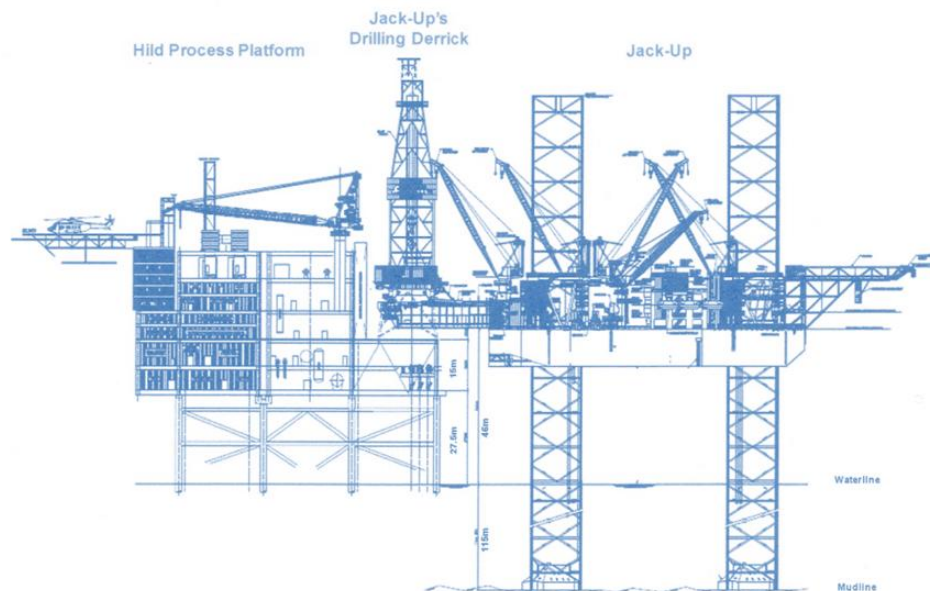


RIG STRATEGY FOR HILD FIELD DEVELOPMENT



University of Stavanger

Master in Industrial Economics

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Summary:

The purpose of this thesis is to look into and make a new form of incentive scheme that could be used for a drilling rig contract at the Hild field development.

Total E&P Norge and their partners are in the starting-phase for developing the Hild field in the Norwegian Continental Shelf. This thesis describes and follows this tender process for getting a suitable Heavy Duty Jack-Up rig to drill the wells at the Hild field commencing the second quarter in 2014.

The focus with the incentive scheme is to get the drilling contractor to collaborate with the operator with operating a high efficient rig and motivated crew under the drilling operations, in order for the operator and its partners to save time which implies reduced cost that is to be shared with the drilling contractor on the basis of a bonus paid for achieving defined target and objectives.

Rig hire and the cost of drilling services comprise the main costs in drilling operations, where drilling costs have increased sharply in recent years. Since 2001 there has been a substantial decline in the measured drilling efficiency on the Norwegian Continental Shelf, where the efficiency has dropped from 102 meter per day to 80 meter per day at present. This has led to sky high drilling costs, given the lower drilling efficiency and the high rig rates.

When there is a shortage of rigs, it is important to utilize the rig time as efficient as possible. One way of making this possible is by using incentive schemes between the operator and the drilling contractor, in order to motivate the contractor and the drilling crew to increase the efficiency of the drilling operations. Introducing the drilling contractor to an incentive scheme that could lead to an improved collaboration between the parties, common goals and rig efficiency is the main goal of this proposed incentive scheme and this thesis.

Preface:

This thesis is a closure of my master degree in Industrial Economics at the University of Stavanger. I had a specialization in petroleum drilling, and contract management in my master degree, with a bachelor degree in petroleum technology which was also completed at the University of Stavanger.

The object of the thesis has been to do an independent research and work that covers my educational background, with regards to the contract and petroleum specialization. The theme about drilling contracts has been very attractive and interesting to me through the master degree. This topic is very relevant, especially at the moment when there are a great number of drilling operations in the Norwegian Continental Sector, and extreme high dayrates for hiring a drilling unit. This has led to a focus on optimizing the drilling contracts, so the drilling operations are done with more efficiency and lower cost.

I want first of all to express gratitude to the people working at the Hild field development in Total E&P Norge for giving me great support and assistance during this thesis. They have been very welcoming and friendly through this semester. So I want to send my gratitude to Reidar Wold, Gry-Einum Foyen and Mikkel Fjeldheim at Total E&P Norge.

I also want to send my gratitude to my mother, father, brothers and my family for supporting and motivating me through these five years of studies in Stavanger.

Lastly I send my thankfulness to Petter Osmundsen for constructive and motivating conversation and guidance through this process, and for also inspiring me about the incentive-topic with his lectures at the University of Stavanger.

Stavanger 29.06.2011

Simon Folkestad Førland

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1. Introduction:

1.1. Total E&P Norge AS:

Total E&P Norge AS (from now called TEPN), - Total Exploration & Production Norge AS is a part of the French based Total-group, which is one of the largest oil and gas-companies in the world, with activity in 130 countries.

Total E&P Norge AS has a very extensive license-portfolio on the Norwegian Continental Shelf and had in 2009 a net production of 327.000 boe/day¹ (1).

In the beginning this company was one of three prominent energy companies – Total, Fina and Elf. During the period 1999-2001 the three companies were fusion to the company that we now know as Total E&P Norge AS (1).

Total E&P Norge AS has around 300 employees at their main office in Norway is located in Stavanger.

Total E&P Norge AS is today partners in a large number of licenses. Some of these are licenses: Ekofisk, Troll, Snøhvit and Åsgard (1).

Further TEPN is operator of the following licenses: Tor, Frigg, Rind, Skrine, Tir, Alve Nord, Victoria, Atla and Hild (1).

¹ Boe/day: Barrels of oil equivalent per day

1.2. Background of the field Hild:

1.2.1. The history of the Hild-field:

The Hild field is one of the largest un-developed gas discoveries in the North Sea. The discovery was made 30 years ago, and is today operated by Total E&P Norge AS.

The Hild field consists of four blocks – 29/9, 30/7, 29/6 and 30/4, located 42 kilometers west of Oseberg, and the reservoir is at a depth of 4000 meters. (1)

The field was discovered in 1975, and between 1977 and 1983 Norsk Hydro drilled five exploration/appraisal wells at the Upper Jurassic. (1)

Despite being attractive, the Hild resources have been left stranded for many years for several reasons. Firstly, the structural complexity creates intense fracturing and faulting, together with different fluid contacts and pressure regimes. Secondly, drilling is very challenging due to an HPHT² regime and a narrow mud weight window. Last but not least, seismic imaging of the Jurassic series in the main accumulation is extremely complicated due to both multiple energy and a seismic obscured area caused by gas dis-migration into the overlying Cretaceous.

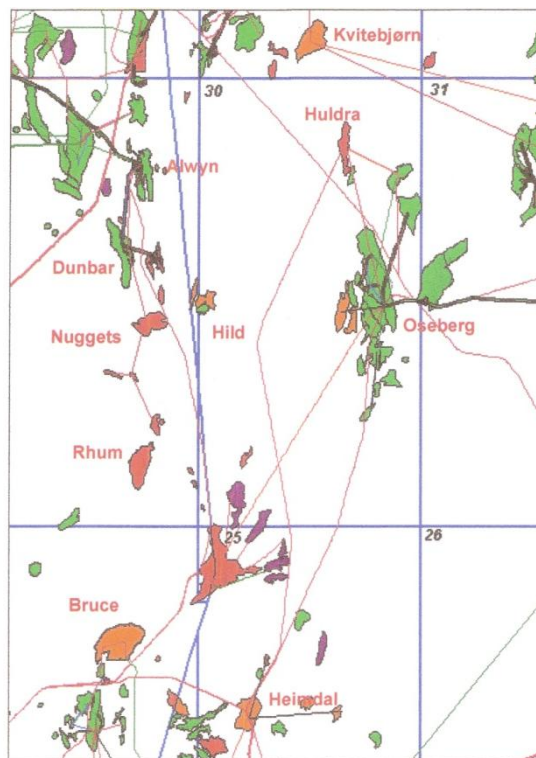


Figure 1: Map of location of the Hild field. (1)

² High Pressure, High Temperature

1.2.2. The Hild-field development:

Total E&P Norge AS took over as an operator in 1990, and are now developing the Hild Field on the Norwegian Continental Shelf, - this consist of the following areas: Hild West, Hild Central, Hild South and Hild East.

In 2003, a 3D seismic survey was performed over the area, which confirmed the area is heavily faulted with gas and condensate at high temperatures and high pressure, making the field complicated to develop.

Despite all the reservoir uncertainties, an appraisal well was drilled in the fall of 2009. The well results have given a much better understanding of both the Hild East Brent gas reservoir, and the overlaying Frigg Sands, oil reservoir.

1.2.2.1. The partnership:

There are following owners in the Hild-licence:

Company:	Share:
<i>Total E&P Norge AS</i>	<i>49%</i>
<i>Petoro AS</i>	<i>30%</i>
<i>Statoil Petroleum AS</i>	<i>21%</i>

Table 1: Overview of the partners at the Hild field, with their shares. (1)

1.2.2.2. The estimated reserves:

After the seismic survey and the appraisal well, Total estimated the reserves for the Hild field:

2P - Reserves	Gas	Oil*	Boe
	Gsm ³	M Bbls	Mboe
Brent gas	16,0	21,3	125,7
Frigg oil	0,7	28,5	32,8
Total field	16,6	49,8	158,5

*oil+condensates+NGL+C5+

3 4 5

Table 2: The estimated reserves for the Hild field. (1)

³ Gsm³: 10⁹ Standard cubic meter

⁴ MBbl: 10⁶ Barrels

⁵ Mboe: 10⁶ Barrels of oil equivalent

1.3. The reservoir:

The Hild area comprises several faulted and segmented high pressure gas accumulations in the Jurassic Upper Brent located at depths between 3,800 meters to 4,000 meters with different pressures and fluid properties and an oil discovery in Jurassic – referred to as the Frigg formation.

The shallower oil discovery in the Frigg formation is a thin oil layer with a low pressure and a very strong aquifer underneath, that requires an artificial lift due to the high water production. This Hild Oil reservoir is planned to be developed and produced simultaneously with the deeper Hild Brent gas/condensate reservoirs. There is no contact or connection between the HPHT gas and condensate reservoirs in the Brent formation and the Frigg formation.

The sea-depth at the Hild field is approximately 100-120 metres.

Hild has 92 MBBL of original oil in place, where 30 MBBL of oil can be recovered.

The oil is categorized as heavy-viscous oil with an API grade of 21,5. The oil has also a high Total Acid Number (TAN) of 3,5 which has eliminated a possible pipeline export due to commercial reasons. To maximize oil recovery the reservoir will be drained as fast as possible to prevent water trapping oil. (1)

For this field there is planned a gas production with a plateau at 8,25 million Sm³/day⁶, which halved after 3-4 years production. The oil- and condensate production will be high at the start-up and a few years after, and will have a plateau at 10-12.000 Sm³/day before the production gradually decreases. (1)

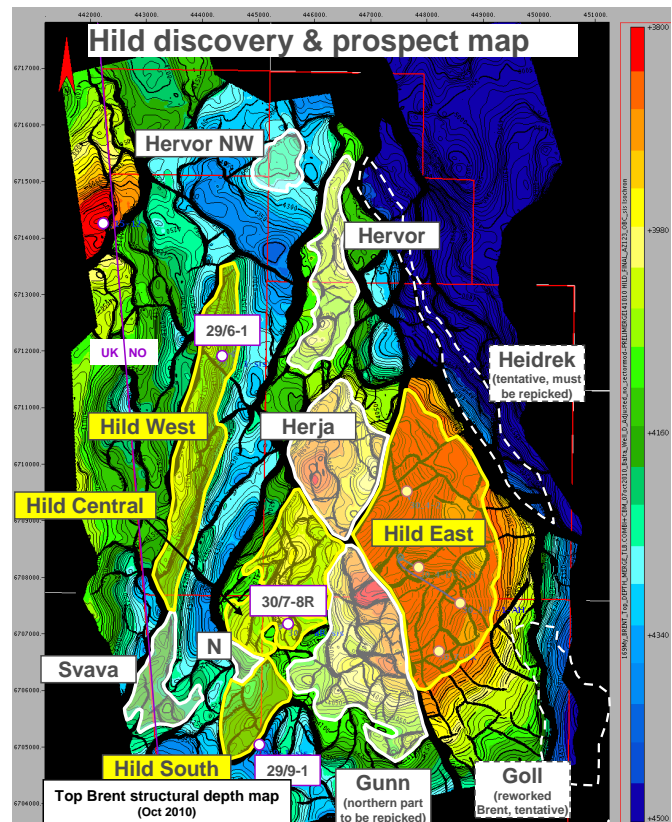


Figure 2: Overview of the Hild reservoir. (1)

⁶ Sm³/day: Standard cubic meter per day

1.4. The appraisal wells:

In 2009 an appraisal and a side track well was drilled at the Hild field. The objective of the drilling was to confirm the potential of the main Brent Group reservoir and in the Frigg formation, and to de-risk the segmentation of the field with extended well testing. The drilling operation was carried out by Semi-submersible drilling unit “West Phoenix”. (2)



Figure 3: The West Phoenix drilling rig. (10)

A specific objective for the Hild well was to drill the well down to specified targets, and establish the best quality formation evaluation possible. After the appraisal wells was drilled, the evaluation of the wells was that there are very difficult drilling conditions below the Frigg formation towards the Balder formation, where both static and dynamic losses occurred. It took a long time to drill through this difficult area. And there was a lot of problems with mud losses during the drilling due to a poor cement job. (2)

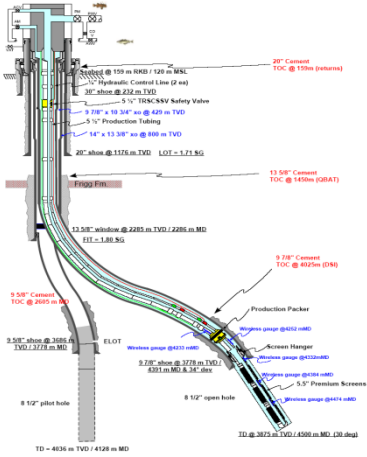


Figure 4: Well path for the appraisal well. (10)

1.5. The concept for Hild field development:

The total cost of the project is estimated to 18.5 BNOK⁷ (1)

TEPN as an operator recommend the following solution for the Hild field development (1):

1. Integrated WPUQ⁸ platform with JU⁹ assisted drilling
2. A platform with end well-bay lay-out is the most robust platform concept
3. Gas export to FUKA¹⁰
4. Oil export to FSO¹¹ with water wash treatment

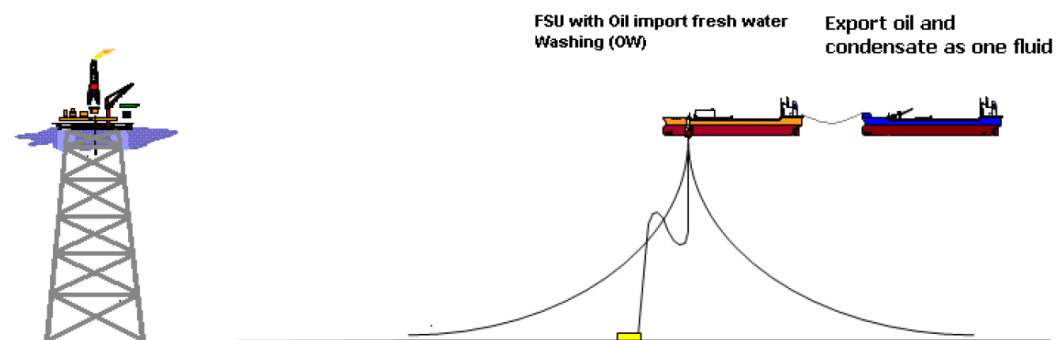


Figure 5: The concept for the Hild field development. (1)

During the last two – three years several development options has been studied, like sub-sea and minimum facilities platform tie-backs to a nearby host. None of these were proven feasible.

Due to the complexity and quality of the oil the best recovery and simplest process solution is to export via an on site FSO (Floating, Storage and Offloading unit).

The gas will be dehydrated and treated, and exported in pipelines that lead to FUKA.

The oil which is very heavy will be treated, separated and processed on the FSO that will be located next to the platform. The oil will be exported from the FSO by pumping the oil into oil tankers and transported to shore.

⁷ BNOK: Billion Norwegian Kroner

⁸ WPUQ: Well, Production, Utilities and Quarters

⁹ JU: Jack-up

¹⁰ FUKA: Frigg UK Pipeline that leads to St. Fergus Gas Terminal

¹¹ FSO: Floating, Storage and Offloading unit

The FSO will be a leased converted shuttle tanker or a new built. The FSO will be interconnected by oil and water pipelines, a gas pipeline, power cable and fibre optic cable. The FSO will provide the final decantation of the oil, and the produced water from the FSO will be returned to the platform for reinjection. The FSO will be located approximately 3 km South-East of the platform.

The Hild platform will export partially processed oil that still contains water through a pipeline to the FSO that will store and offload oil to shuttle tankers. In addition to the oil and water pipeline, the FSO is connected to the platform by several cables and service lines.

A number of options for the gas export have been considered both to existing infrastructure on the Norwegian and UK Continental Shelf. Consequently, the option retained for the gas export for further evaluation retained by the partnership to the St. Fergus Gas Terminal in Scotland, with the FUKA pipeline. Where there is two pipeline options – which consist of a bypass skid with the 32” pipeline from Alwyn, or with a hot tap on the 24” pipeline from Alwyn.

The start-up for oil and gas production is set to the spring 2016, and the operating time for the Hild field is expected to be around 10 years. (1)

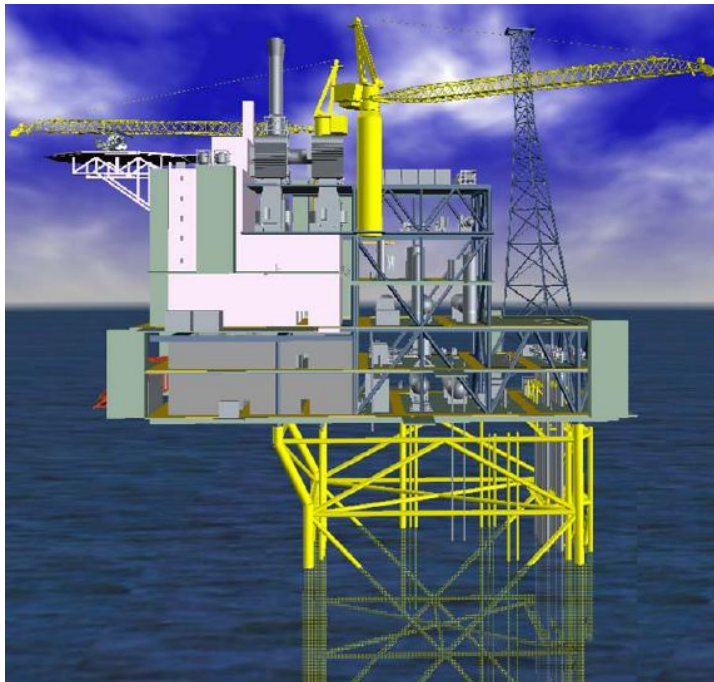


Figure 6: The Integrated WPUQ platform. (12)

1.5.1. The wells:

The jacket design includes 21 well slots and the total number of wells currently envisaged in the development is 20. These wells are split between oil, gas, water injection and prospect wells.

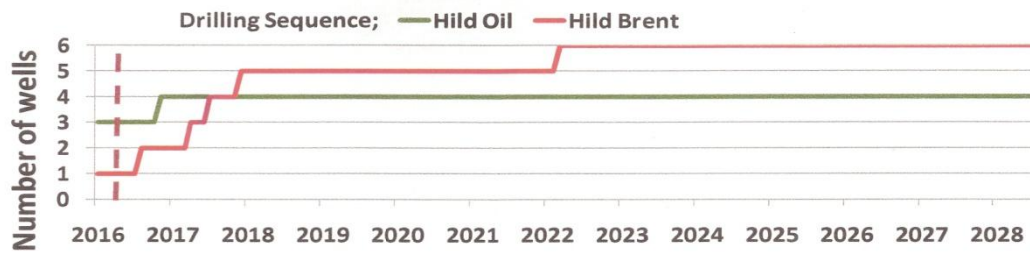


Figure 7: The drilling sequence after start-up (1)

The base case well programme for this study is based on the latest planning which is to drill and complete 4 Brent Gas producers, 4 Frigg Oil producers and 2 injection wells. The injection wells are not part of the platform location optimization as they might be drilled as subsea wells.

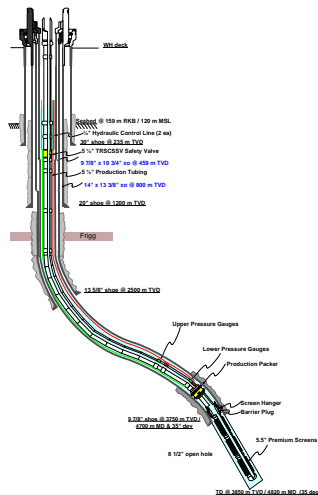


Figure 8: Well path for the Brent gas wells (12)

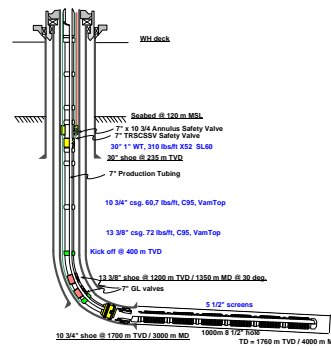


Figure 9: Well path for the Frigg Oil wells (12)

The base case wells to develop the main Hild East oil and gas reservoirs extends to a drilling period of around 4 years. With the inclusion of additional and prospect wells the initial drilling period extends to around 6,5 years. Due to the water depth at Hild, the HDJU will operate close to its design limits and the verification of Jack-up stability at the Hild site will be a critical issue.

Drilling is planned to commence in Q2 2014 with drilling through the jacket. Pre-drilling prior to jacket installation is not in the base case plan. Drilling and completion will continue after the installation of the topsites.

There are four different possible locations where the HDJU can be placed, the locations are named H, G, E and D and are split in one group of locations (H, G, E) in “Deep Water” (+/- 120m.) and one location (D) in Shallower Water (+/- 105m). The locations were picked with the objective to minimize total well length, avoid geotechnical hazards, and reduce the technical complexity to reach the targets and with the one location in shallower water (+/- 105m) to potentially increase the number of Jack-Up rigs capable of working on the location.

1.5.2. The production plans:

The facilities will be designed to accommodate a gas processing capacity of 10,2 MSm³/day, and an oil and condensate export of 12,200 Sm³/day.

The gas production is currently planned with a plateau export production of 8,25 MSm³/day, which will start to decline after approximately 5 years of production and will gradually decline over the next 7 years. The oil and condensate production will be high at the initial start-up, ranging between 10,000 to 12,000 Sm³/day for the first two years and then gradually decrease. The water production is assumed to be approximately 10,000 m³/day for most of the operational years. All the produced water will be cleaned and re-injected back in the formation. (1)

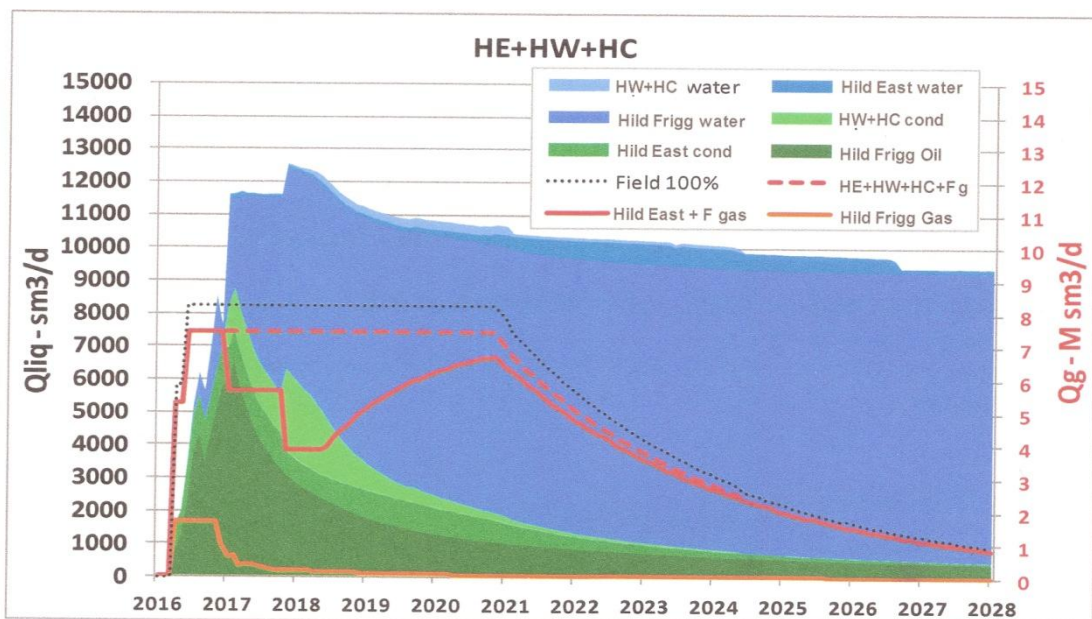


Figure 8: The preliminary production for the Hild field (1)

1.6. The drilling rigs:

1.6.1. The Marked Screening:

In order to meet the planned start-up date in Q2 2016 it will be necessary to commence drilling operations in 2014. In order to secure a suitable drilling unit for such purpose a Call for Tender (CFT) for a Heavy Duty Jack-Up rig (HD JU) was issued 27th December 2010 by TEPN.

The market for HDJU's capable of drilling in 115-120 meters depth is relatively limited, and most of the existing suitable units are tied up in long term agreements.

A market survey / prequalification process was conducted in May 2010 with the purpose of identifying:

- Possible drilling units currently working in the Norwegian sector
- Units working outside the sector, but capable of gaining the required AoC¹²
- Or new units proposed to be constructed specifically to undertake the Hild drilling programme.

The market screening for drilling rigs was carried out by Fearnley offshore in May 2010.

They concluded the review with:

“The market for Heavy Duty Jack-Up's (HDJU) in NCS¹³ is today extremely tight for 120m WD and is forecasted to remain such in the forthcoming years. Most of the existing units are contracted on long term periods but new comers may bring some flexibility.”

¹² AoC: Acknowledgement of Compliance

¹³ NCS: Norwegian Continental Shelf

The study concluded that 5 rigs were potentially available and capable of working on Hild in 120m water depth with an additional 2 rigs available if the water depth was reduced to 105m.

Norway Jackups Supply & Demand: 2005-2015

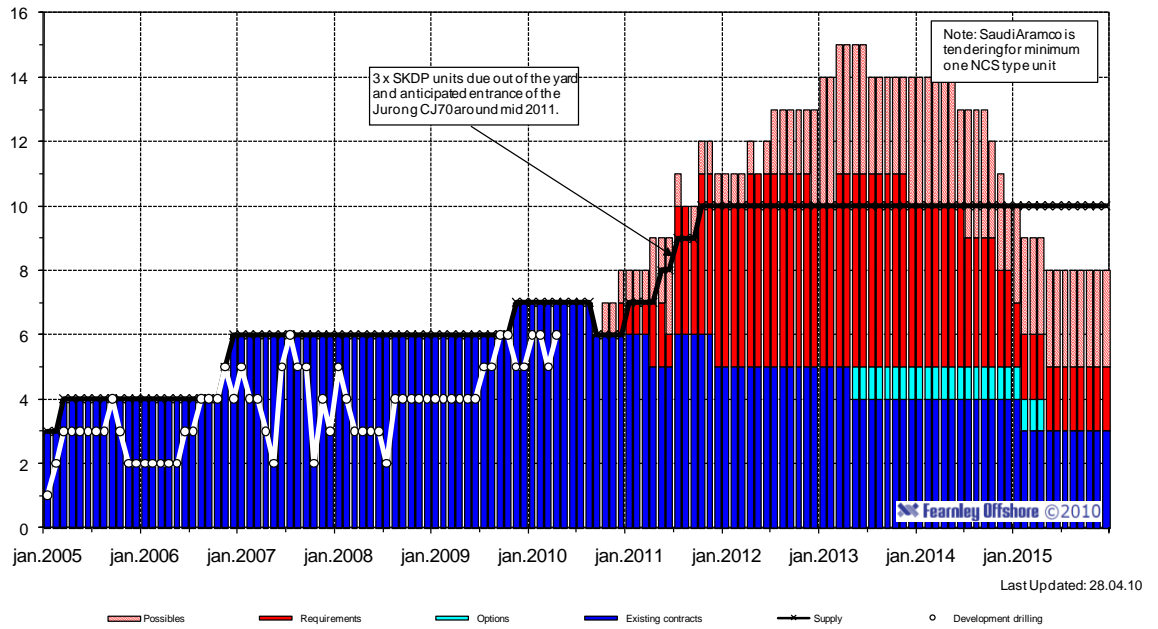


Figure 9: The Supply and demand for Jack-Ups in Norwegian Continental Sector (14)

1.6.2. The prequalification:

24th August 2010 there was a prequalification with a response due date set to 30th September 2010, where 15 contractors were cut down to 3 recommended contractors.

After the prequalification, there came a 4th contractor that also gained a prequalification.

The Call for Tender was then sent out to the four contractors, with a due date of delivering the Tender documents back to TEPN on 1st March 2011.

The tenderers delivered also technical specifications about their drilling rigs regarding the drilling efficiency to the rigs. The form with the drilling technical specifications can be found in Attachment 1 in this thesis.

The contractor awarded the contract will be responsible for operation of the drilling unit according to TEPN requirements and maintenance of all equipment within contractor's responsibility.

The Hild field will be developed from an integrated wellhead jacket with wells drilled and completed using a HDJU in cantilever mode over the jacket well-bay.

As the Hild requirements, particularly the water depth, are close to the limits for all Jack-up's but the very largest HDJU's a pre-qualification exercise was carried out in order to better define the actual technical suitability of potential units.

The pre-qualification was based on a broad set of criteria with water depth suitability being the primary criteria. Pre-qualification was also intended to identify contractors who would consider building new units for Hild development, based on a minimum 3 year drilling programme.

In order to better understand the impact of shallower water depth the pre-qualification, which cited a base case water depth of 120m, also included pre-qualification of units capable of working in shallower water of 105m.

The pre-qualification was open to units with a current AOC for operating in Norwegian waters and those worldwide that the contractors considered capable of gaining one for the Hild development.

The pre-qualification was issued to 15 contractors.

Only 3 contractors responded positively Company A, Company B and Company D. Between them they offered in total 7 rigs. These are in summary:

New build rigs (two): Both Company B and Company A offered to build CJ70 drilling units. These are the biggest jack-ups available today and are well suited for Hild. Company A have subsequently confirmed they will build two CJ70 rigs, not linked to a Hild commitment, with orders to be placed by end 2010. The Company B offer is linked to a Hild commitment.

Existing new build rigs (three): Company D offered the N class jack-up, three of which are under construction for delivery between 2010 and 2011. These rigs are smaller than the CJ70 and would need leg extensions to operate in 120m of water. The structural capability of these rigs to remain on site long term at Hild is to be reviewed.

Existing Rigs (two): Company A offered a N-Class rig, which would require modifications to work in 120m water depth and again is a smaller rig than the CJ70. This rig is however currently contracted to another oil company which has the option to extend the contract until 2015 and may therefore not be available. Company D offered a rig named Gorilla VI which could only operate in 105m water depth.

A summary of the responses is given in the following table.

Rig Pre-Qualification Responses

	Company A		Company B	Company D	
Rig	CJ70	N-class	CJ 70	N Class	RG6
Summary	New build based on N-class	Existing rig	New build based on N-class	New builds (3) currently under construction	Existing rig
Technical Summary	120m depth. Spec can be optimised for Hild. Top spec.	105m OK with spud can extension for 120m. Lower spec than CJ70 or N class	120m depth. Spec can be optimised for Hild. Top spec	105m OK with leg extension for 120m. Lower spec than CJ70 – to be determined	105m OK Lower spec than CJ70 or N class
Availability	Order planned end 2010. (not Hild dependent) Available Q1 2014	With COP, under option to April 2015.	Order planned on Hild commitment. If Q2 2011 then available Q1 2014	3 units available 2010 -2011 out of yard. No current contracts but bidding.	Available from Q2 2012 (to be confirmed)

Table 3: The response for pre-qualification for the HDJU

1.6.3. The rig types:

There are three types of Heavy Duty Jack-Up rigs that are of interest:

- **N-Class (CJ-62):**

A jack-up rig that was designed in the beginning of the 1990's, and which can operate at a water depth of 120 meters, and can drill down to a depth of 7.620 meters. It has an accommodation level up to 90 persons.

- **MSC CJ-70**

Are one of the largest Jack-up rig in the world, and would be more efficient, larger deck and reaches out to higher water depths. The rig will also decrease connection time, and drills 15-20% faster than other Jack-up models. The unit will have 2500 m² deck space and will weight 12.000 metric tons.

- **Super Gorilla VI**

This rig can operate up to water depths of 121,9 meters, and can drill to a depth of total 10.668 meters.

All of these rig types are designed to operate in harsh water in the North Sea, and have a higher efficiency standard compared to older jack-up rigs.

The MSC CJ-70 has a higher efficiency because the rig can handle two pipes at the same time, can run casing faster, quicker and safer. The derrick is designed for handling four drillpipes at the same time, saving 25% connection time. The rig has a large deck space and storage capacity, which can be loaded up to 10.000 tonnes. It has cutting and slurry handling systems, which allows a high rate of penetration. The physical size of the rig, does it less vulnerable for Non-productive time (NPT) due to weather downtime.

Compared to the N-class, the CJ-70 are about 33% more efficient with respect to drilling of wells, and are significantly quicker for drilling horizontal wells.

Even though the companies are offering the same kind of drilling unit, there are differences in the quality of equipment and hardware provided on the drilling rig – which will contribute to a difference in the total rig efficiency.

1.6.4. Water depth and rig availability:

The water depth in the Hild East area varies from more than 120 meters on the eastern side of the field towards 102 meters on the western side, see graphic 1 in appendix.

The market for Heavy Duty Jack-Up rigs on the Norwegian Continental Shelf is today extremely tight for 120 meters water depth and is forecast to remain such in the forthcoming years. Most of the existing units are as described earlier on long term contracts but newcomers may bring some flexibility. Potentially the majority of available rigs can operate in 120 meters water depth though only 2 out of 6 rigs can do so without modifications.

Should the water depth be below 105 meters, potentially one additional unit could be considered.

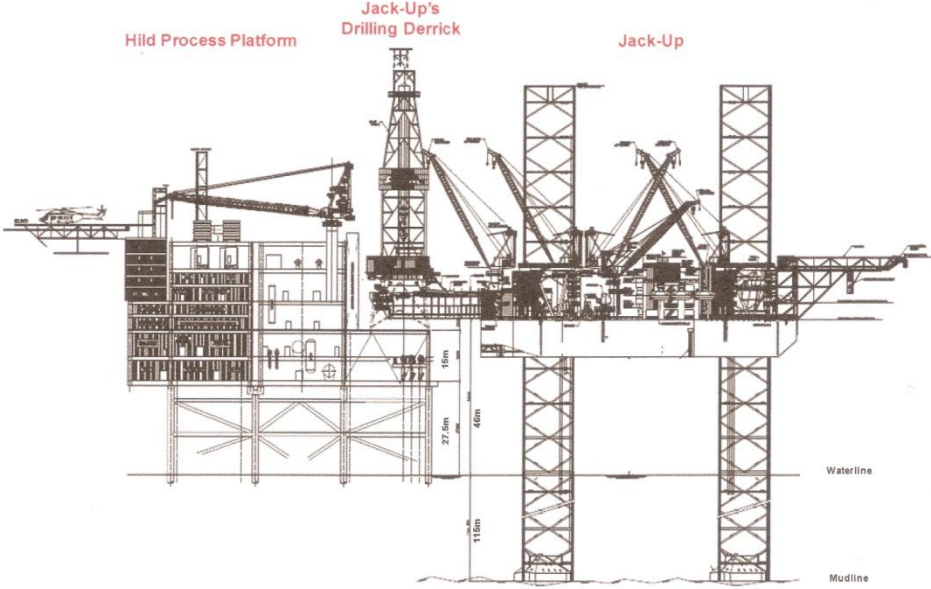


Figure 10: The jack-up next to the Hild platform (1)

1.6.5. Contract details:

Based on the maturity of the prospects Total E&P Norge AS envisage three possible scenarios with respect to contract duration (2):

- 3 years firm period + 3x1 year options
- 4 years firm period + 2x1 year options
- 5 years firm period + 2x1 year options

The bidders will be requested to provide rates based on all these three scenarios in the Tender documents.

In order to mitigate any exposure related to contract duration and a continuous utilisation of the rig during the firm contract period, the intention is to arrange for a possible deployment on the U.K. Continental Shelf. Tenderers will therefore be requested to provide rates applicable for operations on the U.K. Continental Shelf.

It is estimated a rig rate of KUSD¹⁴ 345 per day, which gives an estimated contract value for the three possible contract scenarios (3):

- Based on a firm period of 3 years – MUSD 380
- Based on a firm period of 4 years – MUSD 510
- Based on a firm period of 5 years – MUSD 650

In addition to the rig rate costs related to rig intake will be applicable. Mobilisation cost for a new build rig is estimated to MUSD 30-40, while mobilisation of a “warm rig” is estimated to 1.4 MUSD¹⁵ (3).

¹⁴ KUSD: 1000 US Dollar

¹⁵ MUSD: 1.000.000 US Dollar

The time schedule:

Activity:	Time schedule:
Approve strategy	20 th December 2010
CFT issue	22 nd December 2010
Tender due date	01 st March 2011
Contract award recommendation to partners	End June 2011
Contract award – subject to PDO approval	July 2011
Contract start date	June 2014

Table 4: The time schedule for the HDJU contract (4)

It should be noted that the contract award will be subject to authority approval, which is estimated to be obtained in June 2012. This will imply a financial exposure related to a possible early termination of the contract.

2. The approach to the problem:

The drilling operations on the Norwegian Continental Shelf has during the last years been in a shortage of drilling rigs and we are experiencing very high dayrates on these units. In addition to this there has been observed a steady decrease in drilling efficiency since 2001.

It has also been very difficult to get hand on the most technical correct and efficient drilling rigs. This has led to a large decrease in number of wells drilled on the Norwegian Continental Sector.

TEPN is going to drill minimum 10 new wells on the Hild Field, - 5 Brent gas wells, 4 Frigg oil wells and one injection well.

All of these wells are quite complex, and the time limit to complete these wells prior to the start-up of production is very limited.

It is important to enter into a contract with the drilling company that offers the best technical and commercial solution for drilling at the Hild field, and which are able to perform the best and most efficient drilling operations – in order to have wells ready for production in the right time. By having these wells ready, TEPN and their partners at the Hild field, could have maximum income at the right time, and not losing money because of a lower NPV¹⁶.

To make this possible – the operator and the drilling company must have the same goals and collaborate to enable the wells to be completed to a lower cost, and according to the project schedule.

To make this collaboration possible TEPN can implement incentives in the contract in order to make the drilling company interested and focused in saving time and thereby costs during the operations.

The incentive provides the drilling company with a bonus for doing the drilling operations quicker and less costly – and a penalty for doing the operations inefficient and more costly.

There have been used a lot of different incentive schemes in the oil industry, - where a lot of the incentives has been very unbalanced and rigid. This has led to some of the drilling companies refusing to use the incentive scheme in a drilling operation, if this represents an increased risk for their company.

Through this thesis I am going to find a new incentive scheme that could be used for the Hild's drilling program to increase the efficiency, collaboration and the quality on the wells being drilled. This would lead to a reduction in the drilling cost for the Hild wells, making an expenditure cut for TEPN and their partners, and an extra bonus to the drilling company.

¹⁶ NPV: Net-Present Value

3. Incentive theory:

3.1. Introduction to incentive theory:

An incentive can simpler be described as an economical bonus or punishment mechanism established in order to get another part to collaborate in the best manner.

Incentive is one of many directing- and motivation-mechanism, which is any factor both financial or non-financial that enables or motivates a particular course of actions, and encourages the agent to behave in a certain way, as a reward offered to the agent for increased productivity or efficiency.

3.1.1. Principal-agent theory:

Principal-agent theory is a central theory that forms the basis for usage of incentives.

Mainly, this goes out that the principal delegates to care of their interests of agents – depending on the principal agent to achieve their goals.

For this theses –

The principals: TEPN as the operator, and Total E&P Norge, Statoil Petroleum and Petoro as the owners, - and the agents: the drilling company, and the service companies.

The central problem is how to draw up contracts that provides the agent with incentives to maintain the principal's interests in an efficient way.

One problem is that the principal and the agent do not necessarily have common goals.

Furthermore doesn't the principal necessarily hold complete information about the agent, that the information is asymmetric.

An example of this is that the agent can conceal the most effective way of working under the contract.

This is possible because the agent has control of better information and knowledge about how the work should be done.

This gives the agent a certain freedom to determine their own behavior.

Among other things he can in secret work for their own goals, which is opportunistic, and is called moral hazard in incentive schemes.

Because of the asymmetric information flow, it is difficult for the principal to find out about this moral hazard.

To avoid this effect, the principal must make a contract that provides the agent with incentives to ensure principal interests in an efficient manner, and/or he must establish procedures that reveal an opportunistic behavior, by monitoring the agent.

In addition, the agent has a risk that there is no clear relationship between the agent actions and principal goals. For example, the agent does the work in the best way to obtain the results that the principal wants, but in circumstances beyond the agent's control may prevent the agent from achieving these goals. The agent will have a "reward" for this risk, which also causes principal-agent costs. An element that should be mentioned here is that the agent typically is more risk averse than the principal. The main reason for this is that the principal has the opportunity to diversify the risk, while the agent has little chances.

3.1.2. The design of incentive contracts:

Incentive contracts can contain multiple elements, and most importantly is how remuneration should be regulated.

The most important aspects in the remuneration to the agent, is to get the agent to show it's real qualities, and motivate the agent to follow the principal goals in a efficient way.

Furthermore the agents risk must be taken into account; the most common way to remunerated in relation to the incentive contract is performance-related payment.

The performance-related payment is a way to give the agent remuneration in relations to the achieved results. The agent remuneration can be defined as follow:

$$W = A + BX$$

Formula 1 (6)

Where W = agents remuneration, A = agents fixes remuneration, B = intensity of the incentive, X = the result.

Performance-related payment promotes focus, prioritizing and performance in the execution of the work.

Issues when performance-related remuneration is used (6):

- How high should the intensity of the incentives be, - how strong should element of achieving the result be?
- What kind of result should be rewarded?
- What kind of forms should the performance-related remuneration be given?
- Which organization level should the result be measured at?

3.1.3. Incentive intensity:

What determines the incentive intensity are several factors that will be described in more detail.

These factors are within the agent's sphere of control, agent's risk willingness, simplicity, agent's willingness to contribute, the degree of contribution to company's performance, predictability. In addition, the incentive intensity can be fixed or variable (6).

The factors will be commented below:

Within the agent's sphere of control is that one must consider the intensity relative to the possibilities of influence the agent has on the result. The more accurate the result can be measured; the incentive intensity can be higher because of the lower risk.

Risk willingness to the agent, affects how strong the incentives can be. The more risk adverse the agent is, the higher can the incentive intensity be.

The easier and more transparent incentive scheme can be made, the higher the incentive intensity can be. This is called the simplicity principle. The reason for this is that by having a simple system, agents can easier notice the consequences of their actions, and therefore undertake actions that achieve results. The risk for the agent is reduced by this simplicity principle.

The willingness to contribute principle – the less motivated the agent is basically, the lower should the intensity of the incentive be. The reason for this is that the motivation of a low-motivated agent will require a very high intensity. This will lead to the agent receives a high risk, and demand high risk premium. In summary, this will increase the agency costs more than any gain in improved performance from the agent, and the principal will be beneficial to use low incentive intensity.

Contribution principle says that the more the employee's performance contributes to organizational goals, the higher should the intensity of the incentive be.

The strength of the incentive should be stable over time, it should be predictable in order to prevent the "ratchet effect" – that is if the agent can manipulate the standard targets which are based on previous obtained results. If the incentive and performance constant is adjusted on the basis of the result, it will be a danger that the agent is holding back performance, to achieve future goals more easily. A question is; what to do if certain events have major consequences and if shall have the opportunity to renegotiate.

The incentives don't necessarily need to be linear in its design. Incentive strength can be both decreasing and increasing with the results that are achieved. Then it's called variable incentive strength.

By using convex incentive schemes where the strength increases, there will be more to win on good results. This provides a high upside and a low downside on the deal. The effect of such a mechanism will be stimulating for risk-takers, and will attract risk-seekers (6).

With concave systems the incentive strength will decrease with results. One has less to gain by better results; such a system will promote caution and attract those who want low risk.

3.2. The rig status and incentives:

Rig hire and the cost of oil services are the dominant components in drilling expenses, where drilling expenses have increased sharply in recent years.

Since 2001 there has been a substantially decline in the measured drilling efficiency on the Norwegian Continental Shelf, where the efficiency has dropped from 102 meter per day to 80 meter per day at present. (6)

This has lead to sky high drilling costs, given the lower drilling efficiency and the high rig rates.

Given this very sharp fall in drilling efficiency, it is hardly surprising that various types of incentive contract have been tried out in this sector. But it can be added here that other measures might be better at identifying value creation in drilling.

The decline in the drilling efficiency can be due to the technological research which have made it possible to drill longer wells and multilaterals wells. This kind of wells are much more demanding and complex to drill, but are much better qualitatively since they can drain out larger reservoirs.

Since the start of producing petroleum on the Norwegian Continental Shelf, the easiest fields have been drilled first, leaving the more complex fields to drilling and development today. These fields are much more demanding to drill and complete where there is more focus on making the wells better qualitative.

Through the lasts years, there has been an aging of the rig fleet, where the older fleets has rarely been upgraded or maintained because of derive advantage from renting the rig out to the oil companies. The high rig rate has been the primary and most important factor and driving force for this.

Companies such as Transocean have been criticized for rarely upgrading their rig fleet.

There is also a large shortage of available rigs capable to drill at the Norwegian Continental Shelf. Reasons for this is mainly due to a large number of the rigs have drilling contracts for oil companies, and new-built rigs are often booked a long time before they leave the yard.

3.3. Rig efficiency and incentives:

Drilling operations on the Norwegian Continental Shelf are characterized by a shortage of capable jack-up rigs and very high dayrates.

When there is a shortage of jack-up rigs, it is important to utilize the rig time as efficient as possible. One way of making this possible is by using incentive schemes between the operator and the drilling contractor, for motivation of the contractor and the drilling crew in order to increase the efficiency of the drilling rig and the operations.

Osmundsen has described that the incentives in the drilling sector has been unbalanced, since the contractors have been rewarded for uptime, but hardly at all for the efficiency (6).

He also mentions by losing resources that could otherwise have been profitably produced because of rig capacity shortage and reduced drilling efficiency is also a matter of concern from a socio-economic perspective (6).

Because many petroleum resources are quite time-critical to recover, since the fields can be harder to recover after some years, and for the small fields it is important to drill efficient to have positive total income after the production of the petroleum.

The authorities have a much more long term perspective on the recovery of the petroleum deposit, and are more open for drilling more correctly than drilling faster, because they fear that the increased drilling speed instead of the drilling quality can damage the reservoir, and therefore reduce the reservoir drainage.

So by introducing incentive schemes to the drilling contractor to improve collaboration and to increase both the quality and the efficiency for the drilling operations this can promote more profit and improve utilization of the petroleum field production both for the authorities, oil companies and the contractors, in both short and long time perspective.

3.4. Rig hire – evaluation criteria and compensation format:

Some typical evaluation criteria for the hire of drilling rig:

- Rig intake cost
- Dayrate
- The drilling companies expertise
- Financial strength
- Lump sum for mobilization and demobilization
- Ability to commence on time, and late delivery risked cost
- Compliance with regulations for drilling on the NCS
- Operational efficiency and achievements
- HSE¹⁷ system and culture, both on- and offshore
- High pressure, high temperature (HPHT) expertise and experience

From the bullet points above, we can see that the dayrate is one of many evaluation criteria. Osmundsen has written that the oil industry provides perhaps the foremost example of an industry where opting for the lowest price does not necessarily represent the best economics (6).

The most important element when hiring a rig, is the lifetime cost for the rig hire, where the income for the field production must be taken into account. By evaluating the tenders, not by the lowest dayrate, but taken for example the efficiency for the drilling rig, and the crew – it is easier to get a more correct economic picture of the total rig costs. By choosing a drilling contractor with lack of experience and expertise, this could have incredible consequences, both financial, technical and environmental, - for example if the drilling contractor damages the reservoir, or has an uncontrolled blow-out in the well.

So it is important to also take the experience, the HSE in to consideration when choosing a drilling contractor. These elements are important to be carried out in the pre-qualification.

Previously the compensation format for hiring a drilling rig was based on payment per meter drilled, - the compensation format was very simple, but it was difficult to use when there was disagreement between the operator and the drilling contractor in events of change in drilling plans, problems with non productive time and when the rig was placed in stand-by.

¹⁷ HSE: Health, Security and Environment

Today the compensation format has been more complex, but much more justified with different rates associated with the rigs operating status.

There is an ordinary dayrate that is called base rate T, which is used under normal drilling operations. There are also various reduced dayrates when the rig operating status is in stand-by mode, the rig is mobilizing/demobilizing, when a force majeure is happening or the rig has reduced performance because of overhauling.

If the drilling contractor can't deliver the drilling rig with the technical requirements at the pre-agreed mobilization date, a zero rate applies. For the contractor it means a loss of income of each day the rig isn't operational. These different compensation formats provides a very strong and justified incentive to ensure rig uptime.

Osmundsen mention also that one of the most important reasons why rig hire is not tied to the number of meters drilled is because this lies largely outside the contractor's control (6).

Since there are a large number of third party oil service companies that influences the progress of the drilling operation. In addition the operator normally reserves the right to adjust the drilling program by changing wells, drilling depth and so on. All of this calls for a much more flexible compensation format than the old, simple remuneration per meter drilled.

3.5. The design and challenges for an design of an incentive scheme:

There are several challenges when designing an incentive scheme (6):

Asymmetric information:

There is an information gap between the operating oil company who has most information about the reservoir and the planned drilling, but which has less information about the actual drilling process.

Renegotiation:

Often an opportunity for the contractor and the oil company to renegotiate is needed. This opportunity weakens the incentive in the drilling contract, where the drilling contractor may do a poor job and have a low efficiency on a test well, - and then renegotiate the incentive system to have better conditions for the measured drilling parameters that are used in the incentive scheme.

After the first test well, and the new renegotiated drilling parameters, they do the drilling job as normal, and get the incentive bonus.

Measurable performance parameters:

By tying the incentive scheme to measurable performance parameters, it could make the contractor have more focus on the efficiency rather than the quality on the wells, since it's easier to measure the drilling efficiency rather than the quality.

When designing an incentive scheme which is based on measurable performance parameters – it is of importance that the parameters are (6):

- Measurable for both parties
- Observable for both parties
- Within the drilling contractor's sphere of control
- Legally verifiable

Incentive theory can describe the conditions in which fixed-price (lump sum) or reimbursable (cost-plus) terms are suitable. Where incentives in drilling contracts are concerned, a

difference exist between payment per meter drilled (unit rate) and per day (time rate). The unit rate is closer to the fixed-price model and the time rate to reimbursable contracts.

Contracts with fixed-price provides stronger cost incentives and more predictable final amount for the cost. Meanwhile, such a contract can produce considerable conflicts with respect to change orders and quality during the contract time. By arranging meetings between the operator and the drilling company in advance, where detailed drilling plans are reviewed and planned together, one can avoid such conflicts. Fixed-price contracts are more probable to be delayed and will involve a more rigid bureaucratic process when changes are made.

Reimbursable contracts provides a weaker basis for incentives and a more uncertain final price. But the possibility of conflict will be reduced, and faster completion of the drilling can also be achieved.

By having a reimbursable contract it is easier for the operator to ensure changes and by having the possibility to influence the work and the drilling process.

This represents a trade-off from the oil company's perspective. Theory prescribes reimbursable contracts and incomplete plans when a low level of friction is required in renegotiations – in other words, when we have a complex project, an impatient operator, and an operator, when wishes to exert influence during the work, then the reimbursable contract is the best contact form.

3.6. European Economic Area's procurement directive:

Oil companies on the Norwegian Continental Shelf are subject to the European Economic Area's procurement directive.

The purpose of the directive is to secure competition in the market, and to prevent corruption. However, the directive does not prevent other criteria than price being used, providing bidders are made aware of this in the invitation to tender.

4. Tender Evaluation Procedure for Hild Field Development:

4.1. The evaluation:

The objective of this procedure is to define a tender evaluation process securing optimal and impartial treatment of the tenders received, and to ensure that both on a technical and commercial basis the best qualified tenderer is selected.

In order to meet the planned start-up date in Q2 2016 it will be necessary to commence drilling operations in 2014.

In order to secure a suitable drilling unit for such purpose a Call for Tender (CFT) for a Heavy Duty Jack-Up rig (HD JU) was issued 27th December 2010.

The scope of work for the contract comprises hire and operation of a Heavy Duty Jack-Up Drilling Unit capable of drilling in 115-120m. Water, alternatively 105m.

The Tender Evaluation Procedure was divided into two evaluation teams, - one technical and one commercial/contractual evaluation team, containing members with different background and disciplines work.

4.2. The evaluation teams:

The two evaluation teams' had the following main responsibilities:

Technical evaluation team:	Contract evaluation team:
Establish technical evaluation model, forms and spread sheets.	Overall responsible for the tender evaluation and compliance with this procedure.
Coordinate input to and complete technical evaluation/spread sheets.	Establish the contractual and commercial evaluation model, forms and spread sheets.
Participate in tender clarifications.	Coordinate input to and complete the contractual and commercial evaluation/spread sheets.
Provide input/clarifications to project/technical elements in the contract terms and conditions.	Responsible for all communication with tenderers.
Prepare Short List and Joint Award Recommendation together with the contracts coordinator.	Organize and chair clarification meetings.
Prepare report and presentation as required for internal and partners approval together with the contracts coordinator.	Prepare short list and Joint Award recommendations together with the technical coordinator.
	Prepare report and presentation as required for internal and partners approval together with the technical coordinator.

Table 5: Total E&P Norge two evaluation teams with their main responsibilities (2)

4.3. The schedule for the evaluation process:

The schedule for the tender process is as follows:

Invitation to tender issue	27. December 2010
Receipt of Tenders	8. March 2011
Tender Opening	8. March 2011
Stage 1 technical & contractual evaluation	8. March – 25. March 2011
Short listing	25. March 2011
Detailed evaluation	25. March – 1. May 2011
Final evaluation Report	27. May 2011
Internal approval/Contracts Committee	1. June 2011
TDO/DIR ¹⁸ approval (CR EO TDO 005)	8. June 2011
Partner approval	16. June 2011
LOI subj. to PDO ¹⁹ & COMEX approval	17. June 2011

Table 6: The schedule for the tender process (2)

Tenderers were requested to submit their tender in two separate envelopes/packages – one envelope/package with the technical and contractual part and one envelope/package with the commercial part.

The commercial envelope/package was opened when a short list was established on the basis of the stage 1 technical and contractual evaluation.

¹⁸ TDO/DIR: Management at Total Group's headquarters

¹⁹ PDO: Plan for development and operation

4.4. Evaluation:

The evaluation was performed in 2 stages covering the following main elements:

4.4.1. Stage 1 Technical and Contractual evaluation (basis for short listing):

Yes/no criteria focusing on (2):

- Availability of unit
- Operational capabilities on Hild site
- Tenderers Management system including Safety Management system
- Tenderers safety record
- Tenderers HPHT experience
- Contractual exceptions & qualifications

Based on the results of the stage 1 technical and contractual evaluation, a “short list” were established. The objective was to have the two (as a minimum) best qualified tenderers on the shortlist, this number, however, were dependant on the results on the stage 1 evaluation.

Tenderers failing to meet such criteria were disqualified.

4.4.2. Stage 2 detailed evaluation including commercial:

The commercial envelope/package was opened when a short list had been established on the basis of the stage 1 technical and contractual evaluation.

The short listed tenders were subject to a detailed evaluation with particular emphasis on (2):

- Assessment of the comparative overall unit capital and operating cost for the projected development work scope.
- Incremental costs to drill from the shallow water location (D)
- Lump sum for mobilisation / demobilisation
- Rig intake cost
- Late Delivery Risked Cost
- Slot Access Move Time
- Topside Installation Standby Time
- Detailed assessment of structural capability

The commercial evaluation will also include (2):

- Detailed contractual evaluation
- Financial evaluation
- Upside considerations incl. Incentive Scheme

Based on the results of the stage 2 detailed combined evaluation the most attractive Tender will be recommended. The evaluation team shall present a joint award recommendation to TEPN management and management at head quarter for approval.

Under the stage 2 evaluation, a technical/commercial combined evaluation has been conducted – where there is focus on the dayrate/time related drilling cost:

The total dayrate/time related cost has been calculated for the alternative durations of the contract. The Base Operations Times calculated has been converted into comparative costs using the dayrates for each unit. This provides an Incremental Drilling Cost for each unit, either on H or D location, compared to the best performer (the most efficient unit). Other time related costs/savings has also be taken into consideration, such as Slot Access Move Time, Topside Installation Standby Time, simultaneous operation time reduction etc.

In addition to the dayrate/time related costs, the following cost elements has been included (2):

- Lump sum for mobilisation / demobilisation
- Rig intake cost including Company follow up in case of new build/modifications
- Late Delivery Risked Cost/loss due to delayed production start up (NPV)
- Slot Access Move Time
- NO_x²⁰ Costs
- Cost of Modification(s) to meet TEPN's requirements
- Conflict with topsite installation risked cost
- Costs related to improvement of HSEQ²¹ score to align Tenderers

²⁰ NO_x: Nitrogen-oxide

²¹ HSEQ: Health, Security, Environment and Quality

4.5. Upside Considerations:

The below will not be directly included in direct comparative figures but will be considered as an upside which can be used as a secondary measure for comparison. These are not quantified in terms of cost but can be used for differentiate between equal/close commercial bids.

Incentive Scheme:

An incentive scheme to be proposed by the tenderers. An assessment will be carried out however due to the assumptions that is required to be made (well actual performance verse planned, LTI frequency, etc.) this assessment will be very dependent on assumptions.

The assessment will be based on a small range of scenarios – good performance, bad performance etc however the specifics of assessment will require to be adjusted based on the detail of the incentive scheme proposed. The willingness of contractors to enter into such agreements and the scope of the scheme (malus as well as benefit for example) can be used to differentiate.

- HSEQ ranking – Whilst unacceptable HSEQ will lead to a rejection in the short list exercise, different HSEQ rankings can be used to differentiate. To the extent possible the cost related to improvement of HSEQ score to align TENDERERS will be calculated.
- Rig Specification and age: Whilst this will be assessed in the comparative ranking, where two units are close the overall level of specification may be used to rank them in preference due to perceived risk of poorer performance than assessed linked for example to rig age or limited specification.

5. Incentives schemes and non-commercial offer from the tenders:

5.1. Introduction:

The four tenderers delivered a bid to TEPN with their technical proposed for the HDJU-rig for the Hild Field.

The proposed consisted of two copies that comprised of the technical information about the rigs and exceptions to the legal terms and conditions of the contract.

In the Tender Documents there is an appendix 6, where TEPN invites the tenderers to make an incentive scheme that could be applied in the contract.

The following objectives and principles was included in the tender documents submitted to the tenderers.

5.1.1. Objectives:

“In this CONTRACT, an Incentive (P.I.) is implemented by COMPANY to improve co-operation between Company And CONTRACTOR for time saving on well operations, while keeping the highest level of Quality, Safety and Environment protection.

CONTRACTOR has a key role in time saving on well operations: Firstly by being directly involved and responsible for many operations, CONTRACTOR can save time by improving the level of performance and efficiency of CONTRACTOR’s PERSONNEL on these operations. Secondly by having a central role among other service contractors, CONTRACTOR can save time by improving organization of tasks and schedule of operations.”

5.1.2. Principles:

“The Incentive is applied to reward CONTRACTOR for his active participation in the optimization of operational efficiency and HSEQ performance.

Bonus/Malus:

The Performance Incentive should contain a strong element of positive benefit to CONTRACTOR where performance exceeds defined targets. An element of reduced payment for poor performance should be included.

Sharing with crew:

CONTRACTOR should allocate a portion of the Incentive Bonus among CONTRACTOR’s PERSONNEL working on the WORKSITE.

Communication to Crew:

CONTRACTOR has the obligation to communicate the Incentive scheme to CONTRACTOR’s PERSONNEL at the beginning of the campaign and during the campaign if necessary.

HSEQ Performance:

An element related to the HSEQ performance on the rig shall be included in the structure of the Incentive Scheme.” (3)

5.1.3. Article 4 in the Tender Documents – Financial conditions:

In the tender document, there is a section about the financial conditions for the rig contract, where the dayrate and reduced rates are mentioned:

5.1.3.1. Rates:

“The remuneration of CONTRACTOR for the performance of the SERVICES throughout the OPERATIONAL PERIOD shall be on the basis of the rates indicated in the CONTRACT. The daily rates shall be applicable for a twenty-four (24) hours period or prorate thereof to the nearest half of an hour.

Base Rate T:

CONTRACTOR shall be remunerated for the correct performance of the SERVICES at the Base Rate T as listed in Appendix 5, except as otherwise specified in the CONTRACT.

Reduced Rates:

STAND-BY Rate:

This rate shall apply for all STAND-BY periods. STAND-BY Rate is equal to ninety percent (90%) of Base Rate(s) T.

Stand-by rate is applied when drilling activities are ceased at the request of the client. This could be waiting for the cement to set, waiting for survey results and instructions.

FORCE MAJEURE Rate:

This rate shall apply for periods when the performance of the SERVICES is prevented by FORCE MAJEURE as per sub-Article 7.3. FORCE MAJEURE Rate is equal to seventy percent (70%) of Base Rate(s) T.

Force Majeure means any act, event or cause beyond the reasonable control of a party including, but not limited to, acts of god, war, sabotage, riot, cyclone, earthquake, landslide, explosion, strike and other labour difficulties or expropriation.

REDUCED PERFORMANCE Rate:

Should performance of the SERVICES be hindered due to reasons attributable to CONTRACTOR COMPANY shall be entitled to continue the performance of the SERVICES under Reduced Performance Rate or to suspend the performance of the SERVICES as per sub-Article 7.1.1. Reduced Performance Rate is equal to eighty percent (80%) of Base Rate(s) T.

BREAKDOWN Rate and Remedial Operation Rate:

a) BREAKDOWN Rate shall apply when the performance of the SERVICES is prevented due to BREAKDOWN. BREAKDOWN Rate shall apply when the performance of the SERVICES is prevented due to BREAKDOWN. BREAKDOWN Rate shall be equal to:

- For the first 60 days after COMMENCEMENT DATE
 - Rate Zero
- For the 61st day after COMMENCEMENT DATE
 - For the first 12 hours
 - Base Rate T
 - After 12 hours
 - Rate Zero

Maximum cumulative duration of BREAKDOWN per month shall be 12 hours.

Should CONTRACTOR exceed the BREAKDOWN allowance in any calendar month and as a consequence, be subject to Rate zero at the month end, Rate zero shall be applicable in the succeeding month until normal operations recommence and Base rate T becomes applicable. Such period of Rate zero shall not constitute a part of the BREAKDOWN allowance for the new calendar month.

b) Remedial Operation Rate shall apply during remedial operations to repair well damages resulting from a previous BREAKDOWN.

Remedial Operations Rate is equal to:

- For the first 12 hours Base Rate T
- Between 12 and 24 hours Ninety percent (90%) of Base Rate T
- After 24 hours Eighty percent (80%) of Base Rate T

The time considered shall be from the beginning of the relevant remedial operations on the damaged well, until the said well is in same condition and at the same corresponding depth as it was before BREAKDOWN.

In case of BREAKDOWN during such remedial operations, the BREAKDOWN rate as per a) shall prevail.

Such provisions shall apply to each occurrence.

- c) Notwithstanding the above, should the events considered under BREAKDOWN and remedial operations here above be caused by CONTRACTOR GROUP's act omission or negligence, no remuneration shall apply for a maximum period of fifteen (15) days from the commencement of relevant remedial operations. Should remedial operations not be completed within such maximum period, Remedial Operations Rate shall apply beyond fifteen (15) days from the commencement of remedial operations, until the well is in same condition and at the same depth as it was before corresponding BREAKDOWN.
- d) During periods on Rate zero exceeding fourteen (14) days continuously, COMPANY may, at its sole option and without assuming any liabilities for such, either elect to discontinue the provision of certain services and supplies actually provided by COMPANY to CONTRACTOR, or notify CONTRACTOR that such services and supplies shall be at CONTRACTOR's cost if CONTRACTOR wishes them to be continued.

STOP FOR PREVENTIVE MAINTENANCE Rate:

STOP FOR PREVENTIVE MAINTENANCE Rate shall apply for all STOP FOR PREVENTIVE MAINTENANCE periods. STOP FOR PREVENTIVE MAINTENANCE Rate is:

- For the first 12 hours Base Rate T
- After 12 hours Rate Zero

Such provisions shall apply to the cumulative period of STOP FOR PREVENTIVE MAINTENANCE for one or several occurrences during any calendar month.

Maximum cumulative duration of STOP FOR PREVENTIVE MAINTENANCE shall be 12 hours.

List of preventive maintenance tasks preventing the performance of SERVICES taken into account for STOP FOR PREVENTIVE MAINTENANCE shall include, but not be limited to:

- Slipping of drilling line
- Cutting of drilling line
- Greasing of Top drive
- Inspection of Top drive
- Inspection of Drawwork” (3)

5.2. Answer to the tender - Company A:

5.2.1. Background:

Company A offers with their tender documents three Jack-up rigs: two MSC CJ-70 jack-up rigs, and one N-Class jack-up rig. From now on called – Rig A1, A2 and A3.

Where rig A1 and rig A2 have the same basis as two jack-up rigs that Company A build in 2003 and 2004, but with some modifications.

Rig A1 are finished 15.12.2013 and will need 2 months with mobilization and 2 months with start-up, and will be ready for drilling operations in the North Sea from mid of April 2014.

Company A makes also possibility for delivering the Rig A2, but this rig will be ready for drilling in November 2014.

Company A base their construction contract on a Turn-Key basis.

5.2.2. Incentives:

Company A made an incentive scheme which they called Performance based compensation Structure (PBCS).

The scheme are based on a 10% reduced base rate T.

Bonus only to the extent that the pre-agreed target is met, and only applied whenever the work scope for the rig allows.

No bonus is payable if the target duration is exceed, irrespective of who may be at fault.

If nature of the work scope occurs – the PBCS is not applied.

Mechanics should be simple, targets realistic – and bonus achievable.

Company A understands that the time spent during the operations are actual cost of the well, and wants to focus on co-operation with TEPN, Company A and the 3th. party service contractors.

This incentive scheme has been used earlier, and Company A has learned from PBCS that it is important on influence of third party.

Company A also welcomes other incentive structures, with a reduced base rate T plus a pre-agreed lumpsum for a well as an alternative.

TEPN and Company A will during the negotiation process, establish and agree on the principals for the PBCS, and then after having drilled the first well on Hild, the parties shall meet again and agree on the overall targets for each of the welltypes.

HSEQ is not a part of the PBCS, but a separate HSEQ bonus arranged with the crew participation can be introduced.

Both through this invitation of an incentive scheme in the drilling contract, and through meetings with TEPN and Company A has been very positive to an incentive scheme, - and are open for new proposals in this regard.

5.3. Answer to the tender - Company B:

5.3.1. Background:

Company B offers a new build MSC CJ-70 Jack-up rig that is going to be ready for drilling-operations in the third quarter 2014.

Company B have just constructed a similar rig, but this one will have better performance start, better training for the crew and it's easier to get hands on extra parts.

The new MSC CJ-70 Jack-up rig will be one of the largest Jack-up rigs in the world, and will be more efficient, larger deck capacity and reach out to higher waterdepths.

The rig will also decrease connection time, and it is drilling 15-20% faster than other Jack-up models.

It will have 2500 m² deck capacity and will weight 12.000 metric tons.

Company B offers a 2 year x 1 opson, and wants to increase the standby rate from 90% to 98%.

They also want to be pay in both USD and NOK.

Where the capital elements are pay in USD and the operating elements are pay in NOK.

Company B also wants to double the allowance of breakdown-time in the contract, and that the unused allowance from one month shall be transferred to the next month.

The offer is to have a higher sum at completion if they finish before time, then they want a 0,75 x Base Rate T for the existing time of the contract.

This bid and the quoted rates are subject to a 4, 5 or 6 years fixed contract duration.

5.3.2. Incentives:

Company B answered that they are positive to an incentive scheme. They suggest an incentive scheme is discussed further at a later stage.

Company B was interested in an incentive scheme on top of the ordinary base rate T. And they wanted to have an extra bonus without any term of penalty in the event of poor drilling beyond the conditions already covered by the contract.

5.4. Answer to the tender - Company C1 & Company C2:

5.4.1. Background:

This is a joint venture between Company C1 and Company C2, where Company C1 have the capital element and Company C2 is responsible for the operating element of the contract.

Company C1 & Company C2 offers a new build MSC CJ70 – 150 MC Jack-up. The rig will be operational from second quarter in 2014, or there is a second opportunity, - where the same rig are built and will be operational from Q2-Q3 in 2014, and then provided at lower day rate for Total.

Alternative Solution:

As an alternative proposal to the three scenarios provided with respect to contract duration, rates have also been proposed applicable for the fourth alternative contract duration which implies a fixed contract period of 6 (six) years.

5.4.1.1. “Hell or High Water”:

There is an other alternative that Company C1 & Company C2 offers, this is called “Hell or High water”, where all extra savings will be transferred back to Total, and shared with Company C1.

This is claimed by the Tenderer to give 30-40% lower day rate for the Jack-up, - around 2 Million USD lower cost/year.

The exit options for Total are:

- a) During the first five year execute a sale, where the price = remaining dept + 50 Million USD that are transferred to Company C1.
- b) Sublease without any change in the dayrate from Company C1 or its non SPV.

5.4.2. Incentives:

It is company's intent to establish a performance Incentive Scheme with the successful contractor.

Based on this, our proposal of an incentive scheme for operations undertaken during the Hild Development campaign will be:

Proposal:

Tenderer would propose that performance is measured against a set of Key Performance Indicators (KPIs) and that its performance against these KPIs is linked to the achievement of a Performance Based Dayrate mechanism (PBDR) which is calculated on a monthly basis.

The following proposal is presented for consideration by TEPN, the basis of which has already been successfully implemented with another client.

The maximum performance based dayrate (PBDR) available shall be XXX²².

The PBDR shall be applicable at all times except when the Force Majeure rate applies.

Index type	Condition / month	Res. Index	Less than 3 applicable operations / month
NPT	Rig NPT < 4% or 4%	0,35	0,5
	Rig NPT > 4%	0	0
Recordable incidents	No rec. incident	0,2	0,3
	One or more	0	0
PMF	Total PMF-points < 150	0,15	0,2
	Total PMF-points > 150	0	0
Operating Index	See note below	0,30	0
	TOTAL	1,00	1,00

Table 7: The PBDR table for Company C1 & C2

²² The price is undisclosed because of the confidentiality.

Calculation of Operation Index:

The Operation Index shall apply to each of the applicable operations performed during the reporting month. (“applicable operations”)

The time or rate for applicable operations shall be measured during the month against the set performance standards as detailed below:

- Drill Pipe Tripping, Gross Running Speed (unrestricted, in cased hole) shall average 20 stands or better per hour over the duration of the reporting month.
- Casing/Liner/Screen Gross Running (unrestricted, in cased hole) shall average 10 joints per hour or better per Applicable Operation performed during the reporting month.
- Drilling, Weight to Weight Time (W2W) average (min): 14 min.
- Drilling, Net ROP pr stand, average (m/hr): 20 m/hr. Individual section KPI to be agreed with Client.
- BOP Nipple Up shall average 10 hours or better per Applicable Operation performed during the reporting month.
- BOP pressure test time shall average 10 hours or better per Applicable Operation for the month.
- BOP Nipple Down shall average 6 hours or better Applicable Operation performed during the reporting month.

For clarity, the performance of each applicable operation shall be measured on an individual operation basis. For example if two separate strings are run during the month, this shall count as two applicable operations. (Rather than the average of the two runs being used to decide whether the metric has been achieved.) However for Tripping Operations, the metric shall be calculated on the average performance achieved over the whole of the reporting month.

In relations to the performance of those operations listed above, should TEPN Due to operational purpose or well conditions instruct the drilling contractor that the performance of the work be slowed or altered from contractor’s normal operating practice for such an operation, then the instance of the operations affected by this instruction shall not be considered an applicable operation and hence shall be excluded from monthly calculation of the Operation Incentive.

For clarity only casing running and BOP operations that have been concluded in the month shall be included for consideration; operations started prior to month end and continuing into the next month shall be considered as being applicable for next month's calculation.

Tripping times shall be calculated on the total time over the given month.

The Operational Index is given by the number of applicable operations where the target rate has been achieved, divided by the total number of applicable operations conducted.

However, if less than three applicable operations are performed during the month then the performance against the operational metrics shall not be considered in the calculation of the total PBDR payable.

In this case, the formula for calculating the total PBDR payable shall be revised as follows:

Total PBDR PAYABLE = TOTAL AVAILABLE BONUS x [NPT INDEX + Recordable Incident Index + PMF Index]

Formula 2: Company C's formula for calculation of "total PBDR payable"

Method of Capturing Data & Reporting:

The statics that are entered into the Operational Index Calculation on a monthly basis shall be gathered on the agreed Monthly Approval Sheet by the contractors Rig Manager (or nominated deputy) "in country", and reviewed with the agreed with the TEPN Drilling Superintendent (or nominated deputy). Copies shall be sent by e-mail to the Respective Company and contractors representatives.

In the event of a dispute over the figures which cannot be resolved, the matter will be referred to the TEPN and contractors representatives for resolution, and if a solution still cannot be reached it shall become subject to the provision of Clause 37 – Resolution of Disputes thereafter.

Definitions:

The following definitions shall apply:

- Applicable operations: shall mean a period during which one or more of the items described above occurs.
- NPT: shall mean “Non productive time” – a period during which the Drilling Rig is capable of conducting normal operations but is idle due to the unavailability of equipment and/or personnel.
- PBDR: shall have the meaning ascribed to it above.
- PMF: shall mean Potential Matrix Factor.

5.5. Answer to the tender - Company D:

5.5.1. Background:

Company D offers two Jack-up rigs of which the first one is a Company D N-Class – a Super B Class Jack-up drilling unit that is a HPHT drilling rig with 568” legs.

The second one is a Super Gorilla Class VI with 607” legs.

Both of the Jack-up rigs must be modified before being operational for drilling at the Hild field.

5.5.2. Incentives:

Company D has not included an incentive scheme for this contract, and though that there was enough incentives in the general contract, with respect to stand-by, reduced performance breakdown rate, etc.

6. Proposal for an incentive scheme for Company A:

Background information:

There is first going to be drilled 10 wells at the Hild field, where the following wells are:

- 5 Brent gas wells
- 4 Frigg oil wells
- 1 water injection well

Where the 5 Brent gas wells are quite alike, and the 4 Frigg oil wells and the one injection well is very alike.

Generally about the incentive scheme:

As Company A proposed in the Tender documents, they were open for an 10% reduction of the Base rate T, in order to make an incentive scheme that can gain both Total E&P Norge and Company A.

The incentive scheme is going to be divided into to separate parts, - one incentive around the drilling, and one incentive around the HSE.

HSE specifications around the incentive scheme:

If the drilling crew members have a low injury status every third month, there will be given a bonus to the crew's welfare case.

If there are one or more serious injuries in this period, there will not be given any bonus to the welfare case that time.

The crew must also send in Stop Cards to Company A about actions taken to secure and lift the HSE aboard the drilling rig.

The best Stop Card every month will be given a reward.

Technical specifications around the incentive scheme:

The drilling incentive is divided into two parts:

- When Company A is in charge of the drilling operations – from now called “unrestricted operations”:

This is the part where Company A is in charge of the drilling operation. There will be drilled a “pilot/reference well” for the first gas and the first oil well, that is used as a reference for the rest of the wells.

The data gathered from this reference wells will be used to calculate the incentive payment, with focus on:

- Drilling time and quality in the unrestricted drilling sections
 - Tripping time
 - BOP-testing time
 - Connection time
 - Slip & cut time
 - Quality on the drilling in the unrestricted sections.
- When TEPN is in charge of the drilling operations – from now called “restricted operations”:

TEPN is going to have control of 70% of the drilling, especially in the complex zones closer to the drilling target.

Then Company A will be rewarded after following references:

- BOP-testing time
- Connection time
- Slip & cut drill-line

Other:

Learning: Company A will be given a bonus if they can hold a low – normal NPT during the first month after the mobilization of the drilling rig. This could be attained if Company A have a clear goal about having excellent training and courses for the crew that is going to work at the drilling rig.

Slop: If Company A provide the drilling rig with equipment that can handle and clean larger amount of slop generated under the drilling operations, - Company A will be given a bonus for this service.

Reporting:

The data from the HSE under the drilling operations is gathered by Company A.

The data from the drilling operations will be gathered by TEPN using the electronically live drilling system.

The data for the HSE is gathered by Company A, and, there must be set requirement for a minimum number of observation delivered each month.

The data will be analyzed and prepared by TEPN, and be approved both by the representative for Company A and TEPN repentant for the Hild Field drilling operations.

Renegotiation:

After the first reference wells for the first gas and oil well, the input data for the incentive scheme is discussed in order to find a correct reference point to be used for the rest of the wells.

Payment:

The bonus for the drilling and the HSE incentive is payable per month.

Where the HSE bonus is paid directly to the crew members welfare case.

Stop of the incentive scheme:

If one of the parties disagree to the incentive scheme, the incentive scheme will stop after the reporting month.

7. Discussion:

Incentive scheme:

By introducing an incentive scheme for the drilling contractors that is going to drill at the Hild field development for TEPN and the partners at the Hild license, the main goal is to get a more efficient drilling operation, saving both drilling expenditure and time.

With an incentive scheme included in the contract to the drilling contractor, it is more possible that the operators and the drilling contractor may have more common goals, than without this scheme.

Then the drilling contractor have mainly the same focus as the operator on decreasing time and expenditure, with drilling efficiency and have control of operating expenses.

By forming an incentive scheme, where the contractor can gain extra bonus by good performance, and by losing a part of their base rate T, if they don't perform as planned.

Indirect incentive in the contract:

As drilling performance improves, the emphasis is changing from dayrate to value for money, which benefits both contractor and operator through the minimization of non productive time. Since the interrupted time caused by either contractor, operator or third parties will result in considerable loss of time and money.

There are many indirect incentives in the general contract for the drilling contractor, not only the extra incentive scheme:

The base rate T can be reduced if the rig has to be at stand-by, has downtime, when occurrence of force majeure and when the rig has reduced performance.

The indirect incentives in the contract have large consequences for the drilling companies, since they reduce the base rate T, which represents a significant reduction of income.

Some of the incentives aren't in the drilling contractors influence of sphere, - like force majeure (30% reduction) and stand-by rate (10% reduction). But the other moments are in the contractor's sphere of influence, with reduced performance rate (20% reduction), - which the contractor can handle with having a low NPT with few remedial operations.

These indirect incentives provide the drilling contractor to have focus to have their drilling unit with the highest possible uptime during the contract duration.

The target and drilling parameters tied to an incentive scheme:

By giving measurable targets and drilling parameters to the drilling contractors, which are both measurable for both parties and in the contractor's sphere of control and influence, are important elements in an incentive scheme that are based on performance based mechanism.

Through this thesis with making a suitable incentive scheme for a drilling contractor operating at the Hild field, it was important to decreasing key elements and parameters that would increase the efficiency of drilling operations, without exceed the quality and the safety aboard the rig during these operations.

The incentive scheme has been devided into three parts, where one part was about the technical specifications during drilling, the second part about the HSE and the third part about the miscellaneous elements as learning factor aboard the rig and slop generation.

It was easier to secure and divide the elements such that will not lead to under-reporting of injuries and accident, compared to if the HSE and the technical incentive were tied together as one common incentive.

The technical parameters was divided into to different parts, one called unrestricted operations, where the drilling contractor has the control of the drilling operation, where there are parameters they are measured after, which are both measurable, observable and easy to improve. The second part of the technical parameters is when TEPN are in charge of the drilling operations – which are called restricted operations. Here are the more important to drill more carefully since these zones are quite complex and risky. The drilling contractor can under such operation focus on some elements and parameters where they must have a high efficiency.

By reducing these parameters both under unrestricted and restricted drilling operations, the rig can save a large number of days of drilling throughout the contract duration.

Learning factor:

Starting rigs, and new built drilling rigs up are time consuming, and can be slow and unproductive if the training of personnel is not properly managed. By having focus on both informal and formal processes can lead to good advantage in order to maximize the HSE and efficiency aboard the rig.

Good planning is a key aspect in drilling operations, and it's essential that the contractor has devoted enough time and manpower to this initial phase. This could be done by maximizing the teamwork through alliances and partnership through incentives and cooperation, matching well plans to optimize the mix of technology and equipment to maximize the return from the learning curve. The purpose of this is for the contractor to recognize the drilling risks and hazards which are likely to be encountered so that the most appropriate solution is determined for each drilling operation – so the drilling contractor can make recommendations for more efficient rig procedures, and discuss them with TEPN.

If the drilling company uses good time to learn up their employees on the drilling rig that's are going to be used for the Hild drilling operations, - there is less probability for NPT and accidents the first essential months of the drilling operations. By having high-quality training, the drilling company can have a low NPT, and be exposed to a reduction in dayrate because of a high NPT in the starting month.

For TEPN the low NPT under the vital start-up time can secure that the drilling operations goes as planned, and without uncertainty for the further drilling operations.

Slop generation:

If the contractor are willing to collaborate in reducing the amount of slop that is generated under the drilling operations, there will be large cut in the expenditures for TEPN, as this will have to be transported to shore and undergo special treatment.

By having better equipment aboard the drilling rig that can handle and clean considerable more slop, and thereby re-inject the slop back into the reservoir, the volume of slop can be reduced with 50% from 1460 m³ to 730 m³. In terms of cost, this will mean a reduction around 1 Million NOK just in slop generation since the price on slop cleaning onshore is 1600 NOK/m³. Meanwhile there is a indirect cost attach to this cost, if the volume of slop is not cleansed, the slop must be transported by vessels back onshore. By reducing the volume of slop, the number of vessels required for the drilling operations at the Hild field will also be reduced.

By including this aspect in the incentive scheme, there is a win-win situation for both parties, that the contractor gets a amount of money for cleaning the slop offshore, meanwhile TEPN can reduce the cost for vessels for transporting the slop back onshore.

Different contract forms and incentive schemes:

There are different forms of incentives in a drilling contract, either:

- A contract with only “basic” incentives
- A contract with the “basic” incentives and in addition an extra incentive scheme with reduced day rate.
- A contract with “basic” incentives and in addition an extra incentive scheme without any reduced day rate.

The evaluation of the efficiency to the drilling rigs:

TEPN has used a ranking system with focus on efficiency for calculating and estimating the total cost for using the different drilling rig at the Hild Field.

By applying this evaluation, the ranking system provides more correct information about which drilling rig which is most cost-efficient for the Hild Field.

The rig types are compared to each other, where the rig floor efficiency for the rig is calculated up to the time the rig uses for drilling the 10 wells at the Hild Field.

After this calculation, it is easier to identify which rig that uses less time compared to the others, and find out the total cost for using these rigs for the Hild drilling contract by adding the day rate into the equation.

The old rig types have a lower day rate compared to the new rig types, but are less efficient compared to the new rig types like CJ-70.

For such drilling operation like the Hild Field, this evaluation has concluded that the new rig types like CJ-70 are around 10% more efficient than the N-Class, and RG-VI.

The lack of drilling efficiency has a cost difference from the cheapest, to the most costly drilling rig– there is a total difference in real cost of 1051 millions NOK from the CJ-70 to the N-Class during this contract period.

Joint Venture:

As mentioned earlier in this thesis, Company C invited TEPN to a joint venture for the drilling contract, that they called “Hell or High Water” – see chapter 4.4.1.1.

This kind of proposal is quite new in drilling contract-terms, such contracts have been made earlier in the shipping industry, - where the cost of constructing the boat has been divided between the shipping company and the operator. Such risk sharing will reduce this divides the risk for both parties, especially in the shipping business, where conjectures for building ships, and getting contracts are very fluctuation.

Company C introduced such a joint venture for TEPN and their partners for a drilling rig operating on the Hild field. By joining in this joint venture, the tenderer claimed that TEPN and their partners could have a 30-40% lower dayrate for the jack-up rig, around 2 Million USD in lower cost each year.

The agreement provides for all savings to be transferred to TEPN, and then shared with Company C1. This gives Company C1 more equity capital, and gives them a lower interest at on the loan provided by DNB Nor – which results in a lower dayrate for TEPN. For Company C1, such a joint venture, will give them a part of the extra savings, and also security for having a rig that would be faster paid down.

Based on the results of the 1st stage evaluation of Company C’s offer, TEPN decided to not put Company C on the shortlist, one of the reasons being that, there are much risk tied to this involvement. Compared to and the shipping industry, there are much more uncertainty and risk tied to drilling operations.

8. Conclusion:

By adding an incentive scheme into the drilling contract there is a better adaption for increasing the co-operation between the operator and the contractor during the drilling operations.

An incentive makes a mechanism that provides the two parties a common goal to be efficient during the drilling operations, and collaborate during these operations. It will also enable the operator and their partners to reduce in the drilling expenses and more likely be able to complete the drilling operations at, or before, the scheduled time.

Oil companies will probably move away from standard dayrates to incentive contracts as the merits of this form of contracts gain recognition and acceptance. Oil companies may find advantages like, - a more motivated and efficient drilling crew, renewed team spirit and better co-operation between contractor and the operator both on- and offshore. In addition the oil companies will get new input from the drilling contactors experience, not only from the current drilling operations, but also from earlier operations conducted by the drilling company has.

9. Attachment 1: Rig performance

Phase	Operation	Comment	Measure	Rig NAME	COMMENTS
Casing Operations	Running 20"	Unrestricted	joints/hr		
	Running 13 3/8"	Unrestricted	joints/hr		
	Running 9 5/8"	Unrestricted	joints/hr		
	Running 5 1/2"	Unrestricted	joints/hr		
Tripping	Rig up to run casing		hrs		
	Connection time		mins		
	DP	Unrestricted	joints/hr		
	Connection time		mins		
BOP Operations	Pick up singles		joints/hr		
	Lay out singles		joints/hr		
	BHA Handling	Collars/HWDP/Jars	joints/hr		
	Nipple up		hrs		
Wireline operations	Testing		hrs		
	Nipple down		hrs		
	Rig up to run		hrs		
	Rig down		hrs		
Coiled Tubing operations	Rig up to run		hrs		
	Rig down		hrs		
Cementing operations	Rig up cement head		hrs		
	Rig down		hrs		
Others	Slip & Cut drill line		hrs		
	Slip & Cut drill line		hrs		
	Slop generation		frequency		
	Skidding time	Slot to slot	m ³ /day		
	Fuel consumption		hrs		
	NPT		m ³ /day		
			%		

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