University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/Specialization: Master´s degree programme in Offshore Technology – Industrial Asset Management	Spring semester, 2016 Open / ~~Restricted access~~
Writer: Hilde Marie Hårde	…………………………………………. (Writer's signature)
Faculty supervisor: Jonas Odland External supervisor(s):	
Thesis title: The competition between Norwegian and Far East yards in fabrication of offshore platforms and modules	
Credits (ECTS): 30	
Key words: Norwegian yards Far East yards Market situation Competition Fabrication Cost development Norwegian value creation Gjøa, Edvard Grieg, Goliat, Ivar Aasen, Aasta Hansteen	Pages: 97 + Enclosure: 10 Stavanger, 13.06.2016 Date/year

The competition between Norwegian and Far East yards in fabrication of offshore platforms and modules

By

Hilde Marie Hårde

A Thesis
Presented to the Faculty of Science and Technology University of Stavanger

In Fulfilment of the Requirements for the degree of Master of Science (MSc)

University of Stavanger

Faculty of Science and Technology

2016

Abstract

For each specific offshore development project the partnership agrees on a project execution strategy and a contract strategy. These strategies determine how the project will be executed - how the contracts will be defined, awarded and followed up. The facility will often have a combination of “local” and “global” content. For fabrication in Norway the Norwegian value creation will be the contract value minus the value of imported goods and services. For fabrication in the Far East, the Norwegian value creation will be the value of Norwegian goods and services used in the fabrication.

It has been a common understanding that Far East fabrication is less expensive than Norwegian fabrication and Far East yards have won an increasing number of contracts. This has mainly happened during the last ten years, a period with dramatic cost increases worldwide. However, the market is currently changing and three main contributing factors to this has been illuminated in this thesis:

- Globalization
- Oil price
- Currency

With the reduced oil price, and a change by approximately 30 pct. in the ratio between Norwegian kroner and American dollars, there is a general trend towards a reduced cost level. At the same time, the globalization of the industry is increasing the competition for contracts on the Norwegian continental shelf, forcing the yards to give more competitive prices. This thesis seeks to discover whether this new market situation has changed the competition between Norwegian and Far East yards.

A qualitative research study has been conducted by collecting primary data through interviews, and secondary data from books, news articles, reports, and online databases. Through a study of the current trends and challenges in the industry today, the current market situation has been discussed and evaluated. Further, a quantitative analysis of five representative project developments has been conducted regarding their cost development and level of Norwegian content, in order to get a deeper understanding of how the market situation has influenced them. The analysis includes the projects: Gjøa, Edvard Grieg, Goliat, Ivar Aasen, and Aasta Hansteen. These projects vary in both technical concept and fabrication yard. The analysis shows a general cost increase in all the five project developments. In addition, the level of Norwegian content in the developments indicates a trend where the projects with the lowest level of Norwegian content are also those projects with the largest cost overrun and delay.

This thesis is aimed at providing useful insight towards the current market situation and its effect on the facility topside contractors, with focus on the competition between Norwegian and Far East yards. The work conducted throughout this thesis shows that the new market situation has contributed to a change in the competition between the two. The trend being that while the Far East yards are struggling to meet their expectations, the Norwegian yards are increasing their competitiveness in the competition for contracts on the Norwegian continental shelf.

Acknowledgements

I would like to express my sincere appreciation and gratitude to those who have contributed and helped me along the way, to make this thesis a reality. I am truly thankful for everything each and every one of you has done for me! I could never have done it without you!

Thanks to my supervisor
A big thank you goes to my supervisor, Jonas Odland (Professor II at the University of Stavanger). I am so grateful for the support, patience, and guidance. Jonas has given me great insight, and provided me with valuable feedback and advice throughout the whole thesis. Thank you so much, Jonas!

Thanks to Terje Birkenes
I´m so thankful for all the help I have received from Terje (Project Manager at Repsol). Despite his busy day-to-day life, he took his time to help me, mentoring me, and giving me valuable advice, input and guidance. Thank you so much for all the interesting conversations and for taking your time to share your experience with me!

Thanks to Ernst Abrahamsen
I would like to give a huge thank you to Ernst Abrahamsen (Principal Advisor – Project Planning and Execution at Acona) for participating in my thesis. Thank you for taking your time to give me valuable input and knowledge about petroleum operations on the Norwegian continental shelf.

Thanks to Tore Guldbrandsøy
I would like to express my gratitude to Tore Guldbrandsøy (Senior Vice President & Head of Stavanger Office at Rystad Energy) for participating in my thesis. Thank you for sharing your expertise and knowledge about the industry, and the industry market.

Thanks to my friends and study partners
I´m sincerely thankful to all I have shared my university experience with. Thank you for all the fun times, help and support. Thank you for being there through the long and challenging days. Thank you for making my time at the university so memorable!

Thanks to my family
Finally, I would like to thank my family. They have been a massive support throughout my whole time at the university. I could never have done it without their love and help. I am so lucky to have you, and I am forever grateful!

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List of Abbreviations

ACES – Acona Cost Estimating System
AoC – Acknowledgment of Compliance
CAPEX – Capital Expense
CVP – Capital Value Process
DSME – Daewoo Shipbuilding and Marine Engineering
EPC – Engineering, Procurement and Construction
EPCH – Engineering, Procurement, Construction and Hook-up
EPCI – Engineering, Procurement, Construction and Installation
EPMA – Engineering, Procurement and Management
EU – European Unions
FC – Fabrication and Construction
FEED – Front End Engineering Design
FID – Financial Investment Decision
FLAGS – Far North Liquids and Associated Gas System
FPSO – Floating Production, Storage and Offloading
HHI – Hyundai Heavy Industries
HSE – Health, Security and Environment
HPHT – High Pressure, High Temperature
INTSOK – (Norwegian: Internasjonalisering av samordning av oljeaktiviteten)
ISO – International Organization for Standardization
IT – Information Technology
LO – Norwegian Confederation of Trade Unions (Norwegian: Landsorganisasjonen i Norge)
Mill. – Millions
MMO – Maintenance, Modification and Operations
MPE – Ministry of Petroleum and Energy (Norwegian: Olje - og Energi Departementet)
NCS – Norwegian Continental Shelf
NGL – Natural Gas Liquids
NTK – Norwegian Total Contract (Norwegian: Norsk Total Kontrakt)
NOK – Norwegian kroner
NORSOK – (Norwegian: Norsk Sokkels Konkurranseposisjon)
NPD – The Norwegian Petroleum Directorate
OPEC – Organization of the Petroleum Exporting Countries
OPEX – Operating Expense
Pct. – Percent
PDO – Plan for Development and Operation
PDQ – Process, Drilling and Quarters
PLEM – Pipeline End Manifold
PLET – Pipeline End Terminations
PSA – Petroleum Safety Authority

RB – Riser Base
SHI – Samsung Heavy Industries
Sm^3 – Standard cubic meter
SMOE – SembCorp Marine´s Subsidiary
T – T connection
UiS – University of Stavanger (Norwegian: Universitetet i Stavanger)
USA – United States of America
U.S. – United States
USD – United States Dollars
UFR – Umbilicals, Flowlines, Risers
WHP – Well Head Production
Y – Y connection

PART 1: Background and objective

1 Introduction

1.1 Background

For each specific offshore development project the partnership agrees on a project execution strategy and a contract strategy. These strategies determine how the project will be executed - how the contracts will be defined, awarded and followed up. The platform project will have combination of “local” and “global” content. For fabrication in Norway the Norwegian value creation will be the contract value minus the value of imported goods and services. For fabrication in the Far East, the Norwegian value creation will be the value of Norwegian goods and services used in the fabrication.

It has been a common understanding that Far East fabrication is less expensive than Norwegian fabrication and Far East yards have won an increasing number of contracts. This has mainly happened during the last ten years, a period with dramatic cost increases worldwide. Today, because of the reduced oil price there is a general trend towards a reduced cost level. At the same time, the ratio between NOK and USD has changed by around 30 pct. Lastly; the globalization of the industry is increasing the competition for contracts on the Norwegian continental shelf (NCS). This has contributed to a new market situation, with new challenges and opportunities.

1.2 Objective of study

The objective of this study is to reflect on how the current market situation is affecting the competition between Norwegian and Far East yards in fabrication of offshore platforms and modules. By selecting a number of different and representative projects an analysis of how the new market situation may have affected the project developments has been conducted. The analyses of the fields give a description of each project individually regarding the actual cost development, level of Norwegian content, and experiences related to the execution of the project.

1.3 Important problems to be illuminated

Listed underneath are the most important problems:

- What are the reasons for selection of fabrication yard?
- What are the main differences between Norwegian and Far East yards in fabrication of offshore platforms and modules?
- How has the cost and execution time developed through the representative development projects?
- What is the level of Norwegian content in the representative development projects?
- How does the level of Norwegian content impact the representative development projects?
- Has the competition between Norwegian and Far East yards changed because of the new market situation?

1.4 Choice of development projects

In this thesis, five representative projects on the NCS have been selected for further analysis. In order to create a good foundation for the analysis and to make it possible to compare some of the projects, a variety of projects have been selected. The projects vary in technical concept, contract type, and yard of fabrication. An overview of the projects is displayed in table 1.1 below.

Table 1.1: Overview of development projects for analysis

Name	Field type	Development solution	Fabrication yard (topside)	Recoverable reserves		Development period	Start up
				Oil/condensate mill. Sm^3	Gas bill. Sm^3		
Gjøa	Gas (oil)	Anchored semi	Kværner Stord	13,20	39,70	2007-2010	F2010*
Goliat	Oil (gas)	FPSO (Sevan)	Hyundai Heavy Industries	30,50	7,30	2010-2014	S2016*
Edvard Grieg	Oil	Fixed platform	Kværner Stord	26,20	1,80	2012-2015	F2015
Ivar Aasen	Oil (gas)	Fixed platform	SMOE Ltd. Singapore	18,30	5,30	2013-2016	(F2016)
Aasta Hansteen	Gas	Anchored SPAR	Hyundai Heavy Industries	0,90	46,50	2014-2018	(F2018)

* F= fall, S= spring

As one can see, the selected projects contain both gas - and oil fields, and are all middle-large fields with different development solutions. Edvard Grieg and Ivar Aasen have fixed platforms, Gjøa an anchored semi, Aasta Hansteen an anchored SPAR, and Goliat a Sevan development. Three of the development projects are fabricated on Far East yards, and two of them on Norwegian yards.

The development period stretches from 2007 to 2018. All of the development projects are now in production, except Ivar Aasen, which has expected start up in late 2016, and Aasta Hansteen which has expected start up in late 2018.

1.5 Earlier analyses

Previously there have been done several larger analyses of petroleum projects to survey the level of Norwegian content and value creation in different projects. A list of the most known are listed below (Holmelin, 2015):

- Statoil: Social analysis of Statoil establishment of gas-based industry Tjeldbergodden. Agenda 1996
- ConocoPhillips: Ekofisk II. Evaluation of social effects. Asplan Viak ca. 2000
- MPE: Demand impulses for Norwegian industry of petroleum activities on the Norwegian continental shelf. Agenda 2004
- Norwegian Oil and Gas: Regional impact assessment North Sea. Evaluation of four development projects. Agenda 2006
- MPE: Norwegian value creation in development of petroleum fields. Agenda 2015

Previously it has also been done analyses of the increasingly international market the oil- and gas industry has evolved to be, and how this has influenced the competitiveness of the Norwegian offshore yards. Also, evaluations of the cost development of projects implemented on the NCS have been conducted. The most frequently referred to in this thesis is listed below:

- Rystad Energy: International revenue from Norwegian oil service companies. Report, The Ministry of Petroleum and Energy. 2015
- KonKraft: Norwegian Offshore Yards Competitiveness. 2013
- NPD: Evaluation of projects implemented on the Norwegian shelf. 2013

1.6 Methodology

1.6.1 General

This thesis will present both quantitative and qualitative research strategies.

Qualitative research
Within the domain of qualitative research the data was collected through primary data from interviews, and secondary data from books, news articles, reports, online databases, etc. In addition, relevant presentations and lecture notes given by the professors at the University of Stavanger (UiS) throughout this masters degree form the theoretical foundation of the thesis.

Quantitative research
Within the domain of quantitative research there have been presented estimates of the cost development and Norwegian content of five offshore field developments, based on the information and data gathered from the qualitative research study.

1.6.2 Interview

To better understand and describe the competition between Norwegian and Far East yards two interviews were conducted. The participants in the interviews were asked to reflect on their experiences and knowledge of companies' execution of offshore development projects, regarding the new market situation. This includes the different companies´ processes when choosing contractor, contract type and fabrication yard. The participants in the interviews were Tore Guldbrandsøy (Senior Vice President & Head of Stavanger Office at Rystad Energy), and Ernst Abrahamsen (Principal Advisor – Project Planning and Execution at Acona). The interview protocol is presented in Appendix 1.

1.6.3 ACES

In the quantitative research study the Acona cost estimating system (ACES) has been used. ACES is a calculations tool in Excel that has been used throughout this thesis to make the estimates for the selected project developments. An example of the cost estimates of the Gjøa development done in ACES is presented in Appendix 2.

1.7 Methods for analyses of petroleum development projects

1.7.1 What does a development project involve?

The companies that have jointly come together to develop the petroleum field are the project´s owners of the development license. The development project involves license´s economical responsibility areas, i.e. all installations that are needed to produce petroleum and get the product delivered to the market (Holmelin, 2015).

Therefore, development projects involve fixed installations on the field, including the production unit that can be an FPSO, platform, Sevan etc., subsea installations, intra-field pipelines, risers, and wells. Further, offshore loading facilities for oil and potential gas – and oil pipelines that connect the field to other fields nearby or to regional pipelines are included. In addition, potential modification work that is needed other places to be able to receive petroleum from development projects, and potential power supply from other fields nearby is also a part of the development (Holmelin, 2015).

The cost of the export facilities for oil and gas varies a lot between the different development projects, depending on the export solution, distance to existing infrastructure etc. (Holmelin, 2015). In order to get a fair comparison between the development projects, the export facilities and the potential modification work needed other places, have not been included in the thesis.

1.7.2 What does Norwegian value creation mean?

According to Holmelin’s delimitations (2013) he defines Norwegian value creation as follows:

“With Norwegian value creation in a contract one means, for production that is conducted in Norway, the contract value, deducting the value of goods and services that are imported to the production from abroad. For production that is conducted abroad, or on the Norwegian continental shelf with foreign ships and drilling facilities, one means the value of the Norwegian produced goods and services that are delivered to this production.”

1.7.3 Method for calculation of Norwegian content

The numbers for calculating the Norwegian content in the development projects, except Ivar Aasen, have mostly been gathered from a report created by the Ministry of petroleum and energy (Holmelin, 2015). The report is based on numbers collected from the operator companies of the different development projects. In addition, other relevant webpages, news articles, and reports have been used. As Ivar Aasen was not represented in the report by the Ministry of Petroleum and Energy, the numbers for calculating the Norwegian content in the project is based on the plan for development and operation (PDO), the factpages of the Norwegian petroleum directorate, news articles, and other relevant webpages. All the collected information and numbers were further inserted in ACES in order to get the estimates for the level of Norwegian content in the five projects.

1.7.4 Method for calculation of cost development

The method for calculating the cost development for the five representative projects is similar to the method for calculating the Norwegian content. The information was gathered from the same resources and further inserted in ACES to get the estimates.

1.8 Delimitations of the study

Offshore field development projects are enormous and complex. Many factors and variables are involved when analysing each project. The projects selected for further analysis have some major differences related to cost, development, and location. Thus, some constraints were necessary in order to get a fair comparison. In addition, some of the projects are not yet fully completed (Ivar Aasen and Aasta Hansteen) therefore some of the information needed was challenging to uncover. For this thesis, the constraints include the following:

- Export facilities have not been included in the thesis, since the cost of them varies a lot between the different developments, and is very dependent on where they are located, type of development, etc.
- Modifications work needed elsewhere is not included.
- The thesis focuses on the fabrication of the topside and substructure of the field developments.

1.9 Structure of the thesis

The thesis has been divided into five main parts. Part one consists of the sections regarding the background and objective of the thesis. Part two comprises the theory foundation of the thesis, consisting of chapters 2-5. A brief introduction is given to the Petroleum Safety Authority, the capital value process, the tendering process and related contract theory. Part three consisting of the chapters 6 and 7, a deeper understanding of the current market situation is given, with its current trends and challenges. Part four and five represent the two main parts in the thesis. Part four comprises the analyses of the five project developments. And finally, in part 5 the discussion and conclusion is presented.

In this part a brief introduction to the theoretical foundation of the thesis is presented. This includes a short description of the Petroleum Safety Authority, the capital value process, the tender process, and lastly, associated contract theory.

2 Petroleum Safety Authority

The Norwegian petroleum industry is well organized, with clearly defined areas of responsibility. This is to ensure that important public interests are taken into consideration and that resources are utilized as efficiently as possible by the petroleum industry (Norwegian Petroleum, 2016). An overview of the state organization of petroleum activities is shown in figure 2.1.

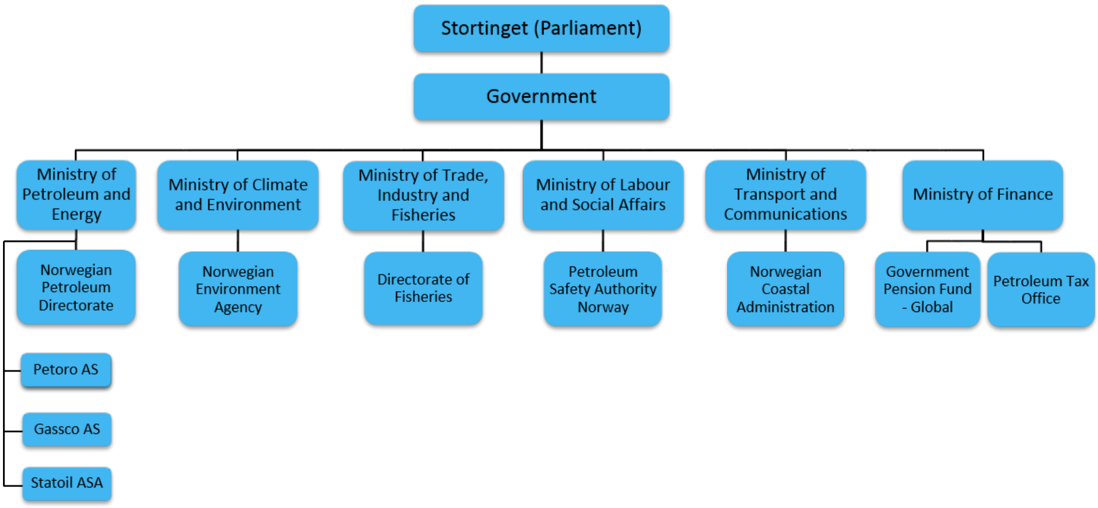

Figure 2.1: State organization of petroleum activities

Source: (Norwegian Petroleum, 2016)

The Petroleum Safety Authority (PSA) serves as the regulator for the working environment, emergency preparedness, and operational and technical safety in all phases of the petroleum industry on the NCS. Meaning that they supervise every stage in offshore development projects from initial planning, through the design, fabrication and if necessary decommissioning of the project (Petroleum Safety Authority Norway, 2016b). A description of all the different stages in an offshore field development is further discussed in chapter 3.

The Ministry of Labour and Social Affairs has delegated authority to the PSA to issue more detailed regulations for the working environment and the safety in the industry. The guidelines to the regulations often refer to known standards, such as NORSOK

(A definition of NORSOK will be presented in subchapter 6.2), as a way to achieve the functional requirements of the regulations. In addition, they are authorised to take company-detailed decisions in the form of consents and permits, enforcement fines, orders, prohibitions, halting operations, exemptions, etc. (Petroleum Safety Authority Norway, 2016b).

Duties
The government has issued the following duties to PSA (Petroleum Safety Authority Norway, 2016b):

- Through their own assessments and in cooperation with other HSE regulators, to sustain that the petroleum industry and related activities are supervised in a consistent manner.
- To advise and supply information to the actors in the industry, to found an appropriate collaboration with other HSE regulators domestically and internationally, and to contribute actively to transferring knowledge about HSE to society in general.
- To offer input and support to the supervising ministry on difficulties being dealt with by the latter.

In accordance with the Petroleum Safety Authority (Petroleum Safety Authority Norway, 2016b), their goal is as follows:

"The Petroleum Safety Authority Norway will set the terms for health, safety, the environment and emergency preparedness in the petroleum sector, ensure that the industry players maintain high standards in this area, and thereby contribute to creating maximum value for society."

3 The operators´ capital value process

3.1 Introduction

Planning, deciding, and implementing a large offshore development is a large administrative challenge. Petroleum projects are known for their high level of complexity, the amount of money involved, and the high risk (Gudmestad et al., 2010).

To cope with the challenges involved in these developments, many companies in the industry have created their own processes to follow when carrying out large projects. These processes include procedures, principles, and models. The thesis focuses mainly on the process created and used by Statoil Hydro, which it calls the capital value process (CVP). The company have created this process based on its experience from its many years in the industry (Gudmestad et al., 2010).

The CVP is a systematized decision process aimed to achieve competitive and predictable investments, by combining all utilities into one operative process where an investment project is developed from a business prospect into the most profitable operation for the total value chain in agreement with the company's corporate requirements (StatoilHydro, 2008). A development project involves several critical events, from license award to end of production, which define the stages (Gudmestad et al., 2010). Figure 3.1 below illustrates the different stages, which will be discussed further in the chapter.

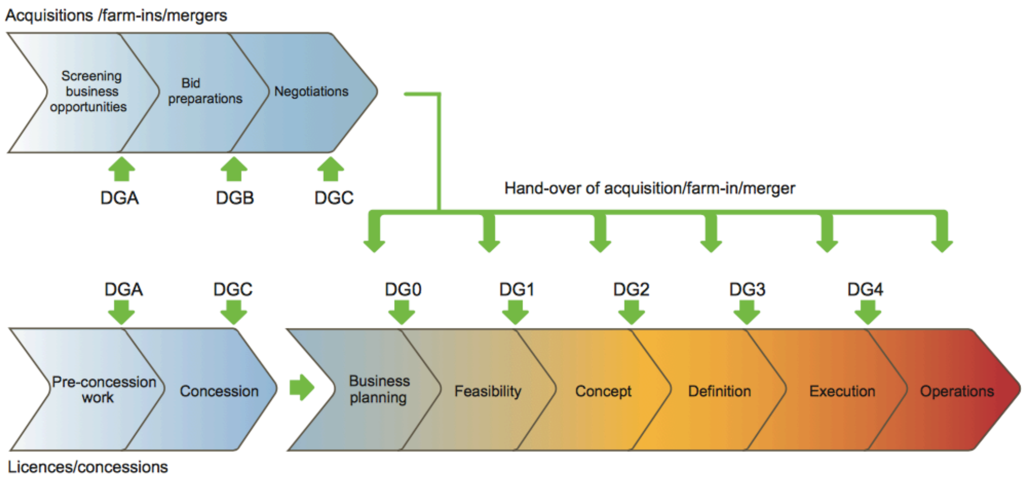

Figure 3.1: The operators' capital value process

Source: (StatoilHydro, 2008)

3.2 The basic structure of the capital value process

1) Feasibility stage

In this stage the main objective is to put together the first execution model and project strategy to establish whether or not the hydrocarbon resources are economically and technically feasible, as well as to document a viable technical and commercial concept. Already here the project will start to go in a direction that can favorize Norwegian or Far East yards. Traditionally, the prequalification of the contractors has not started in this stage, but market surveys are initiated to give input to the contractors' strategy.

2) Concept stage

The objective of this stage is to choose the one concept that the company wishes to develop. The profitability and feasibility of the concept has to be confirmed, and the prequalification of contractors is started.

Detailed estimates for the whole development need to be established at this point. Putting together the estimates is a comprehensive task. The estimates should cover everything from logistics to follow-up costs of the construction activities in the project execution. These estimates affect the contract strategy because they show the robustness of the project. A meeting with the PSA is also conducted in this stage, in order to get concept approval.

3) Definition stage

The objective in this stage is to develop and document the scope and project requirements to such a level that a final execution model and contract strategy can be made; this process is called the front end engineering development (FEED). An illustration of FEED is shown in figure 3.2 below. In addition, the PDO has to be sent to the authorities, and contracts can be entered into (Gudmestad et al., 2010). As a result the operators will achieve a more predictable execution of the project.

FEED is crucial for a project in order to avoid large expensive or impossible changes at a later stage in the project. Important decisions can be relatively inexpensive, as long as they are implemented at an early stage in the project process. Any decisions and changes done after the financial investment decisions (FID) are taken are guaranteed to be more expensive and complicated to conduct. Thus, it is vital to make the right decisions from the beginning of the project development (OR&A Ltd.).

Contract strategy

At the definition stage of the process the contract strategy that is best suited for the projects objectives should be in place. The contract strategy gives vital input to evaluation criteria that will be used in the final selection of organizational and contractual policies required for the development of a specific project. The contract strategy should ensure quality and cost – effective progress, including the operator´s opportunity for verification and corrective measures and follow-up through the whole process (Oljedirektoratet, 2013).

As a part of the process of developing the contract strategy the operator rates the project´s technical and commercial level. A complex project has a high technical rating, which means that it will most likely be an expensive project. This is because there will be fewer contractors to choose from. On the other hand, a less complex project give more possible contractors to choose from, meaning that the project also gets less expensive. Traditionally, the rating is 60 pct. commercial and 40 pct. technical. Norwegian projects are often more complex, and are often given a higher technical than commercial rating. In addition, the Norwegian petroleum industry has specific regulations, like HSE regulations, facility regulations, technical and operational regulations etc. which are enforced by the PSA (Petroleum Safety Authority Norway, 2016a).

Execution model

A project execution model that is well defined increases the efficiency and the possibility for a quicker start-up of the project. The execution model specifies what shall be done, how and when it shall be done, what resources are required, what the cost estimate is, and who is responsible (Odland, 2013).

To finalize the execution model the operator defines the contractors' strengths and weaknesses, their capabilities, and how to follow them up. The capability of the contractors will affect the final selection of the contractor. After evaluating the different contractors, they decide which ones to invite to the tender process (see chapter 4 for more information about the tender process).

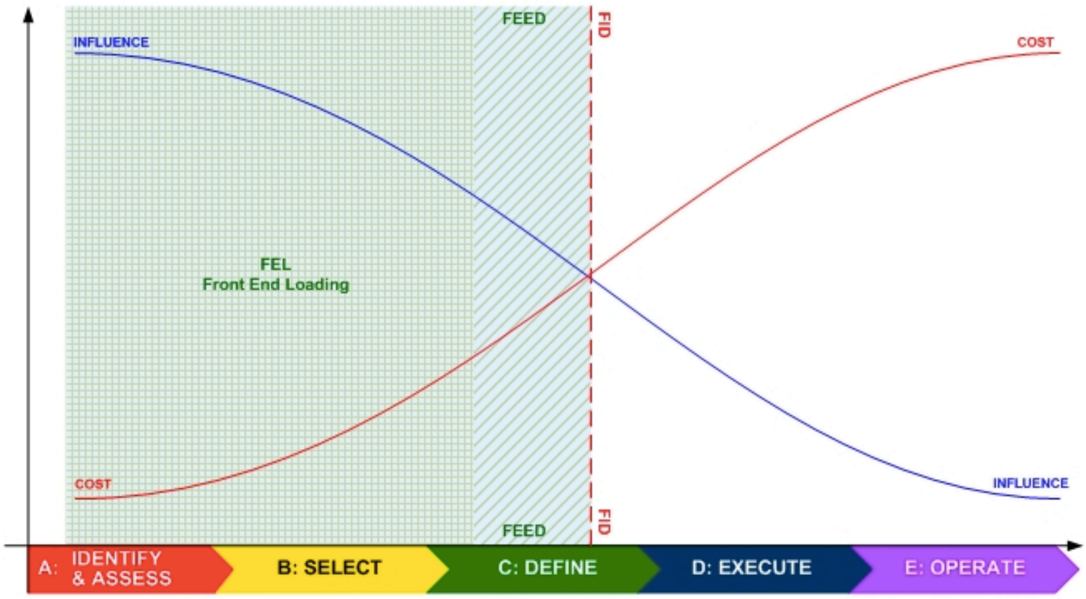

Figure 3.2: Illustration of FEED

Source: (OR&A Ltd.)

4) Execution stage

The objective in this stage is to prepare detailed drawings and technical plans of the facilities as a foundation for construction. The main contracts for construction and procurement are entered into. Construction and installation of the facility are conducted. The wells that will be used from start-up are being drilled. And finally, the preparations for production operations are completed and confirmation of safe operations is made by the PSA (Gudmestad et al., 2010). For mobile facilities an acknowledgment of compliance (AoC) is required from the PSA. This is to get the facility confirmed to be in compliance with the regulations (Petroleum Safety Authority Norway, 2016c).

5) Operation stage

The objective in this stage is to start the production. At this stage of the process the decision of start up of the installation is made. But only after thorough testing of the system, which confirms it safe and ready for operation (Gudmestad et al., 2010).

4 The tender process

4.1 Introduction

Some work with the tender process is already started during the development of the contract strategy, but it is not officially started before the contract strategy is fully in place. The tender process enables the operator to evaluate different technical products or solutions, and pricing arrangements from competing offers. The tender process makes it possible for the operator to negotiate not only technical aspects, but also to some degree the commercial contract's provisions (Frihagen, 1983).

The formal framework of the tender process and details will differ between each oil company, as well as to some degree in each individual instance. Consequently, differences will occur between different types of procurement i.e. between procurement of service and supplies, construction work, but also in the individual instances depending on the specific competitive situation, the size of the contract, and on how clearly defined and complicated the work is. How thoroughly and how far the operator will go in order to obtain the best offer will differ. But all things considered, the practices and procedures are generally consistent and similar (Frihagen, 1983).

4.2 The basic structure of the tender process

Already before the tender process has started the contractors have gone through an evaluation process. The operator has a clear conviction of what is needed from the contractor in order to conduct the project. To find the best-suited contractors the operator goes through their track record. They check if the contractor has done any similar work before, and if they have done it within the implemented time and cost in the PDO. At the end, only contractors that the operator is convinced of having the needed facilities and capabilities are selected, and invited to the tender process.

Once the tender process has started the operator's immediate task is to evaluate the different bids. This is done based on the technical and commercial criteria of the project. It is important for the operator to obtain offers from a broad range of contractors. This is to obtain the most capable, and most advanced contractor for difficult assignments, and of course the most competitive prices (Frihagen, 1983).

Once a set of favourable competitive offers is clear a final contractor is chosen either by the operator or a joint group of the licensees.

4.3 Evaluation criteria for the final selection of the contractor

There are several evaluation criteria that are important in the process of finding the best contractor for the development project. Some of the most typical are listed below in random order (Osmundsen, 2011):

- Operational achievements, experience, and efficiency
- Expertise
- Capability to complete the contract within the implemented time and cost
- Economic strength
- Trust and credibility
- Compliance with regulations on the Norwegian continental shelf
- Day rates (price)
- High pressure and temperature (HPHT) experience and expertise
- Health, safety and environment (HSE) system and culture

These evaluation criteria are thoroughly examined by the operator to establish the contractor’s track record. The price is one of many evaluation parameters at the list, but might be the one parameter that has the most impact on the operator’s decision. One can perhaps say that the oil and gas industry is an excellent example of how the lowest price doesn’t necessarily mean the best economic solution. What counts is the lifetime costs, including the income (Osmundsen, 2011).

The last decade the location of the contractor might have been the evaluation parameter that has had the most effect on the final cost and result of the development project. When offers have been normalized the tendency has been that Norwegian yards are pricier than the Far East yards. This has tempted an increasing number of operating companies to select a yard abroad.

5 Contract theory

5.1 Introduction

Offshore projects vary in complexity, size and development. How demanding, unique and compounded the project is determines what parts of the project that are included in one and the same contract (see table 5.1). As a result, a lot of different participants and firms are involved in a development project. It is the contracts that bind everyone involved together, and therefore sets high demands for them.

The larger and more complex the contracts are, the more time consuming they can be. This also increases the possibility of disagreements between the parts involved and changes along the way. How to handle these types of situations must therefore be clearly defined in advance between the involved parts.

Table 5.1: Regular main activities that are included in contracts for offshore projects

Source: (Oljedirektoratet, 2013)

E	Engineering
P	Procurement
C	Construction
I	Installation
C	Commissioning
H	Hook up
F	Fabrication

There are several conditions that need to be evaluated in order to select the right combination of activities to be included in a contract. Some of them are listed below (Odland, 2013):

- Availability of qualified contractors in the market
- Available company personnel
- Technical interfaces
- Quality of engineering basis and planning in general
- Company´s and contractor´s attitude to financial risk
- Health, safety, environment issues
- Commerciality and sensitivity to duration, costs, quality (availability) or other penalties.

5.2 Contract types

5.2.1 Total contracts

Large contracts like the EPC contract often go by the name total contracts. In this type of contract the main contractor is responsible for e.g. delivering an offshore module, an offshore platform ready for installation, or a ready installed offshore platform. In other words the contractor has the sole responsibility to deliver a total product according to the contract's guidelines and conditions. By using a total contract, the tender process is simplified, and costs regarding the execution and operation of the development project become more predictable.

As mentioned the contracts can differ in contract format, specialized or complex:

Table 5.2: Contract format

Source: (Odland, 2013)

E	Engineering
EP	Engineering/procurement
EPC	EP + fabrication (construction)
EPCI	EPC + installation
TURN KEY	EPCI + commissioning

Listed in table 5.1 are the most common activities involved in a contract, and in table 5.2 one can see the most common combinations of the activities.

5.2.2 Standard contracts

Over the years oil companies and suppliers have developed some standard contracts. One of the most frequently used on the Norwegian continental shelf is the Norwegian total contract 2000 (NTK 2000). Statoil Hydro representing the company side and Norwegian Industry representing the supplier side have together compiled it. It was developed in order to avoid unpredictable and unreliable contracts (Spanne, 2005). A further development of the NTK 2000 is the Norwegian total contract 2007 (NTK 2007), also developed by Statoil Hydro and Norwegian Industry. It is most commonly used in regards to new construction and installation in the petroleum sector (Berge, 2010).

5.3 Contract form – Compensation

The four main contract forms are (Odland, 2013):

- Fixed price contract
- Reimbursable contract
- Combination of fixed price and reimbursable contract
- Unit price contracts

Many factors and details need to be considered when choosing the contract form. What type of contract form that is best suited varies from company to company.

In regards to the model selected the following main points need to be considered (Odland, 2013):

- The operating companies′ experience
- The location of the development
- The experience within the relevant country
- The experience of engineering contractors within the country
- The experience of the fabrication/installation contractors within the country
- The government policy
- Economic importance of the development for the country/company

1) Fixed price

This form of contract is used for procurement of well-stated equipment and is awarded after evaluation of several bids from different vendors. The factors that are evaluated are delivery, price, and quality. Thorough evaluation both on a technical and commercial level should be undertaken. Its not necessarily the cheapest bid that is the best bid. This contract type gives little opportunity for changes. Changes that are made along the way often become costly and time-consuming (Oljedirektoratet, 2013).

2) Reimbursable

This form of contract is often used for procurement of services, such as installation and engineering. An agreed pay rate has been established between the operator and contractor, and the contractor is paid for each hour their employees work on the development accordingly. The agreed rate is set based on the type of personnel that is involved. The hours spent on different work tasks are thoroughly monitored by the operating company to make sure that the contractor doesn't overcharge. Normally, the operator and contractor have agreed upon a budget estimate.

Several contractors usually bid on the contract. In order for the operator to choose the most beneficial bid a number of factors should be evaluated (Odland, 2013):

- Quality of personnel
- Budget estimate
- Hourly rate for the different personnel
- Past experience

3) Combination of fixed price and reimbursable contract

This form of contract can also be used for procurement of services, where clearly defined activities can be bid on at a fixed price while those service activities that are problematic to outline beforehand are reimbursed with an hourly compensation as a reimbursable contract. The issue with this form of contracts is that it is very challenging to administer. Work from the fixed element can be moved to the reimbursable part, and as a result the contractor can be paid for the same work twice (Odland, 2013).

4) Unit price contracts

This form of contract is used for services that are clearly defined, but the total request for the services is uncertain, and a legal commitment to the services is required. It is often used for contracted routine service requirements. In such cases one multiplies identical units of work by a fixed unit price to get the total value of the contract. Unit price contracts may also be useful in situations where a specific service is required over a given time-interval, where the amount of work may be unknown. They may also be suitable for reoccurring requirements.

It is essential that the intended service requirements have a clearly defined scope in order for the contractor to know in detail what's included in the contract (Northwest Territories, 2009).

In this part of the thesis some key topics of the current market situation is presented, in order to give a deeper understanding of what challenges and trends the industry is facing today. In addition, some of the core differences in regards to competitiveness between Norwegian and Far East yards are discussed. At the end a few of the main reasons for cost overruns in project developments of the last years have been mentioned.

6 Current situation and trends in the offshore fabrication industry

6.1 Introduction

Globalization

Globalization has reduced the barriers between nations, and encouraged a closer integration of social, economic and political activity. It has enhanced the competitiveness in the oil and gas industry, which in turn has pushed the involved countries and companies to adopt strategies designed to increase quality, effectiveness, productivity and innovation. The industry has evolved to be an increasingly global industry, and Europe and North America is no longer alone at the top of the large offshore-regions. As one can see in figure 6.1, purchases taken by oil companies originate from all around the world.

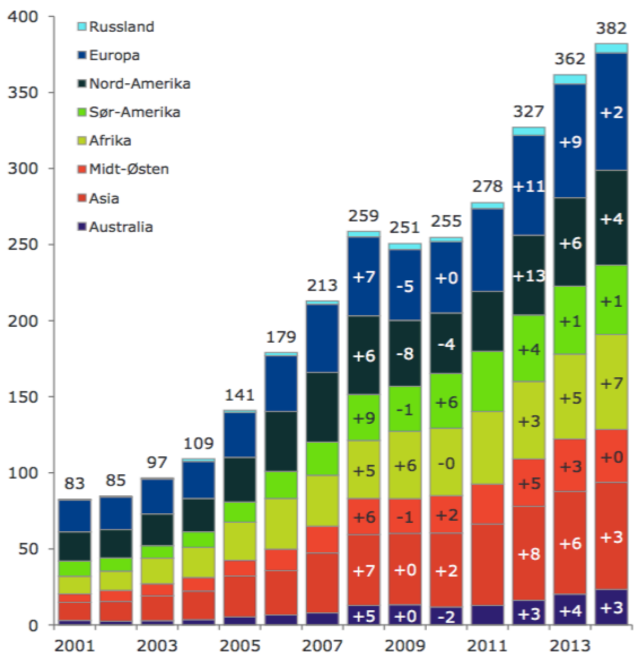

Figure 6.1: Purchases taken by oil companies, offshore, per continent (mill. USD)

Source: (Rystad Energy, 2015)

Impulses and expertise from the outside world has played a crucial role in developing petroleum activity on the NCS. In return, this has resulted in more Norwegian companies achieving international success. By implementing their expertise and technology, several companies have expanded from the domestic market into the global one. By comparing the international and domestic market, one can clearly see that the international sales have been increasing drastically, with a growth of 17 pct. in 2014, compared to 4 pct. in the domestic market (Rystad Energy, 2015). As a result, the international revenue has increased from 43 billion NOK in 2003 to 195 billion NOK in 2014 (see figure 6.2).

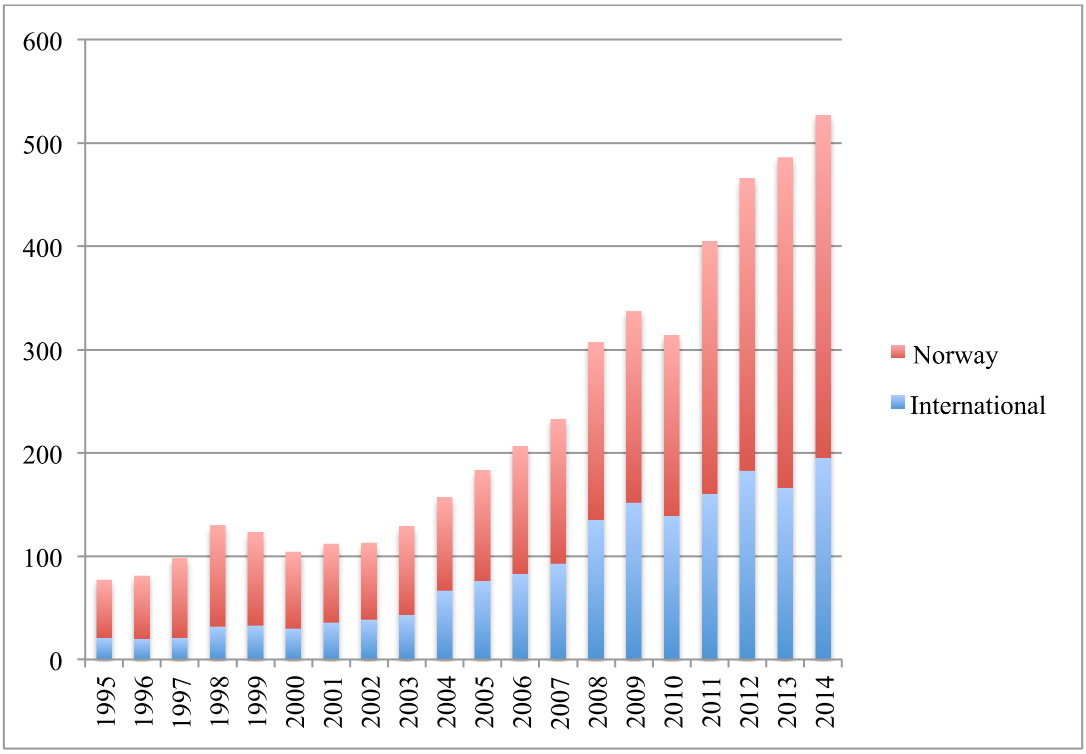

Figure 6.2: Total revenue from Norwegian suppliers, Norway vs. International (mill. NOK)

Source: (Rystad Energy, 2015)

The most dominating markets for the Norwegian supply industry today, are West-Europe (excluded Norway) and East Asia. The West-Europe market (mainly United Kingdom, France, Denmark and Netherlands) is beneficial because of its geographical, economical, and technological proximity to Norway. It simplifies the sales process of services and equipment. In regards to the East Asia market (mainly South-Korea, China and Singapore in South-East Asia), the sales are greatly influenced by the large increase in offshore contracts awarded to Far East yards. This has resulted in more deliveries of process-and topside equipment.

As the petroleum industry has become more globalized, more countries are now able to produce oil, much because of new knowledge and technology development. This has led to a growth in the oil production. Today, the production of oil is larger than the demand. Because of the abundance of oil, the oil price has declined. This has had a huge effect on the NCS market, as a larger part of segments is run by operation costs. The two main reasons for the abundance of oil is 1) the shale oil revolution in USA, and 2) Saudi-Arabia is refusing to put on the breaks (Aarøy, 2016).

The USA has increased its total oil production with more than 60 pct. the last five years, and almost all of this extra production comes from the shale oil fields in North Dakota and Texas. The USA is today producing more oil then Saudi-Arabia, and almost as much as they did in the beginning of the 1970s. All because of new technological developments the U.S. can recover the shale oil far more effectively and cheaper than anyone had expected, only a few years ago (Aarøy, 2016).

Because the supply of crude oil is far larger than before, the best option for Norway would be that the oil nations limited their production in order to get the oil price up again worldwide. However, Saudi-Arabia and the OPEC – countries still make a profit with today's oil price, and are refusing to put on the breaks. Saudi-Arabia can recover their oil for 5 – 30 dollars per barrel, Norway on the other hand recover their oil for 30 – 100 dollars per barrel (Aarøy, 2016).

For the supply and fabrication industry 2016 has so far been a challenging year with a lower activity level as a consequence of a high number of contracts being awarded to Far East yards in 2012/2013. The pressure is intensified by the British supply industry eagerness for the opportunity to get assignments on the Norwegian continental shelf. Several of the large projects that have kept the wheels going, such as Gina Krog, Martin Linge, and Ivar Aasen is close to completion (Stangeland, 2016). In addition, there is still a large insecurity linked to the development in the oil price.

Oil price

The oil and gas industry is in shock after the dramatic downfall in the oil price. From the oil price top at 109 U.S. dollars per barrel in 2012, the oil price decreased to 49,5 U.S. dollars per barrel in 2015 (Statista, 2016). That is a decline of 54 pct. in 3 years. At the start of 2016 the oil price fell to a new low level at 27,1 U.S. dollars per barrel, which is the lowest since 2003 (Frafjord, 2016). The difference this time around is that the price has stayed low for a longer period of time. Causing massive effects and disturbances in the market, and has forced the industry to make drastic and fundamental changes to their work model. The last few months the oil price has been climbing, and is currently at 50,12 U.S. dollars per barrel (Date: 26.May 2016). See overview of the average annual OPEC oil price in figure 6.3.

A sustainable oil price at the current level will result in a further cost reduction. The increased focus on cost and reduced investment level has resulted in a drop in OPEX reductions and demand. The oil industry has entered into a recession, and oil companies are prioritizing to postpone, or even stop new investments. The operator is focusing on prioritization and simplification, leaner maintenance projects, and improved operation and drilling efficiency (Abrahamsen, 2016). However, the oil price is expected to rise again, which is crucial in order to produce enough oil in the future (Guldbrandsøy, 2016).

Currency

The oil price development has affected the currency market in varying degree. In 2015 the Norwegian krone had a solid recession year and reached a historical low level (Aarø, 2015). Since 2008 the ratio between NOK and USD has changed by approximately 40 pct. See overview of the exchange rate in figure 6.4. A weak Norwegian krone is positive for the revenue in terms of Norwegian kroner for companies that mostly have their revenue in foreign currency (USD). This adds to the international revenue, even though contracts in Norway can be priced in foreign currency, such as rig contracts (Rystad Energy, 2015).

What has been seen in 2016 is that the currency has stopped following the trend in the oil price. The Norwegian krone has remained weak even when the oil price has been increasing. This has contributed to a substantial increase in profitability for the export industry, which has increased the productivity and won market shares. The weak Norwegian krone has been positive in regards to competitiveness for both the Norwegian suppliers and the Norwegian industry in general. But the weak Norwegian krone will only get them so far. Some companies will eventually reach their capacity limit. In addition, a weak Norwegian krone means that the cost of imported goods and services increases (Sundberg, 2016).

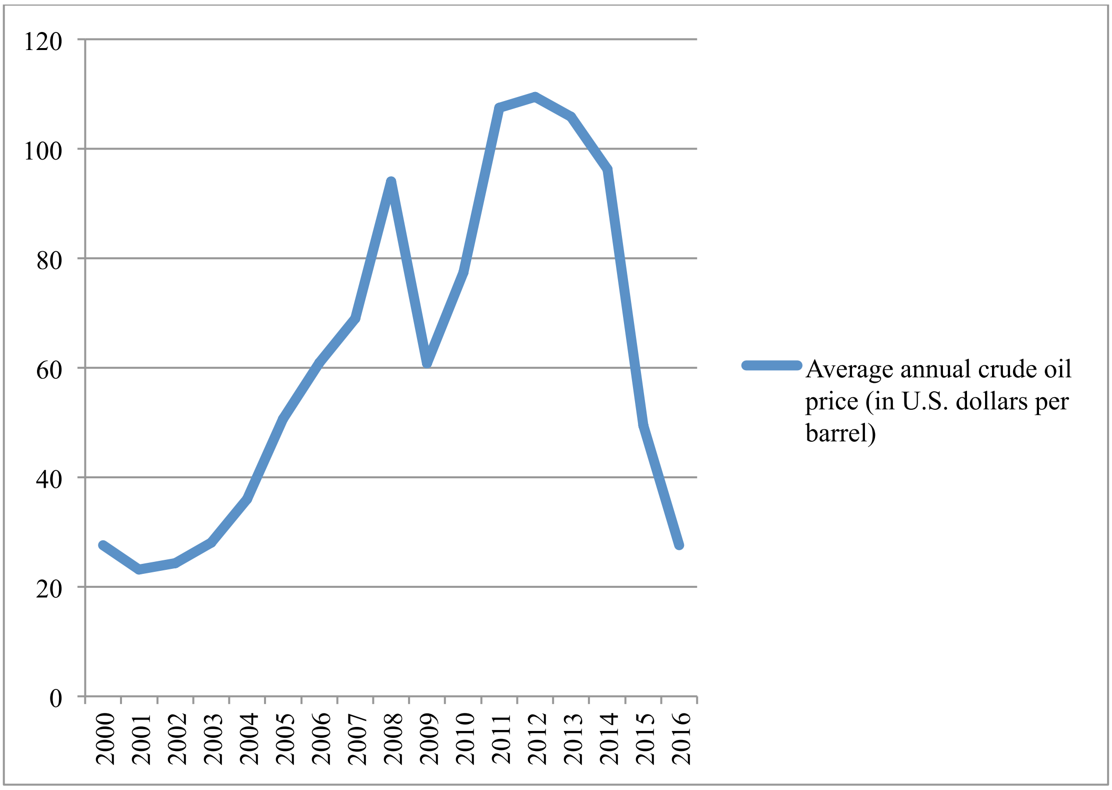

Figure 6.3: Overview of the total annual OPEC crude oil price 2000-2016 (in U.S. dollars per barrel)

Source: (Statista, 2016)

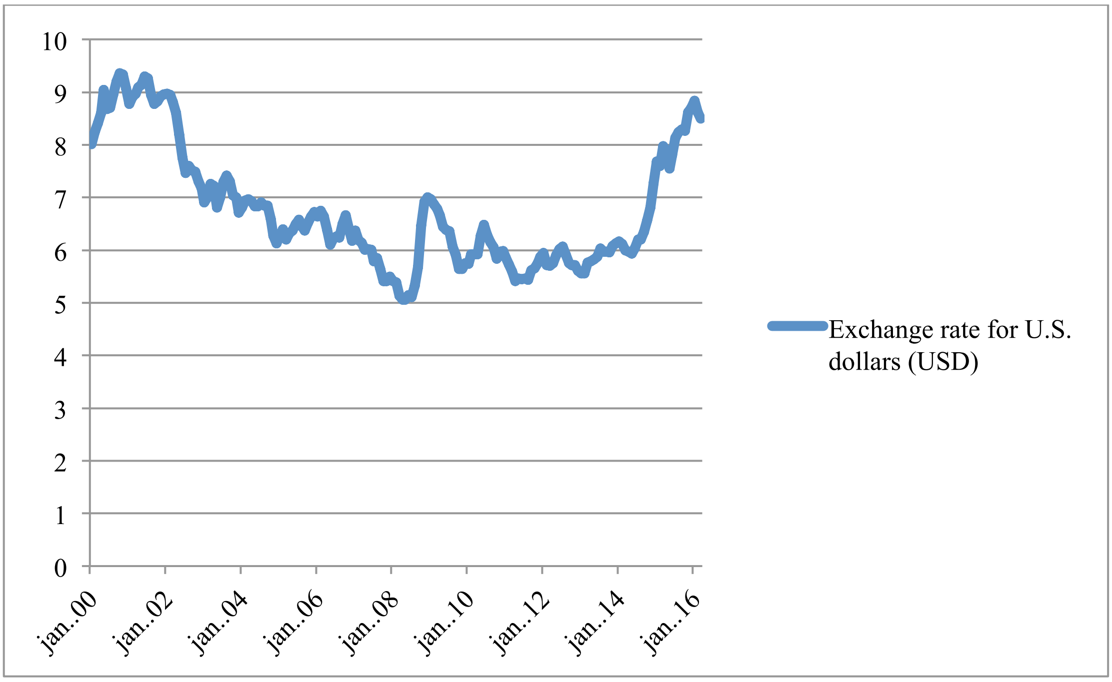

Figure 6.4: Overview of the exchange rate for U.S. dollars 2000-2016

Source: (Norges Bank, 2016)

Implemented measures

As a result of the changing market situation the industry has been forced to think of new and innovative ways to run their operations.

One measure that has been implemented is new constellations of contracts ("EPC" E+P+C, EPMA – FC). For instance, Statoil and their partnership in the development of Johan Sverdrup have implemented a contract including engineering and procurement management (EPMA). An EPMA contract worth 4,5 billion NOK has been awarded Aker Solution in the project development (Statoil, 2015). Centrica on the other hand has chosen to award larger total contracts. It has awarded three companies the role of main supplier for the next five years (Subsea 7, Aibel and DNV GL), with possibility of expansion. Subsea 7 and Aibel will deliver everything from pre-studies to completed installations on Centrica's projects on the NCS. This type of contract is a measure done by Centrica in order to cut costs (Lewis, 2015a). They hope that this new way of working will contribute to find the most optimal and cost effective technical solutions.

As mentioned earlier many of the oilfields on the Norwegian continental shelf are dependent on a high oil price, as they're not profitable with the current oil price. Some fields require a break-even price of at least 70 U.S. dollars per barrel. Today, most operating companies are pushing for a break-even price at 35 U.S. dollars per barrel in order to meet the economical thresholds. In figure 6.5 you can see the difference between the current break-even price and oil price. By implementing measures, like new types of contracts, companies like Statoil and Centrica hope this will result in more development projects getting realized.

Figure 6.5: The difference between the current break-even price and oil price

Source: (e24, 2016)

The rent of mobile drilling units has had a strong decrease; the new building business on the other hand has not. The rent of a mobile drilling units have decreased from approximately 500 000 dollars a day to around 150 000 dollars in a short matter of time (Birkenes, 2016). As a result, more companies are also looking at the possibility of reusing old existing FPSOs, which is a much cheaper alternative. In the new build business, we see a trend where oil companies are revising their target price for the developments. For instance, Statoil has renegotiated many of their contracts. Because of Statoil's position in the market they have managed to get good offers, and as a result lowered the cost significantly (Abrahamsen, 2016).

Development within equipment and workmanship is also one of the implemented measures. Currently, several large heavy lift vessels are under construction, e.g. Pioneering Spirit and Sleipnir (See figure 6.6 and 6.7). Pioneering Spirit is a mobile vessel for single-lift, installations of oil and gas pipelines, and installation and removal of large offshore oil and gas platforms (Allseas, 2016). Pioneering Spirit has a topside lift capacity of 48 000 tons, and a jacket lift capacity of 25 000 tons, which enables it to install and remove entire platform topsides and jackets in a single lift. In addition, the pipelay equipment installed on Pioneering Spirit enables it to install record weight pipelines from shallow to extremely deep water, and achieve high lay rates. Pioneering Spirit is suitable for worldwide use, as it sails under own power at a high transfer speed (Allseas, 2016). Sleipnir is a smaller vessel than Pioneering Spirit but still has a lifting capacity of 20 000 tons. As Pioneering Spirit it runs on own power, which enables it to do operations all around the world (Heerema Marine Contractors, 2016). These types of vessels mark a new era in the heavy lift industry, and make a positive contribution to the fabrication and development of offshore field developments. It opens for new possibilities in engineering, execution models and decommissioning.

Figure 6.6: Picture of Pioneering Spirit

Source: (Allseas, 2016)

Figure 6.7: Illustration of Sleipnir

Source: (Heerema Marine Contractors, 2016)

Lastly, an increased involvement from the government will most likely be seen in the time to come. In regards to new initiatives, and implantation of measures (Guldbrandsøy, 2016). This has been seen earlier when the government implemented measures such as INTSOK, KonKraft and NORSOK (more about these measures in the next subchapter). One might see more involvement from the government in regards to the operators' selection of contractors. Where they will influence the operators selection on who should get the contracts, and where the work should take place. After all, the oil and gas industry are meant to generate workplaces in Norway. It has also been discussed whether or not the new offshore – directive introduced in EU will be applicable on the NCS, but so far Norwegian politicians and Norwegian Oil and Gas are rejecting it (Lewis, 2013).

6.2 The competitiveness of Norwegian – and Far East Yards

Norwegian petroleum industry has been through ups and downs, and cost overruns have always been an ever-going battle for offshore field developments on the NCS. However, considering the low oil price and the weakened Norwegian krone it sets even higher demands for efficiency, time and cost. The Norwegian fabrication yards have to handle the increased expectations from investors and financial markets, in addition to increased demands internationally on both production companies and supply companies to benefit the national industry.

In order to increase the NCS competitiveness the Norwegian government has played a central role by implementing measures like INTSOK, KonKraft and NORSOK (KonKraft, 2013). Today, the government is less active with respect to these types of initiatives.

INTSOK
Stated by (INTSOK, 2013):
INTSOK was established in 1997 as an independent non-profit foundation to strengthen the long-term basis for value creation and employment in the Norwegian oil and gas industry through expanding the industry´s international business activities.

KonKraft
Stated by (KonKraft, 2016):
KonKraft is a collaboration arena for Norwegian Oil and Gas, Norwegian Industry, the Norwegian Ship owners' Association and the Norwegian Confederation of Trade Unions (LO), with the LO unions "Fellesforbundet" and "Industri Energi".

NORSOK
Stated by (KonKraft, 2013):
NORSOK are standards that describe functional requirements for the petroleum industry on the NCS. It is developed to international ISO standards in several areas. Originally, it was an initiative in 1993 to reduce development and operating costs on the Norwegian continental shelf.

In the beginning of the 2000s the oil price was low, and the Norwegian supply industry faced major challenges. Norwegian operators started to invite more contractors from the Far East as an attempt to lower the costs and improve the competitive international market. Making sure that Norwegian offshore yards are internationally competitive is a vested interest for the whole Norwegian petroleum industry. The yards play an important part in the petroleum cluster´s level of competitiveness and vitality.

Despite productivity, quality, innovation and efficient solutions, there has been a general increase in the oil companies' cost, and cost of engineering, design, administration, and construction for the offshore yards over the last years (KonKraft, 2013). This has had an impact on the activity on the NCS, and Norwegian offshore yards. Several large new building contracts were awarded to Far East yards, because of a decreased competitiveness for the Norwegian yards regarding cost and capacity. However, because of the market change the competitiveness of the yards seem to have changed.

6.2.1 Norwegian yards

Competitiveness

The international competition has fully manifested itself in the competition for contracts on the NCS. In order to get a foothold in the Norwegian petroleum industry, international companies challenge Norwegian companies with other business terms and conditions, in regard to access to cheap capital, risk assessment, and wage level. In the period 2012-2013, a period with high activity on the NCS, Norwegian offshore yards lost all contracts for substructures and topsides to yards abroad (KonKraft, 2013). If one looks at the selected projects in this thesis (Gjøa, Edvard Grieg, Ivar Aasen, Aasta Hansteen, and Goliat), a lot of the activity related to these developments has taken place in the Far East or South Europe.

Competiveness include cost, capacity, competence, and quality (KonKraft, 2013). As mentioned earlier in subchapter 4.3, even though the price might be the evaluation criterion that has the most impact on the operators' choice of contractor, quality and implementation capacity also have a huge effect on their decision. This is expressed repeatedly by acceptance of bids that doesn't have the lowest price.

Cost

It has been a common understanding and knowledge over the last few years that Norwegian yards are pricier than Far East yards. This might be the largest challenge for Norwegian yards in the competition for contracts. One issue related to cost that is brought up frequently, is the high labour cost in Norway. To defend this the Norwegian industry has to show that their productivity is higher compared to other countries. In addition, the high demand that has been on the NCS has pushed the suppliers near their capacity limit, contributing to a high cost (KonKraft, 2013). On the other hand, despite the Norwegian yards' high capital expense (CAPEX), they have shown a low operating expense (OPEX) for their project developments (Abrahamsen, 2016).

Capacity

In 2012 the Norwegian yards indicated that they had some capacity limitations at their own yards (KonKraft, 2013). This was a result of a year with a much exploration activity and important discoveries. This affected the operating companies in the tender process, in regard to implementation time and evaluation criteria for the projects. The Norwegian yards were worried that the capacity could be a challenge, and had to take this into consideration when they placed bids for the contracts in order to avoid lower productivity and overburdened yards. For the operators capacity is fundamental for their final selection of contractor, as it constitutes a risk for project overruns in time and cost. However, given the current market situation the capacity issue in Norwegian yards has changed. The low activity has made the market hungry, and eager to get contracts. This enables the operating companies to focus more on getting the contracts at a lower price, and receive better quality (Guldbrandsøy, 2016).

Competence

The state of internal competence is always a concern for most companies. They have concerns about lacking basic competence in e.g. project management, construction management, disciplinary leads, controls, and last but not least cost estimation. In regards to EPC contracts, there may also be some concern about the engineering quality.

Loss of contracts may in the long-term result in loss of competence. In order to maintain and further develop the competence in the industry Norwegian yards depend on winning contracts. Since the oil adventure started in Norway the Norwegian industry has evolved to be one of the worlds leading oil and gas nations, with a high competence level. One of the largest advantages for Norwegian yards is their competence level and knowledge within the Norwegian standards and regulations. In addition, no yards have yet to challenge Norwegian yards in their implementation of EPC contracts.

Quality

In order to achieve a high quality delivery these points have to be fulfilled (KonKraft, 2013):

- Good planning
- Satisfies the requirement specifications
- Gives stable operations and is well adapted to the operating conditions.
- Gives high HSE standard
- Stays within time – and cost-estimates

As a result of difficult assignments on the NCS, Norwegian companies have developed significant expertise in maintenance, modification and operations (MMO) (KonKraft, 2012). Norwegian yards are well known for their consistently high level of quality and timely delivery, but there is always room for improvement. Considering the modernized IT-equipment that is available today, the productivity and efficiency should be improving. But instead there has been an increase in the amount of engineering hours. There can be several reasons for this e.g. increased documentation requirements, increased HSE requirements, etc. (KonKraft, 2013).

Implementation capacity and time schedule
The contractor that presents and is capable of providing the best implementation plan will have a competitive advantage in the tender process. A basic requirement for the operator when selecting contractor is the contractor's ability to deliver as planned and agreed upon. The additional cost as a result of delays will vary in scope. But can be particularly expensive if the delivery date is close to a "weather-window" for installation.

Given that Norwegian yards have considerably high EPC – experience with a high level of parallelism and interaction between construction and engineering, and their geographical proximity, they should be competitive. As you can see in table 6.1, a lot of the contracts that have been awarded Norwegian yards the last years have been EPC contracts.

Technology development
Norwegian yards have a continuous focus on technological development, in order to work more effectively and improve the quality of their deliveries. By hosting equipment that is state of the art the Norwegian yards secure their competitiveness in the market. The Norwegian FPSO cluster is a suitable example of technological innovation and a business area that has been developed by the country´s shipping and petroleum industries. Norwegian yards are still enjoying competitive advantages in producing special types of tailored equipment, and services, but it's only a matter of time before other countries catch up (KonKraft, 2013).

Cooperation and communication operator/supplier
Cooperation with the contractor, and also internally in the company is often the most cited problem by operating companies. By using a Norwegian yard for the fabrication of the project development the communication process between the involved parts may be simplified. In addition, because of the geographical proximity it is much easier for the operator to follow-up on the work, and if necessary make changes to the project.

Table 6.1: Overview of some of the contracts for projects on NCS awarded to Norwegian yards

Field	Operator	PDO approved	Todays status	Production type	Contract	Fabrication yard	
						Location	Company
TROLL C	Statoil Petroleum AS	1986	Producing	Semisub	EPC	Norway	Aibel
SNORRE B	Statoil Petroleum AS	1988	Producing	Semisub	EPC	Norway	Kværner Stord
VISUND	Statoil Petroleum AS	1996	Producing	Semisub	EPC	Norway	Aibel
JOTUN A	ExxonMobil Exploration and Production Norway AS	1997	Producing	FPSO	Hull/Topside EPC	Norway	Kværner Rosenberg/ Masa Yards
JOTUN B	ExxonMobil Exploration and Production Norway AS	1997	Producing	Drilling platform	Topside FC	Norway	Herema Tonsberg
HULDRA	Statoil Petroleum AS	1999	Shut down	Jacket	EPC	Norway	Kværner
GRANE	Statoil Petroleum AS	2000	Producing	Jacket	EPC	Norway	Kværner
KVITEBJØRN	Statoil Petroleum AS	2000	Producing	Jacket	Topside FC	Norway	Umoe Olje og Gass
TAMBAR	BP Norge AS	2000	Producing	Jacket	EPC	Norway	Kværner Brug Steel
KRISTIN	Statoil Petroleum AS	2001	Producing	Semisub	EPC	Norway	Kværner Stord
GJØA	Engie E&P Norway AS	2007	Producing	Semisub	Topside EPCH	Norway	Kværner Stord
GUDRUN	Statoil Petroleum AS	2010	Producing	Jacket	EPCI	Norway	Aker Solutions
EDVARD GRIEG	Lundin Norway AS	2012	Producing	Jacket	EPC	Norway	Kværner Stord
JOHAN SVERDRUP (phase 1)	Statoil Petroleum AS	2015	PDO approved	Jacket	EPC	Norway	Kværner

6.2.2 Far East Yards

Competitiveness

After their entry into the offshore industry Far East yards have evolved from fabricating relatively simple structures, such as the hull of floating facilities and steel jackets, to fabricating large platforms such as Goliat and Aasta Hansteen.

Today, the Far East has several large and well-established yards e.g. Hyundai Heavy Industries (HHI), Samsung Heavy Industries (SHI), and Daewoo Shipbuilding and Marine Engineering (DSME). These yards, among others, can account for several projects related to developments on NCS, see table 6.2.

The dark side to the large industry development in the Far East is that the Korean government is subsidizing many of the yards. This means that many companies that shouldn't be in operation are being kept artificially alive by the government, pending that they will turn things around. These companies are often called zombie-companies, and among them we find DSME. DSME was saved after the Asia crisis at the end of the 1990s with tens of billions of kroner in loans and subsidies (Iversen, 2015).

Cost

Far East yards have won an increasing number of contracts over the last years, largely because of their low price compared to Norwegian yards. They have the advantage of e.g. low labour cost and low material cost. But there is reason to believe that the Far East yards will eventually lose their price advantage as labour costs in the countries are increasing.

Capacity

With sustained and robust growth the Far East yards have been speeding up their construction and expanding their yards. They have a high capacity and production level, which was a contributing factor for the number of contracts awarded to them in 2012-2013. Today, the capacity level is not the same, and they are struggling with overburdened yards. This has forced them to use smaller yards, in addition to the main yard in their construction process. This has contributed to the delays, and poor quality of their deliveries, and made it increasingly difficult for the operating companies to give the required follow-up.

Competence

Far East yards have emerged as a large competitor in the fabrication of offshore platforms and modules. Far East yards have been making considerable investments in an effort to catch-up with Norwegian yards' technologies and expertise while the rising production costs considerably threaten the competitiveness of the Norwegian yards. The Far East yards have developed some key competences, e.g. steel compositions and line production. Nevertheless, Far East yards are still in need of more highly skilled experts. Also, they have little competence when it comes to execution of total contracts, such as EPC. This is much because of the engineering part of the contract. The experience from earlier projects has been that too much time has gone to engineering, much because of their lack of competence with new types of constructions, and changes demanded by the operator along the way. For simpler constructions that they are familiar to, like substructures etc. they have achieved better results (Abrahamsen, 2016).

Quality
Most of the Far East yards have backgrounds as shipyards. Despite some similarities, regarding equipment and material, the transformation from shipyard to offshore yard involves several risks and changes. There are differences in regard to construction process, customization requirements, strict safety regulations (NORSOK), and severe environmental standards. The Far East yards and the staff there do not have the same introduction to these regulations and standards as the Norwegian yards. This has been one of the main problems in projects that have been constructed in the Far East, where there have been large errors and defects.

Implementation capacity and time schedule
The productivity at Far East yards is relatively high for constructions where there are no orders of change along the way. But the productivity becomes considerably lower in situations where changes occur. As a result the risk of errors and defects becomes significantly higher. There have been several cases of delays and cost overruns for development projects constructed in the Far East (e.g. Goliat, Aasta Hansteen). Many of the fabrications have been in need of changes and overhauls after their arrival in Norway. When choosing a Far East yard for construction the operator has to expect to add approximately 9 months to the time schedule (Abrahamsen, 2016). This is due to their work processes. The Far East yards are (as mentioned earlier) sometimes using smaller fabrication yards to construct some of the modules for their projects. These smaller yards are difficult to follow up. The trend has been that the modules from these smaller yards are delayed and do not hold up to the quality requirements, affecting the construction on the main yard. Further, a lot of time is spent on putting the different modules together after their arrival at the main yard. It can also be mentioned that the additional time needed is partly because of the long transportation route for the modules and platforms, although this is not a main contributing factor.

Technology development
Far East yards have focused the most on developing a high competence and knowledge within technology related to floating structures and semisubmersibles. In addition they specialize in tugboats and offshore support vessels.

Cooperation and communication operator/supplier

For a project development conducted on a Far East yard the communication and cooperation process is made more complex. The management culture is different in regard to transparency and fear/tolerance for mistakes, and improvised capability. In addition, there are language challenges, distance to engineering houses and subcontractors (Offshore.no, 2013). Lastly, the operator company is dependent on sending employees to the Far East to follow up the project during fabrication, which are additional costs that are often underestimated.

Table 6.2: Overview of some of the contracts for projects on the NCS awarded to Far East yards

Field	Operator	PDO approved	Todays status	Production type	Contract	Fabrication yard	
						Location	Company
NORNE	Statoil Petroleum AS	1995	Producing	FPSO	Hull FC	Singapore	Keppel
BALDER	ExxonMobil Exploration and Production Norway AS	1996	Producing	FPSO	Conversion	Singapore	Keppel
VARG	Repsol Norge AS	1996	Producing	FPSO	Hull FC	Singapore	Keppel
ÅSGARD A	Statoil Petroleum AS	1996	Producing	FPSO	Hull FC	Japan	Hitachi
ÅSGARD B	Statoil Petroleum AS	1996	Producing	Semisub	Hull FC	Korea	DSME
KRISTIN	Statoil Petroleum AS	2001	Producing	Semisub	Hull FC	Korea	SHI
GJØA	ENGIE E&P Norge AS	2007	Producing	Semisub	Hull FC	Korea	SHI
SKARV	BP Norge AS	2007	Producing	FPSO	Hull/Topside FC	Korea	SHI
GOLIAT	Eni Norge AS	2009	Producing	FPSO	EPC	Korea	HHI
KNARR	BG Norge AS	2011	Producing	FPSO	Hull/Topside FC	Korea	SHI
VALEMON	Statoil Petroleum AS	2011	Producing	Jacket	Topside EPC	Korea	SHI
MARTIN LINGE	Total E&P Norge AS	2012	PDO approved	Jacket	Topside EPC	Korea	SHI
GINA KROG	Statoil Petroleum AS	2013	PDO approved	Jacket	Topside EPC	Korea	DSME
IVAR AASEN	Det Norske oljeselskap ASA	2013	PDO approved	Jacket	Topside EPC	Singapore	SMOE
AASTA HANSTEEN	Statoil Petroleum AS	2013	PDO approved	Spar	Topside/substructure EPC	Korea	HHI

7 Assessment of cost trends

According to a report done by the Norwegian Petroleum Directorate, the following aspects are key to success in implementing major projects (Oljedirektoratet, 2013):

- Early phase work
- Prequalification of contractors
- Contract strategy
- Project follow-up

7.1 Early phase work

One of the main reasons of cost overruns and delays of offshore field developments today are deficiencies and deviations in the first phases in the capital value process. The time allocated for early phase work has been insufficient. As mentioned in subchapter 3.2, it is the early phases (feasibility-, concept-, and definition stage) that set the foundation for the whole project, and the cost estimates for the PDO. It is crucial that the FEED and the engineering are done properly and are 100 pct. completed before the PDO is submitted. Any deviation from this can lead to substantial, expensive, and even impossible changes at a later stage in the project. In some cases new information can surface after the first phases are completed, this information might then not be included as the project already is well underway. As a result work might have to be done over again, which causes severe delays and cost overruns (Oljedirektoratet, 2013).

The trend has been that an internal decision programme for sufficient maturing of projects has been absent in many operating companies. The overall maturity level has been too low for the new and more complex facilities. Thus, there have been unclear quality requirements in the decision foundation for the project sanctioning. An improvement can be obtained by increasing the focus on FEED and competence, resulting in enhanced project line accountability in the future (Abrahamsen, 2016)

7.2 Prequalification of contractors

Thorough prequalification of the suppliers who contribute to the project is a necessity (Abrahamsen, 2016). The selection of contractor is something that can decide the whole faith to a project development. The operator must have a clear conviction of what they want from the contractor, so that they have an overview of what they can rely on the contractor to do, and what needs follow-up. As mentioned in subchapter 4.3 the operating company goes through several evaluation criteria before final selection of contractor. If the prequalification of suppliers is done thoroughly it reduces the risk of problems at later stages in the development project.

What has been seen over the last years is that the operator companies have executed improper and insufficient prequalification of the contractors. They have not been critical enough of who makes the list of qualified and competent contractors. Once a contractor/supplier has made the list, it is difficult to find reasons not to choose the cheapest option. This may be considered a contributing factor to why so many contracts have been awarded to Far East yards in the last decade (Abrahamsen, 2016).

7.3 Contract strategy

The key risk elements in the project should be reflected in the contract strategy, such as new technology and major equipment components. The contract strategy is an important and fully necessary tool in regard to prequalification of suppliers and the operator´s direct follow-up. Experience from earlier projects has shown that the operator has much to gain by taking on a greater direct contract responsibility (Oljedirektoratet, 2013). The contract strategy for some projects, especially for contracts awarded to international yards, has proven to be faulty and characterized by deficiencies. The contract strategies of many operators have not been successful in the transition to a more globalized market. They have proven to be too optimistic, and have underestimated the scope, work, and complexity involved. As a result, we see a trend of new contract types today, with an increased focus on standardisation.

7.4 Project follow-up

Good operator follow-up of the project is crucial, regardless of where in the world the construction takes place. However, there is a difference in the level of follow-up needed for a Far East yard compared to a Norwegian yard. First of all the Norwegian yards have a much better understanding of the Norwegian regulatory system and the NORSOK standards. The lack of understanding of this on Far East yards represents a great challenge. It is the operator responsibility that the yards get a proper introduction and course in these standards and requirements, and that the work is followed up through the whole construction. In cases where deficiencies in fabrication are caused by poor understanding of NORSOK, this is a consequence of the operator's underprovided follow-up of the construction work in relation to what is stated in the contracts (Oljedirektoratet, 2013). Secondly, given that Far East yards are geographically distant from Norway, the yards depend on the operating companies to send personnel with sufficient expertise and experience to follow up the project progress and requirements. This is three times the price of follow-up in Norway. However, given the extra time used on fabrication in the Far East over the last years, the price of personnel for follow up has become up to six times the price (Abrahamsen, 2016).

PART 4: Analyses

This part contains an analysis of each of the five selected projects. The analysis emphasises the development in costs compared with the plans in the PDO, and presents the level of Norwegian content in the projects. Finally, some experiences related to execution of the projects are briefly mentioned for each project.

8 Analyses of five development projects on the Norwegian continental shelf

8.1 Data basis and level of detail in the analyses

The analyses of the different fields are based on the best available data. It is a combination of data from the propositions to the Storting, the petroleum directorate's fact pages, impact assessment reports, and other relevant webpages.

The information and numbers that have been operated with in the analysis may vary in the different documents. In addition, not all of the projects are fully completed. Hence, there will be some uncertainties in the numbers that are given.

The numbers and data collected have been inserted into the Excel calculation programme, ACES, in order to get the level of Norwegian content and cost estimates of the different fields.

8.2 Analysis of the Gjøa field

8.2.1 Background on the field

The Gjøa field is middle-large field located approximately 65 km southwest of Florø, north of the Troll field. The water depth in the area is 360 metres. The field is located in the block 35/9 and block 37/7 (see figure 8.1). The field was discovered in 1989, and the production licence 153 was awarded in 1988 (Det kongelege olje - og energi departementet, 2007). The field's development period was 2007-2010, with additional drilling in 2011 and 2012. Production start was in November 2010. The two fields Vega and Vega South is located near Gjøa, and is developed with subsea installations tied back to Gjøa (Holmelin, 2015). However, these smaller fields are not included in this analysis.

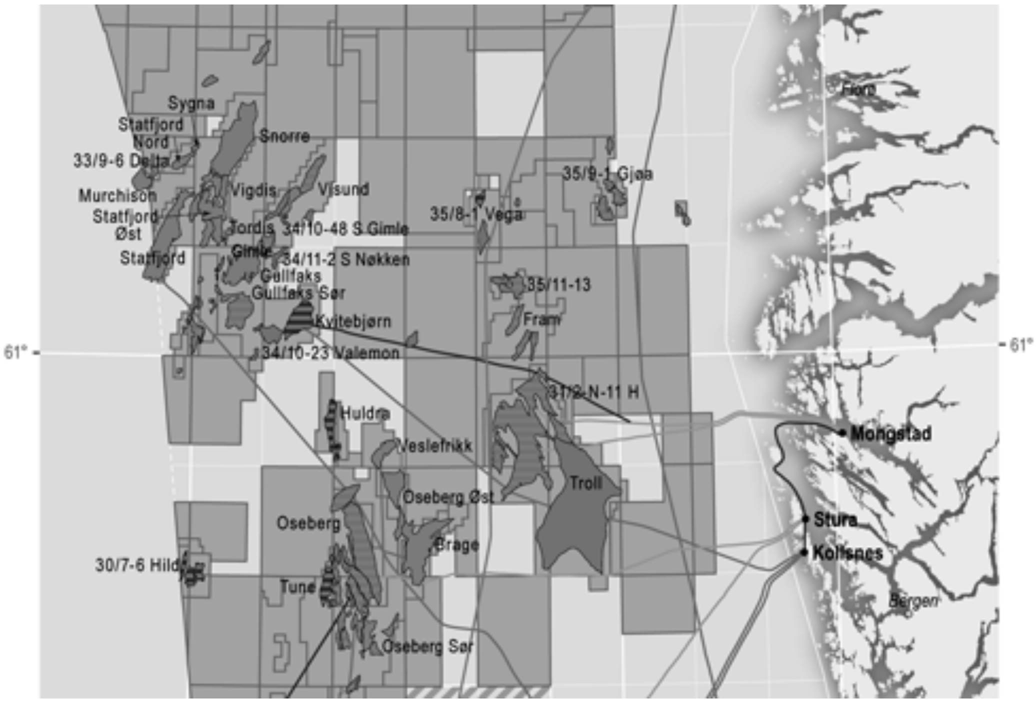

Figure 8.1: Overview of Gjøa, Vega and Vega South

Source: (Det kongelege olje - og energi departementet, 2007)

Recoverable petroleum reserves are expected to be 39,7 billion Sm^3 rich gas and 13,2 million Sm^3 oil and condensate, where 9,2 Sm^3 is oil. The recovery rate is 21 pct. and 69 pct. for oil and gas, respectively (Det kongelege olje - og energi departementet, 2007). The production period for the Gjøa field is expected to be 17 years with possibilities for extension (Holmelin, 2015).

The licensees are Engie E&P Norway AS (then Gaz de France Norway AS), Petoro, Statoil Petroleum AS, AS Norwegian Shell and RWE Dea Norway AS. Their interests are listed in table 8.1 below. Statoil was the operator during the development period, before Engie E&P Norway AS took over when the commercial production started, and now has the overall responsibility of the production (Det kongelege olje - og energi departementet, 2007).

Table 8.1: Overview of the shareholders in Gjøa

Source: (Det kongelege olje - og energi departementet, 2007)

Company	Participating interest (pct.)
Engie E&P Norway AS	30
Petoro AS	30
Statoil Petroleum ASA	20
A/S Norwegian Shell	12
RWE Dea Norway AS	8

8.2.2 Development concept for Gjøa

The Gjøa development is a semisubmersible with a production and process facility for export of stabilized oil and rich gas (see figure 8.2) (Det kongelege olje - og energi departementet, 2007). Stabilized oil from Gjøa is further exported through a 60 km long pipeline on the seabed tied up to Troll oil pipeline II, for further transport to Mongstad. The rich gas is exported trough a 130 km long pipeline on the seabed that is tied to the British gas pipeline system FLAGS, for further transport to St. Fergus (Holmelin, 2015). The platform also includes a living quarter module, but lacks drilling facilities. The development includes three templates with a total of 13 production wells that are tied back to the semi. The production takes place by depressurization (Holmelin, 2015).

Figure 8.2: The Gjøa platform

Source: (Engie E&P Norway AS, 2016)

8.2.3 Analysis of the development project

Platform

Both the topside and the living quarter were built in Norway. The topside was fabricated by Kværners offshore yard on Stord as total contract (EPCH), and the living quarter by the neighbour company Apply (earlier Leirvik Sveis). SHI in Korea fabricated the substructure (hull). The substructure was further transported to Norway for paring. A heavy lift vessel completed the pairing, before it was towed to the field for installation, which was conducted by EMAS AMC (Holmelin, 2015).

Subsea systems

A Danish company, Rambøll, engineered the subsea system, but some Norwegian survey work was included. A Danish company also conducted the procurement of the risers. The underwater production systems were constructed by FMC, and Acergy, now a part of Subsea 7, conducted the installation of templates and risers. Technip and FMC did most of the substantial connection work on the seabed. Several firms were involved in the completion work (Holmelin, 2015).

Export systems

Rambøll was also responsible for the engineering of export pipelines. Since there are no Norwegian suppliers of export pipelines the export pipelines were procured from abroad. The Intra-field pipelines were procured from Japan. Technip conducted the installation and hook-up. Saipem did the installation, with engineering in Italy. And several firms were involved in the completion work (Holmelin, 2015).

Drilling and completion

Norwegian companies prepared all the reservoir development. Transocean conducted the drilling operation, and diverse drilling services were conducted by several of the large drilling service companies.

An overview of the estimated cost of the different parts of the Gjøa development today is shown in table 8.2.

Table 8.2: Estimated cost of the Gjøa field development (ACES)

CAPEX facilities overview	mill. NOK
Cost element	Total
Topsides Substructure incl. conductors/risers Piles, anchors and mooring lines	17117 3002 752
Sum Platform	20871
Subsea/WHP production equipment Flowlines and spools Structures (RB, PLET, PLEM, T, Y) Risers for flowlines/pipelines Umbilicals with risers	3096 1773 760 1234 534
Sum Subsea	7396
Export pipelines Power cables with risers	3561 939
SUM facilities	32768
CAPEX wells overview	
Drilling Completion	4026 3756
Drilling and completion	7782
TOTAL	40550

8.2.4 Cost development of the project

As one can see from table 8.2 above, the Gjøa field development would have had an estimated cost of 40,5 billion Norwegian kroner in today's market. This is a cost increase of 12,4 billion kroner compared with the unbiased estimate in the PDO that was approved in 2007. This gives a cost increase of 30,5 pct. over the last 9 years. Since start of production in 2011 the cost has increased with 5,9 billion kroner, 14,6 pct. In figure 8.3 below you can see the cost development over the last decade. The columns presented for 2007-2011 shows the last official numbers gathered from the Storting propositions. The period 2012-2015 is not presented as the Gjøa development started production in 2011. The column presented for 2016, shows the estimate done in ACES, in accordance with today's market situation.

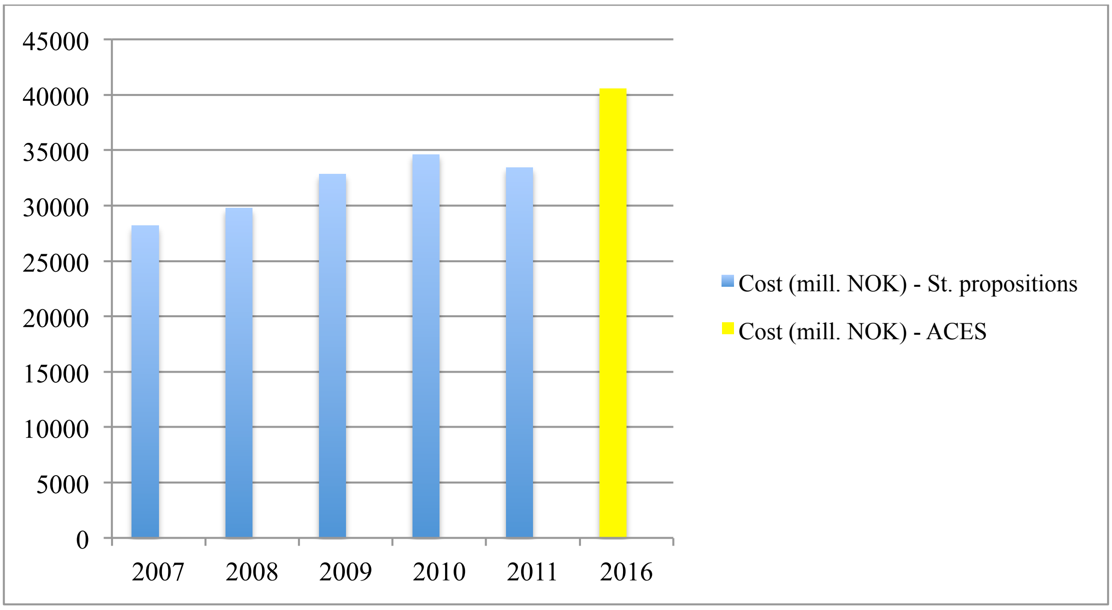

Figure 8.3: The cost development of the Gjøa field (2007-2016) (mill. NOK)

8.2.5 Norwegian content

Statoil has stated that approximately 70 pct. of the work on Gjøa is performed by Norwegian suppliers, but the field development still consists of pieces from all around the world (Statoil, 2010). In the report by the Ministry of petroleum and energy they have concluded that 63 pct. of the work on Gjøa is performed by Norwegian suppliers.

Based on the numbers in table 8.2, and information gathered from the report by the Ministry of petroleum and energy (Holmelin, 2015) it has been estimated in this thesis that the total Norwegian content in the Gjøa development is 55 pct. In figure 8.4 below you can see the level of Norwegian content in the different parts of the field development.

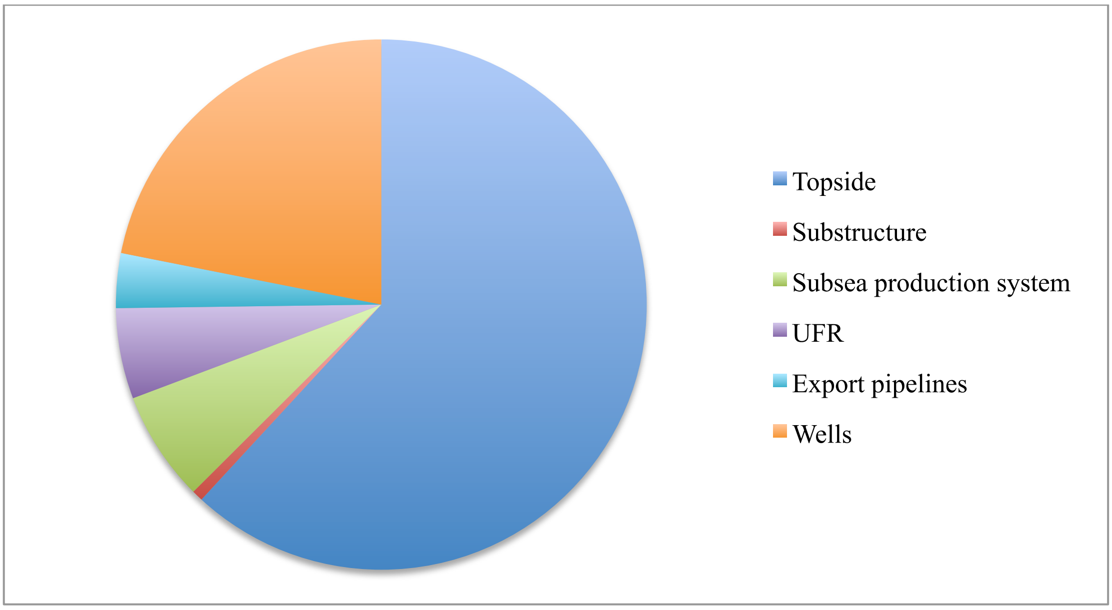

Figure 8.4: Distribution of Norwegian content (55 pct.) in the different parts of the Gjøa development

The topside has the highest level of Norwegian content, as it was fabricated in Norway. Norwegian companies also dominated the drilling and completion of the wells, hence the high level of Norwegian content. SHI in Korea built the substructure (hull), with little or no equipment and material from Norway, giving a low level of Norwegian content.

8.2.6 Experiences related to the project

Despite some cost overruns in relation to the unbiased estimate in the PDO, Gjøa was a success overall. The as-built cost for Gjøa is only just exceeding its uncertainty range for the estimate in the PDO, and the start-up was only delayed by a week (Oljedirektoratet, 2013). The project exceeded all expectations given that the project ended up in the middle of a price war, and was built during an inflation period. Skarv on the other hand, which was built on the same time, suffered great cost overrun and delays (Abrahamsen, 2016).

The largest contributors to the cost overrun in the project were the drilling and completion, the engineering, and the changes made to the platform topside.

The cost increase related to drilling and completion is largely due to the estimated time schedule for the drilling in the PDO being fairly optimistic. During drilling it was discovered that some of the planned segments were dry, also some changes to the drilling design had to be made. The dry segments led to delays and cost overrun, as the planned producers had to be plugged before new ones could be drilled (Oljedirektoratet, 2013).

In regard to the cost overrun related to the topside of the platform this was because of a drastic weight increase (3000 tonnes), increase in engineering hours, and poor quality of the fittings. The engineering took longer than planned because the engineering was split between two engineering houses; one in Mumbai (India) and one in Oslo, and it took some time before a good communication workflow was established. An additional issue leading to the weight increase was sub-suppliers deliveries exceeding the estimated weights agreed upon. Lastly, at a late stage in the project it was discovered that the fitting was not of sufficient quality. This resulted in an extensive replacement job, and a substantial contribution to the cost overrun to the platform topside (Oljedirektoratet, 2013).

The causes mentioned above is largely because of unforeseen situations, but might have been avoided if better work was done during the early phases of the project development. While 100 pct. of the FEED was completed before submission of the PDO, new information surfaced at a point where the project was already well underway, and as a result work had to be done over again.

Prequalification of the relevant suppliers was a success in the Gjøa field development, and key factor to the good project implementation. However, there were some issues in regard to the sub-suppliers, as they didn't use the same procedures and processes as they did during prequalification. This is a good example of the insecurity related to the deliveries, but prequalification is still an important step of the process (Oljedirektoratet, 2013).

The Gjøa project also conducted a successful cooperation with the Far East yard, SHI, in fabrication of the substructure, much because of a well-implemented follow-up process. It was completed in accordance with cost, time schedule, and quality. For instance, SHI was obligated to review the engineering work done by Aker, and therefore travelled to Aker in Oslo prior to construction start. In this way SHI got a thorough understanding of the design, and the Norwegian regulations and standards (Oljedirektoratet, 2013).

To ensure that the suppliers and sub-suppliers had a proper understanding of the requirements related to their deliveries a pre-fabrication meeting was held. By using a Far East yard for the fabrication of the substructure a well-established work scope was a necessity. Only one major change was applied during construction, and was dealt with without any further delays or problems. In addition, the operator put together a team of both commercial and technical expertise to follow up the construction on the Samsung yard. A local company was also hired to follow up specific quality requirements, these workers also travelled to Oslo to get a good understanding themselves of the Norwegian standards and requirements (Oljedirektoratet, 2013).

8.3 Analysis of Edvard Grieg field

8.3.1 Background on the field

The Edvard Grieg field is a middle-large field located approximately 180 kilometres west of Stavanger, in the middle section of the North Sea in block 16/1 (see figure 8.5) (Det kongelege olje - og energi departementet, 2012). Other fields like the large oil field Johan Sverdrup and the field Ivar Aasen lie close by (Holmelin, 2015). The Edvard Grieg field was discovered in 2007, and the PDO was approved in 2012. The development period was 2012-2015 (Holmelin, 2015). The production start was in November 2015 (Det kongelege olje - og energi departementet, 2012).

Recoverable petroleum reserves are estimated to 26,2 mill. Sm^3 oil, and 1,8 bill. Sm^3 gas (Det kongelege olje - og energi departementet, 2012). The expected production period is up to 25 years. Through higher recovery rate or tie-in of other structures close by, there is a possibility of extension (Holmelin, 2015).

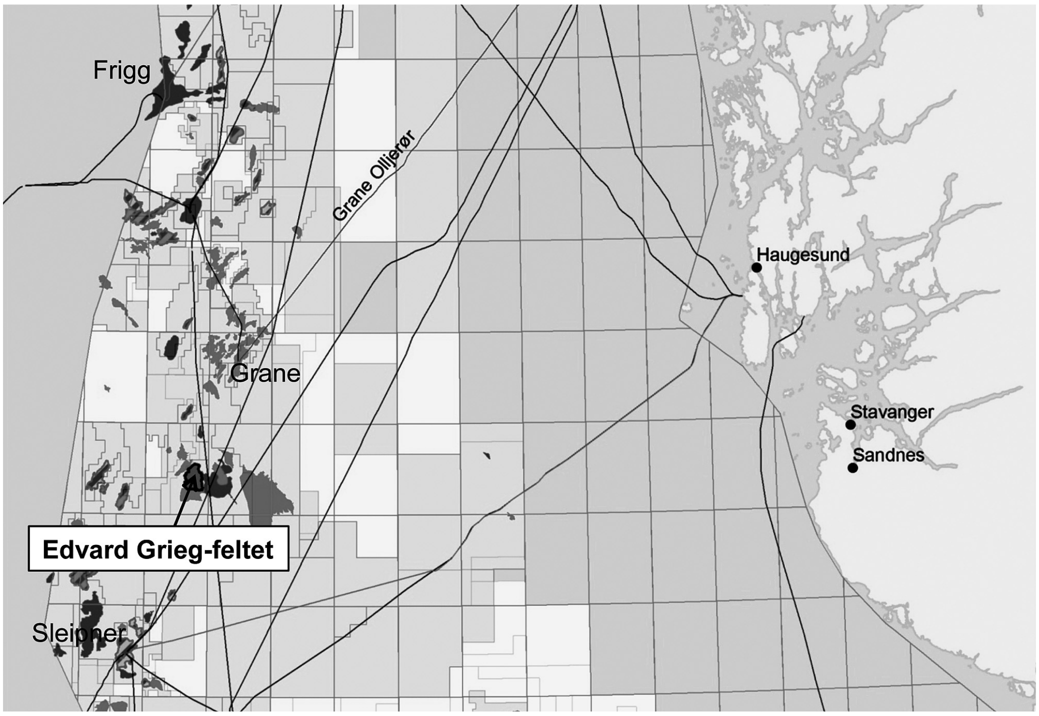

Figure 8.5: The location of The Edvard Grieg field

Source: (Det kongelege olje - og energi departementet, 2012)

The licensees are Lundin Norway AS, OMV (Norway) AS, Statoil Petroleum, and Wintershall Norge ASA. Their interests are listed in table 8.3 below. The operator of the field is Lundin Norway AS, during both the development and operational phase (Holmelin, 2015).

Table 8.3: Overview of the shareholders in Edvard Grieg

Source: (Holmelin, 2015)

Company	Participating interest (pct.)
Lundin Norway AS	50
OMV (Norway) AS	20
Statoil Petroleum	15
Wintershall Norge ASA	15

8.3.2 Development concept for the Edvard Grieg field

The water depth in the area is 110 metres. The development consists of a platform with a steel jacket, resting on the seabed (see figure 8.6). The platform has wellhead equipment with 20 slots for production and injection wells, living quarters, and a production facility for both oil and gas (Det kongelege olje - og energi departementet, 2012). The first couple of years the power supply will be upheld by gas turbines installed on the platform. The plan is to get power from land, once there are sufficient amounts of power available at Utsira High. The power line is not included in the development project at this point.

Edvard Grieg started production at 28. November 2015 (Lundin Petroleum, 2015). Further drilling will according to plans proceed until 2018 (Holmelin, 2015).

Figure 8.6: Drawing of the Edvard Grieg platform

Source: (Oljedirektoratet, 2016)

8.3.3 Analysis of the development project

Platform

The construction work mainly took place in Norway, with Kværner Verdal as main contractor and a long list of both foreign and Norwegian sub-contractors. Aker Solutions conducted the engineering, Apply Leirvik delivered the helicopter deck and living quarters, and Kværner Verdal constructed the jacket. Aker Solutions in Egersund and Kværner Stord built the platform deck (Lundin Petroleum, 2015).

Export systems

Construction and installation of the export pipelines has been Statoil Petroleum's responsibility (Lundin Petroleum, 2015). The contract including procurement, laying, and welding of the export pipelines was awarded to Allseas. Allseas used their own boats for the job (Holmelin, 2015).

Drilling and completion

The Edvard Grieg development has platform-completed wells. Lundin did the planning of the drilling activities, and Rowan Companies conducted the drilling (Lundin Petroleum, 2015).

An overview of the estimated cost of the different parts of the Edvard Grieg development today is shown in table 8.4.

Table 8.4: Estimated cost of the Edvard Grieg field development (ACES)

CAPEX facilities overview	mill. NOK
Cost element	Total
Topsides	15630
Substructure incl. conductors/risers	2204
Piles, anchors and mooring lines	743
Sum Platform	18578
Subsea/WHP production equipment	0
Flowlines and spools	0
Structures (RB, PLET, PLEM, T, Y)	94
Risers for flowlines/pipelines	37
Umbilicals with risers	0
Sum Subsea	131
Export pipelines	2841
Power cables with risers	0
SUM facilities	21550
CAPEX wells overview	
Drilling	3961
Completion	1836
Drilling and completion	5796
TOTAL	27346

8.3.4 Cost development in the project

Based on the estimates done in ACES the Edvard Grieg field would have had an estimated price of 27,3 billion Norwegian kroner today (see table 8.4 above). This is a cost increase of 3,1 billion Norwegian kroner compared with the unbiased estimate in the PDO that was approved in 2012. This gives a cost increase of 11,5 pct. over the last 4 years. Since start of production in 2015 the cost has increased with 2,5 billion kroner, 9,3 pct. In figure 8.7 below you can see the cost development over the last few years. The columns presented for 2012-2015 show the last official numbers gathered from the Storting propositions. The column presented for 2016, shows the estimate done in ACES, in accordance with today's market situation.

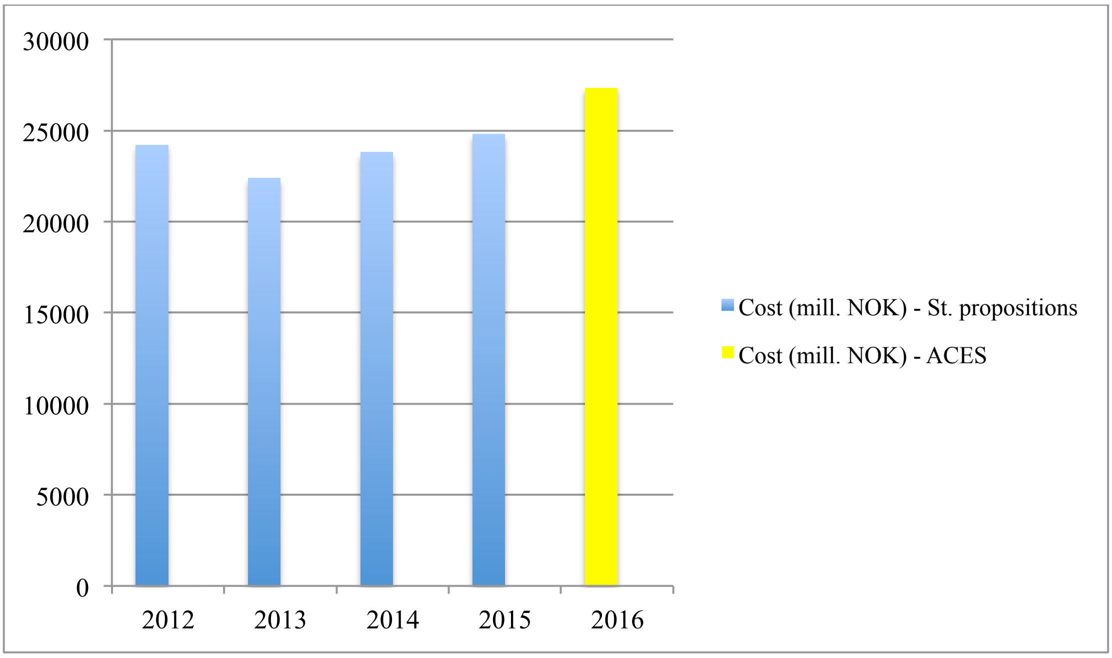

Figure 8.7: The cost development of the Edvard Grieg field (2012-2016) (mill. NOK)

8.3.5 Norwegian content

Lundin has stated that approximately 60 pct. of the work on Edvard Grieg is performed by Norwegian suppliers, which is high for a project on NCS (Det kongelege olje - og energi departementet, 2016) . In the report performed by the Ministry of petroleum and energy they have concluded that 61 pct. of the work on Edvard Grieg is performed by Norwegian suppliers.

Based on the numbers in table 8.4, and information gathered from the report by the Ministry of petroleum and energy (Holmelin, 2015) it has been estimated in this thesis that the total Norwegian content in the Edvard Grieg development is 66 pct. In figure 8.8 below you can see the level of Norwegian content in the different parts of the field development.

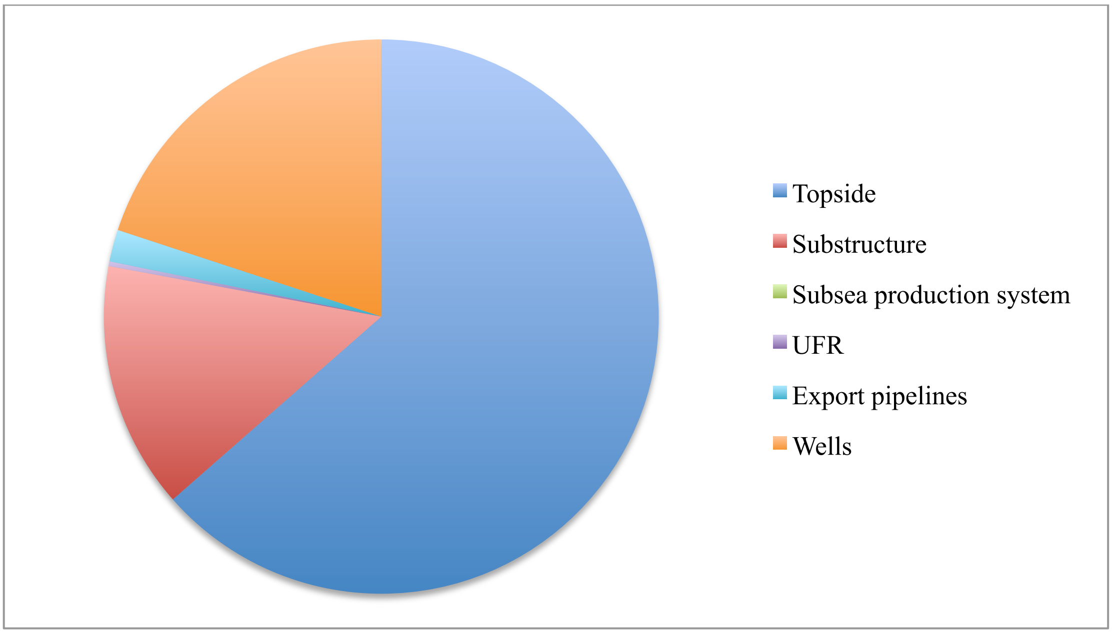

Figure 8.8: Distribution of the Norwegian content (66 pct.) in the different parts of the Edvard Grieg development

The topside has a high level of Norwegian content considering Norwegian companies constructed it, Aker Solution and Kværner. Kværner also constructed the substructure of the platform, which gives a high level of Norwegian content also here. A high level of Norwegian content can also be seen in the drilling and completion of the wells, which was conducted by Rowan Company in Norway.

8.3.6 Experiences related to the project

Edvard Grieg has been a successful project, like Gjøa. The project had start-up a week before the planned start-up, and both the topside and the substructure was delivered on time and without any cost overrun.

The project emphasized the price with 60 pct., the quality with 20 pct. and the timeliness 20 pct. when choosing contractor (Holm, 2015). The project experienced huge success by basing the project on an EPC contract with Norwegian suppliers. Common for this type of contract is that there has been successful engineering and sufficient progression in procurement and fabrication, and a seamless interaction between the different phases and stages of the development (Andersen et al., 2016).

As both the topside and the substructure was built in Norway it made the project follow-up, and communication between operator and contractor substantially easier. In addition, the long transportation for the modules was not a factor compared to if it had been constructed in the Far East.
Overall, the project has fulfilled the four aspects represented in chapter 7, and as a result the project was completed within time and without any large cost overruns.

8.4 Analysis of the Goliat field

8.4.1 Background on the field

The Goliat field is located southwest in the Barents Sea, approximately 85 km northwest of Hammerfest in Finnmark, and 50 km southeast of the Snøhvit field. Located in block 229 and 229B (see figure 8.9). The field was discovered in 2000, and the PDO was approved in 2009 (Det kongelege olje - og energi departementet, 2009). The production at Goliat started in March 2016, three years after planned start up. The water depth in the area is approximately 360-420 metres (Holmelin, 2015).

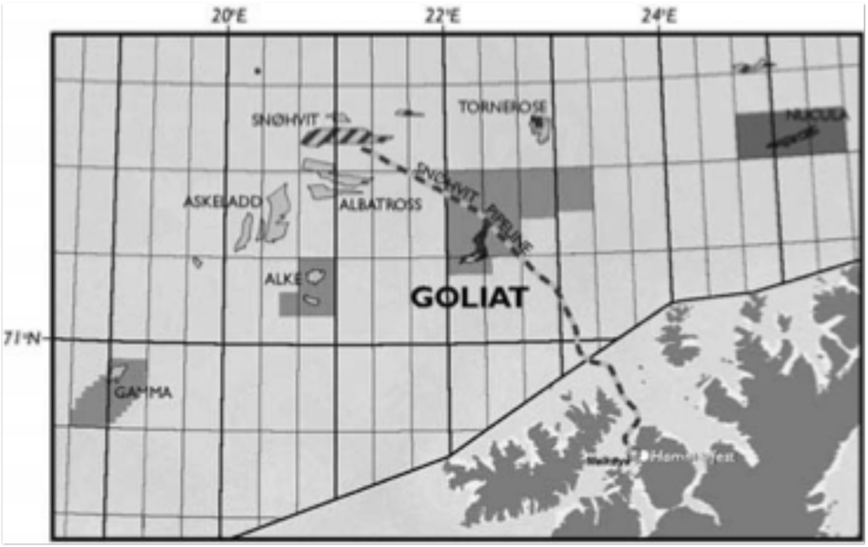

Figure 8.9: Location of the Goliat field

Source: (Det kongelege olje - og energi departementet, 2009)

The recoverable reserves in the Goliat field is estimated to be 30, 2 mill. Sm^3 oil, 0,3 mill. ton NGL, and 7,3 mill. Sm^3 gas.

The licensees are ENI Norway AS, and Statoil Petroleum AS. Their interests are listed in table 8.5 below. ENI Norway AS is the operator of the field during development and operation (Holmelin, 2015).

Table 8.5: Overview of the shareholders in the Goliat field

Source: (Holmelin, 2015)

Company	Participating interest (pct.)
ENI Norway AS	65
Statoil Petroleum AS	35

8.4.2 Development concept for the Goliat field

The Goliat field development concept is a circular floating production unit, a Sevan 1000 (see figure 8.10). The Sevan will be permanently anchored on the field. The facility has full processing, living quarters, and integrated storage and loading systems. The oil and NGL will be transported directly form the field with shuttle tankers. The gas together with water will be re-injected to the reservoir the first years, before a new plan of export of the gas is developed (Holmelin, 2015). The power supply will partly be covered by power from land, in addition to self-produced power by gas compressors (Det kongelege olje - og energi departementet, 2009).

The reserves will be recovered by 22 wells. 11 oil producers, 2 gas injectors, and 9 water injectors. The development plan consists of 8 templates; 4 production wells, 3 water injection wells and one for the gas injection wells (Det kongelege olje - og energi departementet, 2009).

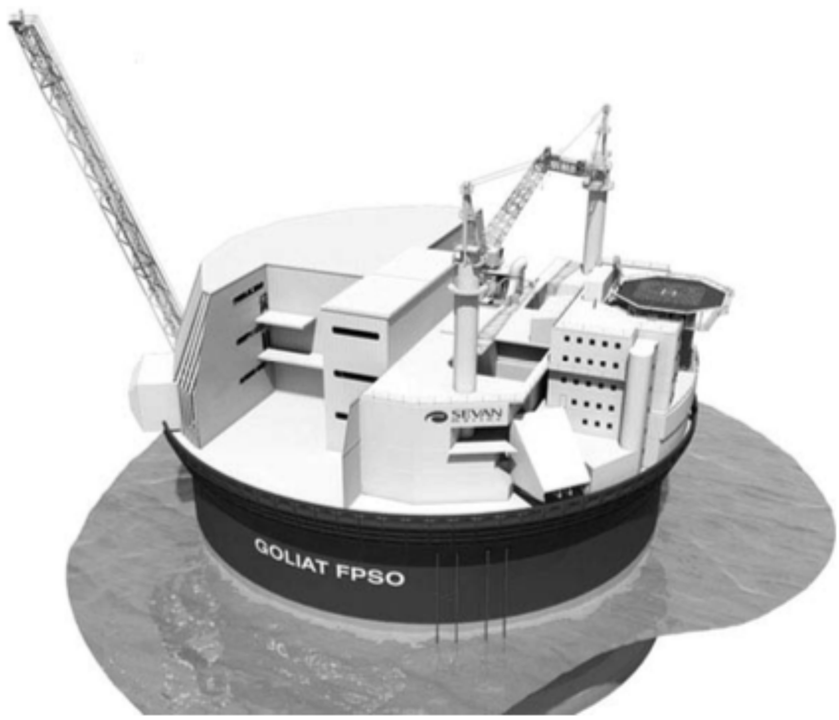

Figure 8.10: Drawing of the Goliat platform

Source: (Det kongelege olje - og energi departementet, 2009)

8.4.3 Analysis of the development project

Platform

Hyundai Heavy Industries in Korea has constructed the large Sevan FPSO. Some equipment and bulk has been procured from Norway, in accordance with NORSOK. Aibel has conducted the connection work both inshore and offshore. The anchoring system is produced abroad, and DOF conducted the installation (Holmelin, 2015).

Subsea systems

Aker Subsea is the main supplier of the subsea production systems. Technip Norway has conducted the work with risers and pipelines. The risers and pipelines are not fabricated in Norway (Holmelin, 2015).

Export systems

Aker Pusnes has delivered the loading system for oil from the FPSO. Currently, the produced gas is injected for pressure support, or used for power production. The plan is to find a gas export solution at a later stage (Holmelin, 2015).

Drilling and completion

The drilling rig, Scarabeo 8 is performing the drilling at the field. Halliburton and Schlumberger is delivering drilling services and material (Holmelin, 2015).

An overview of the estimated cost of the different parts of the Goliat development today is shown in table 8.6.

Table 8.6: Estimated cost of the Goliat field development (ACES)

CAPEX facilities overview	mill. NOK
Cost element	Total
Topsides	16216
Substructure incl. conductors/risers	3948
Piles, anchors and mooring lines	858
Sum Platform	21022
Subsea/WHP production equipment	6179
Flowlines and spools	2751
Structures (RB, PLET, PLEM, T, Y)	348
Risers for flowlines/pipelines	862
Umbilicals with risers	933
Sum Subsea	11072
Export pipelines	463
Power cables with risers	1137
SUM facilities	33694
CAPEX wells overview	
Drilling	5973
Completion	2739
Drilling and completion	8712
TOTAL	42406

8.4.4 The cost development of the project

Based on the estimates done in ACES the Goliat field would have had an estimated price of 42,4 billion Norwegian kroner today (see table 8.6 above). This is a cost increase of 13,8 billion Norwegian kroner compared with the unbiased estimate in the PDO that was approved in 2009. This gives a cost increase of 32,6 pct. over the last 7 years. The planned start-up time for the project was in 2013, but the production didn't start before March 2016. After the planned start-up the cost of the project has increased by 3,8 billion Norwegian kroner, 9,2 pct. just the last 3 years. In figure 8.11 below you can see the cost development over the last few years. The columns presented for 2009-2015 show the last official numbers gathered from the Storting propositions. The column presented for 2016, shows the estimate done in ACES, in accordance with today's market situation.

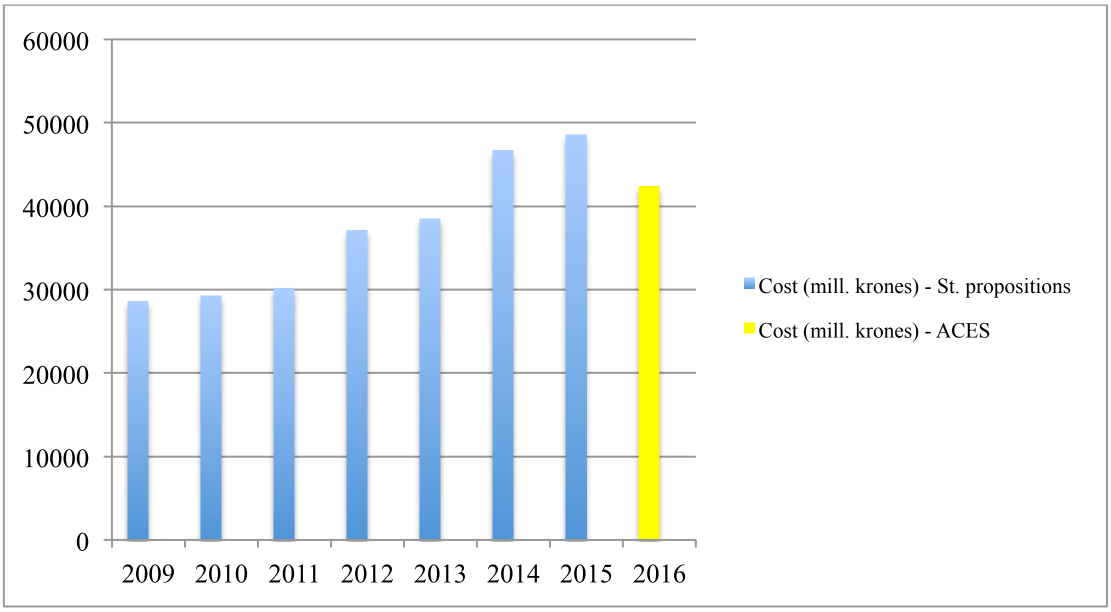

Figure 8.11: The cost development of the Goliat field (2009-2016) (mill. NOK)

8.4.5 Norwegian content

It has not been possible to obtain an official statement from Eni regarding the level of work done by Norwegian suppliers in the Goliat development. However, in the report performed by the Ministry of petroleum and energy they have concluded that Norwegian suppliers performed 43 pct. of the work on Goliat.

Based on the numbers in table 8.6, and information gathered from the report by the Ministry of petroleum and energy (Holmelin, 2015) it has been estimated in this thesis that the total Norwegian content in the Goliat development is 38 pct. In figure 8.12 below you can see the level of Norwegian content in the different parts of the field development.

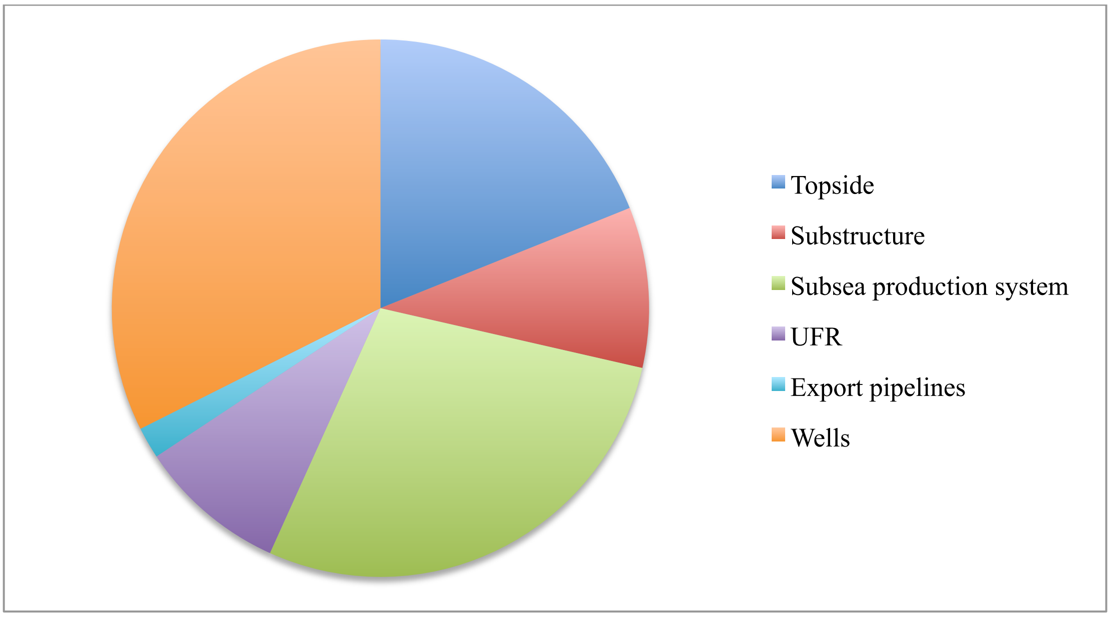

Figure 8.12: Distribution of the Norwegian content (38 pct.) in the different parts of the Goliat development

Norwegian companies performed the drilling, and constructed and installed the subsea production system. Therefore, these are the parts of the field development with the most Norwegian content. Compared to Gjøa and Edvard Grieg, the topside and substructure of the Goliat platform has a low level of Norwegian content as a result of being constructed on a Far East yard.

8.4.6 Experiences related to the project

The Goliat field development will go down in history as a horror story of an offshore field development, with deaths during construction, tens of billions in cost overrun, and massive delays. Planned start-up was in 2013, but production didn't start before March 2016. Goliat is an excellent example of why cheap is cheap. It is cheap because bills come at a later stage in the process, because the quality isn't how it should be, and because of unforeseen delays (Taraldsen, 2016).

Goliat has shown itself to be a troublesome project, where the trouble already started in the prequalification of the contractors. Eni did not accept Aker Solutions and Aibel together with the South Korean yard SHI as a consortium. Eni believed this wouldn't give a fair competition. As a result, it was the South Korean yard HHI that won the prestigious contract for the floating production unit (Taraldsen, 2016).

The Goliat development is the first floating production unit in the Barents Sea ever, this was a project with a lot of new elements, but still Eni chose a yard with little experience with such installations. In such projects with a high level of complexity, and where everything is new, changes in construction and supply along the way are not uncommon. As mentioned in subchapter 6.2.2 the productivity for Far East yards becomes considerably lower in situations where changes are made. This was proven throughout the Goliat development. In addition, compared to the other platforms considered in this thesis Goliat is not built in two parts (substructure and topside), but is a combined development. This means increased complexity, and more comprehensive work for the contractor. This may have been a contributing factor to the many problems during construction. As a result of low productivity at the Far East yard, much work was remaining after tow out to the location in the Barents Sea, and comprehensive completion work had to be done at sea.

Had Eni done better preparations and work in the early phases of the capital value process, much of the changes along the way might have been avoided, and the cost and delays might not have been as great. The selection of contract strategy has also been a point of discussion, whether it was the most suitable for this kind of development. A variant of the EPC-model was used with engineering and procurement with the sub-suppliers. What is often seen in projects with such contracts, especially with inexperienced contractors in the Norwegian market, is that they are struggling already in the engineering phase and/or in the transitions between engineering, procurement, and fabrication.

As the project was constructed in the Far East, project follow-up for the development was crucial. Although many people were sent to provide the contractor with the needed guidance, the operator failed in this. It can be discussed whether the personnel lacked the proper knowledge, training, and experience in order to help the contractor in a substantial way.

To summarize, one can say that the Goliat development was a risky project with a new location (Barents Sea), new concept (Sevan), new contractor (HHI), and a new operator (Eni). The project had too optimistic assumptions, lack of technical maturity, and several scope changes at a late stage in the process. In addition, the complexity and scope of work were underestimated (Abrahamsen, 2016).

8.5 Analysis of the Ivar Aasen field

8.5.1 Background on the field

Ivar Aasen is a middle-large field located in the middle part of the North Sea, and includes the three findings Ivar Aasen, West Cable and Hanz. The field is located in block 16/1 and 25/10, approximately 10 kilometres northwest of the Edvard Grieg field, and 200 kilometres west of Stavanger, with Utsira High (see figure 8.13). The field was discovered in 2008, and the PDO was approved in 2013. The planned start up is in the fourth quarter of 2016, and expected lifetime is 15 years. The water depth in the area is approximately 110 metres (Det kongelege olje - og energi departementet, 2013b).

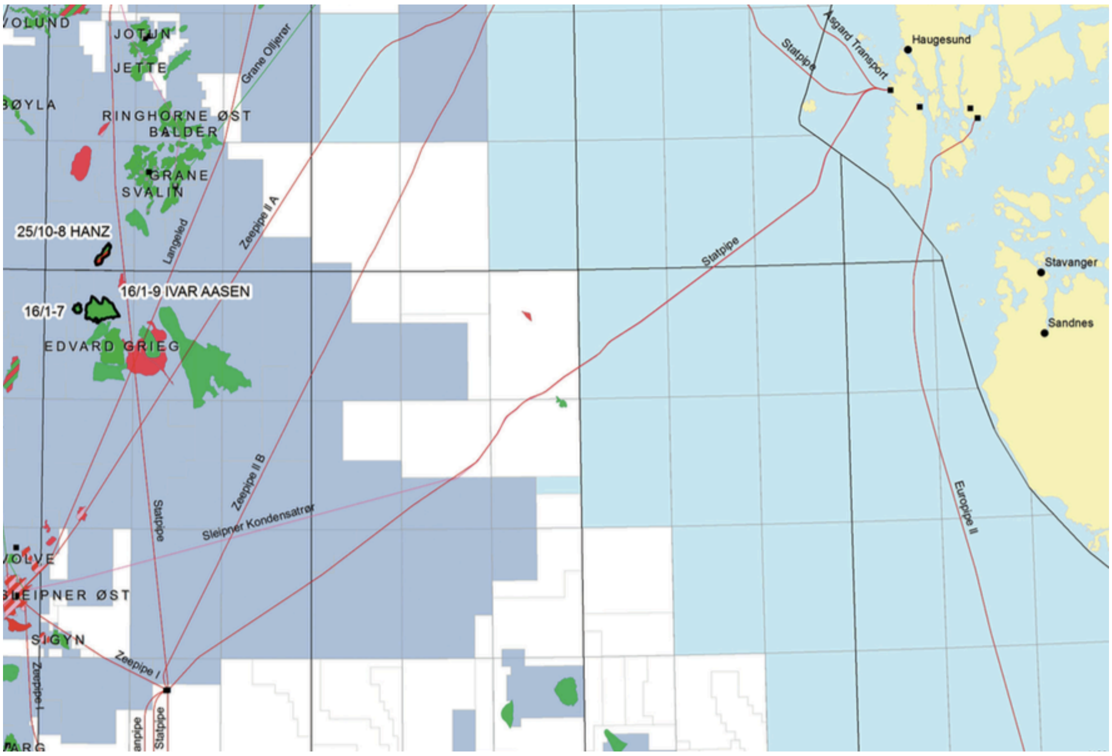

Figure 8.13: Location of the Ivar Aasen field

Source: (Det kongelege olje - og energi departementet, 2013b)

The recoverable reserves in the Ivar Aasen field are estimated to be 18,3 mill. Sm^3 oil and 5,3 bill. Sm^3 gas.

The licensees are Det Norske oljeselskap ASA, Statoil Petroleum AS, and Bayerngas Norway AS. Their interests are listed in table 8.7 below. Det Norske oljeselskap ASA is the operator of the field during development and operation (Det kongelege olje - og energi departementet, 2013b).

Table 8.7: Overview of the shareholders in the Ivar Aasen field

Source: (Det kongelege olje - og energi departementet, 2013b)

Company	Participating interest (pct.)
Det Norske oljeselskap ASA	35
Statoil Petroleum AS	50
Bayerngas Norway AS	15

8.5.2 Development concept for the Ivar Aasen field

The Ivar Aasen field development concept is a fixed installation with wells, facility for partial processing, and living quarters (see figure 8.14). The installation is placed over the Ivar Aasen finding. The Ivar Aasen field will be tied up to the Edvard Grieg field for further processing of the oil and gas, in addition to further export. A new pipeline to the Grane oil pipeline will export the oil from the two fields further to the Sture terminal. The gas will be transported via the British continental shelf. The power supply will be covered by the Edvard Grieg installation (Det kongelege olje - og energi departementet, 2013b).

The field will be carried out in two phases, where phase one includes the development of the findings West Cable and Ivar Aasen, and phase two includes the development of Hanz.

20 well slots will recover the reserves, 13 of these are included in the first phase of the development. The Ivar Aasen finding will have 6 oil producers, 6 water injectors, while West Cable will have 1 oil producer. Hanz will have 2 oil producers, and 1 water injector. The seven remaining well slots will be used to drill for additional resources to the Ivar Aasen field. There are also possibilities for tie-in of additional resources from other fields nearby (Det kongelege olje - og energi departementet, 2013b).

Figure 8.14: Drawing of the Ivar Aasen installation

Source: (Det norske oljeselskap ASA, 2016)

8.5.3 Analyses of the development project

Platform

Wood Group Mustang provided the engineering and design for the topside. SembCorp Marine´s Subsidiary (SMOE) in Singapore have conducted the procurement and construction of the Ivar Aasen development process, drilling and quarters (PDQ) platform. Apply Leirvik Stord have constructed the living quarters. Saipem, located in Sardinia, constructed the substructure. Heerema installed the substructure with one of the world's largest heavy-lift vessels (Det norske oljeselskap ASA, 2016).

Subsea systems

The first phase of the development, including the Ivar Aasen and West cable findings are tied up to the platform with the use of dry trees. Hanz on the other hand will be tied up to the platform with a satellite well. But phase two is not scheduled to start producing before 2019 (Det norske oljeselskap ASA, 2013).

Export systems

Partly processed oil and gas from Ivar Aasen will be sent to Edvard Grieg for further processing and export. In addition, Edvard Grieg will provide Ivar Aasen with lift-gas and power. EMAS AMC laid the cables connecting Ivar Aasen to Edvard Grieg.

Drilling and completion

The world largest drilling rig, Maersk Interceptor conducted the drilling on the field.

An overview of the estimated cost of the different parts of the Ivar Aasen development today is shown in table 8.8.

Table 8.8: Estimated cost of the Ivar Aasen field development (ACES)

CAPEX facilities overview	mill. NOK
Cost element	Total
Topsides	12518
Substructure incl. conductors/risers	1987
Piles, anchors and mooring lines	692
Sum Platform	15197
Subsea/WHP production equipment	854
Flowlines and spools	2158
Structures (RB, PLET, PLEM, T, Y)	72
Risers for flowlines/pipelines	83
Umbilicals with risers	339
Sum Subsea	3506
Export pipelines	0
Power cables with risers	180
SUM facilities	18883
CAPEX wells overview	
Drilling	5486
Completion	2600
Drilling and completion	8086
TOTAL	26969

8.5.4 The cost development of the project

Based on the estimates done in ACES the Ivar Aasen field would have had an estimated price of 26,9 billion Norwegian kroner today. This is a cost increase of 1,65 billion Norwegian kroner compared with the unbiased estimate in the PDO that was approved in 2013. This gives a cost increase of 6,1 pct. over the last 3 years. The planned start-up time for the project is late 2016. In figure 8.15 below you can see the cost development over the last few years. The columns presented for 2013-2015 show the last official numbers gathered from the Storting propositions. The column presented for 2016, shows the estimate done in ACES, in accordance with today's market situation.

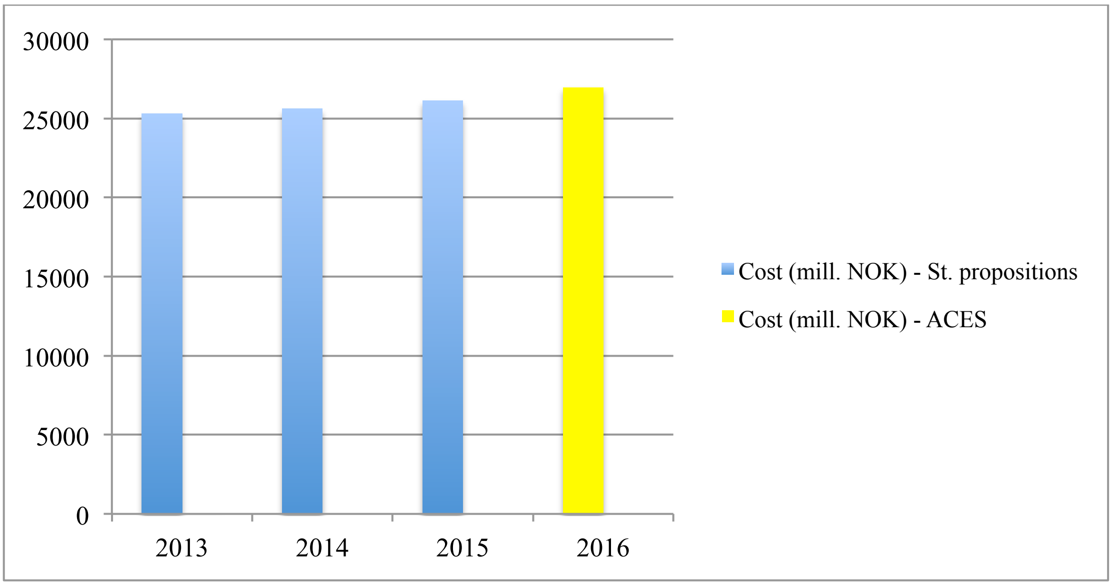

Figure 8.15: The cost development of the Ivar Aasen field (2013-2016) (mill. NOK)

8.5.5 Norwegian content

It has not been possible to obtain an official statement from Det Norske oljeselskap ASA regarding the level of work done by Norwegian suppliers in the Ivar Aasen development. However, based on the numbers in table 8.8, and information gathered from propositions to the Storting, the petroleum directorate's fact pages, impact assessment reports, and other relevant webpages it has been estimated in this thesis that the total Norwegian content in the Ivar Aasen development is 42 pct. In figure 8.16 below you can see the level of Norwegian content in the different parts of the field development.

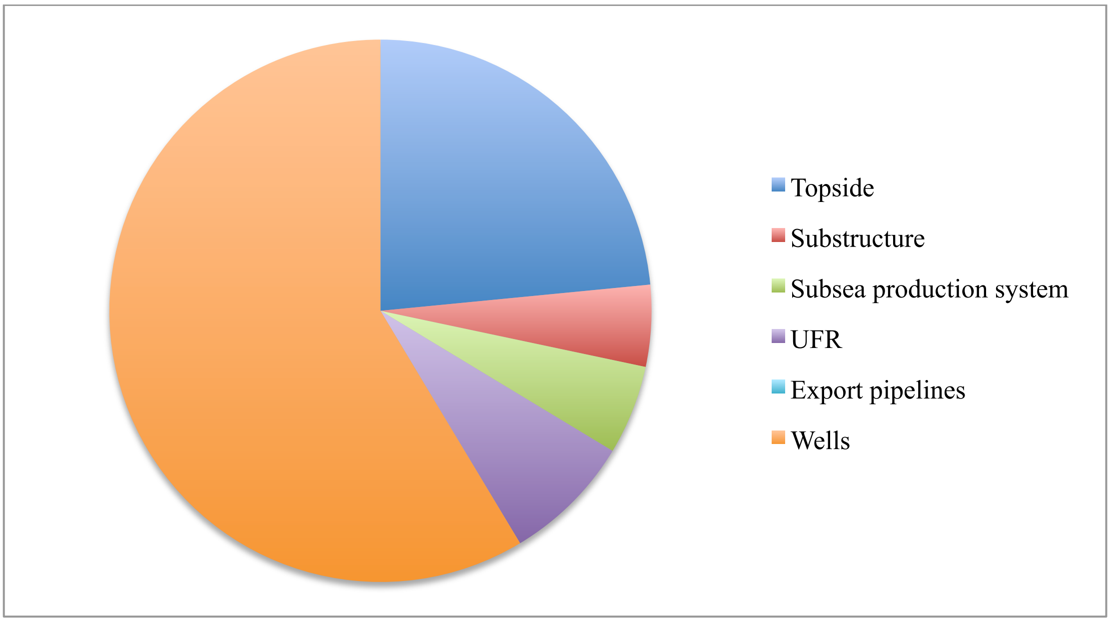

Figure 8.16: Distribution of the Norwegian content (42 pct.) in the different parts of the Ivar Aasen development

The development that has the most Norwegian content is the drilling and completion of the wells, as Maersk performed it. The topside also has some Norwegian content even though most of the topside was constructed in Singapore. For example, Apply Leirvik Stord constructed the living quarters, and some Norwegian services and equipment was used during construction in Singapore.

8.5.6 Experiences related to the project

The Ivar Aasen development is based on the same version of the EPC-model as Goliat. But compared to Goliat, Ivar Aasen has been able to deliver with this type of contract. This is due to a lower complexity level for Ivar Aasen compared to Goliat and Aasta Hansteen. Ivar Aasen is not a full process platform, and has a lot of support from the Edvard Grieg development.

SMOE has limited experience with production units to the NCS, but so far the time schedule seems to go according to plan. The operator has focused on giving good guidance and follow-up. Overall, the Ivar Aasen project seems to turn out to be a successful project between a Norwegian operator and a Far East yard.

Compared to the high activity level at the South Korean yard the Goliat development and the Aasta Hansteen development were and are being constructed at (HHI), the Ivar Aasen field has been the only oil and gas project on the yard in Singapore. This has allowed SMOE to fully focus on the Ivar Aasen project. This has also been a contributing factor to the well-established communication between the operator and contractor. Even though Norwegian and Asian business culture aren't necessarily two cultures that harmonize together, the operator and the yard has found a way to understand and respect these differences.

The Ivar Aasen field is not yet in production, but the platform is currently ready for transportation to Norway. According to Rystad Energy the field will be more profitable than Johan Sverdrup (see figure 6.5 in subchapter 6.1), and will only need an oil price at 33 dollars per barrel to be profitable (Hammerstrøm, 2016).

8.6 Analysis of Aasta Hansteen field

8.6.1 Background on the field

Aasta Hansteen is a middle-large gas field, with small amounts of associated condensate located approximately 140 km north of Norne, and 300 km west of Bodø. The field consists of the three discoveries Luva, Haklang and Snefrid South in the blocks 6607/1, 6706/12, and 6707/10 (see figure 8.17). Aasta Hansteen was discovered in 1997, and the PDO was approved in 2013 (Det kongelege olje - og energi departementet, 2013a). Aasta Hansteen is still under development, and the planned start up is the third quarter of 2018 (Holmelin, 2015). The water depth in the area is approximately 1300 metres (Det kongelege olje - og energi departementet, 2013a).

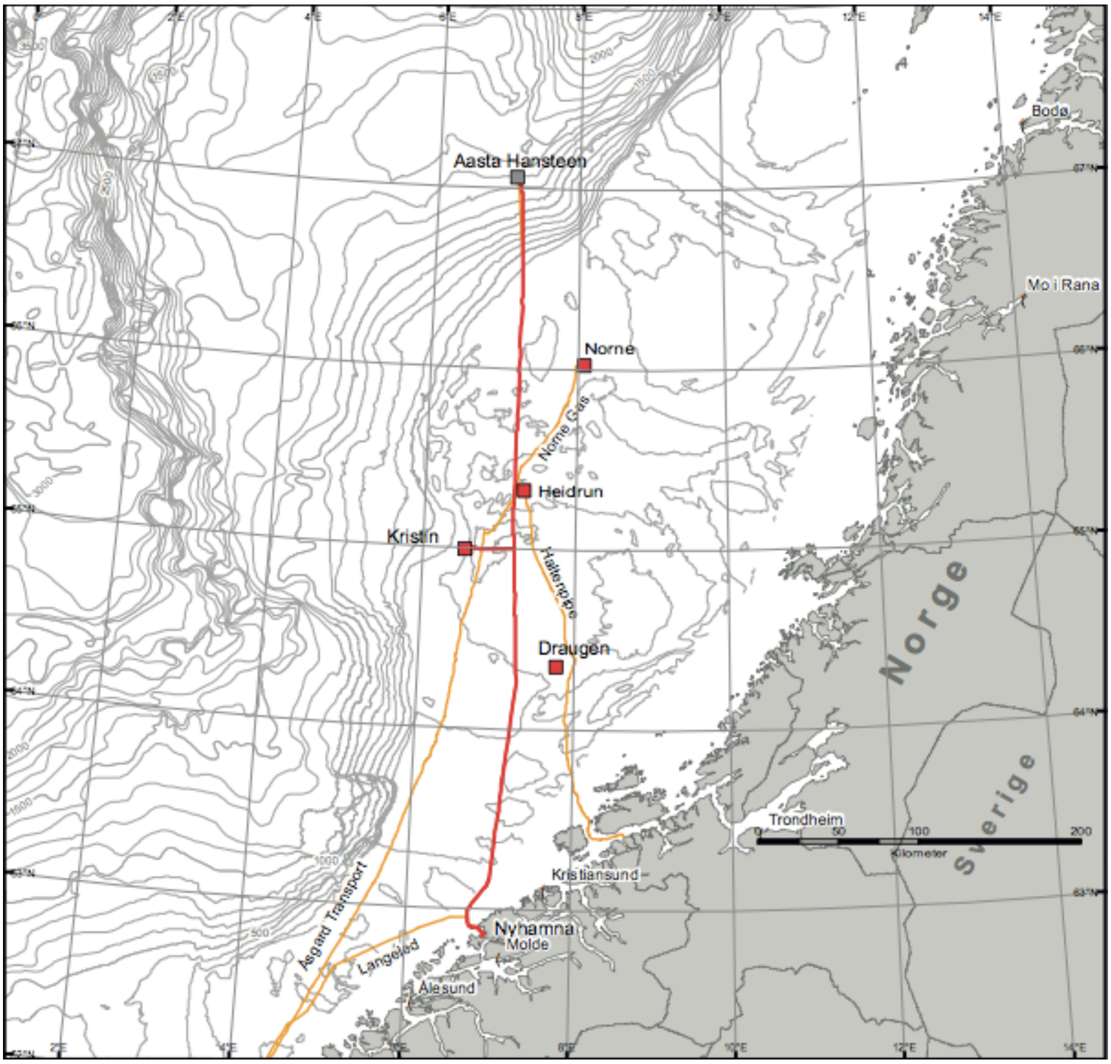

Figure 8.17: The location of the Aasta Hansteen field and the Polarled facilities

Source: (Det kongelege olje - og energi departementet, 2013a)

The recoverable reserves from Aasta Hansteen are estimated to 46,5 bill. Sm^3 gas and 0,9 mill. Sm^3 condensate. The expected production period is 9 years, with possibilities for extension by tie-in of other resources in the area (Det kongelege olje - og energi departementet, 2013a).

The licensees are Statoil Petroleum AS, OMV (Norway), Wintershall, and ConocoPhillips Scandinavia AS. Their interests are listed in table 8.9 below. The developer and operator of the field is Statoil (Holmelin, 2015).

Table 8.9: Overview of the shareholders in the Aasta Hansteen field

Source: (Holmelin, 2015)

Company	Participating interest (pct.)
Statoil Petroleum AS	51
OMV (Norway)	15
Wintershall	24
ConocoPhillips Scandinavia AS	10

8.6.2 Development concept for The Aasta Hansteen field

The Aasta Hansteen development concept is a floating production unit, a so-called SPAR platform with subsea facilities and embedded condensate storage (see figure 8.18). The SPAR substructure is 97 metres long consisting of a deep floating circular hull section. Beneath the hull there is a framework with a ballast tank in the base for stabilization, located 180 metres beneath the sea level. The platform will be anchored with 17 slack anchor lines. The topside consisting of modules for a process- and help centre, and living quarters will be connected to the substructure before towing (Det kongelege olje - og energi departementet, 2013a).

The stabilized condensate will be stored in the floater and exported from the field directly by shuttle-tankers. A new 36" regional export pipeline, called Polarled, will transport the produced gas approximately 500 km south to Nyhamna gas terminal on Aukra. Here the gas will be further processed to export and sales gas quality. Several other projects are expected to be tied in on the way (Holmelin, 2015).

Power generation is done by the use of gas turbines. One gas turbine runs the export generator and delivers electric power (Det kongelege olje - og energi departementet, 2013a).

There are seven production wells planned, which will be brought up to the production facility by three flowline wires and risers in steel. Four wells will be located in the Luva area, two in the Haklang area and one in the Snefrid South area. The flowlines will be isolated to avoid hydrate issues and heat loss. In addition, there will be laid control lines for control signals to the subsea facilities and supply of hydrate inhibitors and chemicals (Det kongelege olje - og energi departementet, 2013a).

The Aasta Hansteen development is the first of its kind on the Norwegian continental shelf, and is so far the largest SPAR platform in the world.

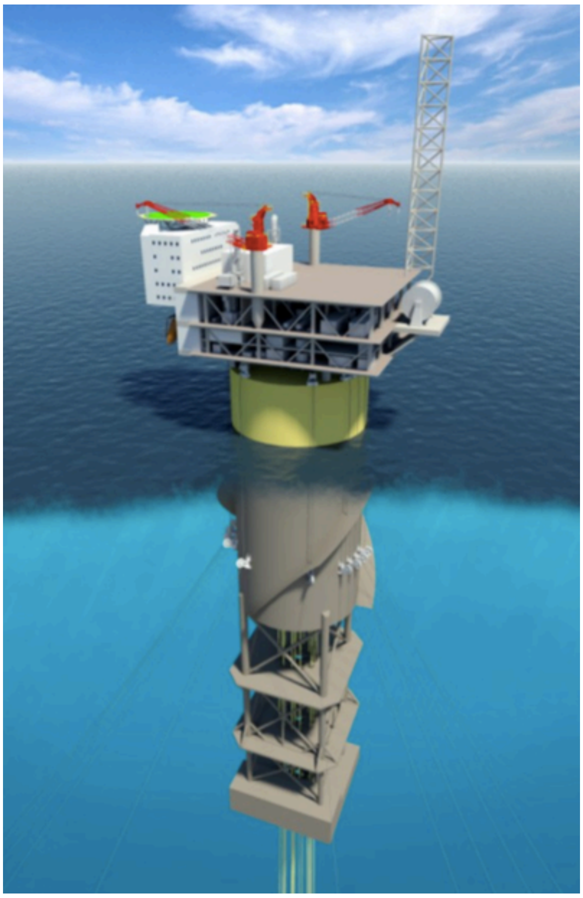

Figure 8.18: Illustration of the Aasta Hansteen facility

Source: (Holmelin, 2015)

8.6.3 Analysis of the development project

Platform

The engineering of the substructure (hull) is done in Houston USA, and the engineering of the topside is done in the Netherlands (Holmelin, 2015). HHI in Korea has constructed the platform (SPAR). Some bulk and equipment from Norway was used under construction of the platform. In addition, the completion for operation is a pure Norwegian delivery by Kværner.

Subsea systems

Aker Subsea constructed the subsea installations, and Subsea 7 conducted all the marine operations to install the equipment. Intra-field pipelines were procured from Japan.

Export systems

The gas is transported through a fixed riser, to a manifold placed on the seabed where Polarled takes over the further transportation. Aker Pusnes has constructed the export facility for the condensate (Holmelin, 2015).

Drilling and completion
Seadrill´s West Elara rig conducted the drilling on the field. Baker Hughes and Halliburton provided drilling services.

An overview of the estimated cost of the different parts of the Aasta Hansteen development today is shown in table 8.10.

Table 8.10: Estimated cost of the Aasta Hansteen field development (ACES)

CAPEX facilities overview	mill. NOK
Cost element	Total
Topsides	19056
Substructure incl. conductors/risers	9388
Piles, anchors and mooring lines	1321
Sum Platform	29765
Subsea/WHP production equipment	2222
Flowlines and spools	1601
Structures (RB, PLET, PLEM, T, Y)	781
Risers for flowlines/pipelines	2025
Umbilicals with risers	734
Sum Subsea	7363
Export pipelines	509
Power cables with risers	0
SUM facilities	37637
CAPEX wells overview	
Drilling	2337
Completion	1708
Drilling and completion	4044
TOTAL	41681

8.6.4 The cost development of the project

Based on the estimates done in ACES the Aasta Hansteen field would have had an estimated price of 41,6 billion Norwegian kroner today (see table 8.10 above). This is a cost increase of 9,7 billion Norwegian kroner compared with the unbiased estimate in the PDO that was approved in 2013. This gives a cost increase of 24,1 pct. over the last 3 years. The expected start up is in late 2017. In figure 8.19 below you can see the cost development over the last few years. The columns presented for 2013-2015 show the last official numbers gathered from the Storting propositions. The column presented for 2016, shows the estimate done in ACES, in accordance with today's market situation.

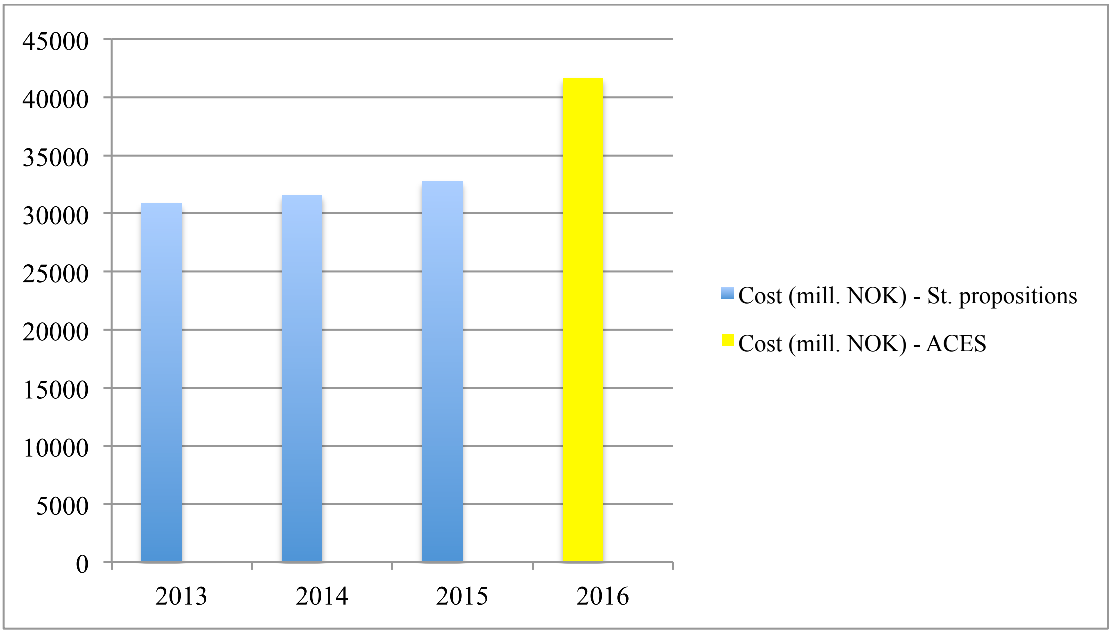

Figure 8.19: The cost development of the Aasta Hansteen field (2013-2016) (mill. NOK)

8.6.5 Norwegian content

It has not been possible to obtain an official statement from Statoil regarding the level of work done by Norwegian suppliers in the Aasta Hansteen development. However, in the report performed by the Ministry of petroleum and energy they have concluded that 40 pct. of the work on Aasta Hansteen is performed by Norwegian suppliers.

Based on the numbers in table 8.10, and information gathered from the report by the Ministry of petroleum and energy (Holmelin, 2015) it has been estimated in this thesis that the total Norwegian content in the Aasta Hansteen development is 31 pct. In figure 8.20 below you can see the level of Norwegian content in the different parts of the field development.

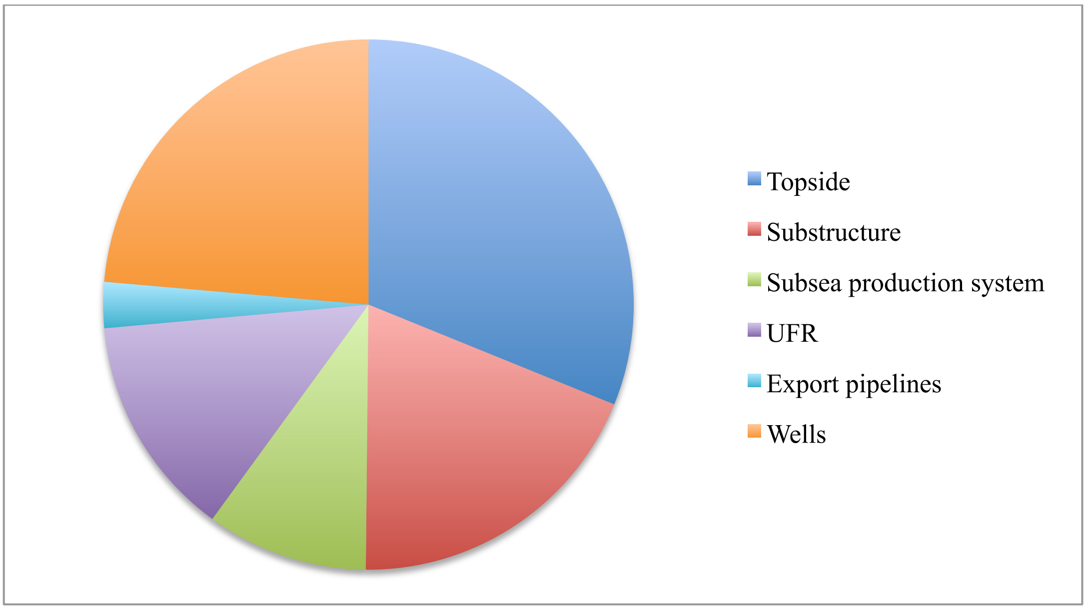

Figure 8.20: Distribution of the Norwegian content (31 pct.) in the different parts of the Aasta Hansteen development

Since Kværner is performing the completion of the topside after delivery, and some Norwegian bulk and equipment has been used in the construction, the topside still has some level of Norwegian content even though it is being constructed in Korea. The same can be said for the substructure. Baker Hughes and Halliburton performed the drilling services, which contributes to a high level of Norwegian content.

8.6.6 Experiences related to the project

The Aasta Hansteen field development is not yet in production, the planned start up was in late 2017. However, recently it has been announced that the start-up will be postponed to the second half of 2018 (Lewis, 2015b).

Aasta Hansteen has a lot of similarities with the Goliat development. It is being constructed at the same yard in South Korea (HHI), it is based on the same version of the EPC-model, it is located at a new location, and lastly it is a new and complex project development. Aasta Hansteen will at completion be the largest Spar platform in the world, and the first of its kind on the NCS.

Similar to the Goliat development, Aasta Hansteen is as mentioned suffering some delay. There are three main reasons for the delay. First, the engineering has shown a decrease in productivity, second the equipment packages have increased in cost, and last but not least is the delays on the yard (Lewis, 2015b).

The delay from the yard is largely related to the massive delay of the Goliat development. The delays of the Goliat development resulted in space that was actually awarded the Aasta Hansteen construction being occupied by the Goliat construction. This led to parts of the Aasta Hansteen development being built at other smaller yards. That is not ideal, and increases the implementation time. Even though this is not the only reason for the delay of the platform, this is brought up as one of the main reasons. Because of the delays, Aasta Hansteen misses a “weather-window”, which has resulted in the additional costs and delays (Madsen, 2015).

Aasta Hansteen is full of new elements and technology, and still Statoil chose a yard with little experience with such installations, and little experience with the Norwegian regulations and standards, just like Eni did with the Goliat development. The Aasta Hansteen development is a classic example of a project that was awarded to the Far East because of lacking capacity at Norwegian yards.

The gas from Aasta Hansteen will, as mentioned earlier, be transported through the new pipeline, Polarled. This project has also become more expensive than estimated because of the many neighbour fields that were supposed to be connected to the Polarled pipeline being postponed or stopped.

9 Analysis of the calculating numbers

9.1 The cost development of the five projects

When the operating companies are estimating a price for the project to present in the PDO submission the operators commonly use an uncertainty range of 20 pct. (Oljedirektoratet, 2013). In figure 9.1 you can see the cost estimates presented in the PDO with uncertainty range, the cost estimates done in ACES, and the cost for the projects when they were built. Since Ivar Aasen and Aasta Hansteen is not yet in production the last official numbers from the propositions to the Storting represent their as-built cost. So far, both Ivar Aasen and Aasta Hansteen is still within the uncertainty range if one considers the as built cost. The same can be said for Edvard Grieg. Goliat has greatly exceeded its uncertainty range, and Gjøa has just slightly exceeded it.

If one considers the estimates done in ACES, only two of the five projects are within their uncertainty range, with possibilities for change regarding Ivar Aasen and Aasta Hansteen. Goliat clearly has the worst outcome, considering what was actually estimated in the PDO, with an estimated cost increase of 32,6 pct. And so far, Aasta Hansteen seems to follow the Goliat developments footsteps. Gjøa has also had a considerable increase in cost, but here it’s over a longer time period, and it has mainly happened after start-up. Edvard Grieg and Ivar Aasen have not had the same level of cost increase as the other developments.

Overall, the majority of the projects are ending up with a cost estimate that is substantially higher than the unbiased estimate in the PDO, with some standing more out than others. Looking at all the five projects the estimated cost increase in relation to the PDO is 41 billion, see table 9.1. Together the five projects have an estimated average cost increase of approximately 21 pct.

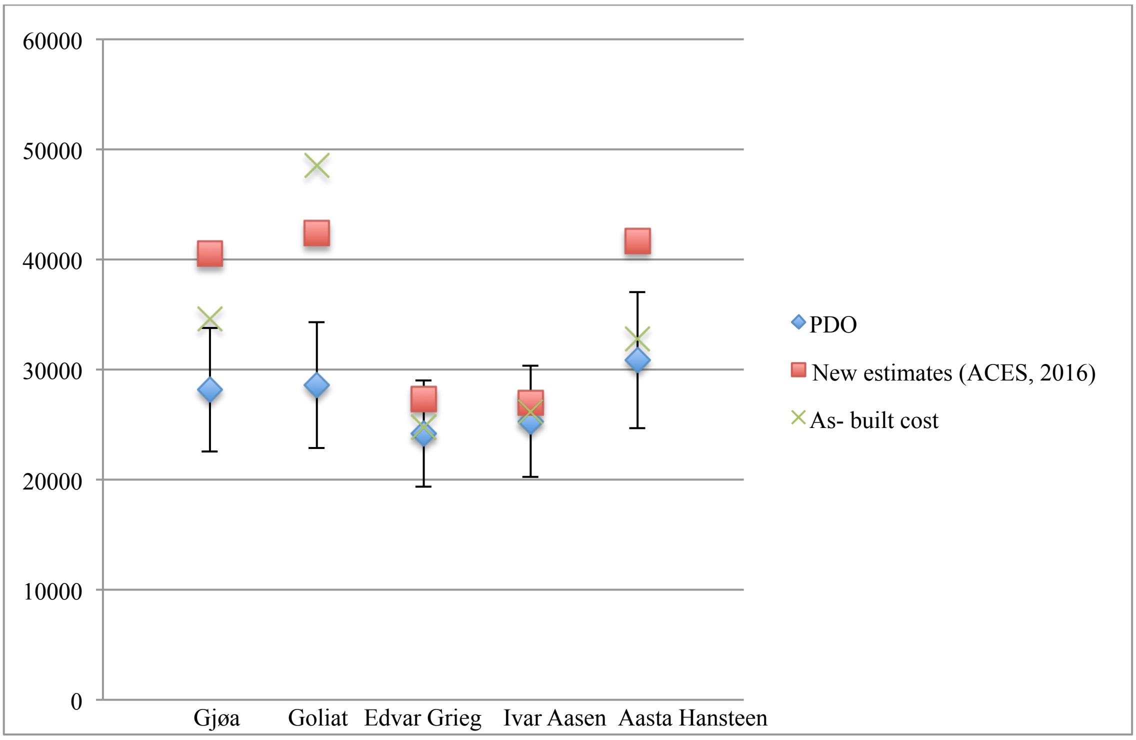

Figure 9.1: Cost estimate in PDO with uncertainty range, cost estimates done in ACES, and as-built costs (mill. NOK)

Table 9.1: Cost changes for the five representative projects (mill. NOK)

Project	PDO approved	PDO estimate	New estimates (ACES)	Change	Change (pct.)	Norwegian content (pct.)
Gjøa	2007	28177	40550	12373	30,50	55
Goliat	2009	28600	42406	13806	32,50	38
Edvard Grieg	2012	24205	27346	3141	11,50	66
Ivar Aasen	2013	25318	26969	1651	6,10	42
Aasta Hansteen	2013	30853	41681	10828	25,90	31
Total		137153	178952	41799		

9.2 The Norwegian content in the five development projects

Through the analysis in the thesis there has been presented an estimate of the level of Norwegian content in the five representative projects. An overview of the total Norwegian content in the projects is listed in table 9.2 below.

Table 9.2: Estimated Norwegian content in the five project developments

Development project	Development period	Norwegian content (pct.)	Main construction location	Comment
Gjøa	2007-2010	55	Norway	Substructure: Kværner Verdal, Topside: Aibel Haugesund. Platform completed wells
Edvard Grieg	2013-2015	66	Norway	Substructure: Kværner Verdal, Topside: Kværner Stord. Platform completed wells
Goliat	2010-2016	38	Korea	Hyundai Korea. Subsea completed wells. Comprehensive drilling programme.
Ivar Aasen	2013-(2016)	42	Singapore	Substructure: Saipem Topside: SMOE Platform completed wells
Aasta Hansteen	2013-(2018)	31	Korea	Hyundai Korea. Subsea completed wells.

Topside and substructure

Topside and substructure stand for more than half (53 pct.) of the estimated Norwegian content of the five development projects. The Norwegian content in the projects are clearly much higher for the projects where the topside and substructure has been constructed on a Norwegian yard. Gjøa and Edvard Grieg both have a level of Norwegian content well over 50 pct. Admittedly, Gjøa´s substructure is built in Korea, but in return Gjøa has a comprehensive and expansive subsea production system (Holmelin, 2015).

The other projects however, where the substructure and topside mainly are or are currently being constructed on Far East yards, have a considerably lower level of Norwegian content. Ivar Aasen, Goliat, and Aasta Hansteen have estimated Norwegian content of 42 pct., 38 pct., and 31 pct., respectively. Ivar Aasen has comprehensive subsea work by connecting it up to the Edvard Grieg platform, which contributes to the level of Norwegian content. Goliat has an expansive subsea production system, and needed substantial Norwegian efforts during completion of the platform (Holmelin, 2015).

In other words, when contracts for fabrication of platforms and platform modules are awarded to Far East yards, the project developments are losing approximately 10-30 pct. Norwegian content. That means loss of billions of Norwegian kroner for the Norwegian industry.

Wells

Drilling and completion represents 28 pct. of the estimated Norwegian content in the five project developments, which makes it the part of the developments with the second most Norwegian content, after topside and substructure combined. Norwegian companies are market leaders in drilling and underwater equipment, supply services and floating production, which is the reason for this high level of Norwegian content. Several highly skilled drilling companies are located here in Norway, and some of the top drilling vendors at the moment is Schlumberger, Halliburton, Weatherford, Transocean, Ensco and Seadrill.

Subsea production systems

As mentioned above some of the developments have comprehensive subsea work and production systems. As the Norwegian supply industry is world leading on subsea technology, it is as expected a lot of Norwegian content in this part of the development for all the five projects. The subsea production systems represent 10 pct. of the estimated Norwegian content in the five development projects. The large development within subsea technology has made it possible to conduct petroleum operations at increasing distances from shore and at increasingly deeper water. For instance, Aasta Hansteen, which is located 300 km west of Bodø with a water depth of 1300 metres.

Export pipelines and UFR

As we in Norway don’t have any producers of pipelines all of the projects have a relatively low Norwegian content in this part of the development. Some Norwegian content is registered, but then in the form of project management, or subsea services related to installation of the export pipelines, umbilicals, flowlines and risers. Combined the total estimated Norwegian content is 9 pct. for all the five development projects.

In figure 9.2 below you can see the distribution of the Norwegian content for all the five projects combined.

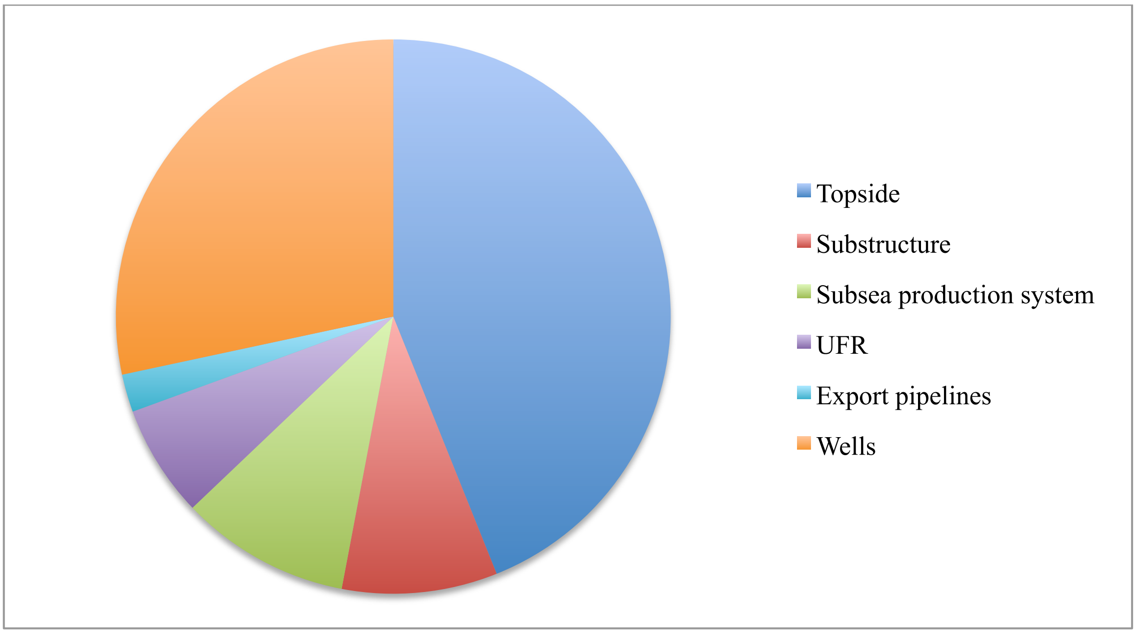

Figure 9.2: Distribution of the Norwegian content for all the five projects combined

PART 5: Discussion and Conclusion

In this last and final part of the thesis a discussion and conclusion of the thesis is presented. In regard to the objective of the thesis, it has been identified if the work and analyses conducted through the thesis have been sufficient. First in chapter 10, discussion of the project developments, findings, and challenges encountered during the work are presented. Chapter 11 follows this, where a short conclusion is given which aims to summarize the calculations, analysis and results of the thesis in a short but comprehensive way. Lastly, the bibliography is presented in chapter 12.

10 Discussion

10.1 Scope of work and objectives

The scope of this thesis involves the objective of explaining the competition between Norwegian and Far East yards in the fabrication of platforms and platform modules in relation to the current market situation. To get a closer and more specific look on how the market situation has affected different offshore field developments, five representative projects have been selected and analysed.

By first representing the theoretical foundation for the development of an offshore project, and discussing the current market situation with the trends and challenges that are relevant on the NCS today, it has been possible to identify some important parts that need focus and attention from the actors in the industry in order to maintain a good competitive market situation and achieve well executed project developments in the future.

Through the analyses of the five representative projects a cost development and the level of Norwegian content has been estimated for the five projects. In addition, some experiences related to the projects regarding their execution were briefly discussed for each development.

Through discussing and comparing the five developments some key points regarding how the market situation has affected the competition between Norwegian and Far East yards were established.

From the above it is the writer of the thesis' opinion that the defined scope of work and objective of this thesis have been fulfilled.

10.2 Main findings

Through the work with this thesis it has become clear that the competition between Norwegian and Far East yards is changing. Due to the globalization of the market, low oil price and the instability in the exchange rate of NOK and USD, a new market situation has formed, and the requirements of an offshore field development are no longer the same.

The offshore field developments are increasing in complexity as the technology is developing, and the petroleum is extracted from increasingly remote and difficult locations. While the complexity of the developments is increasing, new regulations and standards are presented. At the same time given the low oil price, operating companies are stressing the fact that the cost of the offshore developments has to go down, pushing the fabrication yards to give lower and more competitive prices. Furthermore, due to the globalization, the number of competitors for the different contracts has increased, and puts even more pressure on the fabrication yards when placing bids. This rapid development in both requirements and cut of cost has made it difficult for the yards to follow.

The Far East yards have earlier had the advantage of high capacity and productivity, and low cost related to labour and material. However, after entering the market on the NCS, the Far East yards have been struggling to deliver according to specified quality, time frame and cost. Many of the projects fabricated on Far East yards have had errors and deficiencies, and have needed a substantial work over after their arrival in Norway, e.g. Goliat. Therefore, one now sees a change in both cost and capacity of the Far East yards, affecting their competitiveness. A contradiction to this trend is the Ivar Aasen development. Ivar Aasen is still not in production, but so far things look like they are going according to plan. Although, one has to consider the fact that Ivar Aasen is a considerably less complex project than Goliat and Aasta Hansteen.

Despite the thriving innovation, efficient solutions, productivity and quality, there has been a general increase in the cost, and lower capacity for Norwegian yards in the last decade. These are some of the main reasons for the many contracts awarded to Far East yards. However, given the new market situation where the activity level has gone down, the capacity and productivity on Norwegian yards are no longer an issue. The yards are hungry, and are fighting for new contracts. As the Norwegian krone is weak, it has been possible for the Norwegian yards to give more competitive offers in the tender processes. In addition, the Norwegian yards still have the advantage of excellent knowledge within Norwegian standards and regulations, and the benefit of geographical proximity.

Through the analysis of the five development projects, it has been estimated a cost increase in all of them. The cost increase is related to the fact that they were approved during a time with high oil prices, where the requirements for reduced cost were not as pressing. With the current oil price many existing and planned offshore developments are no longer profitable, which is the reason for the lower activity level on the NCS, where new building contracts are being postponed or even stopped. Also, the Norwegian content estimated in the analysis shows a general trend where the projects with the lowest level of Norwegian content have proven to be the projects with the greatest cost overrun and delays.

Considering the total cost of the recent projects on the NCS, conducted by both Norwegian and Far East yards, it has subsequently been shown that Norwegian yards are actually giving competitive prices. The total cost of the projects fabricated on Far East yards has shown that even though the Far East yards bids are less expensive, the final cost of the projects has proven to be far over the estimated price stated in the PDO. In addition, the projects fabricated on Far East yards have had problems with low quality and suffered great delays. This trend has not gone unnoticed with the oil companies, who have started to question the Far East yards' competence.

Because of the unstable market situation, the actors in the industry have opened their eyes and realised how much excess work and unnecessary developments that are realised. In order to avoid large cost overruns and delays, the operators are making more risk free and safer decisions related to their developments. The stakes are high and the importance of selecting the right contractor for their projects has increased. Through the analysis it might seem like the Norwegian yards are the safer and more risk free option. Hence, it's believed that an increasing number of contracts awarded to Norwegian yards will be seen in the time to come, as the focus on Norwegian content increases. This can already be seen for the Johan Sverdrup development, where over 50 pct. of the contracts have been awarded to Norwegian suppliers, or at least to companies with a Norwegian address. The Far East yards will continue to have a strong position in fabrication of offshore installations on the NCS, but the operator will most likely take a larger responsibility related to the engineering and procurement of the developments.

10.3 Obtained learning

The writing of this thesis has provided the author with an overall learning and better understanding of the development of offshore fields, and the current market situation for the oil – and gas industry. A wider understanding of the pressing issues and trends that the operators and contractors on the NCS have to deal with regarding how to perform better planning, implementation and execution of offshore installations has been obtained.

Through the study of the Norwegian and Far East yards, a deeper understanding of their competitive advantages and disadvantages regarding their operations has been

obtained. Learning about how the competition between them has evolved over the years and its current state has been both challenging and interesting.
By breaking the five developments down to their different modules and parts through the analyses it has provided the author with a better understanding of how comprehensive and complex an offshore installation is and how much planning and work that is involved in all of them. The author has obtained a greater knowledge of how many people and companies that are involved and are depended on to complete and realize the developments.

Last but not least knowledge and greater understanding of how the changing market both domestically and internationally influences the oil and gas industry on the NCS has been obtained.

10.4 Encountered challenges

It has proven to be hard to collect a detailed breakdown of the projects' cost, and level of Norwegian content of the specific parts of the different development projects throughout the thesis. The numbers used are collected from a broad range of sources including the Storting propositions, the petroleum department's factpages, the impact assessment studies, and other relevant reports and webpages. Since Ivar Aasen and Aasta Hansteen are not yet in production, some assumptions have been made. The best available data has been used, but may vary between the different documents. Hence, there is some uncertainty related to the final estimates done in ACES regarding new cost estimates and the Norwegian content in the representative projects.

By comparing the results to the numbers for Norwegian content presented in the report by the Ministry of Norwegian Petroleum and Energy, we see that the numbers estimated in ACES are not far off. Unfortunately, Ivar Aasen was not presented in the report, and therefore does not have any similar number to compare with, which adds to the uncertainty of the estimates done for this project development. The numbers for the final cost of the projects represented in the Storting propositions (see figure 9.1) show some deviations from the estimates done in ACES, but the general trend is the same.

The oil- and gas industry is a large and complex industry, and to state anything about how the situation currently is, and what affects it, is a challenging task. There will always be contradictions and exceptions to the stated observations. Through the thesis the overall objective has been to find a general trend for the conducted analyses and observations.

11 Conclusion

This thesis set out to analyse and describe whether or not the new market situation has affected the competition between Norwegian and Far East yards. A contextualization of the objective has been achieved by looking into what current trends and challenges the petroleum industry on the NCS is currently facing, which has led to the identification of several factors. Firstly, the globalization contributes to a more influenced market on the NCS, with far more possibilities and players than before, increasing the competition for the different contracts. Secondly, the oil price is currently very low and unstable. This leads to a very risky and unpredictable market situation, forcing the operators to be even fiercer in their final selection of contractor. Finally, the exchange rate between NOK and USD has changed by around 30 pct., contributing to a more competitive Norwegian market in regard to cost.

The analysis of the five development projects shows a trend in increasingly expensive projects, where the projects' total costs turn out to be substantially higher than what was estimated in the PDO. Combined the average cost increase for the five projects is 21 pct. A contributing factor to the substantial cost increase is the market situation at the time when the estimates were set. The estimates were set at a time with a high oil price, meaning that the estimates are based on a high break-even price. This shows how challenging it can be to set an estimate for a project development, because it stretches over a long period of time. In addition, the projects have been developed through a trial period, by awarding a lot of contracts to the Far East, with new conditions in regard to development processes, cost, and location. The development period for the projects is characterized by a lot of trying and failing in the execution phase, regarding early phase work, prequalification of contractors, contract strategy, and project follow-up.

Through the estimation of the Norwegian content in the five developments it has been identified a considerably higher level of Norwegian content for those projects that have constructed their platform topside and substructure on a Norwegian yard, such as Gjøa and Edvard Grieg. By not using a Norwegian yard for the construction of platform or platform modules it means a loss of 10 – 30 pct. in Norwegian content, resulting in billions in losses for the Norwegian industry. In addition, its been shown a trend where the project developments with the lowest level of Norwegian content (Goliat and Aasta Hansteen) have the largest increase in cost and delays.

By considering both the cost development and the level of Norwegian content obtained through the analyses it can be stated that the projects fabricated on a Far East yard are the projects that have suffered the most in regard to cost development, and that a high level of Norwegian content reduces the risk of the projects. Far East yards are generally struggling to meet the expectations, as they have failed to deliver on both time and cost on their recent projects. It can be said that there has evolved a gap between what is expected by the Far East yards and what is actually delivered. On the other hand, Norwegian yards have shown that despite their pricy bids, they have managed to deliver on both time and cost. Considering the final cost of all the projects it has been shown that Norwegian yards actually have competitive prices.

It can be concluded that through the study of the current market situation, and the analysis of the five development projects, that the market situation has changed the competition between Norwegian and Far East yards. Because of the new market situation the stakes and risk are higher. The importance of reducing costs and delays has increased. The operators have learned from their own and other companies' mistakes, showing that the lowest price doesn't necessarily mean the best economic solution. This will most likely lead to implementation of new comprehensive processes, and criteria for final selection of contractor. As a result, an increased number of contracts will most likely be awarded to Norwegian yards, as the focus on Norwegian content will be intensified in the time to come. The Far East yards will still have a strong position in the competition for the fabrication contracts on the NCS, but the operators will most likely be setting new demands and requirements in regards to contract strategy, prequalification of the contractors, and follow-up of the projects.

The Norwegian petroleum industry invited the Far East yards to attend in the competition for contracts on the NCS as an attempt to improve the competitive international market. Considering the current situation for the Norwegian yards, this has been a success, where one sees that the Norwegian yards are coming back with an increased competitiveness. Nevertheless, this is an ever-going cycle. It is yet to see if the Far East yards will improve, but it is believed that they will come back stronger with embedded lessons learned. They will most likely come back to be more streamlined for projects implemented on the NCS. It is a constant competition, which is healthy for the industry in terms of continuing development and improvement of the fabrication industry.

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Appendix 1

Interview protocol

Interview objects:

- Tore Guldbrandsøy (Senior Vice President & Head of Stavanger Office at Rystad Energy)
- Ernst Abrahamsen (Principal Advisor – Project Planning and Execution at Acona)

1. Introduction

i. *Greeting*
   - It's a pleasure to see you, and thank you for participating in my thesis.

ii. *Purpose of the interview*
   - The purpose of the interview is to ask you to reflect over your experiences and knowledge of the companies' execution of offshore development projects, regarding the new market situation. In addition, to get a better insight into the different companies' processes when choosing contractor, contract type and fabrication yard.

iii. *Who am I*
   - My name is Hilde Marie Hårde. I study offshore technology – Industrial Asset Management at the University of Stavanger. This interview will be a part of my master thesis.

iv. *Letter of consent*
   - The interview will be treated completely anonymous if that is wished for.
   - You may choose not to answer any of the questions.
   - May I have your permission to record the interview?

v. *Structure of interview*
   - The questions are about your experience and conviction with respect to the challenges arising in the course of the different companies' offshore project developments.
   - There is no right/wrong answer
   - Your subjective opinion on the thesis subject counts
   - The questions might not be directly linked to the area of your speciality.

2. Basic interview information

   - How long have you worked in your current employment firm?

- Have you worked with other companies or been involved with project developments before?
- If so, what was your involvement in those projects?

3. Market situation

   i. *Trends and challenges*
      1) In your opinion what are the most current trends and challenges that form the new market situation?
      2) How does these trends/challenges affect the development in the Norwegian oil- and gas industry?
      3) What measures have been implemented in order to counteract these trends?
      4) The decreasing oil price has been a hot topic in the last year. How has this affected the industry, and how will it affect the industry in the time to come?
      5) Do you think the oil price will increase and stabilize? Why, why not?
      6) The exchange rate between Norwegian kroner and U.S. dollars has also increased substantially. What affect has this had on the industry?

4. The capital value process

   i. *Concept*
      1) In your opinion, to which extent does the operator think of possible contractors in their choice of concept?
      2) What type of concepts favours Norwegian yards? Far East yards?
      3) What is the reason for this?

   ii. *Contract*
      1) What requirements are the most important for the operator in their choice of contract type and format?
      2) Do the operating companies have different criteria and requirements for Norwegian yards than for Far East yards, when negotiating and choosing type of contract?
      3) Is there a contract type that is most frequently used in development projects that are fabricated on Far East yards? Why?
      4) What type of contract is most frequently used on Norwegian yards? Why?

   iii. *Contractor*
      1) When choosing contractor, what is it that affects the operators' choice?
      2) Has the process for choice of contractor changed regarding the new market situation?

3) Does the operators make new requirements?

5. The competition between Norwegian and Far East yards

1) What do you mean the main competitive advantages for Norwegian yards are in the competition for contracts? Disadvantages?
2) What do you mean the main competitive advantages for Far East yards are in the competition for contracts? Disadvantages?
3) What effect has the trends and challenges that form the new market situation had on the competition between Norwegian and Far East yards?
4) What are your thoughts on the level of trust between the operating company and the yard? Does the operating company have the same level of trust of Far East yards as Norwegian yards?
5) In your opinion, is there a difference in competence level between Norwegian and Far East yards? Do they produce the same level of quality?
6) Several large contracts have in the last years been awarded to Far East yards, what are your thoughts about this?
7) What would you say is the main reason for this?
8) Do you think this trend will continue? Why, why not?
9) What can Norwegian yards do in order to improve their competitiveness?

6. Cost development

1) Through analyses conducted of five field developments (Gjøa, Edvard Grieg, Goliat, Ivar Aasen, Aasta Hansteen) in this thesis, it's been estimated a cost overrun compared to what was estimated in the PDO for all the five projects. In regard to the new market situation, what would you say is the main reasons for this?
2) Especially Goliat and Aasta Hansteen, which are fabricated on a Far East yard, have exceeded their estimate in the PDO substantially. What are your thoughts about this?
3) But Ivar Aasen has been doing well. What do you think the reason for that is?
4) Edvard Grieg and Gjøa have both been successful developments, being completed within the estimated time and with relatively small cost overruns. Why do you think these developments went as planned?
5) Do you think that there has evolved a gap between what is expected of Far East yards and what is actually delivered?

7. Norwegian value creation

    1) In your opinion, does a high level of Norwegian content contribute to a project with lower risk?
    2) Do you believe that there will be an increased focus on Norwegian value creation in the project developments on the NCS in the coming future?

8. Experiences

    1) In your opinion, what experiences do you mean we should take with us from the different development projects we have seen on the NCS in the last years?
    2) Are there any other experiences you wish to mention regarding the object of this thesis?

Appendix 2

ENGINEERING

Last updated: 09.11.15 ***PROCAL_13***

Table 1. General input parameters

Initials: *HMH* Date *12.06.16*

Project name	Gjøa				
Cost reference year	2016				
Currency (select USD, EUR or NOK)	NOK		Currency: Value of 1,0 USD =	8,27	NOK
Water depth (metres)	360				
Location (1, 2, 3 or 4)	2	1=North Sea South; 2=North Sea North; 3=Norwegian Sea; 4=Barents Sea			
Stand-alone or tie-back (1 or 2)	1	1=Stand alone; 2=Tie-back			
Initial reservoir pressure (bar)	254	*254*			
Average number of stream-days per year	340	days per year	Oil price	40,05	USD/bbl
Discount rate for economic analyses	7	percent	Oil tariff	1,63	USD/bbl
Recoverable volume of oil or condensate	13,2	MScm	Gas price	2,07	NOK/scm
Recoverable volume of gas	39,7	GScm	Gas tariff	0,52	NOK/scm

Table 2. Well input

Definitions and codes (10 different groups of wells can be defined)

Well function: (1, 2 or 3)	1=Producer; 2=Water injector; 3=Gas injector
Well type: (1, 2, 3 or 4)	1=Dry tree platform; 2=Wet tree platform; 3=Wet tree satellite; 4=Dry tree satellite
Drilling method: (1, 2 or 3)	1=Platform rig; 2=MODU Semisub; 3=MODU Jack-up 7

Well groups	1	2	3	4	5	6	7	8	9	10
Number of wells per group	2	4	3	2	0	0	0	0	0	0
Well function (1, 2 or 3)	1	1	1	1	0	0	0	0	0	0
Well type (1, 2 or 3)	3	3	3	3	0	0	0	0	0	0
Drilling method	2	2	2	2	0	0	0	0	0	0
True Vertical depth (TVD MSL)	2250	2250	2250	2250	0	0	0	0	0	0
Horizontal reach	1500	2500	4000	4500	0	0	0	0	0	0
Length of horizontal section	0	0	0	0	0	0	0	0	0	0
Gas lift in well (0=no; 1=yes)	1	0	1	1	0	0	0	0	0	0
ESP in well (0=no; 1=yes)	0	0	0	0	0	0	0	0	0	0
Proposed progress rate (m/day)	*85*	*85*	*78*	*76*	*0*	*0*	*0*	*0*	*0*	*0*
Selected progress rate (m/day)	85	85	78	74	0	0	0	0	0	0
Proposed completion time (days)	*27*	*28*	*31*	*31*	*0*	*0*	*0*	*0*	*0*	*0*
Selected completion time (days per well)	34	43	48	52	0	0	0	0	0	0
Heavy intervention - class C										
Frequency (per year per well)	0,05	0,05	0,05	0,05	0	0	0	0	0	0
Number of days per intervention	15	15	15	15	0	0	0	0	0	0
Medium intervention - class B										
Frequency (per year per well)	0,1	0,1	0,1	0,1	0	0	0	0	0	0
Number of days per intervention	15	15	15	15	0	0	0	0	0	0
Light intervention - class A										
Frequency (per year per well)	0,15	0,15	0,15	0,15	0	0	0	0	0	0
Number of days per intervention	15	15	15	15	0	0	0	0	0	0

Table 3a. Subsea systems input

				22	21	7	1			6703
Production stations	SPS1	SPS2	SPS3	SPS4	SPS5	SPS6	SPS7	SPS8	SPS9	SPS10
Number of X-mas trees	3	3	2	2	1	0	0	0	0	0
Number of template well slots	4	4	4	4	0	0	0	0	0	0
Number of single satellite slots	0	0	0	0	1	0	0	0	0	0
Template protection (1=yes; 0=no)	1	1	1	1	0	0	0	0	0	0
Satellite protection (1=yes; 0=no)	0	0	0	0	1	0	0	0	0	0
Pressure class (5000; 10000; 15000 psi)	10000	10000	10000	10000	10000	0	0	0	0	0
Number of Multiphase Flow Meters	0	0	0	0	0	0	0	0	0	0
Number of Multiphase Pumps	0	0	0	0	0	0	0	0	0	0
Distance from platform (km)	4	4	4	8	8	0	0	0	0	0

Table 3b. Wellhead platform input - unmanned platform

Production stations	WHP1	WHP2	WHP3	WHP4	WHP5
Number of X-mas trees	0	0	0	0	0
Number of well slots	0	0	0	0	0
Distance from host platform (km)	0	0	0	0	0

Table 4. UFR (umbilical, flowline, riser) input

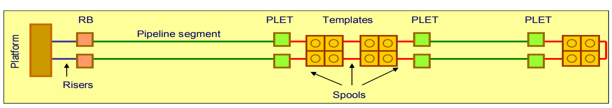
Definitions and codes (10 different groups of pipelines/flowlines/risers can be defined)

Function	Oil exp	1	Gas exp	2	Water inj	3	Gas inj	4	Wellstr	5
Material	Carbon	1	Clad	2	Cr steel	3	Flexible	4		
Surface coating/insulation/heating	None	1	Coating	2	Insulation	3	DEH	4	P-in-P	5
Lay-method	S-lay	1	J-lay	2	Reel-lay	3	Other	4		
Gravel dumping code	Very low	1	Low	2	Medium	3	High	4		
Riser concept	J-tube	1	Supp riser	2	Tens riser	3	Flexible	4	None	5

Flowline/riser groups	1	2	3	4	5	6	7	8	9	10
Specifications	*Oil exp*	*Gas exp*	*Gas inj*	*Wellstr*	*Wellstr*	*Wellstr*	*Wellstr*	*0*	*0*	*0*
Function code per group	1	2	4	5	5	5	5	0	0	0
Material code	1	1	1	3	3	3	3	0	0	0
Surface cover/heating option	2	2	3	3	3	3	3	0	0	0
Lay-method	1	1	3	3	3	3	3	0	0	0
Gravel dumping code	2	2	3	3	3	3	3	0	0	0
Riser concept	4	4	4	4	4	4	4	0	0	0
Total pipe length per group (km)	55	130	7,1	3,2	3,4	3,2	6,7	0	0	0
Number of pipe segments per group	1	1	2	1	1	1	2	0	0	0
Number of spools per group	0	0	5	3	2	3	4	0	0	0
Number of PLETs and Ts per group	0	0	3	1	2	1	4	0	0	0
Number of PLEMs per group	1	1	0	0	0	0	0	0	0	0
Number of risers per group	1	2	1	1	1	1	0	0	0	0
Number of riser bases per group	1	1	1	1	1	1	0	0	0	0
HIPPS system (1 = yes; 0 = no)	0	0	0	0	0	0	0	0	0	0
Pipe diameter										
Flow capacity (Scm o.e. per day)	15000	17000	3000	15000	10000	15000	10000	0	0	0
Inlet (design) pressure - bar	110	160	300	300	300	300	300	0	0	0
Pressure drop in pipeline - bar	30	15	30	20	20	20	20	0	0	0
Proposed diameter (inches)	*16*	*26*	*6*	*14*	*12*	*14*	*12*	*0*	*0*	*0*
Selected diameter (inches)	16	28	5	14	12	14	12	0	0	0
Wall thickness										
Proposed thickness (millimeter)	*10,0*	*17,3*	*10,0*	*17,7*	*13,8*	*17,7*	*13,8*	*1,0*	*1,0*	*1,0*
Selected thickness (millimeter)	10,0	17,3	10,0	17,7	13,8	17,7	13,8	1,0	1,0	1,0

Umbilicals and cables

Total length of static umilicals and cables	*km*		
Static Umbilicals - without centreline	0		
Static Umbilicals - with centreline	10,4		
Electric power cables	98		
Number of segments of static umbilicals and cables	*number*		
Static Umbilicals - without centreline	0		
Static Umbilicals - with centreline	3		
Electric power cables	1		
Number of jumpers and dynamic umbilicals and cables	*number*	*km*	
Umbilical jumpers with terminations	2	*0,20*	*total length*
Dynamic Umbilicals - (risers without cl)	0	*0,00*	*total length*
Dynamic Umbilicals - (risers with cl)	2	*1,36*	*total length*
Dynamic el cables - (cable risers)	1	*0,68*	*total length*

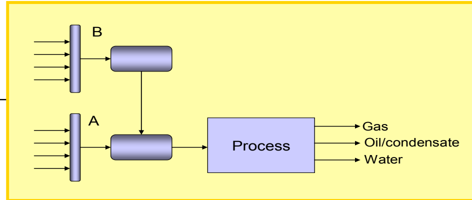


Example

Table 5. Platform input

	Gjøa		Semi
Platform concept	3		(Jacket =1; TLP = 2; Semi = 3; Buoy = 4; Ship = 5; Spar = 10; Jack-up = 11)
Number of beds in living quarters	100		(Basis for design of living quarters)
Drilling package	0		(0 = no drilling package; 1 = full drilling package; 2 = jack-up drilling)
Maximum well length (m)	7000		(Used for scaling of drilling package weight)
Oil/condensate storage volume integrated in platform	0	m3	Relevant only for Buoy, Ship and Spar
Oil/condensate storage tanker volume (FSU)	0	m3	The FSU is defined as a leased unit and will not appear in the Capex summary

Number of inlet separators	2		(1 or 2 separators referred to as separator A and separator B)
System A (main system)			
Oil production	10000	Scm/d	
Gas production	10,00	mill.Scm/d	
Inlet separator pressure	65	bar	*100*
Upstream shut-in pressure	220	bar	*214*
Number of dry tree well slots	0		
Number of riser slots	10		
System B (tie-in system)			
Oil production	3800	Scm/d	
Gas production	7	mill.Scm/d	
Inlet separator pressure	65	bar	*100*
Upstream shut-in pressure	220	bar	*219*
Number of dry tree well slots	0		
Number of riser slots	6		



Process concept (1, 2, 3, 4 or 5)	1			
Maximum liquid capacity	23000	Scm/d		
Produced water treatment capacity	19000	m3/d		
Sea water treatment capacity	0	m3/d		
Water injection capacity (produced water + sea water)	0	m3/d		
Gas export capacity	17,0	mill.Scm/d		
Gas re-injection capacity	0,0	mill.Scm/d		
Lift gas injection capacity	0,3	mill.Scm/d		
Oil/condensate density	29	°API		
Stable oil = 1; Unstable oil = 0	1	Stable oil		
Oil/condensate export pressure*	110	bar	*160*	*proposed pressure*
Gas export pressure	160	bar	*200*	*proposed pressure*
Gas injection pressure	0	bar	*267*	*proposed pressure*
Lift gas pressure	233	bar	*234*	*proposed pressure*
Water injection pressure	179	bar	*180*	*proposed pressure*
Number of oil export riser slots	1			
Number of gas export riser slots	1			

Concept 1: Full processing of oil/condensate and gas
Concept 2: Simplified process. One-stage separation - no recompression
Concept 3: Simplified process. Water separation. Common pipeline for oil/condensate and gas
Concept 4: No processing - wellstream export
Concept 5: Process modification. Tie-back project. Host platform is assumed to be a full processing platform with sufficient capacities.

Main power generation (0 or 1)	0	power import
Test separator (0 or 1)	1	yes
MEG regeneration, long tie-backs	1	no
De-sulphatation of injection water (0 or 1)	0	no
Gas sweetening (0 or 1)	0	no
Gas conditioning (0 or 1)	0	no
Gas de-hydration (0 or 1)	1	yes
Fiscal metering of oil (0 or 1)	1	yes
Fiscal metering of gas (0 or 1)	1	yes

Table 6. Design/construction assumptions

Living quarters material	1	Steel	(1 or 2)
Topside construction site	2	Far East	(1 or 2)
Hull construction site (Jack-up, TLP, Spar, Semi, Buoy, Ship)	2	Far East	(1 or 2)
Topside weight margin (growth and future needs)	0	percent	(0 is minimum)
Ice reinforcement of hull (yes or no)	1	No	(1 or 2)

Topside dry weight + Variable loads + Weight margins	Max allowable weight

Table 7. Tie-back projects - additional specifications

Topside modification weight per discipline (tonnes)	*selected*	*proposed*
Equipment	0	219
Electrical	0	30
HVAC	0	8
Instrument/telecom	0	68
Piping	0	293
Surface protection, fire proofing	0	22
Safety and loss prevention	0	36
Architectural	0	25
Structural steel	0	360
Total weight	***0***	***1060***
Degree of pre-fabrication for new facilities	20	between 20 and 80 percent

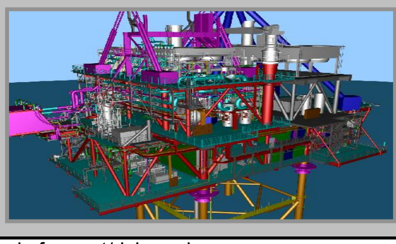


Table 8. User controlled Contingency (percent)

	Input	*proposed*
Topsides	15,0	*15,0*
Substructure	15,0	*15,0*
Rigid conductors/risers	15,0	*15,0*
Piles and anchors	15,0	*15,0*
Mooring lines	15,0	*15,0*
Wellhead platforms	15,0	*15,0*
Subsea production equipment	15,0	*15,0*
Flowlines	15,0	*15,0*
Flowline risers	15,0	*15,0*
Umbilicals/risers	15,0	*15,0*
Riser bases, PLETs, PLEMs	15,0	*15,0*
Export pipelines	15,0	*15,0*
Power cables/risers	15,0	*15,0*

Basis for cost/risk analyses

Facilities Capex	base estimate:	**24891** (cost!j19)		0 or 1
		calculated	copied	
Topside weight	28494	0,74148	0,50936	**0**
Structures weight	28494	0,74148	0,11089	**0**
Export pipeline weight	28494	0,74148	0,05880	**0**
Flowline weight	28494	0,74148	0,02269	**0**
Platform equipment cost	28494	0,74148	0,13517	**0**
Bulk materials cost	28494	0,74148	0,29806	**0**
Subsea equipment cost	28494	0,74148	0,11615	**0**
Labour cost	28494	0,74148	0,35992	**0**
Vessel dayrates	28494	0,74148	0,16603	**0**
Vessel days	28494	0,74148	0,14465	**0**

Table 9. User controlled Allowances (percent)

	Input	*proposed*	*sensitivity*	
Rig time for drilling, incl mobilization of rig	10,0	*10,0*	10	**1,0**
Drilled length	0,0	*0,0*	0	**1,0**
Progress rate for drilling	0,0	*0,0*	0	**1,0**
Rig time for completion	10,0	*10,0*	10	**1,0**
Vessel time for marine operations	15,0	*15,0*	15	**1,0**
Topside weight allowance	7,5	*7,5*	7,5	**1,0**
Structures weight allowance	0,0	*0,0*	0	**1,0**
Export pipeline weight allowance	5,0	*5,0*	5	**1,0**
Flowline weight allowance	10,0	*10,0*	10	**1,0**

Basis for cost/risk analyses

Drilling and completion Capex		**6507** (cost!l24)		
Rig time for drilling	7782	0,98172	0,58340	**0**
Drilled length	7782	0,98172	0,63846	**0**
Progress rate for drilling	7782	0,98172	0,63846	**0**
Rig time for completion	7782	0,98172	0,36905	**0**
Rig rates	7782	0,98172	0,58109	**0**
Drilling services	7782	0,98172	0,46386	**0**

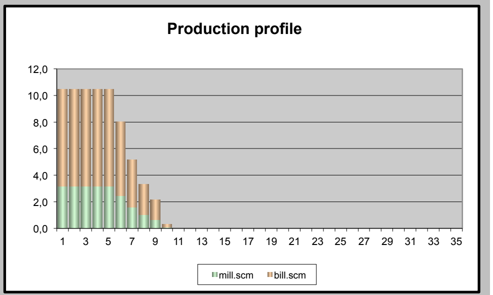
Table 10. User controlled cost indexes (percent)

	input	*proposed*	*sensitivity*	
Material costs (procurement)				
Topside equipment	100	*100*	100	**1,0**
Topside bulk materials ex structural	100	*100*	100	**1,0**

Structural steel	100	*100*	100	**1,0**
Structural aluminium	100	*100*	100	**1,0**
Mooring equipment	100	*100*	100	**1,0**
Pipelines - steel	100	*100*	100	**1,0**
Pipelines - flexibles	100	*100*	100	**1,0**
Umbilicals, cables	100	*100*	100	**1,0**
X-mas trees	100	*100*	100	**1,0**
Subsea equipment ex X-mas trees	100	*100*	100	**1,0**
Subsea structures	100	*100*	100	**1,0**
Labour costs				
Onshore/atshore work (Norway)	100	*100*	100	**1,0**
Onshore/atshore work (International)	100	*100*	100	**1,0**
Inshore work (Norway)	100	*100*	100	**1,0**
Offshore work	100	*100*	100	**1,0**
Engineering	100	*100*	100	**1,0**
Vessel dayrates				
Installation of pipelines, umbilicals and cables	100	*100*	100	**1,0**
Lifting and construction	100	*100*	100	**1,0**
Dredging, trenching, gravel dumping, surveys	100	*100*	100	**1,0**
Tugs, anchor handling	100	*100*	100	**1,0**
Barges	100	*100*	100	**1,0**
Drilling and workover	100	*100*	100	**1,0**
Drilling services	100	*100*	100	**1,0**

Table 11. Production profile input

Production year	Oil/condensate mill.scm	Gas bill.scm
1	3,19	7,28
2	3,19	7,28
3	3,19	7,28
4	3,19	7,28
5	3,19	7,28
6	2,44	5,58
7	1,57	3,59
8	1,01	2,31
9	0,65	1,49
10	0,09	0,20
11	0,00	0,00
12	0,00	0,00
13	0,00	0,00
14	0,00	0,00
15	0,00	0,00
16	0,00	0,00
17	0,00	0,00
18	0,00	0,00
19	0,00	0,00
20	0,00	0,00
21	0,00	0,00
22	0,00	0,00
23	0,00	0,00
24	0,00	0,00
25	0,00	0,00
26	0,00	0,00
27	0,00	0,00
28	0,00	0,00
29	0,00	0,00
30	0,00	0,00
31	0,00	0,00
32	0,00	0,00
33		
34		
35		



Annual production at plateau	10,472 mill.scm
Alfa	0,198
Gamma	0,609

Tie-back projects

For tie-back projects; systems can be deleted

Topside systems	Code	0 or 1		219
Drilling derrick	10	1	include	0
Drilling systems, mud	11	1	include	0
Platform well control system	12	1	include	0
Pig receiver, riser pull-in	13	1	include	0
Dry tree related	13	1	include	0
Wet tree related	13	1	include	31
Export related	13	1	include	0
Drilling control, BOP	14	1	include	0
Drilling utilities	15	1	include	0
Subsea well control system	19	1	include	11
Separation and stabilization	20	1	include	0
Test separator	20	1	include	2
Inlet separator A	20	1	include	11
Inlet separator B	20	1	include	124
2. stage separator	20	0	delete	0
3.stage separator	20	0	delete	0
Coalesher	20	0	delete	0
Heating/cooling	20	0	delete	0
Allocation metering syst B	20	1	include	39
Crude handling/metering	21	0	delete	0
Booster pumping	21	0	delete	0
Export pumping	21	0	delete	0
Metering	21	0	delete	0
Gas compression	23	0	delete	0
Gas re-compression A	23	0	delete	0
Gas re-compression B	23	0	delete	0
Gas re-compression C	23	1	include	0
Gas re-injection	23	0	delete	0
Gas export compression	23	0	delete	0
Gas dehydration	24	0	delete	0
Gas conditioning	25	0	delete	0
Lift gas	26	0	delete	0
Gas export/metering	27	0	delete	0
Gas sweetening	28	0	delete	0
Water injection	29	0	delete	0
Sea water treatment	29	0	delete	0
Sea water de-sulphatation	29	0	delete	0
Water injection	29	0	delete	0
MEG regeneration	38	0	delete	0
Loading and other	39	0	delete	0
Cooling	40	0	delete	0
Heating	41	0	delete	0
Chemical injection	42	0	delete	0
Flare system	43	0	delete	0
Oily water treatment	44	0	delete	0
Fuel gas	45	0	delete	0
Injection Methanol/MEG	46	0	delete	0
Sea water	50	0	delete	0
Ballast	52	0	delete	0
Fresh water, hot water	53	0	delete	0
Drains	56	0	delete	0
Other utilities	69	0	delete	0
Fire water	71	0	delete	0
Fire fighting	72	0	delete	0
Material handling	73	0	delete	0
Main deck cranes	73	0	delete	0
Other lifting equipment	73	0	delete	0
Life boats etc	76	0	delete	0
HVAC etc	77	0	delete	0
Emergency shutdown	79	0	delete	0
Main power generation	80	0	delete	0
Main power distribution	82	0	delete	0
Essential power	83	0	delete	0
Emergency power	84	0	delete	0
Battery, no-break	85	0	delete	0
Telecommunication	86	0	delete	0
Automation	87	0	delete	0
Workshops, watertight doors	93	0	delete	0

COST REPORT

Latest software up-date: 09.11.15

Gjøa	2	Cost year: 2016	Currency: NOK	Region:	North Sea North

CAPEX FACILITIES OVERVIEW (mill.NOK)

Cost element	Engineering	Procurement	Construction	SUM EPC	Marine op	SUM EPCI	Management	Base estimate	Contingency	Total
Topsides	3982	5742	3175	12899	157	13057	1828	14885	2233	17117
Substructure incl conductors/risers	253	851	730	1834	455	2290	321	2610	392	3002
Piles, anchors and mooring lines	0	363	0	363	210	574	80	654	98	752
Sum Platform	*4235*	*6957*	*3905*	*15097*	*823*	*15920*	*2229*	*18149*	*2722*	*20871*
Subsea/WHP production equipment	234	1875	57	2166	196	2362	331	2692	404	3096
Flowlines and spools	63	517	246	826	527	1352	189	1542	231	1773
Structures (RB, PLET, PLEM, T, Y)	81	268	0	349	230	580	81	661	99	760
Risers for flowlines/pipelines	95	686	62	842	99	941	132	1073	161	1234
Umbilicals with risers	64	212	25	301	106	407	57	464	70	534
Sum Subsea	*537*	*3557*	*391*	*4484*	*1157*	*5642*	*790*	*6432*	*965*	*7396*
Export pipelines	49	1225	201	1475	1240	2716	380	3096	464	3561
Power cables wih risers	57	373	7	437	280	717	100	817	123	939
SUM Facilities	*4878*	*12112*	*4504*	*21494*	*3501*	*24994*	*3499*	*28494*	*4274*	*32768*

CAPEX WELLS OVERVIEW

	days per well	days	mill.NOK
Drilling	*53*	587	4026
Completion	*47*	512	3756
Drilling and completion	*100*	1098	7782

OPEX OVERVIEW (mill.NOK)

	Offshore work	Onshore support	Well maintenance	Modifications	SUM	Contingency	SUM	Insurance	CO2 tax	Total
OPEX per year (average)	707	112	107	24	951	93	1044	89	58	1190
Total OPEX	*7072*	*1122*	*1073*	*242*	*9509*	*927*	*10436*	*892*	*577*	*11905*

REMOVAL COST OVERVIEW (mill.NOK)

	Engineering	Decommissioning	Removal operations	Dismantling	Sub-total	Management	Base estimate	Continency	TOTAL
Well plugging and abandonment	*48*	*0*	*1808*	*0*	*1856*	*186*	*2042*	*306*	*2348*
Platform topsides	60	150	0	271	480	48	528	79	608
Platform substructure	32	20	33	61	146	15	160	24	184
Mooring lines, piles, anchors	5	25	37	9	76	8	84	13	96
Risers, conductors	1	2	27	2	32	3	35	5	40
Flowlines, umbilicals and cables	16	41	163	0	220	22	242	36	278
Export pipelines	26	133	46	0	205	21	226	34	260
Subsea equipment and structures	32	44	182	13	271	27	298	45	343
Sea bottom clean-up	2	0	40	0	42	4	46	7	53
TOTAL	*222*	*414*	*2336*	*356*	*3329*	*333*	*3661*	*549*	*4211*

FSU CAPEX OVERVIEW (Not included in Capex - Included as leased element in NPV)

Cost element	Engineering	Procurement	Construction	SUM EPC	Marine op	SUM EPCI	Management	Base estimate	Contingency	Total
FSU	0	0	0	0		0	0	0	0	0
Marine operations					0	0	0	0	0	0
Mooring				0	0	0	0	0	0	0
FSU total	0	0	0	0	0	0	0	0	0	0

COST PHASING ASSUMPTIONS

CAPEX FACILITIES

Number of months from project sanction to production start-up: 46

		mill.NOK
Expenditure in year	1	5157
Expenditure in year	2	12570
Expenditure in year	3	11684
Expenditure in year	4	3357
Total expenditure		32768

CAPEX WELLS

Number of months for drilling and completion: 37

		mill.NOK
Expenditure in year	1	0
Expenditure in year	2	2550
Expenditure in year	3	2550
Expenditure in year	4	2550
Expenditure in year	5	131
Expenditure in year	6	0
Expenditure in year	7	0
Expenditure in year	8	0
Expenditure in year	9	0
Expenditure in year	10	0
Expenditure in year	11	0
Expenditure in year	12	0
Total expenditure		7782

OPEX

Basis for cost phasing - OPEX			mill.NOK
Preparation for operation - last year before production start			706
First period; start-up	Duration - years	1	1413
Second period; drilling and production	Duration - years	2	1059
Third period; production, maintenance and modification	Duration - years	5	1322
Fourth period; preparation for abandonment	Duration - years	2	529
Total	Duration - years	10	11905

REAL versus NOMINAL		Constant		Market adjusted		Market adjusted		Nominal - no market		
Project sanction	Capex facilities	Capex wells	Capex facilities	Capex wells	Capex facilities	Capex wells	Capex facilities	Capex wells	Inflation indexes	
2016	Real	Real	Real	Real	Nominal	Nominal	Nominal	Nominal	Market	General
2017	5157	0	5157	0	5157	0	5157	0	*100,0*	*100,0*
2018	12570	2550	12570	2550	12884	2614	12884	2614	*102,5*	*102,5*
2019	11684	2550	11684	2550	12275	2680	12275	2680	*105,1*	*105,1*
2020	3357	2550	3357	2550	3615	2747	3615	2747	*107,7*	*107,7*
2021	0	131	0	131	0	145	0	145	*110,4*	*110,4*
2022	0	0	0	0	0	0	0	0	*113,1*	*113,1*
2023	0	0	0	0	0	0	0	0	*116,0*	*116,0*
2024	0	0	0	0	0	0	0	0	*118,9*	*118,9*
2025	0	0	0	0	0	0	0	0	*121,8*	*121,8*
2026	0	0	0	0	0	0	0	0	*124,9*	*124,9*
2027	0	0	0	0	0	0	0	0	*128,0*	*128,0*
2028	0	0	0	0	0	0	0	0	*131,2*	*131,2*
2029	0	0	0	0	0	0	0	0	*134,5*	*134,5*
2030	0	0	0	0	0	0	0	0	*137,9*	*137,9*
2031	0	0	0	0	0	0	0	0	*141,3*	*141,3*
2032	0	0	0	0	0	0	0	0	*144,8*	*144,8*
	32768	*7782*	*32768*	*7782*	*33932*	*8185*	*33932*	*8185*		
Estimated market adjustment			*0*	*0*	*0*	*0*				

TOPSIDE EQUIPMENT LIST			
System	Number	tonnes	mill.NOK
Drilling derrick	10	0	0
Drilling systems, mud	11	0	0
Platform well control system	12	0	0
Pig receiver, riser pull-in	13		
Dry tree related (incl ESP power)		0	0
Wet tree related (incl MPP power)		73	34
Export related - oil		8	4
Export related - gas		10	7
Drilling control, BOP	14	0	0
Drilling utilities	15	0	0
Subsea well control system	19	28	13
Separation and stabilization	20		
Test separator		30	10
Inlet separator A		136	47
Inlet separator B		124	43
2. stage separator		77	27
3.stage separator		17	6
Coalesher		17	6
Heating/cooling		18	6
Allocation metering syst B		39	14
Crude handling/metering	21		
Booster pumping		20	16
Export pumping		35	23
Metering		8	13
Gas compression	23		
Gas re-compression A		111	116
Gas re-compression B		221	231
Gas re-compression C		0	0
Gas re-injection		0	0
Gas export compression		323	337
Gas dehydration	24	274	138
Gas conditioning	25	0	0
Lift gas	26	58	61
Gas export/metering	27	43	70
Gas sweetening	28	0	0
Water injection	29		
Sea water treatment		0	0
Sea water de-sulphatation		0	0
Water injection		0	0
MEG regeneration	38	333	103
Loading and other	39	25	10
Cooling	40	44	31
Heating	41	98	64
Chemical injection	42	34	34
Flare system	43	68	60
Oily water treatment	44	71	71
Fuel gas	45	0	0
Injection Methanol/MEG	46	30	31
Sea water	50	65	43
Ballast	52	16	21
Fresh water, hot water	53	111	181
Drains	56	21	18
Other utilities	69	141	114
Fire water	71	353	245
Fire fighting	72	20	23
Material handling	73		
Main deck cranes		362	84
Other lifting equipment		25	6
Life boats etc	76	151	64
HVAC etc	77	107	66
Emergency shutdown	79	1	8
Main power generation	80	80	81
Main power distribution	82	91	46
Essential power	83	73	51
Emergency power	84	43	30
Battery, no-break	85	29	14
Telecommunication	86	21	164
Automation	87	18	183
Workshops, watertight doors	93	57	31
Sum equipment		4162	3099

EQUIPMENT SUMMARY		
Equipment by area	tonnes	mill.NOK
Sum Drilling	0	0
Sum Wellhead and Risers	119	58
Sum Process	2026	1400
Sum Utilities	1163	1267
Sum Power	316	220
Sum Water injection	0	0
Other appurtenances	538	154
Total equipment list ex substructure	4162	3099
Average cost per tonne		0,7445

EQUIPMENT FACTORS	
Total topside weight / equipment weight	5,200
Topside EPCI cost / equipment cost	4,214