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Making risk-informed decisions to optimize drilling operations using along string measurements with Wired drill pipe a high-speed, high-quality telemetry alternative to traditional mud pulse telemetry.

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Abstract

The ever-increasing demand for energy resources has led to drilling more complex and challenging wells. The information required to navigate through these complex geologies is provided by highly sophisticated sensors embedded in logging-while-drilling and measurements-while-drilling downhole tools. These combined with rotary steerable systems have made it possible to drill highly deviated, extended reach, and multilateral wells with high precision.

Drilling operations can be considered high-risk operations due to the large number of sources that can lead to undesirable outcomes. Therefore, data transmission from downhole sensors and communication with downhole tools is vital to drill safely and successfully a well.

Mud-pulse telemetry is the most used telemetry method to transmit the data from downhole tools to the surface. However, advancements in sensor technology and the development of new tools have resulted in higher amounts of data needed to be transmitted to the surface to take advantage of the resolution they now provide fully. The reliance on mud-pulse telemetry, which offers relatively low data transmission speed and broadband, has been the limiting factor, often sacrificing higher drilling rates to obtain the required data quality.

The introduction of wired drill pipe, capable of delivering bi-directional telemetry at speeds up to 10.000 times faster than traditional mud-pulse, has removed the reliance on mud-pulse, making it possible to obtain memory-mode quality real-time data. Wired drill pipe also enables the use of along string measurements. These measurement tools are placed along the string and gather pressure, temperature, and drilling dynamics data. Thus, it is now possible to understand the downhole environment along the wellbore and not just a few meters behind the bit. This makes it possible to timely identify well control and well stability events, thereby making risk-informed decisions to mitigate the risk of hazardous events and additionally optimizing drilling operations.

The objective of this thesis is to provide a description of the drilling process and the tools that have made it possible to drill the wells that nowadays are drilled. Further, it describes different telemetry methods but focuses on mud-pulse telemetry and its limitations. Then, the wired drill pipe system is extensively described, and it is presented the way it allows the integration of measurement tools along the string. Furthermore, it is shown how these tools enable making risk-informed decisions to reduce the risk during drilling operations. The result is safer drilling operations to be achieved while also saving time by reducing the telemetry time, preventing tool failures, and avoiding resource-demanding well remediation operations. Finally, it is discussed how the availability of real-time high-quality data and full bi-directional instantaneous communication with downhole tools has enabled a step towards more automated drilling operations. The combination of high-speed data transfer with machine learning and artificial intelligence has made it possible to develop autonomous drilling services capable of optimizing the well path and reducing well times.

Acknowledgments

I want to express my deepest gratitude to my supervisor, Finn Sandberg, for his excellent guidance and support given throughout writing this thesis. I am sure it would not have been possible without his help.

I would also like to thank my mother and brother for all the support and love given to me. Thank you for always being there for me and teaching me that the path to success is by working hard, being dedicated, and treating others with respect.

In loving memory of my godmother, you played a big part in my life, and even though you are not with us anymore, the respect and love I have for you will just go on and on.

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Abbreviations

AI – artificial intelligence

ASM – Along-string-measurements

BHA – Bottom hole assembly

BOP – Blow out preventer

Bps – Bits-per-second

DWT – Data-while-tripping

ECD – Equivalent circulating density

EMT - Electromagnetic Telemetry

FIT – Formation integrity test

IBOP – Internal blow out preventer

Kbps- Kilobits-per-second

LCM – Loss of circulation materials

LOT – Leak-off-test

LWD - Logging-While-Drilling.

MPT - Mud Pulse Telemetry

MWD - Measurement-While-Drilling.

NCS – Norwegian continental Shelf

NetCon – Network Controller

PWD – Pressure-while-drilling

ROP – Rate of penetration

RIH – Run-in-hole

ROC – Remote operations center

RSS - Rotary Steerable System.

TD – Target depth

WDP – Wired Drill Pipe

WOB – Weight-on-bit

Chapter One. Drilling

Oil and gas are essential sources of energy that contribute to meet the world´s energy demand. These are concealed under the earth´s surface. Thus, it is necessary to create or establish a path to these sources of energy. Drilling for oil and gas addresses this need. Drilling is the process of creating a pathway, a wellbore, from the surface to the hydrocarbon reservoir. The goal to achieve is to recover as much oil and gas as possible at the lowest cost and with specified safety standards.

The constant increase in energetic demand encouraged exploration for oil and gas in remote areas. This resulted in more challenging drilling operations and projects such as drilling extended reach wells both offshore and onshore, the development of more complex fields, re-development of mature fields, and drilling more challenging wells. Each of these cases carries its own specific set of challenges and risks. Advancements in drilling technology and drilling tools such as rotary steerable systems (RSSs), measurement-while-drilling (MWD), and logging-while-drilling (LWD) have made it possible to carry out these kinds of projects and operations. These specialized downhole tools contain different sensors which take different types of measurements of downhole conditions and formation properties. These measurements are then sent to the surface by a communication channel. These measurements provide important downhole information that allows timely decision-making to deliver wells safely and successfully.

Directional drilling.

Directional drilling is defined as "*the intentional deviation of a wellbore from the path it would naturally take*" (Schlumberger Oilfield Glossary, 2021). Directional drilling involves all activities related to design and drilling a wellbore to reach a target that is located at some horizontal distance from the top of the hole. The purpose of directional drilling is to create a connection between the surface location and the oil and gas reservoirs that are not located right below it (Mitchell & Miska, 2011).

Further, directional drilling reduces costs related to infrastructure by drilling many different wells from one location instead of having to build one platform per well to gather the produced hydrocarbons. It also allows drilling horizontal sections that will make it possible to increase the drainage area of the reservoir, hence increasing the recovered oil. In the case of encountering geological problems, directional drilling allows to avoid these problematic geologies by drilling from a more desirable angle that reduces the risk of losing control of the well. Also, it reduces the risk of collision with nearby wells. Last, in the unlucky event of wellbore collapse due to wellbore stability issues or in the case of drill string failure, directional drilling allows to sidetrack the wellbore by starting a horizontal section from the original wellbore (Azar & Samuel, 2008; Inglis, 1987; Nguyen, 1996).

The oilfield Troll is an example worth mentioning regarding the importance of directional drilling. This field was discovered in 1979 and it was first considered to produce only gas since the oil reserves were deemed too expensive and challenging to produce. The available technology didn't provide the accuracy needed. However, the development of highly maneuverable drilling tools led to the capability to drill and steer horizontal wells resulting in the successful development of the Troll field (Saeverhagen et al., 2008).

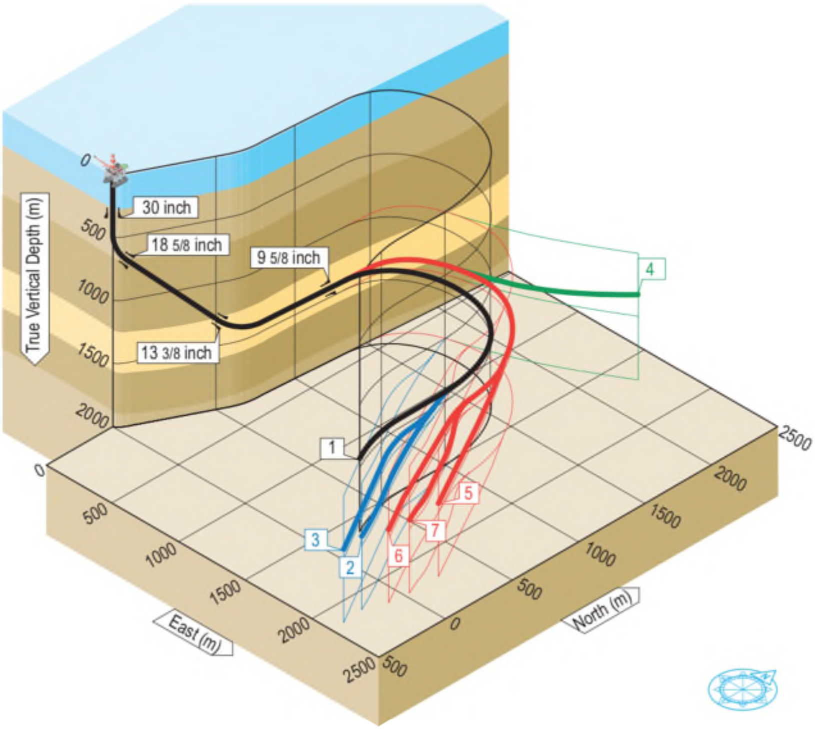

Figure 1 Troll field development (Saeverhagen et al., 2008).

To directionally drill a well successfully, it is necessary to obtain downhole information. As mentioned previously, downhole information is obtained by downhole measurement tools known as measurements-while-drilling (MWD) and logging-while-drilling (LWD). The information obtained will make it possible to have a better understanding of downhole conditions and wellbore stability. Hence, better decisions can be taken to place a well in the right section of the reservoir for maximum contact achieving increased productivity and ensuring optimal long-term recovery (PET505,2018).

Measurements-while-Drilling MWD

Measurements-while-drilling tools contain sensors that perform evaluation tests of physical properties such as pressure, temperature, and wellbore trajectory in three-dimensional space while drilling a wellbore (Schlumberger Oilfield Glossary, 2021). In addition, measurements are taken of the wellbore, bottom-hole assembly, and drill string to identify hazardous conditions that could damage equipment and thereby leading to non-productive time events. “*Surveying technology is used to determine the well path and its position in three-dimensional space. MWD is a valuable tool that can establish true vertical depth, bottom-hole location, and orientation of directional drilling systems*“(Halliburton, 2021b). The MWD tools are built with a transmitter that sends the measurements through signals to the surface via a telemetry channel (Inglis, 1987)

Survey

A survey is a complete measurement of the inclination and azimuth of a location in a well. The measurements themselves include inclination from vertical and the azimuth (or compass heading) of the wellbore. Several survey points are taken as the well is being drilled. These survey points are used to calculate the changes in position. In both directional and straight drilling, the position of the well must be known with reasonable accuracy to ensure the correct wellbore path (*Directional Drilling Lecture Notes PET505 2018*, 2018; Schlumberger Oilfield Glossary, 2021)

Logging-while-drilling LWD

Tools that measure formation parameters (resistivity, porosity, sonic velocity, gamma-ray) are referred to as logging-while-drilling (LWD) tools, and these are integrated into the BHA. Drilling service companies provide a variety of services and tools to evaluate and enhance the drilling of a wellbore. LWD tools provide real-time petrophysical data about downhole/reservoir pressure, reservoir boundaries, permeability, hydrocarbon content. Timely LWD data is used to guide well placement so that the wellbore remains within the zone of interest or in the most productive portion of a reservoir (Schlumberger Oilfield Glossary, 2021).

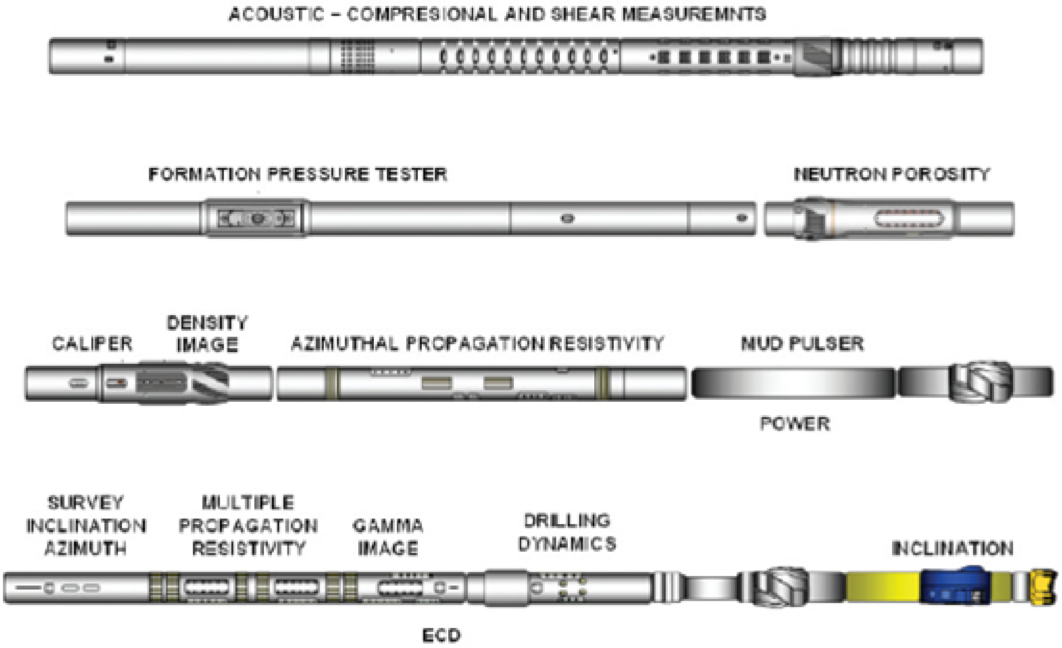

Figure 2 Bottom hole assembly LWD tools used to drill extended reach wells (Klotz, Kaniappan, et al., 2008)

Rotary steerable systems RSS

Rotary steerable systems (RSS) are defined as “A tool designed to drill directionally with continuous rotation of the drill string while steering the bit. RSS have minimal interaction with the borehole, thereby preserving borehole quality. The most advanced systems exert consistent side force similar to traditional stabilizers that rotate with the drillstring or orient the bit in the desired direction while continuously rotating at the same number of rotations per minute as the drillstring”(Schlumberger Oilfield Glossary, 2021). Rotary steerable systems are used to drill a well directionally. These tools provide an almost immediate response to commands from the surface when downhole trajectory has to be adjusted (Felczak et al., 2011). RSS provides directional control either by adjusting an internal drive shaft that points the drill bit in the desired orientation or by applying lateral force against the formation. Pads placed near the bit exerts force against the borehole to steer the drillstring. Regardless of which of these two systems are used, commands from the surface are send downhole to operate them and achieve the wished changes in direction, these commands are known as downlinks (Schaaf et al., 2000).

Geosteering

Geosteering is the result of the development of logging-while-drilling tools and rotary steerable systems. The increased ease in drilling that was provided by RSS, made operators realize that they could increase production by landing horizontal wells in large reservoir compared to vertical or standard deviated wells and have better control over a well path which allows drillers to navigate with greater precision(Chemali et al., 2010). Thus, geosteering can be defined as “the processes of making intentional well-directional adjustments of a well based on the results of downhole geological logging measurements on real-time acquired while drilling, rather than following a predetermined trajectory, usually to keep a directional wellbore within a pay zone” (Schlumberger Oilfield Glossary, 2021)

The interplay between geosteering-related technologies, downhole information-gathering tools, real-time data transmission, and data analysis applications makes it possible to reduce geological and operational risks and uncertainties by taking high-quality decisions in real-time to optimize outcomes such as reservoir contact or production rates. This is why geosteering has been widely adopted in the petroleum industry (Kullawan et al., 2013).

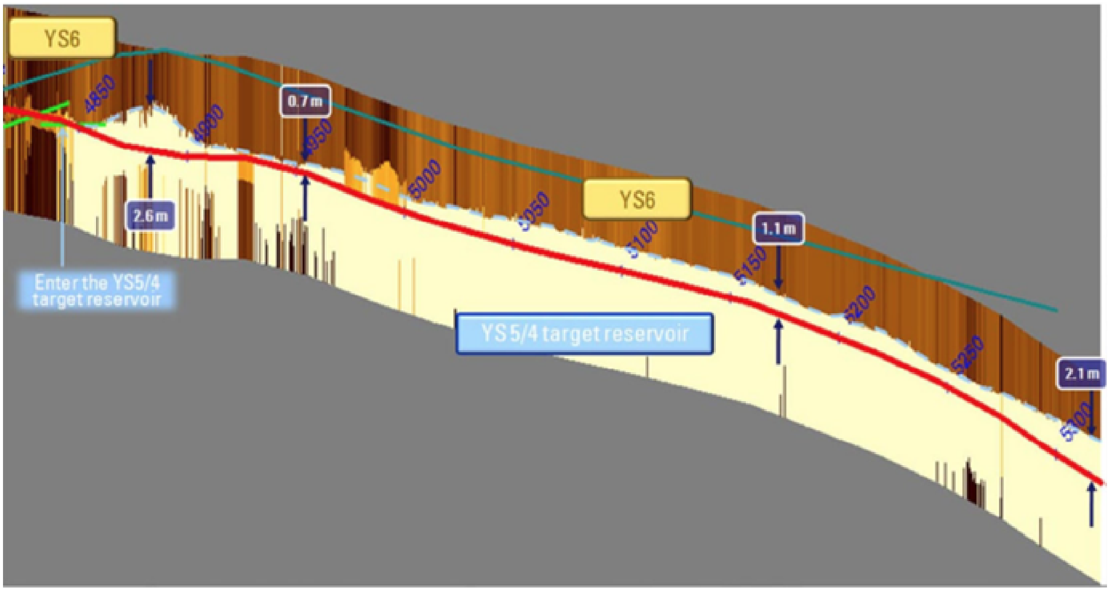

Figure 3 Planned well path (green) vs. geosteered well through the target reservoir (red) (Spotkaeff et al., 2011)

Chapter two. Data transmission- Telemetry methods

As described in the previous section, special downhole tools take directional measurements of the wellbore and petrophysical measurements of formation properties that make it possible to understand downhole conditions in real-time. However, these measurements and downhole data need to be sent to the surface through some means of signal transmission.

A system for converting the measurements taken by MWD/LWD tools into a suitable form for transmission to the surface is known as telemetry(Schlumberger Oilfield Glossary, 2021). A limited number of transmission channels are available to transmit data from downhole to surface (Cooper & Santos, 2015). Moreover, there are two types of telemetry wired and wireless.

Electromagnetic telemetry

Electromagnetic telemetry methods in oil and gas wells involve using the drill string to propagate electromagnetic waves that can be measured on the earth's surface (Franconi et al., 2014). The EMT system establishes a two-way communications link between the surface and the tool downhole. Using low-frequency electromagnetic wave propagation, the EMT system facilitates high-speed data transmission to and from the surface (Halliburton Sperry Drilling, 2021). Information is received at a surface antenna, decoded, and then processed by a computer (National Oilwell Varco, 2021a). EMT allows data transfer rates of up to 12 bps- bits per second depending on the depth of the well (Franconi et al., 2014).

EMT is a reliable telemetry system (because of the lack of moving parts) but has limitations on the types of wells where it can be used. It is primarily used in land rigs and shallow wells where good results have been observed. Nonetheless, it is limited by depth, formation resistivities, and mud resistivity (Cooper & Santos, 2015). The main bottleneck of this technology is that the formation conductivity will have a negative effect on the electromagnetic propagation depth and hence in the data transfer. In addition, it is an expensive technology to use in the field (SU et al., 2013).

Drilling fluids and Mud pulse Telemetry

The mud system is extremely important during drilling operations. It serves many different purposes, the most central being the primary barrier between the wellbore and the surface.

Controlling the hydrostatic pressure of a mud column is a critical part of a drilling operation. The weight of the mud balances or overcomes pore pressure in the wellbore. Moreover, the mud weight and the mud properties must be monitored and adjusted to stay within the requirements of the drilling operation. An influx of fluids from the formation, also known as a kick, is prevented by having sufficient hydrostatic pressure or mud weight. However, excessive pressure must be avoided as it can create hydraulic fractures in the formation, which leads to loss of circulation into the formation. Furthermore, the mud being pumped cools and lubricates the drill bit, and then it flows upwards to the surface, through the annulus, transporting the removed formation or cuttings from the wellbore (Bourgoyne et al., 1986; Schlumberger Oilfield Glossary, 2021).

Mud Pulse Telemetry (MPT) uses the drilling mud system to transmit LWD/MWD data acquired downhole to the surface (Schlumberger Oilfield Glossary, 2021). Downhole data is transmitted to the surface through the mud column in the form of pressure waves. The data is encoded by the tool within the pressure variations or pulses in the mud flow. Then, these pressure variations are decoded at the surface by the surface equipment. Three different approaches to create pressure fluctuations are described by (Cooper & Santos, 2015) below:

Positive pulse telemetry

These are the most common type of mud pulse telemetry systems. It reduces the flow area of the mud by temporarily creating a flow restriction downhole, which results in a positive pressure pulse that will propagate to the surface.

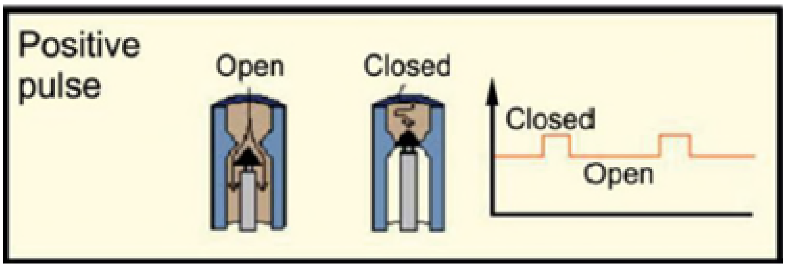

Figure 4 Representation of a positive mud-pulse system (Cooper & Santos, 2015)

Continuous-wave telemetry

These systems contain a motor and stator to generate pressure fluctuations. By varying the motor's position, drilling fluids will either flow smoother (increased opening) or more restricted (reduced opening) flow is achieved. Continuous opening and closing of the motor will result in constant pressure oscillations.

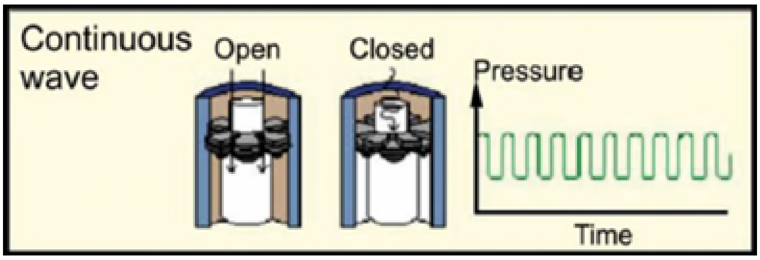

Figure 5 Representation of Continuous mud-pulse system (Cooper & Santos, 2015)

Annular-venting telemetry

A discharge valve opens and closes, leading to drilling fluid from the drill string entering the annulus. This will create pressure fluctuations within the mud column, which are known as negative pulses. These will transmit the tool's encoded data to the surface and will be decoded by the surface systems.

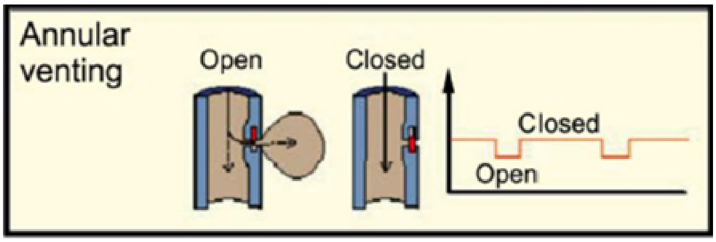

Figure 6 Representation of negative mud-pulse system (Cooper & Santos, 2015)

Mud pulse telemetry importance in the oil and gas industry and its drawbacks

MPT is the global standard for data delivery from downhole tools and the most widely used communication technique in the drilling industry due to the robustness of the downhole system and proven performance (Klotz et al., 2008). This technique has proven its value for most drilling applications both from an economic and technological perspective (W. Emmerich et al., 2016). Economically, by making use of the mud column as the transmission channel, the operation cost is significantly reduced as no cables or special equipment is required. Technologically, important improvements have been made throughout the years, as this system has been used for the past 40 years. Improvements in design for the mud pulsing equipment, improved signal processing capabilities. Moreover, more intelligent and robust algorithms are used to encode, decode, and process signal detection. These improvements resulted in an increased overall reliability of the system (Klotz et al., 2008).

Oilfield service providers within the oil industry have developed different MPT solutions that can be deployed on the field depending on the requirements and complexity of the drilling project. Small drilling projects with basic needs for MWD data and LWD formation evaluation measurements are likely to choose basic MPT services with slow data transmission rates of up to 2 bits per second, as this is enough to fulfill the data acquisition requirements. Projects where more sophisticated L/MWD tools are used, will require higher data transmission rates. A limited number of drilling service providers can offer high-speed mud pulse solutions with data transmission rates higher than 10 bits per second, also known as high-speed telemetry systems. Offshore drilling, which has a high day rate of operation, provides an obvious economic justification for choosing expensive high-end technical solutions to optimize drilling; thereby, money will save by reducing the cost of drilling a well (Wojciech Emmerich et al., 2016)

However, the introduction of new high-end L/MWD technologies resulted in an increased amount of downhole data. The current commercial data telemetry rates that MPT offers represent a severe bottleneck that restricts the use of the large amounts of downhole information available with existing L/MWD tools (Lesso et al., 2008). The introduction of these new tools created the need for broader bandwidth and faster data transmission rates (W. Emmerich et al., 2016). Also, improvements in drill bit technology and optimized drilling procedures increased the rate of penetration (ROP), which also requires faster real-time data rates to maintain a good log density (Wojciech Emmerich et al., 2016). In addition, deeper wells require the use of special types of drilling fluids, which will affect the capability of transmitting data. The fluid’s physical properties such as density, temperature, and plastic viscosity make encoding pressure pulses into the mud a very challenging task. All of these challenges MPT faces are significant, however, a relatively new telemetry system has already overcome them, and that is wired drill pipe telemetry. Wired drill pipe (WDP) technology was developed and commercially introduced in 2006.

Chapter three. Wired drill pipe (WDP)

WDP provides high-speed data transmission up to 10,000 times faster than MPT, therefore solving the data transmission and bandwidth limitations faced by MPT (Foster & Macmillan, 2018). A massive increase in data transmission speed, achieving up to 57,600 bits per second, makes it possible to get real-time downhole information and measurements for surface processing. WDP provides high data bandwidth. WDP enables instantaneous bi-directional communication between the downhole tools and the surface equipment, which is a key factor in achieving a better understanding of the downhole environment (Lesso et al., 2008).

Instantaneous data transmission allows drilling processes to proceed without interruption, thus saving valuable rig time that will result in a reduction of the cost of the drilling project. “Rig time is saved as surveys, downlinks, slide orientations, and other data-driven activities are performed in a manner of seconds versus minutes with conventional telemetry”(National Oilwell Varco Wellbore Technologies, 2021). The availability of downhole parameters in real-time allows decision-makers to identify any drilling dysfunction events and take corrective measures. “Performance limiters associated with LWD data density, directional control, well placement, and hole cleaning management can be addressed with high frequency and low latency data. Thus, enabling higher rates of penetration (ROP) to be achieved”(National Oilwell Varco Wellbore Technologies, 2021). These will be thoroughly explored later in this work, but now the focus will be placed on the wired drill pipe network and components.

It is important to point out that as per 2021, it is only National Oilwell Varco Wellbore Technologies that provides this telemetry service. Thus, the following section will describe their proprietary network, namely the IntelliServ™ Broadband Networked Drill string, tools, and how the integration to third-party service providers occurs.

The wired drill pipe network

The implementation of WDP requires specialized equipment to enable real-time communication between surface systems and downhole components. (Salomone et al., 2019) describes the five main components that must be installed to utilize WDP telemetry, namely:

1. A Network Controller (NetCon) and surface cables
2. Wired string, including drill pipe, jars, drill collars, valves, etc
3. DataSwivel
4. Downhole electronic signal amplifiers, also known as DataLinks
5. Interface sub to allow for third-party L/MWD tool integration

All these components constitute the path that data will travel through instantaneously from surface to downhole and then back to surface.

NetCon™

The IntelliServ™ network controller, also known as NetCon, is the master controller and computer interface of the WDP telemetry system. A series of surface cabling running from the top drive to the NetCon provides the data input feed. NetCon contains the software and infrastructure to translate the acquired downhole data and securely transfer it to multiple users and vendors. Equally, tool commands are sent through and to the NetCon. Furthermore, it is used as a diagnostic tool to monitor the wired network in order to keep continuous data transfer and communication to downhole tools (National Oilwell Varco Wellbore Technologies, 2021). A representation of the IntelliServ™ network is shown below:

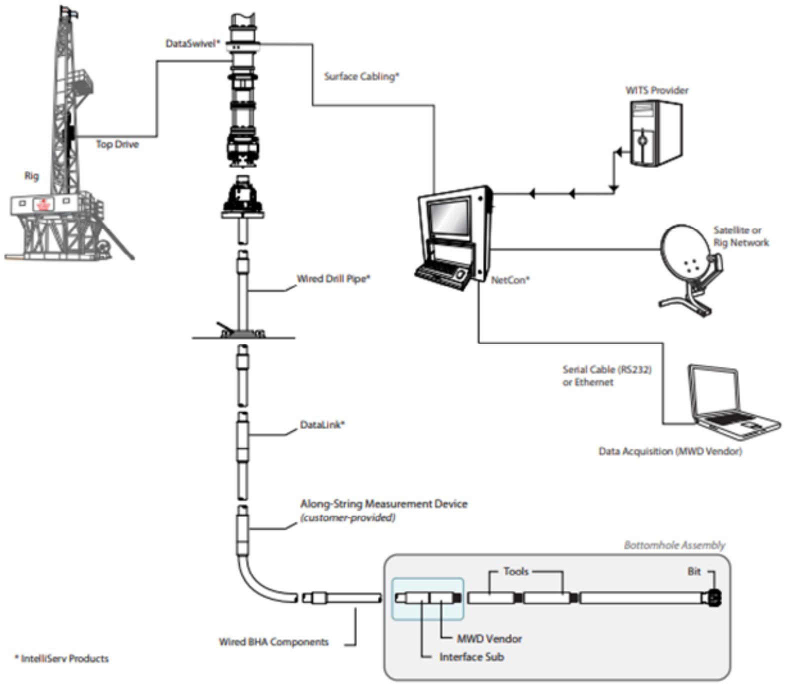

Figure 7 IntelliServ™ network general overview (National Oilwell Varco Wellbore Technologies, 2021)

Wired pipe

A modified drill string constitutes the conduit through which data is transfer. Although similar to a regular drillstring, a wired drillstring has been modified to include the required components and features which will enable data to pass through the drillstring.

The first component is an armored co-axial cable called DataCable. A hole is gun-drilled on each joint which allows the DataCable to run inside and along every component. It is encased in a stainless steel sheath which is held in tension next to the inner wall. This enables high-speed downhole data to be transmitted across the drill string (Edwards et al., 2013)

The next component in a wired string is an inductive coil embedded on both pin-end and box-end of each wired component. These inductive coils are called IntelliCoils, and they allow the bi-directional data traveling through the DataCable to pass from one joint to the next. Once a connection is made up, these coils come in proximity and allow the data to pass through induction (Edwards et al., 2013).

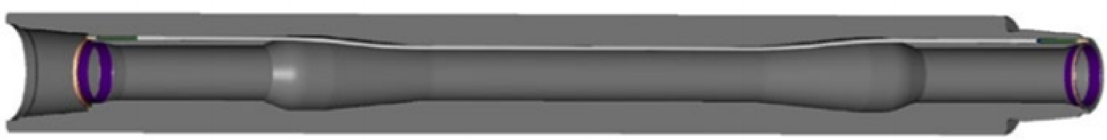

Figure 8 DataCable, running through a joint of pipe, connected to the intelliCoils (National Oilwell Varco Wellbore Technologies, 2021)

Figure 9 IntelliCoil on pin-end (Sehsah et al., 2017)

DataSwivel™

The WDP system not only requires the modification of drill string components but also requires to wire the top drive equipment. A top drive is a device that provides the force required to make the drillstring turn. It consists of electrical or hydraulic motors and appropriate gearing connected to a short section of pipe and then to the drillstring (Schlumberger Oilfield Glossary, 2021).

The WDP system requires installing wired top drive components such as the upper and lower Internal Blow Out Preventers (IBOP), top drive saver sub, and a swivel (Salomone et al., 2019). The DataSwivel is the uppermost component of the WDP network, and it is installed on the top drive. It is composed of a stator and a rotor. The rotor spins freely, whereas the stator, which is held by anti-rotation cables, remains stationary allowing it to connect to the surface cables. Thus, this swivel is the interface between downhole components and the surface network. Data travels from the BHA through the data cable and IntelliCoils along the drillstring to the swivel, which sends the data to the NetCon through the surface cabling (Edwards et al., 2013).

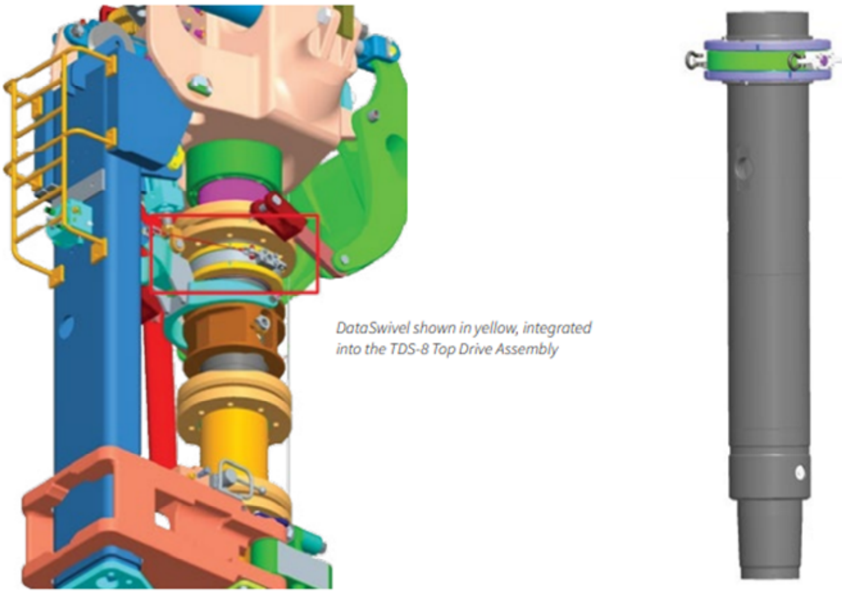

Figure 10 Left: DataSwivel installed on a top drive. Right: Dataswivel installed on top of an upper IBOP (National Oilwell Varco Wellbore Technologies, 2021)

Datalinks™

Datalinks are signal boosters or repeaters that are placed along the string to ensure an acceptable signal-to-noise ratio is maintained (Russell et al., 2008). As the data travels through the drillstring, the signal strength will get weaker or attenuated. Datalinks are battery-powered and are equipped with electronics to amplify the signal traveling through the WDP network so the surface equipment can process it. The placement of DataLink along the string depends on the length of the string. However, it is usual to find one of these repeaters every 10 to 15 stands or every 300 to 450m (National Oilwell Varco Wellbore Technologies, 2021).

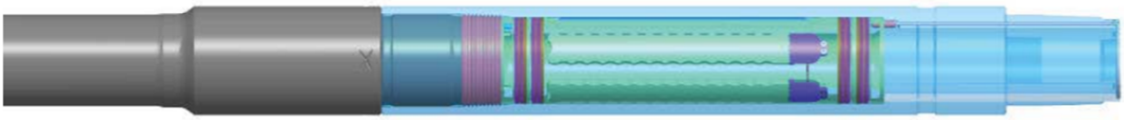

Figure 11 DataLink™ assembly design (National Oilwell Varco Wellbore Technologies, 2021)

Interface Sub

The wired drill pipe network receives data from and connects to L/MWD tools and RSS through an interface sub. This interface sub contains the electronics to create the bridge from third-party service providers and the WDP network. (Russell et al., 2008) explains, "Each company that connects to the WDP network has slight differences in how they transmit data between their tools. Each interface sub is configured to have a downhole connection configured to receive data from their tools and an uphole connection that connects to the network. The data is converted in a modem board within the interface sub so that it can be transmitted to the surface. This connection effectively gives the MWD/LWD/DD engineers control and access functionality as if the tools were connected to their systems at the surface".

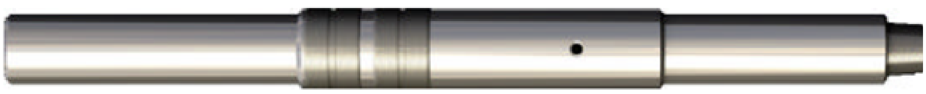

Figure 12 Halliburton's interface sub IXO (Lawrence et al., 2009)

All the components mentioned above allow the implementation of the WDP network at the rig site. The following figure shows how the whole system will look like once installed and commissioned.

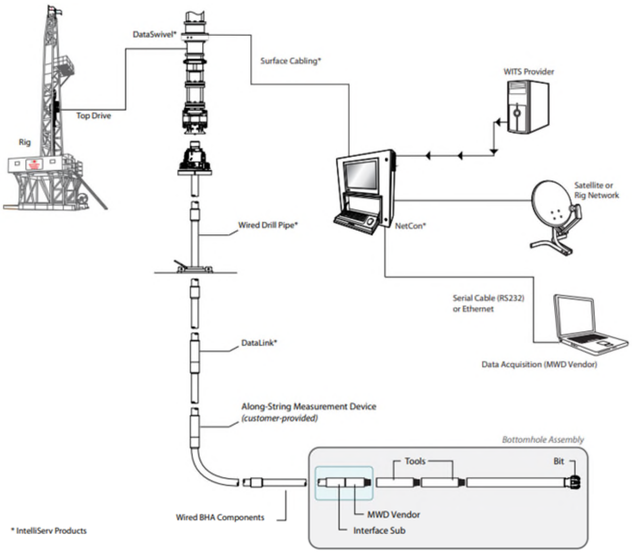

Figure 13 The Wired Drill Pipe network (National Oilwell Varco Wellbore Technologies, 2021)

The implementation of WDP as the selected telemetry channel not only brings benefits by providing a high-speed transmission rate with its 57,600 bps. It also opens up the possibility of placing measurement tools along the string, something that is not possible with MPT. Usually, measurement tools are restricted to be placed on the BHA below the assembly responsible for encoding the data gathered and the mud pulser. The following section presents and explores the benefits of having along string measurements and how they significantly contribute to the optimization of drilling operations while reducing risks involved with such operations.

Chapter Four – Along string measurements

The introduction of MWD tools opened up the possibility of gaining a greater understanding of downhole conditions. The question of what is happening downhole? Could be answered by interpreting the data coming up to the surface from downhole tools (Veeningen et al., 2014). The availability of two types of measurements is critical for achieving successful drilling operations, namely Pressure-While-Drilling (PWD) and Drilling dynamics tools. These tools mitigate the source of the majority of drilling downtime, resulting from either hole problems or tool failure (Aadnoy et al., 2009).

Pressure measurements while drilling PWD

It has been estimated that hole problems account for approximately 10 to 15% of the drilling operations in the North Sea. Pressure measurements while drilling (PWD) provide the data needed to understand the mechanisms that lead to hole problems, thereby allowing remedial actions to be taken (Aadnoy et al., 2009).

Formation pressure limits are defined by the pore, collapse, and fracture pressures. Most of the drilling problems are directly related to these limits. Thus, the development of downhole tools which can provide pressure measurements was greatly wished. During the mid-1990s, PWD tools have been developed and widely used since then. All the major drilling service providers have their own downhole PWD sensors. These are used to closely monitor the pressure at a certain true vertical depth (vertical distance from a point in the well to a point in the surface) in the annulus and maintain the mud weight and equivalent circulating density (ECD) within safe operating limits (Aadnoy et al., 2009).

(Aadnoy et al., 2009) discusses the three modes PWD take measurements and how this data could be displayed for interpretation:

1. Real-time mode. The downhole pressure data is sent to the surface in real-time after a defined interval of time, depending on the telemetry channel. With an MPT system, the amount of real-time data will be limited. A particular flow rate is needed to be maintained to send the data through the mud column. If the flow rate is below this threshold, no information will be sent to the surface.

2. Memory mode. The downhole tool will store the continuous measurements on the memory tool. Once the tool is at the surface, the data will be retrieved. Recorded data have the benefit of having richer quality.

3. Pumps-Off mode. In this mode, the tool will recognize when the pumps are off, and once pumps are on again and flow is established, the tool will send limited information to the surface.

For all those mentioned above, it is easy to understand the benefits of using WDP telemetry since the PWD measurements can be sent to the surface regardless of flow is established or not. Thus, allowing to improve safety in drilling operations by identifying unwanted drilling problems at all times. Hole problems will be further discussed later in this thesis and how the implementation of WDP can manage them.

Drilling dynamics measurements.

The understanding of drilling dynamics, especially vibration monitoring and mitigation, is vital for successful drilling optimization. Rising drilling costs and also the costs of L/MWD tools require mitigating vibrations to avoid tool failure/loss. The financial losses incurred due to drilling dynamics have been estimated to be up 5% to 10% of drilling costs. Therefore, it is important to get insights on the downhole conditions to take corrective actions (Aadnoy et al., 2009).

MWD tools have the necessary sensors to detect and monitor shocks, accelerations, torque, and weight-on-bit (WOB). Usually, these sensors are gyroscopes, strain-gauges, accelerometers, among others. How these sensors operate will not be discussed in the present work; instead, it will be presented the advantages these sensors bring.

Drilling dynamic tools continuously monitor BHA vibrations and diagnose the occurrence of vibrations-related problems. Next, vibrational information is transmitted to the surface and displayed to the decision-makers, usually the driller and directional driller. They are responsible for adjusting drilling parameters as needed (RPM, flow rate, WOB) in order to mitigate vibrations and optimize the drilling process (Aadnoy et al., 2009).

Nevertheless, one of the limitations of using MPT is that it does not permit the real-time transmission of all the raw measurement data to the surface. It does not provide a timely transmission of the drilling dynamics and diagnostic data. Hence, it is difficult to identify and flag harmful vibration events that occur at the BHA that could lead to tool failure and operational downtime as a result of the time that will be spent in changing the tools (Aadnoy et al., 2009).

Once again, it is not difficult to understand the benefits that WDP could provide when it is needed to identify hazardous vibrations events. The broad bandwidth and data transmission speeds that WDP offers are ideal for sending hi-frequency vibration measurements. This way, all the raw data can be sent to the surface in real-time to understand better the severity of these events, hence allowing better decision-making.

Now, if sensors that are placed a few meters behind the bit can provide vast amounts of data and valuable information about downhole pressure and drilling dynamics, what advantages will these sensors provide by taking the same measurements at different points along the whole string?

In fact, this becomes possible by using WDP. WDP provides the capability of placing sensors along the string in areas of interest. Thus, downhole visibility will be improved since a clearer and more complete picture of downhole conditions will be available. These tools are known as Along-string-measurements.

Along-String-Measurements (ASM)

For many years the oil industry has been limited to take measurements only at the BHA and at the surface. There is a significant reliance on simulations done before drilling to predict the conditions in regions of the wellbore where measurements are not available. The introduction of sensors that can be placed at any point along the drill string gives the opportunity to observe and monitor the downhole environment along the whole wellbore and not just at the BHA (Coley & Edwards, 2013).

Along string measurement (ASM) tools have been developed to take advantage of the WDP network. These tools are built in a similar way to Datalinks, so they are signal boosters that can be placed anywhere in the drillstring, but ASMs are equipped with sensors that measure three-axis vibrations, rotation, temperature, internal and annular pressure. Given that ASMs run on batteries, they can provide real-time flow-off readings. The high-frequency measurements (0.5Hz) taken by ASMs are sent to the surface at high speed (57.6 Kbps). These data provide the necessary information about hole cleaning/quality and provide the support needed to make informed decisions and prevent drilling risks such as damaging vibrations and wellbore stability issues (Salomone et al., 2019).

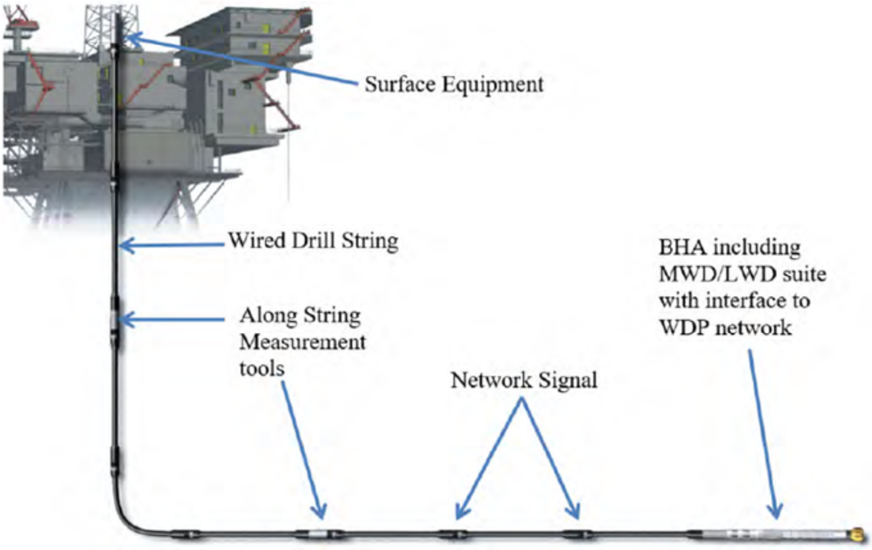

Figure 14 The Wired Drill Pipe system (Salomone et al., 2019)

Thus far, the WDP network has been described. The advantages of having a high-speed telemetry channel and the new tools that WDP allows to place along the string have been introduced. This combination of telemetry and tools has been used for almost a decade now. The results and applications have increased drilling efficiency, enhanced drilling processes, reduced HSE risks, and reduced well times (Vandvik et al., 2021).

Chapter Five- Optimization of the drilling process using WDP and ASMs

Drilling operations are exposed to many sources of risk that can lead to negative outcomes. Risk is defined as the unknown consequences (impact on health, environment, assets, etc) as a result of an activity and its associated uncertainties. Risk management involves decision-making under hazardous events characterized by high risk and large uncertainties (Aven, 2015). Therefore, it is imperative to understand and characterize the sources of risk by making use of all the sources of information available. This way, the strength of knowledge related to a given event will increase, thereby allowing decision-makers to assess different situations better and make risk-informed decisions.

The application of WDP and ASMs has a proven benefit to reduce operative risks and optimize the drilling process. The drilling process of a planned section hole can be resumed in the following way:

- Pick up drill bit, directional steering tool, and L/MWD tools. These become the drilling BHA
- Run in hole (RIH) drilling BHA on drill pipe
- Tag top of cement or formation
- Displace the well to the drilling fluid specially designed to drill the section
- Commence drilling cement and 3 meters of new formation
- Perform a Formation Integrity Test (FIT) or Leak-off Test (LOT) to verify the strength of the new formation and the maximum ECD that the formation can withstand
- Drill the section to target depth (TD)
- Circulate hole clean of cuttings. Pump drilling fluids to remove cuttings from the annulus. Verify cuttings are no longer observed at the surface, then the hole is considered clean
- Pump/pull out of the hole the drilling BHA
- RIH with casing to TD and perform cement job to secure the newly drilled formation

The added visibility provided by ASMs and high-speed telemetry allows improving the process mentioned above by:

Drilling dynamics management

As previously mentioned, it is of great importance to timely identify damaging vibrations. These unwanted events can lead to increased risk of BHA twist offs, early wear of the drill bit cutters leading to reduced ROP, and accelerated downhole tool failure (Aadnoy et al., 2009). These vibrations events usually occur when drilling cement and when encountering harder formations. Real-time transmission through WDP and display of high-frequency vibrations data, downhole weight-on-bit (dWOB), and torque-on-bit, with an update rate of 2 seconds, help identify high vibration events. The update rate on WDP shows a clear advantage compared to the refresh rate of one data point every 150 seconds that MPT provides. This has led to enhanced downhole monitoring, thereby increasing the understanding of downhole conditions. WDP's high refresh rate makes it possible to take mitigation actions earlier to find the suitable drilling parameters by adjusting RPM, WOB, and flow rate to manage this type of vibrations (Nygård et al., 2021). Successful mitigation of damaging vibrations will result in improved

ROP and reduction of unexpected trips out of the hole to change damaged bit/BHA (Teelken et al., 2016). Trips due to tool failures result in a full stop of the drilling operation, leading to very expensive non-productive time.

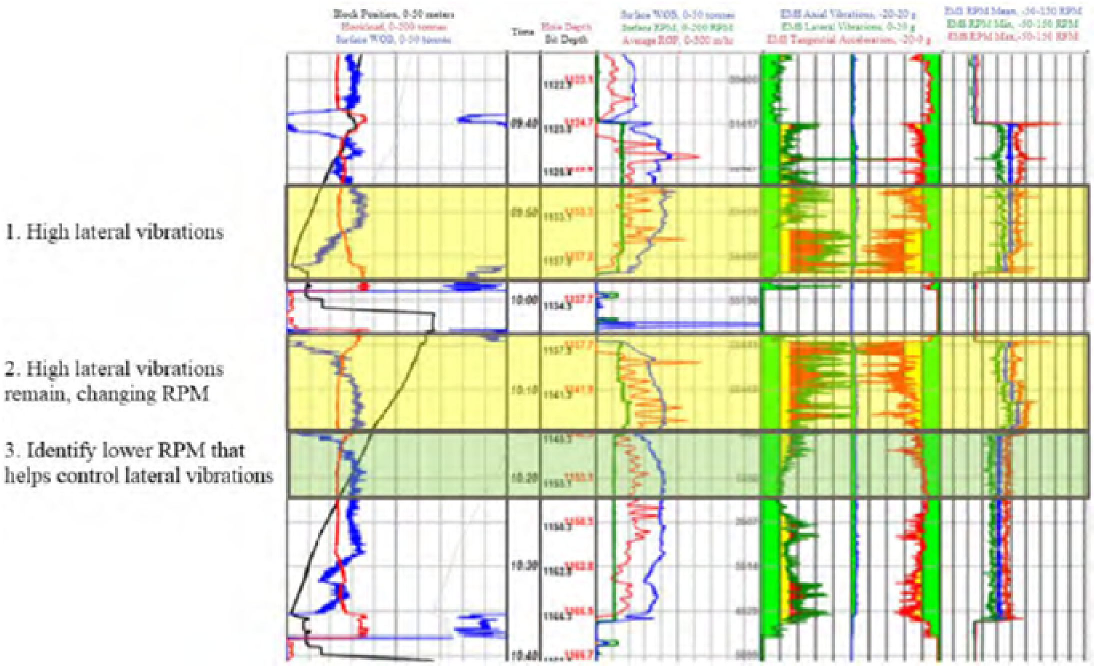

Figure 15 Time-log showing downhole vibration identification and successful mitigation (Nygård et al., 2021)

Formation integrity test (FIT) Leak-off Test (LOT)

Formation fracture pressure is estimated by performing either a Formation Integrity test (FIT) or Leak-off Test (LOT). These tests estimate the formation breakdown or the minimum formation strength, respectively (Veeningen et al., 2014). It is a NORSOK D-010 requirement to test barrier elements regularly and estimate the formation strength after drilling a few meters of a new formation (Nygård et al., 2021). Thus, with high rig costs, it is critical to perform these tests efficiently in order to reduce the time spent (Aadnoy et al., 2009).

These tests are performed by pressurizing up the well, which will result in an increase in the mud's equivalent mud weight (EMW) under static conditions(Veeningen et al., 2014). The pressure measurements taken during these tests are used to validate the formation strength. When an MPT system is chosen, the tools need to be prepared and programmed to record data continuously while performing the test since MPT cannot transmit data without flow. Once the test is finished and flow reestablished, the tools send the measurements to the surface so they can be reviewed. Drilling sometimes cannot be resumed until a successful test with the required results has been performed (Nygård et al., 2021).

(Nygård et al., 2021) presents the benefits of using WDP to perform these tests as it reduces the time needed to complete them. The ability to get data regardless of flow allows observing the tests being executed and the tool's responses in real-time. Furthermore, there is no need to use time preparing the MWD tools prior to the test. The required data to validate such tests is streamed continuously with high resolution, which leads to the possibility of faster interpretation of the measurements. The decision whether to re-take the test or drill ahead can now be made right after the test is finished, thereby reducing uncertainties, improving operational efficiency, reducing valuable rig time, and improving the quality of the decisions taken.

Hole cleaning and validation of cuttings transport

How can it be determined whether the cuttings that are being produced due to drilling are being transported effectively through the wellbore and out to the surface? The value of PWD indeed lies in its ability to monitor the flow of cuttings. By monitoring the pressures where the sensors are located, it can be understood the distribution of cuttings along the annulus (Aadnoy et al., 2009).

Well stability and hole problems constitute the primary source of risk and downtime under drilling operations. Well events such as poor hole cleaning, hole collapse, loss of circulation, formation fluid influx lead to time- and resource-demanding remedial actions (Aadnoy et al., 2009). The use of PWD reveals important downhole information, which helps identify the events previously mentioned. Nevertheless, the full capabilities of PWD cannot be achieved with MPT. The common problem of annular pressure monitoring on MPT is that annular pressure data will not be available when the pumps are off, and there is no flow (Lesso et al., 2008; Nygård et al., 2021).

As mentioned before, WDP allows for high-speed transmission of data from downhole to the surface. In addition, it allows the placement of multiple ASMs anywhere on the drillstring. Thus, it is possible to acquire internal pressure, annular pressure, and temperature data along the wellbore, which allows not only to gain a greater understanding of well stability and cutting transportation but also to reduce the risk of unwanted well events from happening. The distribution of sensors along the string helps to determine whether cuttings are being removed optimally or if accumulations of cuttings are occurring.

Hole cleaning

One of the main challenges while drilling a section is achieving effective hole cleaning. Efficient hole cleaning is of great importance when drilling directional, high deviated, and extended-reach wells. Insufficient cutting removals can result in pack offs (Aadnoy et al., 2009). A pack off occurs when cuttings accumulation leads to plugging the wellbore or when the wellbore wall collapse around the drillstring (Schlumberger Oilfield Glossary, 2021). Having sensors along the string enables monitoring of annular pressures and ECD along the string. The movements of solids can therefore be monitored deep down from the BHA all the way to the surface in real-time (Coley & Edwards, 2013). This allows to identify and localize these events promptly. A high-pressure differential between two sensors indicates an obstruction along the string (Nygård et al., 2021). Likewise, a drop in ECD of a shallow sensor with an increase of ECD on a deeper sensor indicates a cutting accumulation or restriction above the deep sensor. The ability to identify these events and assess hole cleaning in real-time with multiple data points allows taking risk-informed decisions. Remedial actions can be taken on time, allowing to avoid expensive events of stuck pipe. Drilling parameters such as flow rate and RPM can be adjusted to optimize hole cleaning.

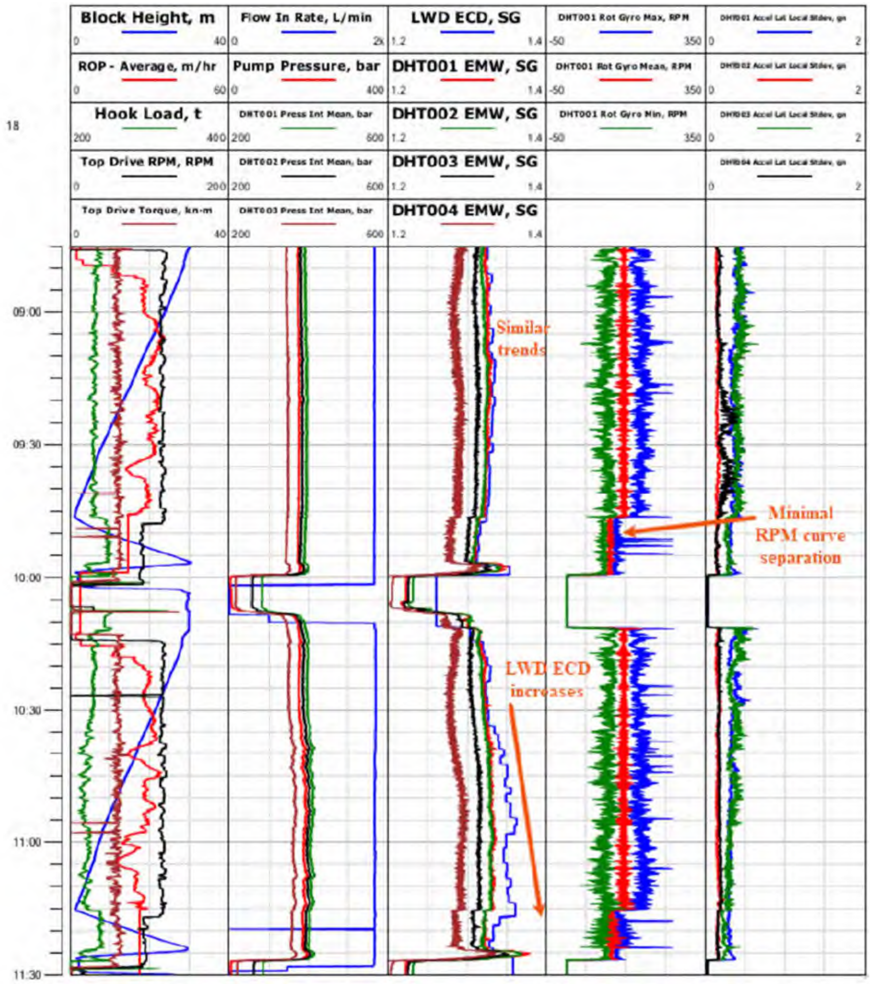

Figure 16 Assessing hole cleaning by ECD trend monitoring (Salomone et al., 2019)

Well control and lost circulation monitoring

One of the most severe risks during drilling is the influx of formations fluid into the wellbore, also known as a kick. During gas kicks, a reduction in density of the mud column can be expected as a result of less dense gas replacing heavier fluids. Similarly, increased annular pressure loss and increased temperature can be expected. If a kick occurs, all drilling activities are halted, and the well gets shut-in, thus becoming a closed system. Therefore, it is critical to monitor all available data to detect a kick event in time (Aadnoy et al., 2009). The use of ASMs placed in the open hole section allows detecting these fluctuations in time. Moreover, if a kick is taken and the well is shut-in, downhole data will still be streamed to the surface (Coley & Edwards, 2013). This way, decision-makers will have a clearer picture of the situation they are dealing with and act accordingly.

Similarly, lost circulation events can be identified. Lost circulation refers to the situation where reduced or total absence of drilling fluid up the annulus occurs due to fractures in the formation. These not only represent a severe loss of well control, in the most extreme case. It also means a significant financial loss as the drilling fluid is being lost into the formation, which requires remedial actions to be taken immediately (Schlumberger Oilfield Glossary, 2021). However, remedial operations are time-demanding and require special fluids to be pumped down, namely loss of circulation material (LCM). Constant monitoring of ECD and annular pressure along the string allows pinpointing the place of occurrence of a lost circulation event enabling the possibility of accurate management of the wellbore pressure. In addition, LCM fluids can be used as needed when operating on WDP in contrast to MPT. This is because a blockage can occur on the pulsing equipment leading to loss of telemetry, which would require a costly trip out of the hole to replace the equipment and also increasing the risk of a well control event on the open hole.

Increased ROP

ROP is defined as “The speed at which the drill bit can break the rock under it and thus deepen the wellbore. This speed is usually reported in units of feet per hour or meters per hour” (Schlumberger Oilfield Glossary, 2021). Thus, the higher ROP that can be achieved translates into drilling a well faster. WDP permits achieving high ROP above 250m/hr while keeping high-quality data transfer from L/MWD tools as it provides a large bandwidth. Usually, this is not possible with MPT systems as they are limited by their low bandwidth, thereby drilling slower to acquire the amount of data needed with the resolution required (Teelken et al., 2016).

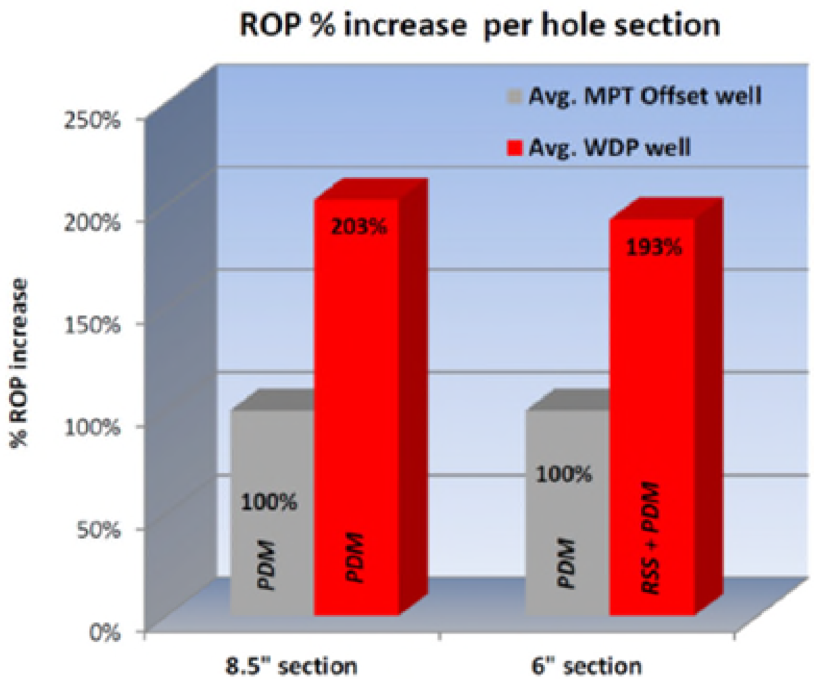

Figure 17 Comparison of ROP increase per hole section (Teelken et al., 2016)

Telemetry time

Telemetry time is the time spent sending commands to downhole tools by downlinking. Downlinking is the practice through which commands are transmitted from the surface to the L/MWD and RSSs. These commands send specific instructions to these tools, and once the tool has received the command, it will send a confirmation message up to the surface.

When MPT is used, downlinking is achieved by creating a pressure pulse from the surface. This involves staging up the rig pumps to create a specific pressure pulse that will be recognized by the pulser tool. The low data transmission speed that MPT offers makes this process time demanding, as sometimes a downlink is not received successfully.

Furthermore, the process of creating the pressure waves for downlinks can potentially damage the formation due to pressure fluctuations, especially when drilling through a formation with a narrow pressure window (Teelken et al., 2016).

WDP allows for instantaneous bi-directional communication with downhole tools, allowing to send as many downlinks as the MWD engineer needs and wants at the touch of a button. These downlinks can be sent anytime through the cable running inside the pipe. Thus, eliminating the unwanted effects of the pressure fluctuations (Teelken et al., 2016). Moreover, having instantaneous communication with downhole tools saves time spent on sending downlinks and allows full control of the actions to be performed by the L/MWD and RSS tools.

(Schils et al., 2016) present the results of a comparison in telemetry time during drilling the Martin Linge field in the Norwegian Continental Shelf (NCS). After drilling five wells, the telemetry time used was found per well. The wells had similar well profiles, and after normalizing the telemetry values, it was found that the average telemetry time per well using MPT was 24.53 hours in comparison to the 6.82 hours used with WDP. This represented a reduction of 72% in telemetry time per well. Considering the high day rates that drilling rigs have, this time reduction represents money saved to the operator.

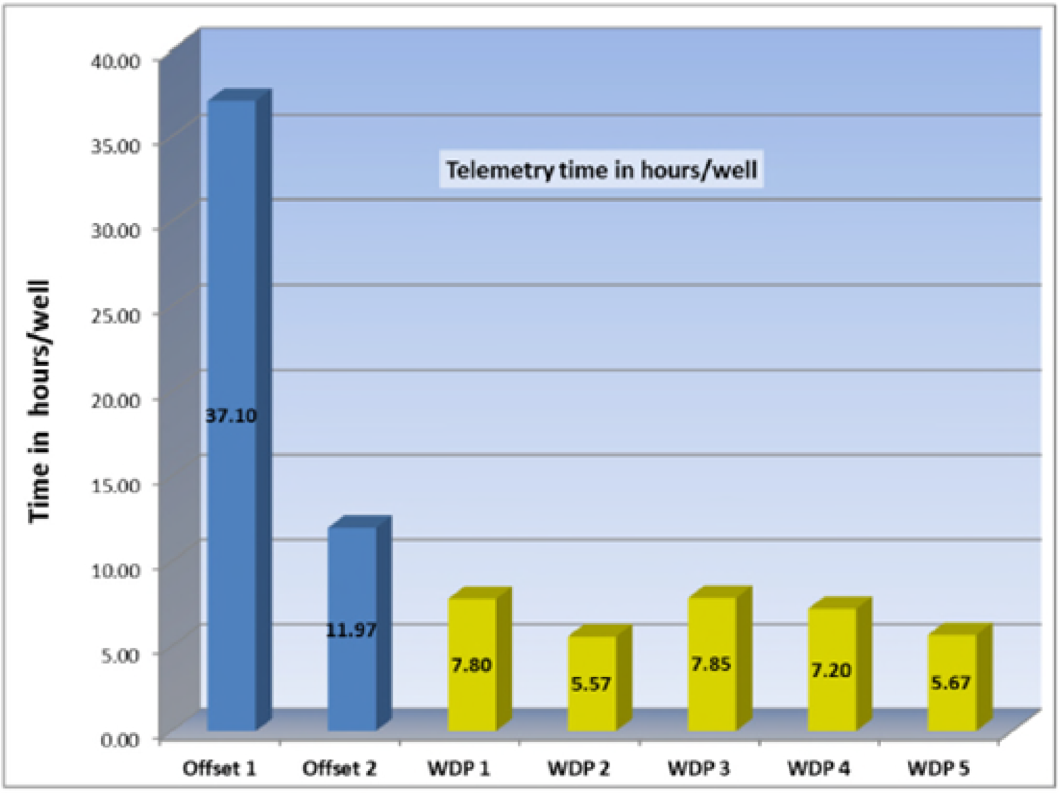

Figure 18 Telemetry time analysis on five wells at Martin Linge field (Schils et al., 2016)

Taking full advantage of the latest L/MWD tools

Constant development and improvement of downhole sensors have resulted in incredibly advanced L/MWD and directional steering tools that generate vast amounts of data. The use of WDP allows making the most out of these tool's steering capabilities and measurements, such as imaging, acoustic and seismic, to enhance drilling operations and reduce uncertainties while drilling.

High directional control Improved Geosteering

RSSs utilizes two-way communication to control and confirm the tool status in real-time. When RRSs are used with WDP, the system allows for instant control and feedback from the tools enabling precise tool steering and control to optimize and keep the well trajectory.

Geosteering makes use of very advanced tools designed for optimal well placement and accurate formation evaluation known as azimuthal deep resistivity (Clegg et al., 2018). The sensors are fully integrated into the RSS, and these acquire data in 32 discrete directions around the tool. Thus, allowing to send commands to the RSS to go in the desired direction. The number of measurements can result in over 2000 measurements taken by the tool. This large amount of data is easily handled through the WDP system, which is transmitted to the surface with high resolution to improve geosteering practices, reduce trajectory uncertainty and improve geosteering decisions.

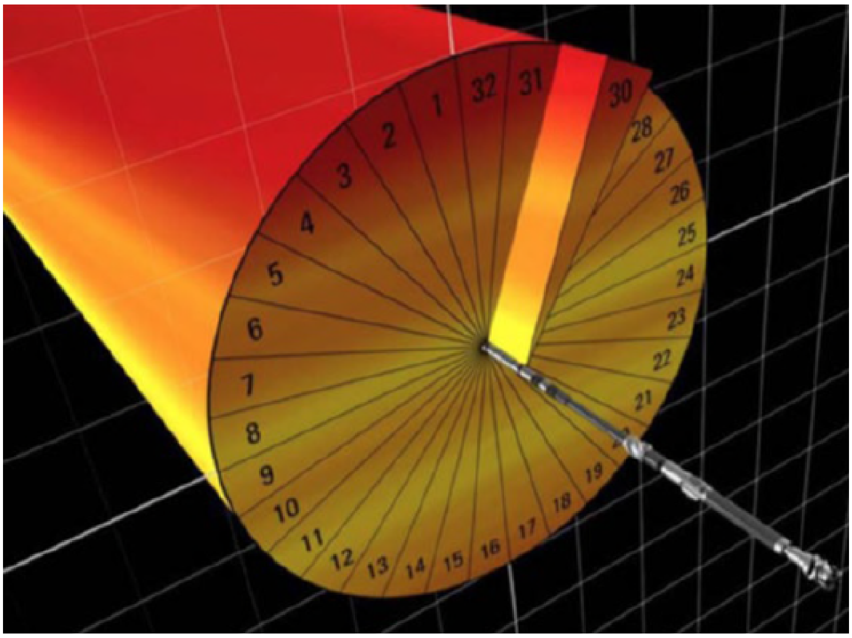

Figure 19 360° azimuthal resistivity image, represented by 32 bins of resistivity data around the borehole (Clegg et al., 2018)

Imaging

Imaging tools provide measurements around the circumference of the wellbore as the tool rotates. Transmission of the full resolution of the imaging tool on MPT requires considerable bandwidth. This leads to operators having to decide whether to lower the resolution of the images in order to get measurements from other tools or to discard these to get full resolution images. WDP allows transmitting memory-mode quality images in real-time while keeping high ROP. This not only allows achieving higher ROP, which results in wells being drilled faster. It also reduces uncertainties around the wellbore leading to improved decision making (Russell et al., 2008).

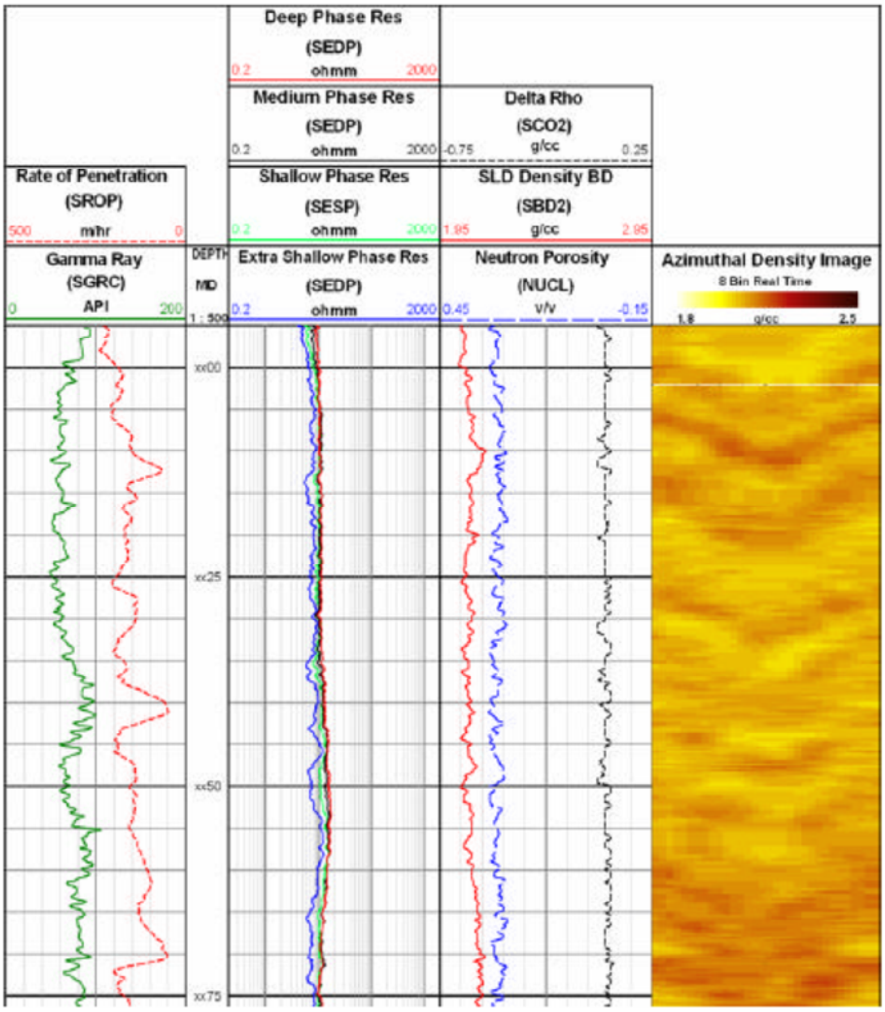

Figure 20 High-quality density image obtained at high ROP 200m/hr (Lawrence et al., 2009)

Acoustic measurements

Acoustic measurements generate large amounts of data by taking measurements from multiple receiver arrays. Usually, this data is available after the tool is out of the hole and the tool's memory has been retrieved for analysis. Once again, the large bandwidth that WDP provides allows transmitting this type of measurement in real-time, opening up for the opportunity to detect fractures (Russell et al., 2008).

Seismic measurements

The WDP network allows transmitting memory-quality real-time seismic time-depth data to the surface, which is "a technique using a seismic source on the surface and receivers in the borehole to acquire a vertical seismic profile (VSP)" (Schlumberger Oilfield Glossary, 2021). This data is of great importance as it enables ahead of bit formation detection and logging. Furthermore, using the WDP network removes the need to send downlinks on MPT and permits taking seismic shots at connections, thereby saving valuable time (Schils et al., 2016).

Data while tripping – Removing uncertainties during tripping operations

Being connected to a wired drillstring during tripping operations has been a concept that the oil and gas industry has longed wished to be available (Jeffery et al., 2020). Tripping operations refer to either running pipe in the hole or pulling it out of the hole. The movement of the pipe in the hole generates pressure fluctuations that could lead to increased risk of well events and wellbore stability (Aadnoy et al., 2009). Thus, it is essential to identify and define a safe pressure operational envelope.

Commonly, simulations before operations are performed to develop a trip speed model. These simulations use inferred pressure data, post-run memory of an offset well to determine safe speeds to run the pipe in or out of the hole to avoid swab, surge, and hole stability problems (Vandvik et al., 2021). Swab refers to the pipe's upward movement, which creates a reduction in pressure (Schlumberger Oilfield Glossary, 2021). If this reduction in pressure gets below the swab limit, reservoir fluids may flow into the wellbore, leading to taking a kick and wellbore stability problems. Similarly, a downward movement of the pipe exerts extra pressure into the formation (Schlumberger Oilfield Glossary, 2021). If this pressure exceeds the surge limit, there is the risk of fracturing the formation requiring resource-demanding remedial actions. Therefore, remaining within the operational pressure window is imperative.

Figure 21 DWT tripping detail view. The red area defines pore pressure. Blue area represents fracture pressure (National Oilwell Varco, 2021b)

Previously, access to pressure data under operations was not possible, given that a connection to the wired pipe was established only by being connected to the top drive. However, the introduction of the Data While Tripping (DWT) has enabled operators to access this valuable information in real-time. In 2019, the DWT equipment was deployed on two drilling rigs in the North Sea. This equipment is mounted on the elevator bails and allows to establish full connectivity with downhole tools and ASMs (Vandvik et al., 2021). The DWT assembly once activated, swings an arm that has attached a reading head and lowers it inside the box end of the pipe. This reading head establishes the connection with the WDP system.

Having full connectivity with downhole tools while tripping in or out has enabled operators to take data-driven quality decisions to adjust tripping speeds based on the real-time pressure measurements taken, thereby reducing the risk of swabbing or surging the well.

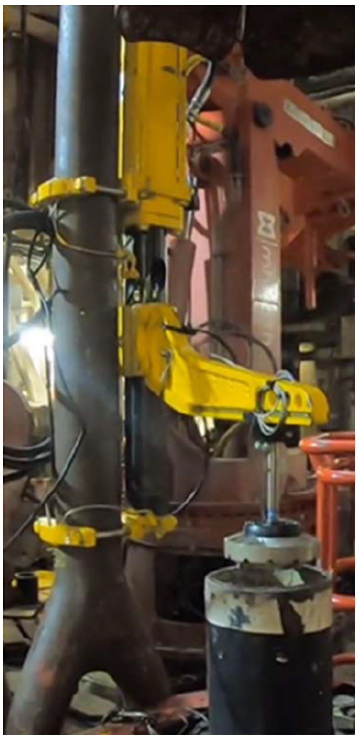

Figure 22 Data While Tripping device mounted the elevator bails of a drilling rig (Vandvik et al., 2021)

DWT use is not limited to just monitoring Swab and Surge; it opens up the possibility for formation testing while tripping. Formation testing is an LWD capability that reduces the need for wireline operations, thereby saving rig time and costs. As mentioned throughout this paper, L/MWD tools rely on flow to send data through MPT. The flow rate required can aid the development of unwanted increased pressure. These formation tests on MPT take between 18 to 30 min per test, and it is common to perform multiple tests. The adoption and use of DWT establish full communication with L/MWD tools while tripping. Once communication with the downhole tools is established, it takes approximately 11 minutes to complete these formation tests without flow. Hence, the time spent taking formation tests is significantly reduced. Also, the total static time of the drill string is reduced, which reduces the risk of it getting stuck (Jeffery et al., 2020).

Chapter six. Challenges of WDP and future improvements and opportunities

WDP has come a long way since its introduction to the market. It has proven the positive impact that high-speed, high-quality real-time data has on the drilling process. However, some areas are still a concern when considering WDP as the telemetry method for a given drilling project. These concerns usually are due to handling practices, reliability, cost of running the technology, and doubting the benefits of "so much data."

Handle and care

WDP requires to be handled with "special care." Proper pipe handling practices consist of ensuring the cleanliness of the connections, applying good and even amounts of thread compound when making up connections, applying the right makeup torque to avoid deformation and damage to internal components, and careful stabbing in connections. Complying with all of the requirements mentioned above usually is seen as a factor that could potentially affect the drilling contractor meeting the key performance indicators. Avoidance to follow the advised handling practices increases the chance of the WDP components getting damaged, which increases the risk of a failure of the system.

Reliability

Reliability refers to the ability of a system to function as it is expected. The WDP system is composed of many components connected in series. A series system means that all the components that make up a system have to work in order for the system to function (Aven, 2015).

Figure 23 Reliability of a system in series (Aven, 2015)

At the time of writing the present work, WDP is running its second-generation design that addresses many of the failures that were seen on the first generation. Significant improvements have been made to the design and placement of the inductive coil and armored cable that runs through the pipe. The material of the armored cable was changed from stainless steel to Inconel to avoid stress corrosion cracking. As for the Intellicoil, it was re-designed to sit recessed and mounted on the internal diameter of the pin connection. These improvements not only led to improved reliability but also increased repairability. (Sehsah et al., 2017).

Nevertheless, as the equipment usage increases, the durability of WDP components becomes a limiting factor. Hence, drill pipe management becomes essential, which means constantly rotating the equipment to alternate the use of components and demobilize equipment for service after around 750 hours of use (Edwards et al., 2013).

Ensuring every WDP component is working is vital. All components need to be functional; otherwise, if one component fails, the WDP system will not be available depending on the point of failure. For example, if a component located in the middle of the string fails, then the signal will be able to travel until that point. Hence, there is the need to test WDP components regularly and as they are being run in the hole.

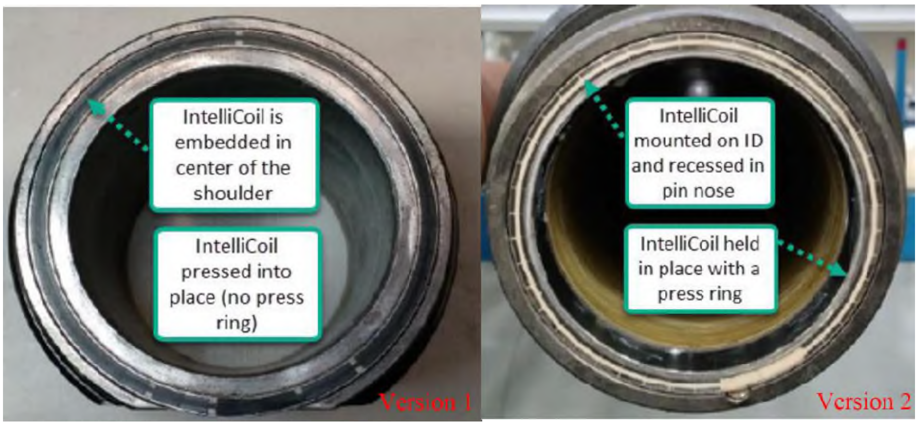

Figure 24 Left: Intellicoil's first generation. Right: Intellicoil's second-generation (Sehsah et al., 2017)

The introduction of the DWT assembly allowed for testing all the components of the wired string, making it possible to identify faulty components and removed them in time. However, removing defective components during running-in-hole operations means incurring in non-productive time. Another likely adverse scenario is when a component fails, and this one is located downhole making it very difficult to get to it to replace it. Usually, if this scenario occurs, operators decide to finish drilling the section by seamlessly switching to mud-pulse telemetry since a pulser is a part of every MWD package.

Now, let us consider running WDP as the primary telemetry and the pulser as a backup. This situation allows for operators to increase the reliability of the telemetry system. Having both channels ready to be used create redundancy in the system, improving its performance. Under normal operations with only MPT, a failure in the pulsing equipment leads to unplanned trips out of the hole to replace the damaged equipment incurring in expensive non-productive time. The ability to easily transition from WDP to MPT ensures a communication channel will be available.

Cost of investment

WDP, like any other new technology, represents a considerable investment cost. Even though information regarding the exact cost figures of deploying WDP is not easily accessible since this is considered internal information for the service provider. Additionally, the investment cost will depend on the type and amount of pipe to be used, the tools, and the project's scope. However, (Schils et al., 2016) provide some insights on the cost of using WDP, which provides an analysis of the benefits of implementing WDP from the start of the Martin Linge offshore field development. It was identified that the technology introduction investment would break even. However, as the project progressed, many other benefits were recognized.

“Drilling offshore is one of the single most expensive activities anywhere. It costs an average of USD 450,000 per day to hire a rig, and it takes between 30 and 70 days to complete the drilling job itself” (Equinor, 2021b). With these numbers in mind, it is easy to realize that any possible minute saved will positively reduce costs and vice-versa. For the Martin Linge project, the motivation towards choosing WDP and ASMs was due to the structurally complex reservoir conditions. The complex drilling environment posed many wellbore instabilities and well control challenges. Therefore, a full understanding of downhole conditions was absolutely necessary to drill successfully (Schils et al., 2016). Chapter five of the present work described thoroughly how WDP aids in optimizing the drilling process and how telemetry times are highly reduced by having instantaneous communication with and full control of downhole tools. These benefits were observed throughout Martin Linge's drilling project. Drilling dynamics management allowed avoiding damaging downhole equipment, thus avoiding unwanted TOH to replace equipment. During critical events, such as well stability issues, real-time data delivery permitted timely decision-making to take remedial actions. Optimal hole cleaning and reduced time spent on hole cleaning were achieved using the ECD information provided by the ASMs (Schils et al., 2016).

Now let us try to get an idea of the possible time that can be saved by using WDP, which will result in cost savings. For the Martin Linge offshore field development, the following figures were calculated at the end of the project.

Time	per 1000m	4000m well
Telemetry time saving	6.28 hrs	25 hrs
NPT	0.8 hrs	3.2 hrs
PT	0.4 hrs	1.6 hrs
TOTAL Saving	**5.08 hrs**	**20.2 hrs**

Figure 25 Timed saved by using WDP (Schils et al., 2016)

Furthermore, it has to be taken into consideration the initial capital expenditure to acquire the WDP system and increased operational costs related to the rental of the equipment and additional at least two WDP engineers on the rig, one per 12-hour shift, to operate and maintain the WDP system. At the end of the 11 planned wells, the following cost overview was obtained:

	Martin Linge
Telemetry time saving	9.25 rig days
CAPEX investment	4 rig days
Spread rate increase	1 rig day
Saving	**4.25 rig days**

Figure 26 Martin Linge field development results after an 11 wells campaign (Schils et al., 2016)

The total savings accounted for up to 4.25 rig days. Let us assume that, as stated before, it costs 450.000 USD per day to hire a rig; then this equates to a total of 1,912,500 USD saved. (Schils et al., 2016) argues that this justifies the technological investment. Further, it is also mentioned the upsides of deploying WDP as it allowed to increase the drainage area of the wells drilled, which contributes directly to increase the net present value of the project.

It is clear that the deployment of WDP represents a high investment cost, which leads to operators needing to consider if the benefits of using WDP outweigh the costs. The analysis to be carried must consider many factors such as the length of the project and the complexity of

the drilling environment, which could result in the need to use advanced and sophisticated BHAs.
Last but not least, it is important to point out that an increase in WDP deployments will allow further technology development. Cooperation between the operator and the service provider will allow addressing current flaws and identify potential new applications. Such cooperation allowed the development of the Data-While-Tripping assembly.

Large amounts of data

How much data can a person process? “Very few people have the mental capacity to constantly pay attention, analyze possible outcomes, and conduct a multitude of repetitive tasks at the same time. So, drilling has to take place more slowly than is physically possible, to allow for the limitations of the human operators” (Equinor, 2021b). Therefore, it is important to keep in mind that the amount of data available can become a risk if it is not handled and processed in the right way. To accomplish this, there has to be a continuous improvement of visualization software and, more importantly, the cooperation across the different disciplines involved in the drilling process.

Future opportunities- Digitalization and Automated drilling

Advancement in technology has placed greater emphasis on how digital data could be applied and the possibilities they could offer, which ultimately could open up for automated drilling to evolve. Digitalization of drilling has the potential to allow safer operations by reducing the amount of personnel needed and therefore exposed to the risks that drilling tasks involve. Furthermore, it could result in improved efficiencies throughout the whole drilling process, thus reducing operative costs (Israel et al., 2018). This is the reason why many operators and service providers have opted to seek more operations to be carried out remotely, which has resulted in the creation of Remote Operation Centers (ROC).

New digital tools allow better decisions to be taken through the close cooperation between the onshore support centers and offshore operations (Equinor, 2021a). However, ROCs and automated drilling are highly dependent on having the required data available in real time. It is here that the large amounts of data that WDP is capable of transmitting, from surface to downhole tools and vice versa, have the potential to close the loop thereby opening up the possibility for more automation.

The development of digital infrastructure and systems makes it possible to create a collaborative digital environment. This environment permits the control of operations regardless of the location, anytime and anywhere. Thus, breaking down geographic barriers and allowing for a seamless collaboration of all parties involved in the drilling process. The ability to monitor operations remotely leads to reduced personnel needed to carry out a job, hence reducing their risk exposure to wellsite red zones.

Therefore, the benefits of using high-quality, high-resolution, and real-time data from WDP could be significant. The capability to feed all the required data from L/MWD tools in real-time to more sophisticated models will enable new levels of accuracy and insight to be achieved. Numerous major drilling service providers have developed the infrastructure necessary and created highly intelligent networks where complex algorithms, artificial intelligence (AI), and machine learning are utilized to optimize downhole understanding and achieve a higher degree of drilling autonomy.

The future of drilling wells is automated. The use of WDP high-speed data transmission of downhole sensors (ASMs, L/MWD, and RSSs) in combination with data-driven models, machine learning, and AI enables taking full advantage of the latest developments within automation services. These services make use of all the data gathered from the downhole tools to continuously:

- Update the well trajectory based on many well projections that allow reducing the uncertainty of where the bit is located, thus reducing the risk of colliding with nearby wells (Halliburton, 2021a).

- Predictive steering allows to precisely steer to the target optimizing well placement (Schlumberger, 2021).

- Data-driven tendency analysis allows detecting changes in the downhole dynamics and environment making it possible to mitigate harmful vibration events, thereby improving ROP and extending the life of the bit (Baker Hughes, 2021).

- Optimal annular pressure management to avoid well control. The system is capable of adjusting surface parameters to stay within a safe operative pressure window.

Figure 27 Halliburton's LOGIX^{TM} automated drilling service dashboard (Halliburton, 2021a)

All the downhole data is not only sent to the autonomous drilling services but the data is also transmitted live to ROCs and to the visualization system of the drilling rig. Real-time wellbore monitoring by all the involved parties allows achieving increased efficiencies by close cooperation among different disciplines, thereby allowing to drill wells safer and faster.

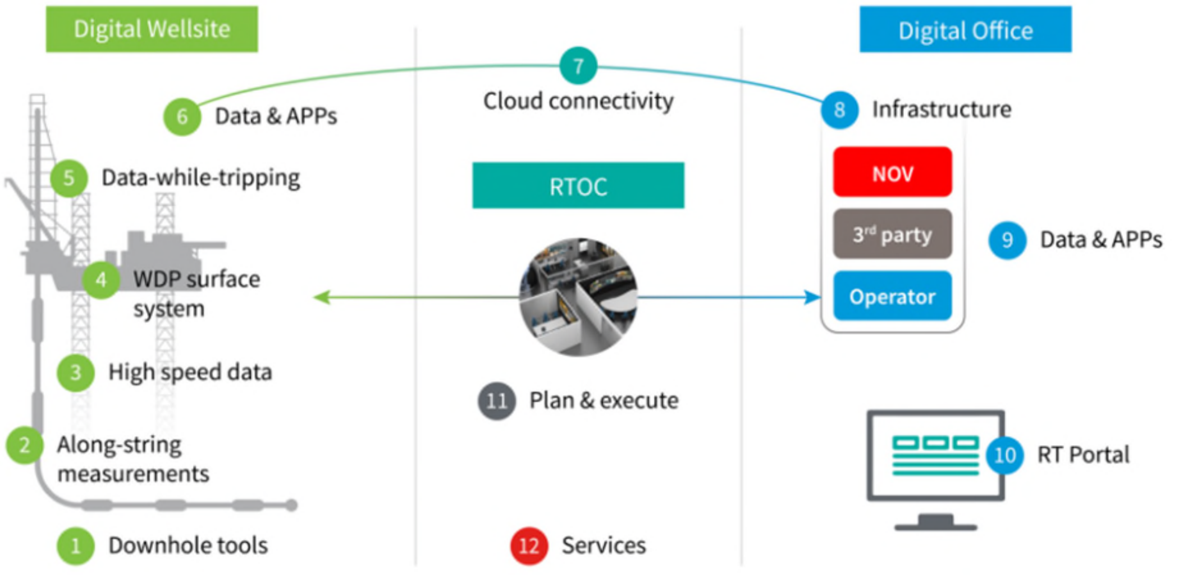

Figure 28 Wired drill pipe dataflow from downhole tools to ROCs, service providers, and operators (National Oilwell Varco, 2021b)

Conclusions

This study intended to present the benefits that wired drill pipe have over traditional mud-pulse telemetry. The high-speed, high-quality data transmission from downhole to the surface removes the constraints posed by mud-pulse relatively low data transmission rates. It has also enabled taking full advantage of the latest L/MWD tools and sensors. Moreover, the bi-directional communication capability that WDP offers allows for maintaining full directional control in real-time. Thus, making it possible to stay within the well path and optimize well placement.

It has been introduced and described new technologies that wired drill pipe allows to be deployed in the field. Along string measurements have enabled the possibility of gaining great understandings of the downhole environment. Pressure, temperature, and drilling dynamics data can be obtained along the string by placing measurement sensors, something that was previously only available a few meters behind the bit. This extra visibility allows real-time identification of well control events such as losses and influx, managing drilling dynamics effectively to avoid BHA failures, optimize hole cleaning. The development of the Data-While-Tripping assembly has made it possible to have full communication with downhole tools while running in the hole or out of the hole. This has finally opened up the ability to monitor the well to avoid damaging surge/swab pressures, thereby optimizing tripping operations. All this information reduces the uncertainties related to the downhole environment allowing decision-makers to make the right risk-informed decisions to mitigate the likelihood of an undesirable event. Thus, increasing safety in drilling operations.

Telemetry times have been compared for WDP and MPT where it can be concluded that the high data transmission rate of WDP enables operators to reduce the time required to drill a well. Further, WDP allows taking formation tests much faster, in real-time, and without flow whereas, MPT still relies on establishing a minimum flow rate for downhole tools to send the required data to the surface. Therefore, the use of WDP has made it possible to achieve new levels of drilling efficiencies.

As with any other new technology, WDP has a high investment cost due to the need to acquire all the wired components and make all the needed modifications to the drilling rig equipment. Also, reliability and handling are two areas where WDP can be further improved. Future cooperation between operators and service providers is vital to keep improving WDP. Even though WDP has a high investment cost, the advantages it provides make the investment worthwhile. It allows wells to be delivered faster, safer, and with improved hole quality. The time saved will result in an overall cost reduction of the drilling project. Future work could aim to get access to WDP cost figures to quantify the potential economic benefits. WDP costs will highly depend on the type and amount of equipment that a drilling project will require.

Finally, WDP represents a big step forward towards drilling automation. Future development of machine learning and artificial intelligence combined with the expansion of WDP infrastructure has the potential to introduce fully automated drilling services. Using WDP over time will keep providing all the benefits discussed herein. It will allow identifying new application areas where high-speed telemetry can add value, and it will keep improving to handle the challenges that the oil and gas industry may face in years to come.

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