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Abstract

The most common form of rig contracts are day rate contracts, in which the oil company rents the rig for a stated rate for each day of the contract term. However, with the shift in negotiation power from rig companies to oil companies and the increased focus on cost among oil companies, well based contracts with incentive schemes rewarding time efficient performance have gained popularity. Designing such contracts presents new challenges for the oil companies. These are important to consider in order to get the desired effect – increased efficiency and lower cost.

This thesis investigates challenges associated with determining the properties of a time based incentive model, how the model can be adjusted depending on various factors, and determining the target time. The thesis focuses on drilling contracts for semisubmersible rigs in a market similar to that seen in 2017, i.e. a market with low rig utilization.

Based on studies of three rig contracts, interviews and discussions with Wintershall Norge AS, the challenges were first mapped. Analytical approaches were used to conclude on the most suitable shape of an incentive model for drilling rig compensation. Several factors that could influence the way compensation rates are adjusted were considered: the rig efficiency, the rig company's OPEX and crew size, rate in subsequent contract, rig company's market share, and size of the oil company.

The results suggest to use a convex incentive model. Regarding the slope of the curve, the oil company could implement less generous incentives in cases when there is a higher rate in the subsequent contract and there is a newly started rig company. A large oil company with big market shares could have less generous incentives than smaller oil companies, and comparing rigs with different efficiencies, it is suggested to have a steeper slope for the less efficient.

Due to the large time gap between the contract signing and the actual commencement date for the drilling operation, estimation of a fixed target time is very uncertain. This could prevent the desired drop in the rig company's base rate. If a fixed target time is given and the oil company makes adjustments in the project reducing the expected project duration, there is a risk the rig company achieves a higher rate for the same level of performance. In cases when the oil company makes adjustments increasing the expected project duration, it is likely to result in costly renegotiations of the target time and/or rates. Otherwise, measures might be taken by the rig company to reduce its cost, which could negatively affect the progress in the drilling operation.

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Stavanger, 15. June 2017

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Abbreviations

Abbreviations used in the thesis are listed below in alphabetic order:

CAPEX	Capital Expenditure
EPC	Engineering, Procurement and Construction
HSE	Health, Safety and Environment
HSEQ	Health, Safety, Environment and Quality
LWD	Logging While Drilling
MWD	Measurement While Drilling
NCS	Norwegian Continental Shelf
OPEX	Operating Expense
ROV	Remotely (underwater) Operated Vehicle
WOW	Waiting On Weather

Definitions

Definitions used in the thesis are listed below in alphabetic order:

- Base rate – The rig company’s rate at target time
- Casing – A steel pipe cemented in place in a wellbore
- Christmas tree – An assembly of valves, spools, chokes and pressure gauges fitted to the wellhead of a completed well to control production
- Contractor – The party that is contracted to perform a defined scope of work. Used in this thesis as a more general term than “rig company”
- Derrick – The structure used to support the crown blocks and the drill string of a drilling rig
- Incentive contract – A contract with an incentive scheme
- Incentive curve – Defines the adjustment of the compensation for the achieved performance relative to the defined target
- Incentive model – A detailed description of the elements affecting compensation and determination of target in an incentive scheme
- Incentive scheme – A large-scale systematic plan for the incentive arrangement
- Offset wells – Wells close to a proposed well. It provides valuable information about expected characteristics about the geology and problems that might be encountered
- Permeability – A measure of a porous material’s ability to allow fluid to pass through it
- Principal – Refers to the project owner who awards the project to a contractor
- Rig company – The company that owns the rig
- Target time – The time estimate the oil company sets as the starting for the incentive model
- Tripping – The process of pulling the drill string out of the wellbore.
- Tubing – The flow conduit used in a well to either transport produced fluids to the surface or inject fluids to the formation.

1 Introduction

1.1 Background for thesis

There has been an explosive increase in drilling cost on the NCS. From 2004 to 2014 the drilling costs tripled for semisubmersible drilling rigs. This challenged the profitability of mature fields and several development projects. The bulk of projects involve relatively small volumes, and half of the discoveries under consideration had major profitability challenges (Moen, 2014, 08.05; Molde, 2015, 06.01). The high cost level left oil companies with no other choice but to postpone or cancel planned wells. Such a situation is unfortunate for the recovery of petroleum resources on the NCS. That is because, despite many sophisticated methods available to improve recovery, none equal the importance of drilling additional wells (Molde, 2015, 06.01). With the considerable amount of money the industry generates and the Norwegian tax system, where the oil companies pay 78 percent tax of net profit (Norskpetroleum, 2017, 15.05), lower drilling activity is also a matter of concern from a socio-economic perspective.

However, as Figure 1 shows, significant changes have occurred the last three years. The rig rates have slumped and the industry has halved the drilling costs (Lewis, 2016). These savings are offset by the significant drop in oil price. This forces oil companies to still focus on cost.

The saying “time is money” is seldom more true than for the drilling industry. For the ongoing Maria project daily costs are around NOK 8 million (Sagmoen, 2017) and the lion’s share of these are time related.

As a result of the drop in oil price the negotiation power has shifted from the contractors to the oil companies, allowing oil companies to be more innovative in their contract design. This shift in negotiation power, and the importance of time, has prompted the use of time based incentive contracts in drilling.

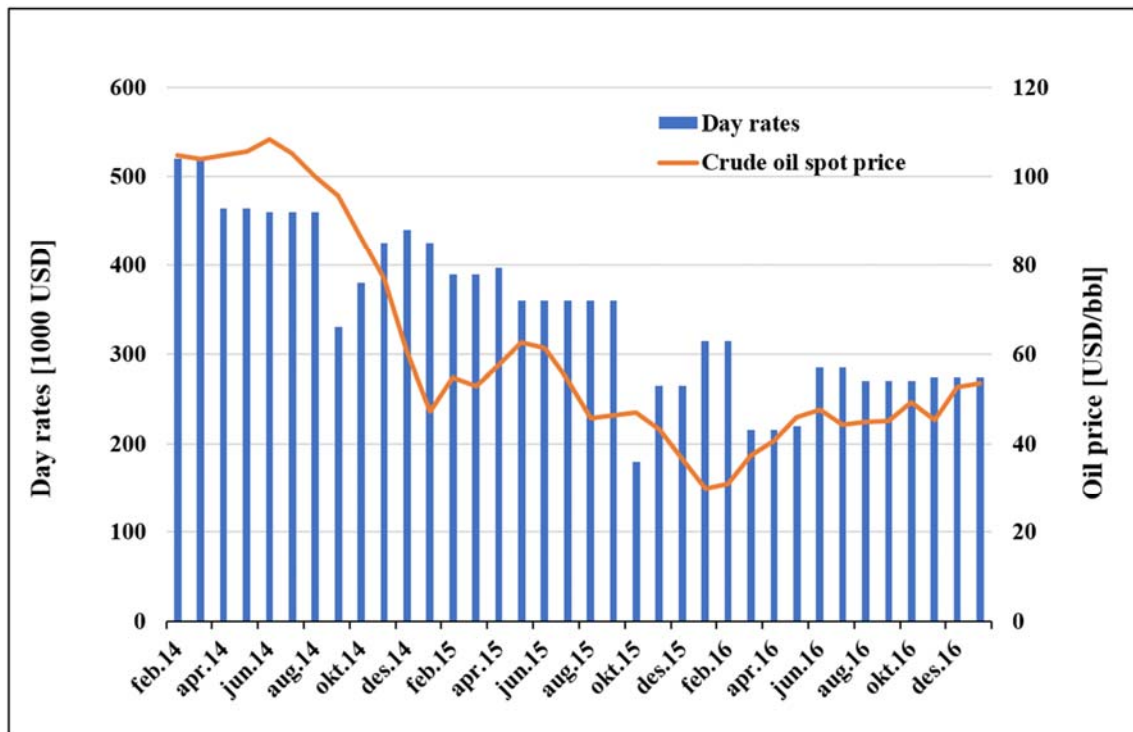


Figure 1 Average rates worldwide semisubmersibles > 7 500 ft. and average crude oil spot price from January 2014 to January 2017. Modified from IHS Markit (2017a)

1.2 Definition of thesis

Wintershall have recently implemented incentive models rewarding time efficient operations in their drilling- and oil service contracts. In the tender process with contractors, it has been proposed two compensation formats; one with an incentive model and one based on traditional day rates. Different response among the contractors have been observed. Some have reduced their base rate, while others have not been willing to do so because the incentive model has not been generous enough. Wintershall's first idea for subject of thesis was therefore to investigate factors that can affect how an incentive curve should be adjusted to be of interest for the rig company. Working on this, two closely related challenges with time based incentive design became apparent; the shape of the curve and how to establish the target time. The objective of this thesis was therefore modified to elucidate three challenges an oil company could face when designing time based incentive models:

1. Determining the shape of the incentive curve.
2. How different factors can influence the adjustment of the incentive curve.
3. How to determine the target time.

1.3 Limitations

This thesis only investigates three challenges associated with the design of time based incentive models in drilling contracts. It is not an attempt to fully address these, though it suggests a shape and how the curve can be adjusted depending on various factors. The challenges with determining a target time and the corresponding suggestions for reducing these are related to the Maria project.

The focus in this thesis is on a market with low rig utilization on the NCS, and the discussions are related to well based contracts and not fixed-term contracts. In connection with the thesis writing, only contracts for semisubmersible drilling rigs have been examined. Drillships, jack-up rigs, drilling services to fixed platforms and third party services were not subject to investigation.

2 Theory

The purpose of this section is to provide the reader with relevant theory with respect to the thesis. Firstly, the rig market and drilling contracts are briefly explained. This is followed by an explanation of target cost contracts, both in general and more related to the drilling industry. An introduction to state contingent strategy is given in section 2.4, and in section 2.5 some of the challenges with designing incentives are elucidated.

2.1 Rig market

Day rates for the drilling rigs are the primary descriptor of the rig market (Kaiser & Snyder, 2013). Supply in the drilling market is essentially inelastic in the short run, while demand is highly variable (Carter & Ghiselin, 2003). The rig companies add capacity to their fleet through newbuilding, but it takes years to deliver the rigs. Because of this, and as rigs are long-lived assets that are not readily removed from the market, there are periods of over- and under capacity. These periods have corresponding responds in rig rates (Kaiser, 2014).

A number of asset-specific and market-driven factors influences rig demand and day rates. High expected oil and gas prices stimulate development projects and hence increases rig demand and therefore prices. High rig utilization also leads to high prices (Osmundsen, Rosendahl & Skjerpen, 2015).

The bargaining power of the rig companies is closely related to the market demand for rigs (Osmundsen et. al., 2015). In a tight rig market the rig utilization is high and there is competition among exploration and production companies for access to drilling. The rig companies are then able to negotiate favorable terms (Moomjian, 1999a; Kaiser & Ghiselin, 2013). In a tight market rig companies will only consent to share the upside while being protected against the downside (Osmundsen, Sørensen & Toft, 2010). Conversely, in a soft market the rig utilization is low and the rig companies bid aggressively to win work. This increases competition and reduces rates. I.e. the rig companies' negotiation power is weakened and oil companies are able to negotiate contracts in their favor (Moomjian, 1999a).

The current market condition is soft. Only 17 of 44 rigs on the NCS were employed January 1st 2017, and by August the number is expected to be reduced to 12 (Økland, 2016, 12.12). This is equivalent to a rig utilization of 27 percent. In comparison, the rig utilization at the end of 2014 was 93 percent (EY, 2015).

2.2 Drilling contracts

A drilling contract serves as rule book between the rig company and oil company. It specifies the personnel, equipment, materials and services each party has to provide, defines the scope of work and compensation manner, and addresses contingent risks and liabilities. Over time, drilling contracts have become more sophisticated and complex, especially in offshore operations (Moomjian, 1989).

There are several principal types of offshore drilling contracts. Moomjian (1992) finds that the most commonly used are day work contracts, in which the rig company furnishes its rig and crews, and receives a stated rate for each day of the contract term. Associated services with drilling a well like casing and cementing are not included in the day rates. In turnkey (total) contracts, the rig company receives a lump sum for drilling a specified well or wells, and in footage contracts the remuneration is based on the number of meters drilled. In the offshore industry, the two latter contracts are not often employed.

Incentive drilling contracts have been used with varying frequency during the past several decades. Traditionally they have been based on footage or turnkey concepts emphasizing several objectives and characteristics. Among them are financial inducements for good contractor performance, cost predictability for a given well or series of wells, transfer of operational control and risk from the oil company to the contractor, and transfer from the oil company to the contractor of responsibility and administrative burdens associated with ancillary services and procurements of well consumables (Moomjian, 1992).

Drilling contracts often include options for prolonged service at similar conditions. Sometimes there are options for drilling different well types and/or wells at other locations than the initial agreement, and the rates may be adjusted for this. For example, the rates usually increases for high pressure and high temperature (HPHT) wells. This is due to increased wear on equipment, like elastomers. Changes in drilling area could also increase the rates, as there are statutory requirements when drilling in climatic challenging areas. One such example is winterization, which objective is to ensure that a vessel is capable of, and suitably prepared for operations in cold climates. Winterization measures include amongst other protecting the vessel's functions, systems and equipment considered important to safety (DNV GL, 2013).

2.2.1 Tender process of rig rates

In rig contracts, there are usually several different rates specified. The contracts may include some or all of the following rates:

1. Mobilization and demobilization rate: Applies when the rig travels to and from location.
2. Operating rate: Applies during drilling activities. It is commonly the sum of the rig company's given OPEX and CAPEX.
3. Standby rate: Applies when the rig is not performing normal operation or any of the other rates do not apply. It is often given as a percentage of the operating rate.
4. Moving rate: Applies when the rig moves between the oil company's well sites. It is often a percentage of the operating rate.
5. Waiting on weather rate: Applies when work cannot take place because of the weather conditions. It is often given as a percentage of the operating rate.
6. Repair, maintenance and breakdown rate: Applies when the rig is not operating and permitted maintenance, repairs or breakdowns are performed. It is often given as a percentage of the operating rate.
7. Force majeure rate: Applies in periods of force majeure. It is often given as a percentage of the operating rate.
8. Zero rate: Applies when operations have stopped due to faults by the rig company, or under other specified circumstances.

The rates could be specified in the tender by the oil company or be a part of the rig company's offer. In the tender process it is important to document and detail the time periods and triggers at which the different rates apply (see Appendix B for an overview of applicable rates for selected situations). If the compensation structure is not properly drafted it can present ambiguity, and disputes can arise (Moomjian, 1989).

Before awarding a contract, the oil company carefully evaluates all bids. Because the rigs' rates, capability of handling weather, their uptime and operational efficiency vary significantly, it is a complex process to find the best offer – it is not given that the one with the lowest rates results in the lowest cost. Other common evaluation criteria are competence, experience, financial strength, compliance with regulations on NCS, and HSE-system and culture. Finalizing a contract often requires further negotiation with the preferred rig company (Corts & Singh, 2004; Osmundsen, Toft & Dragvik, 2006).

2.3 Target Cost Contract

Target cost contracts are contractual forms which lie between fixed-price and reimbursable types (Osmundsen et. al., 2010). The use of such contracts has increased in recent years as the principal have sought means to incentivize contractors to finish projects within cost budgets. With this aim in mind, these contracts provide for a pain/gain sharing mechanism (Godwin, Gilmore, Kratochvilova & Roughton, 2013). When the project is finished, typically, the recorded cost is compared with the target cost and any savings are shared between the employer and contractor in a pre-agreed manner. Likewise, overruns relative to the target cost are shared.

A type of target cost contract which has been used in the Norwegian offshore industry is EPC (Engineering, Procurement and Construction) contracts. EPC contracts are turnkey contracts, which imposes greater responsibility to the contractors compared to many other contract strategies - from design to construction and delivery.

In the 1980s, the offshore industry identified a need for substantial cost reduction and had to take action in order to remain competitive in a global market. Extensive changes in roles and structures in the Norwegian petroleum sector therefore took place during the 1990s. These changes evolved into today's EPC model. The contractors undertook a larger and more complete responsibility of the project, and started to do tasks that previously were performed by operating companies. Project management, detailed design and interface control were some of these tasks. In addition, there was an increasing focus on performing parallel activities. This was a response to the sequential activities during the 1980s (Nielsen & Braadland, 2004).

Many of the costs attributed to the petroleum industry are time-dependent. Particularly this is the case for drilling where the rig and well services constitute the majority of the costs. Hence, the 'ordinary' target cost contract could be transferred to a time based incentive contract with incentive models rewarding/punishing efficient/inefficient operations. Like for the target cost contract, it is determined a target, but the target is now the time estimate used as the starting for the incentive model.

2.3.1 Sharing Ratio

The sharing ratio between the principal and contractor is the essential feature of the target cost/time contract that differentiates it from other types of payment mechanisms. The mechanism is based on a formula which specifies how much each party should carry of any overrun and/or gain from any savings.

Theory

A common method used for the sharing mechanism is to divide overspend or underspend (in terms of monetary value or time) into “sections” on a percentage basis. One way of doing this is for the parties to agree on a sharing ratio of *all* over-and underruns. However, this is not common. It is usually added a floor on the profit to ensure that contractor does not carry too much risk, as will be explained more in section 2.3.2. The graph below illustrates a target cost contract with constant sharing ratio for all over-and overruns. The subscript C refers to the contractor.

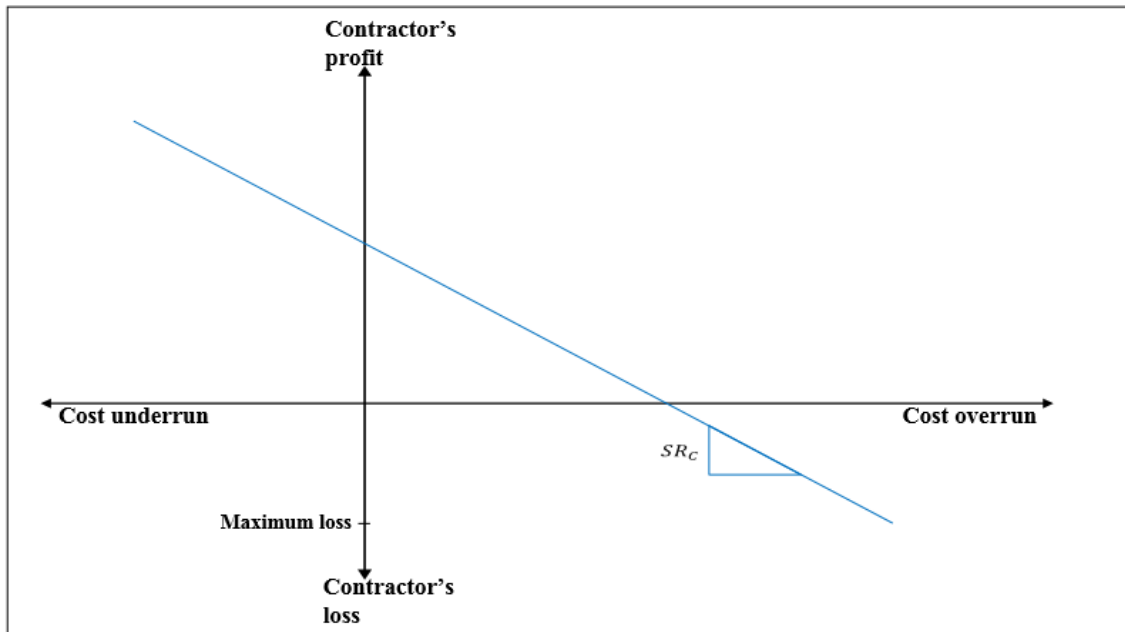


Figure 2 Contractor's profit in a target cost contract with constant sharing ratio, SR

2.3.2 Risk sharing

When it comes to incentive contracts, theory indicates that optimal contracts on the NCS should balance the need for optimal risk sharing between the oil company and contractor, and the incentives to contractor. Isolated, the incentive consideration suggests the contractor carries a large portion of the risk; for incentives to reduce costs, the contractor's remuneration should depend strongly on the project's cost. However, when it comes to consideration for risk sharing it is often argued that the principal, when looking at the offshore industry, should carry most of the risk because it is better able to do so (Osmundsen, 1999). The reason is partly because the oil companies usually are financially solid companies, partly because the government carries a significant share of the downside risk through the Norwegian petroleum tax system, and partly because they are more diversified. The latter is assured through joint ventures in license groups

Theory

and because the oil companies are involved in several licenses (Osmundsen et. al., 2006). The contractors on their hand usually have less diversified portfolios as their portfolios commonly are dominated by some major projects. However, it should be mentioned that this is not always the case. There are contractors that have a well-diversified portfolio, and there are small oil companies that are not as diversified as larger oil companies. Thus, there may be contracts where consideration for risk sharing implies that the contractor should bear the risk. This clearly shows that contracts should be customized based on the parties' ability to carry risk (Osmundsen, 1999).

I.e., considering only risk sharing the contractor should, in most cases, carry little risk, while incentive considerations suggests the opposite. A trade-off is to share the risk between the oil company/license and the contractor (Osmundsen, 1999). This is the case in the most common form of target cost contracts. The EPC contract below shows how risk sharing is achieved between the two parties: The contractor has incentives to reduce cost relative to the target cost/benchmark cost to increase its profits and any overruns are shared according to the sharing ratio. At the same time, there is an upper risk for the contractor because of the absolute floor on the downside (Osmundsen 1999). The cost where the graph becomes flat is the maximum cost the contractor is burdened. I.e. all costs above this level would be at the expense of the oil company.

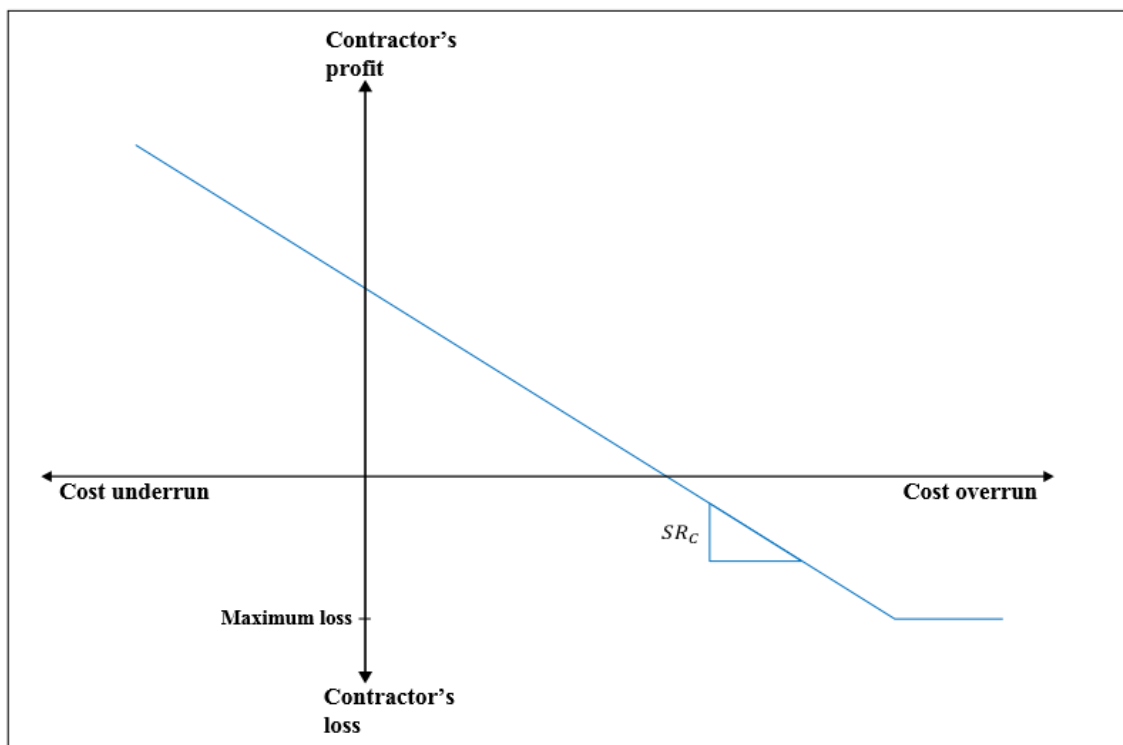


Figure 3 Illustration of a EPC contract. Adapted from Osmundsen (1999)

A similar reasoning follows for time based incentive contracts with incentive models like that shown in Figure 4. The rate increases for time reductions relative to a target time, T , and declines if the contractor exceeds the target time. Because time reductions result in a bigger margin per day or hour for the contractor the contractor has incentives to shorten the time (and hence the oil company's costs). Like for the target cost contract there is an absolute floor on the downside; the minimum rate the contractor can get. The shape and slope can vary between different contracts.

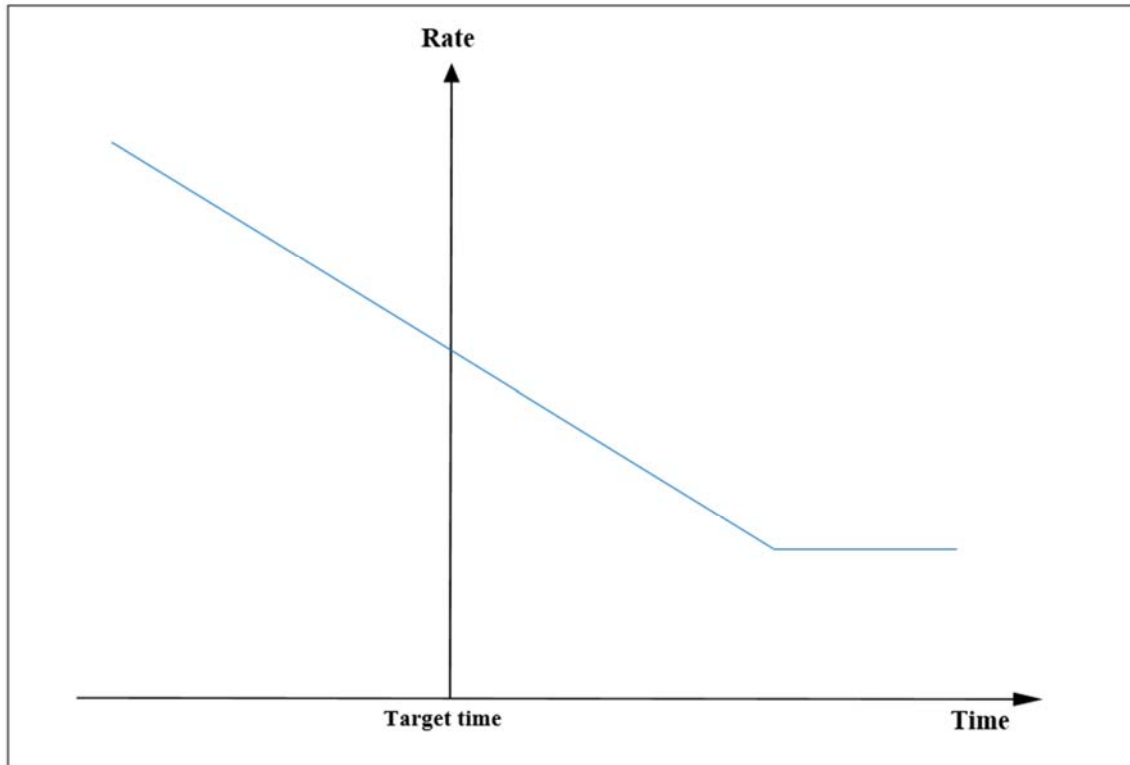


Figure 4 Illustration of an incentive model with a target time, and an upside, downside and absolute floor on the rate

2.4 State Contingent Contract Strategy

What type of contract being agreed between the principal and contractor, and its design, is highly context-specific. I.e. the contractual and organizational design must be adapted to the specific properties and conditions of the project, the principal and the contractor. Various combinations of these properties may result in a large number of projects with different qualitative characteristics. All the unique projects may require customized contractual solutions (Osmundsen, 2007). In the following, a selection of these properties will be explicated, as well as a brief description of their implications.

2.4.1 Rigidity of scope of work

If the work description is not sufficiently detailed, fixed price contracts and target based contracts are not applicable. Osmundsen (2007) argues that the principal is best served using reimbursable contracts if the scope is not clear, since the contractor always can find ways to claim that overruns are due to inadequate specifications (as cited by Bajari & Tadelis, 1999).

2.4.2 Available time

If the project is time-critical, it is important to find flexible organizational solutions to avoid conflicts. In such cases, reimbursable contracts may be more appropriate than fixed price contracts (Osmundsen, 2007). Incentive contracts with time based incentive schemes could also be appropriate as it sends a clear signal to the contractor that time is important.

2.4.3 Budgetary freedom

Fixed price contracts allow for good cost-control for the principal, while reimbursable- or incentive based contracts entails more cost-uncertainty. Therefore, fixed price contracts are preferred if the principal has little budgetary freedom (Osmundsen, 2007). However, there are higher costs related to the contract design. For a drilling rig, the oil company must draw up a time-consuming and expensive drilling specification in advance of the operation, and cedes in practice much of the flexibility during drilling. Should desired project specifications change once the project is under way, it may result in holdups and typically expensive and difficult renegotiations (Corts & Singh, 2004; Osmundsen et. al., 2010). Another possible disadvantage of fixed price contracts (and incentive based for that matter) for the oil company is that it can lead to distortion of the activity. Rewarding one measurable dimension (meters drilled per day) can be at the expense of other important, but hard-to-measure indicators such as efficient reservoir drainage and information gathering (Osmundsen et. al., 2010). Because of this, and the fact that the rig company carries a great deal of risk using such contracts, fixed price contracts are not an option on the NCS¹.

2.4.4 Oil company's flexibility

The degree to which the oil company would like to influence and control operations is important when choosing contract format. This concerns important factors such as the company's strategic core. The strategic core includes amongst other who is to manage the drilling (Osmundsen et. al., 2010). This may vary on the specific project or phase of the project. Drilling the reservoir

¹ However, turnkey contracts are used for some wells in the Gulf of Mexico. Day rate contracts governs the drilling of more than 80 per cent of the wells, while turnkey contracts are used for the remaining (Corts & Singh, 2004)

Theory

section is one example where the oil company might want to influence the execution of the project and maintain flexibility (Osmundsen, 2007). During drilling, information from MWD/LWD tools is acquired. This information is used to steer the drill string in desired direction, and adjustments in the original plan may be desired. Especially, having the opportunity to adjust the well path is of importance in the reservoir as it concerns hydrocarbon drainage. For example, in a reservoir with an underlying water aquifer it is common to steer the well as close to the cap rock as possible. This is done to delay water breakthrough because the water provides pressure support to the reservoir. In a reservoir with overlaying gas, a gas driven reservoir, the well is usually placed near the oil-water contact to avoid gas entrance into the well. When drilling fast less information is acquired and the measurements contain more uncertainty. I.e. drilling fast could potentially be at the expense of drilling precisely, and by that affect the recovery of hydrocarbons. The additional income from drilling precisely and acquiring valuable information can thus end up far outweighing the costs incurred from it. An oil company's desire for control and flexibility could accordingly place constraints on the use of incentive contracts. If performance-based incentive schemes are to be used, the goals must be adjusted when the oil company modifies the original drilling plan. A simpler way of achieving flexibility is through various forms of cost-plus payments, like day rates (Osmundsen et. al., 2010).

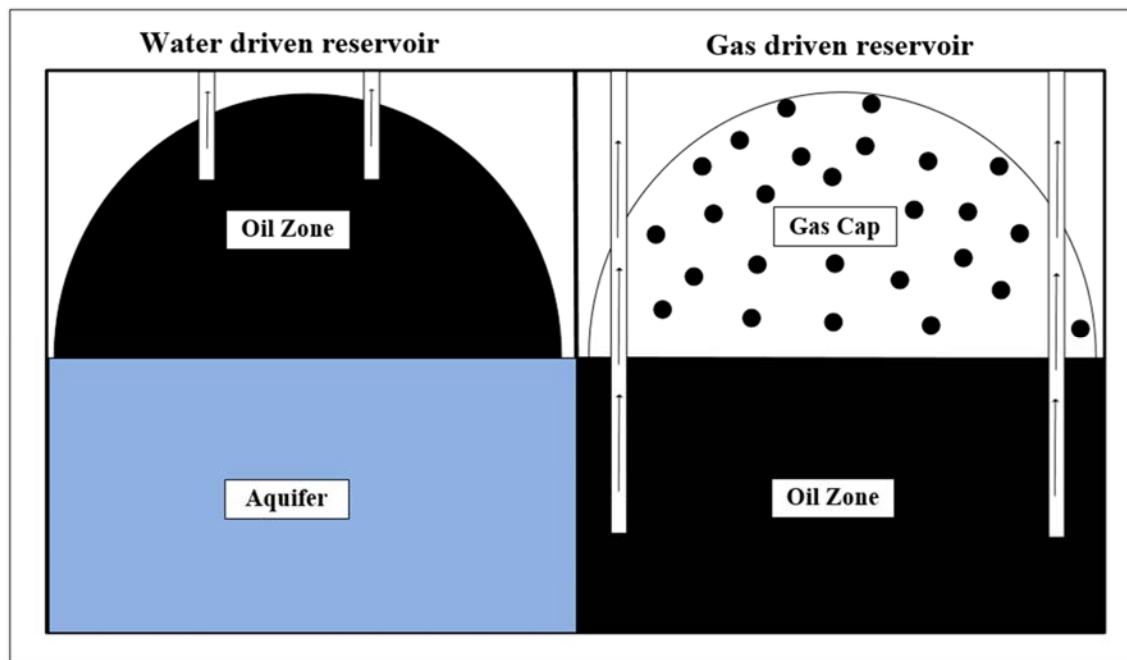


Figure 5 Illustration of well paths in water- and gas driven reservoirs

2.4.5 Spot vs agreed rate

In drilling, some companies enter long-term supply agreements that pre-determines the financial terms, such as the day rates. As the rig market is characterized by high price volatility the agreed rates can differ significantly from the spot rates. The relationship between the spot and agreed rates is essential when determining additional incentives. When the agreed rate is lower than the spot rate the rig company would like to terminate the relationship as quickly as possible. This may have a negative impact on quality. Conversely, when the agreed rate is higher than the spot rate, time schedules can be adversely affected because the rig company would have incentives to stall. These challenges in contract administration must be addressed at the time of contract design (Osmundsen, 2007).

2.4.6 Other oil companies' contracts and incentive schemes

A contractor usually has several contracts for different oil companies simultaneously, i.e. there is a multi-principal-agent relationship. The contractor has limited resources and must then allocate these among the various customers. This implies that the oil companies compete for the contractors' personnel and equipment, even after signing a contract. Each oil company must therefore consider competitive contracts when choosing contract format and/or when designing their own incentive scheme. If one oil company e.g. uses incentive based contracts and another uses daily rates, there is a risk that the contractor assigns the best equipment and most competent staff to the contract with the bonus scheme. However, this is not a problem if the oil companies can regulate the contracts to decide which staff and equipment to be used (Osmundsen, 2007)

2.4.7 The contracting parties' relative risk aversion

In order to incentivize the contractor it must carry risk. However, the incentive intensity, or share of variable remuneration, depends on four factors: The incremental profit to the principal of additional effort by the contractor, the contractor's degree of risk aversion, the precision with which the principal can measure the contractor's performance, and the responsiveness/sensitivity of the contractor's performance to incentives (Howard & Bell, 1998, p. 117).

There is no point in motivating the contractor with incentives for improved performance if the result is not profitable for the principal. In such cases, the incentive intensity should be low. On the other side, if additional effort from the contractor is very profitable, the incentive intensity should be high.

All other factors equal, less risk averse contractor's should be provided with more intense incentives because low risk aversion indicates that the contractor is more willing to carry risk

(Howard & Bell, 1998, p. 117). I.e. if the contractor has a low risk aversion it would accept a risky incentive scheme without demanding a high risk premium (Osmundsen, 2007).

The incentive intensity should also be large if the principal can measure the contractor's performance with high accuracy, or if the contractor's incentive sensitivity is high, i.e. its effort is largely affected by economic incentives (Osmundsen, 2007).

2.4.8 The extent to which the contractor can participate in the delivery lifecycle

Economic incentives can be on different levels. A high level indicates that the contractor's incentives is linked to the principal's objectives, i.e. the contractor's compensation is tied to the entire value chain its input(s) contributes to. This means that the contractor's compensation is a function of the life-cycle costs and income. In a low-level incentive scheme, the contractor's compensation is only a function of the project input's cost. Using low-level incentive schemes, the contractor thus might have inadequate incentives to improve quality, ensure operational flexibility and reduce life-cycle costs. At first sight, a high-level incentive scheme therefore seems like the better option. However, there are two necessary conditions that must be fulfilled in order to be able to benefit from high-level incentive schemes, and these are difficult to satisfy:

- 1) Congruence of goals can be achieved and
- 2) the contractor is willing and able to defer some of its cash flow.

A major obstacle for satisfying these conditions is that the contractor normally is involved only in a limited part of the value chain. For instance, when drilling and completing a well, it is difficult to make incentives contingent on the life-cycle profit. There are several reasons for this. One is that it is difficult to separate factors within the contractor's sphere of control (this term is explained in section 2.5.1) that influence long-term profit from factors outside the contractor's sphere of control. The controllability principle is therefore violated. For example, the drainage of the reservoir depends on formation permeability. A lower permeability than expected can be due to formation property or due to formation damage. Both the former and latter is outside the rig company's sphere of control under normal conditions, but a major failure in drilling practice could potentially damage the formation. However, it would be impossible to know the recovery loss from such a failure. Another reason why it is difficult to satisfy these conditions is that for the contractor's remuneration to depend on the project's long-term profit, it must typically have a share of the project. A subsea field usually have several templates with several slots (often four slots, but it could be fewer or more). During the lifetime of a field, the slots may have been re-entered to drill new wells. Most often, there are more than one rig

company which has drilled the different wells. Keeping this in mind, it is evident that the partnership structure would become extremely complex. In addition, the production of each well is usually not known, but estimated based on the total production of all the wells and the theoretical production of each well². Therefore the remuneration of the companies' is likely to be contingent on other's work and again the controllability principle is violated. Such a partnership structure also touches upon optimal risk sharing and is incompatible with the rig companies' core competencies.

In the absence of goal congruence it is essential to have a clear definition of the obligations and the risks in the contract, so that the parties are aware who is responsible (Osmundsen, 2007).

2.5 Challenges when designing incentives

There are several challenges when designing incentives. Some of them have briefly been touched upon in the above section. In the below some more will be elucidated.

2.5.1 Meet requirements for incentive parameters

From incentive theory, there are a few requirements that should be satisfied for incentive parameters. First and foremost, incentives must be tied directly to conditions and quantities the contractor can control. This is referred to as the controllability principle, sphere of control principle or influence principle. If rewards are related to conditions outside the contractor's sphere of control, incentive schemes can be akin to gambling. This might increase remuneration without improving performance and will accordingly be sub-optimum from the buyer's perspective (Osmundsen et. al., 2010). Incentives should also be linked to measurable parameters, like drilling speed, to ensure that they are legally verifiable. In addition, risks that does not lead to increased incentives should be eliminated, i.e. the contractor should only carry risk if it leads to increased incentives.

It will be in the oil company's interest to follow these principles as unnecessary risk bearing for the contractors generally results in higher risk premiums in contracts (Osmundsen, 1999).

² This is called well allocation. However, some new subsea fields have multiphase meters in each well to measure the flow of each phase (water, oil and gas) more accurately, but these sensors may drift so there are some uncertainty.

Conflicts between the two parties can also arise because of measurement disagreements (Osmundsen, 2007). Such conflicts can be both time- and cost consuming.

2.5.2 Determining performance levels

It is often difficult to determine appropriate performance levels on which to base incentives. The principal may wish to associate average compensation with average performance, and to tie maximum compensation to aggressive, but achievable targets. What constitutes acceptable performance and what constitutes outstanding performance is however difficult to determine (Howard & Bell, p. 124, 1998).

There are according to Howard & Bell (1998, p. 124) basically two options for the principal when determining performance levels. The first is to base them on comparison to what other similar contractors achieve on similar projects, using the principal's prior experience, benchmarking, or other information sources. The second option is to base performance on the particular contractor's past performance on similar work.

For drilling operations there is a concern for exploiting *asymmetric information*, a situation that arises whenever parties have access to different information when making decisions (Andresen, 2014, 15.05). The oil company generally have more knowledge about the formations and reservoir than the contractor, but less about the actual drilling operations (Osmundsen et. al., 2010). This information may be utilized to benefit from it. If, for instance, a well is to be drilled and the rig company has little or none experience about the area, while the oil company knows it contains sections with hard and abrasive formation, the oil company could take advantage of this. The two parties may agree on a too aggressive time target. In this way the oil company could achieve a favorable rate. One way of getting around this problem is to agree in writing, in advance of the drilling operation, that if formation conditions fail to match expectations, the benchmarks can be modified along the way (Osmundsen et. al., 2010). Another way is to freely and openly exchange historical field and offset well data. The latter is, according to Moomjian (1992), essential during implementation of an innovative incentive contract.

The continuous improvement philosophy obtained in manufacturing is often also apparent in other industries (Howard & Bell, 1998, p. 124). When a contractor does really well and generates big profits for its principal, the contract tends to be amended at the next crossroads, or renegotiated in the event of a long-term agreement. Last project's excellent might end up being this project's expectation. Such a continuous raising of the performance standard is referred to as the *ratchet effect* (Weitzman, 1980). The point is that the customer believes the

bonus being paid to the contractor is too high and demands a less generous contract. That can sometimes be justified because productivity improvements are to be expected over time. On other occasions it can be unfavorable for both the contractor and principal (Osmundsen et. al., 2010). In the short term, excellent performance increases incentives and therefore profits (or margins if it is a target rate contract and the contractor is not fully compensated for its lost profit from reducing time). However, in a continuing relationship the contractor may reason that outstanding performance also raises subsequent targets and decreases long-term incentives and profits. Hence, the contractor has a long-term incentive to hold down the performance level (Bell & Howard, 1998).

There can be found several examples of the ratchet effect in the drilling and oil service sector, such as contracts which relate payment to drilling speed. A possible way of reducing this problem is to agree on productivity improvements in advance of drilling operation (Osmundsen et. al., 2010).

2.5.3 Countervailing incentives

In normal market conditions there is usually a profit margin to the contractor in the agreed rates. If the contractor exceeds the target time, it faces countervailing (conflicting) incentives: By increasing the number of working days the contractor gets a profit through the profit margin on the additional days, but there is also a “loss” since the contractor has to cover a share of the cost overruns. There have been examples where the incentive has been too weak. This can drive the contractor towards stalling time. (Osmundsen, 1999)

3 About Wintershall

Wintershall is a wholly owned subsidiary of the world's largest chemical group, BASF. It is Germany's largest internationally active crude oil and natural gas producer. The company have more than 2000 employees, and explore and produce oil and gas in Europe, Russia, North Africa, South America and the Middle East.

Wintershall Norge AS was established in 2006 and is now one of the leading operators on the Norwegian Continental shelf, with a daily production from own operated and partner operated fields of around 90 000 barrels of oil equivalent. The company is the operator on two producing fields on the NCS; Brage and Vega.

The Maria field was discovered in 2010 as one of Wintershall's first exploration successes in Norway. Estimated to contain 180 million barrels of recoverable oil it is Wintershall's flagship development project in the country and is an essential part of the plan to become one of the leading operators in Norway. The project is now in the execution phase and is being developed for production in 2018.

4 Methodology

The case study research methodology was used for this thesis. The main reasons for this is its appropriateness for real-life problems and the available documents while writing. Before the case study is explained a review of the literature used in section 2 and the articles referred to in section 5 is given. The thesis is also positioned in the literature.

4.1 Existing literature

The number of papers that discuss challenges with incentives in drilling is low, and during the search for relevant literature, no papers discussing the three challenges investigated in this thesis were found.

The articles by Carter and Ghiselin (2003), Kaiser (2014), and Kaiser and Snyder (2013) give a concise overview of supply and demand in the rig market. Osmundsen, Rosendahl and Skjerpen (2015) also contribute to explaining the dynamics of the rig market. Their regression analysis shows how parameters crucial to the relative bargaining power between the rig companies and oil and gas companies affect rig rates. The parameters include oil and gas prices, rig capacity utilization, contract length, lead time, and rig-specific characteristics like drilling depth capacities and rig classifications.

The main elements of a target cost contract are explained by Godwin et. al. (2013). A particular target cost contract, the EPC contract, is the focus in Nielsen and Braadland's (2004) article. They elucidate pros and cons with this contract format.

Burgess and Ratto (2003) review the issues involved in designing performance related incentives in the public sector, and the evidence on their structure and effects. This is not directly relevant to the thesis' topics, but the article also reviews general issues in incentive design. This was used in the discussion of alternative shapes of the incentive curve.

Corts and Singh (2004) show that repeat contracts between an oil company and a rig company led increasingly to an abandonment of turnkey contracts in favor of day rates. This is explained by the build-up of relationship and trust, which reduce the incentive problems and thereby the need for high incentive intensity. Osmundsen (2007) examines optimal design for construction projects. The article mainly discusses the appropriateness of fixed price contracts, incentive based contracts and reimbursable contracts depending on specific properties and conditions of the project, the principal and the contractor. Parts of this thesis can be seen as a continuation of

Osmundsen's article because the thesis goes more into the design of and how the incentive curve can be adjusted depending on specific properties and conditions of the project, the oil company, the rig company and the rig.

Examples of innovative incentive schemes in drilling projects and their effects on the project are given by Moomjian (1992) and Osmundsen et. al. (2010). The articles presents in total five cases with performance based incentives, and in all of the cases the oil companies could report of efficiency improvements for their projects. An innovative incentive contract for a drilling project has also been examined in the research process for this thesis. However, the effects of the incentives have not been investigated because it is too soon to tell as the drilling project is currently in the execution phase. Carter and Ghiselin (2003) addresses other opportunities for efficiency improvements than implementing incentive schemes in the contracts. More precisely, they address the opportunity for efficiency improvements by adopting digital technologies and give examples of efficiency improvements by doing so.

Challenges with determining the incentive intensity and performance levels are among the topics Howard and Bell (1998, pp. 108-128) discuss, while Weitzman describes the ratchet principle in a detailed way using a multiperiod stochastic optimization model. These challenges are general challenges associated with incentive design. Other literature link such general challenges particularly to drilling: Osmundsen et.al. (2010) put asymmetric information, the ratchet effect, distortion of activity and satisfying the controllability principle in a drilling context. The free-rider problem for well-based contracts and the concern for sub-optimization when section-based contracts are used are also discussed by Osmundsen et. al. (2010).

A general discussion of the formulation of rig contracts is given in an article by Moomjian (1989) and a series of three articles by Moomjian (1999). The first article addresses the fundamental objectives of drilling contracts, the fairness in commercial terms, and discusses liabilities, indemnity and insurance provisions. The series of articles from 1999 considers risk allocations and insurance provisions of offshore drilling contracts. Challenges with risk sharing have also been discussed by Osmundsen (1999), who considers the risk sharing for field development projects offshore.

Incentives' effects on HSE are investigated by Osmundsen, Toft and Dragvik (2006). The paper discusses both explicit incentives like compensation for progress, and implicit incentives like evaluation criteria in the tender process.

Kaiser and Snyder (2013) model capital investment and operational decision making in the offshore contract drilling industry. Their operational decision model for the rig company is more detailed than the one presented in this thesis in the way that it includes more parameters. The model e.g. includes rig utilization rate and the reactivation cost. Because of the potential very high reactivation costs in today's market, which Shinn (2017, 26.01) discusses, assumptions were made in this thesis that the rig companies would increase the preservation cost before stacking to avoid the reactivation costs. Therefore, reactivation costs were not included in the operational decision model in this thesis. The two models also differs in the way that the one presented by Kaiser and Snyder considers the two operational statuses "in operation" and "cold stacked", whereas the one presented in the thesis also includes the option for "warm stacking".

4.2 Case study Methodology

In general, case studies are the preferred method when "how" or "why" questions are being posed, when the investigator has little control over events, and the focus is on a phenomenon within a real-life context (Yin, 1994, p. 2). "How" questions have been important for this research: The initial goal was to investigate how an oil company can adjust its incentive curve depending on several factors. Working on this, particularly two other closely related challenges associated with incentive design in drilling contracts surfaced; which shape the incentive curve should have, and how the target time can be determined.

Some case studies are exploratory. Their "(...) goal is not to conclude a study but to develop ideas for further study" (Yin, 2009, p. 141). Because limited research was found discussing the above-mentioned challenges with incentive design on the NCS, and as the thesis does not try to fully address the challenges, the exploratory case study becomes applicable.

The six most commonly used sources of evidence in case studies are; documentation, archival records, interviews, direct observations, participant observations and physical artifacts. (Yin, 2009, p. 99)

For this thesis, the two sources of evidence used were documentations and interviews/discussions.

4.3 Documentations

The documentations used as the basis for the discussion in this thesis were drilling contracts provided by Wintershall Norge AS. Three different drilling contracts were examined. The rigs were from 1986, 1999 and 2012, and the contracts were signed in 2010, 2012 and 2015 respectively. The latter contract was an incentive contract with Odfjell Drilling for the ongoing Maria project. This allowed me to get an insight into how such contracts may be designed, which was highly relevant for the thesis. The contracts also explained scope of work and compensation format like the different rates used and triggers for when the rates applies. In addition, due to the different signing years, the contracts gave an idea about how the rig market have changed.

4.4 The interviews

Interviews are one of the most important sources of information of case studies (Yin, 2009, p. 106). For this thesis the interviews was semi-structured because Yin (2009, p. 106) suggests the interviews in a case study to “(...) be guided conversations rather than structured queries”. The interviews were not free in the sense that it was desirable that the interviewees talked about the same themes, but it was opened for follow-up questions where it was natural. This made the conversation less rigid and formal than structured conversation. Semi-structured interviews also allows the interviewer to be more involved by focusing the conversation on issues considered important for the research project. In this way, semi-structured interviews can make better use of the knowledge-producing potentials of dialogues than unstructured interviews (Brinkmann, 2012, p. 21).

It was conducted four interviews with Wintershall employees. The participants from Wintershall have many years of experience from the petroleum industry, both technical and with contracts. In addition, together they have worked for several oil- and service companies. Three of the interviews were performed in Norwegian because this is our native language and would minimize the chance of misunderstandings. The questions for the last interview were also given in Norwegian, but though the interviewee speaks Norwegian, the answers were given in English to allow the conversation to flow naturally.

Two interviews were also conducted with Songa Offshore, both with the same person. The second was done in order to clarify certain topics and go a bit more in depth. Having worked

Methodology

for several rig- and drilling companies, the Songa representative also has a lot of experience from the industry.

Six interviews are not sufficient to elucidate all challenges with incentive design. However, it was enough to map some of them. The last three and a half months of writing was done in Wintershall's offices in Stavanger. This gave me the opportunity to ask when needed, and much of the input for this thesis have come from everyday conversations with Wintershall. Because of these conversations, six interviews were considered sufficient. It was during these discussions the relevancy of shape and target time when discussing the slope became apparent to me. Therefore, these topics was chosen to be included in the thesis.

The purpose for interviewing both an oil comapany and rig company was to get a thorough understanding of rig contracts from both sides of the table and the challenges associated with incentives.

All the participants were given the opportunity to read the thesis before being published, and to make any adjustments if desirable.

5 Results and Discussion

5.1 Challenges when designing incentives – an industry perspective

There are a number of challenging decisions to take when incentive schemes are to be used in drilling. To illustrate some of them, imagine a field development project where there is a contract for drilling twelve wells on three templates (four wells on each template). The drilling process can be organized in several ways: One well could be drilled and completed at a time, or all the top hole sections could be drilled first, before drilling the remaining parts of the wells (one well at a time). The latter is called batch drilling. There are often five sections for each well³ so this can be assumed for the imaginary project. The oil company then separates the project into as many work scopes as it finds convenient. For the imaginary drilling project, it could for example be sixty scopes if the oil company wants a section-based incentive scheme for all of the wells, twelve if it wants a well-based incentive scheme, or one if it wants an incentive scheme for the entire project. The batch drilling could be organized differently by e.g. having one scope for all the top holes, and then separate the rest of the wells into other scopes. The separation of scopes is in itself an important decision. After this is done the oil company must establish targets, shapes of the incentive model and slopes for each of the scopes. Many scenarios must be expected during operation; WOW, maintenance, breakdown and loss of cement are some of them. It has to be agreed rates for these scenarios and triggers at which the different rates applies. Such rates and triggers are also included in the traditional day rate contracts, but for an incentive contract the oil company must also decide which operations that is going to be incentivized for the rig company. Should for example the time keep ticking when the crew performs maintenance, breakdown occurs, the operation has to stop due to rough weather conditions, or cement is lost during a cement job⁴? Other challenges that surfaced in discussions with both the operator and rig company is the allocation of potential bonuses. Should the rig company get it all, or should the people on the deck get a share, either as increased payments, welfare services or socialization activities?

Mapping and discussing all challenges associated with incentive design is beyond the scope of this thesis. It has rather been focused on three determining properties of a time based incentive model; the shape and slope of the curve, and the target time.

³ Common section sizes are 36" top hole, 26", 17 ½", 12 ¼" and 8 ½" with casing sizes of 30", 20", 13 3/8", 9 5/8" and 7".

⁴ If cement is lost during a cement job the oil company sometimes has to log the well in order to see if the cement job was properly done. This takes around one and a half day.

The shape of the incentive curve will be discussed first as this might have implications on the incentive contingent factors which is discussed in relation to the slope of the curve. Thereafter the target time is discussed.

5.1.1 Shape of incentive curve

The shape and slope of the incentive model was subject for most of the discussions and interviews with Wintershall. Below are some examples of shapes of incentive curves illustrated. The various shapes will be discussed and analyzed in context with theory. Wintershall's opinion regarding the shape of the incentive curve is explained and thereafter it is recommended a shape by the author of this thesis. Lastly, a potential downside and cap on the upside in the incentive model are discussed.

For drilling and service equipment there are usually day rates, and if the rig or equipment is in the hands of the oil company the first minute of a day the oil company has to pay the entire rate. However, this does not imply that incentives should be based on daily savings relative to an agreed target. The incentive can for example be based on hourly savings, or bonuses can be paid if certain amount of days are reduced, like Alternative 1 below.

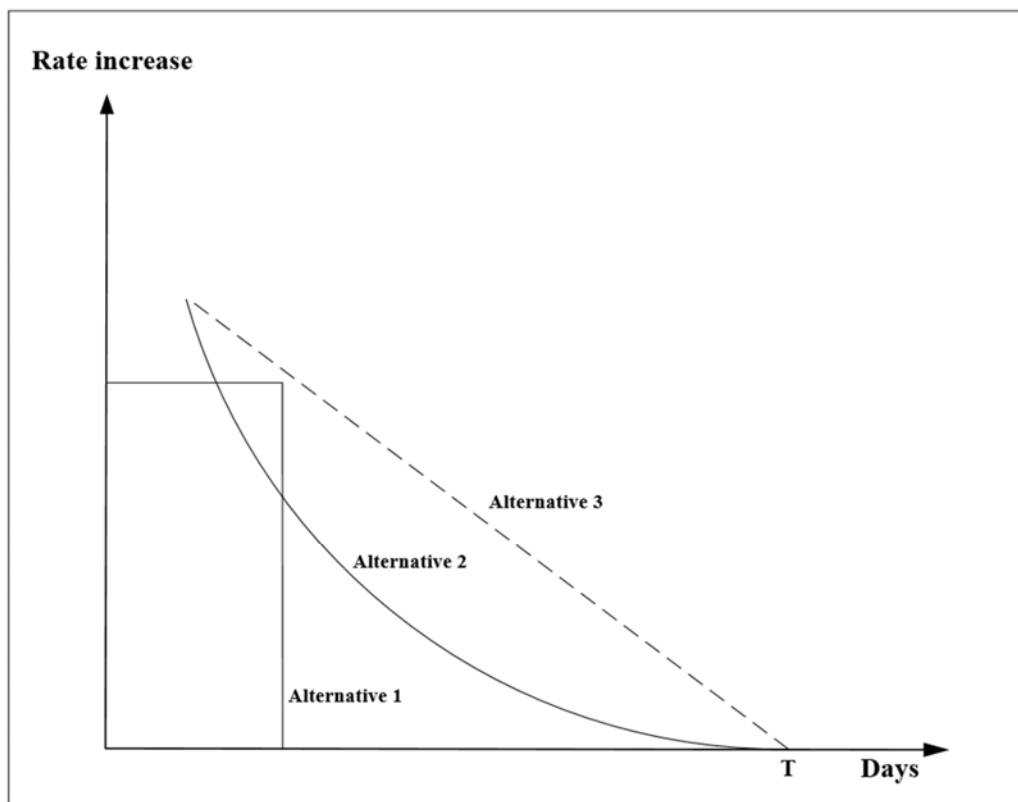


Figure 6 Alternative shapes of incentive curves

5.1.1.1 *Stepwise incentives*

Alternative 1 illustrates a stepwise incentive model. Such models make the compensation largely conditional on achieving a certain threshold of performance - at a certain threshold the contractor gets a rather generous bonus. This is optimal when the output is very sensitive to the contractor's effort in the neighborhood of the threshold (Burgess & Ratto, 2003).

In drilling, there are limited situations where the output is so sensitive to time⁵, but stepwise incentive models have still been used in the industry. The rig company has for example gotten a bonus of NOK 1 000 000 if it finishes the operation before a given date (Wintershall, personal communication, 18.04.2017). Drilling situations where stepwise incentive models might be appropriate according to the theory are suggested below:

1. Before installation of pipes on subsea template: The floating rig has to be removed before pipes can be connected to the template. If the rig has a short window before the vessel that is going to connect the pipes arrives, it is of great interest to finish drilling the well. If the well is not finished by the arrival date of the vessel, plugs are usually installed, the rig is removed and has to continue on the well later.
2. Predrilling of wells on jackets: It is often predrilled wells on jackets (like that shown on the picture below), when drilling on shallow water. When the topside is going to be installed, the jack-up rig has to be removed. Since there is a limited period of time the topside can be installed it has higher priority than finish drilling a well. If a well is not finished by the arrival date of the vessel, plugs are usually installed, the rig is removed and has to continue on the well later. Thus, it is desirable to finish before the topside is going to be installed.

⁵ However, when it comes to e.g. HSE incidents the output is very sensitive to a threshold. One accident can be catastrophic. Hence, there have been incentive schemes rewarding HSE performance on drilling rigs.



Figure 7 Jack-up rig predrilling on a jacket. The jacket is the yellow construction Figure 8 Topside installed on a jacket

The main disadvantage of stepwise models is that they are vulnerable to manipulation by the contractor.

Though stepwise incentive models may not be “appropriate” in many drilling situations according to the theory just mentioned, and are vulnerable to manipulation, one should not neglect one of its major advantages; its simplicity. As Moomjian (1992, p. 9) writes; “(...) the best incentive programs are those that are simple in concept and easy to administer”. Stepwise functions are easy to understand and communicate between the contracting parties, which reduces the chances for misunderstandings. Just as easy is the model to communicate within the companies, which also is important. As explained by a Wintershall employee working with drilling and service contracts: “You might have half an hour to present your ideas to the management. It’s important to communicate them in an understandable way” (personal communication, 03.04.2017).

5.1.1.2 Linear incentives

Like stepwise models, linear incentive models have the benefit of being easy to understand. However, strategic behavior by the contractor is not fully addressed by these models either. This will be explained in the following, taking basis in Figure 9:

Symbol	Description	Unit
R	Rate at target time	\$/Day
r_t	Rate at time t	\$/Day
c	Contractor's daily cost	\$/Day
Δr	Change in rate per day	\$/Day
T	Target time	Days
t	Time spent on the work scope	Days
π_c	Contractor's daily profit	\$/Day
π	Contractor's total profit	\$

Table 1 Description of symbols

If one assumes that the contractor would like to balance its profit relative to a certain amount of days, a linear model will not be appropriate. The profit at time T is $\pi_T = (R - c) * T$, and the profit at time $T - 1$ is $\pi_{T-1} = (r_{T-1} - c) * (T - 1)$. To balance the profit the rate has to increase, i.e. $r_{T-1} = R + \Delta r_1$. Solving the two equations;

$$(R + \Delta r_1 - c) * (T - 1) = (R - c) * T$$

$$\Delta r_1 = \frac{R - c}{T - 1}$$

This increase is not sufficient to make the contractor indifferent between spending T on the operation and $T - 2$ or fewer days. At $T - 2$ days the contractor's profit is:

$$\begin{aligned} \pi_{T-2} &= (R + \Delta r_1 - c) * (T - 2) \\ &= (R + \Delta r_1 - c) * (T - 2) \\ &= \pi_{T-1} - (R + \Delta r_1 - c), \quad \text{or} \\ &= \pi_T - (R + \Delta r_1 - c) \end{aligned} \tag{1}$$

For now it can be assumed that $R - c > 0$. Hence also $\Delta r_1 > 0$, and the contractor's profit decreases if it spends less than $T - 1$ days. At $T - 3$ days, the profit would have been reduced by $2 * (R + \Delta r_1 - c)$, and at $T - 4$ days, the profit would have been reduced by $3 * (R + \Delta r_1 - c)$. I.e. the contractor may not have sufficient incentives to reduce time, though its *daily* margin increases. In other words, the contractor faces countervailing incentives: The margin increases, while the profit decreases.

Further, consider the scenario where the oil company chooses to balance the contractor's profit if three days are saved relative to the target time:

$$(R + \Delta r_3 - c) * (T - 3) = (R - c) * T$$

$$\Delta r_3 = 3 * \frac{R - c}{T - 3}$$

Spending less than $T - 3$ days, the contractor's profit decreases, and hence the incentive model may not provide strong enough incentives to the contractor to further reduce time. E.g. at $T - 4$ the profit is:

$$\begin{aligned} \pi_{T-4} &= (R + \Delta r_3 - c) * (T - 4) \\ &= \pi_{T-3} - (R + \Delta r_3 - c), \quad \text{or} \\ &= \pi_T - (R + \Delta r_3 - c) \end{aligned}$$

The contractor would on the other hand have strong incentives to spend any time between T and the time at which the profit is balanced (in this case $T - 3$) since its profit increases. This is seen from equation (2) and (3). At $T - 2$ the profit is:

$$\begin{aligned} \pi_{T-2} &= (R + \Delta r_3 - c) * (T - 2) \\ &= (R - c) * T - 2(R - c) + \Delta r_3 * (T - 2) \\ &= \pi_T + (R - c) \left[3 * \frac{T-2}{T-3} - 2 \right], \end{aligned} \quad (2)$$

and at $T - 1$ similar calculations gives a profit of:

$$\pi_{T-1} = \pi_T + (R - c) \left[3 * \frac{T-1}{T-3} - 1 \right] \quad (3)$$

From (2) and (3) it is obtained that it is optimal for the contractor to spend $T - 1$ days.

Though the overall payment for the oil company could be less than at T there is a concern for strategic behavior by the contractor: The contractor's profit increases for time between T and the time at which the profit is balanced, but decreases for further reduction of time. The oil company wants to reduce time as much as possible, but this is not optimal for the contractor if it wants to maximize profit.

5.1.1.3 Convex incentives

The convex incentive model shown in Alternative 2 is another possible incentive model. "When would the contractor be indifferent towards spending e.g. T days on the operation and reducing

the time?” Using the assumption that the contractor would like to balance its profit relative to a certain amount of days one might get an idea of how the curve should look like. The principle is shown in Figure 9. The blue parts are the contractor’s lost profit for reducing time if a constant rate is used and the dashed green line shows the increase in rate if the above-mentioned principle is used; keeping the contractor’s profit constant relative to a target time. If for instance the operating rate in a rig contract is \$ 250 000 and the rig company has a margin of \$ 50 000, and one day is saved, the rig company must be reimbursed \$ 50 000. This implies a rate of \$ 250 847 the remaining 59 days. If two days are saved relative to the target time the rate must be \$ 251 724 per day because the rig company must be reimbursed \$ 100 000, and so on. Using that the contractor should be reimbursed its lost profit a general formula for the rate can be derived:

$$(r_t - c) * t = (R - c) * t + \pi_c * (T - t)$$
$$r_t = R + \pi_c * \frac{T-t}{t} \quad t < T,$$

The “balancing contractor’s profit”-principle was used by Wintershall to decide on shape of their incentive models. It should be emphasized that this way of thinking does not imply that the contractor should be reimbursed all of its lost profit – it only gives an idea about the shape. Talking to Wintershall employees it was also argued for convex incentives because “the rate should increase more for each day saved because it gets gradually more difficult to reduce time” (personal communication, 05.04.2017).

Despite that convex incentive models are more complex than stepwise and linear incentive models it is the recommended shape by the author of this thesis because convex incentives reduce the concern for strategical behavior by the contractor. Because of this, and as it is the shape currently being used by Wintershall, the rest of the thesis focuses on convex incentives.

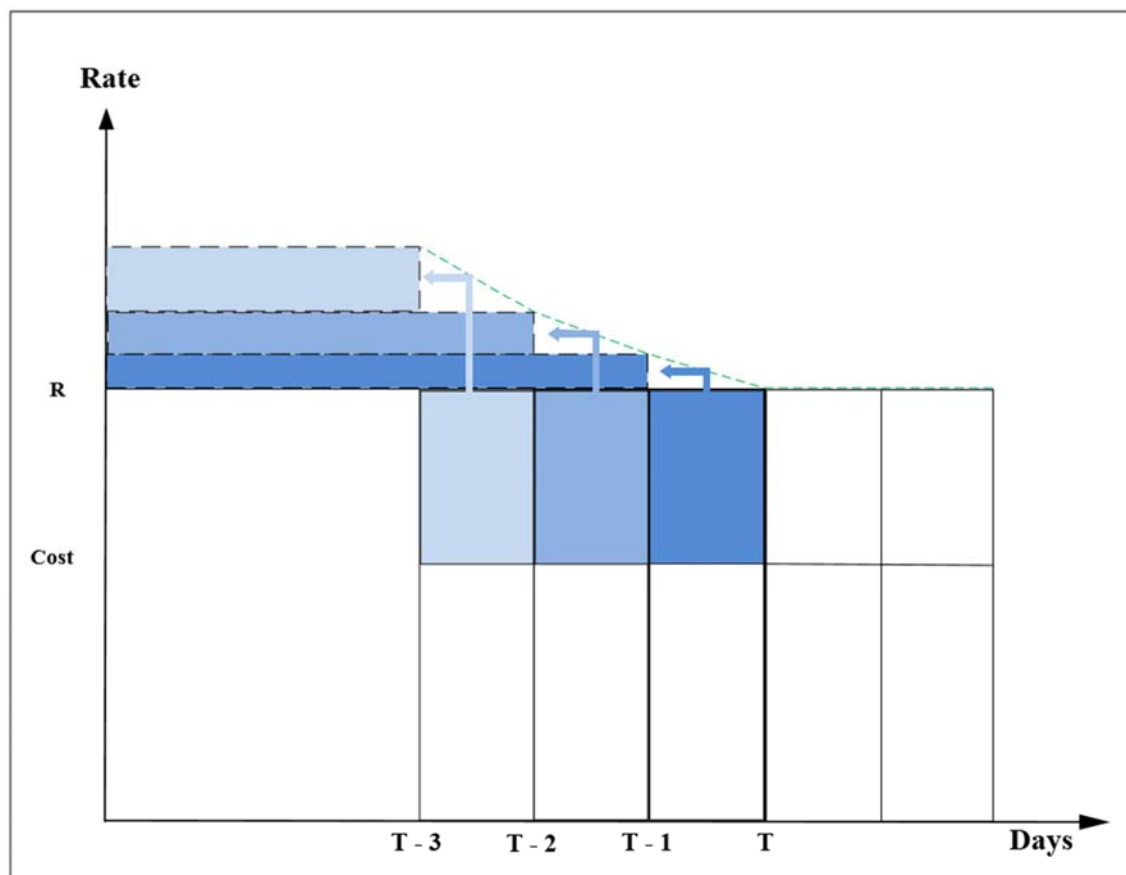


Figure 9 Rate increase to maintain the same profit as the profit at time T

Potential upper cap and downside

An upper cap on the rate might be implemented in the incentive model. This could ensure that the oil company does not pay what is perceived as a “too high rate”. However, the intention of the incentive model is to motivate the contractor to work more efficiently to achieve a higher rate. If the contractor appears to reach the cap, there will be no economic benefit for it to further reduce time. Therefore, adding a cap on the rate could be counterproductive. Yet, the “too high rate”-argument is fair if one does not believe that incentives increase the contractor’s performance, and thinks that savings relative to a target is a matter of good luck or uncertainties in the estimation of the target. However, it can then be questioned why an incentive model was designed in the first place. Someone would also mean that it is better to be excessively generous on the bonuses to ensure motivating the rig company. It was explained by Wintershall that in today’s market there is a tendency that rig companies reduce their base rate if an incentive scheme is part of the contract (personal communication, 05.04.2017). Therefore, it was suggested by an employee that the slope had very little impact on what the rig company’s rate

ends up being. As long as the rig company thinks it can get a bonus it will reduce its base rate according to the slope to be competitive: If the slope is steeper, the base rate is reduced more than if it is less steep. This is shown in Figure 10. The dotted black line represents the base rate if a traditional day rate contract is used, the red and blue lines are the rates for two incentive models with different slope, T is the target time and $T - a$ is the time the rig company thinks the operation will take.

Whether or not incentives work is source of an everlasting discussion since none of the sides in an oil company have any evidence. A cap on the model could therefore be a sort of settlement between those who believe in the possible effects of incentives and those who do not.

A downside on the rate could also be a part of the incentive model. However, the rig company would account for this in their bids. The result of adding downside could be lack of willingness among rig companies to reduce the base rate because possibilities of a further reduction in rate would transfer more risk to already heavily pressed companies.

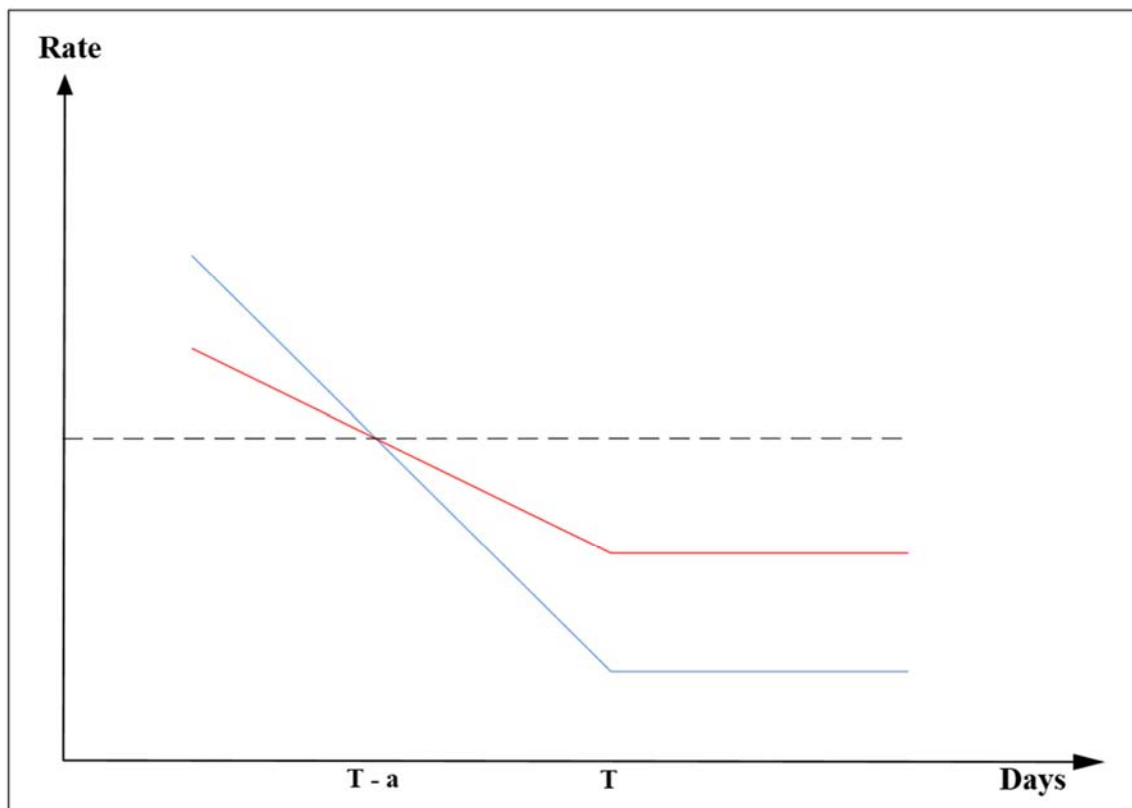


Figure 10 Rate reductions for incentive models with different slopes

5.1.2 State contingent incentive strategy

Are there any factors an oil company can consider when designing incentive curves, either in the way that it can be adjusted down, or needs to be increased in order to get the desired effect – increased efficiency? Below some properties and conditions of the project, the oil company, the rig company and the rigs are discussed, and how the curve may be adjusted. How the curve can be adjusted is likely to be contingent on many factors and hence the factors discussed below is a gross simplification of reality, but still the discussion might give an idea about how the curve can be adjusted.

5.1.2.1 Rig efficiency

The list of factors affecting rig efficiency is long. Three of the most important and their implications on efficiency are tabulated below:

- Number of derricks: Two derricks allow for parallel operations like racking of casings in one derrick while drilling with the other. This reduces the time it takes to set casings compared to having one derrick.
- Derrick height: Determines the height and number of pipes (drill pipe, casing or tubing) that can be prepared before being run in the hole. It also affects tripping time because longer pipes means fewer pipes and thus fewer connections on the drillstring.
- Cutting handling capacity: Can potentially restrict drilling speed.

Increased rig efficiency makes it easier to reduce time, assuming that the target time is the same. Therefore, preferences towards incentive contracts may vary between rig companies, depending on the company's fleet efficiency. It could potentially also vary between which drilling rig being rented out because most of the rig companies on the NCS have a diversified rig fleet. Referring to section 5.1.1 it was argued by some employees that “the rate should increase more for each day saved because it gets gradually more difficult to reduce time”. This implies that if the target time is the same for different rigs, the incentive curve should have a steeper slope for the less efficient rig.

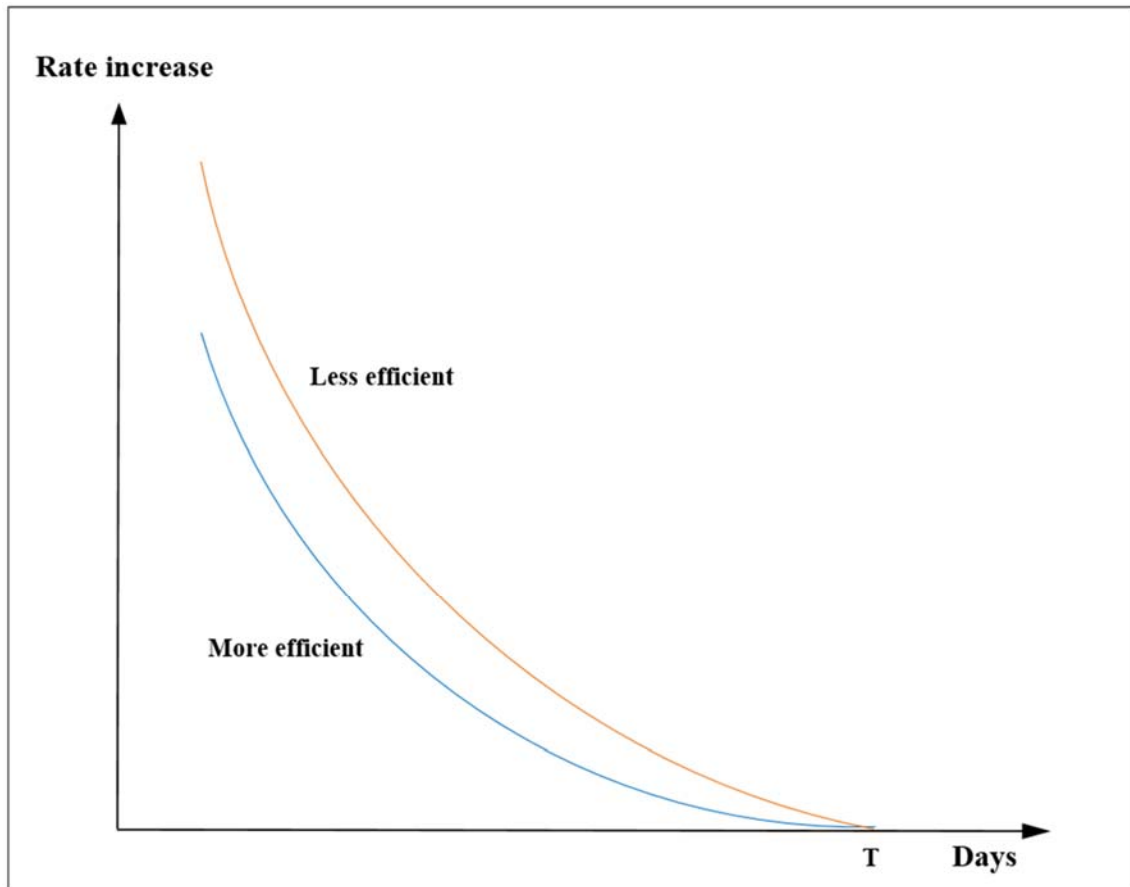


Figure 11 Adjustments of slope for rigs with different efficiency according to Wintershall reasoning for shape

5.1.2.2 Rig company's OPEX and crew size

The best way to preserve and maintain an offshore rig is to operate it. However, in today's market, many rigs do not have drilling contracts and are forced to be stacked. The goal with stacking is to balance between reducing current cost and limiting future expenditures: Stacking allows rig companies to reduce operational costs, but it is important to avoid incurring high activation costs when the rig goes back to work (Shinn, 2017, 26.01).

It is usually separated between warm stacked rigs and cold stacked. The degree of stacking depends on how ready the owner wants the rig to be when, or if, the rig needs to start drilling again (Shinn, 2017, 26.01).

Warm stacked rigs are supposed to be maintained almost as if they were on contract. All systems and machinery are run and checked regularly, and security practices are maintained. This is done by a reduced, but adequate crew on board. By warm stacking a rig, the operational costs

are reduced to around one third of what they are when the rig is in operation (Shinn, 2017, 26.01).

Cold stacked rigs are virtually abandoned, and focus is on preservation. Operational costs then usually ranges between one fourth and one tenth of the operating cost (Kaiser & Snyder, 2013), but extensive preservation programs require a significant up-front investment. These programs are implemented before a rig is cold stacked because the lack of preventive maintenance and operation of generators, station keeping systems (for floaters), marine ballast systems, and safety systems creates a major deferred time and cost risk to the rig companies *if* the rig is going back to service again. For 6th and 7th generation rigs this risk pose a real threat to rig companies' ability to perform when the market recovers, while for older rigs it is of little concern because most of them will never return to work again anyway (Shinn, 2017, 26.01).

Today, there is a tendency that both the rigs drilling on the NCS and the rigs being awarded contracts are new and modern (see Figure 13). It was explained by Songa that many of these often barely are reimbursed their OPEX, and some even go in minus (personal communication, 15.05.2017). OPEX when drilling is around \$ 150 000 per day (Kaiser & Snyder, 2013; Shinn, 2017, 26.01). When the rigs waits on weathers or performs maintenance, the rates are reduced and consequently the rig company's losses increases. Adding the financial costs of sitting on \$ 600 *million* assets clearly shows how distressed the market is.

So why would a rig company rent out a rig and barely break even or go in minus? Part of the answer is the rig companies' balancing challenge with stacking, where the rig company estimates the loss of different operational statuses. This is shown in the calculations below where it is used that the OPEX when in operation is \$ 150 000 per day, the OPEX for warm stacking is one third of that in operation and the OPEX for cold stacking is one tenth of that in operation. It is further assumed the rig company invests enough in the preservation program to avoid the high reactivating costs. This up-front investment is assumed to be \$ 10 *million*.

- During a contract period, the rig company's profit is; $\pi = (r - OPEX) * t$ (4)

- If the rig is warm stacked; $\pi = -\frac{1}{3} OPEX * t$ (5)

- If the rig is cold stacked; $\pi = -\frac{1}{10} OPEX * t - Cost_{preservation}$ (6)

The below calculation shows when the rig company would choose being in operation over warm stacking the rig:

$$(r - OPEX) * t \geq -\frac{1}{3}OPEX * t$$

$$r \geq \frac{2}{3}OPEX \quad (7)$$

Using the numbers from the example:

$$r \geq \$ 100\ 000 \text{ per day}$$

However, this must not be understood as the rate at which the rig company would be better off being in operation than stacking the rig, because it might still choose to cold stack the rig. This is seen from the brown line in Figure 12. Only considering inequality (7) one might conclude that for a rate of \$110 000 per day, operating the rig is the most profitable. However, for a time greater than 400 days it is better to cold stack the rig. This indicates that another condition also has to be satisfied in order to conclude if it is the optimal decision to be in operation or not. That condition is given below:

$$(r - OPEX) * t \geq -\frac{1}{10}OPEX * t - Cost_{preservation}$$

$$r(t) \geq \frac{9}{10}OPEX - Cost_{preservation} * \frac{1}{t} \quad (8)$$

For this example (8) gives:

$$r(t) \geq \$ 135\ 000 \text{ per day} - \$ 10\ 000\ 000 * \frac{1}{t}$$

The plot below shows the rig company's profit when in operation for rates of \$ 50 000, \$ 90 000, \$ 100 000, \$ 110 000 and \$ 150 000 for time between 0 and 475 days, and the profit when it is cold- and warm stacked. Note from equation (5) and (6) that the profit when cold stacked and warm stacked are independent of the rate. Also note that the line with purple markers have identical values as when the rig is warm stacked. The reason for this is that the rate (\$ 100 000) is exactly two thirds of the OPEX.

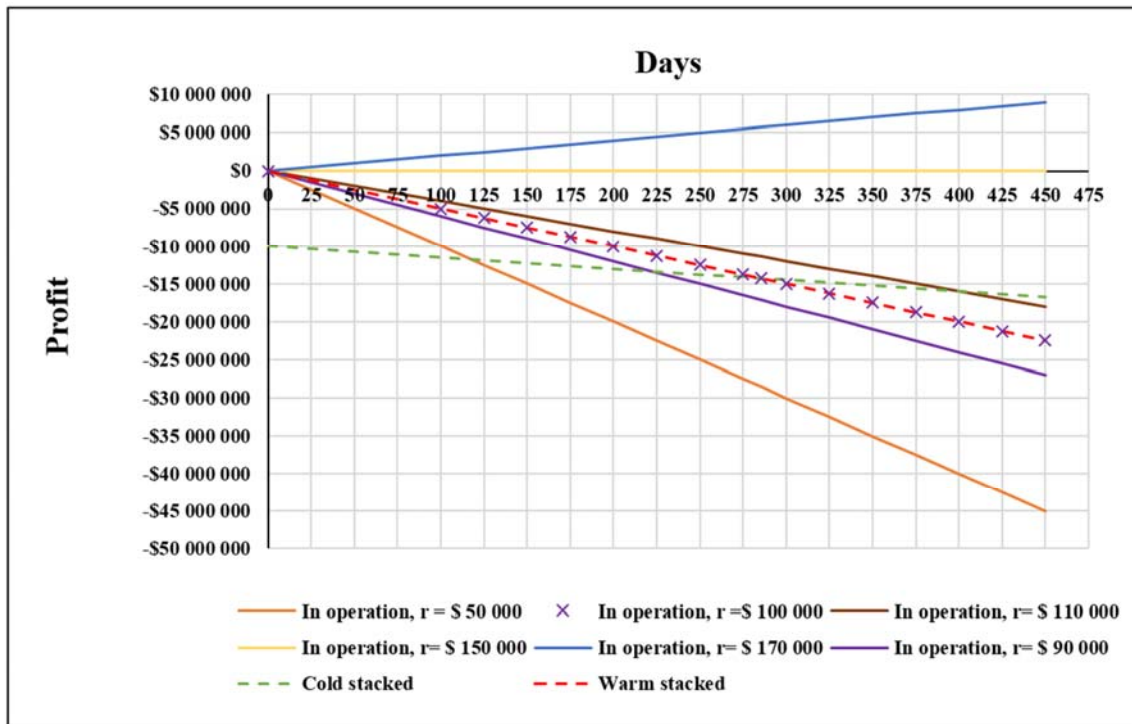


Figure 12 Rig company's profit on a rig for different operational statuses and different rates

In other words, if the rig company is able to get a contract which satisfies (7) and (8), it should take the contract. However, what is optimal stacking strategy if it does not get such a contract? Fulfilling the below conditions, the rig company should choose to cold stack over warm stack:

$$-\frac{1}{10} OPEX * t - Cost_{preservation} < -\frac{1}{3} OPEX * t \tag{9}$$

$$t > \frac{30}{7} * \frac{Cost_{preservation}}{OPEX} \tag{10}$$

For this example (10) gives:

$$t > 285,7 \text{ days}$$

To summarize;

- Operate the rig if (7) and (8) is fulfilled. Using numbers it means a rate of more than \$ 100 000 per day and more than \$ 135 000 per day – \$ 10 000 000 * $\frac{1}{t}$

- Cold stack if (10) is fulfilled, and (8) is *not* fulfilled. Using the numbers this gives that the rig should be cold stacked if the stacking period is expected to exceed 285 days and the rate is less than \$ 135 000 *per day* – $\$ 10\,000\,000 * \frac{1}{t}$
- Warm stack otherwise. I.e. if the stacking period is expected to be less than 285 days and the rate is lower than \$ 100 000 per day.

It should be emphasized that the above calculations are mathematical simplifications of an intricate situation. Costs should be expected when the rig returns to work and the costs are likely to increase with stacking time, and strictly speaking, these costs should be discounted. In addition, it takes longer to take a cold stacked rig into the market than a warm stacked. Having the opportunity to get back into service has a value and hence the optimal stacking strategy is not fully explained by (10). However, this does not mean that warm stacking is preferred when the costs for warm- and cold stacking are close to equal. Shinn (2017, 26.01) points out that the problem for warm stacking over longer periods of time, is that maintenance activity tends to decrease and equipment, which has not been prioritized to be preserved, starts to deteriorate. “In effect, long term warm stacked rigs may turn into poorly preserved cold stacked rigs” (Shinn, 2017, 26.01).

The tendency that it is used modern rigs on the NCS is interesting. In the tender process, the oil company chooses the rig that is able to finish the project at the lowest cost. As mentioned in section 5.1.2.1 there are many factors affecting the efficiency and therefore time, and thus have implications on cost. However, a new rig doing the job faster is more expensive than an older so why are newer rigs chosen over older to a larger degree than just some year ago? The relative price drop is likely to have been bigger for newer rigs than older⁶. This was also confirmed by Wintershall (personal communication, 24.04.2017). But why have this happened? The rig companies apparently are more interested in having the newer rigs on contracts than the older. This seems reasonable: In some ways it is actually beneficial for the rig companies to scrap their old rigs because supply is then reduced and the rates for the remaining modern rigs increases, which allows the rig companies to make money on their new rigs. Further, the possibility of significant reactivation costs for new semisubmersible rigs makes rig companies more or less desperate to have these rigs on contract, reducing their bids.

⁶ Another reason why older rigs were more frequently used just some years ago is because they filled the gap between supply and demand pending the deliveries of new rigs

In addition, new rigs have a higher stacking cost. This gives the contractor further incentives to keep these on contract rather than older. The reason for the higher stacking cost is that more modern rigs have automated and more complex equipment and systems than older rigs. Odfjell Drilling explained that around fifteen people work on a modern rig when it is warm stacked, whereas only five is needed on an older rig (personal communication, 24.04.2017).

Being off contract for a new rigs also concerns human capital to a larger degree than for older rigs because there is a larger crew. From the drilling contracts examined, the rig company had a crew of around 80 people on the 6th generation rig from 2015, while it had around 50 on the smaller 4th generation rig from 2012. This means that stacking the newer rig would imply that 65 people ($80-15 = 65$) cannot go to their ordinary working place, while on the 4th generation rig 45 people would be in the same situation. Often the result is that some employees are offered other positions in the company, but downsizing might also be necessary. One such example is when Statoil cancelled a contract with COSL Pioneer in June 2015. Because COSL also had another rig stacked and did not see opportunities for employment within the next 6-12 months, the company chose to downsize with 209 people offshore and 20 onshore (COSL, 2015, 24.06). By having to let people go a company risk losing highly competent staff. Particularly the crew on high spec rigs have coveted skills, as they are trained in running the advanced equipment on these rigs, and training of new personnel on modern rigs is expensive.

There is also an incentive for the rig companies to keep the rigs on contract because it is easier to get new contracts when the rig have been in operation, rather than being stacked (Wintershall, personal communication, 24.04.2017; Songa, personal communication, 16.05.2017). The crew gets more and more experience and hence perform their tasks more efficiently. This makes them the preferred alternative for the oil companies.

The distressed bidding, for both new and old rigs, can also be explained by some rig companies' loan agreements, which impose on them to have a certain income. The low bidding it therefore not only controlled by supply and demand, but also corporate governance (Songa, personal communication, 15.05.2017).

Because of the above-mentioned reasons, the rig company might be willing to enter contracts where it goes more in minus than it would if it was stacked. In cases when the rig company does so, an incentive-based contract, regardless of potential bonuses, could be preferred as the rig company has the potential of reducing its losses.

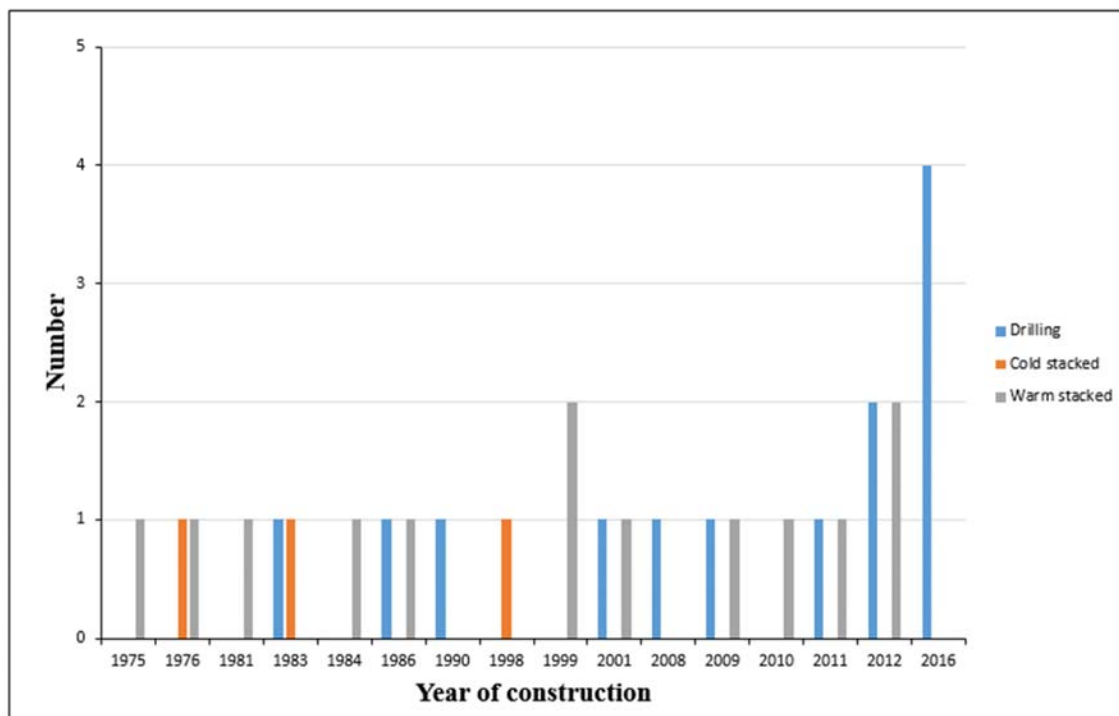


Figure 13 Status of semisubmersible drilling rigs on the NCS, spring 2017. Data from Infield (2017)

5.1.2.3 Remuneration in subsequent contract

Before the peak of the oil price, fixed-term contracts, i.e. contracts for a certain period of time, were common in the drilling industry. Often these contracts lasted many years. Rig companies then also carried less risk – they could go from one operation to the next. The last years however, well-based contracts have been the most frequently used (Wintershall, personal communication, 05.04.2017; Songa, personal communication, 16.05.2017) and the below-mentioned argument assumes that such contracts are used. Well-based contracts means that the oil company or license retains the rig until drilling has been completed. This creates planning problems in that the next company or license does not know when it will get the rig. However, there is a commencement window, which is agreed in during tender, that says when the operation is going to start. The commencement window could be around three months, but it varies. It is also a delay date, which indicates when the rig company is “in delay”. The delay date is either at the end of the commencement window or some time after. If the rig company is in delay, there is a penalty in the form of reduced payment, and if the rig company is delayed more than a certain time the oil company has the right to terminate the contract. If the contract is terminated, the rig company has to pay accrued liquidated damages to the oil company.

While working on an operation the rig company has to notify the next oil company of its best estimate for the commencement date. As time goes, the commencement window shrinks (see Appendix C) because the oil company has to plan with third party companies as well (MWD, LWD, cementing, casing and tubular running, and other services). The oil company tries to mobilize according to the provided information so that the two parties can begin relatively shortly after the other contract ends. However, if the operation is well ahead of schedule and ready to start before the initial commencement date the operation cannot commence.

Exact rates for drilling and oil services are usually not public data, but because the contract's value and length often are revealed in the media the rates are given indirectly. An oil company could use this when designing its incentive model.

The last years there have been many cases when the rates in subsequent contracts have been significantly lower than in the previous, and also cases when the rig company does not even have a new contract. In these situations, the rig company could have incentives towards stalling time in order to maintain a higher rate for a longer period. However, a rig company with a new contract would have strong incentives towards reaching the commencement window of the next operation, and the rig company's next commencement date can be considered an upper limit to how much the rig company might delay the operation: Penalties on the top of already low rates and potential cancellation of contract is the last rig companies want when their economy is on today's levels. In addition, any delays would be well known for the other partners in the license and other oil companies on the NCS, which is very unfortunate for the rig companies. The latter argument also applies for rig companies without a new contract. It seems more reasonable that the rig company would strive to be efficient in order to get good references and merits. Operational merits and efficiency is available data in the tender process and this gives strong indirect incentives to the rig companies to perform well – particularly in a soft rig market. Therefore, in distressed rig markets, it is doubtful that the incentive curve needs to be adjusted to give further incentives to the rig company to be efficient – its desire to delay operations would be outweighed by other factors. In particular, the shorter time until the next operation, the less adjustments needs to be made.

Nevertheless, if it is a long period between planned completion date of an oil company's operation and the next commencement date, or if the rig company does not have a new contract, the oil company might want to protect itself from big delays. One way of doing this is to add a downside in the incentive model, especially if the contractor is delayed more than any

reasonable time. This could e.g. be the P90-estimate (see more on time estimates in section 5.1.3). However, it should be emphasized that it is questionable if this is necessary.

If there is a *higher* rate in the subsequent contract the rig company would have incentives to work efficiently to start on the next contract. Since the rig company already has incentives to work efficiently, achieving bonuses, regardless of its size, would be a synergistic side-effect of starting on the next project earlier. Therefore, a less generous incentive model may have the same effect as a more generous one, and the incentive curve could be adjusted accordingly.

5.1.2.4 Rig company's market share

A relatively new rig company with small or no market shares might to a greater extent than many of its competitors negotiate at the oil companies' premises. This could mean reducing the rates and/or accepting less generous incentive schemes. Such contractors might also prefer an incentive based contracts as it already have incentives to work efficiently. The additional incentives comes from the fact that it would like to get good merits which is helpful in subsequent tender processes with other potential customers. In addition, the current client might also exercise its options for prolonged services, (such arrangements are usually part of the contract). This is beneficial for the rig company for at least two, and possibly three reasons: 1) The company gets more experience. 2) It sends a clear signal to other companies that it has performed well, because in today's market an oil company would not exercise its options if the contractor does not live up to expectations. 3) As long as the rate gives a smaller loss than the stacking costs and potential re-activating costs if it is cold stacked, the rig company is also financially better off having the rig in operation.

Today some rig companies are looking at potential asset acquisition targets. Some rigs are purchased for around half of the new build price. Two of the most aggressive companies are newly established; Borr Drilling and Northern Drilling (Strandli, 2017). Starting a rig company today must be said to be risky business, but the founders of the two companies, Tor Olav Trøim and John Fredriksen respectively, are not exactly known to refrain from risk. This might be reflected in the companies having a low risk aversion. Referring to the theory section, the low risk aversion substantiates what is already said about new or small companies - they would accept a riskier incentive scheme. Thus the slope of the incentive curve might be lowered compared to the incentive curve for other rig companies.

5.1.2.5 *Size of oil company*

In section 2.4.6 it was explained how the contract design might benefit from being contingent on other oil company's contract format and design. However, it can be argued that the degree to which the company should consider this depends on the size of the oil company. On the NCS, Statoil, the world's largest offshore operator, operates the majority of the fields. A natural consequence of this is that they also control the majority of drilling activity. In 2015, it was approximately 75-80% (Ciekals, Hassan & Norheim, 2015). For oil companies with so large market shares, allocation of contractor's resources is more or less a zero-sum game. If one, or some of their contracts are designed such that the contractor is highly motivated to perform well, the result might be that the contractor (if working on several projects for the oil company) reallocates resources between the oil company's own projects. Oil companies operating fewer fields does not face this problem, at least not to the same degree. In other words, it is more likely that the contractor's resources are reallocated to their projects. Therefore, incentive contracts may not be equally beneficial for big and small oil companies. Another reason to this is that many contractors have other incentives than increased payments on the current operation to perform well for big oil companies. Due to Statoil's size, in terms of market shares and volume purchased from contractors, it is vitally important for oil-service and rig companies on the NCS to have Statoil in their customer portfolio. "It is their bread and butter", as explained by a Wintershall employee. In addition, Statoil is a "door opener": If a contractor gets a contract with Statoil and performs well it seems to easier be accepted by smaller oil companies as well (personal communication. 05.04.2017).

5.1.3 Determine the target time

Determining the shape and slope of incentive model are two challenging strategic decisions an oil company faces if it is going to design a time based incentive contract. The third and last decision that will be discussed in this thesis is determining the target time.

5.1.3.1 *Estimate the target time*

There are several ways to estimate the target time. One possible way to estimate the target is by using the oil company's own database. However, this requires a lot of drilling experience on the NCS. It has been drilled more than 6000 wells on the NCS (Norsk Oljemuseum, 2017). Assuming that Statoil have drilled 80 percent of the wells because it operates roughly 80 percent of the fields (Ciekals et. al., 2015) the company have drilled more than 4800 wells, and therefore has enough experience to estimate target times using their own database.

Another way to estimate the target time is to use the database provided by NPD on its webpage. Companies have access to a large amount of well data from the NCS. These data are free of charge and may be analyzed and processed. The well data includes both raw and interpreted data. However, the raw data is usually available two years after the well has been completed (NPD, 2015). To some degree, this restricts NPD's use because oil companies would like information about wells as fast as possible. In addition, the data is not as detailed as the oil companies prefer when estimating their targets. Therefore, many companies use Rushmore Reviews.

Most oil companies reports to Rushmore Reviews⁷ when they drill wells. It is a company that collects, analyses and publishes offset well data for participating operators in the oil industry. Rushmore's global database consists of more than 60 000 wells, 15 000 completions and workovers, and hundreds of well abandonments, and is available for the participating companies (IHS Markit, 2017b). The database allows oil companies to filter data after a number of parameters. Some of them are; length, inclination, location, number of casings, reservoir pressure and temperature, rig specifications, and whether it is conventional hydrocarbons or not. The oil companies can use this data to estimate expected drilling durations of planned operations. P10, P50, P90, minimum, mean and maximum are some of the available performance metrics.

5.1.3.2 Target time in tender process

When the rig company gives an offer in a tender process, transparency and predictability are important. For a time based incentive contract the transparency and predictability are closely related to the definition of target time. But how should the target time be given in the tender process? As mentioned, the base rate is usually reduced if an incentive scheme is part of the contract, but not always. In cases when the rig company expects to perform better than the target it can take account of the incentive model when calculating its bid. A conservative target means that the rig company will have a fair chance of performing better than the target and achieve an upside on the rate. To remain competitive the rig company might choose to lower the rate compared to when a traditional day rate contract is used. This is shown in Figure 14. The dotted black line represents the base rate if a traditional day rate is used, and the blue line is the rate if there is an incentive contract *and* the rig company believes it will be able to outperform the target by *a* days.

⁷ Rushmore Reviews was acquired by IHS Energy in February 2015

If the target is perceived as too aggressive by the rig company, the rig company may not reduce its base rate. This is shown in Figure 15. The dotted black line still represents the base rate if a traditional day rate contract is used and the red line shows the rate if the rig company thinks that it is unable to finish the operation in shorter time than the target time. In the figure, $T + b$ is the time the rig company thinks the operation will take. Consequently, the rig company may not reduce its base rate because it entails a great risk.

Because both the incentive curve and target time is important when the rig company calculate its bids, and because it can contribute to lower rates and corresponding lower cost for the oil company, it seems reasonable that the ideal decision is to give both the incentive curve and target time in the tender process. However, providing a fixed target as early as during tender is difficult. The tender process of a rig is usually at least a year ahead of operation. Just the procurement process typically takes approximately nine months, and the following rig acceptance period, where the rig's HSEQ, management systems and technical conditions are checked, is normally concluded in six months (Wintershall, personal communication, 10.05.2017). Because the tender process of the rig is at such an early stage, the operational plans are not very detailed. The drilling program and completion program are just some of the uncertainties (see Figure 17 and Appendix D). It is of course also impossible to filter the rig specifications in Rushmore, and such filtering could greatly influence the target time. However, the latter risk might be reduced by having different targets for e.g. different rig generations. Nevertheless, there is a risk implementing a fixed target at this stage. If the oil company makes adjustments in the project reducing the expected project duration, there is a risk the rig company achieves a higher rate for the same level of performance. Consider an oil company planning a 4500 meter well. However, by commencement date it has decided to shorten the length to 4000 meters. Assuming a drilling progress of 100 meters per day⁸, this would give the rig company a head start of five days relative to the target time. This is illustrated in Figure 16 where Δr_2 is the additional rate for the same level of performance. In addition, the fact that the well plans cannot be very detailed at an early stage is well known by rig companies, who therefore accounts for this in the tender process. The result could be the scenario illustrated in Figure 15; reluctance to reduce the base rate.

⁸ This is an average of the drilling progress, including among other things casing setting and cementing. It should not be confused with the ROP, which is the drilling speed, and could be around 100 meters per *hour*.

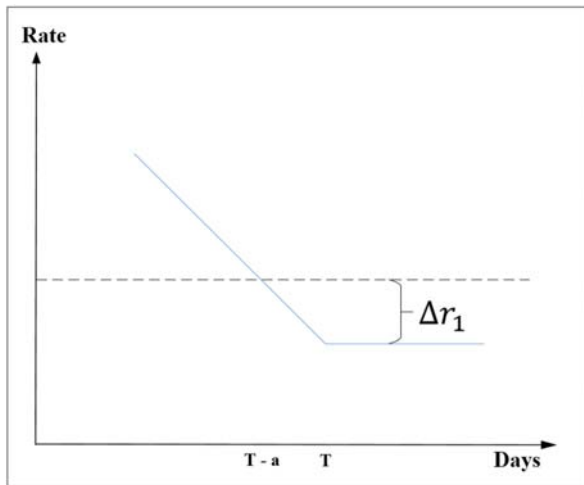


Figure 14 Drop in rate if the rig company expects to outperform the target time

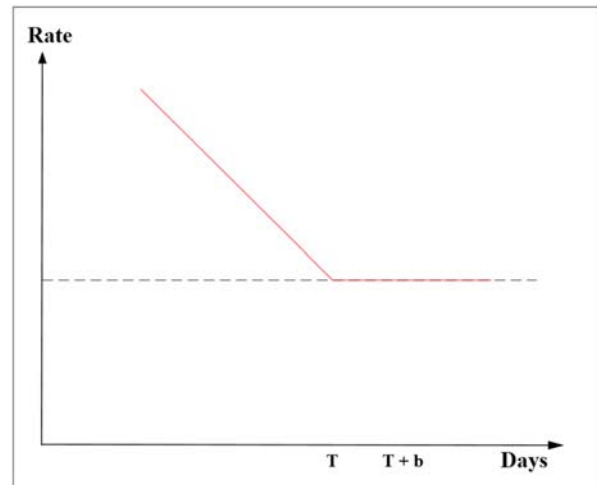


Figure 15 No drop in rate since the rig company expects to exceed the target time

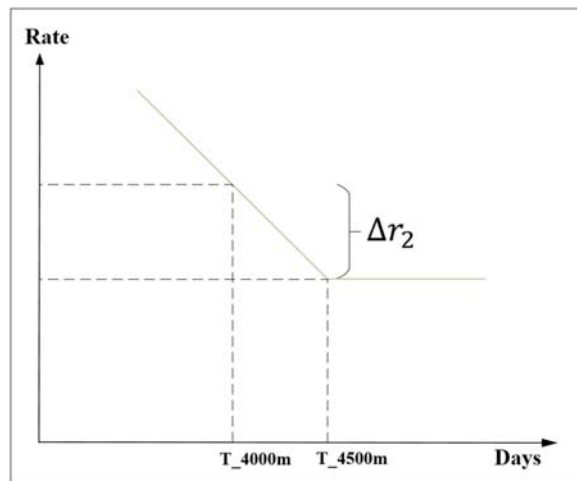


Figure 16 Additional rate for the same level of performance if adjustments are made reducing the expected project duration

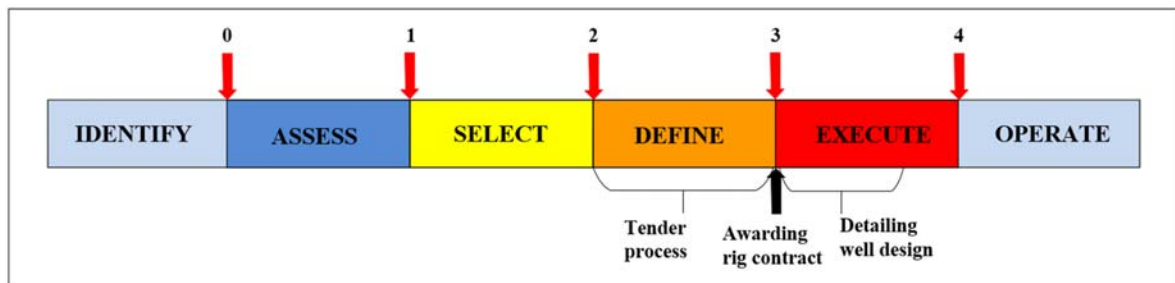


Figure 17 Wintershall's stage gate process for capital investment projects > 15 million euro (Wintershall Norge AS, 2016)

In cases when the oil company makes adjustments in the project increasing the expected project duration, it is likely to be perceived as unjust by the rig company who has calculated its bid based on the original target. Hence, renegotiations of either the target time, the rates, or both will probably be required. Such renegotiations imposes transaction costs. If the oil company is reluctant to renegotiations, it measures might be taken by the rig company to reduce its cost, which could negatively affect the progress in drilling operation. Examples of such measures will be given on the next page.

In one way or another, a target has to be given in the tender, but as discussed above there are limitations to how well defined it can be. A compromise is to determine in the tender what should form the basis of the target time. This was done for the ongoing Maria project. An excerpt from the incentive contract is shown below. The target time is referred to as “BUDGET TIME” in the Maria contract:

“A selection of relevant wells shall form the basis for the BUDGET TIME time estimate. The selection of wells in the Rushmore database shall follow criteria stated below, and other filters shall be applied to select a set of offset wells that most correctly reflects COMPANYs planned wells.

- *Drilled from semi-submersible vessel*
- *Development wells*
- *Total depth and true vertical depth comparable to COMPANY’s wells*
- *Norwegian Continental Shelf from 58-62degrees North*
- *Excluding high pressure high temperature wells*
- *Other relevant filters to select a representative set of offset wells (necessary to represent correctly the diversity of potential new wells).”*

It can be questioned if this method of defining the target time can be exploited by the oil company. For the rig company it is difficult to fully know the selection of “relevant wells”. The oil company could for example select the best wells only. Choosing wells drilled from the last two years compared to the last ten would e.g. reduce the target because more modern rigs have been used recently. By adding a time period for the relevant wells and specifying “all wells” or the number of wells there would be more transparency and less uncertainty for the rig company. The concern for oil companies utilizing asymmetric information would be reduced, which might also benefit the oil companies in terms of reduced rates.

The further question is whether the oil company really would have incentives to exploit such an agreement. If the two parties agree on a too aggressive target time the oil company could achieve a lower rate for the duration of the project. However, this could be counterproductive. Remember that many rig companies enter contracts with rates close to, or even under break-even price. The rig company is therefore likely to take measures to minimize economic losses or increase their small profit. Such measures could be to reduce staff both on- and offshore, which might result in decreased efficiency and increased delivery time if any equipment is broken. The rig company could also choose to reduce wear on equipment by e.g. slowing down ROP, and it could choose to postpone maintenance on the rig in anticipation of economically better times. The former would increase project duration and the latter could potentially cause breakdown.

As said in the introduction, the daily costs for the Maria project is around NOK 8 million (Sagmoen, 2017). From the cost distribution in Figure 18 the importance of time is obvious. Well services, logistics and the rig hire constitute 75 percent of the drilling costs. Parts of the overhead is also time related, meaning that one day delay in operation amounts to more than NOK 6 million. This illustrates the potential economic downside of fooling the rig company and might in itself be sufficient to weigh up for the oil company's desire to save a few thousand dollars on the rate. If one day delay amounts to more than NOK 6 million it also means that one day saved from reducing time on the operation gives savings of more than NOK 6 million. In addition, there is a major benefit of finishing a field development project like Maria early: Generating an early cash flow from starting production. It is therefore reason to believe that the oil companies' desire is as written in the contract; "(...) to align individual targets and focus to achieve a common goal for well delivery and to reward time efficiency".

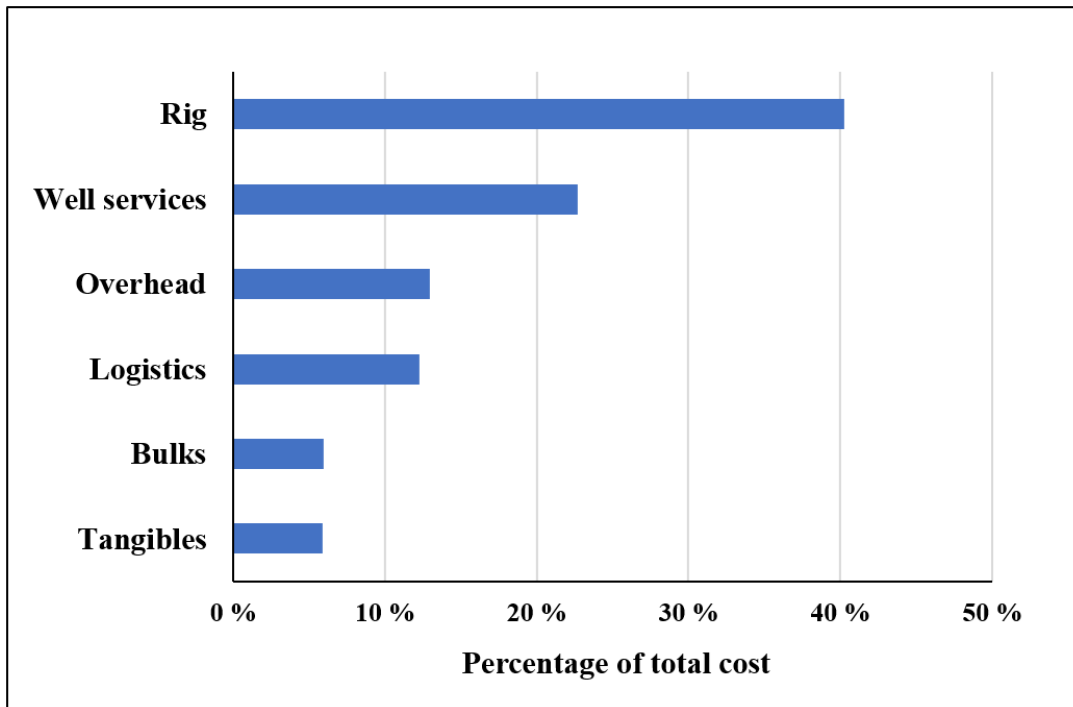


Figure 18 Typical composition of drilling costs in 2017. Source: Data from Wintershall Norge AS

6 Conclusion

This thesis provides insight into three challenges associated with the design of time based incentive models for drilling rig contracts on the NCS; deciding the shape, adjusting the curve, and establishing a target time. The goal was not to conclude on the best shape of the incentive curve or give any economic values how much to adjust the curve, but suggest a shape and how the curve can be adjusted depending on various factors. Nor was the goal to find best practices of how to determine the target time, but elucidate the challenges with determining the target time. The suggestions for reducing the challenges with determining the target time must be seen in context with the particular contract examined in this thesis; the Maria rig contract.

Three alternative shapes of incentive models are evaluated; stepwise, linear and convex incentives. Though stepwise and linear incentive models are easy to understand and communicate between and within the contracting companies, they are vulnerable to manipulation by the contractor. Convex incentives reduces the concern for strategical behavior and are therefore concluded to be a better alternative, despite that the incentive model is more complex.

How different factors can influence the adjustment of the incentive curve in a distressed market was considered. The rig company is to a larger degree than in a tight rig market willing to enter incentive based contracts in a distressed market. Comparing rigs with different efficiencies and using Wintershall's reasoning for shape, it is argued that the less efficient rig should have a steeper curve, assuming target time is the same. The higher stacking cost, the greater concerns for human capital and the uncertain reactivation cost, gives the rig company incentives to keep their rigs with high specification in operation over their older rigs, at rates below OPEX. Because several rigs not break even today, incentive based contracts might be preferred as it gives the rig company the potential to reduce its losses. The oil company then have the opportunity to implement less generous incentive model than in more normal rig markets when the contractor has a positive margin. It is also suggested that a newly started rig company would enter riskier incentive contracts, and that bigger oil companies can have a less generous incentive schemes than smaller because of additional incentives working for them.

There are different practices for determining target time and the presentation of these in the tender process. The oil company may provide a fixed target time during tender in an attempt to get reduced base rate due to better predictability for the rig companies. However, because of the time gap between the tender process and commencement date of the drilling operation, the

Conclusion

target time is highly uncertain. This could prevent the drop in base rate. If the oil company makes adjustments in the original drilling plan, the expected project duration is likely to either decrease or increase. In cases when the expected project duration decreases, there is a risk the rig company achieves a higher rate for the same level of performance, and in cases when the expected project duration increases, costly renegotiation of the target time and/or rates are likely to occur. If such renegotiation does not occur, the rig company may take measures to reduce its costs, which could cause project delays.

For the tender process of the Maria project it was chosen to implement how to establish a target time. However, the formulation may not be comprehensive enough to get the desired drop in base rate because of lack of predictability for the rig company. The formulation also entails a concern for asymmetric information the oil company could exploit. Despite of a potential lower rate, it is concluded that the oil company has too much to gain from an efficient project execution to be tempted to exploit the information. The benefits of an efficient project execution are reduced overall spending on the rig, savings on third party companies, and starting production early.

6.1 Recommendations for Future Work

In a larger thesis it would have been interesting to investigate which services it is appropriate to incentivize on the rig. Oil companies have started to incentivize thirds party services like directional drilling. Integrated services has also become more common. Which other services could it serve the oil company to incentivize? Which of these services could have integrated incentive schemes? And how may the incentive design look like for these services?

Investigation of operations and activities to be incentivized for the rig company is also subject to discussion. Should for example the time keep ticking when cement is lost, the bottom hole assembly breaks, the ROV is out of service, casing supplier are delayed, or other third party companies causes delays?

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Appendix A

Appendix A1: Interview Guide Oil Company

<ul style="list-style-type: none">• What is the weakness of today's drilling contract format?<ul style="list-style-type: none">○ What would you suggest to overcome these
<ul style="list-style-type: none">• What challenges do you face when designing incentives for drilling contracts?
<ul style="list-style-type: none">• What is your preferred incentive format?<ul style="list-style-type: none">○ Why is this your preferred format?
<ul style="list-style-type: none">• Are there any factors you think should affect the slope of an incentive curve?
<ul style="list-style-type: none">• How do you estimate the target time?
<ul style="list-style-type: none">• At what stage do you estimate the target time?

Appendix A2: Interview Guide Rig Contractor

<ul style="list-style-type: none">• What is the weakness of today's drilling contract format?<ul style="list-style-type: none">○ What would you suggest to overcome these
<ul style="list-style-type: none">• What challenges do you see with incentive design for drilling contracts?
<ul style="list-style-type: none">• What is your preferred incentive format?<ul style="list-style-type: none">○ Why is this your preferred format?
<ul style="list-style-type: none">• Are there any factors you think should affect the slope of an incentive curve?

Appendix A3: Interviewee List

Name	Title	Company
Torgeir Larsen	D&W Partner Ops and Tech Support Manager	Wintershall Norge AS
Ida Hassan	Procurements manager	Wintershall Norge AS
Espen Rydberg	Contract Specialist	Wintershall Norge AS
Henning Schutz	Senior Procurement Specialist	Wintershall Norge AS
Arne Jacobsen	Senior Technical Advisor, Marketing & BD	Songa Offshore

Appendix B: Day Rate Application

1. OPERATING RATE
2. STANDBY RATE
3. MOVING RATE
4. WAITING ON WEATHER RATE
5. REDRILL RATE
6. REPAIR, MAINTENANCE AND BREAKDOWN RATE
7. ZERO RATE

The purpose of the below table is to give an overview of applicable DAY RATES for selected situations. The list is not intended to be exhaustive. For some situations and applicable DAY RATES, the applicable DAY RATE may change after a certain time or as the situation changes. Such changes are not illustrated in the below, but the described in the Conditions of Contract and in Exhibit B

	Operation	1	2	3	4	5	6	7
WORK ACCORDIN COMPANY'S DRILLING PROGRAMME:								
1	Drilling formation	X						
2	Tripping	X						
3	Laying down drill pipes/drill collars for changing string or at end of operations	X						
4	Hole conditioning – wipertrips, reaming, circulation	X						
5	Casing and tubing running, incl. rig up, circulation, cementing	X						
6	Completion activities – running of tubing/completion strings, XT and other subsea equipment, including any preparation	X						

Appendix B: Day Rate Application

7	Well testing/clean-up – rig up and test of equipment, flowing, building-up, shut-in	X						
8	Cementing – rig-up, pumping of cement /cement plugs	X						
9	All pressure testing of required equipment	X						
10	Fishing activities not due to CONTRACTOR	X						
11	Fishing activities due to CONTRACTORs negligence					X		
12	Well abandonment activities - csg cutting, cementing, pulling pipe	X						
13	Wireline operations		X					
14	Waiting on cement to set up (WOC)		X					
15	Testing of BOB and well control equipment	X						
OTHER ACTIVITIES:								
16	Slipping and cutting of drilling line						X	
17	Changing drilling line						X	
18	Checking of drill string during tripping (within normal operation)	X						
19	Changing of pump liners due COMPANY's request	X						
20	Waiting on COMPANY's instructions		X					
21	Routine inspection, inspection for dropped objects, lubrication		X					

Appendix B: Day Rate Application

22	Waiting on COMPANY provided items or the replacement addition, maintenance or repair of same		X					
23	Moving between wells			X				
24	Waiting on weather				X			
25	5 year renewal survey (SPS)							X
26	Regular inspections and surveys for dripped objects in derrick and other relevant areas of the rig		X					
27	Inspection after jarring and top hole section drilling		X					

Appendix C: Contract Window and Notifications

The COMMENCEMENT DATE is the date and time when the following conditions are met:

- i. CONTRACTOR has given COMPANY written notification that the DRILLING UNIT has completed its scheduled or non-scheduled repairs / maintenance, renewal surveys or other classification surveys;
- ii. All agreed ACCEPTANCE TEST procedures have been completed to COMPANY's satisfaction;
- iii. the DRILLING UNIT is ready and in the condition required under the CONTRACT enabling it to provide the WORK; and;
- iv. the DRILLING UNIT is in transit 500 meters away from COMPANY's first WELL.

COMPANY/CONTRACTOR shall on a continuous basis notify the COMPANY/CONTRACTOR REPRESENTATIVE of its best estimate for the COMMENCEMENT DATE under the CONTRACT/CALL-OFF. The estimates shall be given with accuracy as set out in the following plans:

Table 1 – from Yard

Date of notice	Duration of commencement window
From [xx] months prior to the estimated COMMENCEMENT DATE	XX MONTH
From [xx] days prior to the estimated COMMENCEMENT DATE	X MONTH
From [x] weeks prior to estimated EARLIEST COMMENCEMENT DATE	X DAYS
From [x] week prior to earliest estimated EARLIEST COMMENCEMENT DATE	X hours

Appendix C: Contract Window and Notifications

From [x] weeks prior to estimated LATEST COMMENCEMENT DATE	X DAYS
From [x] week prior to earliest estimated LATEST COMMENCEMENT DATE	X hours

TABLE 2- in Direct Continuation

Date of notice	Duration of commencement window
From [xx] months prior to the estimated COMMENCEMENT DATE	XX MONTH
From [xx] days prior to the estimated COMMENCEMENT DATE	X MONTH
From [x] weeks prior to estimated EARLIEST COMMENCEMENT DATE	X DAYS
From [x] week prior to earliest estimated EARLIEST COMMENCEMENT DATE	X hours
From [x] weeks prior to estimated LATEST COMMENCEMENT DATE	X DAYS
From [x] week prior to earliest estimated LATEST COMMENCEMENT DATE	X hours

The COMMENCEMENT DATE shall not in any event occur before the EARLIEST COMMENCEMENT DATE or after the LATEST COMMENCEMENT DATE unless otherwise agreed by confirmation from the COMPANY.

Appendix D: D&W Deliveries in Project Phase

The following products should be prepared for the various decision gates (on Project level) as input from D&W to the project:

Requirements	Gate 1	Gate 2	Gate 3	Start WCP	State of D&W Execution
D&W input to Project BOK	x				
D&W input to Project BOV		x			
D&W BoD document		x			
D&W input to PUD/Gate 3 documentation			x		
D&W PUD supporting documentation or eqv. Gate 3 support report			x		
Main drilling program				x	
Main completion program				x	
Risk and register and mitigation plan	x	x	x	x	x
Well lifecycle assessment (input in BOK)	x				
Well lifecycle strategy		x	x*		
Time and cost estimates	x	x	x		
Early phase Project plan	x	x	x		
Drilling rig schedule		x	x	x	x
Market and procurement strategy		x			
HSE program					x
Authority applications					x

Appendix D: D&W Deliveries in Project Phase

Technology development assessment	x	x			
Technology qualification program		x	x		
Individual well programs according to WCP					x

* Performed early in Define Phase, post selected concept