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Performance Measurement and Efficiency Improvement for Onshore Drilling Rigs Operated by OMV

DEPARTMENT PETROLEUM ENGINEERING

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Affidavit

I declare in lieu of oath that I wrote this thesis and performed the associated research myself using only literature cited in this volume.

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Ich erkläre an Eides statt, dass ich diese Arbeit selbständig verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und mich auch sonst keiner unerlaubten Hilfsmittel bedient habe.

Name, 26 November 2016

Abstract

The major objective of oil companies has become to increase drilling efficiency and minimize drilling cost, saving as much as possible is important today more than any time else due to the drastic drop of oil price in addition to the increase of the cost of well drilling and contracting.
The cost of any well includes several factors such as: the rig, casing, personnel, drilling fluids, drilling equipment, etc. The cost of the well depends mainly on the time it takes to drill a well and complete it successfully. Therefore, the less time it takes, the less is spent.
Different methods and ways have been employed by operating companies to achieve operation optimization and cost reduction in order to decrease the non- productive time (NPT) and the invisible lost time (ILT) which usually occur because of; unnecessary operations such, use of sub-optimal equipment, and unexperienced crew. For that reason the identification and reduction of ILT and NPT events is the key point for huge savings during the well construction process that is why rig performance monitoring has become a very essential role for operators in order to improve drilling performance, increase the efficiency, and reduce drilling operation cost.
Automatic Drilling Performance Measurement of drilling crews and equipment (ADPM) is a real-time analytical tool was developed and its able to collect, visualize and observe the performance of drilling and rig-related Key Performance Indicators (KPIs), Prior to this tool, it was difficult to track, record, and highlight ILT and NPT events. APDM analyzes and calculates KPIs such as connection times and pipe moving times during tripping and casing; this tool is capable of accurately recognizing the rigs that are not performing around their contractual targets as well as identifying the saving potential of each KPI.
The objective of this thesis is to analyze the performance of the various rigs that have been employed by OMV in onshore drilling operations in Austria, Pakistan and Yemen in terms of identifying ILT and analyzing the causes of NPT by measuring and evaluating the effective KPIs that contribute to the drilling operations, this thesis also aims to set new targets for some KPIs that would reduce the duration in future wells with consideration to safety and consistency. The thesis will also highlight the rooms of improvements, the lessons learnt and the operations that can be eliminated or reduced in time. Best practice wells will be generated based upon already achieved performance for possible future wells for the three countries using best composite time approach.

Zusammenfassung

Zurzeit liegt das Hauptaugenmerk in der Ölindustrie darauf die Effizienz der Bohrungen zu steigern und deren Kosten zu minimieren. Auf Grund des aktuell niedrigen Ölpreises und der nach wie vor steigenden Kosten für Bohrungen und Ölfeldservice-Dienstleistungen ist diese Thematik besonders aktuell.

Die Kosten einer Sonde setzen sich aus verschieden Faktoren wie Bohranlage, Verrohrung, Arbeitskräfte, Bohrspülungsmittel und andere Bohrausrüstung zusammen. Daher hängen die Kosten insgesamt stark von der Dauer der Bohrung und Komplettierung ab. Deshalb gilt, je geringer der Zeitaufwand, desto niedriger die Kosten.

Verschiedene Methoden wurden von den Betreiberunternehmen umgesetzt, um eine Prozessoptimierung und eine Reduktion der NonProductive Time (NPT) und der Invisible Lost Time (ILT) zu erzielen. Zu diesen kommt es oft wegen suboptimaler Ausrüstung und unerfahrenen Arbeitskräften. Die Bestimmung und Prävention von NPT- und ILT-Ereignissen sind Kernpunkte bei der Kostensenkung von Tiefbohrungen. Deshalb spielt die Performanceanlyse des Bohrvorganges für Betreiber eine essentielle Rolle um Leistung und Effizienz zu steigern und Kosten zu reduzieren.

Automatic Drilling Performance Measurement (ADPM) ist ein Echtzeit-Analysewerkzeug, das entwickelt wurde, um Daten zu sammeln und zu visualisieren und bohrungsrelevante Key Performance Indicators (KPIs) zu überwachen. Zuvor war es oft schwierig ILT- und NPT-Ereignisse zu verfolgen, aufzuzeichnen und zu behandeln. ADPM analysiert und berechnet KPIs wie Verschraubungszeiten, die Zeiten für das Ziehen und Einsetzen von Bohrgestänge und Verrohrung. Dieses Werkzeug ermöglicht sowohl das Erkennen von Einsparungspotential zu jedem KPI, sowie von Bohranlagen, die die vertraglich festgelegten Ziele nicht erreichen.

Ziel dieser Diplomarbeit ist es, die Effizienz verschiedener Bohranlagen die von der OMV zu Lande in Österreich, Pakistan und im Jemen betrieben werden, im Bezug auf NPT und ILT, und deren Ursachen, zu analysieren. Durch Messung und Auswertung der für Tiefbohrungen relevanten KPIs, zielt diese Arbeit auch darauf ab, neue Sollwerte dieser KPIs zu definieren, die die Dauer künftiger Bohrungen, unter Beachtung von Sicherheit und Beständigkeit, reduzieren würden. Diese Arbeit wird sowohl Verbesserungsmöglichkeiten, die gewonnenen Erkenntnisse als auch Abläufe bei denen Zeit gespart werden kann oder auf die verzichtet werden kann, aufzeigen. Aus bereits erreichten Leistungszielen werden Vorbild-Bohrungen für die Zukunft, in den drei Ländern, nach dem Ansatz der besten Gesamtzeit erstellt.

Acknowledgement

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Contents

Chapter 1 Introduction

1.1 Overview

Nowadays, as the drastic drop of the oil price continues, a major objective of petroleum operating companies has become to increase drilling efficiency and minimize drilling cost given the fact that the cost of well construction has increased drastically specially after the raise in the costs of drilling equipment as well as drilling contracting. According to Svenson (2015), drilling to top reservoirs takes twice the time today compared to 20 years ago when top reservoirs were not that deep. [1] The cost of any well includes several factors such as: the rig cost, casing, personnel, drilling fluids, drilling equipment, etc. However, A big part of the well cost is considered time sensitive, meaning that the cost depends on the time it takes to drill a well and complete it successfully. Therefore, the less time it takes, the less is spent.

One element of drilling time is the non-productive time (NPT) or known as Lost Time (LT), which is considered trouble time, it is where the rig operates off the plan. An additional important aspect, which is often neglected, despite the big influence it has on the total drilling operation is the invisible lost time (ILT), also known as Hidden Lost Time; this is the time where operations are performed off benchmark; it is usually absorbed in productive and flat time. There are several factors that contribute to ILT such as: unnecessary operations, use of sub-optimal equipment, and unexperienced crew. Therefore, improving drilling operations and enhance the performance through the identification and reduction of NPT and ILT is an important key point for a huge savings during the well construction process.

However, prior to improve any performance, first it should be measured, in drilling operation a useful way of measuring the drilling performance is to measure the time each operation has taken. Automatic detection and recognition of drilling operation is the first step towards drilling performance measurement and improvement (G.Thonhauser, Mathis, et al. 2006) [2], such automatic detection and performance measurement can be done by automatic drilling performance measurement of drilling crews and equipment (ADPM); it is a tool that is based on collecting real time rig sensor data and recognizing the rig state. APDM helps to evaluate and measure the different effective Key Performance Indicators (KPIs) that are generated by rig crews, such evaluation is an essential step towards performance improvement and drilling process optimization, often KPIs related to drilling crew and equipment represent 30% - 40% of the total rig time, thus when these KPIs are performed off benchmark their ILT can contribute up to 30% of the total productive time in operations such as tripping in or out, making up or breaking BHA, casing running, etc.

It is observed that during the construction of different wells using the same rig there is always a variation in the duration of the different tasks performed sometimes even by the same crew and under the same conditions.

If we train the crews to perform the different operations in a more consistent way during the well construction process we could achieve hugs savings of the total rig days. For example if we can save up to 10 seconds from the time of making connections during tripping for one rig considering an operation count of 52702, which is the case with T52 KCA DEUTAG rig we can save up to approximately 7 days, this saving even makes a bigger difference in the case of offshore operations considering the high daily operation's bill. These huge savings emphasize the importance monitoring the rig performance in order to reduce ILT and NPT events, thus, increasing the efficiency and reducing drilling operation cost.

This thesis aims to evaluate and measure the performance of the different rigs that have been employed by OMV in onshore drilling operations in Austria, Pakistan and Yemen in terms of identifying ILT and analyzing the causes of NPT.

A total of 8 rigs were analyzed in this thesis, 2 rigs in Yemen, 1 rig in Pakistan and 5 rigs in Austria.

The evaluation process of this thesis goes as the following:

- Rig overview; showing the number of wells drilled as well as the rig specifications.
- Analyzing and quantifying the NPT and highlighting the root causes that contributed to that NPT.
- KPIs and ILT analysis; for some of the formation- dependent and rig-dependent KPIs.
- KPIs improvement analysis; the thesis also demonstrates if there is a learning and improvement over time for the average value of the operations based on selected KPIs.
- Saving Potential analysis; demonstrating the learning and improvement of the saving potential percentage of some selected operations. In addition to illustrating the saving potential report for selected KPIs.
- New targets selection; new targets are selected for future wells aiming to increase the performance considering safety and consistency of the operations.
- Lessons learnt and conclusion; highlighting the lessons learnt from the events contributed to NPT and giving the recommendations for the expected behavior in future well in addition to giving an overall summary and observations of the rig's performance.
- The thesis then ranks the different rigs based on some selected KPIs in terms of the fastest rig, as well as ranking based on the less NPT and ILT was spent.
- Finally, best practice wells will be generated based upon already achieved performance for possible future wells for the three countries using best composite time approach.

1.2 Special Drilling Definitions

1.2.1 Well Phases

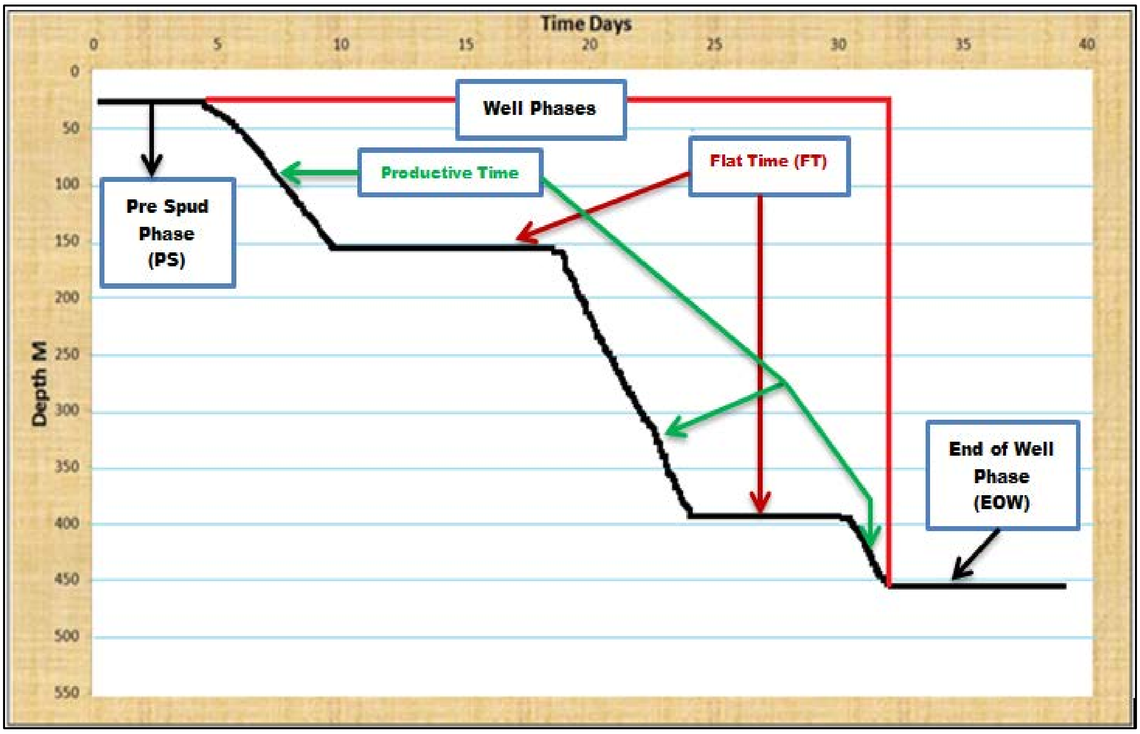


Figure 1: Well Phases [3]

1.2.1.1 Pre-spud Phase [PS]

This phase includes all the operations and preparations that take place before drilling starts; for example rigging up, making up the first Bottom hole assembly (BHA), and mixing the spud mud.

1.2.1.2 Well Phases

This includes all the phases between the pre-spud phase and end of well phase, the well phases are recognized by the hole sizes of the well, a new well phase starts by making up the first BHA to drill that phase, and ends with the making up of the first BHA of the next phase.

1.2.1.3 End of Well Phase [EOW]

End of well phase start point is different from company to another; most of the companies consider the start point of EOW once the well has made it to the total depth (TD), while other companies consider the start of EOW once the well head has been installed.

1.3 Total Well Duration Break Down

Drilling and completion operations are divided in many major groups that are derived from using the time versus depth curve as seen in Figure 1 above

1.3.1 Productive Time [PT]

Productive time is defined as the time required drilling formation; it's the time when the bit is on bottom drilling formation wither its rotating or sliding.

1.3.2 Flat Time [FT]

FT is part of the productive time, it includes all the planned drilling activities that are taking place but without making hole, in other words where the bit is not bottom making a hole. However, making connections during drilling is included in this time, Examples of Flat time activities are;

- Running and cement the casing string
- Making up and breaking down the BHA.
- Nipple UP/Down blowout preventer [BOP].
- Circulation time.
- Formation evaluation time.
- Running completion

1.3.3 Lost Time [LT]

Lost Time also known as Non-productive time (NPT) is any event that interrupts the progress of a planned operation causing a time delay; it includes the total time needed to resolve the problem until the operation is resumed again from the point or the depth where the LT event occurred. LT is used to reflect lost time to describe flat time caused by problems, such as downhole problems, equipment failures, and unpredicted environmental events etc. LT results in pushing drilling operation behind the schedule and that leads to a huge loss of time and money considering that costs arising from LT typically account for about 10% to 15% of total drilling costs, and can rise as high as 30%. [4]

LT is the main cause of drilling project delays and over spends, it is directly proportional to drilling cost and if uncontrolled it could lead to escalation of costs sometimes beyond budget [5], that is why operators sometimes consider 10 to 25% of the Authorization of Expenditure (AFE) during well planning to cover the costs of any unexpected NPT that can impact drilling budgets.

There are numerous events that cause the disturbance of drilling operations or marginal reduction in advancement of the drilling progress leading to LT, these events are either observable or unobservable and could be due to; the physical characteristics of the well, geology, drilling parameters, operator experience, wellbore quality, equipment down time, well planning and execution, team communication, leadership, or project management skills [5].

Mitigating and eliminating LT can lead to savings potential from 10 to 25%, some oil companies are implementing planning programs that assess and integrate the latest processes and technologies to reduce drilling risks up-front. Cutting-edge technologies such as managed pressure drilling technologies, drilling with casing, drilling with liners, and solid expandable casing have been highly effective. Implementing proactive evaluation processes and applying the latest tools and techniques can reduce operational risks and trouble zones to ultimately reduce NPT and associated costs. [4]

Reducing NPT can also be achieved by conducting a root cause analysis. "*That's definitely one of the things we need to do to get to the root causes, not just get to a symptomatic problem .That would alleviate a lot of problems*"(Keene, 2010) [6]. Figure 2 below illustrates an example of the root causes for the total NPT that had occurred for one of the rigs analyzed in this thesis's case study.

Nevertheless, (Keene, 2010) believes that the industry should not keep the definition of NPT so narrowly focused. According to him NPT is anything that happens not aligning with the original well plan and should be counted as such, so that the operators and drilling contractors really understand where precious rig time is going.

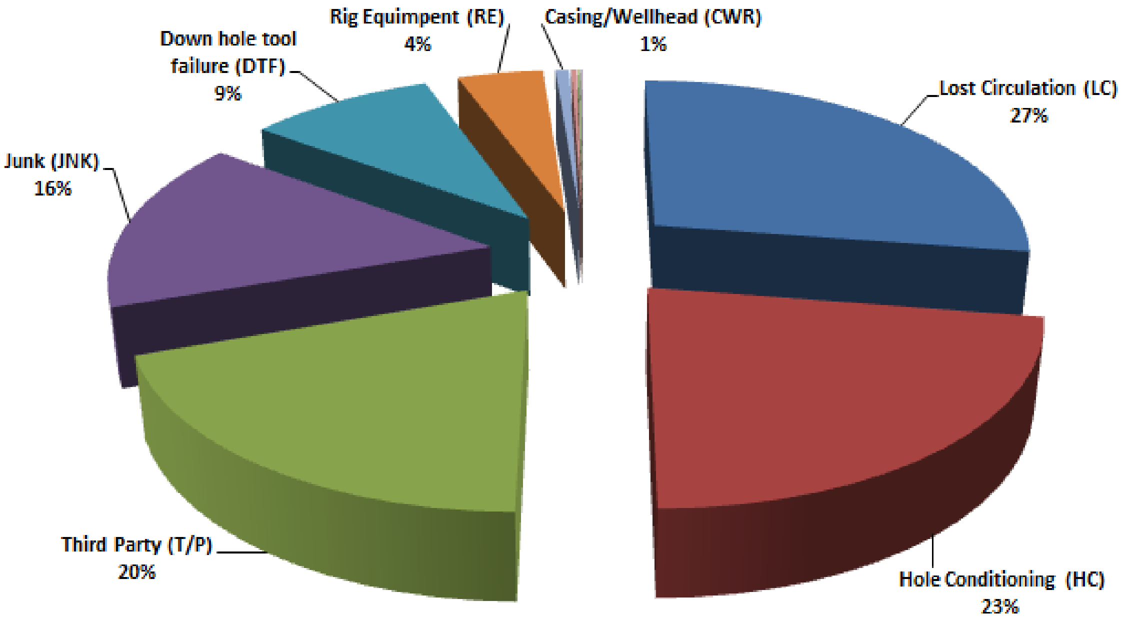


Figure 2: NPT Root Cause for Rig 221, Yemen

1.3.4 Technical Limit Time (TLT)

It is the time that represents a stretched target of what is possible (by theory) in a perfect world where both ideal and optimized drilling operations are met. According to Bond (1996) [7], in order to measure and plan the TLT, firstly, we have to answer the following questions:

- Where are we now? Current performance.
- What is the possible? Theoretical limit.
- How do we get there? New technology tools.

After these questions are answered properly, we can proceed to the processing steps, which by then we should be able to do the following:

- Identifying current performance in terms of time for each individual task.
- Defining the best practical time for every individual task.
- Planning for eliminating the gap between the current performance and the technical limit for future wells.

1.3.5 Invisible Lost Time (ILT)

ILT known also as hidden time is the difference between actual operational duration and a best practice target, in other words it is time by which actual drilling operations lag behind planned drilling operations, it is called invisible due to the fact that it is not recognized on any conventional morning drilling reports. There are several events that contribute to ILT such as: unnecessary operations, use of sub-optimal equipment, and unexperienced crew.

Invisible lost time occurs during the other 70 –90% of operation when the rig is actively engaged in productive operations but is not performing them as efficiently as possible, given the large amount of time for such operations, there is a significant cost to recognize the lost time during normal operations. [8]

For this thesis ILT is defined as the difference between a predefined key performance Indicator (KPI) target and the actual KPI performance shown by a crew, rig, or entire rig fleet. ILT is mainly associated with efficiency improvements in rig crew activities and drilling optimization. The drilling contractor is responsible for parts of the invisible lost time, and hence, can reduce ILT by improving the efficiency of their operation. [9]

Most drilling performance campaigns try to eliminating wellbore-related problems as well as equipment failures that can result in NPT. But on the other hand, operators cannot identify the ILT that results from inefficient drilling operations, such as drill pipe connections during drilling or tripping.

1.3.5.1 ILT Recognition for Routine Drilling Operations

Recognizing and measuring Invisible Lost Time (ILT) starts by a rigorous analyzing for each KPI that can be produced by a particular rig or crew or by a machine automated operation or a combination of both, the automatic operations recognition provides a highly accurate determination of ILT. Figure 3 below illustrates how this process is done by computing the duration each individual rig performs a particular routine drilling operation over a period of time. The time period is typically selected to allow for different rigs to perform the same operation many times under similar conditions, what can be taken as an example of time interval is the duration to complete a particular hole size, or the time to complete a particular tubular run, [10] after gathering this data, individual histograms are generated for each routine drilling operation for any given rig.

Chapter 2 Automated Drilling Performance Measurement of Drilling Crews and Equipment (ADPM)

Evaluating and measuring the performance of rig crews and equipment requires some key performance indicators (KPIs) to be identified, then be measured and benchmarked.
The performance of crews and rigs presented in this thesis is based on automatic drilling performance measurement of drilling crews and equipment (ADPM); it is real-time analytical tool that can identify the rig state as shown in Figure 3. Moreover, it can visualize and observe the performance of formation and rig-related KPIs.

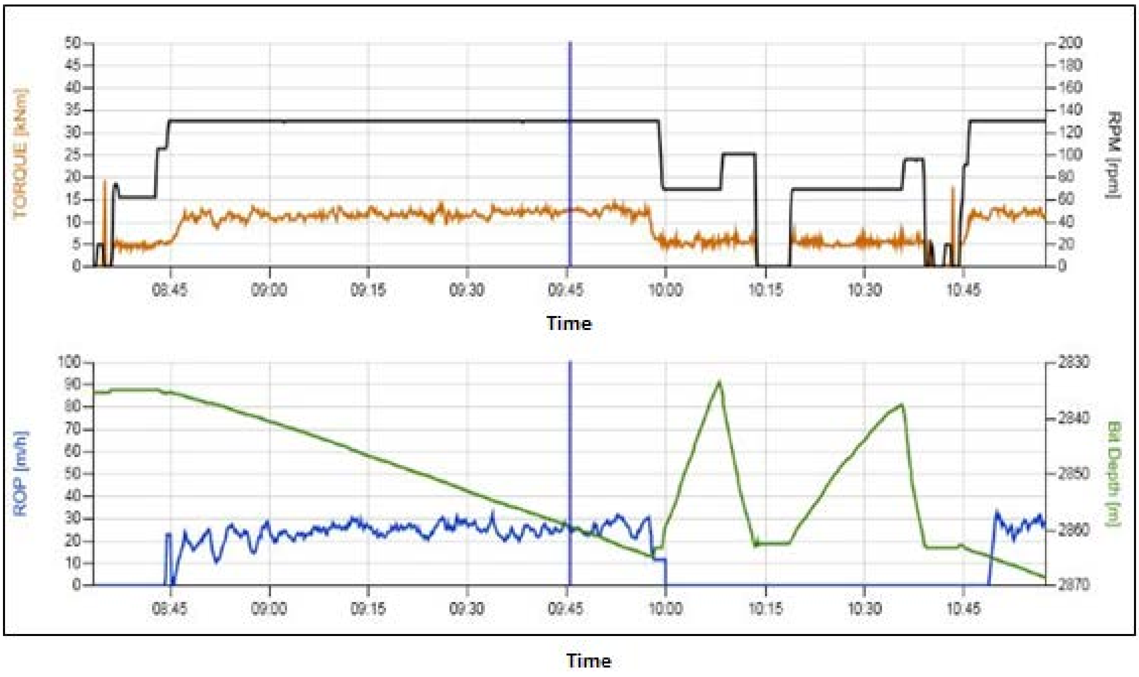


Figure 3: ADPM Drilling Operation Detection

ADPM works as an independent third party data quality controller, this way confirms that there is no any mean of conflict of goals or interests. After the quality data process, the data is classified and processed, the rig state is assigned to every time interval as shown in Figure 4. The automatic identified rig states will be the fundamental building blocks for the classifications and KPIs analysis in this thesis

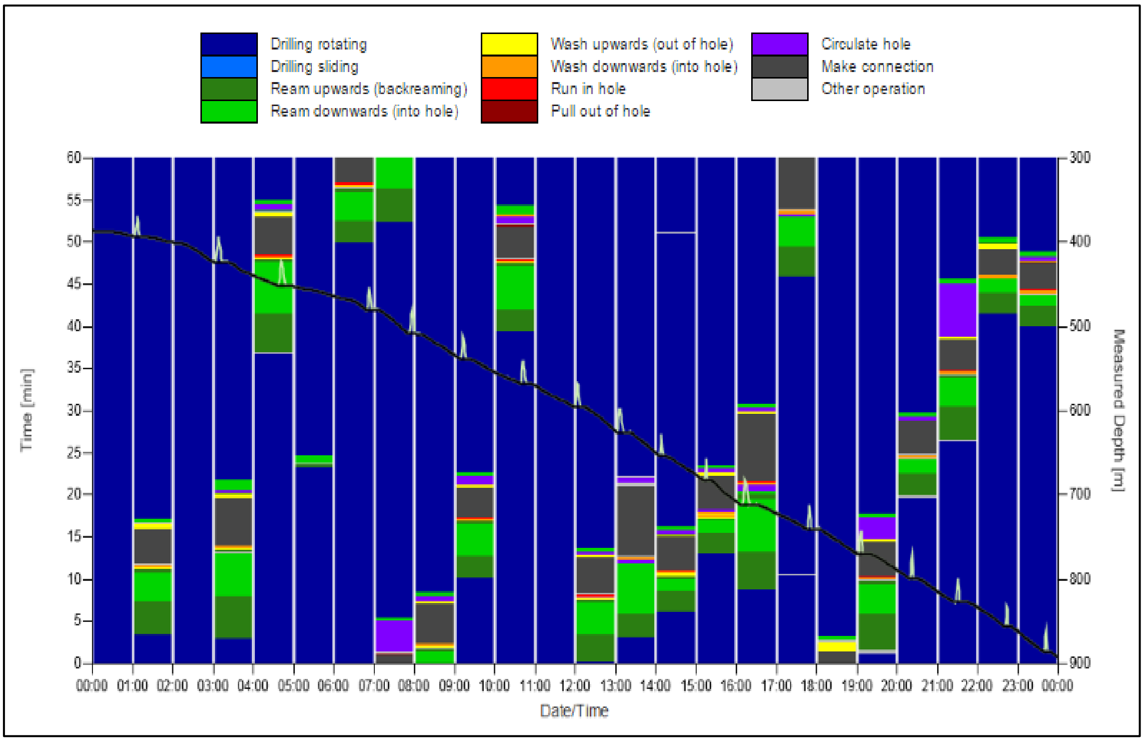


Figure 4: ADPM Rig Status Detection Example

2.1 Routine Drilling Operation Detection

Identification of drilling operations is an essential step to optimize drilling process, automatic detection and recognition of drilling operation is the first step towards drilling performance measurement and improvement (G. Thonhauser, Mathis, et al. 2006) [11]. Being able to classify drilling operations rigorously leads to producing detailed performance reports not only on drilling rigs and crews; such reports help rig operators to measure and evaluate the drilling performance as well as finding out the state of drilling rig instantly, giving a detailed information on rig state over any period of time which makes it easier for rig's operator to observe the actual operating time of drilling rig and compare it with the well plan.

In order to classify drilling operations, APDM uses two sources of data which are; daily drilling reports (DDR) data and the surface sensor data that is provided by the mud logger, the surface sensors measurements can be considered as a main source of information about drilling operations, they are used for detecting the routine drilling operation, while the daily drilling reports are used to link certain operations to the pre-defined key performance indicators. During drilling operations an enormous amount of data in form of sensors measurements is produced over time. This data contains information about each drilling operation i.e. start, end, and behavior of each equipment. Drilling operations such as drilling formation, making connection for new drill stand, breaking connection, pulling out of hole, running in hole, and cleaning hole are carefully chosen as basic drilling operations performed by drilling crew[12], an example of the drilling operations highlighted on drilling sensors data is shown in Figure 5.

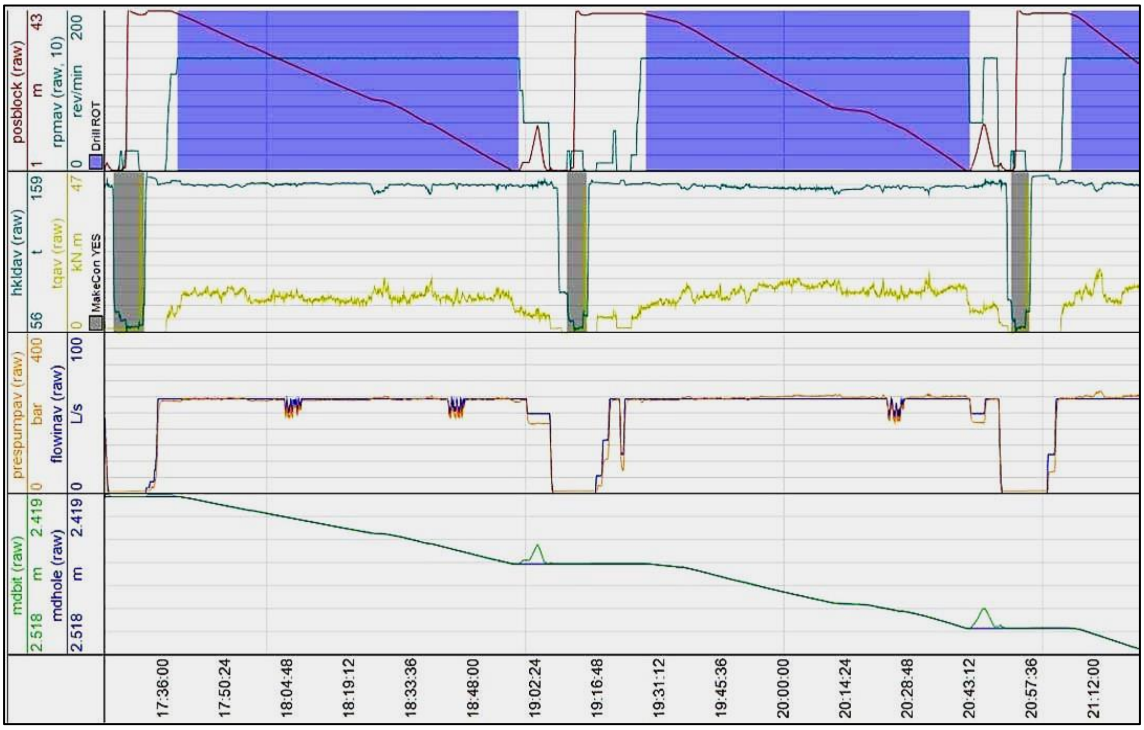


Figure 5: Drilling Operations Highlighted on Drilling Sensors Data (Blue color: drilling operation and making hole. Gray color: making connection) [12]

2.2 Key Performance Indicators (KPIs) relevant to this Thesis

Key performance indicators are an analytical metric and continuous assessment of performance at multiple levels within the organization; they can be based on financial and technical measures.[13]

KPIs in general aim to reduce the complex nature of performance to a smaller number of key indicators in order to make it more digestible. KPIs should be designed to track the progress and provide relevant insights to help managing and improving the overall performance. Moreover, decision making process can be made faster when there are accurate and visible measures.

In well construction operations, KPIs are produced by the different operations that take place during drilling and completion operations; by either a rig or crew or by a machine automated operations or a combination of both.

KPIs have contributed largely in supporting drilling operations; they aim to provide analytical and continuous assessment of performance at several levels, in addition to indicating where we can improve the performance.

The selection criteria for the KPIs that were analyzed throughout this thesis was done based on some criteria; first one is based on the duration they took. On other words, the most time consuming KPIs were selected to be evaluated and analyzed due to the fact that they represent the major time spent during constructing the well, thus, improving them would achieve a lot of savings, what was observed from the case study of this thesis is that the KPIs related to drilling activities represent the highest time among the other KPIs, followed by indicators related to wellbore conditioning and treatment, and the tripping indicators as seen in Figure 6 below.

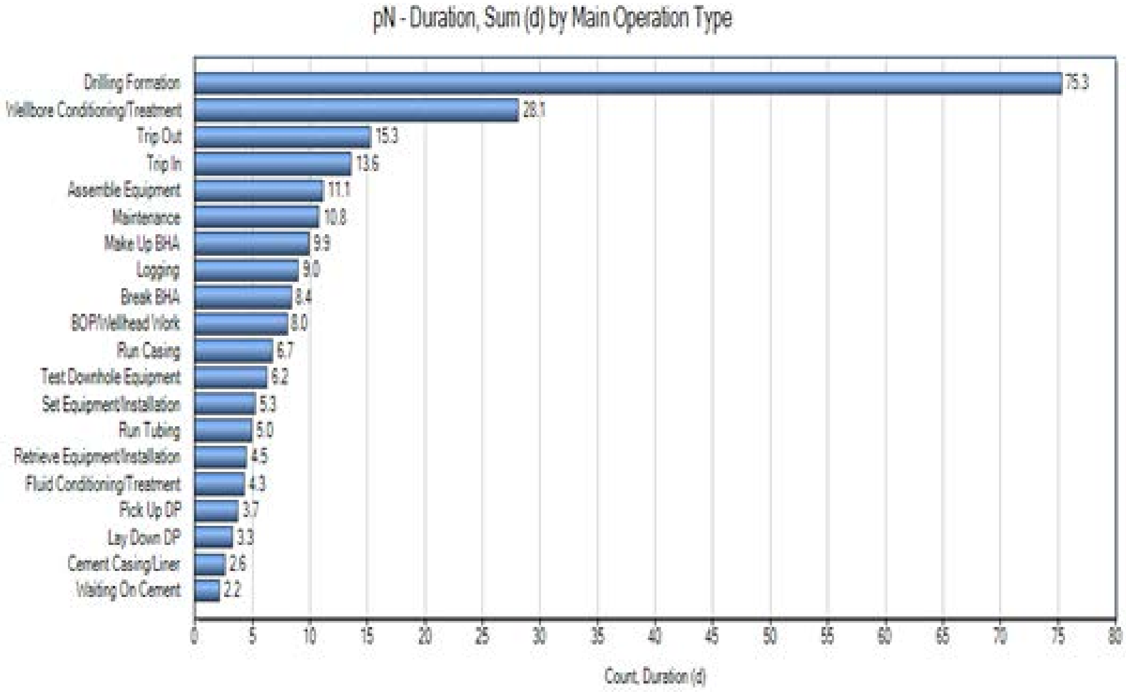


Figure 6: Different KPIs Total Time Breakdown in Days for the Rig Saxon 215

Another criteria for selecting the KPIs is the routine nature of performing that particular operation, which means it's an operation that is repeated over the time under the same conditions and it is just related to the rig crew performance; an example of such indicators are casing running and tubing running KPIs, tripping KPIs are also categorized under this criteria. However, the analysis for casing running indicator was done for each phase diameter individually for more accurate and representative results.

The APDM tool is capable of calculating several KPIs and categorize them in different categorizes; the main KPIs that were analyzed in this thesis are explained and defined in this section.

2.2.1 KPIs Related to Tripping

The Tripping KPIs are derived for the time intervals defined as 'Trip In' and 'Trip Out' in the APDM Operations Classification. 'Tripping In' starts when the top of the drill collars go through the rotary table and lasts until the bottom of the hole is reached. Tripping KPIs are derived and displayed for open and closed holes individually, and they can be displayed together as well. [14]

In this thesis the analysis of pipe moving time indicator was done only for the cased hole due to the fact that there is no surge and swab effects influencing and restricting the pipe moving speed.

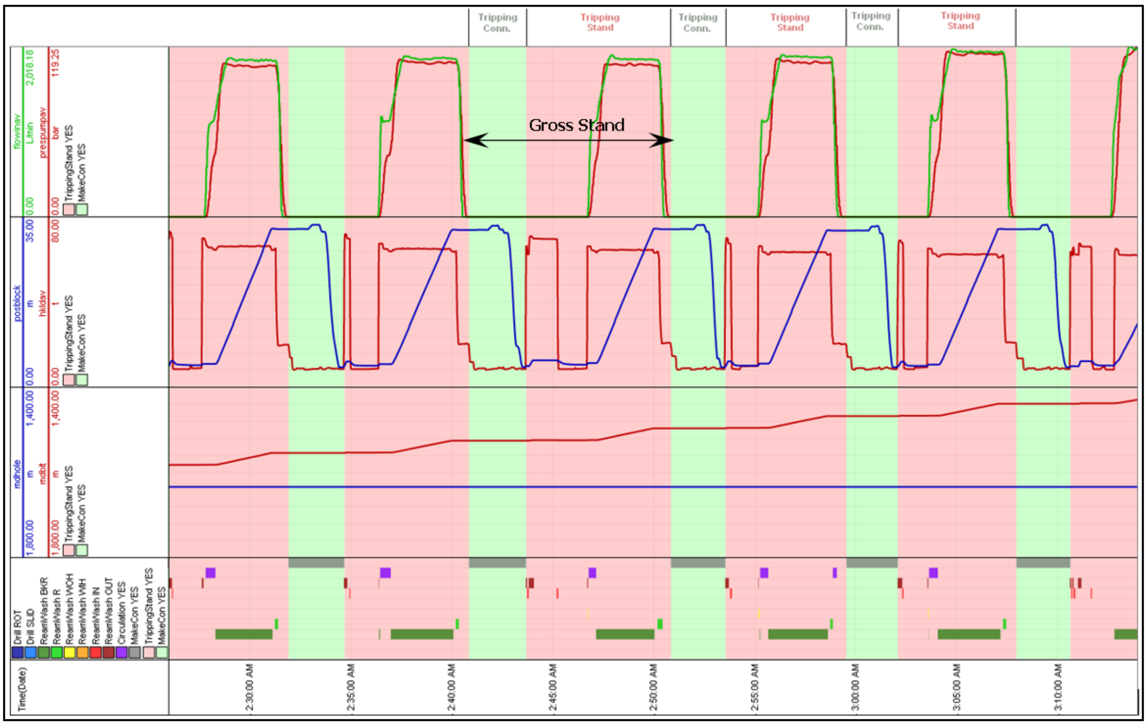


Figure 7: Definition of Tripping Time Intervals [14]

2.2.1.1 Tripping Slip to Slip Connection Time

The time spent in slips and making a connection during tripping operations. This KPI is also available separately for the running (RIH) and pulling (POOH) part of the run.

2.2.1.2 Tripping Pipe Moving Time for Cased Hole (CH)

It represents the time needed for running one stand of drill pipe in or out of the hole in the cased hole only.

2.2.2 KPIs Related to Running BHA

The Running BHA KPIs are derived for the time intervals defined as 'Make up BHA' and 'Break BHA' in the APDM Operations Classification. Running in BHA in this context starts when the bit goes through the rotary table and lasts as long as the drill collars are run into the hole. In contrast to this, running out BHA starts when the top of the collars passes the rotary table and stops when the bit is out of the hole.

2.2.2.1 BHA Slip to Slip Connection Time

The time spent in slips during running BHA. This KPI is also available separately for the running (RIH) and pulling (POOH) part of the run.

2.2.3 KPIs Related to Drilling

2.2.3.1 Drilling Weight to Weight Time

The time between two drilled stands. This KPI starts when the drill string is lifted off from bottom and lasts until the string is on bottom drilling again. This operation includes all wellbore conditioning as well as the drilling slip to slip connection conducted during this interval.

2.2.4 KPIs Related to Casing Running

The Running Casing/Liner KPIs are derived for the time intervals defined as 'Trip In' during Casing/Liner Runs in the APDM Operations Classification. Running Casing Indicator in this context starts when the first joint goes through the rotary table and lasts until the bottom of the hole is reached. In contrast to this, Running Liner lasts only until the first stand of drill pipe is attached to the last liner joint. The closed hole theory applies to casing pipe moving time as well, the analysis of the pipe moving time during casing was done only for the cased hole.

2.2.4.1 Casing Slip to Slip Connection Time

The time spent in slips during casing running/or liner (excluding the drill pipe).

2.2.4.2 Casing Pipe Moving Time (CH)

The time needed for running one joint of casing/liner into the cased hole. Actually it is the time between two casing/liner slip to slip connections.

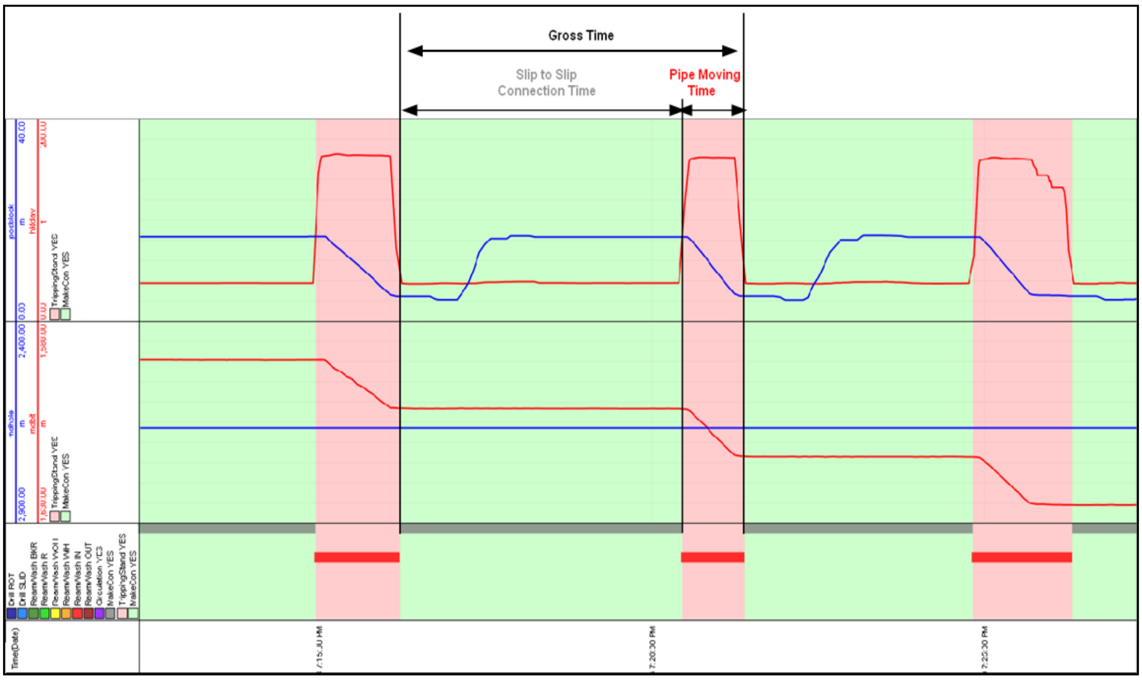


Figure 8: Definition of Casing Time Intervals [14]

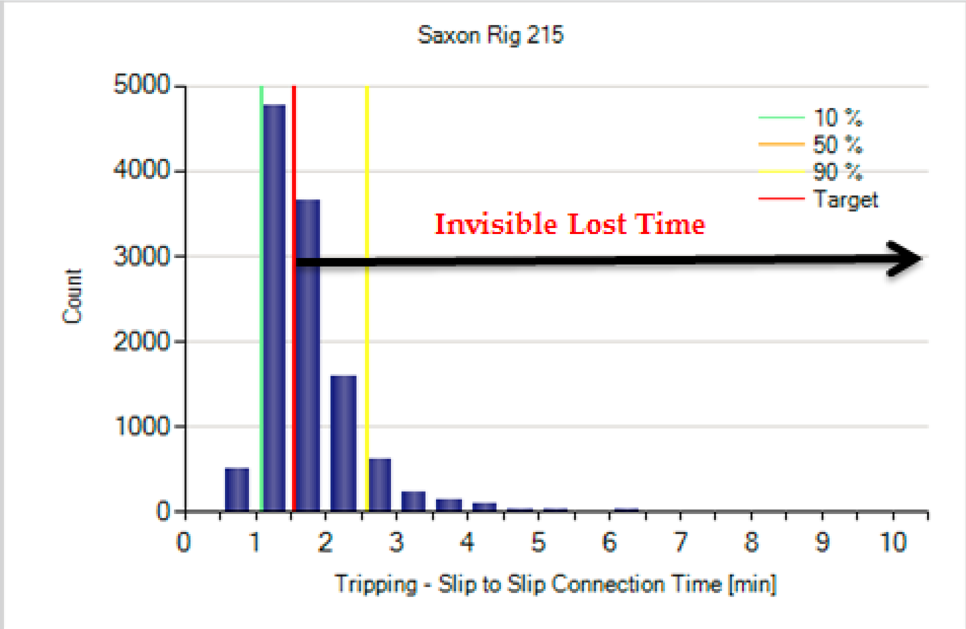
2.2.5 KPIs Related to Tubing Running

2.2.5.1 Tubing Slip to Slip Connection Time

The time spent in slips and making a connection during tubing running.

2.3 ILT Recognition by APDM

ADPM creates a set of histogram plots which are used to analyze any KPIs at any phase, time interval and it can be filtered by well or by rig. Histograms are desirable for a better visual understanding of the KPI. In addition to that, they include other important information about any KPI such as; total amount of operations, P10, P50, and P90 values, average, and the total duration of the KPI, what is more important is that they include the saving potential that can be saved from each KPI as seen in Figure 9, another good feature recognized by histograms is the consistency indicator of any operation



Rig	**Saxon Rig 215**
Operation Count	11825
10 %	1.10 min
50 %	1.57 min
90 %	2.58 min
Average	1.78 min
Deviation Avg	0.91 min
Deviation Target	0.93 min
Target	1.57 min
Total Duration	14 d 15 h 11 min
Savings Potential	3 d 0 h 5 min
Savings Potential [%]	20.53 %

Figure 9: Invisible Lost Time Recognition Example

By looking at the histogram in Figure 9, it is easy to identify the invisible lost time which is the duration in the right to the target (the black arrow); the ILT is 3 days which represents 20.53% of the total KPI duration.
Targets selection depends on the company decision, some of them select the target according to the best practical time, while others do based on benchmarking. Lower and Upper cutoffs are the operations that are above and below those values which are not considered for analysis and calculations, they are related to data quality control. After targets are selected for each individual KPIs, ADPM can calculate the ILT for all the KPIs and generates a final saving potential report that shows how much time that the company could have saved if the operations of those particular KPIs were done consistently around the selected target, Figure 10 shows an example of a saving potential report for one of the rigs analyzed.

KPI	Savings Potential [d]	Savings Potential [%]
Tripping - Slip to Slip Connection Time	2.95	22.71
Tripping - Pipe Moving Time - CH	1.85	33.07
BHA - Slip to Slip Connection Time	1.32	40.53
Drilling - Weight to Weight Time	0.58	12.80
Casing - Slip to Slip Connection Time	1.30	37.73
Casing - Pipe Moving Time - CH	0.34	45.68

Total Savings Potential: 8.33 days (27.30 %)
Total KPI Duration: 30.53 days

Figure 10: An Example of Saving Potential Report Generated by ADPM

Chapter 3 OMV Rigs (Case Study)

3.1 Overview

The performance of the different rigs that have been employed by OMV in onshore drilling operations in Austria, Pakistan and Yemen have been analyzed and measured in this case study.
A total of 8 rigs were analyzed, the analysis starts by rig total time breakdown illustrating the duration of the main operations that were performed for each rig, followed by NPT analysis for the rigs that are still active within the company (5 rigs) out of the total 8 rigs.
The NPT analysis is quantified by operational code as well as the root cause. After analyzing the NPT some KPIs were picked and analyzed based on the KPIs criteria selection mentioned in Chapter 3, those KPIs included formation-dependent KPIs such as Drilling-weight to weight time and Rig-dependent KPIs such as tripping, and casing & tubing running KPIs.
The casing running KPIs analysis was done for each individual phase diameter, in this section of KPIs analysis the main parameters are illustrated in tables showing the operation count, the target based on the P50 value , saving potential, and some other necessary parameters. By the end of this section there is a bar chart that ranks the KPIs based on the largest ILT showing how much ILT each KPI had made.
The case study also included an analysis of the average value of the selected KPIs over months, quarters, or years depending on how long that particular rig was active this analysis aimed to show if there is a self-learning and improvement by the crew which can be obvious if there is a decrease in the average value over the time.
In addition to that, another analysis was done for the percentage of the saving potential for the selected KPIs for each individual rig showing also if there was learning and a drop in the saving potential percentage over a period of time.
After that new targets are selected based on the best P50 value for each well that was drilled by that particular rig. By the end of the analysis the lessons learnt are listed as well as recommendations, potential areas of improvements.
In the conclusion chapter, several graphs are presented to show the rank of the rigs based on the durations they had taken to perform the tripping and casing running KPIs.
It is important to mention that the analysis was done based on the available historical data because not all the data is available, the APDM data was missing for some phases in several wells specially those wells which were drilled several years ago, thus, the analysis was done for them based on historical data but not a live analysis as the case with the most recent wells like Lamwari 1 in Pakistan.

The flow chart in Figure 11 illustrates the process of this case study

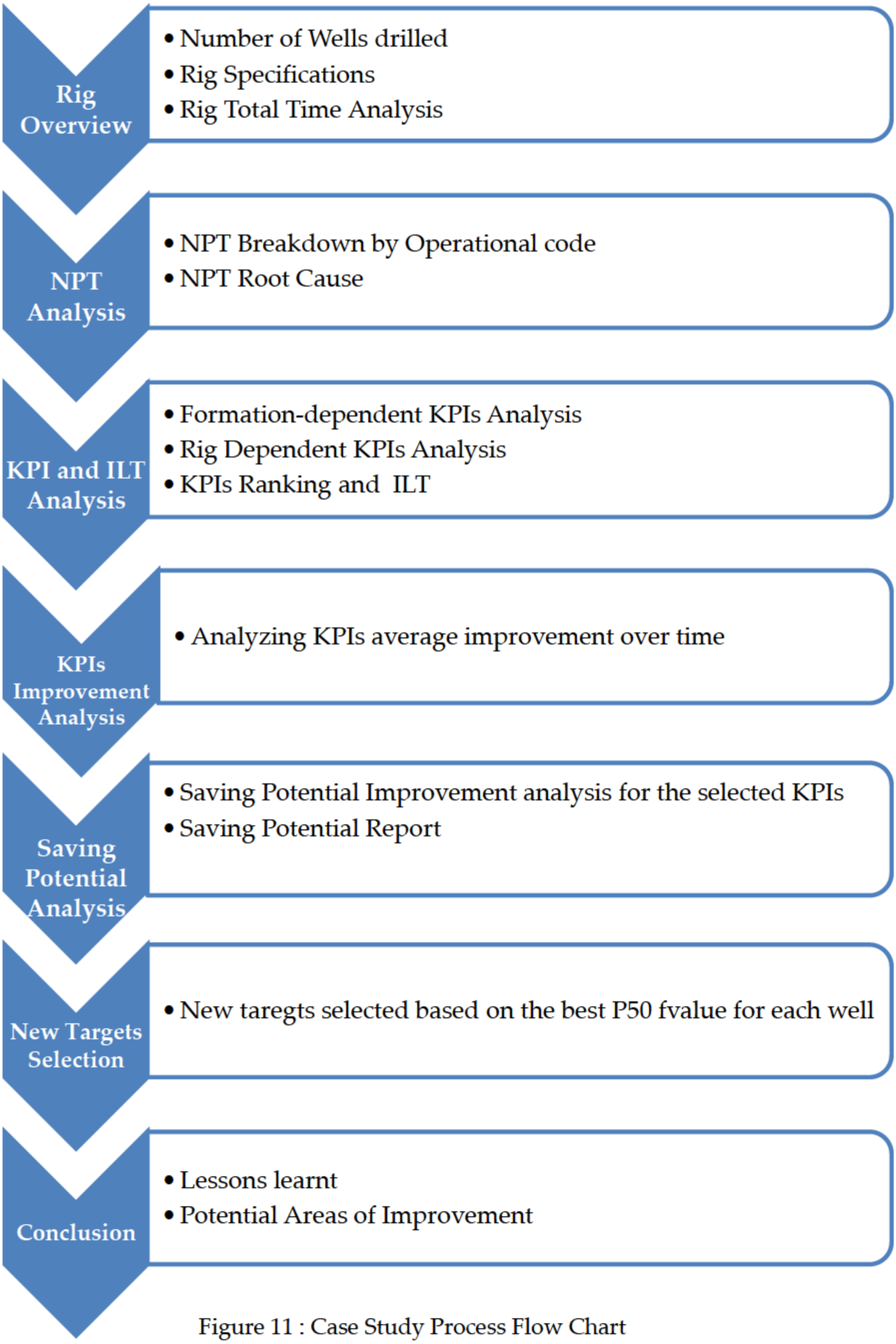


Figure 11 : Case Study Process Flow Chart

3.2 Rig 221, Yemen

The rig 221 drilled two wells, the first was Habban 37 followed by Habban Sat-N-01, the total rig time is 291 days.

3.2.1 Rig Specification

Table 1: Rig 221 Specifications

Classification	Land Rig, Diesel Electric with SCR
Max. Drilling Depth	3048 m with 5" DP
Mast	142 ft clear height Lee C. Moore
Gross Nominal Capacity	1,000,000 lb with 12 lines
Crown Block	1000 Klbs static hook load capacity
Travelling Block	National (500 Ton)
Drawworks	Mid-Continent U-914-EC, 1500 HP
Substructure	Lee C. Moore.
Substructure Height	9.15m
Rotary Table	National 27 ½"
Swivel	Emsco LB-650 (with 500 Tons static load, 5000 psi)
Top Drive System	Canrig 1050E, 500 Ton
Mud Pumps	2 x Emsco FB-1600 Triplex
Standpipe Pressure Rating	5000 Psi

3.2.2 Rig Total Time Analysis and Breakdown

Based on the total time breakdown in Figure 12, the following is noted:

- Drilling formation (both rotating and sliding) was the largest time consumer; it consumed 30 % of the total rig time.
- Tripping out represented the second largest time consumer; it consumed 15 days of the total rig time.
- Wellbore treatment and conditioning consumed a significant time which represented 10% of the total time.
- As the 4th largest time consumer, Tripping in consumed 13 days of the total rig time.
- BHA making up and breaking consumed quite significant time (12 days)

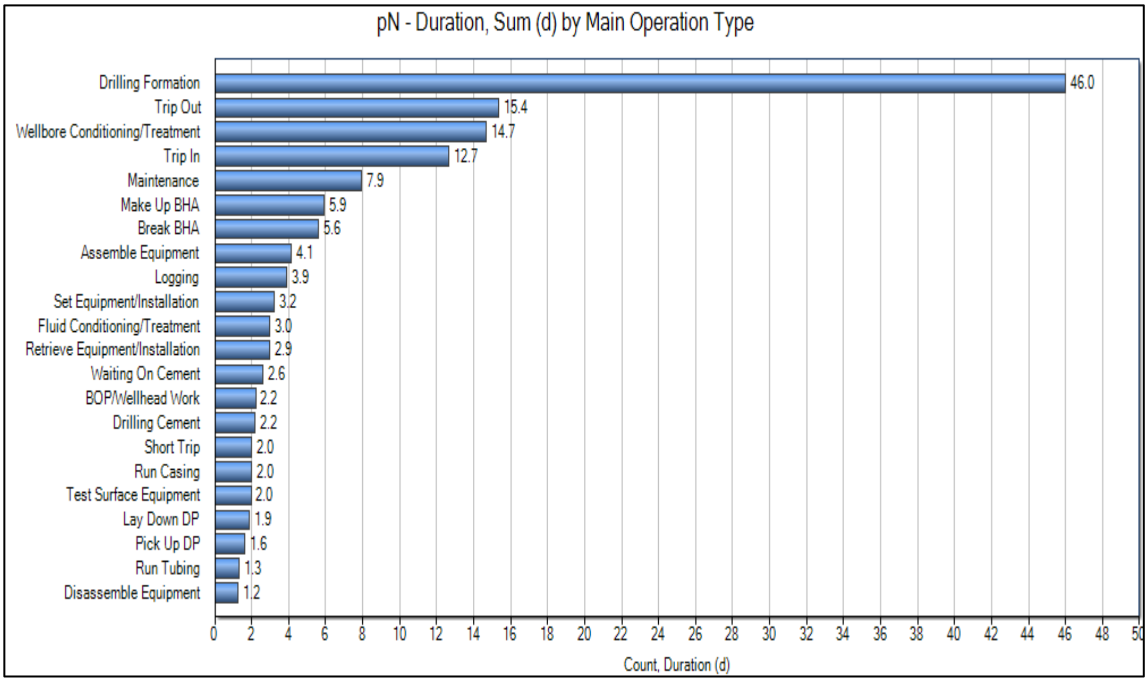


Figure 12: Rig 221 Total Time Breakdown in Days

3.2.3 NPT Analysis

- The total NPT for this rig is 1314 hours, which is equivalent to 55 days or 19% of the total rig time.
- Habban Sat-001 had NPT of 761 hours compared to Habban 37 which lost 553 hours.
- For Habban 37, there is a big deviation between the planned days and the actual days resulting in 48 days difference. The lost time is mainly due to junk, and total losses
- Habban Sat-001 showed a deviation of 10 days between the planned days and the actual days, the NPT events occurred mainly the 17.5" phase, the main events that contributed to this big lost time are; total losses, stuck pipe, and Junk representing 44%, 39%, 9% respectively of the total lost time of the well.

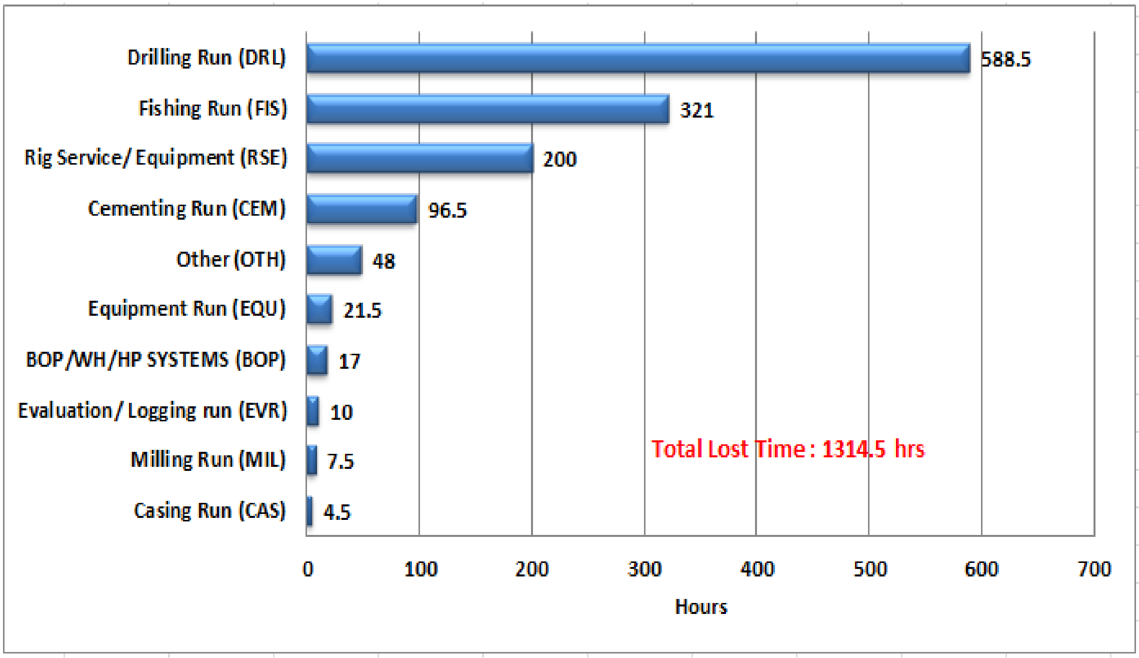


Figure 13: Rig 221 NPT Breakdown by Operational Code

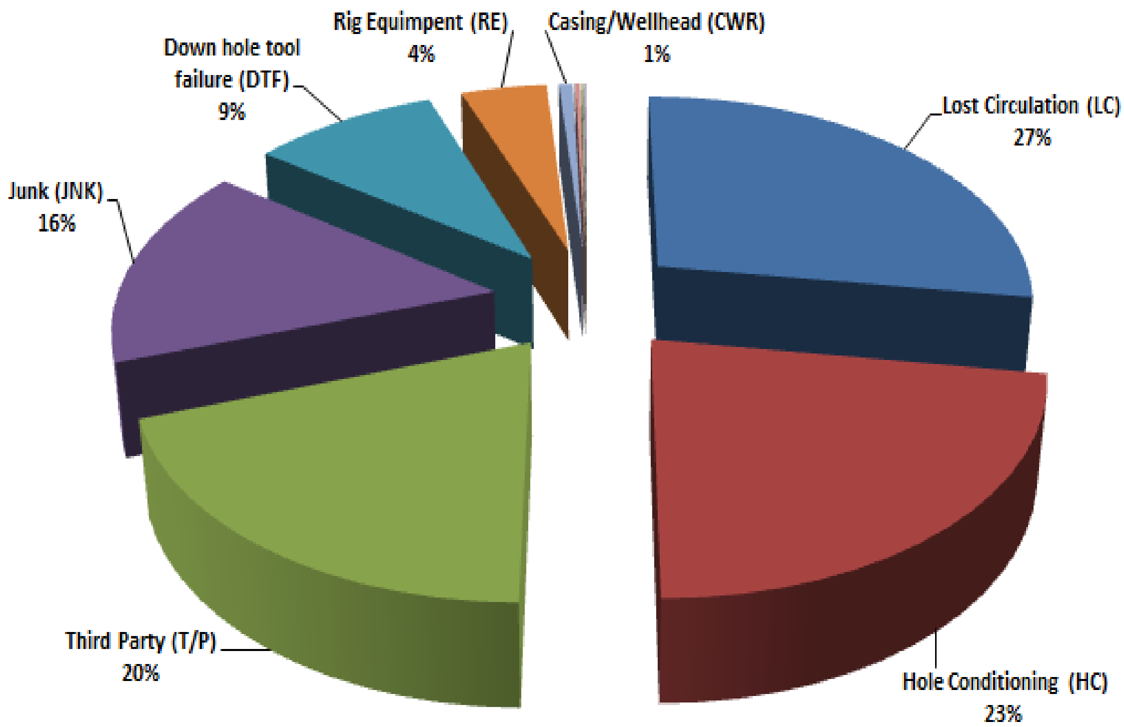


Figure 14: Rig 221 NPT Root Cause

3.2.4 KPIs and Invisible Lost Time Analysis

3.2.4.1 Formation- dependent KPIs

- The well Habban Sat-001 performed better than Habban 37 in drilling the 6" phase as seen in the P50 value as well as the average in Table 2.
- However, the ILT for both KPIs is not that large, only 1 hour.

Table 2: Rig 221 Formation dependent KPIs Summary

Drilling- Weight to Weight time		
Well	**Habban 37**	**Habban Sat-001**
Phase Diameters	**6.00"**	**6.00"**
Operation Count	5	6
P50 (minutes)	40.80	30.23
Average Duration (minutes)	42.09	35.86
Total Duration	3 h 30 min	3 h 35 min
Savings Potential	31 min	37 min
Savings Potential (%)	14.53 %	17.19 %
Total Savings Potential	1 h 8 min	

3.2.4.2 Rig- dependent KPIs

- Tripping KPIs

Table 3: Rig 221 Tripping KPIs Summary

KPI	Tripping- Slip to Slip Connection Time	Tripping- Pipe Moving Time (CH)
Phase Diameters	**26.00", 17.50", 12.25", 8.50", 6.00"**	**26.00", 17.50", 12.25", 8.50", 6.00"**
Operation Count	9112	7764
P50 (min)	2.33	1.07
Average Duration (minutes)	2.62	1.30
Total Duration	16 d 14 h 3 min	7 d 0h 14 min
Savings Potential	3 d 9 h 36 min	1 d 23 h 35 min
Savings Potential (%)	20.50 %	28.28 %
Total Savings Potential	5d 9 h 11 min	

- The largest ILT occurred during making connections while tripping, yielding in approximately 3.5 days, which represents 21 % of the total duration of that operation.
- Pipe moving time showed a good consistency. However, it showed a saving potential of approximately 2 days.
- Both KPIs could have saved 5.5 days if they were performed consistently around the P50 value.

➢ Casing Running KPIs

Table 4: Rig 211 Casing KPIs Summary

KPI	Casing- Slip to Slip Connection Time				Casing - Pipe Moving Time (CH)		
Phase Diameters	**26″**	**17.5″**	**12.25″**	**8.5″**	**26″**	**17.5″**	**8.5″**
Operation Count	64	107	81	58	20	57	47
P50 (minutes)	5.93	3.88	2.38	4.07	1.34	1.05	0.73
Average Duration (minutes)	8.19	4.48	3.44	5.20	3.11	1.13	0.88
Total Duration (hours)	8.73	8	4.63	5	1	1.06	0.7
Savings Potential (h)	2.85	2	1.6	1.46	0.65	0.15	0.16
Savings Potential (%)	32.61%	25.34%	34.58%	29.25%	62.37 %	13.83%	23.61%
Total Saving Potential	9 hours						

From **Table 4** ,the following is noticed:

- The pipe moving time in the 8.5″ phase showed a good performance and consistency, the average value was close to the P50 value.
- Pipe moving time for the 17.5″ phase showed the lowest ILT, while making connection for the first phase showed the largest ILT
- If all KPIs were performed consistently around the P50 value, 9 hours could have been saved from casing running operation.

3.2.5 KPIs Ranking and ILT

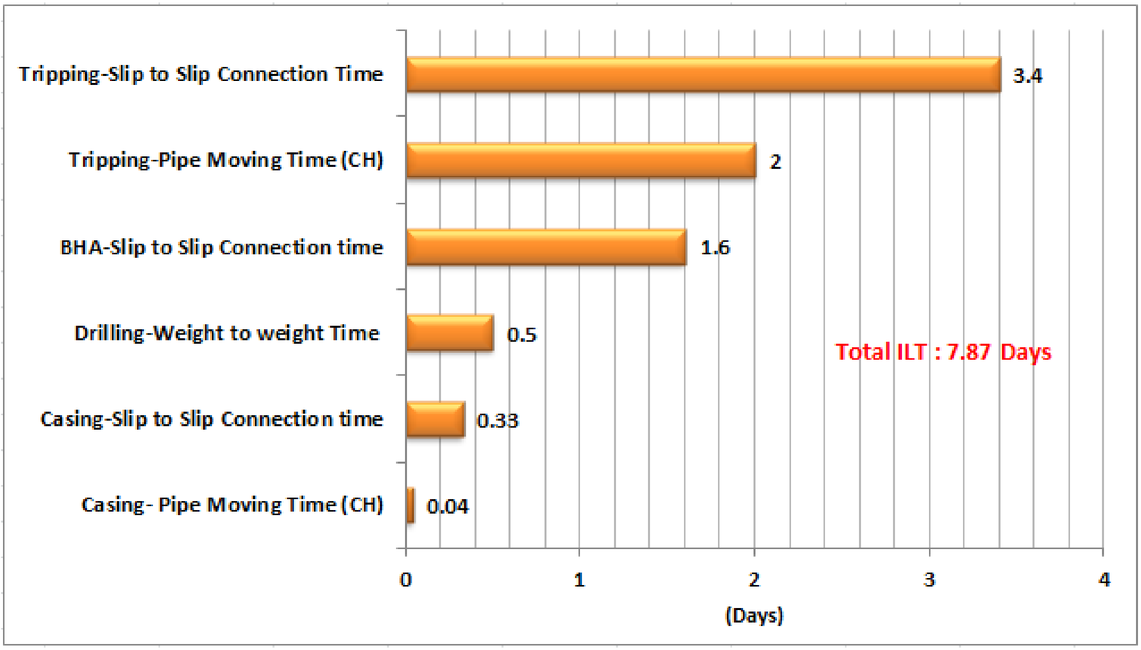


Figure 15: Rig 221 KPIs Ranking and ILT

3.2.6 KPIs Average Improvement

In this section the average value of the different KPIs is analyzed over the time; to observe if there is any kind of learning and improvement by the crew in terms of the time they took to perform the different operations, the learning and improvement is simply observed by the reduction of the average value with time.

The Analysis was done based on rigs, except for drilling –weight to weight indicator it was done based on wells and phases to have more representative and comparable results. It is important to mention that if there was any improvement and learning it happened naturally due to self-learning and improvement by the crew themselves, there was no monitoring or motivation campaign for the crew to improve their performance.

3.2.6.1 Tripping- Slip to Slip Connection Time

Figure 16 illustrates the change of the monthly average for this indicator, it improved in the first two months from 2.5 to 2.4 minutes then it kept increasing to 2.9 minutes by the end of the rig time, the increase could be due to the different performance by the day and the night crews.

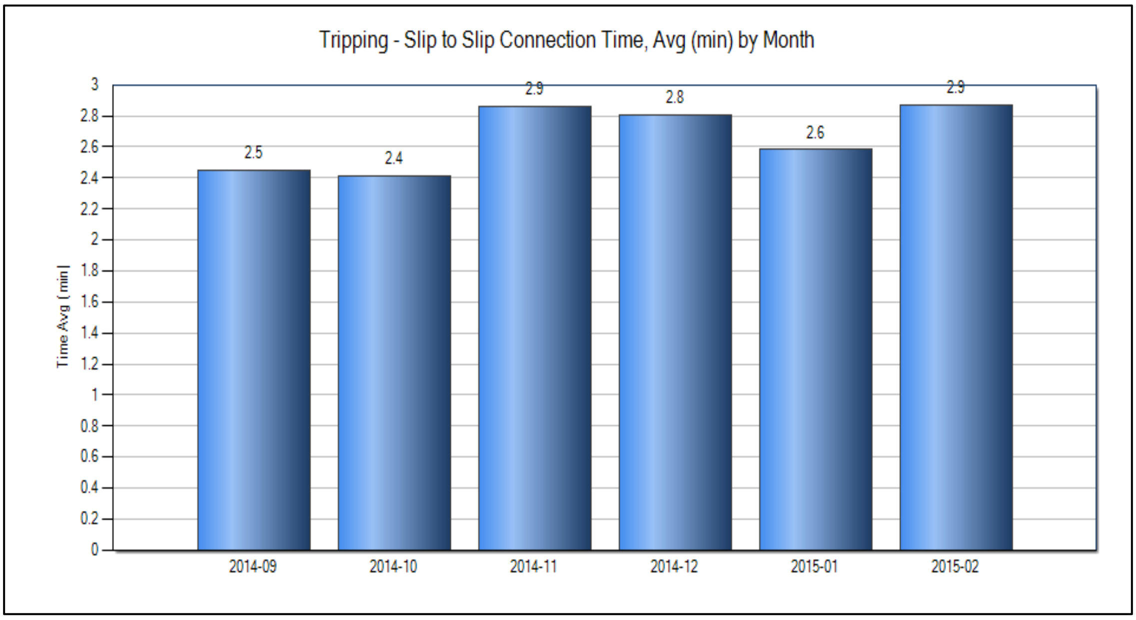


Figure 16 : Rig 221 Tripping- average connection time per

3.2.6.2 Tripping- Pipe Moving Time (CH)

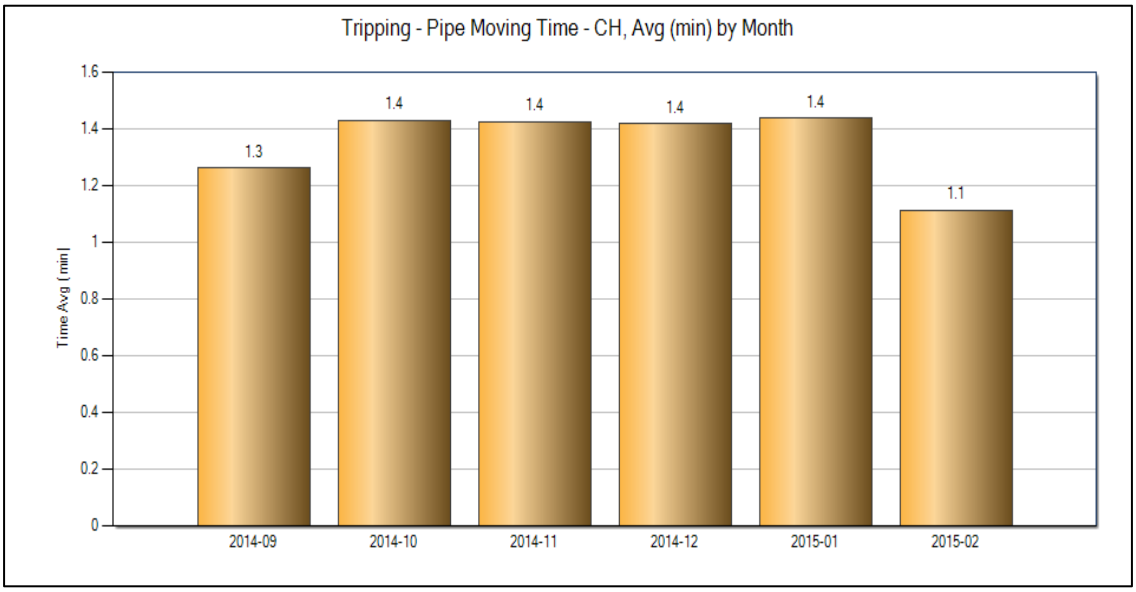


Figure 17 : Rig 221 Tripping- average pipe moving time (CH) per month

Figure 17 shows how this KPI average improved over the time with an improvement of approximately 21 % from October 2014 to February 2015.

3.2.6.3 Casing- Slip to slip Connection Time

As can be seen from Figure 18, the only improvement over time occurred in the 8.5" phase with an improvement of 6 % over two days.

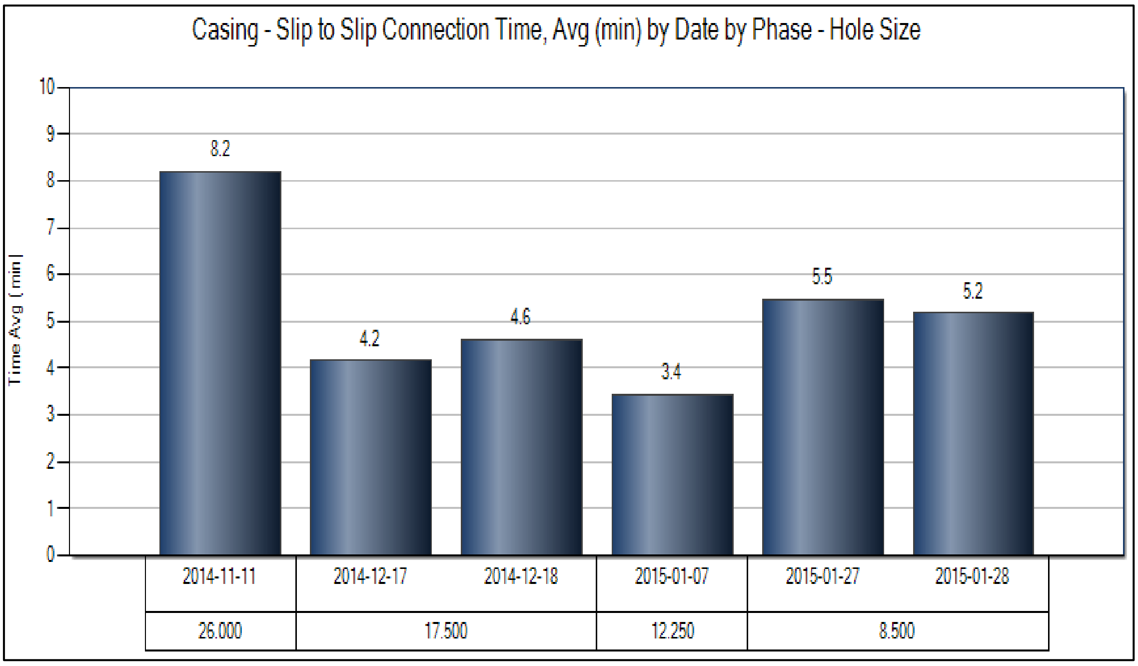


Figure 18: Rig 221 Casing- average connection time by date

3.2.6.4 Casing- Pipe Moving Time (CH)

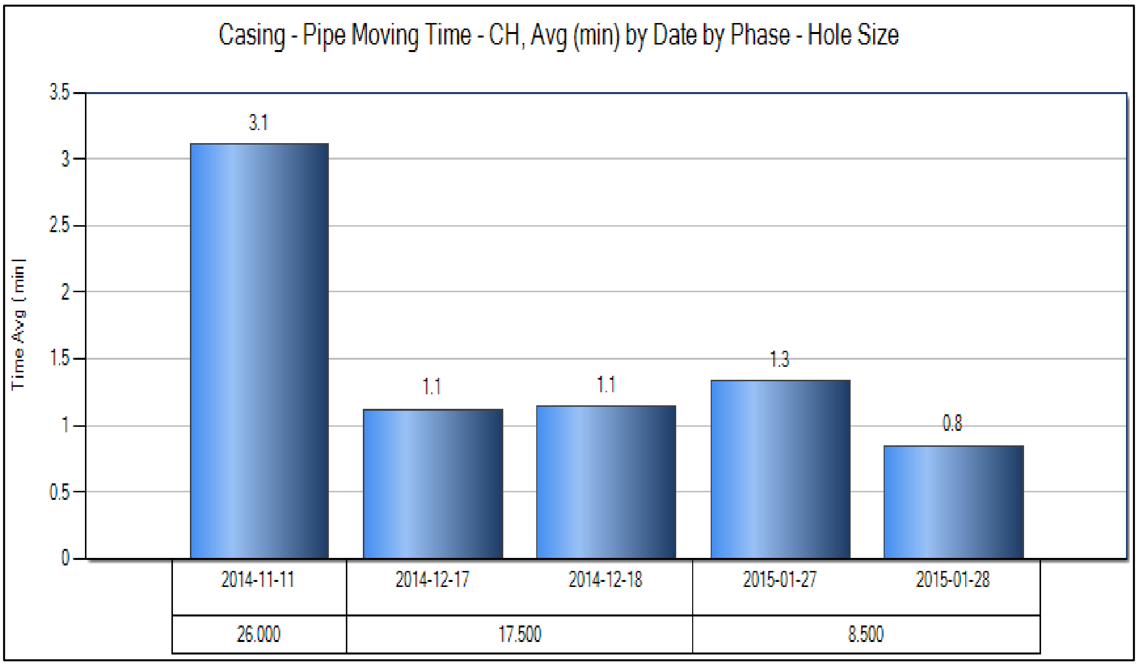


Figure 19: Rig 221 Casing- average pipe moving time (CH) by date

- The average remained the same in the 17.5" phase, while there was a good improvement of 39 % from the first to the second day of performing this operation in the last phase.

3.2.6.5 Drilling- Weight to Weight Time

As seen in Figure 20, the first day of drilling the 6" phase showed almost a similar average for both wells. However, it increased after that to almost an hour before it showed an improvement and decreases for both wells, more noticeably for Habban-Sat-N-01.

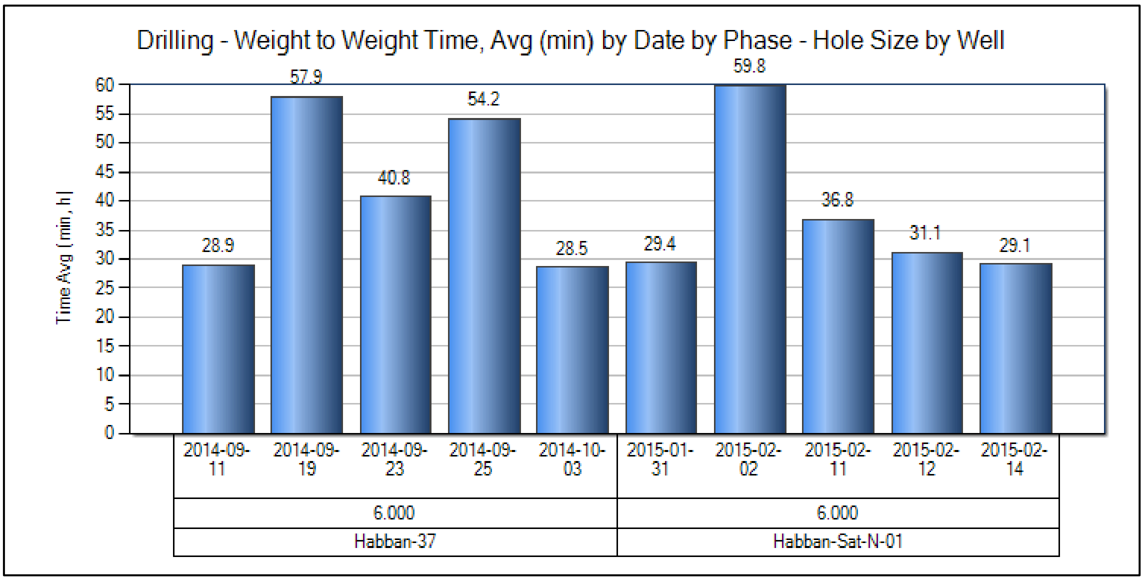


Figure 20: Rig 221 Drilling- Weight to Weight average time per day [minutes]

3.2.6.6 Tubing- Slip to Slip Connection Time

Figure 21 shows the evolution of this indicator's average improvement from October 2014 to the last tubing running operation, at the start the average was 6.8 minutes decreasing with an improvement of 50 % to 3.3 minutes by February 2015.

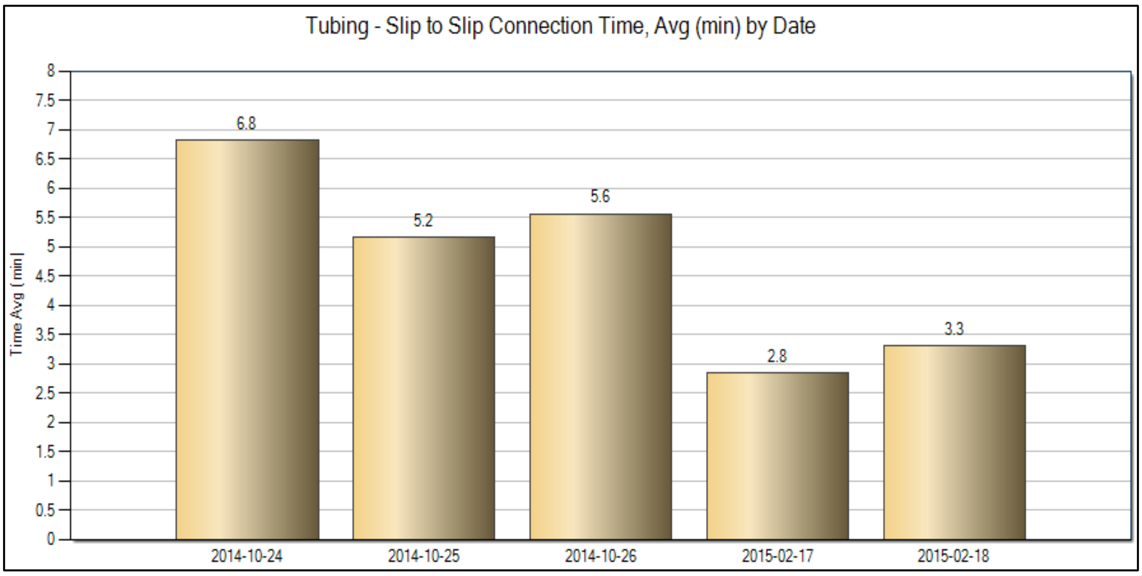


Figure 21: Rig 221 Tubing average connection time per day

3.2.7 Saving Potential Analysis

3.2.7.1 Saving Potential Indicator

The saving potential of different KPIs was analyzed over a period of time to observe if there is an improvement in the percentage of saving potential; it is preferred that the saving potential percentage decreases because it is an indicator of ILT. Therefore, the smallest percentage value of saving potential demonstrates the smallest cumulative time greater than the target value and therefore, the best performance for this particular KPI.
It is noted that the saving potential analysis for casing running is not representative due to the lack of data arising from phases issue, because the casing running analysis was done based on phases, thus, it's hard to do the analysis based on phases given the fact that the different phases were performed in different times which makes it not possible to track the saving potential percentage over time for phases individually. Therefore, it was analyzed as an average for all the phases.

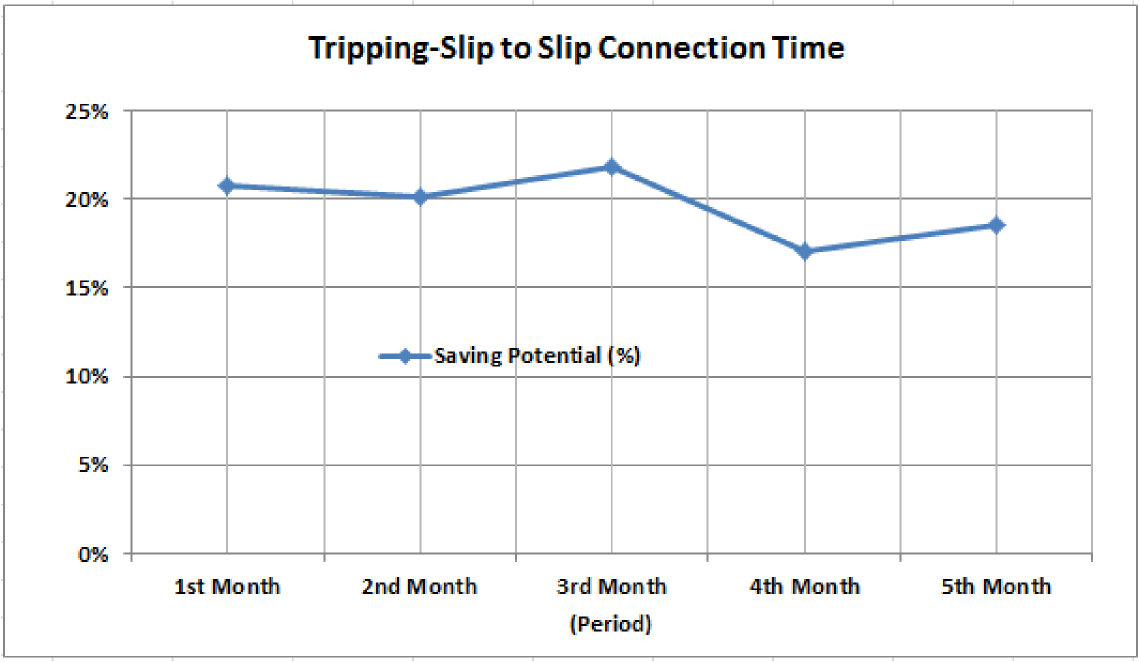


Figure 22: Rig 221 Tripping Connection Saving Potential Percentage per Month

As seen in Figure 22, there was an improvement in the saving potential percentage over time for this indicator although it was the highest in the third month but then it decreased to approximately 19% and 17 % in the last two months respectively compared to 21% in the first month.

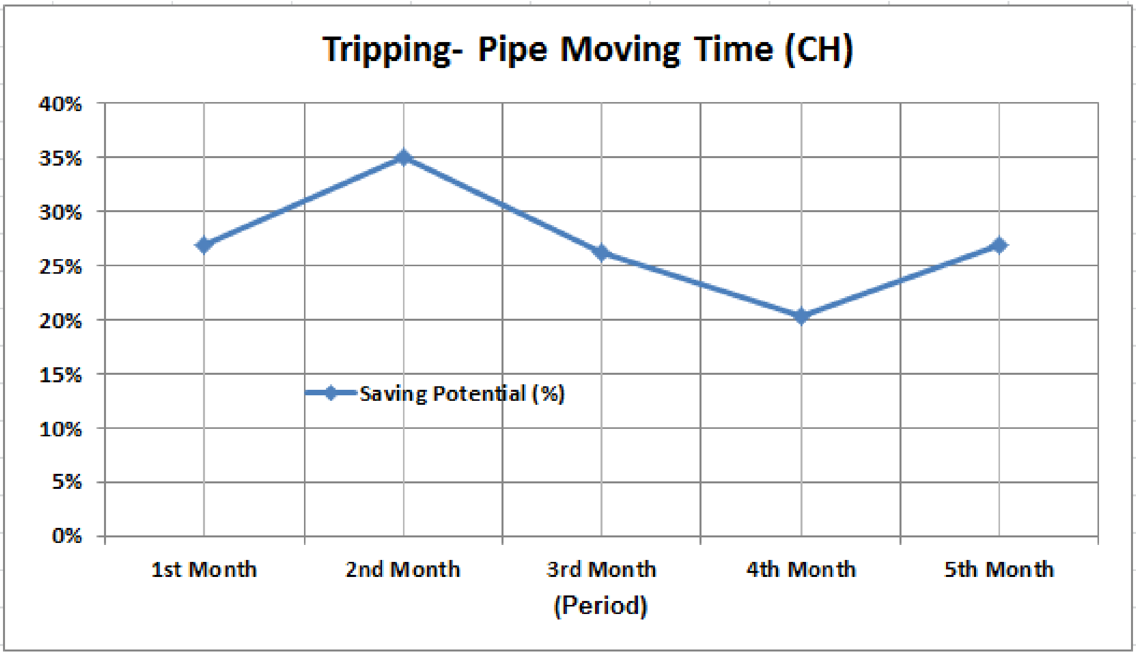


Figure 23: Rig 221 Tripping- Pipe Moving Time Saving Potential Percentage per Month

Figure 23 illustrates that Pipe moving time saving potential made an improvement decreasing to 20 % in the fourth month. However, the last month saving potential was as the first month (27%).

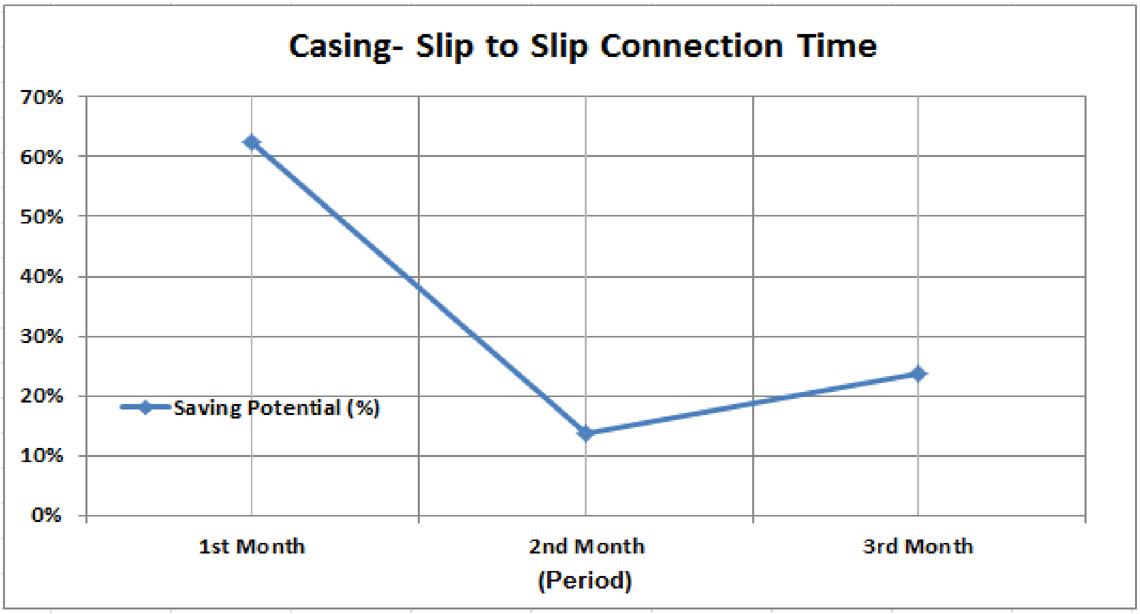


Figure 24: Casing- Connection Time Saving Potential Percentage per Month

The saving potential of making connection during Casing showed an improvement over the time decreasing from 62% in the first month to 23 % in the last month.

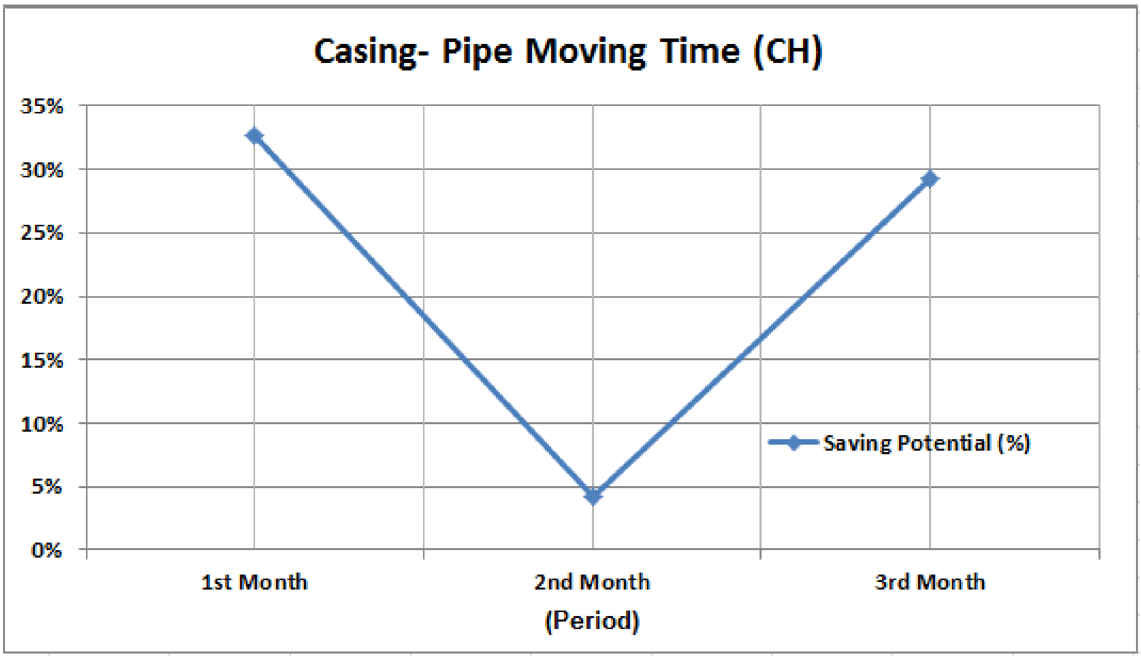


Figure 25: Rig 221 Casing- Pipe Moving Saving Potential Percentage per Month

Casing pipe moving time showed a good saving potential decrease over time, decreasing from 33% in the first month to 4% and 29 % in the second and third month respectively.

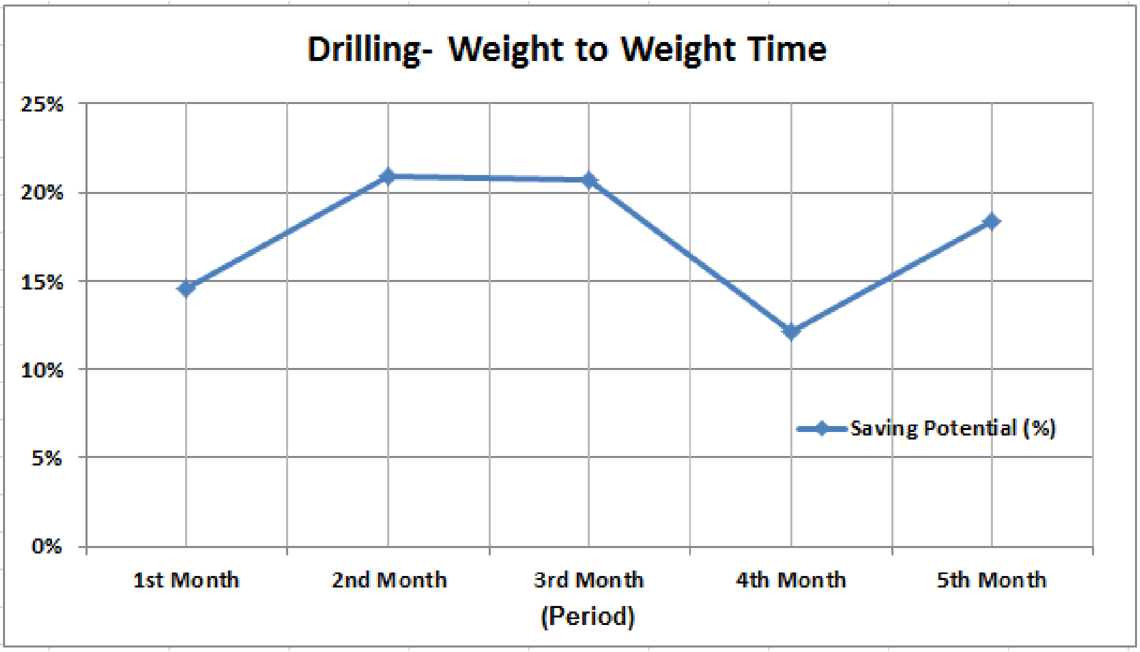


Figure 26: Rig 221 Drilling-Weight to Weight Saving Potential Percentage per Month

For this indicator's saving potential there was an improvement only from the third month to the fourth decreasing from 21 % to 18 %.

3.2.7.2 Saving Potential Report

KPI	Savings Potential [d]	Savings Potential [%]
Tripping - Slip to Slip Connection Time	3.40	20.50
Tripping - Pipe Moving Time - CH	1.98	28.28
BHA - Slip to Slip Connection Time	1.57	45.54
Drilling - Weight to Weight Time	0.47	16.08
Casing - Slip to Slip Connection Time	0.33	30.12
Casing - Pipe Moving Time - CH	0.04	34.19

Total Savings Potential: 7.79 days (24.99 %)
Total KPI Duration: 31.19 days

Figure 27: Rig 221 Saving Potential Report

Figure 27 shows saving potential for 6 KPIs that lasted for 31.19 days of operation. However, if these operations were done consistently around the P50 value a total saving of approximately 8 days (25% of total KPIs duration) could have been saved.

3.2.8 New Targets Selection

In this section new targets are identified for each rig after analyzing the performance of each individual well. Previously, the targets of OMV rigs were set by default to international targets.
The new targets are selected based on the lowest P50 value from all wells, which means the performance value that includes the best 50 % of the data. However, it is emphasized that the target should not be a fast moving target, but it should yield a safe and consistent operation rather than pushing the technical limit.
Table 5 shows the targets selection process for Tripping KPIs, as seen in the table the crew of Habban 37 managed to perform the tripping connection, and Pipe moving time routinely below **2.12** min and **1.07** min respectively. For that, these two values are selected to be the new targets for the rig 221.
The same analysis was done for the other KPIs for each individual well for each individual rig selecting the best P50 value of the data to be the new targets and making a final table that looks like Table 6 that summarizes the new targets. However, the tables that include the other KPIs for this rig and the rest of the rigs are attached in Appendix A.

Table 5: Rig 221 Tripping KPIs analysis based on wells

Well	Habban 37		Habban Sat - 01	
KPI	Tripping- S2S Connection time	Tripping- PMT (CH)	Tripping- S2S Connection time	Tripping- PMT (CH)
Operation Count	4218	3525	4894	4221
P50	***2.12***	***1.07***	2.57	1.10
Average Duration	2.43	1.34	2.78	1.27

Table 6**:** Rig 221 New Targets for Future Wells

KPI	**Phase**	**New target(min)**
Drilling-weight to weight time	**All Phases**	28
Tripping-slip to slip connection time		2.12
Tripping-Pipe moving time (CH)		1.07
Tubing- slip to slip connection time		2.80
Casing-slip to slip connection time	26″	6
	17.5″	4
	12.25″	2.4
	8.5″	4
Casing-Pipe moving time (CH)	26″	1
	17.5″	1
	8.5″	0.80

3.2.9 Lessons learnt

- Deepening 20″ surface casing to as deep as possible to around 850m in order to avoid hole collapse due to the loose sand in the upper Tawilah. And facilitate treating next section 17-1/2″ total lost circulation.
- To ensure a good hole cleaning, using Low-Vis then High-Vis pill combinations is highly recommended, as it proved its positive affection in Habban Sat-01.
- It is recommended to use tri-cone or PDC bits with low RPM on the bit given the fact that basement reservoirs are extremely abrasive and hard formations which required 14 drilling runs (for Habban 37), the average depth drilled by every BHA run was 18 m only. For Habban Sat 1 the basement formation required eight drilling runs, the ROP dropped below 2 m/h.

- It's recommended that the MWD system enable its system to export Under Balanced Drilling (UBD) relevant data (bottom hole annular pressure, TVD of pressure sensor) via WITS to be displayed for company man, UBD command center, driller, etc., or ASCII files (for daily reporting) if WITS is not possible.
- It's recommended to perform MWD surveys in 2-phase circulation whenever possible to avoid unnecessary circulation of single fluid through the well that may induce fluid losses.
- Using the D&M PowerDrive and the good practice in 12-1/4 and 8-1/2" sections resulted in completing the sections successfully and effectively.

3.2.10 Conclusion and Potential Areas of Improvement

- The rig needs to improve its operation's consistency.
- The crew of Habban 37 showed a better performance in tripping, and casing running.
- Habban Sat- 01 crew was better in formation related KPIs, and was faster in tubing running than Habban 37 crew.
- New targets were selected for 6 KPIs
- A significant time was spent on wellbore treatment (15 days), reaming and washing consumed a quite large time of that. Therefore, to reduce the time spent in washing and reaming during drilling, the hook load measurements should be analyzed to eliminate any unnecessary reaming.
- Tripping indicators; slip to slip connection time and pipe moving time had the largest ILT, if they had been performed consistently around the target they would approximately have saved 8 days.
- The time of making connection for the bottom hole assembly showed a large ILT as well, a total of 1.6 days.
- The saving potential time for only six selected KPIs (if they were performed consistently around the P50 value) is 7.79 days, which is equivalent to 24.98 % of the total KPIs duration.
- Tripping KPIs shows a large room for improvement which would bring savings to the company.
- The averages of Casing pipe moving time and drilling weight to weight time showed the best improvement through time compared to other KPIs.
- The saving potential of casing-slip to slip connection time showed the best performance among other KPIs in terms of reducing with time.

3.3 Nabors 98, Yemen

The rig Nabors 98 drilled two wells; Habban 42, and Habban 41 respectively with a total rig days of 179 days.

3.3.1 Rig Specifications

Table 7: Nabors 98 Specification

Classification	**Land Rig; Diesel Electric with SCR**
Max. Drilling Depth	5,000 m
Mast	Lee c. Moore (500 Ton)
Gross Nominal Capacity	350 Ton w/ 12 lines
Crown Block	Dreco (550 Ton)
Travelling Block	National Emsco (550 Ton)
Draw works	Mid-Continent U-914-EC, 1500 HP
Substructure	Lee c. Moore
Substructure Height	9.3 m
Rotary Table	Mid-Continent S-27 ½"; 500 Ton; chain driven from Drawworks)
Swivel	N/A
Top Drive System	Canrig 8035E, 1130 HP, 350 MT, 5000Psi
Mud Pumps	2 x Gardner Denver PZ-11. Triplex
Standpipe Pressure Rating	5000 Psi
Mud Tank Capacity	Suction: 376 bbl, Cleaning system: 696 bbl. Reserve: 543 bbl. Total: 1615 bbl

3.3.2 Rig Total Time Analysis and Breakdown

- Drilling was the largest time consumer; it took 43 days of the total rig days.
- Wellbore conditioning and treatment was the second largest time consumer; it consumed approximately 21 % of the total rig time.
- Tripping in and out consumed what is equivalent to 16 % of the total rig time.

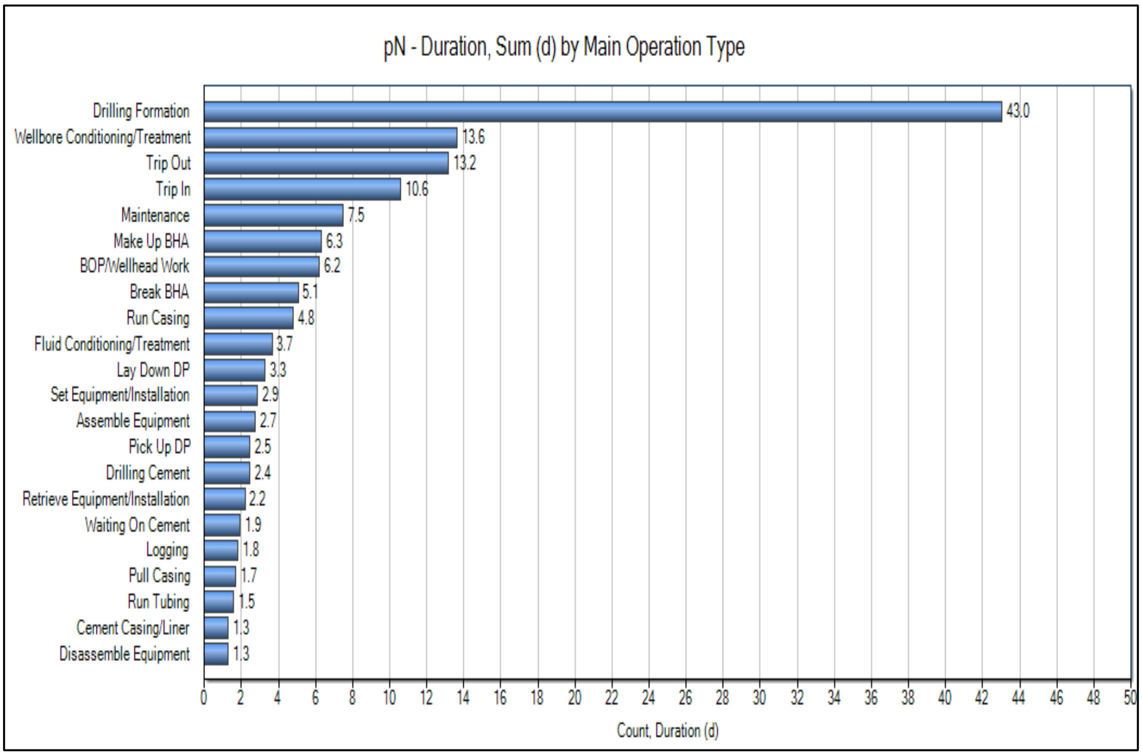


Figure 28: Nabors 98 Total Time Breakdown in days

3.3.3 NPT Analysis

- The total NPT for this rig is approximately 21 days, which is 11.6% of the total rig time.
- The well Habban 41 had the larger NPT consuming 342 hours compared to Habban 42 which consumed 160 hours.
- Habban 42 showed a good performance and was completed in seven days less than the plan, the well was planned to be completed in 75 days, but it took 67 days to be completed, the main events that contributed to the NPT are; Lost circulation (66%) partial losses occurred in the 12.25” phase, and multiple total losses in the last phase, stuck pipe (15%) in the 12.25” phase, Rig repairing (15%)
- For Habban 41 there is a deviation of 15 days between the planned days and the actual days, the main events that contributed to the lost time are; Downhole tool failure (72%) the well lost 3 cones of Smith TCI bit, Junk (19%) missing two casing joints in the 17.5” phase, the fishing job was unsuccessful and required a sidetrack.

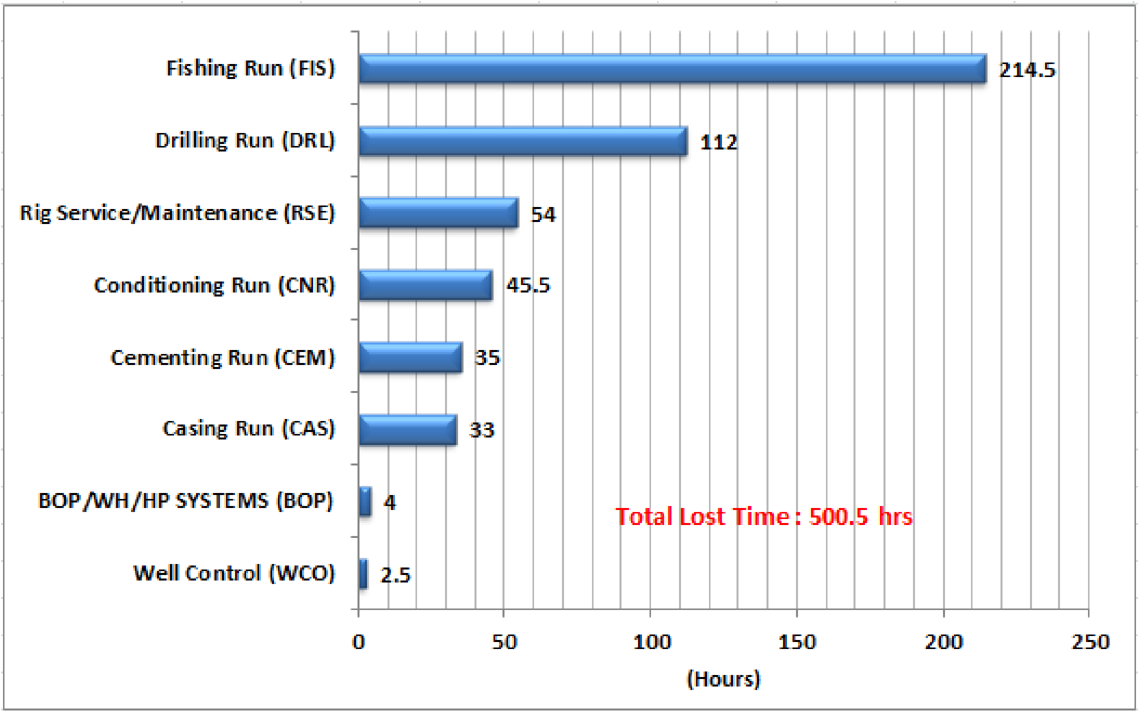


Figure 29: Nabors NPT by Operational Code

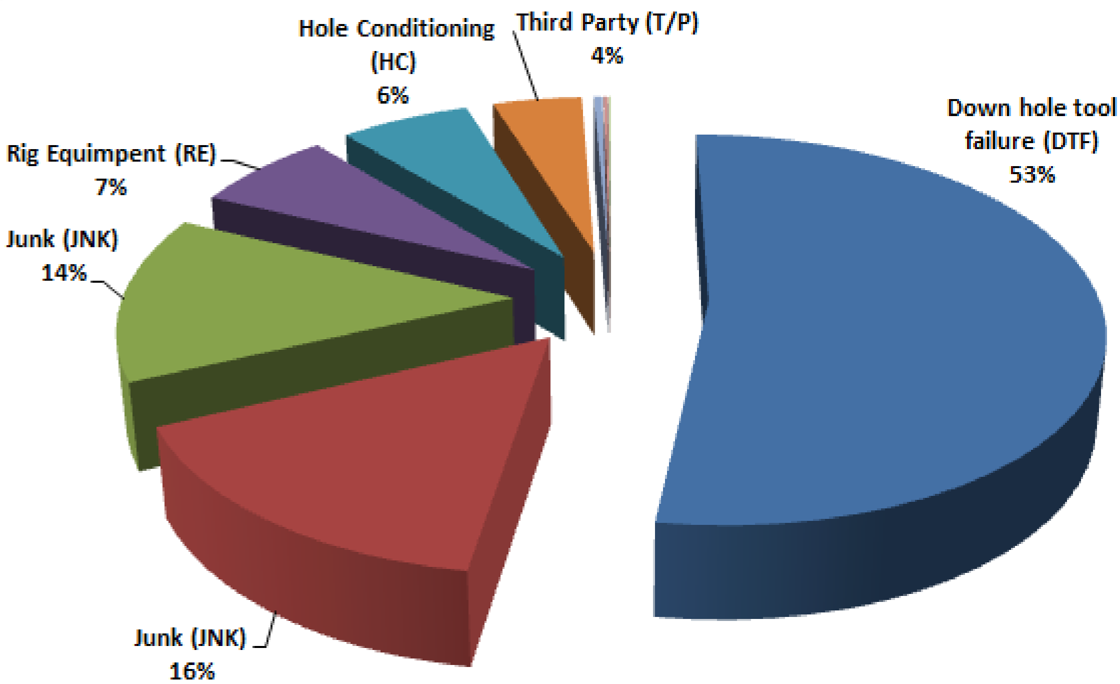


Figure 30 : Nabors 98 NPT Root Cause

3.3.4 KPIs and Invisible Lost Time Analysis

3.3.4.1 Formation- dependent KPIs

Table 8: Nabors 98 Formation dependent KPIs Summary

Drilling- Weight to Weight time						
Well	**Habban** 42			**Habban** 41		
Phase Diameters	**12.25″**	**8.5″**	**6″**	**12.25″**	**8.5″**	**6″**
Operation Count	20	11	26	20	17	30
P50 (minutes)	35.29	30	33.98	42.63	31.83	42.18
Average Duration (minutes)	37.22	31.97	34.74	42.49	31.86	42.34
Total Duration (hours)	12.4	5.86	15.05	14.16	9.03	21.16
Savings Potential (hours)	1.26	0.5	1.75	1	1	1.68
Savings Potential (%)	10.17%	8.65%	11.61%	7.20%	10.65%	7.95%
Total Savings Potential	18.20 hours					

- The three phases of the well Habban 42 showed a good performance and performed 50% of this operation in a time that is less than Habban 41 as seen in the P50 value.
- The total saving potential for the rig from the two wells is 18.2 hours.

3.3.4.2 Rig- dependent KPIs

- Tripping KPIs

- As seen in Table 9 below, the average time between two connections could have a saving of approximately 3 days if it was done consistently around the P50 Value. However, this indicator showed more consistency than Pipe moving time
- Both KPIs could have saved 4.5 days if performed with consistency around P50.

Table 9: Nabors 98 Tripping KPIs Summary

KPI	Tripping - Slip to Slip Connection Time	Tripping - Pipe Moving Time (CH)
Phase Diameters	26.00", 17.50", 12.25", 8.50", 6.00"	26.00", 17.50", 12.25", 8.50", 6.00"
Operation Count	8072	6502
P50 (min)	1.95	1.07
Average Duration (min)	2.32	1.24
Total Duration	12 d 23 h 58 min	5 d 14 h 38 min
Savings Potential	3 d 3 h 31 min	1 d 10 h 59 min
Savings Potential (%)	24.21 %	25.99 %
Total Savings Potential	4 d 14 h 30 min	

- Casing Running KPIs

Table 10: Nabors 98 Casing Running KPIs Summary

KPI	Casing- Slip to Slip Connection Time				Casing - Pipe Moving Time (CH)			
Phase Diameters	**26″**	**17.5″**	**12.25″**	**8.5″**	**26″**	**17.5″**	**12.25″**	**8.5″**
Operation Count	66	298	333	223	3	209	212	221
50% (minute)	7.27	3.78	4.65	5.05	1.02	1.50	0.98	2
Average Duration (minutes)	8.18	4.83	5.29	5.42	1.09	1.76	1.13	2.15
Total Duration (h)	9	24	29.4	20.1	0.05	6.2	4	7.55
Savings Potential (h)	1.55	8.63	14.75	7.3	0	2.7	0.9	4.22
Savings Potential (%)	17.27 %	36.03 %	50,17 %	36.48 %	0	43.82 %	22.29 %	55.90 %
Total Saving Potential	43.65 hours							

From Table 10, the following is observed:

- Largest ILT was during making the connection of the 12.25" phase.
- Pipe moving time indicator in the 12.25" phase showed a fast and consistent running by looking at the P50 value
- If all KPIs for all phases were done consistently around the target a saving potential of approximately 2 days could have been saved from the total rig days.

3.3.5 KPIs Ranking and ILT

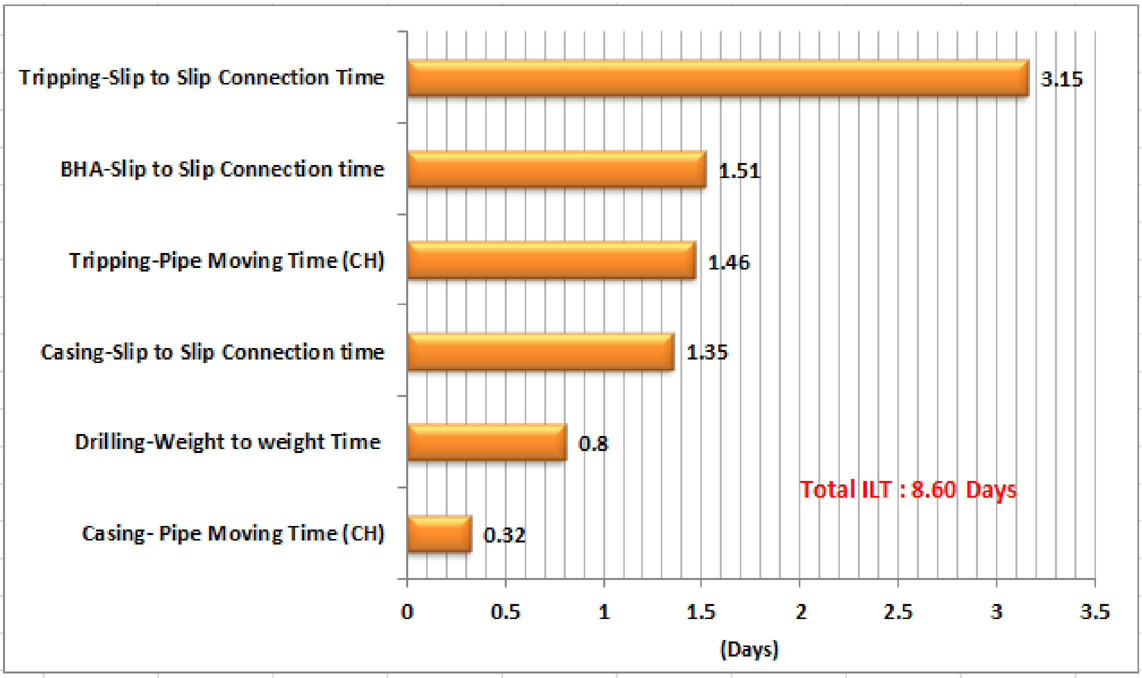


Figure 31: Nabors 98 KPIs Ranking and ILT

3.3.6 KPIs Average Improvement

3.3.6.1 Tripping- Slip to Slip Connection Time

Figure 32 illustrates the improvement of the average for this KPI in the first two months and then it increased again. By the end of the operation it achieved an improvement of only 9 %.

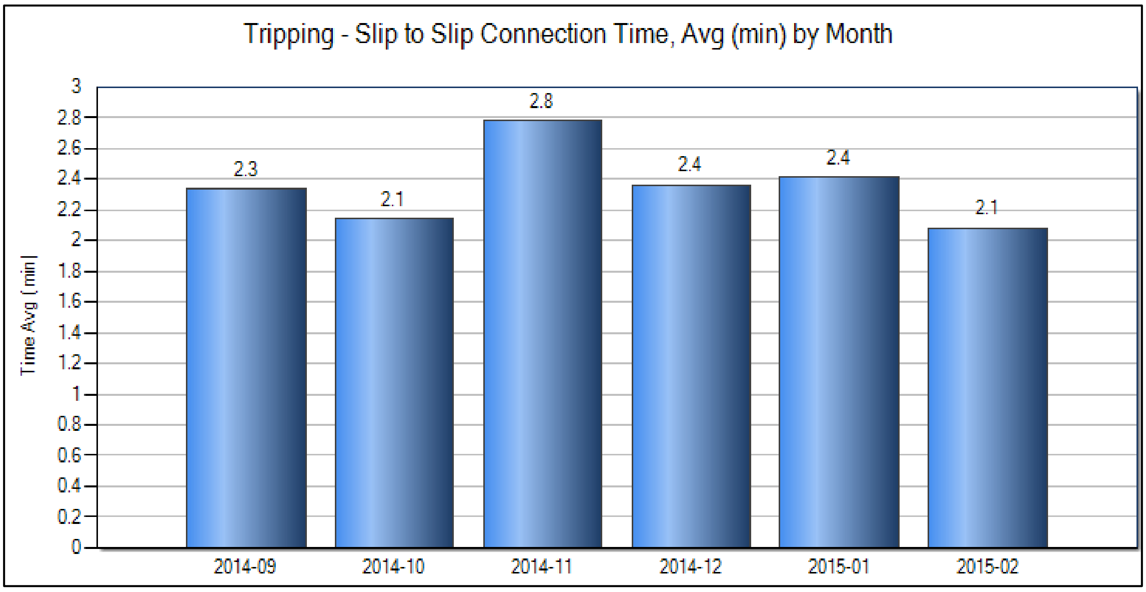


Figure 32: Nabors 98 Tripping Average Connection Time per Month [Minutes]

3.3.6.2 Tripping- Pipe Moving Time (CH)

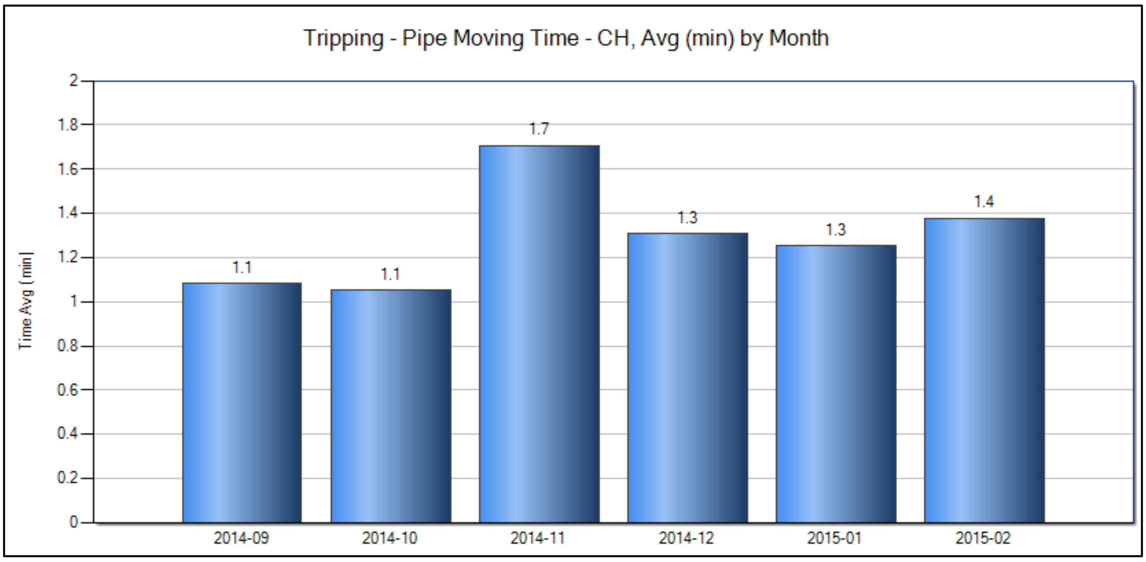


Figure 33 : Nabors 98 Tripping Average Pipe Moving Time (CH) per Month [Minutes]

- Pipe moving time average for Nabors 98 showed no improvement; the average kept varying showing no learning over the months.

3.3.6.3 Casing- Slip to Slip Connection Time

- The second phase (17.5”) is the only phase that showed a small improvement by the end of casing running. However, the average for the rest of the phases kept increasing over the days showing no improvement as seen in Figure 34.

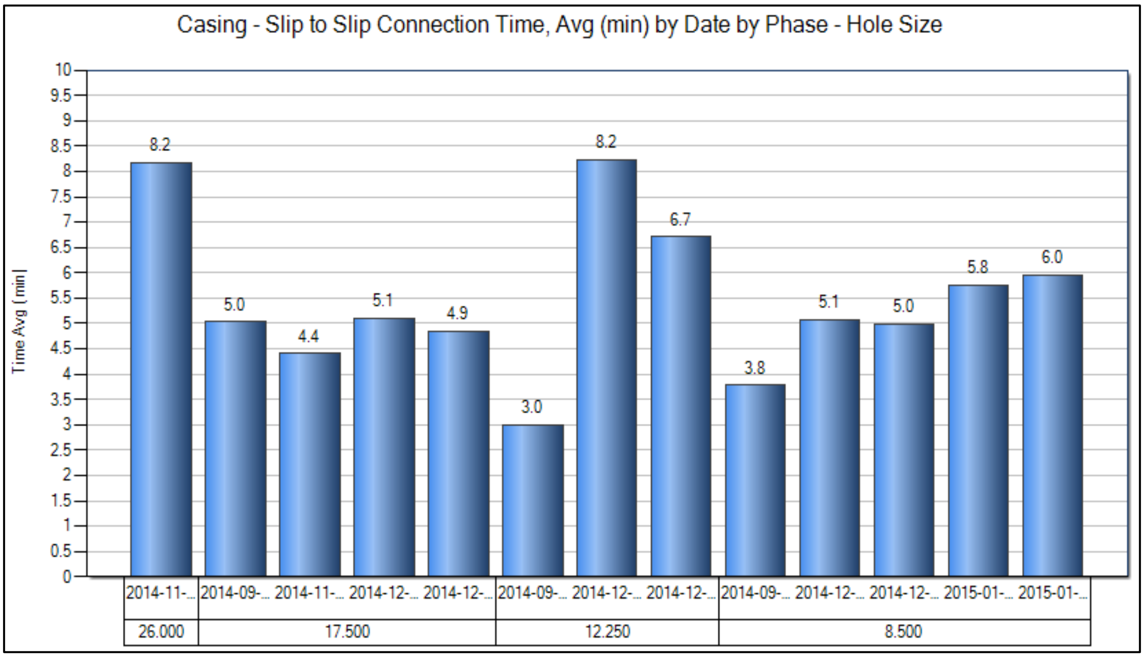


Figure 34: Nabors 98 Casing- Average Connection Time by Day [Minutes]

3.3.6.4 Casing- Pipe Moving Time (CH)

The average of casing pipe moving time in cased hole showed no improvement as seen in Figure 35, instead it was increasing from day to another.

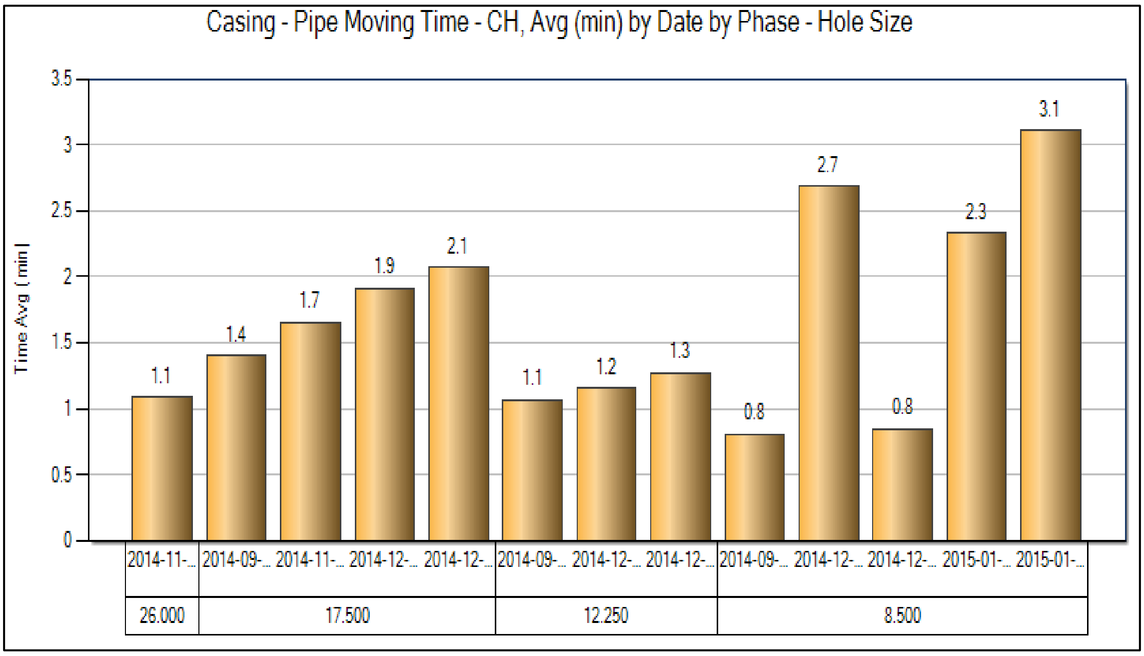


Figure 35: Nabors 98 Casing- Average Pipe Moving Time (CH) by Day [Minutes]

3.3.6.5 Drilling- Weight to Weight Time

From Figure 36 we see the following:

- In the 8.5″ phase of Habban 41 the average of this indicator showed an improvement of 8 %.
- Habban 42 showed a good improvement for the reservoir phase (6″), the average dropped from 41.2 minutes to 32.8 minutes in the last week of this operation.

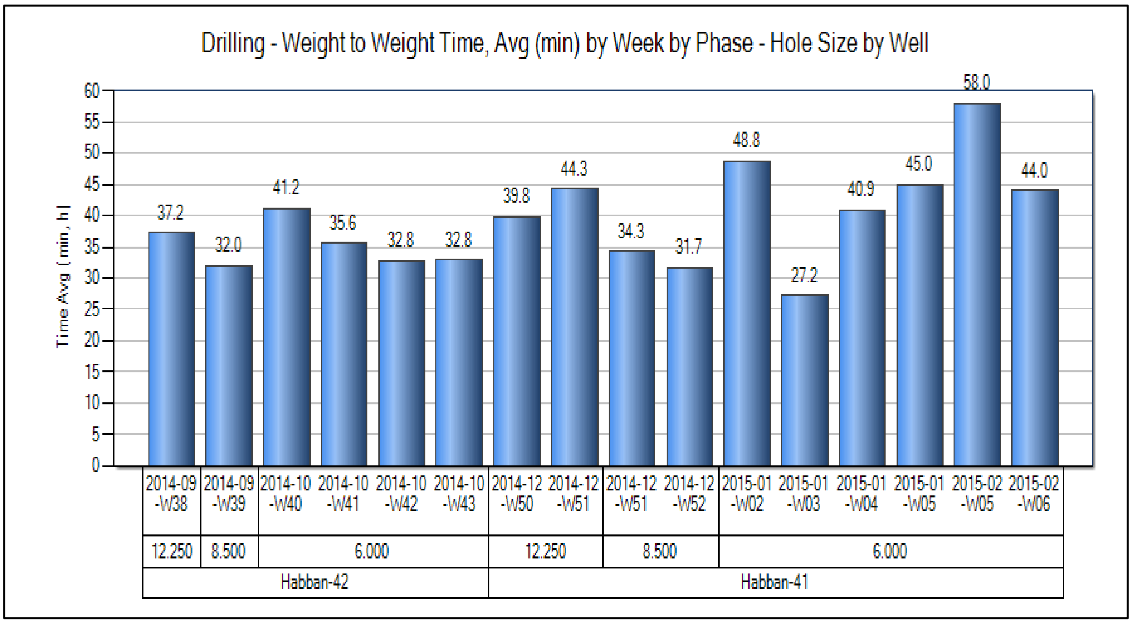


Figure 36: Nabors 98 Drilling- Weight to Weight Average Time per Week [Minutes]

3.3.6.6 Tubing- Slip to Slip Connection Time

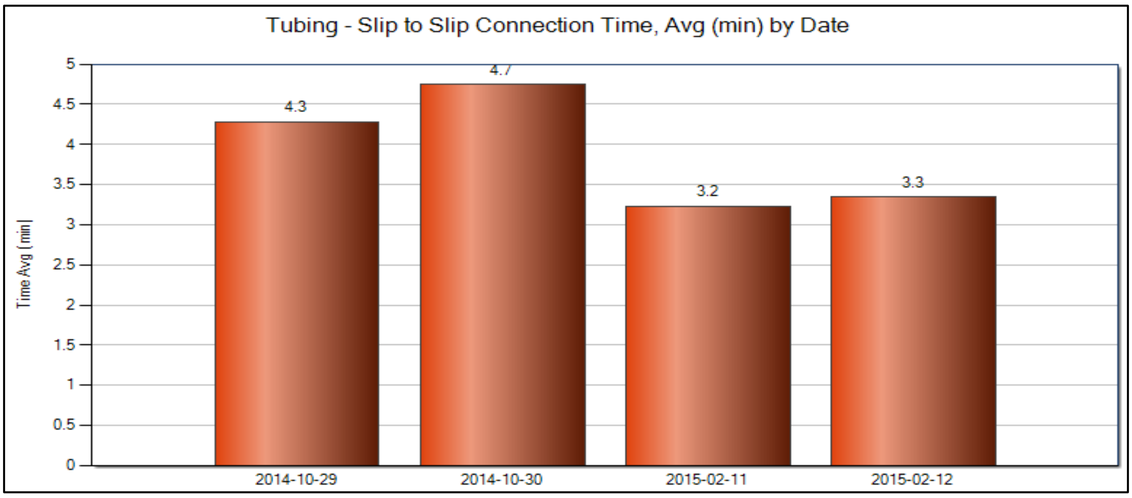


Figure 37: Nabors 98 Tubing Average Connection Time by Day [Minutes]

- The average for Tubing slip to slip connection time showed no improvement for Nabors 98 as seen in Figure 37.

3.3.7 Saving Potential Analysis

3.3.7.1 Saving Potential Indicator

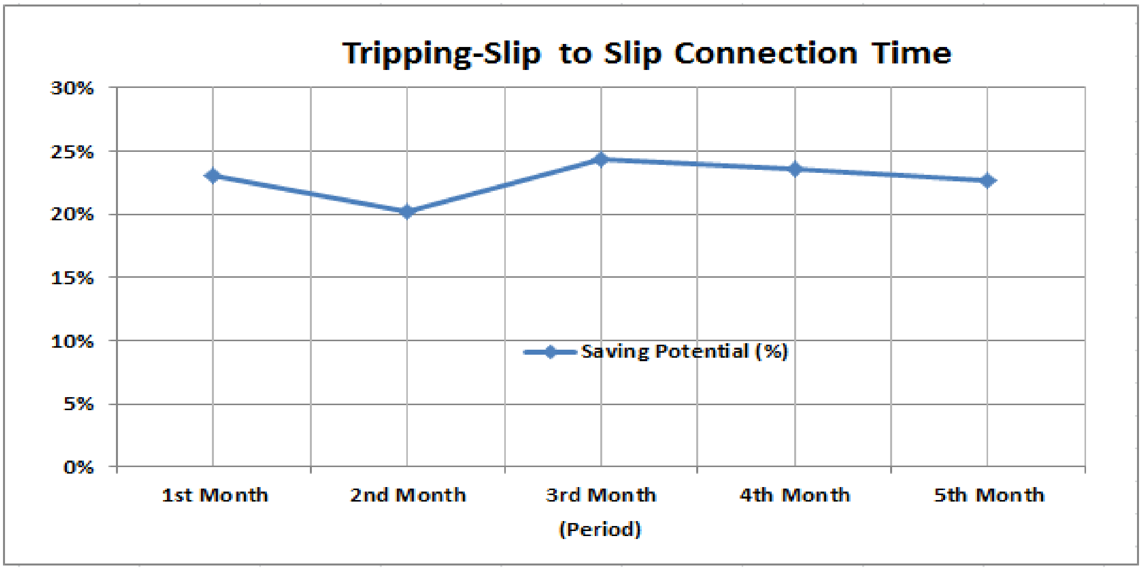


Figure 38: Nabors 98 Tripping Connection Saving Potential Percentage per Month

- As seen in Figure 38, the saving potential of this indicator decreased only in the second month to 20 %, it increased after that in the third month before decreasing again.

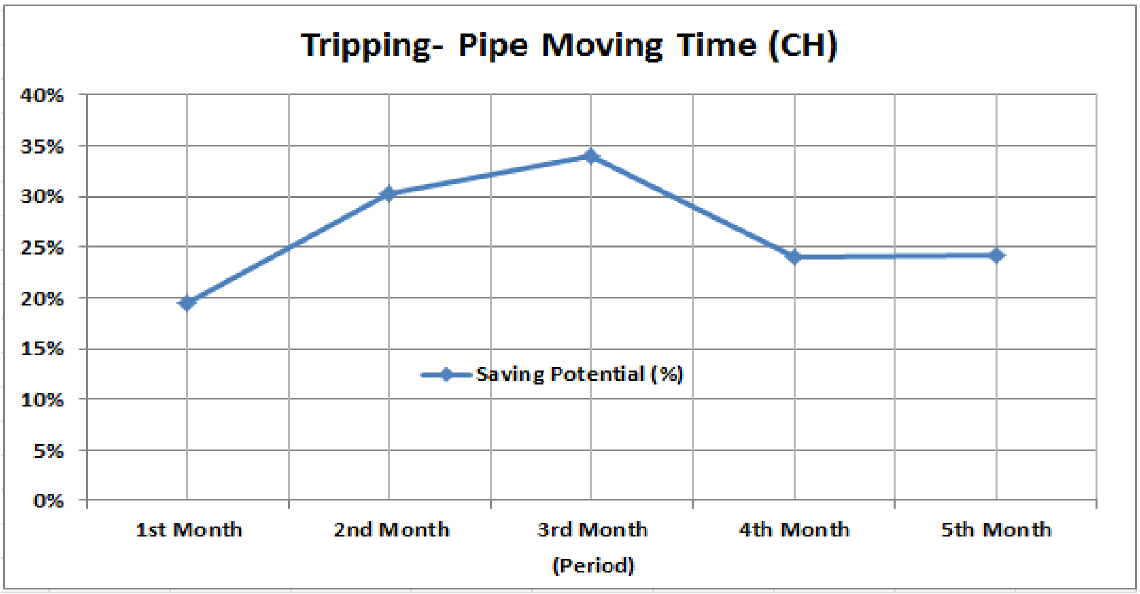


Figure 39: Nabors 98 Tripping Pipe Moving Saving Potential Percentage per Month

- The saving potential of pipe moving time kept increasing through the first, second, and third months but in the fourth month it decreased from 34 % to 24 % as seen in Figure 39.

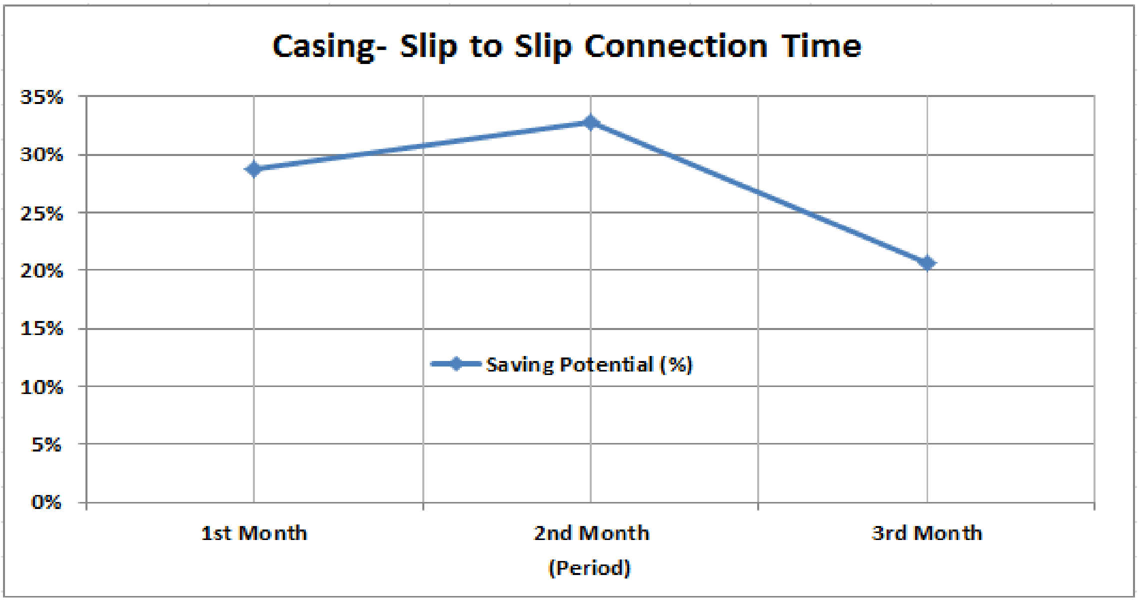


Figure 40: Nabors 98 Casing Connection Saving Potential Percentage per Month

- As seen in Figure 40, the saving potential improved reducing to 21% compared to 29 % in the first month

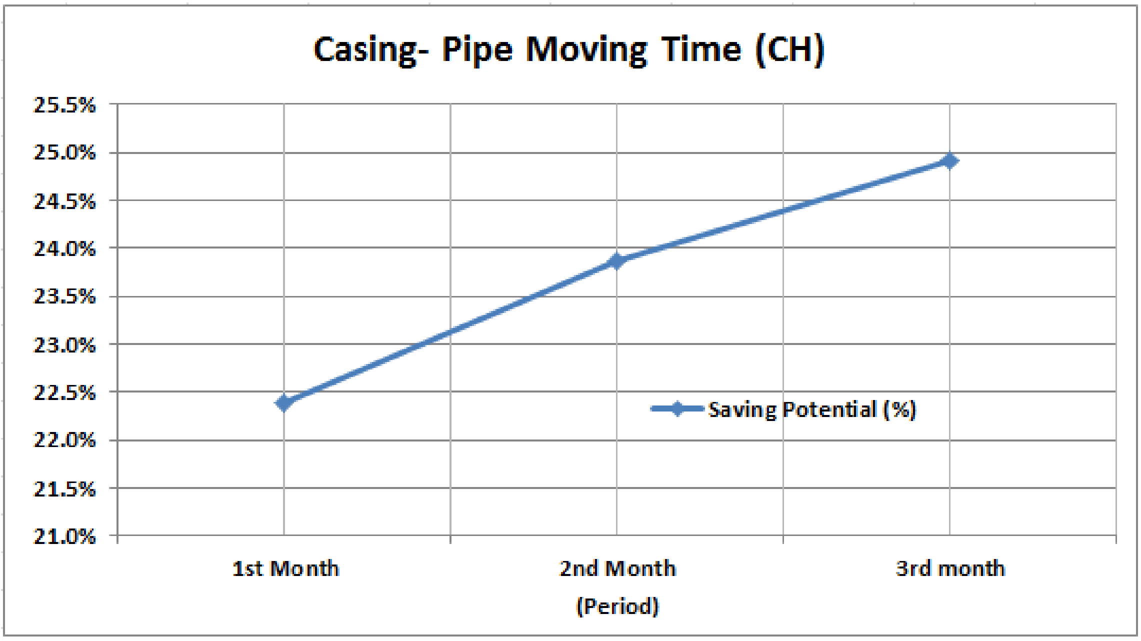


Figure 41: Nabors 98 Casing Pipe Moving Saving Potential Percentage per Month

- There percentage of this KPI's saving potential did not improve and kept increasing over time.

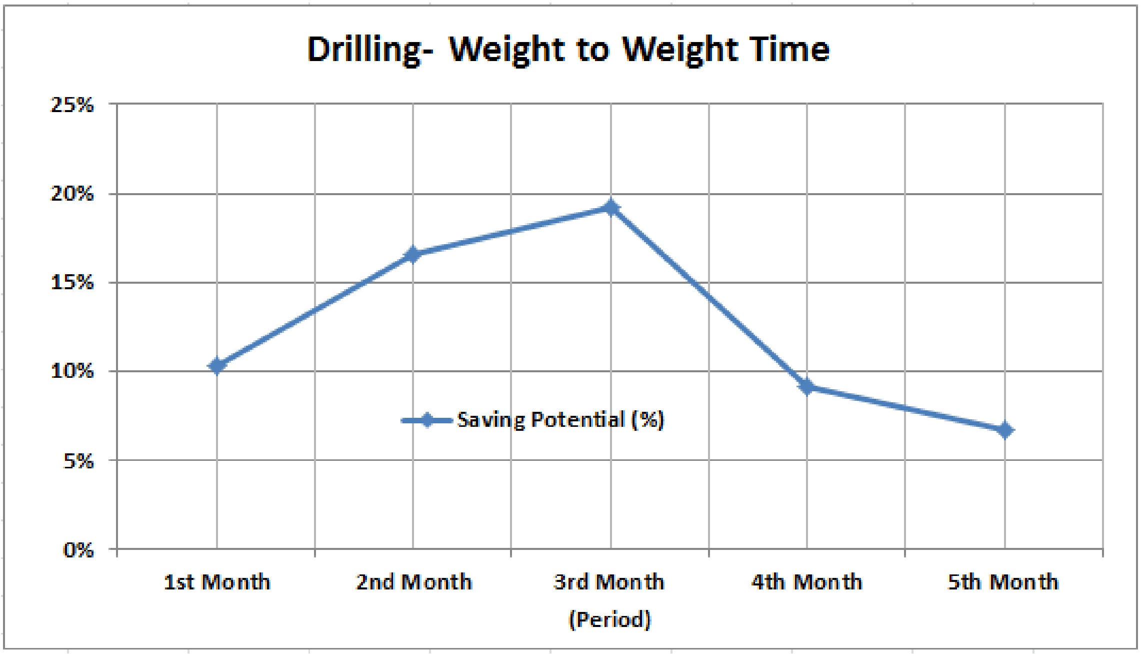


Figure 42: Nabors 98 Drilling- Weight to Weight Saving Potential Percentage per Month

- Drilling-weight to weight saving potential decreased from 11% in the first month to 6.6% in the last month despite the increase in the second and third months.

3.3.7.2 Saving Potential Report

KPI	Savings Potential [d]	Savings Potential [%]
Tripping - Slip to Slip Connection Time	2.95	22.71
Tripping - Pipe Moving Time - CH	1.85	33.07
BHA - Slip to Slip Connection Time	1.32	40.53
Drilling - Weight to Weight Time	0.58	12.80
Casing - Slip to Slip Connection Time	1.30	37.73
Casing - Pipe Moving Time - CH	0.34	45.68

Total Savings Potential: 8.33 days (27.30 %)
Total KPI Duration: 30.53 days

Figure 43: Nabors 98 Saving Potential Report

3.3.8 New Targets Selection

Selecting new targets for Nabors 98 followed the same process of selecting the targets for Rig 221 by analyzing the KPIs based on wells and select the best P 50% value; the tables which compare the wells are illustrated in Appendix A and based on them Table 11 is generated which shows the final targets selected for the chosen KPIs.

Table 11: Nabors 98 New Targets for Future Wells

<table>
<tr><th>KPI</th><th>Phase</th><th>New target (min)</th></tr>
<tr><td>Drilling-weight to weight time</td><td rowspan="4">All Phases</td><td>27</td></tr>
<tr><td>Tripping-slip to slip connection time</td><td>2</td></tr>
<tr><td>Tripping-Pipe moving time (CH)</td><td>1</td></tr>
<tr><td>Tubing- slip to slip connection time</td><td>3</td></tr>
<tr><td rowspan="4">Casing-slip to slip connection time</td><td>26″</td><td>7.27</td></tr>
<tr><td>17.5″</td><td>3.50</td></tr>
<tr><td>12.25″</td><td>2.80</td></tr>
<tr><td>8.5″</td><td>3.70</td></tr>
<tr><td rowspan="4">Casing-Pipe moving time (CH)</td><td>26″</td><td>1</td></tr>
<tr><td>17.5″</td><td>1.30</td></tr>
<tr><td>12.25″</td><td>1</td></tr>
<tr><td>8.5″</td><td>0.70</td></tr>
</table>

3.3.9 Lessons learnt

- It is recommended to use tri-cone or PDC bits with low RPM on the bit given the fact that a long time and drilling runs were spent in the basement formation; 9 and 12 drilling runs for Habban 42 and Habban 41 respectively.
- In the 26″ phase heavy vibrations were encountered, various drilling parameters were applied to reduce vibration.
- During POOH the 13 3/8" casing in Habban 41 two joints found lost in the hole, such events happen when casing running procedures are not properly handled. Therefore it is recommended to run the casing smoothly, avoiding high acceleration and deceleration which could cause unnecessary surge/swab pressures.
- During drilling the 6″ phase using UBD at the depth 3465 m partial returns were observed, to achieve a full return the nitrogen rate was increased and the Equivalent circulating Density (ECD) was decreased.

3.3.10 Conclusion and Potential Areas of Improvement

- Consistency should be given more attention and improvement.
- The crew of Habban 42 made faster and more consistent tripping and casing running than the crew of Habban 41.
- Habban 41 crew was better in drilling weight to weight time, and run the tubing faster than the crew of the Habban 42.
- New targets were selected for 6 KPIs
- Drilling was the largest time consumer compared to other operations, followed by Wellbore treatment time which consumed 14 days of the total rig time, reaming consumed 2.6 days, it is always necessary to look through the hook look measurements to avoid the unnecessary reaming and washing.
- Slip to slip connection time and the time of making connection for the bottom hole assembly showed the largest ILT,
- This rig showed a potential performance improvement of 8.5 days, for only 6 KPIs, this time represents 28% of the total KPIs duration.
- Tripping KPIs shows a large room for improvement which would bring savings to the company.
- The averages of slip to slip connection time for both tripping and tubing showed the best performance among other indicators concerning improvement over time.
- The saving potential percentage of casing-slip to slip connection time showed a better performance than other indicators in terms of decreasing with time, thus improving.

3.4 Saxon 215, Pakistan

Saxon 215 drilled six wells; Kohar 1, Latif South 1, Miano 19, Latif-5 ST2, Latif 14, and Lamwari 1. The total time for Saxon 215 is 290 days.

3.4.1 Rig Specifications

Table 12: Saxon 215 Specification

Unit Name	SLDC Rig 215
Classification	Land rig, Diesel Electric powered
Max. Drilling Depth	20000 ft
Static Hook Load Capacity	500 tons
Substructure / Derrick Height	26 ft / 142 ft
Crown Block Rating	500 tons
Travelling Block Rating	550 tons
Max. Hook/Elevator Load	500 tons (GNC:650 tons)
Top Drive	9S
Stand Pipe Pressure Rating	5000 psi
Mud Pumps	3 x 1600 HP (Triplex)
Mud Tank Capacity	3000 bbl.

3.4.2 Rig Total Time Analysis and Breakdown

Based on the total time breakdown in Figure 45, the following is noted;

- Drilling formation was the largest time consumer; it consumed 30 % of the total rig time.
- Wellbore treatment and conditioning consumed a significant time which represented 10% of the total time.
- Tripping (both in and out) respectively represented the third and fourth largest time consumers; combined they consumed 30 days of the total rig time.

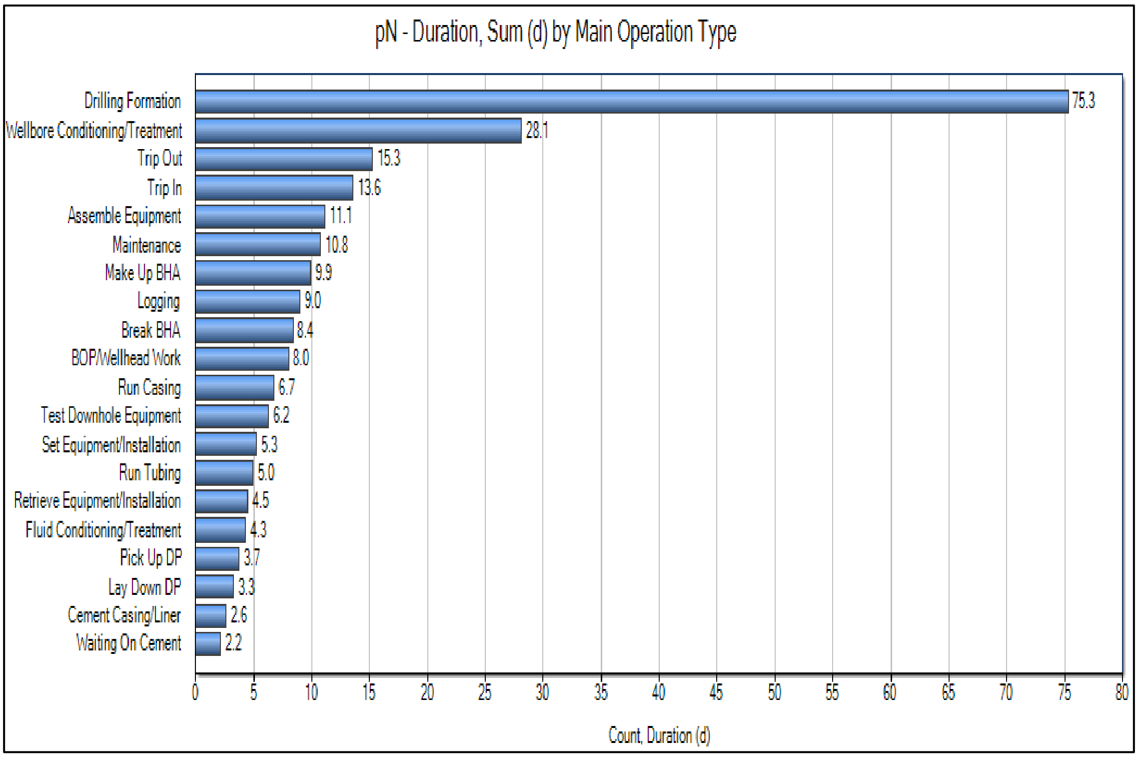


Figure 44: Saxon 215 Total Time Breakdown

3.4.3 NPT Analysis

The total NPT for this rig is 541.5 hours; which is approximately 8% of the total rig time, the NPT was divided between wells as seen in Figure 45 below.

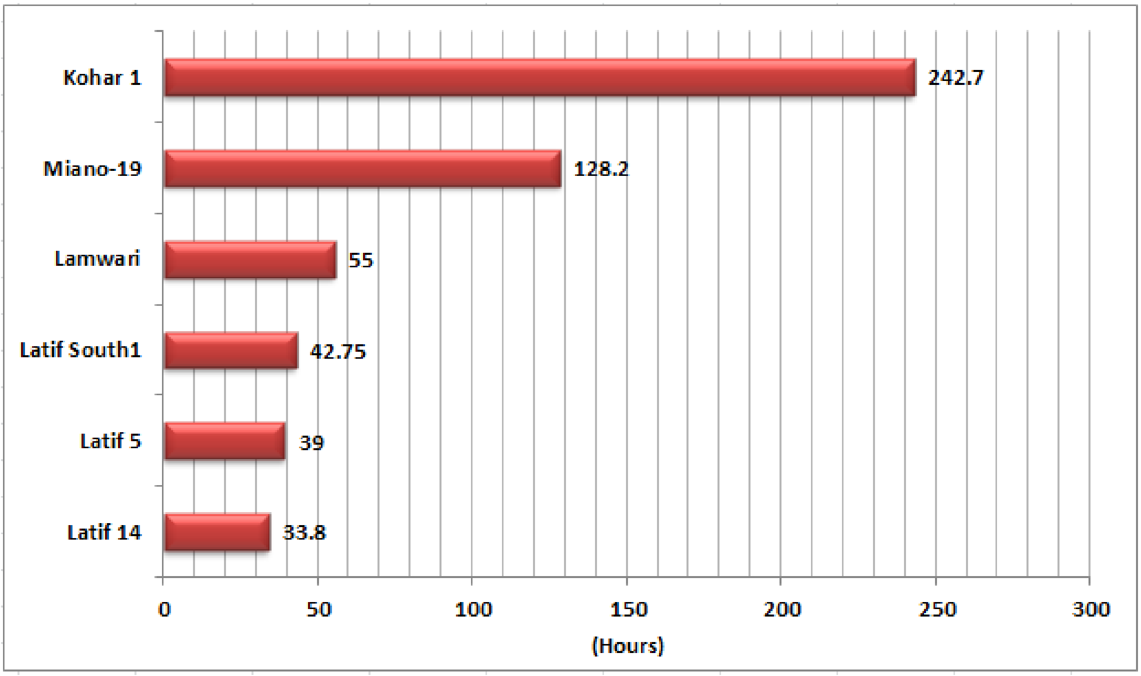


Figure 45: Saxon 215 NPT Breakdown per Well

- The total NPT for Kohar 1 is 261 hours, the main events that contributed to the NPT are; the tight spots in the 26" section which deterred to run 20" casing even after two reaming trips, 4 centralizers and 4 stop collars were lost in hole during POOH. Other events are the failure in the rotating head of TDS which took 39 hours, and Failure of packer compatibility with 9-5/8" 47ppf casing during overdrive job for casing running and reaming.
- Miano-19 was the second well in terms of losing time.
- Latif 5, showed a big deviation between the planned and the actual days that makes a total of 46 days which is almost the double of the plan.
- There is a deviation of 8 days between planned and actual days for Latif south 1.
- Latif 14 showed a good performance in terms of lost time, a difference of only 2 days between actual and planned days, the main event that contributed to the lost time is a fault in the TDS that required two times of repair.

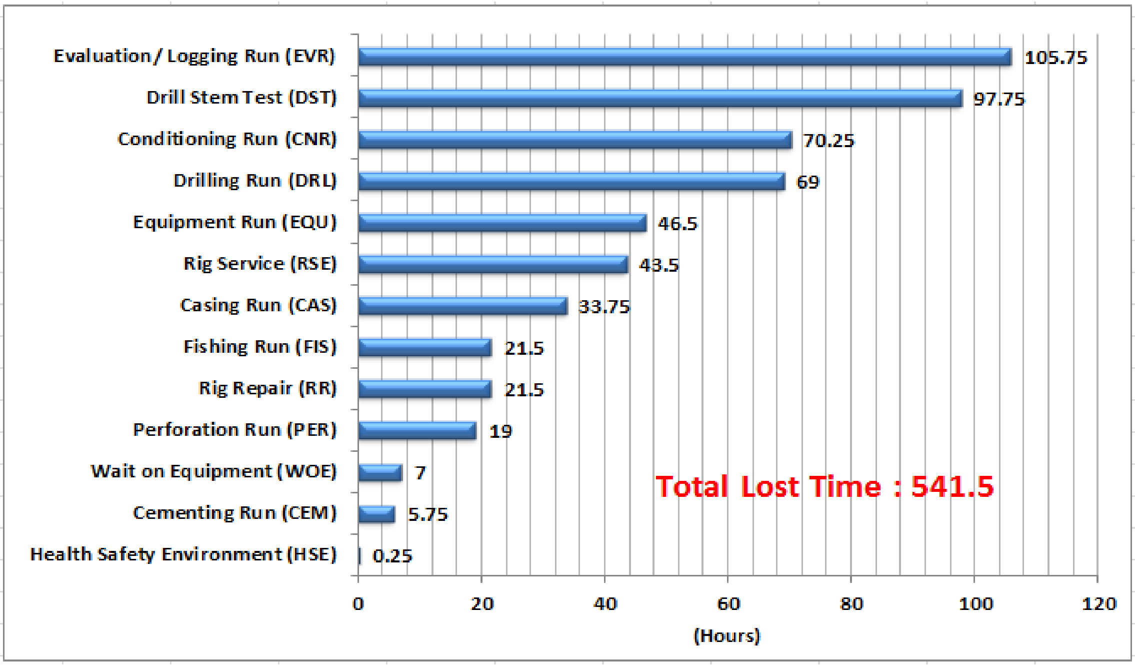


Figure 46: Saxon 215 NPT Breakdown by Operational Code

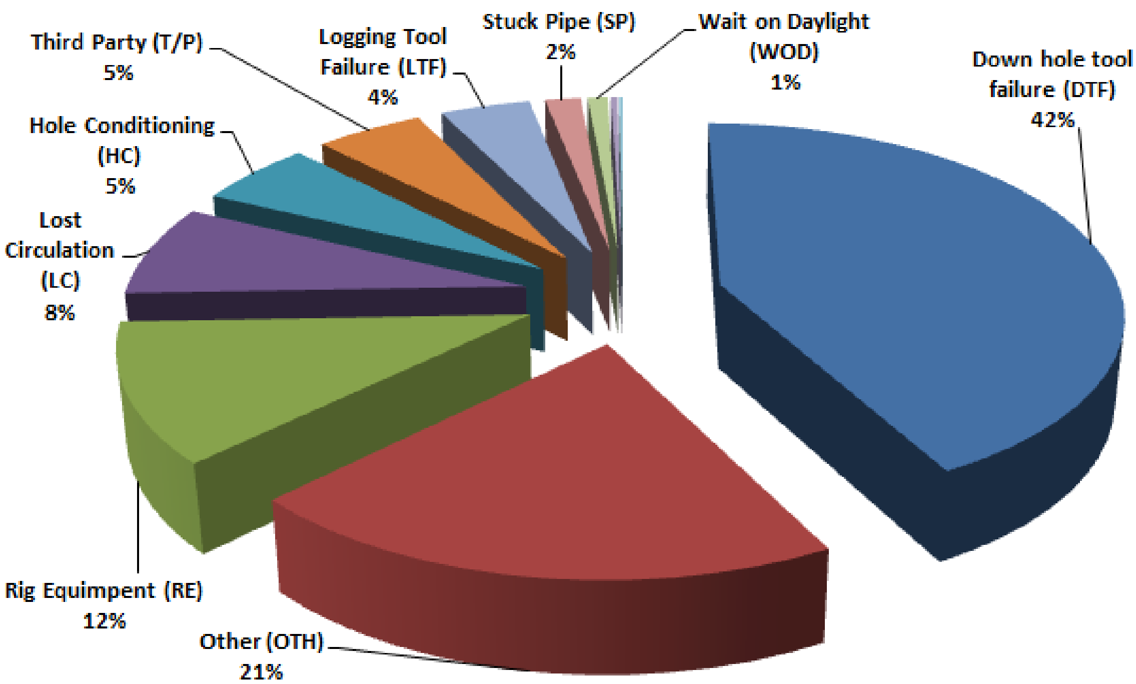


Figure 47: Saxon 215 NPT Root Cause

3.4.4 KPIs and Invisible Lost Time Analysis

3.4.4.1 Formation- dependent KPIs

Table 13: Saxon 215 Formation dependent KPIs Summary for 17.5" Phase

Drilling- Weight to Weight time					
Phase Diameters	**17.5"**				
Wells	**Kohar1**	**Latif-S 1**	**Miano 19**	**Latif 14**	**Lamwari 1**
Operation Count	29	21	34	47	29
P50 (minutes)	15	15.63	20.14	16.48	13.78
Average Duration (minutes)	14.76	17.88	22.01	19.89	14.55
Total Duration(h)	7.13	6.25	12.46	15.58	7
Savings Potential (hours)	0.78	1.35	2.62	3.72	1.03
Savings Potential (%)	10.97%	21.68%	20.96%	23.81%	14.72
Total Savings Potential	9.5 hours				

From Table 13 we notice the following:

- Lamwari-1 showed the best consistency among other wells with the least figure for the P50 value for this indicator, it has performed this operation with consistency around 13.78 minutes. It also has showed the lowest number for the average value.
- The highest ILT for this phase was seen in Latif-14.
- The five wells combined could have saved 9.5 hours if weight to weight time was performed with consistency around the P50 value.

Table 14: Saxon 215 Formation dependent KPIs Summary for 12.25″ Phase

Drilling- Weight to Weight time					
Phase Diameters	**12.25″**				
Wells	**Kohar1**	**Latif-S 1**	**Miano 19**	**Latif 14**	**Lamwari 1**
Operation Count	38	25	29	33	63
P50 (minutes)	15.10	15.07	13.27	21.92	17.23
Average Duration (minutes)	18.04	16.80	14.41	23.28	20.13
Total Duration(h)	11.43	7	6.96	12.8	21.13
Savings Potential (h)	2.95	1.3	0.85	2.08	4.93
Savings Potential (%)	25.86%	18.56%	12.28%	16.34%	23.33%
Total Savings Potential	12.11 hours				

By analyzing the 12.25″ phase in Table 14 the following is noticed:

- Miano 19 showed a good consistency in performing this operation for this phase. In addition, the P50 value was the lowest among other wells.
- Lamwari-1 showed the largest ILT (4.93 hours) while Miano 19 showed the lowest ILT.
- All Wells have a saving potential of 12.11 hours if this operation was performed with consistency around the P50 value.

Analyzing the 8.5″ phase in Table 15 the following is noticed:

- Latif south 1 showed a good consistency in performing this operation; it also showed the lowest times for both P50 value and the average.
- The lowest ILT was seen in Latif 14, followed by Kohar 1.
- The wells combined could have saved 13.35 hours if they were performed with consistency around the P50 value.

Table 15: Saxon 215 Formation dependent KPIs Summary for 8.5″ Phase

Drilling- Weight to Weight time					
Phase Diameters	**8.5″**				
Wells	**Kohar 1**	**Latif-S 1**	**Miano 19**	**Latif-5**	**Latif 14**
Operation Count	28	52	54	57	34
P50 (min)	25.43	17.61	23.93	24.15	26.81
Average Duration (min)	27.38	20.75	24.64	25.11	26.73
Total Duration(h)	12.78	18	22.16	23.85	15.15
Savings Potential (h)	2	3.76	3.28	2.76	1.5
Savings Potential (%)	15.50%	20.97%	14.80%	11.61%	9.92%
Total Savings Potential (h)	13.35				

3.4.4.2 Rig- dependent KPIs

- Tripping KPIs

Table 16: Saxon 215 Tripping KPIs Summary

KPI	Tripping - Slip to Slip Connection Time	Tripping - Pipe Moving Time (CH)
Phase Diameters	26.00", 17.50", 12.25", 8.50", 6.00"	26.00", 17.50", 12.25", 8.50", 6.00"
Operation Count	11825	8978
P50 (min)	1.57	0.93
Average Duration (min)	1.78	1.23
Total Duration	14 d 15 h 11 min	7 d 16 h 37 min
Savings Potential	3 d 0 h 5 min	2 d 13 h 44 min
Savings Potential (%)	20.53 %	33.44 %
Total Savings Potential	5 d 13 h 49 min	

From Table 16, the following is observed:

- Making a connection was performed in more consistent manner than Pipe moving time indicator.
- Due to the inconsistent performance of pipe moving a large ILT was seen which is equivalent to 2.5 days.
- Both KPIs combined have a saving potential of 5.6 days.

➢ Casing Running KPIs

Table 17: Saxon 215 Casing Running KPIs Summary

KPI	Casing- Slip to Slip Connection Time				Casing - Pipe Moving Time (CH)			
Phase Diameters	**26′**	**17.5′**	**12.25′**	**8.5′**	**26″**	**17.5′**	**12.25′**	**8.5′**
Operation Count	74	452	862	494	2	55	436	290
P50 (minutes)	6.08	2.58	2.35	2.25	1.05	1	0.95	0.67
Average Duration (minutes)	7.04	3.07	2.70	2.91	1.05	1.08	1.18	0.70
Total Duration (h)	8.68	23.15	38.8	24	0.03	1	8.58	3.4
Savings Potential (h)	2.18	5.58	8.25	7	0.005	0.2	2.5	0.4
Savings Potential (%)	25.05%	24.16%	21.27%	29.23%	15.87%	19.47%	28.87	11.69%
Total Saving Potential	26.12 hours							

What we can see from Table 17 is the following:

- The phase 8.5″ showed a great performance and consistency, it is noted that the P50 value was small and was very close to the average. Furthermore, it showed the lowest saving potential.
- The largest saving potential was seen during making the connection of the 8.5″ phase, if that operation was performed consistently around the P50 value it could have saved 30% of the operation time
- If all KPIs were consistent and performed around the P50, Saxon 215 could have saved a total of 1.1 days of the total rig time.

3.4.5 KPIs Ranking and ILT

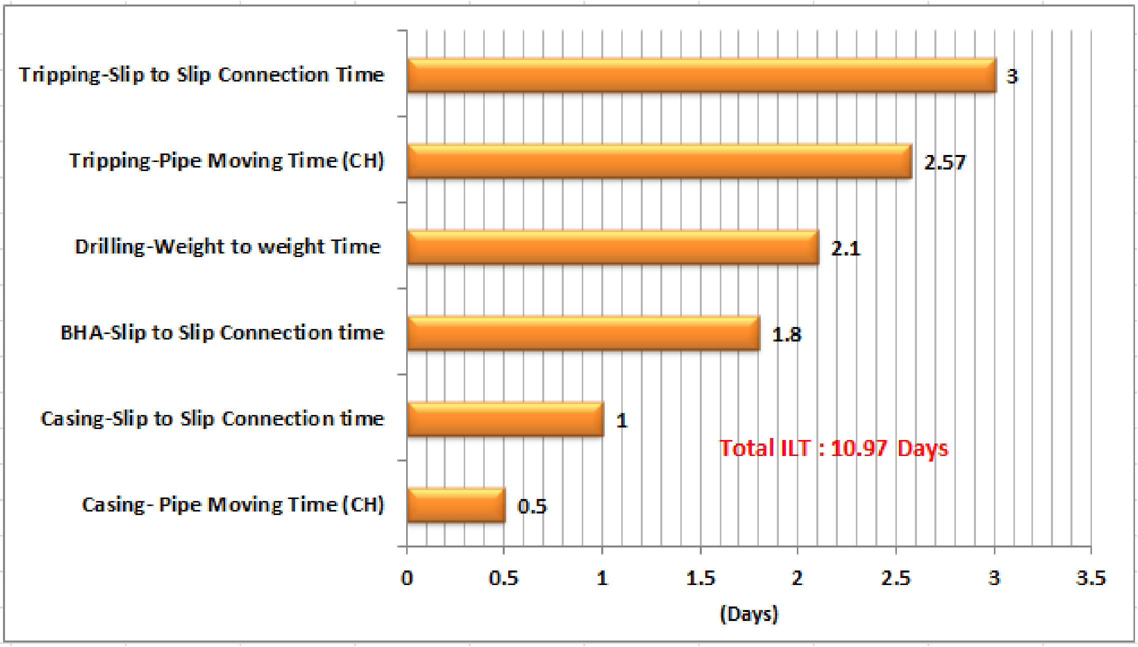


Figure 48: Saxon 215 KPIs Ranking and ILT

3.4.6 KPIs Average Improvement

3.4.6.1 Tripping- Slip to Slip Connection Time

- Figure 49 shows no learning or improvement of this indicator average, it remained the same and sometimes it increased over the quarters.

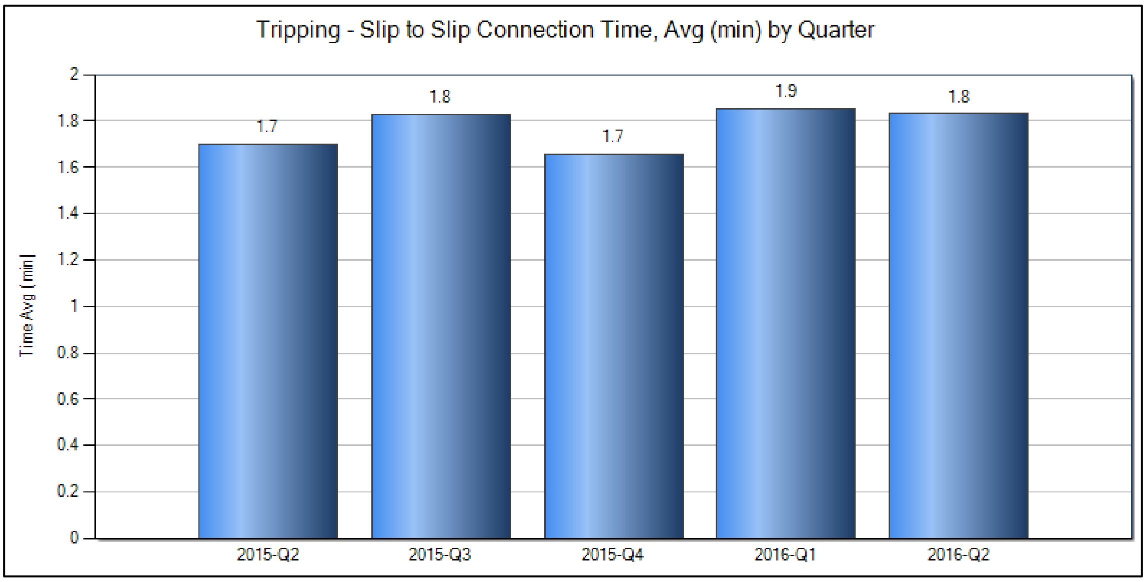


Figure 49: Saxon 215 Tripping Average Connection Time per Quarter [Minutes]

3.4.6.2 Tripping- Pipe Moving Time (CH)

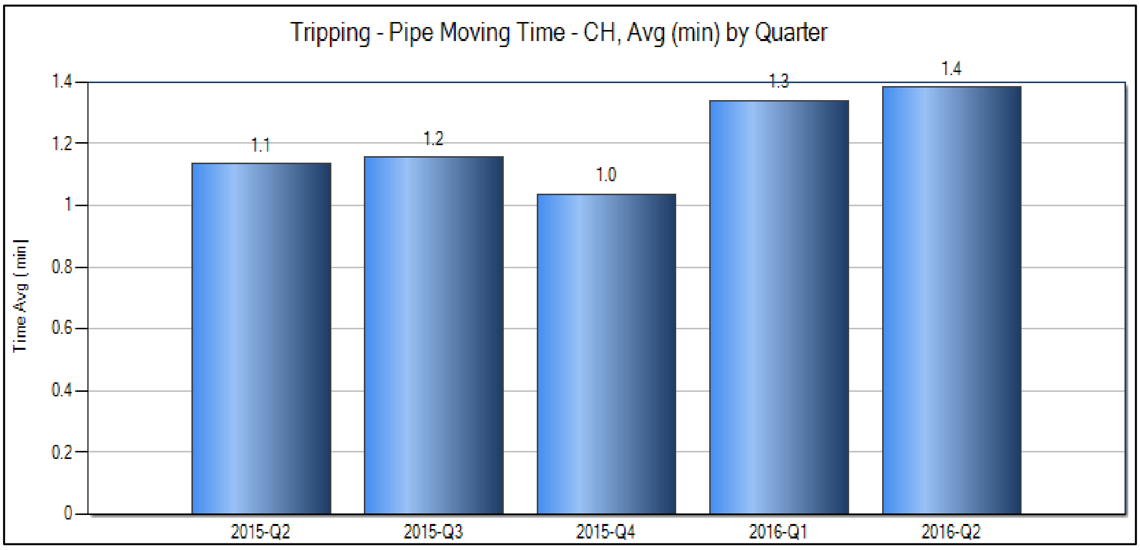


Figure 50: Saxon 215 Tripping Average Pipe Moving Time (CH) per Quarter [Minutes]

- This KPI's average also showed no improvement or learning over the time.

3.4.6.3 Casing- Slip to Slip Connection Time

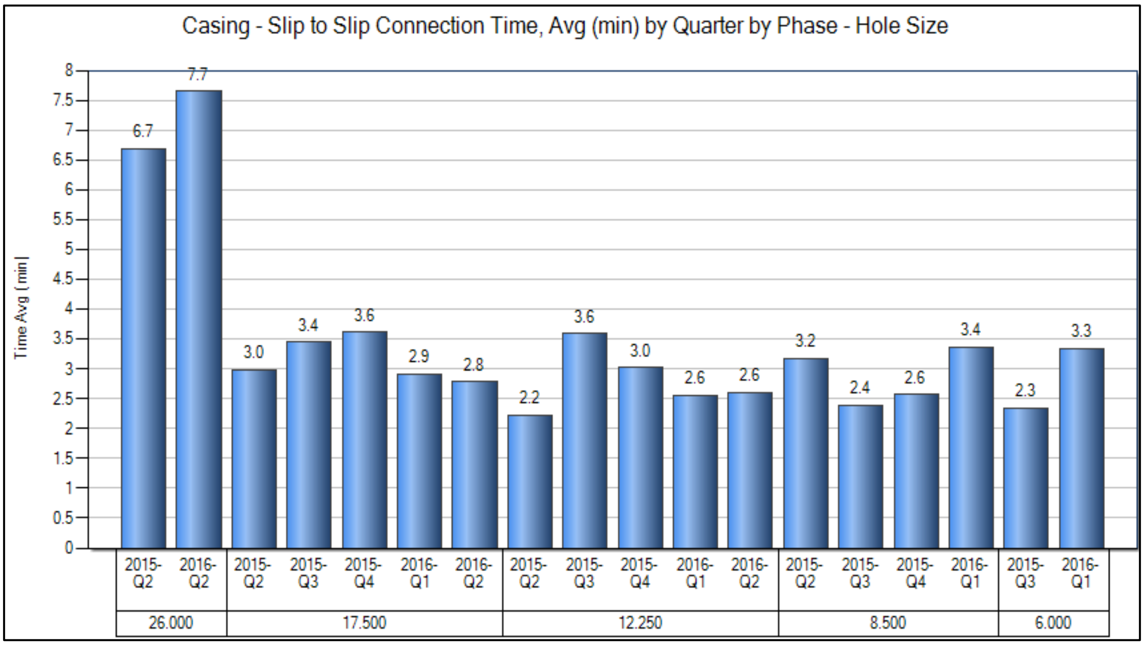


Figure 51: Saxon 215 Casing Average Connection Time by Quarter [Minutes]

- The second phase (17.5") is the only phase among others that showed a slight improvement in the average of casing connection time. Over four quarters the average had an improvement of approximately 7 %.

3.4.6.4 Casing- Pipe Moving Time (CH)

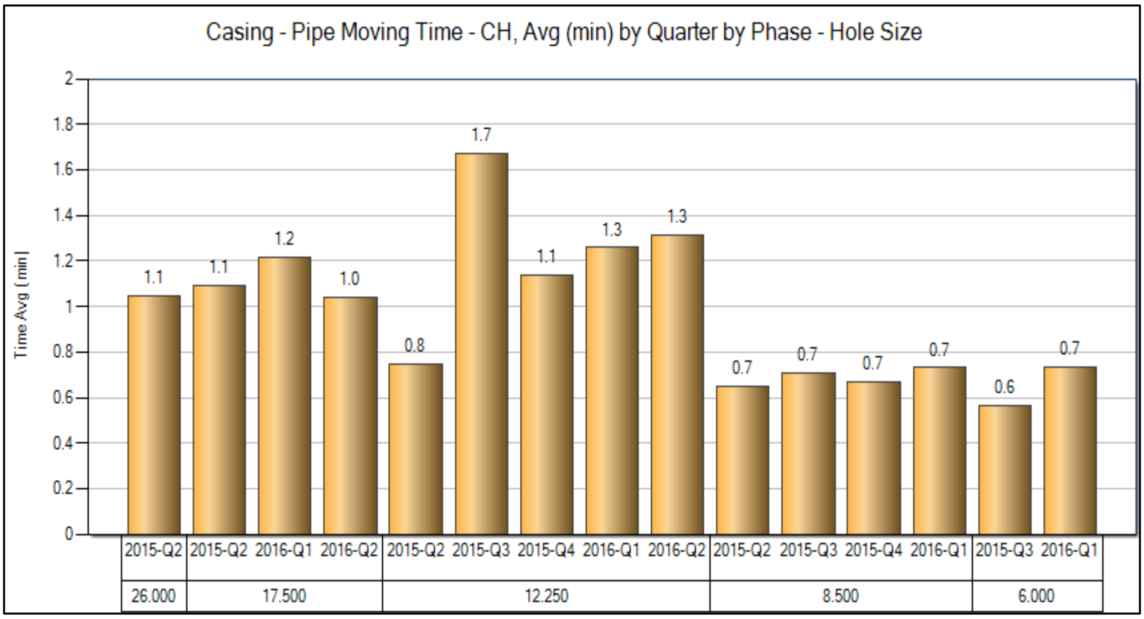


Figure 52: Saxon 215 Casing Average Pipe Moving Time by Quarter (CH) By [Minutes]

- For this indicator an improvement of only 10 % occurred in 17.5" phase, this average stayed the same in the 8.5" phase and it kept increasing over the quarters for the other phases.

3.4.6.5 Drilling- Weight to Weight Time

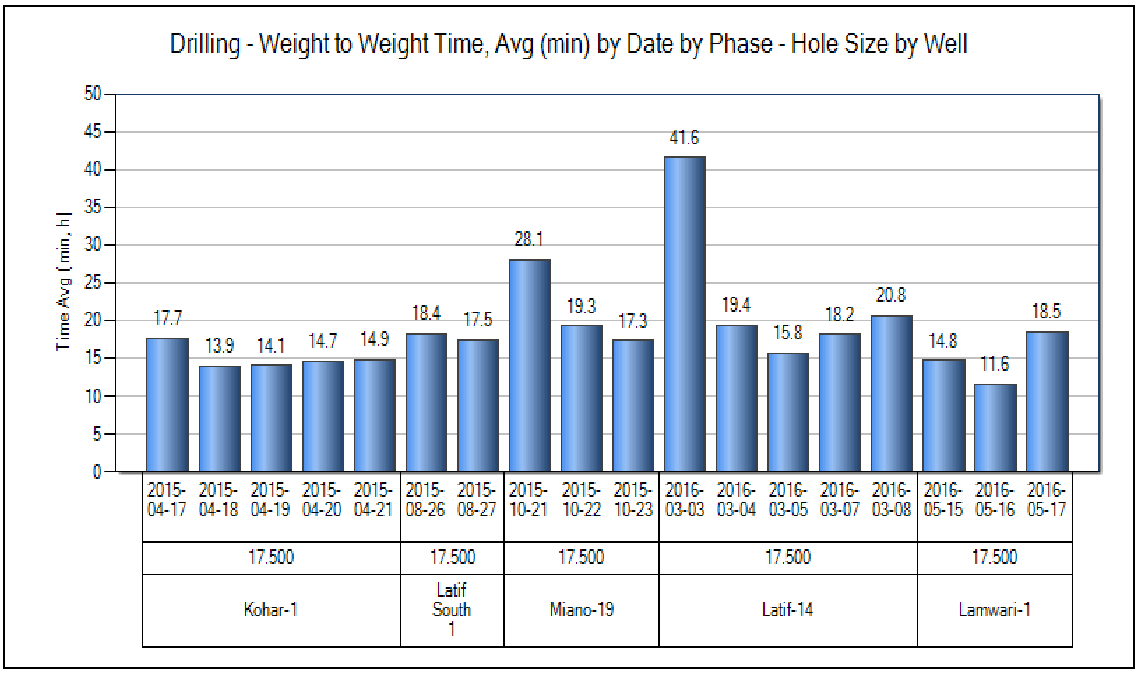


Figure 53: Saxon 215 Drilling-Weight to Weight Average Time per Day for 17.5" Phase [Minutes]

- Figure 54 illustrates that all the wells have shown a good learning trend by the drop of the average, most significantly in Latif-14 and Miano -19 with an improvement of 50% and 38% respectively.

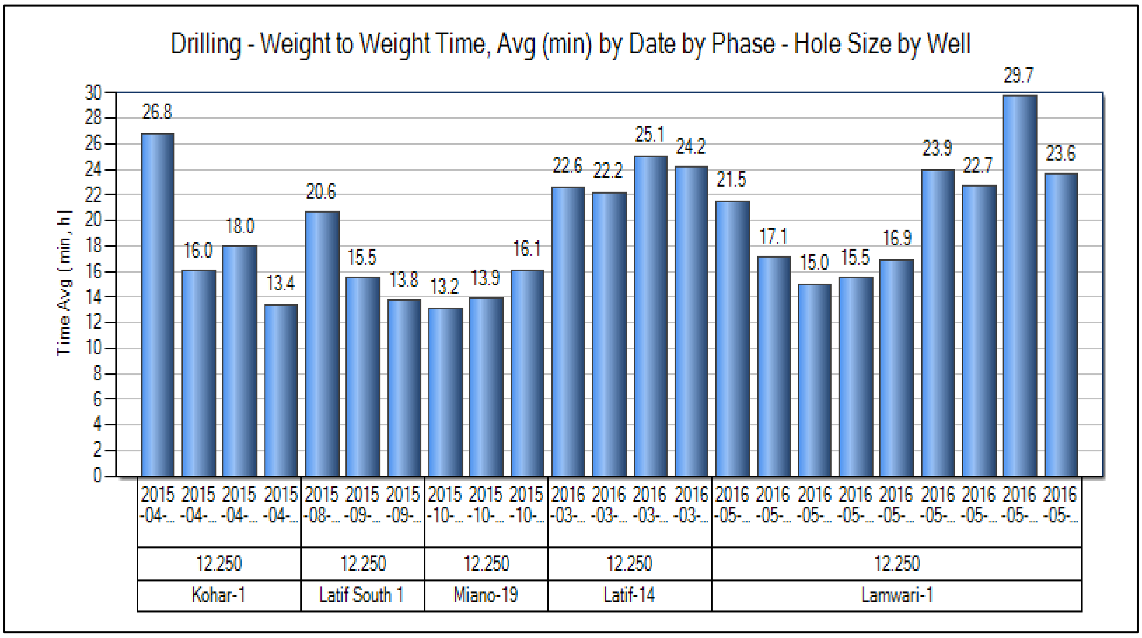


Figure 54: Saxon 215 Drilling-Weight to Weight Average Time per Day for 12.25″ Phase [Minutes]

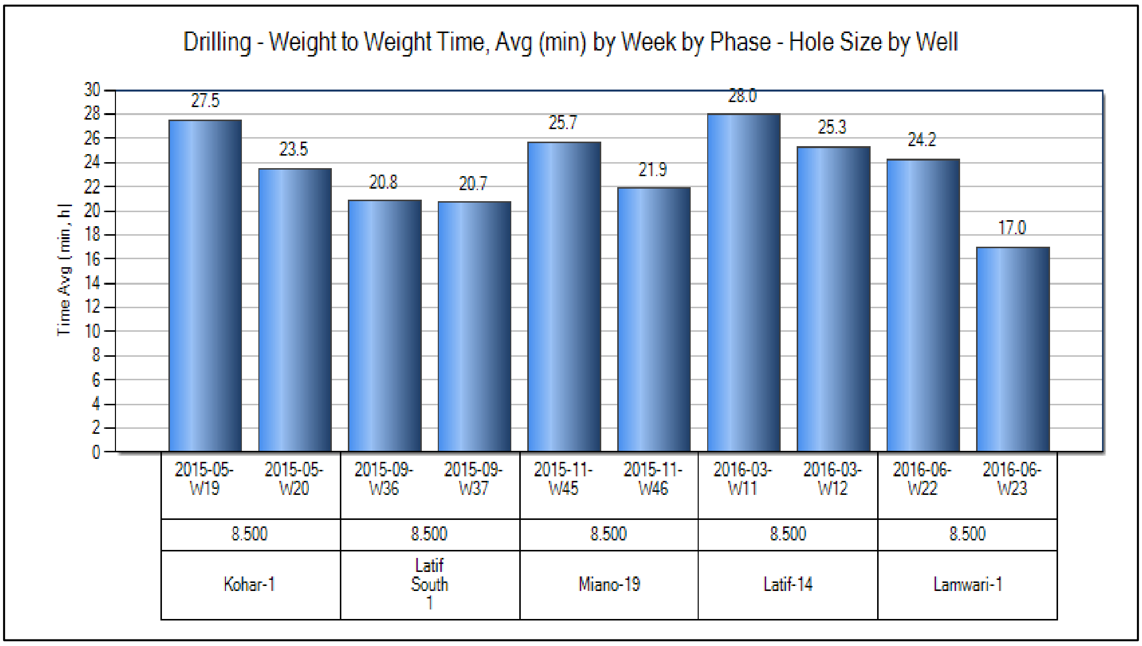


Figure 55: Saxon 215 Drilling-Weight to Weight Average Time Week Day for 8.5″ Phase [Minutes]

- All wells have shown a good learning and drop in the average value as seen in Figure 55.

3.4.6.6 Tubing- Slip to Slip Connection Time

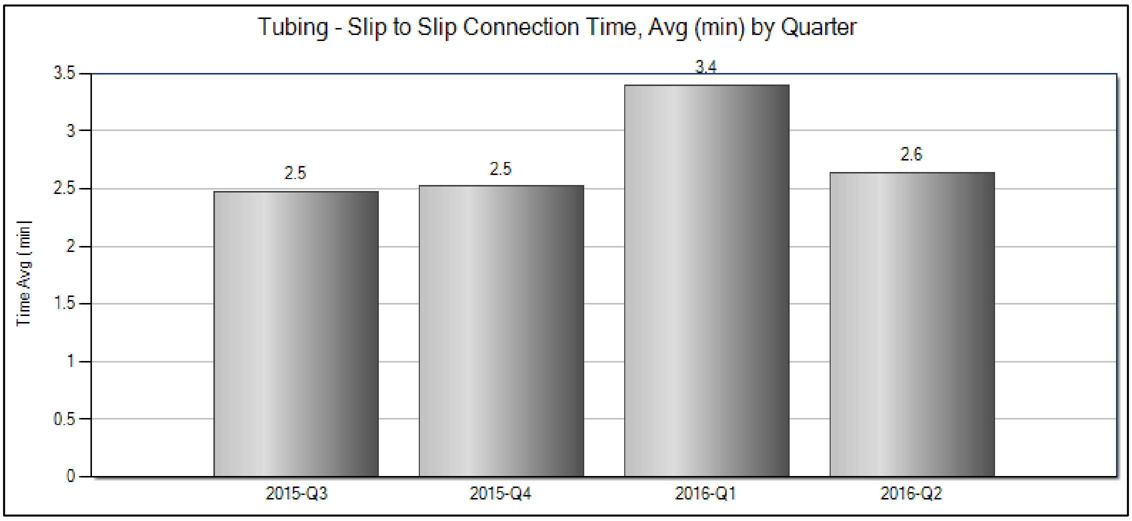


Figure 56: Saxon 215 Tubing Average Connection Time per Quarter [Minutes]

- The average time between making two connections during tubing showed no improvement over the quarters.

3.4.7 Saving Potential Analysis

3.4.7.1 Saving Potential Indicator

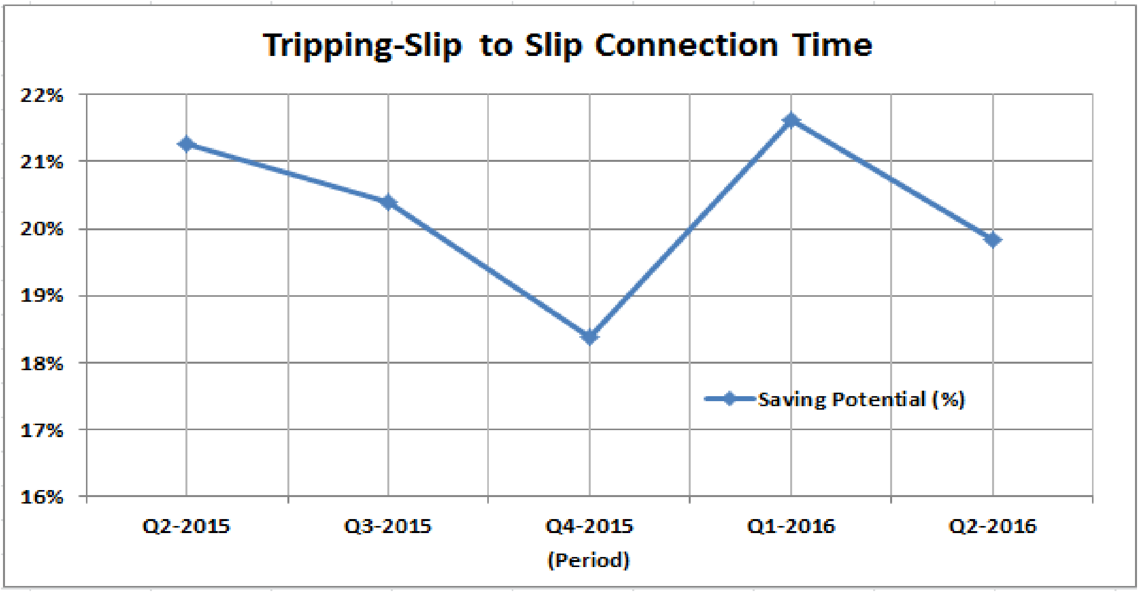


Figure 57: Saxon 215 Tripping Connection Saving Potential Percentage per Quarter

- As seen in Figure 57, the saving potential of this indicator improved and kept reducing with time except for the first quarter of 2016. However, by the last quarter there was an improvement of 2 %.

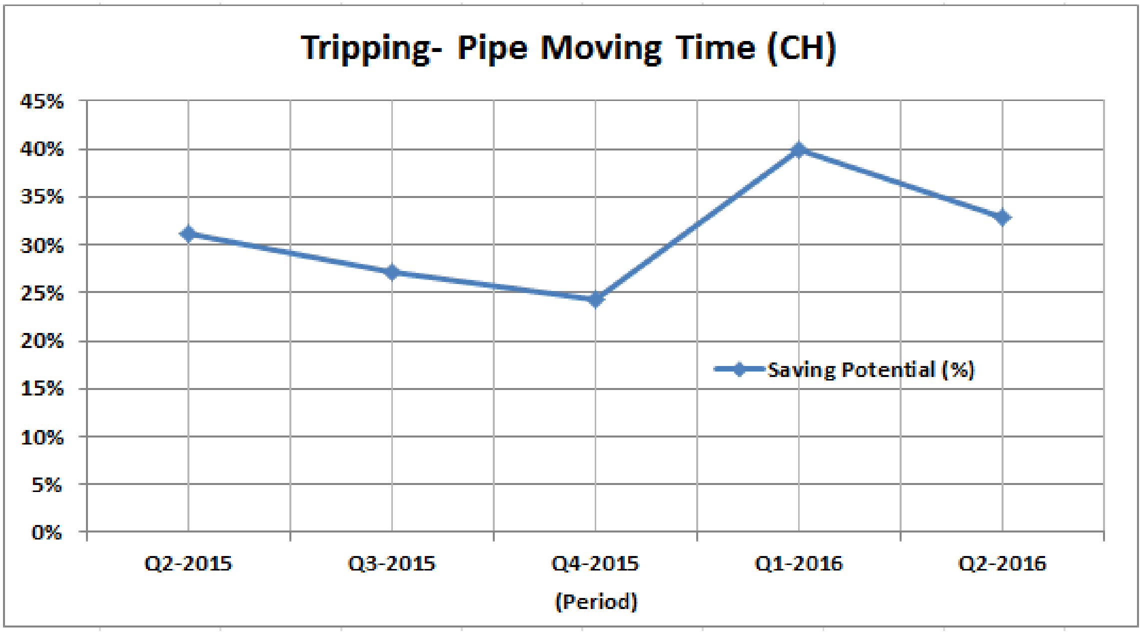


Figure 58: Saxon 215 Tripping Pipe Moving Saving Potential Percentage per Quarter

- Pipe moving time during tripping showed an improvement from the second quarter of 2015 to the fourth quarter of the same year, reducing from 31 % to 24 %. However, the saving potential percentage increased again.

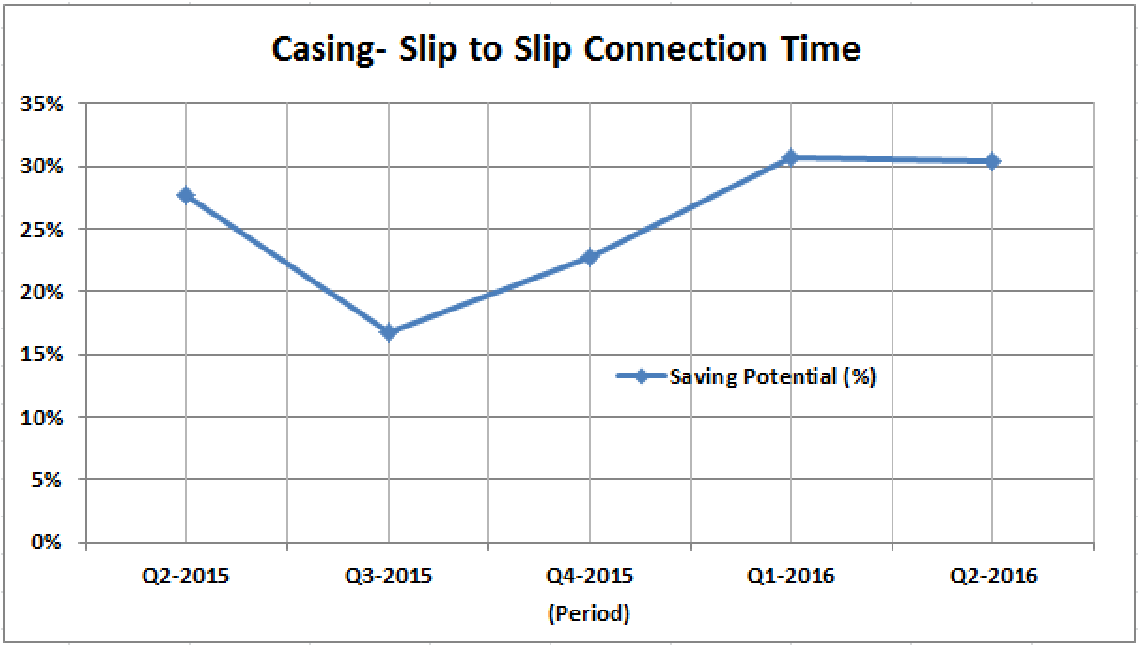


Figure 59: Saxon 215 Casing Connection Saving Potential Percentage per Quarter

- This KPI's saving potential improved from the first to the second quarter by 11%, then kept increasing over the other quarters.

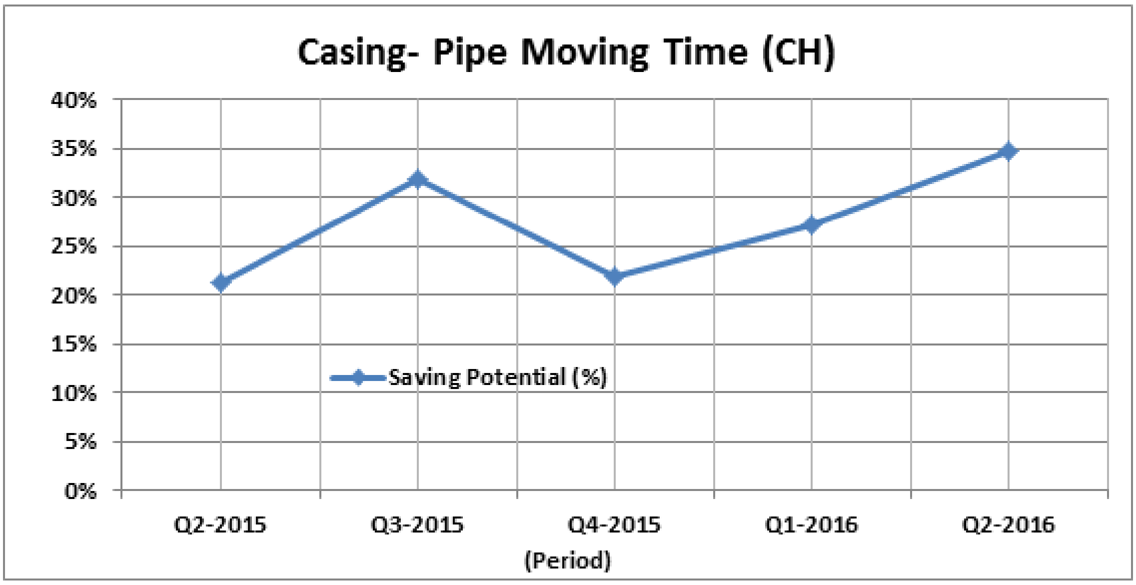


Figure 60: Saxon 215 Casing Pipe Moving Time Saving Potential Percentage per Quarter

- The casing pipe moving time's saving potential did not make an improvement over the time as seen in Figure 60

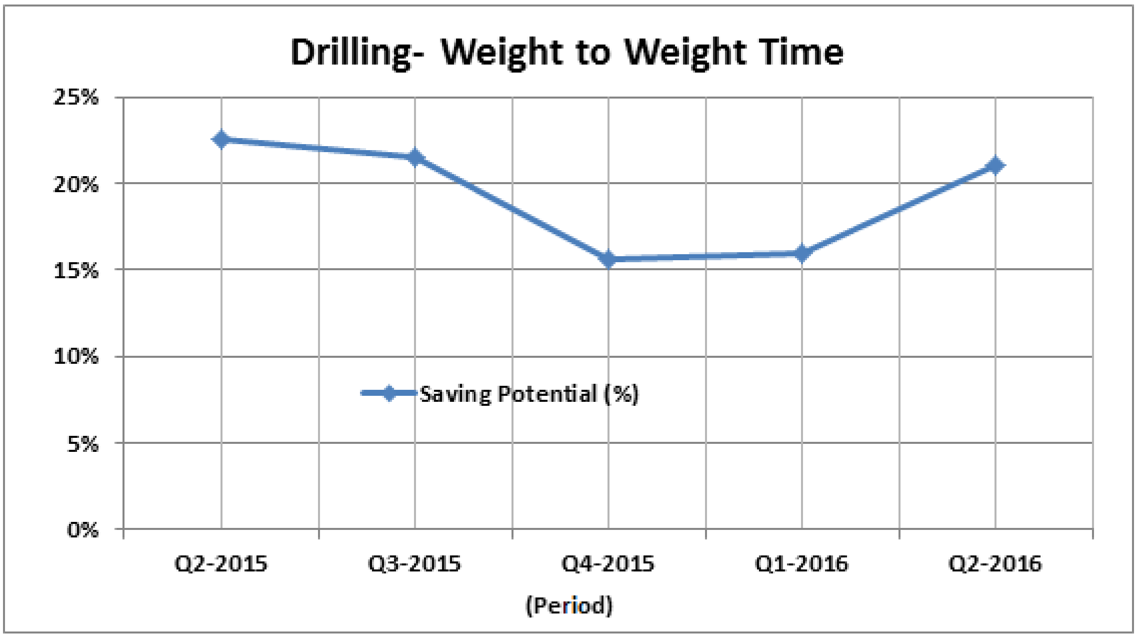


Figure 61: Saxon 215 Drilling- Weight to Weight Time Saving Potential Percentage per Quarter

- The saving potential of this KPI showed a good improvement over the time, and dropped from 23 % in the first quarter analyzed to 16 % in the fourth quarter.

3.4.7.2 Saving Potential Report

KPI	Savings Potential [d]	Savings Potential [%]
Tripping - Slip to Slip Connection Time	3.00	20.53
Tripping - Pipe Moving Time - CH	2.57	33.44
BHA - Slip to Slip Connection Time	1.80	28.33
Drilling - Weight to Weight Time	1.83	16.51
Casing - Slip to Slip Connection Time	1.04	24.85
Casing - Pipe Moving Time - CH	0.13	23.36

Total Savings Potential: 10.38 days (23.32 %)
Total KPI Duration: 44.50 days

Figure 62: Saxon 215 Saving Potential Report

3.4.8 New Targets Selection

Table 18: Saxon 215 New Targets for Future Wells

KPI	Phase	New target (min)
Drilling-weight to weight time	All Phases	17
Tripping-slip to slip connection time		1.42
Tripping-Pipe moving time (CH)		0.80
Tubing- slip to slip connection time		2.08
Casing-slip to slip connection time	26″	3.50
	17.5″	2.15
	12.25″	2
	8.5″	2
Casing-Pipe moving time (CH)	26″	1
	17.5″	0.70
	12.25″	0.70
	8.5″	0.60

3.4.9 Lessons learnt

- In future, casing seat selection at Parh formation need to be optimized because of losses at casing shoe.
- First time in Latif block, three casing string design was implemented. Formerly 13-3/8″ casing was set at the top of Ghazij formation and subsequently Ghazij and SML are isolated by 9-5/8″ casing at top of Ranikot, but in Latif-14 the first casing i.e. 13-3/8″ was set at top of Ranikot formation with no wellbore stability issues.
- During running the 20″ casing for Kohar-1 it got stuck and when it was pulled out it left 4 centralizers with stop collars, casing run attempt was done after that and it got stuck again where cemented in place. The lessons learnt from these observations are as follows;
  - Improve mud system (Use Ultra drill in top hole)
  - Centralization
  - Utilize Over-drive system and design casing string accordingly.
  - Optimize diameter of casing (18-5/8″ instead of 20″)
- The 17 ½″ Hole section of Kohar-1 was not drilled to section TD, the drilling stopped in a different formation (Prah formation) and a different depth due to continuous losses, Losses could not be cured by sweeping and spotting 50ppb LCM pills. Entering into حrah formation could not be avoided, and the possible losses were not considered in the plan.
- Using a smith bit failed due to the presence of Chert. Therefore, Chert prediction should be more precise and bit durability should be therefore enhanced to cross any Chert streak encountered, Reed bits are recommended in this case.
- Use of Ultra drill mud with proper concentrations of Ultrahib (Inhibition) and Ultra cap (Encapsulation) for Mud saving & drilling efficiency
- In Latif South-1, the Weatherford Over Drive system was used to RIH the 9-5/8″ casing to the TD, it showed a good performance by saving the additional conditioning trips.
- The 8 1⁄2″ section of Latif south-1 was drilled very smoothly, without any drilling problems in a good time and therefore these parameters can be taken as good bench marks for the drilling of 8 1⁄2″ sections in the proximity.
- In Latif field, generally the 7″ liner does encounter problems during cementation, losses of approximately 200 – 300 bbls occur while the cement rise across the sand bodies. This issue was avoided in Latif South-1 by cleaning the annulus thoroughly by circulating it properly to reduce the likelihood of any surging due to the rising column of the cement .Furthermore, the flow rates were kept relatively modest and that helped to reduce the chance of losses to occur during cementing. Lastly, the cement slurries were optimized with the requirements of the loss mitigation and this also helped.

- In Miano 19, Econoglider type of centralizer could not pass through Flush Mounted Slips of Weatherford while running 13-3/8" casing. Therefore, everytime it was needed to remove spider slips while passing through the Econoglider below the rotary table that consumed a time and such centralizers should not be used in future wells.
- Weatherford Torqdrive system failed after 330m of running 13-3/8" casing of Miano-19 because of broken hoses this caused a lost time for rigging up and rigging down. Therefore, proper inspection and maintenance before delivering is highly recommended, it is also recommended to have back up tools for problem rectification.
- Reamer shoe was not available in Miano-19. They ran Eccentric guide shoe because it has less OD, it worked well while washing down and clearing the hole fill via rotation and circulation.
- Old FOX casing from PETRONAS was used in 7" liner without any problem.
- PDC bit DP605X which also was used in Latif-5 ST was used to drill the 12 1⁄4" section of Latif-14 it showed a good performance throughout the section. Therefore it should be considered in upcoming wells.
- Using Baker's PDC bit in the 8-1/2" phase of Latif-14 showed a good performance and a good ROP while drilling the shale formation, but then the ROP reduced as it encountered the sands, the Lithology of Latif-14 lower Goru sand had a high strength compared to offset wells.
- Centrifuges were unable to cut down the MW in 12-1/4" section from 9.7ppg to required 9.2ppgin Latif-14.Therefore, the reservoir was drilled with 9.7ppg without facing any losses or well bore stability.

3.4.10 Conclusion and Potential Areas of Improvement

- Drilling was the largest time consumer compared to other operations, followed by wellbore treatment time, both of them consumed 75 and 28 days respectively.
- The crew of Miano 19 made faster and more consistent connections during tripping; Latif-14 crew was faster in Tripping-Pipe moving time.
- Latif south -1 showed a good and fast performance for making a tubing connection.
- Six new targets were selected; pipe moving time for casing had no targets for all phases.
- ILT of 6 days was seen for the indicators of tripping.

- BHA connection making time was the third largest in terms of ILT.
- This rig showed a potential performance improvement of 11 days, for only 6 KPIs, this time represents 24 % of the total KPIs duration.
- Tripping KPIs shows a large room for improvement which would bring savings to the company.
- The average of casing pipe moving time showed a good improvement over time compared to other KPIs.
- Analyzing saving potential reduction over time showed that the time between drilling two stands indicator showed the most drop over time, thus improvement and learning.

3.5 Rag E-200, Austria

Rag E-200 drilled 5 wells; Ebenthal Tief-3, Bockfliess-205, Hatzenbach-1, Aderklaa Tief3, Bernhardsthal Sud 7. The rig was active rom June 2014 to December 2014 with a total rig days of 241.2 days.

3.5.1 Rig specification

Table 19: Rag E-200 Specifications

Unit Name	Rag E 200
Classification	Land rig, Diesel Electric powered
Gross Nominal Capacity	250 t (300 t max hookload)
Static Hook Load Capacity	500 tons
Substructure Height	6,2 m nominal; 5,1 m clear height (max preventer height)
Crown Block Rating	318 tons
Travelling Block Rating	Bentec TB-350-5-42-1 1/4
Max. Hook/Elevator Load	500 tons (GNC:650 tons)
Top Drive System	Maritime Hydraulics PTD 500 AC (500 t max load)
Stand Pipe Pressure Rating	5000 psi
Mud Pumps	2 x Wirth TPK 1600 AC
Mud Tank Capacity	96 m^3
Draw works	Bentec E-1250-AC

3.5.2 Rig Total Time Analysis and Breakdown

Based on the total time breakdown, the following is noted;

- Drilling is the largest time consumer, taking 42 hours of the total 136 days.
- Wellbore treatment and conditioning consumed what is equivalent to 21 % of the total rig time.
- Tripping in was the third largest time consumer, taking 8.2 days
- Tripping out took 7.7 days as the fourth largest time consumer.
- As the 4th largest time consumer, Tripping in needed 13 days of the total rig time.

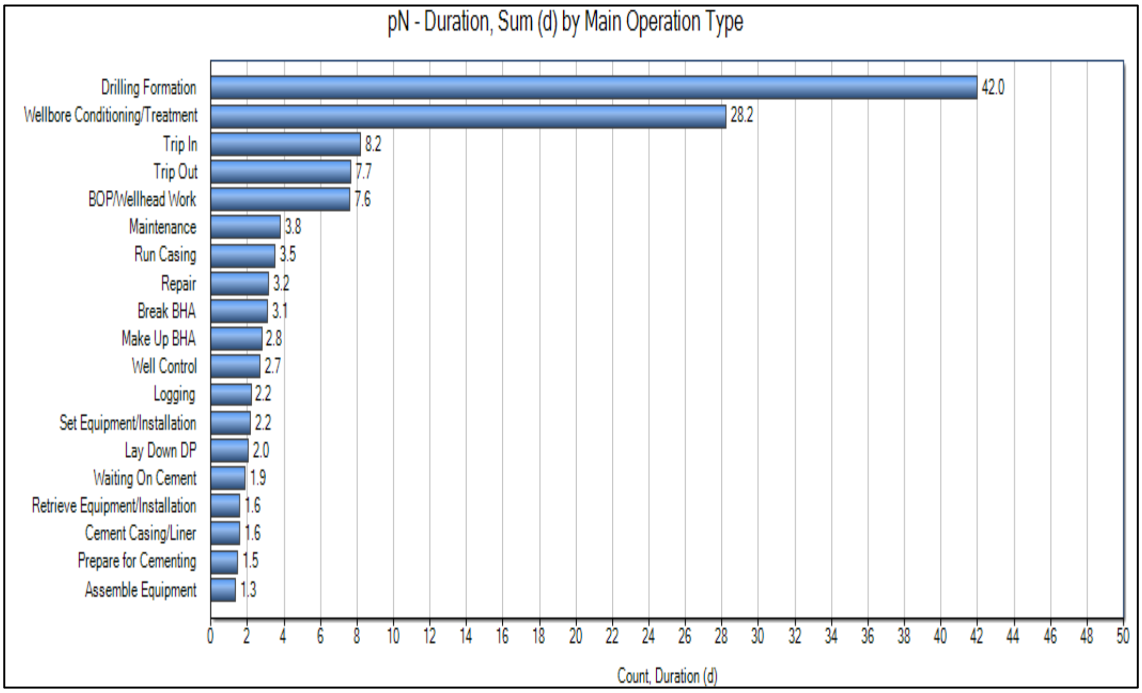


Figure 63: Rag E-200 Total Time Breakdown in Days

3.5.3 NPT Analysis

The total NPT for this rig is 36 days; which is 15% of the total rig time, the NPT breakdown of the wells is seen in Figure 64

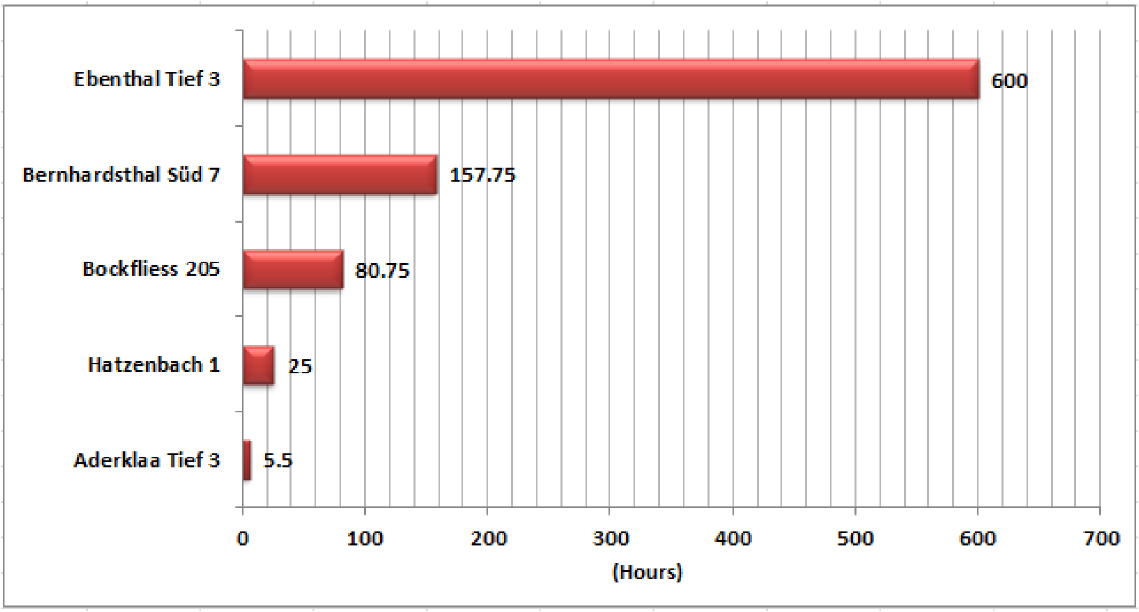


Figure 64: Rag E-200 NPT Break Down per Well

- Ebenthal Tief 3 showed a significant deviation of 23 days between the actual and planned days, the lost time is relatively high with a total of 600 hours that represents 30% of the total well time.

- Bernhardsthal Süd-7 was the second well in terms of NPT, with a total of approximately 158 hours.
- Bockfliess showed a lost time of approximately 3.4 days.
- Hatzenbach 1showed an excellent performance being completed ahead the plan by one day, with only 25 h of lost time.
- Aderklaa Tief 3 showed the best results in comparison with the other wells drilled; it was completed 5 days ahead of the plan with only 5.5 hours of NPT.

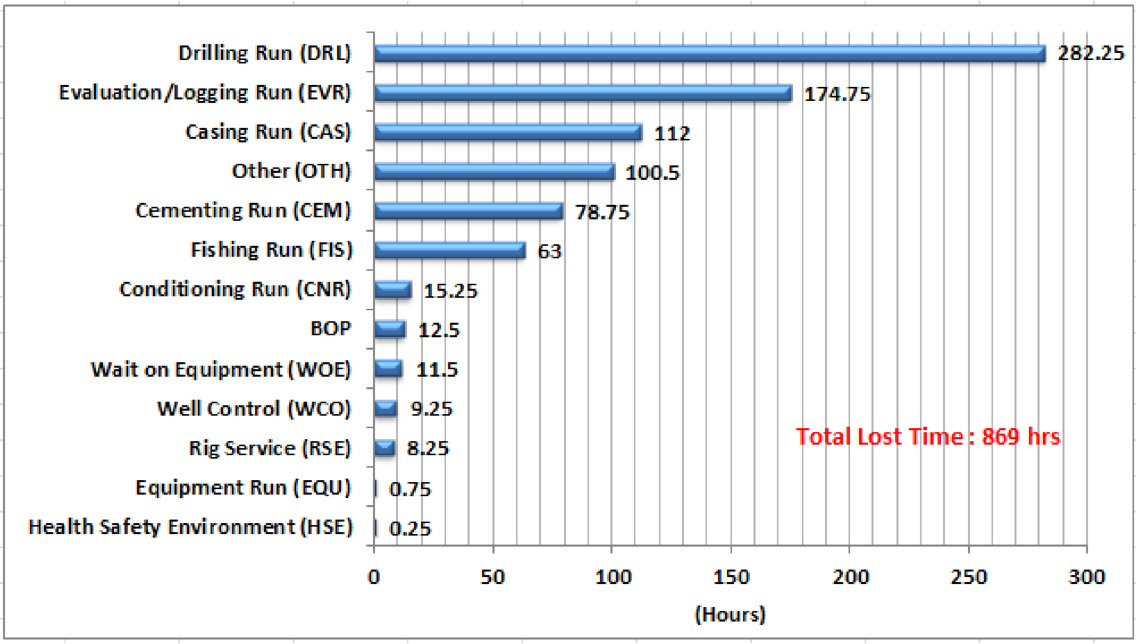


Figure 65: Rag E-200 NPT Breakdown by Operational Code

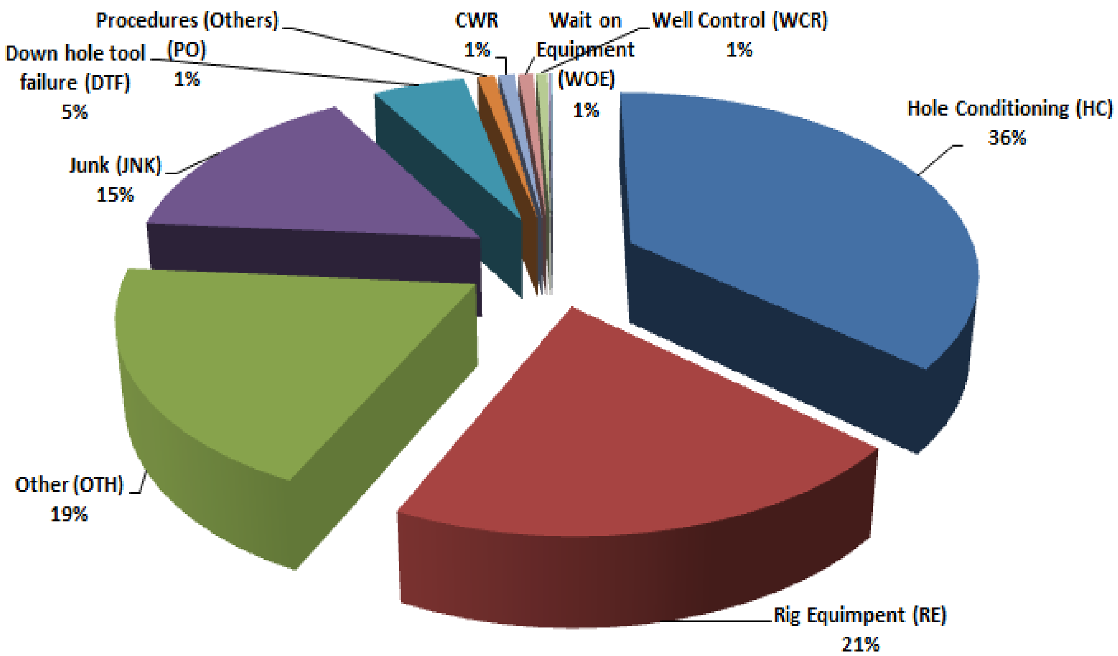


Figure 66: Rag E-200 NPT Root Cause

3.5.4 KPIs and Invisible Lost Time Analysis

3.5.4.1 Formation- dependent KPIs

Table 20: Rag E-200 formation dependent KPIs summary

Drilling- Weight to Weight time							
Well	**Bockflies 205**		**Hatzenbach1**		**AT3**		**BS7**
Phase Diameters	**12.25″**	**8.5″**	**12.25″**	**8.5″**	**12.25″**	**8.5″**	**8.5″**
Operation Count	55	21	67	46	89	31	102
P50 (minutes)	23.93	31.63	23.18	23.33	21.65	23.35	24.83
Average Duration (minutes)	24.42	32.41	24.45	24.23	22.52	23.12	27.67
Total Duration(h)	22.38	11.35	28.3	18.58	33.42	11.95	47
Savings Potential (hours)	2.56	1.68	3.35	2.76	3.82	0.8	8.78
Savings Potential (%)	11.48%	14.83%	12.25%	14.85%	11.45%	6.72%	18.69%
Total Savings Potential	23.75 hours						

- For the 12.25″ phase it is noted that Aderklaa Tief 3 showed the lowest duration for the P50 value, it also showed a good consistency with resulted also in the lowest saving potential percentage.
- Hatzenbach1 showed a good consistency when perform this operation for the 8.5″ phase, it also showed the lowest P50 value for the same phase compared to other wells.
- A total saving potential of approximately one day could have been saved if this operation was performed with consistency around the P50 value.

3.5.4.2 Rig- dependent KPIs

- Tripping KPIs

As seen in Table 21 below

- Both KPIs showed a good consistency specially during making a connection.
- However, both KPIs could have saved approximately 3 days if they were performed with consistency around the P50 value.

Table 21: Rag E-200 Tripping KPIs Summary

KPI	Tripping - Slip to Slip Connection Time	Tripping - Pipe Moving Time (CH)
Phase Diameters	17.50",12.25" 8.50", 6″	17.50",12.25" 8.50", 6″
Operation Count	8854	7448
P50 (min)	1.40	0.60
Average Duration (minutes)	1.66	0.70
Total Duration	10 d 4 h 54 min	3 d 14 h 37 min
Saving Potential	2 d 2 h 1 min	17 h 30 min
Saving Potential (%)	20.42 %	20.21 %
Total Savings Potential	2 d 19 h 31 min	

- Casing Running KPIs

Table 22: Rag E-200 Casing Running KPIs Summary

KPI	Casing- Slip to Slip Connection Time				Casing - Pipe Moving Time (CH)		
Phase Diameters	**23″**	**17.5″**	**12.25″**	**8.5″**	**17.5″**	**12.25″**	**8.5″**
Operation Count	14	48	419	306	12	97	141
50% (minutes)	6.53	4.19	3.72	4.02	1.35	1.27	0.93
Average Duration (minutes)	8.12	4.50	3.94	4.11	1.98	1.25	1.10
Total Duration (hours)	1.9	3.6	27.5	21	0.4	2	2.56
Savings Potential (hours)	0.5	0.35	3	1.95	0.15	0.3	0.7
Savings Potential (%)	27.39%	9.76%	10.76%	9.08%	37.22%	15.02%	27.27%
Total Saving Potential	7 hours						

- The first phase 23″ demonstrated inconsistency in performing the connections.
- The last two phases (12.25″ and 8.5″) showed a good consistency in connections making, it is also noted that the P50 value and average are close to each other.
- Pipe moving time was quite consistent in the 12.25″ phase with an ILT of only 0.3 hours.

3.5.5 KPIs Ranking and ILT

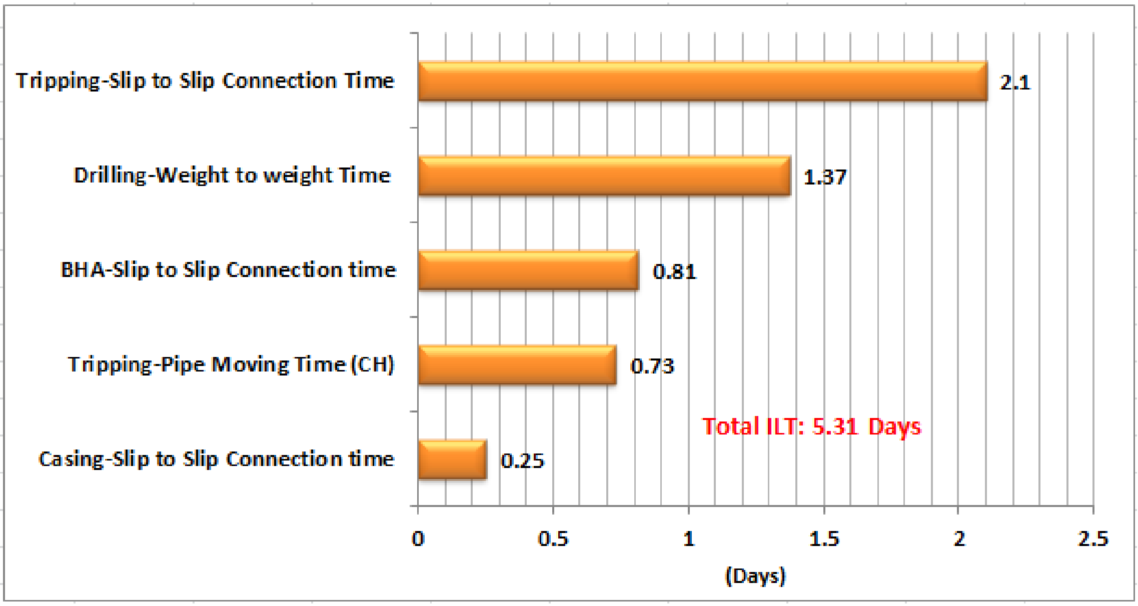


Figure 67: Rag E-200 KPIs Ranking and ILT

3.5.6 KPIs Average Improvement

3.5.6.1 Tripping- Slip to Slip Connection Time

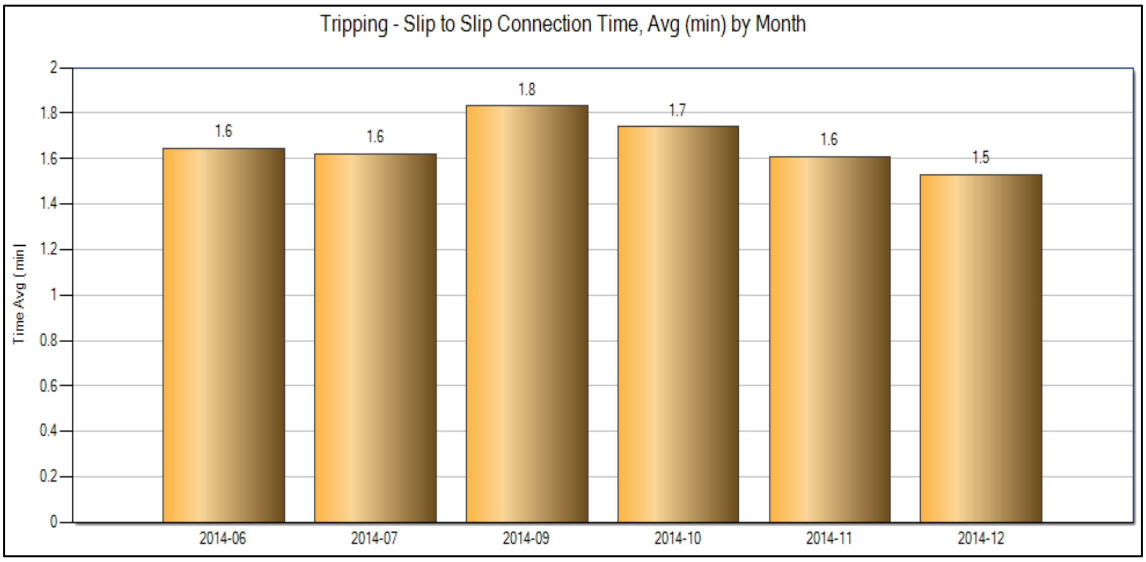


Figure 68: Rag E-200 Tripping- Average Connection Time per Month [Minutes]

- Figure 68 illustrates a small improvement of only 0.1 minute from June-2014 to December 2014

3.5.6.2 Tripping- Pipe Moving Time (CH)

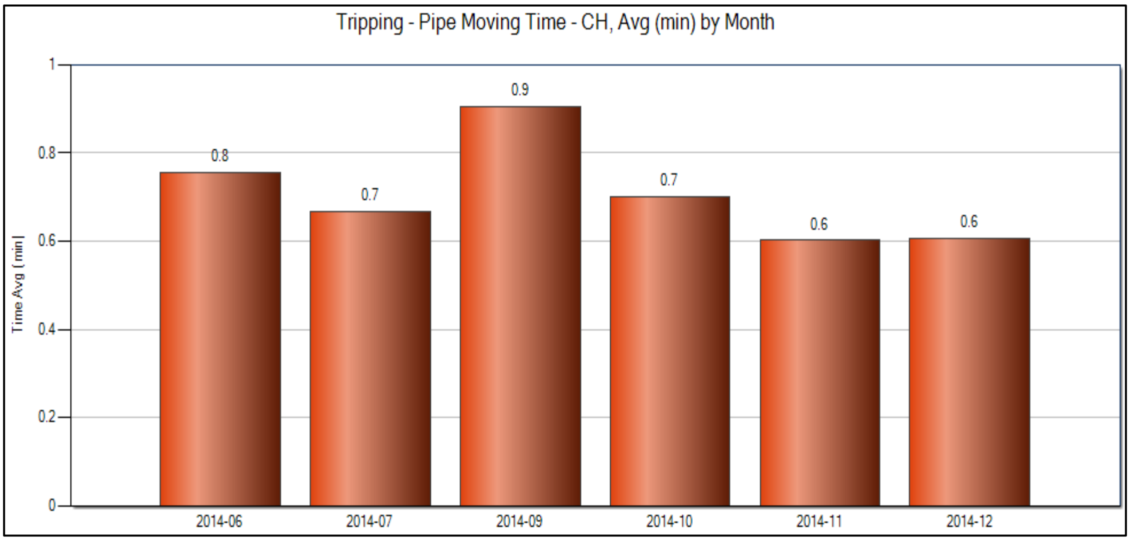


Figure 69: Tripping- Average Pipe Moving Time (CH) per Month [Minutes]

- The average of pipe moving time improved by 25 % dropping from 0.8 minutes in June 2014 to 0.6 minutes in December 2014.

3.5.6.3 Casing- Slip to Slip Connection Time

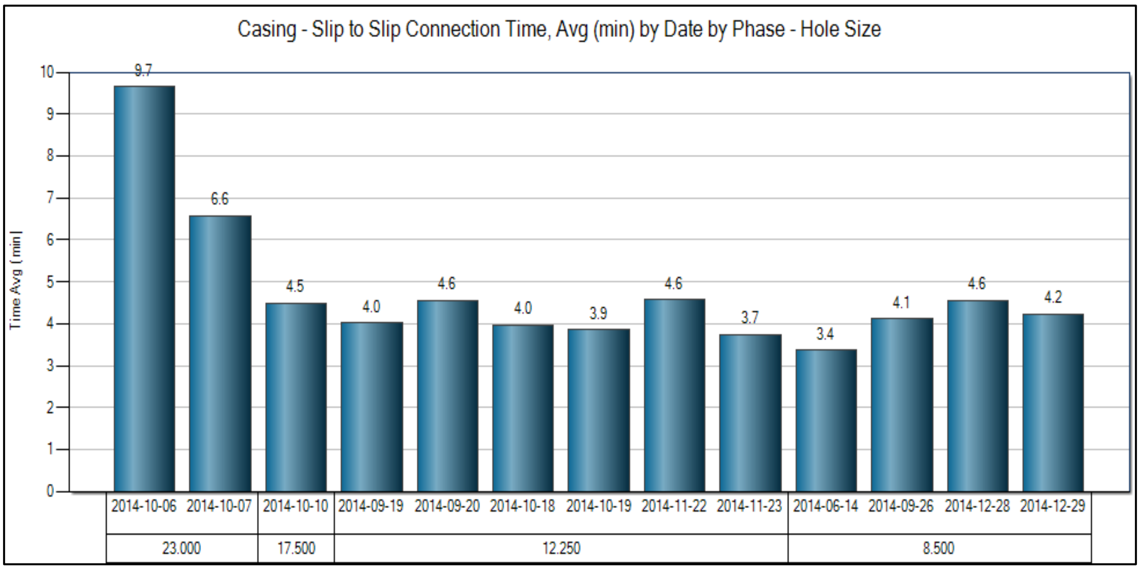


Figure 70: Rag E-200 Casing- Average Connection Time by Date [Minutes]

- This KPI shows an improvement of 32 % for the first phase (23″) from the first day to the second.
- The 12.25″ phase shows an improvement of approximately 18 % by the last day of performing this operation.
- The last phase (8.5″) did not show any improvement.

3.5.6.4 Casing- Pipe Moving Time (CH)

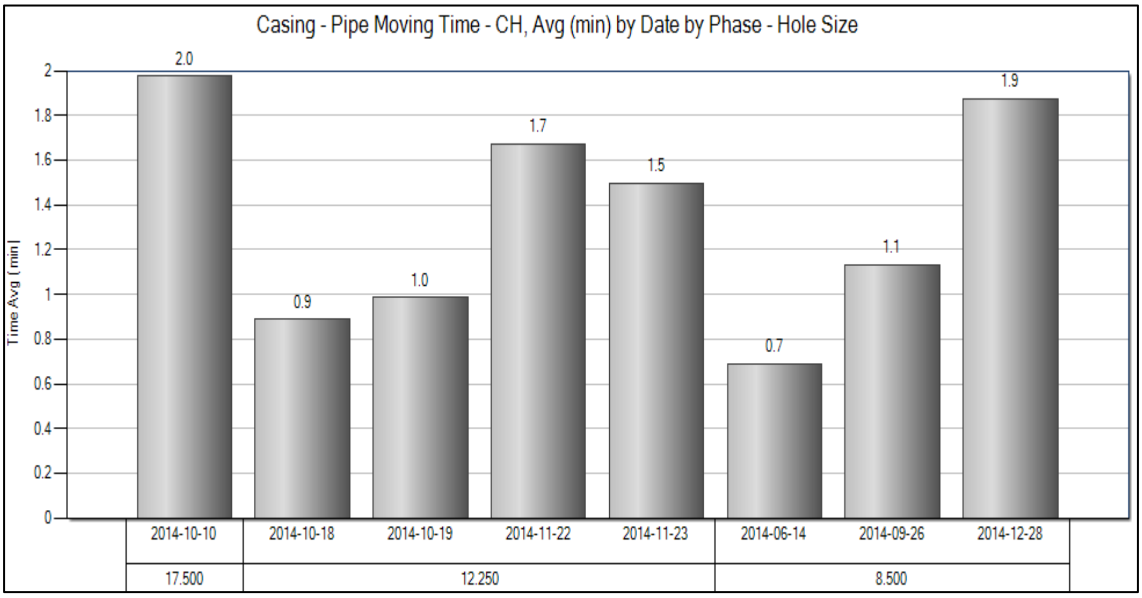


Figure 71: Casing- Average Pipe Moving Time by Date (CH)

- No improvement was seen for any of the phases for pipe moving indicator.

3.5.6.5 Drilling- Weight to Weight Time

➢ 12.25″ phase

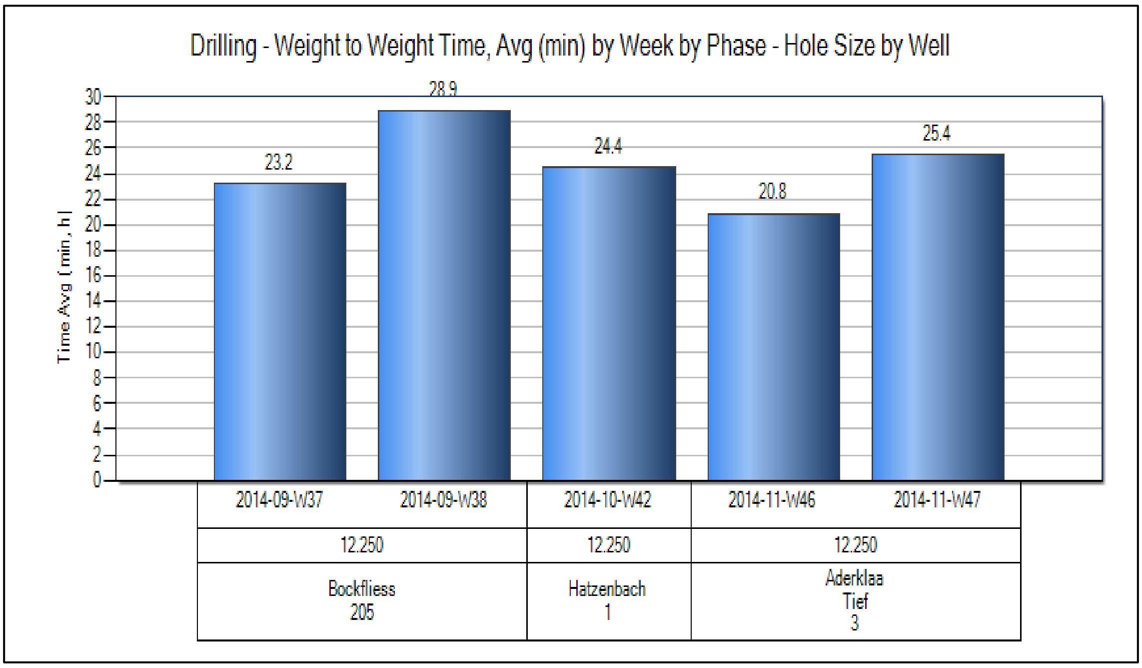


Figure 72: Rag E-200 Drilling- Weight to Weight Average Time per Week for 12.25″ Phase [Minutes]

- As seen in Figure 72 no improvement was recorded for the average value in this phase for all the wells.

➢ 8.5" phase

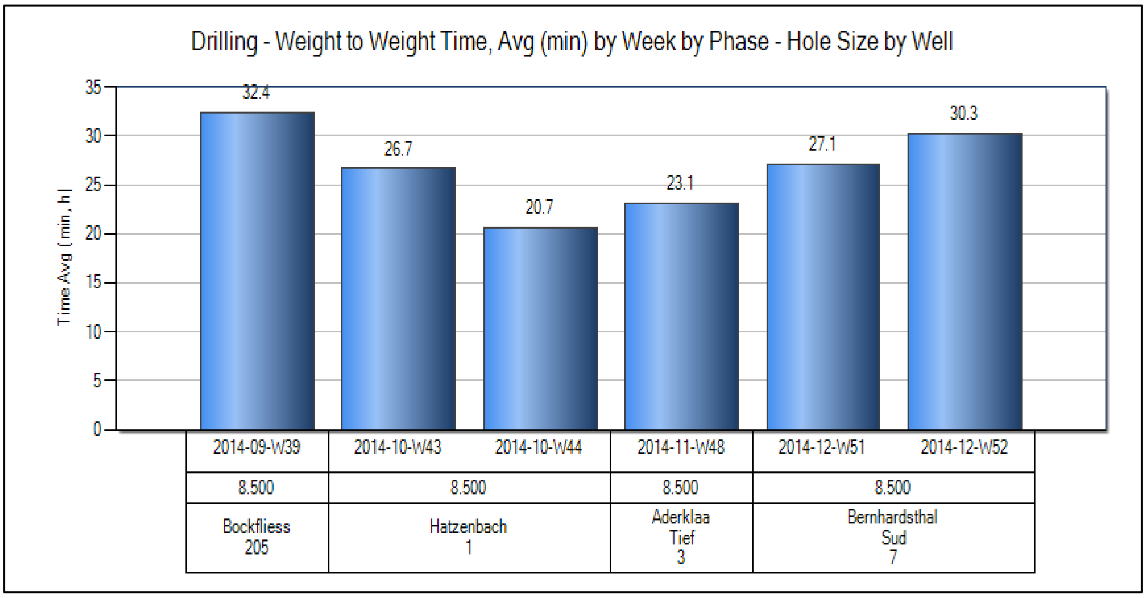


Figure 73: Rag E-200 Drilling- Weight to Weight Average Time per Week for 8.5" Phase [Minutes]

- The only improvement was seen in Hatzenbach1 making an improvement of 23%. The other wells did not make any improvement.

3.5.7 Saving Potential Analysis

3.5.7.1 Saving Potential Indicator

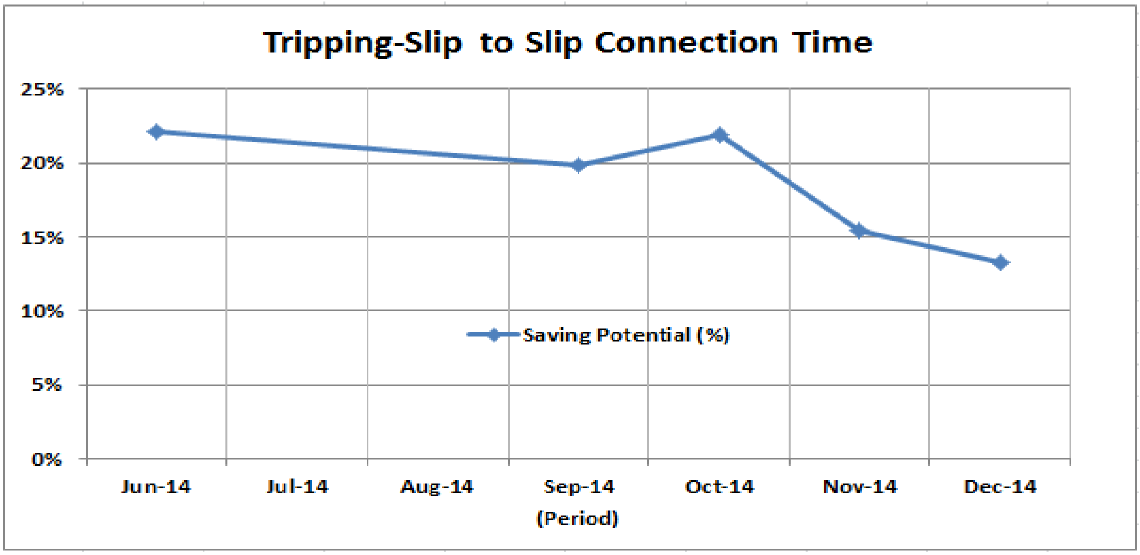


Figure 74: Rag E-200 Tripping Connection Saving Potential Percentage per Month

- The saving potential improved through time reducing from 22% in June 2014 to 13 % in December 2014 as seen in Figure 74.

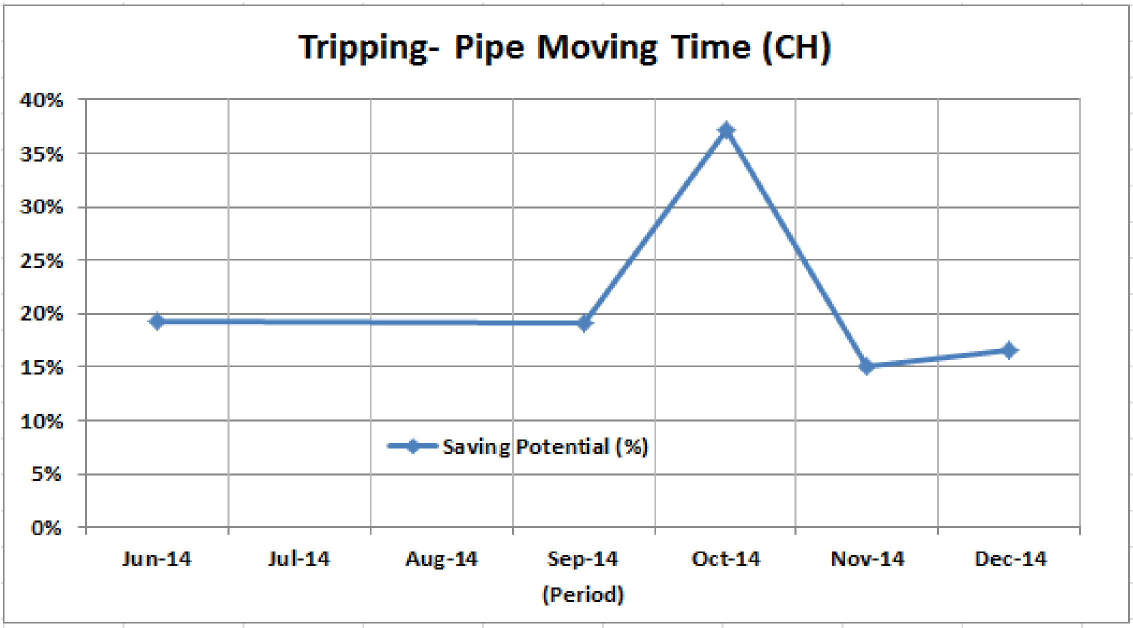


Figure 75: Rag E-200 Tripping Pipe Moving Saving Potential Percentage per Month

- Although the saving potential increased in the third month, it made an improvement of 3% by the last month as seen in Figure 75.

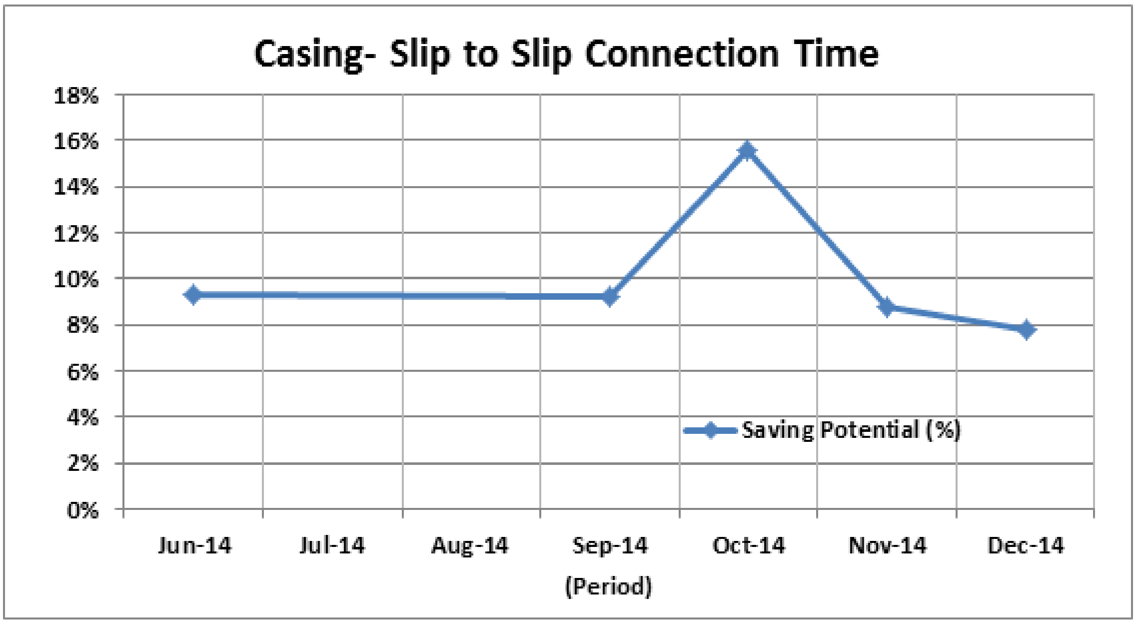


Figure 76: Rag E-200 Casing Connection Time Saving Potential Percentage per Month

- The saving potential of casing-slip to slip connection time made an improvement and the percentage reduced over the months.

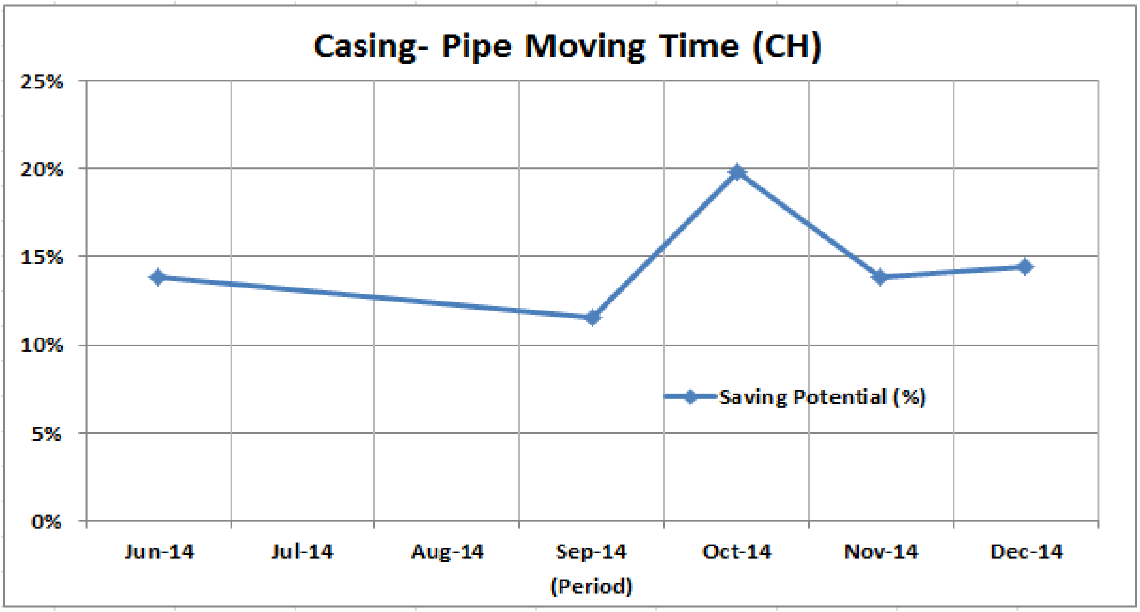


Figure 77: Rag E-200 Casing Pipe Moving Time Saving Potential Percentage per Month

- The only improvement occurred from June to September 2014, after that the saving potential for this KPI kept increasing over the months.

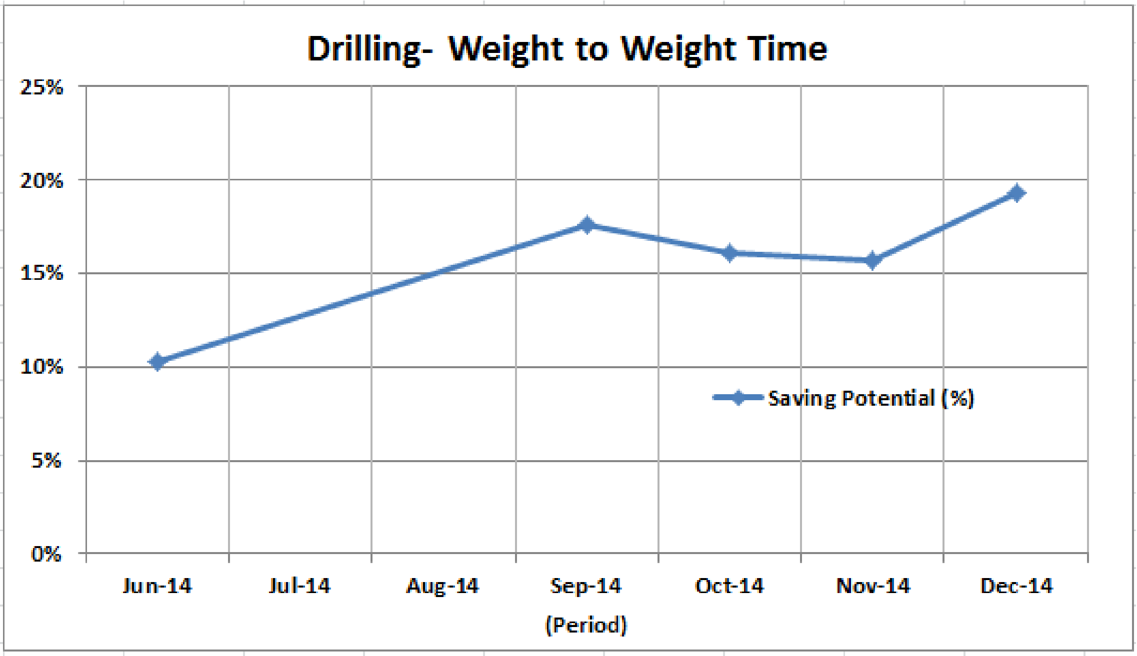


Figure 78: Rag E-200 Drilling-Weight to Weight Saving Potential Percentage per Month

- The saving potential of this KPI did not make improvement over the time; it kept increasing instead as seen in Figure 78.

3.5.7.2 Saving Potential Report

KPI	Savings Potential [d]	Savings Potential [%]
Tripping - Slip to Slip Connection Time	2.08	20.42
Tripping - Pipe Moving Time - CH	0.73	20.21
BHA - Slip to Slip Connection Time	0.81	48.77
Drilling - Weight to Weight Time	1.33	15.69
Casing - Slip to Slip Connection Time	0.24	10.62
Casing - Pipe Moving Time - CH	0.05	23.09

Total Savings Potential: 5.25 days (19.84 %)
Total KPI Duration: 26.44 days

Figure 79: Rag E-200 Saving Potential Report

3.5.8 New Targets Selection

Table 23: Rag E-200 New Targets for Future Wells

KPI	Phase	New target (min)
Drilling-weight to weight time	All Phases	22
Tripping-slip to slip connection time		1.35
Tripping-Pipe moving time (CH)		0.60
Casing-slip to slip connection time	23″	7
	17.5″	4
	12.25″	3.50
	8.5″	3.20
Casing-Pipe moving time (CH)	17.5″	1.40
	12.25″	0.90
	8.5″	0.60

3.5.9 Lessons learnt

- Using one slurry for cementing for shallow casing setting depth to simplify cementing operation and reduce excess cement to surface.
- It is not recommended to take surveys inside casing with a mud motor and PDC. This could cause damage to the casing or the bit, it is recommended to run inclination or azimuth log in OH before running the casing.
- For casing, it is recommended to use Flush Mounted Slips (FMS) instead of rotary mounted slips (RMS), it helps to set the landing joint lower and achieve an appropriate working height.
- Two PDC bits with different cutter types were sent to the rig. Only one of the cutter types was suitable for the formation present. Therefore, for future wells more attention should be paid to the type of cutters as well as following up on the bits delivered to the rig.
- High Bent-Housing on the mud motor produces side loads to the bit and wear the gauge of it while drilling through hard and abrasive formations, Bits with IADC 437 (and below) are not suitable to drill these hard formations, and for vertical wells, it is recommended to use lower bent housing.
- Stick & slip in some formations damaged the bit cutters severely and reduced the life of the bit, to avoid that it's recommended to use High RPM.
- 8 1/2" BHA for Hatzenbach-1 could not be built as specified in the drilling program, less number of drilling collars was provided by the contractor in the rig site. Therefore, it is recommended to do good inspection at early time, and Focus on pre-spud checklist to avoid any future issues with missing equipment. Or it is suggested to send drilling program to rig contractor upfront.
- The landing joint got stuck while trying to release it from the slips in the Rotary Mounted Slips (RMS), which caused a lost time of two hours to release the slips and the landing joint. Therefore, in future the casing slips have to be properly greased and evenly set in the RMS prior to setting the casing.

3.5.10 Conclusion and Potential Areas of Improvement

- Concerning time consumption, drilling was the largest time consumer followed by wellbore treatment time.
- It's noted that reaming consumed approximately 5 days which is quite a lot, given the fact that reaming in Austria is done because it's a practice rather than necessary. Therefore, there is a big room for improvement and saving if reaming is done based on hook load measurements.

- The crew of Ebenthal Tief 3 was faster and more consistent than others in making connections during tripping, as well as casing running for the last phase (8.5”).
- Aderklaa Tief 3 crew on the other hand showed a better performance than other crews for pipe moving time during tripping. In addition to a faster time between drilling two stands.
- Casing-slip to slip connection time for the first three phases (23”, 17.5”, 12.25”) was done faster than others by the crew of Hatzenbach1.
- The indicator of making connection during tripping showed the largest ILT, thus the largest saving potential, followed by the drilling-weight to weight time.
- This rig showed a potential performance improvement of 5.23 days, for only 6 KPIs, this time represents 20% of the total KPIs duration.
- The average of drilling-weight to weight showed the best improvement through time, it dropped from 33.4 minutes in the first month to 24 minutes in the last month making an improvement of 28 %.
- Concerning saving potential over time, making connections during tripping indicator showed the best improvement compared to others.

3.6 DrillTec VDD 2001, Austria

DrillTec VDD 2001 drilled four wells; Erdpress 17a, Erdpress 24, Erdpress 25a, and Schoenkirchen 443 with a total rig days of 53.54 day. The rig was active between May 2013 and July 2014.

3.6.1 Rig Specifications

Table 24: DrillTec VDD 2001 Specifications

Unit Name	DrillTec VDD 2001
Classification	Land rig, Diesel Hydraulic
Gross Nominal Capacity	180 t
Static Hook Load Capacity	500 tons
Substructure Height	8,74m nominal; 7,8 m clear height
Max. Hook/Elevator Load	500 tons (GNC:650 tons)
Top Drive System	MAX STREICHER GmbH & Co. KG aA, 180 t
Stand Pipe Pressure Rating	5000 psi
Mud Pumps	2x MAX STREICHER / Hong Hua, 879 kW
Mud Tank Capacity	106 m^3
Draw works	Hydraulic Hoist Rig, 800 hp

3.6.2 Rig Total Time Analysis and Breakdown

- Based on the total time breakdown, the following is noted;
- Drilling formation (both rotating and sliding) was the largest time consumer; it consumed 35 % of the total rig time.
- Wellbore treatment and conditioning consumed a significant time that is equivalent to 126 hours.
- Casing running and BOP/well head work came as the third and fourth time consumers respectively 49.1 and 38 hours.
- As the 4th largest time consumer, Tripping in needed 13 days of the total rig time.

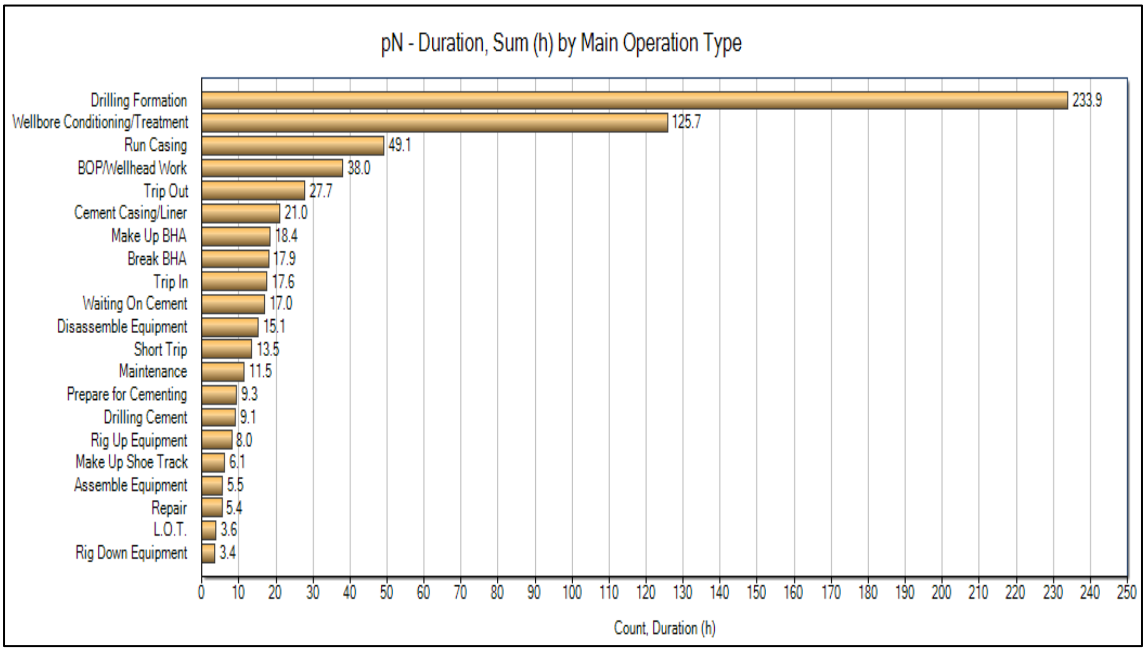


Figure 80: DrillTec VDD 2001 Total Time Breakdown

3.6.3 NPT Analysis

The total NPT for this rig is 71.75 hours; which represents 5.6% of the total rig time, the NPT breakdown of the wells is seen below

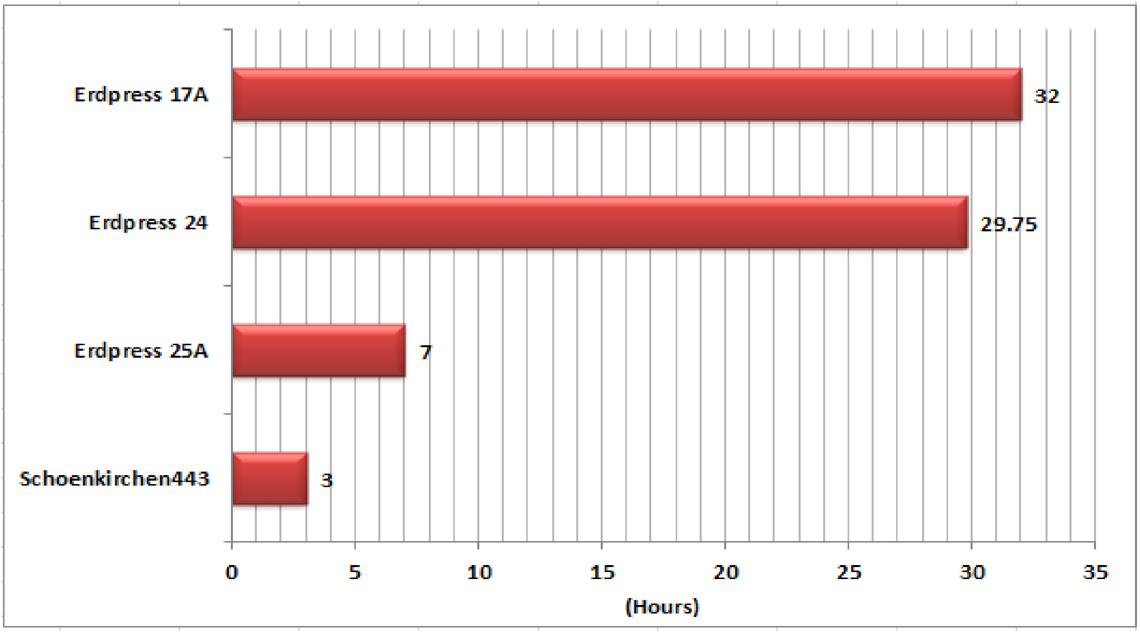


Figure 81: DrillTec VDD 2001 NPT Break Down per Well

- Erdpress 17 A, and Erdpress 24 had the largest NPT of 32 and 20 hours respectively.
- Erdpress 25a and Schoenkirchen 443 showed a good performance they were both completed 4 days ahead of the plan with LT of only 7 and 3 hours respectively.

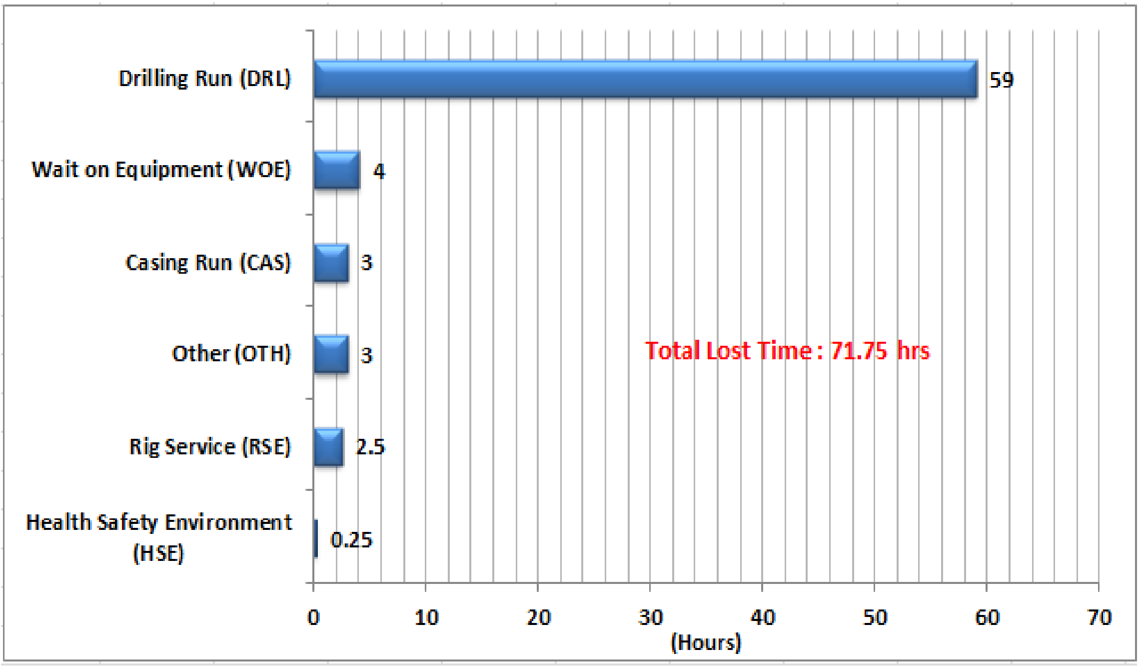


Figure 82: DrillTec VDD 2001 NPT Break Down by Operational Code

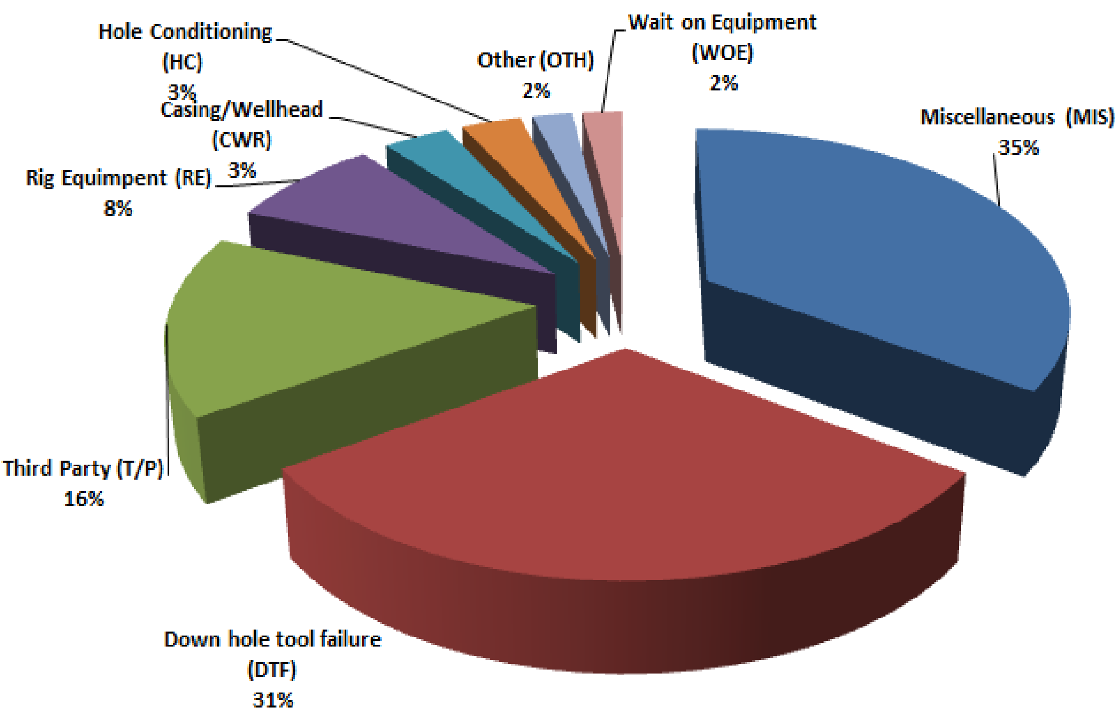


Figure 83: DrillTec VDD 2001 NPT Root Cause

3.6.4 KPIs and Invisible Lost Time Analysis

3.6.4.1 Formation- dependent KPIs

Table 25: DrillTec VDD 2001 Formation dependent KPIs Summary

Drilling- Weight to Weight time						
Well	**Schoenkirchen 443**		**Erdpress 24**		**Erdpress 17A**	
Phase Diameters	**12.25″**	**8.5″**	**12.25″**	**8.5″**	**12.25″**	**8.5″**
Operation Count	55	16	143	47	43	9
P50 (minutes)	17.55	13.96	17.15	19.72	6.80	18.60
Average Duration(minute)	18.37	16.80	18.25	23.30	7.02	18.26
Total Duration (hours)	16.83	4.5	43.5	18.25	5	2.73
Savings Potential (hours)	2.16	0.92	5.35	4.43	0.5	0.1
Savings Potential (%)	12.85%	20.34%	12.29%	24.29%	9.50%	3.59%
Total Savings Potential	13.5 hours					

- The 12.5″ phase of Erdpress 17A showed a good performance and consistency during performing this operation with the lowest P50 value as well as the average value.
- The 8.5″ phase in Schoenkirchen 443 showed a better performance compared to other wells.
- The wells combined have a saving potential of 13.5 hours.

3.6.4.2 Rig- dependent KPIs

- Tripping KPIs

Table 26 : DrillTec VDD 2001 Tripping KPIs Summary

KPI	Tripping - Slip to Slip Connection Time	Tripping - Pipe Moving Time (CH)
Phase Diameters	12.25", 8.50"	12.25″ , 8.50"
Operation Count	946	538
P50 (minutes)	1.93	0.75
Average Duration (minutes)	2.08	0.97
Total Duration	1 d 8 h 46 min	8 h 40 min
Saving Potential	4 h 16 min	2 h 21 min
Saving Potential (%)	13%	27.18%
Total Savings Potential	6 h 37 min	

From Table 29 the following is noticed:

- Slip to slip time indicator showed a better consistency than pipe moving time it also has shown a less saving potential.
- The two KPIs combined could have saved approximately 7 hours if they were performed with consistency around the P50 value.

➢ Casing Running KPIs

Table 27: DrillTec VDD 2001 Casing Running KPIs Summary

KPI	Casing- Slip to Slip Connection Time		Casing - Pipe Moving Time (CH)	
Phase Diameters	**12.25″**	**8.5″**	**12.25″**	**8.5″**
Operation Count	228	335	60	176
P50 (minutes)	2.48	2.25	2.26	1.78
Average Duration (minutes)	2.70	2.40	2.51	2.18
Total Duration	10 h 16 min	13 h 23 min	2 h 31 min	6 h 24 min
Savings Potential	1 h 33 min	2 h 25 min	37 min	1 h 36 min
Savings Potential (%)	15.05 %	18.03 %	24.38 %	25.10 %
Total Saving Potential	7 h 15 min			

- The phase 8.5″ demonstrated a better consistency than the 12.25″ phase for connection making time.
- The saving potential for the two KPIs combined is 7.15 hours.

3.6.5 KPIs Ranking and ILT

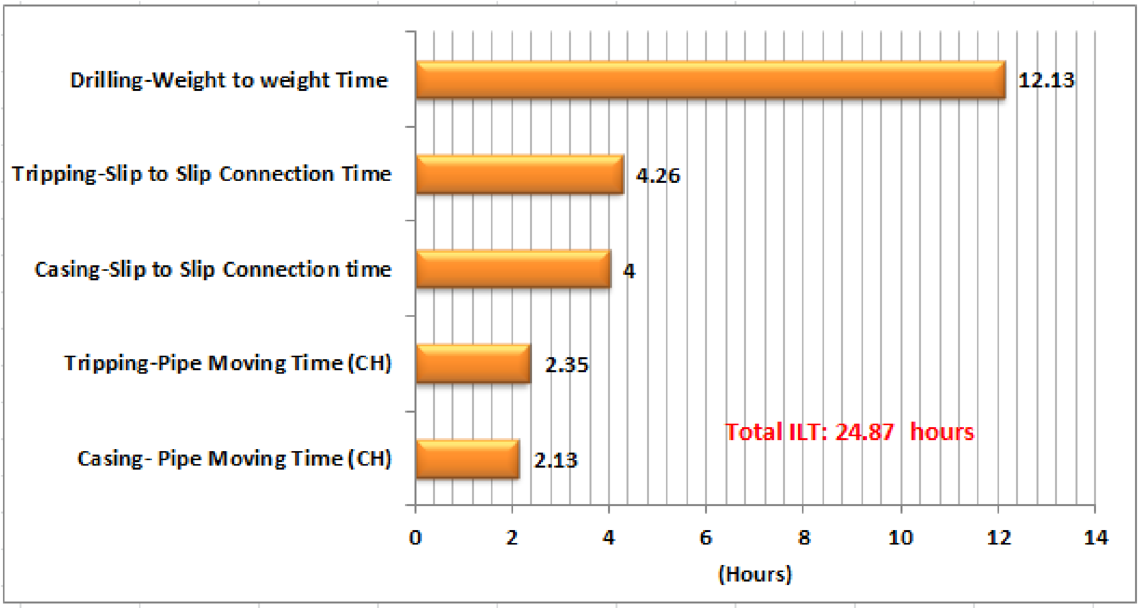


Figure 84: KPIs Ranking and ILT

3.6.6 KPIs Average Improvement

3.6.6.1 Tripping- Slip to Slip Connection Time

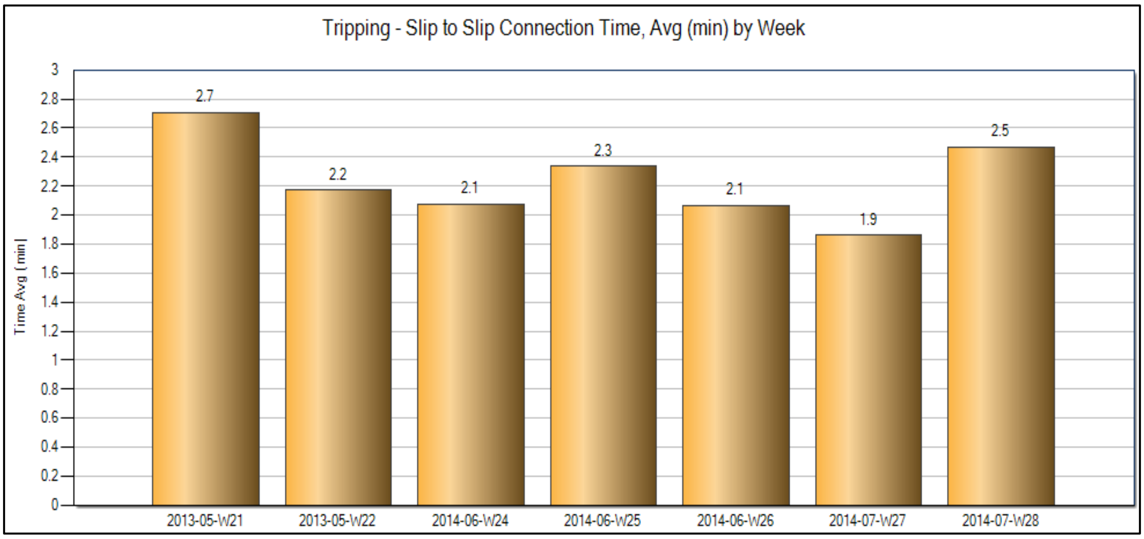


Figure 85: DrillTec VDD 2001 Tripping- Average Connection Time per Week [Minutes]

- Figure 85 illustrates the change of the weekly average for this KPI, it improved by approximately 8% by the end of the rig time.

3.6.6.2 Tripping- Pipe Moving Time (CH)

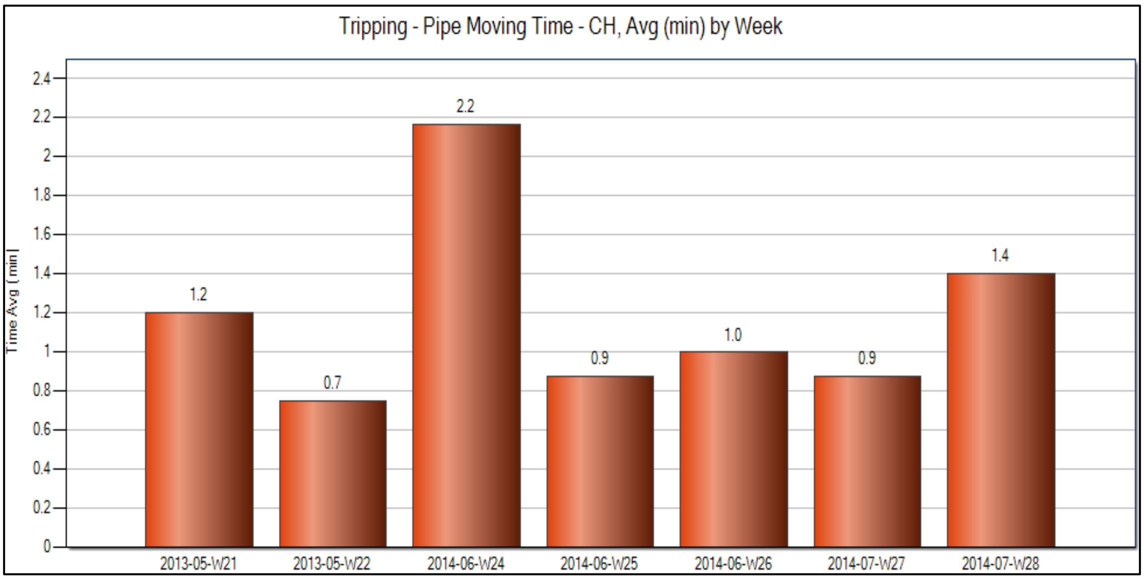


Figure 86: Tripping- Average Pipe Moving Time (CH) per Week [Minutes]

- The average of pipe moving time improved by 41 % from week 21 to week 22. However, the improvement trend did not continue to the last week.

3.6.6.3 Casing- Slip to Slip Connection Time

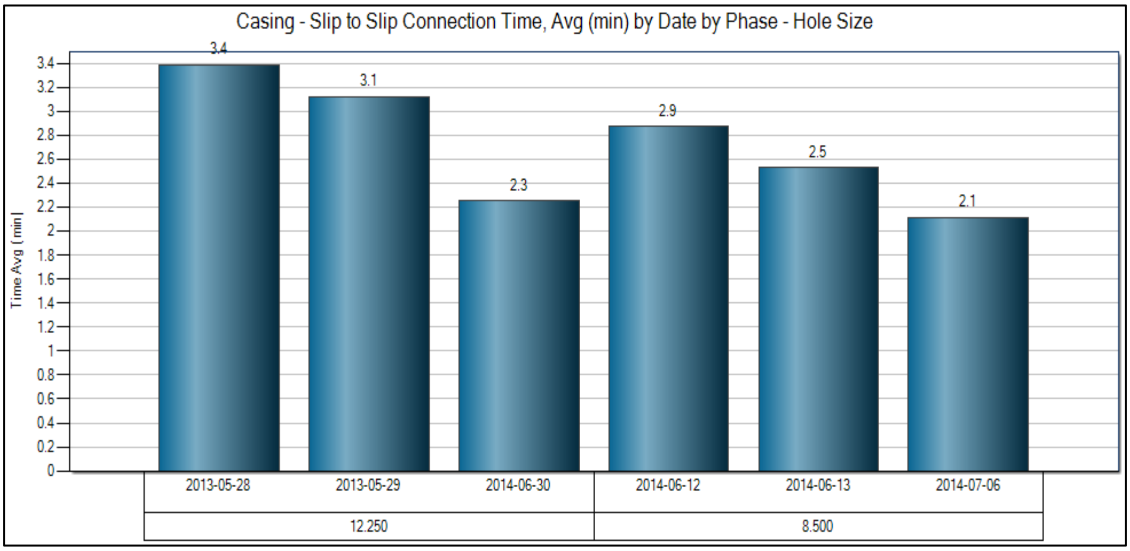


Figure 87: Casing- Average Connection Time by Date [Minutes]

- A huge improvement of this KPI's average occurred in the 12.25" phase within three days, dropping from 3.4 minutes to 2.3 minutes making an improvement of approximately 33 %. For the 8.5" phase as well a good improvement is seen, the average decreased from 2.9 to 2.1 minutes that is an improvement of 28 %.

3.6.6.4 Drilling- Weight to Weight Time

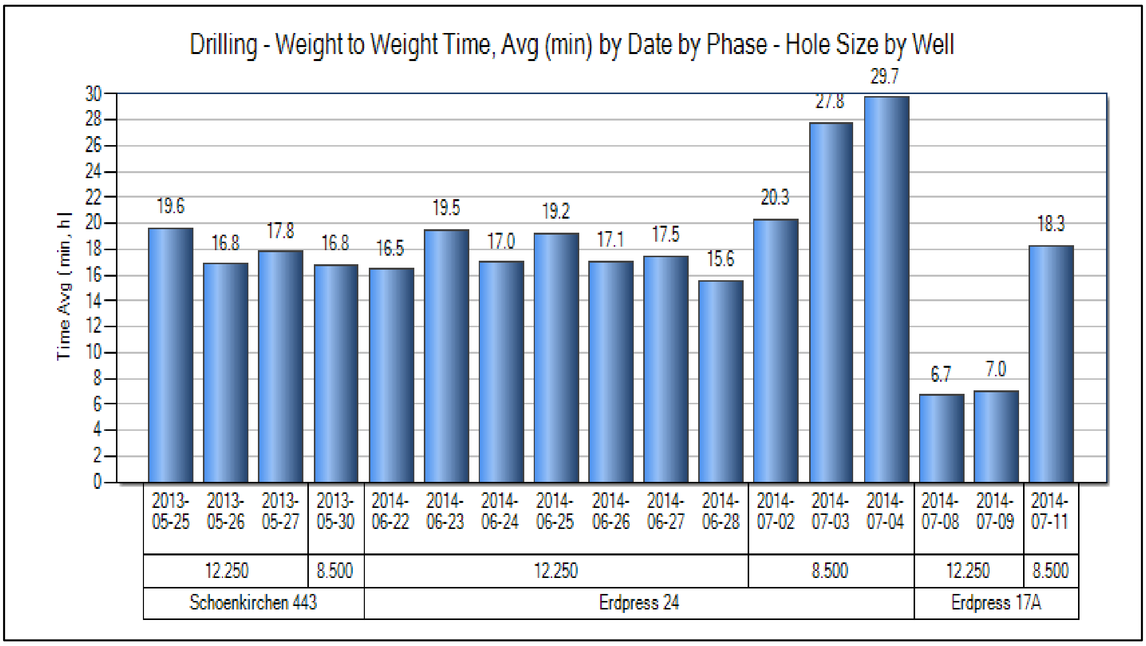


Figure 88: Drilling- Weight to Weight Average Time per Day [Minutes]

- The only improvement was seen in the 12.25" phase of Schoenkirchen 443 recording a slight improvement of 10 % as seen in Figure 88.

3.6.7 Saving Potential Analysis

3.6.7.1 Saving Potential Indicator

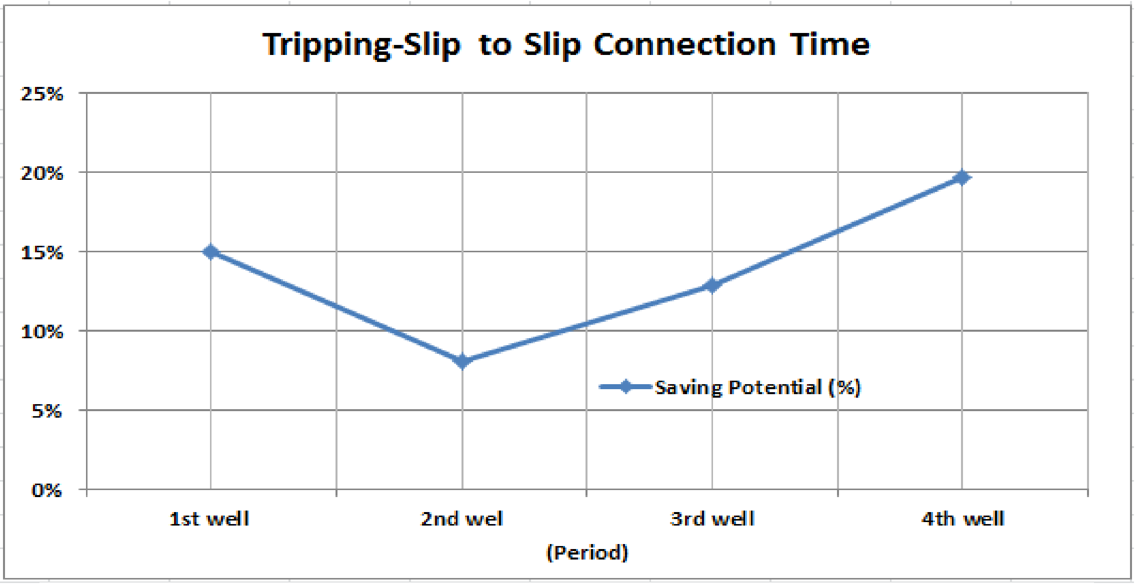


Figure 89: Tripping Connection Saving Potential Percentage per Well

- An improvement was seen only from the first to the third well as seen in Figure 89, the saving potential percentage dropped from 15 % to 8 % in the second well and 13 % in the third well.

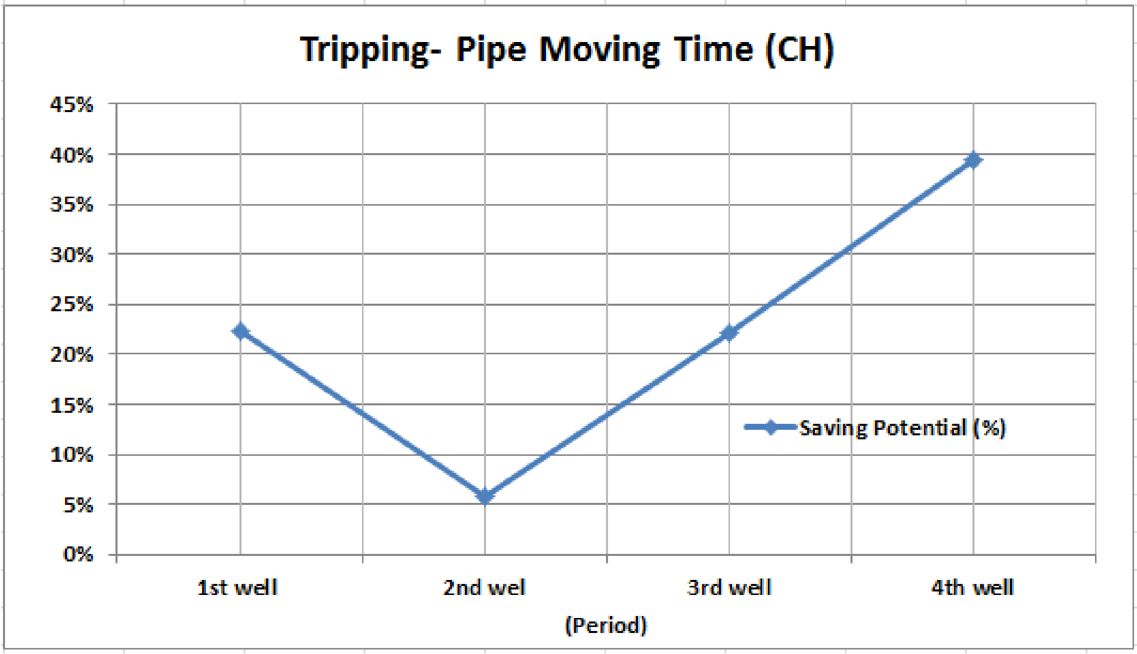


Figure 90: Tripping Pipe Moving Saving Potential Percentage per Well

- A good improvement of approximately 17 % was seen in the second well. However, the saving potential percentage kept increasing through the other wells as seen in Figure 90.

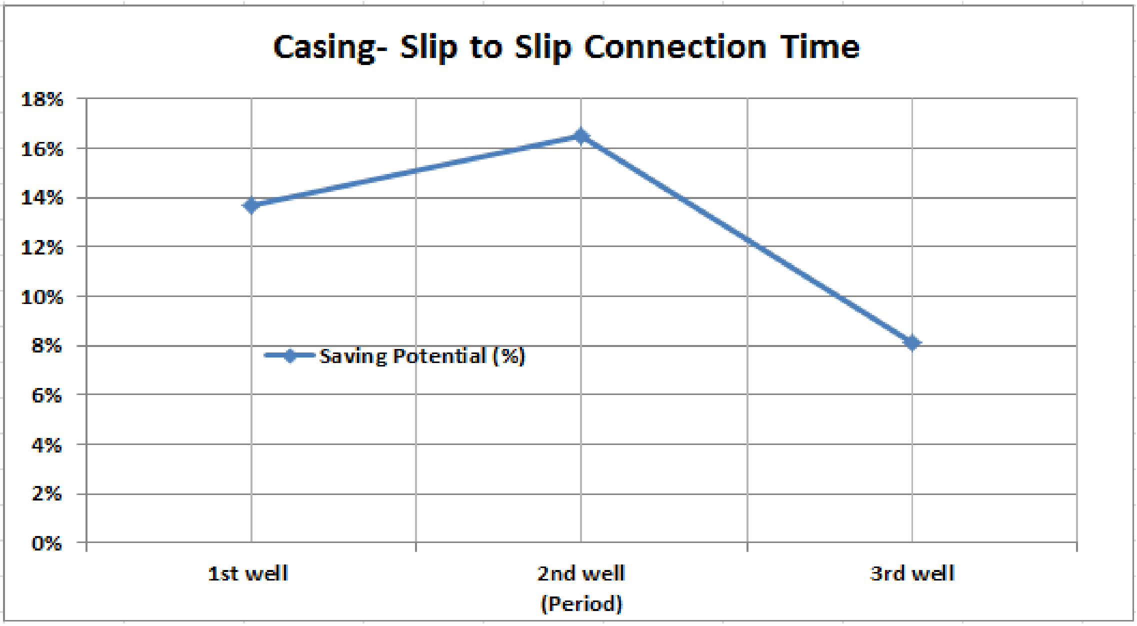


Figure 91: Casing Connection Saving Potential Percentage per Well

- Figure 91 shows an improvement of 6 % from the first well to the third well for this indicator's saving potential

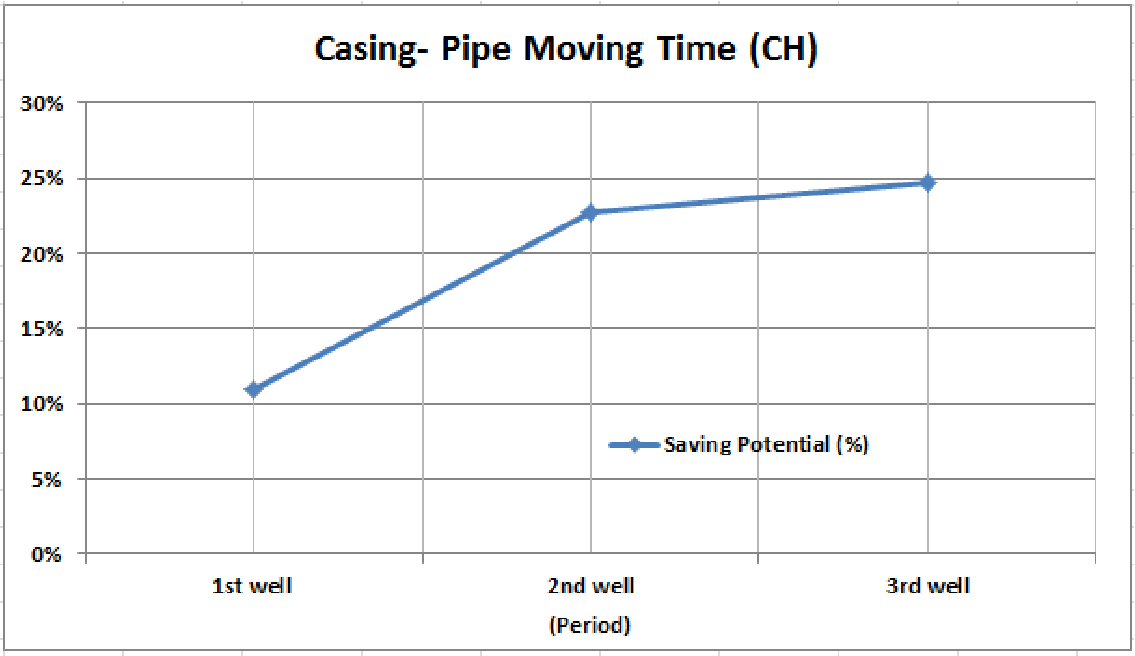


Figure 92: Casing Pipe Moving Saving Potential Percentage per Well

- No reduction in the saving potential was observed over the wells; therefore no improvement was achieved for this indicator.

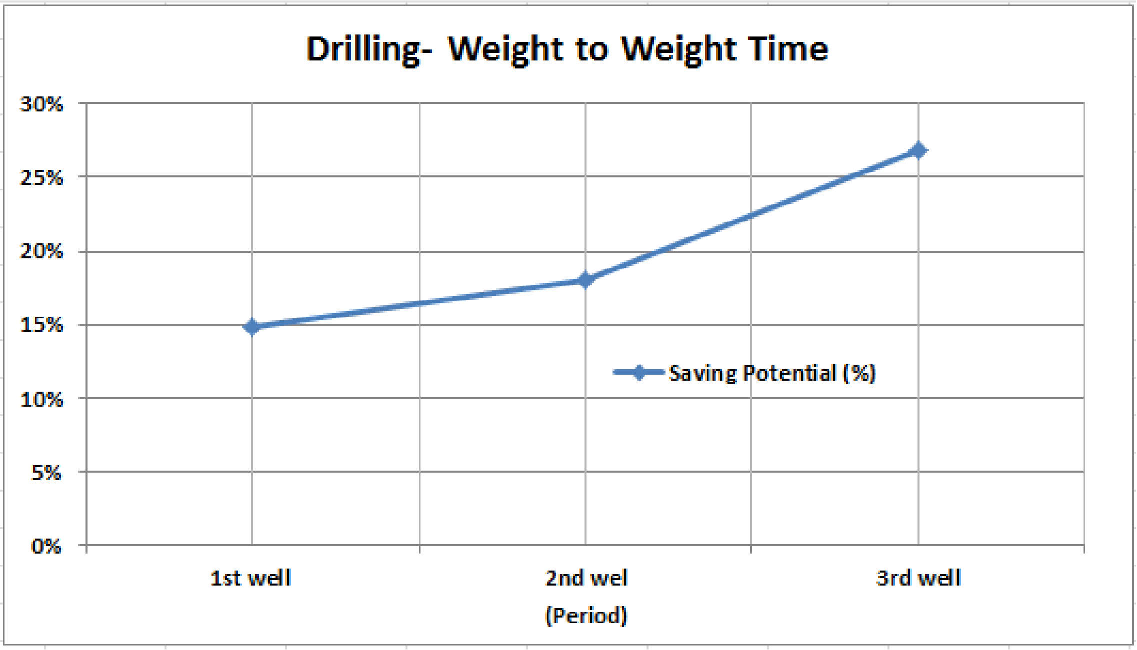


Figure 93: Drilling- Weight to Weight Saving Potential Percentage per Well

- No improvement was seen for the KPI, the saving potential kept increasing from the first to the last well.

3.6.7.2 Saving Potential Report

KPI	Savings Potential [d]	Savings Potential [%]
Tripping - Slip to Slip Connection Time	0.18	13.00
Tripping - Pipe Moving Time - CH	0.10	27.18
BHA - Slip to Slip Connection Time	0.16	35.72
Drilling - Weight to Weight Time	1.37	47.14
Casing - Slip to Slip Connection Time	0.16	16.73
Casing - Pipe Moving Time - CH	0.09	24.90

Total Savings Potential: 2.06 days (32.02 %)
Total KPI Duration: 6.42 days

Figure 94: DrillTec VDD 2001 Saving Potential Report

3.6.8 New Targets Selection

Table 28: DrillTec VDD 2001 New Targets for Future Wells

KPI	Phase	New target (min)
Drilling-weight to weight time	All Phases	7
Tripping-slip to slip connection time		1.90
Tripping-Pipe moving time (CH)		0.70
Casing-slip to slip connection time	12.25″	2.20
	8.5″	2
Casing-Pipe moving time (CH)	12.25″	1.60
	8.5″	1.60

Lessons Learnt

- Throughout the Erdpress campaign it was noted that 9 5/8in casing is drifting during drilling with casing (DwC). Various methods were attempted in order to minimize this drift and keep the casing as vertical as possible. Therefore, in future wells when drilling with casing its recommended to limit flowrate to 800-1000L/min in order to reduce drift from straight vertical, other factors that should be investigated are WOB, centralizer placement, and bit design.
- In Erdpress 25a, during kick-off, the rotary steerable BHA "slipped" off the cement plug since it was much harder than the formation surrounding it. This resulted in the BHA kicking off the well too soon and into a wrong azimuth, from that it was learnt that setting Kick-Off plugs in shallow depths might not have the desired effect since the surrounding formation is too soft to keep the bit on the plug until the KOP.
- From Schoenkirchen 443 it was learnt that ROP shall be reduced to 20 m/hr to get a good LWD data quality , LWD real time data quality improved due to the reduced ROP - no more re logging was required. Pathfinder tools in combination with rotary steerable system (RSS) create too much noise to read.
- Caliper logging cannot be done in casing drilling. Therefore, cement volume shall be calculated manually and extra volume (25%) is added to cover potential excess and guarantee cement to surface, because potential top-job would have a higher cost impact than pumping some more volumes of cement slurry.

3.6.9 Conclusion and Potential Areas of Improvement

- Concerning time consumer operations, drilling (both rotating and sliding) was the largest time consumer (234 h) followed by wellbore treatment and conditioning (125h).
- Reaming and washing represented 30% of the wellbore treatment time, as mentioned earlier its recommended to do reaming only based on hook load measurements to save time and unnecessary operations.
- Tripping-slip to slip and casing running indicators showed more consistency and faster performance by the crew of Erdpress 24.
- Concerning drilling-weight to weight time, the crew of Schoenkirchen 443 showed a faster performance than others.
- Regarding ILT and KPIs ranking; drilling-weight to weight showed the largest ILT, followed by making connection during tripping.
- The saving potential for five selected KPIs is 1.08 days or 18 % of the total KPIs duration, if they were performed in consistency around the P50 value.
- The indicator of making connection during casing running showed a good improvement over time for its average as well as the saving potential.

Chapter 4 Rigs Comparison and Ranking

4.1 Overview

This chapter demonstrates a comparison between the rigs based on the average of the duration every rig took to perform the selected KPIs; the rigs are listed and ranked from the fastest to the slowest. The saving potential percentage rank for all rigs is demonstrated as well.
It is noted that there are three additional rigs from Austria which were included in this comparison but not in the case study analysis due to the fact that they were active with OMV so long time ago but not anymore, in addition to the absence of daily drilling reports for them.

4.2 Tripping Ranking

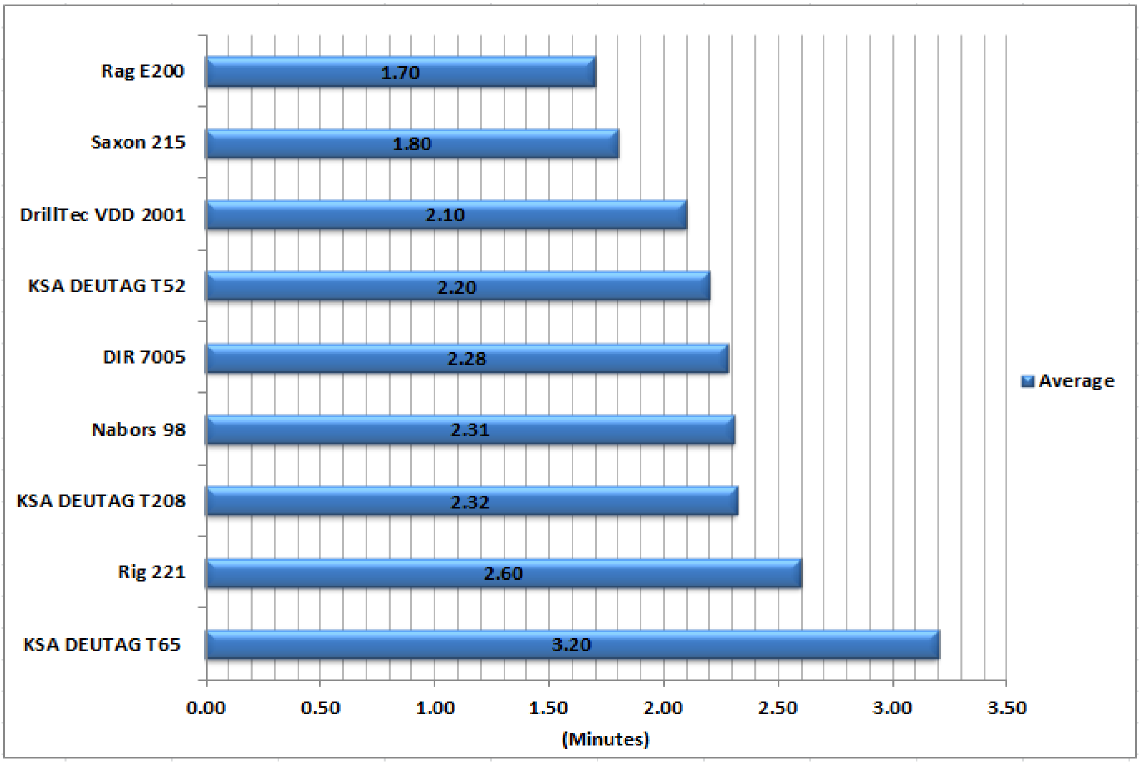


Figure 95: Tripping-Slip to Slip Connection Time Ranking

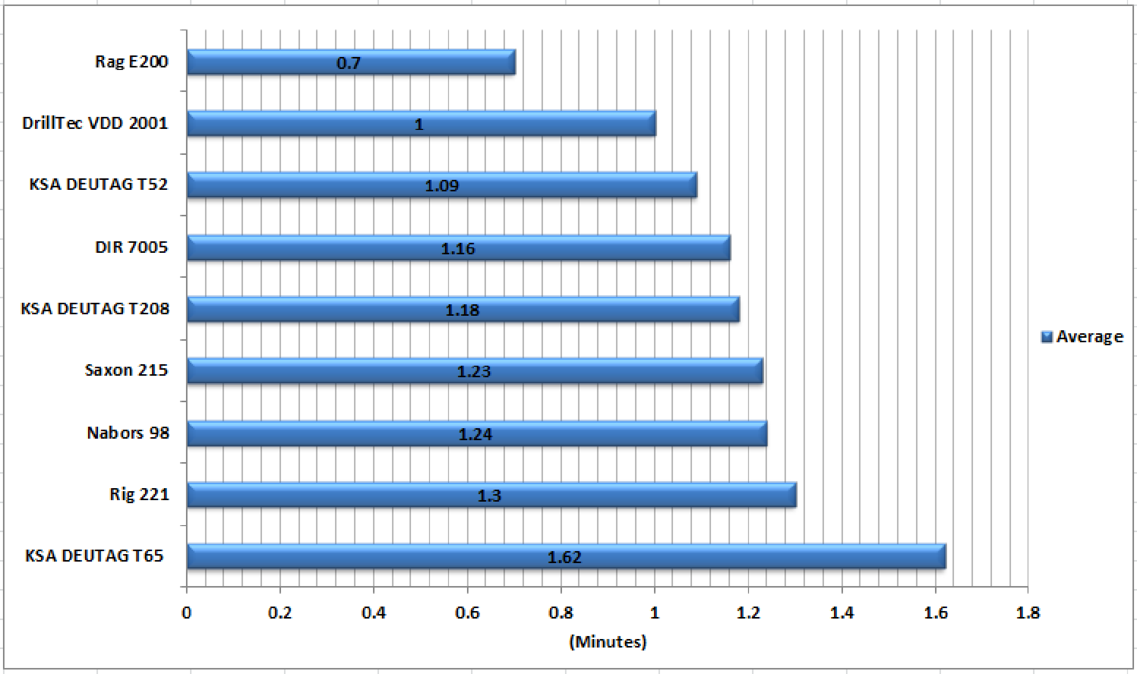


Figure 96: Tipping-Pipe Moving Time Ranking

4.3 Casing Running Ranking

4.3.1 Casing - Connection Time

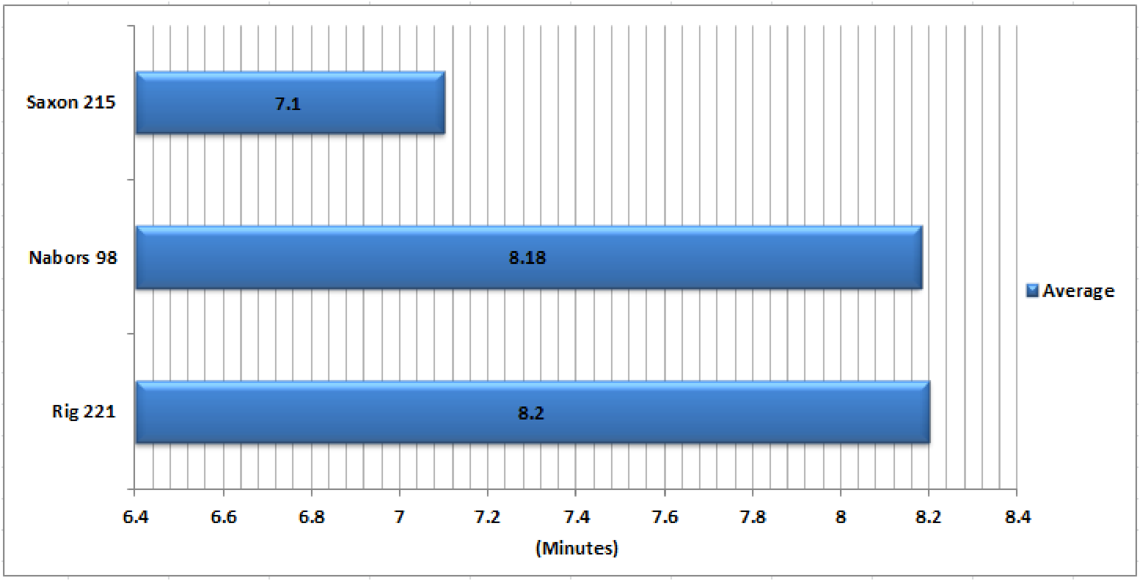


Figure 97: Casing Connection Time Ranking for 26" Phase

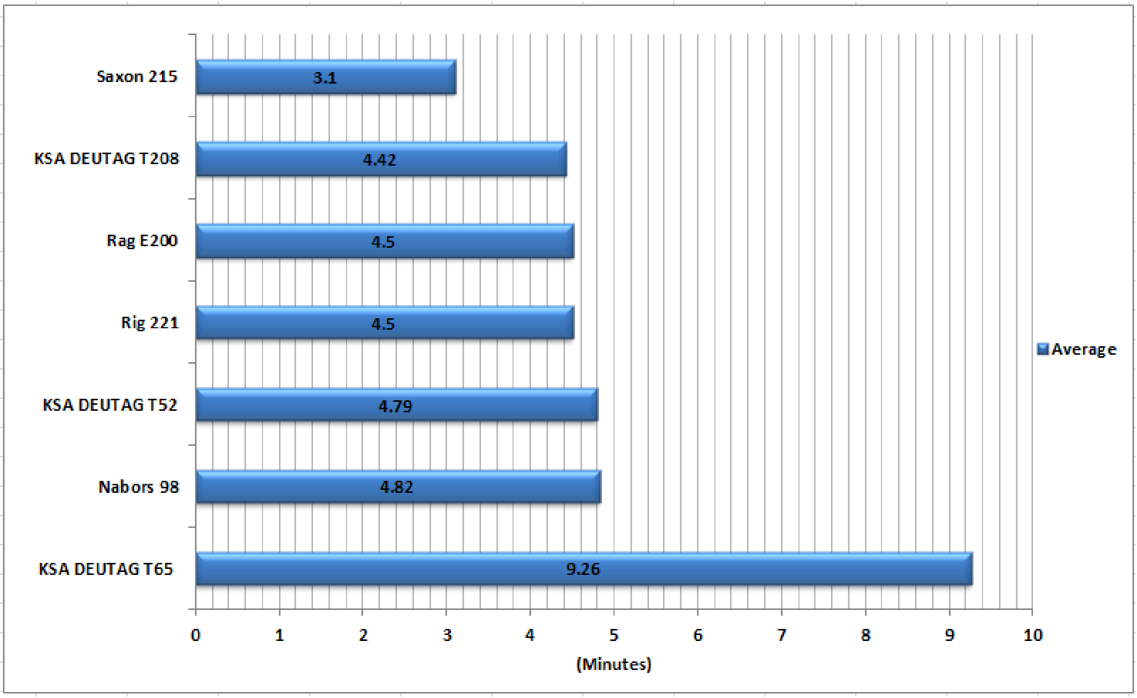


Figure 99: Casing Connection Time Ranking for 17.5" Phase

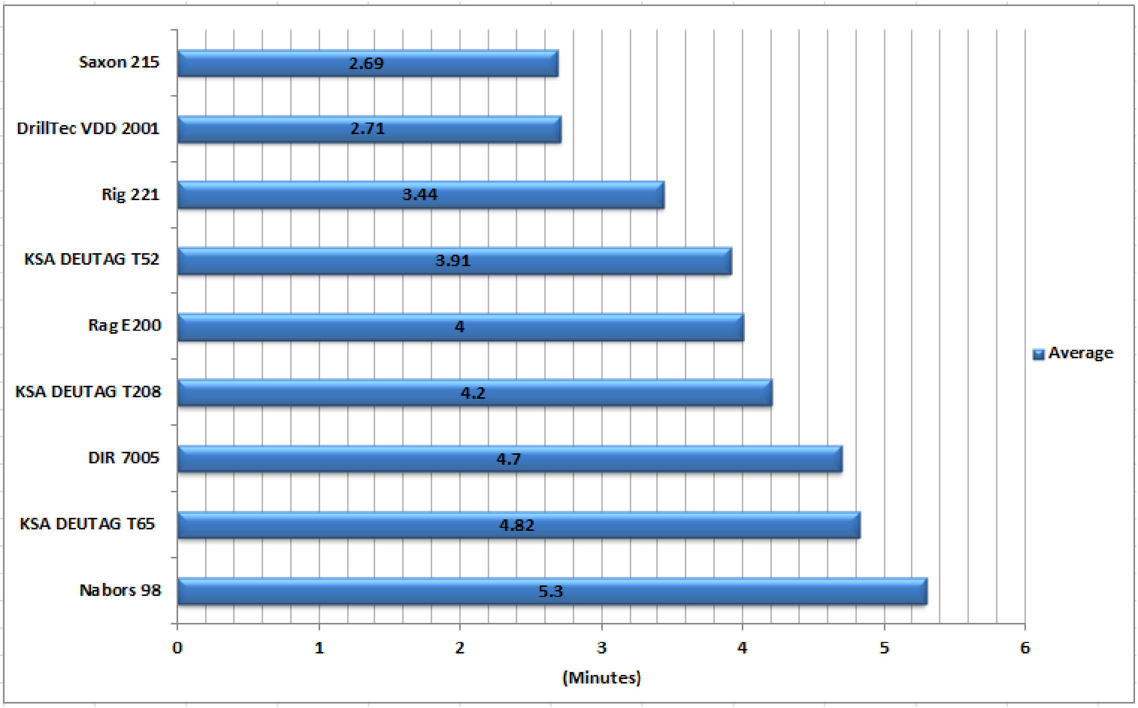


Figure 100: Casing connection Time Ranking for 12.25" Phase

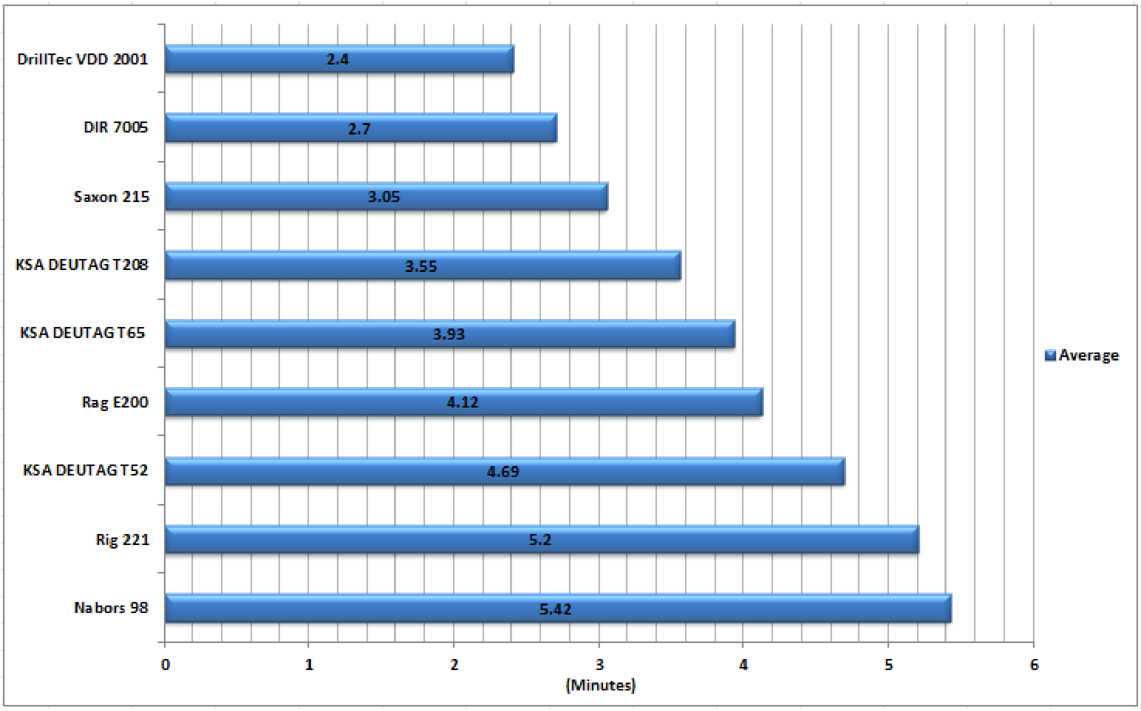


Figure 101: Casing Connection Time Ranking for 8.5" Phase

4.3.2 Casing-Pipe Moving Time (CH)

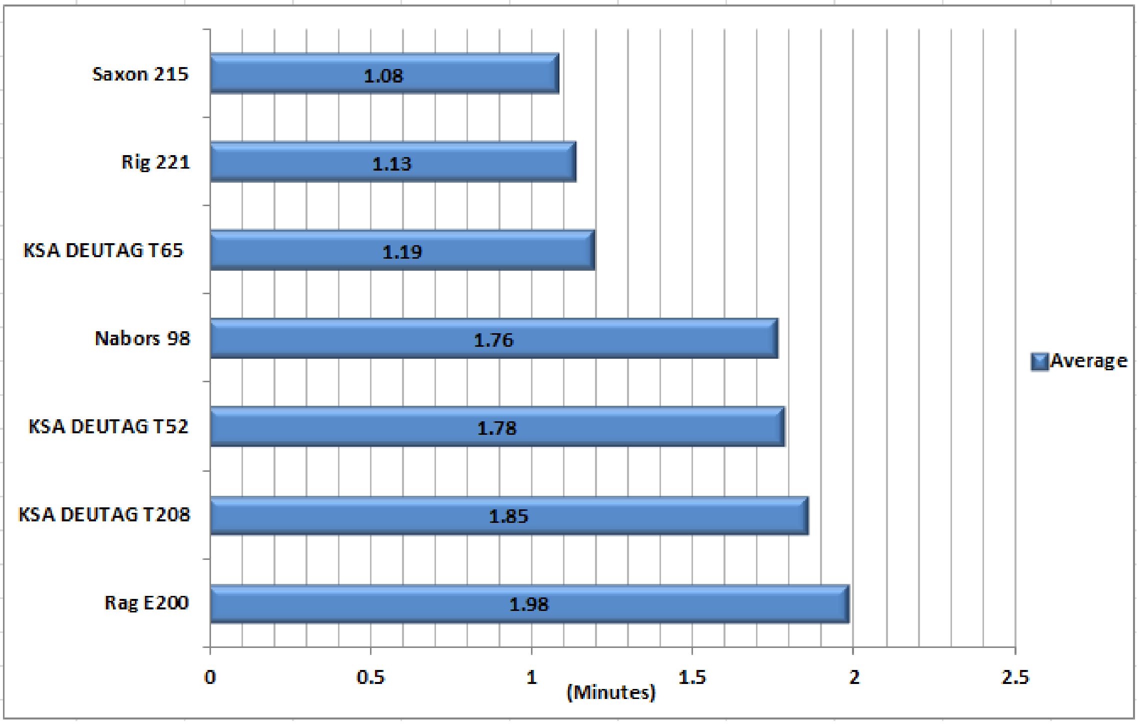


Figure 102: Casing Pipe Moving Time Ranking for 17.5" Phase

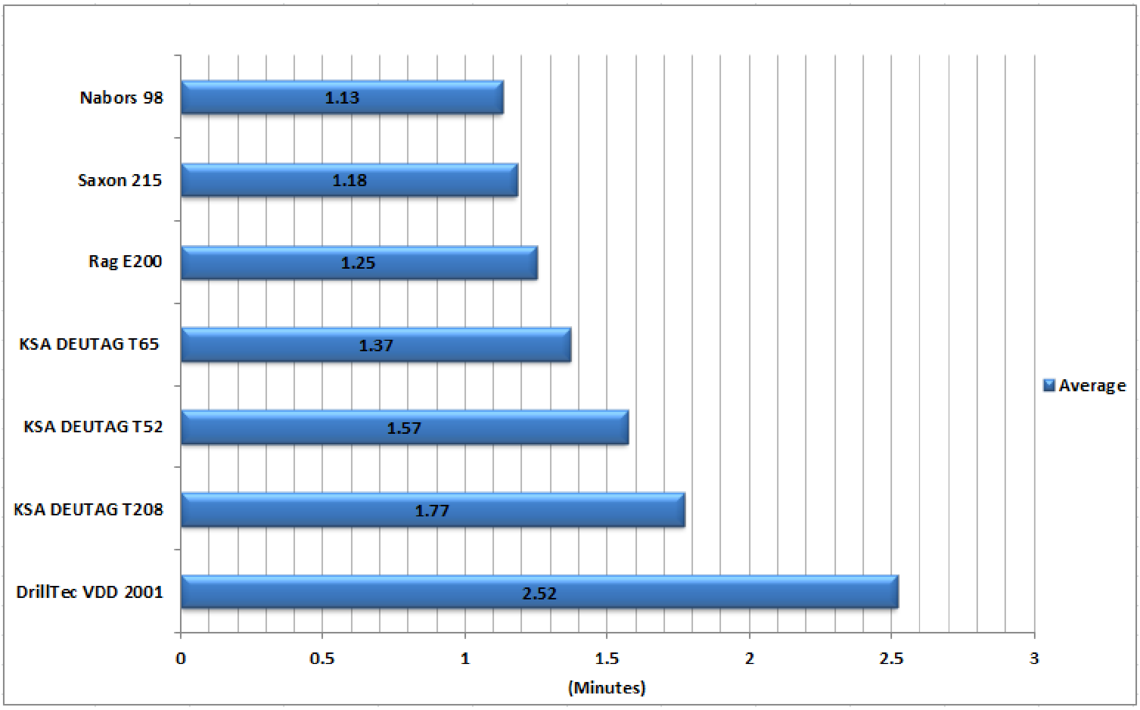


Figure 103: Casing Pipe Moving Time Ranking for 12.25" Phase

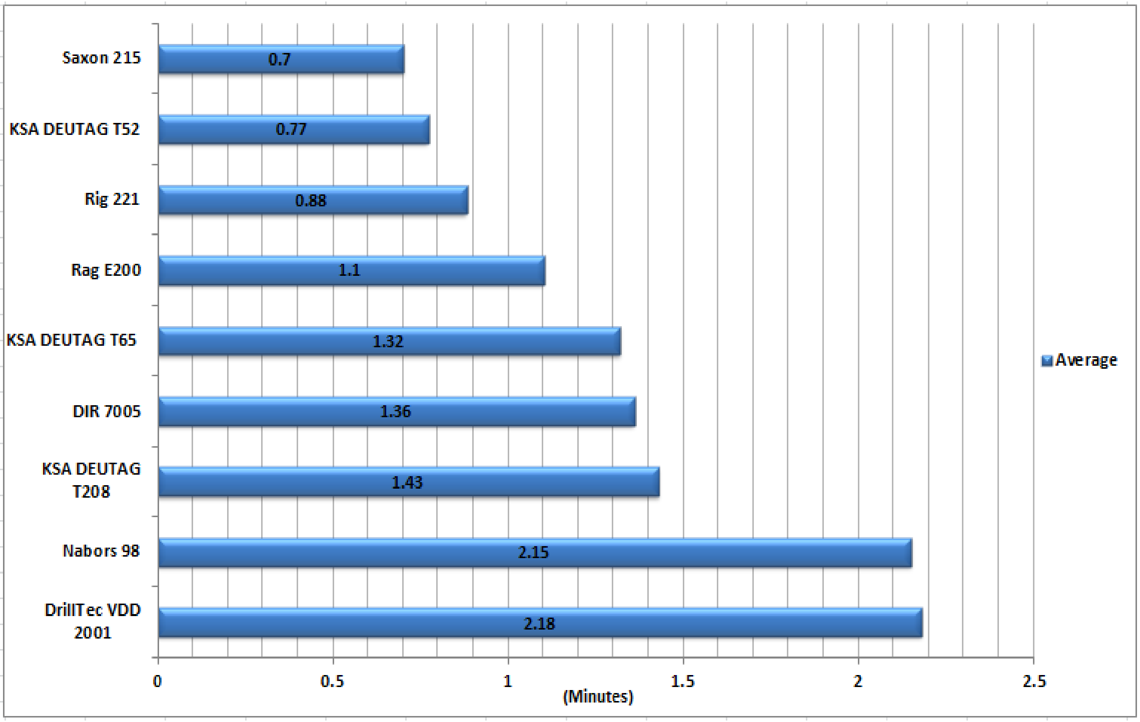


Figure 104: Casing Pipe Moving Time Ranking for 8.5" Phase

4.4 NPT Ranking

This section compares between the rigs in terms of the NPT each rig has spent, the rigs are compared against each other based on the percentage of the NPT from the total rig time then the rigs are ranked from the less NPT spent which is DrillTec VDD 2001 as seen in Figure 105 to the most NPT spent.

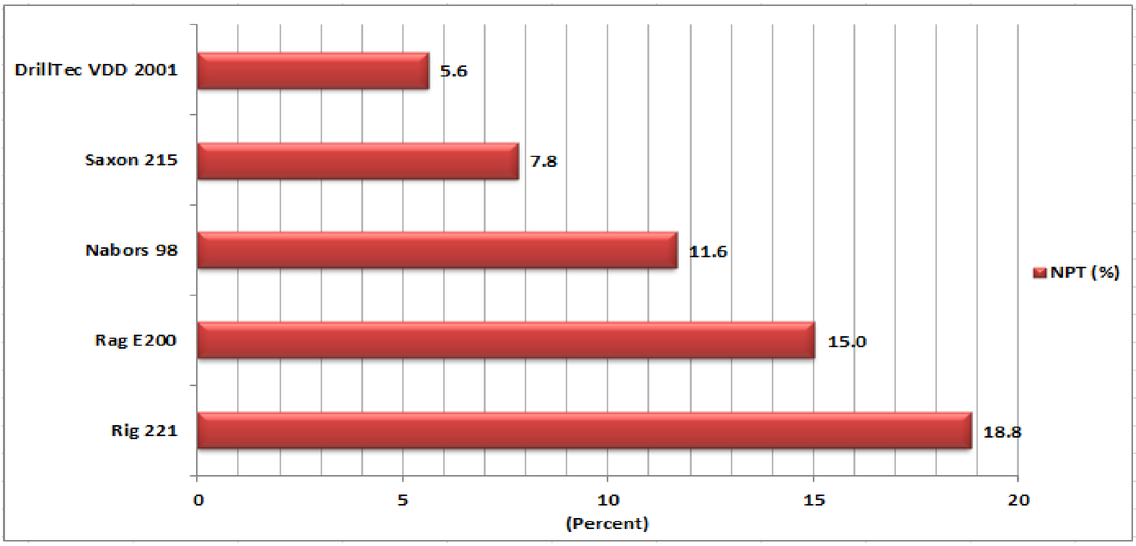


Figure 105: NPT Percentage Ranking

4.5 Saving Potential Ranking

In this section the saving potential percentage for six KPIs is compared and ranked between the different rigs as seen in Figure 106, this percentage is calculated out of the total rig time.

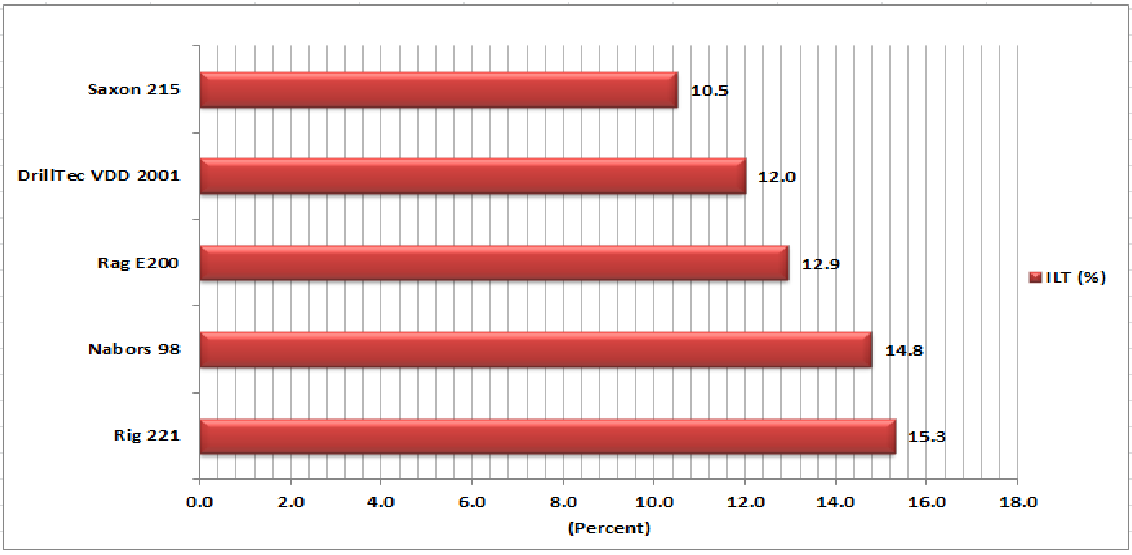


Figure 106: Saving Potential Percentage Ranking

4.6 Overall Saving Potential

This section shows the overall saving potential for each rig; on other words it illustrates what each rig could have saved if the well construction process was completed according to the plan without any NPT in addition to considering the saving potential time for the six KPIs if they were performed with consistency around the P50 value.
The overall saving potential in days is the sum of both the NPT and the saving potential from the six KPIs, while the cost saving potential considers the daily rig rate plus the fuel cost with an average of 47,000 $, 35500$, and 22500 $ per day respectively for Yemen, Pakistan, and Austria.

Table 29 : Overall Saving Potential

Rig	NPT (days)	Saving Potential (days)	Overall Saving Potential (days)	Cost Saving Potential ($)
Rig 221	55	44.5	99.5	4.67 MM
Nabors 98	21	26.4	47.4	2.22 MM
Saxon 215	22.5	30.5	53	1.8 MM
Rag E200	36	31.2	67.2	1.5 MM
DrillTec VDD 2001	3	6.4	9.4	2 M
Total	**137.5**	**139**	**276.5**	**10.40 MM**

As seen in Table 29 the total cost saving potential for five rigs is 10.44 million dollars, that is equivalent to a cost of drilling one well in Yemen. It should be mentioned that the real daily costs are way larger than the numbers mentioned above if we consider the cost of the services and operations that are performed throughout the daily drilling operations. By looking at the daily costs of Habban 42 for three random days, the following figures were seen; 198,745$, 80,185$, and 123, 842$.

Chapter 5 Best Practice Wells

5.1 Overview

The oil and gas operators spend millions of dollars yearly as a cost of collecting huge amount of drilling data, yet have not made effective use of this data to improve drilling performance[19]. Drilling analysis is an essential method towards the efficiency of drilling operations. However, drilling analysis is not routinely practiced as it should be, this is driven by the fact that drilling engineers are principally rewarded for well planning and well construction [20].
Millheim et al. (1998) believes that 95% of drilling activities are operationally focused, placing emphasis on doing, most of the operations are done by "gut instincts" rather than planning or analyzing.[19]
Accepting waste and inefficiency in drilling operations continues as an unavoidable, it is difficult to imagine another industry that would accept 60% waste which can be avoided or at least widely reduced by better planning. [7]
For that, the need to develop best practices and continuous learning is a key to drilling operations improvement. Otherwise, the history will repeat itself "If you always do what you have always done, you will always get what you have always got".[21]

5.2 Well Planning

Estimating the time required to drill and complete a well is an important part of well planning, time estimation directly influences the economic analysis of any drilling project.
A big part of well cost is a time sensitive, estimating the time accurately is a key word to produce accurate and objective time forecasts which may be compared with actual times from daily reports. Rigorous time forecasting leads to real business benefits including the following: [7]

- The accuracy of cost estimates during well planning.
- Candidate drilling options may be objectively compared as a route to optimization.
- Areas of good and bad performance are highlighted by comparing actual and predicted times, thereby encouraging lesson learning and maximizing opportunities for performance improvement.

During the planning stage, the best practices identified from the analysis of best composite time (BCT) are intended to aid the well-planning and construction effort, including the Authorization for expenditure (AFE) adjustments.

5.2.1 Best Composite Time (BCT) Approach

Several approaches were developed over the years to optimize the well construction process but only a few of these have approaches addressed the issue of improving drilling performance through a systematic analysis of historical data.
Best composite time is one of the approaches for well planning, it is the summation of the best time recorded for each drilling activity and hole section in a series of similar wells. BCT approach is considered to be a simple approach; it represents practical, challenging but achievable benchmarks. However, it depends on the quality of historical data and it requires an upfront investment in drilling analysis tools and knowledge management applications. It should be noted that the BCT is a moving target which gets upgraded as data from an increasing number of wells become available providing significant steps in the process of drilling costs reduction. [22]
Eventually, the BCT flattens out to the technical limit of the field as more pacesetter wells are drilled. This is illustrated in Figure 107.

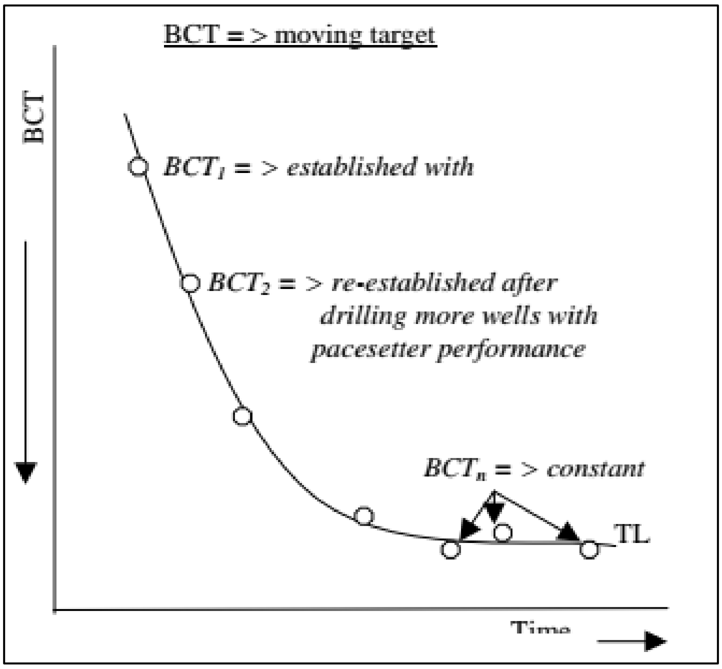


Figure 107: BCT tends towrds Technical Limit as more pacestter wells are drilled [22]

BCT is obtained by performing a detailed analysis on drilling execution time, the drilling process for each well is broken down into phases in accordance with the hole sizes. Then, the best time, based on the best-ever performance achieved for each hole phase is selected from the offset wells, this results in a well time estimate composed of the best performance seen to date and is, therefore, considered the "perfect well" possible with current technology and operational practices.[20]

5.3 Best Practice Wells Generation

In this section theoretical wells are generated for each country based upon already achieved performance using BCT approach. Two offset wells from each country (Yemen, Pakistan, and Austria) were analyzed to generate a theoretical well in the same field. Theoretical wells generation was done according the following process:

- **Offset wells selection:** two offset wells that are in the same field and having the same geological conditions.
- **Break wells down into phases:** the drilling process for each well was broken down into phases in accordance with the hole sizes (e.g 26" phase, 17.5" .etc).
- **Break down phases into sub-activities:** each phase was then broken into its sub-activities. Sub- activities can be seen in Table 30
- **Remove Non-Productive Time:** Analyzing the daily drilling reports (DDR) activity by activity and remove all the activities that caused a trouble time.
- **Generate well schematic:** the well schematic was obtained based on the selected offset wells.
- **Obtain bit on bottom time:** Analyzing DDRs to get only the time where the bit was on bottom drilling formation (Net drilling time).
- **Calculate Average ROP:** calculating average ROP for each phase based on the net drilling time to get the fastest ROP for each phase for each well.
- **Calculate actual durations of sub-activities:** Analyzing DDRs to calculate the actual durations that each activity lasted.

After the abovementioned process is done for the offset wells, the process of generating theoretical wells is performed according to the following process:

- **Estimate drilling duration:** for each phase based on the best ROP of the offset wells.
- **Estimate BHA running duration:** BHA length and number of connections for each phase are calculated from DDRs, then the running in hole and pulling out of hole durations are estimated using the targets that were selected for each particular rig.
- **Estimate Tripping and casing running duration:** based on the targets that were selected for each rig.
- **Estimate the duration of the other sub-activities :** based on BCT approach the duration of the other activities are estimated, examples of such activities are ; Rigging up casing, rigging down casing, rigging up cementing tool, rigging down cementing tool, WOC, BOP and wellhead work , drilling cement, LOT, Hole conditioning after reaching TD, …etc)
- **Generate Time vs Depth Chart:** showing the duration of drilling each phase.

Figure 108 shows the process of generating theoretical wells

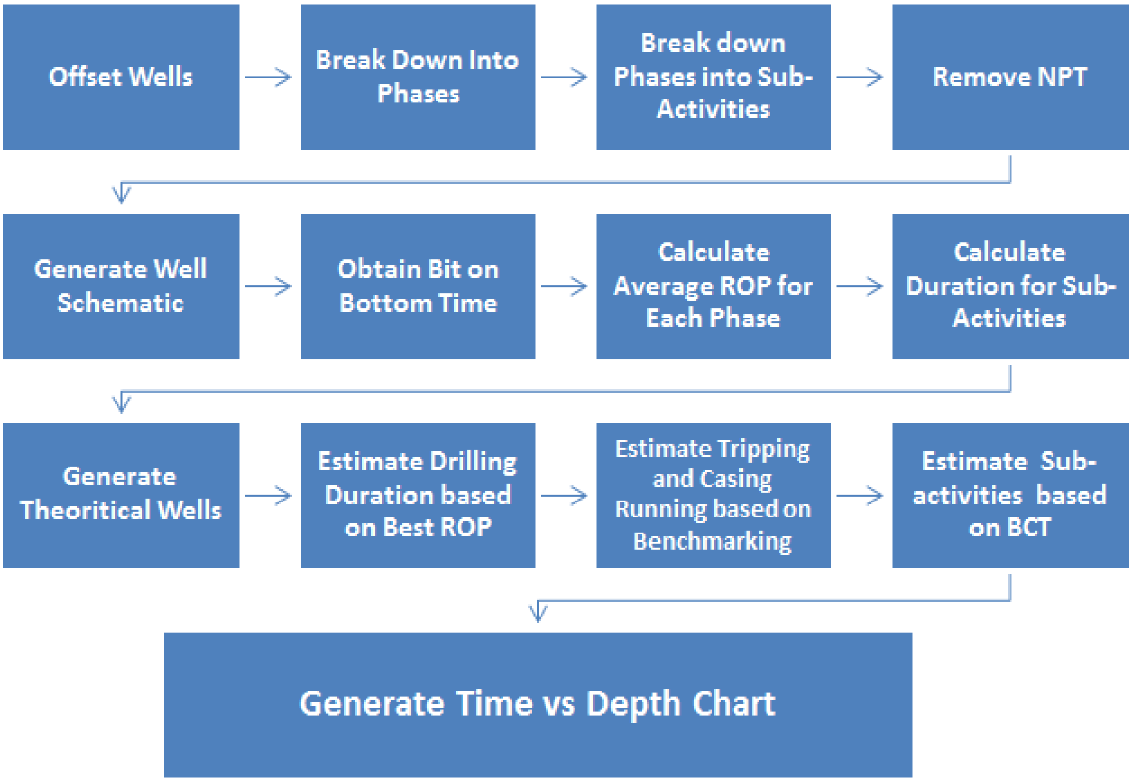


Figure 108: Process of Best Practice Theoretical Wells Generation

5.3.1 Habban 43, Yemen

The theoretical well "Habban 43" is planned to be drilled in Habban field using the rig Nabors 98.
Habban 43 was generated according to the following Process:

- **Offset wells selection**: the last two wells drilled by the rig were selected to be the offset wells; in Nabors 98 case they are Habban 42 and Habban 41.
- **Break wells down into phases:** Both wells were broken down into main phases according to the hole sizes, 5 phases were detected for each well.
- **Break down phases into sub-activities:** After breaking the offset wells into main phases, each phase was broken down into its sub-activities as seen in Table 30.

Table 30: Breaking Phases into Sub-Activities Example

Phase: 12.25" **Total Time:** 193 hrs **NPT Time:** 8.5 **Depth:** 2090m **ROP:** 11.8 m/h	
Sub-Activity	**Duration (Hours)**
Pull up and Make 12.25" BHA and RIH and drilling shoe track and cement and testing casing and filling with mud	19
FIT	3.5
POOH From 1425 m	5
P/U make BHA and RIH to 1439 m	10.5
CNR, vis Pill	2.5
POOH from 2090m	9.5
Remove Wear bushing	0.5
Rig up casing tool	2
Running casing to 2090 m	29.5
Circulate casing	2
Rig down casing tool	1
Rig up cementing with circulation and test	3
Cement job	4
Rig down cement tool	1
WOC	13.5
BOP	7
Wellhead work	2.5
BOB and Wellhead P/T	7
Install Wearbushing	0.5
Laying drill collar	2
Net Drilling Time to TD	55.5

- **Remove Non-Productive Time:** By analyzing the daily drilling reports (DDR) activity by activity all the activities that caused a trouble time were removed.
- **Obtain bit on bottom time:** The net drilling time where the bit was on bottom drilling formation was calculated by analyzing DDRs and a sum of that time was obtained for each phase and labeled as "Net Drilling time to TD".
- **Calculate average ROP:** The Total Depth of each phase was divided by the Net Drilling Time to TD to obtain the average ROP.
- **Calculate actual durations of sub-activities:** Each sub-activity duration was calculated for both wells from DDRs, an example of that from the 12.25" phase of Habban 41 is seen in Table 30.

After the above-mentioned analysis was done for the offset wells, the process of generating the offset well Habban 43 was done according to the following process:

- **Generate Well Schematic**

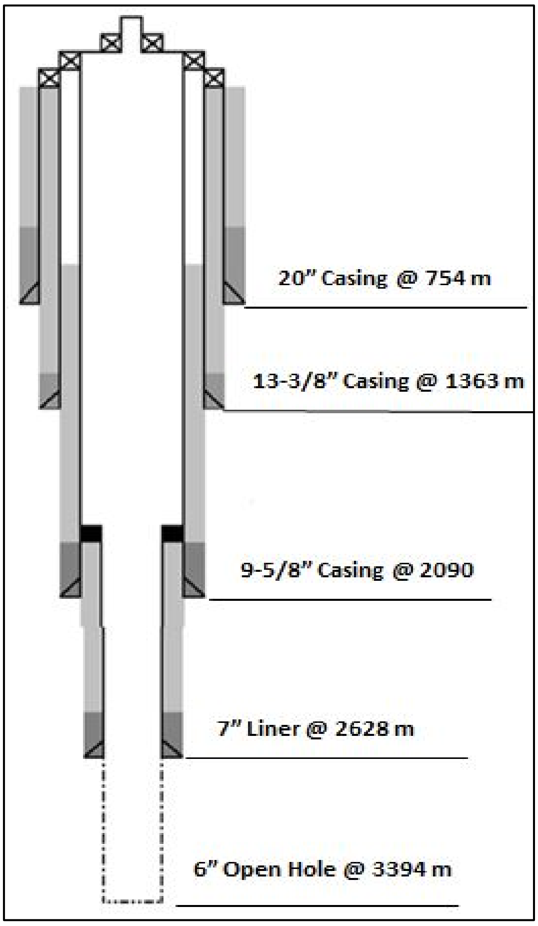


Figure 109: Habban 43 Schematic

- **Estimate drilling duration:** the Net drilling time to TD was obtained by dividing the depth drilled for each phase by the best average ROP from both offset wells.
- **Estimate BHA running duration:** BHA length and number of connections for each phase are calculated from DDRs, then the running in hole and pulling out of hole durations are estimated using the targets that were selected for each particular rig.
- **Estimate Tripping and Casing Running Duration:** based on the targets that were selected for each rig, , an example of the calculations for tripping, casing, and BHA running duration is shown in the spreadsheet in Figure 110 and Figure 111.

Phase: 26"			
# of BHA	33		Section Depth (m)
BHA Length (m)	266		754.0
# of Connections	33		
DP Length (Triple stand) (m)	488		
# of Connections	16		
POOH	Target (min)	(Minutes)	(Hours)
BHA-Slip to Slip Connection time	7.0	231.0	3.9
BHA-Moving Time	2.0	66.0	1.1
DP-Slip to Slip Connection Time	3.3	53.7	0.9
DP-Moving Time	3.5	56.9	0.9
		Total	6.8
Casing Run Run			
Joint Length (m)	12		
#Joints	63		
Casing Length	750		
Casing KPIs	Target (min)	(Minutes)	(Hours)
Casing-Slip to Slip Connection Time	7.3	456.3	7.6
Casing-Pipe Moving Time	1.1	68.8	1.1
		Total	8.8

Figure 110: Example of Tripping and Casing Running Durations Calculation

Phase:17.5''			
# of BHA	33		Section Depth (m)
BHA Length (m)	250		1363
# of Connections	33		
DP Length (Triple stand) (m)	1113		
# of Connections	37		
RIH			
Top of Cement (m)	750		
# of BHA	33		
BHA Length	250		
#Connections	33		
Remaining DP (m)	500		
#Connections	17		
KPI	Target(min)	(Minutes)	(Hours)
BHA-Slip to Slip Connection time	10	330	5.5
BHA-Moving Time	2.5	82.5	1.4
DP-Slip to Slip Connection Time	2.5	42.5	0.7
DP-Moving Time	1.3	22.1	0.4
			8.0

Figure 111: Example of Running in Hole Duration Calculation

- **Estimate the duration of the other Sub-Activities:** based on BCT approach the duration of the other activities are estimated.
- **Phase's duration estimation:** all the durations are summed up into a table that looks like Table 31, which will be used to generate the Time vs Depth Chart.

Table 31: Habban 43 Summary

Habban 43			
Operation	**Section time (days)**	**Depth(m)**	**Cum. Time(m)**
Spud	0.6	0	0.6
Drill 26" hole section	5.7	754	6.3
Run 20" CSG	2.7	754	9.0
Drill 17.50" hole section	3.4	1363	12.4
Run 13.375" CSG	2.2	1363	14.6
Drill 12.25" phase	3.2	2090	17.8
Run 9.625" casing	2.6	2090	20.4
Drill 8.5" phase	5.3	2628	25.7
Logging	0.2	2628	25.9
7" Liner run	2.0	2628	27.8
Drill 6" phase	15.5	3394	43.3
Logging	0.7	3394	43.9
Completion phase	6.5	3394	50.4
Total	**50.4**		

- **Generate Time vs Depth Chart:** The summary of Habban 43 in Table 31 was used to generate the Time vs Depth chart which is illustrated in Figure 112.

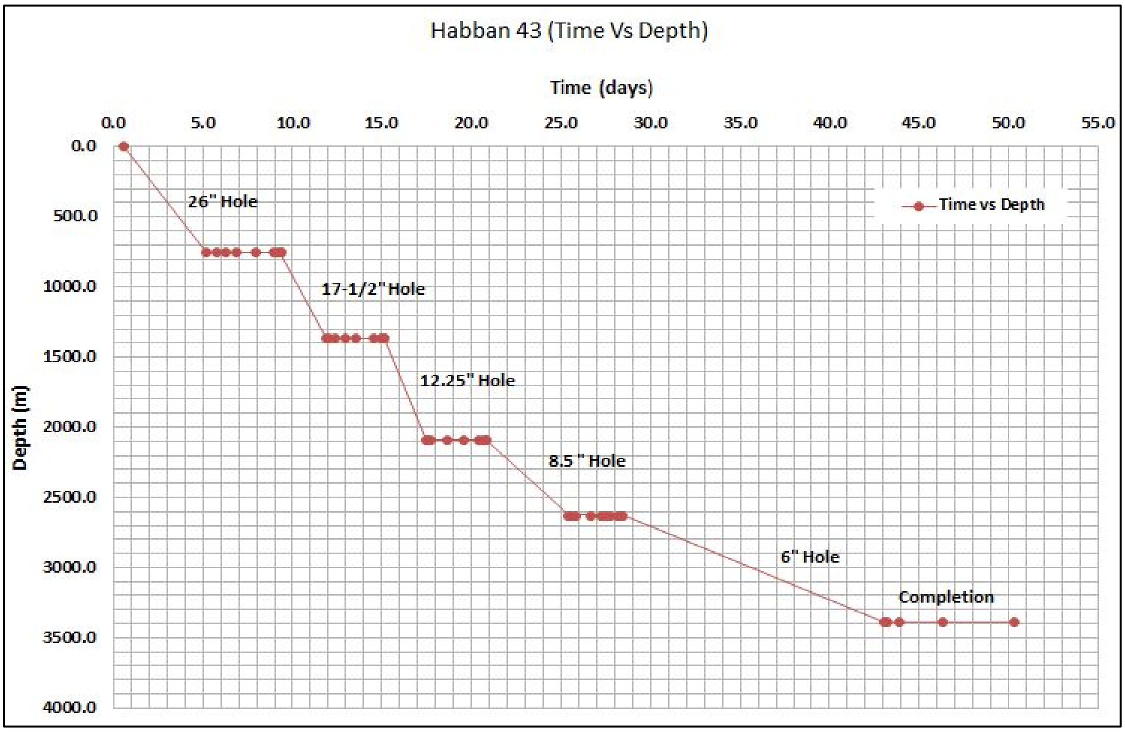


Figure 112: Habban 43 Depth vs Time Chart

As seen in Table 31 and Figure 112, the theoretical well "Habban 43" will be drilled in 50.4 days to the depth of 3394 m.
Table 32 below shows the actual durations (including NPT) for drilling and completing each phase for the offset wells to get an idea about the duration's difference between the theoretical well and the offset wells

Table 32: Yemen Offset Wells Actual Duration

Operation	Habban 42	Habban 41
	Duration (days)	**Duration (days)**
Drill 26" hole section	5.3	7.2
Run 20" CSG	5.4	3.8
Drill 17.50" hole section	6.1	8.1
Run 13.375" CSG	3.6	16.3
Drill 12.25" phase	4.2	5.0
Run 9.625" casing	3.5	3.0
Drill 8.5" phase	5.0	7.4
7" Liner run	3.5	3.0
Drill 6" phase	23.0	28.3
Completion phase	8.0	12.0
Total	**67.5**	**94.1**

5.3.2 Latif 15, Pakistan

Two offset wells (Latif 14 and Lamwari 1) were analyzed to generate the theoritocal well "Latif 15" in Gambat Block using the rig Saxon 215.
Offset wells and theoretical wells summary are illustrated in Appendix B.
Figures 109 and 110 shows that Latif 15 will be drilled in 32 days, the last production casing will be set in the depth of 3461 m.

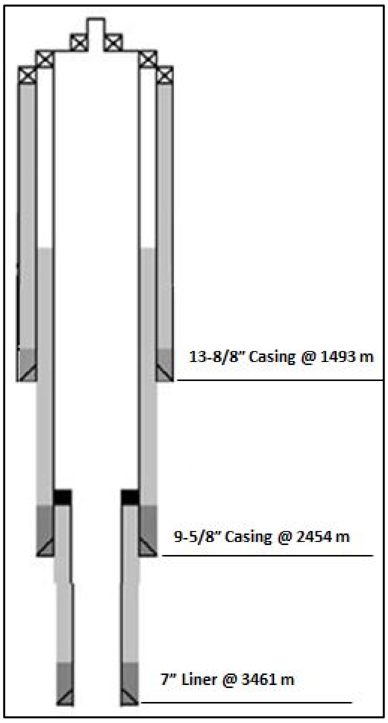


Figure 113: Latif 15 Schematic

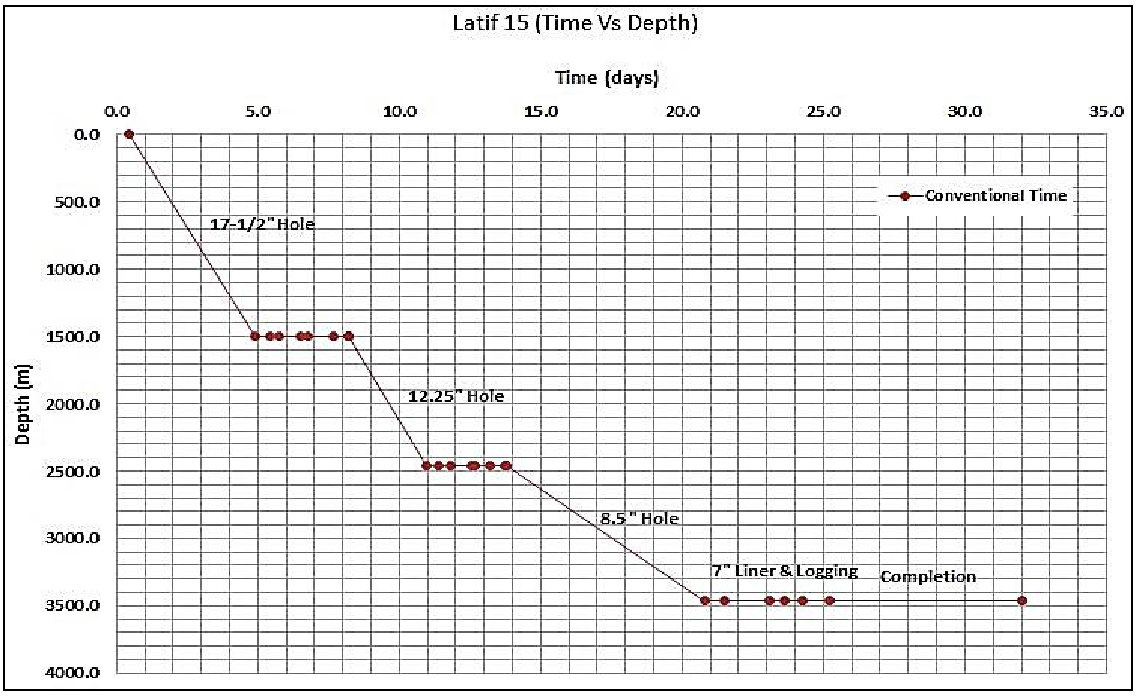


Figure 114: Latif 15 Time vs Depth

5.3.3 Erdpress 28, Austria

Erdpress 20 and Erdpress 24 were analyzed as the offset wells for the theoritical well Erdpress 28 that will be drilled in Gänserndorf using DrillTec VDD 2001 drilling rig. The new well "Erdpress 28" will be drilled in 20.5 days to the depth of 2872 m.

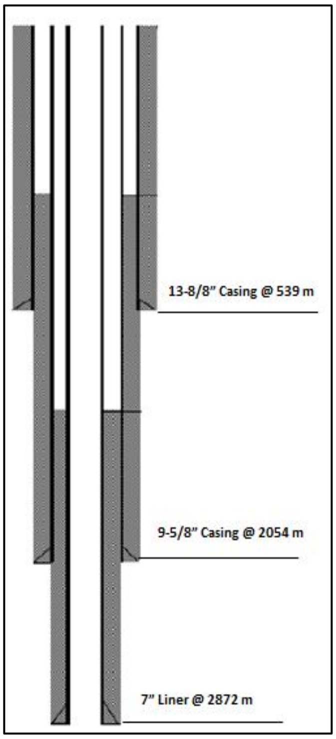


Figure 113: Erdpress 28 Schematic

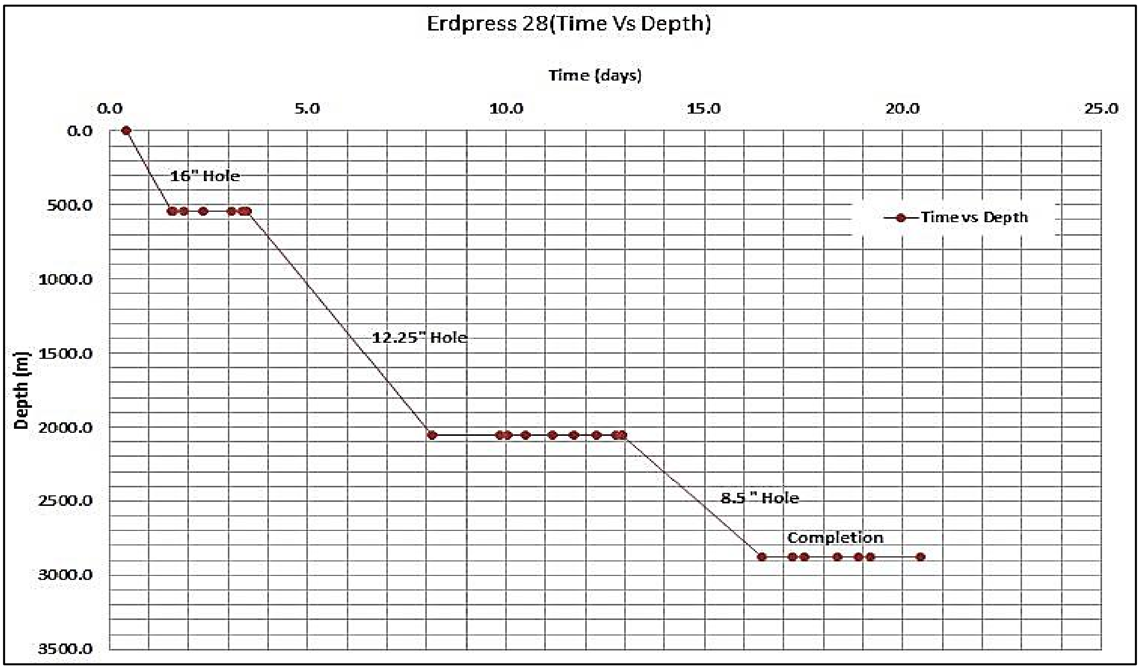


Figure 114: Erdpress 28 Time vs Depth Chart

Chapter 6 Conclusion and Recommendations

6.1 Conclusion

Increasing drilling efficiency and minimizing drilling cost is an important objective of oil companies to tackle the continuous drop of oil price and the increase in the drilling equipment and contract bill.
During the construction of different wells using the same rig there is always a variation in the duration of the different tasks performed, sometimes even by the same crew and under the same conditions. Training the crews of OMV to perform the different operations in a more consistent way during the well construction process could achieve a huge saving of the total rig days. For example if 10 seconds from the time of making connections during tripping were saved for 9 rigs that have a sum of 131872 operation counts we could save up to approximately 16 days. Because time is money, operators are struggling to lower the non-productive time and the invisible lost time using different approaches of optimization. One of these approaches is the automatic drilling performance measurement of drilling crews and equipment (ADPM).
This thesis evaluated the performance of the different rigs that have been employed by OMV in onshore drilling operations in Austria, Pakistan and Yemen, analyzing the non-productive time and the invisible lost time with highlighting the lessons learnt and the potential areas of improvement including the operations that can be eliminated or reduced in time, the thesis also demonstrated the learning and improvement over time for the operations average duration and the saving potential, the following conclusions can be made from the case study:

- The overall performance of the rigs is varied; there is a huge variation in the rig-related KPIs between the different rigs as seen in Chapter 5.

- Tripping consumed a significant large time for all rigs, at the same time it seems to have the largest room for improvement and savings for OMV according to the set targets because most of tripping routine operation is crew/equipment related only; especially for cased holes, unlike formation related operations which are of course formation-dependent. For that reason the improvement process for this indicator over a period of time is achievable.

- Rag E200 showed the best performance compared to the other rigs for tripping KPIs recording an average of 1.70 minutes and 0.7 minutes respectively for tripping connection time and pipe moving time.

- Saxon 215 was not far from Rag E200 achieving an average of 1.80 minutes for making the connection during tripping.

- The rank based on countries for tripping KPIs goes as the following order;

Austria, Pakistan, and lastly Yemen.

- Saxon 215 was ranked first for making connection during casing for the 26″, 17.5″, and 12.25″ phases. However, for the 8.5″ phase DrillTec VDD 2001showed the fastest performance for the same KPI.
- For Pipe moving time for the cased hole during casing Saxon 215 was ranked first for the phases 17.5″ and 8.5″ while Nabors 98 came first for the 12.25″ phase.
- DrillTec VDD 2001 showed the least NPT compared to the other rigs, while Saxon 215 showed the least saving potential.
- The overall saving potential for all the rigs shows that OMV could have saved approximately 277 days if no troubles occurred and if six KPIs were performed around the P50 value.
- Some rigs showed a quite good improvement and learning over the time for both; the average duration and saving potential.
- The three countries had no local targets for all the KPIs, an analysis was done for the performance of all the wells within the same rig and new targets were set for some KPIs for future wells considering safety and consistency of the operations.
- Using best composite time method as well as benchmarking tripping and casing KPIs showed a big saving in terms of days for the three theoretical wells designed.
- A historical understanding of well construction can contribute to continuous drilling improvement.

6.2 Recommendations

- APDM system should be implemented in OMV and the Crews should be trained and involved in the implementation to perform operations in more consistent way specially the rig-related operations.
- It is highly recommended to perform reaming operation based on hook load measurements and interpretations rather than performing it because it is a practice.
- Improve APDM to show the histograms of the well KPIs independently rather than adding them up to the same rig without showing the well names.
- APDM should cover all the phases drilled, especially the first phases.

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Acronyms

DDR	Daily Drilling Report
ROP	Rate of Penetration
TLT	Technical Limit Time
ILT	Invisible Lost Time
LT	Lost Time
FT	Flat Time
NT	Net Time
BOBT	Bit On Bottom Time
SP	Saving Potential
BHA	Bottom Hole Assembly
ADPM	Automated Drilling Performance Measurement
KPIs	Key Performance Indicators
MWD	Measurement while drilling
CH	Cased Hole
TVD	True Vertical Depth
POOH	Pull out of hole
WITS	Wellsite Information Transfer Specification
ASCII	American Standard Code for Information Interchange
S2S	Slip to Slip
PMT	Pipe Moving Time
W2WT	Weight to weight time

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Appendix A

Table 33: Rig 221 Target Selection Analysis

Triping Running KPIs				
Well	**Habban 42**		**Habban 41**	
KPI	**Tripping- S2S Connection time**	**Tripping- PMT (CH)**	**Tripping- S2S Connection time**	**Tripping- PMT (CH)**
Operation Count	2760	2101	5312	4401
P50 (min)	1.92	0.92	1.98	1.13
Average (min)	2.20	1.06	2.38	1.33

Drilling-related KPIs		
Well	**Habban 42**	**Habban 41**
KPI	**Drilling- W2WT**	**Drilling- W2WT**
Operation Count	57	151
P50 (min)	33.87	27.17
Average (min)	35.08	29.62

Casing Running KPIs								
Well	**Habban 42**				**Habban 41**			
KPI	**Casing- PMT (CH)**				**Casing- PMT (CH)**			
Phase (inch)	**26**	**17.5**	**12.25**	**8.5**	**26**	**17.5**	**12.25**	**8.5**
Operation Count	N/A	56	101	19	3	153	111	192
P50 (min)	N/A	1.33	0.88	0.67	1.02	1.65	1.03	2.02
Average (min)	N/A	1.40	1.07	0.80	1.09	1.89	1.18	2.28

Well	**Habban 42**				**Habban 41**			
KPI	**Casing- S2S Connection time**				**Casing - S2S Connection time**			
Phase (inch)	**26**	**17.5**	**12.25**	**8.5**	**26**	**17.5**	**12.25**	**8.5**
Operation Count	N/A	114	164	29	66	184	169	194
P50 (min)	N/A	3.53	2.72	3.70	7.27	3.81	6.52	5.16
Average (min)	N/A	5.04	3	3.78	8.18	4.69	7.52	5.66

Tubing Running KPIs		
Well	**Habban 42**	**Habban 41**
KPI	**Tubing- S2S Connection time**	**Tubing- S2S Connection time**
Operation Count	192	208
P50 (min)	4.22	3
Average (min)	4.69	3.30

Table 34: Nabors 98 Targets Selection Analysis

Triping Running KPIs				
Well	**Habban 42**		**Habban 41**	
KPI	**Tripping- S2S Connection time**	**Tripping- PMT (CH)**	**Tripping- S2S Connection time**	**Tripping- PMT (CH)**
Operation Count	2760	2101	5312	4401
P50 (min)	1.92	0.92	1.98	1.13
Average (min)	2.20	1.06	2.38	1.33

Drilling-related KPIs		
Well	**Habban 42**	**Habban 41**
KPI	**Drilling- W2WT**	**Drilling- W2WT**
Operation Count	57	151
P50 (min)	33.87	27.17
Average (min)	35.08	29.62

Casing Running KPIs								
Well	**Habban 42**				**Habban 41**			
KPI	**Casing- PMT (CH)**				**Casing- PMT (CH)**			
Phase (inch)	**26**	**17.5**	**12.25**	**8.5**	**26**	**17.5**	**12.25**	**8.5**
Operation Count	N/A	56	101	19	3	153	111	192
P50 (min)	N/A	1.33	0.88	0.67	1.02	1.65	1.03	2.02
Average (min)	N/A	1.40	1.07	0.80	1.09	1.89	1.18	2.28
Well	**Habban 42**				**Habban 41**			
KPI	**Casing- S2S Connection time**				**Casing - S2S Connection time**			
Phase (inch)	**26**	**17.5**	**12.25**	**8.5**	**26**	**17.5**	**12.25**	**8.5**
Operation Count	N/A	114	164	29	66	184	169	194
P50 (min)	N/A	3.53	2.72	3.70	7.27	3.81	6.52	5.16
Average (min)	N/A	5.04	3	3.78	8.18	4.69	7.52	5.66

Tubing Running KPIs		
Well	**Habban 42**	**Habban 41**
KPI	**Tubing- S2S Connection time**	**Tubing- S2S Connection time**
Operation Count	192	208
P50 (min)	4.22	3
Average (min)	4.69	3.30

Table 35: Saxon 215 Drilling and Tripping Target Selection Analysis

Saxon 215						
Wells						
Tripping-S2S	**Kohar-1**	**Latif S 1**	**Miano-19**	**Latif-5**	**Latif-14**	**Lamwari-1**
Operation Count	2651	1269	1204	3860	1145	1696
P50 (min)	1.45	1.62	1.42	1.70	1.50	1.63
Average (min)	1.70	1.83	1.58	1.90	1.64	1.83

Saxon 215						
Wells						
PMT- CH	**Kohar-1**	**Latif S 1**	**Miano-19**	**Latif-5**	**Latif-14**	**Lamwari-1**
Operation Count	1906	971	761	3363	663	1314
P50 (min)	0.88	0.95	0.87	0.98	0.80	1.05
Average (min)	1.13	1.15	0.97	1.36	1.01	1.38

Saxon 215						
Wells						
Drilling- W2WT	**Kohar-1**	**Latif S 1**	**Miano-19**	**Latif-5**	**Latif-14**	**Lamwari1**
Operation Count	109	112	117	166	114	115
P50 (min)	17.45	17.10	19.98	24.65	20.96	17.07
Average (min)	19.58	19.77	21.34	25.93	22.91	10.03

Saxon 215				
Wells				
Tubing-S2S	**Latif south1**	**Miano-19**	**Latif-5**	**Latif-14**
Operation Count	348	371	273	308
P50 (min)	2.08	2.37	2.97	2.47
Average Duration (min)	2.48	2.52	4.13	2.59

Table 36: Saxon 215 Casing-Slip to Slip Targets Selection Analysis

Casing-Slip to Slip Connection Time											
Wells	Kohar1				Latif south1				Miano 19		
Phase (inch)	26	17.5	12.25	8.5	17.5	12.25	8.5	6	17.5	12.25	8.5
Operation Count	47	116	210	71	52	111	116	27	70	138	124
P50 (min)	3.48	2.78	1.93	2.77	3.01	3.42	2.10	1.75	2.93	2.98	1.89
Average (min)	6.70	2.98	2.23	3.18	3.45	3.59	2.39	2.35	3.62	3.03	2.57

Table 37: Saxon 215 Casing Pipe Moving Time Target Selection Analysis

Casing-Slip to Slip Connection Time								
Wells	**Latif-5**		**Latif 14**			**Lamwari 1**		
Phase (inch)	**8.5**	**6**	**17.5**	**12.25**	**8.5**	**26**	**17.5**	**12.25**
Operation Count	136	84	116	179	47	27	98	224
P50 (min)	2.35	2.26	2.24	2.10	2.63	7.05	2.13	2.28
Average (min)	3.20	3.34	2.91	2.56	3.84	7.65	2.78	2.60

Casing-Pipe Moving Time (CH)									
Wells	**Kohar1**				**Latif south1**			**Miano 19**	
Phase (inch)	**26**	**17.5**	**12.25**	**8.5**	**12.25**	**8.5**	**6**	**12.25**	**8.5**
Operation Count	2	30	100	28	50	87	11	76	63
P50 (min)	1.05	1.05	0.64	0.58	1.43	0.68	0.53	1	0.58
Average (min)	1.05	1.10	0.75	0.65	1.67	0.71	0.57	1.14	0.67

Casing-Pipe Moving Time (CH)							
Wells	**Latif-5**		**Latif 14**			**Lamwari 1**	
Phase (inch)	**8.5**	**6**	**17.5**	**12.25**	**8.5**	**17.5**	**12.25**
Operation Count	136	84	116	179	47	98	224
P50 (min)	2.35	2.26	2.24	2.10	2.63	2.13	2.28
Average (min)	3.20	3.34	2.91	2.56	3.84	2.78	2.60

Table 38: RAG E-200 Targets Selection Analysis

Tripping-Slip to Slip Connection Time						
Wells	**ET 3**	**BS 205**	**HAT1**	**AT3**	**BS 7**	**ET3**
Operation Count	4705	963	1705	1265	216	4705
P50 (min)	*1.35*	1.58	1.47	1.43	1.38	*1.35*
Average (min)	1.63	1.83	1.69	1.59	1.74	1.63
Tripping- Pipe Moving Time (CH)						
Wells	**ET 3**	**BS 205**	**HAT1**	**AT3**	**BS 7**	**ET3**
Operation Count	4549	649	1229	991	30	4549
P50 (min)	0.60	0.73	0.57	***0.55***	0.57	0.60
Average (min)	0.69	0.90	0.67	0.62	0.62	0.69
Drilling-Weight to Weight Time						
Wells	**ET 3**	**BS 205**	**HAT1**	**AT3**	**BS 7**	**ET3**
Operation Count	23	89	143	133	23	89
P50 (min)	32.25	23.92	22.73	***21.62***	32.25	23.92
Average (min)	34.38	24.29	23.55	21.79	34.38	24.29

Casing- Slip to Slip Connection Time								
Wells	**ET 3**	**BS 205**		**HAT1**			**AT3**	**BS 7**
Phase (inch)	**8.5″**	**12.25″**	**8.5″**	**23″**	**17.5″**	**12.25″**	**12.25″**	**8.5“**
Operation Count	74	76	32	14	48	165	178	200
P50 (min)	*3.16*	3.97	3.92	*6.53*	*4.19*	*3.53*	3.77	4.27
Average (min)	3.36	4.16	4.12	8.12	4.50	3.88	3.91	3.39

Casing-Pipe Moving Time (CH)							
Wells	**ET 3**	**BS 205**		**HAT1**		**AT3**	**BS 7**
Phase (inch)	**8.5″**	**8.5″**	**23″**	**17.5″**	**12.25″**	**12.25″**	**8.5“**
Operation Count	72	33	12	51	46	36	72
P50 (min)	0.62	1.07	1.35	0.88	1.43	1.67	0.62
Average (min)	0.69	1.13	1.98	0.92	1.62	1.87	0.69

Table 39: DrillTac VDD 2001 Tripping and Drilling Related Target Selection Analysis

Tripping-Slip to Slip Connection Time						
Wells	**ET 3**	**BS 205**	**HAT1**	**AT3**	**BS 7**	**ET3**
Operation Count	4705	963	1705	1265	216	4705
P50 (min)	*1.35*	1.58	1.47	1.43	1.38	*1.35*
Average (min)	1.63	1.83	1.69	1.59	1.74	1.63
Tripping- Pipe Moving Time (CH)						
Wells	**ET 3**	**BS 205**	**HAT1**	**AT3**	**BS 7**	**ET3**
Operation Count	4549	649	1229	991	30	4549
P50 (min)	0.60	0.73	0.57	**0.55**	0.57	0.60
Average (min)	0.69	0.90	0.67	0.62	0.62	0.69
Drilling-Weight to Weight Time						
Wells	**ET 3**	**BS 205**	**HAT1**	**AT3**	**BS 7**	**ET3**
Operation Count	23	89	143	133	23	89
P50 (min)	32.25	23.92	22.73	***21.62***	32.25	23.92
Average (min)	34.38	24.29	23.55	21.79	34.38	24.29

Table 40 : DrillTac VDD 2001 Casing Running Target Selection Analysis

Casing- Slip to Slip Connection Time								
Wells	**ET 3**	**BS 205**		**HAT1**			**AT3**	**BS 7**
Phase (inch)	**8.5″**	**12.25″**	**8.5″**	**23″**	**17.5″**	**12.25″**	**12.25″**	**8.5“**
Operation Count	74	76	32	14	48	165	178	200
P50 (min)	*3.16*	3.97	3.92	*6.53*	*4.19*	*3.53*	3.77	4.27
Average (min)	3.36	4.16	4.12	8.12	4.50	3.88	3.91	3.39

Casing-Pipe Moving Time (CH)							
Wells	**ET 3**	**BS 205**		**HAT1**		**AT3**	**BS 7**
Phase (inch)	**8.5″**	**8.5″**	**23″**	**17.5″**	**12.25″**	**12.25″**	**8.5“**
Operation Count	72	33	12	51	46	36	72
P50 (min)	0.62	1.07	1.35	0.88	1.43	1.67	0.62
Average (min)	0.69	1.13	1.98	0.92	1.62	1.87	0.69

Appendix B

Table 41: Pakistan Offset Wells

Operation	Latif 14	Lamwari 1
	Section Time (days)	Section Time (days)
Drill 26" hole section	N/A	2.1
Run 20" CSG	N/A	1.9
Drill 17.50" hole section	6.3	2.9
Run 13.375" CSG	2.5	4.5
Drill 12.25" phase	4.3	9.0
Run 9.625" casing	1.7	4.6
Drill 8.5" phase	9.8	3.4
7" Liner run	5.1	4.8
Completion phase	6.6	N/A
Total	**36.3**	**33.2**

Table 42: Latif 15 Summary

Latif 15			
Operation	**Section time(Days)**	**Depth (m)**	**Cum. Time (m)**
Spud	0.4	0	0.4
Drill 17.50" hole section	4.5	1494	4.9
Run 13.375" CSG	2.7	1494	7.6
Drill 12.25" phase	3.3	2457	10.9
Run 9.625" casing	2.2	2457	13.1
Drill 8.5" phase	7.6	3461	20.7
Logging	1.6	3461	22.3
7" Liner run	2.9	3461	25.2
Logging	0.7	3461	25.8
Completion phase	6.2	3461	32.0
Total	32.0		

Table 43: Austria Offset Wells

Operation	Erdpress 20	Erdpress 24
	Section Time (days)	Section Time (days)
Drill 16" hole section	1.14	1.55
Run 13.375" CSG	1.56	2
Drill 12.25" phase	5.38	5.4
Run 9.625" casing	5	4.4
Drill 8.5" phase	5.60	2.9
Run 7” Liner	3.54	3.6
Total	22.22	20

Table 44: Erdpress 28 Summary

Erdpress 28			
Operation	**Section Time (Days)**	**Depth (m)**	**Cum. Time (m)**
Spud	0.4	0	0.4
Drill 16" hole section	1.1	539	1.5
Run 13.375" CSG	1.6	539	3.1
Drill 12.25" phase	5.1	2054	8.2
Logging	0.5	2054	8.7
Run 9.625" casing	3.7	2054	12.4
Drill 8.5" phase	4.1	2872	16.5
Logging	0.3	2872	16.9
7" Liner run	2.4	2872	19.3
Completion phase	1.3	2872	20.5
Total	20.5		

Appendix B