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Author: Alan Achmatukaev	(Signature of author)

Faculty supervisor:
Bernt S. Aadnoy

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Abstract

This thesis will present relevant literature study, data quality assertion and performance evaluation and economic considerations based on field data from Valhall Flank West. The aim is to investigate, explain and suggest improvements for wells drilled in this field.

From the overall studies, the results showed that:

- Data quality is very poor despite the wells being drilled in the timeframe of 2019 – 2020, hence supporting the continued need and push for improved digitalization
- Bits of size 8.5 in. and 6.5 in. performed at a significantly lower ROP and significantly higher MSE and d-exponent than bits of bigger sizes, hence suggesting high droppage of drilling efficiency for the lower sections
- The existence of calcite stringer and geological effects on drilling
- Economic considerations and the importance of long bit runs for cost reductions

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List of abbreviations

DOC – Depth of cut

FWR – Final Well Report

IADC – The International Association of Drilling Contractors

K_f – Drillability factor

MD – Measure depth

MSE – Mechanical Specific Energy

NCS – Norwegian Continental Shelf

NPD – Norwegian Petroleum Directorate

ONGC – Oil and Natural Gas Corporation

PDC – Polycrystalline Diamond Compact

ROP – Rate of penetration

RPM – Rotation per minute

SPE – Society of Petroleum Engineers

T – Torque

TCI - Tungsten Carbide Inserts

TSP – Thermally Stable PDC

UCS – Unconsolidated Compressive Strength

WOB – Weight on bit

WR – Mechanical energy

List of symbols

A_B – Area of bit

d_b – Bit diameter

d_{exp} – d-exponent

d_t – Drilling time

m – Meter

m_c – Motor cost

r_r – Rig rate

t_t – Trip time

Δt_p – Sonic travel time

ρ_m = Mud weight

$ – Dollar

'' / in. = Inches

1 Introduction

This thesis presents a field case study of drill bit performance in Valhall Flank West. The Valhall Flank West field is chosen as it is a relatively new field drilled with modern bits and technology, margins for improvement are therefore theoretically slimmer and more relevant for future wells.

The primary objective of the work is to present the field data and determine trends and suggest improvement for the drilling performance, this is mainly done by analyzing the ROP and other drilling parameters. The different wells are compared, analyzed, and explained for the different observed behaviors. Additionally, an ideal well is constructed to illustrate the optimal performance in this field.

Furthermore, economic considerations are done to present cost savings.

1.1 Background

The petroleum industry is the world's largest provider of energy and is an important partner in the collaboration of reducing greenhouse gas emissions and subsequently meeting the long-term requirements set by the Paris Agreement. However, the industry seems to be facing challenges in the short-term too as low oil prices, an unstable political climate and the COVID-19 pandemic has resulted in a sharp decrease in revenues. Cost reductions and learning from past mistakes is therefore needed and highly relevant to remain competitive and maximize economic recovery [3], making optimalization of existing procedures and past field overviews an important prioritization.

One of the most important tasks in petroleum drilling is the selection, operation, and performance evaluation of drill bits. A drill bit is the tool that conducts the drilling and is located at the end of the drillstring. [4] A drill bit drills by scraping, chipping, gouging, and grinding the formation while drilling fluid is circulated through the bit to remove the cuttings and cool the bit. [4] The selection of a drill bit in an important decision and the choice will depend on the type of formation that is to be drilled and the drilling conditions during the procedure. The performance of the drill bit is a function of several operating parameters such as ROP, WOB, hydraulic efficiency and drill mud properties. It is therefore important control for these properties in order to choose the most appropriate bit for the formation that is to be drilled.

Petroleum drilling and production is a high cost operation with total costs exceed several million dollars. One major part of the costs associated with petroleum operations comes from drilling of wells. As more and more wells are being drilled in increasingly demanding geological locations with difficult conditions, the cost of drilling is set to increase in the near future. Furthermore, as the average Rig Day Rate (RDR) for an offshore rig lays between 100 000$ – 200 000$ per day [1], we clearly observe that there are economic benefits in optimizing drilling performance and reducing drilling time.

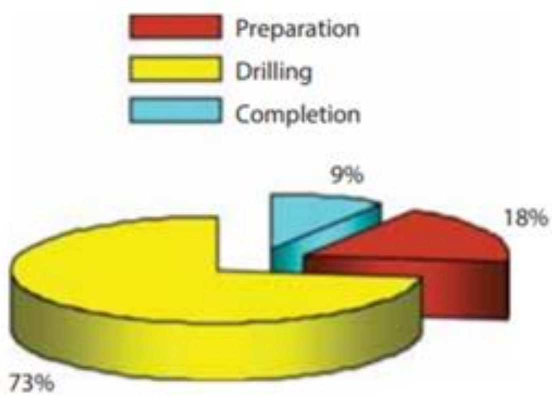

Figure 1.1: Breakdown of total drilling costs [2]

One way this is done is by analyzing past wells, ideally drilled close in proximity or in the same formations as this would provide the opportunity to learn from past runs and optimize for improve drilling efficiency which in turn could lead to cost reduction. This is tied in with the industry push towards digitalization and big data analytics as past data, experience and lessons learns is transformed into insights that can aid drilling today. Big data analytics is done by collecting, processing, cleaning, and analyzing data for the benefit of cost savings, product development and market insights [65], highly relevant procedures for the oil and gas industry.

1.2 Problem formulation and Research question

In the aforementioned, drilling operation is a high-cost factor for the oil and gas industry. Studies show that despite technological developments and new improved drilling methods, the non-productive time still accounts for over 25%. [66] For instance, among others, poorly designed drilling operation and wrongly selected drill bits results in undesired tripping operations, which indirectly increases non-productive time. As touched upon in the introduction, the interpretation of field data is of high importance and has a direct effect on future drilling in the same field and other fields in proximity. Therefore, this thesis will address the issue:

- How analysis and interpretation of field data will add value in optimizing bit performance in order to reduce tripping operation and hence have a positive impact on project economy

1.3 Scope and Objective

The objective of this thesis is to answer the issues addressed in section 1.2 as well as:

- Conduct literature study on drill bits and ROP models and methods
- Analyze the geology and drilling data of Valhall Flank West in order to evaluate the performance evaluation. Moreover, investigate the correlations among the drilling and formation strength parameters along with bit dull evaluation
- Select and construct an ideal well and compare with other wells in terms of the ROP, drilling cost and drilling per footage
- Finally, based on the analysis present a methodology on how to optimize drill bit with regards to improving performance and economic considerations

1.4 Research method

The methodology of this thesis is categorized into three main parts as shown in figure 1.2. The first part introduces the relevant literature study on drill bits; different types, classifications, and dull grading. The second part deals with the theory regarding drilling dysfunctions and the different processes associated with this. Furthermore, methods for performance evaluation are explored and discussed.

Using the subsequent literature and theory studies, the third part deals with field data from the Valhall Flank West field which is interpreted for performance evaluation and economic considerations.

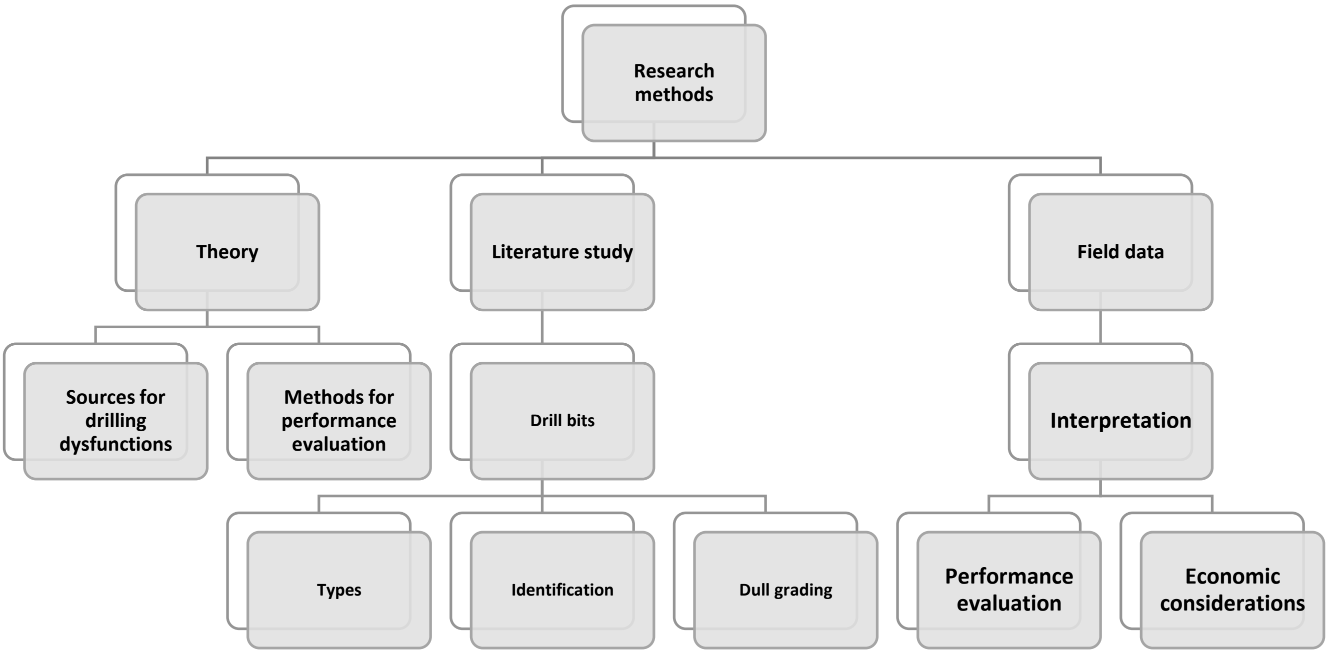

Figure 1.2: Outline of research methods employed

2 Literature study

The chapter presents the literature study of drill bits and the different aspects related to bits such as bit dulling standards.

2.1 Drill bits

Drilling operations mainly require two major components, manpower and hardware systems. Manpower encompasses operational work and support for optimal drilling by rig selection, mud design, choice of casing and cementation, etc. The hardware on the other hand encompasses those elements that make up the rotary rig, which are

1. Power generation system
2. Hoisting system
3. Drilling fluid circulation system
4. Rotary system
5. Blowout control systems
6. Drilling data acquisition and monitoring system

The drilling process is illustrated in figure 2.1.

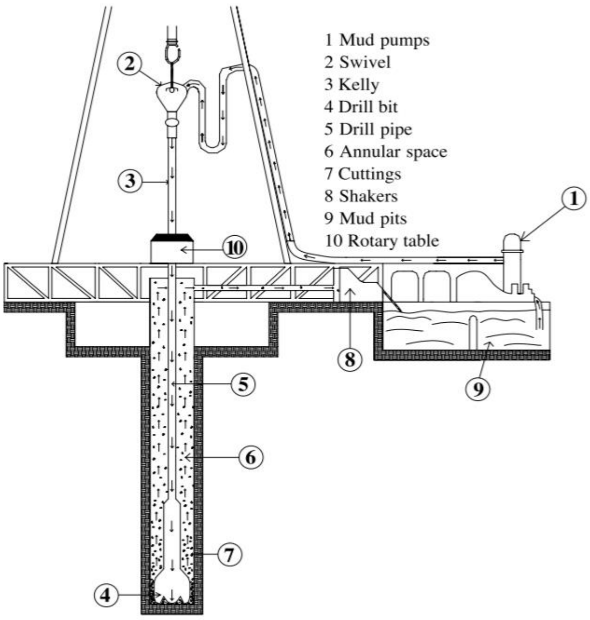

Figure 2.1: Scheme of the drilling process [36]

Whether drilling a vertical hole or a directional hole, several elements are needed in order to drill as successfully and as economically as viable. One of the most fundamental processes here is the selection, operation, and the performance evaluation of the drill bit. The drill bit is the main tool in the drilling process, positioned at the end of the drillstring. It operates by applying a force acting downwards on the drill bit while it applies drilling action by grinding the formation rock, resulting in penetration of the formation. [4] Simultaneously, drilling fluid circulates through the bit to decrease bit wear by cooling, and to help the penetration rate by removing cuttings

The choice of drill bit is important in order to identify the lowest drilling cost, performance efficiency and for the safety of the drilling operation. There is a great selection of bits available, however, these can roughly be categories as either roller-cone bits or fixed-cutter bits.

2.1.1 Bit types

Rotary drilling mainly uses two categories of drill bits, roller-cone bits, and fixed-cutter bits, with various subcategories under these two. [4] Roller-cone bits have one or more cones which contain cutting elements that rotate about the axis of the cone as the bit is rotated at the bottom of the well. Two subcategories of roller-cone bits are milled-tooth bits and insert-bits. Fixed-cutter bits, including the two subcategories polycrystalline bits and diamond bits, can drill in an extensive array of formations at various depths. These types of bits rotate as a single unit and consist of fixed blades integrated with the body of the bit. The various bit types are displayed in figure 2.2.

As earlier stated, the choice of drill bit is important and must be considered taking formation data, historic data, and the various drilling parameters into consideration. This is so as the correct choice of drill bit is important in cost reductions and effective drilling. It is not uncommon to use different bit types within the same well as formation characteristic might vary significantly, thus, the selection process is important.

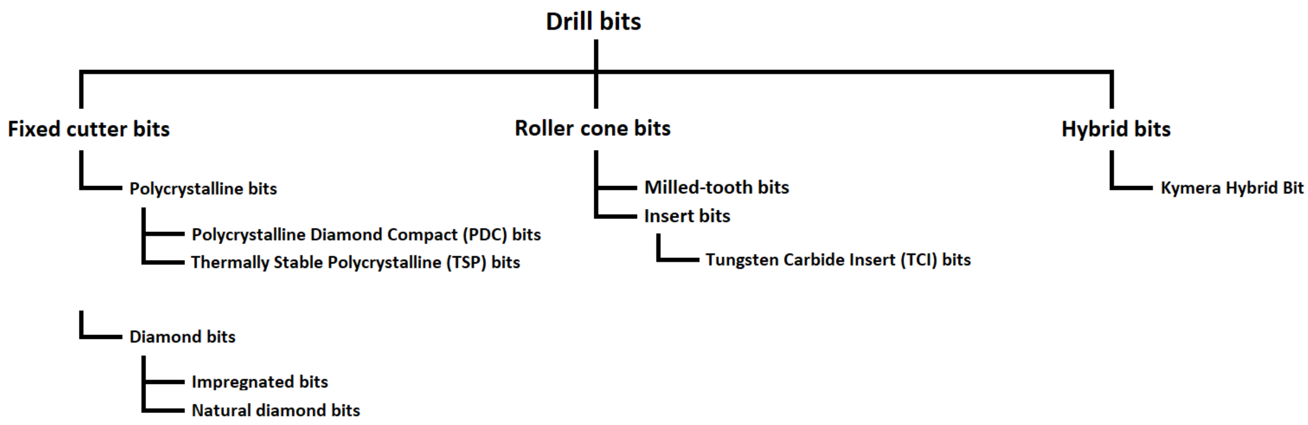

Figure 2.2: Bit types and subcategories

2.1.1.1 Roller-cone bits

Roller-cone drill bits are one of the most commonly used type of rotary drill bits and have since its inception in the beginning of the 20th century undergone several improvements. [25] This bit type is accessible with a wide range of tooth design and bearing types, thus making it highly suitable for drilling in various types of rock formations. These bits can handle rougher drilling conditions than its counterpart, fixed-cutter bits, and are generally less expensive, making them highly suitable.

A roller-cone drill bit consists of mainly three major components, cone cutters, the bearings, and the bit body. The bit has one or more cones containing cutting elements, which are referred to as inserts. The inserts are circumferential rows of teeth expanding from each individual cone that collaborate and fit into the teeth from adjacent cones. The cones are fixed on bearings which rotate about the axis of the cone as the bit is rotated at the bottom of the hole. [4] Their design features consist of: [5]

- Conventional jet and extended jet bits
- Roller, sealed and journal bearings
- Gauge protection
- Small to large diameter
- Application in soft to very hard formations

Roller-cone bits are classified as milled-tooth or insert, which are portrayed in figure 2.3. Milled-tooth bits, also known as steel tooth bits, are typically used for drilling relatively soft formations [26] and the cutting structure is milled from the steel making up the cone. Milled-tooth drill bits are very robust and will tolerate severe drilling conditions, however, they wear relatively quickly. [24] Insert bits, most commonly known by the newer Tungsten Carbide Inserts (TCI) bit, are used in a wider range of formations, including for the hardest and most abrasive formations. The cutting structure consists of a series of inserts pressed into the cone. These bits are generally more expensive to operate, however, they can drill a long distance before wearing out, albeit, not being able to tolerate shock loadings. [24]

Figure 2.3: Different roller-cone bit types (from left to right: milled-tooth bit and insert bit) [26]

Roller-cone bits bodies and cones are forged from a nickel-chrome-molybdenum steel alloy which requires sufficient hardenability, yield strength, heat treatment and impact resistance. Nozzles and the tungsten carbide insert teeth are made of sintered tungsten carbide. Design of the bit has generally four focus areas: geometry and type of cutting structure, hydraulic requirements, material selection and mechanical operating requirements. [27] The bit design is chosen based on how it will operate and in what conditions it will operate in. Formation is an important operational condition to take into consideration and because formations are not homogenous, sizable variations exists in their drillability and this might have a significant effect on the cutting-structure geometry. For a given WOB, cones with a rounded profile and wide spacing between the inserts provides a faster ROP, however, these bits are more labile. Cones with a flat profile and closely spaced inserts are more durable, however, this design delivers a reduce ROP. Thus, we have that various aspects are interrelated, this is displayed in table 2.1.

Formation Characteristics	Insert/Tooth Spacing	Insert/Tooth Properties	Penetration and Cuttings Generation	Cleaning Flow-Rate Requirements
Soft	Wide	Long and sharp		
Medium	Relatively wide	Shorter and stubbier	Relatively high	Relatively high
High	Close	Short and rounded	Relatively low	Relatively low

Table 2.1: Relationship between inserts, teeth, cuttings-production rate, hydraulic requirements, and the formations [4]

2.1.1.2 Fixed-cutter bits

Fixed-cutter bits can be categorized into polycrystalline bits and diamond bits, both categories consisting of different bit types. Drag bits are also a category of drill bits, however, drag bits are rarely used in the industry today. Fixed-cutter bits does not have any moving parts, which is a positive as it makes it possible to drill for a longer time and makes drilling with small hole sizes easier as space is not available for the cone/bearing systems with proper teeth structure. [4] The system of these drill bits is composed of: [23]

- Body material
- Cutter density
- Cutter size or type
- Bit profile

2.1.1.2.1 Diamond bits

Diamond bits first became popular in the oil and gas industry in the late 1940s and have been a subject to improvements over time. These bits essentially work by scraping industrial grade diamonds against the formation, breaking and scraping away the rocks. Diamonds are used as the cutting element as it is the hardest and most abrasive resistant material with high compressive strength and high thermal conductivity.

For natural diamonds, we have impregnated and natural diamond bits:

Impregnated bits are a PDC bit type at which the diamond cutting elements are imbedded within the PDC bit body matrix. [28] Natural and synthetic diamonds are prone to breakage from impact, thus, for impregnated bits the diamonds are supported to the greatest extent possible and are therefore less susceptible to breakage. [4] Since the largest diamonds are relatively small, cut depth must be small and ROP is sustained by high rotation speed.

In the past, impregnated bits were limited to drilling hard formations with high-speed turbines, however, the range of applications have over time expanded, making impregnated bits capable of drilling many types of formations. [29]

For cutting and gauge protection, impregnated bits use combinations of: [28]

- PDC
- Natural diamond
- Synthetic diamond
- TSP

Natural diamond bits consist of a solid steel head impregnated with surface-set natural diamonds as cutters. There are mainly two design variables of diamonds bits, the crown profile, and the face layout. The crown profile dictates the type of formation the bit is suited for. The following profiles are dictated for the various formations: [11]

- Round crown profile – Hard to extremely hard formations

- Parabolic crown profile – Medium to hard formations
- Tapered and flat crown – Soft formations, for fracturing formations, sidetracks and kick-offs

Natural diamond bits drill by high-speed plowing action that breaks cementation between rock grains by scraping away the rock. To achieve a sustainable ROP, diamond bits must be rotated at high speeds. Despite high wear resistance, it must be taken into consideration that diamonds are sensitive to shocks and vibrations. Thus, effective fluid circulation to prevent overheating of the diamonds and the matrix material to prevent bit balling is needed.

2.1.1.2.2 Polycrystalline bits

Polycrystalline drill bits use synthetic polycrystalline diamond elements as the cutting media. These bit crowns consist of a wear resistant tough matrix body that includes natural diamond gauge protection. [31]

In soft formations, polycrystalline bits are capable of very high ROP compared to diamond bits because of the high degree of cutter exposure. Polycrystalline drill bits are categorized into TSP and PDC.

Thermally Stable Polycrystalline (TSP) bits are produced with small triangular or cubic shaped cutters that are composed of synthetic diamond particles with semi-round crown profile with either an internal discharge type or face-discharge type waterway configurations. [30] These diamond elements are permanently embedded in a wear resistant, tough metal matrix body that is fused to a steel tool body and is resistant to thermally induced diamond lattice breakout. [5]

One main application of these bits is wearing protection on the gage of the bit, the other main application being its thermal resistance. [32] While PDC bits wear rate increases exponentially above 372 °C (700 °F) and fails structurally at 750 °C, TSP bits maintain a constant wear rate up to 1200 °C (2192 °F) and are able to withstand drilling impact forces. Due to the increased thermal resistance, TSP bits can be used to drill soft to medium hard abrasive formations.

TSP cutters are generally not economically viable due to low ROP with small sizes and insufficient fracture resistance for most applications. [33] However, it has seen a resurgence in recent years as new brazing methods have improved the fracture resistance and attachment shear strength, resulting in reduced well costs.

Polycrystalline Diamond Compact (PDC) bits use small disks of synthetic diamonds to provide the cutting surface. This bit does not consist of any moving parts such as bearings and cones which make them more reliable and is designed to break the rock in shear and not in compression as is the case with roller-cone bits. Furthermore, it requires less energy to operate and thus, a lower WOB is necessary for efficient drilling. It is used in drilling a variety of different formations due to its long lifespan, good impact resistance and high efficiency. A PDC bit is designed based on four considerations:

- Materials
- Formation properties
- Hydraulic conditions
- Mechanical parameters

PDC bits commonly fall into two types, steel-body type, and matrix type. The steel-body type has the polycrystalline diamond composite sheet welded onto the steel body, incorporating diamond compacts on tungsten carbide posts. The steel-body type’s cutters are secured to the bit body by interference fitting and shrink fitting. It also consists of three or more carbide nozzles and buttons on the gauge. Steel-body bits have limitations of erosion of the bit face and wear of gauge section, however, newer technology has increased its wear-resistance.

The matrix types are cast in a moldlike natural diamond bit, thus, offering greater bit design freedom. [11] These bits have more complex profiles and incorporate cast nozzles and waterways. The matrix type bits have an advantage regarding bit face configuration, erosion resistance and contains natural diamonds to maintain full gage hole. However, cost effectiveness needs to be taken into consideration when deploying these bits.

Generally, the PDC bit design varies according to formation strength. Bits used for soft formations has huge junk slots for removing large amounts of cuttings. For hard formations the bit is equipped with many small cutter and smaller junk slots. PDC bits can be used for drilling soft to medium rock formations, the variety of the bits are displayed in figure 2.4.

Figure 2.4: PDC bit design for varying formation hardness (from soft (A) to hard (D)) [35]

2.1.1.3 Hybrid bits

The onslaught of improvements in production and technology has rendered new hybrid bits which technology is the combination of multiple drill bit designs. Significant advances have been made in PDC-cutter technology and fixed-blade PDC bits have replaced roller-cone bits in various drilling operations. [4] Roller-cone bits on the other hand still retains its usage when drilling hard, abrasive and interbedded formation, for complex directional drilling applications or generally when the torque requirements of a conventional PDC bit exceed the capabilities of the given drilling system. Thus, the hybrid bit can act as an intermediary.

The concept of hybrid bits has existed as early as back to the 1930s, however, the development has only been feasible with recent advances in PDC cutter technology. In modern hybrid bits, the intermittent crushing of a roller-cone bit is combined with the shearing and scarping of a fixed-cutter bit. [4] It can therefore drill very hard and abrasive formations and presents significant advantages over conventional drill bits such as reduced tripping time for changing bits, improved ROP and increased durability. [37]

There are several hybrid bit designs, a two-cone, two-bladed version for smaller diameter bits and a larger three-cone, three-bladed version for larger diameters are most common. [38] However, the recent development of the Kymera Hybrid Bit from Baker Hughes has shown to be a more than viable competitor to convention drill bits.

Kymera Hybrid Bit design is the combination of a roller-cone and PDC bit. It is based on a four-bladed and six-bladed advanced PDC cutter where the secondary blades have been replaced with a TCI rolling cone. [39] The intention is to combine the diamond shearing and roller-cone crushing of the formation and is mainly designed for:

- Roller-cone application limited by ROP
- Torque and WOB limited large diameter applications
- Highly interbedded formations

Figure 2.5: 2-cone, 2-blade hybrid and 3-cone, 3-bladed hybrid [38]

2.2 The International Association of Drilling Contractors (IADC)

Numerous different designs are available for drill bits from various manufactures. The drill bit is designed for optimum performance in various formation types and the manufacturers have their own classification systems for their bits. This necessitated the need of a unified system to avoid confusion and enable better decision making. In 1987, IADC initiated the use of a four-character system for the classification of drill bits. This is still the standard today, however, the system has been expanded to include more features. [22]

The IADC classifies drill bits according to their design characteristics and their application. It differentiates between roller-cone bits and fixed-cutter bits. Rotary drilling bits are classified into these types:

1. Roller rock bits (milled tooth bits) – Roller-cone bits
2. Tungsten carbide insert roller bits – Roller-cone bits
3. Diamond bits and core bits – Fixed-cutter bits
4. Polycrystalline diamond compacts (PDC) bits – Fixed-cutter bits

Although the system might suggest which bit to use in what formation and whose bit is better, it should be noted that it is only by trial-and-error by the individual operator the most optimal bit is selected as many different factors affect optimal bit performance. [11]

2.2.1 Roller-Cone-Bit Classification

The IADC roller-cone-bit classification method is the industry standard for the description of milled-tooth and insert-type roller-cone bits. The system is a four-character design and application-related code.

				Design Features								
	Series	Formations	Types	Standard Roller Bearing (1)	Roller Bearing, Air (2)	Roller Bearing, Gage Protected (3)	Sealed Roller Bearing (4)	Sealed Roller Bearing, Gage Protected (5)	Sealed Friction Bearing (6)	Sealed Friction Bearing, Gage Protected (7)	Directional (8)	Other (9)
Milled-Tooth Bits	1	Soft formations with low compressive strength and high drillability	1									
			2									
			3									
			4									
	2	Medium to medium-hard formations with high compressive strength	1									
			2									
			3									
			4									
	3	Hard semi-abrasive and abrasive formations	1									
			2									
			3									
			4									
Insert Bits	4	Soft formations with low compressive strength and high drillability	1									
			2									
			3									
			4									
	5	Soft to medium formations with low compressive strength	1									
			2									
			3									
			4									
	6	Medium-hard formations with high compressive strength	1									
			2									
			3									
			4									
	7	Hard semi-abrasive and abrasive formations	1									
			2									
			3									
			4									
	8	Extremely hard and abrasive formations	1									
			2									
			3									
			4									

Figure 2.6: Roller-cone drill bit IADC classification table [4]

The first digit refers to bit series, the second to the bit type, the third to bearings and gauge arrangement, and the fourth alphabetic character to bit features. The classification is portrayed in figure 2.6. [4]

The different bits are categorized after general formation characteristics and bit properties. Series 1 through 3 apply to milled-tooth bits and series 4 through 8 apply to insert-type bits. The higher the series number is the harder or more abrasive the rock type is.

The second digit is a subdivision of hardness of the different classes defined by the first digit. Rock hardness is not clearly defined by the IADC system and the classification of "soft", "medium" and "hard" are subjective and could therefore lead to misunderstanding. Generally, when it comes to rock hardness, we have that: [4]

- Soft formations: Unconsolidated clays and sands
  - Drilled with a relatively low WOB (3000 – 5000 lbf/in) and high RPM (125 – 250 rev/min)
  - High ROPs are expected, and recommended flow rates are 500 – 800 gal/min to clean the hole effectively

- Medium formations: Shales, gypsum, sand and siltstone
  - Drilled with low WOB (3000 – 6000 lbf/in) and medium RPM (100 – 150 rev/min)
  - High flow rates are recommended for sufficient hole cleaning

- Hard formations: Limestone, anhydrite, hard sandstone and dolomite
  - Drilled with high WOB (6000 – 10 000 lbf/in) and low RPM (40 – 100 rev/min)
  - Flow rates are not as critical as in relatively softer formations

The third IADC character relates to design features such as bearing system or gouge protection. The nine different categories are: [4]

1: Non-sealed roller bearing (also known as open-bearing bits)

2: Air-cooled roller bearing (designed for air-, foam-, or mist-drilling applications)

3: Non-sealed roller bearing, gauge protected

4: Sealed roller bearing

5: Sealed roller bearing, gauge protected

6: Sealed friction bearing

7: Sealed friction bearing, gauge protected

8: Directional

9: Other

The fourth character used in the system defines the available features, this alphabetic character is not always recorded on bit records but can be used withing the bit manufacturers’ records. The different categories are: [4]

A: Air application

B: Special bearing seal

C: Center jet

D: Deviation control

E: Extended reach

F:

G: Extra gauge/body protection

H: Horizontal/steering application

I:

J: Jet deflection

K:

L: Lug pads

M: Motor application

N:

O:

P:

Q:

R:

S: Standard steel tooth model

T: Two-cone bits

U:

V:

W: Enhanced cuttings structure

X: Chisel insert

Y: Conical insert

Z: Other insert shape

2.2.2 Fixed-Cutter-Bit Classification

A large variety of fixed-cutter bit designs are available from several different manufacturers, the IADC classification standards stem from Winters and Doiron (1987) and uses a four-character code classification system. This classification includes rock properties, structural peculiarities and also takes special cases of application of drilling tools into consideration. The classification is seen in figure 2.7. [4]

			Bit Type	Design Feature								
			Drill bit	Step Type	Long Taper	Short Taper	Nontaper	Downhole Motor	Sidetrack	Oil Base	Core Ejector	Other
Formation	IADC Series Number		Core bit	Conventional Core Barrel	Face Discharge							
				1	2	3	4	5	6	7	8	9
Soft	1	0										
		1										
		2										
		3										
		4										
Medium Soft	2	0										
		1										
		2										
		3										
		4										
Medium	3	0										
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		2										
		3										
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Medium Hard	4	0										
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Hard	5	0										
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		3										
		4										
Very Hard	6	0										
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		2										
		3										
		4										
Soft	7	0										
		1										
		2										
		3										
		4										
Medium	8	0										
		1										
		2										
		3										
		4										
Hard	9	0										
		1										
		2										
		3										
		4										

Figure 2.7: Fixed-cutter drill bit IADC classification table [4]

The first letter of the fixed-cutter-classification code describes the primary cutter type and the body material. We have:

D: Natural diamond / matrix body

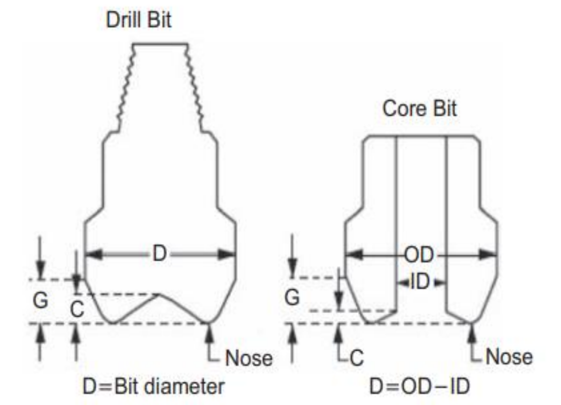
M: PDC / matrix body

S: PDC / steel body

T: TSP / matrix body

O: Other

The second letter refers to the drill bit's cross-sectional profile. The term describes the cross section of the cutter/bottomhole pattern and is defined because the cutter/bottomhole profile is not necessarily identical to the bit-body profile. The nine basic bit profiles are defined by arranging gauge height and cone height in a 3x3 matrix. This is shown is figure 2.8.



G—Gauge Height	C—Cone Height		
	High C>1/4D	Medium 1/8D≤C≤1/4D	Low C>1/8D
High G > 3/8D	1	2	3
Med 1/8 ≤ G ≤ 3/8D	4	5	6
Low G < 1/8D	7	8	9

Figure 2.8: IADC fixed-cutter-bit classifications, second character: a) Bit profile codes [4]

We therefore have these nine profiles:

1: G high, C high

2: G high, C medium

3: G high, C low

4: G medium, C high

5: G medium, C medium

6: G medium, C low

7: G low, C high

8: G low, C medium

9: G low, C low

The criteria are provided to provide functional division between the different bit designs. Figure 2.9 provides a visual reference which is used by field personnel to differential the different drill bits. It should also be noted that 0 is used for unusual bit profiles that cannot be profiled by the 3x3 matrix depicted in figure 2.10.

The numbers 1 to 9 for the third character define the bit hydraulic. The hydraulic design is described by the type of fluid outlet and the flow distribution. The numbers adhere to:

1: Changeable jets, bladed

2: Fixed ports, bladed

3: Open throat, bladed

4: Changeable jets, ribbed

5: Fixed ports, ribbed

6: Open throat, ribbed

7: Changeable jets, open faced

8: Fixed ports, open face

9: Open throat, open face

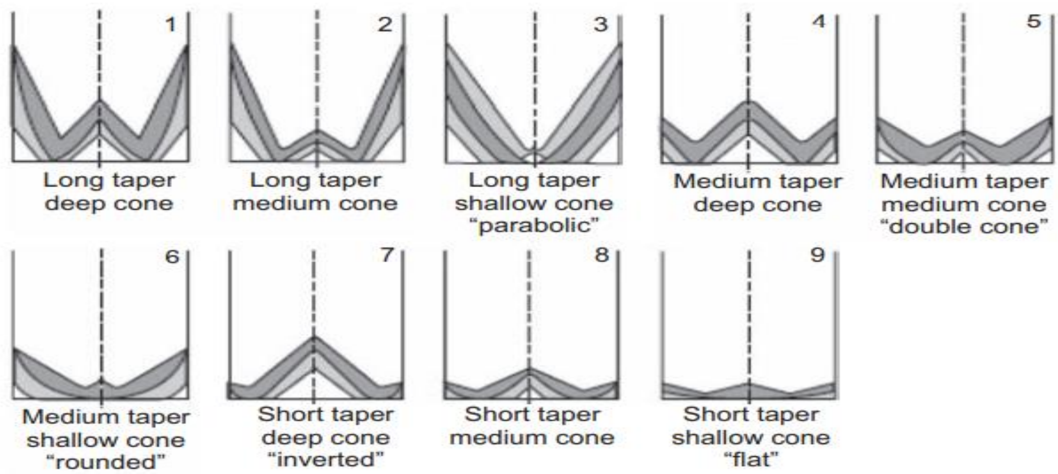


Figure 2.9: IADC fixed-cutter-bit classifications, second character: b) bit profiles [4]

A special case is that the letters R (mud channels arranged radially), X (mud channels positioned transversely) and O (other) can be used for the numbers 6 and 9. This is so because these two numbers describe the crowfoot/water-course design of most natural-diamond and many TSP bits. As these bits may have either radial flow, crossflow or other hydraulics, the letters are used as the hydraulic design code for such bits.

The last character of the fixed-cutter-classification code refer to the cutter size and placement density on the drill bit. The placement density varies from light to heavy while the cutter size varies from large to small. [4]

Generally, bits with minimal cutter redundancy are classified as having a light placement density. Contrary, bits with high cutter redundancy are classified as having heavy placement density.

The cutter density is determined by the manufacturer and often comes as “light-set” and “heavy-set” versions of a standard product.

	Density		
Size	Light	Medium	Heavy
Large	1	2	3
Medium	4	5	6
Small	7	8	9

O—Impregnated

Cutter size ranges	Natural diamonds stones/carat	Natural diamonds usable cutter height
Large	<3	>⅝ in.
Medium	3–7	⅜–⅝ in.
Small	>7	⅜ in.

Figure 2.10: IADC fixed-cutter-bit classification, fourth character – cutter size and density [4]

2.2.3 IADC Bit Dull-Grading System

As the drill bit grinds against formation rocks it will experience fatigue and wear in its structural integrity, resulting in reduced drilling parameters and a subsequent drop in drilling efficiency. IADC and SPE has therefore established a system, called dull grading, for communicating bit failure. The intent of the system is to facilitate and accelerate product and operation development based on recording bit performance. [23]

Dull grading and drill bit performance evaluation is an important aspect as it aids in bit-design and production operation efficiency improvement. This is so as successful design features can be reapplied and improved further upon while unsuccessful features can be corrected. Drill bit manufacturers therefore require the collection of dull information for every bit run. [4]

The IADC dull grading system is closely associated with its bit classification system and generally differentials between fixed-cutter and roller-cone bit dull grading. IADC dull grading reviews four general bit-wear categories: cutting structure (T), bearings/seals (B), gauge (G) and remarks (O & R). The general IADC dull grading system is portrayed in table 2.2.

Cutting Structure				Bearings/Seals	Gauge	Other Dull Char	Reason Pulled
Inner	Outer	Dull Char.	Location				
1	2	3	4	5	6	7	8

Table 2.2: IADC Dull Bit Grading System [11]

2.2.3.1 Dull Grading for Roller-Cone Bits

For roller-cone bits, cutting structure or tooth wear (T) is estimated in $\left(\frac{1}{8}\right)$ of the initial tooth height. Dull grading is evaluated on wear on the inner rows of inserts/teeth and outer rows of inserts/teeth that touch the wall of the hole. Since tooth wear is rarely uniform, several readings are taken in order to report an average figure. [11] We have the following report for tooth wear:

Tooth Dullness	**Milled Tooth**	**Insert Bits**
T1	Tooth height ⅛ gone	⅛ of inserts lost or broken
T2	Tooth height ¼ gone	¼ of inserts lost or broken
T3	Tooth height ⅜ gone	⅜ of inserts lost or broken
T4	Tooth height ½ gone	½ of inserts lost or broken
T5	Tooth height ⅝ gone	⅝ of inserts lost or broken
T6	Tooth height ¾ gone	¾ of inserts lost or broken
T7	Tooth height ⅞ gone	⅞ of inserts lost or broken
T8	Tooth height all gone	All of inserts lost or broken

Table 2.3: Tooth wear for roller-cone bits [11]

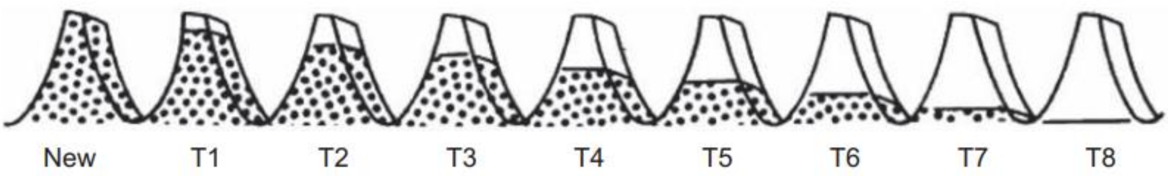


Figure 2.11: Roller-cone teeth-wear schematic view [4]

The second classification in the dull grade assessment of roller-cone bits is the assessment of the bearing (B). The measurement of the bearing wear is subjective as a detailed field evaluation of exact bearing wear would only be possible if the bit is disassembled to examine the condition. Field evaluations therefore often only reveal whether the bearings have failed or are still intact. However, in order to get a closer estimate, it is necessary to estimate the rotating hours left by knowing the rotating hours of the bit at the bottom of the well and from this estimated in eights the life of the bearings. We thus have:

Bearing Condition		
B1	Bearing life used:	⅛
B2	Bearing life used:	¼ (tight)
B3	Bearing life used:	⅜
B4	Bearing life used:	½ (medium)
B5	Bearing life used:	⅝
B6	Bearing life used:	¾ (loose)
B7	Bearing life used:	⅞
B8	Bearing life all gone:	(Locked or lost)

Table 2.4: Bearing condition schematic [11]

The gauge (G) category for the dull-bit-grading system is used to report the undergauge condition for cutting elements intended to touch the wall of the hole. [4] For roller-cone bits the “two-thirds rule” is applied to measure the gauge condition. This means that the amount out of gauge is multiplied by 2/3 to give the true gauge condition. In the IADC system, a bit pulled out of the hole that is in gage is reported by the letter “I”. When the bit pulled out of the hole is out of gage, the amount of gage wear is reported in increments of 1/16 inches. This gives:

Gauge report	
1	1/16 in. undergauge
2	1/8 in. undergauge
3	3/16 in. undergauge
4	1/4 in. undergauge

Table 2.5: Gauge report for roller-cone bits [4]

It should be noted that the gauge wear is rounded to the nearest 1/16 in and that the gauge rules apply to cutting-structure elements only.

The section referred to as "remarks" allows further explanation of other dull characteristics and reason pulled, for reporting of characteristics that does not correctly fit into the other categories. Other dull characteristics (O) may be used to report other forms of dulling not reported in cutting structure (T), secondary bit wear is reported under (O) as well. Reasons pulled (R) simply reports the reason for why for why a bit was pulled. The list of codes is portrayed in figure 2.12.

Hence, dull grading of roller-cone bits is done with taking the aforementioned general bit-wear categories of cutting structure (T), bearings/seals (B), gauge (G) and remarks (O & R). It gives a coherent system that is reported after every pulled bit.

REASON PULLED	
BHA	Change bottomhole assembly
DMF	Downhole motor failure
DTF	Downhole tool failure
DSF	Downhole string failure
DST	Drillstem test
LOG	Run logs
LIH	Left in hole
RIG	Rig repair
CM	Condition mud
CP	Core point
DP	Drill plug
FM	Formation change
HP	Hours on bit
PP	Pump pressure
PR	Penetration rate
TD	Total depth/casing depth
TQ	Torque
TW	Twistoff
WC	Weather conditions

Figure 2.12: Reason pulled [4]

2.2.3.2 Dull Grading for Fixed-Cutter Bits

The system of dull grading fixed-cutter bits is comparable to the system for the roller-cone bits. Similarly, the condition of the cutting structure (T), bearings/seals (B), gauge (G) and remarks (O & R) are taken into consideration.

Assessing the cutting structure (T), the amount of cutting structure wear is recorded using a linear scale from 0 to 8 based on the initial useable cutter height. In this scheme 0 represents no wear while 8 represents that no usable cutting surface remains. The wear is measured across the diamond table regardless of the cutter shape, size, type or exposure. [4] Subsequently, the location of the cutter wear is categorized as either at the inner 2/3 or outer 1/3 of the bit radius. This and the schematics of cutters wear is displayed in figure 2.13.

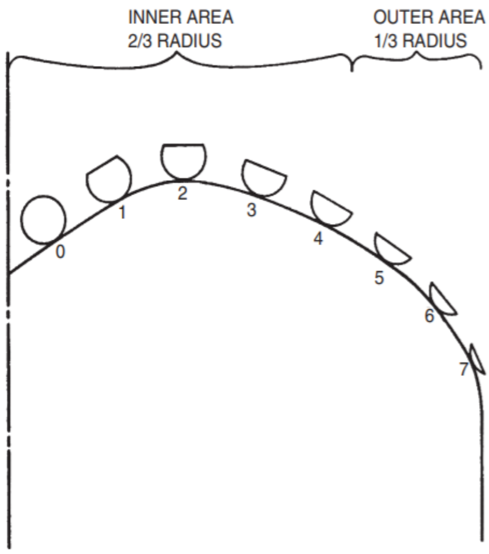


Figure 2.13: Schematics of cutters wear [11]

When grading the dull bit, the average amount of wear in each area should be recorded. To obtain the average wear for the inner rows of cutter, the individual cutters within the inner 2/3 radius must be individually graded, summed and the average obtained in order to deduce the inner-row wear grade. The same approach is done for finding the average wear for the outer area of cutters. Thus, both the inner and outer dull in cutting structure is defined. Other than this, the cutting-structure dull characteristic is reported for the most likely characteristic to limit the further use of the drill bit of its intended application. The grading codes for the dull characteristics is displayed in figure 2.14.

The location of the major dull characteristic is also of importance and is also noted under cutting structure (T). Although it is agreed upon that there are areas in which the profile boundaries are not fully clear, however, figure 2.15 shows the general areas that are reported.

The reporting of bearing and seal grading only applies to roller-cone bits because there are no bearings for fixed-cutter bits, it will therefore be marked “X”.

Bit gauge is recorded in a matter similar to roller-cone bits for fixed-cutter bits. If the bit is still in gauge “I” is reported. Otherwise, the amount of the bit that is undergauge is noted to the nearest 1/16 of an inch. For diamond and PDC bits, gauge is measured with a nominal ring gauge. [4] The gauge report is displayed in figure 2.16.

DULL CHARACTERISTICS	
BC	Broken cone
BF	Bond failure
BT	Broken teeth
BU	Balled-up bit
CC	Cracked cone
CD	Cone dragged
CI	Cone interference
CR	Cored
CT	Chipped teeth/cutter
ER	Erosion
FC	Flat crested wear
HC	Heat checking
JD	Junk damage
LC	Lost cone
LN	Lost nozzle
LT	Lost teeth
NR	Not rerunnable (fixed cutter)
OC	Off-center wear
PB	Pinched bit
PN	Plugged nozzle/flow package
RG	Rounded gauge
RO	Ring out
RR	Rerunnable (fixed cutter)
SD	Shirttail damage
SS	Self-sharpening wear
TR	Tracking
WO	Washed-out bit
WT	Worn teeth/cutters
NO	No dull characteristics

Figure 2.14: Dull characteristics [4]

The remarks are also reported in a manner similar to dull grading of roller-cone bits. Other dull characteristics (O) describes other forms of dulling or aspects that can be additionally reported while reasons pulled (R) states the reason the particular bit was pulled. The different codes are displayed in figure 2.12.

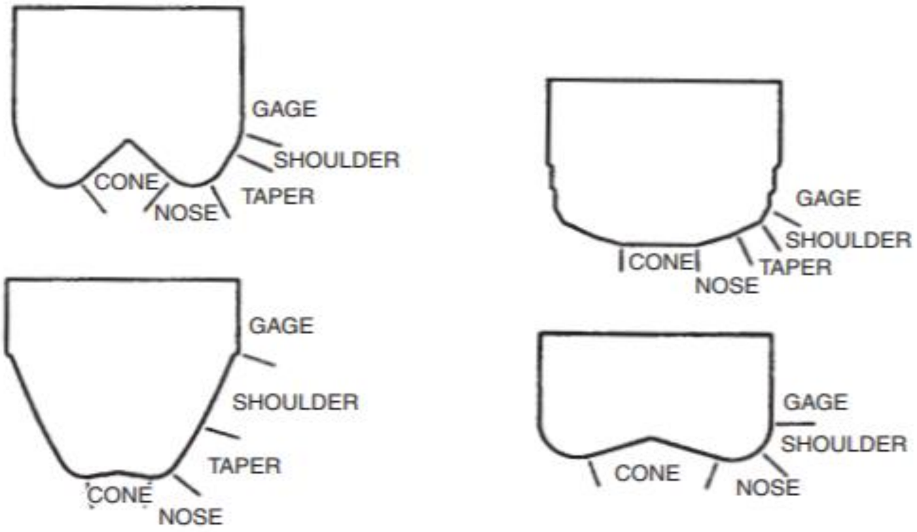


Figure 2.15: Location of wear on fixed-cutter bit [11]

2.3 Economic Considerations:

This section deals with assumptions made regarding costs of prices of different aspect.

2.3.1 Financial Assumption:

Economic considerations are made in regard to the costs associated with common drilling practices, providing a base line for comparisons relative to future wells.

Following assumptions are made for the rates of the equipment and processes: [6, 25, 50]

- Rig rate: 145 000 $ / day
- Motor cost: 475 $ / hr
- Trip time: 300 m / hr
- Bit prices: Tricone: 60 000 $
  Kymera: 60 000 $
  PDC: 50 000 $

3 Theory

The chapter reviews the crucial theory, reasons for and calculations related to drill bit performance evaluation and optimalization.

3.1 ROP modelling

The objective of drilling optimalization is the establishment of efficient drilling operation ultimately leading to reduced non-productive time consumption and costs. However, this is usually a difficult process as many different factors and parameters are present, limiting increase of ROP.

Different mathematical models are proposed in an effort to describe the relationship between ROP and different drilling variables.

3.1.1 Mechanical Specific Energy (MSE)

MSE was formulated by Teale (1965) and is widely used in bit mechanics, as a metric for drilling efficiency and for post-well performance analysis. [21] However, MSE analysis has also been used in a limited manner to investigate inefficiencies in field operations. A pilot study in 2004 demonstrated that rig site personnel could use the MSE to improve performance in real-time operations. The outcome of the study showed that the use of MSE had rendered an increase by 133% in ROP in six of the rigs selected for study over a period of three months as well as establishing new field records on 10 out of 11 wells. [15] Furthermore, ExxonMobil implemented this concept in its global organization a year after the pilot-study, reporting 50 new drilling records, solid safety records and a cost reduction of $54 million, thus, displaying the importance of MSE. [17]

MSE is defined as the energy required to drill a defined unit of volume of rock. [7] There are several drilling parameters involved, these are:

- Related to the drilling equipment
  - Such as drilling machine, rod, or bit
- Related to the drilling process
  - Such as WOB, rotary speed, drilling fluid properties and circulation speed
- Related to the ground response

- Such as ROP, rotational torque, drilling fluid pressure

MSE is, generally speaking, the quantified ratio between the mechanical energy input from the rig and the responding ROP. This ratio should be constant for a given rock and was derived by Teale (1965) as: [15]

$$MSE \approx \frac{Input\ energy}{Output\ ROP} \qquad \text{Eq. (3.1)}$$

For a rotary non-percussive drilling process, the work done is a product of thrust (F) and torque (T) because of indention and rotation. Teale proposed that the total work performed withing a given time could be derived by the relationship $eAu = Fu + 2\pi NT$. [27] Thus, for a giving the MSE model for rotating drilling system: [18]

$$MSE = \frac{WOB}{A_b} + \frac{120\pi \times RPM \times T}{A_b \times ROP} \qquad \text{Eq. (3.2)}$$

Where,

WOB = Weight on bit
A_b = Area of bit
RPM = Rotation per minute
T = Torque
ROP = Rate of penetration

Expressed for ROP, this gives:

$$ROP = \frac{120\pi \times RPM \times T}{MSE \times A_b - WOB} \qquad \text{Eq. (3.3)}$$

During drilling, energy will be lost in the transaction between the bit and the formation. Study show that even under ideal conditions, the bit will only be able to deliver approximately 30% - 40% of the input energy into the rock destruction process, a process illustrated in figure 3.1. [15]

The industry therefore required a method to unify the bit efficiency in the drill section on a meter-by-meter basis. MSE provides a good measure of efficiency for the entire drilling process and to calculate the bit efficiency factor (E_m) a correlation was established between the actual borehole lithology and the rock compressive strength (UCS). [51]

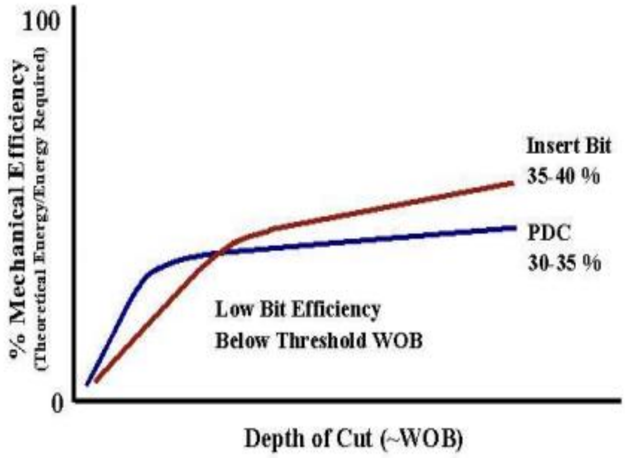


Figure 3.1: Bit efficiency against depth of cut [15]

Adjusted to include the mechanical efficiency factor, the originally derived equation from Teale gives:

$$MSE_{adj} = E_m \times MSE \quad \text{Eq. (3.4)}$$

The value of E_m has by laboratory study been deduced to commonly vary from 0.30 to 0.40 with an acceptable degree of error, however, the industry has generally set the value of E_m uniformly as 0.35 regardless of bit type of WOB. [51]

Another way to estimating the MSE is by factoring in the rock compressive strength (UCS). Deriving the equation for MSE (Eq. (3.2)), Teale also introduced the concept of minimum specific energy and maximum specific energy. [52] The minimum specific energy, i.e. when the bit efficiency is 100%, is roughly equal to the compressive strength of the rock being drilled, meaning: [52]

$$MSE = MSE_{min} \approx UCS \quad \text{Eq. (3.5)}$$

The mechanical efficiency is then: [52]

$$E_m = \frac{MSE_{min}}{MSE} \times 100 \quad \text{Eq. (3.6)}$$

Giving us that the maximum efficiency is reached when $\frac{MSE_{min}}{MSE} \approx 1$. Displaying that the relationship between MSE and UCS and be expressed as: [52]

$$MSE = \frac{UCS}{E_m} \qquad \text{Eq. (3.7)}$$

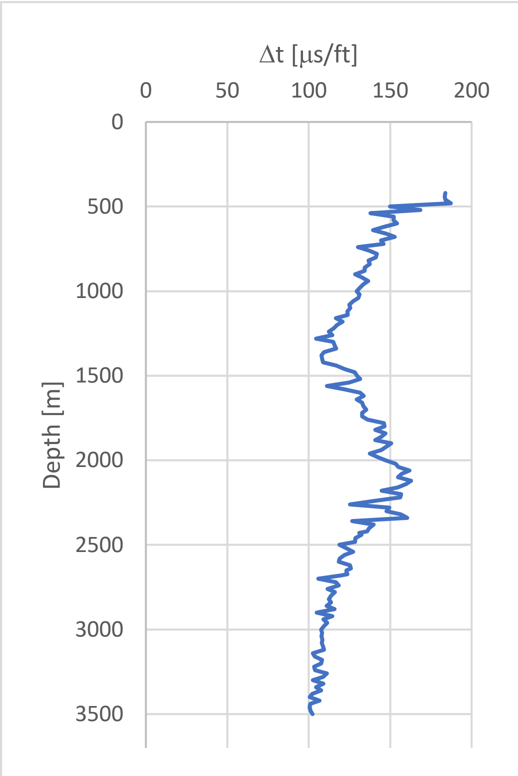
Therefore, we see that that MSE and UCS are proportional, adding an additional way in which MSE can be calculated. Different sources can be used to develop rock strength information along the wellbore. A way to calculate the UCS in a given formation interval is to take a core sample and test it in a laboratory setting. This is the most accurate method for estimation of rock strength, however, this does not give a continuous profile of rock strength along the wellbore. Furthermore, this an expensive process and is sensitive to stress unloading as the formation rock will lose its properties when taken out of the formation as the in-situ stresses dissipate in the removal process. [53] Therefore, a different approach is the use of sonic travel time to calculate UCS as it reflects the effect of lithology, porosity, and fluid content.

There are several empirical equations for the calculation of UCS with the use of sonic travel time, these are listed in table 3.1. Note that $\Delta tp\ (\mu s/ft) = 1/V_p$.

Reference	**UCS [MPa]**	**Lithology**
McNally (1987)	$1200 \times e^{-0.037 \times \Delta \mathrm{tp}}$	Fine-grained sandstones (Bowen Basin, Australia)
McNally (1987)	$1.4138\ \times 10^{7}\ \Delta tp^{-3}$	Weak, unconsolidated sandstones (Gulf Coast)
Militzer & Stoll (1973)	$(7682/\Delta tp)^{1.82}/145$	Limestone and dolomite
Horsrud (2001)	$0.77(304.8/\Delta tp)^{2.93}$	High porosity tertiary shales (North Sea)
Lal (1999)	$10\left(\frac{304.8}{\Delta tp} - 1\right)$	High porosity tertiary shales

Table 3.1: Empirical relationships between UCS and P-wave velocity V_p [54]

Although the empirical models display the same principle of predicting UCS with the use of sonic logs, the results can vary significantly. This is illustrated in figure 3.2 which takes the sonic log data from an arbitrary known field to display how significantly the predicted UCS can vary based on which empirical model is chosen. This significant variation is UCS presents an error when calculating MSE as one can reach different conclusions about the well based on which empirical model is chosen. For the basis of this thesis, the Horsrud (2001) model will be chosen as this model is based on shales from the NCS, which is most relevant for this thesis as well data are computed for the Vallhall Flank West oilfield.



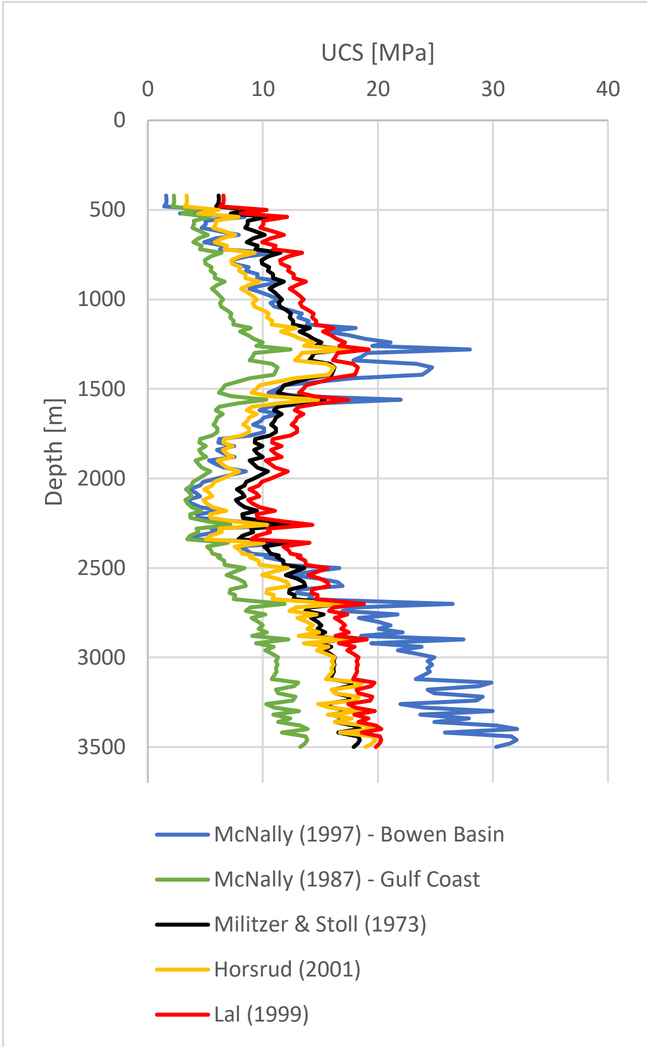


Figure 3.2: Comparison of UCS-predictions by different empirical models

The seismic velocities for different objects vary a lot and is affected by many different factors, making it impossible to set definitive universal values for the different rocks. Typical seismic velocities however are generally listed as:

Rock type	v_p (km/sec)
Unconsolidated sediments	
clay	1.0–2.5
sand, dry	0.2–1.0
sand, saturated	1.5–2.0
Sedimentary rocks	
anhydrite	6.0
chalk	2.1–4.5
coal	1.7–3.4
dolomite	4.0–7.0
limestone	3.9–6.2
shale	2.0–5.5
salt	4.6
sandstone	2.0–5.0
Igneous and metamorphic rocks	
basalt	5.3–6.5
granite	4.7–6.0
gabbro	6.5–7.0
slate	3.5–4.4
ultramafic rocks	7.5–8.5
Other	
air	0.3
natural gas	0.43
ice	3.4
water	1.4–1.5
oil	1.3–1.4

Ranges of velocities, which are from a variety of sources, are approximate.

Figure 3.3: Seismic velocities for different rocks [63]

3.1.2 D-exponent

There are several empirical models for the rotary drilling process to illustrate the changes in the important variables affecting penetration rate. Detecting the over-pressured zones using ROP is complicated in practice as there are several factors that influence the ROP such as WOB, bit properties and many other. Thus, in order to determine the drilling rate and detect the formation pressures the "D-exponent" model was developed to normalize the penetration rate from drilling parameters.

Bingham (1964) developed the initial model for the d-exponent to improve the drilling rate, formulating into the following general equation: [47]

$$ROP = A_M N^E \left(\frac{WOB}{d_b}\right)^{d_{exp}} \qquad \text{Eq. (3.8)}$$

Where A_M is the rock matrix strength constant and E is the rotary speed exponent. Jordan and Shirley attempted to make a correlation between the d-exponent and differential pressure and proposed a simplification of Bingham's model in 1966. [48] The simplification assumed that the rock matrix strength is constant, and the rotary speed exponent remained unchanged and equal to one, (i.e. $A_M = E = 1$) giving the following equation: [41]

$$d_{exp} = \frac{\log\left(\frac{ROP}{60N}\right)}{\log\left(\frac{12WOB}{1000\ d_b}\right)} \qquad \text{Eq. (3.9)}$$

Where,

ROP = Rate of penetration

N = Revolutions per minute

WOB = Weight on bit

d_b = Bit diameter

The d-exponent can be calculated to detect the transition from normal to abnormal pressure when the drilling fluid density is held constant. [45] This is done by plotting the calculated d values obtained in a given low permeability formation as a function of depth, shale formations are preferably selected.

D-exponent is proportional to the rock strength and increases linearly with depth in pressured formations. Formations with abnormal pressures are detected with the d-exponent increasing less rapidly. In some cases, a reversal trend might also occur at which the d-exponent beings to decrease with depth. This concept is displayed in figure 3.4.

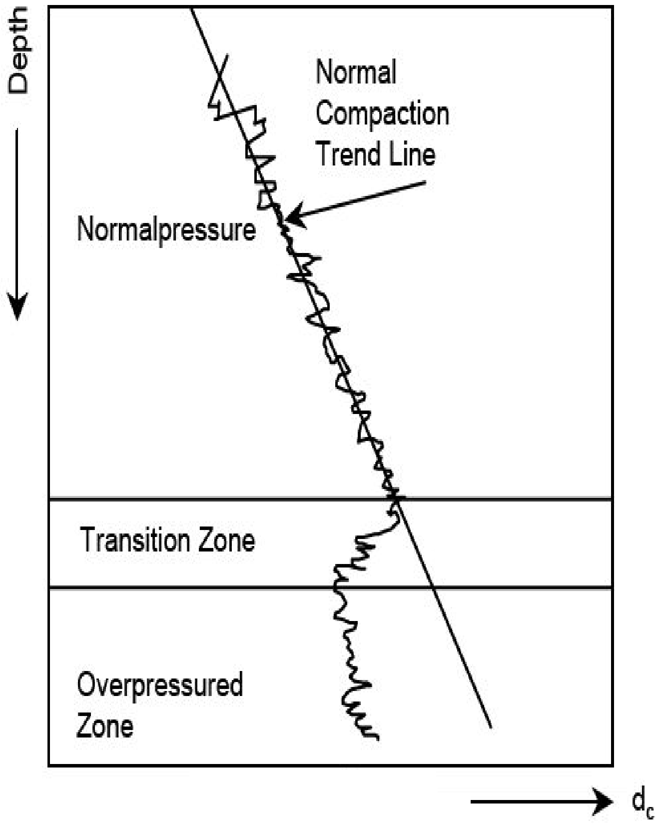


Figure 3.4: Response of d_c in normal pressure, transition, and overpressure zones [46]

This is the case because drilling through overpressure zones means the formation rock is less dense and more porous, resulting in increased drillability. The reduced pressure differential between the drilling fluid and formation pressure also results in increased ROP. [49] The d-exponent formula works pretty well for constant mud weight, however, in reality several drilling operations require and use various mud weights. Rehm and McClendon therefore proposed a modification which would correct for the effect of mud density, this gave the corrected d-exponent,

$$d_c = d_{exp} \frac{\rho_{normal}}{\rho_{actual}} \qquad \text{Eq. (3.10)}$$

where ρ_{normal} is the normal hydrostatic gradient and ρ_{actual} is the current mud weight. The corrected d-exponent is often used to quantitatively estimate the pore pressure gradient as well as for the qualitative detection of abnormal formation pressure and is more sensitive to changes in both pore pressure and mud weight. [41]

The d-exponent method is efficient in calculating the pressure, however, in situations with increased mud weight the value of d_c can be reduced, giving skewed results. The method is also affected by factors such as formation characteristics, poor hydraulics, bit dulling and more. [49] Thus, taking all into consideration, re-writing equation 3.10 with respect to ROP gives the following expression:

$$ROP = \left(\frac{12WOB}{1000\ d_b}\right)^{d_c \times \frac{\rho_{actual}}{\rho_{normal}}} \times 60N \qquad \text{Eq. (3.11)}$$

3.2 Sources for drilling inefficiency

During drilling operations there are several causes for drilling inefficiencies and dysfunctions. In many situations the causes are complex or there may be multiple dysfunctions occurring simultaneously, thus making it difficult to identify and take appropriate action. In some cases, the cause might be apparent, however, the industry lacks solutions that are consistently effective. [21] This is especially true when it comes to vibrationally-induced drilling inefficiency.

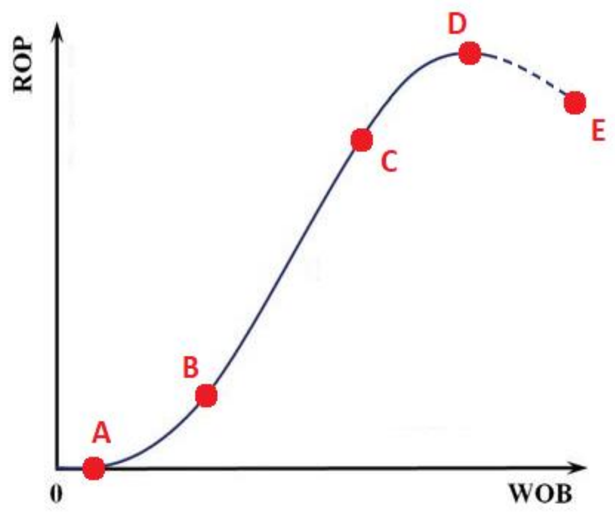
Operators have identified more than 40 different ROP limiters, 4 of which are related to the bit. [21] The limiters can be divided into two categories, bit limiters relating to bit dysfunction or founder and non-bit limiters, these are demonstrated in figure 3.5.

Figure 3.5: Potential efficiency of drilling. How redesign of the system can postpone the founder point [21]

Generally, both categories can be broken down to factors that limit input energy and factors that create inefficiency or founder. The first category is usually caused by insufficient equipment and are often too expensive to repair. This could be rig-limits such as insufficient rig top drive or rotary torque. The second category prohibits the energy from being properly transferred to the formation, causing large portions of the input energy to not be used efficiently. [17] The most common problems here are bit balling, bottomhole balling and vibrations.

3.2.1 Founder point

The relationship between WOB and rotary speed on ROP is of interest as these are drilling parameters that can be altered to sustain efficient drilling. The relationship shows the drilling response for a given bit and formation which define the static relationships between WOB, RPM, ROP and the bit torque (T) based on bit and formation properties as determined by Detournay et al. [40]. The Detournay model relies on the existence of three distinct drilling regimes that relates the amount of applied WOB and the resulting ROP, this displayed in figure 3.6. [41]



Point A: No significant ROP until threshold bit weight is applied

Segment A-B: Penetration increases with increasing values of bit weight

Segment B-C: Linear curve observed at moderate bit weights

Segment C-D: Subsequent increase in WOB only renders slight improvements in ROP

Segment D-E: Decrease in ROP is observed despite increase in WOB

Figure 3.6: ROP vs. WOB plot

Point A and segment A-B, referred to as phase I, displays that initially the WOB is not adequate to force the cutters to engage, resulting in inefficient drilling. In this phase, increasing the WOB will result in higher ROP. Segments B-C, referred to as phase II, on the other hand is characterized by efficient drilling with an increase in WOB, rendering an increase in ROP at peak efficient up to a point at which drilling dysfunction starts reducing the efficiency.

The relationship between the applied WOB, RPM, the resulting bit torque (T) and ROP is these two phases may be expressed by the equations: [40]

$$ROP(WOB, RPM) = \begin{cases} \frac{c_1 \times WOB \times RPM}{r}, \ WOB \ \leq WOB_* \\ \frac{c_2 (WOB - WOB_*) \times RPM}{r} + ROP_*, \ WOB > WOB_* \end{cases} \quad (3.1)$$

$$T(WOB) = \begin{cases} c_3 \times r \times WOB, \ WOB \ \leq WOB_* \\ c_4 \times r \times (WOB - WOB_*) + T_*, \ WOB \ > WOB_* \end{cases} \quad (3.2)$$

The asterisk subscript here signifies the transition point between phase I and II with the values of ROP_* and T_* corresponding to the ROP and torque at a weight of bit of WOB_*. Furthermore, r is the bit radius and c_1, c_2, c_3 and c_4 are model parameters that are dependent on bit and formation properties. Equation 3.1 is generally speaking an expression for the calculated cut of depth per bit revolution determined by the model parameters and the applied WOB multiplied with the RPM, giving us ROP. On the other hand, equation 3.2 demonstrates that the torque is independent of the RPM, which is a general assumption in drilling models. [40]

However, the equations do not account for phase III effects as the ROP response here is not unique, depending on the loading path and dysfunctions which causes reduction in the ROP. The point at which the ROP stops responding linearly with increasing WOB is referred to as “founder” or “flounder” point. [16] This is taken as the optimum WOB and the point at which the ROP is maximized. The lower than expected response in ROP is the result of drilling dysfunctions which negatively impacts drilling efficiency and causes drastic increase in MSE. The founder point can therefore be expressed as the combination of WOB and ROP that corresponds to minimum MSE. [40]

Drilling at the founder point results in high ROP and the most energy efficient drilling, parameters are therefore used to keep the operation at or just below this point. Performance has been maximized and cannot be improved unless the cause of inefficiency is addressed, and the founder point is increased to be at a higher WOB. [42] This is displayed in Figure 3.7. Similarly, it should be noted that the bit dulling can also move the founder point dramatically. [44] The founder point must be maintained as drilling beyond the founder point results in dysfunction which can be damaging for the bit, downhole tools and borehole quality. This can further result in equipment wear and having to pull the bit prematurely. [40] On the other hand, it should also be noted that drilling at the founder point might not be feasible because of processes such as maximal allowable ROP related to hole cleaning and upper limit of WOB to prevent bit damage. [40] It is therefore not a trivial task to choose the correct WOB and RPM for drilling.

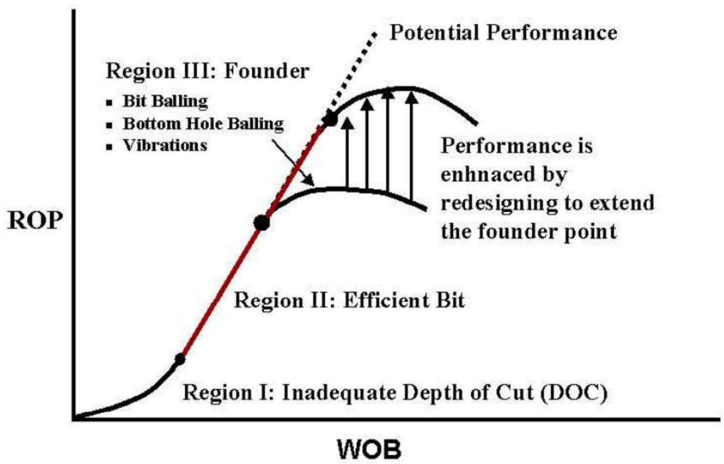


Figure 3.7: ROP response to WOB with extension of the founder point [16]

3.2.2 Bit balling

Bit balling occurs when the accumulation of material within the cutting structure interferes with the transfer of energy to the rock, thus, being a common cause of founder. In other words, it is a failure mode of the drill bit caused by mud and formation cuttings to gather around the bit. This is usually a problem while drilling in sticky shales, while it can occur in loose sandstone too. Since approximately 60% of wells are drilled in shale/clays it is inevitable to avoid bit balling. [12]

The effect of bit balling is drop in ROP and possible increase in standpipe pressure when the nozzles of drill bits are stuck. It can be recognized when drilling torque is lower than normal drilling, however, MSE plots can also be used to suggest bit balling. High values for MSE means that energy consumption for the bit is high and this can therefore indicate balling.

Bit balling is affected by factors such as formation, WOB, bit design and hydrostatic pressure in the wellbore. Furthermore, it is also affected by hydraulics as a low flow rate will not be able to clean the cutting around the drill bit. [14] Figure 3.8 demonstrates the effect hydraulics has on ROP and founder. The required HSI for a bit and formation depends on the desired ROP and there is no single threshold of hydraulics at which balling can be avoided.

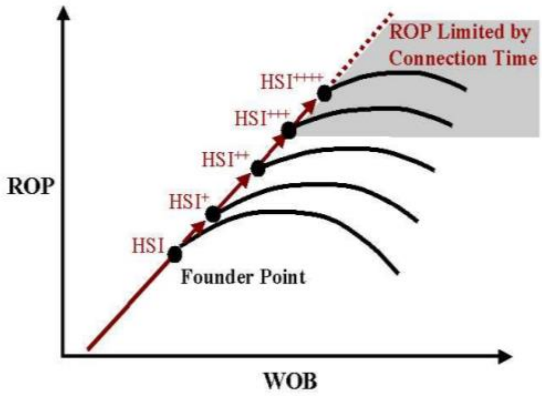


Figure 3.8: The effect of hydraulics in WBM on ROP and founder-point [15]

It can therefore be said that hydraulics does not eliminate balling, however, it extends the founder point so balling occurs at higher or lower ROP and WOB. [15]

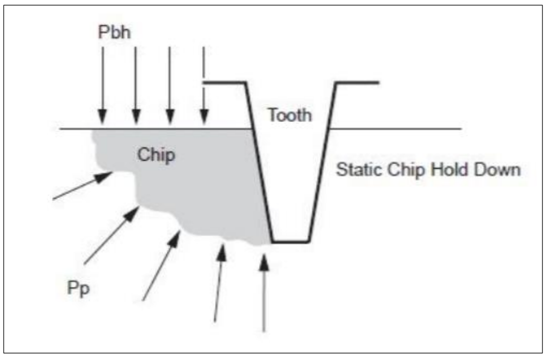
Conventional methods to avoid bit balling have been:

1. Change in drilling fluid rheology
2. Use OBM in reactive clay/shale formations
3. Developing electric potential between the formation and drill bit
4. Modification in drill bit hydraulics

Additionally, increasing the gas injection rate, adding detergent, adding a drying agent, or switching to mist can help solve this problem too. [13]

3.2.3 Bottom hole balling

Bottom hole balling occurs as cuttings gradually accumulate at the bottom of the wellbore. Because of pressure differentials and inadequate bottomhole circulation, lots of cutting might attach to the bit and the bottom, causing bottom hole balling. [16] This is also associated with the term chip hold down effect in which particles broken loose from the formation are held in place by differential pressure, hindering them from moving. [17]



Bottom hole balling hinders the efficient transmission of energy, resulting in lower ROP than anticipated. It can therefore be said that it inhibits the transfer of a portion of the WOB to the cutting structure. [18]

Figure 3.9: Chip hold down effect caused by differential pressure between bottom hole pressure and pore pressure [17]

It usually occurs in soft formations and can be treated by increasing the flow rate and reducing the WOB. It is usually an unlikely issue when drilling in hard formations. Like bit balling, bottom hole balling is identified by the reduction of ROP and drilling torque [17], however, contrary to bit balling, no changes in stand-pipe pressure is observed. Bottom hole can be prevented by increasing the hydraulic horsepower and using another bit than an insert bit. [17]

3.2.4 Vibrations

Drillstring vibrations is a common cause for drilling inefficiency and is a major contributor to downhole tool failure. [19] The most common problem associated with vibrations is the additional stress caused to both the wellbore and the drill string. This additional stress can cause fatigue and damage to the drillstring over time, which might result in tool failure, hole damage and more frequent rig repairs. This is rather expensive both in terms of time and costs, thus, there is an economic incentive to avoid this.

Vibrations are detected by reduced WOB and ROP, however, an increase of MSE can also be an indicator of vibrations as it can cause inadequate depth of cut (DOC). [16] Vibrations can also be detected by downhole vibration sensors, surface sensors and post-run inspection. [5]

Drillstring vibrations can be divided into three categories or modes: whirl (lateral), stick-slip (torsional) and bit bounce (axial). This is demonstrated in figure 3.10.

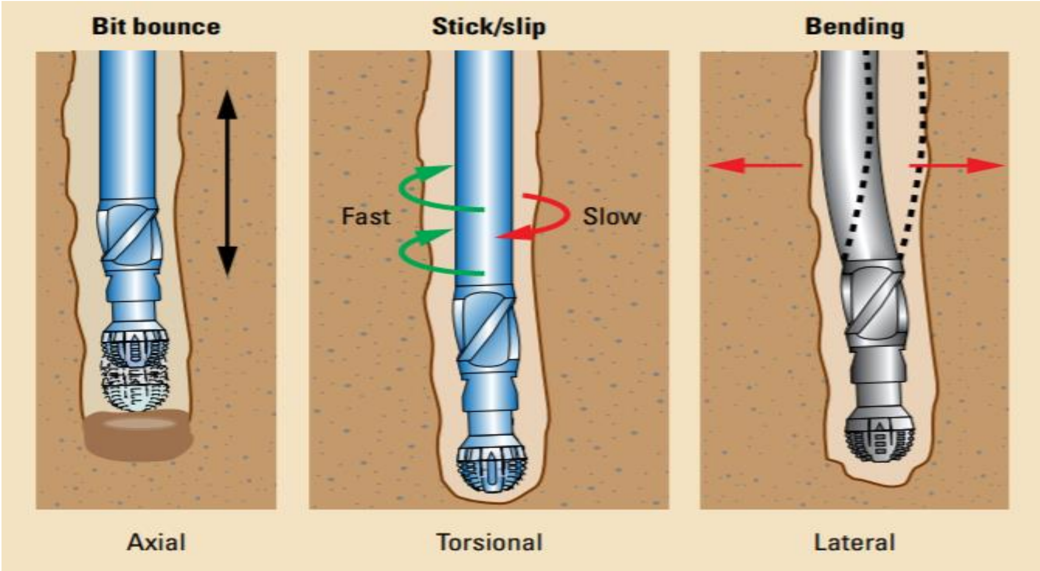


Figure 3.10: The three different types of vibrations acting on the drillstring [20]

Axial vibration can cause the bit to repeatedly lift off and impact the bottom hole, resulting in WOB fluctuations. [5] This is referred to as bit bounce and may damage bit cutters, bearings or the surface hoisting equipment. Axial vibrations can be mitigated by altering the drilling parameters. If the bouncing is initiated when running a high WOB and low RPM, the solution will be to increase RPM and reduce WOB. Similarly, if vibrations are caused when drilling with high RPM and low WOB, the solution will be to reduce ROP and increase WOB.

Changing the hardware such as using a less aggressive roller cone bit or using a shock sub has also been shown to be a more effective way to mitigate axial vibrations than changing the drilling parameters. [5] It also be a necessary to stop surface rotation and drill in slide mode through the problematic formation section to avoid axial vibrations. [18]

Torsional vibration is a non-uniform bit rotation in which the bit stops from rotating at regular intervals, meaning it can lead to irregular downhole rotation. As a result, this causes the drillstring to periodically torque up and then spin freely. [5] This is also known as “Stick and Slip” or “stick-slip” and happens as the drillstring gathers potential energy as it gets twirled. At a point the torque becomes too high for the wellbore to hold and the formation lets go of the drillstring. [17] The release of torsional energy causes the drillstring to rotate rapidly. If this is not addressed, the drillstring will get stuck until enough energy is reached again.

These torsional fluctuations cause fatigue in drill collar connections which may lead to bit damage. It may also cause reduced ROP, connection overtorque, back-off and drillstring twist-off. There are several methods in which these vibrations can be mitigated. Changing the drilling parameters is an effective way at which stick-slip can be avoided, for which it is recommended to reduce WOB and increase RPM. [18] As a rule of thumb, one should increase RPM or decrease WOB by around 15%. [5] If stick-slip persists, one should stop the rotary and restart drilling under a higher RPM and/or lower WOB.

Lateral vibration is the most destructive vibration mode because it can create large shocks as the BHA impacts the wellbore wall, causing downhole tool and drillstring failures. This interaction between the BHA and drillstring contact point can then drive the system into a backwards whirl. [20] Whirl is the most severe form of vibration, creating high-frequency large-magnitude bending moment fluctuations that result in high rates of components and connection fatigue. Comparably, imbalance in an assembly will cause centrifugally induced bowing of the drillstring, producing forward whirl. Similarly, forward whirl may result in one-sided wear of components. The two types of whirl, as touched upon, is forward and backward whirl. Low WOB and high RPM can induce forward whirl while a combination of high WOB and high RPM can result in backward whirl. [40]

One of the main reasons for lateral vibration is resonance which leads to self-excited high-magnitude vibration. [5] This occurs when the rotary speed is close to one of the natural frequencies of the BHA. Thus, the natural frequencies of the BHA, sometimes called critical rotary speeds, should be calculated in order to mitigate lateral vibrations. Other than that, whirl can also be effectively eliminated by reducing RPM while increasing WOB. [18]

Critical values of RPM and WOB that trigger the onset of whirl and stick-slip are heavily dependent on the bit and BHA characteristics. For appropriately designed drill strings, a certain region of WOB and ROP is expected that is not notably affected, hence, a safe zone can be established. This is displayed in figure 3.11.

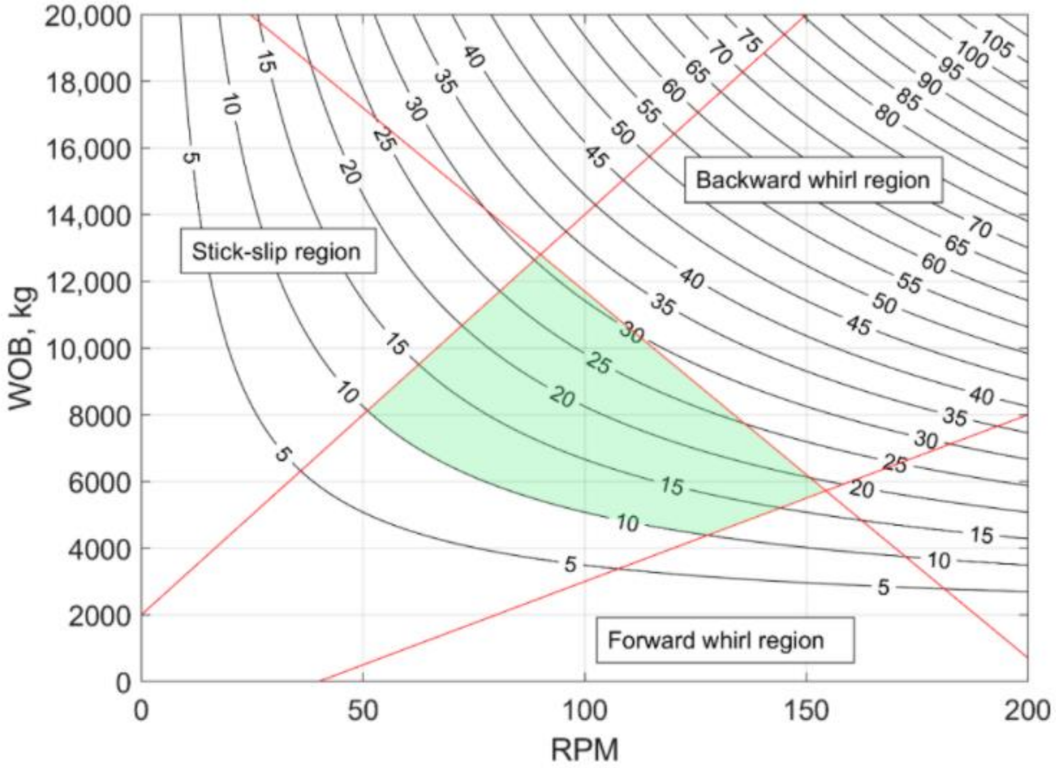


Figure 3.11: Contour map of dysfunction-free ROP as a function of WOB and ROP

The figure shows the concept of different regions in the WOB-RPM plane where the drilling process might be affected by vibrations. The shaded region in the figure represents the different combination of WOB and RPM which results in the most efficient drilling.

Generally, vibrations are very common when drilling in hard formations and usually occur when different factors such as lithological transitions, poor bottom hole assembly design and parameter management usually in combination with high WOB and RPM is present. [17] Because the industry is primarily concerned with tool damage, vibration monitoring does not transmit a warning until accelerations of 25-50 G’s are observed. [16] Consequently, operators might therefore not be aware of vibrations, thus, not capitalizing on significant opportunities to improve ROP. While balling is recognized immediately and there are several mitigation strategies available, vibrations are often more subtle and cannot always be distinguished from changes in rock compressive strength. Furthermore, vibrations may change with lithology and other factors, requiring continuous monitoring and change in WOB and RPM.

3.2.5 Bit dulling

Bit dulling refers to the gradual degradation of the drill bit with continued use. The duration of a drill bit is the product of the accumulated drilling time when the bit rotates on the bottom and penetrates the formation. An important distinction to make is the difference between bit wear and bit failure. While bit wear refers to the gradual loss of performance due to cutter elements becoming duller over time, bit failure is characterized by the sudden drop in the bit performance due to loss of cutters or cones. [43]

Several factors play an integral part in determining the bit dulling over time, the most important ones are:

- Formation hardness
- Bit type and tooth geometry
- Vibrations
- Bit force
- Rotary speed

Knowledge of how the various drilling parameters affect the rate of bit wear is important to prolong the use of the bit. While factors such as the formation hardness is out of the driller's control, other factors should be established such to minimize the wear. However, compromises must be found as the formation characteristics vary a lot during a bit run. In order to estimate the bit dull state and how incremental bit wear effects performance, two different mathematical models have been developed for approximating the effect of the bit wear on drilling performance. [44] We observe that:

<u>Galle and Woods: [44]</u>

$$ROP \propto \left(\frac{K}{0.928\ DG^2+6\ DG+1}\right)^{a_1} \qquad \text{Eq. (3.3)}$$

<u>Bourgoyne and Young: [44]</u>

$$ROP\ \propto K(e^{-a_1 \times DG}) \qquad \text{Eq. (3.4)}$$

Where,

DG – IADC Dull Grade
K – Field data constant
a_1 – Field data exponent

Equation (3.3) and (3.4) demonstrates that dull grading has an effect on ROP and thus act as a performance limiter. Many performance models exist today, however, these models typically fail to capture the dependency on formation hardness and balling tendencies versus the type of drill bit used. [44]

Deducing bit wear is rather difficult to achieve as the reduction in ROP and other drilling parameters might be the combined result of different aspects combined, making it difficult to deduce bit wear separately. The monitoring of real time Specific Energy (SE) has shown to be acting as a tool in deciding when to pull a bit. This is achieved by establishing a base line reference for the SE in the formation for the given bit by gathering field data.

As a rule of thumb, if the recorded SE has moved by 200% from the reference base line for a distance of 4 meters or more with GR of 120 API or more, pulling the bit should be considered. [44] This basis is demonstrated in figure 3.12 that shows that bit wear can be suggested by recording the SE.

The economic consideration here lies in deciding when to pull the bit versus continuing to drill despite the wear. Recognizing when a bit is dull and past its true economic life can be difficult and often has speculation and hope of drilling into something that is more drillable remained as a bias when deciding to change the bit or leave it in the hole.

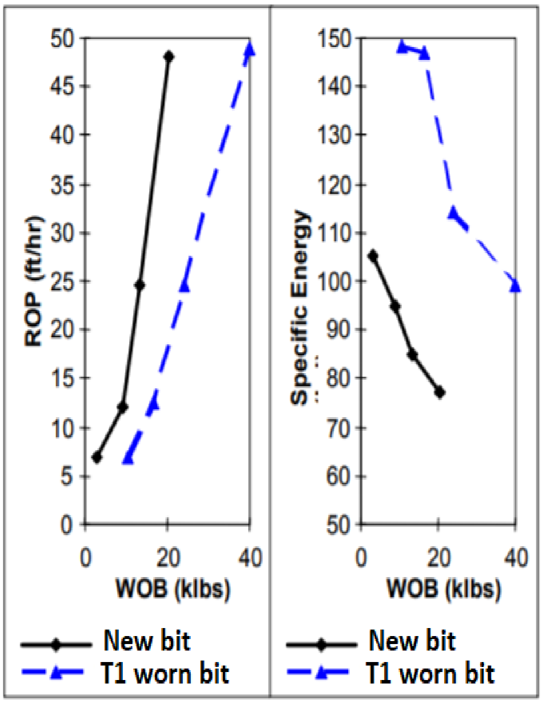


Figure 3.12: Case study drilling $6^{3/4}$'' Anti-Whirl PDC bit in medium strength formation. Performance evaluation of a new bit versus a T1 worn bit.

3.3 Bit Selection

The drill bit is the most important and crucial tool in the drilling of an oil well. It is estimated by ONGC in India that around 120 rig-ray per year is lost due to bit failures. [10] It is therefore evident that bit selection is economically viable in cost reduction as reduced rig-days and minimalizing bit runs can be achieved.

There are several methods used for optimal bit selection, some of which will be discussed in this thesis. Commonly, the criteria used for bit selection has been the bit type with the highest ROP or the bit with minimum Cost per Meter. Additionally, factors such as hydraulics, formation, etc. are also considered in the selection process.

As there are variables to consider, various methods exist as mentioned earlier. Due to this, the selection process is a trial-and-error procedure. [10] In many of these cases this approach ignores some of the important parameters in bit performance, thus, not guaranteeing the selection of the optimal bit type. It is therefore important to look at as many methods as possible when deducing the most optimal bit.

3.3.1 Cost per meter method:

An important factor to consider in the choice of drill bit is the costs associated with the drilling. This may be done by calculating cost/meter for a given section which gives the average cost of drilling per unit length drilled. [6]

This can be expressed as:

$$Cost/meter = \frac{d_t \times (r_r + m_c) + t_t \times r_r}{m_d} \qquad \text{Eq. (3.5)}$$

Where,

d_t = Drilling time [hr]

r_r = Rig rate [$/hr]

m_c = Motor cost [$/hr]

t_t = Trip time [hr]

m_d = Meters drilled [m]

While some of the parameters can be reasonably known for a given well, other parameters are determined by the average ROP and the overall bit life. Thus, the uncertainty in the estimates affects the overall accuracy. This is certainly true as one uses offset well records to estimate some of the parameters.

3.3.2 WR and K_f

Fullerton (1973) developed the concept of constant energy drilling which quantifies the mechanical energy available at the bit as the number WR. This is given by: [6]

$$WR = (WOB \times RPM) \,/\, Bit\ size \qquad \text{Eq. (3.6)}$$

From the equation we see that WR is attained at various combinations of WBM and RPM. WR can therefore be used for comparisons in bit performance analysis. We know then for instance that if two comparable wells are drilled in a formation interval with the same ROP, the well with the lowest WR calculated required was drilled most efficient. This is so because less energy was used to fail the rock.

Developing further upon this, we can also express the formation drillability factor K_f as:

$$K_f = ROP \,/\, WR \qquad \text{Eq. (3.7)}$$

The drillability factor represents the drilling efficiency of the cutting structure in a particular formation. [6] Thus, we have that a high K_f means high drilling efficiency. The K_f factor varies from bit type to bit type, it is therefore a useful tool that can be applied to drill bit performance evaluation. However, in order to compare the drillability factors of different bits the hydraulic conditions must be compatible.

Comparisons of WR and K_f are most relevant for rotary drilling. For directional drilling, high ROP is normally secondary to directional control. The motor used also has limitations in regard to the WOB and reactive torque. This is so because generally motor runs use less WOB and high RPM.

4 Valhall Flank West

The Valhall Flank West project is a development of the western flank of the Valhall oilfield located at the southern part of the Norwegian section of the North Sea. The location of the development is illustrated in figure 4.1 a) and b).

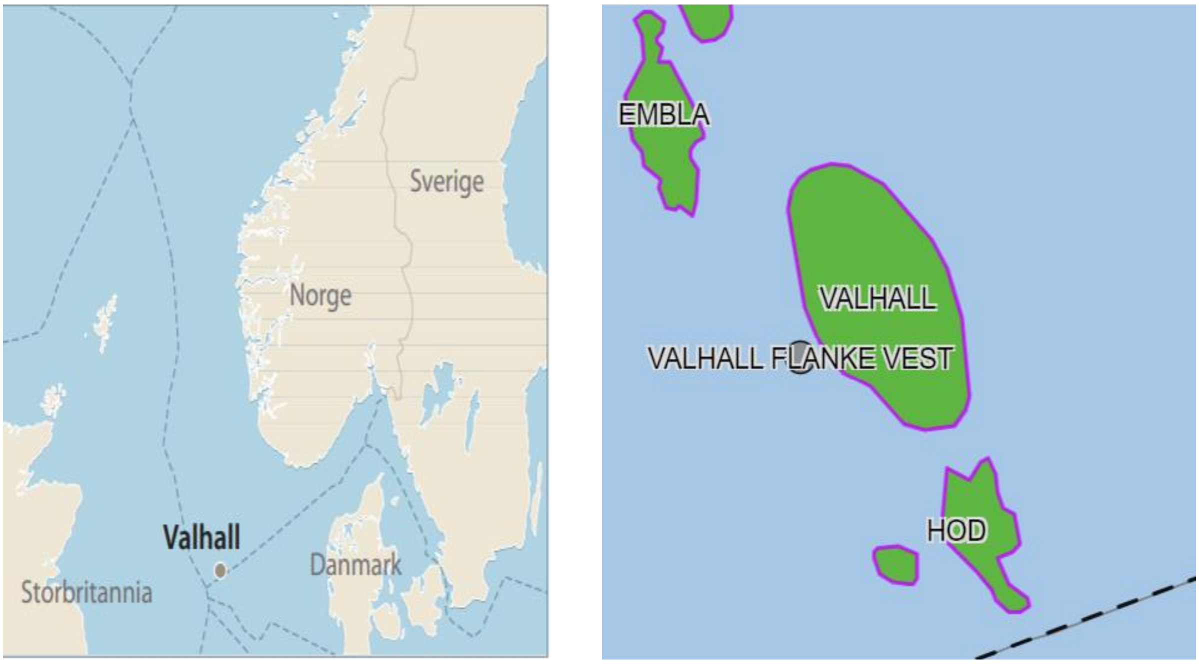


Figure 4.1 a) and b) Location of the Valhall Flank West development [58, 59]

The Valhall Flank West is expected to target the Tor formation with first oil produced in 2019, making it a relatively new field. It is a wellhead platform that will normally be unmanned with the power source from shore via the Valhall field center. [60] The development will envelop the drilling of production wells with two wells that may be converted into water injection wells in the future.

The recovery rate from the general Valhall field area is 27%, however, the Flank West proposes to increase recovery rate to 40% by 2042. [55] Estimated to contain around 60 million metric barrels of oil equivalent (Mmboe), it is a significant field.

4.1 Geology

The Valhall Flank West is a fractured chalk reservoir in the NCS, located within the Central Graben, southern part of the North Sea. The structure is located on an elongated anticline characterized as the Lindesnes Ridge, estimated to have developed during the Late

Cenomanian to Oligocene tectonic movements. [56] The reservoir is of the Upper Cretaceous chalk group with hydrocarbons contained in the Hod and Tor formation. [55] The formations are at around 2400 m TVD with the Tor formation divided into four reservoir zones and the Hod formation divided into six reservoir zones. Both formations are separated by a low porosity hard ground.

The Hod formation on the other hand is of Mid-Turonian to Campanian geological age and consists of partly pink to red, argillaceous chalky limestone with thickness varying from 200 – 700 m. [57] The Tor formation is generally very clean and of fine-grained chalk with a low content of insoluble (<5%), meaning it has excellent reservoir quality. The Tor formation typically varies from 0 – 80 m in thickness and is the main reservoir with 66% of the reserves.

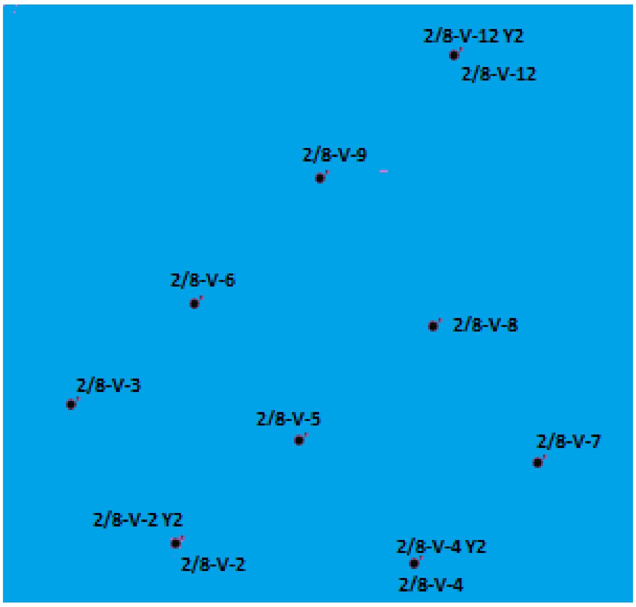
The reservoir properties vary quite a bit with the primary porosity of the chalk varying between 36% – 50% on the crest structure. The high porosity primarily being a result due to formation overpressure causing mechanical compaction of the reservoir chalk. [56] The matrix permeability varies in the range of 1 – 10 mD, with the permeability decreasing as a result of strong depletion.

Analyzing the reported formation tops in the final well reports for all wells in Valhall Flank West, we establish that on average, the formation had lithostratigraphy presented in table 4.1.

Groups	**Depths [m]**	**Formations**	**Depths [m]**
		Forth Fm.	140 – 225
		Ling Bank Fm.	225 – 325
Zulu Gp.	325 – 820	Aberdeen Fm.	325 – 820
Nordland Gp.	820 – 1845	Nordland Fm.	820 – 1845
Hordaland Gp.	1845 – 3410	Lark Fm.	1845 – 2810
		Horda Fm.	2810 – 3410
Rogaland Gp.	3410 – 3570	Balder Fm.	3410 – 3460
		Sele Fm.	3460 – 3500
		Lista Fm.	3500 – 3560
		Våle Fm.	3560 – 3570
Shetland Gp.	3570 – 3630	Ekofisk Fm.	3570 – 3585
		Tor Fm.	3585 - 3630

Table 4.1: Lithostratigraphy of Valhall Flank West

4.2 Wells



The platform features 12 well sloth with wells drilled during the timeframe of 2019 – 2020. The wells 2/8-V-1, 2/8-V-10 and 2/8-V-11 have the status as predrilled at the writing of this thesis and will therefore not be included in further analysis.

The remaining wells are analyzed section by section to determine its properties. The wells are displayed in figure 4.2.

Figure 4.2: Wells in Valhall Flank West development [59]

Furthermore, the wells 2/8-V-3, 2/8-V-4, 2/8-V-8 and 2/8-V-12 contains sidetracks that will also be analyzed. The depths at which the different bit sizes have been used varies accord the wells, however, analyzing all the wells we can generalize the following:

Bit size	**Average depth interval**	**Lithology**	**Lithostratigraphy**
32''	0 – 200 MD	Claystone	Forth Fm.
24''	200 – 565 MD	Claystone	Forth Fm., Ling Bank Fm and Aberdeen Fm.
16.5''	565 – 1680 MD	Claystone + minor siltstone sections	Aberdeem Fm. and Nordland Fm.
12.25''	1610 – 3320 MD	Claystone + minor limestone sections Balder tuff & Diatom clay Marl/Chalk at the bottom	Nordland Fm. + Horda Fm.
8.5''	3340 – 4980 MD	Chalk	Horda Fm., Rogaland Gp. and Shetland Gp.
6.5''	4990 – 6320 MD	Chalk	Horda Fm., Rogaland Gp. and Shetland Gp.

Table 4.2: Average depth intervals and lithology of different bit sizes across wells in the Valhall Flank West field

5 Results

This part of the thesis presents the results obtained from the analysis of the Valhall Flank West field development.

5.1 Data quality

From previous studies it is clear that many wellbore stability studies suffer from various inconsistencies which may lead to incorrect results or results that cannot be extrapolated to other well configurations. [61] The drilling industry is operating within a complex space as it includes both geological and engineering aspects which are of different natures. Aadnoy (2011) attempted to express the uncertainty for different fundamental information, giving:

Fundamental information	**Scale**	**Numerical precision**	**Uncertainty**
Geology	Large	Small	Large
Petrophysics	Small	Medium	Medium
Drilling data	Small	High	Small

Figure 5.1: Input data from a drilling perspective [61]

Drilling data is therefore considered to be of high numerical precision with low uncertainty, however, this does not show that drilling data is of high quality. This was an issue when analyzing drilling data from the Valhall Flank West field as there were significant variation in the data presented by the operator (Aker BP) and the service company (Halliburton).

The drilling data from Halliburton is accessed from the mudlogging report and the End of Well Report. Although data from both reports seem to differ, the average is taken and presented in this thesis as the reported differences are minor and conducted by the same company, hence, making them reliable. Drilling data from Aker BP is presented as an end of well summary Excel sheet with various drilling parameters.

An example of the variation in data is presented in figure 5.2, displaying the significant differences in the reporting. In overall, for all wells, the overview shows that at the largest, there is a 127.3% difference in the reported ROP in the data source while the average difference between the data was approximately 17.4%. There are also significant differences in the other drilling parameters too. Overview for all reported ROP differences across all wells are presented in Appendix A.2.

Well name	Bit size	Bit type	ROP (Aker BP)	ROP (Halliburton)	Percentage difference
2/8-V-2	32’’	XR+	33.48	NaN	NaN
2/8-V-2	24’’	SR1GRC	52.73	NaN	NaN
2/8-V-2	16.5’’	GTD66DCs	73.01	72.8	0.29 %
2/8-V-2	12.25’’	GTi76WMKHOs	102.74	76.2	29.66 %
2/8-V-2	8.5’’	GTD64MKOs	17.83	32	56.87 %
2/8-V-2 Y2	8.5’’	GTD64MKOs	15.94	25	44.26 %
2/8-V-2 Y2	6.5’’	GTD54WMK	22.50	5	127.27 %
2/8-V-2 Y2	6.5’’	GTE54D	18.55	19.8	6.52 %

Figure 5.2: Differences in reported ROP between operator- and service company for well 2/8-V-2

This therefore shows the inconsistence and lack of data quality as the variation is of the magnitude that it may lead to different conclusions based on which dataset is used. This is especially noteworthy as the wells in Valhall Flank West are mostly drilled in the timeframe of 2019 – 2020, displaying the lack of quality assurance even in recent modern wells. There is therefore a need for redundancy in the data collection and reporting systems as there clearly are significant inconsistencies, showing that the oil and gas industry still have a long way to go in regard to digitalization and improvements.

For the basis of this thesis, the data provided by Aker BP will be used as this data is the most complete set. Data provided by Halliburton will be considered where data from Aker BP is not available. This is done so in order to establish consistency and reduce the limitation and uncertainties of mixing data.

5.2 Valhall Flank West field overview

In this section, the data provided for the field overview has been read and reported for further investigation to be conducted. The research will focus on operating parameters (i.e. WOB, RPM) as these can be altered and has the primary effect on drilling outputs such as ROP. Furthermore, other aspects such as geology, drilling time, run length and etc. will also be given emphasis on when being analyzed. The full data is reported in Appendix A.3.

5.2.1 ROP

As argued for in earlier sections, comparing the ROP can be a direct way of identifying the best performing bit as the a high ROP is desired for efficient drilling. For the reported drilling data, the ROP is differentiated based on which bit size is used.

Sidenote, for the reported data the symbol "*", "**" and "***" refers to Y2, T2 and T3 sidetracks respectively. Furthermore, special bit sizes such as 26'', 17.5''and 16'' have not been taken into the report as these have only been used once and therefore cannot be used for analysis as they do not provide performance data that can be compared.

The ROP data obtained from the Valhall Flank West field is presented in figure 5.3 a) and b).

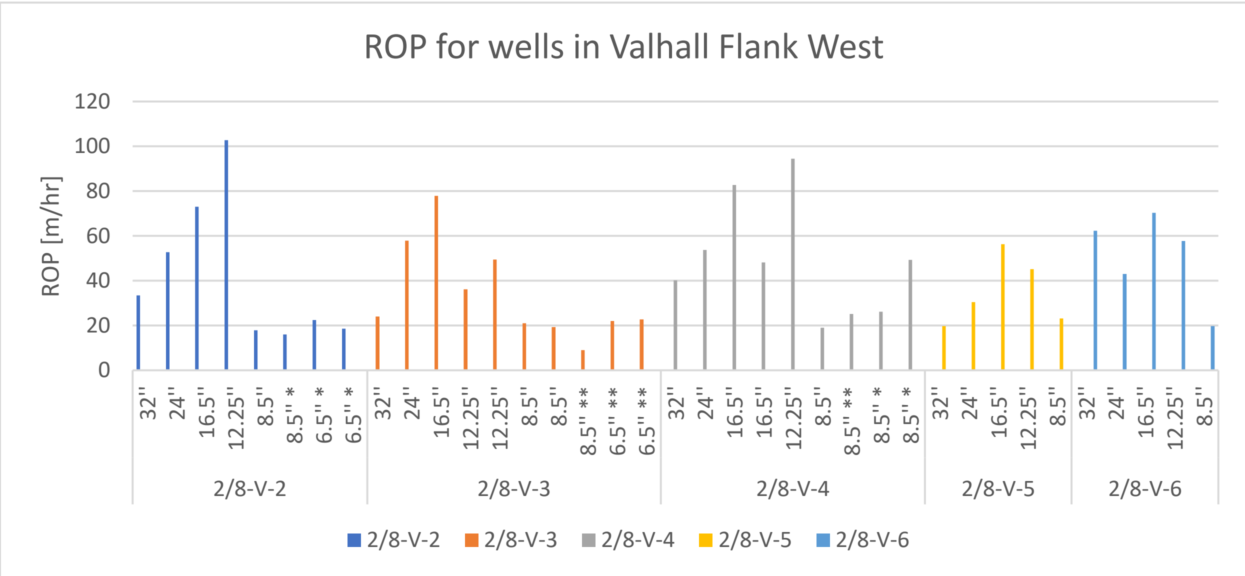


Figure 5.3 a) Reported ROP for the different wells in the Valhall Flank West field

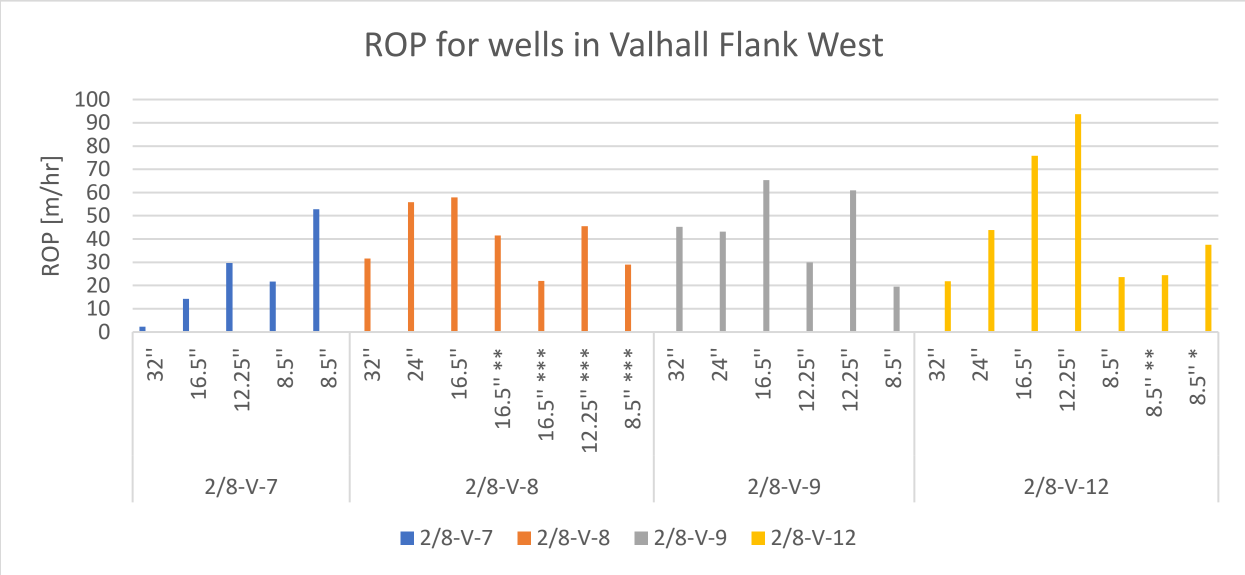


Figure 5.3 b) Reported ROP for the different wells in the Valhall Flank West field

5.2.1.1 ROP by bit size

The reported ROP for the different wells show that there are rather significant variations between the different bit sizes with the 12.25'' drill bits performing at the highest recorded ROP in most of the wells. However, for a better understanding of the underlying process, the ROP of the different wells will be compared for bits of the same size. This will reduce the impact of other factors such as bit type, depth, and geological properties of the drilled sections as the wells are rather close in proximity, making it a fair assumption to assume that geology is rather similar for every section. Doing this, we observe the following:

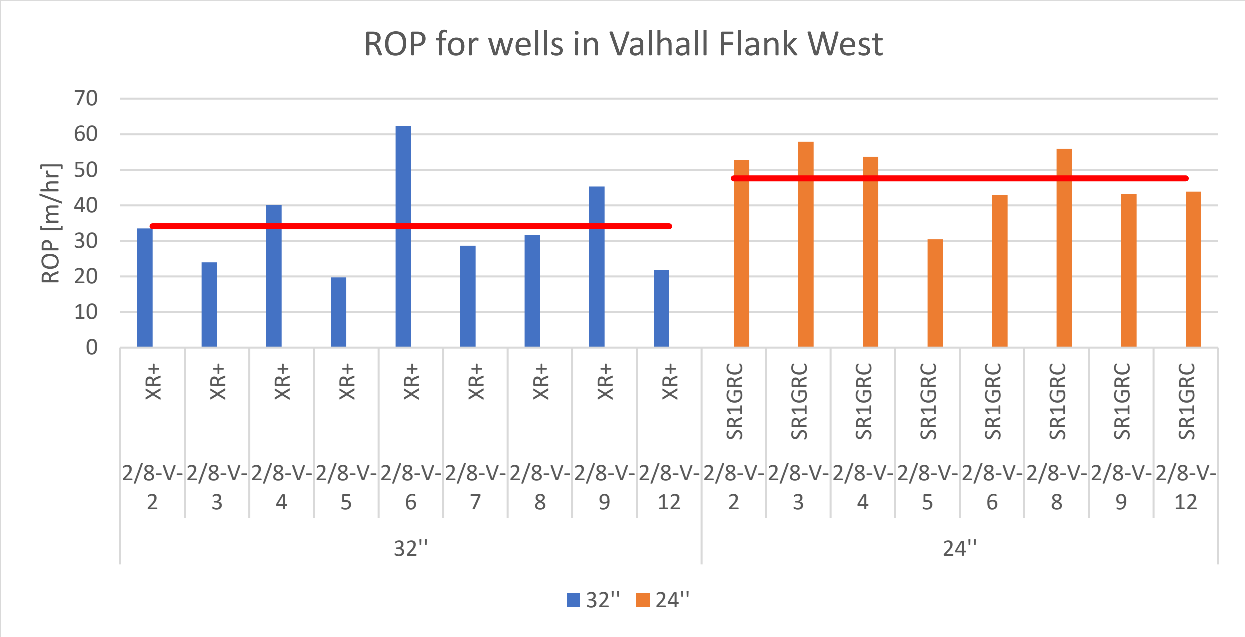


Figure 5.4 a): Reported ROP for same sized bits in different wells

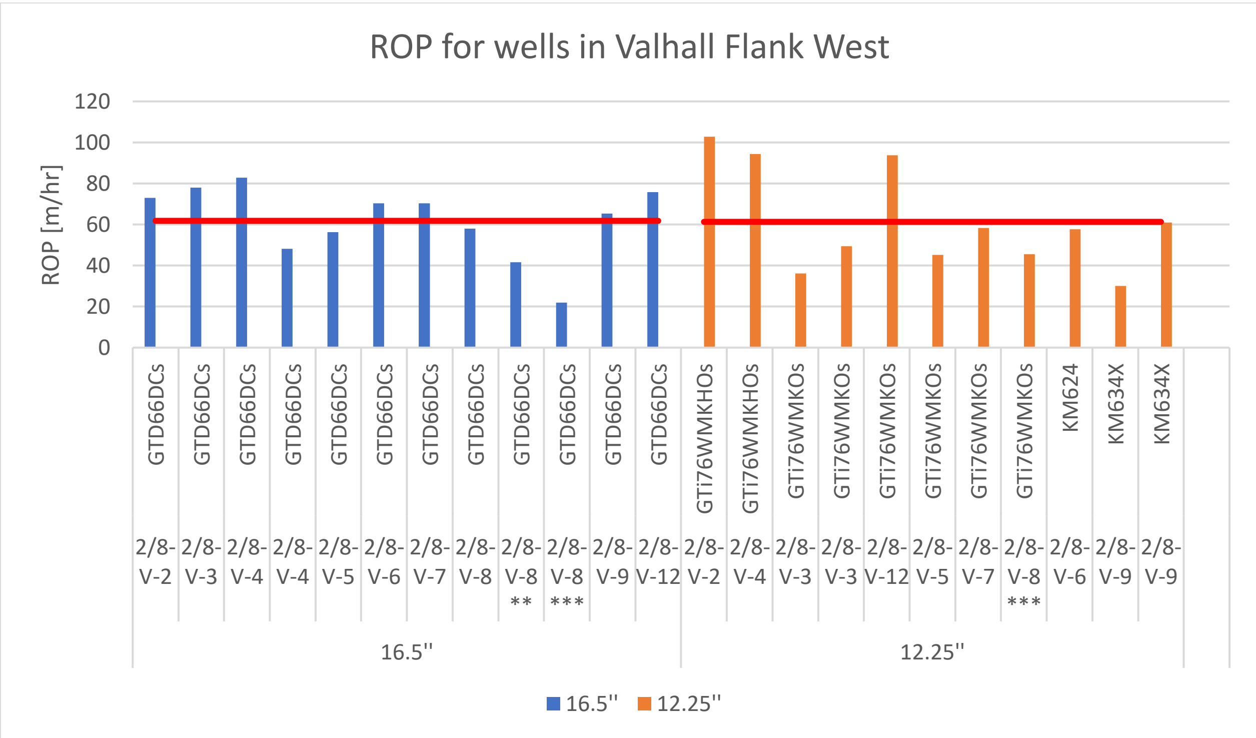


Figure 5.4 b): Reported ROP for same sized bits in different wells

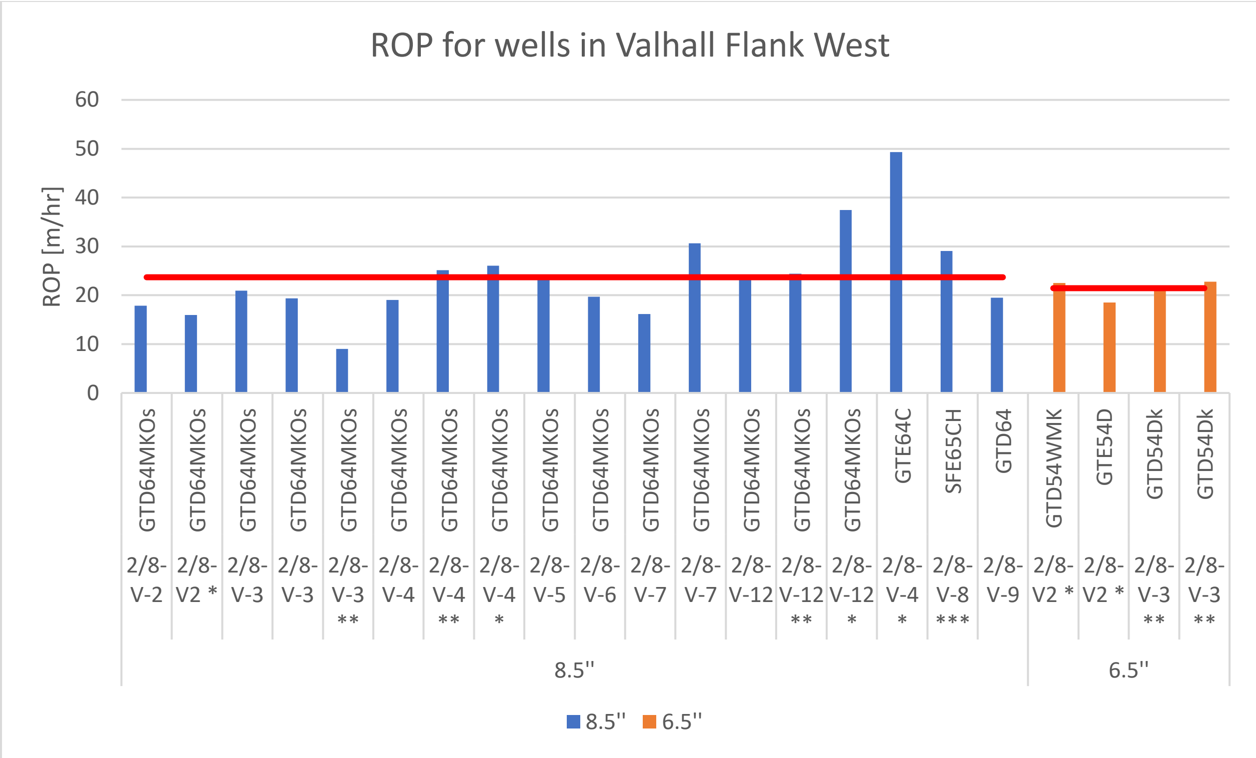
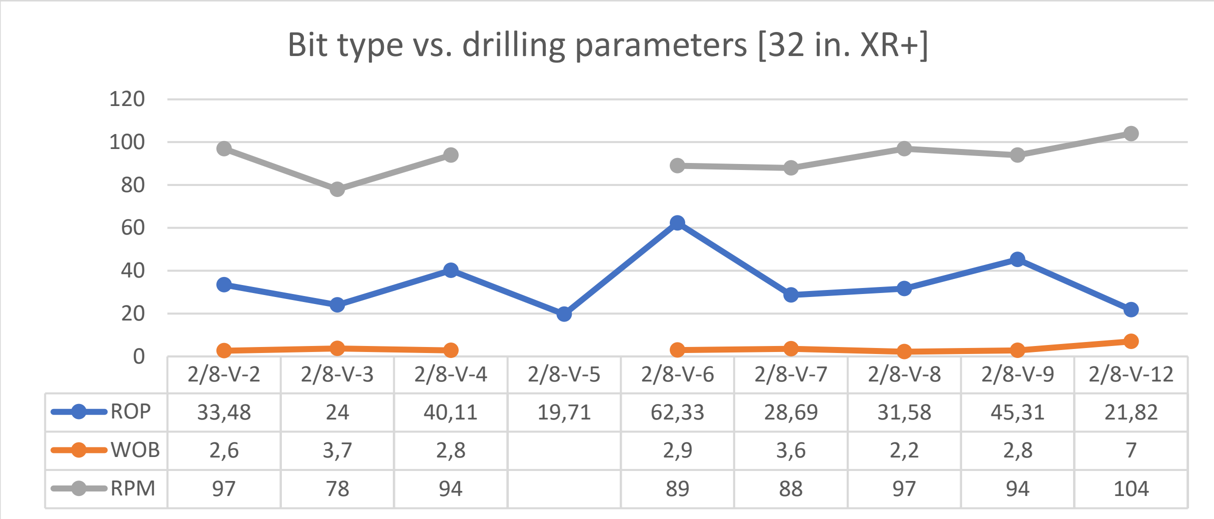


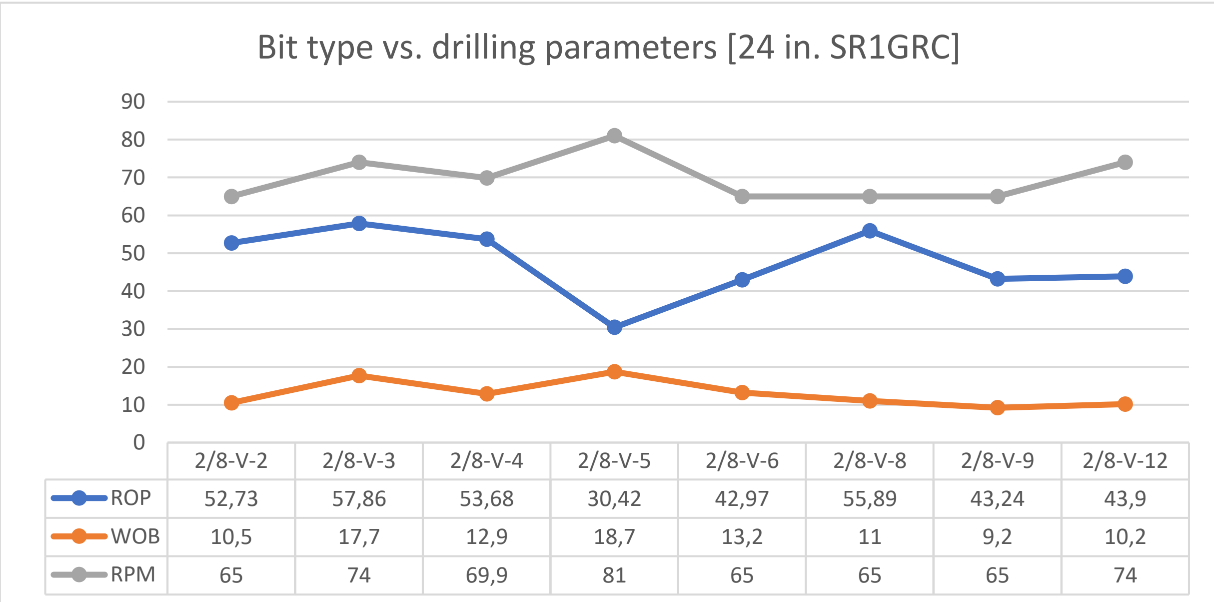
Figure 5.4 c): Reported ROP for same sized bits in different wells

Observing the ROP performance of the drill bits in the varying wells compared section by section displays varying drill bit performances. The red line in each figure illustrates the average ROP of every well in each section, hence, we can observe which wells performance above or below the average. To explain the difference in performance between the different bits we analyze the drilling parameters of each well. Established earlier in this thesis and displayed by equation 3.1, we know that ROP is proportional to WOB and RPM, meaning that we should expect high values of WOB and RPM at wells which have a high reported ROP. This is investigated in the following figures.



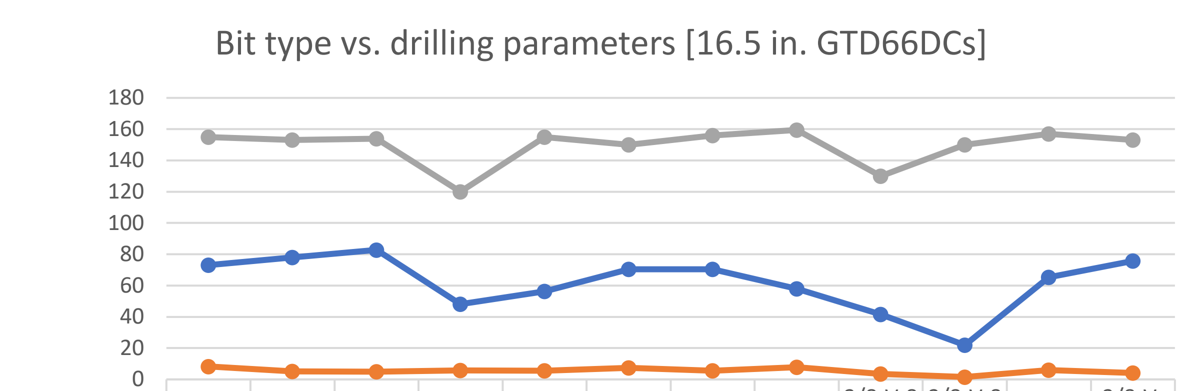
	2/8-V-2	2/8-V-3	2/8-V-4	2/8-V-5	2/8-V-6	2/8-V-7	2/8-V-8	2/8-V-9	2/8-V-12
ROP	33,48	24	40,11	19,71	62,33	28,69	31,58	45,31	21,82
WOB	2,6	3,7	2,8		2,9	3,6	2,2	2,8	7
RPM	97	78	94		89	88	97	94	104

Figure 5.5 a) ROP, WOB and RPM for wells drilled with bit size 32 in. and bit type XR+



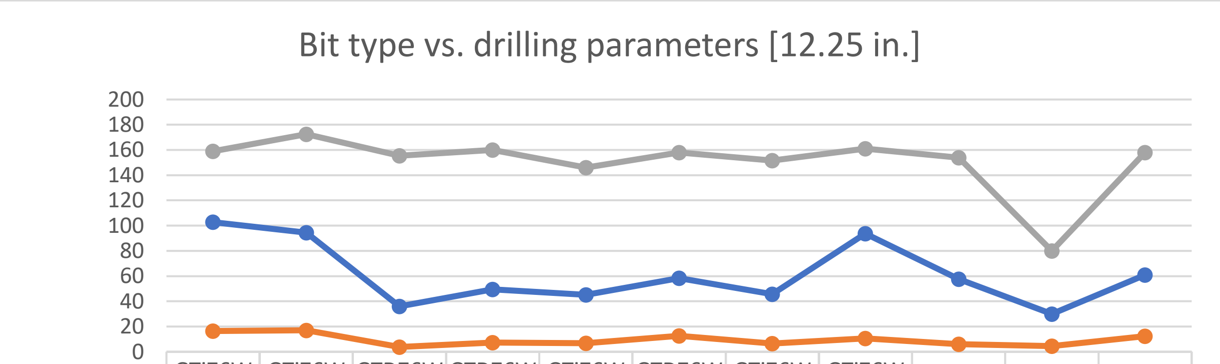
	2/8-V-2	2/8-V-3	2/8-V-4	2/8-V-5	2/8-V-6	2/8-V-8	2/8-V-9	2/8-V-12
ROP	52,73	57,86	53,68	30,42	42,97	55,89	43,24	43,9
WOB	10,5	17,7	12,9	18,7	13,2	11	9,2	10,2
RPM	65	74	69,9	81	65	65	65	74

Figure 5.5 b) ROP, WOB and RPM for wells drilled with bit size 24 in. and bit type SR1GRC



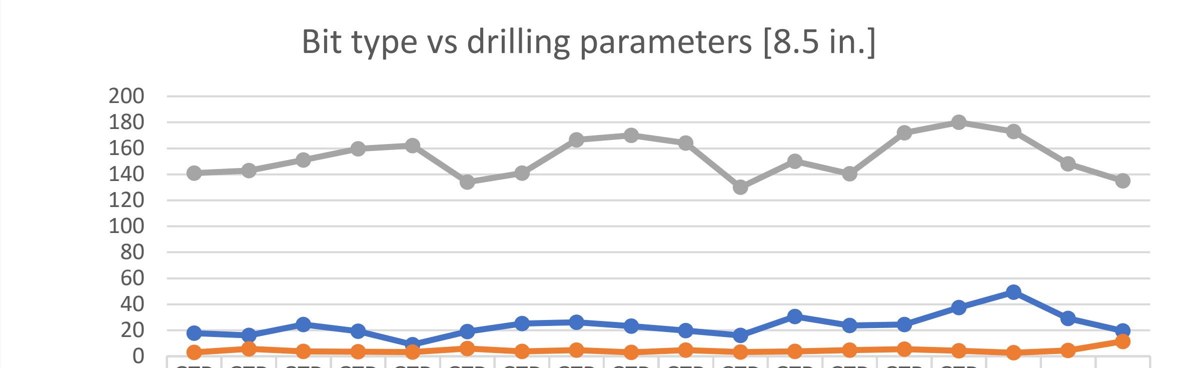
	2/8-V-2	2/8-V-3	2/8-V-4	2/8-V-4	2/8-V-5	2/8-V-6	2/8-V-7	2/8-V-8	2/8-V-8 T2	2/8-V-8 T3	2/8-V-9	2/8-V-12
ROP	73,01	77,91	82,79	48,09	56,34	70,37	70,39	57,96	41,59	21,95	65,38	75,76
WOB	8,3	5,05	4,85	5,8	5,6	7,3	5,6	7,7	3,45	1,55	6	4,15
RPM	155	153	154	120	155	150	156	159,5	130	150	157	153

Figure 5.5 c) ROP, WOB and RPM for wells drilled with bit size 16.5 in. and bit type GTD66DCs



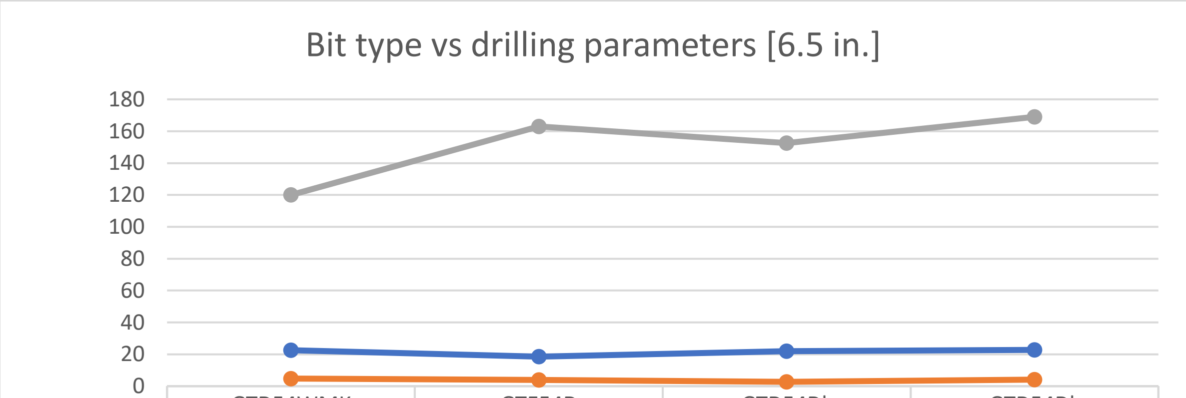
	GTi76W MKHOs 2/8-V-2	GTi76W MKHOs 2/8-V-4	GTD76W MKOs 2/8-V-3	GTD76W MKOs 2/8-V-3	GTi76W MKOs 2/8-V-5	GTD76W MKOs 2/8-V-7	GTi76W MKOs 2/8-V-8 T3	GTi76W MKOs 2/8-V-12	KM624 2/8-V-6	KM634X 2/8-V-9	KM634X 2/8-V-9
ROP	102,74	94,42	36,15	49,48	45,15	58,29	45,57	93,76	57,75	30	60,97
WOB	16,5	17,1	3,85	7,25	6,9	12,6	6,6	10,6	6	4,5	12,3
RPM	159	172,5	155,5	160	146	158	151,5	161	154	80	158

Figure 5.5 d) ROP, WOB and RPM for wells drilled with bit size 12.25 in. and varying bit type



	GTD 64M KOs 2/8-V-2	GTD 64M KOs 2/8-V2 Y2	GTD 64M KOs 2/8-V-3	GTD 64M KOs 2/8-V-3	GTD 64M KOs 2/8-V-3 T2	GTD 64M KOs 2/8-V-4	GTD 64M KOs 2/8-V-4 T2	GTD 64M KOs 2/8-V-4 Y2	GTD 64M KOs 2/8-V-5	GTD 64M KOs 2/8-V-6	GTD 64M KOs 2/8-V-7	GTD 64M KOs 2/8-V-7	GTD 64M KOs 2/8-V-12	GTD 64M KOs 2/8-V-12 T2	GTD 64M KOs 2/8-V-12 Y2	GTE64C 2/8-V-4 Y2	SFE65CH 2/8-V-8 T3	GTD 64 2/8-V-9
ROP	17,8	15,9	24,4	19,4	9,02	19	25,2	26,1	23,2	19,7	16,2	30,6	23,6	24,4	37,5	49,3	29,1	19,5
WOB	2,9	5,8	3,85	3,45	3,35	6	3,8	4,7	3	4,8	3,2	3,7	4,85	5,55	4,25	2,7	4,6	11,5
RPM	141	143	151	160	162	134	141	167	170	164	130	150	141	172	180	173	148	135

Figure 5.5 e) ROP, WOB and RPM for wells drilled with bit size 8.5 in. and varying bit type



	GTD54WMK 2/8-V2 Y2	GTE54D 2/8-V2 Y2	GTD54Dk 2/8-V-3 T2	GTD54Dk 2/8-V-3 T2
ROP	22,5	18,55	21,96	22,78
WOB	4,8	3,9	2,75	4,15
RPM	120	163	152,5	169

Figure 5.5 f) ROP, WOB and RPM for wells drilled with bit size 6.5 in. and varying bit type

From figure 5.5 a) – f), we observe that variation in ROP coincide with variation in RPM and WOB, as an increase in WOB and RPM renders an increase in ROP. This seems to especially be the case with ROP and RPM as the cures follow roughly the same trajectories. As ROP is directly proportional to WOB and RPM, one should therefore expect a corresponding increases/decreases in WOB and RPM to the ROP of the different bits. Established by Pearson's correlation matrix we observe that we should expect the effect of RPM to be more significant than the effect of WOB. Hence, coinciding with what we observe in our data.

Variables	ROP	WOB	RPM	FR
ROP	1			
WOB	0.140*	1		
RPM	0.39*	0.039*	1	
FR	0.39*	0.25*	0.57*	1

Significant at the 0.001 level

Figure 5.6: Pearson's correlation matrix [62]

However, data also illustrates deviations from this principle. This is noticeably displayed for the 24 in. bit in well 2/8-V-5. For this particular case we observe that this section at this well has the highest WOB and RPM of all the wells for that particular bit size while still having the lowest ROP. As suggested earlier, from the nature of this comparison, we suggested that lithology and bit type is similar across all wells, hence, making these insignificant parameters. However, unbeknown to us, there might have been smaller section(s) of dolomite or another hard rock formation in that particular section that might have worn the bit. Unfortunately, a lithological summary is not made in the geological report for this section, hence, making this explanation only a suggestion.

Furthermore, this inconsistency is also illustrated in the discrepancy in the reported drilling parameters between well 2/8-V-6 and 2/8-V-7 for bit size 32 in. For this case, we observe that well 2/8-V-7 has practically speaking the same RPM as well 2/8-V-6 as well as a higher WOB. However, despite this we observe that well 2/8-V-7 has a significantly lower reported ROP. Again, the particular reason(s) for this observation is difficult to pinpoint as there might be many different factors that affects the results, however this does seem to suggest other factors than the drilling parameters are at hand.

As a general observation, it might be said that there seems to be a suggestion based on the data that some bits had a significantly better performance than other bits for the same size and same bit type. Furthermore, we observe that drilling parameters such as WOB and RPM had an effect on ROP for the different bits, hence suggesting that the variation in ROP might be down on how the bit was drilled. On the other hand, we observe cases at which the relationship between WOB, RPM and ROP doesn't seem to coincide, giving rather unexpected results. This might as a result of lithology or the poor data quality discussed in section 5.1.

In general terms, this investigation seems to suggest that there are several different factors are at play, meaning for future reference better reporting of geology and "lessons learned" should be applied as the illustrated data shows there are significant opportunities for bit optimalization for achieve maximized ROP.

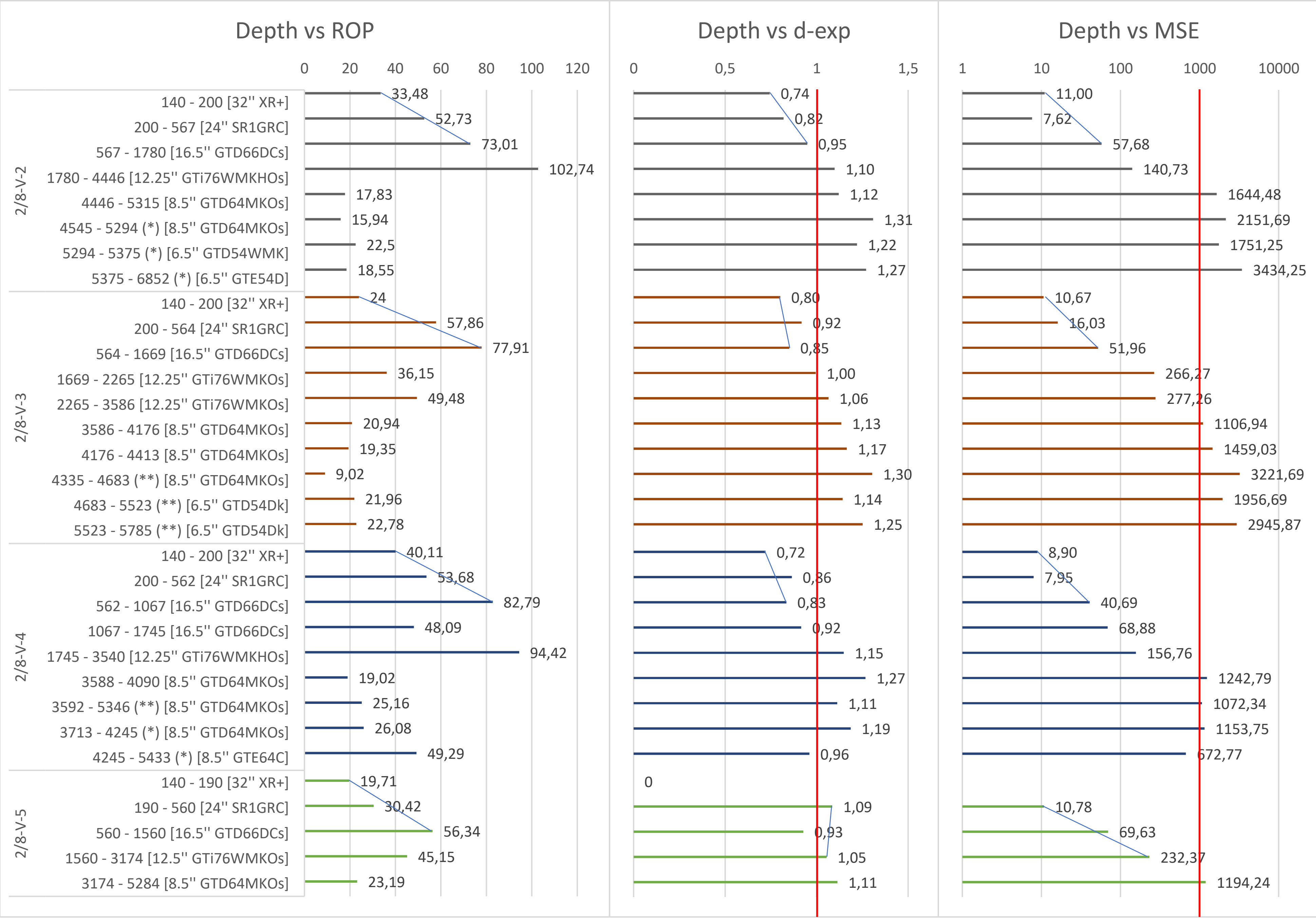
5.2.1.2 ROP by depth

To compare bit performance against depth we plot ROP, d-exponent and MSE to compare the overall performance of the different bits. This is displayed in figure 5.7 a) and b). Initial analysis of the plotted figures shows a general trend at which the ROP initially increases for the first 3 drilled sections, i.e. the 32'', 24'' and 16.5'' bit sizes (XR+, SR1GRC and GTD66DCs bits respectively) followed by a rapid decrease in reported ROP for the lower bit sizes. This seems to be the case for all wells expect for the wells 2/8-V-6, 2/8-V-7, 2/8-V-8, and 2/8-V-9 which has the 24'' SR1GRC drill bit either over- or underperforming in accordance with the suggested trend.

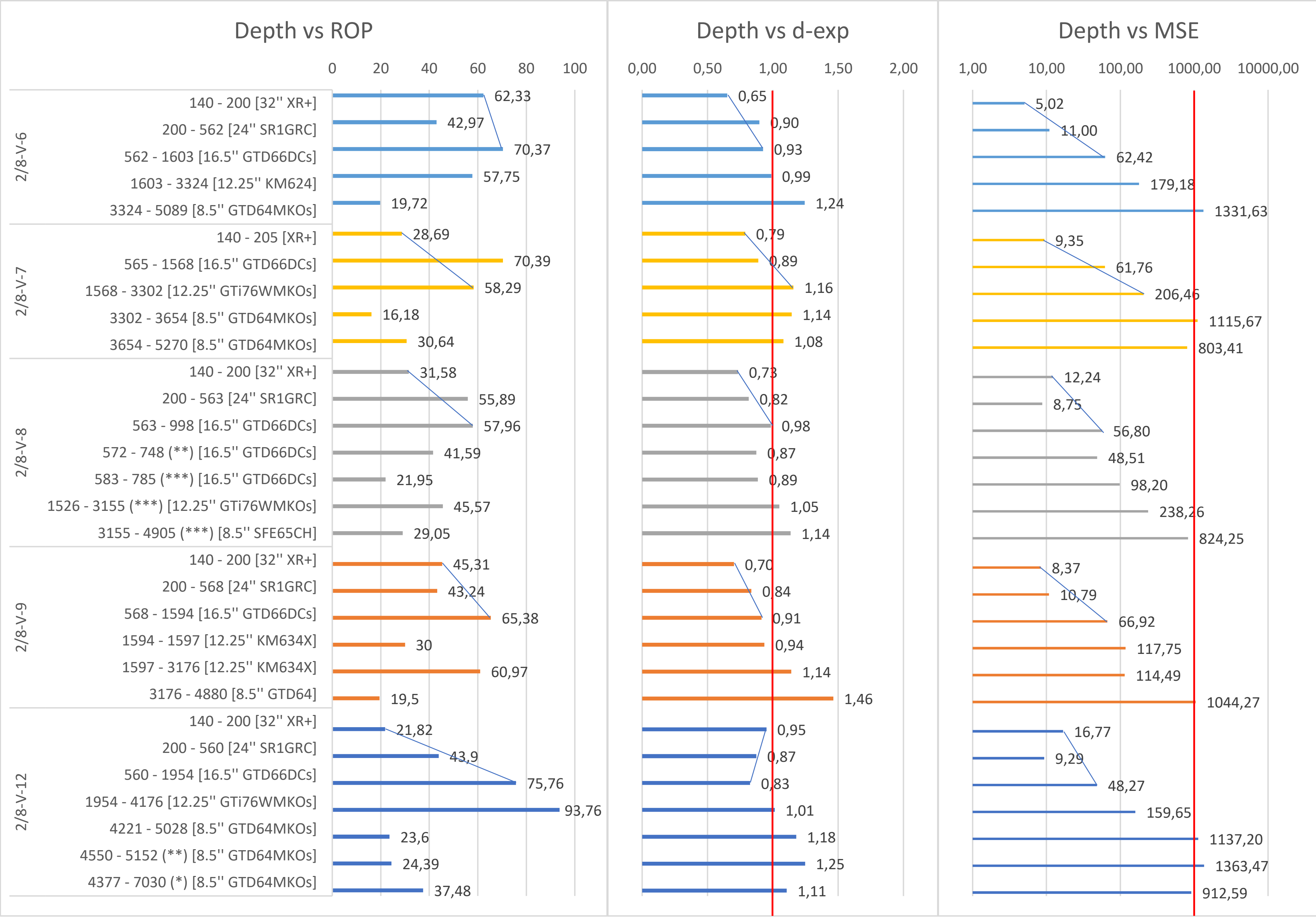
After the first 3 section, the general trend for most of the wells seems to be that the ROP falls drastically. To further analyze this, we draw a critical line for d-exponent equal to 1 and MSE equal to 1000. Doing this we can observe that the low ROP performance bits have d-exponent values over the critical line and significantly higher calculated MSE. This is of interest as it seems to be consistent across the different wells. High values of MSE is usually associated with low efficient drilling, which should be avoided. This is also reflected when observing that the bit runs that have a low ROP usually has a high MSE, which is explained by equation 3.2 that shows that ROP and MSE are inversely proportional to each other. The d-exponent on the other hand shows that for our low ROP runs, the drilling parameters are such that the nominator in equation 3.9 becomes dominated over the denominator, meaning the choice of the operational drilling parameters is having an effect on the reported ROP.

We therefore observe that there is a significant discrepancy in the efficiency of drilling between the top and bottom drill sections in the wells, hence, suggesting there are opportunities her for optimization. The reasons for this should be further analyzed.

Figures 5.7 a): Depth vs ROP, D-exponent and MSE



Figures 5.7 b): Depth vs ROP, D-exponent and MSE



As argued for earlier, the variation in ROP might be as a result of the controllable drilling parameters, in particular the choice of WOB and RPM. We observe that the bits with low ROP seems to be followed by a combination of low WOB and RPM. The ROP, WOB and ROM ranges are illustrated in figure 5.9 a) and b). In overall, the data does indeed seem to show a trend, however, it does not appear to be consistent as there are cases at which some bits perform better than others despite having a lower WOB and RPM. To illustrate this, we look at well 2/8-V-2 as a case study.

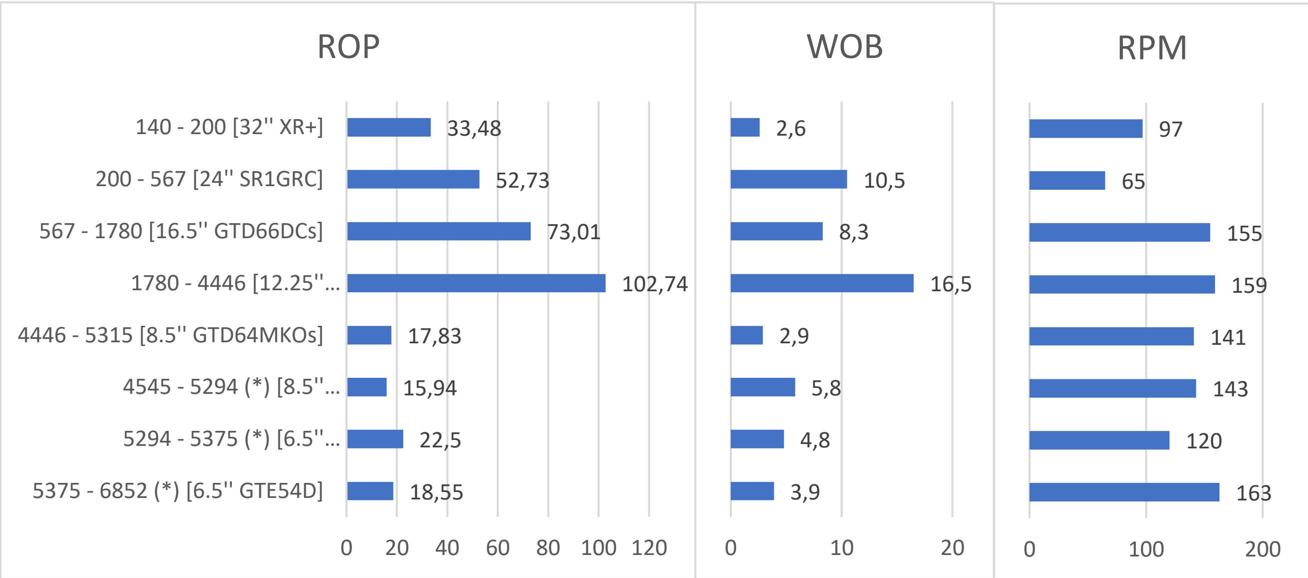


Figure 5.8: Well 2/8-V-2 Depth vs ROP, WOB, RPM

In the case study, we observe the aforementioned initial trend at which increase in ROP is followed with the increase in the reported WOB and RPM. In some cases, such as with the 24 in. SR1GRC bit, we have a very low RPM, however, this is compensated with a very high WOB, i.e. being in accordance to theory established earlier.

However, comparing the 32 in. bit against the 8.5 in. and 6.5 in. bit we observe that all lower sized bits operate at a higher WOB and RPM compared to the 32 in. bit while still having a significantly lower ROP, up to twice as low for some sections. This is unexpected and suggests there is more at hand giving us the ROP results we have plotted. The case study is by enlarge reflective of the bit behavior for most wells at this field.

In order to propose an explanation, we analyze the predominant lithology for both bit sizes. We have that the 32 in. bit is drilled in claystone while the 8.5 in. and 6.5 in. bits are drilled in chalk. The Mohr’s scale hardness rating is 1.0 for chalk and 3.5 – 4.0 for claystone [64], this should therefore mean that the 8.5 in. and 6.5 in. are drilled easier. However, our trend seems to suggest otherwise, this is therefore an interesting point to further investigate.

Figure 5.9 a): Depth vs ROP, WOB and RPM

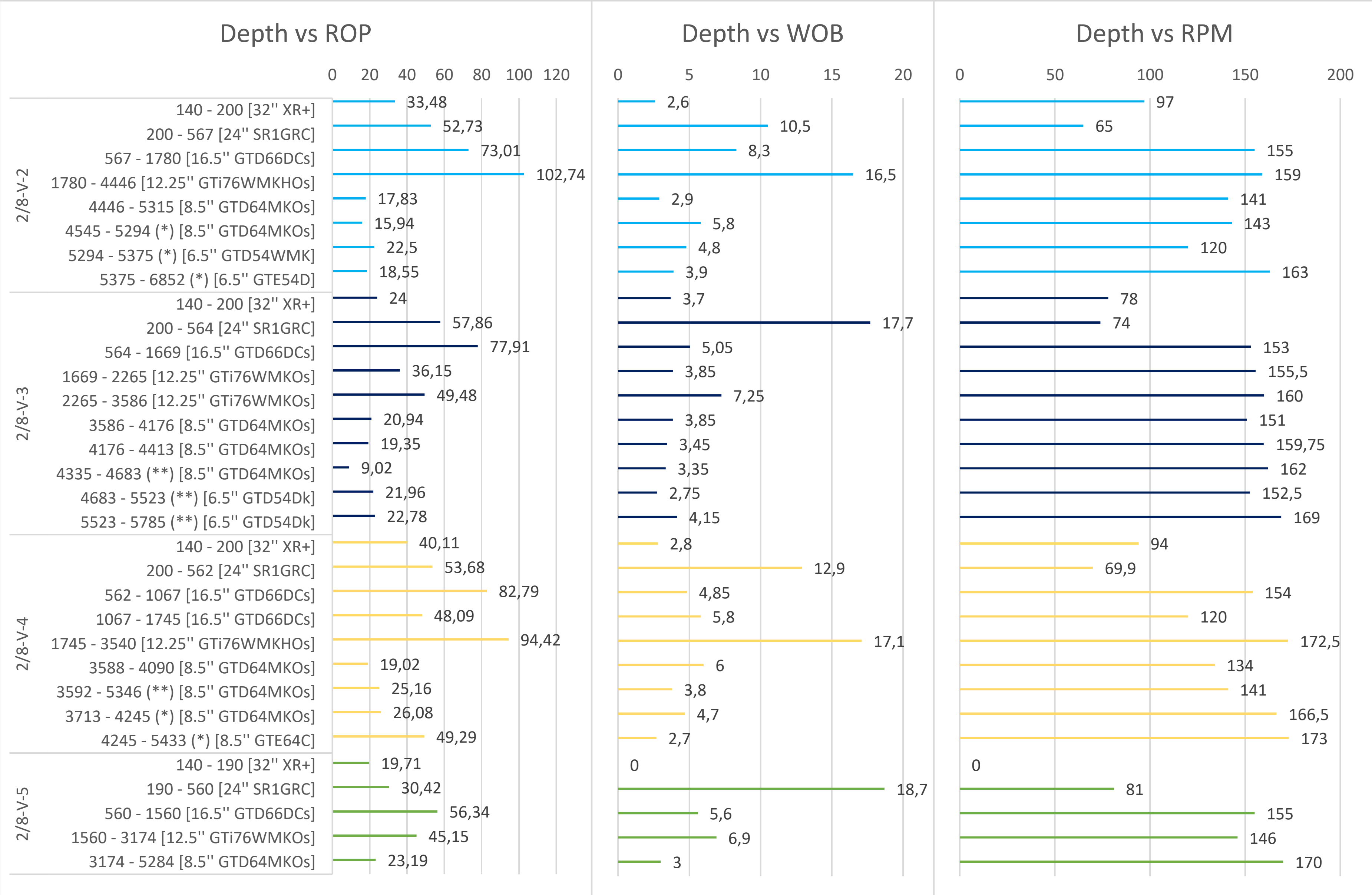
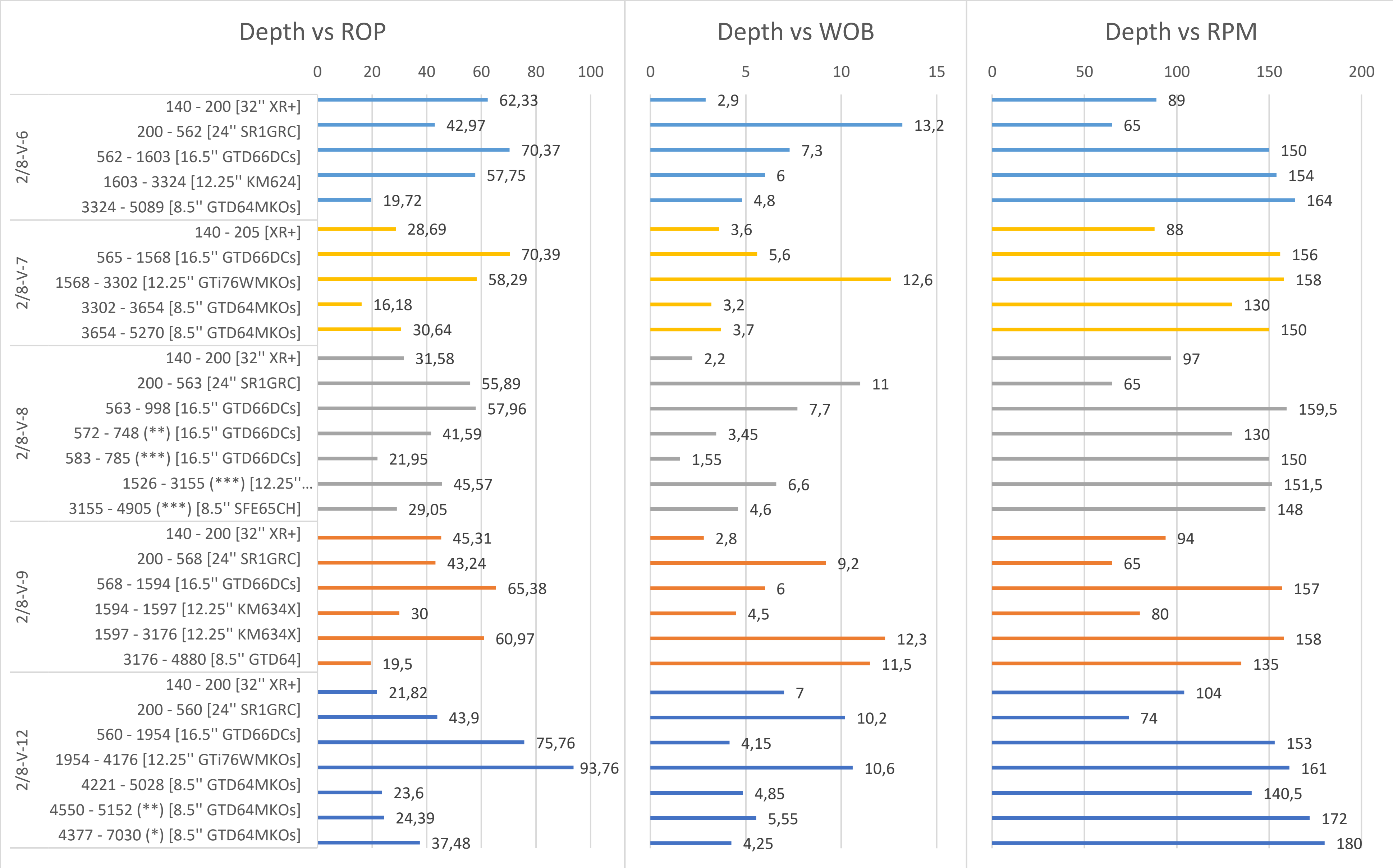


Figure 5.9 b): Depth vs ROP, WOB and RPM



5.2.2 Formation evaluation

The results from our investigation suggest that there are different factors affecting the drilling performance other than the drilling parameters. A more in-depth look into the lithological differences between the different sections are therefore needed. The UCS values between different rocks vary significantly, however, as the sonic log values are not included for the dataset provided, variation in UCS can unfortunately not be used for the investigation.

To deduce the geology of the Valhall Flank West field, we use tables 4.1 and 4.2 for this investigation. Furthermore, from section 5.2.1.2, we generally saw that ROP was significantly lower for the bit sizes 8.5 in. and 6.5 in. across all wells, despite reporting adequate values of WOB and RPM. We will therefore look for an explanation for the reduced ROP for these bit sizes.

The 32 in., 24 in., 16.5 in., and 12.25 in. section are mostly drilled in the Zulu, Nordland and Hordaland groups, which consists predominately of claystone with some minor siltstone sections. The consistency of the lithology with depth makes it possible to choose the drill bit that works the best in the formation in question, making it easier to record good drilling performance. On the other hand, drilling in claystone presents some issues such as shale swelling, however, it is reported that oil-based mud has been used for these sections, negating the problem.

5.2.2.1 Calcite stingers

The 8.5 in. and 6.5 in. drill bits are mostly drilled in the Rogaland and Shetland formation groups, where the lithology is mostly chalk. Chalk is generally reported as a soft and highly porous rock, hence, suggesting drilling should have been easier here. This notion however is not representative of our finding in Valhall Flank West. An explanation for this might be the presence of calcite stringers. A stringer is a large rock inclusion embedded in the formation which is very hard. Drilling through stringers is therefore followed by inefficient drilling and fatigue of the drill bit. Checking the public records of the Norwegian Petroleum Directorate (NPD), we have that the Lista and Balder formations from the Rogaland group has reported occasional sections of stringers of limestone, dolomite and pyrite for well drilled in these formations. This might therefore indicate we have this in wells at Valhall Flank West too. The presence of hard formations of dolomite and pyrite presents a significant challenge as these rocks/mineral results in fatigue and wear of the drill bit, resulting in reduced drilling performance.

To determine the presence of calcite stringers we analyze the well logs for the different wells in the Valhall Flank West field. Figure 5.10 is a snippet from the Surface Data Logging Formation Evaluation Log by Halliburton, and the selected depth corresponds to the 8.5 in. bit drilled in well 2/8-V-2. At depths 4910 – 4912 m MD, we observe an event at which the ROP is drastically reduced, effectively 0 m/hr. The same is the case for the hookload.

The hookload is defined as the effective total force pulling force on the hook as in our case, since we're tripping in (-) and tripping out (+) is given by:

$$Hookload = Travelling\ block + self\text{–}weight\ \pm drag\ force \quad \text{Eq. (5.1)}$$

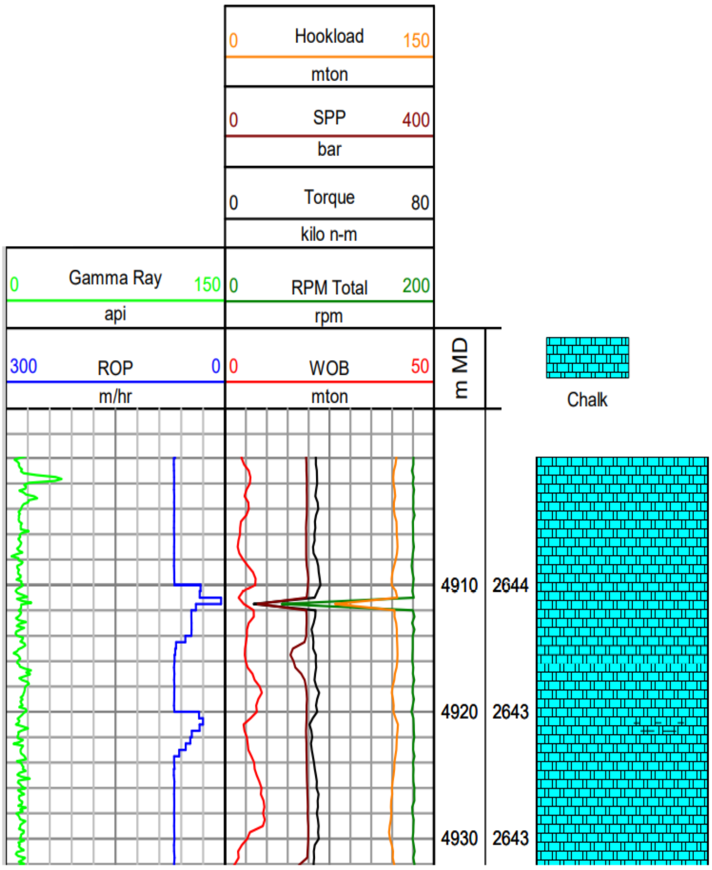


Figure 5.10: Snippet from the well log of well 2/8-V-2

Analyzing the definition, we observe that the drastic reduction in hookload must come as a result of significant increase in drag force. The lithology descriptions do not show any changes however, showing that the entire section consists of chalk. We may therefore strongly suggest that we have the presence of calcite stringer in the lower sections. It should also be noted that the ROP and hookload behavior noted in figure 5.10 is observed several times in deeper sections too.

The run lengths of the 8.5 in. bits and the 6.5 in. bits are usually around 500 m – 1500 m and 750 m – 1500 m respectively, it is therefore highly likely that the runs might have encountered calcite stringers, hence the low reported average ROP for the given section.

Taking into consideration that the reported ROP is the average across the entire run length, the effect of the calcite stringers is highly significant as these sections push the average value drastically down. We therefore have a possible suggestion for the reduction in ROP in the lower sections. This is also supported by the fact that the observation made in figure 5.10 is observed multiple times in the well logs for the different wells in Valhall Flank West.

5.2.2.2 Bit dulling

Another factor which leads to reduced drilling performance is bit dulling, the process at which the drill bit is damaged by the drilling of the formation. Bit dulling generally results in increased MSE and the fall of ROP as the drilling is done inefficiently, observations done in the earlier sections and displayed by figure 5.7 a) and b). This might therefore suggest we have bit dulling as a possible explanation as for the reduction in drilling performance.

The drill bits used are roller-cone bits for the 32 in. and 24 in. sizes, while primarily fixed-cutter and occasionally hybrid bits are used for the other bit sizes. The FWR as well as standard drilling practices say that all bits used were new at the start of the drilling, hence, the bit damage can only be attributed to drilling of the formation. To investigate the effect of bit dulling on the drilling performance, we have analyzed the bit deterioration for all bits used in all wells. The full reports of the dull grading for the different wells is presented in appendix A.3. To present the findings, we illustrate the general trend seen in all the wells by presenting dull grading in well 2/8-V-2.

Analyzing the reported results in table 5.1, the consensus seems to be that the wear of the bit is more substantial in the lower sections than in the upper. The 32 in. bit was reported to display a T1 tooth wear, but the dull characterization of "NO" (No dull characteristic) tells that this was not of significance. This is also observed for the 24 in. and 16.5 in. bits that were reported to have a T1 tooth wear, however, these bits report the dull characteristic WT (Worn teeth/cutters) more substantial than the "NO" (No dull characteristics) reported for the 32 in. bit. As 24 in. and 16.5 in. bits have a significantly longer bit run compared to the 32 in. bit, the increase in bit wear is expected as the bit is prone to more wear the longer it has been used.

Beyond this, an interesting observation emerges when analyzing the 12.25 in. and 8.5 in. drill bits. The 12.25 in. drill bit has by far the longest run length, 2666 m, and was registered has having a T1 wear and BT (Broken teeth) dull characteristic. The 8.5 in. bit on the other hand registered a run length of 869 m but a had a T2 inner row wear, T1 out row wear and it was registered it had a WT dull characteristic.

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-2	XR+	32	140 – 200	New	1-1-NO-A-E-I-NO-TD
2/8-V-2	SR1GRC	24	200 – 567	New	1-1-WT-A-E-I-NO-TD
2/8-V-2	GTD66DCs	16.5	567 – 1780	New	1-1-WT-A-X-I-NO-TD
2/8-V-2	GTi76WMKHOs	12.25	1780 – 4446	New	1-1-BT-G-X-I-NO-TD
2/8-V-2	GTD64MKOs	8.5	4446 – 5315	New	2-1-WT-A-X-I-NO-TD

Table 5.1: Dull grading for bits in well 2/8-V-2

We therefore see that the 8.5 in. bit had the most wear despite not having the longest bit run. To further illustrate this, we observe the differences in the bit wear between bit 16.5 in. and 8.5 in. as these two bits had the closest bit run as well as being registered with WT (Worn teeth/cutter). This is illustrated in figure 5.11. From the figure, we observe the difference in wear between the two bits, primarily the tooth wear. In this case we see that the 8.5 in. bit has substantial dulling with several teeth showing wear. The 16.5 in. bit seems to also demonstrate to wear, albeit, not to the extend seen for the 8.5 in. bit. The bit dulling in this case would severally reduce the drilling performance for the section drilled with the 8.5 in. compared to the section drilled with the 16.5 in. bit.

This coincides with the observations made earlier regarding the significant reduction in ROP and other drilling parameters with depth. Bit wear has previously been shows to hamper with drilling performance as inefficient drilling leads to increased MSE and reduced ROP, a process seen for the bits used in Valhall Flank West. The investigation for well 2/8-V-2 as well as for the other wells (presented in appendix A.3) seems to back this claim as we see high bit wear for sections that were drilled less efficiently. The reason for the increased wear in the lower sections might again be as a result of the presence of calcite stringers which are very hard to drill through and not fully mapped location wise, hence, resulting in high bit wear.

Furthermore, the NPD has listed the presence of dolomite and pyrite for the Rogaland and Shetland formation groups, both hard rocks/minerals that result in wear.

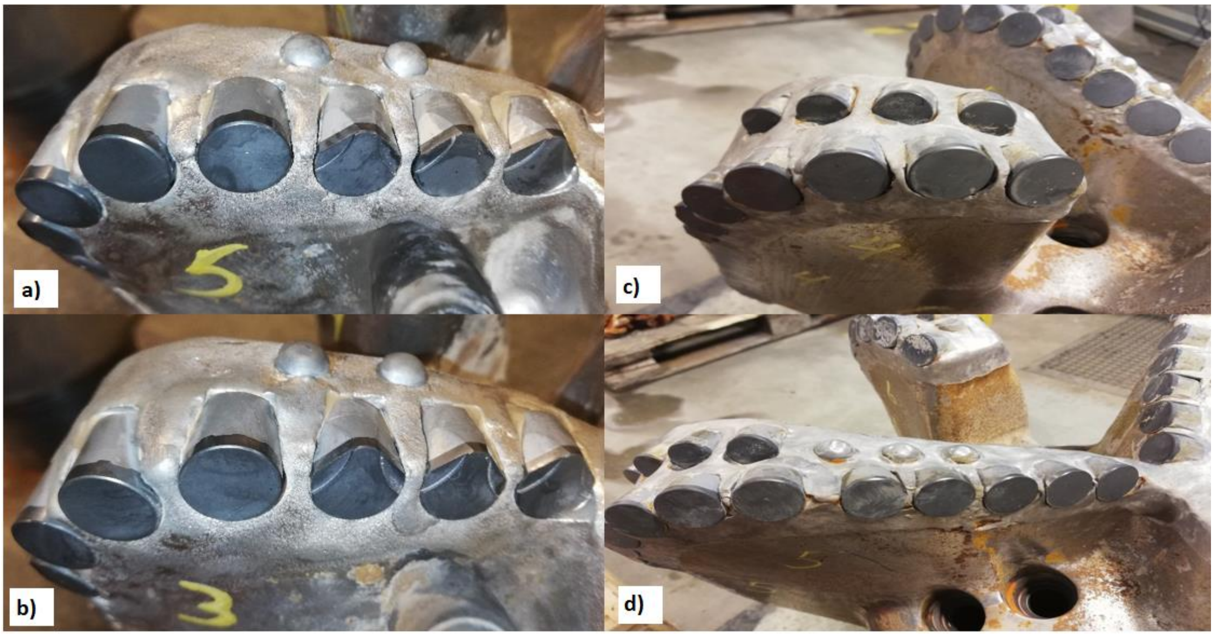


Figure 5.11: Presentation of drill bits sized 8.5 in. (a & b) and drill bit sized 16.5 (c & d)

As a conclusion it might be said that for wells in Valhall Flank West, bit dulling may provide a suggestion for the reduced efficiency when drilling in the deeper section as we observe significant reduction in ROP and sharp increase in MSE. As the increased bit wear seems to be tied with the geology of lower section, we might conclude that the combined effect of stringers and the subsequent bit wear they cause may be a possible cause of the observed trend.

5.3 Ideal well configuration

To deduce the ideal performance of the different bits, we construct an ideal well to visualize further production by systematically improving on a learning curve. The nine different wells in the Valhall Flank West field are set at approximately the same depth and are relatively close, making it possible to assume same geology is present for each individual section. Normalization for the drilling parameters is not needed as the selection criteria such as ROP, MSE and etc. are already depth normalized.

5.3.1 Breakdown of drilling parameters for each bit size section

In the following, drilling parameters for each bit in all wells for each particular size will be compared. Deciding which section from which well was drilled most efficiently is a difficult process and there are many different factors that hinges on the decision making. For the basis of this thesis, the best performing bit will be chosen by the criteria:

- ROP – As high as possible
- MSE – As low as possible
- D-exponent – As low as possible
- WR – As low as possible
- K_f – As high as possible

For each section listed, the best well based on the different criteria is highlighted. In case no particular bit significantly differentiates as having the best performance based on said criteria, ROP/MSE will be calculated and used to provide a definitive conclusion.

<u>32'' bit size hole section:</u>

Table 5.2 is the summary of calculated performance for the upmost section. We observe that there was a significant variation in the performance, however, some overall trends are:

- The data highlighted significant differences in ROP
- Well 2/8-V-6 performed the best regarding ROP, MSE, D-exp and K_f and is therefore chosen. The WR on the other hand seems to suggest that the 2/8-V-8 was drilled more efficiently, however, since the 2/8-V-6 well scores better in the other criteria and has the second best WR, this well is chosen.

Well name	Bit type	Bit size	ROP	MSE	D-exp	WR	K_f
2/8-V-2	XR+	32’’	33.48	11.00	0.74	7.88	4.25
2/8-V-3	XR+	32’’	24	10.67	0.80	9.02	2.66
2/8-V-4	XR+	32’’	40.11	8.90	0.72	8.23	4.88
2/8-V-5	XR+	32’’	19.71	NaN	NaN	NaN	NaN
2/8-V-6	XR+	32’’	62.33	5.02	0.65	8.07	7.73
2/8-V-7	XR+	32’’	28.69	9.35	0.79	9.90	2.90
2/8-V-8	XR+	32’’	31.58	12.24	0.73	6.67	4.74
2/8-V-9	XR+	32’’	45.31	8.37	0.70	8.23	5.51
2/8-V-12	XR+	32’’	21.82	16.77	0.95	22.75	0.96

Table 5.2: Bit performance of 32’’ bits

24’’ bit size hole section:

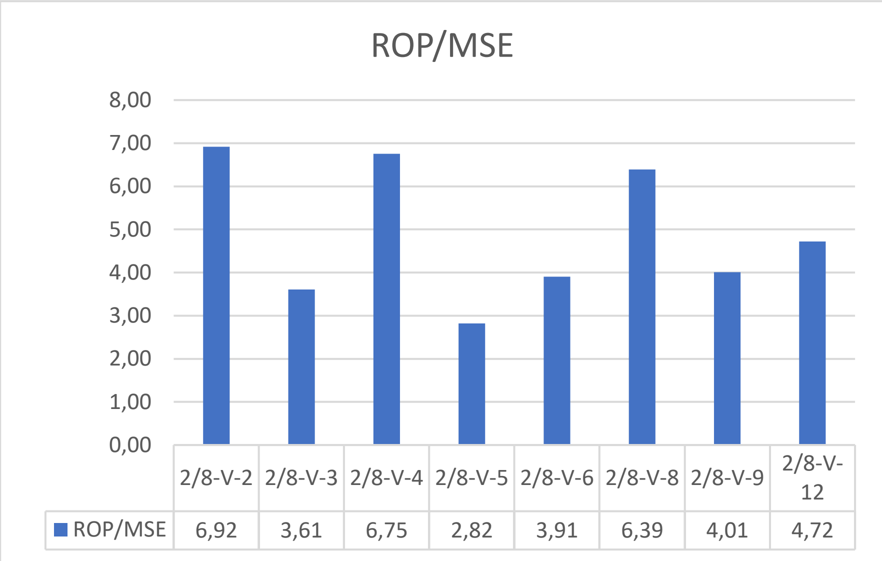
Table 5.3 is the summary of calculated performance for the 24’’ bit size hole section. We observe that there was a significant variation in the performance, however, some overall trends are:

- The different criteria seem to disagree with which well performed best. In total, there are 4 different wells to choose between with significant variations when analyzing the best scoring criteria against the other criteria for the said wells.
- In general, the performance seemed to be rather consistent for all wells with the exception for the 2/8-V-5 wells that performed the worse in nearly all of the criteria.

Well name	Bit type	Bit size	ROP	MSE	D-exp	WR	K_f
2/8-V-2	SR1GRC	24’’	52.73	7.62	0.82	28.44	1.85
2/8-V-3	SR1GRC	24’’	57.86	16.03	0.92	54.58	1.06
2/8-V-4	SR1GRC	24’’	53.68	7.95	0.86	37.57	1.43
2/8-V-5	SR1GRC	24’’	30.42	10.78	1.09	63.11	0.48
2/8-V-6	SR1GRC	24’’	42.97	11.00	0.90	35.75	1.20
2/8-V-8	SR1GRC	24’’	55.89	8.75	0.82	29.79	1.88
2/8-V-9	SR1GRC	24’’	43.24	10.79	0.84	24.92	1.74
2/8-V-12	SR1GRC	24’’	43.90	9.29	0.87	31.45	1.40

Table 5.3: Bit performance of 24’’ bits

To deduce which well performed highest, we need to look at the different properties more in depth. ROP can be seen as drilling resistance while MSE can be seen as drilling efficiency and rock resistance. Thus, we might take the ROP/MSE ratio and use this to differentiate the bits as a high ROP/MSE would suggest the bit was drilled with high efficiency as the rock resistance will stay the same.



From the figure we observe that well 2/8-V-2 records the highest ROP/MSE, narrowly edging out well 2/8-V-4. As this well has the highest ROP/MSE, MSE and d-exponent, we choose this as the best performing section.

Figure 5.12: ROP/MSE values of 24’’ bits

<u>16.5’’ bit size hole section</u>

Table 5.4 is the summary of the performance for the 16.5’’ bit size hole section. General observations seem to be:

- The sidetracked sections performed significantly worse in regard to ROP
- Well 2/8-V-4 (1) performed the highest ROP, lowest MSE and shared lowest d-exponent with well 2/8-V-12
- The calculated WR and K_f on the contrary show that the 2/8-V-8 T3 and 2/8-V-12 wells performed significantly better at the former and the latter respectively
- As the 2/8-V-4 (1) well has the best performance in ROP, MSE and d-exponent, while still having the second-best performance in calculated K_f, this section is therefore chosen.

Well name	Bit type	Bit size	ROP	MSE	D-exp	WR	K_f
2/8-V-2	GTD66DCs	16.5’’	73.01	57.68	0.95	77.97	0.94
2/8-V-3	GTD66DCs	16.5’’	77.91	51.96	0.85	46.83	1.66
2/8-V-4 (1)	GTD66DCs	16.5’’	82.79	40.69	0.83	45.27	1.83
2/8-V-4 (2)	GTD66DCs	16.5’’	48.09	68.88	0.92	42.18	1.14
2/8-V-5	GTD66DCs	16.5’’	56.34	69.63	0.93	52.61	1.07
2/8-V-6	GTD66DCs	16.5’’	70.37	62.42	0.93	66.36	1.06
2/8-V-7	GTD66DCs	16.5’’	70.39	61.76	0.89	52.95	1.33
2/8-V-8	GTD66DCs	16.5’’	57.96	56.80	0.98	74.43	0.78
2/8-V-8 (**)	GTD66DCs	16.5’’	41.59	48.51	0.87	27.18	1.53
2/8-V-8 (***)	GTD66DCs	16.5’’	21.95	98.20	0.89	14.09	1.56
2/8-V-9	GTD66DCs	16.5’’	65.38	66.92	0.91	57.09	1.15
2/8-V-12	GTD66DCs	16.5’’	75.76	48.27	0.83	38.48	1.97

Table 5.4: Bit performance of 16.5’’ bits

<u>12.25’’ bit size hole section</u>

The performance of the 12.25’’ bit size hole section is presented in table 5.5 below. This bit size is rather important as this section has the longest run length. Analysis of the drilling performance highlights that:

- The 2/8-V-2 had a significantly higher ROP compared to the other wells.
- The Kymera hybrid bits performed best in all performance criteria expect for ROP.
- The KM634X bit in 2/8-V-9 (1) seems to be the best performing bit comparing MSE, d-exponent, WR and K_f, however, this bit has only a 3 m run length and a recorded 0.1 hours of drilling time. It is therefore not possible to choose this as the best performing bit as low amount of usage gives uncertainties and not a true picture of its performance. Hence, another bit will be chosen.
- The second-best performing bit in regard to d-exponent, WR and K_f was the KM624 bit from the 2/8-V-6 well. However, this well records rather poor ROP and MSE values compared to the rest of the wells. To decide which well performed better the ROP/MSE is calculated again (figure 5.13). From this we observe that 2/8-V-2 well is performing better relative to the other wells.
- The section drilled in the 2/8-V-2 well is chosen as the best performing section.

Well name	Bit type	Bit size	ROP	MSE	D-exp	WR	K_f
2/8-V-2	GTi76WMKHOs	12.25''	102.74	140.73	1.10	214.16	0.48
2/8-V-4	GTi76WMKHOs	12.25''	94.42	156.76	1.15	240.80	0.39
2/8-V-3 (1)	GTi76WMKOs	12.25''	36.15	266.27	1.00	48.87	0.74
2/8-V-3 (2)	GTi76WMKOs	12.25''	49.48	277.26	1.06	94.69	0.52
2/8-V-5	GTi76WMKOs	12.25''	45.15	232.37	1.05	82.24	0.55
2/8-V-7	GTi76WMKOs	12.25''	58.29	206.46	1.16	162.51	0.36
2/8-V-8 (***)	GTi76WMKOs	12.25''	45.57	238.26	1.05	81.62	0.56
2/8-V-12	GTi76WMKOs	12.25''	93.76	159.65	1.01	139.31	0.67
2/8-V-6	KM624	12.25''	57.75	179.18	0.99	75.43	0.77
~~2/8-V-9 (1)~~	~~KM634X~~	~~12.25''~~	~~30~~	~~117.75~~	~~0.94~~	~~29.39~~	~~1.02~~
2/8-V-9 (2)	KM634X	12.25''	60.97	114,49	1.14	158.64	0.38

Table 5.5: Bit performance of 12.25'' bits

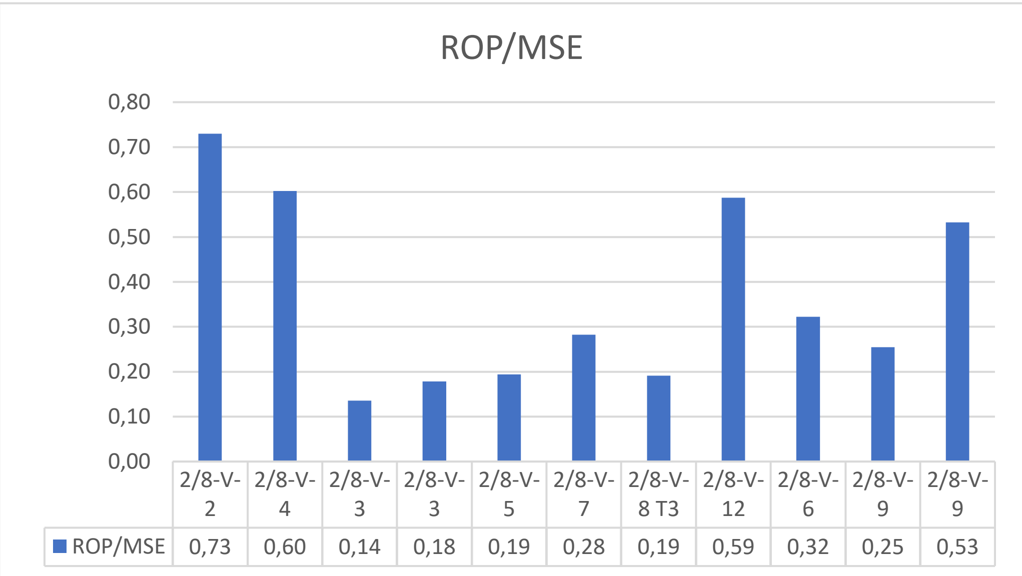


Figure 5.13: ROP/MSE values of 24'' bits

<u>8.5'' bit size hole section</u>

The 8.5'' size bits have been used in the most sidetracks and is predominantly drilled in chalk, analyzing the performance of the drill bits, following observations are made:

- The GTE64C fixed-cutter drill bit performed significantly better than the other bits in all performance criteria expect for the WR.

- The 2/8-V-3 T2 well recorded the worst performance across the board.
- As the 2/8-V-4 Y2 well had the best reported ROP, MSE, d-exponent and K_f, while still having a good WR, this is chosen as the best well.

Well name	Bit type	Bit size	ROP	MSE	D-exp	WR	K_f
2/8-V-2	GTD64MKOs	8.5’’	17.83	1644.48	1.12	48.11	0.37
2/8-V-2 (*)	GTD64MKOs	8.5’’	15.94	2151.69	1.31	97.58	0.16
2/8-V-3 (1)	GTD64MKOs	8.5’’	24.38	1106.94	1.13	68.39	0.36
2/8-V-3 (2)	GTD64MKOs	8.5’’	19.35	1459.03	1.17	64.84	0.30
2/8-V-3 (**)	GTD64MKOs	8.5’’	9.02	3221.69	1.30	63.85	0.14
2/8-V-4	GTD64MKOs	8.5’’	19.02	1242.79	1.27	94.59	0.20
2/8-V-4 (**)	GTD64MKOs	8.5’’	25.16	1072.34	1.11	63.04	0.40
2/8-V-4 (*)	GTD64MKOs	8.5’’	26.08	1153.75	1.19	92.06	0.28
2/8-V-5	GTD64MKOs	8.5’’	23.19	1194.24	1.11	60.00	0.39
2/8-V-6	GTD64MKOs	8.5’’	19.72	1331.63	1.24	92.61	0.21
2/8-V-7 (1)	GTD64MKOs	8.5’’	16.18	1115.67	1.14	48.94	0.33
2/8-V-7 (2)	GTD64MKOs	8.5’’	30.64	803.41	1.08	65.29	0.47
2/8-V-12	GTD64MKOs	8.5’’	23.60	1137.20	1.18	80.17	0.29
2/8-V-12 (**)	GTD64MKOs	8.5’’	24.39	1363.47	1.25	112.31	0.22
2/8-V-12 (*)	GTD64MKOs	8.5’’	37.48	912.59	1.11	90.00	0.42
2/8-V-4 (*)	GTE64C	8.5’’	49.29	672.77	0.96	54.95	0.90
2/8-V-8 (***)	SFE65CH	8.5’’	29.05	824.25	1.14	80.09	0.36
2/8-V-9	GTD55DKS	8.5’’	19.50	1044.27	1.46	182.65	0.11

Table 5.6: Bit performance of 8.5’’ bits

<u>6.5’’ bit size hole section</u>

This bit size was the least used size and was only used for sidetracks. The performance analysis seems to indicate that the GTE54Dk drill bit for the 2/8-V-3 T2 well performed best for d-exponent, WR and K_f while still having suitable ROP and MSE. This bit run is therefore considered as being the best.

However, as the 6.5'' sized bits have only been used as sidetracks and there are few instances of this size being used, this bit size will not be included when constructing the ideal well. This is done to retain as much similarity as possible when conducting a comparison.

Well name	Bit type	Bit size	ROP	MSE	D-exp	WR	K_f
2/8-V-2 (*) (1)	GTD54WMK	6.5''	22.50	1751.25	1.22	88.62	0.25
2/8-V-2 (*) (2)	GTE54D	6.5''	18.55	3434.25	1.27	97.80	0.19
2/8-V-3 (**) (1)	GTE54Dk	6.5''	21.96	1956.69	1.14	64.52	0.34
2/8-V-3 (**) (2)	GTE54Dk	6.5''	22.78	2945.87	1.25	107.90	0.21

Table 5.7: Bit performance of 6.5'' bits

General observations:

Having picked the most ideal bit size sections, one observations seem to be that the 2/8-V-2 and 2/8-V-4 wells generally were drilled efficiently compared to the other wells as 4 out of 5 best performing bits according to its size was from these 2 wells.

These two wells were drilled last and second-to-last chronologically, this may suggest a definitive improvement with time, which is to be expected as prognosed lithology can be more accurately determined with actual data, as well as lessons learned from drilling the previous wells and etc. leading to better drilling performance.

5.3.2 Creating the ideal well

The previous discussion compromised many elements which have be addressed for each bit. Having determined the best performing bits from all wells, we will now use the best bits from each section and generate an ideal well. This ideal well is achievable if no problems arise and if the well is drilled at the best recorded performance. We know, however, that inefficiency will always occur, hence, giving us poorer results than what is prognosed in theory. This ideal well will therefore present the most optimal well based on performance that has already been recorded.

From the previous section, we observed that the following bits were chosen as the best performing:

- In the 32 in. bit size section well **2/8-V-6** performed best
- In the 24 in. bit size section well **2/8-V-2** performed best
- In the 16.5 in. bit size section well **2/8-V-4** performed best
- In the 12.25 in. bit size section well **2/8-V-2** performed best
- In the 8.5 in. bit size section well **2/8-V-4 Y2** performed best

With the information at hand, we compose an ideal well based on the best performances of the other wells. Hence, giving us:

Well (Taken from)	**Bit size**	**Bit type**	**MD in (m)**	**MD out (m)**	**Run length**	**Drilling hours**
2/8-V-6	32’’	XR+	140	200	60	5.8
2/8-V-2	24’’	SR1GRC	200	567	367	6.95
2/8-V-4	16.5’’	GTD66DCs	562	1067	505	6.1
2/8-V-2	12.25’’	GTi76WMKHOs	1780	4445	2665	25.95
2/8-V-4	8.5’’	GTE64C	4245	5433	1188	24.1

Bit size	**Bit type**	**ROP**	**WOB**	**RPM**	**Torque**	**MSE**	**D-exp**	**WR**	K_f
32’’	XR+	62.33	2.9	89	7.5	5.02	0.65	8.07	7.73
24’’	SR1GRC	52.73	10.5	65	7.4	7.62	0.82	28.44	1.85
16.5’’	GTD66DCs	82.79	4.85	154	12.4	40.69	0.83	45.27	1.83
12.25’’	GTi76WMKHOs	102.74	16.5	159	28.4	140.73	1.10	214.16	0.48
8.5’’	GTE64C	49.29	2.7	173	28.85	672.77	0.96	54.95	0.90

Table 5.8: Drilling parameters of the ideal well

To illustrate the improvements of the ideal well in comparison to the other wells, we take the average values of the bit sizes 32’’ – 8.5’’ for all wells and plot these, which is done in figure 5.15. Analyzing the figure, the general observation seems to be that for all bit sizes, the drill bits used in the ideal well perform at a higher ROP. On the other hand, a similar observation is that the WOB seems to be lower for all bits in the ideal well while the RPM is similar. This is not in accordance to established theory as one will expect that if we have two wells, with all other parameters remaining the same, the well with the highest WOB and RPM would have the highest ROP.

Geology of the drilled sections are assumed to be similar, thus, lithology is not assessed as a main contributor for the discrepancy. An explanation might be outliers in the dataset skewing the average values and other sorts of uncertainties in reporting, however, this does not suggest an explanation for the observations. The discrepancy in WOB and RPM is especially noteworthy as these are drilling parameters that by in large is controlled by the driller. This therefore suggests again that there are additional factors affecting the drilling operation.

Further percentage differences between the ideal well and the average well is displayed in figure 5.14. The figure displays the percentage differences for the ideal well in comparison to the averages of the other wells. As argued earlier, the data seems to suggest a significant improvement in ROP, a general reduction in WOB while retaining rather similar values of RPM. Furthermore, we observe sharp improvements regarding MSE and minor improvements of the d-exponent. Note that MSE and d-exponent values should be kept as small as possible, i.e. figure 5.14 illustrates that the ideal well is drilled more efficiently.

The same trend is observed for K_f as the ideal well has higher values for all bit sizes with the exception of the 12.25’’ bit. Analyzing the parameters used when calculating the K_f, i.e. WOB, RPM and ROP, an observation made seems to be that for the drill bit deduced to be the best performing 12.25’’ size bit, we observe a very high WOB. A high WOB is beneficial to achieve a high ROP, however, it does also give a low K_f as these two properties are inversely proportional.

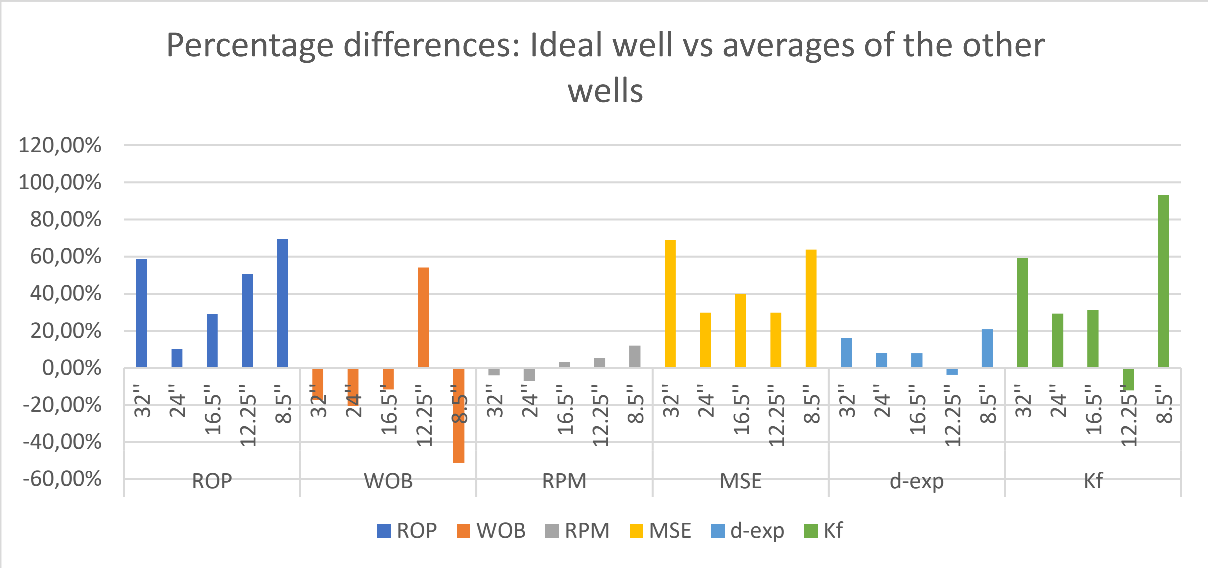


Figure 5.14: Percentage differences in drilling performance of ideal well in comparison with averages of the other wells

We can therefore observe that there is a significant potential for improvement for the wells drilled in Valhall Flank West. This is especially so as the ideal well on average across all bit sizes was drilled at a 43.6% higher ROP and 46.4% lower MSE. The ideal well is not realizable as many different factors affect the drilling process, however, this well does suggest the average performance of the drilled wells are significantly lower than optimal drilling as the ideal well continuously reports significantly better drilling performance at all bit sizes. This may therefore suggest that given the data, drilling strategies must be revived for future wells in this field.

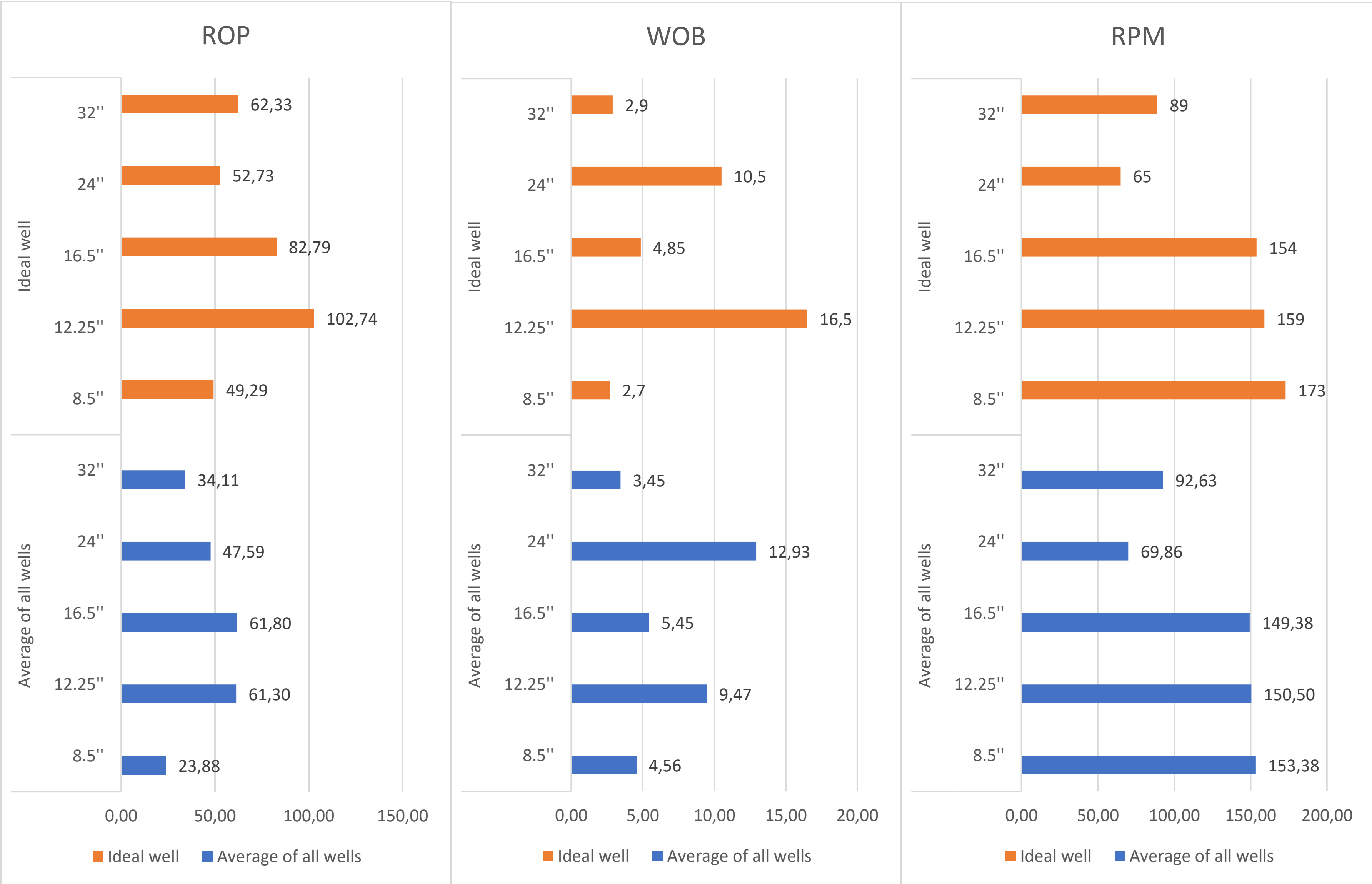


Figure 5.15: Comparison of ROP, WOB and RPM of the ideal well and average values for the other wells for each respective bit size

5.4 Economic consideration

To further analyze the wells in the Valhall Flank West, we conduct an economic analysis for the wells. This is done so to illustrate the economic potential of the ideal well as well as deducing if there are significant cost differences between the different wells. The economic considerations are done by calculating the cost/meter for each well based on the formula presented in section 3.3.1.

For this thesis section, the sidetracks will be included for each individual well and calculated together. This is done because the sidetracks are a part of the well and usually done because of technical reasons, meaning that they too are to be included when calculating the expenditure for the well. Furthermore, the drill bits with sizes 26 in. and 17 in. which was left out for the calculations in section 5.2 and 5.3 are included here as ROP and other drill bit performance parameters are not being used nor being compared. Not including these bit sizes would therefore give incorrect results as we would report a lower run length than what truly was drilled. The cost/meter data is presented in table 5.10 a) and b).

The figures show that by enlarge, the 32 in. bits had the highest cost/meter, making these sections the most expensive to drill. This is followed by 24 in. bit which had on average a 6 times lower cost/meter than the 32 in. bit. Furthermore, we observe that some of the 8.5 in. bits has a very high cost/meter, this is especially observed for the 8.5 in. bit in well 2/8-V-2 Y2. A common factor between these high cost/meter seems to be that they have small run lengths.

As the data is length normalized, we might use the combined cost/meter of all bit size section within a given well to illustrate the performance of the different wells. This will not give us an accurate representation of the costs of the different wells, rather contrary it will provide a suggestion regarding which wells might perform at a lower cost. Furthermore, we look at the total length over total time see how much of the well is drilled per unit time. This is also a useful parameter as this might be used to suggest which well was drilled most time efficiently. Time is of high essence when it comes to petroleum operations as reduction in time consumption and having a low non-productive time leads to cost reductions. The finding for the wells is presented in ascending order in table 5.9.

Well name	**Total run length**	**Total drilling time**		**Total combined cost/meter ($/m)**	**Total length/time (m/hr)**
2/8-V-9	4740	138.93		39 821.59	34.118
2/8-V-6	4949	141.3		40 150.57	35.025
Ideal well	4785	68.90		41 886.31	69.448
2/8-V-7	4770	120.8		43 206.84	39.487
2/8-V-12	8098	182.72		44 618.81	44.319
2/8-V-5	5144	159.3		45 914.61	32.291
2/8-V-4	7376	188.11		51 876.60	39.211
2/8-V-3	5723	190.94		61 721.98	29.973
2/8-V-8	5356	142.55		64 657.57	37.573
2/8-V-2	7482	215.84		67 253.81	34.664

Table 5.9: Summary of total cost/meter and length/time over the different wells

Well	Size	Interval [m]	Run length [m]	Drilling hours [h]	Cost/meter [$/m]		Well	Size	Interval [m]	Run length [m]	Drilling hours [h]	Cost/meter [$/m]
2/8-V-2	32″	140 – 200	60	1.8	30 403.83		2/8-V-4	32″	140 – 200	60	1.5	30 289.47
2/8-V-2	24″	200 – 567	367	6.95	5062.10		2/8-V-4	24″	200 – 562	362	6.8	5129.33
2/8-V-2	16.5″	567 – 1780	1213	16.71	1584.00		2/8-V-4	16.5″	562 – 1067	505	6.1	3667.81
2/8-V-2	12.25″	1780 – 4446	2666	25.95	743.29		2/8-V-4	16.5″	1067 – 1745	678	14.1	2808.83
2/8-V-2	8.5″	4446 – 5315	869	48.75	2451.31		2/8-V-4	12.25″	1745 – 3540	1795	19.01	1078.77
2/8-V-2 Y2	8.5″	4545 – 5294	749	47	2828.82		2/8-V-4	8.5″	3588 – 4090	502	26.4	3953.25
2/8-V-2 Y2	6.5″	5294 – 5375	81	3.6	22 666.17		2/8-V-4 T2	8.5″	3592 – 5346	1754	69.7	1292.31
2/8-V-2 Y2	6.5″	5375 – 6852	1477	65.08	1514.29		2/8-V-4 Y2	8.5″	3713 – 4245	532	20.4	3656.84
Total			**7482**	**215.84**	**67 253.81**		2/8-V-4 Y2	8.5″	4245 – 5433	1188	24.1	1657.87
							Total			**7376**	**188.11**	**51 876.60**
2/8-V-3	32	140 – 200	60	2.5	30 479.86							
2/8-V-3	24	200 – 564	364	6.3	5085.20		2/8-V-5	32″	140 – 190	50	2.8	36 469.06
2/8-V-3	16.5	564 – 1669	1105	14.14	1724.29		2/8-V-5	24″	190 – 560	370	12	5110.00
2/8-V-3	12.25	1669 – 2265	596	16.5	3219.36		2/8-V-5	16.5″	560 – 1560	1000	17.75	1928.17
2/8-V-3	12.25	2265 – 3586	1321	26.7	1503.78		2/8-V-5	12.25″	1560 – 3174	1614	35.75	1267.33
2/8-V-3	8.5	3586 – 4176	590	24.2	3339.33		2/8-V-5	8.5″	3174 – 5284	2110	91	1140.06
2/8-V-3	8.5	4176 – 4413	237	12.25	7984.51		**Total**			**5144**	**159.3**	**45 914.61**
2/8-V-3 T2	8.5	4335 – 4683	348	38.6	5931.18							
2/8-V-3 T2	6.5	4683 – 5523	840	38.25	2454.48		2/8-V-6	32″	140 – 200	60	5.8	30 755.24
2/8-V-3 T2	6.5	5523 – 5785	262	11.5	7203.98		2/8-V-6	24″	200 – 562	361	1.4	5039.08
Total			**5723**	**190.94**	**61 721.98**		2/8-V-6	16.5″	562 – 1603	1042	14.8	1832.88
							2/8-V-6	12.25″	1603 – 3324	1721	29.8	1166.01
							2/8-V-6	8.5″	3324 – 5089	1765	89.5	1357.36
							Total			**4949**	**141.3**	**40 150.57**

Table 5.10 a): Cost/meter analysis of wells in the Valhall Flank West

Well	Size	Interval [m]	Run length [m]	Drilling hours [h]	Cost/meter [$/m]		Well	Size	Interval [m]	Run length [m]	Drilling hours [h]	Cost/meter [$/m]
2/8-V-7	32''	140 – 205	65	2.3	28 115.21		2/8-V-12	32''	140 – 200	60	2.75	30 507.01
2/8-V-7	26''	205 – 565	360	6.3	5148.76		2/8-V-12	24''	200 – 560	360	8.2	5183.17
2/8-V-7	16.5''	565 – 1568	1003	14.25	1899.66		2/8-V-12	16.5''	560 – 1954	1394	18.4	1386.23
2/8-V-7	12.25''	1568 – 3302	1734	29.75	1157.08		2/8-V-12	12.25''	1954 – 4176	2222	23.7	885.21
2/8-V-7	8.5''	3302 – 3654	352	21.75	5551.81		2/8-V-12	8.5''	4221 – 5028	807	34.2	2522.15
2/8-V-7	8.5''	3654 – 5270	1616	52.75	1334.32		2/8-V-12 T2	8.5''	4550 – 5152	602	24.68	3277.95
Total			**4770**	**120.8**	**43 206.84**		2/8-V-12 Y2	8.5''	4377 – 7030	2653	70.79	857.07
							Total			**8098**	**182.72**	**44 618.81**
2/8-V-8	32''	140 – 200	60	1.9	30 414.69							
2/8-V-8	24''	200 – 563	363	6.5	5105.58							
2/8-V-8	16.5''	563 – 998	435	7.5	4281.98		**Ideal well**					
2/8-V-8 T2	16.5''	572 – 748	176	4.4	10461.15		2/8-V-6	32''	140 – 200	60	5.8	30 755.24
2/8-V-8 T3	16.5''	583 – 785	202	9.75	9287.31		2/8-V-2	24''	200 – 567	367	6.95	5062.10
2/8-V-8 T3	16''	785 – 1526	741	16.5	2591.13		2/8-V-4	16.5''	562 – 1067	505	6.1	3667.81
2/8-V-8 T3	12.25''	1526 – 3155	1629	35.75	1255.66		2/8-V-2	12.25''	1780 – 4445	2665	25.95	743.29
2/8-V-8 T3	8.5''	3155 – 4905	1750	60.25	1260.07		2/8-V-4	8.5''	4245 – 5433	1188	24.1	1657.87
Total			**5356**	**142.55**	**64 657.57**		**Total**			**4785**	**68.90**	**41 886.31**
2/8-V-9	32''	140 – 200	60	1.33	30 220.82							
2/8-V-9	24''	200 – 568	368	8.5	5082.70							
2/8-V-9	16.5''	568 – 1594	1026	15.7	1865.38							
2/8-V-9	12.25''	1597 – 3176	1579	25.9	1254.77							
2/8-V-9	8.5''	3176 – 4880	1704	87.4	1397.92							
Total			**4740**	**138.93**	**39 821.59**							

Table 5.10 b): Cost/meter analysis of wells in the Valhall Flank West

From the data we observe that well 2/8-V-9 had the lowest totally combined cost/meter, suggesting this might a cost efficient well out of the study group. Same observation may be made for well 2/8-V-2 which was least cost efficient as this well had a 68.9% higher combined total cost/meter than well 2/8-V-9, suggesting significant variations in the economic properties of the different wells. However, having the lowest combined cost/meter does not give an accurate representation of which well was drilled for the lowest cost as we need to calculate for the run length of each different section. Furthermore, to add to the cost of drilling, we include prices and numbers of bits used. The price for the different bits is taken from the assumptions made in section 2.3.

Analyzing the different bit runs, we establish that:

- **Well 2/8-V-2** has **7 bits used**, 2 roller-cone and 5 fixed-cutter bits
- **Well 2/8-V-3** has **8 bits used**, 2 roller-cone and 6 fixed-cutter bits
- **Well 2/8-V-4** has **7 bits used**, 2 roller-cone and 5 fixed-cutter bits
- **Well 2/8-V-5** has **5 bits used**, 2 roller-cone and 3 fixed-cutter bits
- **Well 2/8-V-6** has **5 bits used**, 2 roller-cone, 2 fixed-cutter and 1 hybrid bits
- **Well 2/8-V-7** has **6 bits used**, 2 roller-cone and 4 fixed-cutter bits
- **Well 2/8-V-8** has **8 bits used**, 2 roller-cone and 6 fixed-cutter bits
- **Well 2/8-V-9** has **5 bits used**, 2 roller-cone, 2 fixed-cutter and 1 hybrid bits
- **Well 2/8-V-12** has **7 bits used**, 2 roller-cone and 5 fixed-cutter bits
- **Ideal well** has **5 bits used**, 2 roller-cone and 3 fixed-cutter bits

From the reported dull grading, we have that all bits used were used new, hence, the bit price was the price for a new bit. For the total bit costs, the prices for the different bits were assumed based on what type of bit it was, i.e. a roller-cone, fixed-cutter or hybrid bit. This assumption is rather optimistic as there can be significant price differences between the bits based on size, type, manufacturer and etc. However, as we don't have the possibility to find the exact bit price for the individual bits, an assumption is made regarding the price. The full names and IADC code for the different bits used in the Valhall Flank West field development is presented in appendix A.1.

Calculating the total drilling cost and total cost of a bits used gives us the calculated total cost of the different wells. It should be noted however that there are several different other costs associated with the drilling operations, hence, this total cost calculation only represents a small portion of the total costs when drilling a well. The results are presented in ascending order, from lowest to highest, in table 5.11.

	Total drilling costs	**Total drill bits costs**	**Total costs**	**Total costs / run length**
Ideal	9 511 498.33 $	270 000 $	9 781 498.33 $	2044.20 $/m
2/8-V-9	9 967 208.83 $	280 000 $	10 247 208.83 $	2161.86 $/m
2/8-V-6	9 983 305.00 $	280 000 $	10 264 305.00 $	2074.02 $/m
2/8-V-5	10 100 605.00 $	270 000 $	10 370 605.00 $	2016.06 $/m
2/8-V-7	11 703 266.93 $	320 000 $	12 023 266.93 $	2520.60 $/m
2/8-V-12	13 878 225.33 $	370 000 $	14 248 225.33 $	1759.47 $/m
2/8-V-8	15 428 953.16 $	420 000 $	15 848 953.16 $	2959.10 $/m
2/8-V-2	15 906 557.33 $	370 000 $	16 276 557.33 $	2175.43 $/m
2/8-V-4	17 538 350.17 $	370 000 $	17 908 350.17 $	2427.92 $/m
2/8-V-3	19 369 292.33 $	420 000 $	19 789 292.33 $	3457.85 $/m

Table 5.11: Total costs for the constructed ideal well and wells drilled in Valhall Flank West

From figure 5.11, we calculate the average total cost across the wells, not including the ideal well, is 14 108 529.34 $. The figure shows that the ideal well had the lowest total drilling cost, being approximately 460 000 $ cheaper than the second cheapest well. Additionally, comparing the ideal well to the well that had the highest total cost, i.e. well 2/8-V-3, we observe a difference of approximately 200% or 10 000 000 $. This is a very significant variation, suggesting there is a huge potential for cost reduction in the wells.

On the other hand, if we take the total costs of the different wells and divide it by the total run length, we can get an approximate estimate of the total well cost per unit length. Doing this however, the results are vastly different as well 2/8-V-12 is suddenly by far the most cost effective well, with the ideal well being the 3rd best forming well in this category. This is rather interesting, especially given that well 2/8-V-12 comes at an approximately 4.47 million $ higher cost compared to the ideal well when comparing the total costs of the wells.

To analyze this, we look at table 5.10 b) and compare the ideal well against well 2/8-V-12, highlighted in table 5.12. Comparing the bit runs in both wells, we notice that bit size 12.25 in. and 8.5 in. (2/8-V-12 Y2) for well 2/8-V-12 are drilled at a low cost/meter. This is also the case for bit size 12.25 in. for the ideal well. These 3 runs are highlighted in the figure. It should also be noted that these runs have the longest run lengths at each respective well.

Well	**Size**	**Interval [m]**	**Run length [m]**	**Drilling hours [h]**	**Cost/meter [$/m]**
2/8-V-12	32''	140 – 200	60	2.75	30 507.01
2/8-V-12	24''	200 – 560	360	8.2	5183.17
2/8-V-12	16.5''	560 – 1954	1394	18.4	1386.23
2/8-V-12	12.25''	1954 – 4176	2222	23.7	885.21
2/8-V-12	8.5''	4221 – 5028	807	34.2	2522.15
2/8-V-12 T2	8.5''	4550 – 5152	602	24.68	3277.95
2/8-V-12 Y2	8.5''	4377 – 7030	2653	70.79	857.07
Ideal well					
2/8-V-6	32''	140 – 200	60	5.8	30 755.24
2/8-V-2	24''	200 – 567	367	6.95	5062.10
2/8-V-4	16.5''	562 – 1067	505	6.1	3667.81
2/8-V-2	12.25''	1780 – 4445	2665	25.95	743.29
2/8-V-4	8.5''	4245 – 5433	1188	24.1	1657.87

Table 5.12: Highlighted comparison of cost/meter analysis for the ideal well and well 2/8-V-12

The consensus seems to be that keeping a high run length is economically beneficial for the drilling operations has this gives a low cost/meter. As the well 2/8-V-12 has 2 of the longest bit runs of all the wells, this gives it an edge when calculating total costs / run length as it has accumulated a low cost drilling over a longer distance, hence, giving the remarkable result presented in table 5.11. On the other hand, it should still be kept in mind that the ideal well was by far the most cost efficient well coming at a lower total cost and having the longest total length / time.

The economic consideration for the different wells seems to highlight the importance of efficient drilling as the ideal well, a well compromised of the best performing sections, was drilled at the lowest cost. However, as illustrated by well 2/8-V-12, there are significant cost reduction opportunities present in using the bit for as long as possible and keeping a long bit run. This is evident by the low cost/meter, the costs saved on using a new drill bit while also saving costs associated with tripping and general petroleum operations. Unfortunately, this is not always possible to maintain for several different reasons. Analyzing the different sections for the well drilled in Valhall Flank West at which 2 or more bits are used within the same drill section, it is evident that the bits are pulled generally because of factors outside of the drillers control such as tool failure, hole problems, lost circulation, drilling dysfunctions and etc.

Rather evidently, drilling as efficiently as possible is beneficiary also from an economic perspective, illustrated with the ideal well coming at a significant lower cost. However, a more important factor was proven to be using fewer bits and having longer runs. This therefore suggests that there are significant cost reduction opportunities readily available for drilling wells in Valhall Flank West.

6 Summary and discussion

This part of the thesis deals with the summary and discussion of the results that has been produced by the field case study. The investigations may be split into 4 different types, data quality, Valhall field overview, ideal well configuration and economic considerations.

6.1 Data quality

In the data collection process for the establishment of a field overview of Valhall Flank West, two dataset of drilling data were available for process and analysis, data provided by Aker BP, the operator of the well, and data provided by Halliburton, the service company providing the drill bits. The initial expectation is that there should be low uncertainty and high numerical precious in the reported data as suggested by Aadnoy (2011). This is especially expected as the wells are primarily drilled in 2019 – 2020, during a period at which the global oil and gas sector is moving harder towards data quality control and digitalization, however, the results of the investigation seemed to suggest otherwise.

The investigation showed that the ROP could at the highest be reported at a 127.3% difference with an average of 17.4% difference between the two datasets across all wells. These are highly significant variations in the datasets and presents a significant problem as the choice of dataset may lead to different conclusions regarding the operation of this field. These variations were reported for all other drilling parameters as well.

The variation in reported drilling data seems to illustrate low data quality. Despite an industry push for digitalization, this discrepancy in the datasets demonstrates that there this is still a long way to go. There is therefore a need for redundancy in the quality control as there seems to be a lack of reliability and a need for improvements of the current registering systems. More emphasis should therefore be put on big data analytics as the discrepancies might be a result of either/or data collection, data processing, cleaning of the data or the analysis. Furthermore, the differences in the reported data seem to indicate the need for better cooperation between the operator and service companies as data share, exchange of experience and review of shared data does not seem to take place. Although there is a business and confidentiality perspective as to why data is not shared between the different companies, this should be evaluated as review of previously drilled wells, lessons learned in drilling different formations and drilling optimization based on experiences from other wells is still a highly relevant approach in achieving efficient drilling. Furthermore, sharing of knowledge and experience is very important for the safety of the crew and the environment, hence, the lack of adequate data quality may present a potential hazard for both.

As shown by this thesis, the variation for reported parameters in Valhall Flank West was highly significant and could lead to different conclusions based on which dataset was used. Hence, more measures are needed to ensure adequate data quality.

6.2 Valhall Field Overview

To map the performance of the wells in the Valhall Flank West field, we analyzed the reported average ROP across each section in each well. This was initially done be comparing every bit used by a given size in all wells against each other. This was done as this approach would reduce the effects of factors such as bit type, depth and geological properties as the wells were close in proximity, possessed similar run lengths and were drilled in the same formations. Hence, reducing other factors that could affect the drill bit performance. Establishing a reference line as the average ROP for all the bits by bit size, we observed there were performance differences as some wells reported better performances than others. A general consensus also showed that the ROP seemed to be low for the smaller sized bits compared to the rest. This therefore gave us the initial suggestion that there were significant variations between the bits. Established earlier, we know that ROP is affected by controllable drilling parameters such as WOB and RPM which are to some extend directly controllable by the driller.

Analyzing RPM and WOB against ROP, we observed that, as theory suggested, that there was a correlation between these parameters as increase of WOB and/or RPM gave increased ROB. Suggesting that the variation in ROP might be down to how the bit was drilled. However, simultaneously, we had some sections that deviated from this. Some sections displayed the opposite effect at which WOB and RPM was increased but ROP decreased, giving unexpected results. The particularities of each specific case are difficult to pinpoint as there might be an array of multiple different factors that affect the drilling performance. Poor data quality might provide an explanation, however, this is an assumption and not possible to prove with the data at hand. This therefore shows that explaining the reduction in ROP by WOB and RPM alone is inconclusive as there are several factors at play, making it difficult to suggest any improvements.

Having this at the back of the mind, we continue the investigation by observing the ROP behavior with increasing depth for each well. ROP, MSE and d-exponent was plotted against depth in order to establish a holistic representation of the wells. Doing this, we observed a trend at which the ROP continuously increased from bit sizes 32 in. – 16.5/12.25 in. until drastically falling for the 8.5 in. and 6.5 in. bits. This was also reflected in the calculated MSE and d-exponent as both these parameters increased drastically, hence, indicating that the small bit size runs were drilled highly inefficient. Again, to suggest an explanation we analyzed the ROP against depth by plotting the subsequent WOB and RPM against depths to see if there were any indications of this trend in the drilling parameters. Doing this we observed cases at which the 8.5 in. bits had higher WOB and RPM than the 32 in. bit in the same well, however, the 8.5 in. bit had significantly lower ROP. It was therefore inconclusive to suggest an explanation based on the drilling parameters, hinting at there being other factors at play.

To find an explanation for this behavior, an investigation was done into the geology of the wells. The geology of the different wells and the formation tops were given in the geological report in the FWR of the different well as well as being provided by the NPD. Having done this we generally established that the 8.5 in. and 6.5 in. bits were drilled in the Rogaland and Shetland formation groups which consisted of chalk, while the 32 in., 24 in., 16.5., and 12.25 in. bits were drilled in the Zulu, Nordland and Hordaland Groups respectively, which consisted predominately of claystone. As chalk is a very soft and porous material, the expectation would be that these sections are drilled the easiest, however, as established earlier this was not the case. Quite the contrary in fact. A possible explanation for this could be the presence of calcite stringers in the formations, very hard rock inclusions embedded in the formation that is associated with issues such as low ROP and high bit wear. To analyze this, we look at the well logs and find sections in the lower chalk formations that could fit the criteria of being a possible calcite stringer. Several cases of smaller sections as which the ROP was close to 0 with a sudden reduction in hookload were reported. Since we are tripping into the hole, the reduction in hookload can only be explained by an increase of drag, hence, further suggesting the existence of stringers. Thus, the geology and lithology of the wells might act as a possible explanation of the reduction in drilling parameters.

Another possible aspect that affects the drilling performance is wear of the drill bit. As the drill bit grind and breaks the formation rocks, it sustains fatigue and wear which results in decrease bit performance. To check for this, we observe and record the presented bit dulling data for the different bits and compare them for each bit against depth. The results here showed that, yet again, the lower sections were standing out as the bits used here had a higher bit wear than the bits used at the upper sections. Run length plays an important role in bit dulling as the longer the drill bit is used the more wear and damage is sustained. In the case of the bits used in the Valhall Flank West field however, we observed that when comparing the 16.5 in. bit against the 8.5 in. bit, we reported more wear on the 8.5 in. bit despite both bits having approximately similar run lengths. This was also the case for the 12.25 in. bits which had the longest runs. Bit wear is a possible explanation for increased MSE and reduced ROP, but to find a reason for why the bits in the lower section experienced more wear, we analyze the geology again. As established earlier, the formation groups in question had reported calcite stringer which cause bit wear. Furthermore, NPD has reported that the Rogaland and Shetland groups may contain smaller sections of dolomite or pyrite, two very hard substances. Dolomite was a hardness rating of 3 – 4 while pyrite has a hardness rating of 6 – 6.5, both significantly higher than the hardness of chalk which has a hardness rating of 1. This would therefore provide an explanation as to why the lower section bits experienced more wear.

The reduction of ROP the deeper we go down the well may therefore be explained by a combination of geology and bit dulling, which may cause the observed trend. The presence of calcite stringers suggests a reason as to why the drilling parameters would drop/increase as significantly as they did. The presence of calcite stringers, dolomite and pyrite does also provide an explanation of increased bit wear. Therefore, it can be said that although we can’t draw concrete and definitive conclusions as there might be other factors at play as well, the geology of the Valhall Flank West field might present a challenge when drilling.

6.3 Ideal well configuration

To visualize the potential for improvement for the different wells, we constructed an ideal well which would consist of the best performing sections from the other wells combined. To choose which section performed better than the others we calculated ROP, MSE, d-exponent, WR and K_f as well as having ROP/MSE as a possible parameter to use in cases where there was not a clear "best" section. The results showed that, as expected, comparing the ideal well against the averages of the other wells, the ideal well performed significantly better in all categories. The ideal well performed at a higher ROP, lower MSE and performed preferably in regard to WR and K_f. However, rather surprisingly, the ideal well operated at, on average, lower WOB and the same approximately the same RPM as the average of all the wells. The high performance of the ideal well can therefore not be explained as a result of optimal drilling parameters.

The construction of the ideal well displays the potential for improvement for wells drilled in Valhall Flank West as all presented sections in the ideal well were drilling performance that had been done in this field, i.e. the ideal well consisted of drilling performance we knew was possible. This would therefore act as a benchmark for what a high efficiency well drilled in this field could be like.

6.4 Economic considerations

As the ideal well had been constructed and deduced to have highest drilling performance, we look at the economic potential of the different bits. Based on the data provided and assumptions made, this would be done by calculating the cost/meter of the different well. Furthermore, the number of bits and the price of these is also included when calculating the total cost. This was done in order to provide an additional dimension to the calculations as using as few bits as possible is an economic incentive taken into consideration before drilling. When calculating the cost/meter of the different wells, it became apparent that 32 in. bits came at a significantly higher cost per meter compared to the other bits, a result of its rather low run length compared to the other bits.

When calculating the total run length over the total drilling time, we observed that the ideal well was drilled significantly faster per unit time compared to the other wells, being over 50% higher than the well 2/8-V-12 which scored the second highest score. This therefore shows that the ideal well was drilled most efficiently, which was to be expected based on the fact that the ideal well is constructed of the highest performing sections of all other wells. When calculating the total cost associated with drilling, including the total drill bit costs, the ideal well again performed significantly better than the other wells as this well was by far the cheapest. However, this comparison is inconclusive as the distance drilled need to be taken into consideration. Taking the total costs / run length was the solution here as it would provide length normalization. In this approach, the data seemed to suggest that well 2/8-V-12 and its sidetracks performed significantly better than the ideal well and the other wells in this field.

Comparison between the ideal well and well 2/8-V-12 suggested that the latter well, though having a longer run length, over half of it were drilled by a highly efficient and low cost 12.25 in. and 8.5 in. bits. The ideal well was therefore despite having the best drilling performance, not the most economically proficient well.

The investigation showed that optimization of drilling performance is an important aspect in cost reductions as one can achieve longer drilling over less time, however, achieving a high ROP does not fully affect the economic potential of a well. As demonstrated by well 2/8-V-12, the importance seems to lie with trying to achieve long bit runs as this reduces tripping, the number of bits used as well as providing low cost/meter drilling. Having high drilling efficiency and low costs seems to go hand in hand, however, different considerations should be done for the different aspects.

7 Conclusion

The objective of this thesis was to investigate and analyze the geology and field data of Valhall Flank West to evaluation drilling performance, which was done with the perspective of investigating correlations among drilling performance, formation geology and bit dulling with the field data at hand. Furthermore, the data quality and economic considerations would be of the different wells were also be investigated. From the work done, following conclusions can be drawn:

Data quality:

- Despite being a modern field with wells drilled in the timeframe of 2019 – 2020, there are clear indications that better cooperation is needed between the different operator and service companies at work. This is because both companies perform the same work/service yet arrive at significantly different results
- For Valhall Flank West, an average difference of 17.4% is observed in the reported ROP with the maximum difference being 127.3%. The differences are of the magnitude that it may lead to different conclusions based on which dataset is used.
- Digitalization and efforts should therefore be put towards improvements in Big Data Analytics as there are clear problems in the data collection, data cleaning and cross-data reviewing processes.
- Push towards digitalization should be maintained as data variations is a potential health and environmental hazard.

Valhall Field Overview:

- Field data showed that when comparing ROP across all bits of certain sizes against each other there were clear differences between the different bits. This was demonstrated by bit 8.5 in. GTE64C from well 2/8-V-4 Y2 that had a 546.4% higher average ROP compared to bit 8.5 in. GTD64MKOs from well 2/8-V-3 T2.
- Analysis for WOB and RPM range seemed consistent with theory as ROP increase/decrease was explainable by WOB and RPM increase/decrease. The investigation however was deemed inconclusive as there were clear outliers from this trend, hence, concluding further factors are present than individual bit performance.

- ROP by depth across all wells shows a trend at which the ROP increases with bit size until for a sharp decrease in ROP and a sharp increase in MSE and d-exponent is reported for the 8.5 in. and 6.5 in. drill bits. This shows highly inefficient drilling for these sections. This effect is not explainable by WOB and RPM analysis.
- Formation evaluation concludes with a high possibility the existence of calcite stringers for the Rogaland and Shetland groups, backed by well log analysis that display small sections of very low ROP and sharp hookload reduction.
- Analysis of dull grading shows the 8.5 in. and 6.5 in. drill bits sustained more wear compared to other bits. This is explained by the possibility of drilling through calcite stringers, dolomite and pyrite causing high bit wear.
- Taking all into consideration, the fall in ROP and subsequent rise in MSE for drill bits in the lower sections may be concluded to be a result of the geology in the Rogaland and Shetland formations groups. This is also a reason for the high bit wear which in turn further supports the observed trend.

Ideal well configuration:

- The construction of the ideal well illustrated optimal drilling performance for as all bits used in the ideal well operated at an average 43.6% higher ROP and 46.4% lower MSE compared to the averages of all wells. Similar improvements were seen for other drilling parameters, hence suggesting the potential for improvement

Economic considerations:

- The economic considerations were done with respect to different parameters and suggested significant potentials for cost reductions, the different analysis showed:
  - The ideal well had the highest (69.448 m/hr) drilling length per unit time
  - The ideal well had the lowest total cost (9 781 498.33 $) of all wells
  - Well 2/8-V-12 had the lowest total cost by run length of all wells
- The investigation showed that well 2/8-V-12 was, when length normalized, significantly cheaper than the ideal well (1759.47 $/m vs 2044.20 $/m), this despite the ideal well having significantly better drilling performance. The investigation concluded that keeping a long run length seems to be more beneficial from cost perspective than high ROP, however, this should be further investigated.

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Appendix

Appendix A: Valhall Flank West

A.1 Bits used

Bit type	IADC code	Classification
XR+	115	Roller-cone
SR1GRC	115W	Roller-cone
GTD66DCs	S322	Fixed-cutter
GTI76WMKOs	S323	Fixed-cutter
GTD64MKOs	S132	Fixed-cutter
GTI76WMKHOs	S323	Fixed-cutter
GTD54WMK	M234	Fixed-cutter
GTE54D	M434	Fixed-cutter
GTD54Dk	M234	Fixed-cutter
GTE64C	M333	Fixed-cutter
GTD64	M233	Fixed-cutter
SFE65CH	S323	Fixed-cutter
EBXT02DSLC	415W	Roller-cone
GTD66Cs	S223	Fixed-cutter
KM634X		Hybrid (Kymera)
KM624		Hybrid (Kymera)

A.2 Data quality

Bit info	ROP [Aker BP]	ROP [Halliburton]	Percentage difference
[2/8-V-2] 32'' XR+	33,48	NaN	NaN
[2/8-V-2] 24'' SR1GRC	52,73	NaN	NaN
[2/8-V-2] 16.5'' GTD66DCs	73,01	72,8	0,29 %
[2/8-V-2] 12.25'' GTi76WMKHOs	102,74	76,2	29,66 %
[2/8-V-2] 8.5'' GTD64MKOs	17,83	32	56,87 %
[2/8-V-2 Y2] 8.5'' GTD64MKOs	15,94	25	44,26 %
[2/8-V-2 Y2] 6.5'' GTD54WMK	22,5	5	127,27 %
[2/8-V-2 Y2] 6.5'' GTE54D	18,55	19,8	6,52 %
[2/8-V-3] 32'' XR+	24	37,19	43,11 %
[2/8-V-3] 24'' SR1GRC	57,86	49,93	14,71 %
[2/8-V-3] 16.5'' GTD66DCs	77,91	66,3	16,10 %
[2/8-V-3] 12.25'' GTD76WMKOs	36,15	45,8	23,55 %
[2/8-V-3] 12.25'' GTD76WMKOs	49,48	56,25	12,81 %
[2/8-V-3] 8.5'' GTD64MKOs	20,94	20,94	0,00 %
[2/8-V-3] 8.5'' GTD64MKOs	19,35	22,225	13,83 %
[2/8-V-3 T2] 8.5'' GTD64MKOs	9,02	8,185	9,71 %
[2/8-V-3 T2] 6.5'' GTD54Dk	21,96	25,175	13,64 %
[2/8-V-3 T2] 6.5'' GTD54Dk	22,78	28,69	22,96 %
[2/8-V-4] 32'' XR+	40,11	40	0,27 %
[2/8-V-4] 24'' SR1GRC	53,68	53,2	0,90 %
[2/8-V-4] 16.5'' GTD66DCs	82,79	76,5	7,90 %
[2/8-V-4] 16.5'' GTD66DCs	48,09	48,55	0,95 %
[2/8-V-4] 12.25'' GTi76WMKHOs	94,42	107,95	13,37 %
[2/8-V-4] 8.5'' GTD64MKOs	19,02	20,5	7,49 %
[2/8-V-4 T2] 8.5'' GTD64MKOs	25,16	24,85	1,24 %
[2/8-V-4 Y2] 8.5'' GTD64MKOs	26,08	23,95	8,51 %
[2/8-V-4 Y2] 8.5'' GTE64C	49,29	40,8	18,85 %
[2/8-V-5] 32'' XR+	19,71	NaN	NaN
[2/8-V-5] 24'' SR1GRC	30,42	46,6	42,02 %
[2/8-V-5] 16.5'' GTD66DCs	56,34	74,4	27,63 %
[2/8-V-5] 12.25'' GTi76WMKOs	45,15	55,69	20,90 %
[2/8-V-5] 8.5'' GTD64MKOs	23,19	27,25	16,10 %
[2/8-V-6] 32'' XR+	62,33	42,8	37,15 %
[2/8-V-6] 24'' SR1GRC	42,97	62,3	36,72 %
[2/8-V-6] 16.5'' GTD66DCs	70,37	70,4	0,04 %
[2/8-V-6] 12.25'' KM624	57,75	57,8	0,09 %
[2/8-V-6] 8.5'' GTD64MKOs	19,72	19,7	0,10 %

[2/8-V-7] 32'' XR+	28,69	27,8	3,15 %
[2/8-V-7] 16.5'' GTD66DCs	70,39	83,2	16,68 %
[2/8-V-7] 12.25'' GTD76WMKOs	58,29	96,93	49,79 %
[2/8-V-7] 8.5'' GTD64MKOs	16,18	23,4	36,48 %
[2/8-V-7] 8.5'' GTD64MKOs	30,64	40,1	26,75 %
[2/8-V-8] 32'' XR+	31,58	35,1	10,56 %
[2/8-V-8] 24'' SR1GRC	55,89	55,8	0,16 %
[2/8-V-8] 16.5'' GTD66DCs	57,96	73,75	23,98 %
[2/8-V-8 T2] 16.5'' GTD66DCs	41,59	40,2	3,40 %
[2/8-V-8 T3] 16.5'' GTD66DCs	21,95	23,05	4,89 %
[2/8-V-8 T3] 12.25'' GTi76WMKOs	45,57	52,415	13,97 %
[2/8-V-8 T3] 8.5'' SFE65CH	29,05	20,72	33,47 %
[2/8-V-9] 32'' XR+	45,31	46,2	1,95 %
[2/8-V-9] 24'' SR1GRC	43,24	43,2	0,09 %
[2/8-V-9] 16.5'' GTD66DCs	65,38	65,4	0,03 %
[2/8-V-9] 12.25'' KM634X	30	37,5	22,22 %
[2/8-V-9] 12.25'' KM634X	60,97	61,4	0,70 %
[2/8-V-9] 8.5'' GTD64	19,5	19,5	0,00 %
[2/8-V-12] 32'' XR+	21,82	20,3	7,22 %
[2/8-V-12] 24'' SR1GRC	43,9	45,4	3,36 %
[2/8-V-12] 16.5'' GTD66DCs	75,76	67,55	11,46 %
[2/8-V-12] 12.25'' GTi76WMKOs	93,76	79,9	15,96 %
[2/8-V-12] 8.5'' GTD64MKOs	23,6	29,5	22,22 %
[2/8-V-12 T2] 8.5'' GTD64MKOs	24,39	21	14,94 %
[2/8-V-12 Y2] 8.5'' GTD64MKOs	37,48	33,15	12,26 %

Average difference in percentage: 17,381%

A.3 Drilling data and parameters

2/8-V-2

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-2	No info	XR+	32	140	200	1	
2/8-V-2	No info	SR1GRC	24	200	567	2	
2/8-V-2	Claystone	GTD66DCs	16,5	567	1780	3	
2/8-V-2	Claystone/Limestone + Balder tuff	GTI76WMKHOs	12,25	1780	4446	4	
2/8-V-2	Chalk	GTD64MKOs	8,5	4446	5315	5	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-2	140	200	1.8	33.48	NaN	NaN	NaN
2/8-V-2	200	567	6.95	52.73	NaN	NaN	NaN
2/8-V-2	567	1780	16.71	73.01	8.3	15.4	155
2/8-V-2	1780	4446	25.95	102.74	16.5	28.4	159
2/8-V-2	4446	5315	48.75	17.83	2.9	31.3	141

2/8-V-2 Y2

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-2 Y2	Chalk	GTD64MKOs	8,5	4545	5294	6	
2/8-V-2 Y2	Chalk	GTD54WMK	8,5	5294	5375	7	Vibrations and ALD failure
2/8-V-2 Y2	Chalk	GTE54D	8,5	5375	6852	7	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-2 Y2	4545	5294	47	15.94	5.8	36.1	143
2/8-V-2 Y2	5294	5375	3.6	22.5	4.8	28.9	120
2/8-V-2 Y2	5375	6852	65.08	18.55	3.9	34.4	163

2/8-V-3

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-3	No info	XR+	32	140	200	1	
2/8-V-3	No info	SR1GRC	24	200	564	2	
2/8-V-3	Claystone / siltstone	GTD66DCs	16,5	564	1669	3	
2/8-V-3	Claystone / Diatom clay	GTD76WMKOs	12,25	1669	2265	4	POOH due to DTF
2/8-V-3	Claystone / limestone	GTD76WMKOs	12,25	2265	3586	4	
2/8-V-3	Chalk	GTD64MKOs	8,5	3586	4176	5	
2/8-V-3	Chalk + claystone	GTD64MKOs	8,5	4176	4413	6	
2/8-V-3 T2	Chalk	GTD64MKOs	8,5	4335	4683	7	
2/8-V-3 T2	Chalk	GTD54Dk	6,5	4683	5523	8	POOH due to jet pulser failure
2/8-V-3 T2	Chalk	GTD54Dk	6,5	5523	5785	8	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-3	140	200	2.5	24	3.7	7	78
2/8-V-3	200	564	6.3	57.86	17.7	15	74
2/8-V-3	564	1669	14.14	77.91	5.05	15	153
2/8-V-3	1669	2265	16.5	36.15	3.85	19.35	155.5
2/8-V-3	2265	3586	26.7	49.48	7.25	26.8	160
2/8-V-3	3586	4176	NaN	NaN	3.85	26.9	151
2/8-V-3	4176	4413	12.25	19.35	3.45	26.6	159.75
2/8-V-3 T2	4335	4683	38.6	9.02	3.35	27	162
2/8-V-3 T2	4683	5523	38.25	21.96	2.75	24.8	152.5
2/8-V-3 T2	5523	5785	11.5	22.78	4.15	34.95	169

2/8-V-4

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-4	No info	XR+	32	140	200	1	
2/8-V-4	No info	SR1GRC	24	200	562	2	
2/8-V-4	No info	GTD66DCs	16,5	562	1067	3	POOH due to severe loss
2/8-V-4	No info	GTD66DCs	16,5	1067	1745	3	
2/8-V-4	Claystone/Limestone + Diatom clay	GTi76WMKHOs	12,25	1745	3540	4	
2/8-V-4	Claystone/Limestone	NaN	NaN	3540	3588	NaN	
2/8-V-4	Claystone/Chalk	GTD64MKOs	8,5	3588	4090	5	
2/8-V-4 T2	Chalk	GTD64MKOs	8,5	3060	5346	6	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-4	140	200	1.5	40.11	2.8	8.1	94
2/8-V-4	200	562	6.8	53.68	12.9	7.3	69.9
2/8-V-4	562	1067	6.1	82.79	4.85	12.4	154
2/8-V-4	1067	1745	14.1	48.09	5.8	15.65	120
2/8-V-4	1745	3540	19.01	94.42	17.1	26.8	172.5
2/8-V-4	3540	3588	NaN	NaN	NaN	NaN	NaN
2/8-V-4	3588	4090	26.4	19.02	6	27.05	134
2/8-V-4 T2	3060	5346	69.7	25.15	3.8	28.8	141

2/8-V-4 Y2

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-4 Y2	Chalk	GTD64MKOs	8,5	3713	4245	7	POOH due to severe losses
2/8-V-4 Y2	Chalk	GTE64C	8,5	4245	5433	7	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-4 Y2	3713	4245	22.45	26.08	4.7	27.2	166.5
2/8-V-4 Y2	4245	5433	24.165	49.29	2.7	28.85	173

2/8-V-5

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-5	No info	XR+	32	140	190	1	
2/8-V-5	No info	SR1GRC	24	190	560	2	
2/8-V-5	Claystone/ siltstone	GTD66DCs	16,5	560	1560	3	
2/8-V-5	Claystone/ limestone	GTI76WMKOs	12,25	1560	3174	4	
2/8-V-5	Chalk	GTD64MKOs	8,5	3174	3174	5	Troubleshoot MWD + ADI crash
2/8-V-5	Chalk	GTD64MKOs	8,5	3174	5284	5	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-5	140	190	2.8	19.71	NaN	NaN	NaN
2/8-V-5	190	560	12	30.42	18.7	NaN	81
2/8-V-5	560	1560	17.75	56.34	5.6	NaN	155
2/8-V-5	1560	3174	35.75	45.15	6.9	NaN	146
2/8-V-5	3174	3174	91	0.01	NaN	NaN	NaN
2/8-V-5	3174	5284	91	23.19	3	NaN	170

2/8-V-6

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-6	No info	XR+	32	140	200	1	
2/8-V-6	No info	SR1GRC	24	200	562	2	
2/8-V-6	Claystone/ Siltstone	GTD66DCs	16,5	562	1603	3	
2/8-V-6	Claystone/ Limestone + Diatom clay	KM624	12,25	1603	3324	4	
2/8-V-6	Chalk	GTD64MKOs	8,5	3324	5089	5	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-6	140	200	5.8	62.33	2.9	7.5	89
2/8-V-6	200	562	1.4	42.97	13.2	8.7	65
2/8-V-6	562	1603	14.8	70.37	7.3	16.6	150
2/8-V-6	1603	3324	29.8	57.75	6	21	154
2/8-V-6	3324	5089	89.5	19.72	4.8	24.1	164

2/8-V-7

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-7	No info	XR+	32	140	205	1	
2/8-V-7	No info	SR1GRC	26	205	565	2	
2/8-V-7	Claystone/ Siltstone	GTD66DCs	16,5	565	1568	3	
2/8-V-7	Claystone	GTD76WMKOs	12,25	1568	1568	4	Jet pulser failure
2/8-V-7	Claystone/ Limestone	GTD76WMKOs	12,25	1568	3302	4	
2/8-V-7	Chalk	GTD64MKOs	8,5	3302	3654	5	DTF (communications)
2/8-V-7	Chalk	GTD64MKOs	8,5	3654	5270	5	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-7	140	205	2.3	28.69	3.6	6.5	88
2/8-V-7	205	565	6.3	57.94	13.1	12.2	85
2/8-V-7	565	1568	14.25	70.39	5.6	15.8	156
2/8-V-7	1568	1568	NaN	NaN	NaN	NaN	NaN
2/8-V-7	1568	3302	29.75	58.29	12.6	23.8	158
2/8-V-7	3302	3654	21.75	16.18	3.2	20.9	130
2/8-V-7	3654	5270	52.75	30.64	3.7	24.7	150

2/8-V-8

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-8	No info	XR+	32	140	200	1	
2/8-V-8	No info	SR1GRC	24	200	563	2	
2/8-V-8	Claystone/ Siltstone	GTD66DCs	16,5	563	998	3	POOH due to hole problems
2/8-V-8 T2	Claystone	GTD66DCs	16,5	572	748	4	POOH due to hole problems
2/8-V-8 T3	Claystone	GTD66DCs	16,5	583	785	5	POOH due to hole problems
2/8-V-8 T3	Claystone	EBXT02DSLC	17,5	785	785	6	Change in hole size
2/8-V-8 T3	Claystone/ Siltstone	GTD66Cs	16	785	1526	7	
2/8-V-8 T3	Claystone/ Limestone + Diatom clay	GTI76WMKOs	12,25	1526	3155	8	
2/8-V-8 T3	Chalk	SFE65CH	8,5	3155	4905	9	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-8	140	200	1.9	31.58	2.2	8.5	97
2/8-V-8	200	563	6.5	55.89	11	9	65
2/8-V-8	563	998	7.5	57.96	7.7	11.7	159.5
2/8-V-8 T2	572	748	4.4	41.59	3.45	8.8	130
2/8-V-8 T3	583	785	9.75	21.95	1.55	8.15	150
2/8-V-8 T3	785	785	NaN	NaN	0.5	1.43	17
2/8-V-8 T3	785	1526	16.5	44.91	5.65	14.6	153.5
2/8-V-8 T3	1526	3155	35.75	45.57	6.6	22.4	151.5
2/8-V-8 T3	3155	4905	60.25	29.05	4.6	24.35	148

2/8-V-9

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-9	No info	XR+	32	140	200	1	
2/8-V-9	No info	SR1GRC	24	200	568	2	
2/8-V-9	Claystone/ Siltstone	GTD66DCs	16,5	568	1594	3	
2/8-V-9	Claystone	KM634X	12,25	1594	1597	4	POOH (platform safety)
2/8-V-9	Claystone/ Chalk	KM634X	12,25	1597	3176	4	
2/8-V-9	Chalk	GTD64	8,5	3176	4880	5	

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-9	140	200	1.33	45.31	2.8	8.6	94
2/8-V-9	200	568	8.5	43.24	9.2	8.6	65
2/8-V-9	568	1594	15.7	65.38	6	15.8	157
2/8-V-9	1594	1597	0.1	30	4.5	13.8	80
2/8-V-9	1597	3176	25.9	60.97	12.3	13.8	158
2/8-V-9	3176	4880	87.4	19.5	11.5	22.7	135

2/8-V-12 & 2/8-V-12 Y2

Well name	Lithology	Bit type	Bit size (in)	MD in (m)	MD out (m)	Run nr.	Info
2/8-V-12	No info	XR+	32	140	200	1	
2/8-V-12	No info	SR1GRC	24	200	560	2	
2/8-V-12	Claystone/ Limestone	GTD66DCs	16,5	560	1954	3	
2/8-V-12	Claystone/ Limestone + Tuff	GTI76WMKOs	12,25	1954	4176	4	
2/8-V-12	No info	NaN	NaN	4176	4221	NaN	Drilling liner run
2/8-V-12	Chalk/ Claystone	GTD64MKOs	8,5	4221	5028	5	
2/8-V-12 T2	Chalk	GTD64MKOs	8,5	4550	5152	6	Section TD due to poor hole conditions
2/8-V-12 Y2	Chalk	GTD64MKOs	8,5	4377	7030	7	Section TD due to severe losses

Well name	MD in (m)	MD out (m)	Drilling hours (hr)	ROP (m/hr)	WOB (mton)	Torque (KN.m)	RPM
2/8-V-12	140	200	2.75	21.82	7	7.5	104
2/8-V-12	200	560	8.2	43.9	10.2	6.6	74
2/8-V-12	560	1954	18.4	75.76	4.15	13.55	153
2/8-V-12	1954	4176	23.7	93.76	10.6	29.05	161
2/8-V-12	4176	4221	NaN	NaN	NaN	NaN	NaN
2/8-V-12	4221	5028	34.2	23.6	4.85	28.75	140.5
2/8-V-12 T2	4550	5152	24.68	24.39	5.55	29.1	171.5
2/8-V-12 Y2	4377	7030	70.79	37.48	4.25	28.6	177

A.3 Bit dull grading

2/8-V-2

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-2	XR+	32	140 – 200	New	1-1-NO-A-E-I-NO-TD
2/8-V-2	SR1GRC	24	200 – 567	New	1-1-WT-A-X-I-NO-TD
2/8-V-2	GTD66DCs	16.5	567 – 1780	New	1-1-WT-A-X-I-NO-TD
2/8-V-2	GTi76WMKHOs	12.25	1780 – 4446	New	1-1-BT-G-X-I-NO-TD
2/8-V-2	GTD64MKOs	8.5	4446 – 5315	New	2-1-WT-A-X-I-NO-TD

2/8-V-2 Y2

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-2 Y2	GTD64MKOs	8.5	4545 – 5294	New	1-1-WT-A-X-I-NO-TD
2/8-V-2 Y2	GTD54WMK	8.5	5294 – 5375	New	0-1-CT-A-X-I-NO-DTD
2/8-V-2 Y2	GTE54D	8.5	5375 – 6852	New	1-1-WT-A-X-I-NO-TD

2/8-V-3

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-3	XR+	32	140 – 200	New	1-1-NO-A-E-I-NO-TD
2/8-V-3	SR1GRC	24	200 – 564	New	1-1-NO-A-E-I-NO-TD
2/8-V-3	GTD66DCs	16.5	564 – 1669	New	1-1-CT-G-X-I-NO-TD
2/8-V-3	GTD76WMKOs	12.25	1669 – 2265	New	1-1-WT-A-X-I-NO-DTF
2/8-V-3	GTD76WMKOs	12.25	2265 – 3586	1-1-WT-A-X-I-NO-DTF	1-1-WT-A-X-I-NO-TD
2/8-V-3	GTD64MKOs	8.5	3586 – 4176	New	0-0-WT-A-X-I-NO-DTF
2/8-V-3	GTD64MKOs	8.5	4176 – 4413	New	0-0-WT-A-X-I-NO-TD
2/8-V-3 T2	GTD64MKOs	8.5	4335 – 4683	New	0-0-WT-A-X-I-NO-TD
2/8-V-3 T2	GTD54Dk	6.5	4683 – 5523	New	0-1-CT-C-X-I-WT-DTF
2/8-V-3 T2	GTD54Dk	6.5	5523 – 5785	0-1-CT-C-X-I-WT-DTF	1-2-CT-G-X-I-WT-TD

2/8-V-4

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-4	XR+	32	140 – 200	New	1-1-WT-A-E-I-NO-TD
2/8-V-4	SR1GRC	24	200 – 562	New	1-1-WT-A-E-I-NO-TD
2/8-V-4	GTD66DCs	16.5	562 – 1067	New	1-1-WT-A-X-I-NO-HP
2/8-V-4	GTD66DCs	16.5	1067 – 1745	1-1-WT-A-X-I-NO-HP	1-1-WT-A-X-I-NO-TD
2/8-V-4	GTi76WMKHOs	12.25	1745 – 3540	New	2-3-BT-A-X-I-NO-TD
2/8-V-4	NaN	NaN	3540 – 3588	NaN	NaN
2/8-V-4	GTD64MKOs	8.5	3588 – 4090	New	1-3-CT-G-X-I-WT-HP
2/8-V-4 T2	GTD66DCs	8.5	3060 – 5346	New	1-1-WT-A-X-I-NO-TD

2/8-V-4 Y2

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-4 Y2	GTD64MKOs	8.5	3713 – 4245	New	1-1-WT-A-X-I-NO-DTF
2/8-V-4 Y2	GTE64C	8.5	4245 – 5433	1-1-WT-A-X-I-NO DTF	1-1-WT-A-X-I-NO-TD

2/8-V-5

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-5	XR+	32	140 – 190	New	1-1-NO-A-E-I-NO-TD
2/8-V-5	SR1GRC	24	190 – 560	New	1-1-NO-A-E-I-NO-TD
2/8-V-5	GTD66DCs	16.5	560 – 1560	New	1-1-WT-A-X-I-NO-TD
2/8-V-5	GTi76WMKOs	12.25	1560 – 3174	New	1-4-CT-ST-X-I-NO-TD
2/8-V-5	GTD64MKOs	8.5	3174 – 3174	New	New
2/8-V-5	GTD64MKOs	8.5	3174 – 5284	New	1-1-WT-A-X-I-NO-DTF

2/8-V-6

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-6	XR+	32	140 – 200	New	1-1-NO-A-E-I-NO-TD
2/8-V-6	SR1GRC	24	200 – 562	New	1-1-NO-A-E-I-NO-TD
2/8-V-6	GTD66DCs	16.5	562 – 1603	New	0-0-WT-A-X-I-NO-TD
2/8-V-6	KM624	12.25	1603 – 3324	New	0-0-NO-A-X-I-NO-TD
2/8-V-6	GTD64MKOs	8.5	3324 – 5089	New	1-1-WT-A-X-I-NO-TD

2/8-V-7

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-7	XR+	32	140 – 205	New	1-1-NO-A-E-I-NO-TD
2/8-V-7	SR1GRC	26	205 – 565	New	1-1-NO-A-E-I-NO-TD
2/8-V-7	GTD66DCs	16.5	565 – 1568	New	1-1-WT-A-X-I-NO-TD
2/8-V-7	GTD76WMKOs	12.25	1568 – 1568	New	0-0-NO-A-X-I-NO-DTF
2/8-V-7	GTD76WMKOs	12.25	1568 – 3302	New	1-1-WT-A-X-I-NO-TD
2/8-V-7	GTD64MKOs	8.5	3302 – 3654	New	1-1-WT-A-X-I-NO-DTF
2/8-V-7	GTD64MKOs	8.5	3654 – 5270	New	1-1-WT-A-X-I-NO-TD

2/8-V-8

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-8	XR+	32	140 – 200	New	1-1-NO-A-E-I-NO-TD
2/8-V-8	SR1GRC	24	200 – 563	New	1-1-NO-A-E-I-NO-TD
2/8-V-8	GTD66DCs	16.5	563 – 998	New	1-1-WT-A-X-I-NO-HP
2/8-V-8 T2	GTD66DCs	16.5	572 – 748	New	1-1-WT-A-X-I-NO-HP
2/8-V-8 T3	GTD66DCs	16.5	583 – 785	1-1-WT-A-X-I-NO-HP	1-1-CT-G-X-I-NO-BHA
2/8-V-8 T3	EBXT02DSLC	17.5	785 – 785		
2/8-V-8 T3	GTD66DCs	16	785 – 1526	New	0-0-NO-A-X-I-NO-TD
2/8-V-8 T3	GTi76WMKOs	12.25	1526 – 3155	New	1-1-CT-S-X-I-NO-TD
2/8-V-8 T3	SFE65CH	8.5	3155 – 4905	New	1-1-WT-A-X-I-NO-TD

2/8-V-9

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-9	XR+	32	140 – 200	New	1-1-NO-A-E-I-NO-TD
2/8-V-9	SR1GRC	24	200 – 568	New	1-1-NO-A-E-I-NO-TD
2/8-V-9	GTD66DCs	16.5	568 – 1594	New	1-1-WT-A-X-I-NO-TD
2/8-V-9	KM634X	12.25	1594 – 1597	New	0-0-A-E-I-NO-RIG
2/8-V-9	KM634X	12.25	1597 – 3176	0-0-A-E-I-NO-RIG	1-1-CT-T-E-I-WT-TD
2/8-V-9	GTD64	8.5	3176 – 4880	New	1-1-CT-A-X-I-WT-TD

2/8-V-12 & 2/8-V-12 Y2

Well name	Bit type	Bit size	Interval	Dull grade in	Dull grade out
2/8-V-12	XR+	32	140 – 200	New	1-1-NO-A-E-I-NO-TD
2/8-V-12	SR1GRC	24	200 – 560	New	1-1-NO-A-E-I-NO-TD
2/8-V-12	GTD66DCs	16.5	560 – 1954	New	1-1-WT-A-X-I-ER-TD
2/8-V-12	GTi76WMKOs	12.25	1954 – 4176	New	1-2-CT-S-X-I-NO-TD
2/8-V-12	NaN	NaN	4176 – 4221		
2/8-V-12	GTD64MKOs	8.5	4221 – 5028	New	No trip to surface
2/8-V-12 T2	GTD64MKOs	8.5	4550 – 5152	NaN	1-2-BT-T-X-I-WT-TD
2/8-V-12 Y2	GTD64MKOs	8.5	4377 – 7030	New	1-1-WT-A-X-I-NO-TD