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Abstract

The author have designed this thesis to give the reader detailed knowledge about wired drill pipe technology (WDP technology). Focusing on providing the reader with unbiased examples and explanations have been of top priority. The optimal result being that the reader will be able to, with only little or none prior knowledge about WDP technology, fully understand the WDP technology's economics and technical aspects.

Wired drill pipe technology (WDP technology) is becoming more and more known to the oil industry. WDP provides wired communication with downhole tools, instead of conventional wireless communicating-methods like mud pulse telemetry (MPT) and electromagnetic telemetry (EMT). Up to this point, this new and sophisticated technology have been used to drill more than 120 wells worldwide. The technology have been around for some time, but have in later years gained more attention from oil companies, especially the companies regularly drilling highly challenging fields.

This thesis gives a close examination of all the technical parts of the technology. Looks closer upon the transmission speed. How the telemetry works and the route between surface equipment and all the way down to the bottom hole assembly (BHA). The thesis also closely examines the economics of the technology and relate this to the cost of drilling operations offshore in the North Sea.

New technology provide new possibilities, but they often tend to have a steep price tag. This thesis examines if the additional cost of wired pipe is worth the investment. It also provides calculations from two different example-wells, and the results from these calculations clearly states the cost of WDP.

The use of WDP technology provide multiple new options in regards of communication with different sensors. Since there now is a constant dataflow, from the drill floor and down to downhole tools, you have the opportunity to place sensors *along the string*. These sensors are more commonly known as *Along String Measurements* or ASMs for short. The ASMs will play an important role within the development of automated drilling rigs. The combination of wired drill pipe network, the ASMs and automated drilling computers are closer examined as well.

The WDP technology is not only saving time during the drilling operation, but it also makes the drilling operation *safer* for the personnel involved. The technology shows strong resilience, but still have a few weak spots that needs further improvement.

Acknowledgement

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Listed in alphabetical order:

Atle Øglend	Associate Professor at UiS. My Academic Supervisor on the thesis.
Marcelo Hernandez	Network Field Specialist at NOV IntelliServ.
Reina Teelken	Senior Technical Advisor at NOV IntelliServ.
Steven Williams	Directional Driller at Baker Hughes.

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Table of Abbreviations, Acronyms and Technical Terms

Acronym, Abbreviation and Technical Terms	Definition and explanation
AFE	Authority of expenditure
ASM	Part of the WDP Technology. Along String Measurement – Sensors along the drill string
Backward whirl	Drill pipe rotates clockwise - the complete string rotates counter-clockwise
BHA	Bottom Hole Assembly. A section of tools/sensors located behind the bit
BIT	Drilling bit – always at the end of the drill string
BOP	Blowout Preventer – Safety Barrier
Box end	The female threaded side of a tool join. Box&Pin makes up a connection.
BPS (as in transfer speed)	Bits Per Second
Coil / IntelliCoil	Part of the WDP Technology. Making the transferal of data over connections possible.
Data Cable	Part of the WDP Technology. An armored coaxial wire, threaded through the inside of the pipe, making wired communication possible.
Data Link / Booster / Transceiver	Part of the WDP Technology. Amplifies signal throughout the drill string
Data Swivel	Part of the WDP Technology. Installed in the top drive
DC	Drill Collar - heavier and larger OD drill pipe to give weight to bit
Derrick / Drilling Derrick	A tall stationary work frame, making it possible to connect stands of 30m to the drill string in slips. Holding racked drill pipe, top drive, piping etc.
DP	Drill Pipe - one single joint of drill pipe – approx. 9 meter long
Drift / Drift ID	The smallest inner diameter of a given section. I.e. a drill pipe, drill collar etc.
Drill Floor	The part of the rig where the roughnecks and the driller work together.
Drill String	All components connected. From the uppermost drill pipe to the bit
Driller	The person who controls the top drive and drills the well
Drilling rig	Construction/Installation used for onshore/offshore drilling
ERD	Extended Reach Drilling – long horizontal wells
HSE	Health Safety and Environment
HWDP	Heavy Weight Drill Pipe. Single joints – but heavier than normal DP
IBOP	Internal Blowout Preventer
ID	Inner/Internal Diameter
IEU	Internal External Upside - The part/section where the ID and OD changes from the “tool joint size” to “normal” ID and OD of the drill pipe.
Interface-sub	Part of the WDP Technology. Communicate with 3rd party BHA
JB	Junction box. A box that protects cable connections from wear.
KPI	Key Performance Indicator
Lag Time	The time from an event actually happens until it is effectively noticed
MD	Measure Depth – Length of the well path
MSL	Mean Sea Level. – often representing depth between drill floor and the MSL
NCS	Norwegian Continental Shelf
NetCon	Part of the WDP Technology. Network Communicator
NOV	National Oilwell Varco

OD	Outer/External diameter
Operator	The oil/operating company that own the oil produced. E.g. Statoil, ExxonMobil, BP, etc.
Petroleum	A liquid mixture of hydrocarbons, which can be refined into products like gasoline, paraffin and oil.
Pin end	The male threaded side of a toll joint. Pin&Box makes up a connection.
POOH/TOH	Pull Out Of Hole or Trip Out Of Hole. Pulling pipe out of your well, without rotation or flow
Proactive (proactivity)	To act/prepare in advance of a future situation
PWB	Printed Wiring Boards. Typically green boards with different communication circuits printed on them.
R&D	Research and Development
RIH/TIH	Run In Hole or Trip In Hole. Putting drill pipe into your well, without rotation or flow
RKB	Rotary Kelly Bushing. Often referred to as start point of your well = 0.0 m
Roughneck	Worker assisting the operation. Working under the drillers supervision
RSS	Rotary Steerable Assembly – technology used for steering while drilling
Stand	A stand is multiple joints of drill pipe connected together. Typically 3 joints of drill pipe are connected, making up a stand of approx. 27 m in length
Stator	A stationary component in a rotating system. Using/generating inductance to transfer signals.
SUB	An intermediate component making different modifications possible. E.g., “cross over sub” helps to connect drill pipe joints with different sizes.
Surface Cabling	Part of the WDP Technology. Connecting the NetCon and Data Swivel
Tool Joint	The part of the drill pipe that connects them together with other drill pipe. Often have a bigger OD and a smaller ID to be more robust.
Top Drive	Tool/Machine used to rotate the drill string and drill the well
TVD	True Vertical Depth – Vertical depth from drill floor to the well path
UPS	Uninterrupted Power Supply. Providing stored battery power, during power shutdowns/emergencies.
WDP	Wired Drill Pipe. Drill pipe with *wired* communication throughout
Wildcatter	A person with little or none relevant education, going all in to find enough oil to live off of it, for the rest of his/hers life.
WPO/WDPO	Wired Drill Pipe Operator. The person running WDP service at the rig site

1. Introduction

The personal motivation behind writing a thesis on wired drill pipe technology, have grown on me the last couple of months. After finishing my bachelor degree within petroleum engineering, I started working in the oil industry myself. Since then, my curiosity for drilling and technology have only increased. When now being a part of the industry, I look upon the different technologies from completely new perspectives.

During the last decades, there have been some developments/improvements on the different ways of communicating with downhole tools, but none labeled revolutionary. The development and reliability of the technology now seems to reach new heights, and that is making it much more interesting. To implement a new technology to an already fixed industry are often very hard, so to look closer at the wired drill pipe technology seemed to make a great topic.

Arguments about the tradeoff between cost and opportunity becomes a hot topic whenever new enhanced technology presents itself. On background of the latter phrase, I thought it would make a very interesting thesis to look closer upon the technology from *both* a technical and an economic viewpoint.

During latter years, wired drill pipe technology have become more and more known to the drilling industry, and I am very excited to follow its future development.

1.1 Aim of the Thesis

Does Wired Drill Pipe Technology provide enough usable possibilities to make up for its cost?

The thesis will look upon the up-and-coming technology known as wired drill pipe. It will study the technical aspect of the technology, and the economics of it. It is often challenging to implement new technology before the industry approves of it.
So what is wired drill pipe technology?
What are the differences between using regular drill pipe and wired drill pipe?
Is wire drill pipe the future of data transmission?
Is wired drill pipe economically beneficial for the user?
Is wired drill pipe just a fancy but not cost-efficient tool for the oil industry, which will not endure into the future?

The thesis will answer these statements. The thesis explains general and detailed information of WDP technology, to provide the reader with a competent understanding of what wired drill pipe costs and how the WDP technology works.

1.2 Structure of the Thesis

This thesis is structured as follows.
Chapter 2 will be giving quick summaries on the history of the oil industry, some economics, how communications with downhole tools are conventionally performed and challenges met in todays' oil industry.
Chapter 3 consists of detailed information about how the WDP technology works and explains the tasks that belong to each of the different vital components in the network.
Chapter 4 is mainly focused on the economics regarding the use of WDP technology, but it also explains the cost of a drilling operation, and how the WDP technology contribute to save time.
Chapter 5 consist of two example-wells, to show realistic time-savings, a section on automated drilling and a discussion on the pros and cons of wired drill pipe technology.
The final conclusion and answer to the aim of the thesis is found in chapter 6.
A table of references is located in the penultimate part of the thesis.
While the appendix are located at the very end of the thesis.

The thesis is designed to give the reader a comprehensive understanding of the WDP technology. Very specific details on how to troubleshoot the network, what materials are used to assemble different parts, what programing language is used for the Network Controller and other very fine details are left out. These limitations are set to enhance the reader's knowledge, without overburdening the reader with too much detail.

2. Background

This chapter takes us briefly back to the start of the petroleum industry. A short historical summary on drilling wells, the development of more and more sophisticated technologies used to communicate with downhole tools. It also touches upon the industry of oil from a brief economic viewpoint and some of the challenges met within the petroleum industry today.

2.1 Petroleum Industry –Brief Historical Summary

Interchangeable use of "Petroleum industry" and "Oil industry" throughout the thesis. Drilling for oil, to meet a certain demand, was first to become an industry in the 20th century. Prior to this, the industry looked more like a monopoly, than a free market. During the late decades of the 19th century, John D. Rockefeller, known for his enormous wealth accumulated by his company *Standard Oil Company*, were running this monopoly in the U.S (Staff, 2015). However, things were to change during the early 20th century, when combustible machines/motors, running on gasoline, were developed. Gasoline is a derivative of petroleum, so then the demand for petroleum/oil increased. From this increase in demand, the activity we today know as exploration drilling began. One of the first surprisingly big oilfield discoveries, where found by the *wildcatter* Pattillo Higgins. The discovery took place on 10th of January 1901, and was located at Spindletop – Beaumont, Texas – United States of America (Linsley, Rienstra, & Stiles, 2002). This finding at Spindletop made it possible for companies involved, to challenge the monopoly position of Standard Oil Company. During the next decade, forced by law, Standard Oil Company needed to split up, forming multiple smaller competing companies. Some of the spin-off companies from this breakup still exist today, like Chevron and ExxonMobil (ExxonMobil merged in 1999 from being two separate companies, Mobil and Exxon) (Corporation, 2015).

Now these spin-off companies started competing with each other as well as other well-known companies like Shell, BP and Texaco. Where there is competition, there is need for advantages and key success factors to become the leading company within the industry. Early in the 1920s, two educated brothers named Marcel and Conrad started their own little business in France. Their business started out from the use of electric prospecting methods, later developed into what we know today as logging tools. The brothers' surnames were Schlumberger, which today is the biggest service company in the world within the oil industry (Statista, 2015). Their very first well log ever performed in USA took place in Kern County, California (Schlumberger, 2015).

The demand for petroleum just kept increasing during the coming decades, and many different companies sprung into life all over the world to make a profit from meeting these demands. Some of these companies where oil *service companies*. A service company delivers services and equipment of different kinds to the *drilling companies*, whom perform the drilling itself. Some of the highest demanded services are logging and drilling services. Many of these services consists of sending tools downhole, to gather data or perform certain tasks, to optimize the drilling operation. To be able to operate these tools, one needs to establish some form of communication between the downhole tools and the surface operators.

During the early startup-years of logging, the only form of “communication” was a wired line connected to the tool, going all the way to surface. This form for logging, knows as “wireline logging”, is still used today, but with a way better definition. Wireline logging is conducted *in-between* the drilling of two sections, not simultaneously as drilling. Schlumberger carried out their first computer processed wireline log in the 1970s. Following up with MWD/LWD, in the 1980s (Schlumberger, 2015). MWD/LWD is short for Measurement/Logging While Drilling, and their task is self-explanatory by their name. Tools are often the lower part of the drill string, known as the BHA, and measures and logs data while drilling. In the decades to come, computers started to become more efficient and complex. This again boosting the developing pace of all sorts of technologies, including the service companies’ tools and equipment.

2.2 Petroleum Industry – Brief Economic Overview

The saying “money makes the world go round” has a lot of truth to it.

There are many different industries in the world, and they exist due to different demands from all over the globe. For any company within any industry, their goal is to survive. To be able to survive and expand over time, the company is dependent on making profit. They then use this profit to expand and evolve newer technologies to keep ahead of competitors in the same market. By doing so, one is likely to keep hold of market shares and make even more money.

One of the world’s biggest industries is petroleum. Petroleum yields oil, gas, and other bi-products that are highly demanded worldwide. The amounts of oil produced vary vastly with time, and therefore we have seen huge fluctuations in the price of oil during past decades. As recently as in 2014, we saw the oil price dropping as much as 50%. In today’s globalized economy, these fluctuations are dependent on many different factors spread all around the world. Due to the limitations of this thesis, it will not go in depth on reasons for oil price fluctuations, but will touch upon the vital role the oil price itself, plays within the petroleum industry. Decrease in oil price, e.g. a quick drop, can often lead to a more strict cost-saving management. The large drop in 2014 have led to many cost-cutting measurements in the industry. The last months (early 2015) many projects have been put on hold, large headcount reductions have been witnessed in service companies, and mergers between significantly large companies have taken place. Reducing storage space and removing older equipment from warehouses around the world, and generally are all the affected companies trying to become leaner. They all strive towards having a leaner chain of supply, and not keep spending unnecessary money on non-efficient products. In times like these, companies are forced to think along new lines and look in different directions for new and better solutions.

The petroleum industry can be divided into three major processes known as the upstream, the midstream and the downstream process. Upstream process is the planning, exploration, drilling and production of fluids at the well site. The midstream process starts when the raw petroleum reaches surface. This process consists of transporting the fluids from the well site to refineries and/or depots, which takes us to the last of the three processes. The downstream process consists of refining the raw petroleum into wanted products, marketing these products and selling them to the end user. The focus of this thesis will be on the upstream process, since wired drill pipe naturally is a part of the drilling process.

Upstream processes are happening all over the world. Many of these locations are offshore well sites, as in the North Sea and in the Gulf of Mexico. In these offshore locations, the rental of equipment, and the operations as a whole, will automatically cost more than drilling onshore. The storage capacity of equipment is limited and the focus on logistics are extremely high. Another focus often being particularly high at offshore installations are health, safety and environment (HSE). If there is an unwanted emergency, e.g. a fire or a gas leak on an installation offshore, you have very limited escape routes. Due to all the limitations of an offshore installation, HSE regulations are commonly very strict. Rules and regulations are vastly different around the world, but on the Norwegian Continental Shelf (NCS) the focus on HSE is extremely high. The mentioned focuses are benefactors to increasing the cost, and there is always a need for smarter and more cost-effective solutions on how to overcome day-to-day tasks.

The want and need for newer and smarter solutions often lead to more competition on the market. Different companies gets the chance to contribute to make the drilling operations safer, more efficient, all with the main goal reducing the overall cost of the operation. The technology is always moving forward, but at different speeds at different times. There are many different opinions on the following matter. Some mean that regression is the correct time to implement new cost-saving products, while other mean it is too risky. All products come with a certain risk attached to them and can therefore face a hard time getting into the market.

2.3 Communication with Downhole Tools

Today, different logging tools are vast in numbers. Within the communicational part of the technology, not so much have happened during latter years. There are different methods to communicate with downhole tools, such as mud pulse telemetry, electromagnetic telemetry (EMT) and wired drill pipe telemetry (WDP). The most commonly used is mud pulse telemetry.

There are different ways of using mud pulse communication, but here is a simplified explanation of the technology. Most wells are using a mud system. The mud is a fluid that the mud engineers design to hold specific properties. The mud is serving many different purposes during a drilling operation, but its main purpose is to act as a primary barrier. A primary barrier between the rig personnel and the formation downhole. The weight of the mud keeps the well stable, by establishing a hydrostatic pressure in the well equal to the in-situ pressure of the formation. You do not want to provoke the formation stability downhole, which can result in fracturing or collapsing the formation. A collapse being the formation packing off into the wellbore, while a fracture is if you exert too high of a pressure on the formation, leading physical cracks and mud losses to the surrounding formation. Other tasks the mud fulfills is cooling the bit, transporting cuttings out of the hole and finally yet importantly, to act as a medium for communication. Mud pulses telemetry consists of signals sent and received by the tools and sensors on surface and downhole.

The technology developed to communicate through liquid mediums mainly consists of sensors and valves. There are limiting factors to how liquid works as a telemetry medium, but this thesis will not go depth on that subject. Communication happens between the programmed tools in the BHA and pressure sensors on surface. The downhole tools and surface sensors recognize different patterns of pulsing. Creating patterns consists of a sequence of starting and stopping flow through different valves. These changes in flow, creates pressure drops and spikes. These drops and spikes travel through the mud and the tools in the BHA interprets them. Then the tools in principle does the exact same thing. The tools open and closes a valve inside the drill string, which creates a pattern that the surface sensors picks up. The surface sensors transmits the signal to a computer, which interprets the signal and displays a message. A MWD engineers read this message and act accordingly. The different patterns of pulses are just like binary coding for computers. There are different transmission speeds obtainable, using different techniques of mud pulse telemetry. The average data transmission speed is around 5-10 BPS (Poletto & Miranda, 2014).

When using electromagnetic telemetry, transmitters located in the BHA sends the information through low-frequency guided waves. These waves travel through the formation and/or casing while surface antennas detects the waves. This technology is originally limited to shallower wells than the use of mud pulse telemetry, due to the attenuation of the signal. There are possibilities of enhancing the signal strength with the use of amplifiers in your drill string. The biggest advantages of the EM technology is getting transmission speed up to 100 BPS (Poletto & Miranda, 2014). EM makes it possible to communicate with tools in wells drilled with aerated fluids like air, mist and/or foam. In the wells where it is not optimal to use the conventional drilling fluid mud, using mud pulse telemetry is naturally out of the picture (Halliburton, 2015).

A third and newer way of communicating with your downhole tools while drilling, is through wired communication. This wired drill pipe technology is the primary focus of this thesis, so there is a lot more to come regarding WDP technology in later chapters.

2.4 Challenges Today

As of today, the challenges of drilling new wells increase by the minute. The technology and industrial development are moving faster and faster, and so are the need for more sophisticated and difficult well paths. As many platforms and other fixed installations already have their slots filled with *extended reach* and *multilateral* wells, the safety issue and difficulty of drilling new well paths increase. Here is a specific example.

The Troll Field, located in the North Sea – 60km west of Bergen. At first Troll was only a gas-field. The thin oil zone made up by tilted thin layers, also known as the reservoir, was at the time of discovery considered impossible to commercialize. Since the startup in 1995, this field have produced over 1.5 billion barrels of oil, due to development of new and better technology. The field today consists of over 180 production well paths, and confirmed plans involve drilling up to 250 horizontal production well paths inside this reservoir. The plan is to have all these wells producing within the year of 2020 (Statoil, 2015).

To mention some distinct challenges; safety challenges e.g. not drilling into other live wells, drilling through unstable and hard formation layers, optimal well path placements, optimal downhole communication, locating certain vital stopping-points as core points, top reservoir, target depth etc.. Proper planning of a new well including well path, downhole tools, drill pipe, casing size and more, is standard procedure for all drilling operations. During the drilling operation itself however, one very often encounter challenges to overcome or changes to implement. In different situations, the only common denominator one has to rely on is data. Having the significant data available to make correct decision are vital for the continuity of any drilling operation. In addition, when renting a rig to drill a well, all operators want to minimize the amount of rig time spent. Rig time is very expensive, thus all operators try to minimize it, without taking on bigger risks or jeopardizing safety.

Amount of data. Defining “significant data” can vary from situation to situation. When drilling an injector well sampling of new data might not be your top priority. When drilling an exploration well on the other hand, looking for new oil discoveries, the sampling might be the number one priority. However, to have precise and correct data at hand to base your decisions on, is always a key success factor. In cases where only slim data samples or even invalid/wrong data is the base for decision-making, it can have terrible consequences. During drilling of a production well, the steering of the well path might be highly important. The placement of the well inside the reservoir might affect the drawdown pressures, and hence the total quantity of petroleum recovered. Cost effective data is always of high priority and the oil companies always want to find the optimal balance of neither spending too much nor too little money on data sampling.

Visibility. When talking about amount of data, another important aspect is the resolution/quality of the data received from tools downhole. How great is the resolution of the received data, are they precise enough for decision-making? They might just be bad data points or they might be in-line with the downhole situation. There are clear challenges for the driller and directional driller to act on different signals from downhole tools, when the uncertainty about the data received is undesirably high. Downhole-visibility is a big challenge today.

Downhole communication. When using mud pulse, if there are different fluids in the well, it can be very hard for the sensors to notice pressure fluctuations. During a lost circulation event, one often have to pump down different types of mud to try to lower the original mud weigh creating the losses. E.g. the result might be having a fluid column of 30% 1.40 SG oil based mud (OBM), 20% 1.10 SG OBM and 50% 0.85 SG base oil. Trying to establish communication through this column of mixed fluids would be very hard, If not impossible. Getting correct data from the tools in situations like these can be vital.

Time-saving. Another important challenge in the drilling industry is time efficiency. Operators always strives to, in a safe and healthy manner, minimize time usage. This especially applies when drilling offshore, where most of the equipment and personnel are invoiced using day-rates. Time can almost be looked upon as an own currency when it comes to this industry. Time is always of the essence, and all oil companies strive to stay within the projected cost budget, AFE (Authority of Expenditures).

Environment. Protecting the environment and not causing harm to sea/wild-life affected by the rig site have become increasingly important in past years. To what extent one protects the environment is a matter of opinion, but it is hard to argue that proactivity trumps all. In addition, being able to have highly advanced technology spotting possible failures/dangers as early as possible, might be the difference between an accident happening or *almost* happening.

Price of Oil. Oil prices fluctuate and as a result, what was profitable one year might not be profitable the next. A highly dynamic and globalized industry, dependent on many different factors all over the world.

Unlikely events. If things does not go according to plan, one can encounter unlikely events. Unlikely events can be of many, but typically a situation that might have a severe impact on the operations, and thus the personnel, the environment and the companies involved. It can be a well control issue or lost time incident. A reason for that some of these unlikely events keeps appearing, is that they start out as a small incident, but due to lack of information wrong decisions are taken and in worst case scenarios, the results are devastating.

3. Technical Specifications and Explanations of WDP Technology

Theory and technical viewpoints on the different components making up the technology. The majorities of the following text is written based on my own knowledge. Minor parts of information are gathered from the manufacturing company's product catalog (NOV I. 2., 2013). Direct quotations are referenced in the text below as well.

3.1 The main advantage of the WDP Technology Network

Briefly explained, the main advantage of the wired drill pipe technology network is that it allows you to transmit and receive real time data at a new level of speed.

The named provider of such technology, which this thesis is based upon, is NOV IntelliServ. Their network/technology are referred to as IntelliServ Network, IntelliServ**2** Network (which is 2nd generation update and improved version of the original IntelliServ Network) or WDP technology throughout the thesis. With this technology it is now possible to send and receive up to 57 600 bits per second (BPS) (National Oilwell Varco, 2015). To give a more general comparison of this speed, think of a road with one single lane (conventional telemetry) and then a road with multiple lanes (WDP technology). If there are 10 000 more lanes than the single lane, then there are room for 10 000 more cars to pass a certain point, during a given time interval. This number, 10 000, is approximately how much more data it is possible to transmit and receive, using WDP technology compared to conventional communication methods like mud pulse and/or electromagnetic telemetry. The speed that one can send or receive data using ordinary mud pulse telemetry is, as earlier mentioned, on average between 5-10 BPS. For EM it can go up to 100 BPS.

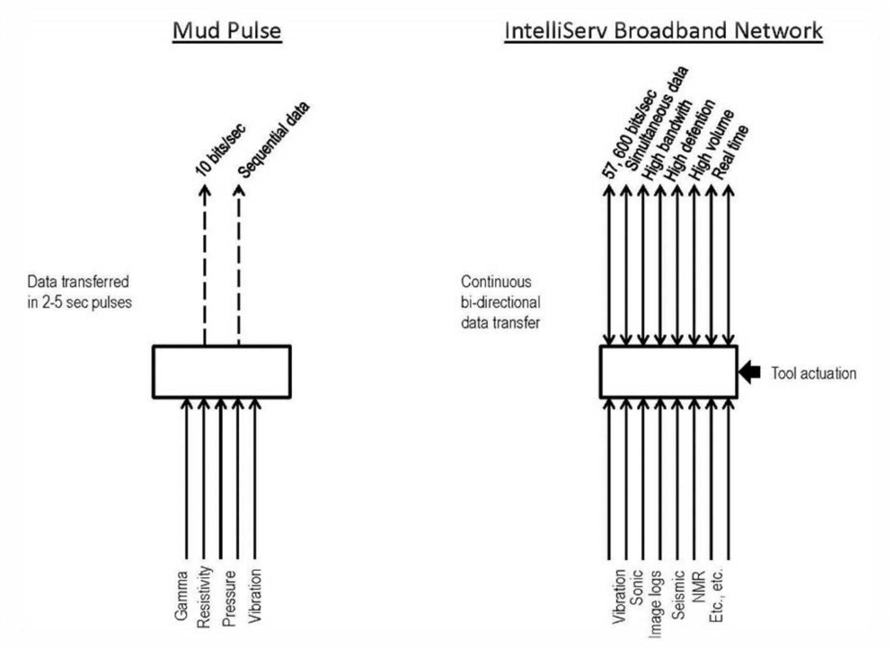

Figure 1: Mud Pulse Telemetry Vs. Wired Drill Pipe Telemetry (Saenz, 2014)

3.2 A quick overview of the complete WDP Technology Network

First, a quick and general overview of the wired drill pipe technology network as a whole. As figure 2 below shows, the network consists of different components. Every component play a crucial role in the transferal of data, this is because of the components are connected in series. If there is a serious fault or a shortage in one of the components, the complete network will not function optimally.

The network consists of a looped circuit. A simplified way to look at it is to imagine a constant flow of packages throughout the looped circuit. This flow starts from the *NetCon,* then it goes through the *surface cabling* and into the *data swivel*. The data swivel is physically a part of the top drive system and needs to be installed prior to using WDP technology on any installation. The flow now continues through the data swivel, and into the *wired drill pipe*. It flows through every joint of WDP, and all the way down to the *interface-sub*, and maybe passing through some ASMs on the way.

Over every tool joint there are *coils* making communication over the connections possible. Inside the wired drill pipes, there is stretched an armored co-axial cable referred to as the *data cable,* which transfers the data through every joint of drill pipe. On the way down to the *interface sub* it passes through x amount of *data links*, depending on the length of the string. The *data links* will interchangeably be referred to as *boosters, amplifiers* or simply *links,* throughout the thesis. The interface sub is a converter that makes the WDP technology serviceable with different third party components, like for instance their respective Bottom Hole Assemblies (BHAs). From the bottom, the flow goes all the way back to surface and into the NetCon, but it does not end here. The NetCon makes it possible to transfer all the downhole data to third party computers/databases. Then service companies and oil companies have the opportunity to interpret the huge amounts of downhole data transmitted, at new record-breaking speed.

A wired drill pipe string lasts almost as long as a regular drill string, around 7 years before it needs a higher level of maintenance. The lifespan will vary, depending on what field the string is used, and what formations it drills on a daily basis. More detailed information about each of the components in the next section.

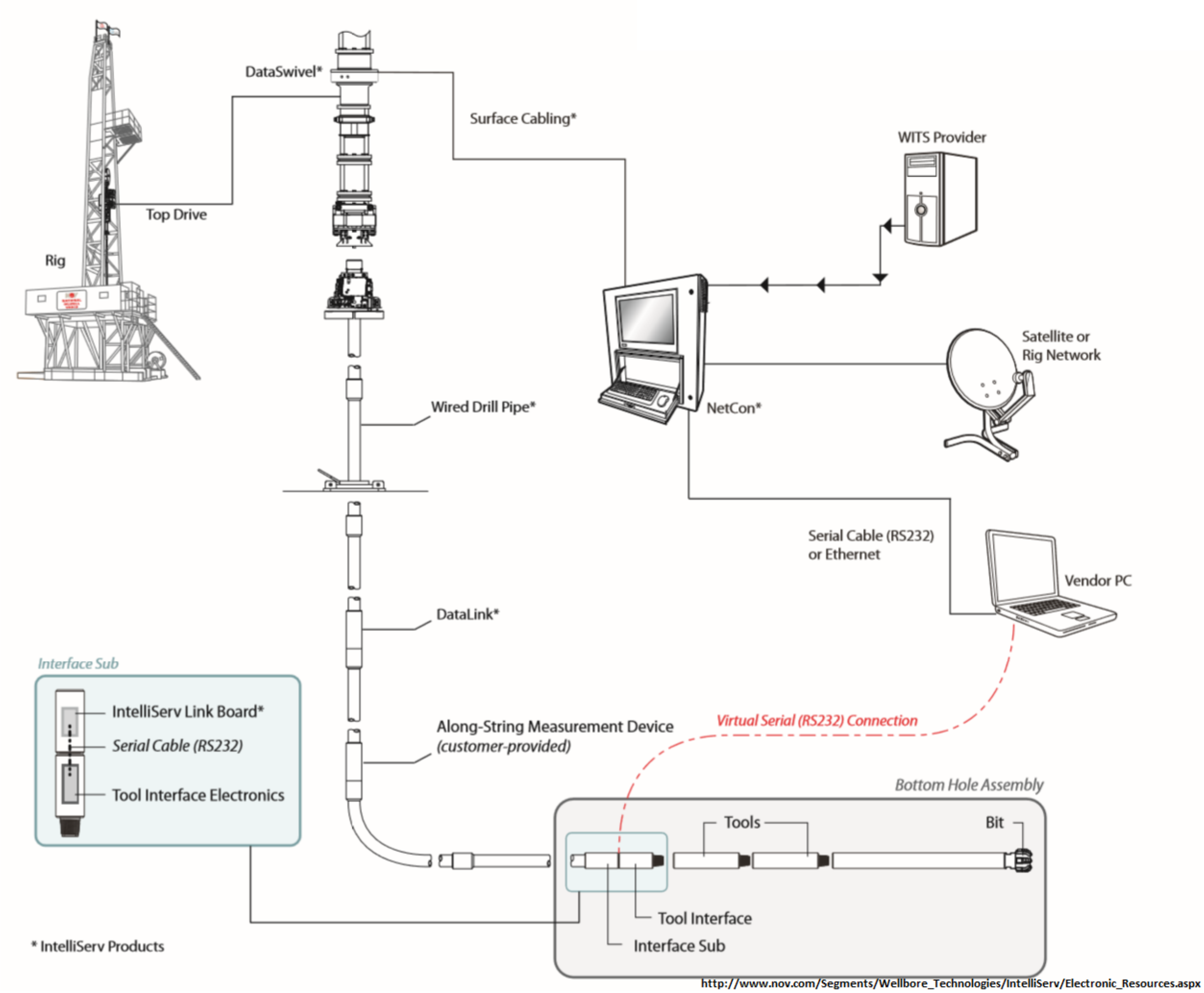

Figure 2: The complete wired drill pipe network (IntelliServ N. C., 2015)

3.3 The Vital Components of the WDP Technology Network

Next, there will be a closer examination of the different vital components making up the IntelliServ WDP Network. These are all crucial components for this technology to function optimally.

1. **The NetCon (**including surface cabling**)**
2. **Data Swivel** (Including saver sub)
3. **Wired Drill Pipe** (including the coils & data cable)
4. **Data Link**
5. **Interface-Sub**
6. **ASM** (Along String Measurements)

3.3.1 The NetCon and Surface Cabling

The Network Controller or *NetCon* for short is a huge cabinet filled with electronics and an integrated touch sensitive screen. It is the working brain of the WDP Technology. Without the NetCon, the information itself would be non-interpretable, or more precisely; the informational flow would be nonexistent. The surface cabling is what connects the NetCon to the Data Swivel, and the rest of the wired drill pipe network.

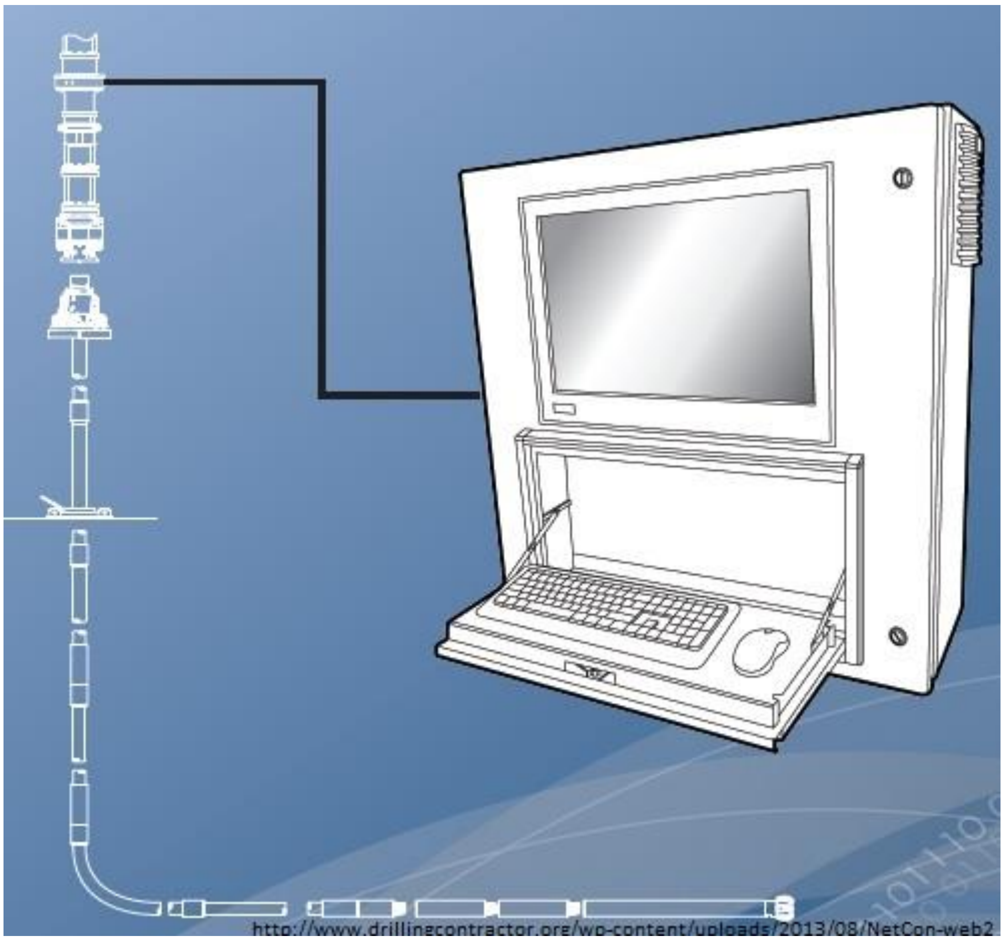

Figure 3: The NetCon (IntelliServ N. C., 2015)

The cabinet is made of robust material and weighs just short of 100 kg. The physical measurements of the NetCon varies, because it is applicable with an adjustable stand. The measurements thus vary accordingly to the adjustable height of: 92-183 cm. The depth and width on the other hand remain constant at 30 and 76 cm, respectively (IntelliServ N. , 2014). The NetCon optionally comes with an internal UPS, which is typical for onshore/land rigs. The other option is to assemble it without the internal UPS, making it a bit lighter but dependent on a direct hook up to an external UPS source, typical for offshore installations. It have different connection points, for different type of cabling and a self-adjusting power supply regarding the differences in power, all over the globe. Lower down in the chapter we examine the field kit of different cables and tools, making up the *surface cabling*. The software installed on the NetCon is a normal Windows based software, tuned specifically for facility operating machines/tools, which makes it very user friendly. The use of a touch sensitive screen or a set of external keyboard & mouse are controlling the NetCon.

In the Driller's Cabin or close to the drill floor, is the most preferable placement of the NetCon. Remote control of the NetCon is also an option, but is not preferred due to the switching between the different cables in use, for the different NetCon day-to-day tasks. The NetCon is as mentioned the working brain of the WDP technology. On the NetCon screen you can control the different programs running on the NetCon and these programs allows you to check upon your connections. Check that the signal strengths is looking good and that the data from your tools, as well as you borehole conditions, are looking great. To get an optimal feel of the borehole conditions, we need to have tools (ASMs and/or a BHA) in the drill string, which provides relative information to the NetCon. More detailed information about ASMs in section 3.3.6 of this chapter.

To check that the connections status is good while tripping new wired drill pipe into the well, a test fixture is connected to the top of approximately every fifth stand. To check that you have communication with the whole drill string, all the way down to the interface-sub and the BHA, the same test fixture is used. Another of the Netcon's vital tasks are to send/receive data to/from external databases and computers. This means that using different connection ports, like serial- or ethernet connections, it is possible for different users to acquire their desired information, while others tasks simultaneously are being performed on the NetCon. There is a lot of information being stored in the NetCon database, both from downhole tools and from surface sensors. The information from the surface sensors make it easier to correlate logs and data, which the NetCon can provide in different format/template files. The simultaneous use of the NetCon requires separate users, easily set up by the wired drill pipe operator (WDPO). Each user will then get access to designated areas of the database, where the relevant information for that user is stored.

The physical connection between the NetCon and the rest of the drill string is through the *surface cabling* and the *data swivel*. Look at figure 2 in section 3.2 to get e better feel for how it is connected. The surface cabling mainly consists of different types of cables, connected through a number of junction boxes (JB), as shown in figure 4.

The first JB being located close to the NetCon and the last JB is mounted to the master gear on the top drive. The different cables between the NetCon and the data swivel is made of different material, to fit its particular functionality and placement on site. The cables that are exposed to mud have better and thicker armor, than the ones placed close to the NetCon (IntelliServ N. , 2014). The cable going from JB3 to JB4 is often referred to as the "sacrificial cable". This cable might be one of the week spots in the network, because JB3 is standing still, while JB4 is rotating when the master gear on the top drive rotates. If the top drive over-rotates, this cable will tend to break/snap, and you lose connection with the rest of the drill string. While operating the wired drill pipe network, the main reason for having multiple JBs on the surface cabling is so that is will be easier to troubleshoot in case of any failures. There are different ways to set up the external connections as well as troubleshooting the surface system, but this thesis will not go into any further detail on these matters.

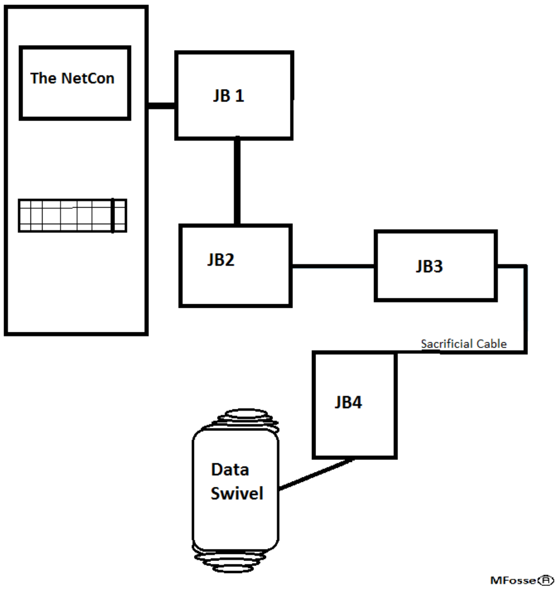

Figure 4: Surface Cabling - From the NetCon to The Data Swivel

3.3.2 The Data Swivel

The data swivel makes it possible to transfer the downhole data to the surface cabling network. It is a part of the top drive system, and is located on top of the internal blowout preventer (IBOP) stack.

The data swivel is a fixed component that allows transferal of the downhole data, to the surface cabling. It comes in different engineered sizes to fit different top drive system. It is part of the components making up the top drive stack and the data swivel's location is on top of the IBOP. Underneath the data swivel comes the upper and lower IBOPs that also are specially manufactured for the use of wired drill pipe technology. The last, but also important part of the top drive stack is the *saver sub*. The saver sub is a sacrificial component of the top drive system, where its main task is to save the top drive itself from abrasion. When the driller make and break connections, to build the entire drill string, the save sub is worn down and when needed replaced with a new one. It also has the purpose of working as a cross over sub, making it possible to connect wired drill pipe with different IDs and ODs to the topdrive.

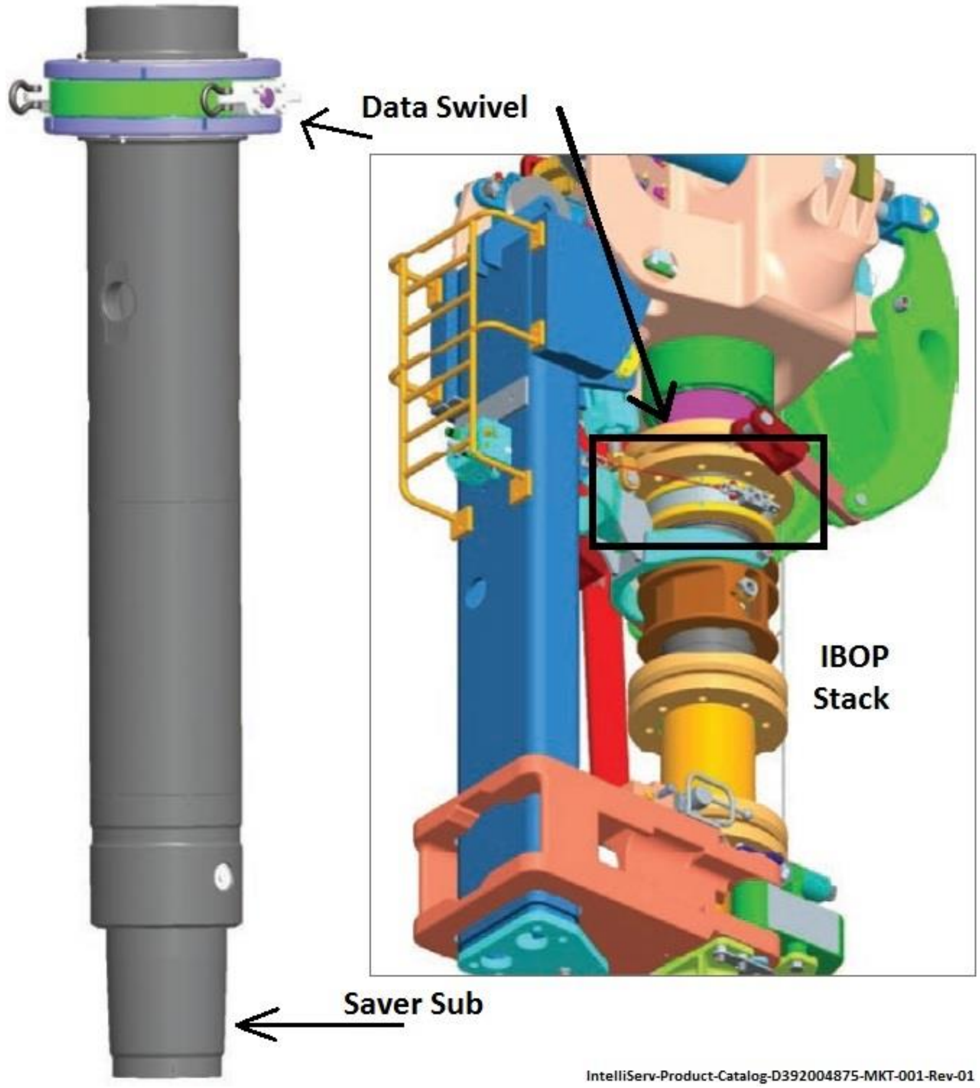

Figure 5: Data Swivel mounted in topdrive (IntelliServ N. R., 2015)

The significant component of the data swivel is the stator. The stator is the component making it possible to transfer the data from the rotating system, to the fixed surface cabling network. Different rigs have different top drive assemblies, and thus there are different components available for making this transferal of data possible (NOV I. 2., 2013). As mentioned earlier in this chapter about troubleshooting, this thesis will not go into any further detail on the subject, but if there is something wrong, the saver sub is a logical component to double check. The saver sub is also one of the weaker links in the system, due to unwanted events like miss stabs, during the making/breaking of wired drill pipe tubulars.

3.3.3 The Wired Drill Pipe, the Coil and the Data Cable

The wired drill pipe is the physical drill pipe joints modified with a high transmission *data cable* inside. The data cable is a robust and armored co-axial cable. At each end of the wired drill pipe, there are embedded a passive inductive *coil* into the tool joints, which makes the data transferal over the connections possible.

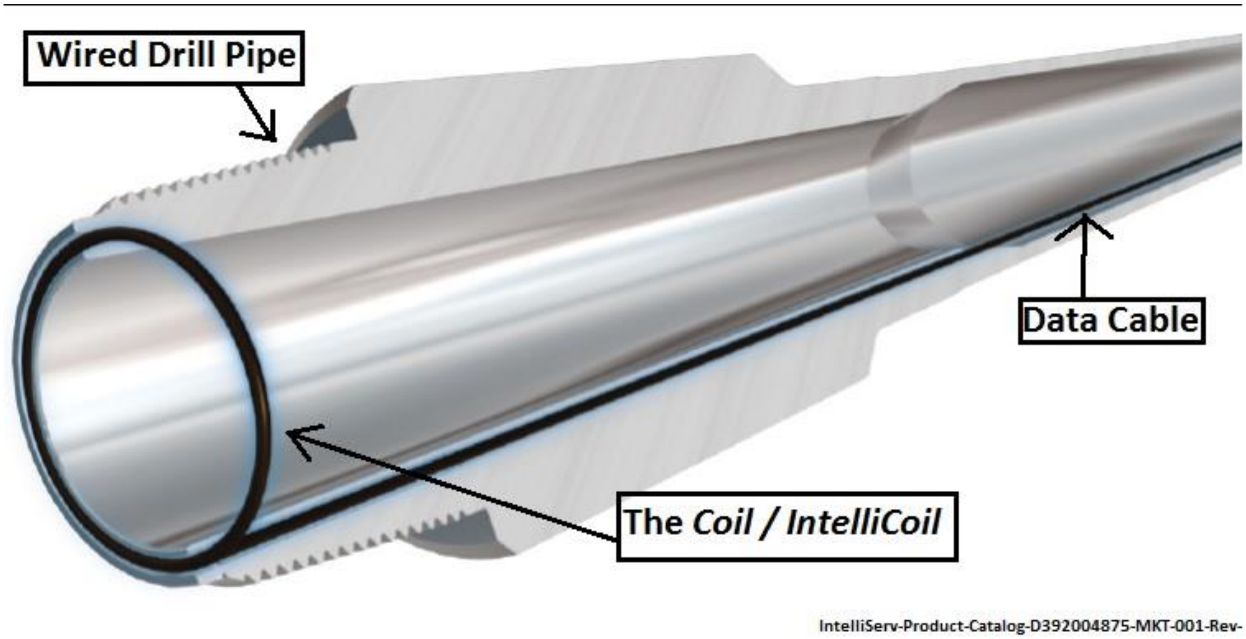

Figure 6: The Coil and Single Wired Joint (IntelliServ N. , 2014)

The drill pipe used to assemble wired drill pipe is standard single tubular joints from Grant Prideco (a company specializing in drill string components). Both Grant Prideco and IntelliServ are NOV owned companies, and by combining their specialties, they try to optimize the IntelliServ WDP technology. The WDP comes in different sizes from 4” to 6 5/8”, and have different connections depending the size of the WDP (IntelliServ N. C., 2015). A listing of different sizes and connections noted in appendix A at the back of this thesis. The “double shoulder” is one of the small differences between a regular drill pipes and the drill pipes used to form the WDP technology network. The double shoulder is where the coils are embedded into the tool join, while the first/original shoulder still have the original sealing function of the connection. Please see figure7 below.

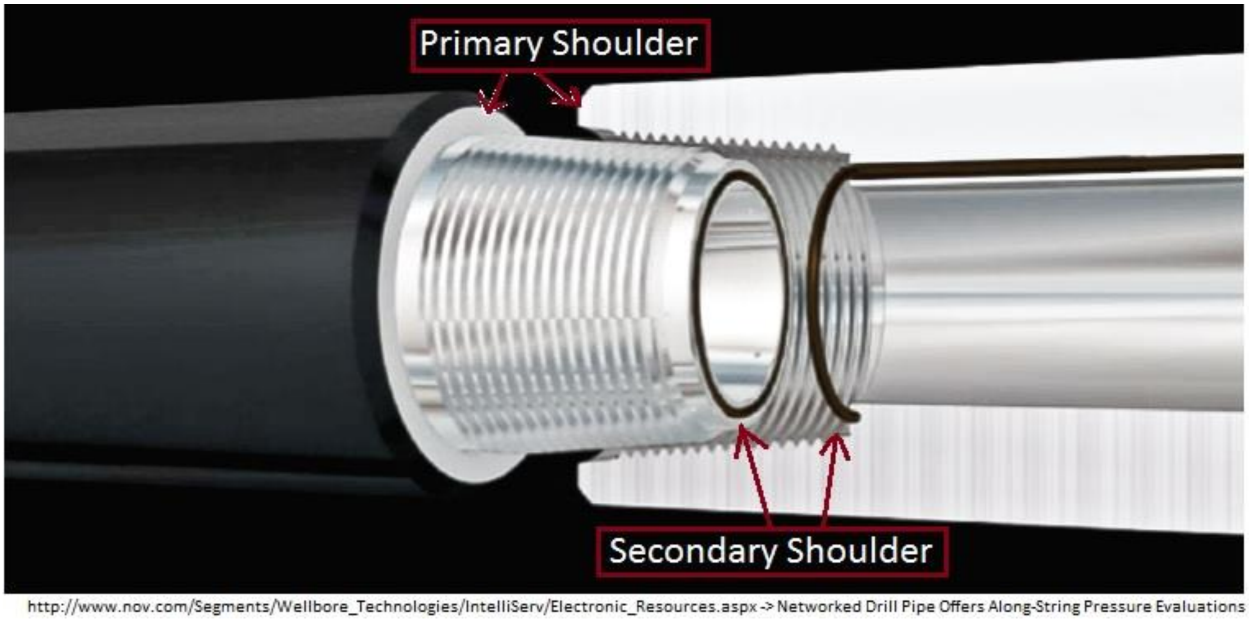

Figure 7: Double Shoulder Tool Joint (IntelliServ N. , 2014)

The operation of pulling the data cable through the joint happens at IntelliServ's plant in Provo, Utah. Custom-made machines drill a hole in the tool joint to pass the cable through. First from the inner secondary shoulder of the box-end of the pipe and through the internal/external upside (IEU). Then on the other side of the joint, the hole is drilled from the pin-end and through the IEU. This makes it is a possible to pass the data cable through the box-end tool joint, through the inside of the pipe, and out through the pin-end tool joint. Before fastening the data cable in both ends of the drill pipe, it is stretched to a certain amount of strain, and then fastened. This strain helps to hold the data cable straight inside the pipe, where it could have buckled and moved freely, if not stretched. The OD of the data cable is 0.2 inches, and thus decreases the drift diameter of the pipe with 0.2 inches (NOV I. 2., 2013).The strain also helps to keep the data cable straight, even though the pipe itself is bent. If the pipe itself is bent, it is important to be aware that the drift diameter of the pipe can decreases even more, due to the data cable taking up more space of the drift diameter than normally, when the pipe was straight. The cable is still straight, which results in making the drift diameter substantially smaller. The drift diameter represent the maximum OD any object flowing through the inside of the pipe can hold, and still be able to pass through without complications. To activate/deactivate some tools used in the string, balls are dropped inside the string from drill floor, and fits into a seat in the BHA, redirecting flow or whatever the task of that particular ball drop was. These balls must never have an OD larger than the strings minimum drift ID.

Now that the cable is in place inside the WDP, how can it provide a continuous stream of data over the connections? Do the data cables have to have *perfectly alignment* over each connection to make this possible? This perfect alignment would not be possible in operations, due to the constant rotating of the pipe, sometimes changing the turn of the connections. This is where the *coil,* also referred to as IntelliCoil, comes into play. This coil is what makes the transfer of data over connections possible, without having to worry about making up an almost impossible *perfect aligned* connection. The coil is made of different conductive material, including ferrite, which makes it possible to send data over the connections. The coil is embedded into small recesses in the double/secondary shoulder of the connection and then connected to the data cable. One coil on the pin-end of the pipe and one coil in the box-end of the pipe. Then when you make up connections out in the field, to build your drill string, the coils will stay very close, almost touching, while the data transferal is made possible with inductive properties of the coil. There is a small signal loss over every connection for different reasons. Mainly because the signal have to cross over from one cable to another, through the coil. The coils wear down over time, due to making/breaking connections among other activities. The signal, passing through the data cables, attenuates over the coils. The signal, depending on the length of the well, needs amplification to maintain its strength so the interpretation by the NetCon at surface will be correct. Read more about signal strength amplification in section 3.3.4 – Data Link.

3.3.4 Data Link

The *data link* is also referred to as booster, transceiver or simply link. The data link is an over average complicated amplifier. The data link receives a signal, then purifies and amplifies it, before transmitting the signal to another link or the NetCon, depending on its position in the WDP drill string.

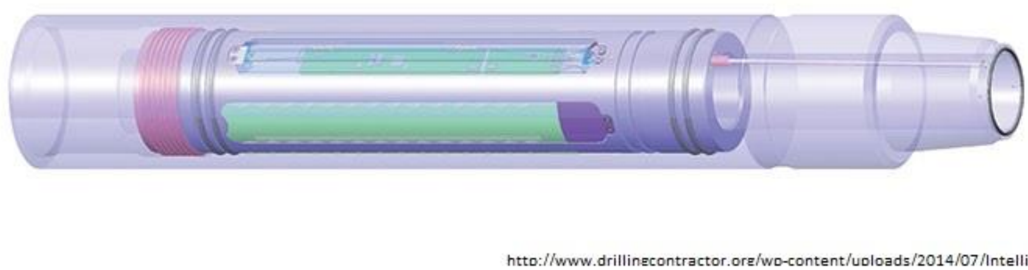

Figure 8: Data Link (DrillingContractor, Drilling Contractor - WP content, 2015)

The data link looks like a typical sub used in the drill string, and comes with different IDs and ODs, depending on what drill pipe size is used. The ID and OD of the data link itself matches the ID and OD of the tool joints in the current drill string used. This is so there is room for the batteries and electronics, but also for simplification when calculating torque, drag and hydraulics, during operation. The data link is about 1.5 m long and often assembled together with a shorter drill pipe joint, to reach the standard length of a drill pipe (NOV I. , 2014). Standard for a range 2 pipe is approx. 9.6 m long. The recommended maximum length between two subsequent data links is 450 m (NOV I. , 2014). In the North Sea this would mean to install a data link approx. every 15th stands (45th joints) of wired drill pipe. A closer look at two different example-wells, drilled in the North Sea, are found in chapter 5.

The data link is communicating through two IntelliCoils, just like regular wired joints. Instead of just cabled joints, the data link/transceiver, have electronics acting as the brain between its two endpoints. To explain this, we can look upon the brain in three parts. A top radio, a bottom radio and in between these radios, there is a computer. The radios have the task of transmitting and receiving – hence the name transceiver. They both *listen* for a signal, and when they *hear* it, they converts this signal from analog to digital, by use of the computer. After the signal conversion, the computer purifies and amplifies the signal – hence the name booster. The last action of the data link is to convert the signal back to analog and pass it along to the next transceiver waiting to pick it up. The booster will always send the same signal it received, but it will also add some status information about itself. Status information regarding battery life, attenuation of the signal received/transmitted and optionally error messages. There is no need to make adjustments on the computer part of data links. It is either working, or it is not. If there is something wrong, the NetCon will interpret the information sent form the booster and alert the wired drill pipe operator, typically by putting an error message on the screen.

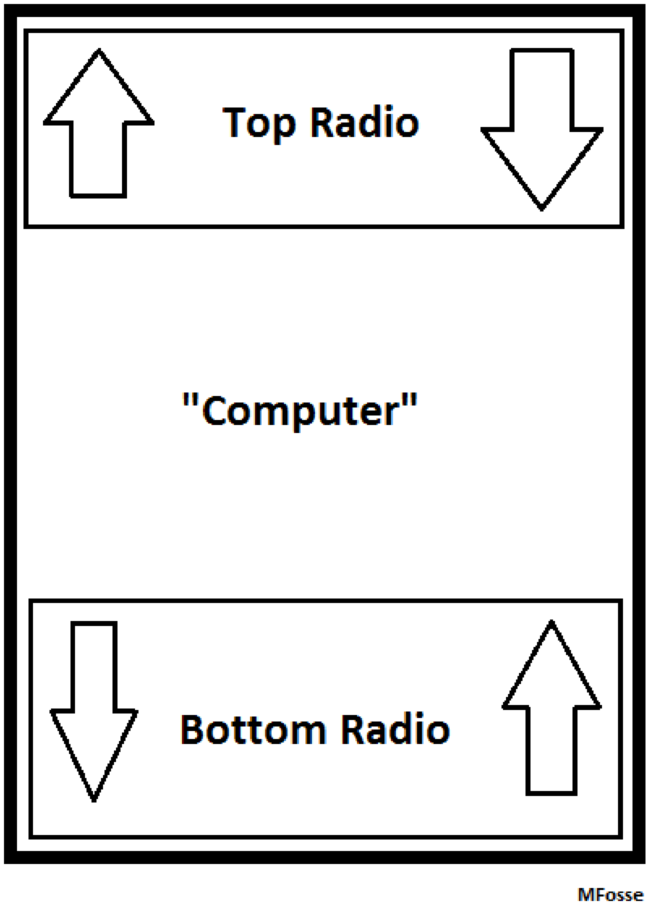

Figure 9: Data Link -Top and Bottom Radio

The data link is a two-part component. The first part containing battery packages that providing power to the link, while the other part holds all the electronics operating within the link. The data link holds two printed wiring boards (PWB), where the first controls the transceiver part, and the second controls the battery part. The data link is not serviceable on the rig, thus it is marked with a “non-break-X” mark mid-body, to show that this connection should not be broken. One of the reasons for not breaking the link is the part containing batteries, or more precisely lithium. If there was to be a lithium spill, it can have fatal impacts on the surroundings. Another reason for marking this non-break-zone clearly, is that the electronic inside the link is highly sensitive to moist, dirt or other form of contamination. Specifications about the data links noted in appendix B.

3.3.5 The Interface Sub

The lowermost component in the WDP network. The interface sub is a converter, making it possible for third party tools/BHAs to communicate through the wired network, instead of using conventional mud pulse telemetry. The interface subs is property of the third parties, due to regulations regarding data transfer.

The interface sub is a converter that makes communication with third parties' BHA possible. Most BHAs are assembled with the purpose of communicating through conventional mud pulse telemetry. When there now is a possibility of transferring data at much higher speed, the interface sub between the BHA and WDP network plays a crucial role. This sub is easiest explained as being a converter. NOV IntelliServ engineers and third party engineers work together on the specific software setup of the interface sub for the representative third party. Third party companies have to make their own tool or interface sub, which makes their BHA compatible with the use of the IntelliServ network. E.g., Halliburton have a component called the "IXO Interface" (Halliburton, 2015) that make their BHA compatible with the IntelliServ network. After the conversion factors are set up, the interface sub are placed in the drill string, in the correct position. Its position will be at the bottom of the wired drill pipe, just prior to the BHA components. From here, it converts all the signals received from the BHA and send this data through the WDP network. Most BHAs have hard drives that conventionally records sampling data while drilling, referred to as memory data. The need for a hard drive is because of the BHA tools are sampling more data than the conventional mud pulse telemetry effectively can send to surface in real time, while drilling. This is now changed, with the WDP network technology, including the interface sub.

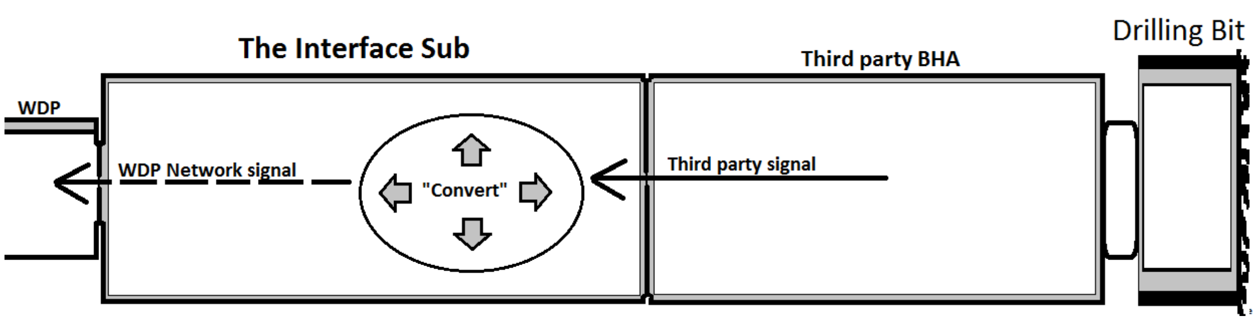

Figure 10: The Interface Sub

3.3.6 ASM – Along String Measurement

Along string measurement, often called ASM, is the general name of different tools that can now be placed anywhere along the drill string, using the WDP network technology. These are more of an additional feature to the wired drill pipe network than a vital one. The network can operate normal without ASMs.

Along string measurements are tools that now can sit anywhere on the wired drill string. Since the WDP technology gives a *network* of communication, instead of just sending and receiving data to and from the BHA, it is now possible to place tools *along* the drill string. The name speaks for itself, and in the future, the ASMs will become an entirely new field of development. NOV IntelliServ have set up their own group -PSI (Partner Support and Integration) that can help third parties with information on how to build their own ASM tools, compatible with the IntelliServ WDP network (IntelliServ A. -N., 2015). The effects of eventually opening this market to third parties are not in within the specs of this thesis, but a freer market will often tend to push technology faster forward, and thereby create an even bigger demand for ASMs and WDP network.

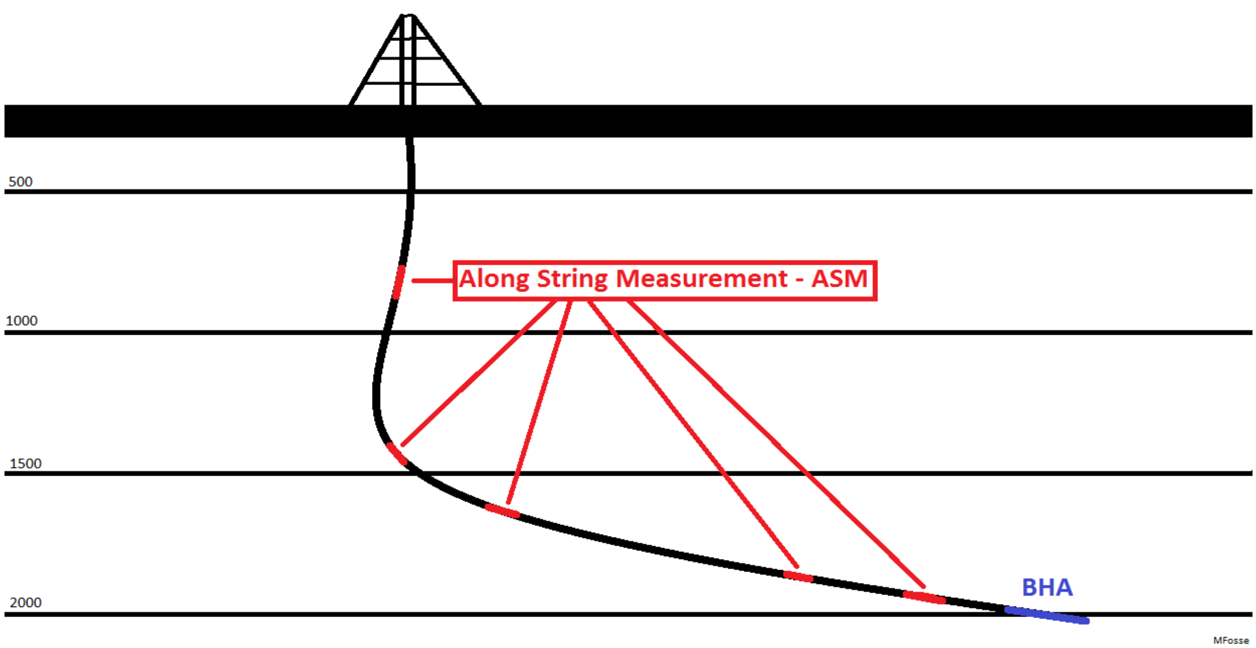

Figure 11: Along String Measurements - ASMs

The ASM sensors measure physical parameters like pressure, stress, strain, vibration, rotation etc. and can give new information from new perspectives. The sensors can also give directional information, like inclinations, azimuthal, gyros measurements and more, so you are able to pinpoint the exact location of sections along the wellbore. ASMs can come in all different kind of shapes and sizes, depending on its purpose. ASMs are still at an early stage of the development process, and will most likely become more reliable in the future. In the future, automated drilling systems will probably also be a new and upcoming technology, only made possible with the speed the WDP network provides. More about automated drilling and ASMs in chapter 5, section 3.

4. Economic Viewpoints of WDP Technology – Drilling Operations

Looking closer on the economics within the oil industry. Examining cost related to the activity of drilling for oil and the use of wired drill pipe technology. When the symbol [$] is used, it refers to US Dollar.

4.1 Value of Time – Oil Price Fluctuation

Within this industry, as mentioned beforehand, time is always of the essence. Due to different currencies worldwide and dynamic exchange rates it can often make more sense to use "time" as the unit for cost, rather than dollars or pounds. I will go as far and state that "time" is an own currency within the oil industry. Most companies are fully aware of the importance of time, and therefore it is often more practical to converse using time as the unit.

The biggest challenge speaking of time as a currency is that the value of time change. As mentioned, fluctuations in the price of oil causes profit margins to change respectively. An oil field can one day be making money on their production, but then be losing money the next day at the exact same production rate. A simplified example to demonstrate follows.

When the overall cost of producing one barrel of oil from a particular field is $50, and the sales price of oil is $55 per barrel, the operator would make a $5 profit on every barrel produced. Now, if the oil price where to drop $25, the operator would lose $20 on each barrel produced, and over a longer period, this might have crucial consequences for the company. This is as mentioned a simplified example, but it paints a picture of how rapidly things change within the industry.

Figure 12 shows the Europe Brent Oil Price from 1987 until first quarter 2015. Brent oil have the properties of relatively low density and low sulfur content and is amongst other, found in the North Sea. This oil is very light and is therefore highly wanted by oil companies.

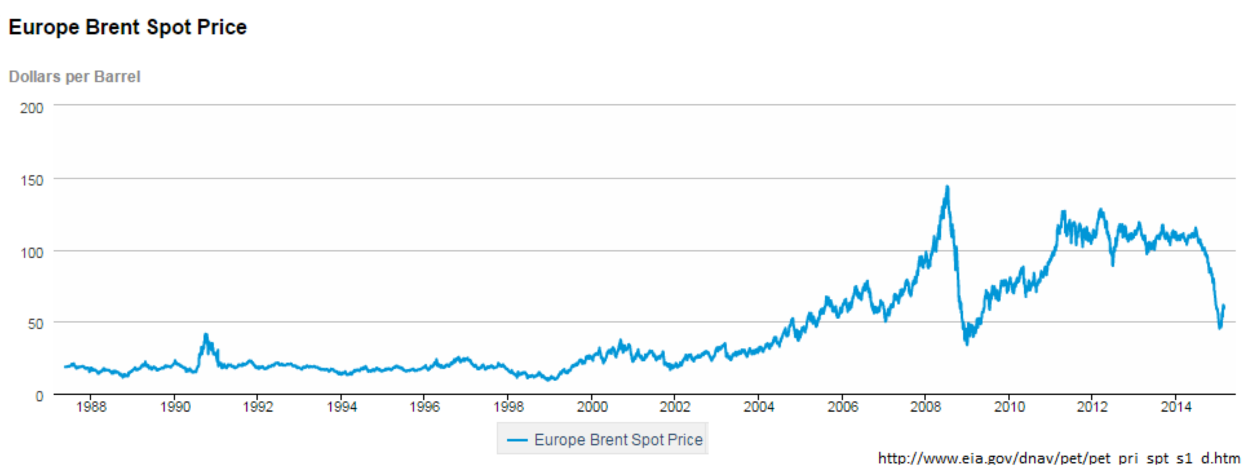

Figure 12: Europe Brent Oil Price (EIA, 2015)

Periods with way lower oil-price than the representative former months are known as down-periods. These down-periods are harsh on the industry, and most often halt development of newer technologies. These halts happen because of big uncertainties regarding the near future. In down-periods like these, the value of time can decrease. This depend on which viewpoint one have on time and the agreement between the operator and the drilling contractor established prior to startup of the drilling project. If no one thought of a quick drop in oil prices, and did not consider this when making the contract, one of the parts might take a heavy blow.

On the other side, when oil prices are high, time most often has greater value. If we look at the period from 2007-2008 where the oil price reach an all-time high, before plunging in the later period of 2008. Also the period from 2011-2014, when the price of oil was on average over 110 USD per barrel of oil. In good times like these, all operators want to produce and sell as much oil as possible, which again can lead to overproduction. Overproduction will over time lead to plunging oil prices, as we have seen so many times before. This thesis will not go in more detail on the rollercoaster behavior of the oil price, but it is important to touch upon this subject for a thesis, regarding the upstream process of the industry.

4.2 The Cost of Drilling Operations

As mentioned, the focus of this thesis will be in the upstream process of the industry. A vital object in the operation of oil extraction is the *drilling installation*. There are many different types of installations available, depending on your requirements. The different installations have different cost, and some form of day rate is the most common way of pricing a drilling installation. The drilling contractor and the operator agrees on a day rate for the specific installation, depending the size of the rig, the water depth where the rig will drill, and other factors like projected rental period. Day rates vary, but most times it follows the changes in the price of oil. When the oil prices are high, operators want to produce more, which increases the demand for drilling installations and thus rig rates go up.

In late 2014, there was a steep decline in the price of oil. This will typically lead to a drop in activity of drilling operations, due to low oil prices. Some operators might go as far as docking their already rented installations. This means putting their drilling installation at a dock somewhere, not drilling for oil, and paying a day-rate agreed upon in the contract. In times like these, docking the rig will often reduce losses for the operator. The contrary option would be to have the installation loaded with drilling crew, marine crew and service companies, operating as normal. The price of having an installation in normal activity drilling for oil can vary a lot. Many of the rates for the different services onboard a rig are hard to come by (they are confidential in many cases). However, we will first take a closer look on what it approximately costs to have a semi-submersible drilling rig in "full-operation" in the North Sea.

There are very many different lines of services, working non-stop on an operative drilling rig. Most positions have two shifts, so there is one person working a 12-hour nightshift and another working a 12-hour dayshift. This leads to the whole rig being in operation all day long, 24 hours a day. This again leads to most services companies charging a fixed day rate for each worker, depending on their individual experience. A typical senior or junior rate is charged. To give a better understanding of the cost of a drilling operation, here are some figures from the article "Så mye koster en letebrønn" ("The price of an exploration well") written in 2009 (Bjerke, 2009). In this article, the expenses are grouped into different batches, as stated below in table 1. The rates in the article were in NOKs, and are converted into US dollars. For more details on the conversion and calculations, see appendix E.

The total rig rate for the semi-submersible rig West Alpha, during its' 116 days stay at the Fulla prospect, summed up to $28 million. These 116 days featured from the beginning of the project, until somewhere in the completion phase (Bjerke, 2009). A closer look at these number shows that this boils down to only $241 000 per day. Today (1Q 2015) the same rig is per contract rented by Karmorneftegaz (Rosneft and ExxonMobil joint venture) at $519 000 per day (Offshore.no, 2015). This gives over 100% increase in price. It is worth mentioning that West Alpha's construction year was 1986.

The 2009 article states that the second largest expenditure during this stay was the group labeled *services*. The total cost of services added up to $12.9 million. The services, which fall into this category, are casing services, measuring & logging services, directional drilling and more. The *logistics* added up to $11.8 million, consisting of diesel fuel for the tankers, onshore-base workers and rig shipments plus more. The next expenditure post is *equipment and material* which consists of different parts and components needed for the drilling operations to run smoothly. These components adding up to $7.0 million. The last category is marked as *personal cost* and ads up to $4.3 million. These numbers are as mentioned from

2009. Today, in 2015, it is not an exaggeration to state that the cost of a “fully operational semi-submersible drilling rig” in the North Sea will come close to $1 million per day. A typical rule of thumb is that the spread cost of a drilling rig in full operations is approximately twice the day rate (IHS, 2015), which suits the numbers below pretty well. For demonstrational purposes throughout the thesis, $1 million per day will be the cost used for a “fully operational semi-submersible drilling rig” in the North Sea. This might be on the more expensive side, but for different operations, prices will be different. This depends on what drilling installation to use, what equipment quality, difficulty level of the well profile etc. The cost designated to the different branches stated in the table 1 below are based on the cost-distribution found in the 2009 article (Bjerke, 2009). For more information on estimated numbers for demonstrational use, see appendix E - Rig Cost Calculations - Currency.

Product	Cost in $ USD
Rig Rate	440 000
Services	200 000
Logistics	190 000
Equipment	100 000
Personnel	70 000
SUM	1 000 000

Table 1: Categorized cost of a drilling operation (Appendix E)

There are lots of different equipment needed to drill a hole in the ground. A lot of different technologies and businesses/companies have grown from the demand for oil. One of these companies are IntelliServ, which NOV bought in 2006. Today IntelliServ, as earlier mention, bring a completely new technology to the table. A technology that might play a big role and change parts of the industry, forever. We will look closer upon these possibilities in the discussion section 5.4.

4.3 The Cost of Drill Pipe

We will first look at one of the most, if not *the most* fundamental component in the operation, the drill string. The drill string consists of drill pipes/joints connected to form a long string of steel. The drill strings purpose is to pave its way through different formations-layers of rock, and ideally enter a reservoir filled with hydrocarbons. A drill bit sits at the bottom of the drill string, making it easier to break down the tough formations. Drill bits come in a vast number of different models, all models specified to optimize the drilling process in particular formations. Drill bits wear out because of all the rough treatment it gets downhole, and the lifespan of a drill bit can vary a lot. A bits' lifespan is dependent on how much exposure the bit sees. Exposure to unwanted abrasion like vibration, torque and stick slip, all contribute to shorten the lifespan of the bit. This also applies for the drill string itself, and if it only was possible to get a better picture of what is happening downhole, this would help a lot.

As mentioned in section 2.4 "challenges today" it often is a challenge for the driller to act on warning signs from downhole tools, when received data is not of sufficient resolution. If the signs were clearer on what was going on down hole, the driller could easily make the drilling process as smooth and non-destructive for the drill string components as possible.

A regular drill string typically lasts from seven to nine years, before replaced with a new string. The cost and lifespan of a regular drill string will vary depending on grade of the steal used, its' dimensions and its' ID/OD specifications. For this thesis, the steal and specification used for the regular drill pipe and the wired drill pipe comparison are identical (except the wired drill pipe will hold the data cable and coils, of course). This makes it possible to make a fair cost comparison of the regular drill pipe versus the wired drill pipe.

The figures used on the cost of the regular and the wired drill pipe are gathered from a NOV representative via e-mail correspondence and interview (NOV R. T., 2015). The NOV owned company Grant Prideco, which is a manufacturer of drill pipe, is the company that makes the special double-shouldered tool joints used in the wired drill pipe system. Grant Prideco make all sorts of different regular pipe *and* they make the joints for the wired drill pipe. The fact that they manufacture both regular and wired pipes it make sense to use Grant Pridecos price for comparison of the two.

The following figures are based on drill pipe needed to drill a 5000 m long well. They originate from e-mail correspondence with a NOV representative (NOV R. T., 2015). For commercial reasons, the specific grade, ID and OD of this particular pipe is confidential. The price tag of this specific regular drill pipe is approximately \$5000 per joint. Thus, to complete a 5000 m MD long well, this sums up to approximately 500 joints. (A typical drill pipe, also known as joint, is typically 9.6 m long, but for convenience 10 m is used throughout the thesis.) This will give a total cost of \$5000 x 500 joints = \$2.5 million for a regular drill string. For a shorter exploration well, with length 2200 m, a number of 220 joints are needed, summing up to the total cost to \$1.1 million for regular drill pipe.

If the operator wanted to run the wired drill pipe instead, the cost would normally be higher. The price tag of wired drill pipe and components needed to run this system, based on the same 5000 m long well, is found in table 2.

The surface cabling and surface equipment will cost $200 000. The surface equipment is a one-time investment, and is reusable for that particular rig. If this equipment is not demobilized, it will function with wired drill pipe in the future as well. There is an insignificant small additional cost, regarding repair and maintenance of the booster links. This amount is already embedded in the price tag of the wired drill pipe. The wired drill pipe, or wired joints, will cost an additional $3000 per joint on top of regular the drill pipe. Hence, the total cost of one single joint of wired drill pipe costs $8000. The production well having the target depth of 5000 m MD, making the total cost of using wired drill pipe $8000 x 500 + $200 000 = $4.2 million. For the explorations well, reaching 2200 m, it would cost $1.96 million. As stated, the extra cost of wired drill pipe is significant. The cost and possible time-savings for each well, will be thoroughly examined in chapter 5, section 5.1 and 5.2.

Type of pipe	Length of well [m]	Joints needed	Per joint [$]	Surface Eq. [$]	Total [$]
Regular Drill Pipe	5000	500	5000	0	2 500 000
Regular Drill Pipe	2200	220	5000	0	1 100 000
Wired Drill Pipe	5000	500	8000	200 000	4 200 000
Wired Drill Pipe	2200	220	8000	200 000	1 960 000

Table 2: Cost of Wired Drill Pipe

4.4 Time-Saving - Categorized

First, a short explanation of all the different *time-saving categories*, then chapter 5 gives a more specific and detailed examination of the time saved with the use of WDP to drill two different wells.

To establish figures for the time saved with wired drill pipe, I have used the “Efficiency Calculator” found on IntelliServ’s website (NOV_Intelliserv, 2015). After a thorough walkthrough regarding this calculator, it was clear to my professor and me that it is trustworthy. The NOV representative explained how the database was built, and how all its data originates from the over 100 wells drilled with wired drill pipe technology (NOV R. T., 2015).

One of biggest benefits of using wired drill pipe today are the time-savings accomplished during the drilling operation. Figure 14 (see page 39) shows a 5000-meter common ERD *production well* in the North Sea. In an ERD well like this, the directional driller needs to do a lot of steering to follow the projected well profile. Figure 16 (see page 45) shows a somewhat shorter well, reaching 2200 meter. This shorter exploration well does not need the same amount of steering to follow the projected well path, and thus the time-savings will be different.

I have chosen two different, but very common, well profiles to demonstrate the time-saving possibilities when using WDP technology. To make it even clearer, I have decided to split the time-saving portions into 5 different quantifiable categories. Underneath you find each category listed (also referred to as batches) with a quick explanation to what part of the drilling operation they contribute. We touch upon each category in more detail while studying the example wells.

<u>The time-saving categories:</u>

1. Data Transmission
2. Drilling Performance - ROP
3. Run Reduction
4. Hole Cleaning
5. Trip Speed Optimization – using ASMs (optional)

4.4.1 - Data Transmission

As of today, the easiest batch to recognize is the time saved on data transmission. The main advantage of using wired drill pipe is that it allows bidirectional communication at speeds up to 57 600 BPS. The result being that all communication with the downhole tools go a lot faster. During drilling there are a lot of communication going on between the surface and the downhole tools. Messages sent back and forth, containing information regarding surveys, pressure parameters, diagnostics of the tools, rotational check shots, formation pressure tests and more. The numbers in this category are very easy to quantify, even without the help of the NOV calculator. Here is an example.

A normal survey will typically take somewhere between 2 to 4 minutes (BHI & Williams, Directional Drilling - Facts, 2015). This will depend on the different companies' procedure on taking surveys, but with wired drill pipe, it takes 4-5 seconds. This might sound like a small saving, but when you add up these savings for the whole well, it sums up to hours, if not days. As mentioned many times before, time is always of the essence.

4.4.2 - Drilling Performance – ROP

The ROP (Rate of Penetration) says something about how fast one drills through the formation. The metric unit used for ROP is [m/hr] and the imperial unit is [ft/hr]. There are often KPIs (key performance indicator) related to the ROP for each section drilled, and one always want to hold as high ROP as possible, without affecting the stability and safety of the operation. There are many different limiting factors when it comes to drilling at certain speeds, and it is the driller's responsibility to optimize the ROP. Using and interpreting data/information from downhole tools, the driller/directional driller can adjust parameters to drill as fast as possible, within set criteria for each section. To mention some criteria, it can be sampling rate, minimum definition on logs, minimum sampling points per meter etc.

4.4.3 - Run Reduction

Run reduction is more of an indirect way of saving time. This batch relates to the huge amount of dataflow sent through the IntelliServ broadband network. When the drill string is experiencing rough conditions downhole, it is now possible to act on such signals way faster. This reduces the number of trips due to tool failure, and accordingly the number of runs needed to drill a section to TD. E.g. *backward whirl*, which exerts unwanted high lateral vibrations on the drill string, can easily destroy important components within 10-15minutes. If a vital component is destroyed, then one have to trip out, replace the component, trip back in and then be able to continue drilling.

4.4.4 - Hole Cleaning

During drilling of every section, it is very important to have good hole cleaning. It can be hard at times to determine if the transportation of cuttings are normal. The ECD (equivalent circulation density) is a result of the hydrostatic pressure of the fluid column and the additional pressure applied when circulating, hence the name equivalent circulating density. Combination of ECD readings downhole and standpipe pressure will most times give a good indication if the hole is cleaning properly. An unexpected increase in standpipe pressure and ECD will often be an indication of non-sufficient hole cleaning. The consequence being that the driller needs to pull off-bottom, stop drilling and circulate the accumulated cuttings out of the hole. Being able to spot these accumulations of cuttings earlier, will give chance to optimize flowrates, and reduce the time needed to circulate the well clean at TD. This again leading to saved rig time. To achieve optimal time saving in this category, the correct use of ASMs can be a key factor.

4.4.5 - Trip Speed Optimization

This last batch is the trip speed optimization. This will not account for the majority of time saved, but still plays a certain role. This shows time-savings while tripping in/pulling out of the hole. Surge and swab events limit the tripping/pulling speed. The definition of a surge event is the creation of an unwanted high pressure in the wellbore while running in hole and worst case this pressure ends up fracturing the formation. The opposite of a surge event is a swab event. Swab events are when creating a vacuum behind a drill string component while pulling the string out of hole, and worst case swabbing unwanted fluids into the wellbore. Unwanted fluid in the well bore can affect well stability and this again affecting the safety of the entire operation. Time-savings in this category are likely to increase in the future, as ASMs and automated drilling becomes more and more common. Read more about the future of ASMs and automated drilling in section 5.3

Figure 13: The NetCon in use (DrillingContractor, Drilling Contractor - WP content, 2015)

5. Review, Savings and Discussion – The complete WDP Network

This section bring us closer to answering the aim of the thesis, based on the earlier chapters regarding technical specifications and the economic viewpoints. This section will also study two specific example-wells drilled with WDP. A discussion about the advantages, possibilities, costs, weaknesses and other sides of the wired drill pipe technology will also take place. My final conclusion is found later, in chapter 6.

5.1 Time-Saving – 5000-meter Production Well

During this section, we examine the time saved when using wired drill pipe, compared to the use of conventional drill pipe. The savings are categorized as in section 4.4, but now with a more detailed explanation to each action that saves time. Figure 14 shows an informative drawing of the 5000-meter extended reach production well. This clearly shows that the projected well path needs proper steering to reach TD. It holds a straight section, a build and a drop section, and finish with a longer horizontal section.

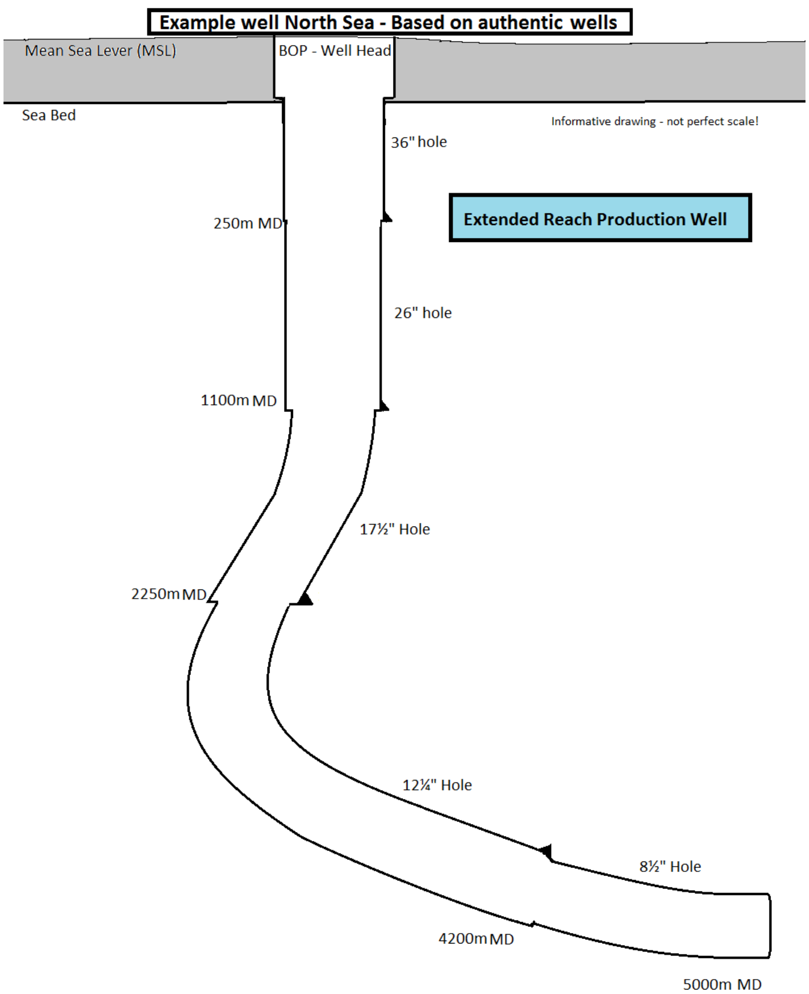

Figure 14: Extended Reach Production well - 5000 meter long

The well profile is based on authentic wells in the North Sea. We will now look closer on the time saved when using wired drill pipe to drill this well. Every category will be closely examined and explained during this analysis of a 5000-meter long well. Afterwards we will study the shorter exploration well with the same accuracy.

Figure 15 on page 43 shows the summary of time saved when using wired drill pipe instead of regular drill pipe to drill this production well. The detailed input and output data/figures for this summary are located in Appendix C. Appendix C also shows which category and sub-category saving the most time. All input data used are thoroughly advice from a very experienced directional driller, with over 30 years of experience in this field, now working for Baker Hughes (BHI & Williams, Directional Drilling - Facts, 2015). The drilling ROPs for each section are from an anonymous well, drilled in the North Sea using RSS (rotary steerable assembly). RSS is a method of steering the well while drilling, instead of using a down hole motor, with pre-determined angle. The RSS is a part of the BHA, located close to the bit. It rotates together with the string, but at a slower pace (designed bearings makes it possible for the RSS to rotate at much lower RPM than the drill string itself). There are sensors keeping track of directions, so the directional driller are able to steer the well path in desired direction.

Data Transmission. We start looking at the time saved on data transmission. When it comes to data transmission through WDP (for more info see section 4.4.1), this is the easiest quantifiable way of saving time. Time saved is directly and intuitively recognized by adding up all the minutes spared on communication with downhole tools. For this 5000-meter long well there are quite a lot of communication needed to actually follow the projected well path. To do so, the directional driller, with help of the MWD engineer, use the system software and communicate with the tools. There are procedures on when to engage in such communication, but also several unwritten rules of thumb to follow, depending on each directional driller's experience.

It is procedure for most directional driller to do a survey on every connection, but when there is a lot of steering involved, surveys are also taken on-bottom (while drilling). The time interval of taking a survey can vary, but on average, a survey takes 3 minutes using conventional methods (BHI & Williams, Directional Drilling - Facts, 2015). When using wired pipe, just on surveys alone, the savings for this well ads up to 8.3 hours. 8.3 hours only account for the good surveys taken on connection; now let us include repeated surveys (repeated because the first survey was bad - no confirmation, bad signal etc) and the surveys mid-stand when steering. Total time saved on surveys alone now ads up to 14.5 hours.

When drilling with RSS, which is the most common way of steering in the North Sea today, downlinks (tool commands) need to be sent on regular basis. Downlinks are commands sent from the MWD engineer's software to the downhole tools. These commands often regards steering, but can also be about activating/deactivating tools. On this well, the WDP technology saves close to 14 hours on downlinks.

Before drilling a new section, a test of the formations integrity is standard procedure. There are varieties of different tests used, depending on the operator. These tests consists of recording data downhole (mainly pressure), while exerting additional pressure on the wellbore, in a controlled environment. After the test is complete, the recorded data are in most cases sent to surface, using the conventional telemetry.

This process can take quite some time, because of limitations on transmission speed of wireless communication. With the wired pipe, the pressure data is received real time during the test, and for this well saves 0.8 hours. You will save approximately 10 minutes on each test performed.

Adding up the data transmission batch, this saves 29.3 hours on this particular well.

Drilling Performance - ROP. When it comes to drilling performance the time-savings are not as easily quantified as the data transmission time. I will divide this category into four sub categories. Shock and Vibration, ECD management, Formation Evaluation (FE) and Directional Control.

Shock and vibration is a common challenge when drilling the latter section of the well, and by receiving more real time data at 5-second intervals, compared to the conventional 1-2 minute intervals, it is now possible to act much faster to optimize the drilling parameters.

The high focus on *ECD management* during the drilling process is vital. As mentioned earlier, it can be hard to ascertain optimal hole cleaning, however, combining optimal flow rate with optimal ROP goes a long way. ECD management and hole cleaning are closely related, since if cuttings are accumulated downhole, the ECD will increase and you have to decrease the ROP. The faster ROP, the more cuttings created down hole, and the more important it is to keep the correct flowrate to obtain optimal hole cleaning. Having the quickly updating data present makes it possible to optimize the ROP, and still keeping ECD management under control.

For reservoir sections essentially, the *Formation Evaluation* are very important. This often limits the ROP, affected by the limitation on transmission speed when using wireless telemetry. E.g. the operator sets a minimum number of data points sampled per meter – minimum acceptable resolution on the real time formation logs. If the ROP goes above a certain point, the tools will still sample at sufficient rate, but it will only save these high definition logs as *memory data* downhole. For the gathered data to be available on surface in real time, it needs to be transmitted. Here, the limiting factor again is the transmission speed available for sending data to surface. These real time data are very important, since it is these data the geologists uses to pinpoint core-points, casing depths or geo-steering the well path, when drilling inside the reservoir. When using wired communication this limitation is no longer an issue, it is the exact opposite. The data sent to surface are now real time memory data (which normally is stored in the memory of the tool, and dumped on surface for analysis *after* the section is complete). The real time data with conventional telemetry holds 1-2 minute interval updates and *ok* resolution. The wired drill pipe provides much more data, with *greater* resolution, which results in today's possibility to drill with a higher ROP, without compromising safety and definition of the FE logs.

During the middle sections of the well, i.e. 17½ and 12¼" sections, the need for *Directional Control* is significant. Being able to spot unwanted deviations from the well projection sooner, will help the directional drillers' confidence and give him opportunity to use a higher overall ROP for the sections. These sections are often the ones with most build/drop angels in them. The end of these build and drop sections are often the starting point for a horizontal 8½" section.

The calculations shows that for all the different sections, one can increase the ROP with approximately 15%. The adjustment on how big of an impact the input will have can be adjusted, and after discussions with representative personnel, I decided to be conservative with the adjustable features of the calculator (NOV R. T., 2015).

Adding up the drilling performance batch, this saves 26.4 hours on this particular well.

Run Reduction. During drilling of a well, occasional need for additional unplanned BHA-runs arises. These non-planned events most often happen because of tool, string or bit failures. Amongst the wells drilled with WDP in different locations around the world, a reduction in BHA-runs needed to complete a well is significant (NOV R. T., 2015). Run reductions are related to quicker response on warning signals, and less exposure to unwanted wear on tools, string and bits. To *trip for failure* is a costly act. Intuitively the longer the well, the more time is wasted. It is hard to determine an average amount of time spent on tripping (from drilling stops until it continues); this naturally depends on the particular well paths and limiting factors when tripping. More about these factors in section 4.4.5 "trip speed optimization". For this particular well, using the average count of unplanned trips encountered because of component-failure, the savings are significant.

Adding up the run reduction batch, this saves 12.0 hours on this particular well.

Hole Cleaning. As touched upon under the drilling performance section, the ECD monitoring is a vital part of drilling a well. Now hole cleaning decisions are made quicker, because of frequently updating (5-second intervals) data in high definition, is displayed and monitored, like never before. This is made possible with use of networked pipe, and the optional use ASMs. The ASMs optimizing the process of pinpointing locations of abnormal pressures. The reduction in time spent circulating the well clean are less than the batches above, but still significant.

Adding up the hole cleaning batch, this saves 6.7 hours on this particular well.

Trip Optimization. Prior to drilling a section, the drill string is made up and tripped into hole. The opposite happens at the end of a section. After drilling to TD, the string is pulled out of hole and laid out on surface. The tripping process can be a very time consuming process, especially on longer wells where pressure margins often are small. Because of the wired drill pipes' amazing bandwidth and feature of transmitting signals to surface without flow, it is now possible to optimize the tripping process drastically. Even more so, with the use of pressure sensors positioned at desired locations along the string (ASMs). These sensors can transmit live feed data of pressures from anywhere in the wellbore, and thus optimize the tripping speed. The system can monitor the whole string being tripped safely, without the risk of breaking the limitations of swab and surge pressures. Per early 2015, as mentioned in section 3.3.6, the ASMs need further research and development (R&D) to become more precise. Nevertheless, when it in the future will be possible to combine ASMs downhole and automated drilling systems on surface, which will really show the benefits of the wired drill pipe network. Read about automated drilling in chapter 5.3.

Adding up the trip optimization batch, this saves 3.5 hours on this particular well.

An event that the calculator does not take into account is the shallow tool test, which is normally performed every time a new BHA is tripped into the hole. The length of this test varies, depending what tools assembled in the BHA. On average this test take somewhere between 10-20 minutes (BHI & Williams, Directional Drilling - Facts, 2015). So taking our five section well, there will be need for a shallow tool test on four of these five sections. (There is no need for a test prior to drilling the 36" hole, as this is so close to the surface anyway). Using the average of 15 minutes per test, multiplying with the four sections, resulting in another hour saved. The possibility for skipping the shallow tool test is that there is no need for circulation to communicate with the tools, as we now have the wired connection. Most operators today still do the shallow tool test, because most third party tools are dependent on flow to power up, and I will not use this 1 hour saved in any of my calculations further down in this section. Nevertheless, it is important to mention that in the future there will probably not be any need for circulation to power up the tools. There will be a simple solution of sending a signal through the wired connection to turn them on; this is already being worked on by different third parties (BHI & Williams, Directional Drilling - Facts, 2015).

WDP Drill Faster Savings Summary

Data	Value	Percentage
Data Transmission Time	29.3	38.2%
Increased Drilling Performance (ROP)	26.4	34.2%
Bit/BHA Run Reduction	12	15.8%
Hole Cleaning Time Optimisation	6.7	7.9%
Trip Speed Optimisation	3.5	3.9%

Total Time Saved (Hours): 77.9

Total Time Saved (Days): 3.2

Figure 15: Time-Savings Summary | 5000 meter long well (NOV_Intelliserv, 2015)

As figure 15 shows, the total saving when using wired drill pipe in a 5000-meter long production well, adds up to almost **78 hours, or 3.2 days**. We will closer examine this number and relate these time-savings to the price tag of operating a drilling installation.

The price tag (ref. table 2 - section 4.3) on all the components needed for a complete wired drill pipe network, used in a 5000-meter long well, is $4.2 million. However, you have to have some sort of drill pipe anyway and the price tag on regular drill pipe, with the exact same specifications, is $2.5 million. This result in $1.7 million additional cost when using WDP, instead of non-wired drill pipe with the exact same specifications.

One important aspect, not touched upon yet, is the uptime of the wired drill pipe network (uptime being the time that the system is working). During different projects, there are noted different results of uptime. One of the WDP technology projects consisted of drilling five wells, in a highly challenging filed, offshore in Trinidad and Tobago. During this project, they used the 1st generation of WDP and the project stretched over a 24 months period (Veeningen, Palmer, Steinicke, Saenz, & Hansen, 2012). The overall broadband network uptime, as a ratio of the total time that telemetry was required, exceeded 85% throughout this project (Veeningen, Palmer, Steinicke, Saenz, & Hansen, 2012). Now, over 100 wells have been drilled using wired drill pipe, and the uptime of the WDP network early 2015, is as high as 91% (NOV R. T., 2015). This 91% is only taking into account the projects that have been drilled with the 1st generation of pipe. The 2nd generation of WDP (IntelliServ2Network) have already been on the market for quite some time. Despite being on the market, not enough wells have been drilled using the 2nd generation pipe that an average number on uptime is manifested yet (NOV R. T., 2015).

Result:

Doing some calculations, and taking into account that the system on average works 91% of the time, lets shorten the time-savings found above, with the given 9%. This will give a more accurate number for the time saved. The calculator bases its final numbers on the system being 100% operative, all the time.

77.9 hours x 91% = 70.9 hours or (2.95 days)

Now we will compare these savings with the figures, found in table 1 - section 4.2, with the cost of having a semi-submersible drilling rig *drilling* in the North Sea.
The cost of this, based on the numbers calculated earlier, summed up to $1.0 million per day.

If we now take the savings and multiply with the cost per day, the time saved represents $2.95 million. Implementing the additional cost of using WDP, which was $ 1.7 million, the overall cost for using WDP on this well is $1.7 million – $2.95 million = -$ 1.25 million. This means that the operator actually **saves $1.25 million** by using the WDP network to drill this particular well. This being under the assumption that the system is working on average uptime, equal to 91%.

Even if the price of renting a rig and personnel plunged by 50%, and the price of WDP remained unchanged, the operator would more or less break even on this well. This shows that one have to invest to save money. In troubled times like the industry are facing today, early 2015, investments in newer technologies can help you save money.

It is worth mentioning that not all wells drilled, are 5000-meter long with a lot of steering and limiting factors of different kinds. The following section contains a run-through of another example, using a much shorter and simpler well path, reaching 2200-meter. This is to set things in a better perspective.

5.2 Time Saving – 2200-meter Exploration Well

During this example, we will be looking at a shorter well. This well have common well profile for an exploration well. The profile shown in figure 16 is based on anonymous authentic exploration wells drilled in the North Sea.

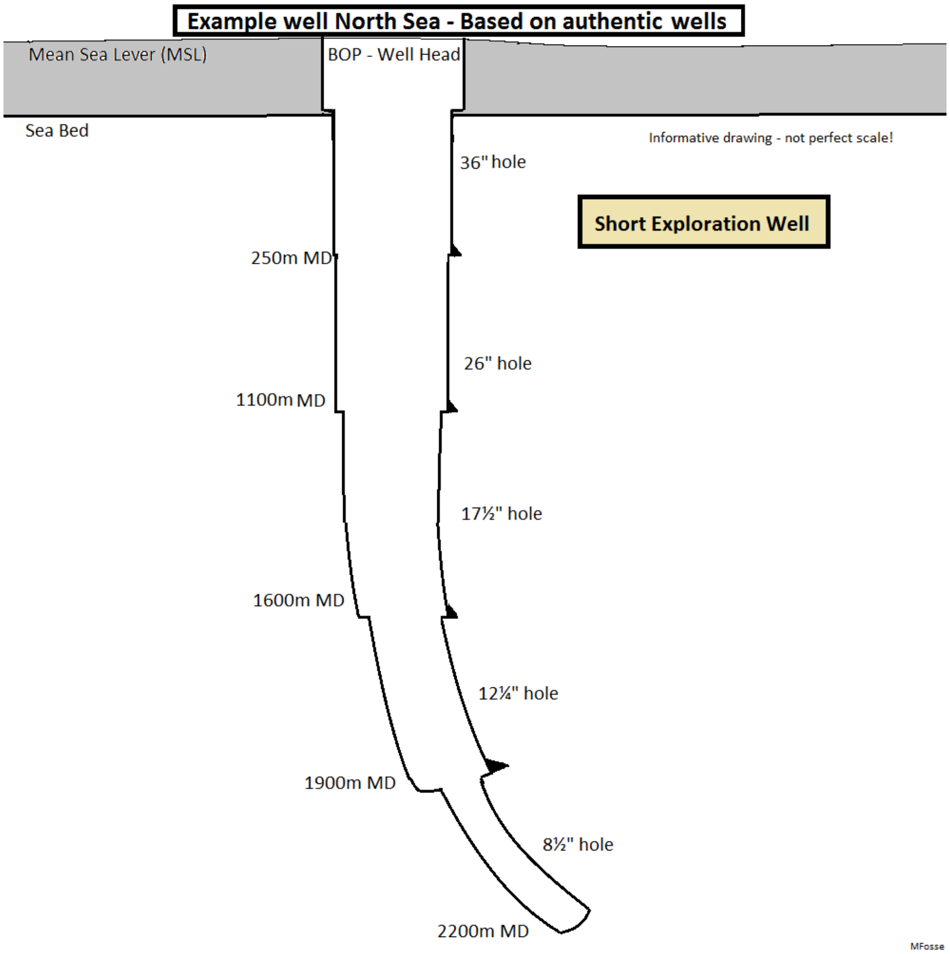

Figure 16: Short Exploration well - 2200 meter long

We will first go through the same categories as the 5000-meter example, without the same level of explanations to each batch. There is no need to repeat oneself more than necessary.

Figure 17 shows the summary of time saved when using wired drill pipe instead of conventional drill pipe to drill an exploration well. Detailed input and output figures for this summary are located in Appendix D. Appendix D also displays which category and sub-category saving significant time. All input data used are thoroughly advice from an experienced directional driller, with over 30 years of experience in this field, now working for Baker Hughes (BHI, Directional Drilling - Facts, 2015). The ROPs for each section are from an anonymous well, drilled in the North Sea using RSS.

Data Transmission. For this well, the data transmission also holds the largest portion of time saved, despite the fact that there is no need for the same amount of downhole communication. There is saved the exact same amount of time on pressure test prior to each section, but the time saved on surveys and downlinks are less than it was for the 5000-meter well. The RSS downlinks still save some time, adding up to 4.4 hours, while the surveys, including repeated ones add up to 3.5 hours. This also seems logical, since this well is under half the length than the production well, and the projected well path does not require much as much steering. The shape of this well relates to most exploration wells drilled, being more or less vertical and with the purpose of striking oil in any of the penetrated layers.

Adding up the data transmission batch, this saves 8.8 hours on this particular well.

Drilling Performance -ROP. The ROPs used when drilling explorations wells differ a lot. For this example, I have chosen to use conservative numbers, with not so high speed, the result being the time-savings also being a bit conservative. Specifically for exploration drilling, there start of the 8½" section is important with respect to finding an eventual core point. If there is oil in the predicted reservoir, it will show on the *formation evaluation* logs (FE logs) and the drilling will in most cases halt, and conducting a coring operation. To observe this typical scenario, the geologist are again very dependent on sufficient data from downhole tools, and when using wireless telemetry the ROP are restricted. Using wired pipe, the driller can hold a much higher ROP, and the geologist still pick the core point without risking drilling too far. Updates every 5-seconds are a huge difference to the conventional 1-2 minute update.

Example to demonstrate the combination of high lag time (lag time – the time from the data sampled until received on surface) and high ROP follows. With an ROP of 40 m/hr, the bit drill through 0.66 meter of formation every minute. If the data then only updates ever other minute, the bit would in a worst-case scenario, pass the core point with over 1.3 meter. To give a perspective, when measuring cores on surface, they are measured in centimeters.

Adding up the drilling performance batch, this saves 5.4 hours on this particular well.

Run Reduction. For a shorter well, naturally the risk of doing unplanned additional BHA-runs are lower. On the contrary, the drilling location might be highly difficult, with hard formations and unpleasant downhole environment. Nevertheless, the time spent tripping are likely to be shorter, because of the wells' length.

Adding up the run reduction batch, this saves 4.0 hours on this particular well.

Hole Cleaning. This category is always of major importance, since you are likely to end up in unwanted well control situations if the hole cleaning is not sufficient. The same surveillance of ECD and standpipe pressure is vital, and if possible, obtaining optimal hole cleaning throughout the section reduces time spent circulating off-bottom.

Adding up the hole cleaning batch, this saves 4.4 hours on this particular well.

Trip Optimization. The limitations on this well is only set to 200 meter. These 200 meters would typically represent the reservoir section, where the danger of swabbing in fluids normally are higher. Only a neglectable portion of time is saved on trip optimization.

Adding up the trip optimization batch, this saves 0.2 hours on this particular well.

WDP Drill Faster Savings Summary

Data	Value	Percentage
Data Transmission Time	8.8	38.1%
Increased Drilling Performance (ROP)	5.4	23.8%
Bit/BHA Run Reduction	4	19.0%
Hole Cleaning Time Optimisation	4.4	19.0%
Trip Speed Optimisation	0.2	0.0%

Total Time Saved (Hours): 22.8

Total Time Saved (Days): 0.9

Figure 17: Time-Savings Summary | 2200 meter long well (NOV_Intelliserv, 2015)

As figure 17 shows, the total time-savings on this exploration well adds up to **22.8 hours, or 0.9 days**. Down below we bring the cost figures into the equation, and calculate the result.

Result:

The price (ref table 2 – section 4.3) for wired drill pipe and surface equipment, to drill this exploration well sum up to $1.98 million. Regular drill pipe have the price tag of $1.1 million and this leaves the additional cost of WDP to be $0.86 million or $860 000.

Next, we will be subtracting the 9% of downtime on the system, leaving us with 20.7 hours, or 0.86 days. Now converting the time saved to the a sum of money, taken ground in the fully operational drilling rig, that costs $1 million per day, the savings equal $0.86 million, or $860 000.

If we now subtract the savings, from the additional cost of using wired drill pipe, the operator saves $860 000 - $860 000 = $0. In this particular case, only accounting for price, it would be indifferent using regular drill pipe or wired drill pipe, they would break even on the dollar. Most likely, the operator would choose to use the WDP, when keeping in mind all the other advantages with this technology. There will be a lot more about possibilities, advantages, disadvantages, and general discussion about the wired drill pipe technology in section 5.4.

5.3 Automated Drilling and ASMs

Fully closed-loop automated drilling systems are now under development, that with a rising level of interest. Very likely, a realistic future situation is where computers are in charge of adjusting the drilling parameters while drilling. The necessity of human supervision and override possibilities for the computerized system might be reality, but ideally, the computerized systems can completely operate on their own. Possibly, the main-reason for not seeing an earlier commitment to the research and development of automated drilling systems, have been the limitations on telemetry speed. Making a system that acts on *real time* data, which in reality has a lag time of 2-3 minutes, would not be reasonable. With new technology as WDP, providing real time data at speeds up to 57 600 BPS mitigating lag time drastically, this is a realistic scenario. More about why and how, down below.

First, let me elaborate what I mean by a fully closed and automated drilling system. As of now, with the possibility of using WDP technology, receiving huge amounts of downhole data instantly, is the new reality. This was not the case ten years ago. Now, high definition data from a 4000-meter long drill string can be present on drill floor with as little as 3 seconds lag time (Pink, Koederitz, Barrie, Bert, & Overgaard, 2013). This makes it possible for a computer on surface to interpreted these data, and adjust surface drilling parameters accordingly, in "real" real time. These adjustments on surface will lead downhole parameters changing and then the sensors will make new reading that are sent back to surface (this happens continuously throughout the drilling operation). The surface computer will then continuously interpret the new feedback data, and adjust surface parameters accordingly.

This computer would know exactly how to adjust surface parameters, to gain the wanted optimal downhole parameters. For downhole readings to be precise, it is necessary to have downhole sensors measuring the wanted parameters like downhole WOB, torque, bending, rpm etc. Many of the downhole parameters estimated/calculated from values measured by surface sensors, and then the *downhole parameters* are calculated from the surface readings. The problem with these methods are that it is not given that the sensors on surface always give exact calculations/readings of downhole parameters. Let me demonstrated by giving an example of how weight on bit readings often are executed today.

Different sensors for weight on bit (WOB) readings exist, but a calculation method is often used. This method takes the calculated weight of the drill string (adding up all the components, always accurately measured before tripped in hole), subtracts the actual sensor reading for the weight of the drill string, and the difference between these two numbers, will represent the weight on bit.

Formula:

"Calculated weigh of the drill string"	**–**	**"Actual weight on hook"**	**=**	**"WOB"**
Example values: 200 tons	–	195 tons	=	**<u>5 tons</u>**

The sensor on surface measuring the weight of the drill string should always be calibrated prior to tripping in hole. The problem with this method is that there is no guarantee that the weight difference is the actual WOB, it could just be a different component hanging up on some ledge down hole, and thus you are somewhat blind to real downhole parameters.

There already exists sensors that measure downhole WOB, but due to conventional telemetry limitations, these readings usually does not have top priority. Now on the other hand, with possibilities of much higher transmission speeds, the automated drilling experience can soon become a reality. This reality being a preprogramed computer on surface, using its database containing algorithms on how to implement adjustments, regarding different input. This closed system will be a looped system with all components connected in series. Figure 18 show a demonstration of the system.

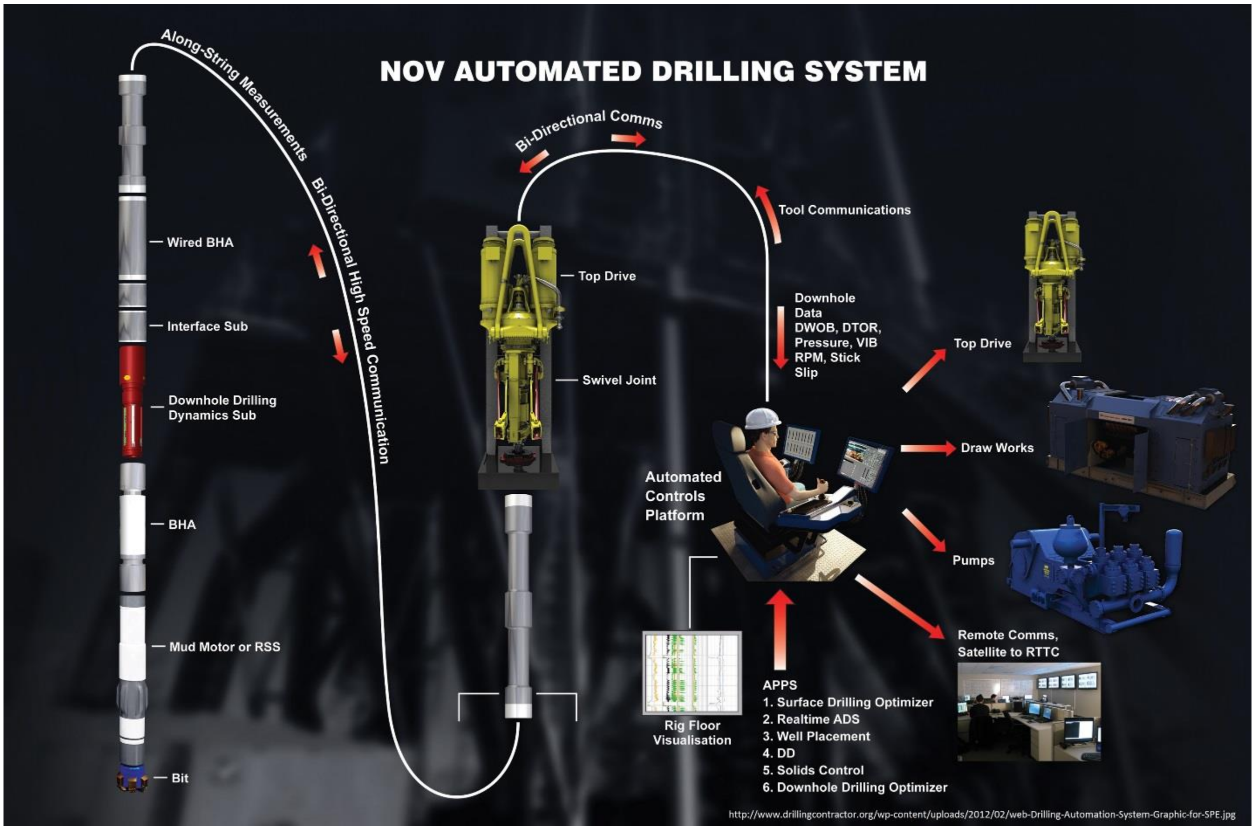

Figure 18: Automated Drilling (DrillingContractor, Drilling Contractor - WP content, 2015)

The detailed figure show how the tools downhole feeds information through the string and up to the surface computer. The surface computer in the figure above are labeled "Automated Controls Platform" and is being supervised by a human. The computer then interprets the received input data and then commands the different surface equipment, such as draw works, top drive and mud pumps, what to do. Common data classes fed from the downhole sensor (in this figure called Downhole Drilling Dynamic Sub - DDDS) in the BHA, to the surface, could be downhole-WOB, -Torque, -Pressures and –RPM. More about the drilling and these parameters below.

This automated drilling system is still in an early phase of the development, but there have already been completed field trials. One of these field trials were the project of drilling six, more or less vertical, wells in eastern Ohio late 2012 (Pink, Koederitz, Barrie, Bert, & Overgaard, 2013). After rigging up the system on the "Patterson 259", the findings were impressive. The focus of this project were comparison of downhole WOB (DWOB) to surface WOB (SWOB), and adjustments of the surface parameters to optimize drilling performance. By allowing an automated "WOB controller" to adjust surface parameters, the results were significant. In the curved sections of the wells, the fluctuations on DWOB decreased by 93%, by going from 28-226% variations from the average, to 8-9% variations from the average (Pink, Koederitz, Barrie, Bert, & Overgaard, 2013). Observation from the straight sections, showed 86% decrease in variations. This further resulting in increased average ROP by 23% (Pink, Koederitz, Barrie, Bert, & Overgaard, 2013).

These figures shows the opportunities that lies within the use of an automated drilling systems. The main reason for this technology now made possible is the wired drill pipe technology. WDP providing high speed, high definition and data with high reliability, at very low lag time. In this section, it would also be natural to mention the ASMs one more time. The only sensor mentioned feeding signals to surface this far have been the Downhole Drilling Dynamic Sub (DDDS). Now, imagine a variety of ASMs placed along the drill string, operating in the exact same way as the DDDS. This will provide data from the entire well bore, not just the bottom of the string. This feature will give room for even more applications and data sampling.

It will probably take years, if not decades, before this technology is *standard* inventory of every drilling installation. One of the reasons for this statement is the complexity of this technology. The complexity of interpreting all input, how to prioritize received data and what changes to implement on surface, to optimize downhole parameters. In the future, when multiple ASMs most likely become a normal part of the drill string, the 57 600 BPS transmission speed might not be enough, and the telemetry ends up being the limiting factor once again. This is how technology works, by changing the limiting factors, forcing improvements and innovation to increase the efficiency of services.

The singular activity of drilling a hole in the ground is relying on multiple persons working on site. The rig crew have a vast number for day-to-day tasks needing fulfillment, just to keep the rig in continuous operation. Another benefit of automated drilling operations, are less human handling of heavy equipment, leading to a safer workplace. The less human exposure to all sorts of operations, the less chance of human error leading to accidents. I am not going to try to predict the future, but in the years to come, it is most likely for humans to perform more *repair and maintenance* related tasks, than the operational tasks themselves, which will most likely be performed by automated machines.

Looking back in time, there is more than enough proof of situations where machines have taken over human tasks. Looking at the manufacturing industry, where today, machines solely complete most tasks. Humans complete the repair and maintenance of these machines that took over their old jobs. In most cases, this improves cost-efficiency for the operator and save the owner a lot of money. Having said that, automation often also results in safer working environment for the employees. Mitigating human exposure to unsafe/hazardous working environments, by using remote-controlled machines, will lead to fewer accidents. An example of such an event is the use of ROV to complete underwater inspections offshore. Now a Remotely Operated Vehicle have taken over the role of the human divers. Instead of the humans being *in* the water, these humans can now safely sit onboard the rig, and operate this "robotic-diver" to complete the inspection for them.

This thesis will not go any deeper into the advantages and disadvantages of an automated drilling system, but have now simply shown the importance of having a high bandwidth network for this technology to become reality.

5.4 Discussing Wired Drill Pipe Technology

The wired drill pipe technology provide many new possibilities. Succeeding is a discussion on how WDP technology makes it easier and more efficient to overcome operational challenges met on a daily basis. We look upon where it provides new solutions, but also on what the more negative sides of the technology is. The drilling operation is a part of the upstream process, as explained in section 2.2, and some of the challenges encountered during drilling can be found in section 2.4.

To keep everyone and everything at minimum risk is always a challenge. Keeping the workplace as safe as possible is a top priority for all companies. Accidents of certain severity have enormous consequences for everyone involved. Not limited to events like loss of life and/or sever injuries, but also environmental accidents like oil spills, which are hazardous to wildlife and causes costly cleanup operations. The wired drill pipe technology might not directly minimize these risks, but indirectly it helps to prevent smaller issues becoming bigger accidents. We also look specifically into how this technology improves the operational tasks *directly*, and as a side effect leading to better safety for the environment and the personnel on site.

The amount of data transmitted to surface is no longer limited in the same way as it would be when using conventional telemetry. With a bandwidth of 57 600 BPS, the data you want displayed on surface can be handpicked by the personnel involved. The possibility to receive memory data in real time on surface bring us into a new era of real time monitoring. Example follow.

You are now able to monitor every sensor in the BHA, instantly. The BHA often consists of many different tools. Tools that the driller and directional driller are dependent on working, to be able to drill the section to TD. If some of these tools fail or turns bad, the result is often to perform a trip for failure. With WDP technology, providing real time data from ***all*** the sensors located in the BHA, this gives the driller the opportunity to react on unwanted parameters, thus saving equipment from destruction.

Example: Lateral vibrations is an unwanted phenomenon to encounter while drilling. These vibrations destroy your components quite quickly, so they need to stop as soon as possible. When using conventional telemetry, the sensors transmitting signals of lateral vibration might only be 2 out of 4 sensors in total, due to telemetry limitations. These two sensors are often located in each end of the BHA, and thus it is very hard to spot lateral vibrations in-between these points. (The option is to go through all the memory logs *after* the section is drilled, and then use these data as a “lessons learned” for next section. You will have no guarantee that the implemented changes will decrease lateral vibrations in the BHA during drilling of the next section, since every section is unique.) The driller’s possibility to have a screen displaying all the sensors in the BHA real time, gives him the opportunity react and thus minimize the amount of unwanted parameters exerted on the drill string components. The result of interacting at the correct time makes it possible to drill longer sections without tripping for failure. As mentioned during the example wells, the run reduction is a result from having the option to display data from all the sensors downhole, and to react in time. This will save a lot of tools, bits, and other components as well as rig time. The advantages mentioned above in this section are dependent on having a driller that knows how to use all the new parameters available, when using WDP technology.

This takes us to an important aspect of using WDP technology, something I chose to name *the adaptation phase*. There are so many new possibilities regarding data transmission that all the personnel involved need some time getting comfortable with using the technology. Most drillers, directional drillers, geologists and other personnel involved need this phase to adapt, to start taking full advantage of the WDP network features. This also goes for the roughnecks on drill floor, which handle the wired drill pipe components. Every single WDP component needs handling with more care than regular pipe. It is not just a regular drill pipe made of steel anymore, it now holds coils in every tool joint and an exposed cable stretched through its inside. This means the roughnecks need to change some of the ways they usually handle regular pipe, they need to be more aware when handling WDP. The adaptations phase apply for most new activities, it take some time getting used to new equipment.

Another point, which in my opinion makes it hard for the WDP technology to enter the market, is skepticism. The oil industry is a very conservative industry, even though it in later years have seen great benefits of new technology. Many of the new technologies only get a few shots to prove itself; if not successful/accepted, it is most likely the end for that particular technology. Either, it is over forever, or at least until someone comes along and significantly improves the technology and then make a new attempt to get acceptance. In my opinion, after asking around about the wired drill pipe technology, most people are skeptical to all parts being connected in series. Connected in series means that if one component dies, you lose connection with the complete string. On the contrary, it is important to mention that the uptime is surprisingly high at 91%. This percentage is only representing the wells drilled with 1st generation pipe. If more customers knew about the actual uptime of WDP technology, it would get more acknowledgment and quicker achieve acceptance from the industry. Commercialization of the IntelliServ network took place in 2007 (Pixton, Graig, & NOV, 2014), and now in 2015, I think it is on the verge of getting more or less complete acceptance from the industry. It have soon persisted 10 years in the industry, and this under contract by a numerous oil companies, with notable results. The 91% uptime might not still be sufficient in this high-demanding industry, but it is getting better and better with time.

The time-savings shown in the examples earlier in this chapter, clearly states how the oil companies can save money using WDP. If an operator are in the planning phase of a new field, they can contact the providers of WDP technology and get calculations on how many wells they need to drill to break even. The result then shows if the oil company will save money on using WDP technology, or if it will not, thus making it easy for the operator to choose to invest in WDP. The time-saving part of the technology is what the provider of WDP technology must use to sell their product to their customers. Then, in addition, explain all the other features and advantages of using their high-bandwidth communication network. In my opinion, if the customer comes close to a break-even price (the additional cost of investing of WDP equals the time saved on transmission speed) on the time-savings alone, they should highly consider using WDP instead of regular drill pipe. Another important aspect of downhole communication and data transmission is visibility.

Visibility is mentioned as one of the challenges encountered in the industry. Visibility being the ability to see what is going on downhole, through communication with tools. When using regular drill pipe and mud pulse telemetry, it happens that bad decoding appears and false values are displayed on the monitor. These bad data points are decreased to a neglectable amount when using WDP technology. The reason being that there now is a physical cabled connection between the sensors and the software interpreting the signals, leaving no room for misinterpretation. As mentioned earlier, the average uptime for the 1st generation WDP is 91%, leaving an average of 9% downtime. Theoretically, this means that the driller is completely blank on downhole information 9% of the time during drilling. In reality, this is of course not the case. When using WDP technology you always run the conventional mud pulse telemetry as backup. Therefore, if the WDP network lose connection, you can continue drilling using conventional telemetry. The uptime is likely to increase from 91% as the 2nd generation becomes standard, but regardless, bad data points related to decoding will not be an issue when using WDP technology.

Another number, which are changing with time, is the price of oil. The oil price have been steady above 100$ per barrel during later years, until the price plunged during late 2014 and early 2015. This huge drop in price already show huge impacts on the industry, where bigger headcounts and cost saving measurements are implemented. During such hard times, newer technologies can be of help to reduce cost, but to get the managements approval to invest in new technology during down-periods are rare. Therefore, the low oil prices now a day will most likely have an impact on amount of upcoming wells drilled with WDP technology. The fluctuation in oil price is not a new phenomenon, it have been like this since the beginning of the industry, and will most likely stay the same in the future. These slow times can halt the development for some period, especially if the company providing WDP technology are not able to make profit, which again is invest in research and development to improve the WDP technology.

A different aspect, which is worth touching upon, is the ability to send and receive data without flow or continuous fluids in the well. E.g. during tripping or loss situations. This ability to use the wired pipe, instead of wireless communication, can have many positive applications. For instance, the ability to receive trustworthy data while in a loss situation. This will increase knowledge about the downhole conditions, and lead to making correct decisions in a timely manner. In situations like these, where you are in risk of losing the well (losing the ability to continue drilling the well path –result being that you need to cement back the drilled hole and create a sidetrack), making correct decisions within short time is crucial. Without the WDP technology, it can be very hard to establish any form of communication with the downhole tools, actually leaving you blinded regarding downhole conditions. As mentioned earlier, it is also very hard to establish downhole communication when there is a variety of different fluids in the wellbore. This option to communicate without flow also saves time during formation pressure tests. There is no need to pulse the test results to surface *after* test completion. With WDP technology, the test results are received on surface in real time, throughout the execution of the test, which is not the case when using regular drill pipe.

Environment and “unlikely events” were both mentioned in the beginning of the thesis. The WDP technology does not directly improve the environment at the rig site, but indirectly and proactively contribute to avoid spills and disasters. With quicker updating cycles, more reliable data, and without the need for a consistent fluid medium to communicate with tools downhole, it decreases the chance of making mistakes. These mistakes, now avoided with the use of WDP technology, could have developed into bigger “unlikely events”, with terrible environmental impacts.

Due to the high speed of data transmission, the result of sending on-bottom downlinks will no longer affect the sampling of FE data, making gaps in the FE logs. When drilling, using regular drill pipe and mud pulse telemetry, an on-bottom downlink would lead to loss of sampling data during the time interval where the downlink is sent, received and interpreted. Depending on the ROP at the time of downlinking, you would lose different amounts of data for the FE logs. With ROP equal to 30 m/hr, you could lose up to 3-4 meter of sampling data on one downlink (BHI & Williams, Directional Drilling - Facts, 2015). When using WDP technology, the downlink takes around 5 seconds, and the result being no data lost and no gaps in the FE logs.

The additional price of the wired drill pipe will of course have a big impact on getting acceptance within the oil industry. As mentioned in the cost chapter, accurate and detailed pricing are dependent on what specifics you want your drill string to hold. It will always be a more expensive option to choose the WDP over the regular drill pipe, but looking at it in a bigger picture; you might end up saving money. In many cases, the additional price tag of WDP combined with lack of knowledge about the technology will leave potential customer to stick with old habits, and continue drilling with regular drill pipe instead of WDP. With these last words, I would like to end this discussion and move on to present my final conclusion.

6. Summary and Conclusion

My final conclusion follows.

The wired drill pipe technology has come to stay. It will endure into the future, and most likely become more or less a revolution within the field of downhole communication. This thesis have already explained how WDP technology works and what makes it so distinct from regular drill pipe and conventional telemetry. During the discussion, there were a lot more positives than negatives. The negatives standing out were price, lack of knowledge and the 9% average downtime.

It is highly important to have a reliable system when working in the oil industry, and WDP technology still have a few steps to climb. The uptime of 91% is a lot higher than most oil companies today actually are aware of, but getting these 91% closer to 100% will most certainly increase the demand for WDP technology.

The price of wired drill pipe are depending on what specifications of the pipe, but the extra cost (compared to regular pipe) will in most cases be returned in favor of time-savings, data-definition, data-availability and data-reliability. The *value* of certain data are hard to quantify, but the ability to make correct decisions based on real time high definition data will save time and money. The skepticism to new technologies will not work in the favor of WDP technology, but with growing knowledge about the reliability (which is now becoming even better with the 2nd generation of pipe), I think this skepticism will pass, and the technology will find its place in the history of the drilling industry. With all the benefits made possible with wired drill pipe technology, it is in most cases economically beneficial for the user/buyer.

The transmission time is outstanding, while the quality and definition of the data is nothing less. The user friendliness of the NetCon is great, and the advantages that comes with the possibility of having ASMs in the drill string are huge. The best is yet to come in regards of ASMs, but WDP technology makes the optimal use of ASMs possible, which is a huge advantage. In addition, the WDP network will play an important role in making fully automated drilling rigs possible, operating with minimal human interaction. Automated drilling will most likely increase the safety on the rig directly, due to less room for human error, but automated drilling as the operating standard is probably still some years away. Nonetheless, the safety onboard the rig *will* increase when using WDP technology today as well, due to the great visibility of downhole conditions. With these reliable data at hand and qualified personnel to take advantage of the vast amount of data, decision-making are optimized and drilling operations are carried out in a more safe and efficient manner.

Based on the research and writing of this thesis, I would most certainly say that the wired drill pipe technology provides more than enough usable possibilities to make up for its cost. My strongest opinion state that WDP technology will get complete acceptance in the oil industry in the near future, and that the technology will be the standard way of communicating with downhole tools for years to come.

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Appendix

A. Wired drill pipe sizes

The different wired drill pipe sizes available as of today, Q1 2015.

Wired Drill Pipe								
Size	Connection	Grades	Wall Thickness	Nominal Weight	Tool Joint ID	Tool Joint OD	Maximum RMUT	Minimum MUT
4" Wired Drill Pipe	XT38	S-135, CYX-105	0.330	14.0 lb/ft	2.438	4.875	17,149 ft-lbs	14,291 ft-lbs
4" Wired Drill Pipe	TT390	S-135, CYX-105	0.330	14.0 lb/ft	2.438	5.000	28,288 ft-lbs	21,760 ft-lbs
5" Wired Drill Pipe	GPDS50	S-135, CYX-105, V-150	0.362	19.5 lb/ft	3.250	6.625	37,179 ft-lbs	30,982 ft-lbs
5-1/2" Wired Drill Pipe	TT550	Z-140, S-135, V-150	0.361	21.9 lb/ft	4.000	6.750	56,306 ft-lbs	43,312 ft-lbs
5-7/8" Wired Drill Pipe	XT57	Z-140, S-135, V-150	0.361	23.4 lb/ft	4.250	7.000	46,840 ft-lbs	39,033 ft-lbs
5-7/8" Wired Drill Pipe	XT57	Z-140, S-135, V-150	0.415	26.3 lb/ft	4.250	7.000	46,840 ft-lbs	39,033 ft-lbs
6-5/8" Wired Drill Pipe	GPDS65	Z-140, S-135, V-150	0.362	27.7 lb/ft	4.250	8.500	83,798 ft-lbs	69,832 ft-lbs
6-5/8" Wired Drill Pipe	GPDS65	Z-140, S-135, V-150	0.522	40.0 lb/ft	4.250	8.500	83,798 ft-lbs	69,832 ft-lbs
6-5/8" Wired Drill Pipe	GPDS65	Z-140, S-135, V-150	0.625	34.0 lb/ft	4.250	8.500	83,798 ft-lbs	69,832 ft-lbs

IntelliServ-Product-Catalog-D392004875-MKT-001-Rev-01

Ref: IntelliServ-Product-Catalog-D392004875-MKT-001-Rev-01 (IntelliServ N. R., 2015).

B. Data Link information

Spesifications on the Data Links features and operating range.

DataLink Features	
Feature	**Description**
Active Battery Life	1000 hours @ > 25°C nominal (Approximately 40 days turned on)
Storage Battery Use	15% of total capacity per year (Approximately 6 days)
Tool Bandwidth	40 kbps maximum
Sensor Interfaces	Non-Integrated (end-of-string), Integrated (along and end-of-string)
Time Synchronization	+/- 50 milliseconds
Power Management	Automatic sleep and deep sleep power saving modes
Automatic Sleep	DataLink turns off after a period of time when not connected to another DataLink.
Deep Sleep Power Saving Modes	Link is turned off in the surface. To turn it on, connect to the NetCon or a tester.
Diagnostics	Temperature, current, voltage, signal level, noise level, battery life
DataLink Environmental Ratings	
Rating	**Description**
Operating Temperature	-40°C to 150°C
Shock Tolerance	250G, half-sine, 0.5 ms, 1Hz, all axes
Vibration Tolerance	20G, random, 10-500Hz, all axes
Maximum Pressure	25,000 PSI

Ref: Component and Inspection certification (NOV I. , 2014).

C. Time-Savings – 5000-meter Production Well – Calculator

Appendix C: Print-Screen (NOV_Intelliserv, 2015).

Well Design

Section	TD (m)	Interval (m)	Drive
26	1100	1100	RSS
17.5	2250	1150	RSS
12.25	4200	1950	RSS
8.5	5000	800	RSS

Data Transmission Time

Survey Interval	20	m	Surveys (at connection)	8.3	hrs
Average Survey Time	3	mins	Check/Repeat Survey	6.2	hrs
RSS Downlink Interval	15	m	RSS Downlinks	13.9	hrs
Off-Bottom Downlinks	50	%	Slide Orientation	0	hrs
Slide Frequency	20	m	Formation Pressure Tests	0.8	hrs
Check/Repeat Survey Frequency	25	%			
Formation Pressure Tests	5	Per Well	**Time Saved:**	**29.3**	hrs

Appendix C1 - Total time saved on data transmission: **29.3 hours**.

Increased Drilling Performance (ROP)

ROP Limiter	ROP Increase (%)	26	17.5	12.25	8.5
Current ROP	m/hr	20	20	30	10
		Check all that apply and estimate the performance limit			
Shock and Vibration /Hard Rock/ Stringers	5 %	☐	☑	☑	☑
Hole Cleaning/ ECD Management	5 %	☐	☑	☑	☑
Formation Evaluation Logging Density	5 %	☐	☐	☐	☑
Directional Control/ Well Placement	5 %	☐	☑	☑	☐
Potential ROP with WDP		20	23	34.5	11.5
Drilling Time Reduction (hrs)		0	7.5	8.5	10.4
Time Saved		**26.4**			

Appendix C2 - Total time saved on ROP increase: **26.4 hours**.

Bit/BHA Run Reduction		
Number of Sections with Multiple Bits/BHAs	2	Per Well
Average Trip Time	15	hrs
Reduction with WDP	40	%
Time Saved	**12**	hrs

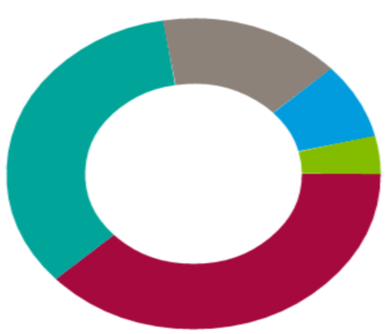
Appendix C3 - Total time saved on run reduction: **12.0 hours**.

Hole Cleaning Time Optimisation	26	17.5	12.25	8.5
Current Hole Cleaning/Circulation Time (hrs)	4	6	12	18
Optimisation with Along String Data (%)	10	15	15	20
Time Reduction (hrs)	0.4	0.9	1.8	3.6
Total Time Reduction	**6.7**	hrs		

Appendix C4 - Total time saved on hole cleaning: 6**.7 hours**.

Trip Speed Optimisation		
Distance Tripped at Limited Speed	3500	m
Current Limited Trip Speed	200	m/hr
Trip Speed Increase with Real-Time Data	25	%
Time Reduction	3.5	hrs

Appendix C1 - Total time saved on trip optimization: **3.5 hours**.



WDP Drill Faster Savings Summary

Data	Value	Percentage
Data Transmission Time	29.3	38.2%
Increased Drilling Performance (ROP)	26.4	34.2%
Bit/BHA Run Reduction	12	15.8%
Hole Cleaning Time Optimisation	6.7	7.9%
Trip Speed Optimisation	3.5	3.9%

Total Time Saved (Hours): 77.9

Total Time Saved (Days): 3.2

Appendix C6 - Total time saved on a 5000m Production Well: **77.9 hours** or **3.2 days.**

D. Time-Savings – 2200-meter Exploration Well – Calculator

Appendix D: Print-Screen (NOV_Intelliserv, 2015).

Well Design

Section	TD (m)	Interval (m)	Drive
26	1100	1100	RSS
17.5	1600	500	RSS
12.25	1900	300	RSS
8.5	2200	300	RSS

Data Transmission Time

Survey Interval	30	m	Surveys (at connection)	2.4	hrs
Average Survey Time	3	mins	Check/Repeat Survey	1.1	hrs
RSS Downlink Interval	25	m	RSS Downlinks	4.4	hrs
Off-Bottom Downlinks	60	%	Slide Orientation	0	hrs
Slide Frequency	20	m	Formation Pressure Tests	0.8	hrs
Check/Repeat Survey Frequency	15	%			
Formation Pressure Tests	5	Per Well	**Time Saved:**	**8.8**	hrs

Appendix D1 - Total time saved on data transmission: **8.8 hours**.

Increased Drilling Performance (ROP)

ROP Limiter		ROP Increase (%)	26	17.5	12.25	8.5
Current ROP		m/hr	20	30	30	20
			Check all that apply and estimate the performance limit			
Shock and Vibration /Hard Rock/ Stringers	5	%	☐	☑	☑	☑
Hole Cleaning/ ECD Management	5	%	☐	☑	☑	☑
Formation Evaluation Logging Density	5	%	☐	☐	☐	☑
Directional Control/ Well Placement	5	%	☐	☑	☑	☐
Potential ROP with WDP			20	34.5	34.5	23
Drilling Time Reduction (hrs)			0	2.2	1.3	2
Time Saved			**5.4**			

Appendix D2 - Total time saved on ROP increase: **5.4 hours**.

Bit/BHA Run Reduction		
Number of Sections with Multiple Bits/BHAs	1	Per Well
Average Trip Time	10	hrs
Reduction with WDP	40	%
Time Saved	**4**	hrs

Appendix D3 - Total time saved on run reduction: **4.0 hours**.

Hole Cleaning Time Optimisation	26	17.5	12.25	8.5
Current Hole Cleaning/Circulation Time (hrs)	2	4	10	15
Optimisation with Along String Data (%)	10	10	15	15
Time Reduction (hrs)	0.2	0.4	1.5	2.2
Total Time Reduction	**4.4**	hrs		

Appendix D4 - Total time saved on hole cleaning: **4.4 hours**.

Trip Speed Optimisation		
Distance Tripped at Limited Speed	200	m
Current Limited Trip Speed	200	m/hr
Trip Speed Increase with Real-Time Data	25	%
Time Reduction	0.2	hrs

Appendix D5 - Total time saved on trip optimization: **0.2 hours**.

WDP Drill Faster Savings Summary

Data	Value	Percentage
Data Transmission Time	8.8	38.1%
Increased Drilling Performance (ROP)	5.4	23.8%
Bit/BHA Run Reduction	4	19.0%
Hole Cleaning Time Optimisation	4.4	19.0%
Trip Speed Optimisation	0.2	0.0%

Total Time Saved (Hours): 22.8

Total Time Saved (Days): 0.9

Appendix D6 - Total time saved on a 2200m Exploration Well: **22.8 hours** or **0.9 days.**

E. Rig Cost Calculations – Currency.

Appendix E - Software: Microsoft Office Excel 2013

	Cost numbers from 2009 Article (Bjerke, 2009) || Estimates for 2015								
	2009 | NOK -> USD			2015 Est. | USD -> NOK					
Category	Total NOK '1000	Total $USD '1000	Pr day $USD '1000	Est. 2015 NOK '1000	Est. 2015 '1000	Pr day $USD '1000	Increase [%]	Aditional Info	
Rig rate	219 000	27 980	241	399 493	51 040	440	82	116	Days
Services	101 000	12 904	111	181 588	23 200	200	80	7,83	Currency
Logistics	92 000	11 754	101	172 508	22 040	190	88		USD->NOK
Equipment	55 000	7 027	61	90 794	11 600	100	65		
Personal cost	34 000	4 344	37	63 556	8 120	70	87		
SUM	501 000	64 009	552	907 939	116 000	1 000	Avg. 80		

Cost figures for 2009 from article | Estimated for 2015 for demonstrational purposes.

	Numbers from 2009 Article (Bjerke, 2009) || Estimates for 2015								
	2009 | NOK -> USD			2015 Est | USD -> NOK					
Category	Cost NOK '1000	Cost $USD '1000	Pr day $USD '1000	Est. 2015 NOK '1000	Est. 2015 '1000	Pr day $USD '1000	Increase [%]	Aditional Info	
Rig rate	219000	=C5/$K$6	=D5/$K$5	=H5*$K$6	=I5*$K$5	440	=((I5/E5)-1)*100	116	Days
Services	101000	13000	=D6/$K$5	=H6*$K$6	=I6*$K$5	200	=((I6/E6)-1)*100	7,82	Currency
Logistics	92000	12000	=D7/$K$5	=H7*$K$6	=I7*$K$5	190	=((I7/E7)-1)*100		USD->NOK
Equipment	55000	6900	=D8/$K$5	=H8*$K$6	=I8*$K$5	100	=((I8/E8)-1)*100		
Personal cost	34000	4300	=D9/$K$5	=H9*$K$6	=I9*$K$5	70	=((I9/E9)-1)*100		
SUM	=SUM(C5:C9)	=SUM(D5:D9)	=SUM(E5:E9)	=SUM(G5:G9)	=SUM(H5:H9)	=SUM(I5:I9)	=AVERAGE(J5:J9)		

Showing formulas used in the calculation spreadsheet | Software: Microsoft Office Excel 2013.