**FACULTY OF SCIENCE AND TECHNOLOGY**

# MASTER THESIS

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Contract strategy and comprehensive drilling unit tender evaluation model for the development of a mature field

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## Forewords

This thesis is split into two parts: Part I covers basic contracting theory and competitive tendering principles, Part II applies the theoretical elements from Part I to construct a comprehensive evaluation model for a drilling unit tender. The evaluation model has been constructed based on a fictive mature field development on the Norwegian continental shelf. Fictive tender responses and bids were used to illustrate the concept. The evaluation model is fully configurable and scalable to cover several different scenarios as required by the operator. Use of external sources are highlighted mainly in Part I since Part II is based on several years of accumulated experience and exposures to drilling unit tenders. Despite rigorous searches on this specific topic very few sources and references were found, which suggests that the topic covered is highly specialized and tailored for well engineering and contract department of oil companies. However, the main principles behind the model can also be expanded or modified to cover any tender exercises where the quality elements and value drivers are defined.

Thanks to Tone Bruvoll for getting me started in the right direction and sharing thoughts and suggestions on how to build the thesis.

## Abstract

The selection of a drilling unit in a tender process has a significant impact on the total costs for a field development project. This impact affects both commercial, technical, and non-technical aspects that goes beyond the daily operating rate, which in some cases is the main element considered in the evaluation process. Using the principles of economically most advantageous tender concept a comprehensive evaluation model has been built to cover the many different elements and dimensions that form part of the overall drilling unit selection based on scope, objectives, and value drivers for the project. When applying the model on a fictive field development and tender process the model suggests differences in costs of close to 20% less when compared with a less sophisticated conventional lowest tender methodology.

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# ABBREVIATIONS

| | |
|---|---|
| **ABC** | Anti-bribery and corruption |
| **AoC** | Acknowledgement of compliance |
| **BHA** | Bottomhole assembly |
| **BOP** | Blowout preventer |
| **CML** | controlled mud level |
| **D&W** | Drilling and wells |
| **EMAT** | Economically most advantageous tender |
| **ERD** | Extended reach drilling |
| **FPSO** | Floating production storage and offloading |
| **KPI** | Key performance indicator |
| **LS** | Lump sum |
| **LT** | Lowest tender |
| **LWD** | Logging while drilling |
| **MODU** | Mobile offshore drilling unit |
| **MPD** | Managed pressure drilling |
| **MR** | Moving rate |
| **MTFR** | Minimum technical and functional requirements |

| | |
|---|---|
| **MWD** | Measurement while drilling |
| **NCS** | Norwegian continental shelf |
| **NPV** | Net present value |
| **OEM** | Original equipment manufacturer |
| **OR** | Operating rate |
| **RER** | Reduced efficiency rate |
| **RMR** | Riserless mud recovery |
| **ROV** | Remote operated vehicle |
| **SCS** | Solids control system |
| **SPS** | Special periodic survey |
| **SR** | Standby rate |
| **SUT** | Samsvarsuttalelse |
| **TCO** | Total cost of ownership |
| **VDL** | Variable deck load |
| **XO** | Crossover |

# PART I - CONTRACT STRATEGY THEORY

# 1 BACKGROUND

## 1.1 Importance of contract strategy

Contracts set out the terms and conditions of the project, including the scope, budget, schedule, quality requirements, and risk allocation. A well-developed contract strategy ensures that the project is executed effectively, efficiently, and with minimum risk (Nwajei, 2021). The most important elements to consider for contract strategy include:

- Scope and objectives to be clearly defined and reflected in the contracts.
- Risk allocation to the parties best able to manage them.
- Remuneration mechanism and payment terms to be established, including the payment schedule, payment method, and payment milestones.
- Quality requirements to be defined and implementation for quality control measures agreed.
- Procurement strategy that identifies the most suitable procurement methods, such as competitive bidding, sole sourcing, or negotiation.

## 1.2 The tendering process

The main principles of the tendering process are described in Brief 9 of Sigma (a joint initiative of the OECD and the EU). The evaluation of tenders is the stage in the procurement process during which a contracting authority identifies which one of the tenders meeting the set requirements is the best based on the pre-announced award criteria. In some lines of business, the winner is the lowest-priced bid.

The evaluation of tenders must be carried out by a suitably competent evaluation panel and in accordance with principles of equal treatment, non-discrimination, and transparency. The confidentiality of the information acquired by those involved in the evaluation process must be preserved. Some of the key governing principles of the tender evaluation process:

- Non-discrimination: This principle means that any discrimination regarding tenderers based on nationality is forbidden and tenderers from other member states must not be discriminated against in favor of domestic tenderers.
- Equal treatment: This general law principle means that all tenders submitted within the set deadline are to be treated equally. They must be evaluated based on the same terms, conditions and requirements set in the tender documents and by applying the same pre-announced award criteria.
- Transparency: This general law principle means that detailed written records must be kept (normally in the form of reports and minutes of the meetings held) of all actions of the evaluation panel. All decisions taken must be sufficiently justified and documented. In this way, any discriminatory behavior can be prevented and if not prevented, then monitored.
- Confidentiality – Apart from any public tender opening, the process of evaluation of tenders must be conducted in camera and must be confidential. During the process of evaluation, the tenders should remain in the premises of the contracting authority and should be kept in a safe place under lock and key when not under review by the evaluation panel. This safeguard is recommended to avoid any leaking of information. Information concerning the process of evaluation of tenders and the award recommendation is not to be disclosed to the tenderers or to any other person who is not officially concerned with the process, until information on the award of the contract is communicated to all tenderers.

## 1.3 Main steps of the tendering process

An integral part of project initiation is definition of the value proposition and key value drivers for the project. The essence of this is to answer the elementary questions: why are we doing this project and what does success look like? (Hill, 2009)

After project initiation follows the contracting and tendering strategy, which involves identification of what contracts are required and the main fundamental guiding principles that steer the tendering- and evaluation process for all disciplines and stakeholders involved. Some key considerations like use of integrated contracts and / or forming wider strategic partnerships will be outlined in the strategy document (op. cit.).

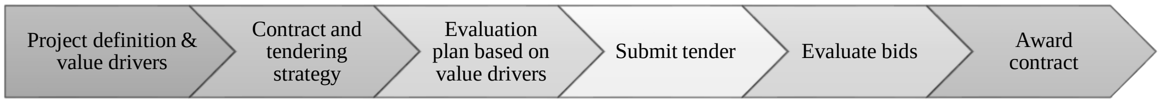



*Figure 1 Main steps of the tendering process*

Before any invitations to tender are submitted, the evaluation plan should be defined and agreed in line with the guiding principles in the strategy document. Any changes to the evaluation criteria should be thoroughly documented and justified in line with the main principles related to transparency and equal treatment outlined in section 1.2.

## 1.4 Integrated contracts and strategic partnerships / alliances

Individual contracts and integrated contracts both have pros and cons. Individual contracts provide greater flexibility and allow for more specific control over each aspect of the project. However, managing multiple contracts can be time-consuming and can result in increased administrative costs. Integrated contracts cover multiple segments of the project and promote collaboration between the parties involved, which can lead to more efficient and effective project delivery. However, integrated contracts can be complex and require a higher level of coordination and cooperation among the parties involved (Lonngren, Rosenkranz, & Kolbe, 2010).

Strategic partnerships and alliances between companies are another approach to project execution. A strategic partnership involves two or more companies working together to achieve a common goal. This approach can be beneficial when the project requires a high level of technical expertise or when the partners have complementary skills. Strategic partnerships and alliances can provide a range of benefits, including access to new markets, increased resources, and reduced costs. However, they require careful planning and management to ensure that the parties involved share the same goals and objectives (op. cit.).

In strategic partnerships between two companies the concept of relational contract theory should also be considered. Relational contract theory predicts that as a relationship evolves over time, the establishment of relational norms will be imposed on the relationship. These relational norms can function as a supportive safeguarding arrangement that harmonizes conflicts, solves strategic dependence, specifies acceptable limits on behavior and should serve as a protective device against opportunistic behavior (Buvik, 2002). Relational contract theory is based on a recognized need for adapting relationships to changing circumstances.

Additionally, empirical research has shown bilateral governance to be highly efficient when dealing with certain forms of uncertainty (Heide, 1994).

# 2 COMPETITIVE TENDERING

## 2.1 Economically most advantageous tender concept

In public procurement the EU, lowest price is used less frequently and instead supplier selection methods that combine price and quality into a total score, also known as the economically most advantageous tender (EMAT), are used more often (Verdeaux, 2003). The use of EMAT normally requires the specification of a scoring rule system. An ongoing trend has also been the transformation of EU procurement rules from framework rules that gave the member states significant discretion to codify the national procurement rules into a system of common rules (Arrowsmith, 2006). As an example, the previous procurement rules made it possible to arrange a tender after the bids had been received, and then choose between giving the contract to the bidder offering the lowest price or to the economically most advantageous tender. The old directives were also in other respects less strict in requiring that the supplier selection methods and, when applied, the scoring rule to be precisely specified in advance (op. cit.).

Using both price and quality in supplier selection can enhance the efficiency of procurement, although it adds complexity to the procedure and the supplier selection methodologies and more specifically the scoring rules that are used in practice are often poorly designed.

The EMAT can be the bid with the highest quality for a given price. It can also be the bid that achieves the highest combined price and quality score. If this approach is used, price(s) and one or more quality measures will have to be combined into a single measure. Either a) quality (differences) must be evaluated in monetary terms or b) price must be transformed into a score that is commensurate with the quality score.

Using method a), also known as ‘quality-to-price scoring’, quality value in excess of the minimum requirement can be subtracted from the price bid or, alternatively, the value of the quality gap relative to the maximum quality level can be added to the price bid. I.e., the supplier selection method will be quality adjusted lowest price.

Using method b), also known as ‘price-to-quality scoring’, price must be transformed into a score that is added to the quality score, making the tender a price adjusted highest-quality tender (Bergman & Lundberg, 2013).

Lowest-price tender evaluation is in principle straight-forward, while in practice it may be challenging to define effective and appropriate minimum quality requirements, as well as to weigh multiple prices into a single cost measure. Quality-only tender can be more complicated. If quality is measured in more than one dimension, the quality measures will have to be combined (weighed) into a single overall score, but, unlike prices, they cannot simply be added together.

The focus of this thesis is related problem of combining and weighing multiple elements and dimensions for a drilling unit tender into a single overall score, using a combination of both the quality-to-price and price-to-quality scoring methodology.

## 2.2 Competitive bidding in EMAT

Most open tendering procedures in the real world are highly complex, uncertain, and costly. With an increasing emphasis on the quality and value of procurement, EMAT has been widely adopted as an alternative contract-awarding criteria, which has changed competitive strategies in the construction industry. Most bidding models have been developed and recommended for use in lowest tender (LT) in the construction industry (Perng, Juan, & Chien, 2006). A great number of bidding factors affecting the bid decision and the markup in LT by using various methods (Ahmad & Minkarah, 1988) which will also be relevant, or even more complex for EMAT bidding. In response to this, a conceptual model of competitive bidding in EMAT was established by Perng, Juan and Chien to reflect the credibility of the bidding situation. Several quality-related evaluation criteria were established and weighed against project requirements and strategic requirements and value drivers. To test the concept a bidding game was performed by several participants to partially test the conceptual model. In addition to traditional cost competition in LT, quality, contractors' previous experiences, schedules, commercial terms, and other relevant points were considered in bid proposal evaluations. The game helped players to formulate a structured approach for delivering a tender and improve their competitive advantage. The result of the game also shows that competitive strategies in EMAT should contain the cultivation of bidding experience, emphasis on company's position and investment in medium- and long-term performance enhancements to reform the company's constitution, as well as the effective adaptation of differentiation strategies for assessing the score, profit, and cost (op. cit.).

# 3 PROJECT VALUE DRIVERS IN CONTRACTING STRATEGY

## 3.1 General

There are different value drivers that should be evaluated as part of project initiation depending on the nature of the project. These value drivers form the foundation for many of the major decisions needed and are of key importance to ensure correct prioritizations and decisions are made throughout the project life cycle.

The main value drivers for a project are **cost**, **schedule**, and **quality**. These elements are interconnected, and their effective management is essential for project success.

## 3.2 Cost

### *3.2.1 General description*

Cost refers to the amount of money required to complete the project. Managing the project cost involves estimating the project budget, tracking expenses, and controlling the project's spending. Cost management is essential as it helps to ensure that the project is completed within the available budget and avoids unnecessary expenditure. Effective cost management can also help to identify opportunities for cost savings and provide a competitive edge to the project.

### *3.2.2 Translation into D&W examples*

Most costs of drilling and well operations are related to time-dependent elements like drilling unit day rate, daily rental costs for tools and equipment, logistics costs (supply vessels and helicopters) and various overheads and organizational costs. By reducing the duration of an operation, the total costs are reduced almost linearly by an equivalent portion. Alternatively, the use of drilling unit and/or drilling services with lower daily rates may reduce costs for non-complex projects where lower quality and/or prolonged duration does not negatively affect the projects objectives.

## 3.3 Schedule

### *3.3.1 General description*

Schedule refers to the timeframe for completing the project activities. It involves the identification of the critical path, the duration of the activities, and the sequencing of the tasks.

Effective scheduling ensures that the project is completed on time, within the expected timeframe, and without delays. Project managers need to ensure that the project is properly resourced and that there is adequate contingency planning to address any unforeseen schedule deviations.

#### *3.3.2 Translation into D&W examples*

The drilling & wells scope may only be a small portion of the overall project scope; however, it is still important that the arrival of the drilling unit and availability of long lead items coincide with all the other project activities for seamless execution. From project initiation to the point in time where the drilling operations can commence can be anything between 9 months and several years. This is a function of the project integrated project planning activities and lead times for materials and equipment required for well construction (for example: casing, subsea x-mas trees, etc.). Particularly when it comes to setting the contractual commencement window for the drilling unit, having a flexible window is a highly favorable element in the negotiations phase since it also maximizes the contractor’s ability to create a continuous sequence of work between different operators.

### 3.4 Quality

#### *3.4.1 General description*

Quality refers to the level of excellence or superiority of the project deliverables. A high level of quality can be achieved using proper planning, execution, and monitoring of the project activities. Quality is a critical value driver as it ensures that the project meets the desired outcome and provides customer satisfaction. Quality assurance and quality control measures are required to be implemented to maintain the project's quality standards.

#### *3.4.2 Translation into D&W examples*

In the front-end engineering and design phase, quality is related to the overall robustness and flexibility of the well architecture. The types, specifications and ratings of the selected casing influences the ability to deal with drilling problems or changes / evolution of the well design during the construction phase.

For complex trajectories, use of expensive tools is needed to drill the wellbore as per the planned trajectory.

If data for formation evaluation is a critical success factor for the project, then the most advanced and highest quality formation evaluation tools will be selected for the job.

## 3.5 Other value drivers to be considered case-by-case

The three value drivers described so far covers most D&W projects. Additional value drivers could be considered depending on the nature and objectives of the project. Some examples of other value drivers could be environment, safety, reputation / publicity, security, etc.

## 3.6 Ranking of value drivers

In summary, quality, schedule, and cost are the main value drivers for a project. These elements are interdependent, and their effective management is essential for project success. Project managers need to prioritize and balance these drivers to ensure that the project meets the desired outcome, is completed on time, and within the available budget.

To ensure consistency and to ensure overall project value is secured throughout the duration, a ranking of the value drivers must be performed. For example: if Quality is selected as the main value driver for the project, this typically comes with additional costs and /or additional time and will therefore be at the expense of Cost and Schedule. Similarly, if Costs is the main value driver, this means that a lower overall quality must be accepted as a compromise.

This ranking can be visually displayed in the value driver pyramid.

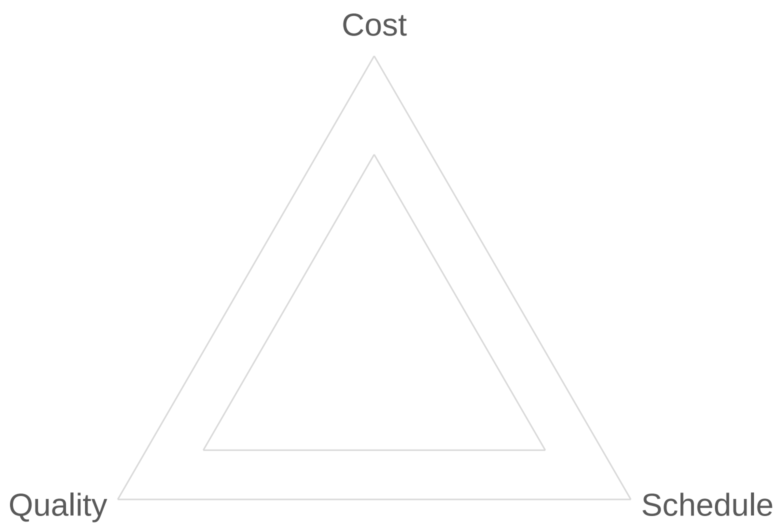
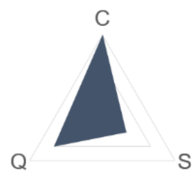
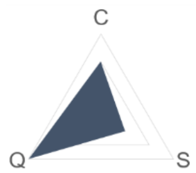
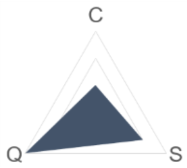
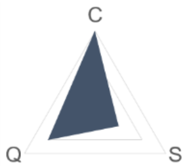



*Figure 2 Value driver pyramid*

Some examples to illustrate how the value drivers can differ between the nature of the project are described below:

*Table 1 Examples of ranked value drivers for projects with different scope and objectives*

| **Project type** | **Description** | **Ranking** | | | |
|---|---|---|---|---|---|
| | | **Cost** | **Schedule** | **Quality** | **Pyramid** |
| Exploration well | The main objective of an exploration well is to drill a well to confirm whether there are any hydrocarbons present and if so, get more information about the nature of the reservoir.<br>The probability of success for an exploration well is typically between 10% - 30%. Therefore, the main priority for the operator is to achieve the minimum objectives at the lowest Cost.<br>Due to subsurface uncertainties and requirement to gather critical formation evaluation data, Quality ranks second.<br>Unless the timing of the exploration well is interlinked with deliverables for other projects and/or budget constraints, Schedule is ranked last. | 1 | 3 | 2 |  |
| Appraisal well | Appraisal wells are drilled to check and confirm the extent and volumes after a successful exploration well. The well design is typically more sophisticated and robust to allow more flexibility for well testing and/or geological sidetrack operations.<br>There will also be a higher demand to more formation evaluation and/or coring operations to provide valuable input into the reservoir modelling which provides input into the overall economics of the field. In this case, Quality will be ranked as the most important value driver, followed by Costs and Schedule. | 2 | 3 | 1 |  |

| **Project type** | **Description** | **Ranking** | | | |
|---|---|---|---|---|---|
| | | **Cost** | **Schedule** | **Quality** | **Pyramid** |
| Complex field development | Complex field development will require a higher emphasis on Quality since these more robust and advanced solutions are critical to achieving the objectives and deliver the total value for the project. In the cases where early completion of the well results in early start of production of oil and/or gas then Schedule is the second most important value driver for the project, followed by Cost. | 3 | 2 | 1 |   |
| Plug and abandon | Plug and abandon campaign are obligated expenditures for the operator with no prospect of any income or revenue. The main driver is clearly to perform these operations and the lowest possible Cost. However, due to uncertainties and operational risks of re-entering old wells the Quality element cannot be disregarded as it can evolve and lead to significant trouble time, spills, or other uncontrolled release of substances to the environment. Apart from regulatory commitments and / or internal budget constraints, there is flexibility in the Schedule for when the activities need to be completed. | 1 | 3 | 2 |   |

# PART II – EXAMPLE CASE

# 1 THE LOKE DEVELOPMENT

## 1.1 Scope of work for this thesis

This thesis will focus on using the challenges, objectives, and value drivers for a fictive field development to produce a drilling unit contracting strategy and evaluation model for the Drilling & Wells aspects of the project at a very early stage of the planning phase.

Although interconnected, the link with- and evaluation of contracts for associated subsea infrastructure activities are out of scope for this thesis.

## 1.2 General information about Loke

In this thesis 'Loke' is a fictive field development is being planned by 'Autumn ASA', a fictive operator on the Norwegian continental shelf. The Loke development is in a mature area with the aim of draining pockets of hydrocarbon-bearing sands that, util now, has not been economically viable to drill and produce from. High sustained oil prices and tax incentives dating back to the COVID-19 pandemic has turned the Loke into a profitable development.

The hydrocarbons are stored in 'injectite' sands, which essentially is mobile sand that has been squeezed into large cracks and fissures of the overlying fractured shales. Once a wellbore has been accurately positioned inside the injectite, the permeability of the sands enables production of more hydrocarbons that are connected to the sand body.

Loke will be developed using subsea satellite templates that are connected back to subsea manifolds that collects and sends the flow of hydrocarbons back to the production facility – in this case it is a floating production, storage, and offloading (FPSO) vessel. In Phase I of the Loke development a total of 10 wells will be drilled, distributed across 5 subsea templates with 4 well slots per template. Phase II will follow within 2 years from completion of Phase I and add another 10 wells to the field.

The locations of the templates are determined by the anticipated presence of injectite sands based on seismic interpretation and historical field data and geological model. Furthermore, the templates should be positioned as much as possible at the mid-point between the various prospect sands so that as many sands as possible can be reached from the same template with the same total well depths and well designs. This ensure that the same equipment can be used and well designs and execution plans can be replicated for improved efficiency and learning curve.

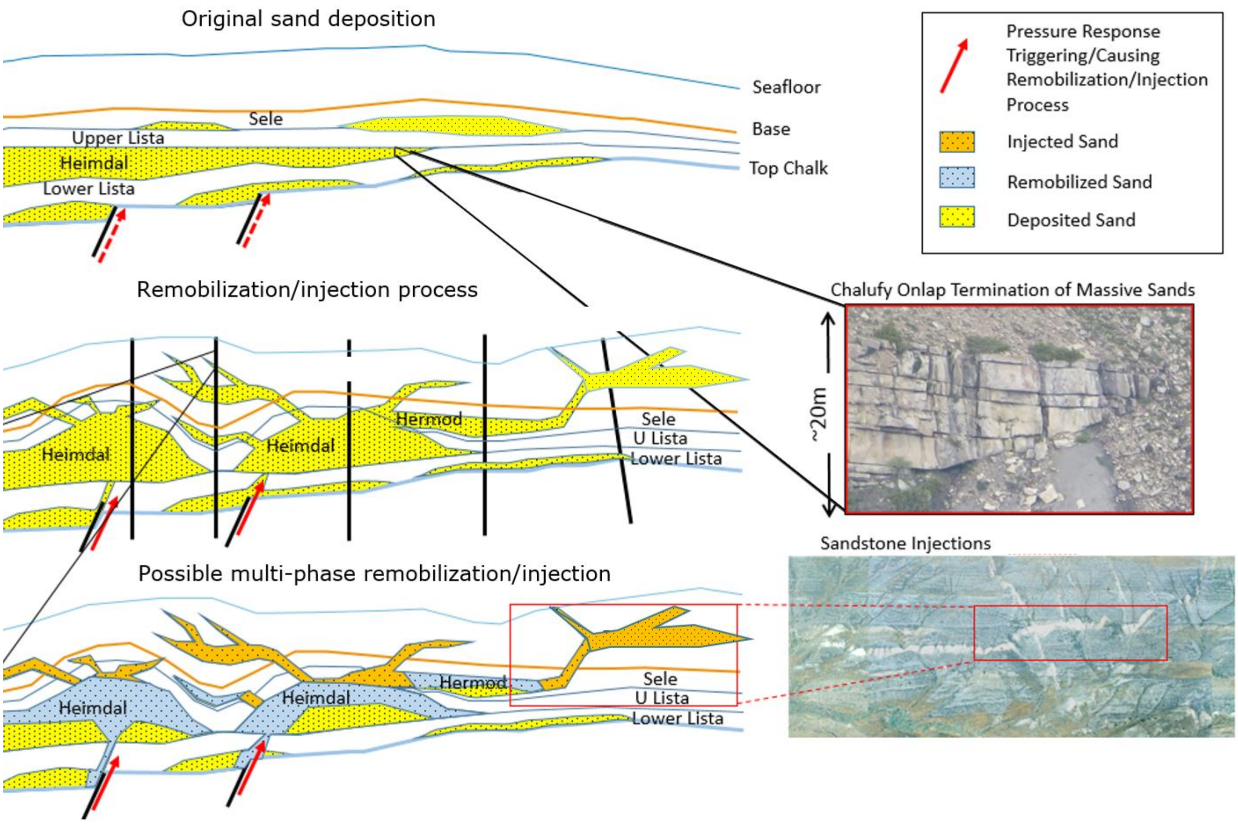



*Figure 3 Geological model of the Loke development*

## 1.3 Subsea challenges and risks

There are many challenges and risks that have been identified with the Loke development project:

- **Wellbore placement / Geosteering:** The trajectory of the wellbore must be continuously adjusted during drilling to penetrate the most productive part of the sands 'channel' whilst also avoiding drilling into the unstable shales above the sand. This drilling process is called "geosteering" and requires deployment of advanced tools that has the capability to look ahead in front of the drilling bit and 360 deg around the sensors. Adjustments to trajectory during drilling is achieved with rotary steerable drilling system that can make changes to the direction based on downlinking of signals from the surface.

- **Depleted formation:** The Loke development is an extension to an existing mature field that has been in production for several decades already. This means that the sands are heavily depleted which increases the risk of downhole losses of drilling fluids during operations. The drilling fluid system must be carefully designed to provide sufficient filter cake against the porous formation but without any permanent plugging that will reduce the inflow of hydrocarbons into the wellbore during production phase. To further reduce the risk of downhole losses the mud system should also be mixed with background particles (lost circulation material) that can go into and plug of any small cracks or fissures that occur during drilling operations.
- **Unstable shales / wellbore collapse:** The depleted formations as mentioned above means that the density of the drilling fluid used must be low to avoid loss of drilling fluid to the formation during drilling. However, if pressure from the drilling fluid is too low then any shale sections penetrated will become unstable and can start to collapse over time. Ultimately, the collapsed shales can pack off around the drilling string and prevent the drilling fluid from being circulated continuously and / or result in high pressure spikes that can fracture the formation and exacerbate the situation further.
- **Narrow margins:** Due depletion and unstable shales, the permissible range of pressures that can be applied in the wellbore during drilling and completion operations is very small. Again, this puts high demand on drill string components, fluid density and properties, procedures, and experience level of crews. Use of new technology can be used to provide improved control of the downhole pressures (managed pressure drilling).
- **Horizontal drilling:** Due to the nature of the injectites, all reservoir sections are drilled horizontally, which add additional challenges with getting enough weight down to the drilling bit and to run the production screens into the open hole after target depth has been reached and the drilling assembly pulled out of the well.

## 1.4 Typical well design for Loke development

The Loke wells are constructed with 4 casing strings, of which the final casing shoe is positioned inside the reservoir. The 36” conductor and 20” casing provide the structural foundation for the well. The overburden is secured with the 13.3/8" intermediate casing and the production casing is a tapered 9.5/8" x 10.3/4". The reservoir is drilled with an 8.1/2" bit and opened to 9.1/2" to create more room to minimize the hydraulic forces acting on the formation during operations and mitigate risk of interbedded shales deteriorating with time before the standalone screens are installed.

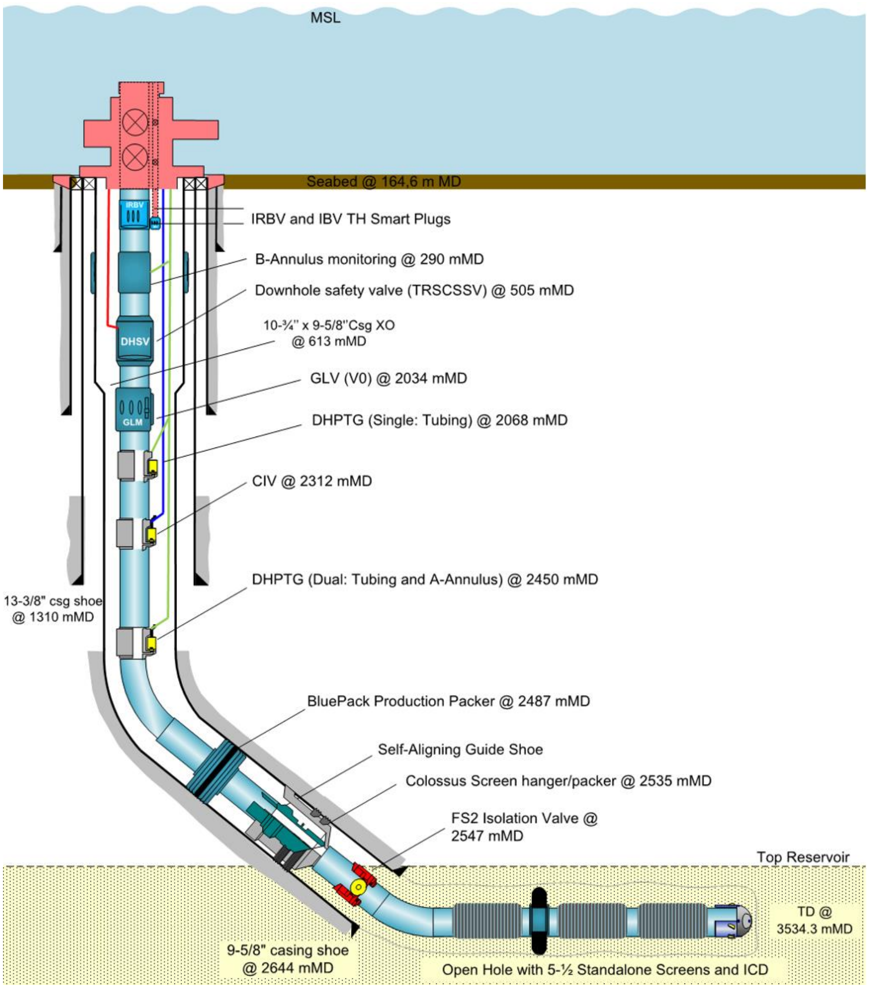



*Figure 4 Example well design for the Loke development*

## 1.5 Loke economics

### *1.5.1 Base case*

The economics of Loke is based on a 10-year production profile with a plateau after 2 years of production. In the base case investment costs for drilling and wells and FPSO upgrade are 1750 mUSD over a 2-year period and abandonment costs of 300 mUSD at the end of field life. Discount rate and tax are set to 15% and 50%, respectively. Production costs are expected to be around 10 USD/bbl of oil produced. For the initial business case a steady oil price of 60 USD/bbl has been used for the screening. Overall, the project has a healthy economy with a discounted net present value of 1037 mUSD and break-even for average oil price of 47 USD/bbl. However, the project is sensitive to several factors as explained below.

### *1.5.2 Sensitivities*

The following sensitivities were run to assess impact on Loke economy:

**CAPEX overruns:** Assuming overall cost overruns of 30% either during drilling operations and/or FPSO or other project costs. This will result in a ~40% loss of NPV and increase in break-even average oil price well above 50 USD/bbl.

**Delayed start:** Considers the case of 1-year delays for first oil due to problems with drilling operations and/or arrival of FPSO. In addition to lost revenue in the delayed period there are other running costs associated with maintaining the organization and progress in the project. This could lead to ~55% loss of NPV.

**Low oil price:** The base case economy for Loke development is that oil remains at or around 60 USD/bbl for the 10-year period of production. The NPV of Loke is highly sensitive to oil price. This sensitivity assumes a collapse in oil price over a 4-year period down to 30 USD/bbl which would result in overall negative NPV for the project.

**Poor production performance:** If the wells are not drilled and completed with high focus on quality, reservoir impairment or other factors can arise that impact the production performance of the wells. In this sensitivity a 60% reduction in production is assumed, which leads to a negative NPV. In fact, a loss of only 25% productivity from the wells results in NPV ~0. This illustrates the importance of delivering high quality wells for Loke as one of the most critical value drivers for the project.

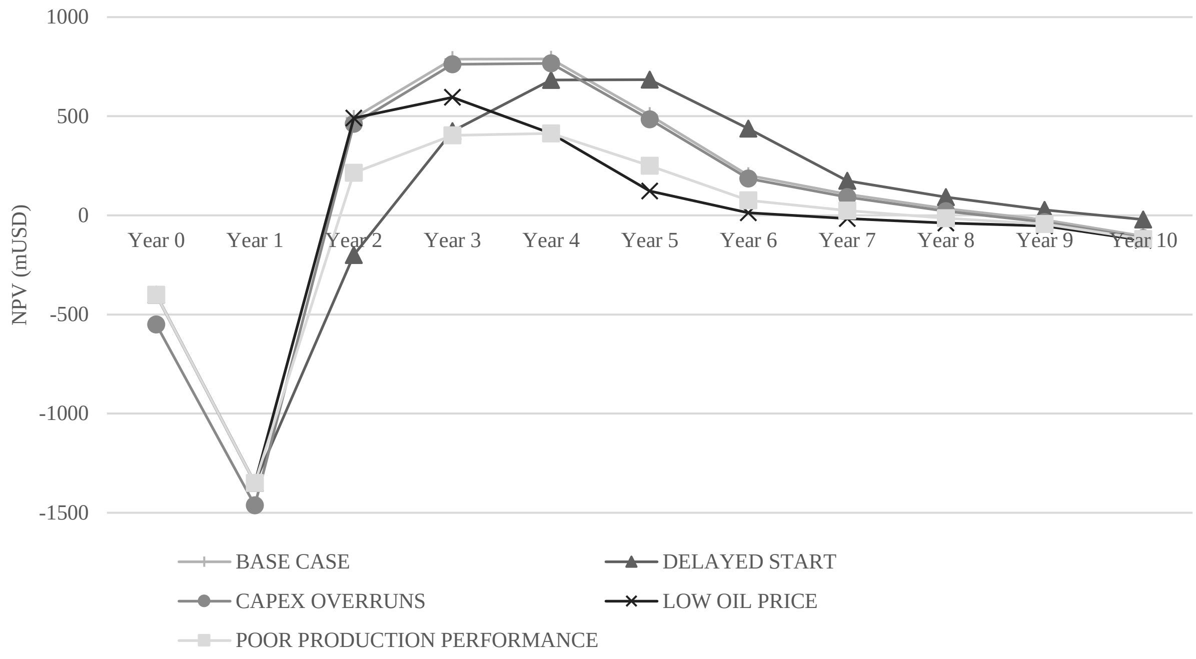



*Figure 5 Loke economics, base case, and sensitivities*

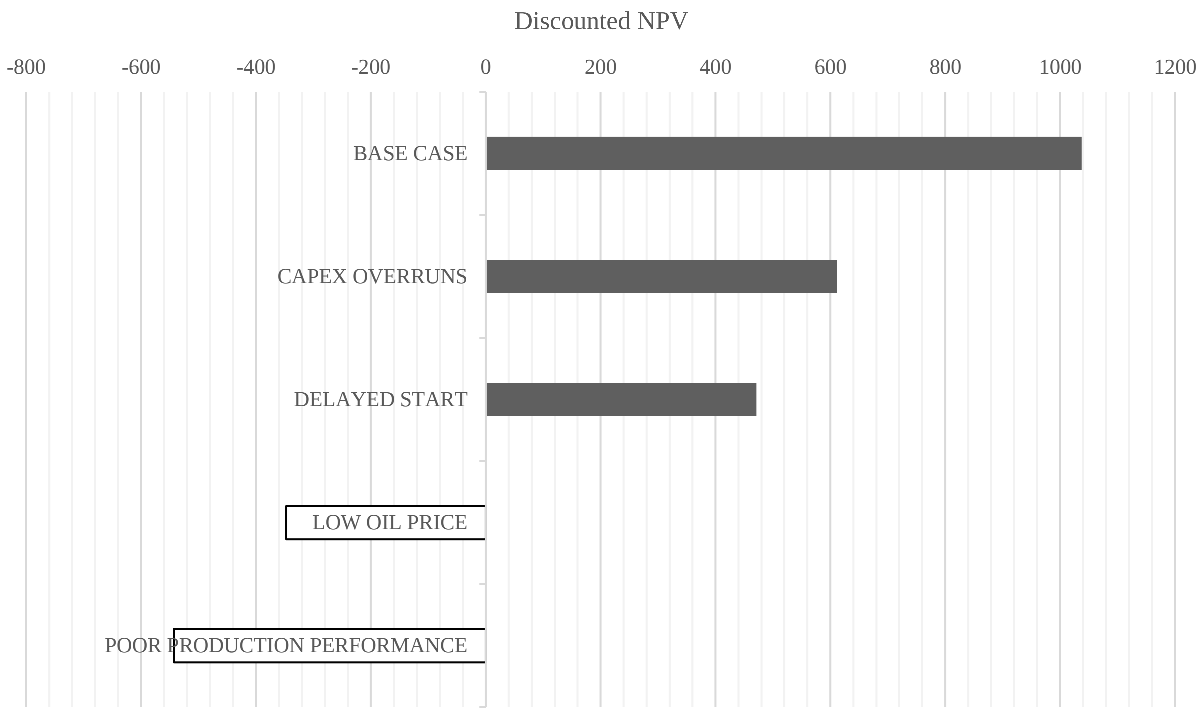



*Figure 6 Economic sensitivities and resulting impact on NPV*

# 2 LOKE VALUE DRIVERS

Based on the three main components described in section 3 (Part I) a holistic evaluation of the Loke development value drivers is summarized in Table 2. In this thesis, the ranking of the value drivers form the foundation for the contracting strategy from a drilling & wells perspective.

*Table 2 Ranking of value drivers for Loke development for D&W perspective.*

| Project driver | Assessment | Ranking |
|---|---|---|
| **Quality** | As described in section 1.3 the Loke development is complex and requires high level of detailed planning, precise engineering, and robust solutions to maximize the value of the marginal reserves being accessed. Use of new technology should be considered that involves detailed planning and integration between various parties involved in the project. Tools and procedures must be reliable, thoroughly reviewed and tested and qualified upfront. As illustrated in Figure 6 production impairment has a big negative impact on the economy of the Loke project, which again emphasizes the need for using Quality as the main value driver for the project. | 1 |
| **Schedule** | As can be seen from the economic analysis the project is sensitive to delays that occur after project start. Delays result in additional costs and longer period between start and point in time where revenue is being generated. As illustrated in Figure 6 a 1-year delay at the start of the production reduces the NPV by more than 50%. Other factors that could impact the project economics in the event of delays, for example production models based on oil price developments and global economy in general. | 2 |
| **Cost** | Cost overruns will also affect NPV negatively. As seen in Figure 6 a 15% cost overrun will recue NPV by 30-40%. However, the impact of production impairment is significantly more severe. In other words, it is worthwhile to spend the money needed to get the best solution and execute the operations flawlessly to deliver robust wells with high productivity. | 3 |

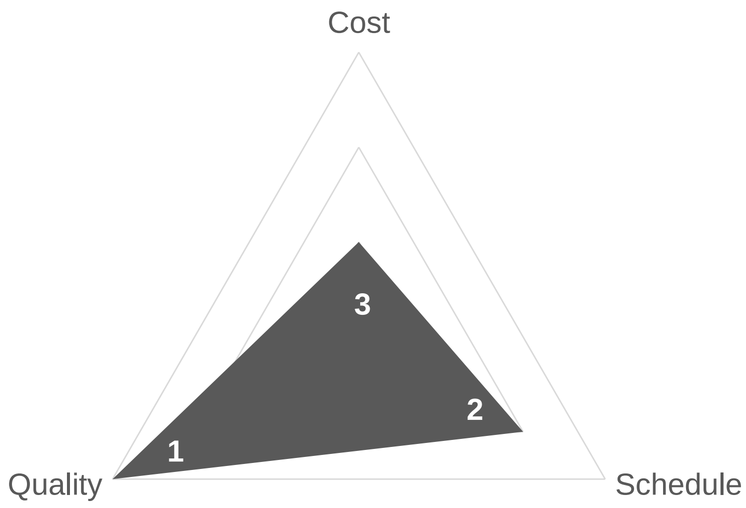



*Figure 7 Loke value driver pyramid*

# 3 CONTRACT STRATEGY FOR THE LOKE DEVELOPMENT (D&W PERSPECTIVE)

## 3.1 General

At the highest level, the Drilling & Wells scope required for the development of the field are a drilling unit and drilling services as described below:

### *3.1.1 Drilling unit*

There are several types of drilling units that are designed for different applications. Since Loke will be developed with the use of subsea templates, a mobile offshore drilling unit (MODU) should be considered. The three main MODU categories are: jack-up, semi-submersible and drillships. The drilling contractor’s typical scope of work is the provision of a drilling machine (also known as top drive), pipe handling and all other equipment and personnel needed to operate the drilling machine directly or indirectly. The inclusion of additional services (for example casing and tubing running) is also considered if this is practicable and in line with overall contract strategy for the project.

### *3.1.2 Drilling Services*

In addition to the drilling unit, which is mostly focused on the topside equipment needed to drill and complete a well, additional drilling services are required for the well construction process itself. This includes the provision of drilling bits, stabilizers and other bottom hole assembly components, drilling fluid, cement, directional drilling, and rotary steerable tools measurement- and logging while drilling tools and more.

### *3.1.3 Long lead items: wellheads, tubulars, and production systems*

For well construction a range of different tubulars and equipment will be required. The rating and grades will be dependent on the well design and modelled loads for drilling and production phases. Also, the connections and type of threads needed to make up the tubulars need to be suitable for the lifetime loads of the well. Typical lead time for these types of tubulars range from 6 -18 months. This means that the well design, complete with technical and functional requirements must be established well in advance of execution phase. In addition, production x-mas tree with various valves, gauges and sensors for the production phase must be specified early since the lead time could be more than 24 months.

## 3.2 The tender process

### *3.2.1 Tendering strategy*

Autumn ASA is a relatively small oil company with limited resources and employees to manage the many aspects of contract management and internal compliance. The amount of drilling operations conducted to date are limited so any existing contracts for drilling services and associated auxiliaries are either expired or overdue for renegotiation and renewal. Because of this, it has been decided to minimize the number of contracts whilst maximizing the potentials of synergies and interlinks between the various segments.

In effect, this means that as many of the drilling services as possible will go into a bundled, integrated service contract as described in next section.

### *3.2.2 Establish contract requirements*

From a D&W standpoint, the project needs to evaluate the various constellations of contracts required. The estimated duration and extent of the project will influence these choices. For short campaigns, the operator may elect to utilize existing contracts for the various services and/or set up new contract if required. However, for the Loke development integrated contracts should be considered to reduce the administrative loads and effort needed to coordinate and align the various providers in the execution phase. The table below is an example matrix showing key considerations for the main contracts:

*Table 3 Contract requirements and acquisition strategy for Loke development*

<table>
<tr><th>Service</th><th>Details / other info</th><th>Contract type</th><th>Recommended duration</th></tr>
<tr><td>Drilling unit</td><td>See section 4.4 for additional services included.</td><td>Direct with rig contractor</td><td>Well-based (e.g., 10 wells, no matter how long / short time it takes)</td></tr>
<tr><td>Directional drilling</td><td>Including bits and all BHA components.</td><td rowspan="2">Integrated drilling services contract</td><td rowspan="2">2 years with optionality to extend no later than 3 months before expiry date</td></tr>
<tr><td>MWD & LWD</td><td>With capability and technology required to meet subsurface teams’ requirements.</td></tr>
</table>

| Service | Details / other info | Contract type | Recommended duration |
|---|---|---|---|
| **Drilling fluids** | Selecting the correct mud system is a critical element for success. | | |
| **Data logging** | Preferable to keep same company as already in use on drilling unit to avoid re-installing sensors and cables. | | |
| **Wireline operations** | Both electric- and slickline. | | |
| **Cementing services** | Including bulks, chemicals, cement head, centralizers, float equipment, etc. | | |
| **Completion equipment and services** | Including all gauges, packers, control lines, etc. | | |
| **Well testing** | Planning and equipment, excluding flare booms | | |
| **Well construction tubulars / casing** | Company-wide contract for all assets, i.e., not dedicated for Loke project | Standalone contract | 2 years |
| **Wellheads and services** | Also linked with x-mas tree and subsea infrastructure. | | Required for lifetime of field, renew / extend every 4 years |
| **Casing and tubing running** | Preferable to keep same company as already in use on drilling unit to save installation, integration, and commissioning costs. | Standalone contract or included via drilling unit contract | 2 years |
| **ROV** | | | |
| **Solids control and treatment** | | | |

# 4 TOTAL COST OF OWNERSHIP (TCO) EVALUATION MODEL

## 4.1 General

There are many elements other than the day rate that influence the total costs of an operation. The TCO model is a tool that enables like-for-like comparison between different drilling units to the extent possible in line with EMAT principle described in section 2.1 (Part I). The TCO model also brings in several elements into the evaluation and attempts to 'normalize', quantify, and visualize the overall effects for the project. Some criteria and elements will also change depending on the nature and technical requirements of the project. The TCO model can also be used to show sensitivities between the various drilling units for different scenarios.

The following elements are considered and built into the TCO model:

- ✓ Non-technical elements with commercial impact
- ✓ Commercial elements
- ✓ Technical elements with commercial impact
- ✓ Technical and functional minimum requirements
- ✓ Technical scoring
- ✓ Greenhouse gas emission score
- ✓ Health, Safety, Environment and Quality score
- ✓ Qualitative elements / 'traffic lights'

Furthermore, the TCO model allows for different criteria and weighing based on what scenarios are being considered as explained in the next section.

## 4.2 Building the scenarios for the tender

Various scenarios can be created which can be used to compare total cost for different drilling units for multiple optional scope / campaigns. Once set up correctly, the TCO model can switch between and compare the evaluation output for all the drilling units for the different scenarios.

For example: in a scenario with multiple campaigns then the selected drilling unit must be able to operate in the required water depth (i.e., will result in FAIL for non-capable drilling units) and may also result in a favorable commercial element for drilling units with recent relevant experience (example: well test, gravel pack, etc.) where this is applicable.

Another example is evaluation of cold-stacked drilling units, then the overall anticipated negative performance / NPT impact will be higher in scenarios with few wells compared with multiple wells as the initial startup / teething problems are expected to decline with time.

The scenarios that will be set up for Loke tender evaluation can be seen in the table below with some of the key points to consider.

*Table 4 Scenarios considered for the Loke TCO model*

| Scenario | Description | Key points |
|---|---|---|
| **Scenario 1** | Loke Phase I | 10 wells, 500 days duration, 130m water depth, managed pressure drilling (MPD) / controlled mud level (CML) |
| **Scenario 2** | Loke Phase I + 4 exploration / appraisal wells | 10 + 4 wells, 620 days duration, 130 – 600 m water depth, MPD / CML, well test capabilities |

## 4.3 Defining the minimum technical and functional requirements

Based on the scope of work for the different scenarios, the minimum technical and functional requirements (MTFR) must be identified and established. This is an important exercise for an efficient tender evaluation process. This should give clear instructions to the contractors that are participating in the tender on what is needed to avoid spending unnecessary time bidding in a unit or a service which is not capable to perform the scope. This will also help with the initial screening and filtering of the bids as they are returned.

The process of defining the MFTR involves close collaboration between D&W and subsurface and other disciplines to clearly define the well objectives, main risks, and challenges. Some of the MFTR will be pass / fail and/or have negative impact on the project execution if not met, thus needs to be compensated with other elements to weigh up against the shortfall.

Below is an example table of the MTFR for the Loke development based on the risks, challenges and value drivers described earlier in this document. The main components of scenarios 1 and 2 are as per Table 4.

*Table 5 Overview of minimum technical and functional requirements for Loke drilling unit*

| Element | Description | Criteria |
|---|---|---|
| **Drilling unit type** | Floating mobile offshore drilling unit (i.e., not jack-up) required for both scenarios | Pass / Fail |
| **Water depth** | Minimum 130m for scenario 1, minimum 600m for scenario 2 | Pass / Fail |
| **Derrick setup** | Dual derrick rig with capability for drilling and cementing operations from auxiliary rig. | Differentiated in TCO model based on operational efficiency |
| **Regulatory compliance** | Valid acknowledgment of compliance (AoC) required for both scenarios | Pass / Fail<br>Alternatively: additional cost to acquire AoC added in TCO model |
| **Status and experience** | Preferably warm / active rig with experienced crew for both scenarios | Differentiated in TCO model |
| **Station keeping** | POSMOOR for scenario 1, DP3 optionality preferred for scenario 2 | Pass / Fail |
| **Operating criteria** | Max waves, period, swells and windspeed to remain in operations based on historical weather data at the different locations in Scenario 1 and 2. | Differentiated in TCO model based on operability assessment |
| **Controlled mud level technology** | Managed pressure drilling technology to enable drilling of narrow margin wells in the Loke development. Also beneficial for exploration wells included in Scenario 2. | CML installation costs added in TCO model (if required) for scenario 1, and performance improvement made for scenario 2 if CML is already included |
| **Well test ready** | Only applicable for scenario 2 where well testing is part of the scope | Additional costs added in TCO model to get drilling unit well test ready for scenario 2 |

## 4.4 Additional services to be included under drilling unit contract

In line with the decision to select integrated drilling services for Loke development as explained in section 3, Autumn ASA will also further minimize number of contracts and maximize synergies by requesting additional services under the drilling unit contract. These additional services should still be requested as optional since not all contractors are capable, or willing to, provide such services. As part of the strategy document, it is useful to set up a ranking of preference for these services which will form the foundation during negotiations with the rig contractors in the evaluation phase. The TCO model must also be constructed to compensate for services included / not included between the various drilling units. This is explained further in section 4.7.

*Table 6 List of optional services for including into drilling unit contract*

| **Element** | **Description** | **Preference (1-5) *** |
|---|---|---|
| **Cement unit** | Contractor to be responsible for maintenance and spare part management in accordance with OEM's maintenance system. | 5 |
| **Controlled Mud Level system** | Required for all Loke scope due to narrow drilling margins. Strong preference to have this provided via rig contract for seamless integration into rig systems and procedures. | 5 |
| **Pit cleaning** | Pit and tank cleaning system, chemicals and personnel required to clean pits and lines as required. | 5 |
| **Telecommunications** | Total comms package for all operations, including minimum high-speed internet. | 4 |
| **Drillpipe inc pups and XOs** | Contractor should provide Premium grade drillpipe needed (including slips, handling tools, saver subs, etc.) to meet Loke objectives. | 4 |
| **ROVs** | Contractor will manage the ROV contract, including equipment and personnel. | 3 |
| **Tubular Running Services** | Equipment and personnel for all casing and tubing running services, fully integrated into the rig floor set-up to maximize efficiency, reduce rig-up/down time, etc. | 3 |
| **Drilled cuttings / solids control** | Contractor to provide all equipment and personnel to meet objectives of the Loke wells. | 3 |
| **Fishing equipment** | Fishing equipment for all components, including third party components and casings. | 1 |

** 1: Low preference, 5: Strong preference*

## 4.5 Non-technical elements with commercial impact

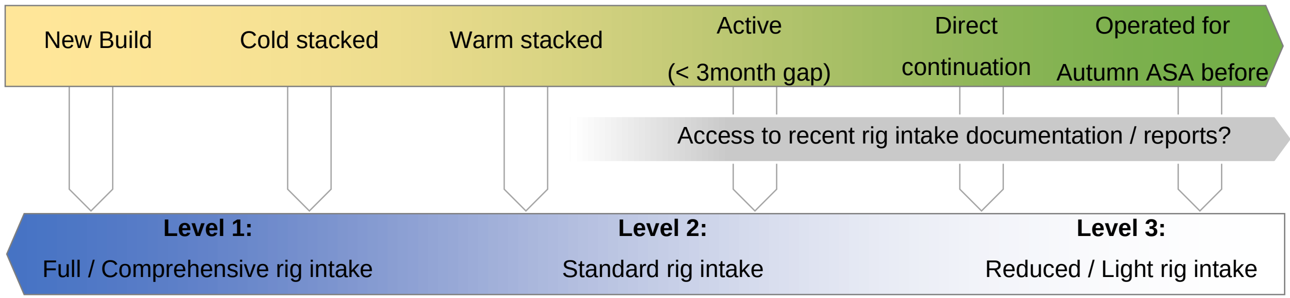
The non-technical elements considered are those that are not directly linked with technical capabilities of the drilling unit, but indirectly leads to higher total cost due to performance, reliability and consequential costs that will apply before operations can commence.

For Loke scenarios the non-technical elements included in TCO model are described below. There is a dedicated column that highlights how the specific elements are linked with the value drivers for the project. This is useful for the evaluation panel to understand the relevance and overall impact it may have on the project.

*Table 7 Non-technical elements with commercial impact used in the TCO model*

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">Crew status and demographics</td><td rowspan="3">1. Quality<br>2. Cost</td><td colspan="3">The crew on board a drilling unit is critical to operate the drilling unit efficiently. Continuity, experience level, familiarity with the drilling unit and cohesion / culture are the main building blocks. For ‘warm’ drilling units in continuous activity the TCO model assumes that the drilling unit is already operating at max efficiency and no adjustments are made. However, new builds or drilling units that have been cold stacked for prolonged periods of time may not yet have a dedicated crew assigned. This is likely to have negative impact on the performance for the project and result in higher total cost. Depending on the selection made for the various drilling units, the TCO model will add a certain % extra time to the total number of days on the project. Depending on the duration of the contract, the total impact of new crews will be less as there is more time to overcome learning curves, gain familiarity with the rig and improve performance. This is an important element which must be estimated based on historical data (if available) and subjective judgement by the tender evaluation panel.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. Regular crew<br>2. Partially new crew (<20%)<br>3. New crew (>20%)</td><td>1. 0% time added<br>2. 1,0% time added<br>3. 3,0% time added</td><td>1. 0% time added<br>2. 0,5% time added<br>3. 2,0% time added</td></tr>
</table>

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">Drilling unit status</td><td rowspan="3">1. Cost<br>2. Schedule</td><td colspan="3">This element is included to differentiate the efficiency and reliability of drilling units depending on the status. Drilling units that are already in operation are assumed to function efficiently and no penalty should be applied for anticipated equipment reliability, failures and repairs, commissioning or costs required to bring the unit into service.<br>A new built drilling unit is expected to have initial start-up problems and system integration challenges, whereas for a cold stacked drilling units non-productive time and delays associated with re-activation of the equipment can be expected. Depending on the duration of the contract, the total impact of the drilling unit status will be less as there is more time to overcome initial problems and improve performance.<br>This element must be estimated based on historical data (if available) and subjective judgement by the tender evaluation panel.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. ‘Warm’ / active<br>2. Warm stacked<br>3. Cold stacked<br>4. New build</td><td>1. 0% time added<br>2. 2,5% time added<br>3. 5,0% time added<br>4. 7,5% time added</td><td>1. 0% time added<br>2. 2,0% time added<br>3. 4,0% time added<br>4. 6,0% time added</td></tr>
</table>

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="5">Drilling unit intake and upgrade costs</td><td rowspan="5">1. Costs<br>2. Schedule</td><td colspan="3">Most operators have internal procedures and requirements for taking a drilling unit under contract to ensure a) regulatory compliance, b) safe operations and c) efficient operations with minimum equipment failures. The rig intake process normally starts 6-9 months before contract commencement and involves various desktop reviews, internal and 3rd party inspections, audits, etc. The level of due diligence required in the rig intake phase is dependent on several things like previous experience with the drilling unit and / or contractor, level of maintenance conducted on the rig over time, access to previous documentation and reports from previous operators. For the Loke assessment, the different levels of rig intake used is based on guidelines from the rig intake manual in the D&W management system.<br><br></td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. Level 1<br>2. Level 2<br>3. Level 3</td><td>1. $2,000,000 added<br>2. $1,000,000 added<br>3. $500,000 added</td><td>Same as scenario 2 - rig intake is a one-off cost irrelevant of project scope and duration</td></tr>
</table>

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">SPS inspection status</td><td rowspan="3">1. Costs<br>2. Schedule</td><td colspan="3">Classification Societies require differing levels of Special Periodic Surveys (SPS) to be conducted every 3, 5, 10 and 15 years. This involves detailed structural investigation and various inspections to ensure structural watertight integrity. In some cases, it might not be possible to avoid interrupting the campaign due to SPS activities. Even though most contracts stipulate that the drilling unit goes off hire (or special rate applies) for the duration of any SPS work, the delay will still result in additional costs to the operators caused by maintaining logistical apparatus, overheads, and other running costs. Some SPS are comprehensive and may take several weeks if drydocking is required for hull inspections. The TCO model assigns additional time to the contract duration which reflects both delays and associated costs for the operator should the SPS scope (or part of it) take place during the planned campaign. Uncertainties associated with these estimates can be reduced through clarification meetings with the rig contractor to better understand the extent of the planned SPS activities (if applicable).</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. No SPS scheduled in campaign<br>2. SPS primarily done offline<br>3. SPS on critical path</td><td>1. 0 days added to total time<br>2. 4 days added to total time<br>3. 14 days added to total time</td><td>Same as scenario 2</td></tr>
<tr><td rowspan="2">AoC / SUT status</td><td rowspan="2">1. Costs<br>2. Schedule</td><td colspan="3">The Acknowledgment of Compliance (AoC, also known as ‘Samsvarsuttalelse’ / SUT in Norwegian) is issued by the Petroleum Safety Directorate. An AoC is mandatory for all drilling units participating in petroleum activities on the NCS (Petroleumstilsynet, 2023). This arrangement clarifies the responsibility of the players, provides more effective consent processes, creates predictability, and makes it easier for mobile facilities to cross national boundaries. To get the AoC the drilling unit must be compliant with Norwegian regulations and requirements which are typically more stringent than international standards. In many cases significant investments must be made to upgrade and/or modify rigs to meet requirements before the AoC is awarded. For drilling units that have been built with the NCS in mind, the extent of the modifications is expected to be limited. However, the AoC process still carries costs in terms of inspection and verification activities, developing and integrating management systems and following up and non-conformances identified in the process.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
</table>

| **Element & value driver link** | | **Description** | | |
|---|---|---|---|---|
| | | 1. AoC / SUT in place<br>2. No AoC / SUT but built for NCS<br>3. No AoC / Sut | 1. No additional costs added<br>2. $5,000,000 added<br>3. $30,000,000 added | Same as scenario 2 |

## 4.6 Commercial elements

This part of the TCO model contains all direct and indirect commercial elements that contribute to total cost. As per contracting strategy, rig contractors will be asked to provide a range of additional services that will be included into the rig rate. Some examples are listed below.

*Table 8 Direct commercial elements used in the TCO model*

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">Rig rate</td><td rowspan="3">1. Cost</td><td colspan="3">Daily operating rate (OR) for the drilling unit.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>Input value</td><td>Input value: $/day</td><td>Input value: $/day if different from scenario 1</td></tr>
<tr><td rowspan="3">Standby Rate</td><td rowspan="3">1. Cost</td><td colspan="3">Standby rate (SR) for the drilling unit during special periods and operations as defined in rig contract (for example: during repairs, non-productive time events of waiting on weather).</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>Input value</td><td>Input value: % of OR</td><td>Same as for scenario 1</td></tr>
<tr><td rowspan="3">% standby rate applies</td><td rowspan="3">1. Cost</td><td colspan="3">Rough assessment based on qualifications to contract submitted with the tender: % time drilling unit will be in standby mode depending on acceptance of the standby terms proposed. The resulting % based on the selection will be used to calculate a reduction in total cost by assuming a delta between OR and SR. This might be difficult to assess early in the tender phase before negotiations commence.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. All terms accepted<br>2. 50% of terms accepted<br>3. 10% of terms accepted</td><td>OP / SR delta applies for:<br>1. 20% of the total duration<br>2. 10% of the total duration<br>3. 5% of the total duration</td><td>Same as for scenario 1</td></tr>
<tr><td>Moving Rate</td><td>1. Cost</td><td colspan="3">Moving rate (MR) offered as % of Operating Rate (applies for BOP hopping and transit). The input is used to calculate a reduction in total costs resulting from the reduced moving rate. The number of days in transit is estimated from the number of wells outlined in the scenario.</td></tr>
</table>

| **Element & value driver link** | | **Description** | | |
|---|---|---|---|---|
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | Input value | Input value: $/day | Same as for scenario 1 |
| **Reduced Efficiency Rate** | 1. Cost | Reduced Efficiency Rate (RER) offered as % of Operating Rate. This rate applies during periods when the drilling unit is not able to operate at its full potential and capacity due to faulty equipment that is not directly impacting on the critical path for operations. This is mostly applicable for rigs with comprehensive offline capabilities and/ or dual derrick. For example: RER should apply if the Auxiliary rig is not functional which prevents offline racking of tubulars during drilling operations in the Main rig. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | Input value | Input value: % of OR | Same as for scenario 1 |
| **% reduced efficiency rate applies** | 1. Cost | Rough assessment based on qualifications to contract submitted with the tender: % time drilling unit will be in RER mode depending on acceptance of the RER terms proposed. The resulting % based on the selection will be used to calculate a reduction in total cost by assuming a delta between OR and RER. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | 1. All terms accepted<br>2. 50% of terms accepted<br>3. 10% of terms accepted | *OP / RER delta applies for:*<br>1. 5% of the total duration<br>2. 3% of the total duration<br>3. 1% of the total duration | Same as for scenario 1 |
| **Accommodation and catering** | 1. Cost | Additional daily rate to cover meals and accommodation out with agreed number of personnel on board already included in OR. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | Input value | Input value: $/day | Input value: $/day if different from scenario 1 |

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">Mob fee</td><td rowspan="3">1. Cost</td><td colspan="3">Estimated, or quoted, costs for the mobilization of the drilling unit to the 500m zone of the Loke field. Unless specified in the tender documents, contractors can propose either lump sum (LS) all-inclusive offers or an estimate of the number of days required where SR applies. The tasks and content of the activities included in the mobilization phase should be carefully reviewed as it may have impact on readiness to commence operations once the rig is at the 500m zone (for example: load all equipment on board rig, pick up and rack back adequate amount of drill pipe, etc.).</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>Input value</td><td>Input value: Lump sum or estimated days x applicable rate</td><td>Same as for scenario 1</td></tr>
<tr><td rowspan="3">Demob fee</td><td rowspan="3">1. Cost</td><td colspan="3">Estimated, or quoted, costs for the demobilization of the drilling unit away from 500m zone of the Loke field. Unless specified in the tender documents, contractors can propose either lump sum (LS) all-inclusive offers or an estimate of the number of days required where SR applies. The tasks and content of the activities included in the demobilization phase should be carefully reviewed to ensure as much scope as possible is done after the drilling unit has been released from the contract (for example: pit cleaning, offload equipment, lay out rental drill pipe, etc.).</td></tr>
<tr><td>Scenario 1</td><td>Scenario 1</td><td>Scenario 1</td></tr>
<tr><td>Input value: Lump sum or estimated days x applicable rate</td><td>Input value: Lump sum or estimated days x applicable rate</td><td>Same as for scenario 1</td></tr>
</table>

## 4.7 Value of additional services included in operating rate

This section considers services potentially provided by the rig contractor and included in the day rate. The estimated value of these services is subtracted from the total cost of the individual drilling units accordingly. i.e., if a certain service is included, the "net" OR for the drilling unit is reduced since the operator otherwise would have to spend additional money to acquire the service through separate contract. In the TCO model the estimated value of the various services are based on benchmarked historical data and applied equally to all drilling units.

*Table 9 Impact of value from additional services used in the TCO model*

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">Cement unit</td><td rowspan="3">1. Cost</td><td colspan="3">Cement unit is in most cases permanently installed on the drilling unit since it is often difficult to replace due to access and general integration into the drilling units high pressure piping and well control systems. Cross-rental agreements are normally in place if the owner of the cement unit is different than the company that provides the cementing services. If included in the OR it is assumed to also mean maintenance, spare parts, and repair.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. Included<br>2. Not included</td><td>Reduction in total costs:<br>1. 1,500 $/day x total duration<br>2. No reduction in total cost</td><td>Same as scenario 1</td></tr>
<tr><td rowspan="3">Controlled Mud Level system</td><td rowspan="3">1. Cost<br>2. Quality</td><td colspan="3">As mentioned in section 4.3 the CML system is considered critical for successful drilling and completion of the depleted Loke wells to deliver against value drivers for the development. In this section, the operating costs for the system is considered, i.e., equipment rental rates and personnel costs. The installation and commissioning costs are covered in Table 10.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. Included<br>2. Not included</td><td>Reduction in total costs:<br>1. 25,000 $/day x total duration<br>2. No reduction in total cost</td><td>Same as scenario 1</td></tr>
</table>

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">Pit cleaning</td><td rowspan="3">1. Cost</td><td colspan="3">Pit cleaning involves use of tank cleaning equipment and specialized personnel. It can be time consuming (3-5 days per well) depending on the frequency of the cleanings and requirements to swap between different fluid types, e.g., water-based and oil-based systems. If all pit cleaning scope is accepted, it means that Zero Rate (ZR) will apply for any time spent on critical path for pit cleaning. Having the pit cleaning included in the operating rate for the rig provides an incentive for the contractor to plan and execute the pit cleaning activities as efficiently as possible – therein lies the value. If partial scope is accepted, some cost sharing between rig contractor and operator is expected and the value is assumed to be ~1/2.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. All scope accepted<br>2. Partial scope accepted<br>3. Limited / no scope accepted</td><td>Reduction in total costs:<br>1. $1,000,000 x number of wells<br>2. $5,00,000 x number of wells<br>3. No reduction in total costs</td><td>Same as scenario 1</td></tr>
<tr><td rowspan="3">Telecomms</td><td rowspan="3">1. Cost</td><td colspan="3">Telecomms includes networking services and access to high-speed internet services used for communicating between drilling unit and onshore offices in addition to streaming of real-time operations data for remote operations. The bandwidth requirement must be specified in the contract framework in the tender documents.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. All scope accepted<br>2. Partial scope accepted<br>3. Limited / no scope accepted</td><td>Reduction in total costs:<br>1. 3,500 $/day x total duration<br>2. 2,000 $/day x total duration<br>3. No reduction in total cost</td><td>Same as scenario 1</td></tr>
<tr><td>Drillpipe inc pups and XOs</td><td>1. Cost</td><td colspan="3">Drilling tubular rentals costs including inspections as defined in the rig contract. The total drillpipe management scope should be defined in the contract. The most comprehensive level would make the contractor solely liable for all drillpipe planning, including derrick management and mobilization. It would also mean that any non-productive time associated with poor drillpipe management may put the drilling unit in Standby- or even Zero Rate. Subject to level of acceptance for the proposed scope, different cost reductions might apply.</td></tr>
</table>

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="2"></td><td rowspan="2"></td><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. All scope accepted<br>2. Partial scope accepted<br>3. Limited / no scope accepted</td><td>Reduction in total costs:<br>1. 3,000 $/day x total duration<br>2. 500 $/day x total duration<br>3. No reduction in total cost</td><td>Same as scenario 1</td></tr>
<tr><td rowspan="3">ROVs</td><td rowspan="3">1. Cost</td><td colspan="3">Remote operated vehicles (ROV) are unmanned submarine units that can monitor subsea operations and perform various functions to support drilling operations. In most cases, and for the Loke development, one work-class ROV is sufficient for the scope required. Therefore, the total reduction in cost is the same whether the drilling unit has one or two ROVs. However, the TCO model still distinguishes between one or two ROVs so it can be applied in future tender evaluations where it makes a difference.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. Included (2 x ROV)<br>2. Included (1 x ROV)<br>3. Not included</td><td>Reduction in total costs:<br>1. 15,000 $/day x total duration<br>2. 15,000 $/day x total duration<br>3. No reduction in total cost</td><td>Same as scenario 1</td></tr>
<tr><td rowspan="2">Tubular Running Services</td><td rowspan="2">1. Cost<br>2. Quality</td><td colspan="3">Once a hole section has been drilled, it must be secured with casing that is cemented in place. Casing comes in a range of sizes and with different threads, ratings, and properties. Correct make-up of the casing, and completion tubing, is a critical element in safeguarding the barriers in the well. Therefore, there is also a link with the quality value driver for this service. This link will prompt additional scrutiny for the evaluation panel. In addition to the commercial advantages of having tubular running services included in the drilling unit day rate, additional assurances and verification activities should be performed to ensure that this service can be conducted with the required level of robustness and quality required for the Loke well designs. Also, the TCO model will distinguish the drilling from the completion phase, which typically requires more specialized and expensive equipment.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
</table>

| Element & value driver link | | Description | | |
|---|---|---|---|---|
| | | 1. Included<br>2. Not included | *Reduction in total costs:*<br>1. 10,000 $/day x total drilling days, 15,000 $/day x total completion days<br>2. No reduction in total cost | Same as scenario 1 |
| **Drilled cuttings / solids control** | 1. Cost | As per regulatory requirements it is not permitted to discharge drilled cuttings covered oil-based mud residue above a certain level. In practice, it means that all drilled cuttings must be contained and shipped onshore for treatment. The equipment used to capture and contain the drilled cuttings typically goes under the name 'solids control system' (SCS). The contract will have different levels of solids control requirements outlines and optional scope. Depending on the level of scope accepted, the TCO model will account for the expected associated cost reduction. Most of the equipment will be on a daily rental regardless of which phase of the operations are taking place. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | 1. Full SCS (equipment and crew)<br>2. Partial SCS<br>3. Not included | *Reduction in total costs:*<br>1. 20,000 $/day x total duration<br>2. 5,000 $/day x total duration<br>3. No reduction in total cost | Same as scenario 1 |
| **Fishing equipment** | 1. Cost | Most contractors carry fishing equipment for their own drilling tubulars. However, in most cases supplementary fishing equipment must be sought to cover any special items that will be run into the well. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | 1. Included<br>2. Not included | *Reduction in total costs:*<br>1. 1,000 $/day x total duration<br>2. No reduction in total cost | Same as scenario 1 |

## 4.8 Technical elements with commercial impact

This section covers various technical aspects and properties of the drilling unit that may impact the total time or performance for the planned scope. Some of these elements require additional engineering analysis to determine, for example: the drilling units' ability to operate in harsh weather. This should be backed up by an operability analysis for based on the rigs motion characteristics and equipment limits. Such a study will be able to estimate and compare the expected weather impact between the units with an adjustment factor.

*Table 10 List of technical elements with commercial impact used in the TCO model*

| Element & value driver link | | Description | | |
|---|---|---|---|---|
| **Dual rig capabilities** | 1. Cost<br>2. Quality | Drilling units with two derricks can perform dual operations with improved efficiency and time savings in certain operations. The biggest contribution is during riserless drilling operations before the BOP is installed. As per Table 5, for the Loke development, the base case is to use a drilling unit with dual derricks. Therefore, rigs with single or 1.5 derricks will get a time penalty added to reflect the missed opportunity for dual operations. This time penalty is then converted into monetary element in the TCO model. This element is also linked with the quality value driver since it means less open hole exposure time and reduced risk for wellbore instability. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | 1. Yes (base case)<br>2. No | *Time added:*<br>1. Zero<br>2. 47 hrs x number of wells | Same as scenario 1 |
| **Aux capabilities** | 1. Cost | Not all rigs with dual derricks can perform full drilling operations from the auxiliary rig. This can be due to not having the high-pressure standpipe that enables pumping and cementing operations, and / or limitations in the torque and hoisting capacity / draw works. This will limit the dual operation opportunities in the top-hole phase and this element makes an adjustment to reflect this accordingly. The default for Loke strategy is to have comprehensive capabilities in the auxiliary. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |

| **Element & value driver link** | | **Description** | | |
|---|---|---|---|---|
| | | 1. Comprehensive (base case)<br>2. Partial<br>3. Limited<br>4. Not applicable (single derrick) | *Time added:*<br>1. Zero<br>2. 25% of dual rig element<br>3. 50% of dual rig element<br>4. Zero (adjustment already made in dual rig selection) | Same as scenario 1 |
| **Offline capabilities** | 1. Cost<br>2. Quality | For drilling units with either dual or ‘1,5’ derricks it is possible to conduct offline activities like racking and laying out drillpipe and casing, building bottom hole assemblies, etc. In addition, some drilling units have bucking machines on deck that allows for even more offline activities to be conducted. Comprehensive = capability for offline racking / stand-building, transfer between derricks, etc. Partial = bucking machine or similar. Similarly to the dual-derrick element, this is linked with quality value driver as it results in reduced open hole exposure time. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | 1. Comprehensive (base case)<br>2. Partial<br>3. Limited | *Time added:*<br>1. Zero<br>2. 48 hrs per well<br>3. 98 hrs per well | Same as scenario 1 |
| **Performance factor based on KPIs** | 1. Cost | The planned scope consists of many different operations which will be conducted at speeds that will be slightly different from one drilling unit to another. This depends on equipment, setup, procedures and crew experience. KPIs based on historical performance data can be used to compare the total time between the drilling units based on the KPIs. Some examples could be tripping pipe in / out of the well, running casing, running BOP, etc. To determine the ‘performance factor’ a separate analysis must be done for the planned scope. The performance factor for the most efficient rig overall will be 1,00 whereas the others will be adjusted with a factor >1 which will be reflected in the over time for the planned scope. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |

| Element & value driver link | | Description | | |
|---|---|---|---|---|
| | | Numerical value based on analysis of drilling units' KPI's that are relevant for the planned scope. | Performance factor | Same as scenario 1 |
| **Harsh weather operability** | 1. Cost<br>2. Quality | The weather on the NCS can be rough during winter times and the amount of downtime due to weather will vary between the drilling units depending on vessel motion characteristics and equipment limitations. This should be backed up by an operability analysis for based on the rigs motion characteristics and equipment limits. Such a study will be able to estimate and compare the expected weather impact between the units with an adjustment factor. This element has a clear link with the quality value driver since there is an improved chance of drilling and securing the sections of the well if they can be done with as few interruptions / stops due to weather as possible. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | Numerical value based on analysis of drilling units' operability in the expected weather conditions. | Performance factor | Same as scenario 1 with any adjustments needed to reflect prolonged duration potentially increasing weather exposure |
| **Well test readiness** | 1. Cost | If a well test is planned, then it is advantageous to select a drilling unit which is currently set up for well testing and preferably with recent experience with well test operations. For scenario 1, this is not applicable since no well test is planned. However, for scenario 2 some penalty time is added to reflect previous recent experience with well testing. The selection for this element is enquiring time since last well test and additional time is added to the completion phase only. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | 1. Less than 12 months<br>2. More than 12 months<br>3. No well test but all preps done<br>4. No previous experience with well test | *Time added:*<br>1. 0,0 %<br>2. 0,0 %<br>3. 0,0 %<br>4. 0,0 % | *Time added:*<br>1. 0,0 %<br>2. 1,5 %<br>3. 2,0 %<br>4. 3,0 % |

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">Automation and digitalization</td><td rowspan="3">1. Cost</td><td colspan="3">Improved performance (reduction in time) depending on level of automation. Three levels of automation are considered, and the efficiency improvements (reduction in total time) is adjusted accordingly on the total duration of the scope.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. Comprehensive<br>2. Partial<br>3. No (base case)</td><td>Time removed:<br>1. -2,0 %<br>2. -1,0 %<br>3. 0,0 %</td><td>Same as scenario 1</td></tr>
<tr><td rowspan="3">Wired pipe readiness</td><td rowspan="3">1. Cost</td><td colspan="3">Use of wired pipe can enhance and maximize potential of automation and real-time monitoring and adjusting drilling operations. This comes with a reward that translates into reduced overall time.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. Yes<br>2. No (base case)</td><td>Time removed:<br>1. -1,0 %<br>2. 0,0 %</td><td>Same as scenario 1</td></tr>
<tr><td rowspan="3">CML readiness</td><td rowspan="3">1. Quality<br>2. Cost</td><td colspan="3">As seen in Table 5 CML is a key enabler to deliver the Loke wells through the narrow margin conditions – not having CML is not an option. Therefore, this element is clearly linked with quality value driver as the delivery of the wells is dependent on it. This element reflects costs for modifications, installation, and commissioning in case the drilling unit is not already fully equipped / prepared for CML operations.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. CML already installed (base case)<br>2. CML ready<br>3. Not used previously</td><td>Costs added:<br>1. Zero<br>2. $2 500 000<br>3. $5 000 000</td><td>Same as scenario 1</td></tr>
<tr><td>Number of mud pumps</td><td>1. Cost<br>2. Quality</td><td colspan="3">Penalty applies for less than four mud pumps due inadequate redundancy leading to increased risk of NPT and/or lower ROP (drilling phase). Any stops in operations and/or inability to utilize CML system compromises the ability to deliver the wells as per plan. This element is therefore also linked with the quality value driver.</td></tr>
</table>

| Element & value driver link | | Description | | |
|---|---|---|---|---|
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | 1. Five rig pumps (base case)<br>2. Four rig pumps<br>3. Less than four rig pumps | *Time added:*<br>0,0 %<br>0,5 %<br>1,0 % | Same as scenario 1 |
| **Dual-fluid mud system** | 1. Quality<br>2. Cost | Due to sensitivity of the Loke reservoirs, several different fluids will be used during the construction phase of each well. A comprehensive dual-fluid system enables seamless fluid management and reduces risk of cross-contamination that could negatively impact the production potential of the Loke wells. This element is closely linked with quality value driver. Since this is not a common feature on drilling units, any rigs with the dual fluid system will be awarded a reduction in time. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | 1. Yes<br>2. No (base case) | *Time removed:*<br>1. -2,0 %<br>2. 0,0 % | Same as scenario 1 |
| **Average fuel consumption** | 1. Cost | In most contracts the operator is responsible for covering costs of fuel to run the drilling unit. Fuel reduction incentive programs should be considered to reduce fuel consumption through close monitoring and adjustments. However, fuel is a direct cost that impact the TCO. The average fuel consumption based on historical data is therefore used to calculate these costs as part of the TCO. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | Average fuel consumption based on historical data. Should preferably be relevant for the season where operations are expected to take place (unless it is year-round operations). | Average fuel consumption per day x average cost of fuel x total number of days | Same as scenario 1 |

## 4.9 Technical Pass / Fail elements

Using the minimum technical and function specs listed in Table 5 the drilling units must also be screened again these criteria to ensure it is capable to deliver the planned scope.

*Table 11 List of Pass / Fail technical elements used in TCO model*

<table>
<tr><th colspan="2">Element & value driver link</th><th colspan="3">Description</th></tr>
<tr><td rowspan="3">Mud pump system pressure rating (psi)</td><td rowspan="3">1. Quality<br>2. Cost</td><td colspan="3">Pressure rating of mud system - minimum 7500 psi required to be able to deliver the flowrates needed for proper hole cleaning during operations. Any compromise on hole cleaning can jeopardize the ability to deliver the well as per program, hence link with quality value driver. Alternatively, the rate of penetration during drilling must be reduced to cope with the lower flowrate, which means it will take longer time to drill the section and impacts costs.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. 7500 psi system<br>2. Less than 7500 psi</td><td>1. PASS<br>2. FAIL</td><td>Same as scenario 1</td></tr>
<tr><td rowspan="3">Station keeping</td><td rowspan="3">n/a</td><td colspan="3">Method of maintaining station. As a minimum, POSMOOR (the drilling unit is anchored up on location and can make minor adjustments to its position with use of thrusters) required for scenario 1 whereas DP3 (the drilling unit is not anchored up and maintains station purely with thrusters in dynamic position mode) is needed for the deeper waters in scenario 2.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>1. DP3 & POSMOOR<br>2. POSMOOR ONLY</td><td>1. PASS<br>2. PASS</td><td>1. PASS<br>2. FAIL</td></tr>
<tr><td rowspan="3">Max water depth</td><td rowspan="3">n/a</td><td colspan="3">Scenario specific to ensure selected drilling units is capable of operating in the water depths required for the different scenarios defined. If not, the drilling unit will receive FAIL flag.</td></tr>
<tr><td>Selection</td><td>Scenario 1</td><td>Scenario 2</td></tr>
<tr><td>Input water depth rating of the drilling unit</td><td>Minimum required:<br>130 m</td><td>Minimum required:<br>600m</td></tr>
</table>

| Element & value driver link | | Description | | |
|---|---|---|---|---|
| **Hookload capacity** | 1. Quality<br>2. Cost | Minimum required hookload capacity to ensure planned casing string and other heavy loads can be handled as per plan. Engineering assessment of torque and drag required. Drilling units that do not meet this requirement will receive a FAIL flag. The link with quality and cost is related to potential changes that would be required to the ‘ideal’ well design to stay within the hookload limitations for the drilling unit. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | Input minimum hookload rating required based on planned scope | 600 mT | 600 mT |
| **Topdrive torque rating** | 1. Quality<br>2. Cost | Minimum required torque capacity to ensure loads can be handled as per plan. Engineering assessment of torque and drag required. Drilling units that do not meet this requirement will receive a FAIL flag. Inability to rotate the drilling string and/or liner (during cement job) impact both quality and costs since it ultimately impacts the drilling unit’s ability to deliver the wells as per plan. | | |
| | | **Selection** | **Scenario 1** | **Scenario 2** |
| | | Input minimum torque required based on planned scope | 1. More than 85 kNm<br>2. Less than 85 kNm | Same as scenario 1 |

## 4.10 Technical scoring

The technical scoring of a drilling unit is purely technical and not directly linked / converted into commercial impact through synthetic time / cost adjustments. The various elements are reviewed against planned scope and assigned a relative score of 0, 2, 4, 6, 8 or 10 points as per system below:

*Table 12 Scoring system used to assessment of technical specifications of the drilling units*

| Score | Definition | Description |
|---|---|---|
| **10** | Excellent | Contractor response and / or drilling unit specifications and capabilities exceeds requirements |
| **8** | Good | Technical requirements met |
| **5** | Adequate | Some shortfalls that can be rectified with minor commercial impact |
| **2** | Poor | Serious shortfalls that require extensive modifications |
| **0** | Non-compliant | Response is incomplete and/or acceptable judgement cannot be made |

The scoring of the technical elements should be based on an overall assessment of specific requirements for the scope and ideally backed up with an engineering report. Each element can also be weighted with a factor between 1,0 – 1,5 to reflect relevance and important for the scope.

*Table 13 Main components of technical scoring for drilling units used in the TCO model*

| Element | Score | Weight | Description |
|---|---|---|---|
| **BOP configuration / suitability** | 0-10 | 1,0 | A quick assessment of the BOP suitability for the project will be initially based on the number of pipe rams, shear rams and annular blowout preventers. In certain cases, there are internal requirements that go above the regulatory requirements, in which case deviations or non-conformance must be raised. The configuration of the BOP rams and placement of the kill and choke line outlets can also have an impact on efficiency during certain operations. |

| Element | Score | Weight | Description |
|---|---|---|---|
| **BOP control system** | 0-10 | 1,0 | Assign scoring for overall capability of the BOP control system: e.g., accumulator / subsea bottle capacity, acoustic system, ROV intervention, EDS configuration, etc. In addition, it must meet minimum internal and regulatory requirements. |
| **Wellhead connector suitability** | 0-10 | 1,0 | The connector suitability must be assessed both to ensure it is compatible with the wellhead profile and pressure / bending rating, especially for DP3 applications. In deepwater operations, suitability for 27" H4 mandrels, presence of hydrate seal and fatigue impact, must also be considered. |
| **Marine drilling riser** | 0-10 | 1,0 | Assign scoring based on sufficient length available for water depths, internal diameter of kill and choke lines, sufficiently rated boost line, inspection / certificate status and connector type. |
| **BOP testing set-up** | 0-10 | 1,0 | The drilling unit’s ability to do offline pressure testing and presence of green-light algorithms that reduce the testing time is evaluated. |
| **Moonpool systems** | 0-10 | 1,0 | This element covers set up in moonpool for efficient operations, again linked with scope for the project. Examples can be cherry pickers, cart for hanging off conductor / surface casing, separate area for hanging off CML / RMR pump and constant-tension winch with adequate wire length to reach seabed. |
| **VDL capacity and deck space** | 0-10 | 1,2 | The available variable deck load and deck space is highly important for efficient operations. Due to the complexity of the Loke development wells large amounts of equipment is needed which takes up a lot of deck space. This is also the reason why this element has been weighted with a factor of 1,2. The element is also linked with costs since it can to a certain degree be compensated for by having additional supply vessels in field. |
| **Fluid pits / tanks capacity** | 0-10 | 1,2 | Loke development wells have a complicated fluids program with several different types of fluids that will be used in the well at separate stages of the operations. Same as VDL and deck load, this is a very important element for Loke wells and will be weighted with a factor of 1,2. Scoring will be assigned based on active / reserve volume meets or exceeds requirements, number of silos, etc. |
| **Pit and tank cleaning systems / set-up** | 0-10 | 1,0 | With the different fluid systems requirement comes more cleaning of tanks and pits between the various phases of a well and between wells. An efficient tanks cleaning system will reduce the amount of time and resources required for this task. Assign scoring based on automated systems with demonstrated performance, whizzy heads, etc. |

| Element | Score | Weight | Description |
|---|---|---|---|
| **Cement unit** | | 1,0 | The cement unit setup is evaluated based on remote operability, LAS system, supply of bulk / fluids, maintenance- and track records. |
| **Completion set-up** | | 1,1 | The setup for completion operations is important for efficient completion running operations with consequent impact on both quality and cost value drivers. A weighing factor of 1,1 is therefore applied. |

## 4.11 Other non-technical and non-commercial elements

In addition to the various evaluation elements described previously in this document there are other qualitative considerations that should be made as part of the overall assessment. These elements can be used as input for the discussions in the later stages of the evaluation after a shorter list of drilling unit candidates are left. The evaluation of these elements is based on narrative, text or information gathered from the contractor in the tender process. Scoring is done with 'traffic' lights and may change and evolve over the evaluation phase as more information and clarifications are discussed with the contactor in engagement sessions.

- Green: No immediate issues to be resolved
- Amber: Some clarifications or issues to be investigated further
- Red: Potential showstoppers and/or issues the needs to be resolved

*Table 14 Other non-technical and non-commercial elements used in the TCO model*

| Topic | Score | Description and link with value drivers |
|---|---|---|
| **Availability versus planned commencement** | Green<br>Amber<br>Red | Reflects risk of delayed start or other negative impact on 'first-oil' promise. Based on the ranked value drivers in Table 2 and economic sensitivity checks in section 1.5 this is element can have a significant impact on the Loke development. Unresolved red light can potentially be a showstopper and justification to not proceed with the tender process for this drilling unit. |
| **Overall qualifications to contract** | Green<br>Amber<br>Red | Together with the commercial bids and technical information requested in the bid, the contactor will also return the contract framework with any clarifications of qualifications identified which needs to be resolved during discussion and negotiations phase. The severity and impact of the qualifications can vary significantly and in some cases conflict with the company's corporate fundamental principles. The traffic light is an objective assessment of the overall severity and number of qualifications and potential outcome of negotiations. |
| **Security set-up and readiness** | Green<br>Amber<br>Red | For operations in NCS this element is less relevant than operations in foreign waters, for example offshore Africa or other places where security can be an issue. The assessment should reflect maturity and recent / relevant experience level of contractor. |

| Topic | Score | Description and link with value drivers |
|---|---|---|
| **ABC / Due Diligence screening** | Green<br>Amber<br>Red | This type of check is normally performed prior to including the contractor in the invitation to tender and a range of standard questionnaires can be used to gather this information. Contractors with global footprint may have affiliates with foreign branches of where the consequences of any ABC incidents will not impact or hinder the contactor's right to conduct business in Norway. However, any ABC incidents should still be flagged for awareness for tender evaluation panel and, ultimately, the endorser of the evaluation panel's final recommendations. |
| **Financial status** | Green<br>Amber<br>Red | Based on separate financial questionnaire the financial health of the contractor's business can be investigated. One of the main risks can be that the contractor becomes insolvent or enters Chapter 11 during operations, which may have negative impact on schedule and therefore potentially big impact for the Loke development. If this risk is flagged (red traffic light) a letter of quiet enjoyment or other separate agreement to mitigate the risks should be discussed and agreed prior to signing the contract. |
| **Previous experience with horizontal ERD wells** | Green<br>Amber<br>Red | Previous experience that is relevant for the Loke development will generally be positive for the operations. Procedures and best practices may already have been developed and / or the crews are familiar with the main risks and challenges associated with the operations. This means improved likelihood of delivering robust wells within the given timeframe and schedule and therefore covers all value drivers. |
| **Previous experience with well test / unload to rig** | Green<br>Amber<br>Red | Same as previous point, but in this case more relevant for scenario 2 than scenario 1 (no well testing planned). |
| **Previous experience with depleted drilling** | Green<br>Amber<br>Red | Same as previous point. |

## 4.12 HSEQ and GHG management

HSEQ and GHG management will in most cases be closely linked with corporate strategic priorities that is reflected in all aspects of the business. Because of this these topics will go through higher level of scrutiny and assessment than the other qualitative topics. The information is gathered through custom made questionnaires, gathering of information and direct engagements between contractor and operator. The internal evaluation and assessment of the response and scoring is done by, or with input and support from, subject matter experts of specialists in these topics. Any major shortfalls or clarifications from the response will be covered in separate engagement sessions with the contractor as required.

The various responses are then ranked where the drilling unit with the highest score will be set to 100 and the others will be scored relative to this.

## 4.13 Ranking and weighing the evaluation criteria based on project value drivers

As described previously in this document the TCO model is used to compile and 'normalize' (where possible) much of the input received from the contractor in the bid. Whereas the TCO model mostly uses direct and indirect commercial elements that are weighted and derived based on value drivers for the project, there are also other elements that cannot so easily be transformed but are still important for the overall success of the project.

At the highest level, the elements can be placed into the following categories:

- Commercial (direct or indirect impact on costs)
- Technical (purely technical score, not transformed into commercial element)
- HSEQ (relative ranking between all units in tender, best unit scores 100)
- GHG strategy (relative ranking between all units in tender, best unit scores 100)

During the evaluation of all elements above, the link with value drivers has been used to influence the impact on the score, for example through additional weighting of the technical scoring as described in 4.10. As a result, the overall output from the TCO model is already reflecting the project value drivers to a certain degree.

However, the categories technical, HSEQ and GHG strategy are also linked with value drivers not only for the project but also corporate strategic priorities and targets. A separate weighing can be applied based on a predetermined allocation key that should already be defined in the contract strategy document prior to start of the tender process.

For Loke the weighing of these elements will be as follows:

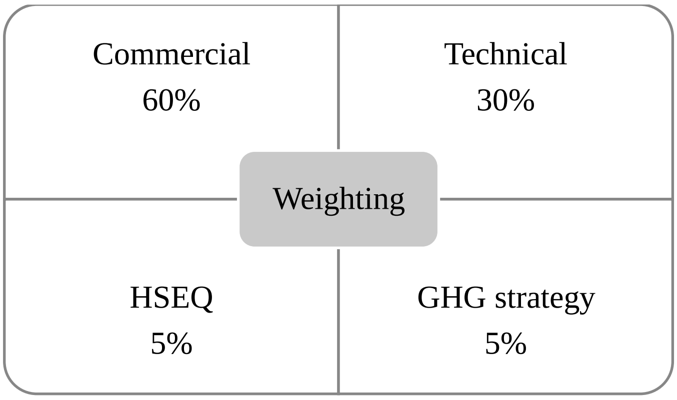



*Figure 8 Overall weighting of the main elements of the evaluation used in the TCO model*

## 4.14 Evaluation output

Based on the functional and technical requirements established in the scenarios defined (Table 4) and the and the actual specs and commercial elements for the various drilling units, the TCO model combines and merges the two sections and creates a total cost of ownership for all the drilling units for any given scenario which has been defined. In other words, the model can be used for quick comparison between the various drilling units for whatever scenario is defined. This can be useful if the company is considering contracting a drilling unit for a range of different projects with varying technical requirements. These projects can be different production licenses with different partners and stakeholders so the output from the TCO model can be used to show and explain the strengths and weaknesses of the recommended drilling unit based on the overall total cost of ownership.

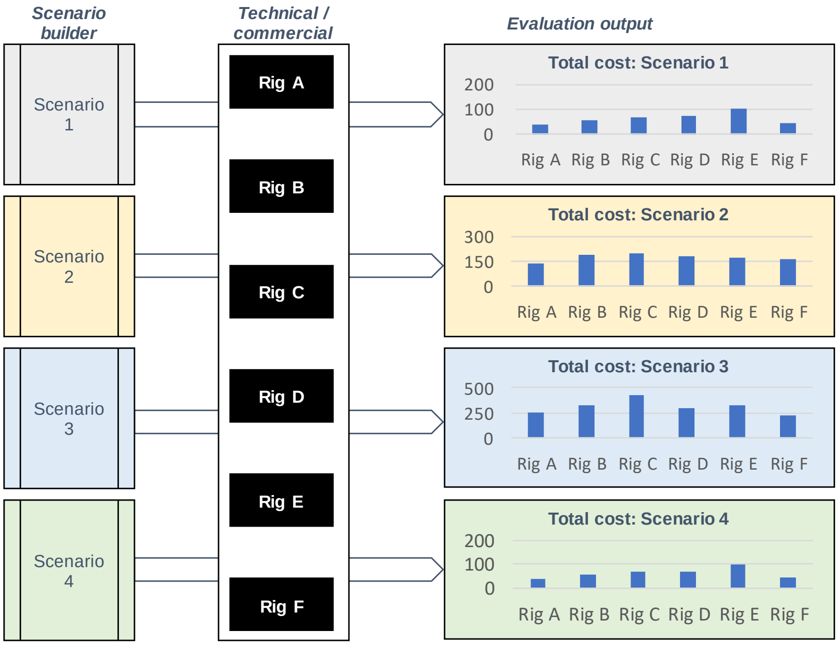



*Figure 9 Conceptual illustration of the TCO model*

## 4.15 Acquiring relevant data and information

Without a defined contract strategy and evaluation plan prior to the drilling unit tender process, it can be a challenge to determine and specify the information and documentation to be requested in the ITT. Typically, the norm has been to request "everything" and then go through and extract relevant pieces of information once the bids have been submitted.

As a result, the contractor spends significant time to compile and systematically organize the requested documentation. In most cases, only a very small portion of the documentation is relevant for the evaluation process. On the receiving end, the evaluation panel also spends significant time to sift through all the information received to find the relevant data for the evaluation. If the information request is not specific and to the point, there could be differences in the responses which means that it can be difficult or impossible to compare like-for-like between the various drilling units.

To mitigate this risk and improve the efficiency of the tender process, an 'input form' should be used with clear instructions and guidance for the contractor on what information is requested and, where applicable, which additional documentation should be provided (both mandatory and optional) as well as a numbering system for easy reference.

The input fields of the form should to the extent possible mirror the structure and layout of the TCO model. By doing this, the evaluation panel can transfer the responses directly into the model without the need to spend any time searching for the response and finding the correct value for the correct field.

Once a recommended shortlist of drilling units has been defined, additional documentation can be requested if and as required to go into more details on any specific topics or elements to finetune the results.

# 5 RESULTS AND DISCUSSION

## 5.1 Supplemental information

For the intend of demonstrating the TCO model a fictive tender evaluation has been simulated. The two scenarios as per Table 4 are summarized in detail in ***Attachment 1***.

Fictive contactor responses for 5 different drilling units have also been created, refer to ***Attachment 2*** for a detailed overview of the various responses.

The complete output matrix for all the various elements considered, scores, total cost and ranking can be found in ***Attachment 3*** and ***Attachment 4***.

## 5.2 Evaluation results

### *5.2.1 Scenario 1*

For the base case scenario 1 (Loke development) the ranking of the drilling units is as follows:

1. Rig C (day rate 520 kUSD/d)
2. Rig A (day rate 510 kUSD/d)
3. Rig B (day rate 460 kUSD/d)
4. Rig D (day rate 515 kUSD/d)

Rig E was disqualified due to technical limitations and Rig D is heavily penalized not having AoC and due to cold-stack status without fixed crews.

Despite being offered in with the highest day rate, Rig C still gives the lowest total costs for the Loke development. The main contributing factors for this result are related to operational efficiency and links with key value drivers for the project:

- Warm / active drilling unit with experienced crew
- Efficient operations with dual derricks and comprehensive offline capabilities
- CML already installed and included in rig rate
- Highest relative technical score compared with the other drilling units

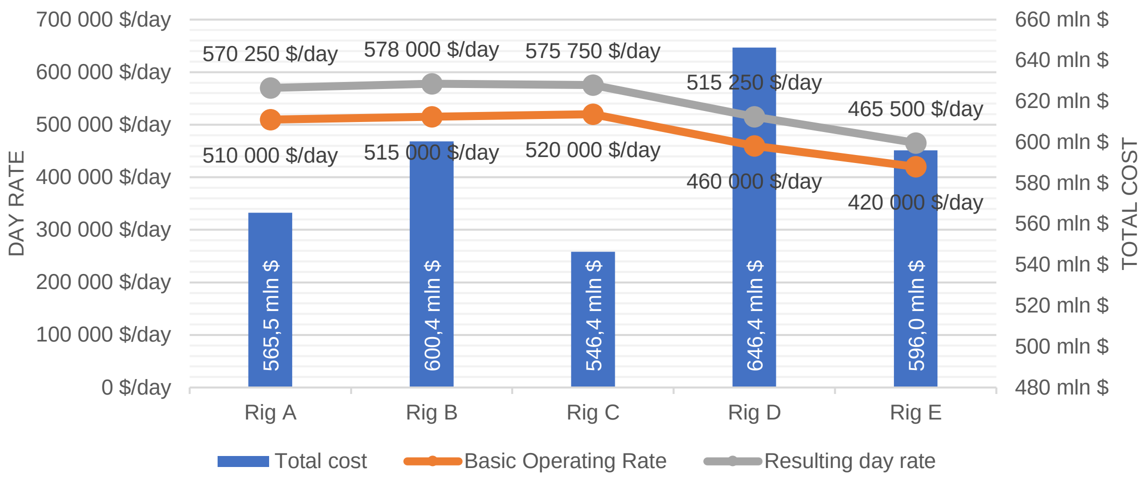



*Figure 10 Total cost and equivalent day rates for scenario 1 output from the TCO model*

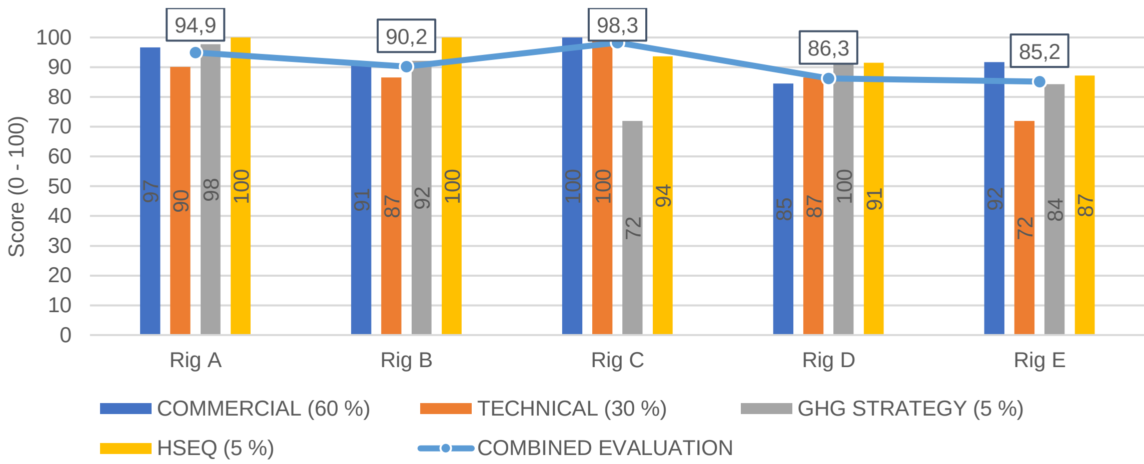



*Figure 11 Summary of scoring for the drilling units in the TCO model*

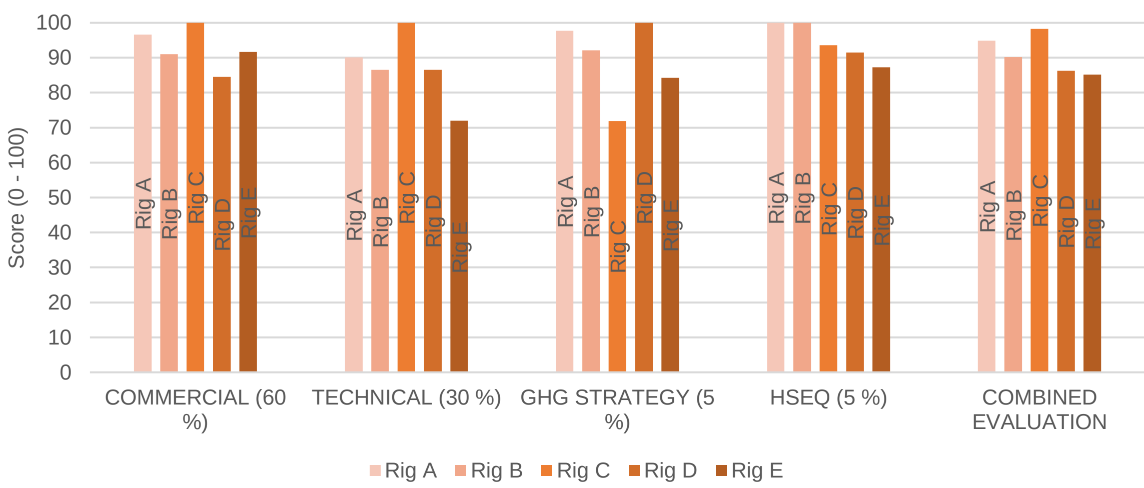



*Figure 12 Overview of scoring per category for the drilling units in the TCO model*

#### *5.2.2 Scenario 2*

Scenario 2 involves drilling of exploration and appraisal wells outside of the Loke area. This means operations in deeper waters and with dynamic position station keeping. Because of this, Rig B, Rig D and Rig E fail on minimum technical requirements. The final ranking of the remaining rigs is the same as for scenario 1:

1. Rig C (day rate 520 kUSD/d)
2. Rig A (day rate 510 kUSD/d)

## 5.3 Comparison of results: TCO versus lowest tender

Without a comprehensive evaluation model linked with value drivers for the project, the lowest tender (LT) evaluation would most likely be limited to the operating rate of the drilling unit and some additional simple elements related to costs.

In the bid for Loke Rig E has the lowest operating rate, but most likely still have been disqualified due to technical limitations, assuming the engineering work to define the operating envelopes has been done upfront prior to the tender. The drilling unit the second lowest operating rate would be Rig D which also meets all minimum requirements. However, by not considering the impact of being cold stacked, not having AoC and limited offline capabilities, a simple LT evaluation could potentially result in almost 20% extra costs for the project compared with selecting the recommended drilling unit from the TCO model (Rig C).

## 5.4 Additional sensitivities and/or adjustments

The TCO model used in this thesis is set up in a spreadsheet (Excel) with automated links between the scenarios and contractor inputs. This means that additional sensitivities can be performed by adjusting the impact of the evaluation criteria for the various scenarios. It also enables the evaluation panel to make any adjustments or fine-tunings as and if required in the evaluation phase provided the changes are thoroughly documented and justified. For example, the general spreadrate for the company that comes in addition to the daily operating rate for the drilling unit (including overheads, logistic costs, drilling, and completion services, etc.). This value will change the impact on total cost associated with time penalties / reductions for the different drilling units.

# 6 CONCLUSION

The success of a project is closely linked with all the different stages from initiation through to execution. Defining the value drivers for the project at an early stage provides guidance and steer for the many facets and sub-tasks needed to execute the project. The plan and overall objectives for the contract strategy should reflect the project value drivers, also in the tender evaluation phase. Based on the EMAT principle, a comprehensive drilling unit tender evaluation model, also known as total cost of ownership (TCO) model, was created where most of the various elements were linked back to the ranked list of value drivers for the project. In the examples used in this thesis it was seen that the use of this type of evaluation model saved project costs of 20% compared with conventional less sophisticated evaluation methods. These type of TCO models are scalable and can be applied for all types of tender evaluation processes that requires an assessment of non-technical / non-commercial elements which are considered critical for the success of the project.

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# ATTACHMENTS

# ATTACHMENT 1 – SCENARIOS

| Category | Description | Remarks | Selection | Scenario 1<br>Loke Phase I | Scenario 2<br>Loke Phase I + 4 exploration wells |
|---|---|---|---|---|---|
| Size of scope | **Drilling scope** | Duration of drilling phase (excluding mob). | # days | 300 days | 420 days |
| | **Completion scope** | Duration of completion phase (including handover). | # days | 200 days | 200 days |
| | **Total duration** | Duration of all scope. | # days | 500 days | 620 days |
| | **Moving days** | Estimated number of days moving rig between wells | # days | 1,25 days | 1,75 days |
| | **Number of wells** | Number of wells in campaign | # wells | 10 wells | 14 wells |
| | **Water depth** | Scenario specific | Depth | 130 | 600 |
| Non-technical elements with commercial impact | **Crew status and demographics** | New crews reduce efficiency, less impact for multi-well campaign (all scope). | 1. Regular crew | 0,0 % | 0,0 % |
| | | | 2. Partially new crew (<20%) | 1,0 % | 0,5 % |
| | | | 3. New crew (>20%) | 3,0 % | 2,0 % |
| | **Rig status** | Impacts performance, less impact for multi-well campaign (all scope). | 1. Active (hot) | 0 % | 0 % |
| | | | 2. Warm-stacked | 2,5 % | 2,0 % |
| | | | 3. Cold-stacked | 5,0 % | 4,0 % |
| | | | 4. New | 7,5 % | 6,0 % |
| | **Rig Intake / modification costs** | Subjective assessment: anticipated level of time and resources needed for rig intake and upgrades. | 1. Level 1 | $2 000 000 | $2 000 000 |
| | | | 2. Level 2 | $1 000 000 | $1 000 000 |
| | | | 3. Level 3 | $500 000 | $500 000 |
| | **SPS inspection status** | In principle, no SPS during contract duration, however, some scope might be required to maintain Class certification | 1. No SPS scheduled in campaign | 0 days | 0 days |
| | | | 2. SPS primarily done offline | 2 days | 2 days |
| | | | 3. SPS on critical path | 14 days | 14 days |
| | **AOC / SUT status** | AOC / SUT is required to operate on NCS. | 1. AOC / SUT in place | $ - | $ - |
| | | | 2. No AOC / SUT but built for NCS ops | $5 000 000 | $5 000 000 |
| | | | 3. No AOC / SUT | $30 000 000 | $30 000 000 |
| Commercial elements | **Rig Rate - Primary** | Operating Rate for Phase 1a | $/day | $/day | $/day |
| | **Not used** | Not used | | | |
| | **% Standby Rate** | Standby Rate offered as % of Operating Rate | % of OR | $/day | $/day |
| | **Standby Rate terms** | Subjective assessment based on qualifications: % time on Standby | 1. All terms accepted | 20 % | 20 % |
| | | | 2. 50% of terms accepted | 10 % | 10 % |

| Category | Description | Remarks | Selection | Scenario 1<br>Loke Phase I | Scenario 2<br>Loke Phase I + 4 exploration wells |
|---|---|---|---|---|---|
| | | mode depending on acceptance of the standby terms proposed in ITT | 3. 10% of terms accepted | 5 % | 5 % |
| | **% Moving Rate** | Moving Rate offered as % of Operating Rate (applies for BOP hopping and transit) | % of OR | $/day | $/day |
| | **Moving Rate days** | Approximate number of moving / transit days for selected scenario | # days | 8 days | 10 days |
| | **%Reduced Efficiency Rate** | Reduced Efficiency Rate offered as % of Operating Rate | % of OR | $/day | $/day |
| | **Reduced Efficiency Rate terms** | Subjective assessment based on qualifications: % of time on Reduced Efficiency mode depending on acceptance of the RER terms proposed in ITT | 1. All terms accepted | 5 % | 5 % |
| | | | 2. 50% of terms accepted | 3 % | 3 % |
| | | | 3. 10% of terms accepted | 1 % | 1 % |
| | **Accommodation and Catering** | Daily rate as offered in line with Appendix B of ITT | Daily Rate | $/day | $/day |
| | **Mob fee** | Lump sum or # days x Burn Rate | Cost element | $ | $ |
| | **Demob fee** | Lump sum or # days x Burn Rate | Cost element | $ | $ |
| | **Not used** | Not used | | | |
| | **Value of additional services** | Tubular running services (equipment and crew) | 1. Included | - $6 000 000 | - $7 200 000 |
| | | | 2. Not included | $ - | $ - |
| | | Solids Control Services | 1. Full SCS (equipment and crew) | - $4 000 000 | - $5 200 000 |
| | | | 2. Partial SCS | - $2 000 000 | - $2 600 000 |
| | | | 3. Not included | $ - | $ - |
| | | CML equipment and personnel | 1. Included | - $12 500 000 | - $15 500 000 |
| | | | 2. Not included | $ - | $ - |
| | | Centrifuges and mud vac units | 1. Included | - $250 000 | - $310 000 |
| | | | 2. Not included | $ - | $ - |
| | | ROV services | 1. Included (2 x WROV) | - $7 500 000 | - $9 300 000 |
| | | | 2. Included (1 x WROV) | - $7 500 000 | - $9 300 000 |
| | | | 3. Not included | $ - | $ - |
| | | Fishing equipment | 1. Included | - $500 000 | - $620 000 |
| | | | 2. Not included | $ - | $ - |
| | | Cementing unit | 1. Included | - $750 000 | - $930 000 |
| | | | 2. Not included | $ - | $ - |
| | | Drillpipe management | 1. All scope accepted | - $1 500 000 | - $1 860 000 |
| | | | 2. Partial scope accepted | - $250 000 | - $310 000 |

| | | | | Scenario 1 | Scenario 2 |
|---|---|---|---|---|---|
| **Category** | **Description** | **Remarks** | **Selection** | **Loke Phase I** | **Loke Phase I + 4 exploration wells** |
| | | | 3. Limited / no scope accepted | $ - | $ - |
| | | Additional transponders | 1. Included | - $125 000 | - $155 000 |
| | | | 2. Not included | $ - | $ - |
| | | All pit cleaning between wells and demob phase | 1. All scope accepted | - $10 000 000 | - $14 000 000 |
| | | | 2. Partial scope accepted | - $5 000 000 | - $7 000 000 |
| | | | 3. Limited / no scope accepted | $ - | $ - |
| | | IT and communications | 1. All scope accepted | - $1 750 000 | - $2 170 000 |
| | | | 2. Partial scope accepted | - $1 000 000 | - $1 240 000 |
| | | | 3. Limited / no scope accepted | $ - | $ - |
| | | Green Light or equivalent p-testing system | 1. Included | - $250 000 | - $310 000 |
| | | | 2. Not included | $ - | $ - |
| | | Shaker screens | 1. Included | - $320 000 | - $440 000 |
| | | | 2. Not included | $ - | $ - |
| | | Ditch magnets | 1. Included | - $125 000 | - $155 000 |
| | | | 2. Not included | $ - | $ - |
| | | Riser analysis | 1. Included | - $5 000 | - $5 000 |
| | | | 2. Not included | $ - | $ - |
| | | BOP acceptance testing | 1. Included | - $150 000 | - $150 000 |
| | | | 2. Not included | $ - | $ - |
| | | Wellhead and LMRP connector gaskets | 1. Included | - $30 000 | - $-30 000 |
| | | | 2. Not included | $ - | $ - |
| | | Other services included in rig rate (day rate) | $/day | $ - | $ - |
| | | Other services included in rig rate (Lump Sum) | Lump sum | $ | $ |
| **Technical elements with commercial impact** | **Dual rig capabilities** | Difference in days between dual- and 1.5 derrick | 1. Yes | 0,0 days | 0,0 days |
| | | | 2. No | 19,6 days | 27,4 days |
| | **Offline capabilities** | % improvement in efficiency (all scope). Comprehensive = capability for offline racking / stand-building, transfer between derricks, etc. Partial = bucking machine or similar. | 1. Comprehensive | 0,0 days | 0,0 days |
| | | | 2. Partial | 20,3 days | 28,5 days |
| | | | 3. Limited | 40,7 days | 57,0 days |
| | **Capabilities of Aux** | Full capabilities for compensated drilling and pumping - no impact, reduced capabilities will add penalty that counteracts dual derrick benefits | 1. Comprehensive | 0,0 days | 0,0 days |
| | | | 2. Partial | 4,9 days | 6,9 days |
| | | | 3. Limited | 9,8 days | 13,7 days |
| | | | 4. Not applicable | 0,0 days | 0,0 days |

| Category | Description | Remarks | Selection | Scenario 1<br>Loke Phase I | Scenario 2<br>Loke Phase I + 4 exploration wells |
|---|---|---|---|---|---|
| | **Performance factor based on KPI assessment** | Adjustment of time element based on relative comparison of performance KPI between drilling units. | Adjustment factor | Independent of scenarios | Independent of scenarios |
| | **Well test readiness** | Recent experience increases efficiency. Less experience adds time to completion scope (well test and unload to rig) and increases likelihood of modification costs. | 1. Less than 12 months | 0,0 % | 0,0 % |
| | | | 2. More than 12 months | 0,0 % | 1,5 % |
| | | | 3. No well test but all preps done | 0,0 % | 2,0 % |
| | | | 4. No previous experience with well test | 0,0 % | 3,0 % |
| | **Automation and digitalization** | Improved performance (reduction in time) depending on level of automation. | 1. Comprehensive | -2,0 % | -2,0 % |
| | | | 2. Partial | -1,0 % | -1,0 % |
| | | | 3. No | 0,0 % | 0,0 % |
| | **Wired pipe offered** | Time savings associated with wired pipe technology opportunities. | 1. Yes | -1,0 % | -1,0 % |
| | | | 2. No | 0,0 % | 0,0 % |
| | **Managed Pressure Drilling / CML** | Additional costs and impact to reflect various degree of CML readiness (example: costs for modified riser joint, modifications for top-fill pump, etc.) | 1. CML already installed | $ - | $ - |
| | | | 2. CML ready | $2 500 000 | $ 500 000 |
| | | | 3. Not used previously | $5 000 000 | $5 000 000 |
| | **Number of BOPs** | Estimated cost of upgrading to two identical BOPs is required. | 1. Two identical BOPs | $ - | $ - |
| | | | 2. Two BOPS - not identical | $ - | $ - |
| | | | 3. One BOP | $ - | $ - |
| | **Number of mud pumps** | Penalty applies for less than four mud pumps due to increased risk of NPT and/or lower ROP (drilling phase). | 1. Five rig pumps | 0,0 % | 0,0 % |
| | | | 2. Four rig pumps | 0,5 % | 0,5 % |
| | | | 3. Less than four rig pumps | 1,0 % | 1,0 % |
| | **Dual-fluid mud system** | Improved performance (reduction in time) resulting from dual-fluid system. | 1. Yes | -2,0 % | -2,0 % |
| | | | 2. No | 0,0 % | 0,0 % |
| | **Cementing and gravel pack through top drive** | Approximately 8 hrs of saving per well for cementing and gravel packing through top drive. | 1. Yes | -3,3 days | -4,7 days |
| | | | 2. No | 0,0 days | 0,0 days |
| | **Harsh weather operability** | Time adjustment based on anticipated WOW for expected weather conditions. To be backs up with separate analysis | 1. Very good | 0,0 % | 0,0 % |
| | | | 2. Adequate | 3,0 % | 3,0 % |
| | | | 3. Poor | 7,5 % | 7,5 % |
| | **Fuel Consumption** | Average amount of fuel consumed pr day against anticipated cost of fuel | $/day | $/day | $/day |

| | | | | Scenario 1 | Scenario 2 |
|---|---|---|---|---|---|
| **Category** | **Description** | **Remarks** | **Selection** | **Loke Phase I** | **Loke Phase I + 4 exploration wells** |
| **Technical Pass / Fail elements** | **Mud pump system pressure rating (psi)** | Pressure rating of mud system - minimum 7500 psi required. | 1. 7500 psi system | PASS | PASS |
| | | | 2. Less than 7500 psi | FAIL | FAIL |
| | **Station keeping** | Method of maintaining station. DP3 required. | 1. DP3 & POSMOOR | PASS | PASS |
| | | | 2. POSMOOR ONLY | PASS | FAIL |
| | **Max water depth** | Scenario specific | Depth | m | m |
| | **Hookload capacity, Main (MT)** | Minimum 600 MT required, Pass / Fail | MT | 600 | 600 |
| | **Topdrive torque rating (kNm)** | Minimum 65 kNm continuous required, Pass / Fail | 1. More than 85 kNm | PASS | PASS |
| | | | 2. Less than 85 kNm | FAIL | FAIL |

| | | | | | |
|---|---|---|---|---|---|
| **Technical scoring (0 - 10) & weighting factor** | **BOP configuration / suitability** | Assign scoring (e.g., presence of blind- and casing shear rams, test rams, etc.) | Score: 0, 2, 5, 8 or 10 | 1,0 | 1,0 |
| | **BOP control system** | Assign scoring (e.g., accumulator / subsea bottle capacity, acoustic system, ROV intervention, EDS configuration, etc.) | Score: 0, 2, 5, 8 or 10 | 1,0 | 1,0 |
| | **Wellhead connector suitability** | Assign scoring (e.g., bending ratings, suitability for 27" H4 mandrels, hydrate seal, etc.) | Score: 0, 2, 5, 8 or 10 | 1,0 | 1,0 |
| | **Marine drilling riser** | Assign scoring (e.g., sufficient quantity available for water depths, 4.1/2" ID k/c lines, 7500 psi rates booster line, etc.) | Score: 0, 2, 5, 8 or 10 | 1,0 | 1,0 |
| | **BOP testing set-up** | Assign scoring (e.g., offline testing for both BOPs, "greenlight" system, etc.) | Score: 0, 2, 5, 8 or 10 | 1,0 | 1,0 |
| | **Moonpool systems** | Assign scoring (e.g., cherry pickers, cart for hanging off conductor / surface casing, CT winch with adequate wire length to reach seabed, etc.) | Score: 0, 2, 5, 8 or 10 | 1,0 | 1,0 |
| | **VDL capacity and deck space** | Assign scoring (e.g., operational VDL meets or exceeds requirements, dedicated areas for well test, etc.) | Score: 0, 2, 5, 8 or 10 | 1,2 | 1,2 |
| | **Fluid pits / tanks capacity** | Assign scoring (e.g., active / reserve volume meets or exceeds requirements, number of silos, etc.) | Score: 0, 2, 5, 8 or 10 | 1,2 | 1,2 |

| | | | | Scenario 1 | Scenario 2 |
|---|---|---|---|---|---|
| **Category** | **Description** | **Remarks** | **Selection** | **Loke Phase I** | **Loke Phase I + 4 exploration wells** |
| | **Pit and tank cleaning systems / set-up** | Assign scoring (e.g., fully automated system with demonstrated performance, whizzy heads, etc.) | Score: 0, 2, 5, 8 or 10 | 1,0 | 1,0 |
| | **Cement unit** | Assign scoring (e.g., remote operated, LAS system, supply of bulk / fluids, etc.) | Score: 0, 2, 5, 8 or 10 | 1,0 | 1,0 |
| | **Completion set-up** | Assign scoring (e.g., control line sheaves, drill floor setup, etc.) | Score: 0, 2, 5, 8 or 10 | 1,1 | 1,1 |
| **GHG** | **GHG emission strategy and implementation** | Assign scoring based on GHG questionnaire | Score | | |
| **HSEQ performance** | **HSEQ performance** | Assign scoring based on HSZEQ questionnaire | Score | | |
| **Traffic lights** | **Availability versus planned commencement** | Traffic light - risks of delayed start and negative impact on 'first-oil' promise | 1. Green | | |
| | | | 2. Orange | | |
| | | | 3. Red | | |
| | **Overall qualifications to contract** | Objective assessment of number of qualifications and potential outcome of negotiations. | 1. Green | | |
| | | | 2. Orange | | |
| | | | 3. Red | | |
| | **Security set-up and readiness** | Overall assessment and maturity and recent / relevant experience level of contractor. | 1. Green | | |
| | | | 2. Orange | | |
| | | | 3. Red | | |
| | **ABC / Due Diligence screening** | Part of pre-screening assessment. | 1. Green | | |
| | | | 2. Orange | | |
| | | | 3. Red | | |
| | **Financial status** | Based on separate financial questionnaire. | 1. Green | | |
| | | | 2. Orange | | |
| | | | 3. Red | | |
| | **Not used** | Not used | 1. Green | | |
| | | | 2. Orange | | |

| | | | | Scenario 1 | Scenario 2 |
|---|---|---|---|---|---|
| **Category** | **Description** | **Remarks** | **Selection** | **Loke Phase I** | **Loke Phase I + 4 exploration wells** |
| | | | 3. Red | | |
| | **Previous experience with horizontal ERD wells** | Based on previous experience. | 1. Green | | |
| | | | 2. Orange | | |
| | | | 3. Red | | |
| | **Previous experience with well test / unload to rig** | Based on previous experience (commercial impact covered elsewhere). | 1. Green | | |
| | | | 2. Orange | | |
| | | | 3. Red | | |
| | **Previous experience with depleted drilling** | Applicable for both scenarios | 1. Green | | |
| | | | 2. Orange | | |
| | | | 3. Red | | |

# ATTACHMENT 2 – CONTRACTOR INPUTS AND SCORING

| | | Rig A | Rig B | Rig C | Rig D | Rig E |
|---|---|---|---|---|---|---|
| Info | Rig Name | Rig A | Rig B | Rig C | Rig D | Rig E |
| | Rig type | A-HF6 | GVA-4 | MCS-50 | GVA-75 | GG-25 |
| | Year Built | 2009 | 2015 | 2008 | 2009 | 2019 |
| | Rig owner / manager | Contractor 1 | Contractor 1 | Contractor 2 | Contractor 3 | Contractor 4 |
| Non-technical | Crew status and demographics | 1. Regular crew | 1. Regular crew | 1. Regular crew | 2. Partially new crew (<20%) | 3. New crew (>20%) |
| | Rig status | 1. Active (hot) | 1. Active (hot) | 1. Active (hot) | 3. Cold-stacked | 2. Warm-stacked |
| | Rig Intake / modification costs | 2. Level 2 | 2. Level 2 | 3. Level 3 | 1. Level 1 | 3. Level 3 |
| | SPS inspection status | 1. No SPS scheduled in campaign | 3. SPS on critical path | 1. No SPS scheduled in campaign | 1. No SPS scheduled in campaign | 2. SPS primarily done offline |
| | AOC / SUT status | 1. AOC / SUT in place | 1. AOC / SUT in place | 1. AOC / SUT in place | 3. No AOC / SUT | 1. AOC / SUT in place |
| Commercial elements | Rig Rate - Primary | 510 000 $/day | 515 000 $/day | 520 000 $/day | 460 000 $/day | 420 000 $/day |
| | % Standby Rate | 98 % | 98 % | 85 % | 95 % | 95 % |
| | Standby Rate terms | 3. 10% of terms accepted | 3. 10% of terms accepted | 2. 50% of terms accepted | 3. 10% of terms accepted | 1. All terms accepted |
| | % Moving Rate | 85 % | 85 % | 80 % | 75 % | 75 % |
| | %Reduced Efficiency Rate | 75 % | 75 % | 75 % | 80 % | 75 % |
| | Reduced Efficiency Rate terms | 2. 50% of terms accepted | 2. 50% of terms accepted | 3. 10% of terms accepted | 3. 10% of terms accepted | 1. All terms accepted |
| | Accommodation and Catering | 2 500 $/day | 2 500 $/day | 3 500 $/day | 3 000 $/day | 1 500 $/day |
| | Mob fee | 500 000 $ | 500 000 $ | 0 $ | 1 500 000 $ | 0 $ |
| | Demob fee | 1 000 000 $ | 1 000 000 $ | 750 000 $ | 1 500 000 $ | 0 $ |
| | Tubular running services (equipment and crew) | 2. Not included | 2. Not included | 2. Not included | 1. Included | 1. Included |
| | Solids Control Services | 2. Partial SCS | 3. Not included | 1. Full SCS (equipment and crew) | 2. Partial SCS | 2. Partial SCS |
| | CML equipment and personnel | 2. Not included | 2. Not included | 1. Included | 2. Not included | 2. Not included |
| | Centrifuges and mud vac units | 1. Included | 1. Included | 1. Included | 2. Not included | 2. Not included |
| | ROV services | 3. Not included | 3. Not included | 3. Not included | 3. Not included | 2. Included (1 x WROV) |
| | Fishing equipment | 2. Not included | 2. Not included | 1. Included | 1. Included | 2. Not included |
| | Cementing unit | 2. Not included | 2. Not included | 2. Not included | 1. Included | 2. Not included |
| | Drillpipe management | 3. Limited / no scope accepted | 3. Limited / no scope accepted | 1. All scope accepted | 2. Partial scope accepted | 2. Partial scope accepted |
| | Additional transponders | 1. Included | 1. Included | 1. Included | 1. Included | 1. Included |
| | All pit cleaning between wells and demob phase | 2. Partial scope accepted | 2. Partial scope accepted | 1. All scope accepted | 2. Partial scope accepted | 1. All scope accepted |

| | | Rig A | Rig B | Rig C | Rig D | Rig E |
|---|---|---|---|---|---|---|
| | IT and communications | 2. Partial scope accepted | 2. Partial scope accepted | 3. Limited / no scope accepted | 3. Limited / no scope accepted | 2. Partial scope accepted |
| | Green Light or equivalent p-testing system | 2. Not included | 2. Not included | 1. Included | 1. Included | 1. Included |
| | Shaker screens | 1. Included | 1. Included | 2. Not included | 2. Not included | 2. Not included |
| | Ditch magnets | 1. Included | 1. Included | 1. Included | 1. Included | 1. Included |
| | Riser analysis | 1. Included | 1. Included | 1. Included | 1. Included | 1. Included |
| | BOP acceptance testing | 2. Not included | 2. Not included | 2. Not included | 1. Included | 2. Not included |
| | Wellhead and LMRP connector gaskets | 1. Included | 1. Included | 1. Included | 1. Included | 1. Included |
| | Other services included in rig rate (day rate) | | | | | |
| | Other services included in rig rate (Lump Sum) | | | | | |
| **Technical elements with commercial impact** | Dual rig capabilities | 1. Yes | 2. No | 1. Yes | 2. No | 2. No |
| | Offline capabilities | 2. Partial | 2. Partial | 1. Comprehensive | 2. Partial | 2. Partial |
| | Capabilities of Aux | 1. Comprehensive | 4. Not applicable | 1. Comprehensive | 4. Not applicable | 4. Not applicable |
| | Performance factor based on KPIs | 0,985 | 1,000 | 0,975 | 0,950 | 0,925 |
| | Well test readiness | 1. Less than 12 months | 2. More than 12 months | 3. No well test but all preps done | 4. No previous experience with well test | 4. No previous experience with well test |
| | Automation and digitalization | 3. No | 1. Comprehensive | 3. No | 3. No | 2. Partial |
| | Wired pipe offered | 2. No | 1. Yes | 2. No | 2. No | 2. No |
| | Managed Pressure Drilling / CML | 2. CML ready | 3. Not used previously | 1. CML already installed | 3. Not used previously | 2. CML ready |
| | Number of BOPs | 3. One BOP | 3. One BOP | 3. One BOP | 3. One BOP | 3. One BOP |
| | Number of mud pumps | 2. Four rig pumps | 2. Four rig pumps | 2. Four rig pumps | 2. Four rig pumps | 3. Less than four rig pumps |
| | Dual-fluid mud system | 2. No | 2. No | 2. No | 1. Yes | 2. No |
| | Cementing and gravel pack through top drive | 1. Yes | 2. No | 2. No | 2. No | 1. Yes |
| | Harsh weather operability | 1. Very good | 1. Very good | 2. Adequate | 2. Adequate | 3. Poor |
| | Fuel Consumption | 42 MT/d | 44 MT/d | 38 MT/d | 38 MT/d | 32 MT/d |
| **Technical Pass / Fail elements** | Mud pump system pressure rating (psi) | 1. 7500 psi system | 1. 7500 psi system | 1. 7500 psi system | 1. 7500 psi system | 2. Less than 7500 psi |
| | Station keeping | 1. DP3 & POSMOOR | 1. DP3 & POSMOOR | 1. DP3 & POSMOOR | 2. POSMOOR ONLY | 2. POSMOOR ONLY |
| | Max water depth | 1500 m | 500 m | 3000 m | 2800 m | 900 m |
| | Hookload capacity, Main (MT) | 908 MT | 750 MT | 907 MT | 750 MT | 600 MT |
| | Topdrive torque rating (kNm) | 1. More than 85 kNm | 1. More than 85 kNm | 1. More than 85 kNm | 1. More than 85 kNm | 2. Less than 85 kNm |

| | | Rig A | Rig B | Rig C | Rig D | Rig E |
|---|---|---|---|---|---|---|
| Traffic lights | Availability versus planned commencement | 2. Orange | 3. Red | 1. Green | 1. Green | 1. Green |
| | Overall qualifications to contract | 2. Orange | 2. Orange | 1. Green | 2. Orange | 1. Green |
| | Security set-up and readiness | 1. Green | 1. Green | 1. Green | 1. Green | 1. Green |
| | ABC / Due Diligence screening | 1. Green | 1. Green | 1. Green | 1. Green | 1. Green |
| | Financial status | 2. Orange | 2. Orange | 1. Green | 3. Red | 3. Red |
| | Previous experience with horizontal ERD wells | 2. Orange | 2. Orange | 1. Green | 2. Orange | 2. Orange |
| | Previous experience with well test / unload to rig | 2. Orange | 2. Orange | 2. Orange | 2. Orange | 2. Orange |
| | Previous experience with depleted drilling | 1. Green | 2. Orange | 1. Green | 2. Orange | 2. Orange |
| GHG emission score | Score based on GHG questionnaire (max score = 100) | 87,0 | 82,0 | 64,0 | 89,0 | 75,0 |
| HSEQ score | Score based on HSEQ questionnaire (max score = 100) | 94,0 | 94,0 | 88,0 | 86,0 | 82,0 |
| Technical scoring (0 - 10) | BOP configuration / suitability | 8. Good | 8. Good | 8. Good | 8. Good | 8. Good |
| | BOP control system | 8. Good | 8. Good | 8. Good | 8. Good | 8. Good |
| | Wellhead connector suitability | 8. Good | 8. Good | 8. Good | 8. Good | 8. Good |
| | Marine drilling riser | 8. Good | 8. Good | 8. Good | 8. Good | 8. Good |
| | BOP testing set-up | 8. Good | 8. Good | 8. Good | 8. Good | 8. Good |
| | Moonpool systems | 8. Good | 8. Good | 8. Good | 8. Good | 8. Good |
| | VDL capacity and deck space | 5. Adequate | 2. Poor | 5. Adequate | 8. Good | 8. Good |
| | Fluid pits / tanks capacity | 5. Adequate | 2. Poor | 5. Adequate | 5. Adequate | 8. Good |
| | Pit and tank cleaning systems / set-up | 5. Adequate | 5. Adequate | 5. Adequate | 5. Adequate | 5. Adequate |
| | Cement unit | 8. Good | 8. Good | 8. Good | 8. Good | 8. Good |
| | Completion set-up | 5. Adequate | 5. Adequate | 5. Adequate | 5. Adequate | 5. Adequate |

# ATTACHMENT 3 – TCO OUTPUT, SCENARIO 1

| | | Rig A | | Rig B | | Rig C | | Rig D | | Rig E | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Info | Rig Name | Rig A | | Rig B | | Rig C | | Rig D | | Rig E | |
| Info | Rig type | A-HF6 | | GVA-4 | | MCS-50 | | GVA-75 | | GG-25 | |
| Info | Year Built | 2009 | | 2015 | | 2008 | | 2009 | | 2019 | |
| Info | Rig owner / manager | Contractor 1 | | Contractor 1 | | Contractor 2 | | Contractor 3 | | Contractor 4 | |
| Non-technical | Crew status and demographics | 0,0 days | | 0,0 days | | 0,0 days | | 0,0 days | | 0,0 days | |
| Non-technical | Rig status | 0,0 days | | 0,0 days | | 0,0 days | | 25,0 days | | 12,5 days | |
| Non-technical | Rig Intake / modification costs | $ 1 000 000 | | $ 1 000 000 | | $ 500 000 | | $ 2 000 000 | | $ 500 000 | |
| Non-technical | SPS inspection status | 0,0 days | | 14,0 days | | 0,0 days | | 0,0 days | | 2,0 days | |
| Non-technical | AOC / SUT status | $ - | | $ - | | $ - | | $ 30 000 000 | | $ - | |
| Commercial elements | Rig Rate - Primary | 510 000 $/day | | 515 000 $/day | | 520 000 $/day | | 460 000 $/day | | 420 000 $/day | |
| Commercial elements | Not used | 0 $/day | | 0 $/day | | 0 $/day | | 0 $/day | | 0 $/day | |
| Commercial elements | % Standby Rate | 98 % | | 98 % | | 85 % | | 95 % | | 95 % | |
| Commercial elements | Standby Rate terms | 25,0 days | $ -255 000 | 25,0 days | $ -257 500 | 50,0 days | $ -3 900 000 | 25,0 days | $ -575 000 | 100,0 days | $ -2 100 000 |
| Commercial elements | % Moving Rate | 85 % | | 85 % | | 80 % | | 75 % | | 75 % | |
| Commercial elements | Moving days | 1,3 days | $ -95 625 | 1,3 days | $ -96 563 | 1,3 days | $ -130 000 | 1,3 days | $ -143 750 | 1,3 days | $ -131 250 |
| Commercial elements | %Reduced Efficiency Rate | 75 % | | 75 % | | 75 % | | 80 % | | 75 % | |
| Commercial elements | Reduced Efficiency Rate terms | 12,5 days | $ -1 593 750 | 12,5 days | $ -1 609 375 | 5,0 days | $ -650 000 | 5,0 days | $ -460 000 | 25,0 days | $ -2 625 000 |
| Commercial elements | Accommodation and Catering | 2 500 $/d | | 2 500 $/d | | 3 500 $/d | | 3 000 $/d | | 1 500 $/d | |
| Commercial elements | Mob fee | $ 500 000 | | $ 500 000 | | $ - | | $ 1 500 000 | | $ - | |
| Commercial elements | Demob fee | $ 1 000 000 | | $ 1 000 000 | | $ 750 000 | | $ 1 500 000 | | $ - | |
| Commercial elements | Not used | 0 $/d | | 0 $/d | | 0 $/d | | 0 $/d | | 0 $/d | |
| Commercial elements | Tubular running services (equipment and crew) | $ - | | $ - | | $ - | | $ -6 000 000 | | $ -6 000 000 | |
| Commercial elements | Solids Control Services | $ -2 000 000 | | $ - | | $ -4 000 000 | | $ -2 000 000 | | $ -2 000 000 | |
| Commercial elements | CML equipment and personnel | $ - | | $ - | | $ -12 500 000 | | $ - | | $ - | |
| Commercial elements | Centrifuges and mud vac units | $ -250 000 | | $ -250 000 | | $ -250 000 | | $ - | | $ - | |
| Commercial elements | ROV services | $ - | | $ - | | $ - | | $ - | | $ -7 500 000 | |
| Commercial elements | Fishing equipment | $ - | | $ - | | $ -500 000 | | $ -500 000 | | $ - | |
| Commercial elements | Cementing unit | $ - | | $ - | | $ - | | $ -750 000 | | $ - | |
| Commercial elements | Drillpipe management | $ - | | $ - | | $ -1 500 000 | | $ -250 000 | | $ -250 000 | |
| Commercial elements | Additional transponders | $ -125 000 | | $ -125 000 | | $ -125 000 | | $ -125 000 | | $ -125 000 | |
| Commercial elements | All pit cleaning between wells and demob phase | $ -5 000 000 | | $ -5 000 000 | | $ -10 000 000 | | $ -5 000 000 | | $ -10 000 000 | |
| Commercial elements | IT and communications | $ -1 000 000 | | $ -1 000 000 | | $ -1 000 000 | | $ -1 000 000 | | $ -1 000 000 | |
| Commercial elements | Green Light or equivalent p-testing system | $ - | | $ - | | $ -250 000 | | $ -250 000 | | $ -250 000 | |
| Commercial elements | Shaker screens | $ -320 000 | | $ -320 000 | | $ - | | $ - | | $ - | |
| Commercial elements | Ditch magnets | $ -125 000 | | $ -125 000 | | $ -125 000 | | $ -125 000 | | $ -125 000 | |
| Commercial elements | Riser analysis | $ -5 000 | | $ -5 000 | | $ -5 000 | | $ -5 000 | | $ -5 000 | |
| Commercial elements | BOP acceptance testing | $ - | | $ - | | $ - | | $ -150 000 | | $ - | |
| Commercial elements | Wellhead and LMRP connector gaskets | $ -30 000 | | $ -30 000 | | $ -30 000 | | $ -30 000 | | $ -30 000 | |
| Commercial elements | Other services included in rig rate (day rate) | 0 $/day | | 0 $/day | | 0 $/day | | 0 $/day | | 0 $/day | |
| Commercial elements | Other services included in rig rate (Lump Sum) | $ - | | $ - | | $ - | | $ - | | $ - | |

**Technical elements with commercial impact**

| | | | | | |
|---|---|---|---|---|---|
| Dual rig capabilities | 0,0 days | 19,6 days | 0,0 days | 19,6 days | 19,6 days |
| Offline capabilities | 20,3 days | 20,3 days | 0,0 days | 20,3 days | 20,3 days |
| Capabilities of Aux | 0,0 days | 9,8 days | 0,0 days | 9,8 days | 9,8 days |
| Performance factor based on KPIs | -7,5 days | 0,0 days | -12,5 days | -25,0 days | -37,5 days |
| Well test readiness | 0,0 days | 0,0 days | 0,0 days | 0,0 days | 0,0 days |
| Automation and digitalisation | 0,0 days | -10,0 days | 0,0 days | 0,0 days | -5,0 days |
| Wired pipe offered | 0,0 days | -5,0 days | 0,0 days | 0,0 days | 0,0 days |
| Managed Pressure Drilling / CML | $ 2 500 000 | $ 5 000 000 | $ - | $ 5 000 000 | $ 2 500 000 |
| Number of BOPs | $ - | $ - | $ - | $ - | $ - |
| Number of mud pumps | 2,5 days | 2,5 days | 2,5 days | 2,5 days | 5,0 days |
| Dual-fluid mud system | 0,0 days | 0,0 days | 0,0 days | -10,0 days | 0,0 days |
| Cementing and gravel pack through top drive | -3,3 days | 0,0 days | 0,0 days | 0,0 days | -3,3 days |
| Harsh weather operability | 0,0 days | 0,0 days | 15,0 days | 15,0 days | 37,5 days |
| Fuel Consumption | 57 750 $/d | 60 500 $/d | 52 250 $/d | 52 250 $/d | 44 000 $/d |
| ***Cost elements*** | *$ -3 855 000* | *$ 645 000* | *$ -29 035 000* | *$ 23 815 000* | *$ -24 285 000* |
| ***Time elements*** | *12,0 days* | *51,2 days* | *5,0 days* | *57,2 days* | *60,9 days* |
| ***Day rate elements*** | *570 250 $/day* | *578 000 $/day* | *575 750 $/day* | *515 250 $/day* | *465 500 $/day* |
| ***Total time*** | ***512,0 days*** | ***551,2 days*** | ***505,0 days*** | ***557,2 days*** | ***560,9 days*** |
| ***Total cost*** | ***549,3 mln $*** | ***600,4 mln $*** | ***519,3 mln $*** | ***595,1 mln $*** | ***522,9 mln $*** |

**Technical Pass / Fail elements**

| | | | | | |
|---|---|---|---|---|---|
| Mud pump system pressure rating (psi) | PASS | PASS | PASS | PASS | FAIL |
| Stationkeeping | PASS | PASS | PASS | PASS | PASS |
| Max water depth | PASS | PASS | PASS | PASS | PASS |
| Hookload capacity, Main (MT) | PASS | PASS | PASS | PASS | FAIL |
| Topdrive torque rating (kNm) | PASS | PASS | PASS | PASS | FAIL |
| ***Overall*** | ***PASS*** | ***PASS*** | ***PASS*** | ***PASS*** | **FAIL** |

**Technical scoring (0 - 10)**

| | | | | | |
|---|---|---|---|---|---|
| BOP configuration / suitability | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ |
| BOP control system | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ |
| Wellhead connector suitability | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ |
| Marine drilling riser | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ |
| BOP testing set-up | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ |
| Moonpool systems | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ |
| VDL capacity and deck space | 6 ◑ | 2,4 ◔ | 6 ◑ | 9,6 ◕ | 9,6 ◕ |
| Fluid pits / tanks capacity | 6 ◑ | 2,4 ◔ | 6 ◑ | 6 ◑ | 9,6 ◕ |
| Pit and tank cleaning systems / set-up | 5 ◑ | 5 ◑ | 5 ◑ | 5 ◑ | 5 ◑ |
| Cement unit | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ | 8 ◕ |
| Completion set-up | 5,5 ◑ | 5,5 ◑ | 5,5 ◑ | 5,5 ◑ | 5,5 ◑ |
| ***Overall technical score*** | ***7,1*** | ***6,5*** | ***7,1*** | ***7,5*** | ***7,8*** |

| | | | | | | |
|---|---|---|---|---|---|---|
| GHG emmission score | Score based on GHG questionnaire (max score = 100) | ***87*** | ***82*** | ***64*** | ***89*** | ***75*** |
| HSEQ score | Score based on HSEQ questionnaire (max score = 100) | ***94*** | ***94*** | ***88*** | ***86*** | ***82*** |
| Weighting and ranking | **COMMERCIAL (60 %)** | 94,5 | 86,5 | 100,0 | 87,3 | 99,3 |
| | **TECHNICAL (30 %)** | 91,6 | 83,2 | 91,6 | 95,8 | 100,0 |
| | **GHG STRATEGY (5 %)** | 97,8 | 92,1 | 71,9 | 100,0 | 84,3 |
| | **HSEQ (5 %)** | 100,0 | 100,0 | 93,6 | 91,5 | 87,2 |
| | **COMBINED EVALUATION** | 94,1 | 86,5 | 95,8 | 90,7 | 98,2 |
| | **FINAL RANKING** | **2 PASS** | **4 PASS** | **1 PASS** | **3 PASS** | **FAIL** |
| Traffic lights | Availability versus planned commencement | 🟡 | 🔴 | 🟢 | 🟢 | 🟢 |
| | Overall qualifications to contract | 🟡 | 🟡 | 🟢 | 🟡 | 🟢 |
| | Security set-up and readiness | 🟢 | 🟢 | 🟢 | 🟢 | 🟢 |
| | ABC / Due Diligence screening | 🟢 | 🟢 | 🟢 | 🟢 | 🟢 |
| | Financial status | 🟡 | 🟡 | 🟢 | 🔴 | 🔴 |
| | Not used | 🟢 | 🟢 | 🟢 | 🟢 | 🟢 |
| | Previous experience with horizontal ERD wells | 🟡 | 🟡 | 🟢 | 🟡 | 🟡 |
| | Previous experience with well test / unload to rig | 🟡 | 🟡 | 🟡 | 🟡 | 🟡 |
| | Previous experience with depleted drilling | 🟢 | 🟡 | 🟢 | 🟡 | 🟡 |

# ATTACHMENT 4 – TCO OUTPUT, SCENARIO 2

| | | Rig A | | Rig B | | Rig C | | Rig D | | Rig E | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Info | Rig Name | Rig A | | Rig B | | Rig C | | Rig D | | Rig E | |
| | Rig type | A-HF6 | | GVA-4 | | MCS-50 | | GVA-75 | | GG-25 | |
| | Year Built | 2009 | | 2015 | | 2008 | | 2009 | | 2019 | |
| | Rig owner / manager | Contractor 1 | | Contractor 1 | | Contractor 2 | | Contractor 3 | | Contractor 4 | |
| Non-technical | Crew status and demographics | 0,0 days | | 0,0 days | | 0,0 days | | 0,0 days | | 0,0 days | |
| | Rig status | 0,0 days | | 0,0 days | | 0,0 days | | 24,8 days | | 12,4 days | |
| | Rig Intake / modification costs | $ 1 000 000 | | $ 1 000 000 | | $ 500 000 | | $ 2 000 000 | | $ 500 000 | |
| | SPS inspection status | 0,0 days | | 14,0 days | | 0,0 days | | 0,0 days | | 2,0 days | |
| | AOC / SUT status | $ - | | $ - | | $ - | | $ 30 000 000 | | $ - | |
| Commercial elements | Rig Rate - Primary | 510 000 $/day | | 515 000 $/day | | 520 000 $/day | | 460 000 $/day | | 420 000 $/day | |
| | Not used | 0 $/day | | 0 $/day | | 0 $/day | | 0 $/day | | 0 $/day | |
| | % Standby Rate | 98 % | | 98 % | | 85 % | | 95 % | | 95 % | |
| | Standby Rate terms | 31,0 days | $ -316 200 | 31,0 days | $ -319 300 | 62,0 days | $ -4 836 000 | 31,0 days | $ -713 000 | 124,0 days | $ -2 604 000 |
| | % Moving Rate | 85 % | | 85 % | | 80 % | | 75 % | | 75 % | |
| | Moving days | 1,8 days | $ -133 875 | 1,8 days | $ -135 188 | 1,8 days | $ -182 000 | 1,8 days | $ -201 250 | 1,8 days | $ -183 750 |
| | %Reduced Efficiency Rate | 75 % | | 75 % | | 75 % | | 80 % | | 75 % | |
| | Reduced Efficiency Rate terms | 15,5 days | $ -1 976 250 | 15,5 days | $ -1 995 625 | 6,2 days | $ -806 000 | 6,2 days | $ -570 400 | 31,0 days | $ -3 255 000 |
| | Accommodation and Catering | 2 500 $/d | | 2 500 $/d | | 3 500 $/d | | 3 000 $/d | | 1 500 $/d | |
| | Mob fee | $ 500 000 | | $ 500 000 | | $ - | | $ 1 500 000 | | $ - | |
| | Demob fee | $ 1 000 000 | | $ 1 000 000 | | $ 750 000 | | $ 1 500 000 | | $ - | |
| | Not used | 0 $/d | | 0 $/d | | 0 $/d | | 0 $/d | | 0 $/d | |
| | Tubular running services (equipment and crew) | $ - | | $ - | | $ - | | $ -7 200 000 | | $ -7 200 000 | |
| | Solids Control Services | $ -2 600 000 | | $ - | | $ -5 200 000 | | $ -2 600 000 | | $ -2 600 000 | |
| | CML equipment and personnel | $ - | | $ - | | $ -15 500 000 | | $ - | | $ - | |
| | Centrifuges and mud vac units | $ -310 000 | | $ -310 000 | | $ -310 000 | | $ - | | $ - | |
| | ROV services | $ - | | $ - | | $ - | | $ - | | $ -9 300 000 | |
| | Fishing equipment | $ - | | $ - | | $ -620 000 | | $ -620 000 | | $ - | |
| | Cementing unit | $ - | | $ - | | $ - | | $ -930 000 | | $ - | |
| | Drillpipe management | $ - | | $ - | | $ -1 860 000 | | $ -310 000 | | $ -310 000 | |
| | Additional transponders | $ -155 000 | | $ -155 000 | | $ -155 000 | | $ -155 000 | | $ -155 000 | |
| | All pit cleaning between wells and demob phase | $ -7 000 000 | | $ -7 000 000 | | $ -14 000 000 | | $ -7 000 000 | | $ -14 000 000 | |
| | IT and communications | $ -1 240 000 | | $ -1 240 000 | | $ -1 240 000 | | $ -1 240 000 | | $ -1 240 000 | |
| | Green Light or equivalent p-testing system | $ - | | $ - | | $ -310 000 | | $ -310 000 | | $ -310 000 | |
| | Shaker screens | $ -440 000 | | $ -440 000 | | $ - | | $ - | | $ - | |
| | Ditch magnets | $ -155 000 | | $ -155 000 | | $ -155 000 | | $ -155 000 | | $ -155 000 | |
| | Riser analysis | $ -5 000 | | $ -5 000 | | $ -5 000 | | $ -5 000 | | $ -5 000 | |
| | BOP acceptance testing | $ - | | $ - | | $ - | | $ -150 000 | | $ - | |
| | Wellhead and LMRP connector gaskets | $ -30 000 | | $ -30 000 | | $ -30 000 | | $ -30 000 | | $ -30 000 | |
| | Other services included in rig rate (day rate) | 0 $/day | | 0 $/day | | 0 $/day | | 0 $/day | | 0 $/day | |
| | Other services included in rig rate (Lump Sum) | $ - | | $ - | | $ - | | $ - | | $ - | |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Technical elements with commercial impact** | Dual rig capabilities | 0,0 days | 27,4 days | 0,0 days | 27,4 days | 27,4 days |
| | Offline capabilities | 28,5 days | 28,5 days | 0,0 days | 28,5 days | 28,5 days |
| | Capabilities of Aux | 0,0 days | 13,7 days | 0,0 days | 13,7 days | 13,7 days |
| | Performance factor based on KPIs | -9,3 days | 0,0 days | -15,5 days | -31,0 days | -46,5 days |
| | Well test readiness | 0,0 days | 3,0 days | 4,0 days | 6,0 days | 6,0 days |
| | Automation and digitalisation | 0,0 days | -12,4 days | 0,0 days | 0,0 days | -6,2 days |
| | Wired pipe offered | 0,0 days | -6,2 days | 0,0 days | 0,0 days | 0,0 days |
| | Managed Pressure Drilling / CML | $ 2 500 000 | $ 5 000 000 | $ - | $ 5 000 000 | $ 2 500 000 |
| | Number of BOPs | $ - | $ - | $ - | $ - | $ - |
| | Number of mud pumps | 3,1 days | 3,1 days | 3,1 days | 3,1 days | 6,2 days |
| | Dual-fluid mud system | 0,0 days | 0,0 days | 0,0 days | -12,4 days | 0,0 days |
| | Cementing and gravel pack through top drive | -4,7 days | 0,0 days | 0,0 days | 0,0 days | -4,7 days |
| | Harsh weather operability | 0,0 days | 0,0 days | 18,6 days | 18,6 days | 46,5 days |
| | Fuel Consumption | 57 750 $/d | 60 500 $/d | 52 250 $/d | 52 250 $/d | 44 000 $/d |
| | ***Cost elements*** | *$ -6 935 000* | *$ -1 835 000* | *$ -38 135 000* | *$ 19 295 000* | *$ -32 305 000* |
| | ***Time elements*** | *17,6 days* | *71,1 days* | *10,2 days* | *78,7 days* | *85,3 days* |
| | ***Day rate elements*** | *570 250 $/day* | *578 000 $/day* | *575 750 $/day* | *515 250 $/day* | *465 500 $/day* |
| | ***Total time*** | ***637,6 days*** | ***691,1 days*** | ***630,2 days*** | ***698,7 days*** | ***705,3 days*** |
| | ***Total cost*** | ***686,8 mln $*** | ***755,4 mln $*** | ***651,0 mln $*** | ***741,1 mln $*** | ***661,2 mln $*** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Technical Pass / Fail elements** | Mud pump system pressure rating (psi) | PASS | PASS | PASS | PASS | FAIL |
| | Stationkeeping | PASS | PASS | PASS | FAIL | FAIL |
| | Max water depth | PASS | FAIL | PASS | PASS | PASS |
| | Hookload capacity, Main (MT) | PASS | PASS | PASS | PASS | FAIL |
| | Topdrive torque rating (kNm) | PASS | PASS | PASS | PASS | FAIL |
| | ***Overall*** | ***PASS*** | ***FAIL*** | ***PASS*** | ***FAIL*** | ***FAIL*** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Technical scoring (0 - 10)** | BOP configuration / suitability | 8 | 8 | 8 | 8 | 8 |
| | BOP control system | 8 | 8 | 8 | 8 | 8 |
| | Wellhead connector suitability | 8 | 8 | 8 | 8 | 8 |
| | Marine drilling riser | 8 | 8 | 8 | 8 | 8 |
| | BOP testing set-up | 8 | 8 | 8 | 8 | 8 |
| | Moonpool systems | 8 | 8 | 8 | 8 | 8 |
| | VDL capacity and deck space | 6 | 2,4 | 6 | 9,6 | 9,6 |
| | Fluid pits / tanks capacity | 6 | 2,4 | 6 | 6 | 9,6 |
| | Pit and tank cleaning systems / set-up | 5 | 5 | 5 | 5 | 5 |
| | Cement unit | 8 | 8 | 8 | 8 | 8 |
| | Completion set-up | 5,5 | 5,5 | 5,5 | 5,5 | 5,5 |
| | ***Overall technical score*** | ***7,1*** | ***6,5*** | ***7,1*** | ***7,5*** | ***7,8*** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **GHG emmission score** | Score based on GHG questionnaire (max score = 100) | ***87*** | ***82*** | ***64*** | ***89*** | ***75*** |
| **HSEQ score** | Score based on HSEQ questionnaire (max score = 100) | ***94*** | ***94*** | ***88*** | ***86*** | ***82*** |
| **Weighting and ranking** | **COMMERCIAL (60 %)** | 94,8 | 86,2 | 100,0 | 87,8 | 98,5 |
| | **TECHNICAL (30 %)** | 91,6 | 83,2 | 91,6 | 95,8 | 100,0 |
| | **GHG STRATEGY (5 %)** | 97,8 | 92,1 | 71,9 | 100,0 | 84,3 |
| | **HSEQ (5 %)** | 100,0 | 100,0 | 93,6 | 91,5 | 87,2 |
| | **COMBINED EVALUATION** | 94,2 | 86,3 | 95,8 | 91,0 | 97,6 |
| | **FINAL RANKING** | **2 PASS** | **4 FAIL** | **1 PASS** | **3 FAIL** | **FAIL** |
| **Traffic lights** | Availability versus planned commencement | 🟡 | 🔴 | 🟢 | 🟢 | 🟢 |
| | Overall qualifications to contract | 🟡 | 🟡 | 🟢 | 🟡 | 🟢 |
| | Security set-up and readiness | 🟢 | 🟢 | 🟢 | 🟢 | 🟢 |
| | ABC / Due Diligence screening | 🟢 | 🟢 | 🟢 | 🟢 | 🟢 |
| | Financial status | 🟡 | 🟡 | 🟢 | 🔴 | 🔴 |
| | Not used | 🟢 | 🟢 | 🟢 | 🟢 | 🟢 |
| | Previous experience with horizontal ERD wells | 🟡 | 🟡 | 🟢 | 🟡 | 🟡 |
| | Previous experience with well test / unload to rig | 🟡 | 🟡 | 🟡 | 🟡 | 🟡 |
| | Previous experience with depleted drilling | 🟢 | 🟡 | 🟢 | 🟡 | 🟡 |