produce mud velocity in the riser to lift the cuttings, illustrated by Figure 7. The higher volume flow rate will require high volume mud handling and processing on the surface. Typically when drilling the smaller diameter hole, using the conventional riser, additional mud is injected at the BOP (circulated down the boost line) to increase the mud flow rate so that the riser effectively can lift the cuttings out of the riser. Again, using the smaller diameter riser the mud boosting line is not required (Theiss, 2012).

The rig needs to be able to support the weight of flotation modules and riser joint. Larger riser will add more weight to the deck, both installed and when stored on deck. Large riser also requires more space on deck when stored. Smaller rigs may not have the adequate deck space and deck load capacity for the long strings. However, a decrease size of the riser will give a substantial reduction to the requirement.

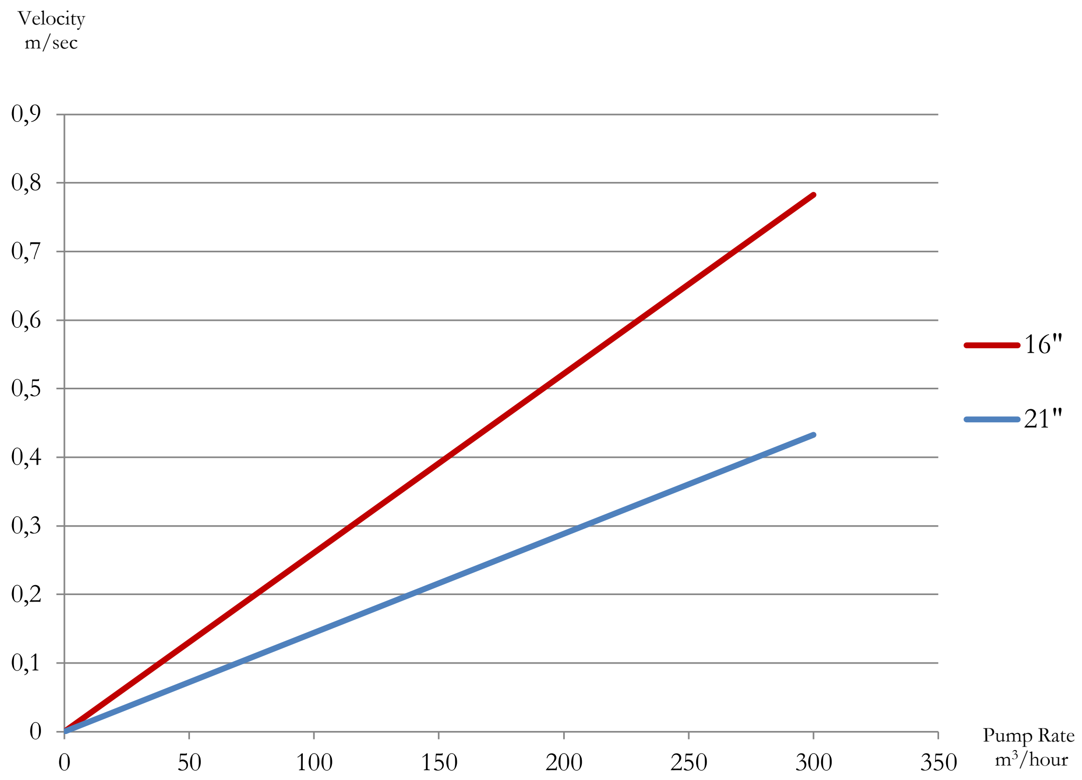

Figure 7 - Difference in velocity of a 16" and 21" drilling riser

Table 12 illustrates the reduction weight requirements when using a slim riser.

Table 12 - Characteristics of Deepwater Risers (Hausken, 2012)

Riser Characteristics			
	21" OD	**16" OD**	**Change**
Joint weight w/lines (dry) (kg/m)	486	298	- 39 %
Weight of floatation modules (dry) (kg/m)	451	273	- 39 %
Buoyancy of floatation modules (kg/m)	582	343	- 41 %
Dimension of Floatation modules (OD)	55-1/8" (1.40 m)	42" (1.07 m)	- 24 %
Total weight (dry) (kg/m)	936	570	- 39 %
Weight of a 1500m Drilling Riser w/ 95% modules (dry) (tonnes)	1370	835	- 535
Weight of a 3000m Drilling Riser w/ 95% modules (dry) (tonnes)	2740	1670	- 1070

From Table 12 it is seen that the dry weight of the 16" riser joint could have up to 40% reduction in weight compared to the 21" riser joint. The total weight (riser joint with auxiliary lines + floatation modules) also has a 40% reduction if a slim riser is selected for the drilling operation. A slim riser of 1500 meters could give a weight reduction of more than 500 tonnes to the rig when the riser is stored on deck. Figure 8 illustrates the riser and the placing of the auxiliary lines and floatation modules.

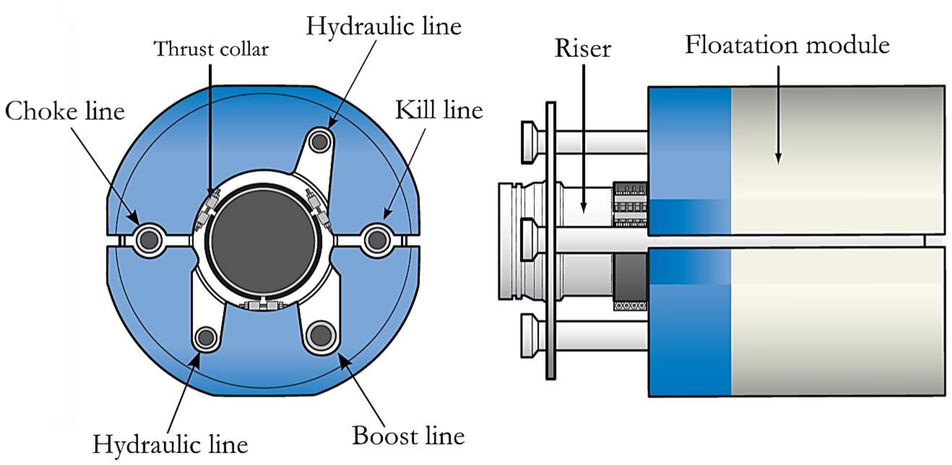

Figure 8 - Riser with auxiliary lines and floatation module (Balmoral, 2012)

When the riser is not deployed it is stored in racks on deck, with floatation modules attached. From Table 12 it can be seen that a space reduction of roughly 24% can be achieved by selecting a slim riser with its outer dimension when the floatation modules are attached. From Taylor *et al.*, a 21" riser of 1500 meters could require near 500m^2 of storage space. By assuming that the 16" riser could be stored at the same height, a reduction of 24% would now require a deck space of 380m^2. Figure 9 illustrates the marine riser stored in racks.

Figure 9 - Riser stored in racks on deck (Dvorak, 2011)

2.5.3 Active Pit, Tension and VDL

The riser top tension is part of the variable deck load when the riser is installed, so a decrease in the volume of the riser and weight reduction of mud in the riser will then have a reduction of requirement to the riser top tension which consumes some of the variable deck load capacity.

Considering drilling in deep water by using a conventional riser will require large tensioning capacity to the drilling unit. The largest tension system is to be found on the 5th and 6th generation semi-submersibles. Considering the usage of a slim riser, a decrease in the following factors is possible:

- requirement to the tension system
- active mud pits
- storage space

These are all factors that influence the variable deck load. Reducing the requirement of deck load capacity and riser tension systems may bring older and smaller rigs into the deepwater market.

2.5.4 Mud and Riser Volume

The reduction of volume of the marine riser will require less mud volume from the active pit, i.e. less mud that are in a circulating loop in the riser and well. Table 13 illustrates weight of mud in a 21” and a 16”riser at a water depth of 1500 meters and a typical mud density of 1.44 SG (12 ppg) and 1.68 SG (14 ppg).

Table 13 - Mud Weight in Marine Riser

Mud weight in a 1500 meters Marine Riser			
	21” OD	**16” OD**	**Change**
Inner Riser Volume (m^3)	290	160	- 130
Mud Weight in Riser (1.44 SG) (tonnes)	417	230	- 187
Mud Weight in Riser (1.68 SG) (tonnes)	487	269	- 218

It is observed that the inner volume of the two different riser sizes have a reduction of $130m^3$, i.e. a reduction of $130m^3$ of mud that is needed in the active pit for the circulation. By reduction the size of the marine riser, a weight reduction of the deck load is achieved as a result from less mud in pits, as well as less mud in riser which influence the tensioning system and furthermore the VDL. Figure 10 illustrate the increase of mud volume in riser when increasing the water depth.

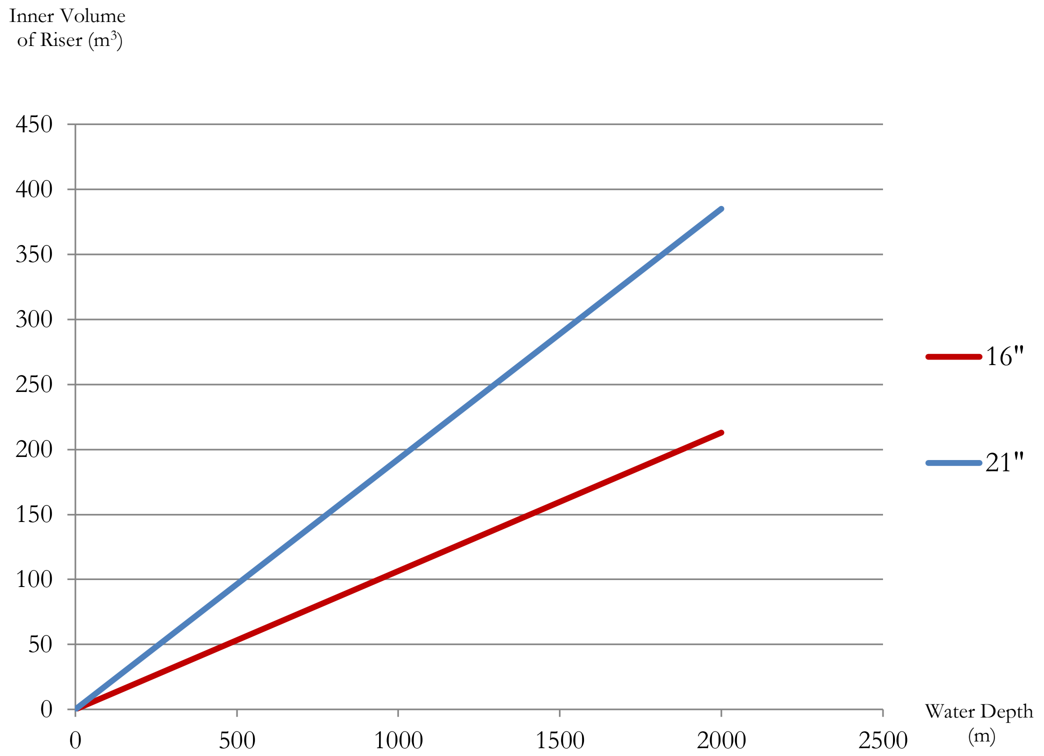

Figure 10 - Difference in mud volume with increasing water depth

2.5.5 Reduction in Required Capacity of the Tensioning System

The function of the tensioner system is to apply vertical forces to the top of the marine riser, holding its weight in water to control the displacements and stresses. The rig will experience both vertically and laterally movement in response to wind and current, so the system needs to provide nearly constant tension to the marine riser while drilling (API, 2001).

An assumption needed to be induced in order to illustrate the tension requirement for usage of a 16" OD marine riser:

- The marine riser has a proportional decrease of cross-section for all pipes, i.e. when the outer diameter (OD) decreases from 21" to 16" the thickness of pipe wall also decreases (proven by zero differential of hoop stresses)

Proportional Reduction of Cross-Section

The hoop stress is generated due to pressure differential between outer and inner pressure of a pipe. If the inner pressure is greater than the outer pressure, the pipe gets a circumferential expansion as well as thinning of the pipe wall (Palmer and King, 2008). The equation for hoop stress for a pipe is given as:

$$\sigma_h = \frac{p_i D_i - p_o D_o}{2t}$$

Where p = pressure, D = diameter and t = wall thickness.

For high D/t pipe the hoop stress is

$$\sigma_h = \frac{\Delta p D}{2t}$$

showing that constant hoop stress is given by proportional reduction between diameter and wall thickness. Thus, the cross-section reduction is given by:

$$\left(\frac{OD_{16"}}{OD_{21"}}\right)^2 = \left(\frac{16}{21}\right)^2 = 0.58$$

The result allows the riser weight to have the potential for downscaling to 0.58, i.e. a 42% reduction. Proof is given by calculation, found in Appendix A.

Simplified Riser Tension Analysis

The reduction of requirement to the tensioning system can also be illustrated by a simplified riser tension analysis. It states that a body immersed in a fluid, would have an uplift force equal to the weight of the displaced fluid. Thus, the tension needed to hold up the pipe is given as total weight (dry) subtracted by the buoyant force (Sparks, 2007):

$$Tension = W_{tot} - W_f$$

Where W_{tot} = total weight (W_{true} + W_{mud}) and W_f = weight of displaced fluid.

Note that this is a simplified calculation where its only purpose is to find the difference or reduced requirement to the tensioning system. Thus, the analysis is applied to the whole riser, where the riser and auxiliary lines are assumed as straight pipes, so the flanges and floatation modules are neglected. Furthermore, the analysis says nothing about internal pressure. The total weight is given from the weight of pipe material and internal mud, with a mud density of 1.68 SG (14 ppg). The calculation is found in Appendix A, and the result is as follows:

$$T_{21"} = 866.7\ tonnes$$

$$T_{16"} = 478.1\ tonnes$$

$$Tension\ Difference = 44.8\ \%$$

The numbers are high as they do not include the buoyant force from the flotation modules. However, the result would give a good indication of what one may expect as a reduction of tensioning requirement, given as a percentage.

From the simplified riser tension analysis, as well as the result from proportional reduction of cross-section and hoop stress, a reduction in requirement of the tensioning system in the range of 40 - 45% is foreseen. A weight reduction of 42% is selected and it is possible to plot the required tension of the 16” marine riser, illustrated in Figure 11.

2.5.6 Required Capacity of the Riser Tensioning

As illustrated in Table 13, a large reduction of the inner volume is achieved by selecting the slim riser, and from Table 12 a weight reduction of the riser joint is illustrated. A similar illustration is given in Figure 11. These figures are created from data collected from almost all the semi-submersibles on the market today (the blue dots), plotted with their tensioning capacity and rated operating water depth. The average tensioning capacity of the different semis is given in Table 14. These semis uses a 21" OD drilling riser, where the 16" OD riser is assumed having a proportional reduction of 42%, given in chapter 2.5.5. The downscaled riser is plotted with red dots. The data is found in Appendix B.

Table 14 - Tension Capacity of Rig

Average Tension Capacity for Semi-Submersibles					
	2nd	3rd	4th	5th	6th
Tensioning Capacity (MN)	2,9	3,6	6,1	12,6	13,8

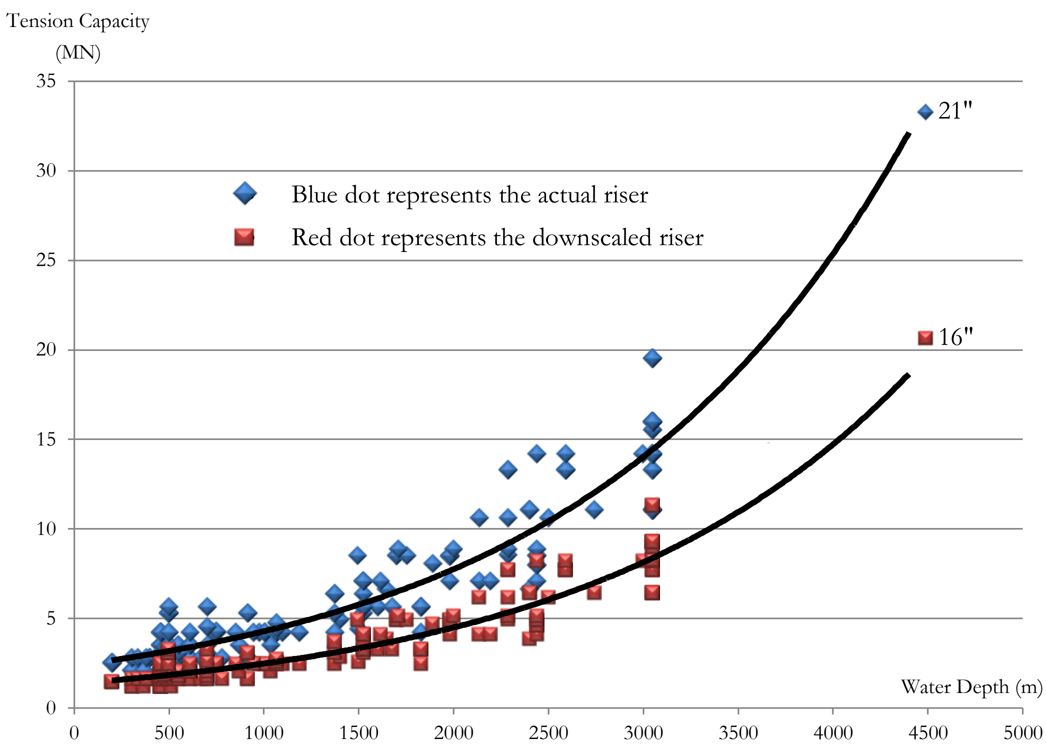

Figure 11 - Requirement of Tension Capacity

From Figure 12 it is seen that just above 10 MN is required from the rig to be doing drilling operation at 2500 meters of water. Table 14 shows that the required rig for an operating depth of 2500 meters and 10 MN would be a 5th generation semi or newer. By selecting a marine riser with 16" OD, one can see from Figure 12 that for the same depth of 2500 meters about 6 MN is required in riser tension capacity, i.e. the 4th generation into this operating water depth is found to meet the requirement. The tensioning system can maintain its capacity of today without requirement for any upgrade, just by replacing the convention drilling riser with a slim drilling riser.

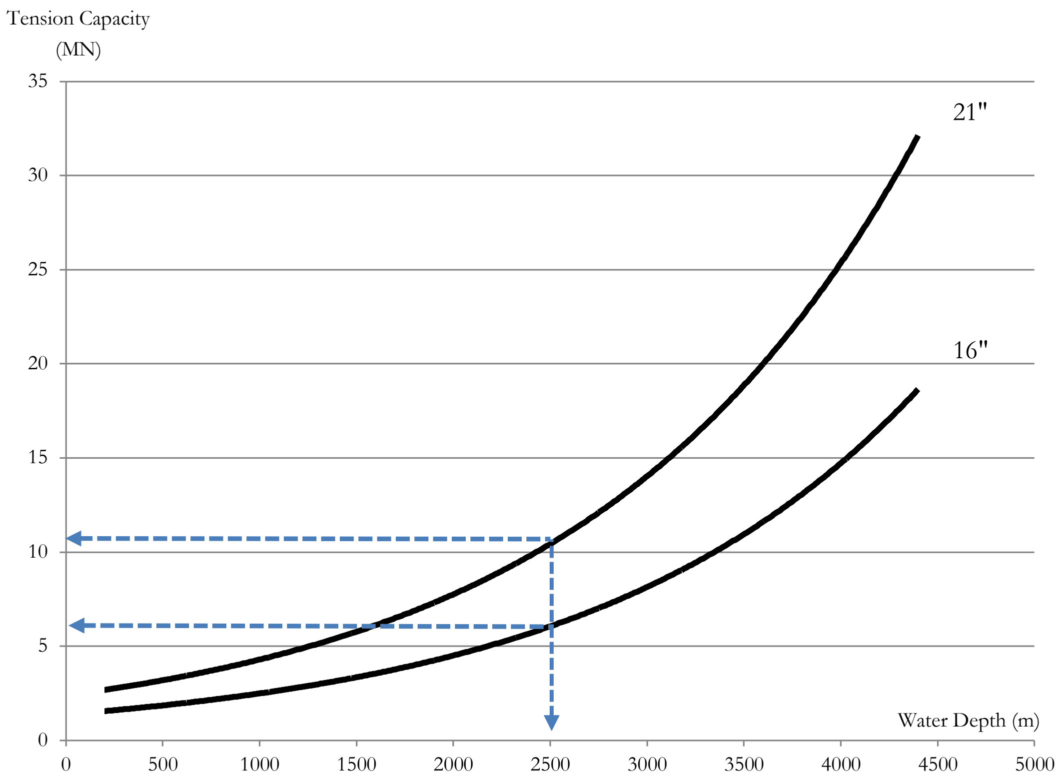

Figure 12 - Tension vs. Water Depth at 2500 meters

By examine the curves in Figure 12 combined with Table 14, it is seen that it could be possible to use one earlier rig generation to perform the drilling operation, at a given depth. Comparing the 4th and 5th generation rig in Table 1, has an average day rate of 370 00 USD and 450 000 USD respectively, would give a reduction in day rate of roughly 18%.

Alternatively, by examine this graph from another angle it is observed that by selecting a 4th generation semi with its 6 MN tensioning capacity, one could achieve 1000 meters of increase in operating water depth, increasing from 1500 meters to 2500 meters. Figure 13 illustrated the potential of increase in water depth by selecting a 16" marine riser.

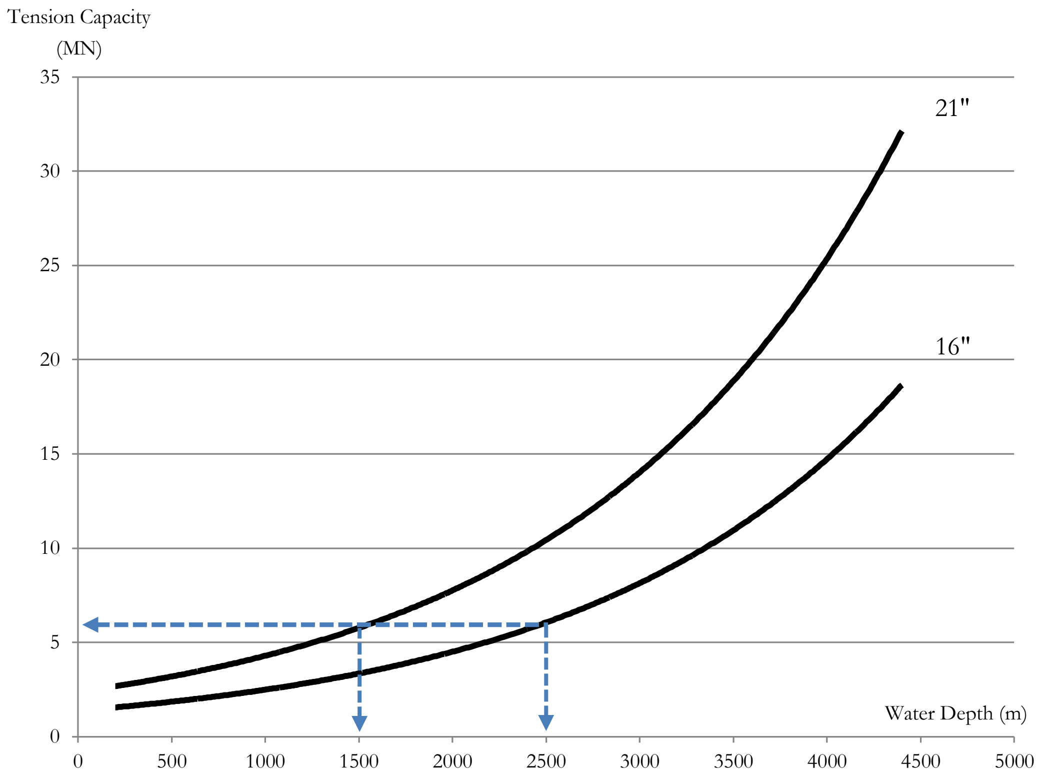

Figure 13 - Increase in WD with existing Tension System

An interesting observation is found by looking at a 3rd generation semi-submersible. From Table 14 an average tension capacity for the 3rd generation semi of 3.6 MN is found. Comparing the water depth at this tension capacity, the depth may be increased by more than double, increasing from 700 meters by using the 21" marine riser to an operating water depth greater than 1500 meters by selecting the 16" marine riser. See Figure 14 for illustration.

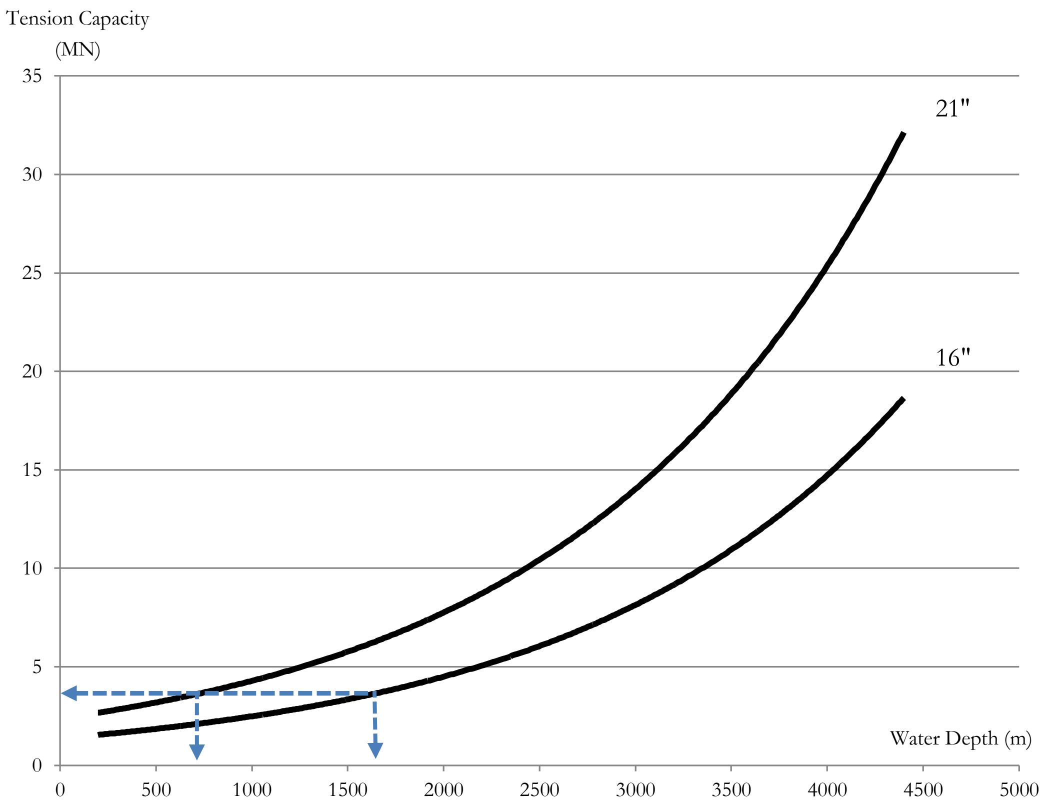

Figure 14 - Tensioning Capacity of 4 MN (3rd generation semis)

From Figure 14 it is illustrated that a 3rd generation semi can extend its operational range. When selecting a 16" OD marine riser these rigs may be able to operate in water depths greater than 1500 meters.

To sum up the discussion of the tension system, two main observations are given as a result from reducing the size of a marine drilling riser:

1) Decreased requirement of the rigs' tensioning system (Figure 12)
2) Increased operating water depth for smaller semis (Figure 13)

3.0 Objective 2

In this 3rd chapter of the thesis an evaluation of a potential increase in water depth capacity is presented. The key issue is what depth of exploration that can be reached in the future by using one of the largest semi-submersibles available on the market today combined with the slim well concept presented in chapter 2.3.

3.1 History Overview and Future Possibilities

As mention in the introduction of the thesis, in present time the progression in water depth capabilities has stalled. The last ten years of records in operational water depth has been around 3000 meters. High cost of either upgrading existing units or building new drilling units results in high day rates are causes for this stagnation. If no changes are made, this could be a major obstacle to improve overall improved recovery.

By using a 16" marine riser on an existing 5th or 6th generation semi-submersible it may be possible to reach unexplored depths and go beyond the barrier of 3500 meters or even 4000 meter water depth. Figure 15 illustrated the history exploration and the request for the next decade.

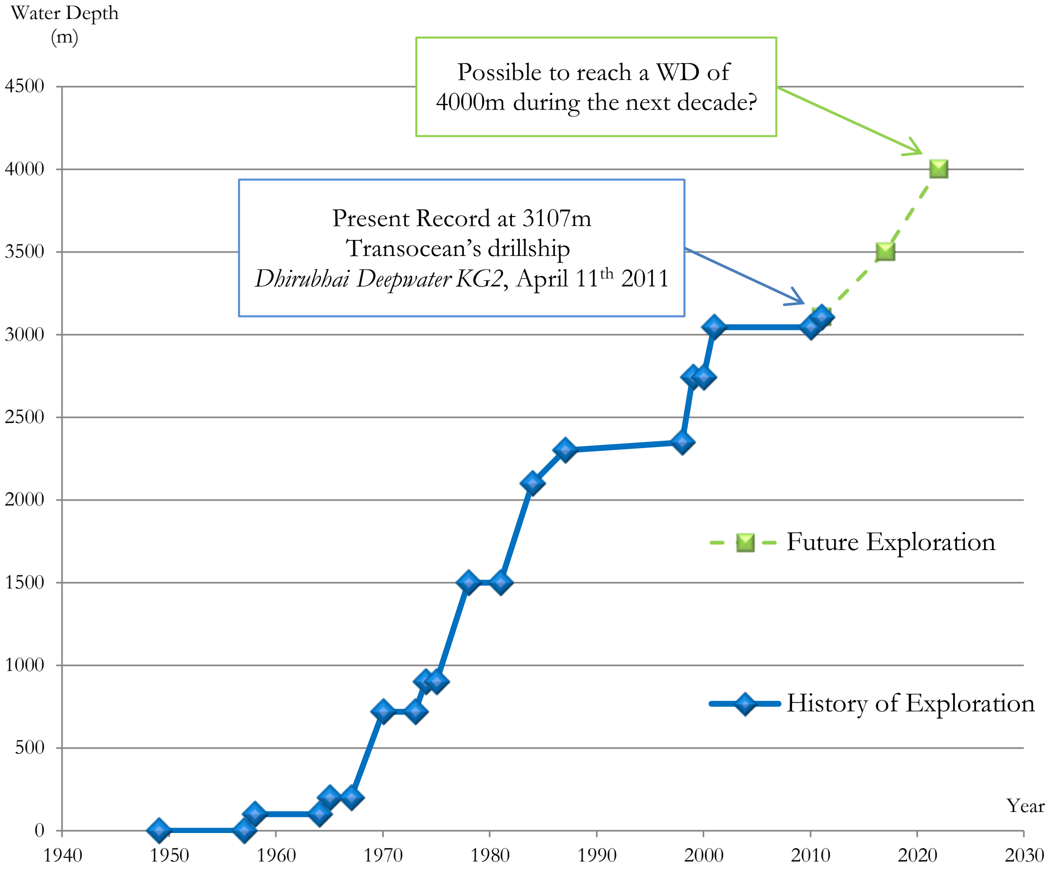

Figure 15 - Future Goals and Possibilities (Nergaard, 2010)

3.2 Potential for Increased Water Depth Capacity

Even some of the largest rigs do not have spare capacity to store the full string of riser for 4000 meters of water depth. Using a slim riser reduces the volume and weight of the riser so that it is possible to store a drilling riser of this length. This can make a difference in whether or not there is a potential for an increase of water depth with today's 5^{th} or 6^{th} generation semi-submersibles.

Figure 11 illustrated the tension capacity required for the two risers, where the curves fit the following equations:

- 21" Marine Riser: $y = 2{,}37e^{0{,}0006x}$
- 16" Marine Riser: $y = 1{,}38e^{0{,}0006x}$

Where y = Tension (MN) and x = Water Depth (m). The data and equations are found in Appendix B.

From Table 15 some water depths of interest are calculated, and its requirement of tensioner to achieve these new records of exploration depths.

Table 15 - Riser Tension Requirement beyond 3000 meters Water Depth

Capacity Requirement to achieve new WD Records			
Water Depth (Meters)	21" (MN)	16" (MN)	Change (MN)
3300	17.2	10.0	7.2
3500	19.4	11.2	8.2
3700	21.8	12.7	9.1
4000	26.1	15.2	10.9
4400	33.2	19.3	13.9

By examine the tension capacity required to the reach a water depth of 4000 meters, the 21" and 16" riser requires 26.1 MN and 15.2 MN, respectively. This is illustrated in Figure 16.

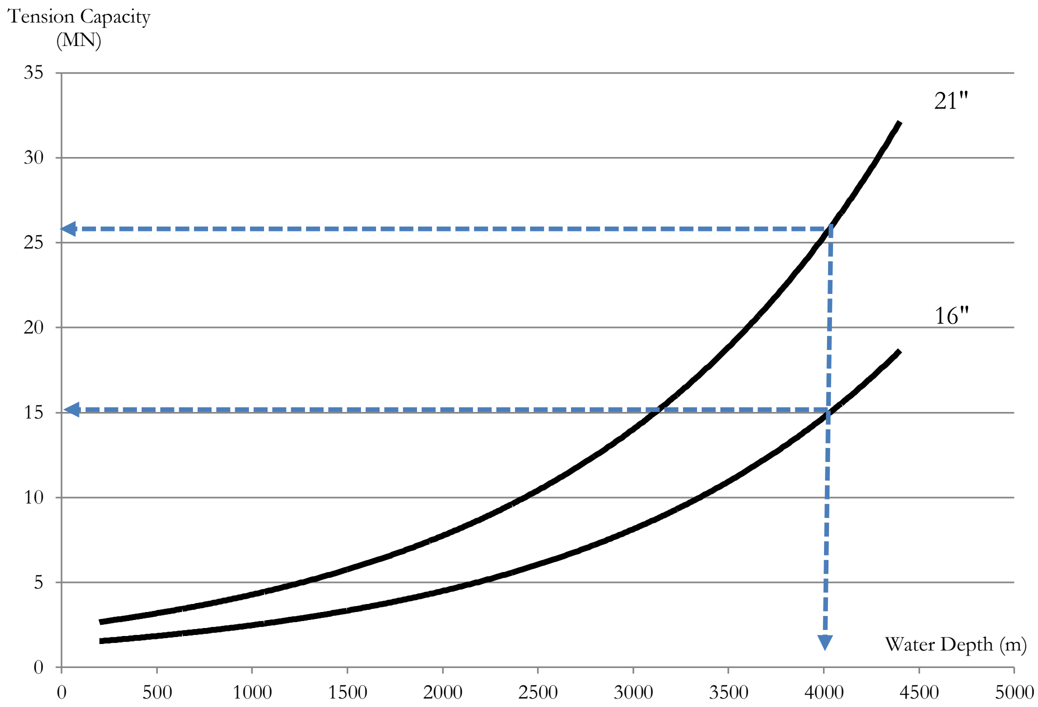

Figure 16 - Requirement to 4000m Water Depth

Comparing these values with some of the largest rigs available on the market today, listed in Table 16, one can see that the requirement of 26.1 MN for a 21" riser system fall short in capacity. Also, assuming the cost of building a new rig with a tension capacity of 26 MN may be uneconomic all together. Hence, by modify the rigs to a 16" riser system it can be observed that all of the largest rigs may be able to reach the 4000 meter barrier, considering tensioning capacity only.

From Table 16 one can see that Seadrill's largest semis are listed to have a riser tensioning capacity of 19.6 MN. From Table 15 a 16" riser at 4400 meters would require 19.3 MN. Using one of the largest semis from Seadrill it may be possible to reach a sufficient water depth record of 4400 meters in the future. As Seadrill provide this capacity from several of their largest rigs already available on the market today, this record may be reached without building new rigs, considering this simplified riser tension capacity model.

It has to be realized that criteria other than the tensioning capacity might limit overall depth capacity increase.

Table 16 - The Largest Semi-Submersibles on the Market Today (RigLogix, 2012)

The Largest Semi-Submersibles available on the Market Today		
Owner	Rig Name	Tension Capacity (MN)
Diamond Offshore	Ocean Monarch	16
Diamond Offshore	Ocean Endeavor	16
Seadrill Ltd	West Aquarius	16
Seadrill Ltd	West Hercules	16
Seadrill Ltd	West Sirius	16
Ventura	SSV Victoria	16
Ventura	SSV Catarina	16
Songa Offshore AS	Songa Eclipse	16
Atwood Oceanics	Atwood Condor	16
Seadrill Ltd	West Taurus	19.6
Seadrill Ltd	West Capricorn	19.6
Seadrill Ltd	West Orion	19.6

Three interesting observations are made:

1) By selecting a 16” riser system, rigs available on the market today that have above 15 MN tensioning capacity may be able to reach the ultra-deep water depth of 4000 meters
2) The largest rigs today, owned by Seadrill, have a tension capacity of 19.6 MN. A modification to a 16” riser system may present the possibility of exceeding a water depth of 4000 meters
3) The rigs and tension capacities needed to reach these ultra-deep water depths are already available on the market today, thus no need for larger rigs to be built

It has to be noted that the model is simplified as no riser analysis is performed, however, the result are thought to give a good indication of the improvement potential.

4.0 Conclusion

Objective 1)

- Evaluation of reduction potential of reduced wellhead size from 18-3/4" to 13-5/8" on overall requirements to rig:

A reduction of the wellhead size from 18-3/4" to 13-5/8" has a potential reduction in day rates and overall time for drilling the well. The lower day rates are related to the reduction of rig requirement as earlier generation rigs can be used for deeper water wells. The reduced time is related to the lighter operation related to slim wells.

This thesis concludes that a reduction in day rate of up to 20% and reduction in drilling time of 20 - 30% may be achieved. The overall saving potential for a 1500 meters water depth well is found to be in excess of 40%.

When evaluating the potential of reducing the wellhead size from 18-3/4" to 13-5/8" on overall requirements to the rig, it becomes clear that there are savings to achieve. By introducing a slim wellhead design with a 16" riser system significant weight savings is obtained. With respect to variable deck load it is possible to achieve up to 50% in weight reduction for the BOP and 40% weight reduction for the slim drilling riser, giving a total reduction of 500 tonnes or more. Reduced diameter of the riser joints and flotation modules give a reduction of deck space of more than $100m^3$. The overall reduction may introduce smaller, lighter rigs into larger arenas.

It is difficult, as well as incorrect, to only look at the factors separately, since one would affects the other. One needs to look at this reduction of requirement from the overall picture.

The merits of the slim wellhead design can be summed up as follows:

- Slim riser has less weight due to less material and less mud volume in riser
- Slim riser thus requires less tension capacity from rig
- Less mud displacement volume
- Less mud chemicals on rig
- A 16" marine drilling riser requires less storage space and VDL capacity
- A slim wellhead results in lighter BOP which gives reduced deck weight before installed
- Lower weight gives an increase in the rig's stability
- Reduced weight in derrick which has an impact on the rig's stability

- Reduced diameter of drilled sections give reduced casing sizes and again reduced weight while stored on deck
- Slim section requires less mud during drilling
- Reduced annulus in well results in less cementing jobs
- Reduced diameters give less drill cuttings that needs to be transported to surface and further to shore by vessels
- Less cuttings to surface results in less weight on rig while stored on deck
- Reduced numbers of casing strings gives less crane lifts
- Less crane lifts reduces the need for supply boats

The conclusion is that a reduction in the nominal drilling system size from 18-3/4" to 13-5/8" could enable the use of smaller, less capable and less expensive drilling vessels. Smaller, less expensive, older generation rigs could be outfitted to drill in deeper water if the wellhead and riser size was reduced. The greater the water depth, the more important this becomes. A 4th generation semi could be used instead of a 5th or 6th generation semi, resulting in a cost saving of 160 000 to 260 000 USD/day included cost of personnel. Furthermore, reducing drill time with 20 - 30% to reach total depth, creating substantial savings in terms of costs.

Objective 2)

- Evaluation of potential increase in water depth capacity by reduction of the wellhead size:

A key consequence of a conventional wellhead design today is the riser size. A larger riser increases the weight and volume of the riser, the weight and volume of the mud in the riser, and therefore the riser top tension required from the vessel. The larger riser requires more space to store on the deck and more variable deck load capacity when the riser is on deck. The larger mud volume requires larger mud tanks and processing equipment.

Reduction of wellhead size can give a potential increase in water depth capacity by reducing the size of the marine drilling riser. When evaluation the size reduction of the riser it was found that by selecting a 16" riser system it may be possible to achieve reduced requirement to tension system capacity with 40%. Turning this around it has been shown that combining today's high tension capacity for 5th/6th generation rig with a 16" riser might facilitate drilling in water depths of 4000 meters and beyond. It is shown that a 15 MN of tensioning capacity might facilitate operations in 4000 meter and beyond. This capacity is found on rigs available on the market today, where the largest rigs today have a tension capacity of 19.6 MN.

5.0 Recommendation for Future Work

The main focus of this thesis has been the consequences of reducing the wellhead size, with special focus on the marine drilling riser and the riser system. The downscaling is based on simple assumptions to give rough indications of change in capabilities. The next step is verification work in terms of detail riser analyses for the different cases presented in the thesis, where one needs to examine the consequences of waves and currents being introduced to the slim drilling riser.

Additionally, an in-depth analysis will have to be done to verify the time saving potential.

Based on this a comprehensive case study should be initiated in which the well related enabling technologies are involved with the subsea and rig related expertise to prepare a complete case that can attract support from different environments.

Finally, it is proposed to explore the potential savings for smaller and lighter subsea production systems associated with the smaller wellheads in terms of lower investment and operational cost.

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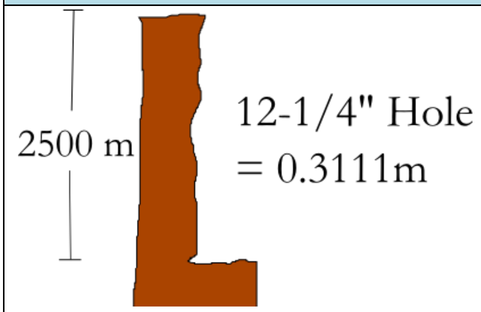
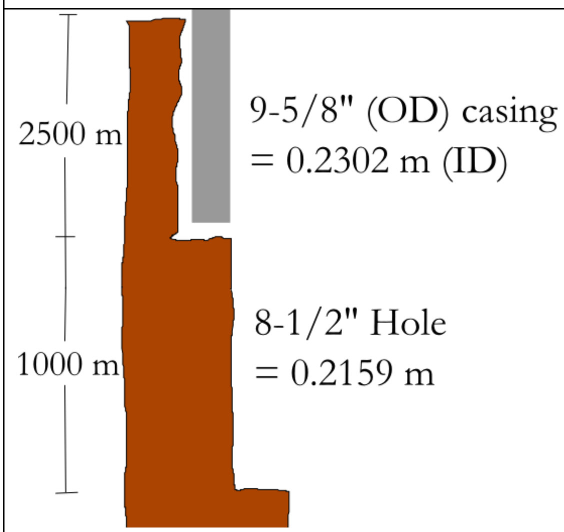
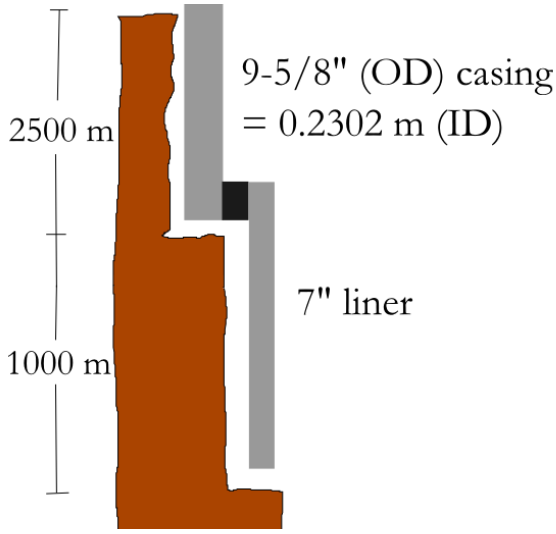
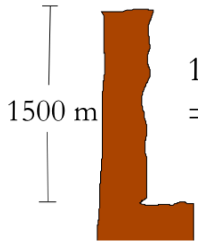
Appendix A – Calculations[3]

Mud Volume in Well 13-5/8" Wellhead Casing Program	
	$V = \left(\frac{\pi}{4}\right)(D)^2 * h = m^3$ $V1 = \left(\frac{\pi}{4}\right)(0.3111)^2 * 2500m = 190m^3$
	$V21 = \left(\frac{\pi}{4}\right)(0.2302)^2 * 2500m = 104m^3$ $V22 = \left(\frac{\pi}{4}\right)(0.2159)^2 * 1000m = 36.6m^3$ $V2 = V21 + V22 = 140.6\ m^3$
	Total of mud from the slim casing program: $V = V1 + V2 = 330m^3$

[3] Formulas for areas and volumes used in the Appendixes are from GABOLDE, G. & NGUYEN, J.-P. 1999. *Drilling data handbook,* Paris, Éditions Technip

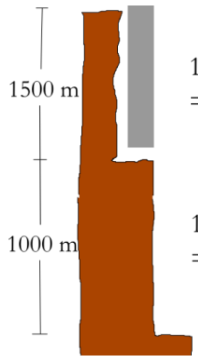
Mud Volume in Well
18-3/4” Wellhead Casing Program



14-3/4" Hole
= 0.3746 m

$$V = \left(\frac{\pi}{4}\right)(D)^2 * h = m^3$$

$$V1 = \left(\frac{\pi}{4}\right)(0.3746)^2 * 1500m = 165.3m^3$$



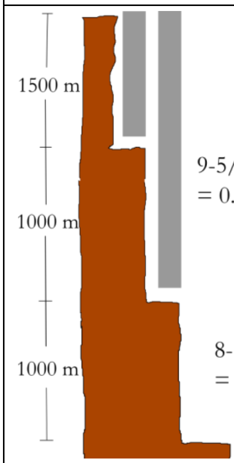
13-3/8" (OD) casing
= 0.3229 m (ID)

12-1/4" Hole
= 0.3111 m

$$V21 = \left(\frac{\pi}{4}\right)(0.3229)^2 * 1500 = 122.8m^3$$

$$V22 = \left(\frac{\pi}{4}\right)(0.3111)^2 * 1000m = 76m^3$$

$$V2 = V21 + V22 = 198.9\ m^3$$



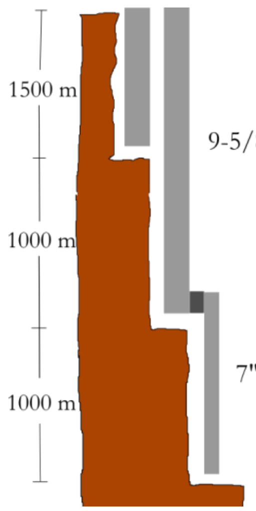
9-5/8" (OD) casing
= 0.2302 m (ID)

8-1/2" Hole
= 0.2159 m

$$V31 = \left(\frac{\pi}{4}\right)(0.2302)^2 * 2500 = 104m^3$$

$$V32 = \left(\frac{\pi}{4}\right)(0.2159)^2 * 1000 = 36.6m^3$$

$$V3 = V31 + V32 = 140.6\ m^3$$



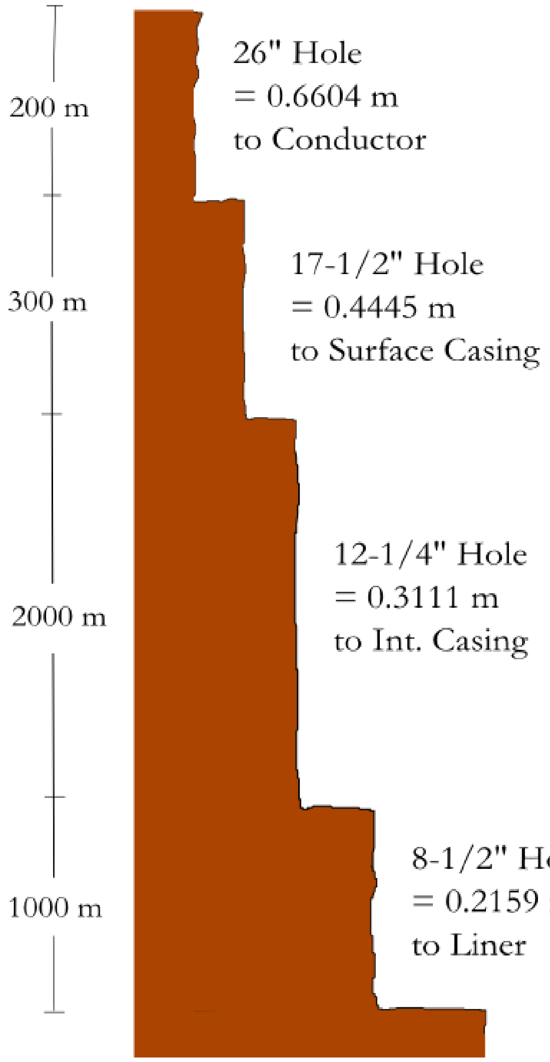
9-5/8" (OD) casing

7" liner

Total of mud from the
conventional casing program:

$$V = V1 + V2 + V3 = 505m^3$$

Extracted Formation
13-5/8” Wellhead Casing Program



$$V = \left(\frac{\pi}{4}\right)(D)^2 * h = m^3$$

$$V26" = \left(\frac{\pi}{4}\right)(0.6604)^2 * 200 = 68.4m^3$$

$$V17" = \left(\frac{\pi}{4}\right)(0.4445)^2 * 300 = 46.5m^3$$

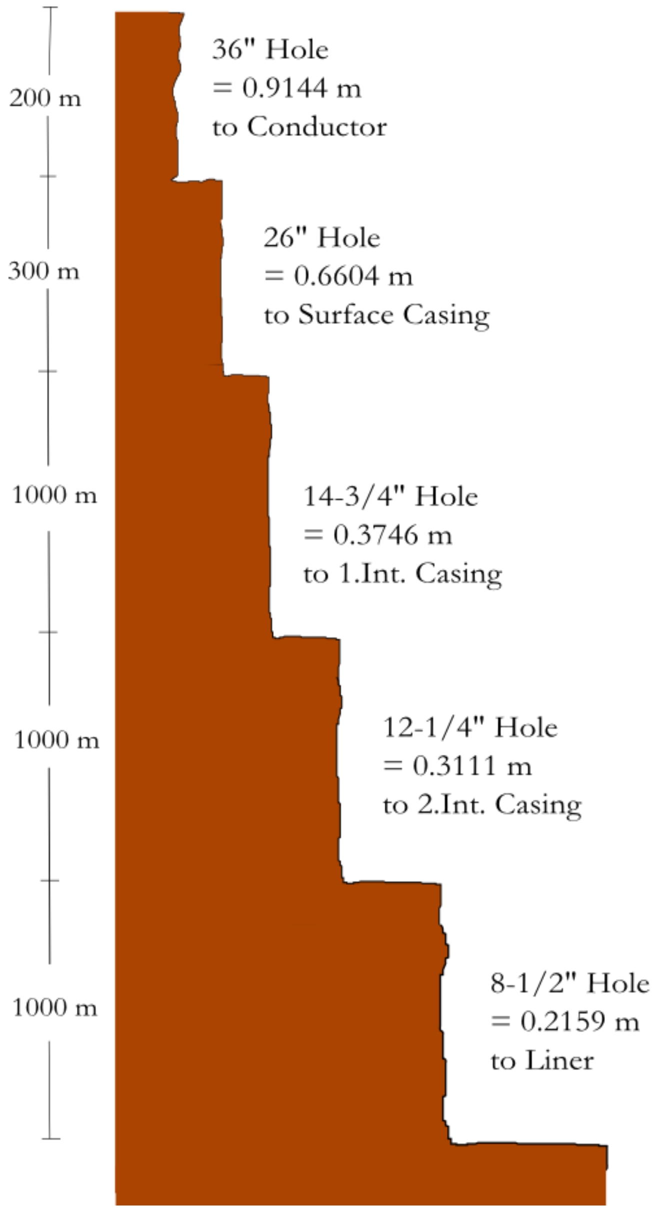
$$V12" = \left(\frac{\pi}{4}\right)(0.3111)^2 * 2000 = 152m^3$$

$$V8" = \left(\frac{\pi}{4}\right)(0.2159)^2 * 1000 = 36.6m^3$$

$$Vsw = V26 + V17 + V12 + V8$$
$$= 303.5m^3$$

Extracted Formation
18-3/4" Wellhead Casing Program

$$V = \left(\frac{\pi}{4}\right)(D)^2 * h = m^3$$



$$V36" = \left(\frac{\pi}{4}\right)(0.9144)^2 * 200$$
$$= 131.3m^3$$

$$V26" = \left(\frac{\pi}{4}\right)(0.6604)^2 * 300$$
$$= 102.6m^3$$

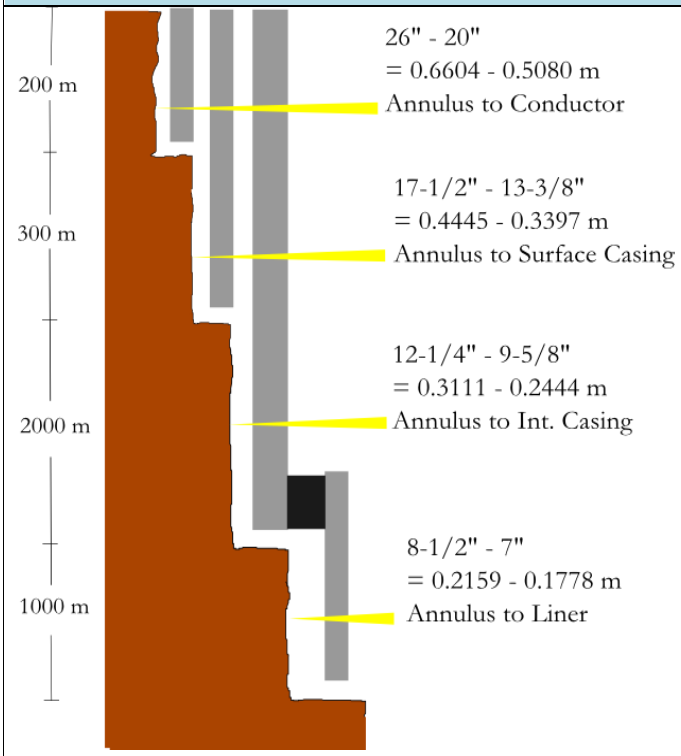
$$V14" = \left(\frac{\pi}{4}\right)(0.3746)^2 * 1000$$
$$= 110.2m^3$$

$$V12" = \left(\frac{\pi}{4}\right)(0.3111)^2 * 1000 = 76m^3$$

$$V8" = \left(\frac{\pi}{4}\right)(0.2159)^2 * 1000 = 36.6m^3$$

$$Vcw = V36 + V26 + V14 + V12 + V8$$
$$= 456.7m^3$$

Cemented Annulus Volume
13-5/8" Wellhead Casing Program



$$V = \left(\frac{\pi}{4}\right)(OD^2 - ID^2) * h = m^3$$

$$V1 = \left(\frac{\pi}{4}\right)(0.6604^2 - 0.5080^2) * 200$$
$$= 28.0m^3$$

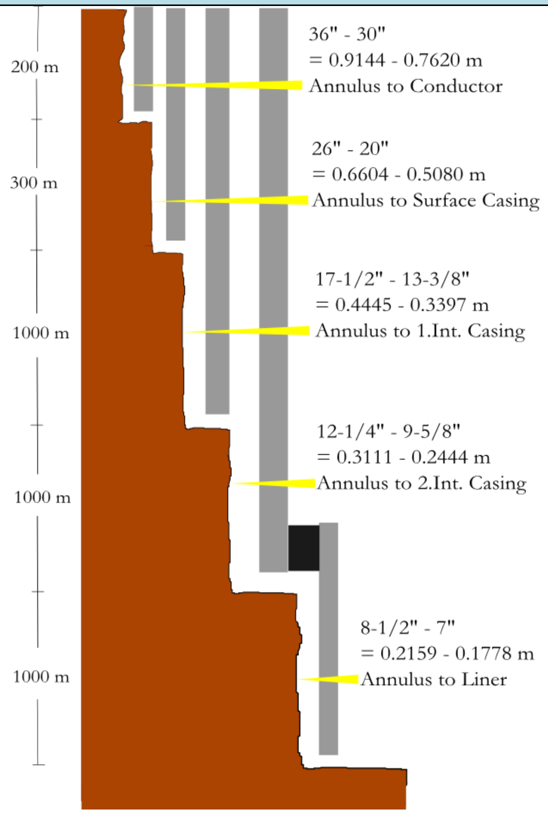
$$V2 = \left(\frac{\pi}{4}\right)(0.4445^2 - 0.3397^2) * 500$$
$$= 32.3m^3$$

$$V3 = \left(\frac{\pi}{4}\right)(0.3111^2 - 0.2444^2) * 2500$$
$$= 72.8m^3$$

$$V4 = \left(\frac{\pi}{4}\right)(0.2159^2 - 0.1778^2) * 1000$$
$$= 11.8m^3$$

$$V = V1 + V2 + V3 + V4 = 144.9m^3$$

Cemented Annulus Volume
18-3/4" Wellhead Casing Program



$$V1 = \left(\frac{\pi}{4}\right)(0.9144^2 - 0.7620^2) * 200$$
$$= 40.1m^3$$

$$V2 = \left(\frac{\pi}{4}\right)(0.6604^2 - 0.5080^2) * 500$$
$$= 70.0m^3$$

$$V3 = \left(\frac{\pi}{4}\right)(0.4445^2 - 0.3397^2) * 1500$$
$$= 96.8m^3$$

$$V4 = \left(\frac{\pi}{4}\right)(0.3111^2 - 0.2444^2) * 2500$$
$$= 72.8m^3$$

$$V5 = \left(\frac{\pi}{4}\right)(0.2159^2 - 0.1778^2) * 1000$$
$$= 11.8m^3$$

$$V = V1 + V2 + V3 + V4 + V5 = 291.5m^3$$

Proof of Proportional Reduction of Cross-Section and Hoop Stress

- $Hoop\ Stress\ Equation^4: \ \sigma_h = \frac{p_i D_i - p_o D_o}{2t}$
- $Reduction\ of\ Cross\ Section: \ \left(\frac{OD_{16"}}{OD_{21"}}\right)^2 = \left(\frac{16}{21}\right)^2 = 0.58$
- $Area\ of\ Riser: \ \left(\frac{\pi}{4}\right)(OD^2 - ID^2) = m^3$
- $p = h * 9.81 m/s^2 * \rho = Pa$
- $pi = 1500m * 9.81 m/s^2 * 1680 kg/m^3 = 24.7 * 10^6 Pa$
- $po = 1500m * 9.81 m/s^2 * 1025 kg/m^3 = 15.1 * 10^6 Pa$

<u>Area of 21" riser:</u>

OD: 21" = 0.5334 m
ID: 19.5 = 0.4953 m
Wall thickness, t = 0.75" = 0.0190 m

$$A21 = \left(\frac{\pi}{4}\right)(0.5334^2 - 0.4953^2) = 0.0308 m^3$$

- *<u>Known wall thickness and ID</u>*

<u>Area of 16" riser:</u>

OD: 16" = 0.4064 m
Area of 21" = 0.0308m^3
Reduction of Cross section = 0.58

$$A16 = \left(\frac{\pi}{4}\right)(0.4064^2) * 0.58 = 0.0179 m^3$$

- *Unknown <u>wall thickness and ID</u> found as follows:*

$$A(OD) = \left(\frac{\pi}{4}\right)(0.4064^2) = 0.1297 m^3$$

$$A(ID) = A(OD) - A16 = 0.1118 m^3$$

$$ID = \left(\frac{\pi}{4}\right)(ID^2) - A(ID)$$

- $ID = \sqrt{\left(\frac{4}{\pi}\right) A(ID)} = 0.3774$
- $t = \frac{OD - ID}{2} = \frac{0.4064 - 0.3774}{2} = 0.0145\ m$

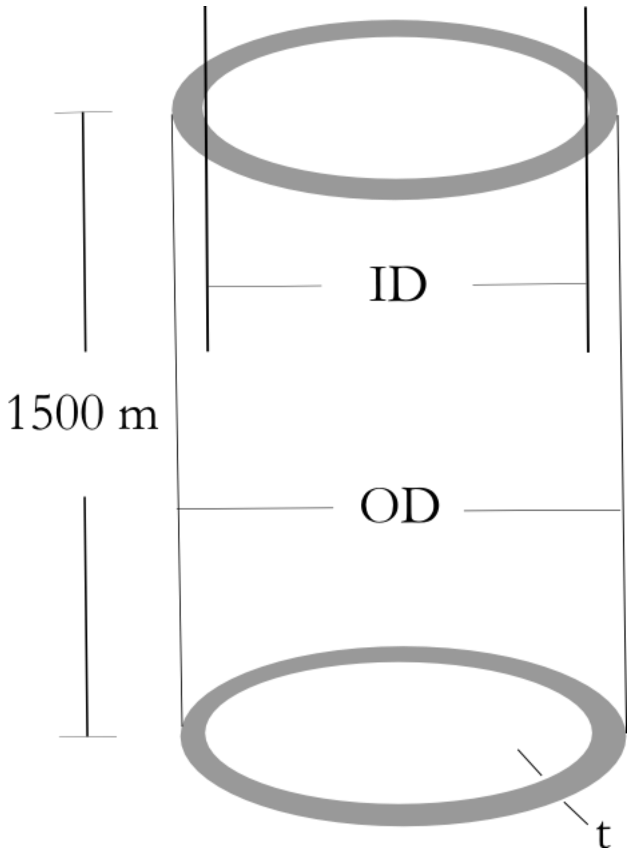
[4] Source: PALMER, A. C. & KING, R. A. 2008. Subsea pipeline engineering, Tulsa, Okla., PennWell.

This gives us Hoop Stress for the 21" and 16" riser:	
$\sigma_{h\,21"} = \dfrac{27.7\,MPa * 0.4943m - 15.1MPa * 0.5334}{2 * 0.0190m} = 109.3\,MPa$	$\sigma_{h\,16"} = \dfrac{27.7\,MPa * 0.3774m - 15.1MPa * 0.4064}{2 * 0.0145m} = 109.8\,MPa$
This gives the final result as: $\sigma_{h\,21"} \approx \sigma_{h\,16"}$	

Nomenclature of Symbols used for Proof of the Hoop Stress calculation

OD	Outer Diameter	A(ID)	Area inside of Riser, i.e. ID
ID	Inner Diameter	p_i	Pressure inside riser
A21	Area of Annulus to the 21" Riser	p_o	External Pressure on riser surface
A16	Area of Annulus to the 16" Riser	σ_h	Hoop stress
A(OD)	Area of Riser with OD	t	Wall thickness
ϱ	rho, density to fluid	D_o	Outer Diamter
h	Riser length of 1500 meters	D_i	Inner diameter

Volume of Marine Riser



$$V = \left(\frac{\pi}{4}\right)(OD^2 - ID^2) * h = m^3$$

<u>21” Marine Riser</u>

OD = 21” = 0.5334 m

ID = 19.5” = 0.4953 m

<u>16” Marine Riser</u>

OD = 16” = 0.4064 m

ID = 14.5” = 0.3648 m

Volumes of a 21” Marine Riser	**Volumes of a 16” Marine Riser**
$V(ID) = \left(\frac{\pi}{4}\right)(0.4953^2) * 1500 = 289.0m^3$ $V(OD) = \left(\frac{\pi}{4}\right)(0.5334^2) * 1500 = 335.2m^3$ $V\ 21" = V(OD) - V(ID) = 46.2m^3$	$V(ID) = \left(\frac{\pi}{4}\right)(0.3683^2) * 1500 = 159.8m^3$ $V(OD) = \left(\frac{\pi}{4}\right)(0.4064^2) * 1500 = 194.6m^3$ $V\ 16" = V(OD) - V(ID) = 34.8m^3$
Mud Weight Inside the 21” Marine Riser	**Mud Weight Inside the 16” Marine Riser**
<u>Mud type 1.44 SG = 1440 kg/m^3</u> 1440kg/m^3 * 289m^3 = 416.2 tonnes	<u>Mud type 1.44 SG = 1440 kg/m^3</u> 1440kg/m^3 * 159.8m^3 = 230.4 tonnes
<u>Mud type 1.68 SG = 1680 kg/m^3</u> 1680kg/m^3 * 289m^3 = 485.5 tonnes	<u>Mud type 1.68 SG = 1680 kg/m^3</u> 1680kg/m^3 * 159.8m^3 = 268.8 tonnes

Steel Weight of the 21" Marine Riser (without auxiliary lines)	Steel Weight of the 16" Marine Riser (without auxiliary lines)
$V\ 21" = V(OD) - V(ID) = 46.2m^3$	$V\ 16" = V(OD) - V(ID) = 34.8m^3$
Steel weight, ϱ = 7850 kg/m^3	
Weight of 1500 m 21" Riser 7850kg/m^3 * 46.2m^3 = 362.7 tonnes	Weight of 1500 m 16" Riser 7850kg/m^3 * 34.8m^3 = 273.2 tonnes
Weight of a 21" Riser per meter $\frac{362.7\ tonnes}{1500\ meters} = 241.8\ kg/m$	Weight of a 16" Riser per meter $\frac{273.2\ tonnes}{1500\ meters} = 182.1\ kg/m$
Weight of a 21" Riser Joint (75 ft.= 22.86m) 241.8 kg/m * 22.86 m = 5.5 tonnes/joint	Weight of a 16" Riser Joint (65 ft.=19.81m) 182.1 kg/m * 19.81 m = 3.6 tonnes/joint

Nomenclature of Symbols used for Marine Riser calculation			
OD	Outer Diameter	h	Riser length of 1500 meters
ID	Inner Diameter	V 21"	Volume of Annulus to the 21" riser
ϱ	rho, density to steel	V 16"	Volume of Annulus to the 16" riser

Volume and Weight of Riser Joint with C&K, Hydraulic and Boost line		
Dimensions used for calculation:	**21" Riser Joint (h = 75 ft. = 22.86 m)**	**16" Riser Joint (h = 65 ft. = 19.81 m)**
C&K line (OD x ID)	6-3/4" x 4-3/4" (0.17 x 0.12m)	5" x 4" (0.13 x 0.10m)
Hydraulic line (OD x ID)	4" x 3.5" (0.10 x 0.09m)	2-5/8" x 2" (0.07 x 0.05m)
Boost line (OD x ID)	5" x 4" (0.13 x 0.10m)	-

21" Riser Joint	**16" Riser Joint**
Volume of auxiliary lines $V = \left(\frac{\pi}{4}\right)(OD^2 - ID^2) * h = m^3$ Density of steel, ϱ = 7850kg/m^3	
$C\&K = \left(\frac{\pi}{4}\right)(0.17^2 - 0.12^2) * 22.86 = 0.260m^3$ $Hyd. = \left(\frac{\pi}{4}\right)(0.10^2 - 0.09^2) * 22.86 = 0.034m^3$ $Boost = \left(\frac{\pi}{4}\right)(0.13^2 - 0.10^2) * 22.86 = 0.124m^3$	$C\&K = \left(\frac{\pi}{4}\right)(0.13^2 - 0.10^2) * 19.81 = 0.107m^3$ $Hyd. = \left(\frac{\pi}{4}\right)(0.07^2 - 0.05^2) * 19.81 = 0.037m^3$
Volume of auxiliary lines: $V.l = 2 * C\&K + 2 * Hyd. + 1 * Boost = \frac{0.712m^3}{joint}$	Volume of auxiliary lines: $V.l = 2 * C\&K + 2 * Hyd = \frac{0.288m^3}{joint}$

Weight of auxiliary lines: $W_l = \varrho * V_l = 7850kg/m^3 * 0.712m^3 =$ 5.6 tonnes/joint	Weight of auxiliary lines: $W_l = \varrho * V_l = 7850kg/m^3 * 0.288m^3 =$ 2.3 tonnes/joint
Weight of flotation modules (dry) W_b = 10.3 tonnes/joint	Weight of flotation modules (dry) W_b = 5.4 tonnes/joint
Weight of a 21" Riser Joint (75 ft.= 22.86m) *(found from previous calculation of the marine riser)* W_r = 241.8 kg/m * 22.86 m = 5.5 tonnes/joint	Weight of a 16" Riser Joint (65 ft.=19.81m) *(found from previous calculation of the marine riser)* W_r = 182.1 kg/m * 19.81 m = 3.6 tonnes/joint
Total Weight of Joint w/ auxiliary lines $W_{tot} = W_t + W_l$ = 11.1 tonnes/joint Kilogram per meter: $\frac{11.1\ tonnes}{22.86\ meters} = 485.56\ kg/m$	Total Weight of Joint w/ auxiliary lines $W_{tot} = W_t + W_l$ = 5.9 tonnes/joint Kilogram per meter: $\frac{5.9\ tonnes}{19.81\ meters} = 297.8\ kg/m$
Total Weight of Joint w/ auxiliary lines and flotation modules: $W_{tot} = W_t + W_b + W_l$ = 21.4 tonne/joint Kilogram per meter: $\frac{21.4\ tonnes}{22.86\ meters} = 936.13\ kg/m$	Total Weight of Joint w/ auxiliary lines and flotation modules: $W_{tot} = W_t + W_b + W_l$ = 11.3 tonnes/joint Kilogram per meter: $\frac{11.3\ tonnes}{19.81\ meters} = 570.41\ kg/m$
Total Weight of a 1500 m riser w/95% of riser with floatation modules W_{1500} = 936.1kg/m * 1425m + 485.6Kg/m * 75m = 1370.4 tonnes	Total Weight of a 1500 m riser w/95% of riser with floatation modules W_{1500} = 570.4kg/m * 1425m + 297.8kg/m * 75m = 835.2 tonnes

<table>
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<u>Total Weight of a 3000 m riser</u>
<u>w/95% of riser with floatation modules</u>

W_{3000} = 936.1kg/m * 2850m + 485.6/m * 150m

= 2740.7 tonnes

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<u>Total Weight of a 3000 m riser</u>
<u>w/95% of riser with floatation modules</u>

W_{3000} = 570.4kg/m * 2850m + 297.8kg/m * 150m

= 1670.3 tonnes

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<tr>
<td colspan="2">Nomenclature of Symbols used for Riser Joint calculation</td>
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OD Outer Diameter
ID Inner Diameter
ϱ rho, density to steel
h Riser Joint length
V_1 Volume of auxiliary lines

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W_1 Weight of auxiliary lines
Wb Weight of flotation modules
Wr Weight of bare riser joint
Wtot Total weight Joint
W1500 Total weight of a 1500m riser
W3000 Total weight of a 3000m riser

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Simplified Riser Tension Analysis

Simplified Calculation of a Riser with auxiliary lines and its displacements, neglecting the floatation modules

(results calculated in "Volume of Marine Riser")

21" (OD = 0.5334m) Marine Riser, 1500m:

- Volume of riser = 46.2 m^3
- Density of steel, ϱ_s = 7850 kg/m^3
- Density of mud, ϱ_m = 1680 kg/m^3
- Density of water, ϱ_w = 1025 kg/m^3
- ID = 19.5" = 0.4953 m
- 21" Riser joint = 22.86 m

W_{true} = 7850kg/m^3 * 46.2 m^3 = 362.7 tonnes

$$WMr = \frac{\pi}{4}(0.4953^2) * 1500m * 1680\text{kg/m}^3$$
$$= 485.5\ tonnes$$

(results calculated in "Volume of Marine Riser")

16" (OD = 0.4064 m) Marine Riser, 1500m:

- Volume of riser = 34.8 m^3
- Density of steel, ϱ_s = 7850 kg/m^3
- Density of mud, ϱ_m = 1680 kg/m^3
- Density of water, ϱ_w = 1025 kg/m^3
- ID = 14.5" = 0.3648 m
- 16" Riser joint = 19.81 m

W_{true} = 7850kg/m^3 * 34.8 m^3 = 273.2 tonnes

$$WMr = \frac{\pi}{4}(0.3638^2) * 1500m * 1680\text{kg/m}^3$$
$$= 236.4\ tonnes$$

21" auxiliary lines, 1500m:

$$\text{Volume of lines } = \frac{0.712m^3}{22.86m} * 1500\ m = \ 46.7\text{m}^3$$

$W_{true\text{-}l}$ = 7850kg/m^3 * 46.7 m^3 = 366.7 tonnes

$$WMl = \frac{\pi}{4}(0.12^2 * 2 + 0.09^2 * 2 + 0.10^2) * 1500m$$
$$* \frac{1680\text{kg}}{\text{m}^3} = 108.9\ tonnes$$

16" auxiliary lines, 1500m:

$$\text{Volume of lines } = \frac{0.288m^3}{19.81m} * 1500\ m = \ 21.8\text{m}^3$$

$W_{true\text{-}l}$ = 7850kg/m^3 * 21.8 m^3 = 171.2 tonnes

$$WMl = \frac{\pi}{4}(0.10^2 * 2 + 0.05^2 * 2) * 1500m * \frac{1680\text{kg}}{\text{m}^3}$$
$$= 49.5 tonnes$$

Area:

$$A\ riser = \frac{\pi}{4}(0.5334^2) = 0.223\ m2$$
$$A\ lines = \frac{\pi}{4}(0.17^2 * 2 + 0.10^2 * 2 + 0.13^2) = 0.0742\ m^2$$
$$A\ total = A\ riser + A\ lines = 0.2973\ m^2$$

Area:

$$A\ riser = \frac{\pi}{4}(0.4064^2) = 0.130\ m2$$
$$A\ lines = \frac{\pi}{4}(0.07^2 * 2 + 0.13^2 * 2) = 0.0342\ m^2$$
$$A\ total = A\ riser + A\ lines = 0.164\ m^2$$

Volume and buoyancy of whole riser:

V_{tot} = A total * 1500m = 445.95 m^3

Buoyancy, B_r = 445.95 m^3 * 1025 kg/m^3 = 457.1 tonnes

Volume and buoyancy of whole riser:

V_{tot} = A total * 1500m = 245.94 m^3

Buoyancy, B_r = 245.94 m^3 * 1025 kg/m^3 = 252.1 tonnes

Tension of riser w/ lines, neglected floatation modules:

= W_{true} + WM_r + $W_{true.l}$ + WM_l – B = W_{tot} - W_f

= 362.7 + 485.5 + 366.7 + 108.9 – 457.1 tonnes

$T_{21"}$ = 866.7 tonnes required to tension

Tension of riser w/ lines, neglected floatation modules:

= W_{true}+ WM_r + $W_{true.l}$ + WM_l – B = W_{tot} - W_f

= 273.2 + 236.3 + 171.2 + 49.5 – 252.1 tonnes

$T_{16"}$ = 478.1 tonnes required to tension

<u>The difference in tension requirement between a 21" and 16" riser system by a simplified calculation is as follows:</u>

$$Tension\ Difference = \frac{478.1\ tonnes}{866.7\ tonnes} - 1 = 44.8\ \%$$

Nomenclature of Symbols used for Riser Tension and Displacement calculations

OD	Outer diameter
ID	Inner diameter
W_{true}	Weight of bare riser tube
WM_r	Weight of Mud in riser
$W_{true.l}$	Weight of auxiliary lines
WM_l	Weight of mud in lines
W_{tot}	Total weight (dry)
W_f	Weight of displaced fluid
A_{riser}	Area of OD riser
A_{lines}	Area of lines, OD
A_{total}	Total area of riser with lines
V_{tot}	Total volume of OD riser and lines
B_r	Buoyancy of displaced riser with lines
$T_{21"}$	Tension for the 21" riser
$T_{16"}$	Tension for the 16" riser

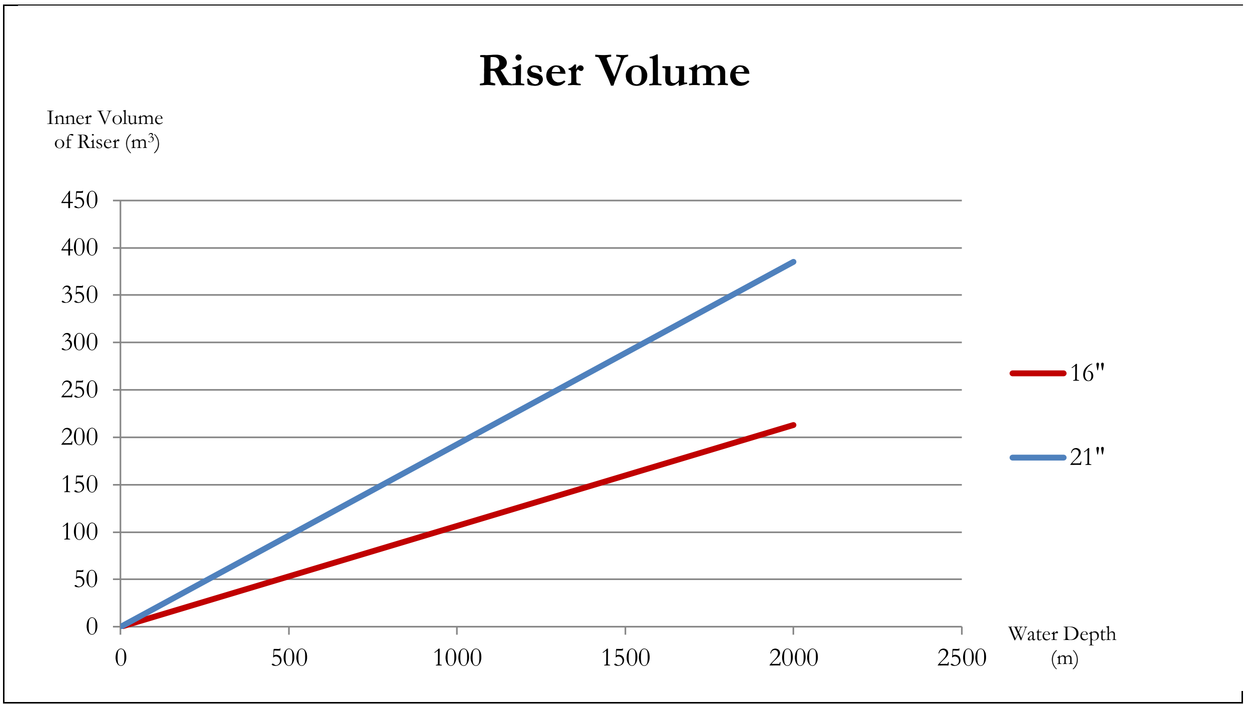
Velocity in Marine Riser

Graph of reduced velocity and pump rate in Marine Riser when reducing size from a 21" to 16" were plotted in Excel by following volume and selected water depths:

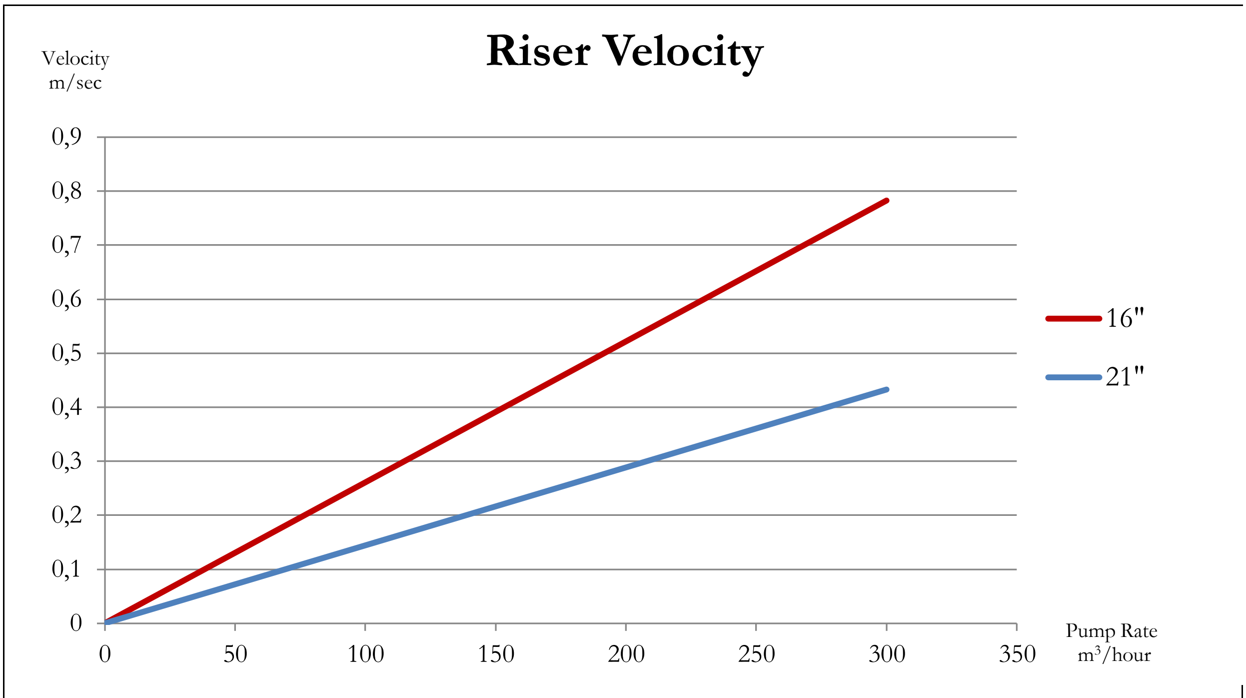
21" OD Riser	**16" OD Riser**
$Area = \left(\frac{\pi}{4}\right)(ID)^2$	
ID = 19.5" = 0.4953 m $Area = \left(\frac{\pi}{4}\right)(0.4953)^2 = 0.1927\ m^2$	ID=14.5" = 0.3683 m $Area = \left(\frac{\pi}{4}\right)(0.3683)^2 = 0.1065\ m^2$
$Volume = \left(\frac{\pi}{4}\right)(ID)^2 * h = m^3$ Selected Water Depth is 0 and 2000 meter	
$Volume\ at\ 0\ m = \left(\frac{\pi}{4}\right)(0.4953)^2 * 0 = 0\ m^3$	$Volume\ at\ 0\ m = \left(\frac{\pi}{4}\right)(0.3683)^2 * 0 = 0\ m^3$
$Volume\ at\ 2000\ m = \left(\frac{\pi}{4}\right)(0.4953)^2 * 2000 = 385.4\ m^3$	$Volume\ at\ 2000\ m = \left(\frac{\pi}{4}\right)(0.3683)^2 * 2000 = 213.1\ m^3$
$Pump\ Rate = \frac{m^3}{hour}$ $Velocity = \frac{m}{sec}$ Selected Pump Rate is 0 and 300 m^3/hour	
$Pump\ rate\ at\ 0m^3/h = \frac{0m^3}{36000sec * Area} = 0.0\ m/sec$	$Pump\ rate\ at\ 0m^3/h = \frac{0m^3}{36000sec * Area} = 0.0\ m/sec$
$Pump\ rate\ at\ 300m^3/h = \frac{300m^3}{36000sec * Area} = 0.78\ m/sec$	$Pump\ rate\ at\ 300m^3/h = \frac{300m^3}{36000sec * Area} = 0.43\ m/sec$

The calculated data from "Velocity Of Marine Riser" we could plot the following graphs

1) Mud difference / volume difference between 21" and 16" Marine Riser:



2) Decrease of velocity in riser when decrease size from a 21" to a 16" Marine Riser:



Appendix B – Collected Data from RigLogix[5]

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m^3)	Sack Storage (m^3)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Stena Drilling	Stena Clyde	2	503	3 220	21 478	458	57	4 800		544
Transocean Ltd.	C Kirk Rhein Jr	2	1 006	3 749	24 278	569	101	4 800		635
Transocean Ltd.	Falcon 100	2	732	3 047	21 962	559	170	4 800	$248 000	590
Queiroz Galvao Oleo e Gas S.A.	Alaskan Star	2	510	2 540	20 113	328	170	3 200		454
Dolphin Drilling	Borgny Dolphin	2	533	3 175	24 184	239	170	4 400	$233 000	567
Dolphin Drilling	Byford Dolphin	2	457	3 025	24 280	633	170	4 800	$324 000	544
Petrobras (NOC)	Petrobras XVI	2	457	2 313	23 005	400	124	3 200		599
Transocean Ltd.	J W McLean	2	381	3 475	27 216	530	113	5 100		590
Transocean Ltd.	GSF Aleutian Key	2	701	2 540	21 654	300	170	4 800		590
Transocean Ltd.	GSF Grand Banks	2	457	5 103	24 055	763	142	4 800	$297 000	590
Diamond Offshore	Ocean Concord	2	671	2 041	16 872	293	170	4 800	$249 000	454
Diamond Offshore	Ocean Epoch	2	610	2 722	22 411	534	144	4 800		454
Diamond Offshore	Ocean General	2	500	2 722	16 668	493	144	4 800		454
Diamond Offshore	Ocean Lexington	2	610	2 722	16 901	349	170	4 800	$271 000	454
Petrobras (NOC)	Petrobras XVII	2	701	2 313	23 005	400	111	3 200		454
Transocean Ltd.	Sedco 709	2	1 524	2 870	23 058	708	85	4 800		590
Diamond Offshore	Ocean New Era	2	457	2 222	16 668	323	142	3 400		454
Diamond Offshore	Ocean Nomad	2	366	2 997	24 508	369	65	4 800	$235 000	635

[5] Source: RIGLOGIX 2012. Online Offshore Rig Reporting System (Online Rig Database). RigZone

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m³)	Sack Storage (m³)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Diamond Offshore	Ocean Princess	2	457	3 312	26 100	719	-	4 800	$230 000	507
Diamond Offshore	Ocean Saratoga	2	610	2 268	19 162	270	170	4 800	$285 000	454
Diamond Offshore	Ocean Onyx	2	975	3 048	23 541	287	113	3 200		454
Diamond Offshore	Ocean Whittington	2	503	2 649	19 637	359	170	4 800	$241 173	454
Transocean Ltd.	Sedco 702	2	2 000	4 001	23 342	398	85	4 800	$357 000	590
Transocean Ltd.	Sedco 703	2	610	3 276	24 504	386	85	4 800		454
Transocean Ltd.	Sedco 704	2	305	2 429	23 886	704	77	3 200	$252 000	590
Transocean Ltd.	Sedco 706	2	2 000	4 001	22 686	332	85	4 800	$311 000	590
Transocean Ltd.	Sedco 601	2	457	2 856	17 714	511	85	3 200		590
Essar Oilfields Services Ltd.	Essar Wildcat	2	396	2 253	24 099	239	85	4 800		454
Diamond Offshore	Ocean Ambassador	2	335	2 540	32 796	420	42	4 800	$260 000	454
Noble Drilling	Noble Therald Martin	2	1 219	2 499	19 057	419	113	4 800	$270 000	499
Noble Drilling	Noble Driller	2	1 524	2 722	23 220	254	45	6 400	$375 000	680
ENSCO	ENSCO 5002	2	305	3 000		395	113	4 800	$200 000	644
ENSCO	ENSCO 5000	2	701	2 095	17 002	410	170	4 800	$239 000	590
ENSCO	ENSCO 5003	2	305	3 000	19 610	270	170	4 800		454
Larsen O&G	Petrolia	2	366	2 100	19 749	350	87	3 200		590
Saipem	Scarabeo 4	2	545	2 631	21 779	348	28	3 200		454
Transocean Ltd.	Sedneth 701	2	457	3 599	24 714	666	85	4 800	$235 000	544
Noble Drilling	Noble Lorris Bouzigard	2	1 219	2 495	15 694	419	113	4 800		454

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m^3)	Sack Storage (m^3)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Songa Offshore AS	Songa Venus	2	457	1 727	19 684	314	170	4 800	$224 600	544
Diamond Offshore	Ocean Bounty	2	457	3 048	30 416	588	278	6 000		454
Dolphin Drilling	Borgsten Dolphin	2	457	3 200	23 650	270	170	4 800		567
Dolphin Drilling	Bredford Dolphin	2	457	4 001	26 575	528	87	4 800	$364 000	454
Diamond Offshore	Ocean Guardian	3	457	3 556	25 741	301	368	4 800	$263 000	605
Transocean Ltd.	Transocean John Shaw	3	549	3 199	29 689	414	198	4 800	$274 000	635
Odfjell	Songa Delta	3	701	3 700	39 482	999	232	4 800	$435 000	567
Noble Drilling	Noble Ton Van Langeveld	3	457	2 994	37 857	350	113	4 800	$247 000	454
Songa Offshore AS	Songa Dee	3	549	4 300	28 625	524	204	4 800	$340 000	567
Atwood Oceanics	Atwood Hunter	3	1 524	3 266	24 067	516	145	4 800	$545 000	544
Transocean Ltd.	M G Hulme Jr	3	1 524	4 400	28 103	329	212	4 800	$220 000	454
ENSCO	ENSCO 5004	3	457	2 350	22 641	352	170	4 800	$220 000	567
Transocean Ltd.	Transocean Winner	3	457	3 899	25 791	341	212	4 800	$482 000	578
Transocean Ltd.	Transocean Prospect	3	457	3 399	29 080	424	170	4 800	$242 000	590
Transocean Ltd.	Transocean Searcher	3	457	3 049	28 301	333	57	4 800	$429 000	590
Transocean Ltd.	Sedco 700	3	1 097	2 092	23 887	539	85	4 800		590
Transocean Ltd.	Transocean Amirante	3	1 067	3 499	29 105	335	210	4 800	$247 000	454
Transocean Ltd.	Transocean Driller	3	914	4 063	30 095	348	227	4 800	$265 000	590
Transocean Ltd.	Transocean Legend	3	1 067	2 599	28 300	391	113	4 800	$293 000	476

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m^3)	Sack Storage (m^3)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Transocean Ltd.	Sedco 710	3	1 372	2 266	24 929	686	85	3 200	$289 000	603
Transocean Ltd.	Sedco 711	3	549	3 536	24 792	312	85	4 800		590
Transocean Ltd.	Sedco 712	3	488	3 989	25 320	382	42	3 200		590
Transocean Ltd.	Sedco 714	3	488	3 446	25 932	334	85	6 600	$256 000	590
Diamond Offshore	Ocean Vanguard	3	457	2 898	27 663	385	-	4 800	$349 000	567
Diamond Offshore	Ocean Winner	3	1 067	3 556	19 637	579	170	4 800	$283 500	454
Diamond Offshore	Ocean Worker	3	1 219	3 856	27 515	429	85	4 800	$283 500	454
Diamond Offshore	Ocean Yatzy	3	1 006	3 039	25 972	525	142	3 200	$257 000	590
Diamond Offshore	Ocean Patriot	3	457	2 268	25 674	313	76	4 800	$260 000	567
Transocean Ltd.	GSF Rig 135	3	853	3 447	26 796	591	99	5 100	$260 000	590
Transocean Ltd.	GSF Rig 140	3	457	3 447	24 309	737	99	5 100	$260 000	590
Transocean Ltd.	GSF Arctic I	3	1 036	3 756	25 642	616	99	5 100	$250 000	635
Awilco Drilling PLC	WilPhoenix	3	366	4 167	25 419	277	170	3 200	$255 000	567
Transocean Ltd.	GSF Arctic III	3	549	2 771	25 642	352	99	4 800	$280 000	635
Awilco Drilling PLC	WilHunter	3	457	4 081	28 395	355	227	3 200	$157 000	635
Transocean Ltd.	Sovereign Explorer	3	1 372	3 515	27 415	500	212	4 800		635
Transocean Ltd.	Jim Cunningham	3	1 402	4 509	28 109	657	212	4 800		631
Saipem	Scarabeo 6	3	780	3 221	31 506	341	72	3 400	$340 000	635
Petrobras (NOC)	Petrobras X	3	1 189	3 336	25 585	477	154	4 800		454
Odfjell	Deepsea Bergen	3	457	4 082	27 958	353	219	4 800	$319 000	590
ENSCO	ENSCO 5005	3	457	3 200	28 109	471	139	4 800	$235 000	603

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m^3)	Sack Storage (m^3)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Transocean Ltd.	Actinia	3	457	2 721	28 110	450	142	3 200	$222 000	590
Atwood Oceanics	Atwood Eagle	3	1 524	4 536	28 924	576	145	5 100	$399 000	544
Atwood Oceanics	Atwood Falcon	3	1 524	3 992	26 222	864	145	4 800		454
Transocean Ltd.	Henry Goodrich	4	1 524	4 999	49 706	525	283	4 800	$335 000	680
Noble Drilling	Noble Homer Ferrington	4	2 195	3 629	26 585	978	99	6 400	$505 000	875
Petrobras (NOC)	Petrobras XXIII	4	1 890	3 773	29 665	1 141	-	4 800		590
Dolphin Drilling	Borgland Dolphin	4	457	3 503	28 766	1 123	-	4 800	$530 000	527
Seadrill Ltd.	West Alpha	4	610	5 289	30 699	760	99	4 800	$503 000	590
Saipem	Scarabeo 5	4	2 000	4 500	41 998	1 090	-	4 800	$399 000	581
Transocean Ltd.	Paul B Loyd Jr	4	610	4 196	39 502	506	113	4 800	$344 000	875
Diamond Offshore	Ocean Alliance	4	1 600	3 912	44 452	653	425	5 100	$341 000	816
Diamond Offshore	Ocean America	4	1 524	7 507	43 721	1 375	465	5 250	$425 000	635
Maersk Drilling	Maersk Explorer	4	914	4 082	30 194	1 028	142	6 600		907
Diamond Offshore	Ocean Star	4	1 676	5 080	33 315	533	227	4 800	$300 000	590
Diamond Offshore	Ocean Quest	4	1 067	5 080	33 270	474	113	5 400	$301 000	522
Transocean Ltd.	Jack Bates	4	1 646	6 109	52 843	636	283	5 100	$380 000	907
Diamond Offshore	Ocean Victory	4	1 829	5 122	33 367	509	113	3 200	$325 000	635
Noble Drilling	Noble Jim Thompson	4	1 829	3 629	28 775	1 739	142	5 400	$352 000	680
Noble Drilling	Noble Amos Runner	4	2 438	3 629	27 230	1 670	142	6 000	$360 000	680
Transocean Ltd.	Transocean Rather	4	1 372	3 499	37 523	668	100	4 800	$437 000	680

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m^3)	Sack Storage (m^3)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Transocean Ltd.	Transocean Richardson	4	1 524	3 499	36 931	763	99	4 800		680
Transocean Ltd.	Sedco 707	4	1 981	4 253	22 713	641	85	4 800	$404 000	603
Transocean Ltd.	Transocean Marianas	4	2 134	3 726	39 600	1 590	-	6 000	$450 000	680
Transocean Ltd.	Transocean Polar Pioneer	4	500	4 460	46 440	983	-	4 800	$512 000	590
Transocean Ltd.	Transocean Leader	4	1 372	4 599	44 459	2 183	-	4 800	$400 000	860
Transocean Ltd.	Transocean Arctic	4	500	4 469	36 199	175	141	4 800	$296 000	590
Transocean Ltd.	GSF Celtic Sea	4	1 753	5 080	46 173	1 297	-	4 800	$320 000	726
Noble Drilling	Noble Max Smith	4	2 134	3 629	27 230	1 852	142	4 800	407000	680
Noble Drilling	Noble Paul Romano	4	1 829	3 629	27 230	1 685	142	4 800	$325 000	680
Noble Drilling	Noble Paul Wolff	4	3 048	4 990	31 701	1 460	142	6 400	$428 000	680
ENSCO	ENSCO 5001	4	1 981	3 850	25 577	844	170	6 400	$275 000	680
ENSCO	ENSCO 5006	4	2 286	8 855	39 316	1 574	170	6 600	$275 000	726
ENSCO	ENSCO 6003	4	1 707	3 500		636	57	4 800	$319 000	590
ENSCO	ENSCO 6004	4	1 707	3 500		636	57	4 800	$315 000	590
Saipem	Scarabeo 7	4	1 494	4 014	38 174	500	71	7 000		680
Diamond Offshore	Ocean Valiant	4	1 524	6 400	44 693	448	465	4 800	$320 000	680
ENSCO	ENSCO 6002	4	1 707	3 500		636	57	4 800	$275 000	590
ENSCO	ENSCO 6001	4	1 707	3 500		636	57	4 800	$275 000	590
Seadrill Ltd.	West Venture	5	1 829	5 500	49 310	2 454	283	8 800	$440 000	590
Seadrill Ltd	West Orion	5	3 048	7 000		2 990	176	8 800	$623 000	-
Seadrill Ltd	West Sirius	5	3 048	7 000		2 989	176	8 800	$474 000	1 134

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m³)	Sack Storage (m³)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Noble Drilling	Noble Clyde Boudreaux	5	3 048	4 990		1 757	85	8 800	$417 000	907
Ocean Rig Asa	Eirik Raude	5	3 048	6 250	52 597	1 668	-	6 600	$535 000	907
Transocean Ltd.	Deepwater Nautilus	5	2 438	7 684	46 932	1 749	283	8 800	$550 000	907
Diamond Offshore	Ocean Monarch	5	3 048	6 096	43 282	1 582	170	8 800	$395 000	907
Diamond Offshore	Ocean Endeavor	5	3 048	6 096	42 464	1 609	170	8 800	$285 000	907
Diamond Offshore	Ocean Rover	5	2 438	5 588	35 641	1 104	170	8 200	$450 000	907
Diamond Offshore	Ocean Confidence	5	3 048	6 001	47 047	1 240	566	8 800	$511 635	907
Ocean Rig Asa	Leiv Eiriksson	5	2 499	6 250	52 597	1 668	-	6 600	$540 000	680
Diamond Offshore	Ocean Baroness	5	1 981	5 588	35 638	1 104	170	8 200	$276 000	907
ENSCO	ENSCO 7500	5	2 438	7 711	24 314	1 936	227	7 000	$325 000	875
Dolphin Drilling	Blackford Dolphin	5	2 134	4 500	33 871	795	87	6 600	$351 000	680
Transocean Ltd.	Sedco Energy	5	2 286	5 998	34 470	1 717	283	8 800	$440 000	907
Transocean Ltd.	Sedco Express	5	2 286	5 998	34 470	1 720	283	6 600	$470 000	933
Transocean Ltd.	Cajun Express	5	2 591	5 987	33 791	1 829	283	8 800	$535 000	680
Transocean Ltd.	GSF Development Driller II	6	2 286	7 000	42 190	3 029	147	8 800	$580 000	907
Diamond Offshore	Ocean Valor	6	3 048	8 001	46 502	3 018	173	8 800	$440 000	1 134
Transocean Ltd.	Development Driller III	6	2 286	13 500	53 717	1 876	-	8 800	$403 000	907
Noble Drilling	Noble Jim Day	6	3 658	7 257	55 429	2 035	283	9 600	$530 000	1 134
Diamond Offshore	Ocean Courage	6	3 048	8 001	46 502	2 968	142	8 800	$407 000	1 134
Noble Drilling	Noble Danny Adkins	6	3 658	7 257	52 597	2 035	283	9 600	$474 000	1 134

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m^3)	Sack Storage (m^3)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Maersk Drilling	Maersk Developer	6	3 048	13 500		3 005	283	8 800	$476 000	1 134
Maersk Drilling	Maersk Discoverer	6	3 048	13 500		3 005	-	8 800		1 134
ENSCO	ENSCO 8502	6	2 591	7 257		2 576	227	8 800	$490 000	907
ENSCO	ENSCO 8503	6	2 591	7 257		2 528	227	8 800	$545 000	907
Noble Drilling	Noble Dave Beard	6	3 048	5 443		1 614	99	9 600	$220 000	907
Transocean Ltd.	GSF Development Driller I	6	2 286	7 000	42 190	3 029	156	8 800	$513 000	907
Seadrill Ltd.	West Phoenix	6	3 048	5 443		1 000	142	8 800	$544 000	907
Seadrill Ltd	West Eminence	6	2 999	6 000		1 100	142	8 800	$623 000	907
Ventura	SSV Catarina	6	3 048	8 500		2 806	212	8 800		907
Ventura	SSV Victoria	6	3 048	8 500		2 806	212	8 800	$473 000	907
Atwood Oceanics	Atwood Condor	6	3 048	8 000	46 567	2 664	177	8 800	514000	907
ENSCO	ENSCO 8504	6	2 591	8 000		2 528	227	8 800	$423 500	907
Seadrill Ltd	West Leo	6	3 048	6 200		2 000	144	8 800	525000	907
Seadrill Ltd	West Capricorn	6	2 286	7 000		2 990	176	8 800	487000	-
ENSCO	ENSCO 8500	6	2 591	8 000		2 576	227	8 800	$295 000	907
ENSCO	ENSCO 8501	6	2 591	8 000		2 576	227	8 800	$375 000	907
Seadrill Ltd	West Pegasus	6	3 048	6 200	49 532	2 000	144	8 800	$465 000	907
Saipem	Scarabeo 9	6	3 658	8 165	48 019	3 037	227	8 800	$471 000	907
Atwood Oceanics	Atwood Osprey	6	2 499	6 001	49 750	2 536	212	8 800	$490 000	907

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	Variable Deck Load (tonnes)	Operating Displacement (tonnes)	Liquid Mud Capacity (m^3)	Sack Storage (m^3)	Mud Pumps Total Capacity (HP)	Day Rate (USD)	Hoisting Capacity (tonnes)
Sevan Drilling	Sevan Driller II (Brasil)	6	3 658	10 000	55 799	2 850	-	8 800		
Songa Offshore AS	Songa Eclipse	6	3 048	6 350	39 372	2 981	201	8 800		1 134
Maersk Drilling	Maersk Deliverer	6	3 048	13 500		3 005	-	8 800		1 134
Seadrill Ltd	West Aquarius	6	3 048	7 000	-	2 465	212	9 200	$525 000	970
Seadrill Ltd	West Hercules	6	3 048	7 000	-	2 465	212	9 200	$495 000	907
Transocean Ltd.	Transocean Spitsbergen	6	3 000	7 000	64 600	1 700	283	8 800	$483 000	907
Transocean Ltd.	Transocean Barents	6	3 000	7 000	64 600	1 700	283	8 800	$564 000	907
Seadrill Ltd	West Taurus	6	2 285	7 000	43 400	2 989	176	8 800	$655 000	

Following table was created by Excel
by taking the average value of the Rig Data

Semi-Submersible Generation	2nd	3rd	4th	5th	6th
Variable Deck Load (tonnes)	2 900	3 400	4 500	6 100	8 000
Hoisting Capacity (tonnes)	530	570	680	860	970
Tensioning Capacity (MN)	2,9	3,6	6,1	12,6	13,8
Liquid Mud Capacity (m^3)	430	460	970	1 760	2 470
Mud Pump Capacity (HP)	4 500	4 600	5 200	8 100	8 900
Sack Storage (m^3)	120	150	170	230	240
Operating Displacement (tonnes)	22 000	27 000	36 000	41 000	50 000
Day Rate (USD)	270 000	300 000	370 000	450 000	500 000

Riser Tension Capacity					
Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	21" Riser Tension Capacity (MN)	16" Riser Tension Capacity (MN) *(-42% from HoopStress)*
ENSCO	ENSCO 5003	2	305 m	2,1 MN	1,2 MN
ENSCO	ENSCO 5002	2	305 m	2,1 MN	1,2 MN
Diamond Offshore	Ocean Nomad	2	366 m	2,1 MN	1,2 MN
Transocean Ltd.	Transocean Prospect	3	457 m	2,1 MN	1,2 MN
Dolphin Drilling	Borgsten Dolphin	2	457 m	2,1 MN	1,2 MN
Songa Offshore AS	Songa Venus	2	457 m	2,1 MN	1,2 MN
Maersk Drilling	Nanhai VI	3	457 m	2,1 MN	1,2 MN
Diamond Offshore	Ocean Vanguard	3	457 m	2,1 MN	1,2 MN
Diamond Offshore	Ocean Princess	2	457 m	2,1 MN	1,2 MN
Queiroz Galvao Oleo e Gas S.A.	Alaskan Star	2	510 m	2,1 MN	1,2 MN
Socar (NOC)	Absheron	2	198 m	2,6 MN	1,5 MN
Socar (NOC)	Shelf 1	2	200 m	2,6 MN	1,5 MN
Socar (NOC)	Shelf 3	2	200 m	2,6 MN	1,5 MN
Noble Drilling	Noble Ton Van Langeveld	3	457 m	2,8 MN	1,6 MN
Transocean Ltd.	Sedco 704	2	305 m	2,8 MN	1,7 MN
Diamond Offshore	Ocean Ambassador	2	335 m	2,8 MN	1,7 MN
Essar Oilfields Services Ltd.	Essar Wildcat	2	396 m	2,8 MN	1,7 MN
Songa Offshore AS	Songa Trym	2	400 m	2,8 MN	1,7 MN
Transocean Ltd.	Transocean Winner	3	457 m	2,8 MN	1,7 MN
Transocean Ltd.	Transocean Searcher	3	457 m	2,8 MN	1,7 MN
KNOC (NOC)	Doo Sung	3	457 m	2,8 MN	1,7 MN
Transocean Ltd.	GSF Grand Banks	2	457 m	2,8 MN	1,7 MN
Transocean Ltd.	Actinia	3	457 m	2,8 MN	1,7 MN
Dolphin Drilling	Bredford Dolphin	2	457 m	2,8 MN	1,7 MN
Dolphin Drilling	Byford Dolphin	2	457 m	2,8 MN	1,7 MN
Odfjell	Deepsea Bergen	3	457 m	2,8 MN	1,7 MN

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	21" Riser Tension Capacity (MN)	16" Riser Tension Capacity (MN)
China Oilfield Services Ltd.	Nanhai V	3	457 m	2,8 MN	1,7 MN
Transocean Ltd.	J W McLean	2	381 m	2,8 MN	1,7 MN
Petrobras (NOC)	Petrobras XVI	2	457 m	2,8 MN	1,7 MN
Diamond Offshore	Ocean Whittington	2	503 m	2,8 MN	1,7 MN
Diamond Offshore	Ocean New Era	2	457 m	2,8 MN	1,7 MN
Diamond Offshore	Ocean Bounty	2	457 m	2,8 MN	1,7 MN
Transocean Ltd.	Sedco 601	2	457 m	2,8 MN	1,7 MN
ENSCO	ENSCO 5005	3	457 m	2,8 MN	1,7 MN
Transocean Ltd.	Sedneth 701	2	457 m	2,8 MN	1,7 MN
Saipem	Scarabeo 3	2	500 m	2,8 MN	1,7 MN
Transocean Ltd.	Transocean Polar Pioneer	4	500 m	2,8 MN	1,7 MN
Dolphin Drilling	Borgny Dolphin	2	533 m	2,8 MN	1,7 MN
Saipem	Scarabeo 4	2	545 m	2,8 MN	1,7 MN
Songa Offshore AS	Songa Mercur	2	549 m	2,8 MN	1,7 MN
Frigstad Offshore	Kan Tan IV	3	610 m	2,8 MN	1,7 MN
Transocean Ltd.	Sedco 703	3	610 m	2,8 MN	1,7 MN
Diamond Offshore	Ocean Concord	2	701 m	2,8 MN	1,7 MN
Diamond Offshore	Ocean Saratoga	2	671 m	2,8 MN	1,7 MN
Odfjell	Songa Delta	3	701 m	2,8 MN	1,7 MN
Saipem	Scarabeo 6	3	780 m	2,8 MN	1,7 MN
Noble Drilling	Noble Lorris Bouzigard	2	914 m	2,8 MN	1,7 MN
Noble Drilling	Noble Therald Martin	2	914 m	2,8 MN	1,7 MN
Crosco Integrated	Zagreb 1	2	450 m	3,0 MN	1,8 MN
Transocean Ltd.	GSF Arctic III	3	549 m	3,1 MN	1,8 MN
Transocean Ltd.	GSF Aleutian Key	2	701 m	3,1 MN	1,8 MN
Transocean Ltd.	GSF Rig 140	3	457 m	3,1 MN	1,8 MN
Caspian Drilling	Dada Gorgud	2	475 m	3,3 MN	1,9 MN
Dolphin Drilling	Bideford Dolphin	2	457 m	3,6 MN	2,1 MN

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	21" Riser Tension Capacity (MN)	16" Riser Tension Capacity (MN)
Dolphin Drilling	Borgland Dolphin	4	457 m	3,6 MN	2,1 MN
Diamond Offshore	Ocean Guardian	3	457 m	3,6 MN	2,1 MN
Stena Drilling	Stena Spey	3	457 m	3,6 MN	2,1 MN
Transocean Ltd.	Sedco 712	3	488 m	3,6 MN	2,1 MN
Transocean Ltd.	Sedco 714	3	488 m	3,6 MN	2,1 MN
Diamond Offshore	Ocean Epoch	2	610 m	3,6 MN	2,1 MN
Diamond Offshore	Ocean General	2	500 m	3,6 MN	2,1 MN
Stena Drilling	Stena Clyde	2	503 m	3,6 MN	2,1 MN
Transocean Ltd.	Sedco 711	3	549 m	3,6 MN	2,1 MN
Transocean Ltd.	Transocean John Shaw	3	549 m	3,6 MN	2,1 MN
Atwood Oceanics	Atwood Southern Cross	2	610 m	3,6 MN	2,1 MN
Transocean Ltd.	Paul B Loyd Jr	4	610 m	3,6 MN	2,1 MN
Diamond Offshore	Ocean Lexington	2	610 m	3,6 MN	2,1 MN
Petrobras (NOC)	Petrobras XVII	2	701 m	3,6 MN	2,1 MN
Diamond Offshore	Ocean Yorktown	2	869 m	3,6 MN	2,1 MN
ENSCO	ENSCO 6000	2	1 036 m	3,6 MN	2,1 MN
Awilco Drilling PLC	WilHunter	3	457 m	4,2 MN	2,5 MN
Viking Offshore (USA)	Viking Producer	2	457 m	4,3 MN	2,5 MN
Diamond Offshore	Ocean Patriot	3	457 m	4,3 MN	2,5 MN
Songa Offshore AS	Songa Dee	3	457 m	4,3 MN	2,5 MN
Japan Drilling	HAKURYU-5	2	500 m	4,3 MN	2,5 MN
Transocean Ltd.	Transocean Arctic	4	500 m	4,3 MN	2,5 MN
North Atlantic Drilling Ltd.	West Alpha	4	610 m	4,3 MN	2,5 MN
Odfjell	Island Innovator	6	751 m	4,3 MN	2,5 MN
Transocean Ltd.	Falcon 100	4	732 m	4,3 MN	2,5 MN
Transocean Ltd.	GSF Rig 135	3	853 m	4,3 MN	2,5 MN
Diamond Offshore	Ocean Onyx	2	975 m	4,3 MN	2,5 MN

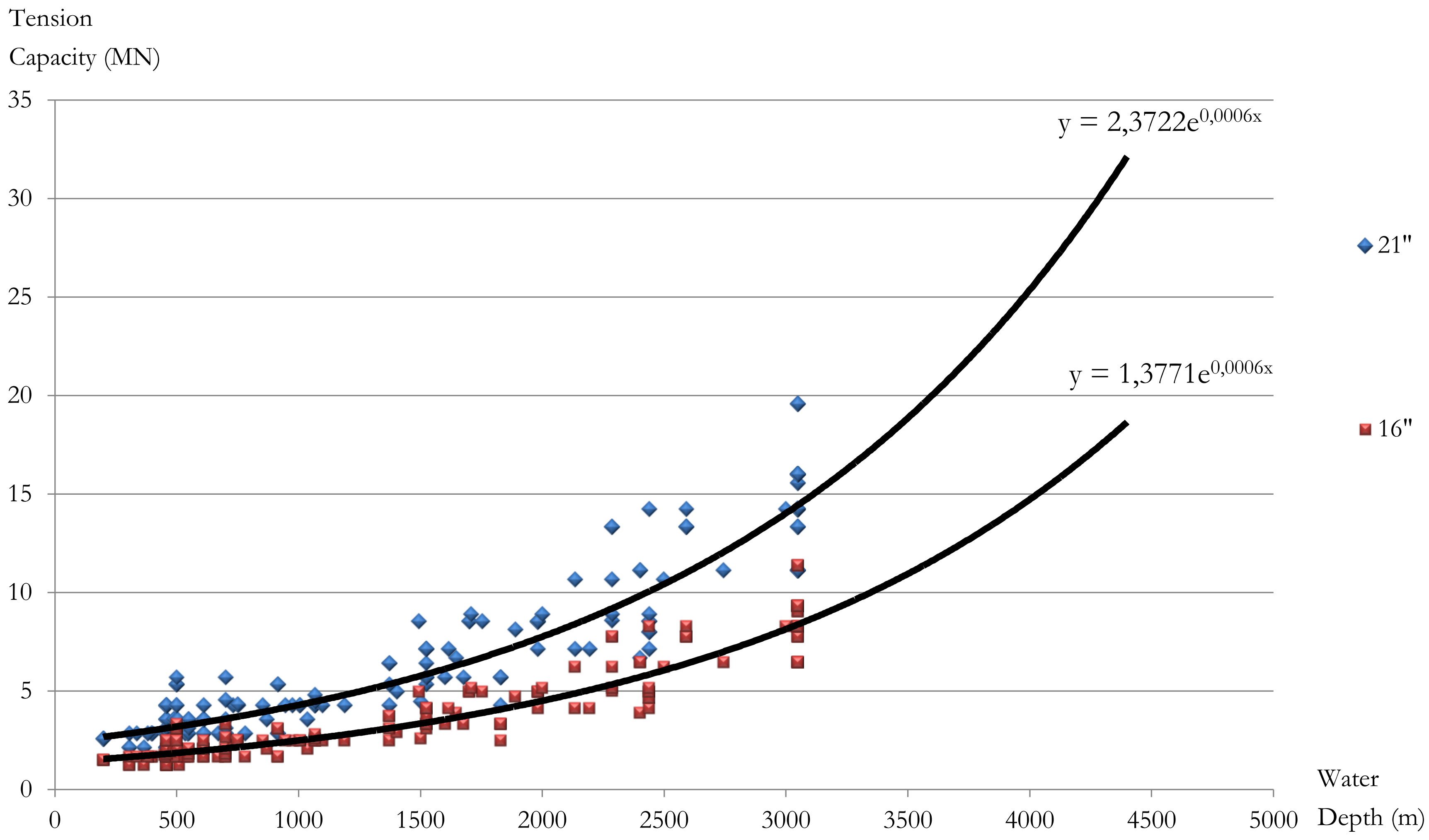
Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	21" Riser Tension Capacity (MN)	16" Riser Tension Capacity (MN)
Diamond Offshore	Ocean Yatzy	4	1 006 m	4,3 MN	2,5 MN
Transocean Ltd.	C Kirk Rhein Jr	4	1 006 m	4,3 MN	2,5 MN
Transocean Ltd.	GSF Arctic I	3	945 m	4,3 MN	2,5 MN
Diamond Offshore	Ocean Winner	2	1 067 m	4,3 MN	2,5 MN
Diamond Offshore	Ocean Worker	3	1 067 m	4,3 MN	2,5 MN
Transocean Ltd.	Transocean Legend	4	1 067 m	4,3 MN	2,5 MN
Transocean Ltd.	Sedco 700	4	1 097 m	4,3 MN	2,5 MN
Petrobras (NOC)	Petrobras X	3	1 189 m	4,3 MN	2,5 MN
Transocean Ltd.	Sedco 710	3	1 372 m	4,3 MN	2,5 MN
North Atlantic Drilling Ltd.	West Venture	5	1 829 m	4,3 MN	2,5 MN
China Oilfield Services Ltd.	COSLPioneer	6	750 m	4,3 MN	2,5 MN
Diamond Offshore	Ocean Quest	4	1 067 m	4,4 MN	2,6 MN
ENSCO	ENSCO 6001	4	1 500 m	4,4 MN	2,6 MN
Caspian Drilling	Istiglal	2	700 m	4,6 MN	2,6 MN
Transocean Ltd.	Transocean Amirante	4	1 067 m	4,8 MN	2,8 MN
Transocean Ltd.	Jim Cunningham	4	1 402 m	5,0 MN	2,9 MN
Songa Offshore AS	Songa Cat-D Semisub TBN 3	6	500 m	5,3 MN	3,1 MN
Songa Offshore AS	Songa Cat-D Semisub TNB 4	6	500 m	5,3 MN	3,1 MN
Songa Offshore AS	Songa Cat-D Semisub TBN 1	6	500 m	5,3 MN	3,1 MN
Songa Offshore AS	Songa Cat-D Semisub TBN 2	6	500 m	5,3 MN	3,1 MN
Maersk Drilling	Maersk Explorer	4	914 m	5,3 MN	3,1 MN
Transocean Ltd.	Transocean Driller	4	914 m	5,3 MN	3,1 MN
Transocean Ltd.	Transocean Rather	4	1 372 m	5,3 MN	3,1 MN
Transocean Ltd.	Transocean Richardson	4	1 524 m	5,3 MN	3,1 MN
Stena Drilling	Stena Don	4	500 m	5,7 MN	3,3 MN
ENSCO	ENSCO 5000	2	701 m	5,7 MN	3,3 MN
Diamond Offshore	Ocean Valiant	4	1 524 m	5,7 MN	3,3 MN
Transocean Ltd.	Sedco 709	4	1 524 m	5,7 MN	3,3 MN
Diamond Offshore	Ocean Alliance	4	1 600 m	5,7 MN	3,3 MN
Atwood Oceanics	Atwood Hunter	3	1 524 m	5,7 MN	3,3 MN

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	21" Riser Tension Capacity (MN)	16" Riser Tension Capacity (MN)
Diamond Offshore	Ocean Star	4	1 676 m	5,7 MN	3,3 MN
Noble Drilling	Noble Jim Thompson	4	1 829 m	5,7 MN	3,3 MN
Noble Drilling	Noble Paul Romano	4	1 829 m	5,7 MN	3,3 MN
Diamond Offshore	Ocean Victory	4	1 829 m	5,7 MN	3,3 MN
Transocean Ltd.	Transocean Leader	4	1 372 m	6,4 MN	3,7 MN
Transocean Ltd.	Sovereign Explorer	3	1 372 m	6,4 MN	3,7 MN
Transocean Ltd.	M G Hulme Jr	4	1 524 m	6,4 MN	3,7 MN
Transocean Ltd.	Jack Bates	4	1 646 m	6,7 MN	3,9 MN
Schahin	Pantanal	4	2 400 m	6,7 MN	3,9 MN
Diamond Offshore	Ocean America	4	1 524 m	7,1 MN	4,1 MN
Atwood Oceanics	Atwood Eagle	3	1 524 m	7,1 MN	4,1 MN
Atwood Oceanics	Atwood Falcon	3	1 524 m	7,1 MN	4,1 MN
Transocean Ltd.	Sedco 707	4	1 981 m	7,1 MN	4,1 MN
Transocean Ltd.	Transocean Marianas	4	1 615 m	7,1 MN	4,1 MN
Noble Drilling	Noble Max Smith	4	2 134 m	7,1 MN	4,1 MN
Noble Drilling	Noble Homer Ferrington	4	2 195 m	7,1 MN	4,1 MN
Noble Drilling	Noble Amos Runner	4	2 438 m	7,1 MN	4,1 MN
Seadrill Ltd	West Leo	6	2 438 m	8,0 MN	4,6 MN
Seadrill Ltd	West Pegasus	6	2 438 m	8,0 MN	4,6 MN
Petrobras (NOC)	Petrobras XXIII	4	1 890 m	8,1 MN	4,7 MN
ENSCO	ENSCO 5001	4	1 981 m	8,5 MN	4,9 MN
Saipem	Scarabeo 7	4	1 494 m	8,5 MN	5,0 MN
ENSCO	ENSCO 6004	4	1 700 m	8,5 MN	5,0 MN
ENSCO	ENSCO 6003	4	1 700 m	8,5 MN	5,0 MN
Transocean Ltd.	GSF Celtic Sea	4	1 753 m	8,5 MN	5,0 MN
Transocean Ltd.	Sedco 706	4	1 981 m	8,5 MN	5,0 MN
Transocean Ltd.	Sedco 702	4	1 981 m	8,5 MN	5,0 MN
Noble Drilling	Noble Paul Wolff	4	2 438 m	8,5 MN	5,0 MN
Noble Drilling	Noble Clyde Boudreaux	5	2 438 m	8,5 MN	5,0 MN
ENSCO	ENSCO 5006	4	2 286 m	8,6 MN	5,0 MN
ENSCO	ENSCO 6002	4	1 707 m	8,9 MN	5,2 MN

Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	21" Riser Tension Capacity (MN)	16" Riser Tension Capacity (MN)
Odebrecht Oil&Gas	Norbe VI	5	2 000 m	8,9 MN	5,2 MN
Transocean Ltd.	Sedco Express	5	2 286 m	8,9 MN	5,2 MN
ENSCO	ENSCO 7500	5	2 438 m	8,9 MN	5,2 MN
Dolphin Drilling	Blackford Dolphin	5	2 134 m	10,7 MN	6,2 MN
Transocean Ltd.	Sedco Energy	5	2 286 m	10,7 MN	6,2 MN
Ocean Rig Asa	Leiv Eiriksson	5	2 499 m	10,7 MN	6,2 MN
Schahin	Amazonia	6	2 400 m	11,1 MN	6,5 MN
Queiroz Galvao Oleo e Gas S.A.	Lone Star	6	2 402 m	11,1 MN	6,5 MN
Queiroz Galvao Oleo e Gas S.A.	Gold Star	5	2 743 m	11,1 MN	6,5 MN
ENSCO	ENSCO 8501	6	3 048 m	11,1 MN	6,5 MN
ENSCO	ENSCO 8500	6	3 048 m	11,1 MN	6,5 MN
ENSCO	ENSCO 8502	6	3 048 m	11,1 MN	6,5 MN
Noble Drilling	Noble Dave Beard	6	3 048 m	11,1 MN	6,5 MN
Noble Drilling	Noble Danny Adkins	6	3 048 m	11,1 MN	6,5 MN
Noble Drilling	Noble Jim Day	6	3 048 m	11,1 MN	6,5 MN
Transocean Ltd.	GSF Development Driller I	5	2 286 m	13,3 MN	7,7 MN
Transocean Ltd.	GSF Development Driller II	5	2 286 m	13,3 MN	7,7 MN
ENSCO	ENSCO 8504	6	2 591 m	13,3 MN	7,7 MN
ENSCO	ENSCO 8505	6	2 591 m	13,3 MN	7,7 MN
ENSCO	ENSCO 8506	6	2 591 m	13,3 MN	7,7 MN
North Atlantic Drilling Ltd.	West Phoenix	6	3 048 m	13,3 MN	7,7 MN
ENSCO	ENSCO 8503	6	3 048 m	13,3 MN	7,7 MN
Diamond Offshore	Ocean Confidence	5	3 048 m	13,3 MN	7,7 MN
Odfjell	Deepsea Stavanger	6	3 048 m	14,2 MN	8,3 MN

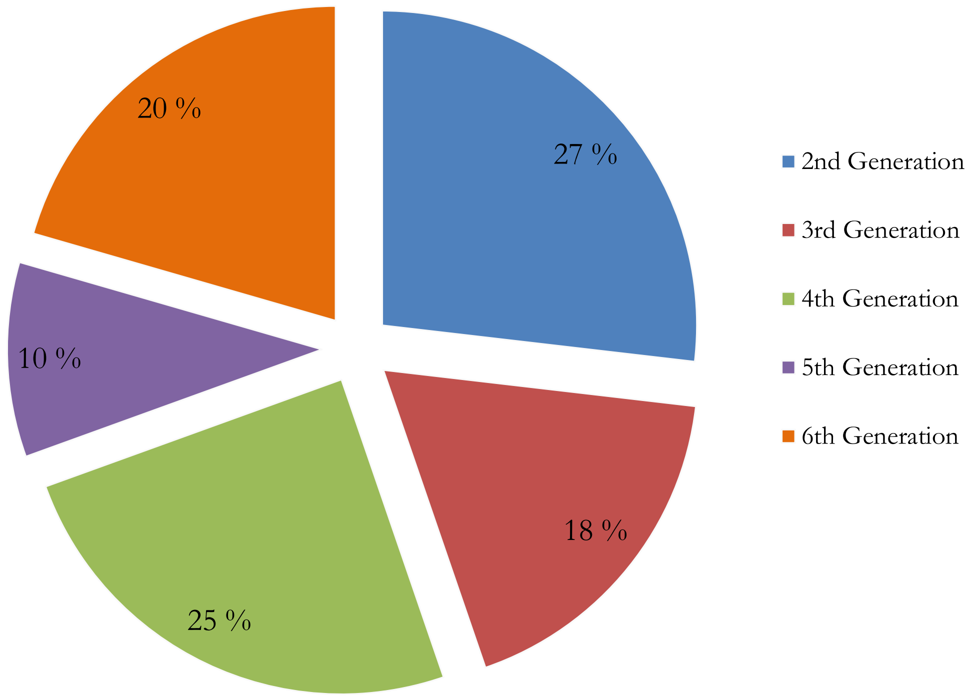
Rig Manager	Rig Name	Semisub Generation	Water Depth (meters)	21" Riser Tension Capacity (MN)	16" Riser Tension Capacity (MN)
Odfjell	Deepsea Aberdeen	6	3 048 m	14,2 MN	8,3 MN
Odfjell	Deepsea Atlantic	6	3 048 m	14,2 MN	8,3 MN
Transocean Ltd.	Deepwater Nautilus	5	2 438 m	14,2 MN	8,3 MN
Transocean Ltd.	Cajun Express	5	2 591 m	14,2 MN	8,3 MN
Seadrill Ltd	West Eminence	6	2 999 m	14,2 MN	8,3 MN
Ocean Rig Asa	Eirik Raude	5	3 048 m	14,2 MN	8,3 MN
Sevan Drilling	Sevan Driller II (Brasil)	6	3 658 m	14,2 MN	8,3 MN
Sevan Drilling	Sevan Driller	6	3 658 m	14,2 MN	8,3 MN
Transocean Ltd.	Transocean Spitsbergen	6	3 048 m	14,3 MN	8,3 MN
Transocean Ltd.	Transocean Barents	6	3 048 m	14,3 MN	8,3 MN
Diamond Offshore	Ocean Courage	6	3 048 m	15,6 MN	9,0 MN
Diamond Offshore	Ocean Valor	6	3 048 m	15,6 MN	9,0 MN
Diamond Offshore	Ocean Monarch	5	3 048 m	16,0 MN	9,3 MN
Seadrill Ltd	West Aquarius	6	3 048 m	16,0 MN	9,3 MN
Seadrill Ltd	West Hercules	6	3 048 m	16,0 MN	9,3 MN
Seadrill Ltd	West Sirius	5	3 048 m	16,0 MN	9,3 MN
Ventura	SSV Victoria	6	3 048 m	16,0 MN	9,3 MN
Ventura	SSV Catarina	6	3 048 m	16,0 MN	9,3 MN
Songa Offshore AS	Songa Eclipse	6	3 048 m	16,0 MN	9,3 MN
Atwood Oceanics	Atwood Condor	6	3 048 m	16,0 MN	9,3 MN
Diamond Offshore	Ocean Endeavor	5	3 048 m	16,0 MN	9,3 MN
Seadrill Ltd	West Taurus	6	3 048 m	19,6 MN	11,4 MN
Seadrill Ltd	West Capricorn	6	3 048 m	19,6 MN	11,4 MN
Seadrill Ltd	West Orion	5	3 048 m	19,6 MN	11,4 MN

Following graph was created by Excel from the Tension Data



Number of Collected Semi-submersible Generations Graph was created by Excel from the Rig Data

- 2^{nd} = 51
- 3^{rd} = 34
- 4^{th} = 47
- 5^{th} = 19
- 6^{th} = 39



Appendix C – Recommended Literature

Title	Author	ISBN
Casing And Cementing	Judy Feder	0-88698-191-3
Casing And Liners For Drilling And Completion	Ted G. Byrom	1-933762-06-3
Drilling Fluids, Mud Pumps And Conditioning Equipment	Kate Van Dyke	0-88698-181-6
Drilling For Oil & Gas	Steve Devereux	0-87814-762-4
Fundamentals Of Marine Riser Mechanics: Basic Principles And Simplified Analyses	Charles P. Sparks	978-1-59370-070-6
Marine Riser Systems And Subsea Blowout Preventers	Hugh McCrae	0-88698-188-3
Modern Well Design	Bernt S. Aadnøy	978-0-415-88467-9
Recommended Practice For Design, Selection, Operation And Maintenance Of Marine Drilling Riser Systems; API Recommended Practice 16Q	American Petroleum Institute	
Specification For Marine Drilling Riser Equipment; API Specification 16F	American Petroleum Institute	
The Rotary Rig And Its Components	K.R. Bork	0-88698-166-2

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