Florian Gamperl

Master Thesis supervised by
Univ.-Prof. Dipl.-Ing. Dr.mont. Gerhard Thonhauser
Mag. Rudolf Nikolaus Knezevic (OMV E&P Austria GmbH)
DI Christian Litzlbauer (OMV E&P Austria GmbH)

Analysis of the Impact of Wellbore Quality

DEPARTMENT PETROLEUM ENGINEERING

MONTAN UNIVERSITÄT

To my late grandfather

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.

Eidesstattliche Erklärung

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.

Florian Gamperl, B.Sc., 12 March 2017

Abstract

Wellbore Quality (WBQ) is an abstract industry term that can be used to describe nearly any cause of problems that can occur on wells throughout their life cycle. However, it has never been precisely defined nor are there industry-wide standards on how to assess wellbore quality.

However, the economic impact of WBQ is not negligible: not only in the early stages, but also towards the end of the well life cycle, quality is the factor that makes a difference. While it may cost more to drill a perfect well, the long-term savings are likely worth making those expenses.

This thesis reviews the importance of wellbore quality and existing assessment strategies from the literature. In a second step, new KPIs will be developed that could become a new industry standard for WBQ assessment. Opposed to existing methods, they rely on physical measurements only, thus being more reliable and unbiased. These will be split into three categories: geometrical, operational and wellbore success indicators.

In a third step, the proposed KPIs will be tested using real-world data provided by OMV E&P Austria GmbH.

Zusammenfassung

Bohrlochqualität (BLQ, bzw. WBQ von engl. Wellbore Quality) ist ein schwammig definierter Begriff, den die Erdölindustrie verwendet, um eine Vielzahl von Problemen zu begründen, die im Lebenszyklus einer Sonde auftreten. Der Begriff wurde allerdings nie in einer Form definiert, den die gesamte Industrie akzeptiert, vielmehr gibt es eine große Zahl rivalisierender, teilweise sogar widersprüchlicher Definitionen. Ebenso existieren mehrere Zugänge, BLQ zu beurteilen.

Das Ziel dieser Masterarbeit ist es zunächst, die Probleme, die durch mangelnde Bohrlochqualität im Leben einer Erdöl- oder Erdgassonde auftreten können, zu erläutern sowie existierende Bewertungsmöglichkeiten auf ihre Stärken und Schwächen zu untersuchen.

In einem zweiten Teil der Arbeit werden neue Key Performance Indicators (KPIs) entwickelt, um BLQ aufgrund von „harten Fakten", d.h. Messwerten, beurteilen zu können. Diese könne in drei Kategorien unterteil werden: Bohrlochgeometrie-, Bohrprozess- und Erfolgs-Indikatoren. Diese Indikatoren sollen möglichst so gestaltet werden, dass sie auf alle Bohrungen weltweit angewandt werden können, und damit zu einem Industriestandard werden können.

Anschließend werden diese KPIs mittels Daten aus einem Feld der OMV E&P Austria GmbH. auf ihre Umsetzbarkeit untersucht.

Acknowledgements

Without the help of many, this thesis would not have been possible. I would like to thank my advisors: Mag. Rudolf Nikolaus Knezevic and DI Christian Litzlbauer from OMV Austria. I would also like to thank DI Hannes Geier, representative of all the experts at OMV, who have been involved in the data acquisition, analysis and interpretation process, for their great help, support and insight on all the topics that this overwhelmingly big area of research covers.

Furthermore, I would like to thank OMV Exploration & Production Austria GmbH for making their data of the Erdpress Field accessible, which only made this thesis possible in the present form, as well as to Thonhauser Data Engineering (TDE), DI Marc-Philipp Liebenberger in particular, for helping me with some last-minute data acquisition.

I would also like to thank my proofreaders for the time they spent on reading this work, and correcting my mistakes.

While this thesis attempts to give a consistent overview some over areas that can be subject to wellbore quality, it is not possible to cover all the contributions and effects in a single thesis.

Florian Gamperl Leoben, January 2017

Contents

Chapter 1 Introduction

The term "Wellbore Quality" (WBQ) refers to a quite abstract theoretical framework that tries to unite several aspects of drilling a well. There is little consensus in the industry, what it actually comprises, and how it should be measured. However, there seems to be a certain "recurring theme" when it comes to comparing definitions. For example, there is a geometrical manifestation of wellbore quality:

"Aesthetically, the perfect wellbore can be envisioned as a flawless, three-dimensional hollow cylinder with a smooth frictionless finish."

Mason & Chen, 2005

"A high-quality wellbore is generally considered to have (1) a gauge hole, (2) a smooth wellbore wall, and (3) a wellbore with minimum tortuosity."

Chen, Gaynor, Comeaux, & Glass, 2002

This means that for a high-quality wellbore it is essential not to have any geometrical flaws, i.e. no deviations from the ideal shape envisioned in the well plan.

This geometrical consideration is still a good starting point, as it provides a simple possibility to measure the wellbore quality: While "smoothness" may not be so easily measured or even defined, it is quite obvious that wellbore diameter and friction factors can be measured and compared. While the wellbore diameter as derived from caliper logs can be compared to the bit diameter, friction factors can be calculated from the recorded pick-up (P/U) and slack-off weights (S/O), and compared to the information obtained from offset wells. The difference between plan (or offset well data) and the actually measured/derived values has to be analyzed subsequently for the reason, which as a further consequence allows to judge the quality of the wellbore.

In this context, it should be mentioned, that even a "normal" value, as observed already in previous wells in the field, may already include some effects of poor wellbore quality. Hence it may be worth considering those values assumed in the very first well plan as the benchmark, rather than those of the current plan; this may give a more objective view of the matter at hand, not being biased by other wells drilled with potentially poor quality.

Another problem that is frequently mentioned to be an issue of wellbore quality is the one of wellbore tortuosity, or "spiraling".

Chapter 2 Contributing Factors

Steven Rassenfoss has summarized some of the most prominent problems arising from poor wellbore quality (Rassenfoss, Drilling Wells Ever Faster May Not Be the Measure of Success 2015). In his article, he identifies four major categories affected by and affecting Wellbore Quality:

1. Drilling
2. Casing and completion
3. Artificial lift
4. Reservoir/geology

These categories do not have well-defined boundaries, drilling-relevant problems may also have an effect on other areas and vice versa. A good example for this would be the issue of trajectory control. On the first glance, this would be a problem categorized as drilling related. However, it has very much an influence on artificial lift, and a certain impact on the reservoir engineering part: Poor directional control can result in overly severe doglegs. This will not only reduce the pump life time, if placed at the position of the dogleg, but it will also have an impact on tubing and rod string life time as well as a higher power requirement from the pump as a result of the added friction at the dogleg. The other thing, this may do, is cause issues with the reservoir itself: poor trajectory control may confront the engineer with a well placed less than optimal within the reservoir, or even completely outside of the reservoir zone.

The factors shown in Figure 1 are some of the most significant ones that influence not only the technical performance of a well, but may also have a significant impact on the project economics. The factors will be explained to a greater detail in the following sections.

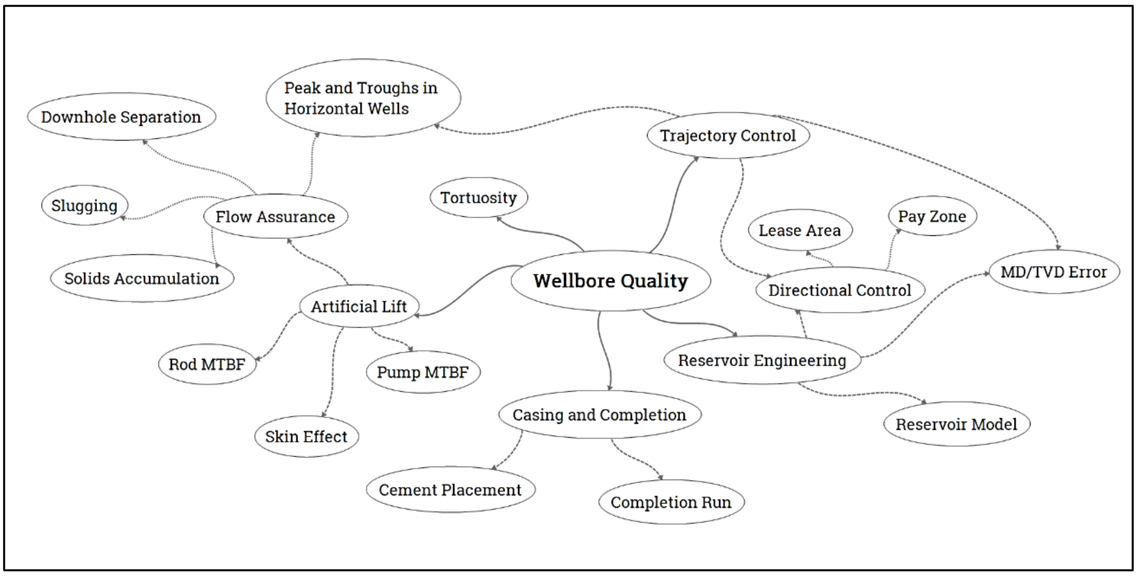


Figure 1: Impact of wellbore quality

Summing up the figure, it is justified to say, that the aforementioned definitions may be true for their respective field, but wellbore quality is more than just these factors, or even their sum. Simply put, WBQ could be defined as

"a measure for the readiness of a wellbore to reliably fulfill its purpose."

This implies, however, that WBQ is no longer a completely objective term in the sense that it can be applied to every well in the exact same way. Exploration wells will have other requirements than development or infill wells. However, there is another area that is important, and is – in some way – also a major factor: Planning.

2.1 Planning and Reviewing

"A high-quality well begins with a good well plan"

Mason & Chen, 2005

This is perhaps the key message of "The Perfect Wellbore!" (Mason and Chen, The Perfect Wellbore! 2005). It shows that there is no way around the well plan, and proves that this plan has to be done properly in order to make a ready-for-purpose wellbore possible. This includes the tidy implementation of all lessons learned, and a permanent process of reviewing and updating a well plan ("maturation") until the well is ready to go on production. One could even go a level higher, and say that the key to successfully drilling a perfect well is not only the well plan, but the field development plan. The importance of this extension will be shown in this thesis.

Now, what makes a plan a good plan? A good plan has two basic functions: documenting assumptions, reference information, calculations leading to designs etc., and stating the goal, objectives and success criteria of the project.

2.1.1 Documentation

One of the reasons of documenting is to be able to go back to the design, reviewing it and making changes as necessary. This is important, because some assumptions may turn out to be wrong or new information becomes available, making changes in designs necessary.

Secondly, if fluctuations occur on the project team, it will still be relatively simple for the new members to quickly familiarize with the project, as the key information to understanding the project is in the documentation.

Furthermore, the inclusion of reference information allows people outside of the project to understand the data source, and it allows quality checks.

Lastly, the project documentation in the plan should include plan changes. But it is important to note that changes alone are not sufficient; it will be of just the same importance to name the reasons for the deviations in order to make the decision understandable, and to allow learning from it.

2.1.2 Stating Goals

Clearly stating goals has a psychological effect: The project team will find motivation in the fact how well they do, compared to the goal, and they will strive for achieving it.

Moreover, it is important to know the goals in order to evaluate the success of the project. Both points can be illustrated with a simple example of drilling a well.

- **Case 1**: The goal is to drill a well in a known oil field to "*find fluids and produce them*". What this will mean to the crew is to complete the well in whatever time frame they deem possible. They will care little about which fluids they find, and in what amounts. Hence the project may not be very successful in an economic way, but according to the plan ("finding and producing fluids"), the well is successful.
- **Case 2**: The goal is to drill the same well, but with detailed goals: "*Drill to horizon X, prove hydrocarbons and produce at rate Y within a certain time frame Z and budget B*," is a much more powerful goal. Additionally, the crew could be included by "drilling the well on paper" (DWOP), giving a second success criterion (performance with regards to drilling time), and an additional motivation. Moreover, it will be unambiguous to define the success of the project: *Was the horizon reached?* – Yes or no.
  Could the rate be achieved? – Yes or no.
  Was the project concluded in time/on budget? – Yes or no.

Thus, a third function could be assigned to the plan as the "reference line" against which the actual performance will be measured. If this is seen as an objective of a planning document, the importance of a tidy plan that fulfills the first two functions unambiguously becomes even more obvious.

2.1.3 Considering the Value of Information

It may not be immediately evident, but gathering information at the right time[1] can certainly pay off. But being prepared or what might happen will save money.

One may say that this has little to do with wellbore quality, but the opposite is in fact true: Information gathered at an early stage of the drilling campaign may yield information that allows the mitigation of WBQ-related incidents in subsequent wells, either from Lessons Learned (LL), from the evaluation of log data, or from the implementation of geomechanical models. (GEM = Geomechanical Earth Model).

Take the latter as an example: Eventually, a geomechanics study will cost money (not only the model creation itself, but also the data acquisition, e.g. coring, sonic or image logs). But compare these expenses to what has to be spent on a well where a standard directional drilling assembly is lost in the hole due to stuck pipe. In many cases a single incident of this kind can already be more expensive than geomechanical studies, which will assist in mitigating exactly those risks. Moreover, early data acquisition will improve efficiency by a proper selection of fluid parameters, trajectories and completion designs.

[1] i.e. when it is still possible, and increasing knowledge will help supporting decisions, for instance focusing on reservoir data and geomechanics at an early stage of a field development campaign, rather than at the end

Clearly, there is no short-term financial benefit in such campaigns, but the long-term effects may easily prevail. And they are simple to explain:

- Understanding the geomechanics can improve the drilling experience and mitigate drilling hazards such as stuck pipe, lost circulation or kicks. This is of particular use in tectonically complex fields, e.g. ones that are dominated by major fault systems, active (or likely-to-be-activated faults). This will also be explained and illustrated to some detail in the Case Study.
- Adjusting the fluid parameters (e.g. lubrication properties, rheology, mud weight) to the particular requirements of the formation reduces formation damage, but also mechanical difficulties such as torque and drag (and as a consequence stuck pipe incidents).
- Stimulation jobs can be optimized: Placing wells in the proper direction relative to rock stresses result in an improved fracturing experience. Additionally, having an actual rock sample available for testing will allow an even more efficient design: Required pressures can be estimated with better confidence, but also the stimulation fluid can be adjusted to meet the respective requirements (e.g. governed by mineralogy).

The above are only a few longer-term benefits from the additional data. It is obvious that they do not only have a positive impact on drilling subsequent wells, but also on production.

After the plan execution, another important process takes place: Reviewing the concluded project, analyzing potential improvements, assessing new technologies, strategies etc. that have been newly applied and thus enabling a learning process. Again, it is important to document the findings clearly, in order to allow the implementation in subsequent projects.

2.1.4 Lessons Learned

Lessons Learned is an important quality factor, which is often neglected due to high time pressure. For example, well designs are often copied and pasted over and over again with only minor adjustments. This is of course a legitimate approach to save time, if the conditions are nearly identical; what is not so legitimate about this approach is that "lessons learned" from previous wells are often not implemented properly. This method of well planning, where the well plan once it has been made, is never reviewed anymore, can easily be called a "fire and forget" method – but in a negative sense.

The quality factor of LL is explained simply: Analyzing mistakes and success from previous projects will allow improving subsequent projects, if similar mistakes can be avoided and successful technology application will be repeated.

One thing that has to be mentioned in the context of the implementation of LL is the well sequence: While it is possible to implement some of the LL from one run to the next, this may not always the case, if the time to analyze a more complex issue (and update subsequent well plans) is not sufficient in the case of a tight drilling schedule.

Needless to say, the implementation of LL again needs to be properly documented in the next plan, closely monitored throughout the execution and finally evaluated during project closeout. In this phase, it is key to evaluate the performance with KPIs pre-defined in the well planning documents.

2.2 Well Geometry

2.2.1 Wellbore Shape

Obviously, the geometry of the wellbore has some significant meaning for the quality of the well. Some factors have already been mentioned (such as wellbore trajectory, wellbore spiraling), because they were deemed important enough to be listed separately. However, there are a number of additional geometry parameters that can be related to WBQ.

2.2.1.1 Wellbore Drift

One of them, also related to wellbore tortuosity, is the so-called wellbore drift: A piece of pipe that will easily fit into a straight well may not be run along a tortuous well path. The explanation is rather simple: When drilling the well, the bit may move not only along the wellbore axis and rotate around it; it may also show some movement perpendicular to the wellbore axis. Such perpendicular movement creates a peak-and-trough pattern; those alternating peaks and troughs caused by this reduce the effective diameter and may thus pose a restriction for pipe size (shown in). This can become a particular problem when running casing, because of the relatively low clearance between casing and wellbore wall.

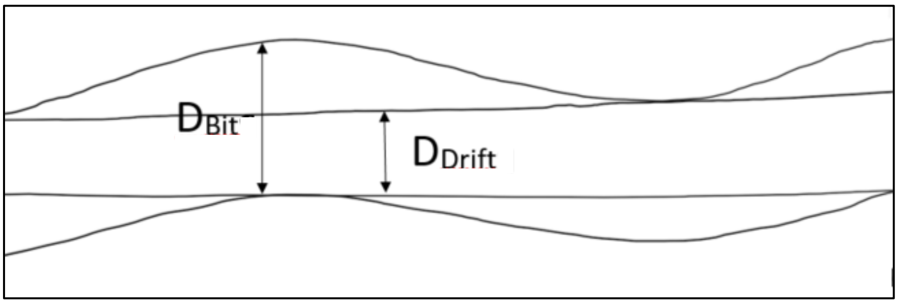


Figure 2: Drift diameter (exaggerated view)

When the well is planned to be completed with casing to TD, this usually has a reason. Hence it is a measure for the readiness of the well for its purpose, whether the casing can be run to TD or not. If this cannot be achieved, it should be noted, by how much it could not be achieved. There may be a difference between missing the last few meters (unless this renders the interval targeted for perforations inaccessible), or if the casing got stuck halfway to TD and cannot be run further nor retrieved. While the first one is most likely something most stakeholders can live with and which may hence be considered a negligible quality issue, the second one is a failure and a definitive sign of poor quality, as it may even result in completely losing the well for production.

2.2.1.2 Breakouts & Washouts

Breakouts and washouts are another indication for poor wellbore quality, especially from the point of wellbore stability (WBS). They are a typical sign of poor operating conditions. Breakouts indicate that the mud weight is too low to support the stresses in the rock, leading to mechanical failure. They can pose a significant issue when the broken rock falls onto and accumulates on the BHA, because this can lead to stuck pipe.

Obtaining geomechanical information, such as density, stress direction and magnitude and rock strength can be essential for reducing such problems. However, it requires planning efforts, and additional expenditures, such as coring, additional logging (sonic velocity), perhaps image logging and subsequent analysis. Such investments can still pay off easily, though, as the information obtained from a well-configured geomechanical Earth model can improve future drilling experience.

Washouts on the other hand are a typical sign of too high flow velocity in the annulus, combined with weak rock. They can be initiated at breakout points, thus making breakouts hard to identify, but they can also occur independently in zones of less/unconsolidated rock. Just like breakouts, washouts may be avoidable when an understanding for the subsurface is developed. However, particularly washouts could also be avoided by applying reduced parameters as a part of the "Lessons Learned" from previous wells.

2.2.1.3 Implications for Zonal Isolation

Any modification of the diameter of the wellbore has a potential impact on zonal isolation: Hole enlargements bear the risk of having a too short cement column and thus not fulfilling the cementation requirements. Even though wireline calipers are run prior to casing and cementing, they may not capture the whole picture, and the volume calculations may still be off.

A larger risk is that cement cannot be pumped around the complete casing due to a highly tortuous well path. This leaves the casing exposed to the formation, potentially vulnerable to corrosion etc. Furthermore, zonal isolation cannot be guaranteed if the casing is not properly confined by cement, which makes remedial cement jobs necessary. However, even those cannot be a guarantee for good zonal isolation under such conditions.

The reason why zonal isolation is of utter importance for any well is to prevent cross flow between two hydrocarbon layers, but even more importantly to stop allow hydrocarbon fluids and/or reservoir brine from flowing into freshwater aquifers or to surface. This poses a significant risk, because the reservoir water is typically not drinkable, potentially even harmful due to its constituents. Hydrocarbons are a risk in water and air: Some constituents are carcinogens, pose a risk to the fauna, and can lead to explosive atmospheres, to name just a few examples. All these issues are an enormous threat to a company's image (not to mention that they mean violations of the law), and thus have to be prevented.

Even if the well is planned not to be cemented, the wellbore geometry, and its diameter in particular, is a key parameter to know: It is required to select a properly sized packer to isolate the producing interval. If the hole size is unknown, and a too small packer is run, the swelling packing elements will not be able to provide the required isolation. This can have impact in two ways: On the one hand, the wellbore will not be properly isolated towards higher layers – which is the more serious problem from an Health, Safety and Environment (HSE) point of view - and on the other hand, it production of undesirable fluids may become an issue.

2.2.1.4 Implications for Tubing String Design

The effect of the design of tubing (TBG) is explained quickly: Improper design results in unnecessary restriction to flow, be it by geometrical restrictions (valves, gauges, etc.) or by increased friction due to unnecessarily high flow velocities. This then results in additional friction pressure to be overcome (larger pumps and more energy input required) and the frictional pressure drop can result in leaving essential phase envelops, such as the two-phase envelop (i.e. dropping below bubble point) or crossing the point at which paraffins or resins can no longer be kept in solution. Plugging by precipitation will be the result unless countermeasures (inhibition) are taken.

The two key variables in this context are tubing inside diameter (ID) and the shape and diameter at restrictions. Tubing ID will essentially control the velocity inside the tubing according to

$$v = \frac{4Q_{pump}}{d_i^2 \pi} \tag{1}$$

where v is the velocity inside the tubing, Q_{pump} is the pump rate of the artificial lift system and d_i is the tubing ID. Smaller diameters will increase the velocity and vice versa. Hence it is possible to optimize wells that are endangered of "drowning" (i.e. only gas is produced and the liquid remains at the bottom) by decreasing the tubing size in order to improve the liquid recovery: At higher flow velocities, the energy of the gas (higher rising velocity) may be sufficient to also lift liquid droplets to surface.

The effect of diameter restrictions is two-fold: Firstly, the decreased diameter adds frictional losses due to the increased velocity. This is, however, a rather negligible value compared to the total amount of pressure losses, and usually even negligible compared to the total frictional losses, as such restrictions are normally no longer than half a meter. The second way restrictions influence TBG performance is by causing turbulences, particularly one their downstream side. Those also create a pressure drop, which may be more significant, and becomes even more important the higher the velocity (contrast) is. And such turbulences also have another effect: Corrosion effects can be observed behind restrictions, reducing the tubing life. This effect is enhanced by solids in the produced fluid; however, solids are not a compelling factor, if the energy is sufficiently high, this may even happen in a completely solids-free environment.

2.2.2 Trajectory

The well path is not only an important input for the drilling engineer, it has actually an effect for almost all "stakeholders" of the well, from the geologist and the reservoir engineer to the production engineer. Factors such as the geological target are just as important as constructing a hole as straight as possible, meeting specifications for production equipment count just as much as avoiding collisions with other wells.

2.2.2.1 Survey Distance Problem

Surveying is not to be seen as the complete truth: A study conducted by Stockhausen and Lesso (2003) found out that the true vertical depth (TVD) calculated from can vary up to 25ft from the actual depth. The fundamental problem they describe is connected with the length of the interval between two survey points. Originally, these intervals were around 30ft (10m), but with the advent of triple stand rigs the interval has increased to 90ft (30m). While this saves quite some time – after all, two out of three surveys are cancelled – it also decreases the resolution. However, such a loss of resolution equals a loss of detail and accuracy. Hence, the result of the study by Stockhausen and Lesso on "artificial[2]" 90ft-surveys is not very surprising. The quantity by which the surveys (based on originally identical data!) differ is amazing, and at the same time unsettling. Another problem that is frequently mentioned to be an issue of wellbore quality is the one of wellbore tortuosity, or "spiraling".

Figure 2 illustrates this problem with a planned horizontal well, the 30-ft survey that matches the planned trajectory quite well and finally the 90-ft survey created by leaving out two of three survey points of the 30-ft survey. This one shows the deceiving image of a well being placed too shallow. This may cause the driller to make wrong directional decisions, which could ultimately cost money, be it because of missing the optimum well location, or be it because of penalties for drilling outside of the lease area.

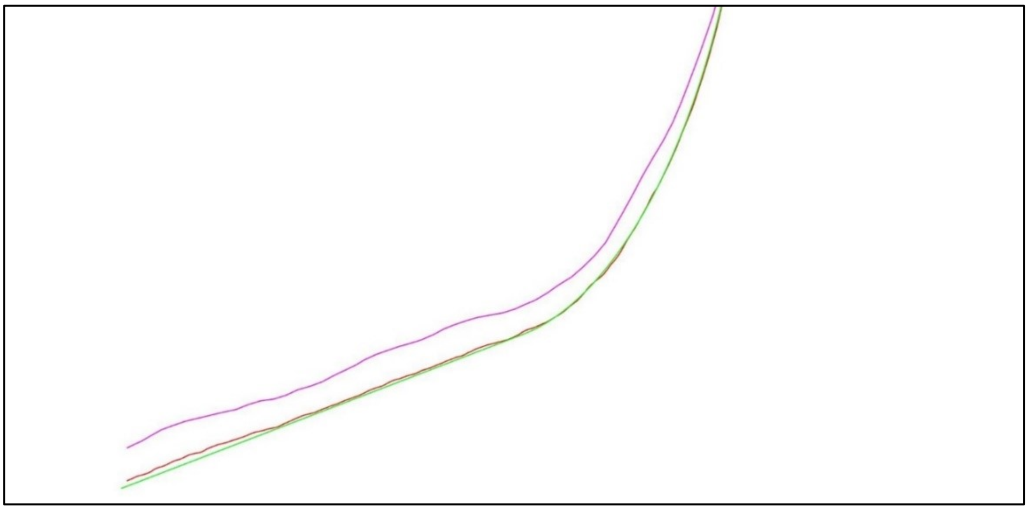


Figure 3: Comparison of the planned trajectory (green), the 30ft survey (red) and the 90ft survey (magenta).

Note how close the red and green lines are to each other in the figure above, indicating that the wellbore closely adheres to the planned trajectory, while the wider spaced survey differs significantly

Moreover, the increased survey distance bears a second problem: it is harder to detect doglegs, as two doglegs in opposite directions can cancel out. The probability of this happening is significantly higher over a 30m interval than over 10m. Furthermore, severe but highly localized kinks are given a lot less significance over a longer interval, due to the averaging nature of the minimum curvature calculations. Hence a well deemed within specs from the less detailed survey may very well exceed the limits for a planned tool. This could be not only a limitation regarding DLS, it could also be that a section appears straight enough to place an ESP, whereas in reality the desired place has a dogleg that exceeds the specifications.

[2]"Artificial" in this context refers to the fact that the study was actually based on 30-ft surveys. Of these surveys, only each 3rd value has then been taken for analysis in said study.

The important question is, whether the (limited) savings in rig time and thus well cost can justify additional costs arising because of early failures of the pump.

2.2.2.2 Reaching the Target

A well that does not reach its target cannot be a good quality well. However, under certain circumstances, this is not necessarily true, particularly when the well has several fallback options in the well plan. Hence it may be excusable not to drill all the planned targets, and it may even be unnecessary, if the targets reached are of sufficient size and reservoir quality.

An important requirement is to hit not only the target layer, but the exact target coordinates (within the allowed radius). Particularly in small fields with many wells this is important for optimum production. In low-permeability reservoirs, this becomes even more important: It becomes of ultimate importance to hit the sweet spot (i.e. location with higher permeability) in tight rocks, e.g. in tight gas reservoirs.

2.2.2.3 Wellbore Tortuosity

Wellbore tortuosity (also referred to as spiraling) describes the deviation of the well path from a straight line. Note “straight”, in this context, means “along a not twisted axis”.

MacDonald and Lubinski (1951) have defined this phenomenon as follows:

“A 3° hole might be rifle-bore straight if the deviation were all in one direction, but obviously far from vertical. Such a straight but non-vertical hole would present little drilling or producing problem. A 2° hole could be more crooked if it swung sharply from 2° in one direction to 2° to the opposite direction several times throughout its depth. Although such a hole might be classed as vertical because the bottom of the hole would be close to a point directly beneath the surface location, it might have sharp doglegs up to 4° at several places and develop relatively serious drilling and producing problems. […]

“A 2° hole following a tight spiral would be vertical but far from straight; and if it held steadily to 2°, there would be no objectionable rate of change in angle, yet the spiral hole might develop serious key-seating difficulties, drill pipe wear on intermediate casing etc.”

MacDonald and Lubinski, 1951

While the 3° hole MacDonald and Lubinski describe in their paper “Straight-Hole Drilling in Crooked-Hole Country” is indeed a straight hole, the two described cases for the 2° wells actually define tortuous holes. “Routine drilling tools” (to keep quoting MacDonald and Lubinski) in 1951 did not allow a conclusive analysis, as azimuth measurements were hardly conducted then. As technology progressed, such measurements became routine measurement while drilling (MWD) components, but still the discussion about wellbore tortuosity kept on going. With another, then – and still nowadays – “non-routine drilling tool”, Gaynor, Hamer, Chen et al. (2002) came to more conclusive results: By the application of image logs they showed that wellbore tortuosity is a real concern, concluding

“[...]Hole spiralling [sic!] *is the primary cause of poor hole quality[...]”*

Gaynor, Hamer, Chen, & Stuart, 2002

They describe tortuosity as the sum of *planned tortuosity* (i.e. sum of all planned directional changes), *large scale tortuosity* (as measured by MWD surveys in 30 or 90 ft intervals, see also), and *micro-tortuosity* (i.e. the deviation of the well path from a straight line). While the first two are easily measurable, and thus also controllable, the last component is trickier to detect. It is typically done by friction factor calculations, but can also be done via logging while drilling (LWD) calipers.

Some of the implications of wellbore tortuosity and spiraling, not only for drilling, but also for completion and production, are:

- Stiffer drill string components, such as the bottomhole assembly (BHA), may not be able to follow the path easily, thus increasing the risk of getting stuck. More generally speaking, it results in an increased pseudo-friction.
  Just the same way, increased drag may be observed when running in casing (and the casing may be subjected to higher wear than in a comparable straight hole). Stuck casing, and inability to run the casing to total depth (TD) may be the result. Similarly, it may also be more complicated to pass stiff production assemblies through a tortuous well path. This can be the pump seat of a sucker rod pump (SRP), an electrical submersible pump (ESP) or sinker bars in rod strings – although the risk with the latter is relatively small due to the large diameter difference between the hole and the sinker bar.
- Connected with the increase in T&D, a loss of drilling progress may be observed. This reduction in the rate of penetration (ROP) can be explained in the following way: The weight of the drill string that should be transferred to the bit is reduced by the amount of friction between the drill string elements and the wellbore wall. As one of the essential parameters to describe ROP is the weight on bit (WOB), it is obvious that a reduced WOB leads to a decreased ROP.
- Increasingly tortuous well paths also convey the danger of increasing drill string vibrations. This puts particularly special tools, such as LWD/MWD tools at risk, as they can be prone to failure due to vibration.
- Poor wellbore cleaning can also be a result of wellbore spiraling: It makes parts of the wellbore nearly inaccessible to the drilling mud, thus allowing cuttings to accumulate, e.g. on pipe or tool upsets, thus again increasing the risk of getting stuck.
- Just the same way as tortuosity can result in poor wellbore cleaning, it can also prevent cement to be displaced along the whole circumference of the casing. The result may be poor zonal isolation and – in the worst case – communications between two horizons.

2.2.2.4 Dogleg Severity

Doglegs are "kinks" in the wellbore that occur whenever the drilling direction is changed, be it due to a voluntary steering input, or due to formation effects. Hence, it is impossible to avoid them completely; however, the issue is that severe doglegs[3] will

[3] The definition of a "severe dogleg" is not simple. It will depend on the definition of a maximum allowable DLS in the well plan, according to certain tool specifications. The literature does not

cause restrictions to stiffer parts of the drill string. Key seating and other forms of getting mechanically stuck are the consequence.

An issue with dog legs is that they may very easily be skipped in survey, as even a very sudden directional change may appear gentle over the complete survey interval. Here comes the problem of the survey station distance into play: The larger the surveyed interval, the more "luck" is necessary to actually detect a severe dogleg.

However, the problems are not just restricted to stuck pipes: Several tools, such LWD/MWD devices may have limitations with respect to the maximum dog leg severity (DLS). This does also apply to pumps. Especially electrical submersible pumps are sensitive to doglegs. As a result, it is required to place pumps in a hole section that is as straight as possible.

A commonly applied solution to reduce doglegs is the application of reamers or hole openers to enlarge the wellbore radius. However, this means changing the wellbore geometry, thus opening another potential WBQ problem. Most likely, the change in geometry is however the more acceptable problem, as long as it can be controlled, and it resolves the DLS issue.

2.2.2.5 Artificial Lift Requirements

Artificial lift systems are among the most sensitive tools in the well. Hence the proper execution of the drilling program with respect to previously agreed limits is essential. However, it should also be noted that the drilling engineers cannot be made responsible for wells that are out of specs due to a scope change (e.g. change of pump type) after drilling has begun. Such requirements are typically related to the wellbore trajectory in some way or another, but there are also some other factors.

- Required Trajectory: Some pump equipment, particularly ESPs have restrictions with respect to DLS, but also to the general trajectory. For example, a typical requirement for placing an ESP is a straight section[4]. This is due to the length of the pump (a single ESP has a length of about 12m, dual ESPs are even longer), and the increased likelihood of failure if the pump is subjected to bending during operations.
  Sucker rod pumps on the other hand can hardly be run and operated in sections close to a horizontal angle without additional measures being taken. The small diameter of the rod string simply makes the string very flexible, which would result in severe buckling on the downstroke.

  Such limitations need to be taken into account already in the planning phase, and the importance of these limitations has to be clearly communicated to the all stakeholders in order to increase the necessary awareness for them.

- Rod String and Tubing Wear: Rod actuated pumps rely on a relatively smooth well trajectory with low dogleg severity. The axial motion of the rod string within the tubing results in frictional wear on both the rod and the tubing string. The

---

mention a specific number as the limit between high and low DLS. Commonly, the maximum allowable dogleg severity is around 3-5°/30m

[4] In this case, "straight" means "shortest line between two points"

more kinks in the wellbore, the more contact will exist between them, thus increasing not only wear but also the force required to move the string.
Matthews and Dunn (1991) have conducted a case study on directional wells in Alberta, Canada. They analyzed the well trajectories with respect to the consequences for pump, rod string and tubing wear related workovers. A more detailed summary of this case study can be found in "Rod String and Tubing Wear", p.100. The key points of this study are:

- Survey intervals exceeding 25m will leave significant features such as doglegs undetected.
- Friction forces occurring at doglegs are responsible for excessive wear, where the rod string or centralizers are in contact with the tubing.
- Curvature reversals at doglegs cause increased wear, regardless of the tensile load below. This is because of the increased contact.
- Different pump types react differently to the trajectory: While SRPs are relatively forgiving towards doglegs at the pump seat, they are very sensitive towards doglegs above; Progressive cavity pumps (PCP) on the other hand behave the other way around.

2.2.2.6 Well Placement

Adhering to a planned trajectory is important for several reasons, and deviation can have a major impact on wellbore quality for exactly those reasons: First of all, the well path is usually optimized in such way that the geological target zone can be reached without significant problems (e.g. landing a well within a certain radius around a subsurface coordinate point). This may not seem of importance to the driller, it will be important for producing the well: Placing a well just half a meter outside of the desired envelope may result in ending up too close to a fluid contact (early production of the undesired fluids), or even outside of the productive zone at all.

Secondly, it is important to avoid hazard zones, such as over-pressured zones or active faults. For example, over-pressured zones will bear the risk of influx from the formation, a kick and ultimately – if not handled correctly – in a blowout (including danger for the personnel, third persons and the environment).

Active fault zones will mainly put drill string components at risk, they may get stuck or be sheared off. However, it may also occur that these things happen only after completion, resulting in the loss of the producing well.

For production, the importance of well placement is to stay clear of fluid contacts and thus postpone coning effects as long as possible. Moreover, it is important to hit the "sweet spots", particularly in reservoirs with low permeability.

In naturally fractured reservoirs, it is also a typical goal to drill as many fractures as possible, if possible perpendicularly to their extension, and to connect the existing network to the wellbore.

2.2.2.7 Anti-Collision

Closely linked to the problem of well placement is the problem of mitigating collisions with other wells (a rare exception to this, and usually by far more complicated, being relief wells, which are intended to hit an out-of-control flowing well). Hitting producing wells can have a similar effect, if the well is free flowing. If not, it will at least result in the need of remedial cementing, or even the loss of the producing well, and a sidetrack on the new well; both cases will result in significant additional costs, which have to attributed to the cost of the newly drilled well.

Apart from the abovementioned problems, there is another limitation to surveys: The formulae for converting the survey coordinates – typically inclination, azimuth and measured depth (MD) – to Cartesian ones (Northing, Easting, TVD) do not take things such as pipe buckling, compression and extension or smaller-scale phenomena such as hole spiraling into account. However, it is obvious that the survey interval may have more to do with WBQ than one would assume at the first glance. However, such problems are already considered in the so called "ellipse of uncertainty". The effects of longer survey intervals, as described above, on the other hand are not part of those considerations.

Being aware of the limitations described above, it is still possible to use the results of positional surveys to assess wellbore quality, in the form of both plan and execution quality.

2.3 Drilling and Well Operations

Drilling operations are a relatively short period, compared to the life time of a well. However, they are key to finding problems with wells: Once the well is drilled and completed, there is little one can do to mitigate problems – all that is left is dealing with them, i.e. spending money on workovers and well interventions. Hence the operational aspect of wellbore quality has a particular importance with respect to the economics.

2.3.1 Drilling Fluids

The importance of proper fluid design is obvious: Wrong density will cause wellbore stability issues, be it hole collapse due to too light fluids, or be it drilling-induced fractures because of too high fluid or circulating density. Likewise, the influence of the rheology is simply explained. In addition to that, poor choice of mud weight will facilitate differential sticking, as explained below.

To be able to clean the wellbore without excessive pressure losses, a compromise between fluid viscosity and gel strength and pump rate has to be found in order to ensure the cuttings to be transported to the surface. Moreover, the correct choice of additives plays a major control, such as clay swelling inhibitors or corrosion inhibition. The compatibility of all additives with the drilled formations should also be considered in order to avoid formation damage by precipitation of components dissolved in the mud.

Other things, that may not always jump to mind, are for example fluid loss and filtration parameters. These can however be of significant importance, especially when drilling into or through the reservoir zone. In that case, fluid loss has to be avoided to the reservoir in order to prevent damage by precipitation in the pore space due to incompatibilities, but at the same time the filter cake be easily removable to not impair production.

2.3.2 Stuck Pipe

Stuck pipes are often a hint that something is wrong with the wellbore. However, from the fact that the pipe is stuck alone, it is normally not possible to judge, why the drill string cannot be moved.

In general, there are three basic reasons for stuck pipe:

- **Differential sticking** occurs when a permeable filter cake forms on the wellbore wall. This filter cake needs to be relatively thick in order for the drill pipe to be able to get stuck. As the pipe rotates touching the filter cake, it drills itself into the filter cake, with the rotation creating a suction pressure. If the mud weight is high, this contributes an additional pressure differential and forces the pipe deeper into the filter cake, up to the point, where ultimately no further movement is possible.
- **Mechanical sticking** due to friction forces can occur under any conditions. It is facilitated by factors such as ledges or wellbore spiraling, leading to increased contact with the wellbore wall.
- **Key seating** occurs at high doglegs, which the drill string cannot follow, thus creating a "shortcut", whose cross section looks similar to a key. However, this "extension" of the well is typically so narrow that the tool joints will not be able to fit trough, thus the drill string is stuck upwards (but usually permitting downward movement). Other issues related to geometry are under-gauge holes (e.g. because the well is drilled with a heavily worn bit), or swelling formations, blocking parts of the wellbore due to chemical reactions.

While all these issues have different causes, the consequence, as experienced by the driller, is ultimately the same: Pipe movement is impossible. It is a popular approach to calculate friction factors from the pick-up, slack-off and drilling weights, and compared to the assumed ones. It has, however, to be noted that the thusly calculated friction factors lump together not only mechanical friction, but also the increased friction due to larger contact area (as caused by spiraling wellbores), resistance or drag caused by the viscosity of the drilling fluid. Furthermore, the type of drilling fluid has an influence as well: Oil-based drilling mud (OBM) has significantly better lubricating properties than water-based fluids (hence their application as lubricating pills when stuck pipe is expected or has occurred already). The resulting friction factor should not be seen as a single true friction value for contact between the (assumedly smooth) wellbore wall and the drill pipe, and should hence always be referred to as "pseudo-friction factor", and more importantly, it should never be used to compare two different wells!

However, such calculations are still handy, because they allow the observation of trends more easily than simply recording the PU and SO weights. Trends are a good indicator of changes in the wellbore condition. For example, a sudden increase in friction over a segment that has not shown this behavior previously can be an indication of a problem that needs to be dealt with, e.g. by a wiper trip or additional reaming.

2.3.3 Flow Assurance

A good well allows the fluids to be produced without any unnecessary resistance to flow, caused by phenomena like slugging, downhole separation or by a trajectory that allows phases to accumulate and become immobile. Several aspects come into play here, among them the trajectory, but also the design of downhole tools and the tubing string itself.

2.3.4 Phase "Movability"

While guaranteeing steady flow through the wellbore is of utter importance throughout the whole life cycle of a well, it is critical during production in order to maintain the desired rates and reduce wear on the pump equipment to a minimum.

Unless production of fluids happens as a pure single phase production (i.e. a pressure above the bubble point throughout the whole wellbore and sufficiently high flow velocities to lift solids suspended in the liquid), phase separation due to the density difference will occur. This may not be a major concern in vertical wells with, but it can become a serious issue in highly deviated and horizontal wells. Add to this a not completely straight trajectory, but rather a wave-like one, and accumulation of different phases will occur quickly.

The problem with phase accumulation has two direct consequences: First of all, pumping becomes more troublesome, as the accumulated phases will show different behavior due to their various rheological properties. This could lead to an additional wear of the pumps, e.g. by running "dry" (i.e. sucking gas instead of liquids), or by rod string buckling due to increased resistance when moving through a more viscous fluid. Secondly, some pump types do not cope well with certain types of fluids, such as SRPs which cannot handle gas at all.

Another phenomenon that can occur, especially in long horizontal section that are not a straight line, but e.g. following a bed guided by geosteering, is slugging. This means that on phase separates from the others and moves through the tubing faster than the rest. Gas is the typical fluid to show this behavior due to the enormous density contrast between the gaseous and the liquid phases. This phenomenon is essentially the same as what can be observed at home with tap water, when a gas bubble enters the piping system. Water will suddenly stop flowing until the gas is circulated out of the system.

While at home, this may only be annoying, this may have serious consequences for production: Surface equipment may not be designed to handle gas. This can result for example in reciprocating pumps that provide the energy for the fluids to flow to a gathering station to essentially stop working, because they start compressing gas instead of expelling liquid, thus reducing the output.

$$v = \frac{4Q_{pump}}{d_i^2 \pi}$$

2.3.5 Skin Effect

Various factors can influence the additional pressure drawdown around a wellbore, also known as the skin effect. The ones that are most relevant in the context of this thesis are probably the following:

- Skin due to wellbore cleanup: This is actually a factor that is influenced in the last stages of drilling, just prior to running casing. However, since skin manifests itself only in the testing and production phase, this issue is discussed here. Wellbore cleanup comprises everything that is related to removing remainders of the drilling mud and cuttings after finishing drilling. This is not only limited to wiper trips and circulating the hole clean. It is also important to remove filter cake if possible. For this, it may also be required to use acid in order to dissolve particles that block the pores and thus impair the inflow into the well
- Skin caused by cementation: If a cased hole completion is chosen, a (relatively heavy) cement slurry is pumped into the wellbore and around the casing. This may serve several purposes. First of all, the cementation isolates several hydrocarbon intervals, and acts as a seal towards the surface, thus ensuring zonal isolation and preventing migration of hydrocarbons outside of the casing.
  A second purpose can be to control an unstable wellbore wall. For example, if there is a risk of breakouts, it is advisable to run and cement CSG; otherwise production equipment such as packers and TBG may end up as a fish in the hole, if the formation breaks down and the debris accumulates on the downhole tools. Likewise, the cementation – together with casing – can be used as a means of sand control: unconsolidated sand particles can be held together by the cement and thus the sand mobility is decreased.
  However, there are some potential problems that can arise from cement jobs. They are related to the high density of cement slurries (except for special, very light mixtures with a weight of around 1.2s.g., slurries have a density of more than 1,600kg/m^3): The high pressure caused by the cement weight results in increased filtration into the formation. The particles in the cement slurry can then block the pores, resulting in reduced flow capacity. Additionally, the flow properties can be impaired by cement slurry hardening within the pores, thus basically irremovably blocking them. These phenomena connected with slurry or components thereof entering the pore space are facilitated by the high specific weight.
  Although this has nothing to do with the skin effect, it also seems worth mentioning in this context that the pressure exerted by a poorly planned cement job can cause the formation to fail, resulting in fracturing and fluid loss (ultimately with the danger of not achieving the required cement column).
- Skin caused by completion: The main issue related to completion is the need for perforations in a cased hole environment. The perforation shots alter the stress situation locally, which affects the permeability of the rock. More importantly, the debris of the shaped chare and the destroyed rock blocks the pores and thus decreases the flow properties even further. Thus, the pathways into the formation – while necessary to allow production – can actually reduce the inflow potential quite significantly. However, the consequences can be limited, e.g. by

ensuring a slight underbalance during perforation. This allows at least part of the debris to flow back into the wellbore immediately, reducing the impact. A second possibility is to implement technology alternatives to perforation with shaped charges, such as hydrojetting.

Other factors that are basically relevant to skin factor are the trajectory, stimulation or turbulence effects in the near-wellbore region; they do not play a major role within the scope of this thesis.

2.3.6 Solids Control

Particularly in unconsolidated rocks, which often are the highest quality reservoirs, solids production is a remarkable issue. The main problem in this context is that solids – particularly quartz, the main constituent of sandstones – are highly abrasive. While some pump types handle solids production quite well (e.g. ESPs), others suffer from significantly decreased equipment life time (for example, the valves of SRPs are very prone to this type of wear).

2.3.7 Pump Life Time

Mechanical equipment is prone to failure. Pumps, due to their very nature of being in contact with various fluids and potentially solids, their size and the permanent motion they are subject to, are among the equipment parts that are most likely to fail. Responsible for this is not only the permanent load cycling, which is amplified by bending moments and friction-related torque as well as drag (depending on the functionality of the pump): Corrosion and erosion affect the pump life time as well as the produced fluids.

Abrasive particles in the production fluids result in an increase of erosion, e.g. on pump seals, and other relatively narrow passages. Fluid components, such as H_2S or CO_2 have a negative decrease the life time of rubber elements, which affects primarily the sealing parts of ESPs. Moreover, these constituents are a significant contributor to corrosion and the related failures (with H2S having a very particular role in this context).

2.3.8 Fitness for Purpose

Readiness for purpose is a key thing: Imagine an oil production well that has perfect quality, but is placed just below the oil water contact (OWC). That well will never be able to produce oil; at best, it can be converted to an injector. Or imagine an injector well that is placed just in a position where the rock has significantly lower permeability than in the rest of the reservoir. This well cannot be used for anything at all.

On the other hand, a less than perfectly drilled well that can exceed the expectations from the production aspects will still be a perfect well of some kind – as long as it is possible to compensate for the things that were not optimal during drilling.

It is obviously important to make compromises and not to focus on a single aspect – it is the "bigger picture" that counts most!

Once the well is drilled and completed, there is no more opportunity of remedying any problems. Any issues related to wellbore quality detected from now on can only be minimized by the application of special technology.

Chapter 3 Indications and Measurement

As there are many factors that can influence wellbore quality, there are just as many manifestations and indications. It is generally possible to detect many of the indications already in the drilling phase, but one has to be aware of their meaning in order to take the right measures.

Sometimes, however, it is not possible to interpret the indications, or they are missing. Hence it is good to have a set of tools that can be applied to quantify wellbore quality. Quantification is also important for performance measurement and in order to make comparisons. For such quantifications to be successful, there are some basic requirements:

- The tool must be simple to apply and even simpler to understand.
- The tool must rely on physical measurements, not on personal judgement.
- The tool must be applicable on a wide variety of cases, not tailored to one specific field or even well.
- Ideally, the tool should rely on data that are measured on a standard MWD, LWD or WL logging run, or on rig sensor data.

3.1 Assessing the Wellbore Shape

3.1.1 Caliper Logs

Caliper measurements are mechanical tools that can measure the diameter of a wellbore in one or more directions. However, there are several alternative technologies that can provide even more detailed information than mechanical calipers. This includes for example ultrasonic or density caliper measurements. The advantage of such technologies is that they can more easily be run on a LWD assembly with a lower risk of getting stuck, as there is no direct contact of the tool with the wellbore wall necessary; these tools are also able to provide true 360° data (compared to the localized information of a mechanical caliper, whose accuracy depends on the number of arms), giving a more detailed impression of the wellbore shape and allowing a more precise volume calculation.

What do such measurements have to do with wellbore quality? The answer is simple: A good quality borehole has an in-gauge (or slightly over gauge) diameter, and this continuously over its total length. The importance of this is explained simply: An under-gauge hole will very much likely cause trouble running casing, cementing it and installing completion equipment as planned. It may not even allow to run casing to TD. Under-gauge holes may be a result of poor drilling practices, such as using a severely worn bit, or of adhering to an inappropriate mud program that is either not supporting the wellbore to ensure WBS, or the system could lack inhibitive properties! Over-gauge holes on the other hand may also be a result of insufficient wellbore stability or of highly unconsolidated zones, which can also put the well at risk. Furthermore, it is important to know the hole volume, in order to be able to cement the well ensuring that the top of cement (TOC) is reached or exceeded.

3.1.1.1 Reasons for Diameter Variations

In order to evaluate wellbore quality based on caliper logs, it is important to understand what can cause deviations from gauge-size. Basically, there is four basic reasons, why that happens:

1. **Lithology**: Some formation types, such as certain clays, tend to react with water-based mud (WBM), causing them to expand ("swelling clays"). Others tend to be dissolved if the chemistry is poorly chosen (salt)
2. **Stress regime**: Subsurface stresses can cause borehole breakouts, if the mud weight is not adjusted to support the formation. This will result in a deformation of the wellbore to a somewhat elliptical shape, which can be easily seen in four-arm caliper logs, which show a distinct pattern: A hole enlargement (over-gauge) in one direction, and a diameter reduction (under-gauge) in the perpendicular direction.
3. **Drilling practices**: On the one hand, obviously mud weight plays a major role in stabilizing the well and avoiding breakouts; on the other hand, circulation rates are also a major impact, particularly in loose formations. These can easily be washed out to several multiples of the bit size, which can be a problem particularly in top hole sections, where accurate hole volume determination may become impossible.
4. **Trajectory**: Aggressive well paths with high bends show a phenomenon where the stiff BHA components start eroding the formation on the inner side of the bend. This results in a characteristic wellbore cross section similar to a key hole. This is often associated with a "key seating", where the drill bit cannot fit through the sharper inner bend when pulling out, and the narrower hole, causing the drill string to get stuck.
   Additionally, it renders the actually drilled hole practically inaccessible for wiper trips etc., which may add hole cleaning problems in those sections.

3.1.1.2 LWD Calipers

LWD calipers measure sonic wave signals or density, and derive the device standoff from those measurements. The implementation in LWD BHAs, allows real-time transfer of data (although most commonly only recorded on the memory gauge) and observation of the development of the wellbore diameter during drilling (e.g. by comparing several passes of the tool, or comparing the LWD data with wireline data after drilling).

Density Caliper

Density caliper logs can measure the tool standoff using the density difference between the rock and the annular fluid. However, a high mud weight – the limit is around 12-14ppg (Butt and Fareed 2007) – has a negative influence on the data quality and hence on the reliability of the measurement. This is, because the density contrast between formation and drilling fluid becomes too small to yield reliable results.

Another factor that influences the data quality is the photoelectric factor (PEF) of the mud: This radioactive effect, which is largely influenced by the potassium content of the mud (for example in the form of KCl used to inhibit clay swelling), is the basic measurement principle.

It should also be noted that this technology can produce 360° data, but data acquisition is only possible when the drill string is rotating. This makes its use during tripping operations and directions (sliding) drilling impossible. The advantage of this technology, however, is that it can be used to obtain real time data.

Ultrasonic Caliper

The alternative tool for LWD calipers is the ultrasonic caliper, measuring the two-way travel time of an ultrasonic signal from the sender to the wellbore wall and back to the receiver. Its measurement principle is, similar to reflection seismic, the contrast of acoustic impedances in two neighboring media. The acoustic impedance is defined as

$$Z = \rho \cdot v_s \tag{2}$$

where Z is the acoustic impedance, ρ is the density of the medium and v_s is the acoustic velocity in the medium. As for the density caliper, the drilling fluid density is a major limitation: As the acoustic impedance of the mud approaches the one of the formation, the reflected signal becomes less defined and hence less reliable (the lower the mud weight the better the accuracy at larger standoff). Furthermore, the attenuation of the signal will increase with increasing mud density, which also deteriorates the signal. Other factors affecting ultrasonic caliper measurements are borehole wall rugosity and the cuttings concentration in the mud, as those will scatter the wave, as well as the presence of gas, disturbing the travel time and causing additional scattering as well.

However, if the drilling fluid has a relatively steady and well-defined acoustic impedance, as the properties will not change much (assuming that no significant compositional changes such as barite sagging happen in the wellbore). Hence the measurement is very precise, detecting very small features of less than two inches extension, and measuring the wellbore diameter with an accuracy of up to 0.5inches.

There are some differences between LWD and mechanical wireline (WL) calipers, that should be kept in mind:

- The LWD tool "sees" the well as it has been drilled, i.e. with only a short lag. Hence even the most reactive formations cannot react quickly enough to be noticed in LWD caliper logs. Moreover, the longer the time the well is exposed to circulation, the more likely hole enlargement will be; again, the LWD is unaffected by this.
- The physical measurements of LWD calipers on the other hand are strongly dependent on various parameters such as density of the drilling fluid or the density contrast between fluid and formation. Hence, they tend to yield distorted data.
- Mechanical calipers rely on arms pressed against the formation by springs. This is a relatively simple and fail-safe measurement, which is hardly influenced.
- Mechanical calipers are run after well has been exposed to influences of the wellbore environment for some time (circulation, fluids…). This means that time-dependent effects can be observed in such logs.

Comparing the readings of LWD and WL logs after the mandatory depth shift can give indication of the wellbore condition.

Hence it makes no sense to compare WL and LWD calipers directly. Also, it is futile to base hole volume calculations on LWD data, as they may not only be off, but they will actually miss the effects of events that happen between the tool has passed a position.

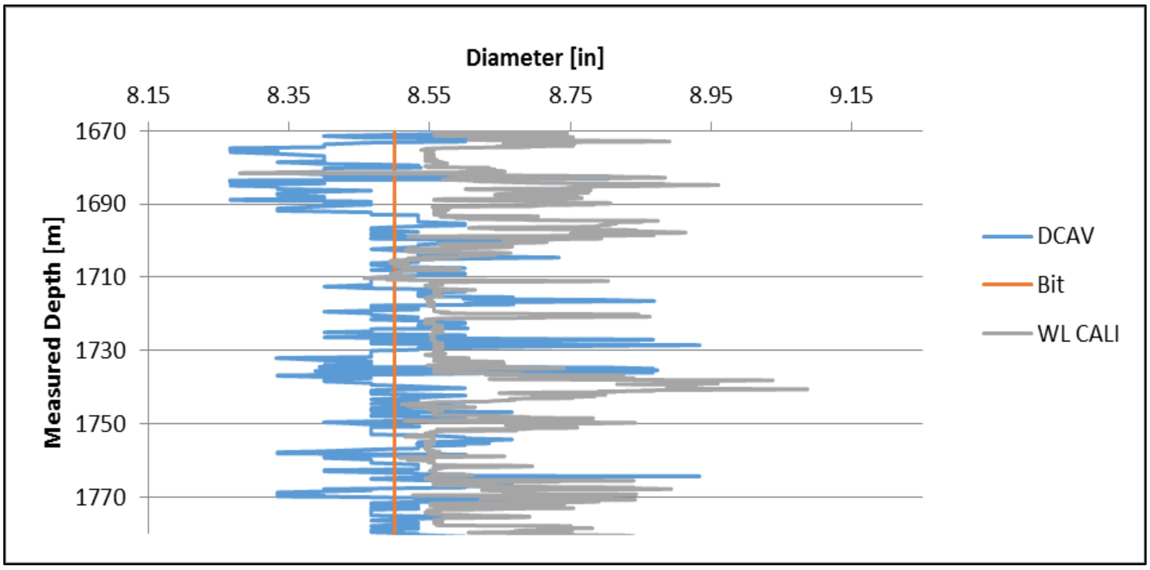


Figure 4: Caliper log from a real well; blue line: LWD caliper, grey line: WL caliper. Note the deviation from the bit size – while the LWD caliper indicates long under-gauge sections, the WL log shows the opposite.

A point that needs to be made is that LWD caliper measurements are a nice thing to have, but may not reflect the real situation at all, as Figure 4. shows. The well has been drilled with a relatively high potassium content in the mud, due to swelling clays. This may have impaired the LWD caliper, as the wireline result is supported by both the tripping and casing running experience on this well: No restrictions encountered although they might be expected due to the quite significant difference between bit size and the LWD diameter measurement.

Moreover, the different reference levels need to be accounted for: Driller's depth and logger's depth are usually not identical, which makes a depth shift of the data necessary prior to comparing them. This becomes increasingly complex as measured depth (MD) increases.

3.1.2 Use of Image Logs

Image logs are 360° visualizations of the wellbore wall based on resistivity or (ultra-) sonic measurements. It is, as MacDonald and Lubinski (1951) put it, a "non-routine drilling tool" these days. Nevertheless, there is a wide spectrum of applications for such tools, reaching from wellbore stability analysis over geological purposes to a good data source for geomechanics applications. Image logs can be run as part of both LWD and wireline logging runs.

3.1.2.1 Detection of Wellbore Spiraling

Wellbore spiraling can be detected in image logs because of its quite distinct signature: Layer boundaries appear as slanted lines instead of horizontal ones, and sinusoidal layer boundaries (if the layer is drilled at an angle other than perpendicular to the boundary) are also distorted. This phenomenon is illustrated in Figure 5. However, these features have to be manually interpreted, with only little assistance by analysis programs. As a result of this, this method is imprecise and should not serve as a quality indication. Moreover, there is no useful means of quantifying the results of such an analysis. Still it is a solid tool for the detection of wellbore spiraling, particularly if the layer boundaries are as prominent as shown in the figure.

It is worth mentioning that image logs need to come from LWD tools in order to use them for the detection of wellbore spiraling: WL tools are too slim to actually record this kind of issue properly, they will simply pass through the free straight pathway, giving the impression of a non-spiraling well path.

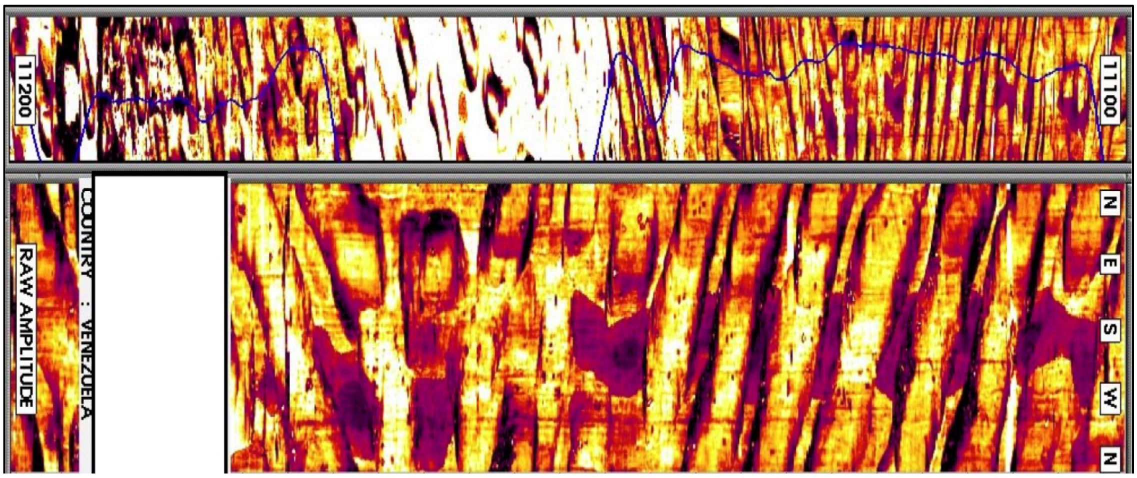


Figure 5: Wellbore spiraling as visualized in image logs. Note the slanted layer boundaries, which are typical for this kind of drilling problem (Gaynor, et al. 2001)

3.1.2.2 Wellbore Stability Interpretation

Wellbore stability issues will always count as a WBQ issue. Be it that a shale formation starts swelling and causes stuck pipe or prevents casing from being run to its planned setting depth, or that a formation starts to break and rocks fall into the wellbore, also causing stuck pipe problems.

First of all, it may be an indicator for poor planning: If such behavior can be expected (offset well information, analogies, geomechanics studies…), preventive measures have to be taken; everything else will count as poor planning, which – as defined by Mason and Chen – is poor WBQ. WBS problems manifest themselves in several ways. It could be as simple as an over-gauge hole because of breakouts, but it could also be some more complex failure like a change of wellbore shape due to the downhole stress situation, fracturing, or the (re-)activation of faults. Most of these (except fracturing) increase the risk of getting stuck, as either the wellbore geometry (cross section) changes, or because debris can accumulate on tool joints.

It could just as well be poor practices: Ignoring the fact that such things can happen and continuing operations without adapting, for example due to time or financial pressure. A practical example would be to drill salt with WBM instead of changing the fluid system to OBM in order to reduce the solubility of the salt in the mud. This costs time (and money for the additional fluid system and equipment), and may hence seem undesirable. On the other hand, the expenses of adding more and more salt to the mud, or of additional cement should not be forgotten; nor should be the long-term costs, if such drilling practices cause safety or environmental hazards.

And even if this is completely unexpected – for example on wildcat wells – WBS problems reflect back on poor wellbore quality. Not being able to run casing to TD is just as much of a problem as not reaching the required top of cement because the whole volume is much larger than anticipated due to washouts or breakouts: Both result in an unreliable well, as formation isolation and hydrocarbon migration outside of the casing cannot be excluded.

A typical tool to detect wellbore stability issues is a multi-arm caliper run on wireline, or perhaps also a sonic LWD caliper. Less common, but when interpreted carefully much more powerful a tool are image logs. They can visualize breakouts and washout zones, giving a 360° view. This makes is less probable that significant diameter changes are missed, which can happen quite easily, when the typical four-arm caliper has an adverse orientation with respect to the breakouts or washouts.

However, caliper logs can also be used, especially oriented caliper logs. These tools do not only record the wellbore diameter, but also the direction in which is measured relative to North. This means is a helpful tool for the WBS interpretation process.

Wellbore stability is an issue that can easily be addressed and de-risked by a detailed study of the geomechanics. Such studies show a detailed image of stress directions, which can assist in making better drilling decisions, and reduce time and money spent on dealing with WBS problems[7].

Compared to caliper measurements, image logs are significantly more complex. However, they also allow a much more detailed and precise interpretation of wellbore stability related data. While breakouts and washouts may not be found in caliper logs, either because they are too small features, or because the tool's arms are adversely oriented, they will always be visible in borehole images, although an expert is required for the interpretation.

[7] As a rule of thumb, it is often said that WBS problems are ca. 10-15% of the total well cost – a significant savings potential.

The advantage of these tools over calipers goes even further – it is not only possible to detect all WBS-related features, but also to find the direction of failure, and even the angular extension. This allows drawing further conclusions about the stresses downhole, and is hence not only a tool to detect WBQ issues, but also (together with other sources like leak-off tests) an excellent data source for geomechanical modeling, and as such for the prevention of repeated events. Figure 6 shows borehole breakouts as darker areas which are not quite as well resolved as the rest of the image.

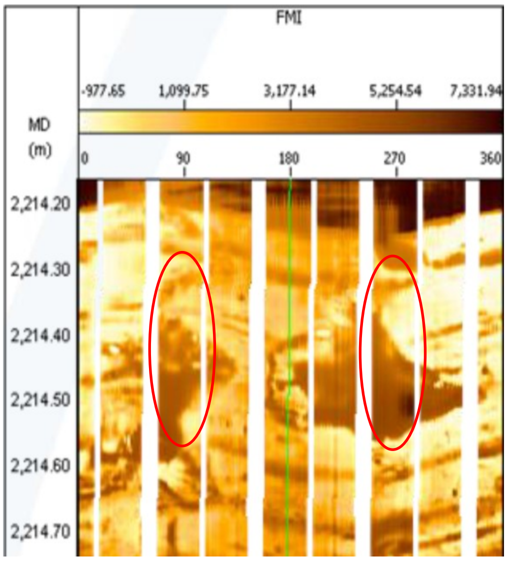


Figure 6: Image log of a breakout zone (darker and slightly blurry areas at around 2,214.4-2,214.6mMD, at the 90° and 270° positions, respectively*)*. (Persaud and Schulze n.d.)

In addition to this, it is possible to interpret faults, fractures (and identify between natural and drilling-induced ones) as well as the dip of all geological features. While this does not have to do directly with wellbore quality, it is important information for understanding the underlying geomechanics, and thus can help improve future wells.

3.1.2.3 Well Placement Assistance: Geosteering Application

There is even more use for image logs, for example on the field of geosteering. This can also assist the improvement of wellbore quality, as it can help placing a well in an optimum position in a reservoir layer along a longer horizontal path. This can be achieved by identifying certain patterns in the real-time image, which indicate whether the well is still within the layer, or whether it moves out of it.

While the improvement of the drilling experience may be little, if any, there are several advantages for completion and production. For example, if the well can be kept in a competent layer, the well can be completed open-hole, which improves inflow, helps keeping skin low and of course saves the money for casing and cementing.

A field study on this topic was published by Tribe, Holm, Harker et al. (2003); a detailed summary can be found in "Image Logs for Well Placement" in the Appendix.

3.1.3 Assessing the Hole Enlargement

Knezevic, Hollerer and Knoop (2016) came up with another approach to determining the hole volume. Their approach is to investigate the shift between theoretical and actual lag times of the response of gas readings to making connections in time logs can be used to derive the wellbore volume: When making a connection, the gas readings will change because of the stopped drilling action and circulation. The theoretical lag with which this change can be detected at surface can easily be calculated using the pump rate and the ideal geometry.

The difference between actual and theoretical lag can be attributed to changes in wellbore shape (hole enlargement) and the subsequent changes in flow velocity. The advantage of using such a system is that it delivers more reliable numbers than LWD calipers in nearly real-time.

3.2 Assessing the Trajectory

Positional surveys can be used to verify well placement objectives; MWD surveys provide the additional advantage of providing nearly real-time (RT) information[8], allowing to make changes immediately after deviations from the plan are detected. However, there will always be a certain deviation that is due to nature not being completely predictable.

Drilling deviated holes will always result in doglegs. Especially the use of rotary steerable systems (RSS) and downhole motors has added an additional source of doglegs, namely at the transition between rotating and sliding mode. Such doglegs result in an additional load on drill pipe and downhole tools, as the bending combined with rotation leads to cyclic stress reversals, reducing the life time of the elements. Furthermore, they are an additional risk for getting stuck (The expected type of stuck pipe at doglegs would be key seating).

3.2.1 Continuous Surveys

An alternative to the traditional surveys are so called continuous direction and inclination measurements (cDNI). Those are MWD tools that can record positional data in a very short time interval while drilling. This is possible thanks to recent developments in the field of gyro and magnetometer tools, which now allow them to work not only under static conditions, but also when fluid is being pumped through them.

This interval can be as short as 30 seconds, and typically is no longer than 90 seconds. At a (quite high) rate of penetration of 30m/hr, this results in a survey distance of 25-75cm. Since this interval is very short compared to the total wellbore length, this type of measurement can be seen as continuous. Although this tool obviously requires additional channels for data recording and transmission, it allows not only for real-time data which can be used to assess trends and counteract earlier, allowing a smoother wellbore trajectory, but it also is relatively simple: There is little additional knowhow required, as the cDNI tool uses the same measurement principle as standard survey tools.

[8] Usually surveys are taken while making a connection, so roughly every 30m. This is not real time, but should normally be sufficient for landing a well. Surveys can be taken in shorter intervals if more detailed information is required for placing the well.

These tools can be used to identify deviations from the planned trajectory. Thus well placement can be optimized and severe doglegs may be mitigated. Furthermore, a more detailed impression of the well path can be obtained during the drilling process, giving more time to select an optimum pump position, starting already while drilling the interval and not only after taking the final survey. This also allows a more thorough consideration of the equipment limitations and production requirements as well as the present state of the wellbore. A limiting factor that needs to be considered in this context is that the MWD tool is not located directly behind the bit. It is, like any other measurement tool, typically at a distance of 5 to 25m behind the bit, which means that any measurement will have a certain lag of minutes up to hours. While this is not necessarily a problem *per se*, it needs to be taken into account!

3.2.2 Bending Moments

Closely related to the both the problem of doglegs and of early tool failure are bending moments. Hence it seems logical to investigate the bending moments acting on tools already in the drilling phase. Marland and Greenwood (2015) have proposed a system that allows to measure this mechanical parameter as part of an LWD BHA.

Their research focuses not only the behavior under drilling conditions, but also on the comparison between bending moments under drilling loads and under tension (=tripping). Typically, these two measurements should yield nearly identical results; however, the results may strongly vary during slide-drilling, "representing the bending moment associated with the directional change." (Marland and Greenwood 2015). The tool design incorporates several additional features:

The strain gauges are lain out over the tool body in such way, that not only the severity of the bending can be measured, but also the direction. The layout also takes into account that bending due to doglegs can be distinguished from bending due to rotation.

Furthermore, knowing the measurement sub dimensions, it is possible to derive the DLS from the measurements. The thus calculated DLS is by far more detailed than the one derived from surveys. Figure 7 (taken from paper SPE-173039-MS) shows that the actual dogleg (as inferred from the bending moment) can be very close to the one calculated from the survey points (shown in the top figure); however, it can also be quite off, or the survey value is "dislocated" due to averaging over a larger interval.

What Figure 7 also shows nicely is that it is possible to relate doglegs to certain drilling events. For example, the bending moment record (blue line) shows a significant increase between the indications 8,450ft and 8,575ft, related to slide-drilling. Logically, the DLS also increases in this interval. However, and this is an important thing to note, the survey DLS shows the peak significantly only at 8,600ft, where already 25ft have been drilled in rotating mode.

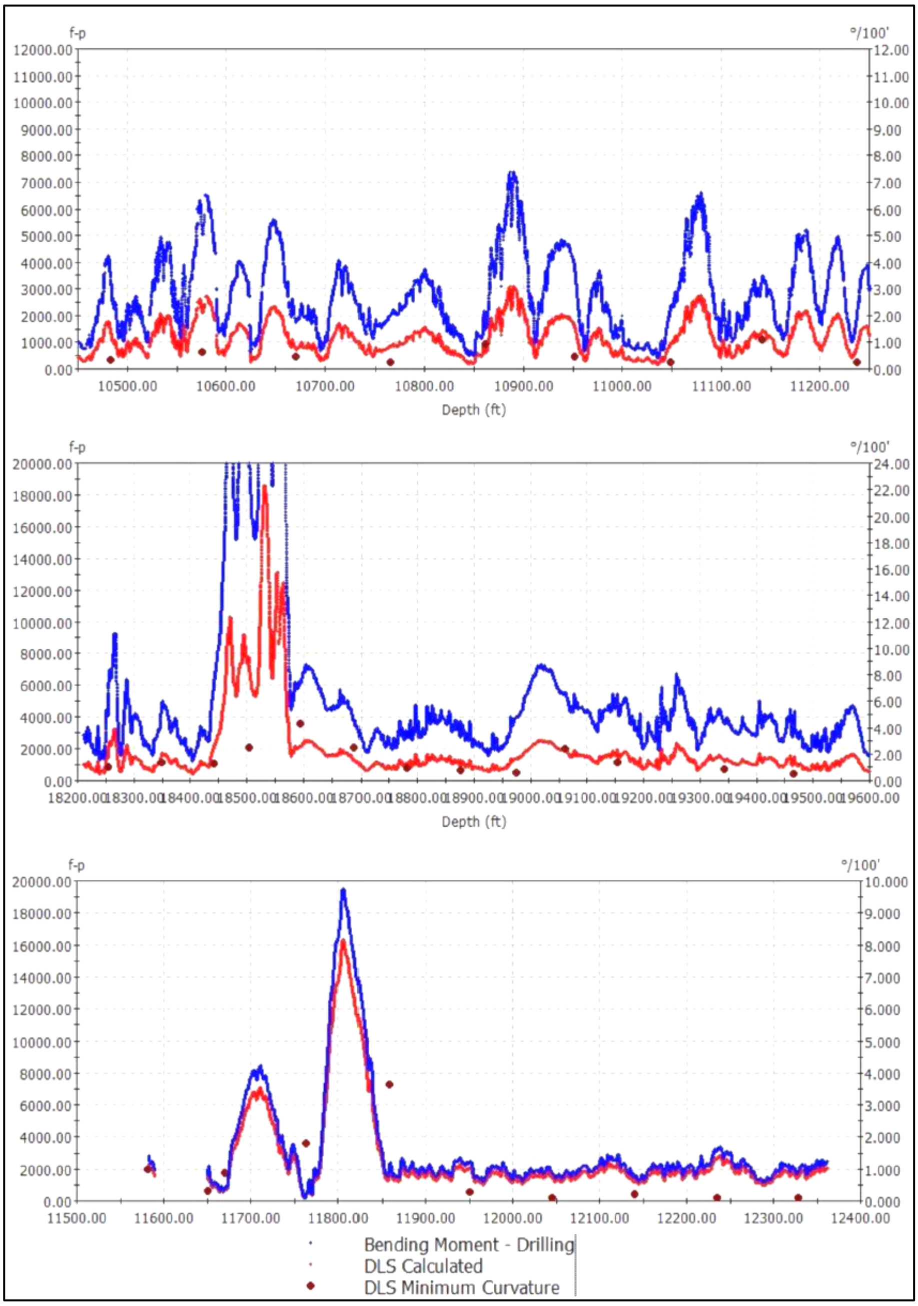


Figure 7: The recordings from three different case studies show that the DLS inferred from bending moments can be very close to the one from surveys, but the survey can also be noticeably off (Marland and Greenwood)

However, it seems worth mentioning that the above findings are all published in a paper authored by two employees of a service company that provides this kind of measurements. A report about the experience from an operator's point of view has not been found, hence the observations could not be verified, nor is it possible to judge the long-term benefits of this measurement. It seems to have potential to improve pump placement decisions and perhaps also for tool design and selection, if the actual loads are better known.

3.2.3 Identifying Wellbore Tortuosity

3.2.3.1 Measurement via "Pseudo-Friction Factors"

Measuring wellbore spiraling is more challenging than measuring friction or hole sizes. While attempts have been made to infer it from friction factor calculations, this method is rather unreliable, as it lumps together several factors, not all of which are actually related to spiraling. Obviously, the longer well path due to wellbore tortuosity – combined with ledges that create additional resistance when moving pipe – manifests itself in higher forces along the pipes. These higher running forces, typically referred to as hook load (HL), pick-up and slack-off weights, will appear as increased friction, but it is questionable whether those things should be considered in a "pseudo-friction factor". While it gives a quick impression of how the actual weights correlated to the anticipated ones, but there are several issues that make a serious derivation of tortuosity from those values unreliable:

- Quality of the pre-drilling estimated friction factors – if the originally assumed friction factor is unrealistically low or high, the planned and actual values will strongly differ, and (potentially wrong) consequences might be drawn. A potential source of friction factors can come from EPSLOG tools, where a knife is run along a core, and from the required force to move the tool, friction factors can be derived on a very small scale level.
- Lumping things together – friction factor calculations from HL, PU and SO weights are the result of several mechanical phenomena, which are all lumped together. Hence, the term "pseudo-friction factor" seems to be better suited. Along with actual mechanical friction (i.e. from the contact of the pipe body with the wellbore wall), these values include the resistance caused by ledges, pressure forces (surge and swab), that are more inertial than frictional forces dependent mainly on BHA design (e.g. open- or closed-ended drill string) and mud viscosity, to name just a few influences.

Due to those above points, it is impractical to infer anything from the data obtained from measuring HL, PU and SO weights, other than trends that show a potential change in downhole conditions and to identify deviations from the plan. The reason for those is, however, to be investigated to a greater extent in order to get valid information.

The observation of hook load trends and events against those trends is an important indicator that something might be wrong with the wellbore (e.g. decreasing loads while tripping in might be an indication for a tight spot to be monitored and possibly reamed free prior to running casing).

3.2.3.2 Detection via Caliper Logs

Wellbore spiraling essentially affects the effective wellbore diameter. For example, it can manifest itself in long (slightly) under-gauge sections, regardless of formation changes etc. It is hence relatively easy to distinguish between localized (and more random) events such as breakouts or washouts and micro-tortuosity.

However, it must be kept in mind that WL tools are narrow compared to the wellbore diameter. Hence it is possible that WL calipers are hardly affected by spiraling. Thus a more reliable source may be LWD calipers, which have their own limitations which are explained on p.20.

3.2.3.3 Directional Difficulty Index

The Directional Difficulty Index (DDI) has been developed as a performance benchmarking system. The idea was to allow an "examination on a like-by-like basis" (Oag and Williams 2000), by classifying wells according to their planned directional difficulty. This became necessary, because with increasingly complex wells the comparison of drilling performance based only on parameters such as cost per meter or time per 1000m became unfair: A vertical well can simply be drilled faster to the same MD as a horizontal one, because technical difficulties such as providing weight on bit and directional drilling slow down the drilling process of directional wells compared to vertical ones.

With the DDI, it is possible to compare only wells of the same difficulty, thus again obtaining a fair ranking.

The authors defined the Directional Difficulty Index as

$$DDI = \log_{10} \frac{MD}{TVD} \cdot AHD \cdot T \tag{3}$$

where MD and TVD are the measured and true vertical depths, respectively, $AHD = \sqrt{N^2 + E^2}$is the along-hole displacement (N and E are northing and easting), and $T = \sum DLS$ is the wellbore tortuosity, the sum of all doglegs. Typical results are in the range of 5-8, with 5 being the easiest well to drill.

Due to the nature of how the DDI is defined by Oag and Williams, it seems possible to also compare the planned and actual DDIs. The difference represents the deviation from the plan, thus being an indication for poor wellbore quality.

There is a major problem with this parameter: It does not consider any contributing factors to directional drilling difficulties other than the well trajectory itself. However, and their influence is often not negligible. For example, the influence of the geological situation alone is quite complex: It can be seen in the contribution of the downhole stress regime, which can make drilling in some directions close to impossible; it can also manifest itself in rock strength, creating a natural directional tendency, or in friction, which basically counteracts any drilling action.

3.2.3.4 Countermeasures

Since the reasons for this phenomenon are well known, attempts to counteract the occurrence of spiraling holes have been made. Among those, the most prolific one is probably the so-called "extended gauge bit". It can be somewhat compared to a drill bit that is used at home to drill wood or concrete, i.e. a longer section of the bit is in-gauge, resulting in a better stability. The extended bit body works similar to a near-bit stabilizer, but with the advantage that the extended gauge actually has the same diameter as the bit itself, thus nearly completely preventing any oscillations.

Nevertheless, such tools may also create some problems, for example with the drilling hydraulics (high pressure losses due to the turbulent flow regime around such a tool). These are, however, not considered to further detail, as this is not within the scope of this thesis.

Another countermeasure, at least to a certain extent could be reaming those sections severely affected by wellbore spiraling. While it may not help to completely erase the problem, it can at least reduce it to a more tolerable level. An ultimate solution could also be the use of hole openers: Increasing the wellbore diameter will automatically also help increasing the tool passage. However, this comes at the cost of more required cement and potentially the need for better centralization of drill pipe and casing in these sections.

3.3 Wellbore Quality Scorecard

The Wellbore Quality Scorecard is a concept presented in "The Wellbore Quality Scorecard (WQS)" (Mason and Chen, 2006). The basic idea is that the driller assumes the role of a "medic for the wellbore" – he collects, assesses and interprets the symptoms as seen by the drilling crew during the well construction process. These symptoms are classified into three categories with different weights in the overall assessment:

1. **Drilling Experience.** This includes factors like stuck pipe, problems related to the circulating system (e.g. fluid losses, poor hole cleaning) and torque and drag responses. It contributes with a maximum of 25% of the total score (corresponding to 5 points).
2. **Final Trip Out of Hole.** The final trip is weighed with 35% (7 points). This is the last chance to take relatively simple countermeasures should problems with the wellbore be detected. The final trip considers again factors such as stuck pipe and drag response, but also includes overpull and the experience during backreaming (torque response).
3. **Casing Running Response.** In this part, problems related to stuck casing, ability to run the casing string to the planned depth, but also the unplanned use of rotation or circulation to run the casing to TD. Casing run contributes the most: 40% of the total score, equivalent to 8 points, are attributed to it. The reason for the high value of the casing running experience is simple: It is the last chance ever to detect and remedy issues with the wellbore.

It has to be noted that stuck pipe will always lead to a score of 0 points in the respective area, be it while drilling, tripping or running casing. Encountering any of the problems considered by Mason and Chen loses the well some points. The total points achieved by the wellbore represent the degree of perfection the wellbore reaches. A "perfect wellbore" scores the maximum of 20 points on the scorecard, whereas a poor job scores less than 5.

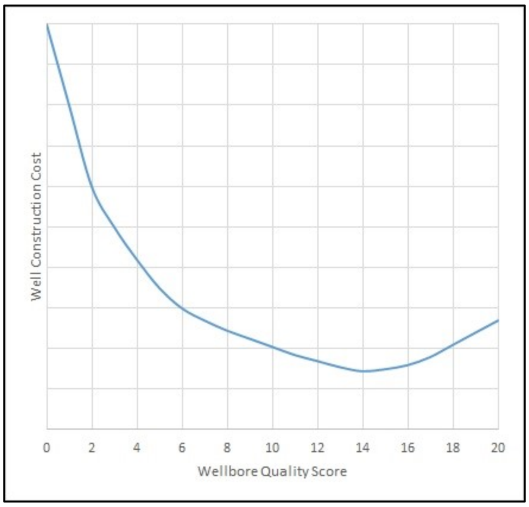


Figure 8: Graph showing the relationship between wellbore quality and well construction cost. Note that the lowest cost is associated with an intermediate to high performing well, rather than the "Perfect Well" (modified after Mason and Chen, 2006)

Mason and Chen have also studied several wells with respect to the project economics compared to wellbore quality. The results are displayed in Figure 8. It also has to be noted that the lowest costs are associated with wells in the "good quality" area of 12-16 points. Only drilling costs were considered in this study. The fact that it is cheaper to score 20 points than 5 or less is not as surprising.

3.3.1 Limitations of the WQS Method

This concept is an after-action review, hence corrective measures can still be taken, but at potentially higher cost (additional tools, more rig days, etc.) than anticipated, and remedial actions may be more difficult as existing equipment may need to be taken care of.

Another downside of this method is that – despite the strict rules of how to apply the WQS – it is still to be considered "expert judgement", and as such not a preferable assessment strategy. For example, there is still room for interpretation if preventing a stuck pipe incident by excessive reaming (because the driller reacts to clear indications that the drill string will get stuck soon) has to be considered stuck pipe or not.

Additionally, relying on daily drilling reports (DDR) is a certain risk: Experience obtained during the field study shows that not all issues are reported, not by the driller only, anyway. Hence the daily reports of all parties involved have to be scanned for hints of issues, and one could still miss important factors.

One of these weaknesses of this system is that it seems to define certain factors quite imprecisely. For instance, it is not clear, whether a wiper trip prior to the final trip out of hole should be counted as the experience of the final trip (this is important, because issues encountered on this wiper trip might be remedied prior to the final trip, which ultimately influences the final tripping experience). Furthermore, there formulations like "severe losses" leave much room for interpretation. For example: Are losses of $3m^3/hr$, which are not treated over a period of 10 hours (thus equaling $30m^3$ lost fluid) severe compared to 15 minutes of losses exceeding 30m^3/hr?[9]. This would most likely be up to the definition of the "expert" or the company.

3.4 Quantification via Skin Factor

While the above factors mainly cover drilling aspects, one should not forget the production effects of wellbore quality. Since production is mainly measured by the rate, a parameter strongly affected by wellbore skin, the skin factor bears some potential of being a measure for wellbore quality. It does not only relate to the production rate itself, but it can also be used as a link between drilling, completion and production, as they all are influencing factors.

Such a thing could be achieved by the comparison between the skin prior to and after workovers, being a measure not only for the well quality, but also for the workover effectiveness: If the difference is significant, this means on the one hand side that the wellbore cleanup has been insufficient, but the workover has been effective.

However, there is a significant problem with the quantification of WBQ via skin effect: The question, how much of the skin is due to bad operational practice, and how much is related to the formation itself, and could not be cured by well interventions, cleanup or stimulation. Hence, it is not a recommended practice to use skin factor as a priority tool to quantify wellbore quality. As mentioned before, it has some potential to judge workover efficiency, though – but still considering the fact that some of the effects that manifest themselves as skin effect may not be caused by drilling and completion.

3.5 Frequency of Downhole Equipment Failure

An abnormally high failure frequency or low mean time between failures (MTBF) of downhole equipment (regardless of purpose) indicates that something is not right with the wellbore.

While drilling tools may be not long enough in the well to show signs of tool failure, or they can be attributed to previous wells drilled, drilling tool failure would be the indicator "preferred" over failure of production equipment. If drilling equipment malfunctions occur and they can be attributed to WBQ issues, remedial actions can be taken. Once the well is cased, this is close to impossible, and at best production tools that can work under higher loads can be selected to cope with the issue – but at increased cost.

Another question is the parameter which failure frequency should be referenced to. While time seems like a convenient normalization parameter, it misses an important point: Failures due to wellbore quality are typically not "normal" load induced, but caused by a combined load of rotation and either tension, compression or bending. Since not all equipment will be used at the same (rotary) speed, time itself becomes quite an unreliable reference: Tool 1 runs for 2 years at a rotary speed of 60rpm and sees the same number of cycles as Tool 2 running for 1 year at 120rpm. If the first tool fails after 2 years,

[9] The author considers the first more of a quality problem, as an obvious issue – such an amount of lost circulation can hardly be missed! – is not being dealt with, whereas the second (extreme) example is not an actual (quality) issue, as it is cured quickly.

and the second one after 1.5, and the reference is time, it seems like Tool 1 is the better one.

However, in fact Tool 2 is the better one when the MTBF is normalized by cycles, as it experiences the same number of cycles as Tool 1 does in 3 years. And since time plays a minor role (unless corrosion comes into play as a cause for malfunction) for tool failure compared to the impact of stress reversals (corresponding to revolutions), it is more meaningful to compare load cycles rather than absolute time. Additionally, absolute time would be ambiguous, because it might or might not include still-standing time.

Another thing that needs to be taken into account is that a single failure is not a compelling indicator of poor wellbore quality. It could also be a manifestation of poor manufacturing quality. This means that only the repeated failure of tools can be seen as a sign of lacking WBQ.

While the above is aimed primarily at production tools, it also applies to downhole equipment used for drilling. However, service providers monitor the conditions closely, and they will inform the operator about conditions outside of the tool specifications. It is then up to the operator to sign an agreement on running the tool outside of the specs (and living with the consequences), or to make the necessary changes. This does not typically happen for production tools.

3.6 Well Performance Indicators

Performance assessment is one of the key duties of an engineer. For future decisions, be it technical or economic ones, it is good to rely on hard facts. This is where key performance indicators come into play. They are easy to comprehend, and they are numbers – and as such "reliable hard facts". Both are important for performance assessment, particularly being objective, i.e. not having to rely on expert opinions, but letting numbers speak for themselves.

3.6.1 Currently Used KPIs

In general, drillers are evaluated based on the distance they drill in a certain time, and by the cost the drilling process creates. Hence it is not amazing that the following "drilling management KPI's" are the most widely spread:

- several kinds of ROP (most often the average from spud to section or well total depth, or to rig release)
- the cost per meter drilled
- the cost per day
- non-productive time(NPT)/lost time(LT)

It is evident that drillers will be striving for keeping the time to a minimum, but as explained in "Drilling Wells Ever Faster May Not be the Measure of Success" (Rassenfoss, Drilling Wells Ever Faster May Not Be the Measure of Success 2015), quality can suffer under these circumstances. Particularly parameters related to the well trajectory and geometry (DLS, well placement within the target zone, wellbore diameter, etc.) will be affected.

On the other hand, also the production side measures the performance of a well. For them, other factors are important, such as lifting costs, water cut or production rates (both net and gross). Additionally, pump and tubing failure times will be used to evaluate the performance, as well as workover frequency.

However, these are not parameters that can provide a link to what has happened in the well's earlier stages, nor are drilling events often considered when the production parameters are not up to the expectations. Nevertheless, it could be worth looking into these things to identify problems and situation that are negatively influencing the production performance. Particularly, because a correlation between well trajectory and pump MTBF has been shown in the past. Hence, it is the author's belief that an increased consciousness of both drilling and production engineers of the mutual impact on each other's aspect of the "product well" will help improving the overall performance of future wells.

3.7 Wellbore Quality Indicators

To enable a more quality-oriented view on wellbore parameters (the focus of this thesis will be the well construction process), a series of other parameters will be proposed in this thesis, which can help understand the well better. These are split into three categories, allowing to judge various aspects of the well construction process and the purposes a well has to serve:

- Geometrical KPIs
- Operational KPIs
- Wellbore Success KPIs

3.7.1 Considerations for WBQ Performance Indicators

Several methods to judge WBQ have been developed, but they always consider certain aspects of a wellbore, and never take the whole life cycle into account. Some of these methods rely on physical measurements, others on the interpretation of drilling reports, and thus giving some kind of an "after action review" image of the quality of a well.

While both of these methods have their advantages, there are some things to note:

- Physical measurements (and only them!) can provide absolute and objective data. However, data processing, storage and analysis are required – and sensor malfunction needs to be considered an issue.
- Physical methods can be implemented as or derived from LWD/MWD measurements, thus allowing real-time data availability.
- Anything involving human interpretation is to be avoided, because any interpretation is not objective any longer. Even the best expert will give a biased and thus subjective judgement of the situation. Besides, the human factor always bears the risk of error.

Moreover, it is imperative that KPIs are easy to understand; translating a process into a KPI should not result a high additional workload. Likewise, the message of the KPI should be clear to understand for anyone who understands the concept of the parameter.

Thus, additional information (reports, complementary data etc.) are not necessary to interpret a KPI and work with it.

However, it is still important to keep in mind that every measurement will also be affected by uncertainty. Hence, all data that should be dealt with must be validated before processing it. Any unexpected measurements must be carefully investigated and properly dealt with!

After-action review type WBQ assessment is good in order to adjust following steps accordingly; however, it makes immediate remedial work, and thus the probably cheapest way of eliminating WBQ issues, more complicated or even impossible.

3.7.2 Geometrical KPIs

Wellbore geometry is often considered to comprise only the shape of the wellbore cross section. This means that washouts and wellbore instabilities are included in this term. However, such a consideration misses an important factor: A well is not a 2-dimensional object, but extends over three dimensions. Hence, the wellbore should be viewed as such a three-dimensional entity. This means that not only the caliper is used to judge the wellbore geometry, but also the well path. This concept is distributed over various aspects:

Firstly, caliper logs should be evaluated over the whole wellbore length, giving a better impression of the degree to which the well deviates from the ideal circular cross section. Secondly, it should be investigated, by how much the drilled well path deviates from the planned one. This does not only include comparing the survey points and the doglegs, but also the deviation from the planned target, the precision in the target horizon.

3.7.3 Operational KPIs

Drilling operations and practices can significantly influence the quality of the wellbore. Not only the choice of drilling fluids, but also less obvious factors do have an impact. This includes the “abnormal” procedures, such as wiper trips, reaming prior to making a connection or circulating while the drill string is static (e.g. to clean the hole). This is essentially a measure for how much time is lost to measures that could probably be avoided by better drilling practices or planning.

A possibility to judge this is to consider the percentage of spud to rig release time lost on such operations. Moreover, it is important to investigate the correlation of such events throughout a field, which can be seen as proof for learning. The question, whether such problems are related with other drilling parameters (such as ROP or circulation rate) should be investigated. Finally, this provides the ability to take a closer look at project economics: Some problems might be mitigated by drilling an additional casing section – but is the additional time worth the effort?

Chapter 4 Introduction to Erdpress Field

4.1 Geology of the Erdpress Field

The field Erdpress is located in the northern part of the Vienna Basin, some 50km north of Vienna. It is dominated by fluvial and shallow marine sediments, such as the sand- and siltstones of the Sarmatian and Badenian[10] horizons, similar to other fields in the area. The fluvial sediment supply is responsible for stacked reservoirs, which can be advantageous for production, as a single well will be able to penetrate several layers at once, providing fallback options for drilling and allowing simultaneous or sequential production from several reservoir horizons.

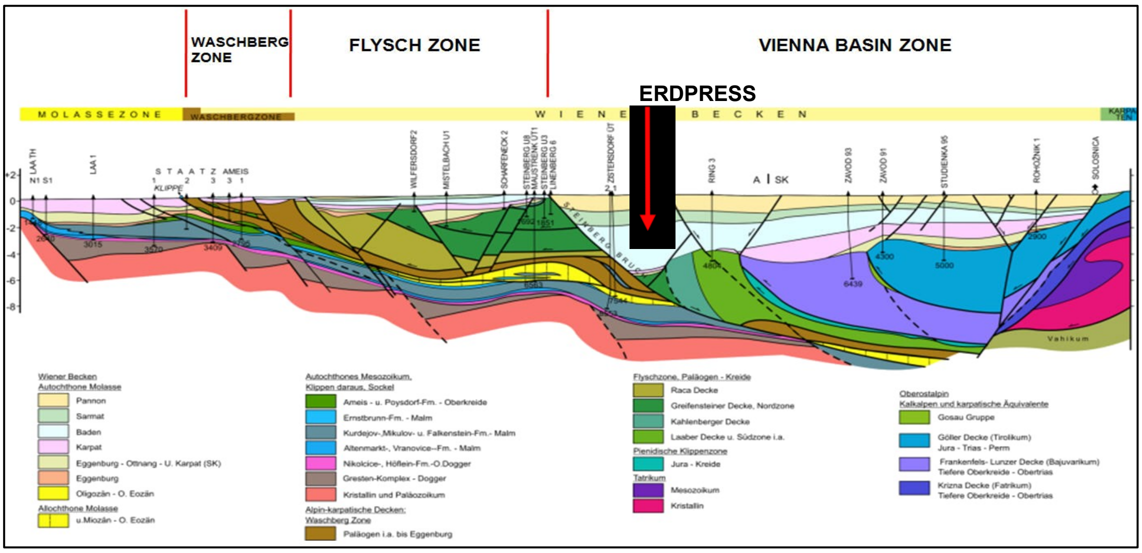


Figure 9: Geological cross section showing the northern Vienna Basin, the general geological setting of the Erdpress Field. Dominant formations are mainly the Sarmatian and Badenian formations; the Ameis and Poysdorf formations are noteworthy as the Flysch below the Steinberg Fault (Hütter, Verient, et al. 2012)

Tectonically, the Erdpress field is dominated by the Steinbergbruch, a northeast-southwest striking normal fault, posing one seal of the reservoir. A 3-way dip closure provides the rest of the seal for the petroleum system. The field itself is located in the downthrown southeastern block of the Steinberg Fault; the uplifted block in the northwest consists of Flysch formations; these are under a high pressure, the hydrocarbon production potential of these layers if proven in some shallower fields (800-1,500mTVD) in the area, such as St. Ulrich and Neusiedl, but only under investigation at these greater depths of about 2,500-3,000mTVD.

[10] The scientifically correct nomenclature is in fact Badenian; however, the OMV internal (scientifically outdated) nomenclature "Tortonian" prevails: The horizons are referred to as "Tortonian horizons", which is what will be used in this thesis as well as long as specific horizons are concerned.

Some wells have been drilled across the fault by accident, which has caused severe problems due to the high pressure. Hence a “safety margin” has been established in order to prevent further wells being drilled into the more dangerous northwestern block, and the subsurface model has been updated to incorporate the findings of those wells. However, not only drilling across the fault poses a problem: The Steinberg Fault is an echelon fault. As shown in Figure 10, it is not necessary to drill across the fault to get into the uplifted block.

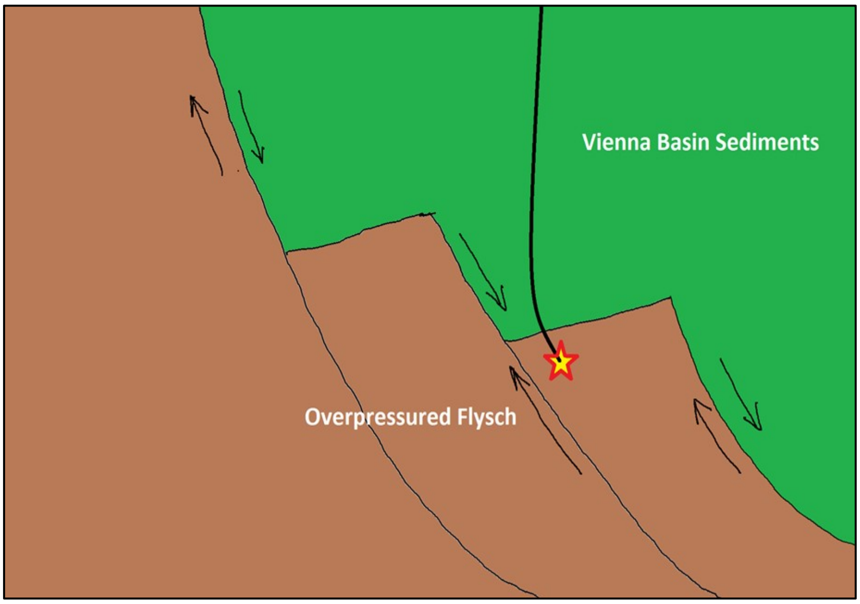


Figure 10: This sketch explains how it may be possible to drill the Flysch (indicated in brown color) below the Steinberg Fault without actually drilling across the fault

The top-hole section (around 500-600mTVD) consists of mainly loose and unconsolidated sediments of Pannonian age (7.25-11.6Ma), as well as unconsolidated sediments of newer age at the top. The Hollabrunner Schotter, a gravel layer, is considered noteworthy, as it is responsible for fluid losses in the top-hole section of many of the Erdpress wells as well as in the neighboring fields. The lower layers of Erdpress are sand- and siltstones as well as shales, predominantly of Sarmatian and Badenian age (11.6-12.7Ma and 13.3-16Ma, respectively). These layers are the drilling targets, with the 11B Sarmatian horizon (11B.SH) being a typical primary target. Notable hydrocarbon volumes are also found in the above 5.-11.SH as well as in the Badenian horizons 8., 8B., 12.TH and 4.-7.UTH. Those are in general at a depth of 1,500-2,000mTVD, which is comparable to many other reservoirs in the Vienna Basin.

The reservoir horizons are furthermore intersected by the minor Hohenruppersdorf West fault system with a general north-south trending strike. These faults are, however, neither a threat to drilling operations nor do they pose a flow barrier, as they intersect only parts of the field.

4.2 Field History

Erdpress Field, discovered in 2003, has been developed in two phases with a total of 27 proposed wells, of which 23 wells were actually drilled. Additionally, five sidetracks (including one planned pilot hole and 4 geologically or technically required side tracks).

4.2.1 Exploration & Discovery

Development Phase 1 contained the discovery well Erdpress A[11], as well as the appraisal wells B1 and its sidetracks B2 and B3, which both had to be drilled because of drilling problems and fishes left in the hole. These incidents were attributed to the high pressure northwest of the Steinbergbruch. Appraisal well C1 was executed as a slimmer pilot hole for the sidetrack C2 because of anticipated high pressure and associated problems similar to those of B1-B3.

Technical difficulties that are relevant to WBQ in those wells were:

- Casing not run to TD on well A – excessive drag was encountered approx. 100mMD above TD.
- Casing resistance in top hole of well B1, most likely due to swelling clays – remedial by enlarging hole diameter by 1.5''
- Multiple stuck pipe incidents with up to 110t overpull, particularly on wells B1, B2, B3, C1 and C2. The "heavy" overpulls were attributed to the tectonically stressed rock close to the Steinberg Fault. They resulted in the creation of a safety envelope around the interpreted location of the fault, as well as in the decision to drill well C1 as a slim pilot hole (6.5'' section) for well C2. This did, however, not bring the desired result, well C2 showed serious stuck pipe incidents again, which could only be resolved by strong overpulls in combination with pumping a diesel pill for lubrication.
- Fishes were left in the holes of wells B1 and B2
- Difficulties in controlling direction were reported on all wells. The directional drilling service provider attributes this to the tectonically stressed zone around the fault zone.

4.2.2 Development Phase 1

Little documentation of the first development stage, other than the well plans, drilling and end of well reports, were available. After the appraisal phase, which ended in June 2006, simulations were conducted that included the results of the first three wells and the three required side tracks. This led to the development drilling of 2005, where wells D, E and F were drilled; additionally, the knowledge from the first three wells led to the increased safety envelope around the Steinberg Fault.

All three wells could then be drilled successfully without technical difficulties. However, it was remarked that directional drilling was sometimes very hard or even impossible, although this has no consequence for reaching the targets of the wells or for the dogleg

[11] The well names have been altered, the numbers in this thesis are not the ones used in the real field. Sidetracked wells are designated with a letter, and an Arabic number, representing the number of the shaft drilled (well B3 would thus be the second well drilled, and has been sidetracked twice). If the surface location has been changed, the well name will be amended with a Latin number, e.g. well M-I. Finally, if a well that has originally been part of the campaign has been cancelled, it will be designated with a 0 prior to the planned position in sequence, e.g. well 0G should have been drilled as the 7th well in sequence, but got cancelled. The next well in sequence has then been named well G

severity: The targets were reached as planned, and the maximum encountered DLS was 2.5°/30m on Erdpress D. Again, those difficulties are most likely due to the disturbance created by the Steinbergbruch.

After the sixth well was drilled, not further effort was made with respect to the simulation model for the Erdpress field. Those models that existed were still based on the petrophysical data obtained from test and log interpretation of the exploration well. Despite the fact that no further development took place after the wells A-F, this is potentially a sign of poor quality in executing this field development project. Data could have been incorporated as it came in, making all decisions based on a better understanding of the field. However, the field development was successful, although the expected rates could not be sustained for a long period.

4.2.3 Development Phase 2 and Redevelopment of Erdpress Field

In 2009 new simulation studies were started on a new reservoir model. Based on the results, the second development phase started to be realized in 2011. 7 wells were drilled in 2011 and put into production. Due to anti-collision concerns, well M had to be re-planned and was shifted to a new surface location, subsequently being named M-I.

A geomechanics study was ordered based on the cores and logs obtained from this well to define the safe mud windows, especially close to the Steinberg fault. An additional image log was run to evaluate wellbore stability issues, such as washouts and breakouts, and features such as fractures and faults. The thus obtained new information was then considered in the to date final development efforts in the field history, the redevelopment of 2013-2014. Furthermore, the relevant lessons learned from the wells of the 2011 drilling campaign were documented and implemented in the redevelopment plan.

All the newly gathered data, including a new seismic interpretation, led to a further update of the static model, and subsequently new hydrodynamic simulations were conducted as the knowledge was growing. Those new findings ultimately led to the Redevelopment Project, also referred to as "Field Development Erdpress" (FDE) by OMV. It was kicked off by a drilling campaign of 12 wells, drilled between June 2013 and August 2014. In this period, wells Erdpress N through Erdpress Y followed; of these wells, all were producers except for two located at the edge of the structure, injecting water below the OWC to maintain the pressure and improve the production.

Due to the two-stage development and the Steinberg Fault posing a major restriction for drilling and the lack of a structured appraisal, the Erdpress field is quite tightly drilled. All wells are drilled deviated to reach their targets and avoid collision with other wells in the proximity. This tightly packed well arrangement (Figure 11) made a very precise well placement necessary, and several measures had to be taken in order to mitigate collisions. For example, some surface sections were (re-)logged with gyro tools in order to increase positional awareness prior to drilling ahead or initiating the build section. Some wells had to be re-planned, shifted, or even cancelled (well 0Y) for anti-collision concerns. However, also the subsurface situation became increasingly complex, as more wells were drilled, lessons learned were implemented and the geology was understood better.

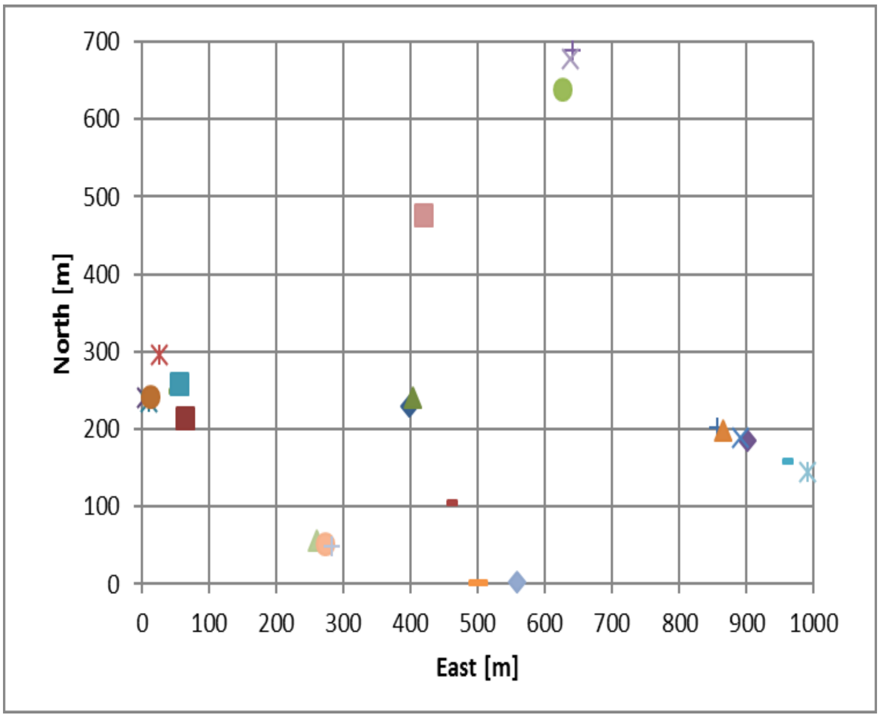


Figure 11: Surface locations of the active wells in the Erdpress field. Note how close many wells are to each other, often resulting in very low separation in the shallower parts of the wells. The clustered structure was also due to the topographic situation on site, which does not permit the construction of well sites at any desired point. This fact is also shown in the map overlays.

The main issues that were encountered during the second development phase are:

- Lost circulation, sometimes severe, mainly into the top-hole formations (down to ca. 550mTVD), but also into the Lower Pannonian (1UP) and Lower Sarmatian (6SH) horizons.
- Overpulls and stuck pipe incidents, sometimes severe
- Well P1 had to be sidetracked, as the BHA could not be run back on bottom after a wiper trip. Reaming was cancelled because the risk of getting stuck and losing the BHA similar to the incidents on B1 and B2 was too high; the sidetrack P2 had a long period of non-productive time due to the well flowing. After killing the well, drilling was complicated because the high mud weight (killing mud weight was 1.48s.g.) promoted differential sticking.
- Stick and slip conditions, particularly in the Lower Sarmatian and Badenian horizons, made directional drilling difficult. Additionally, they caused string vibrations, requiring a limitation of the drilling progress in order to avoid tool failure.
- Possibly related to the directional difficulties, several wells show out of spec DLS. For instance, Erdpress W showed doglegs exceeding the limit, but they could be reduced to an acceptable level by reaming the section in question.

- Well V1 had to be sidetracked, because the limit of 3°/30m was by far exceeded, doglegs up to 5.7°/30m were measured (problems when kicking the sidetrack off subsequently caused an anti-collision alert with the neighboring well Erdpress K).
- Particularly the loose sediments in the top-hole section caused wellbore cleanup issues and annular overload.

During the redevelopment phase, a pilot project for commingled production with dual ESPs was started. Three wells were initially selected, namely wells D, F and J. While well F was quickly discarded, but dual ESPs were installed in the other two wells. The economic performance of the ESP in Erdpress J was not as expected; hence the well was converted back to produce the perforated horizons with a sucker rod pump. The lower part of pump in well D failed after some time; however the upper part is still working, and the well is producing from the upper perforated horizon without issues.

4.2.4 Plan Quality – Lessons Learned and Implementation

Particularly the second stage of FDE is very well documented and the wells were analyzed to improve the successors. Some things have worked very well, while the implementation of other learned lessons has not taken effect at all.

Successful measures include for example the safety envelope around the Steinberg Fault after severe problems have occurred in the first three wells: Already "Erdpress A" encountered an issue somewhat related to the Steinbergbruch, namely the overpressure of the Flysch in the uplifted block. This was, when the drillers realized that crossing the fault can result in pressure-related problems. The expected problems were stuck pipe and kicks. While kicks could be avoided, three BHAs have been lost in the high-pressure zone.

These problems are not due to bad planning: The losses of BHAs occurred on the appraisal wells B1, B2 and C1; hence it seems legit to attribute them to geological uncertainty. The geological model has been updated and a safety envelope has been established, which mitigated almost all potential issues with the Steinberg Fault. The exception being the events on Erdpress P1/P2.

The top-hole sections from the Erdpress G well onwards has been drilled using Drilling with Casing (DwC) technology. This implies that no openhole log data (including caliper logs) are available for those sections. This has proven to be a successful measure to reduce time on site.

Less successful measures (at least in the Erdpress Field) was the finding of the second injector well. It was decided not to run an LWD suite on injector wells to save time and money; this led to the fact that well Erdpress U was drilled in a low permeability zone. Hence the well lacks injectivity and has been shut in after unsuccessful acidizing jobs. Since no further injector was planned for Erdpress, this lesson could not be considered in the field anymore.

Well #	Completed	Function	Remarks
A	02/03	Exploration/Discovery; Producing	
B1	10/03	Appraisal; Plugged back	Fish left in hole
B2	10/03	Appraisal; Plugged back	Fish left in hole
B3	11/03	Appraisal; Producing	
C1	06/04	Appraisal; Plugged back	Pilot hole due to suspected overpressure
C2	06/04	Appraisal; Producing	
D	05/05	Producer	Dual ESP Pilot, still running on ESP
E	06/05	Producer	
F	07/05	Producer	
0G	N/D	Exploration; Cancelled	
G	02/11	Producer	
H	03/11	Producer	
I	04/11	Producer	
J	04/11	Producer	Dual EPS pilot; converted back to SRP
K	05/11	Appraisal; Producing	
L	06/11	Producer	
0M	N/D	Producer; Shifted	Shifted surface location and spud date due to change of target after wells K&L
M-I	08/11	Producer	
N	06/13	Producer	
O	07/13	Producer	
P1	08/13	Producer; Plugged back	Unable to run BHA back to bottom
P2	08/13	Producer	
Q	10/13	Producer	
R	04/14	Producer	
S	05/14	Producer	
T	05/14	Injector	
U	05/14	Injector	
V1	06/14	Producer; Plugged back	Excessive dogleg
V2	06/14	Producer	
W	07/14	Producer	
0X	N/D	Producer; Shifted	Shifted surface location and spud date due to risk of getting stuck after wells P1/P2
X-I	07/14	Producer	
Y	08/14	Producer	
0Y	N/D	Producer; Cancelled	Cancelled due to anti-collision issue

Table 1: Overview over the wells, their drilling date and their function in the field

Chapter 5 Development of Geometrical WBQ KPIs

5.1 Methodology

5.1.1 Data Selection

In the initial phase of the data acquisition process in cooperation with OMV Austria, the available data has been screened for parameters that allow an insight in wellbore geometry. This data is on the one hand side caliper logs to measure the wellbore diameter. On the other hand, it is the planned well path, as well as the well target coordinates (primary and, where applicable, secondary targets) as defined in the well plan.

5.1.2 Data Interpretation

As a next step, the initially selected data sources were analyzed to more detail. This includes range checks of log data, plausibility checks etc. Furthermore, several measurement techniques were compared to each other to understand, if they yield similar results. This is an important question that needs to be answered, because lumping together data with different ranges due to their measurement principle (e.g. mechanical and ultrasonic or density caliper logs) will distort the output. This implies that different data sources may need to be considered independently of each other.

An alternative that has been considered in this context is the possibility of applying a "fudge factor" to data from different sources to convert them to a mutual basis.

5.1.3 Applying Statistics and Mathematics

As the final step before going into details for the KPIs themselves, mathematical methods were applied to obtain a common basis for comparison (e.g. converting well planning points to the actual survey points), and to make the varying data ranges more comparable by normalization.

Subsequently, statistical methods have been applied to the data, computing parameters such as median, average or standard deviation. In the same way, histograms were used to get a quick impression of the data distribution, which is again necessary to compare individual wells or well sections.

Finally, mathematical methods were tested to create KPIs with the available data. This reaches from simple addition and subtraction to curve fits and trend observations. The results of these calculations were interpreted, and reasons for unexpected behavior were investigated. Finally, additional data preparation was considered, which might be helpful to use some KPIs. This is typically the visualization of the basic data, but sometimes also some other kind of data, which is related to the KPI itself, but could provide a more detailed or broader image of the issue.

5.2 Caliper Log as a Quality Indicator

"The perfect wellbore can be envisioned as a flawless, three-dimensional hollow cylinder with a smooth frictionless finish."

Mason & Chen, 2005

This quote summarizes the basic idea for the use of caliper logs to evaluate wellbore quality. The wellbore diameter is relevant for several aspects of drilling and completing a well: Not only is it necessary that the diameter is as large as the drill bit – and that this does not change over time – to be able to pull out of the hole again; an in-gauge (or at least not under-gauge) hole is also prerequisite to run casing to TD. Finally, it is an important factor for cementing. At least the cement volume required to seal off all relevant intervals needs to be known, ideally without the presence of enlarged holes.

5.2.1 Average Deviation of the Wellbore Diameter from Gauge

A first approach to building a KPI based on caliper logs was the deviation of the wellbore diameter from the gauge size. Since deviations could be in both positive (i.e. hole enlargement) and negative (diameter reduction) direction, "normal" subtraction does not make sense: When summing up the point-by-point differences, positive and negative deviations will cancel out eventually. To avoid statistical errors by "normal averaging", a value similar to the root mean square error (RMS) should be used, as it does not equalize positive and negative outliers:

$$IDD = \frac{\int_t^b \sqrt{\left(d_g - d_c\right)^2}\, dx}{\int_t^b dx} \tag{4}$$

where d indicates the wellbore diameter, the indices g and c indicating gauge and caliper, respectively; the integrals would be evaluated in the depth interval between top (t) and bottom (b). IDD stands for *integral differential diameter*. An IDD of 0 would be perfect, the larger the value, the lower the WBQ with respect to WBS.

In practice, the integral in Equation (4) will become a sum, as there is no truly continuous data available.

Problems start to occur when trying to compare wells based on this parameter, but the sampling interval of the log is not equal, e.g. because of different logging speed. Hence it is proposed to use the number of sample points as a weighting factor, resulting in below equation:

$$IDD = \frac{\sum_{i=0}^{n} \sqrt{\left(d_g - d_c\right)^2}}{n(x_b - x_t)} \tag{6}$$

where n is the number of measurements. Thus, the cumulative deviation from bit size will be normalized not only by the length interval, but is also independent of sample points, making any two wells comparable.

A simplified version of this approach is the simple arithmetic mean of the deviations. This loses the advantage of coping with both over- and under-gauge measurements, but it makes the parameter more comprehensible. This is also shown in Table 2: IDD and average diameter are often similar, but there is a significant discrepancy in some of the wells.

Applying this principle to the data obtained from Erdpress field gives the results shown in Table 2. The visualized results can also be seen in Figure 12. It is worth mentioning that two logarithmic trends seem to exist somewhat independently from each other, although they can also be shown as single trend with some reduced accuracy.

Well #	ROP	Average Diameter Difference	IDD	Remarks
	[m/hr]	[mm]	[mm]	
G	7.32	7.49	5.03	Outlier, removed
H	7.02	10.87	10.19	
I	7.82	27.55	22.60	
J	8.77	25.02	23.87	
K	7.79	22.53	18.48	
L	6.32	14.37	13.44	
M-I	6.09	13.74	5.69	
N	10.48	4.75	4.45	Outlier, removed
O	7.27	4.71	4.42	LWD Data; cannot be used for comparison!
P1	19.18	13.73	11.27	
Q	4.59	7.46	6.12	
R	6.40	11.71	10.98	
S	6.31	6.70	5.38	
V2	6.66	5.69	5.33	
W	5.73	2.43	2.00	
X-I	8.28	6.17	5.06	
Y	6.31	7.43	6.74	

Table 2: Caliper Data from Erdpress Field

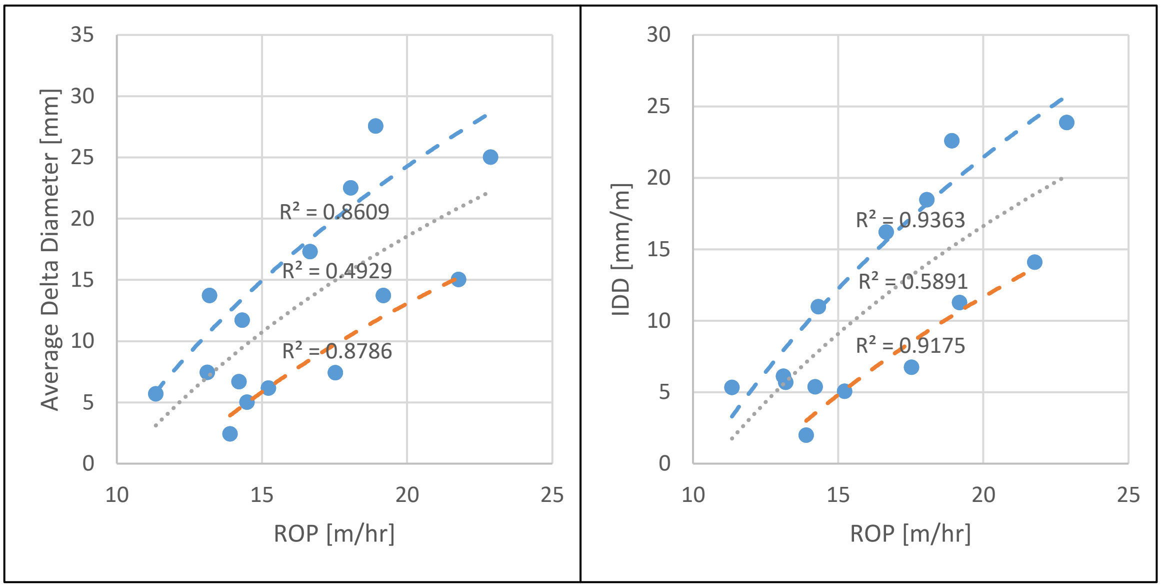


Figure 12: Trends of Caliper with ROP. Note that two individual trends (dashed) exist as well as one – significantly weaker – trend that comprises all data points (dotted)

Such a dual trend as shown above is not realistic; however, it seems necessary to point both possible trends out: Either individual trend has a significantly better curve fit than the global one (compare an R^2 error of 0.86 to 0.49, or 0.92 to 0.59). They could be seen as interval borders – they delimit the area in which the diameter should be expected to vary at a given ROP. The ROP used here is the "drilling job ROP", which starts measuring the time at the moment new formation is drilled and ends at section TD.

The important thing to notice is that all lines follow a logarithmic trend: On the one hand, an increased ROP will result in a larger diameter variance. On the other hand, it would also be expected that this increase is not linear, but tends to "flatten out" as ROP increases further. Both these trends can be observed in the above data set, and both are properties of logarithmic curves. The observed trends can be described mathematically by

$$\Delta d_{avg} = a \cdot \ln(ROP) - b \tag{7}$$

and

$$IDD = c \cdot \ln(ROP) - d \tag{8}$$

where a and c vary between 25 and 32.5 and 23.8 and 92 respectively; b and d vary between 59.7 and 74.4. It has to be noted that these correlation parameters have been observed only on the dataset from Erdpress. They may vary for other fields.

This KPI does not reflect on the geometry of the wellbore, nor does it describe any other property of the wellbore. It is merely the sum or average of the diameter deviation. As such, it may be simple, but the mathematics behind it are already quite complex, and one has to deal with a lot of data points.

The advantage of such an approach is that it is not mandatory to investigate the well sections independently of each other: Since only the deviation from the gauge size is relevant, it is possible to view the whole well as one entity without being inaccurate. This is not true when the gauge size is considered directly.

5.2.2 Statistical Approach

The approach described above does not always make sense. For example, the lack of describing the wellbore shape in any way is a major downside. Hence another approach was taken. This comprises a statistical analysis of the caliper data. The proposed data analysis workflow is more complex, but the analyst will also get a significantly more detailed impression of the wellbore shape.

5.2.2.1 Workflow

1. Quality check and range check, data source
2. Minimum and maximum
3. Quick-look analysis of logs: washouts
    a. Investigate reasons for washouts (operation parameters, circulation time, formations…)
4. Determine average and median

Step one is standard for any data analysis, it will hence not be explained further. What needs to be pointed out, though, is the data source – as stated before already, it is not possible to mix LWD and wireline data!

Minimum and maximum values are not only required for the range check, but they will also give an impression of the diameter variations. The quick-look analysis has a similar aim, but it goes even deeper into the matter: Not only the hole size, but also the quantity of washouts can be determined by looking at the log data. This is the easiest way of distinguishing between localized washouts and zones that are significantly affected by instability.

These zones should then be investigated further in order to understand the mechanisms and avoid such events in the future. For example, the mud weight could have been too low to support the formation, or the circulation rate was inappropriate for the formation. Such factors may need some time, and data from offset wells, and may thus also be postponed, if there are more important matters to be solved. However, for the sake of learning and improving the "product well", it is a necessary process!

Finally, the arithmetic mean ("average") and the median have to be determined. Just as with determining the minimum and maximum, this is a simple task when loading the caliper data in a spreadsheet program such as MS Excel.

To aid the interpretation process, the author also recommends to plot histograms, showing the frequency of measurements within certain intervals. These intervals are recommended to be not equally spaced around the "ideal" in-gauge diameter, but to coarsen, the larger the deviation from bit size becomes. The spacing used in this thesis is shown in Table 3.

±1%	±2%	±5%	±10%	±15%	±20%	±25%	±50%	±75%	±100%

Table 3: Spacing of diameter intervals relative to gauge size

The advantage of such a fining/coarsening method is that it provides more details in the interval that is most interesting, as most deviations are expected to be around five to ten per cent around bit size, while the larger deviations should be nearly unpopulated.

5.2.2.2 Incorporating Wellbore Volume in this Approach

Equation (4) has some similarity with the volume of a cylinder, if only the numerator is considered. Hence another, more general, approach was considered: comparing the ideal wellbore volume of a straight cylinder with a smooth wall (which is similar to how Mason and Chen defined a high-quality well) to the actual one. The most practical approach, as it always yields a positive result, is the ratio

$$R_V = \frac{V_{act}}{V_{ide}} \tag{9}$$

where R_V is the volume ratio, V_{act} depicts the actual and V_{ide} the ideal volume. The ratio of volumes is an easily comprehensible geometrical property, which makes it simple to deal with. The ideal state (i.e. high quality wellbore) is depicted by a unique number, which is defined by the ratio: The best achievable result is 1, i.e. the actual volume is exactly the same as the ideal one. Moreover, R_V can not only never be negative, it is also highly unlikely that the number is smaller than 1. Finally, although positive and negative deviations can be cancelled out, this cancellation does not need special attention. It simply reflects the actual geometry of the wellbore.

Using the hole volume ratio as a KPI has an additional advantage: Both volumes need to be calculated anyway, in order to prepare enough drilling fluid and cement slurry. Hence there is no extra workload to be done. Moreover, it is simple to understand and there is no need for further explanations behind the KPI. Hence it is proposed that the volume ratio be used as the primary indicator for wellbore quality when it comes to the caliper evaluation.

Additional measures that can be used to investigate the problem to more detail could be the difference in volumes,

$$\Delta V = V_{act} - V_{ide} \tag{10}$$

as well as the excessive hole capacity

$$C_{exc} = \frac{\Delta V}{l_{OH}} \tag{11}$$

where C_{exc} is the excessive hole capacity and l_{OH} is the (open hole) section length.

While it seems logical to apply this concept to the data of a whole casing section, this may be interesting even at a more detailed level, such as on a formation-by-formation basis (which requires the exact knowledge of formation tops) or even on a meter-by-meter basis.

5.2.2.3 Application to Field Data

Again, this strategy has been applied to the data from Erdpress. It is nicely visible, that for most wells, regardless of the well section, R_V is in the range of 1.02 and 1.10. Looking at some of the caliper logs, and the maximum values (for each section individually), this is somewhat unexpected, because most of the top hole sections show quite significant hole enlargements. Despite this fact, most hole volume ratios of the surface sections are below 1.1, with only two exceeding a ratio of 2. This fact is also nicely visible in Figure

13, along with the fact that most values for R_V are indeed between 1.0 and 1.1. That indicates that despite the sometime enormous diameter enlargements as indicated by the maxima shown in Figure 13, the wellbore volumes are largely unaffected by them.

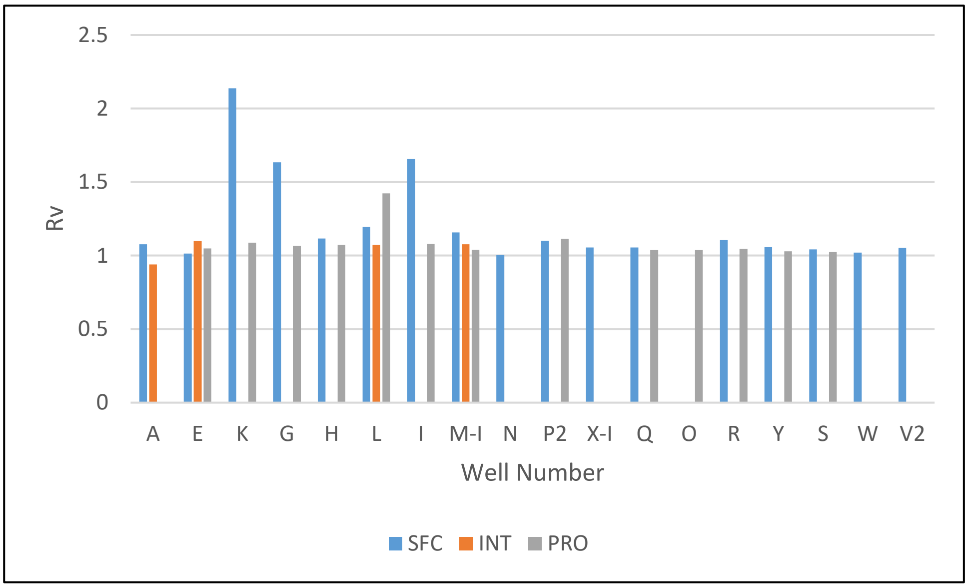


Figure 13: Distribution of R_V in the surface (SFC, blue), intermediate (INT, orange) and production (PRO, grey) sections in Erdpress.

The only significant exceptions to these observations are wells G, I and K, which have hole enlargements to more than 150% of the wellbore volume. The excessive washouts in Well K is most likely associated with the countermeasures of a tight spot encountered at ca. 190mMD. Around this point the diameter has been significantly (up to 29″, while the bit size was 12 ¼″) enlarged by reaming and circulating. Interestingly enough, the tight spot was experienced again when rerunning in the caliper tool, but not when running in casing afterwards. This resulted in the fact that the caliper was run only between the tight spot and the surface.

D_{well}	8.5″	8.6″	8.7″	8.9″	9.4″
R_V	1.44	1.46	1.48	1.51	1.58

Table 4: Hypothetical results for R_V in well Erdpress K, assuming various average well diameters below the inaccessible point.

Table 4 shows some calculation results for R_V, assuming that below the inaccessible point the wellbore diameter is on average in-gauge, or increased by 1, 2, 5 and 10%, respectively. It can be observed that the volume enlargement would be in the range of 40-60%, which is the same range as seen in wells G and I, where the hole enlargement has occurred without excessive reaming or circulating across a tight spot.

This implies two things for the caliper analysis: Firstly, it is not known, how much effect these washouts have on the overall hole volume. While without question the hole volume is significantly influenced, the factor 2 may be too high to reflect the actual R_V over the whole section, as the lower (missing) parts would most likely be more or less in gauge. Secondly, not too much weight should be given to this value, it is hence more handled as an outlier.

This fact effectively shows the strength (but at the same time probably also the greatest weakness) of this KPI: The influence of even severe washouts with respect to the total section length can become insignificant, and this influence may even be decreased by longer under-gauge sections. However, the physical and technical relevance of these parameters is so high that it seems the preferable method to evaluate the well geometry quality.

Figure 14 shows some exemplary distributions of caliper measurements from the Erdpress field. While some wells show noteworthy outliers with respect to the distribution of their diameters (e.g. 17 ½″ surface section of Well E), the volume of this section is close to the ideal volume, as Figure 13 indicates. Such discrepancies can be due to the fact that the interval where the peak lies is the interval between 99% and 100% gauge size – indicating that large parts of the present well are drilled in-gauge. Hence also the close-to-ideal volume in Figure 13.

Ideally, one would expect a normal distribution of the caliper data around the bit size as the expected value. Although, most wells follow this expectation quite closely, some do not. Those wells are the ones that may need some more attention, as their geometry may be less than perfect.

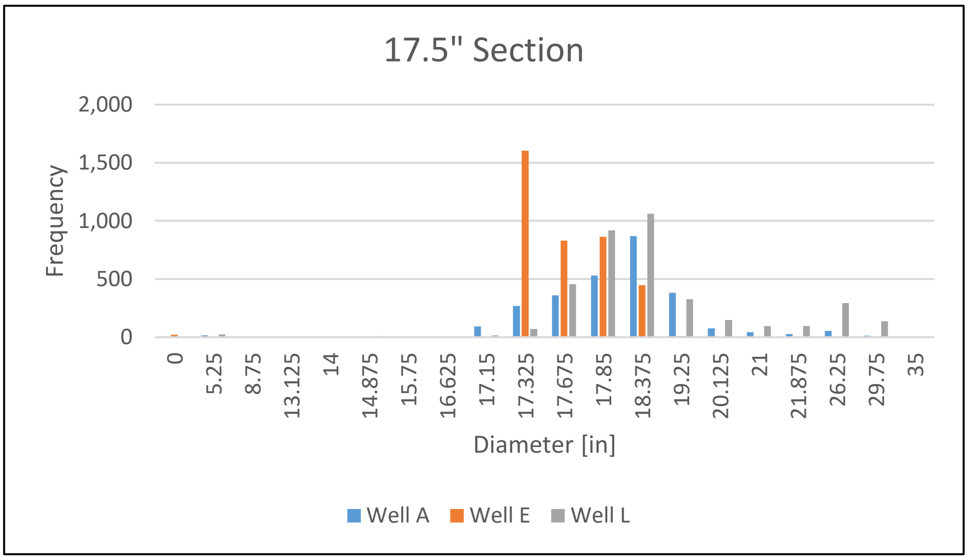
5.2.2.4 Correlation with ROP

Taking a look at the behavior of the hole volume parameters with ROP, an interesting observation can be made: There are two different and actually reverse trends, as shown in Figure 15, Figure 16 and Figure 17.

What can be seen is that in the surface sections an increase in ROP seems to actually help reduce over-gauge zones, whereas the opposite is true for the production sections. Intermediate sections most likely behave similar to production sections with regards to this trend; however, this cannot be proven, as the number of wells with intermediate sections and caliper data is insufficient. Hence there is no data shown for intermediate sections. The few data points (only four exist) do however support the above assumption.

The reason for the discrepancy in behavior in the surface and production sections is very likely related to the formation properties of those sections: The softer sediments in the top-hole section are prone to be washed away by the high circulation rate. At a higher ROP, those sensitive formations are exposed to circulation for a significantly shorter period, hence an increased ROP could help reduce washouts here. However, the limiting factor is again circulation rate: The large amount of removed crock and sediments by the increased ROP needs to be carried away, resulting in a need for higher circulation rates. However, increased flow rates will increase the amount of washouts; the data only allows an empirical proof of this assumption, particularly in surface intervals, where the caliper readings tend to increase at depths where the flow rate has been increased. The data does, however, not permit a compelling scientific quantification of the impact of flow rates on washouts.

It still seems clear that a compromise between ROP and flow rate needs to be found in order to keep washouts to a minimum. This will only be possible for the operator and driller, who need to test various parameter settings, and select the optimum one for future wells. However, it seems interesting to say that the current operator practice of suggesting reduced parameters to prevent washouts may actually have a futile effect.



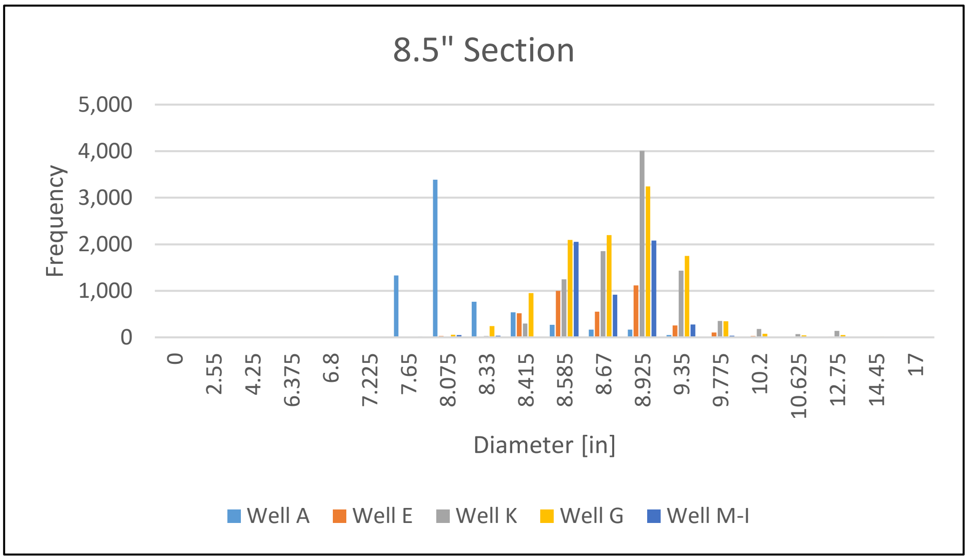


Figure 14: Examples of histograms for the distribution of caliper measurements (note that more detailed histograms of individual wells can be found in the Appendix)

In the lower sections, the mechanism for diameter enlargements is typically different: here it will be caused mainly by oscillations of the bit around the wellbore axis, for example because of bit side forces due to inept weight on bit. Washouts due to high circulation rates become unlikely, because the formations become stronger with increasing depth; moreover, the smaller annular space will reduce the need for high circulation rates, which decrease the risks of washouts even more. On the other hand, the harder rock, which can be expected at greater depth will most probably require higher WOB and rotary speed to keep up the same drilling progress. That means that an increase of ROP ("drilling job ROP") is then likely to be connected to a lower quality wellbore, as far as the cross-section is concerned. A second mechanism that can be observed at points with longer wellbore treatment time, is that circulation (particularly in combination with reaming action and axial string movement) contributes to diameter variations.

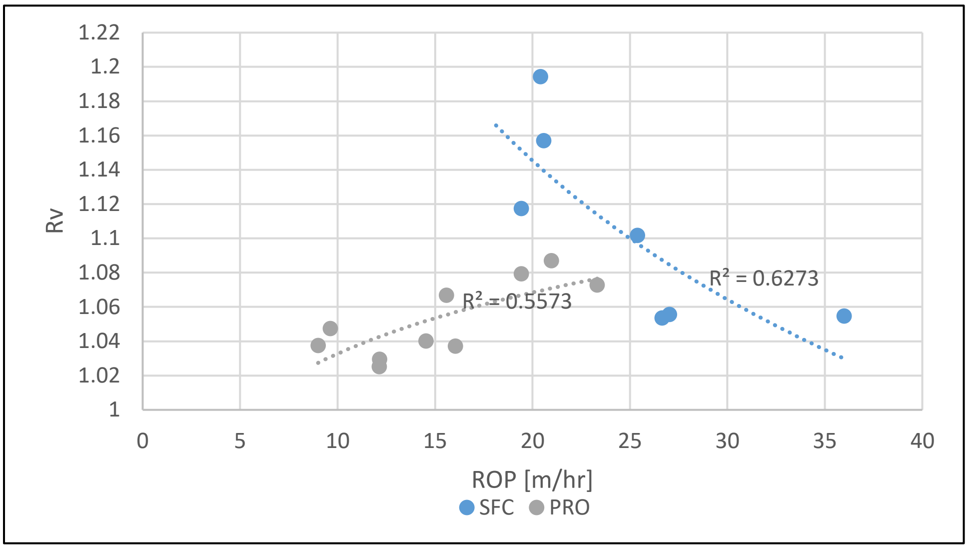


Figure 15: Behavior of Rv with ROP

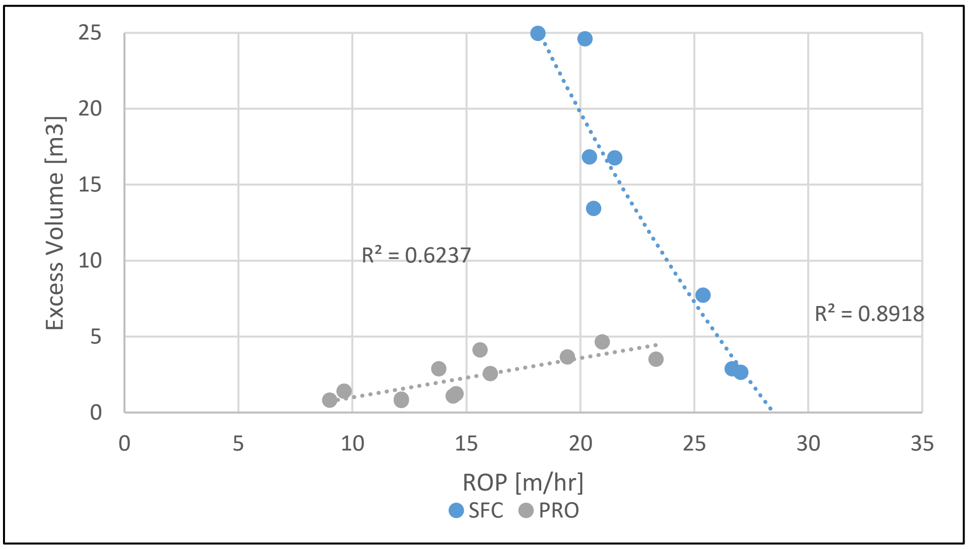


Figure 16: Behavior of Excess Volume with ROP

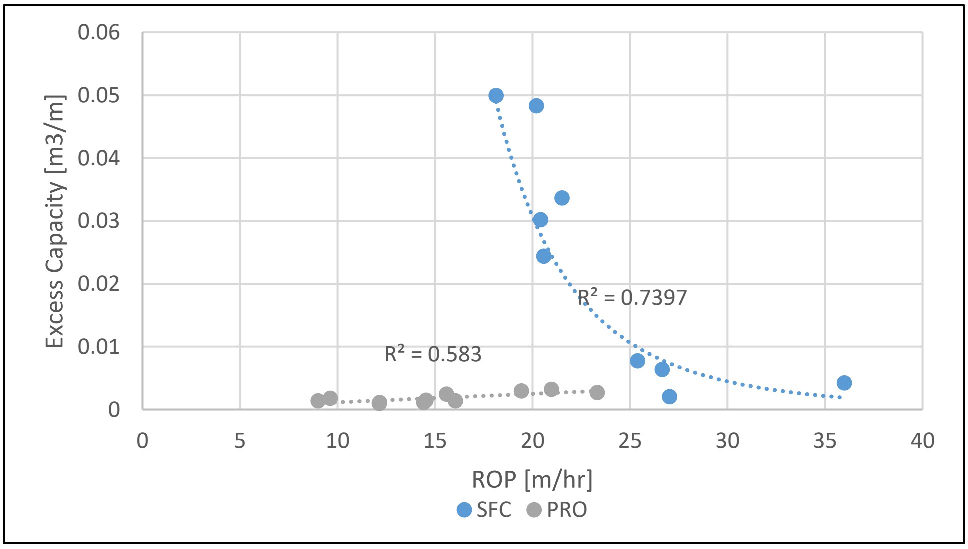


Figure 17: Behavior of Excess Capacity with ROP (SFC=Surface Section, PRO=Production Section)

Two *caveats* exist with those observations: Firstly, they are built on very few data points, which makes them statistically potentially insignificant. Secondly, most of the data show a relatively weak correlation with R^2 errors of significantly less than 0.8; that means that even those few points are potentially not really related. It is also interesting to see that the correlation between ROP and hole volume is notably better in the top-hole section than in the deeper sections.

5.3 Planned vs. Actual Well Path

The planned well path, even though it is not a straight line, and probably not even the shortest possible path, is always the "smoothest" connection between the surface location and the target. The actually drilled hole will deviate from it, simply because nature is not perfect, and even small heterogeneities and deviations from the expectations will result in changes. It seems logical to evaluate these differences between the planned and the actually drilled hole. This thesis concentrates on two aspects of the three-dimensional aspect of the wellbore, the target precision, and the tortuosity.

5.3.1 Target Precision

It is important for the driller to hit the target – not so much from a strictly drilling engineering point of view, but for the other stakeholders of the well. Obviously, they will have to make a compromise when it comes to the target, be it the driller who may have to design a well path that is not the optimum, be it the others who have to sacrifice their optimum target location, if it is technically not reachable. However, once that compromise has been made, everyone has to pursue this target, and there should – under normal circumstances – not be any excuses for not hitting the target. Of course, drilling is subject to positional uncertainty, but that is normally accounted for with a certain radius around the target. It should be noted that the target zone is defined by the operator according to their standards. Whether this is a point, an area or a volume will only depend on the company policy.

Since target precision is such an important issue for all the stakeholders, it seems useful to have a performance indicator that is able to display exactly this – how well has the target been drilled? This may, at the first glance, be easy, and a question that could be answered with either yes or no, but the problem is more complex than that. As the field Erdpress shows, some unexpected things may appear, making changes necessary (e.g. anti-collision measures or geo-hazards) which might not allow the well to actually drill the target anymore.

Hence a way to quantify this deviation has to be found; preferably, this quantification should also account for deviations that were technically necessary to drill the well safely. The idea proposed here is very simple, and can be easily derived from geometry: Using Pythagoras's theorem, it is possible to calculate the distance of the actual wellbore position from the planned target. With the available data, this has been done in the following manner:

All surface locations are given as distance to North and East from a given geodetic reference point as well as the elevation above sea level. The target location is given in the same coordinate system, with depth being referenced to ground level. The actual position can be calculated from the survey results, by adding the surface location and the Northing, Easting and TVD from the survey, respectively. These three values can then be separately subtracted from the planned target coordinates. Applying Pythagoras's theorem to these three differences, it is then possible to calculate the 3-dimensional distance from the planned target:

$$D_{3D} = \sqrt{\Delta N^2 + \Delta E^2 + \Delta TVD^2} \tag{12}$$

Logically, the D_{3D} KPI (Distance in 3D space) indicates a "perfect well" when it is 0, the higher the value, the worse the quality.

The important thing to note in this context is that the target location is typically the area (sometimes even a "corridor", i.e. a volume), at which the reservoir should be reached at a certain angle, as defined by the geologist. In most cases this is not the end of the well, hence close attention needs to be paid to picking the correct point as the one to compare the actual target entry location to the planned one.

Analyzing the target precision in the Erdpress field, most wells have drilled the target within a radius of less than 10m, some slightly above this. Only two wells, namely Erdpress B3 and P2 have missed the planned target by 105 and 282m respectively. Well B3 had to be displaced in order to avoid the Steinberg fault, hence the large step out. P2 missed the target also because of the side track caused by the Steinberg fault; additionally, the risk of encountering further over-pressured zones was too high to continue drilling operations, and the target of the sidetracked well was never reached.

In this context, it will be important to distinguish between deviations from plan due to "sloppiness" of the directional driller, and deviations because of re-planning. An example for the latter would be a geological side track: steering away from a known geo-hazard is a good reason not to hit the planned target.

In light of the results of Erdpress, some adaptions need to be made to the classification of WBQ in terms of target precision. While in theory a D_{3D} value of 0 represents the "perfect well", it makes sense to broaden the limits for practical purposes.

5.3.2 Tortuosity

Wellbore tortuosity describes any deviation of the well path from a straight vertical line. This means that even a well drilled perfectly according to the well plan will eventual be affected by tortuosity, as long as it is not perfectly vertical. In this context, it is important to find a useful measure for the tortuosity. This measure is proposed to be the sum of all directional changes throughout the wellbore, or, in a mathematical form, as

$$T = \sum_{i=1}^{n} \operatorname{acos}(\cos(\epsilon_{i+1} - \epsilon_i) - [\sin(\epsilon_{i+1})\sin(\epsilon_i)\,(1 - \cos(\alpha_{i+1} - \alpha_i)]) \tag{13}$$

where T is the tortuosity, ϵ is the inclination, and α is the azimuth.

5.3.2.1 Problems and basic assumptions

This approach is affected by some problems that require simplifications or at least need to be pointed out as some kind of *caveat*.

One thing is for example, that various plans may exist for one single well, for example because findings of earlier wells needed to be incorporated, or cancelled wells need to be replaced to optimize production with a reduced number of wells. Hence it is important that the benchmark is always the current version of the well plan, and not any older version!

Secondly, hold sections, and particularly the initial vertical section may be the cause for quite a significant amount of additional tortuosity. This is, because the drill bit will not be able to follow a perfectly straight line. The slight inclination changes are not really relevant and will easily be corrected by running casing with a significantly smaller diameter[12]; however, the azimuth changes can have a quite significant impact on the (calculated) tortuosity, as the azimuth can easily change from one direction to the complete opposite from one survey point to the next one.

Well #	Planned Tortuosity	Actual Tortuosity	Tortuosity in Vertical Section	Tortuosity below KOP
	[°]	[°]	[°]	[°]
E	66.96	94.89	4.83	90.50
H	103.09	95.74	4.40	91.33
L	85.44	96.01	7.50	75.16
M-I	34.56	38.04	3.70	34.34
O	93.75	97.12	3.86	93.27
R	84.81	101.27	11.50	89.77
T	40.00	55.16	4.21	50.95
U	41.85	64.78	4.85	59.93

Table 5: Effect of vertical section on total tortuosity

Table 5 shows that some wells have a significant amount of tortuosity in the vertical section already. While this seems unrealistic at the first glance, it is actually only an indication that the driller could not maintain a vertical hole in that section. Already deviations of less than one degree from the vertical can – combined with the unavoidable severe variations in azimuth – result in angular changes exceeding one degree per 30m.

That implies that not too much attention should be paid to the excessive tortuosity itself in the vertical section; however, the significance of these results is not negligible – high tortuosity can be a problem for fitting BHA or casing into the hole! It should be noted, though, that most vertical sections typically have quite large clearance between bit and BHA/CSG size, which mitigates the risks caused by tortuosity to some extent.

5.3.3 Adherence to the Well Plan

Working around the above problem, it is interesting to observe that the two wells shown above behave differently: While the relatively high tortuosity in well L leaves the deviation from the planned trajectory nearly unaffected (deviation stays below 0.5m for the first 360m, and below 1m throughout the whole section), well R deviates from the

[12] A typical pairing for top hole sections would be 17 ½″ holes with 13 ⅜″ casing or 12 ¼″ holes with 9 ⅝″ casing, which leaves quite some space between formation and casing.

plan by ca. 2m on average. It also has to be noted that the survey intervals in the upper section of the well varies between 80 and 100m, which may also contribute to the high lateral deviation (both for tortuosity and for the lateral deviation): The long unobserved distances prevent counteractions to reduce the deviation, allowing the well to drift away from the planned position; for the sake of keeping the wellbore as straight as possible, directional measures to counter the deviation were not taken. However, once the discrepancy had been detected, the survey intervals were decreased and the well could be held at a constant position relative to the plan.

When investigating the lateral deviation further, it can be observed that typically the deviation is close to zero in the vertical, but it starts to increase after the kick-off point (because more inclination is built up when kicking off), but catches up with the plan again towards the end of curve. However, there will always be a slight discrepancy of typically 1-3m. Figure 18 shows a typical curve of the trend of lateral deviation with depth. Prior to the kick-off point (KOP), the deviation is normally less than a meter, but it starts to increase after the KOP, as the driller is not able to control the build rate completely accurate. As the end of curve is approached, the driller stops making directional inputs, thus the deviation from plan decreases again. After the second KOP the deviation starts to increase strongly again, making it impossible to get back to the planned trajectory within the given DLS limits. At this point a new projection into target was made, explaining the even further deviation from the plan. The fact that the well comes very close to the originally planned TD point is – in this specific case – due to the well plan: It was in fact the plan that the well should reach a point quite close to the actual TD point. However, such a behavior can easily point towards an excessive DLS again, if the driller makes aggressive decisions to get close to the planned TD.

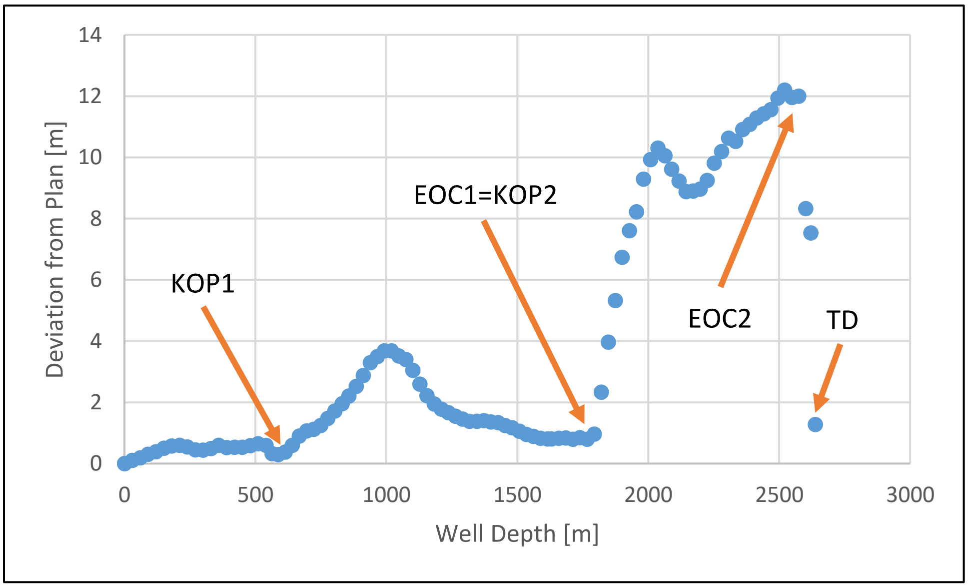


Figure 18: Typical trend of lateral deviation with depth (KOP=Kick-off point, EOC=End of curve, TD=bottom hole)

Another issue that arises in the context of evaluating well trajectories is the fact that the actual survey points do not coincide with the points that were used for planning. However, to have an accurate way of comparing plan and actual values, the plan needs to be converted to the survey points. As the real behavior between two survey stations is unknown, the only possible approach is to assume a direct (i.e. linear) dependency of inclination and azimuth changes with measured depth. In mathematical formulation:

$$\epsilon_i = \epsilon_{i-1} + \Delta MD \cdot \frac{\Delta\epsilon}{\Delta l} \tag{14}$$

and

$$\alpha_i = \alpha_{i-1} + \Delta MD \cdot \frac{\Delta\alpha}{\Delta l} \tag{15}$$

where ΔMD is the measured depth increment between two survey stations and Δl is the build length.

Converting a chart such as Figure 18 into an actual KPI, it is proposed to take the area below the curve (essentially its integral). Since this will unfairly favor shallower wells, it is additionally proposed to use the well MD as a normalizing basis. The plan adherence KPI A_P can hence be defined as

$$A_P = \frac{\int_t^b f_D(MD) \cdot dMD}{b - t} \tag{16}$$

where t and b are the interval top and bottom MD, respectively and $f_D(MD)$ is the function that describes the deviation from the plan; it is a function of MD. It may be of interest to the analyst to split the well into segments, e.g. vertical, build, hold etc. in order to quantify the adherence to the plan on a lower level. The unit of this parameter is then essentially the one of a distance.

The above formula will often be somewhat impractical, as it may not be easy to find a curve that fits the deviation perfectly. Hence the following adaption can be made to the KPI, which allows a more practical implementation in computer programs:

$$A_P^* = \frac{\sum_{i=t}^{b} D_{P,i} L_{u,i}}{n(b - t)} \tag{17}$$

where $D_{P,i}$ is the deviation from plan at the position i, $L_{u,i}$ is a unit length (the distance between two survey points) and n is the number of positions in the interval. It is necessary as an additional normalization, because the survey intervals may vary from well to well. This can be illustrated with an example: A wellbore of 2,000m MD has been logged with 20 survey stations, and the cumulative deviation ($\sum_{i=t}^{b} D_{P,i}$) is 200m. Another well of 2,000m MD logged with 30 survey station yields 210m cumulative deviation. The effect of ex- and including the number of survey stations is shown in

Number of survey points	$\sum_{i=t}^{b} D_{P,i}$	A_P^* without n	A_P^* with n
20	200m	0.1000	0.0050
30	201m	0.1050	0.0035

Table 6: Effect of ex- and including the number of survey stations

A_P^* will ideally be 0, the larger it becomes, the poorer the performance. One thing that needs to be noted is that the numbers are typically in an order of magnitude of 10^{-3}. This means that it makes sense to multiply A_P^* by 1,000 to get a more convenient number.

Hence it is ultimately proposed that the plan adherence KPI be defined as

$$A_P = \frac{\sum_{i=t}^{b} D_{P,i}}{n(b-t)} \cdot 1000 \tag{18}$$

This applies to Equation (16) as well.

As it has been skimmed earlier, the KPI alone may not be sufficient. It is recommended by the author that the KPI itself should be used in combination with a visualization of the deviation with depth similar to Figure 18.

Chapter 6 Development of Operational WBQ KPIs

When dealing with drilling operations and their influence on wellbore quality, it is in important factor to keep an open mind not only on individual operations, but also on the potential interdependencies of processes, how one thing might impact something completely different. For example, a thing that needs to be considered, is how long a section is kept an open hole (i.e. how long it takes to drill the section and run casing) before major problems start occurring. Another thing is how any problem might relate to drilling process or formations. Thirdly, depth reference is a problem, as measured depth is not always the correct one. Details on all those considerations will be provided in this section.

6.1 Methodology

6.1.1 Data Selection

At first, drilling reports, including the daily reports from contractors, final well reports from all parties as well as time-based data logs were screened for reported issues and potential indications for not-reported ones. A register of ca. 1,000 individual events potentially related to wellbore quality has been created. Events have been classified into different categories, and the depth of the incident (as reported) as well as the corresponding formation was noted down.

Moreover, the operation codes breakdown provided by OMVs online documentation via IDS DataNet has been used: It gives not only the possibility to filter the events for productive time (PT) and non-productive time (NPT), but also the option to search for the root cause of problems.

An issue that arises with the use of IDS, however, is the fact that it relies on the manual input of data, and the correct coding. Hence it is biased and should as such be avoided. A workaround that is being looked into in this context is the use of sensor data and classification of operations based on this data (e.g. by the application of automated classification software). These rely on physical measurement only, and can hence yield a more accurate result.

6.1.2 Data Interpretation

When talking about drilling operations, several things are important in the context of wellbore quality. Hence, there was not a single focal point, but several factors that had to be monitored at the same time.

6.1.2.1 WBQ Cost

One thing considered was the question of how much money WBQ-related incidents cost, based on the average cost per day. For this, it was important to check what operations were documented as planned steps in the well plan. Any deviation from that plan could be considered NPT. Only if the root cause of this NPT was linked to "Hole Conditions", it was considered for this thesis. The detailed approach to the problem of defining NPT in this context will be presented later on.

6.1.2.2 Open Hole Time

Another question was, after how much open hole time (OHT) major problems will start to occur. For this, the well-by-well operations were considered. Even though a register of more than 500 problems has been created, ca. 20% of this data proved to be usable for such considerations: Many of the problems that were initially incorporated in the database are either not relevant for time-dependent considerations, or they occur randomly. They were excluded only when OHT was considered.

The first category of excluded problems is, among others, lost circulation incidents. Although fluid loss is a WBQ problem, it is clear that this cannot be significantly related to related to OHT, but the only relevant correlation parameter for this kind of problems is lithology. They were excluded, because they did not add a significant amount of OHT, as they were dealt with and cured quickly. Similarly, insufficient hole cleaning is difficult to relate to open hole time, as it is largely dependent on operational parameters such as WOB, RPM and pump speed, as well as on the lithology.

The second category of excluded problems is such that occur frequently, but at no significant level. This concerns mainly slight overpulls, which are neither a valid indication for WBQ problems, nor do they show any correlation with drilling time. The reason for the exclusion of these events is that the data source for this is limited to drilling reports, which are not a very reliable source for such purposes, especially when it comes to overpulls (reports of severity and frequency may not be very reliable).

Two other issues had to be considered: Well control situations were neglected, as their occurrence in Erdpress is definitely not due to poor planning or execution, but because of a geological feature that is too small to be resolved in seismic images, and hence could not be expected. Subsequently, all stuck pipe issues on Erdpress P1 and P2 were excluded from further analysis with respect to OHT: The slow drilling progress and the related enormous OHT are simply not representative and had to be removed as outliers.

This left only a small amount of data available, essentially problems encountered while moving pipe: resistance, severe overpulls and stuck pipe.

6.1.2.3 Depth Correlation

As indicated already, certain events occur more frequently at certain depths or in certain formations. On the one hand, this can be seen as an indication whether improvements can be made from the previous experience (learning process); on the other hand, such correlations can also be helpful to see which formations may simply be prone to problems due to their very nature, no matter what measures are taken. Both considerations are related to wellbore quality, the first one relates more to planning quality, the other one relates to the aspect of nature being unpredictable and how to deal with that.

Most important in this context, also because it is very easy to correlate it, are lost circulation zones. In Erdpress, lost circulation occurs basically in two situations: either in gravel layers in the top-hole section, or in the more depleted upper reservoir layers. Most newer wells in the field were expected to show problems in the 11.SH, which is not only the most depleted reservoir but also the one that seems to have the best connectivity throughout the whole field.

Other problems that are significantly influenced by lithology are insufficient hole cleaning caused by soft formations (higher ROP) or unstable formations, overpulls and stuck pipe incidents.

Their frequency is investigated both with respect to the formation in which they occur, and with respect to the factor time, to investigate the learning effect.

6.1.3 Data Visualization

The final step before the actual KPI is the visualization of the results from the previous steps. The main purpose this serves is the simplification of a comparison by enabling a "quick-look approach", which eliminates major error sources when comparing numbers directly.

In this steps, histograms and cross-plots (e.g. with ROP) were made to verify trends.

6.2 Non-Productive Time as Quality Indicator

During the well construction process, difficulties and deviations from normal and planned operations will occur, resulting in non-productive time (NPT). This part will analyze some aspects of NPT, which can be related to WBQ issues. The factors investigated are the time lost to washing down pipe (i.e. assisting in passing tight spots or restrictions by circulating), reaming (i.e. passing tight spots in rotation), circulating to clean the hole or to condition the mud, and unplanned wiper trips (pulling out of the newly drilled hole and running back in to bottom to ensure the well is free). On the one hand, NPT can indicate that quality-related problems have occurred; on the other hand, it is also possible that NPT causes quality problems: "Every minute you spend not drilling is against you!"

6.2.1 NPT Activities Related to WBQ

While the relevance and importance of some problems and operations, such as stuck casing or lost circulation has already been described, the relevance of some other activities has yet to be explained:

6.2.1.1 Wash Down

The need for washing down the drill string or casing indicates that something may not be right with the wellbore. Typically, it is an indication for a cuttings bed that has built up (insufficient hole cleaning), or that some ledges occur in the wellbore. The latter pose a significant risk for casing: The casing pipe may be severely damaged, leading to corrosion, and even complete failure.

Passing such restrictions can often be assisted by circulating, helping to remove the cause of the resistance. However, this slows down the running process, as the top drive or Kelly has to be broken up before and made up again after each connection, leading to non-productive time (or more accurately in most cases: invisible lost time), which is related to wellbore quality.

6.2.1.2 Reaming

Some restrictions cannot be passed by circulation alone. However, they can often be passed by rotating the drill string. In this process, it is not uncommon that the drill bit comes into action again, or that special reaming equipment that might have been run in the BHA, also assists in mitigating the restriction.

As above, this requires the top drive or Kelly to be attached to the drill pipe, slowing down the running process.

6.2.1.3 Circulating

Reading some daily drilling reports, it seems like circulating is the "drillers' universal weapon" – it can be used under practically any circumstances, although its success may be questionable. The ones relevant to this thesis are the following:

- Circulate the hole clean – this obviously indicates that cuttings accumulations are suspected, or evident, and extra time has to be spent in order to ensure adequate cleaning. This may also involve the next point:
- Circulate to condition mud – treat the mud to establish the desired properties. This may be as simple as removing solids from the mud, but may also be more complex, e.g. by changing mud viscosity (increases cuttings transport capability, improves hole cleaning), density or other fluids parameters. Not all of them are necessarily WBQ related (e.g. mud weight)

6.2.1.4 Wiper Trips

Wiper trips are – of all the investigated operations – the ones that do not only cost the most time, but they also are the most complicated ones to classify. Many wiper trips conducted are NPT in the sense that they are unnecessary, yet they were executed. On the other hand, OMV sources say that for some personnel, the majority of wiper trips could still be considered "planned operations", as they are "old-school drillers, who adhere to the practice they have learned back in the days". Additionally, a wiper trip may be deemed unnecessary after its execution; but what if it had shown that the well is actually in a poor condition? Monitoring and analyzing deviations from the torque and drag model as well as other operational indications (e.g. overpulls) can aid in the decision-making process, whether or not to conduct a wiper trip.

6.2.2 Field Data Analysis

The analysis of the NPT was split into several aspects, such as the total NPT lost to the above operations in the whole field, the average NPT per well, the per well section, and per meter. Additionally, a chronological analysis was conducted, to show if problems could be reduced as a result of learning.

It should be noted that all the data, unless stated otherwise, is from the DDRs. This means that its source is observations rather than measurements. This implies that it will depend strongly on how eager the driller is in reporting things, and how much attention he will pay to seemingly insignificant events. For example, a young and energetic driller may report to greater detail, whereas an older one is already used to many procedures and only makes "rough estimates" for most of the operations. This affects routine operations in the first row, but may also extend to abnormal procedures.

This means that the data from DDRs can vary strongly, and it provides by far the least confidence level. However, it is still included in this thesis, partly, because this is the only data that has been available with no limitations, but also to show the difference between DDR and sensor data records.

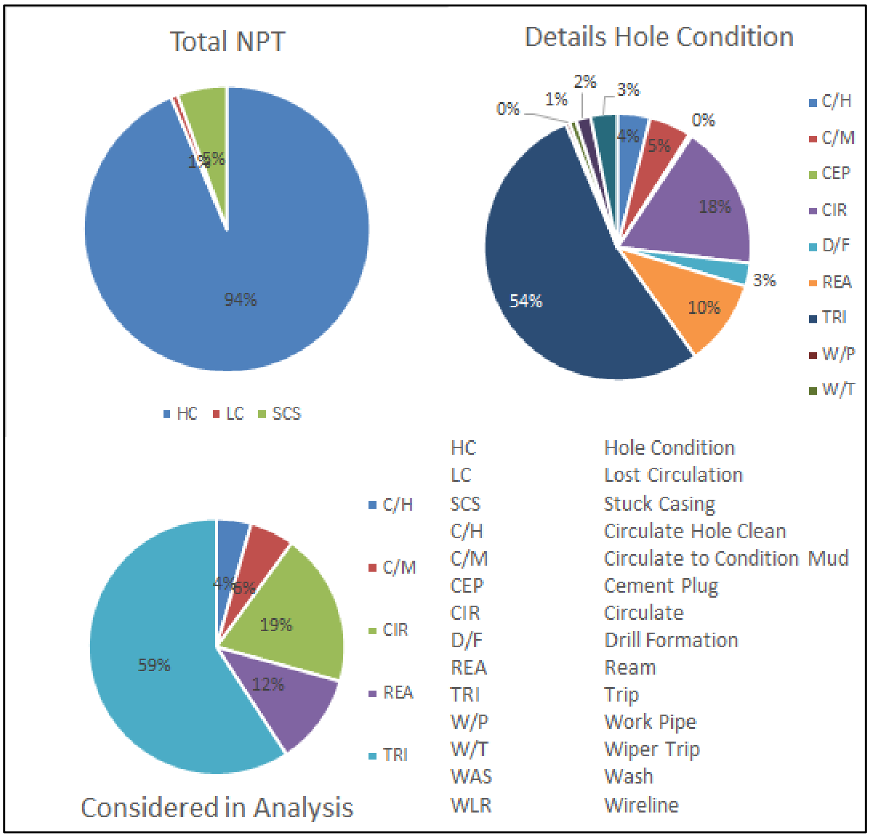


Figure 19: Reported NPT related to WBQ, share of operations considered in analysis

The figure above shows relevant operations and their share of the total reported NPT related to WBQ. It also shows, the share of operations considered in the analysis. What needs to be pointed out is that the largest part of the wiper trips are considered under the point "Trip" because of poor classification practice. For all further considerations, this has been adjusted with the help of time-based logs as much as possible. The original classification shown here to point out another downside of using DDRs as a data source.

6.2.2.1 Cost Impact

The overall NPT that can be directly attributed to WBQ, is caused by 4 major categories: Drilling fluid condition caused lost time of a negligible 5.25 hours in the whole Erdpress field, which is less than 1% of the total WBQ NPT. Likewise, lost circulation (4.75hrs) and stuck casing (34.5hrs, or ca. 6%) are of relatively insignificant impact. What makes the largest part needs to be split further, in order to understand the problems to greater detail: Poor hole condition, which manifests itself in wiper trips, reaming and washing down pipes as well as in stuck pipe, which causes the need for the latter two, caused over 570hrs of NPT. This may seem relatively little, but it turns out to be nearly 7% of the total rig time in Erdpress, starting from well G. Assuming the average daily drilling cost to be 130,866€, this translates into a total of 3.4mn €, of which 3.1mn are related to hole conditions.

To give the reader a better impression: the average well cost in Erdpress is 2.9mn €, and the average drilling time is 16.7days – so both the duration and the cost of more than one well has been lost to poor hole condition.

Root Cause	NPT [hrs]	Cost [€]
Lost circulation	4.75	25,900
Fluid condition	5.25	28,630
Stuck casing	34.50	188,120
Hole condition	571.25	3,114,900

Table 7: Summary of the time and cost impact of NPT due to WBQ in the Erdpress field

In the following paragraphs, abbreviations have been used in order to describe the NPT activities lumped together as "hole condition":

- C/H circulate to clean the hole
- C/M circulate to condition mud
- REA reaming
- WAS wash down pipe
- W/T wiper trip

The other factors have not been analyzed to greater detail, as they are already insignificant in the whole field. The approach, should the need to analyze it more detailed for a specific well arise, would be the same as the one described in the following for poor hole condition.

Sometimes, more than one code can be used to describe the activity (e.g. when a wiper trip is done with circulation). The classification code(s) used in this case are at the driller's discretion, making the whole situation more complicated.

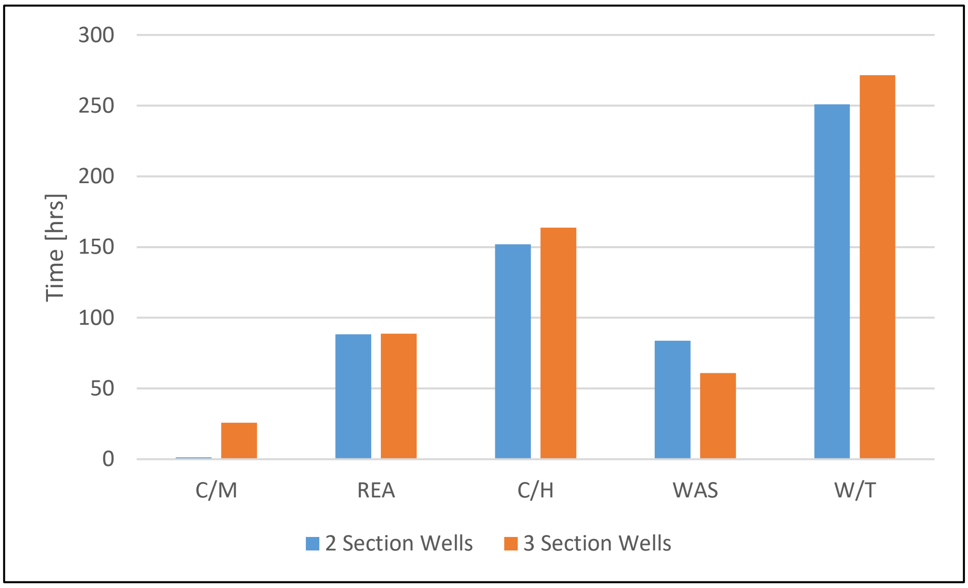


Figure 20: Attribution of NPT due to poor well condition to various operations – total field

6.2.2.2 NPT per Well

Analyzing the NPT due to WBQ per well, it seems that wells that are drilled with only two sections perform significantly better on average. Figure 21 also suggests this conclusion, showing that especially the time lost to wiper trips and circulating differs significantly. This is an interesting fact, given that the wells in Erdpress are quite similar in both TVD and measured depth, and the reason that wells with two and such with three sections exist is actually an operational one: to avoid excessive drag and overpulls on BHA and casing runs.

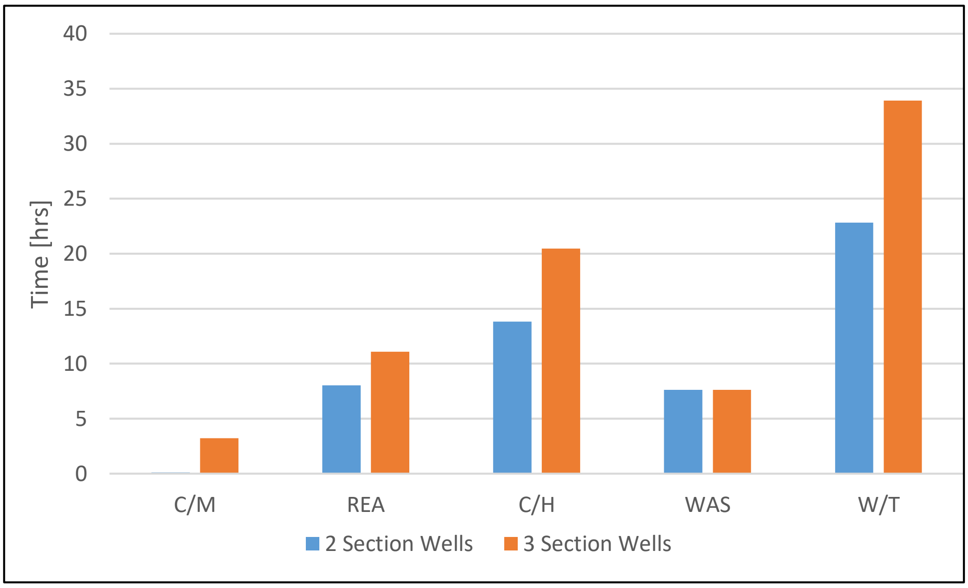


Figure 21: Attribution of the whole field's NPT due to poor well condition to various operations – per well

Extrapolating this data to any future well, it seems like 2 string designs are to be preferred from an economic point of view: not only is it possible to save on the casing string and cement for a section, as well as the time to run and cement that string, but also nearly another day of trouble due to WBQ.

On the other hand, three-section wells have one section more, so it should be expected that the wiper trip NPT would also increase by ca. 30-50%. But they are clearly not. This might be an indication that the third section actually assists decreasing NPT due to WBQ.

6.2.2.3 NPT per Casing Section

Figure 22 shows the same numbers, but now distributed evenly over the casing sections. This already conveys a different image: Now it seems like introducing that third casing section will slightly reduce WBQ-related NPT. However, the potential savings would never justify such a costly decision.

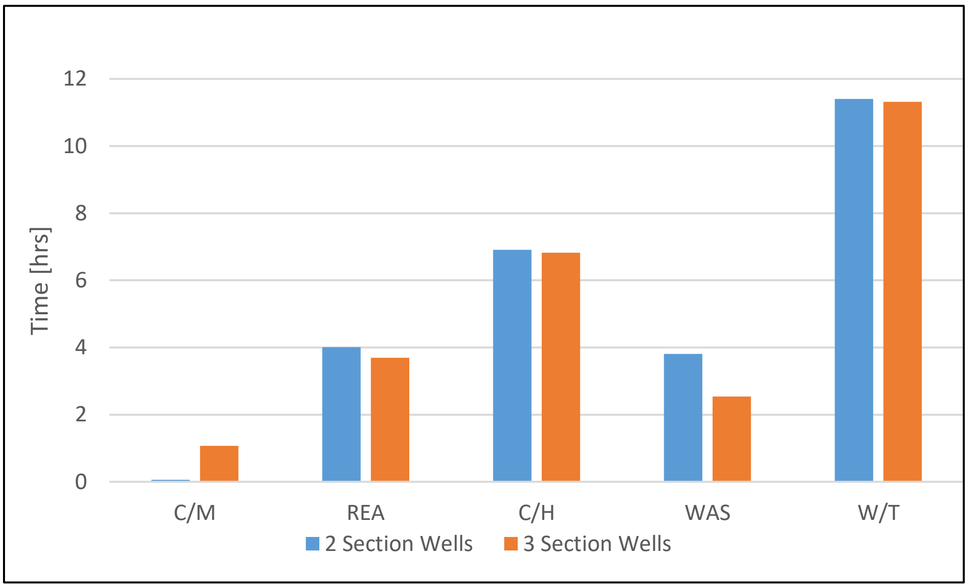


Figure 22: Attribution of the whole field's NPT due to poor well condition to various operations – per well section

6.2.2.4 NPT per 10 Meter

Finally, analyzing the data on the basis of 100m drilled, it seems again that 2 section wells might be favored over three section designs, but again, the difference is significantly less than the expected 30-50%.

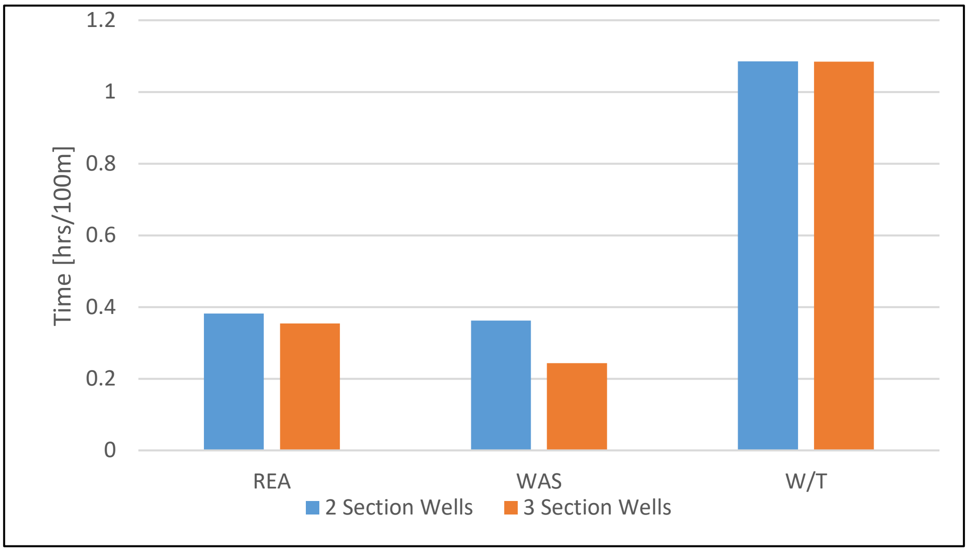


Figure 23: Attribution of the whole field's NPT due to poor well condition to various operations – per 10 meters

The above results are somewhat contradictory, so no clear conclusion can be made. This means that the decision for or against a third section cannot simply be based on a dataset such as the present one. A manifold of factors has to be considered, including the economics, but also technical aspects. Among those could be questions like, "How likely are operational difficulties because of long openhole sections?" (which will be discussed in a later section) – and the obvious geotechnical reasoning behind casing setting depths: formation and pore pressures, expected loss zones or zones that require a special mud system, to name only a few.

What the data seems to indicate, independent of the comparison basis, is that a reduction of well sections can help decrease the time spent on wiper trips. This may be explained by the reason for the introduction of a third casing section: expected operational difficulties, such as stuck pipes due to excessive drag. Those wells, where a third section was designed were already prone to these problems, hence it could be expected that the problems may occur despite the reduced openhole time, resulting in the above numbers.

It needs to be pointed out that the above data is based on the DDRs. This means that the data may not reflect reality 100% accurately, as the driller will most likely not be able to report each single incident. A more accurate data source would be sensor data, if they are available to the analyst. They are "hard facts" which show lost time on a very small scale (5 seconds in the present data) without compromise.

6.2.2.5 Development Over Time

Talking about the non-productive time due to WBQ-issues, it is also worth taking a look at the development of NPT over the whole drilling campaign. This is depicted in Figure 24. If the whole dataset including the outliers is considered, a random picture is the result. However, if the outliers, on which technical or geological difficulties were encountered (as explained in Chapter 4), a learning curve can be identified: Over a series of 19 wells, the NPT could be halved. This translates to an average learning (i.e. reduction of NPT) of 8 per cent compared to the predecessor well.

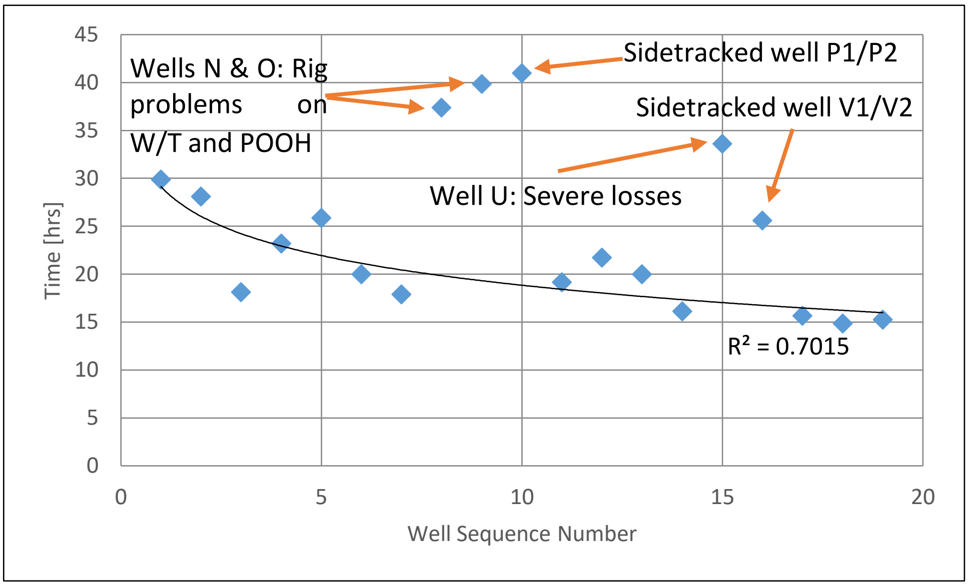


Figure 24: NPT over the drilling campaign in Erdpress. The logarithmic curve fit shows a learning trend, if the outliers are neglected

From this data, no direct KPI can be derived. However, the 8% learning can be seen as a benchmark. For benchmarking, the sedimentary environment needs to be considered, though. This means that such a benchmark may be applied to other fields in the Vienna Basin – provided that only the Sarmatian and Badenian horizons are drilled (the underlying Flysch is not considered in this number!); but drilling in other areas, for example the shale plays in the United States, will most likely yield different numbers!

6.2.3 Comparison of Report and Sensor Data

The reader needs to bear in mind that the data presented above are based on the daily reports as made by the driller in the IDS DataNet system. They are not 100% accurate, because the incidents are not reported immediately but at the end of the night shift. That means that many things may be neglected, and times will always be rounded to at least 10min intervals. Hence a more reliable source would be sensor data, as it can be derived from the mud loggers' data, or software such as TDE's proNova, which are both based on the records of sensor data from the rig. The results are shortly compared to those from the DDRs.

6.2.3.1 DDR vs. Mudloggers' Data Record

Another advantage of using sensor data is that it is easier to distinguish various modes of operations, like wiper trips on elevator ("dry" trips, i.e. without circulation or rotation) compared to wiper trips with circulation ("pump out" and "wash down" modes) or with rotation ("reaming"). While working with DDRs, operations are typically only coded "Wiper Trip[13]", and for more details one has to go into the report

[13] Some exceptions exist, where a second operations code would indicate, whether the wiper trip was done in pump out/wash down mode (i.e. with circulation) or in reaming mode. Most of the

itself. And even then, it is often not possible to get the time spent tripping on elevator, with circulation or rotation. Sensor data on the other hand allow exactly this. Hence there is a quite large discrepancy between the circulation and reaming periods in the comparison charts.

This is shown in Figure 25, where the available well data is compared, focusing on parameters that are key to the driller for judging the wellbore quality when tripping. The significance of wiper trips has already been explained. It is clear that sensor data are the preferred data source, and that supports the point about "hard facts": They do not only increase the accuracy and take away the bias of the person reporting, but also allow an increased level of detail.

It has to be noted that the above data only shows a small part of the NPT, and only a part of the analysis results for the sake of compactness. More details for the comparison of sensor vs. DDR data can be found in the Appendix (p.106). However, the overall image conveyed by this data is similar to the one from the DDRs, so no definitive conclusion can be drawn from the data, except the one that sensor data are the preferred source.

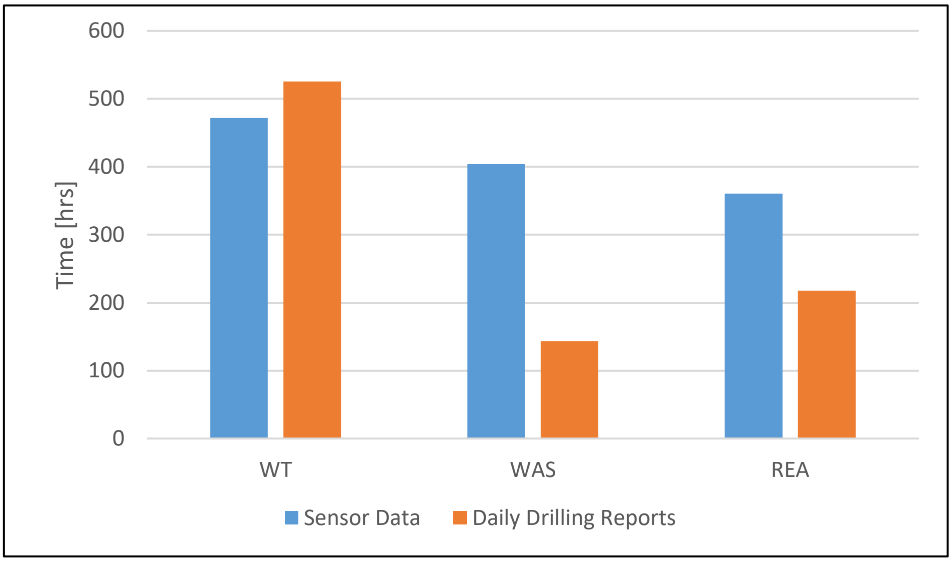


Figure 25: Comparison chart of NPT due to WBQ issues derived from sensor data and DDRs

6.2.3.2 DDR vs. TDE's proNova

For selected wells, TDE was could provide even more detailed data, which are derived from the sensor records: proNova allows to detect drilling operations based on these data, and is as such the most accurate data source. However, the data record available to TDE is limited to one complete well (Erdpress W), one surface section drilling run (Erdpress X-I) as well one production section wiper trip, trip out and casing run (Erdpress V2). The results are here presented on a well-by-well basis, in order to allow a proper comparison. (For the wells with incomplete records only the corresponding time frames were considered.)

---

time, the data could only be considered for wiper trips, which explains the large difference in REA and WAS times between DDR and sensor data.

Figure 26 through Figure 28 show the most accurate data record compared to the least accurate one: proNova sensor data interpretation and the daily drilling report data. The reasons for the significant discrepancies are twofold: Firstly, the DDRs often classify reaming or washing only as wiper trips, whereas TDE's software distinguishes between reaming up and down as well as washing in and out. This means that these operations are not 100% comparable. The second reason for the discrepancy is the often-stressed problem of the driller being inaccurate and not able to report on a minute-by-minute basis, or as the sensors in even shorter intervals of less than ten seconds (five or even 1 second are typical).

Due to a lack of data for Well V2, no comparison chart has been made for this well, but the wellbore treatment time per 100m on wells W and X-I varies strongly: While on Erdpress W it is 1.2hrs/100m according to the DDR, and 4.5hrs/100m in proNova, these numbers go up to 4.1 and 24.1, respectively, on Well X-I. This is not necessarily an indication for poor wellbore quality, as it might simply be that a lot of circulation effort had to be made in order to clean the wellbore. However, looking at the data more closely, and especially after comparing it to the DDR, the problem becomes evident: A lot of NPT is not recorded in the DDR, which means that it has been classified as a wiper trip. As a lot of the NPT is reaming, this indicates that the wiper trip had to be done in reaming mode to overcome overpulls or stuck pipe. This shows that such comparisons can also be a tool to check the consistency of the reports.

Extrapolating the values from Well W to the whole field results in a loss of 1748.7 hours or 9,535,661€. Comparing this to the average well duration and cost of 400.8hrs and 2.9mn€ this threefold increase of NPT and twofold increase of lost money seems somewhat incredible. It may be caused by the extrapolation based on the data of only a single well. However, it is obvious that there is definitely a significant amount of NPT that is simply not reported in the DDRs, which falsifies the savings potential.

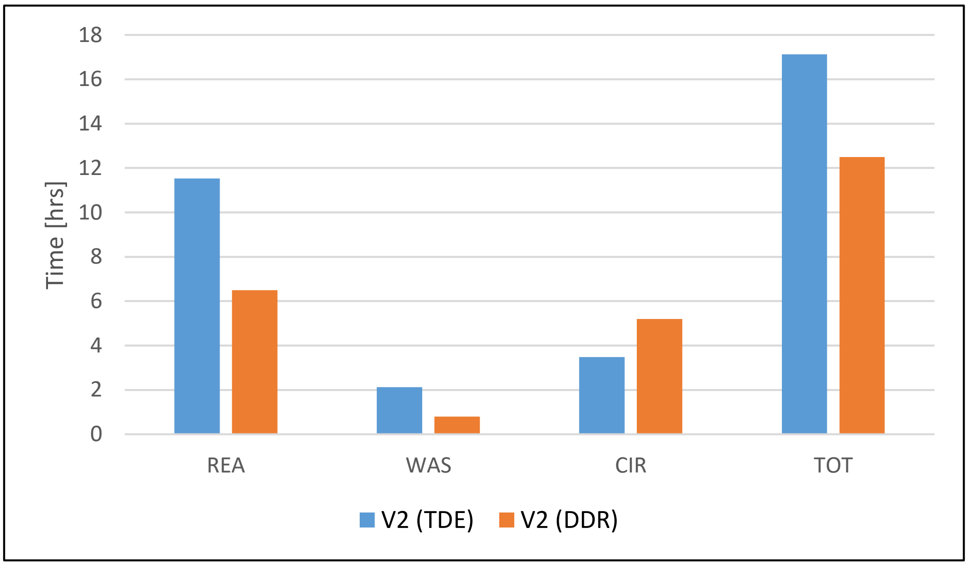


Figure 26: Time spent reaming, washing and circulating as well as the total wellbore treatment time of well V2; note that only the wiper trip, final trip out of hole and the 7'' casing run is available for Erdpress V2

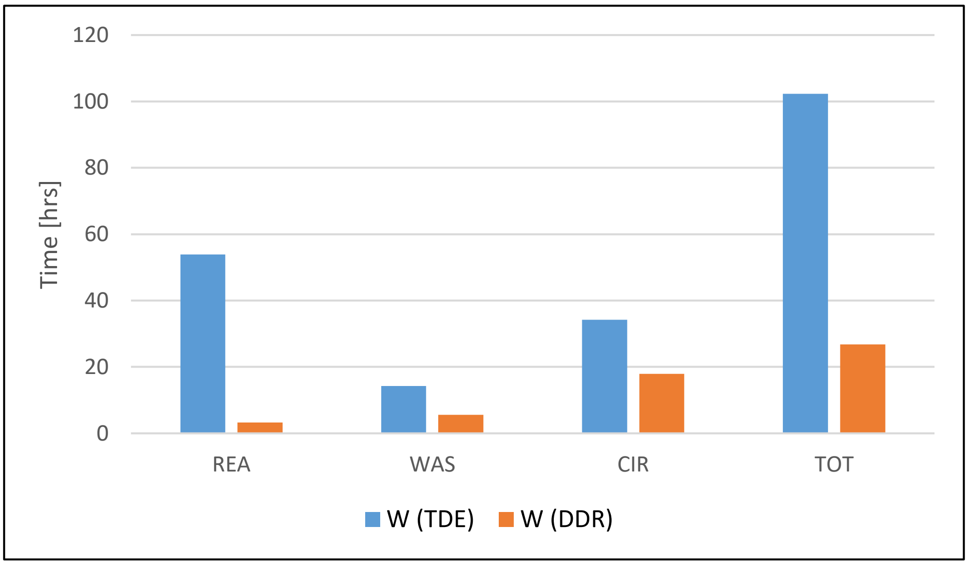


Figure 27: Time spent reaming, washing and circulating as well as the total wellbore treatment time of Well W

Figure 28 Time spent reaming, washing and circulating as well as the total wellbore treatment time of Well X-I

6.3 Correlation with Trajectory

The influence of the trajectory is simple to explain: The more ledges there are in the wellbore, the more bends, the harder it will be to move the drill string. Likewise, long sections at high inclination increase drag, and thus the risk of getting stuck. This shows that trajectories have an influence in two ways – in the direct way via the wellbore geometry, and in an indirect way, as a cause for overpulls, which are generally considered a sign for poor WBQ.

Before going into details, it is important to clarify the use of the term *overpull* as it is used in the context of this thesis: The author defines an overpull as a hook load exceeding the one from the drag simulation. This can have various reasons, as explained above. *Severe overpulls* are such that exceed the simulation by more than 10tons (typically 20% of the drill string weight). Only such are considered in the detailed analysis.

6.3.1 Doglegs

Doglegs are essentially bends, which result in an increased wall contact. This means that additional drag at such positions. This can also be seen in the data from Erdpress, which is exemplarily shown below.

Figure 29 shows that there is a correlation between the position of doglegs and the depths at which local change in pickup and slackoff weights were observed – exactly the behavior that was expected. What is not expected is the severity: Even 3 to 4 degree doglegs only add 2 to 3 tons locally. This is quite a low number, given that drill strings to 3,000m typically have a weight of about 70t; that means that the additional load is only in the area of about two per cent, which is nearly negligible.

This low additional amount also justifies why overpulls lower than 5-10 tons should not be considered when assessing WBQ based on overpulls – they are simply affected by too many factors, such as wrong (global or local) assumptions for friction factors, ledges and doglegs or deviations from the planned inclination and the related increased wall contact, as well as poorly calibrated HL indicators.

Another thing shown in Figure 29 is that the drilling loads are not affected at the position of bends, but they show a reduction immediately below those positions. This load reduction is due to the drill string being in contact with the wellbore wall after the dogleg, which takes a part of the load off the hook.

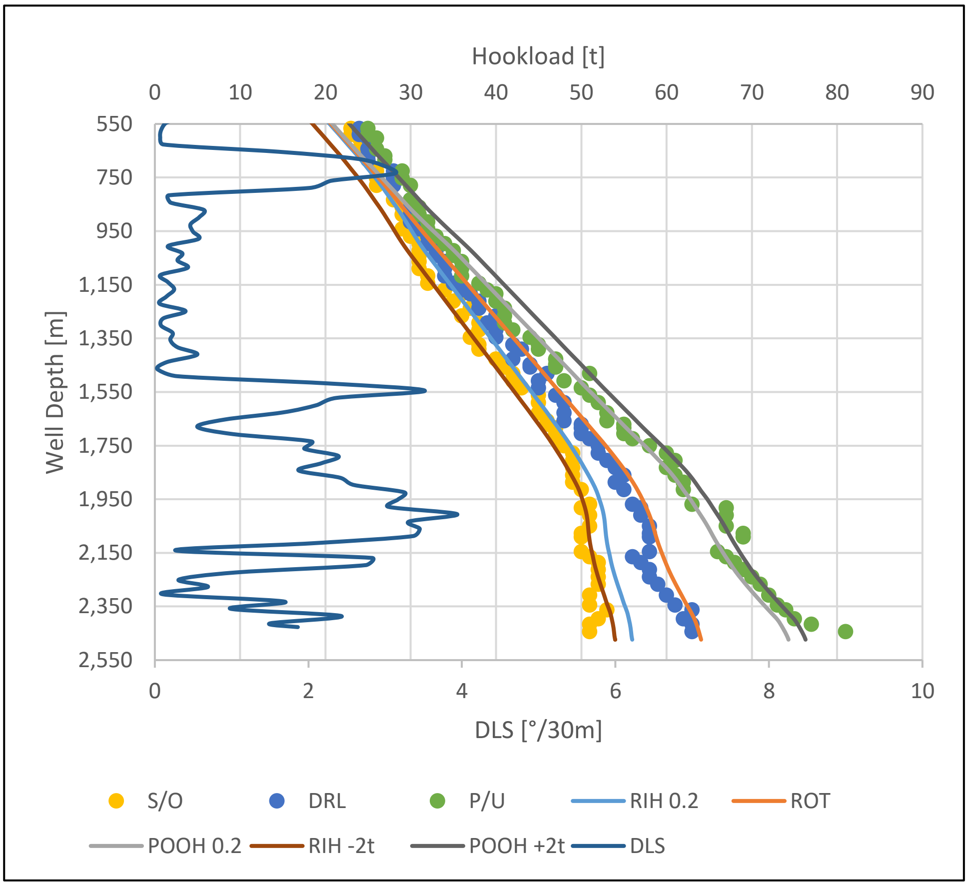


Figure 29: Drag simulation results for tripping in (RIH) and out (POOH) as well as rotating (ROT), overlain by the pickup (P/U) and slackoff (S/O) weights recorded. Additionally, the DLS is plotted to show the positions of bends

It has to be noted that the above chart only show the pickup and slackoff weights, i.e. the weights recorded when the drill string is put into the slips, or pulled out of them. Any overpulls occurring during drilling or tripping are not shown!

6.3.2 Inclination

The link between overpulls and inclination is friction: Friction forces are contact forces, which means that it will increase with the length of the inclined section. The inclination angle plays a major role as well, as it determines what percentage of the weight is taken by the wellbore wall, contributing to the friction force.

This is shown in

Figure 30: Note that the increase in hook load is nearly linear until a depth of ca. 1,950m, and then it starts to deviate. This is the effect of the wellbore wall taking weight of the drill string. The implication of this is that torque and drag will become an increased issue

with increased inclination, in this specific case above 30°. It also means that overpulls will become more likely, if the wellbore is not smooth.

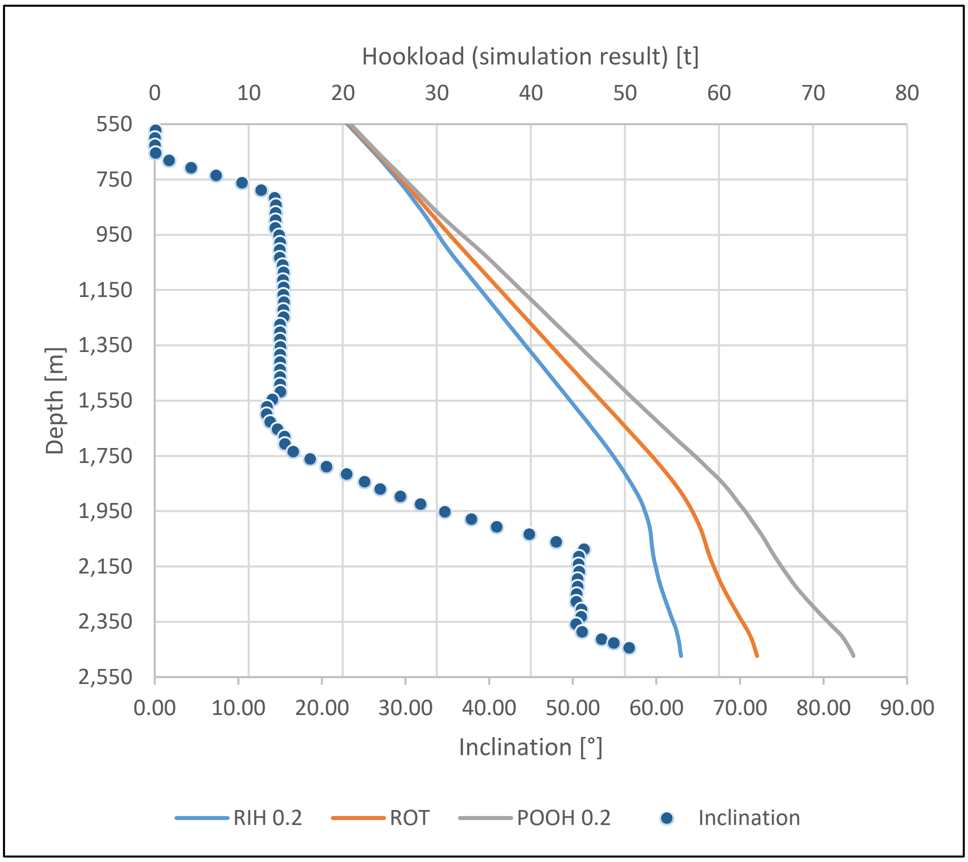


Figure 30: Drag simulations from the same well as above, now plotted with the inclination of the well.

6.3.3 Well Depth

The measured depth is another factor that comes into play for overpulls. It can be expected that the number of overpulls occurring on a well will depend on the measured depth, and the data from Erdpress field support this expectation. Plotting the data obtained from the daily drilling reports results in the chart displayed in Figure 31. It shows a correlation of well depth and the frequency of observed overpulls exceeding 10t.

While no KPI can be inferred from that, the result can still be used as a certain benchmark: The slope of the curve fit indicates that one can expect ca. 1 overpull per 100m drilled, starting from 2200mMD. The reason for that “initial condition” is that only a few shorter wells have been drilled, but they no severe overpull was reported on those wells.

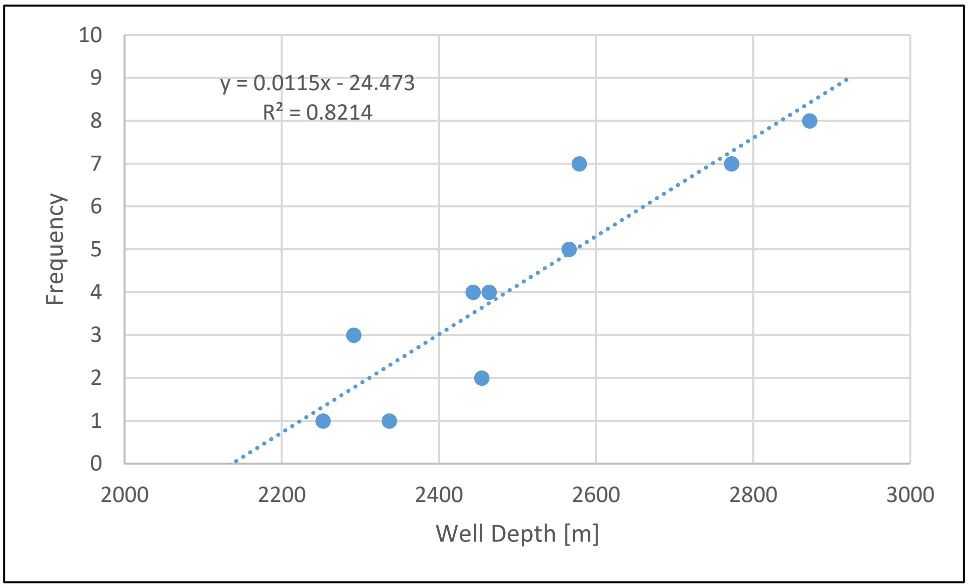


Figure 31: Correlation of the frequency of severe overpulls and well measured depth

6.4 Open Hole Time

Open hole time (OHT) is an interesting planning factor for the mitigation of some drilling problems. The idea behind this is to plan casing sections accordingly, considering not only technical and geological reasons like pore and fracture gradients as well as circulating pressure, but also to find a compromise between avoiding excessive OHT and casing (and rig) cost.

While some issues are not influenced by open hole time, such as bit and BHA balling, lost circulation or fishes that had to be left in the hole[14], others do show a certain dependence. For example, overpulls are often not only related to formations, but also occur only after a certain time after the point had been drilled. The data from Erdpress also suggests that most of the issues occur within the first 24 hours, and with decreasing likelihood exponentially as OHT increases. This is also shown in Figure 32. An explanation for this fact is twofold: Firstly, only few sections lasted long enough to actually allow the observation of events after more than six or seven days – most of the time, even the longer production sections were drilled and cased within a week. Only a few wells took longer to drill, resulting in those long-term observations.

Secondly, most issues (one third) that are observed occurred in a relatively narrow time window of 13 to 23 hours after the bit first passed the position, a few faster, the majority of the rest within the following 24 hours. This means that issues are in fact most likely to occur in the second half of the first day after drilling the rock.

That obviously means that it will not be possible to avoid most of the issues by running casing as early as possible – it is neither technically nor economically justifiable to have casing runs once a day. Besides, even if they could be feasible, they would exceed the observed limit of 13 hours, below which issues are seldom observed.

[14] These issues are mainly related to certain formation properties, which will be explained in Section 6.5

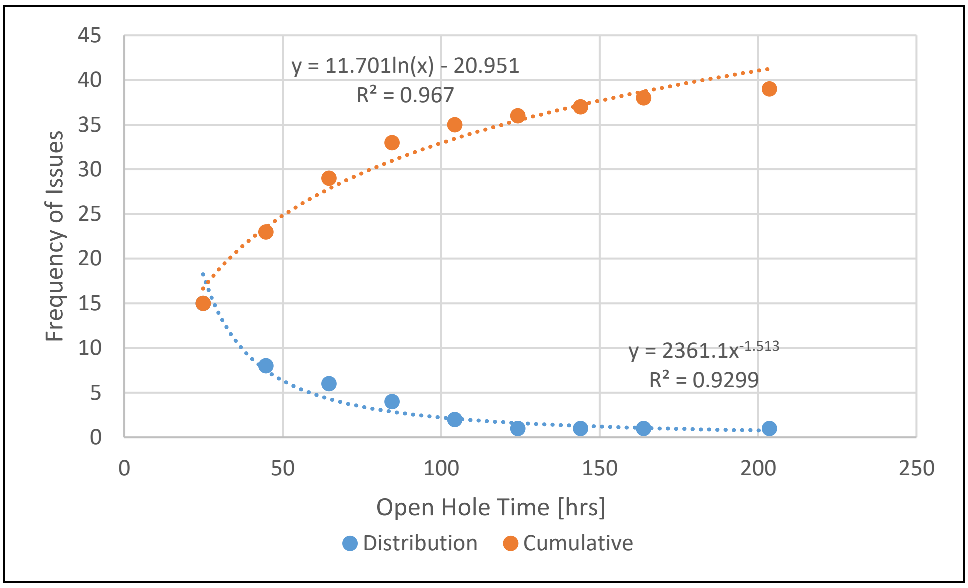


Figure 32: Distribution of frequency of events over time, and the cumulative frequency as observed in the Erdpress field

The data obtained from the field study show a very good correlation between OHT and the frequency of issues. The R^2 error of 0.93 for the distribution and especially of 0.97 for the cumulative issues allow a prediction of events with quite good confidence. This can be done according to

$$F = 2361.1 \cdot OHT^{-1.513} \tag{19}$$

and

$$C = 11.701 \cdot \ln(OHT) - 20.951 \tag{20}$$

where F is the frequency, C the cumulative occurrence and OHT the open hole time. Likewise, the above formulae – provided that they can be applied to other fields as well – can be used also for determining the maximum OHT that can be allowed. This could be accounted for in the well planning stage. To do that, one simply has to rearrange equations (19) and (20) for OHT. That results in

$$OHT_{max} = \exp(\frac{C_{\lim}}{11.701} + 20.951) \tag{21}$$

to determine the maximum OHT, after which the limit $C_{\lim}$ occurs.

It should be noted that the above correlations have been obtained from the analysis of DDRs, they will vary if sensor data is used as a data source!

6.5 Depth and Formation Correlation

A common assumption is that certain formations are simply prone to cause certain problems, in particular when combined with specific operating parameters or practices. For example, top-hole sections are often preferred to be drilled with bentonite WBM as spud mud. This type of fluid is, however, sometimes reported to cause problems related to the hole size. For that reason, OMV has moved from bentonite fluids to other options in most top-hole operations already before the exploration well Erdpress A was spudded.

Other problems that are formation-related are swelling clays (combined with non-inhibitive mud), washouts (emphasized by high circulation rates) or excessive cuttings production in soft formations (leading to annular overload). This is often due to high WOB, which allows an ROP that exceeds the maximum "safe" drilling rate.

Observing such problems and identifying the causes (formation, operation conditions) in the early stages of a field development project, ideally on the exploration and appraisal wells can help reducing the downtime because of these problems, be it reduced progress (i.e. "invisible lost time") or a complete halt of operations. As an example of this, the following drilling problems were analyzed in the Erdpress field, and a depth match to the formations was made:

Cleaning-related problems
- Balling (BALL)
- Cleanup (CLEAN)

Friction-related problems
- Excessive torque (T)
- Drag (DRAG)
- Stick and slip (SNS)

As there is a separate section dedicated to overpulls (Section 6.3), this type of problem is not addressed here again. They would, however, be placed in the friction-related category.

An issue that has been encountered during this analysis is the problem of depth referencing: Some people might use the well depth as the depth reference, others will report in bit depth (which is to be preferred, as it refers to the actual position of the drill string at the time of an incident). The problem is not only that driller and logger use different depth references, making a depth shift necessary, but also that well TVD, MD and bit depth are not to be confused. However, it sometimes happens that well MD is given instead of the bit depth at the time of the incident, making a proper formation reference impossible. In that case, time-based logs are helpful, as long as the bit depth is displayed on those logs. Most of the described problems could be solved this way for the data analysis.

6.5.1 Cleaning-Related Problems

As wellbore cleanup is an issue typical for soft formations, it is expected to be a particular problem in the uppermost parts of wells. In this thesis, not only explicit wellbore cleanup problems, such as annular overload and solids control equipment failing to clean the mud (typical problem: overflowing shale shakers) are considered; also, problems like balled-up bits and BHAs are included – they indicate a direct cleaning problem; on the other hand, it may also indicate that the drilling fluid is inept for the formation: clay particles surrounding the BHA or can bit expand, balling up the equipment.

The expected trend of decreasing with depth is generally true, as shown in Figure 33. Outliers such as the 1st or 6th Sarmatian (1SH, 6SH) are mainly due to the fact that those horizons have not been drilled in all wells, hence they do not fit into the trend that nicely.

As indicated above, balling is not only a cleaning problem related to too high ROP, but it is also related to formation properties (clay chemistry). This is why no actual trend can be observed in the balling frequency. The chart does, however, indicate another thing: Those formations where the blue bars peak, are formations where clay may be a larger issue compared to other formations. Incidentally, the 11.SH is not only on where a relatively high number of balled equipment was observed, but also one where a significant number of overpulls has been recorded. A certain connection between those two is standing to reason.

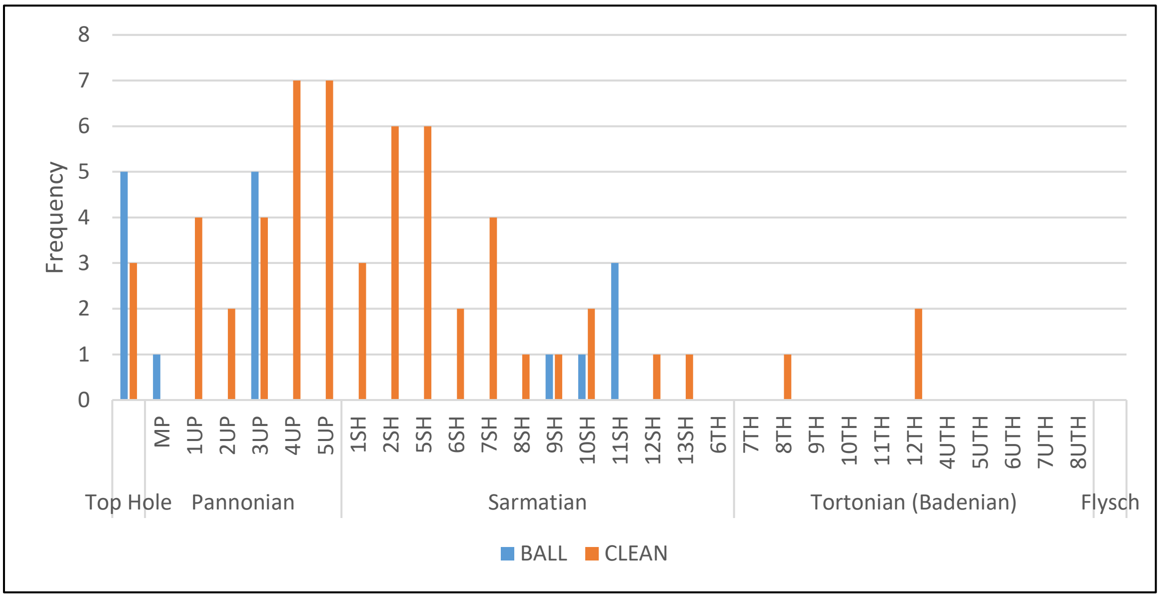


Figure 33: Summary of all cleanup-related drilling problems

The cleanup issues in the deeper parts of the wells, particularly in the 12th Tortonian Horizon, is not directly related to ROP; it is more related to stopped drilling operations and more importantly a lack of circulation caused by other issues in the wells (well control situation, stuck pipe), which allowed the cuttings to settle, causing a large amount of cuttings to appear when re-establishing circulation. Another contributor is the high inclination at the depth, as it leads to decreased cuttings transport.

6.5.2 Friction-Related Problems

A second type of problem is related to friction along the wellbore wall. Among those are drag, torque as well as stick-slip conditions. Those have the ability to harm downhole equipment, causing failure, and more downtime. Ultimately, also overpulls are often caused by friction in some way – but for the above explained reasons, these are not considered here.

One would expect friction problems to increase with depth, as the drill string weight increases, and the likelihood of it being in touch with the wellbore wall is also higher. A second factor that needs to be considered is the trajectory: in sections where the direction changes, as well as in highly inclined sections, the contact between wellbore wall and drill string is almost certain, which adds to the friction problems in such areas.

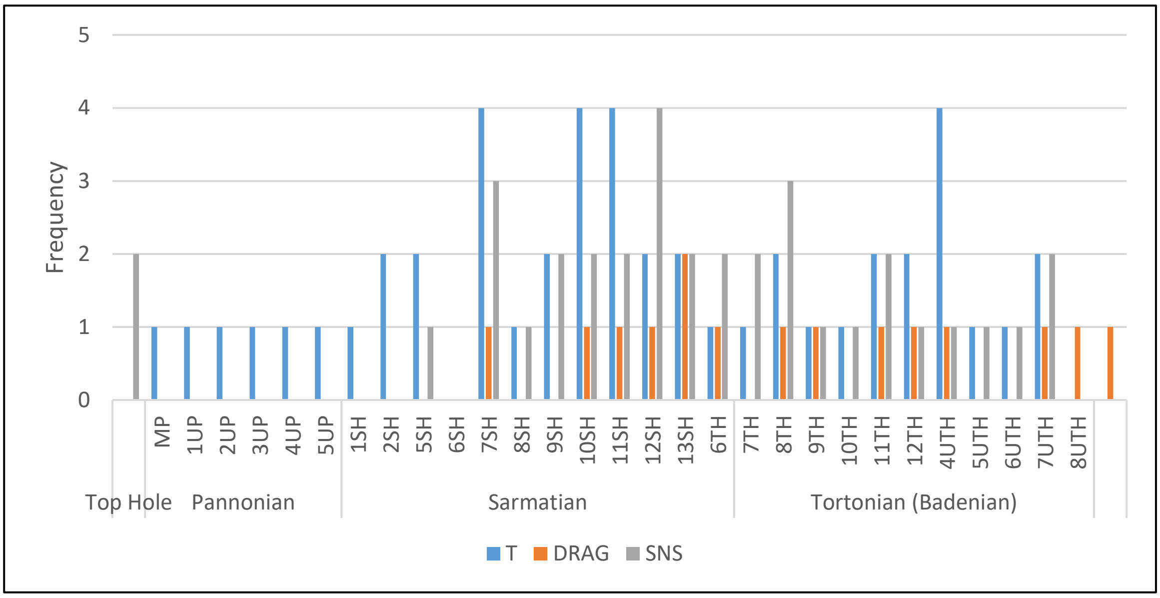


Figure 34: Summary of friction problems in the Erdpress field, per geological horizon

This is exactly what Figure 34 shows: Peaks in the lower Sarmatian Horizons are related to directional drilling in those parts, where the wall contact starts to become recognizable. The torque and stick-and-slip peaks in the Badenian stem from a few individual wells, as many do not extend to those horizons. They are the true manifestation of poorer wellbore quality, as they cannot really be related to the well trajectory. The stick and slip conditions can be explained with poor wellbore cleaning, allowing the bit to get stuck in cuttings – and move forward only when enough torque is stored in the drill string to act as a spring, moving the bit forward again, and so on…

Incidentally, the peak of cleaning problems in the 8TH relates to a peak in stick-slip problems in the same horizon, which indicates that there is a relation between those problems. This also shows that this topic very complex indeed, having an interdependency between different factors and manifestations of WBQ.

The events were derived from the previously mentioned "problems register"; any event that was reported as increased torque, drag or as stick-slip/vibrations issue was counted.

6.6 Cost Impact

It is not easy to quantify the (longer-term) cost impact of poor wellbore quality with a single number. This is, because it is strongly influenced by the period, over which this factor is observed. It may be relatively simple to attribute money lost to WBQ as long as only the well construction process is considered – once that the NPT due to WBQ is determined, which is the major limitation in this context.

But considering on the whole life cycle, it becomes increasingly harder. The reason for workovers needs to be accurately investigated (which probably increases the cost even more) as well the reason for (premature) equipment failure. But there is also a second factor that comes into play: The cost impact of poor quality on the life cycle of a well is a dynamic number: Unlike the drilling cost (which can be considered "static", due to the fact that drilling is typically by far less than 1% of the whole life time), the production-related expenditures accumulate over years. This means that it is also difficult to compare cost trends over wells, because WBQ may manifest itself differently in costs from well to well.

The reason for not going deeper into this topic than mentioned in Section 6.2.2.1 is that the field Erdpress is very young with the newest wells being in production just 2.5 years, and the oldest wells are not very old either (no more than 13 years), and they are too few to be statistically relevant. Hence the production (especially workover and pump failure data) is sparse and would not yield meaningful results at this time.

Hence, there is potential to continue this study on a longer term to be able to properly survey and investigate the impact of wellbore quality on a longer term.

Chapter 7 Development of a Wellbore Success Indicator

As wellbore quality has been defined as the "ability of the well to fulfill its purpose", it seems logical to also measure this ability. However, the approach to this problem is not as trivial as it sounds, and there are some important prerequisites:

The well purpose needs to be clearly defined in the well plan. This obviously requires a certain company culture and there is a series of parameters that need to be clearly stated as a standard (at least internally for every company) to be able to compare wells with each other. The approach to this problem is outlined here.

7.1 Methodology

During the research and data acquisition process, it became clear that OMV has implemented a certain standard over time, what parameters could and should be included in the process. As this developed to a more and more comprehensive list (albeit not really standardized), the idea to incorporate such a list in a "Wellbore Success KPI" was born.

While researching for the main focal points of this thesis, an eye was always kept on the requirements of the wellbore. It became quickly clear, that a key question here will also be the purpose of the well itself: An exploration well will most likely have other objectives than a development well, the success of an appraisal well will be determined by other factors than the one of a producer or injector well.

7.1.1 Initial Approach

However, many requirements of a well are not limited to one well, but will be applicable to various types of wells. To solve this problem, a weighting system was introduced, which still allows to value certain data higher in some types of wells, and makes the same information less valuable in others. This system should reflect the fact that some information may be relevant in some stages of a field development campaign, but less so in others. The exact percentage is left up to each company, but in the following paragraphs the framework of this concept will be shown with estimated percentages, as the authors deems them meaningful for the Erdpress field.

7.1.2 Structured Approach

The wellbore success criteria are split into five main categories, which include:

- Finding/Proving hydrocarbons
- Geology and geophysics (G&G)
- Reservoir Engineering
- Drilling Engineering
- Production Engineering

These categories will receive different weighting factors, depending on which of the following four types the well belongs to:

- **Exploration wells** will have a main focus on finding and proving the existence of hydrocarbons, with rock and fluid data (G&G, Reservoir Engineering) as minor points of interest.
- **Appraisal wells** focus less on finding oil and gas or proving fluid contacts (although this remains a main purpose), but G&G and Reservoir Engineering purposes become more important
- As the production phase starts, the presence of hydrocarbons is already known. Hence for **production wells**, it will no longer be important to prove this. However, what becomes more and more important is to stick to the well plan (e.g. trajectory, DLS limits) and to be able to obtain the production rates as assumed. This results in a higher weight factors on drilling and production parameters.
- Similarly, **injectors** require attention with respect to their well path. The presence of oil or gas becomes even less important, nearly negligible, while reservoir connectivity (Reservoir Engineering) becomes more important again.

The above described concept can be translated into a proposed set of weighting factors as summarized in Table 8.

Category	Exploration	Appraisal	Producer	Injector
Find	90	25	5	5
G&G	5	25	15	20
Reservoir	5	25	15	15
Drilling	0	10	20	20
Production	0	15	45	40

Table 8: Proposal for weight factors depending on well type

It is important to note that the weighting factors in above table are a proposal of the author only. If this system is implemented, the weighting factors should be determined in a peer-review by all stakeholders.

7.2 Data Type

7.2.1 Finding/Proving

This is a simple “yes” or “no” decision – either hydrocarbon fluids (in economic quantities) are encountered or not. Similarly, either a fluid contact can be proven, or not. Depending on that, this aspect is either successful or not.

7.2.2 Geology and Geophysics

G&G data can be from various sources, as specified in the well plan or a similar document[15]. It may not be as easy as answering the question with "yes" or "no", because the usability and reliability of the acquired data needs to be checked. Additionally, there is a huge variety of information and data sources, which makes it somewhat difficult to judge the well success. One possibility is to distinguish between some major categories, for example based on the data source: The obvious classification could then be log data on the one side, and measurements on rock samples (cores) on the other side. Another approach would be to distinguish between geological parameters (e.g. rock type, age…) and geophysical information (such as porosity, resistivity, density…)

7.2.3 Reservoir Engineering

Similar to G&G data, reservoir engineering parameters will be either derived from logs (for instance permeability, saturation, fluid types), or from fluid samples (viscosity, density, phase behavior…). Moreover, some dynamic data can also come from rock samples, such as relative permeability.

7.2.4 Drilling Engineering

Drilling requirements are typically relatively simple. Most of the time, they involve only the adherence to the plan, particularly with respect to the maximum allowable dogleg severity. Even this can, however, become quite challenging in small fields that require a high number of wells, and existing wells pose significant obstacles and even hazards for new ones.

7.2.5 Production Engineering

Production engineering criteria involve the initial testing or production behavior, such as anticipated rates. Another criterion for success under the production aspect is the question if the well could reach all the targets it should, if it can add production from already producing horizons or even start production from new horizons.

It needs to be pointed out that the above described change in weighting factors is not limited to the "major well objective categories", as they were described above. This should also extend to sub-categories, as they are defined by the operator. The change in weight should then describe how much information is valued, whereby "short-term information" should be valued more at earlier stages of the field development (typically the exploration and appraisal phase), whereas "long-term information" will become more important at later stages.

"Short-term information" could be data, that is quickly accessible without much effort, such as log data (porosity, density, resistivity, pore fluid…) – in short, data that supports the reservoir model and allows some more detailed simulations to optimize the further

[15] OMV calls this document, which defines all measurements and requirements to the well before the actual planning phase starts, the Well Design Criteria (WDC) document. Once approved by all parties, this cannot be changed anymore, making it a valuable benchmark for the evaluating well success based on data acquisition.

development program. On the other hand, "long-term information" could be data (sources), that can be used for longer-term purposes, and variable applications, such as cores, well test data or fluid test results. These may not have a significant value during the exploration, but will help improve the production performance, as they add to understanding the reservoir.

7.3 Testing

The field Erdpress with its 25 wells is a good opportunity to test the above concept for its capabilities. The basic idea to this parameter was born because of the Erdpress well U, which has been drilled close to perfectly with respect to both geometry and operational indicators, but has been shut-in after only a few months of unsuccessful operations – the well has been drilled into an impermeable layer within the 11.SH and is thus unable to inject.

Applying the concept presented above to the data from the Erdpress field, accounting for all the goals set in the Well Design Criteria and the well plan, and all the information contained in the End of Well reports yields the results shown in Table 9. If a well had to be sidetracked, only the sidetrack in operation is considered in this table. The plugged back wells would only achieve a percentage of 20 or less.

What can be seen is that no well achieves 100% - something that is not totally astonishing. The closest to perfect well in this regard is well W, which achieves 97.5%. It should be noted that the two main reasons that a well does not achieve the "perfect" score are either doglegs exceeding the specifications, or in more cases, the highly ambitious production rates, which could not be achieved because the anticipated main reservoir 7.UTH was hardly ever drilled, or did not meet the expectations.

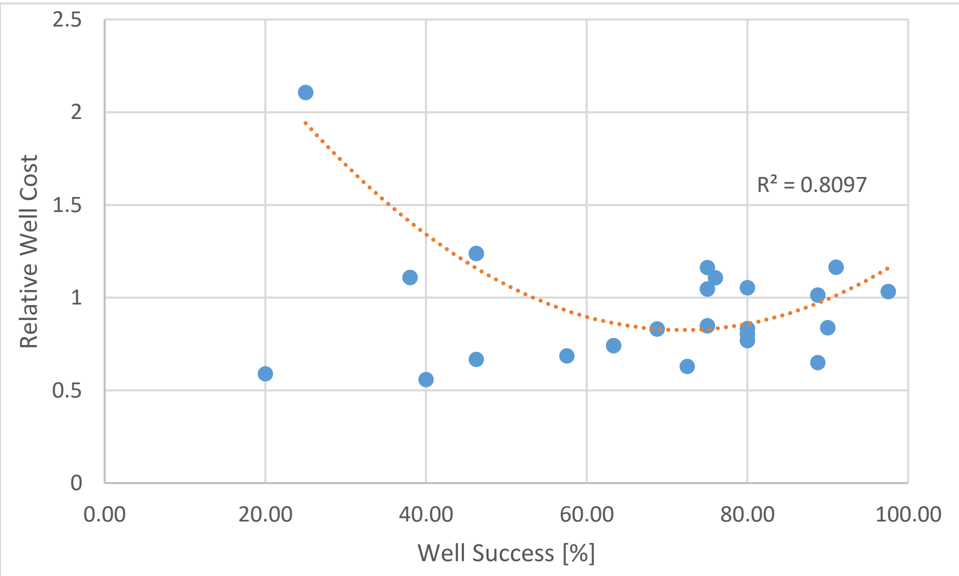


Figure 35: Cost of the wells compared to their success

Figure 35 shows how the well cost compares to the success. The graph looks somewhat similar to the one shown in Figure 8: With the exception of some outliers, low-scoring wells are typically more expensive than (or at least as expensive as) very high achievers. The best compromise between well success and well cost seems to be in the upper third, at around 70-80% success – similar as in the WQS vs. cost diagram.

Table 9: Wellbore success evaluation results

Well #	Find Achieved	Find Total	Find %	Find Weighted	G&G Achieved	G&G Total	G&G %	G&G Weighted	RES Achieved	RES Total	RES %	RES Weighted	PROD Achieved	PROD Total	PROD %	PROD Weighted	DRL Achieved	DRL Total	DRL %	DRL Weighted	Total Success
A	1	1	100.00	90.00	0	4	0.00	0.00	0	1	0.00	0.000	0	5	0.00	0.00	0	1	0.00	0.00	90.00
C2	1	1	100.00	25.00	0	1	0.00	0.00	0	1	0.00	0.000	0	5	0.00	0.00	0	1	0.00	0.00	25.00
F	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	2	2	100.00	45.00	0	1	0.00	0.00	80.00
E	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	2	2	100.00	45.00	0	1	0.00	0.00	80.00
D	1	1	100.00	5.00	2	2	100.00	15.00	1	1	100.00	15.000	2	2	100.00	45.00	0	1	0.00	0.00	80.00
K	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	2	2	100.00	45.00	0	1	0.00	0.00	80.00
G	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	3	4	75.00	33.75	0	1	0.00	0.00	68.75
H	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	3	4	75.00	33.75	1	1	100.00	20.00	88.75
L	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	3	4	75.00	33.75	1	1	100.00	20.00	88.75
I	0	1	0.00	0.00	1	1	100.00	15.00	1	1	100.00	15.000	2	4	50.00	22.50	1	1	100.00	20.00	72.50
J	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	2	4	50.00	22.50	0	1	0.00	0.00	57.50
M-I	0	1	0.00	0.00	3	3	100.00	15.00	1	1	100.00	15.000	2	2	100.00	45.00	0	1	0.00	0.00	75.00
N	2	3	66.67	3.33	1	1	100.00	15.00	0	1	0.00	0.000	1	1	100.00	45.00	0	1	0.00	0.00	63.33
P2	0	1	0.00	0.00	1	1	100.00	15.00	0	1	0.00	0.000	2	5	40.00	18.00	0	1	0.00	0.00	33.00
X-I	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	1	4	25.00	11.25	0	1	0.00	0.00	46.25
Q	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	1	4	25.00	11.25	0	1	0.00	0.00	46.25
O	0	1	0.00	0.00	1	1	100.00	15.00	1	1	100.00	15.000	4	4	100.00	45.00	0	1	0.00	0.00	75.00
R	0	1	0.00	0.00	3	3	100.00	15.00	1	1	100.00	15.000	5	5	100.00	45.00	0	1	0.00	0.00	75.00
Y	1	1	100.00	5.00	1	1	100.00	15.00	0	1	0.00	0.000	4	5	80.00	36.00	1	1	100.00	20.00	76.00
S	1	1	100.00	5.00	1	1	100.00	15.00	0	1	0.00	0.000	2	5	40.00	18.00	0	1	0.00	0.00	38.00
W	1	2	50.00	2.50	1	1	100.00	15.00	1	1	100.00	15.000	5	5	100.00	45.00	1	1	100.00	20.00	97.50
V2	1	1	100.00	5.00	1	1	100.00	15.00	1	1	100.00	15.000	4	5	80.00	36.00	1	1	100.00	20.00	91.00
T	0	4	0.00	0.00	0	4	0.00	0.00	0	1	0.00	0.000	2	2	100.00	40.00	0	1	0.00	0.00	40.00
U	0	4	0.00	0.00	0	4	0.00	0.00	0	1	0.00	0.000	1	2	50.00	20.00	0	1	0.00	0.00	20.00

Chapter 8 Discussion of KPI Results

Having shown various approaches to the problem of assessing WBQ, it would also be interesting to see how these methods compare to each other. In order to do so, six wells have been chosen; all of the presented methods will be applied to these wells. Reasons for similar (or completely different) results will be explained.

8.1 Well and Methods Selection

8.1.1 Wells

The six wells were chosen on the basis of the following criteria:

- All development phases should be included (exploration, appraisal, production).
- All stages of the FDE should be included (2003-2014).
- All well purposes should be represented (exploration, appraisal, production, injection).

The selection was hence made to analyze the exploration well, one appraisal well, three development wells (producers), of which one has been sidetracked as well as an injector well.

8.1.2 Methods

Most of the methods mentioned in this thesis are applicable to all wells. However, some are not, due to a lack of data (for example, the bending moment evaluation could not be done, as no BHA has been equipped with a tool to measure the bending moments in the wellbore). The following methods are included:

- The Wellbore Quality Scorecard
- Caliper Logs:
    - R_V
    - V_{exc}
- Target Precision
- Tortuosity
- Overpulls
- Well Success

NPT is not included in the analysis, because no time-based data is available for the first six wells in the Erdpress field, which means that two out of the six wells could not be investigated.

R_V and V_{exc} are split into the casing sections, where SFC represents the surface section, INT the intermediate and PRO the production section.

8.2 Comparison of Results

Table 10 summarizes the KPIs of the selected wells. It is interesting to see that some wells show quite consistent KPIs (if a single outlier is allowed), whereas others show completely different results. This fact shows that wellbore quality is in fact not an easy parameter to evaluate. It seems necessary to view it from several aspects, and compare all those in order to get a more objective picture.

Well #	A	E	J	U	V2	W	Perfect Score
WBQ Score	5	6	5	14	15	15	20
R_V							
SFC	1.08	1.01	N/M	N/M	1.05	1.04	1
INT	0.94	1.10	N/A	N/A	N/A	N/A	1
PRO	1.05	1.09	1.08	1.04	1.12	1.06	1
V_{exc}							
SFC	6.54	1.15	N/M	N/M	2.90	0.34	0
INT	6.88	10.94	N/A	N/A	N/A	N/A	0
PRO	1.01	4.66	4.52	1.07	3.68	4.61	0
Target Precision	11.2	12.0	27.4	7.2	9.0	7.0	0
Tortuosity	1.07	1.42	1.34	1.55	1.05	1.13	1
Overpulls	7	0	2	9	3	3	0
Success	90.0	80.0	57.5	20.0	91.0	97.5	100

Table 10: Comparison of results of selected wells (N/M = measured, N/A = not available)

In detail, it looks like the WQS approach seems not to be very conclusive when compared to the other aspects. Given also the fact that it relies solely on DDRs, it can certainly be classified as not useful for a sound assessment of WBQ. For example, the exploration well Erdpress A has been drilled nearly in-gauge, close to the planed trajectory and with reasonable precision inside the target. Even from a producing point of view, this well is successful. However, due to some difficulties (e.g. the rather high number of overpulls) it ends up with a rather poor score according to Mason and Chen. On the other hand the "dry injector" Erdpress U has a quite good WQS score, but is actually a complete failure, not only because it does not serve its purpose: Despite the high number of significant overpulls, it scores 14 points on the WQS – meaning that it would be even quite close to perfect without those; however, the poor adherence to plan (high tortuosity) and the fact that the well is completely unable to inject, this score is absolutely useless. It is like a very fancy house – but one without doors or windows.

On the other hand, Well V2 is a good example of how a sidetrack can help rescue an otherwise wrecked well – even if it exceeds the specified limitations itself: Well V1 had to be sidetracked because of a very high dogleg, but even Well V2 ended up exceeding those limits. However, it is fully functional, quite close to the planned trajectory and the target point, as well as to the gauge size, and the sucker rod pump seems to work without problems, too.

A major contribution to the lack of success of Erdpress J is being outside of the target zone, as well as its exceeding tortuosity. Here, the overall impression of the well's quality coincides with the WQS score.

Looking at Table 10, it also becomes visible that there might be a inverse relationship between target precision and tortuosity: The more precise the target has been hit, the higher the tortuosity ratio tends to be. This means that the directional driller has made more "aggressive" steering decisions to come as close to the target as possible – but at the same time possibly risking an out-of-specification DLS. On the other hand, those wells that have a higher deviation from the planned target coordinates have a smaller tortuosity ratio (i.e. smoother well path).

A note that needs to be made is that due to casing drilling, not all surface sections have caliper log data available. Those wells have still been selected, because of some significant other results, and because caliper data of other sections are available. Secondly, not all wells have intermediate casing sections, hence no data is available for those wells in the INT section.

8.3 Implications of the Results

It has already been mentioned, that a unique value will not be able to convey the whole message. Each KPI focuses on a certain aspect, regardless of any other aspect of WBQ. This means that – unless only one aspect is relevant for the investigation – a variety of KPIs should be considered in order to cover as many aspects as possible. What has to be kept in mind in this context is that too many KPIs will become unhandy, which means that a limit needs to be chosen. This should be up to the persons who apply the KPIs, so ultimately a company decision.

One important decision will also be, whether the caliper-based KPIs should be considered for all well sections, or only to some. Especially surface sections are not really representative: Firstly, the loose sediments encountered in such sections will be able to distort the results significantly; secondly, with the increasing popularity of the DwC technology, data availability will tend decrease, making it close to impossible to apply those KPIs to surface section data.

Chapter 9 Conclusions

The importance of wellbore quality has been shown to be significant. While it may not seem obvious at the first glance, there are several aspects that show this, not only on a short term, but also on the longer term. The most important factor that is relevant to both short- and long-term considerations is doubtlessly the economic impact: Any NPT that is caused by WBQ issues – be it stuck pipes, reaming or enlarging hole sections, or be it downhole tool failures due to poor plan adherence – costs money. Rig time is expensive, but it may hurt even more in the production period: Tools are expensive, and a non-productive well is one that does not make any profit!

Hence, several aspects of WBQ have been investigated, focusing on the well construction process. Here, KPIs that assess the geometry of the well, as well as operational difficulties have been developed and tested on real-world field data. While they are very specific and as such relatively useless as unique values, they can be a powerful tool when used in combination with each other. It has also been shown that existing WBQ assessment strategies are incapable of considering some factors that are doubtlessly important. They have, however, their merits, if applied directly at the wellsite, once a relevant event occurs – as a quick assessment of the "*status quo*" of the well.

Moreover, a method to assess the "success " of a well has been introduced. While this concept may not seem completely new, it is an important additional factor to be considered, as it measures the amount, by how much the actual goals have been achieved. This is the link to the long-term effects of wellbore quality, as it considers both short term (i.e. drilling) and long-term (production, reservoir/geology) requirements, unifying them in a unique number. The result is a KPI that measures the ability to deliver the expected value over the whole life cycle.

The KPIs developed and presented in this thesis are shown to be useful to give an impression of the quality of the "product well", the "as-is" status when the well construction process is completed and the product is handed over to the customer. They also show a good consistency with the experience of the operator during the well construction process.

Another important finding of this research is that the data source plays a major role: Sensor data, i.e. measurements, are hard facts that are unbiased and can convey a very detailed image. However, they are less convenient to use, because they require processing in order to be used. Still they are the preferred data source, due to the aforementioned unbiasedness. On the other hand, daily reports are a handy tool to get a quick impression of what was going on at the rig site; but they are inaccurate, and probably biased by the responsible person. This means that such data should not be used for the assessment of WBQ, unless no other data source is available.

It is worth mentioning that the long-term effect of poor WBQ could not be adequately investigated due to the young age of the field. However, this is probably the most interesting and most promising field – at least from an economic point of view. Hence, a recommendation of the author is that this area could and should be subject of further investigation in a longer-term study on the Erdpress field – and perhaps others as well.

Bibliography

Bang, J., O. Jegbefume, A. Ledroz, and J. Thompson. 2015. "Wellbore Tortuosity Analysed by a Novel Method May Help to Improve Drilling, Completion, and Production Operations." Paper SPE-173103-MS.

Butt, P., and A. Fareed. 2007. "Borehole Shape Characterization With Azimuthal LWD Measurements: Evaluation, Applications, and Limitations." *SPE 108272-MS.*

Chen, D. C.-K., T. Gaynor, B. Comeaux, and K. Glass. 2002. "Hole Quality: The Gateway to Efficient Drilling." Paper SPE-14277-MS.

Daborer, T. 2015. *The Effects of Micro Tortuosity on Trajectory Accuracy and Torque and Drag.* Master Thesis at Montanuniversitaet Leoben.

Finkbeiner, T., M. Persaud, E. Angerer, K. Bellmann, O. Knoop, T Kühn, W. Siedl, C. Kling, and A. Metz. 2015. *Technology Project: Mitigating Drilling Risks Near Major Fault Zones.* Preliminary Technical Report by OMV.

Gaynor, T. M., D. C.-K. Chen, D. Stuart, and B. Comeaux. 2001. "Tortuosity vs. Micros-Tortuosity - Why Little Things Mean a Lot." *SPE-67818-MS.* doi:10.2118/67818-MS.

Gaynor, T., D. Hamer, D. C.-K. Chen, and D. Stuart. 2002. "Quantifying Toruosities by Friction Factors in Torque and Drag Models." *SPE 77617-MS.* doi:10.2118/77617-MS.

Grelaud, S., and S. Kumar. 2013. *Sonic Scanner for Geomechanics.* Technical Report by Schlumberger.

Hofstätter, H. SS2013. "Lecture Notes "Oil and Gas Production Principles"." Course 550.071: Montanuniversitaet Leoben.

Hütter, K. 2016. *Field Development Erdpress - Project Close Out Report.* Technical Report by OMV.

Hütter, K., G. Verient, U. Zeitzmann, H. Geier, T. Florian, R.-N. Knezevic, D. Christ, R. Korinek, and O. Müller. 2012. *Field Development Plan Erdpress.* Technical Report by OMV.

Knezevic, R.-N., A. Hollerer, and O. Knoop. 2016. "Lag Correction Using "Air Gap" - Concept and Workflow." London: The Geological Society.

Knudsen, S. D., F. Dupriest, E. Zemach, and D. A. Blankenship. 2014. "Practices Maintain Straigh Hole in Crooked Hole Conditions, While Also Enabling Significant Gains in Drill Rate." *SPE 170904-MS.*

Lowdon, R., S. Brands, and G. Alexander. 2015. "Analysis of the Impact of Wellbore Tortuosity on Well Construction Using Scaled Tortuosity Index and High-Resolution Continuous Surveys." Paper SPE-173110-MS.

MacDonald, G. C., and A. Lubinski. 1951. "Straight Hole Drilling in Crooked-Hole Country." *Drilling & Production Practice* 80-90.

Marck, J., and E. Detournay. 2015. "Influence of Rotary-Steerable System Design on Borehole Spiraling." *SPE-174554-PA.*

Marland, C., and J. Greenwood. 2015. "Strain-Gauge Bending-Moment Measurements Used to Identify Wellbore Tortuosity." Paper SPE-173039-MS.

Mason, C. J., and D. C.-K. Chen. 2005. "The Perfect Wellbore!" Paper SPE-95279-MS.

—. 2006. "The Wellbore Quality Scorecard (WQS)." SPE-98893-MS.

Mason, C. 2007. "Wellbore Quality Characterization for Drilling and Casign Running in Challenging Wells." *SPE 112813-DL.* doi:10.2118/112813-DL.

Matthews, C. M., and L. J. Dunn. 1991. "Drilling and Production Practices to Mitigate Sucker Rod/Tubing Wear-Related Failures in Directional Wells." Paper SPE-22852-PA.

Oag, A.W., and M. Williams. 2000. "The Directional Difficulty Index - A New Approach to Performance Benchmarking." Paper SPE-59196-MS.

Persaud, M., and K. Schulze. n.d. *Geomechanical Earth Model (GEM) for the Erdpress Area, Austria.* Technical Report by GMI Geomechanics Services.

Rassenfoss, S. 2015. "Drilling Wells Ever Faster May Not Be the Measure of Success." *J Pet Technol* 67 (12): 43-47.

Rassenfoss, S. 2015. "The Search for Measures of Drilling Imperfection." *J Pet Technol 67* (12): 48.

Samuel, R., and X. Liu. 2009. "Wellbore Drilling Indices, Tortuosity, Torsion, and Energy: What Do They Have To Do With Wellpath Design?" Paper SPE-124710-MS.

Stockhausen, E.J., and W.G. Lesso Jr. 2003. "Continuous Direction and Inclination Measurements Lead to an Improvement in Wellbore Positioning." Paper SPE-79917-MS.

Stockhausen, E.J., J. Rasmus, and S. Bammi. 2015. "Computation of Apparent Formation Dip From Single Azimuth Sensor Data Having Different Depths of Investigation." Paper SPE-175048-MS.

Tribe, I., G. Holm, S. Harker, C. Longis, K. Milne, S. Stromberg, R. Greiss, and K. Webb. 2003. "Optimized Horizontal Well Placement in the Otter Field, North Sea, Using New Formation Imaging While Drilling Technology." Paper SPE-83968-MS.

Drilling reports, data and correspondence related to the Field Development Project Erdpress, provided by OMV Austria Exploration and Production GmbH

Drilling Data Bases provided by OMV Austria Exploration and Production GmbH

Production Data Base provided by OMV Austria Exploration and Production GmbH

Daily reports of workovers in the Erdpress Field, provided by OMV Austria Exploration and Production GmbH

Rig sensor data evaluation from *proNova* datasets, provided by TDE Thonhauser Data Engineering GmbH

Acronyms

BHA	Bottomhole assembly
cDNI	Continuous direction and inclination (measurement)
C/H	Circulate to clean the hole
C/M	Circulate to condition mud
DDI	Directional Difficulty Index
DDR	Daily drilling report
DLS	Dog leg severity
DwC	Drilling with casing
DWOP	Drilling the well on paper
EOWR	End of well report
ESP	Electrical submersible pump
E&P	Exploration and production
FDE	Field Development Erdpress
GEM	Geomechanical Earth model
G&G	Geology and geophysics
HSE	Health, safety and environment
HL	Hook load
ID	Inside diameter
IDD	Integral differential diameter
INT	Intermediate casing
KPI	Key performance indicator
LL	Lesson(s) learned
LT	Lost time
LWD	Logging while drilling
MD	Measured depth
MTBF	Mean time between failures
MWD	Measurement while drilling
NPT	Non-productive time
N/A	Not available
N/M	Not measured
OBM	Oil based mud
OHT	Open hole time
OWC	Oil-water contact
PCP	Progressive cavity pump
PEF	Photoelectric factor
POOH	Pull out of hole
PRO	Production casing
PT	Productive time
PU	Pick-up (weight)
REA	Reaming
RIH	Run into hole
RMS	Root mean squared error
ROP	Rate of penetration
ROT	Rotate string

RSS	Rotary steerable system
RT	Real-time
SBM	Synthetic (oil) based mud
SFC	Surface casing
SO	Slack-off (weight)
SRP	Sucker rod pump
s.g.	Specific gravity
TBG	Tubing
TD	Total depth, target depth
TOC	Top of cement
TVD	True vertical depth
T&D	Torque and drag
WAS	Wash down
WBM	Water based mud
WBQ	Wellbore quality
WBS	Wellbore stability
WDC	Well Design Criteria
WL	Wireline
WOB	Weight on bit
WQS	Wellbore Quality Scorecard
W/T	Wiper trip

Unit Conversions

To convert from	to	multiply by
Pounds per gallon [ppg]	Kilogram per cubic meter [kg/m^3]	119.8264
Foot [ft]	Meter [m]	0.3048
Inch [in], [“]	Meter [m]	0.0254
Pound mass [lbm]	Kilogram [kg]	0.4536
Pound force [lbf]	Newton [N]	4.4480
Pound per square inch [psi]	Pascal [Pa]	6.8948

List of Figures

List of Tables

Appendix A Reference Case Studies

A.1 Rod String and Tubing Wear

A case study conducted by Matthews and Dunn (1991) on Canadian wells, comprising both deviated (drilled initially vertically and then kicked off to build angle) and slanted (drilled slanted from the surface location without an initial vertical section) wells. The focus of their research was the effect of trajectories, especially microscopic phenomena such as doglegs on wear-related workovers.

They showed that different pump types react differently to downhole conditions. For example, sucker rod pumps (SRPs) are quite tolerant with respect to the dogleg at the pump seat, whereas progressive cavity pumps (PCPs) are sensitive. On the other hand, SRPs show significant wear, both on the rod string and the tubing, when doglegs occur above. This can be explained with the high tensile load below the dogleg in combination with the axial movement, causing high contact forces on the tubing wall. Those contact forces are responsible for the frictional wear.

While these effects can be somewhat mitigated by the use of polymer centralizers, they still remain detectable. Even relining the tubing with low friction material cannot completely eliminate this phenomenon. According to Matthews and Dunn, both the shape and the positioning of the centralizers also has an influence on the rate of wear.

PCPs show less wear on doglegs above the pump seat, because of the rotational rather than axial movement. Hence only very localized wear occurs which can be countered with centralizers at the sensitive positions. Although this is not 100% effective, wear-related failures can be significantly postponed. The sensitivity of PCPs towards doglegs at the pump seat (a DLS of 2°/30m is already a no-go) can be explained with the negative influence of cyclic stress reversals on life time: the dynamic bending load due to rotation (sinusoidal load over time profile, where tension and compression occurs periodically at the same position) decreases material life.

Moreover, there are some additional parameters contributing to wear, which are relevant to the topic of WBQ:

- Tool clearance
- Aggressivity of build/drop sections, although this seems obvious, as it comes into play in the matter of dogleg severity
- Operational factors, such as:
    - Sand cut, because it influences the abrasiveness of the produced fluid and can add friction when trapped between tubing wall and centralizers/rod string
    - Pump size, as it influences the stiffness of the pump, making it more susceptible to cyclic stress reversals
    - Pump speed, because this influences the passes on the sensitive areas, thus reducing the life time

Given the last point, it seems sensible to measure MTBF of production equipment in revolutions or strokes rather than in time. This is the more objective normalizing parameter, as a pump running at more strokes per minute may fail earlier in time, but still after more strokes than a slower pump. This would however be invisible if normalized by time.

There is a second consideration relevant to pump speed mentioned by Matthews and Dunn: Higher pump speed increases the hydrodynamic lubrication; thus the friction is actually reduced when pumping faster; on the other hand, higher pump rates may have a negative influence on production, especially on long-term sustainability. And of course, lubrication effects may be equalized by a larger amount of solids that can be produced at higher pumping rates.

A.2 Image Logs for Well Placement

Tribe, Holm, Harker et al. (2003) have done a case study analyzing the success of applying image logs for geosteering purposes and its impact on making decisions. The constraints for the project in Otter Field (Brent formation, UK North Sea) were as follows:

- Drill the formation without drilling a pilot hole
- Connect four fault blocks with one single geosteered (horizontal) well
- Place an electrical submersible pump (ESP) as close to top of reservoir, with the inclination not exceeding 60°, and the DLS below 4°/100m
- Keep DLS below 4°/100m for the entire well

In addition to the above, the target layer had an average thickness of only 8m.

This posed a certain challenge: 8m is approximately the TVD error margin calculated by Stockhausen and Lesso (2003), meaning that simply the mathematical uncertainty might cause the well to miss the target layer. Since imaging technology via resistivity tools was not available for use in all hole sections, quadrant density measurements have also been applied. The downside of these is that they can only provide limited information. However, this is sufficient for maintaining positional awareness, and ensures that the well was kept in the target layer.

The case study shows that formation image logs do not only support the drilling teams in making the correct decision, but it also shows enormous potential for saving money on drilling time and completion equipment:

- The well could be placed in the optimum position as restricted by geology.
- The technology made geological sidetracks and pilot holes unnecessary, thus reducing rig time.
- Being able to follow a competent layer made completion simple and reduced equipment cost to a minimum. In this particular case, only sand screens had to be used in the well analyzed in the case study, because the well could be kept within this particular layer throughout all four fault blocks

Appendix B Correlating LWD and WL Calipers

What is interesting, however, is the question if it is possible to relate LWD to wireline caliper logs. To do so, the caliper data were visualized in a single plot, to identify similar curves. Where such similarities were identified, the ratio between wireline and LWD calipers has been calculated.

The idea behind this was to see if this ratio stays constant, so that a "fudge factor" can be applied, at least on a well-by-well basis. However, the analysis has shown that such reasonably constant ratios exist only on a local basis. An interesting, yet easily explicable observation during this step was that the upper well sections show much lower correlation between wireline and while-drilling caliper, whereas the lower sections show a relatively similar size and pattern throughout the whole section. The reason for this are the unconsolidated layers of the (Upper) Pannonian, which are more affected by circulation. Furthermore, the larger-sized hole requires higher flow-rates for hole cleaning, which adversely affects the caliper in such unconsolidated layers even more.

The discrepancy can generally be explained by two factors that have been mentioned before – the time the formation is exposed to circulation is much higher for the wireline log than for the (nearly[16]) immediate LWD measurement.

Another thing that needs to be taken care of is the depth shift that needs to be applied: Driller's depth is not the same as Logger's depth. Once that is done, it is, however, relatively simple to see that no constant ratio exists – as mentioned above. For individual layers, this may still be possible, although it is essential to keep in mind that LWD tools provide neither the accuracy nor the precision of wireline tools: They are too much dependent on various parameters, as it has been explained earlier already.

[16] The LWD tool is typically located some 10-30m behind the bit, so there is a delay in measurement, but at a penetration rate of 10m/hr, this is approx. 1-3hrs – negligible compared to the WL measurement which may take place days after drilling.

Appendix C Caliper Histograms

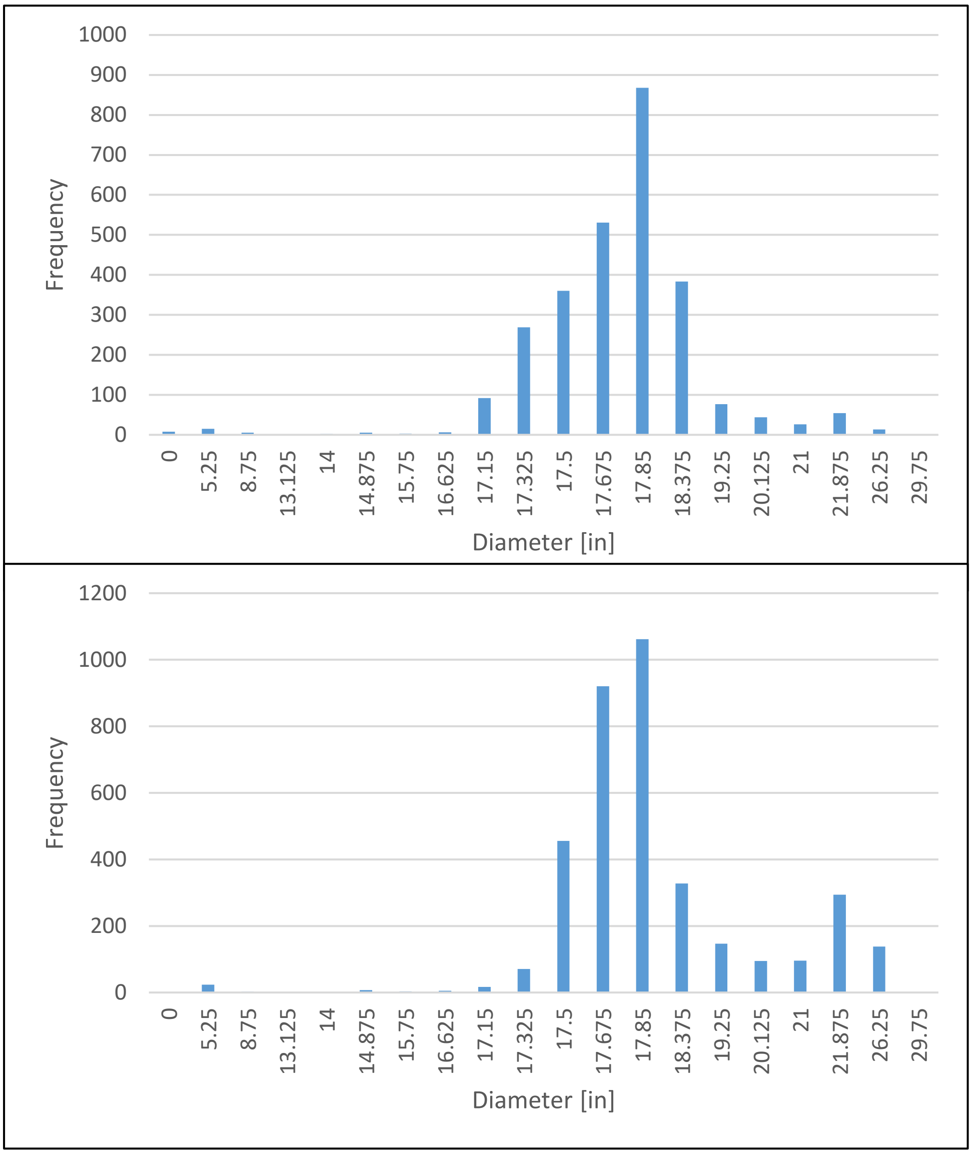


Figure 36: 17.5 inch surface section caliper distribution

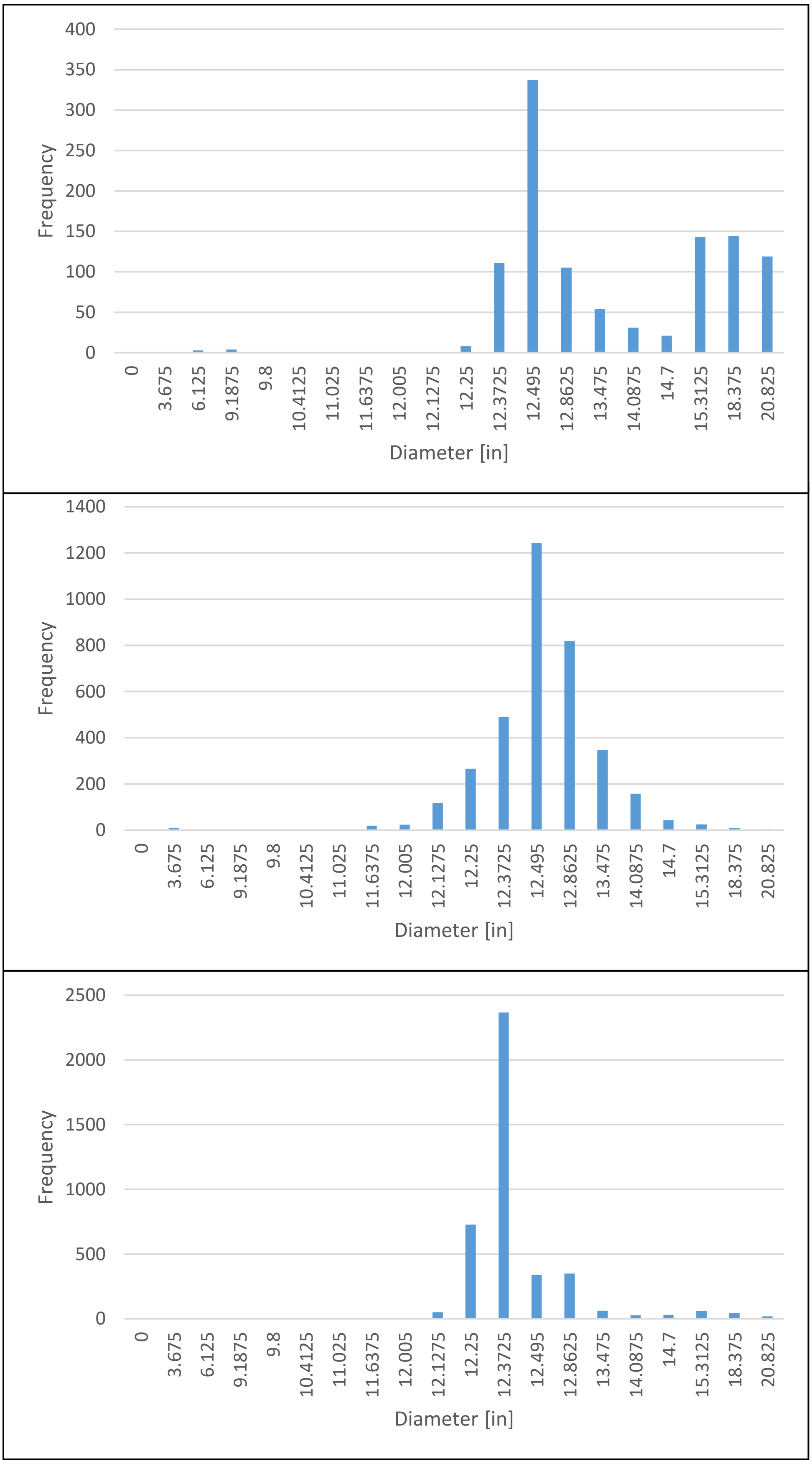


Figure 37: 12 ¼ inch intermediate section caliper distribution

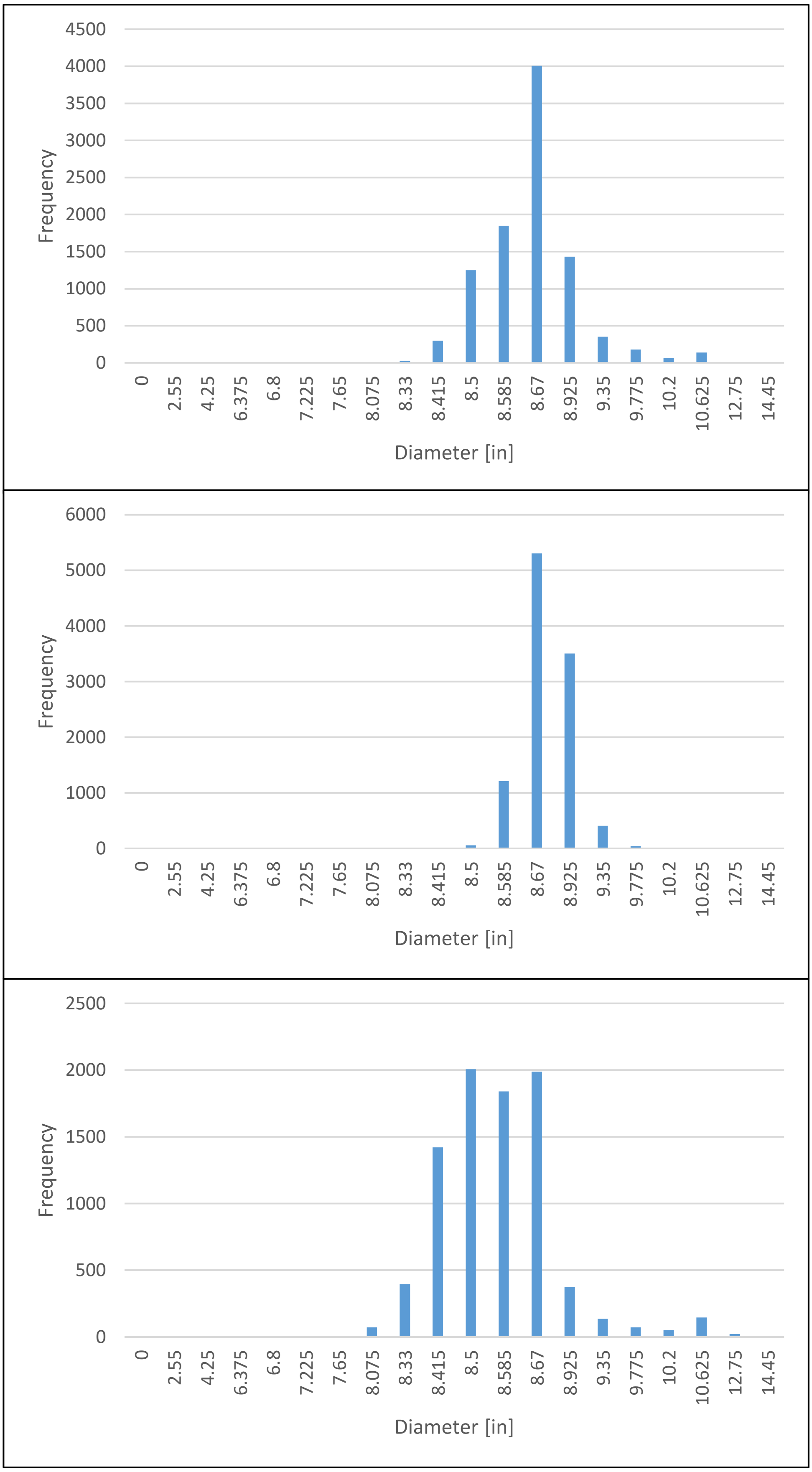
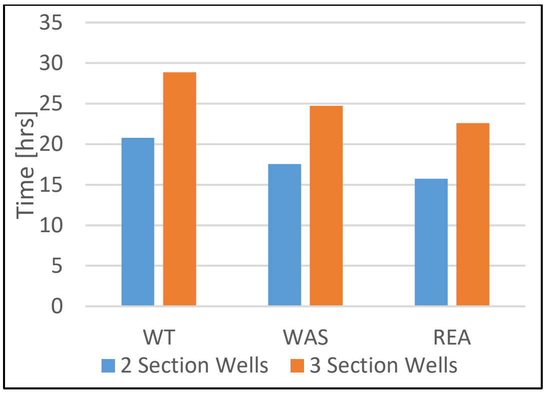


Figure 38: 8 ½ inch production section caliper distribution

Appendix D Sensor Data vs. DDR Data

Sensor Data

DDR Data



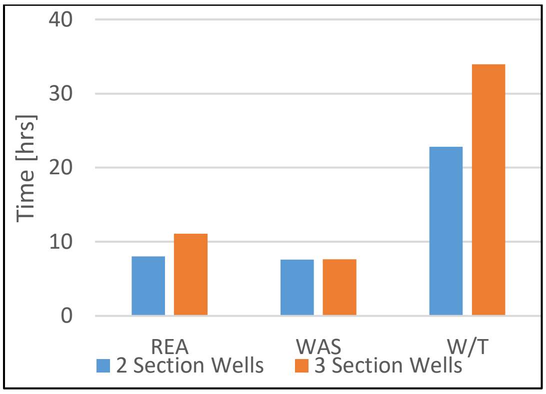
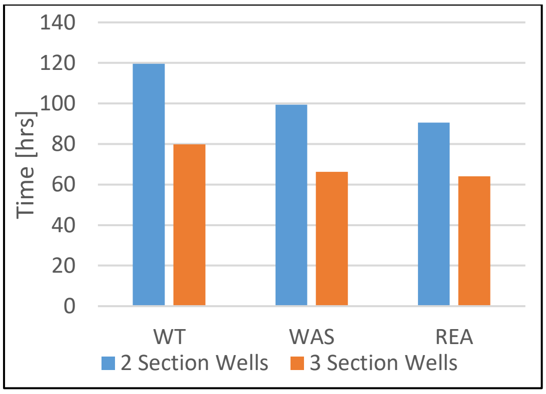


Figure 39: Comparison per well



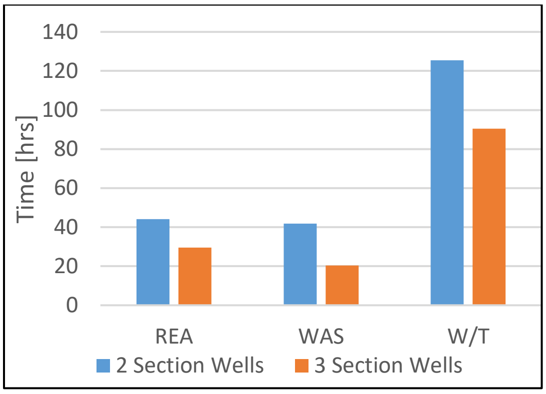
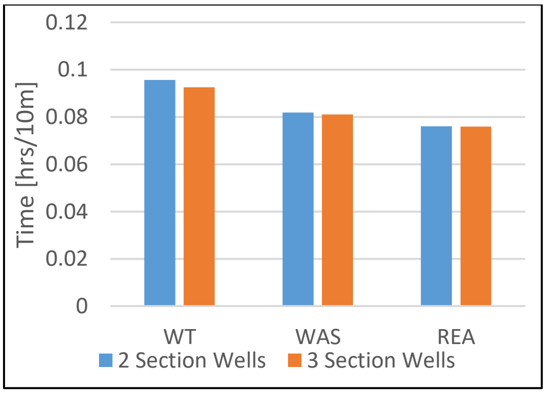


Figure 40: Comparison per casing section



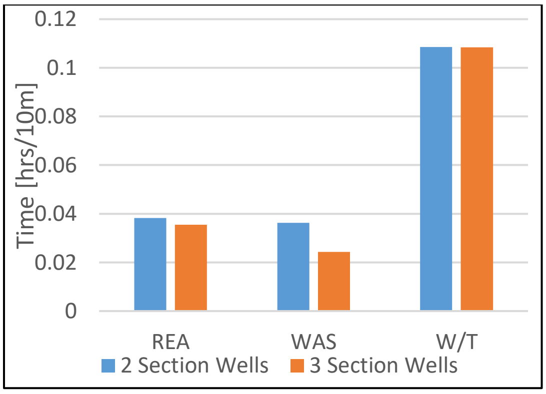


Figure 41: Comparison per 10m