THE ECONOMICS OF ARCTIC OFFSHORE OIL

A case study of the economics of BP Licence EL449 in the Canadian Beaufort Sea

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Abstract

Title: THE ECONOMICS OF ARCTIC OFFSHORE OIL
A case study of the economics of BP Licence EL449 in the Canadian Beaufort Sea

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Issue of study: The time of easily recoverable oil is coming towards an end, and oil companies start to look at other frontiers where the oil is more difficult to reach in order to secure future supply. One of those areas is the arctic which is considered to have a great amount of oil and gas and is at the present time relatively unexplored. Since the arctic climate is severe, it is consistent with extra costs to explore and develop a field in the area in comparison with a conventional oil field, but how much extra is the question, and to what oil price is it profitable for the oil firms to explore and develop those areas. To answer these questions it is crucial to investigate required technologies for the arctic environment, estimate the costs for them and discount the costs back to the present time. To investigate how much oil there is in an arctic field and to estimate a production scenario is also required.

Purpose: The purposes of this study are:

1. Develop a model for evaluating arctic offshore field concepts and estimating the cost drivers of the concept in order to calculate an entry level oil price at which oil firms can beneficially invest in the arctic production.

2. Describe necessary technologies applicable in the arctic for extracting oil and delivering it to the market.

3. Apply the developed model to a case study in order to find an entry level oil price for the case study.

Method: The arctic is a big area and all oil fields have unique characteristics which require unique technologies, which all have different costs. In order to get an accurate view on the present costs consistent with the arctic, a case method has been applied. A field which is believed to be developed in the near future has been the object for the case study and all costs associated with the field exploration, development and distribution have been estimated by investigating and analysing the technologies most likely to be utilised. The production profile has also been estimated. The costs and the production have then been discounted to the present time in order to be able to calculate the lowest required oil price for the investment to be profitable. This has all been done by utilising a developed model, called Gold Digger model, which originates from the theoretical models described in the thesis.

Conclusions: Technologies optimal for arctic exploration and development are currently only at the early stages of development. This makes the cost for the technologies quite difficult to estimate. However, there are many firms developing technologies suitable for the arctic since many people in the oil industry are confident that the arctic has a great future as an oil supplying region. However, extracting oil from the arctic will be costly for the firms deciding to invest in the arctic, and will require large fields with good viscosity of the oil. Even though large fields will be found and the oil is of great quality and viscosity, the cost for the extraction will be higher than today's oil price. The base case of our study of an arctic field will require an entry level oil price of more than USD 55.8 per barrel. The sensitivity analysis of the same field brings a span of oil price ranging from USD 22.0 to 138.6, and it is rather believable that we are facing an entry price level of arctic oil on the higher side of the base case than the lower side of it.

Keywords: Economics, Arctic, Oil, Offshore, Costs, Drilling, Drillship, Gravity Based Structure, Pipeline, Net Present Value, Value shop, Cost driver

Acknowledgements

The spring semester passed by quickly and the thesis period has come to an end. The period has been very interesting and formative. From not knowing the oil industry four month ago, we can now proudly state that we are quite familiar with the industry and the costs associated with it. Even though we can claim that the majority of the work done this semester is performed by us we have to admit that it would not have been possible without help from other great people..

Firstly, we would like to thank our project sponsor Stena Drilling Limited for the possibility to meet with so many wise and informative people in the industry and also for making it possible to perform the thesis.

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Lund, May 2009

Gustav A. Eriksson Don Karlsson

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1 Introduction

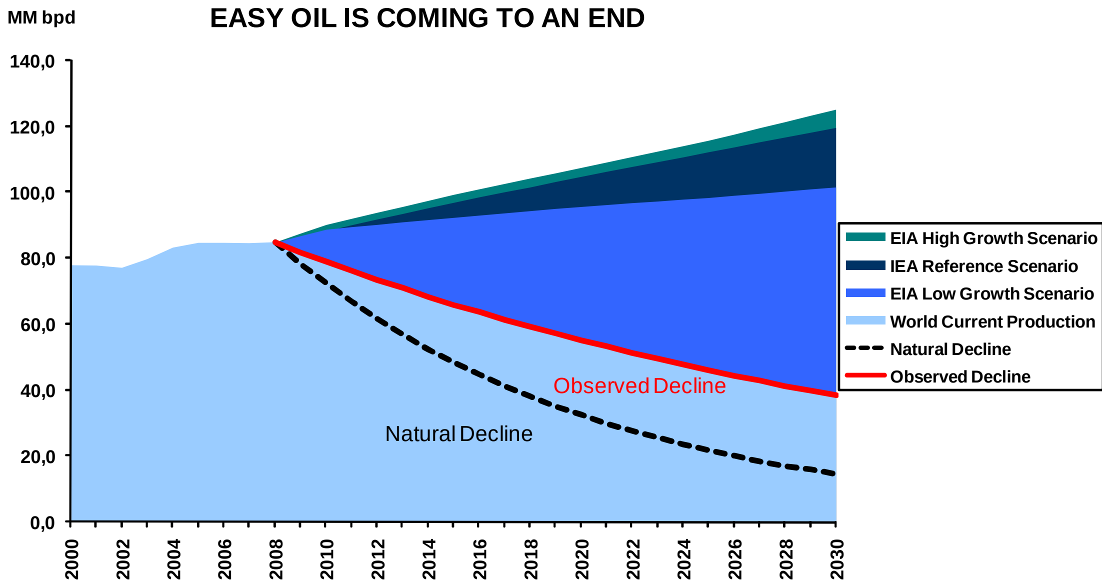
In this chapter the background of the study is presented together with the purpose and goal of the study. Furthermore, a presentation of the project sponsor, delimitations, and the target groups will be realised. Lastly, a general disposition is presented.

1.1 Background

The time of “easy oil”, meaning oil found in large reservoirs, oil close to the surface on shore or near shore in welcoming places, is coming to an end. Energy suppliers are now desperately seeking new ways of finding new supplies of the “black gold” that has become the economic pillar of our society and allowed us humans to consume at levels that no person would have dared to dream of a hundred years ago. For decades still to come we will be dependent on oil, gas and other fossil fuels while waiting for alternatives to reach a significant scale. The ongoing debate regarding global warming as a consequence of fossil energy consumption might hasten the development of more sustainable sources of energy, but until those fuels are here, we are deeply dependent on oil and gas for our world to work as we know it today.

Richard Shepherd, an energy specialist consultant working in the energy consulting firm Petrologica has observed a decline rate in world-wide production from existing resources of 3.52% per year and a natural decline of 7.71% if there were no additional investments to existing fields.1 While production limitations slow the supply of oil, demand for oil is expected to grow. The potential growth in demand for oil and gas is mainly driven by strong economic growth in emerging economies and also by the fact that oil will remain the most important fuel for transportation as there are no competitive alternatives.2 A low growth future scenario requires 40.5 million barrels per day to be added by 2020, see figure 1.

[1] Shepherd, R. (03/02/2009)
[2] Energy Information Administration (2008), pp. 1-4



Required Additional Production Capacity	
2020	**40.5-52.3 MBPD**
2030	**63.0-86.5 MBPD**

Figure 1. Possible oil demand and production scenarios of the future[3]

The increasing demand and diminishing supply of easy oil creates a gap that needs to be filled. This gap can be met by enhanced recovery of conventional oil reserves and/or development of unconventional oil in new frontiers such as arctic oil, oil sands, extreme deep offshore oil, extra heavy oil, gas-to liquids and coal to liquids. This thesis focuses on the economics of one such frontier – namely arctic oil.

Even if economics are the greatest barrier to arctic offshore production there is also an environmental factor. Some of the areas are very sensitive and are home to important wildlife which raises the question as to whether production of hydrocarbons in those areas should be considered at all. In Alaska, this question has been raised with the loudest voice due to the wildlife and the fear of negative impact on the native inhabitants. To make as little impact as possible, new technologies have been developed that minimise the risk of accidents with catastrophic impact as a consequence, and intensive investigations are made of the effects before any production is permitted.[4]

[3] Adapted from Energy Information Administration (2008), p. 24

[4] The Christian science MONITOR (03/02/2009), http://www.csmonitor.com/2007/0925/p04s01-woeu.html?page=2

1.1.1 The Arctic Oil and Gas Potential

The Arctic, defined as the geographic area north of the Arctic Circle (66.56˚ north latitude), holds great potential for oil and gas. The US Geological Survey (USGS) estimates that this area holds potential of 412 billion barrels of oil equivalent and that 84% is expected to occur offshore.[5] Many of the major oil firms have committed to spending great amounts of money in the area, Shell USD 2.5 billion, BP USD 1.2 billion and Exxon USD 585 million in the Canadian and Alaskan Chukchi and Beaufort Seas.

Furthermore, global warming is believed to make the arctic more accessible in the future. Perceptions about global warming and the potential reserves in the Arctic have triggered an international race. The Russians planted a flag on the Lomonosov ridge in August 2007 by submarines with Mir-1 and Mir-2 descending to the sea floor 4000 meters underneath the surface of the Arctic Ocean.[6]

Even though the potential of finding petroleum reserves in the arctic is large, there is to this date no offshore production (Russia's Sakhalin Island production is in Arctic conditions but south of the Arctic Circle itself). Many of the costs associated with extracting the resources in the arctic area are significantly higher than in other offshore areas due to the harsh environment which requires robust, state-of-the art equipment and ice management.[7] [8] [9]

1.1.2 Existing Arctic Oil Economic Research

Earlier research in the arctic has focused mainly on the politics, technical or geological aspects of the area but there exists earlier research of the economics in the arctic. The Canadian Energy Research Institute (CERI) produced a special report in 2005 with the title "The Economics of High Arctic Gas Development: Expanded Sensitivity Analysis". The report provides a re-assessment of the economic feasibility of producing and delivering gas from the high Arctic, based on net present value method and studies the case of Melville Island in the Beaufort Sea. It uses the case as an example of the potential in the high arctic and there are three development options used in the analysis.[10]

The three most important assumptions of the model are the dates for production start up, commodity prices and the capital and operating costs of the different cases. Each case is then applied with a high case, mid case and low case. The capital costs and operating costs vary depending on development case. The conclusions of the analysis are that all scenarios with positive net present value are economical and whether a scenario is economical or not depends heavily on the input factors.[11]

[5] USGS (2008), p. 1
[6] TIMESONLINE (05/02/2009), http://www.timesonline.co.uk/tol/news/world/europe/article2189611.ece
[7] Lowings, M. (29/01/2009)
[8] Shepherd, R. (03/02/2009)
[9] Liljeström, G. (29/01/2009)
[10] CERI (2005), p. 1
[11] CERI (2005), p. 3

There is to this date no economic research made on deeper arctic offshore project frontiers. Therefore we see that this is an area in which we can contribute.

1.2 Purpose and Goal of study

Since sources of “easy oil” are declining it is a question of time and economics before the next frontiers of “tougher oil” resources, as addressed above, will be developed. The future supply of hydrocarbons is uncertain, but what is known is that there will be a need for filling the gap between demand and supply for energy in the near future. To make reliable future predictions of how this gap will be efficiently filled it is crucial to understand the economics behind different alternative frontiers. This thesis evaluates the economics of the offshore arctic oil frontier using case methodology.

The purpose of this study can be summarised as stated below.

1. Develop a model for evaluating arctic offshore field concepts and estimating the cost drivers of the concept in order to calculate an entry level oil price at which oil firms can beneficially invest in the arctic production.

2. Describe necessary technologies applicable in the arctic for extracting oil and delivering it to the market.

3. Apply the developed model to a case study in order to find an entry level oil price for the case study.

1.3 Project sponsor

Stena Drilling Limited, an offshore drilling company based in Aberdeen, owned by its Swedish holding company Stena AB, has sponsored this thesis. They have contributed financially and made available its wide spanning network within the oil industry. This has made it possible for the authors to access information that for many others is impossible. Stena Drilling Limited has also imposed some directions for the thesis. Stena Drilling strongly believes in the potential for arctic oil and has therefore invested in an arctic classed drillship, Stena DrillMAX Ice, with delivery from Samsung shipyard in 2011. The curiosity for the subject is therefore obvious in the case of Stena Drilling since they desire an answer to the question of to what oil price the oil companies will invest in arctic projects where the DrillMAX Ice can be a potential partner.

1.4 Delimitations

This thesis exclusively investigates the economics of extracting oil in an area where Stena DrillMAX Ice can perform in the future, and finding an estimated entry level oil price per barrel in order to be able to economically recover oil in the area investigated. The thesis will hence not answer the questions of which political, environmental or technological factors can threaten the future extraction of oil in the area.

The thesis is limited to one case. Several other cases can be of interest for Stena Drilling in the future and it is difficult to say where DrillMAX Ice will perform when she is built, but during the process of writing the thesis it became clear that the EL449 BP field is a good case and a case which is believed to go into production in the future. The time frame of four months set the limitation of investigating only one case.

The thesis focuses on the economics of the upstream petroleum industry only, which implies only taking the estimated costs of getting the oil to the market, such as to a refinery. No further costs are taken into consideration.

1.5 Target group

This thesis is primarily written for Stena Drilling Limited and the personnel working with the development of Stena DrillMAX Ice. The thesis can be used as strategic support in several areas, such as marketing. Our secondary target group is the academia and people in academia interested in the future of arctic hydrocarbon industry. Tertiary target group is all firms active in the oil industry which has an interest in knowing what costs the arctic extraction of oil will bring.

1.6 Disposition

The thesis has the following disposition:

Chapter 2: Methodology
The section is to describe how we approached this task and how we most efficiently solved the task Stena Drilling Limited and the academia set for us. Firstly, we describe the working process and later we describe why we have chosen to conduct a case study.

Chapter 3: Theoretical framework
The chapter presents the theoretical framework used as a tool to develop our own model in chapter 4, which is later applied to the case study in chapter 5 and 6. Mainly two models originating from theories are described. The theoretical framework and the models are needed to enable a more constructive analysis of the empirical data collected through the case study.

Chapter 4: Gold Digger model
In the chapter a merge of the theoretical models will be presented. The theoretical models will be analysed and modified to better suit the objective with the thesis. The two main models in the previous chapter are used as cornerstones in the model presented in this chapter and aims to find and analyse the empirical data presented later in the thesis.

Chapter 5: Canadian Beaufort Case Study
The case study chapter presents the empirical data of the offshore exploration and development industry. It uses the first step of the Gold Digger model to analyse the empirical data in order to generate and evaluate the cost drivers for the case. The analysis generates a choice suitable for the case and the costs associated with the same concept.

Chapter 6: The net present value calculation
The chapter employs the second step of the Gold Digger model in order to make a calculation of the entry level oil price required for the oil firms to reach a net present value of zero, and hence the level at which they can enter the arctic. To get a broader view and eliminate some uncertainty, a scenario analysis will be performed.

Chapter 7: Theoretical discussion

The discussion chapter aims to discuss the theoretical angle of this thesis with improvements of the models used. It will also highlight why the study has been conducted as a case study.

Chapter 8: Conclusions

The conclusions chapter answers the objectives of the thesis. Further recommended research will be presented and recommendations for improving the methods we have utilised to conduct the study.

2 Methodology

This section is to describe how we approached this task and how we most efficiently answered the objectives Stena Drilling Limited and the academia set for us. Firstly, we describe the working process and later we describe why we have chosen to conduct a case study and other methods used to perform the study.

2.1 The working process

This master thesis is based on the notion that easy oil is coming to an end and that resources in more remote areas, such as the arctic, will in the near future be explored and developed. From the perspective of Stena Drilling Limited, the sponsor of this thesis, the task is to find a way to set a proper entry level oil price for when arctic regions will become economically recoverable.

The working process while writing the report has been iterative. A “living document” during the process has helped us to store, collect and sort all theory, empirical research and analysis. The study has been conducted in some more distinctive sections; initial empirical research, initial theoretical research, building the theoretical model used as an analysing tool, building the case study, method development, analysis and conclusions.

Quite early in the process we understood that the key to success was to quickly gather information about the offshore business and the characteristics of the different geographical areas in the arctic. Therefore the process took its starting point in collecting and reading reports and studies performed in arctic or arctic-like offshore projects. Since very little production has occurred in the arctic, especially within deeper offshore project target areas, we decided to meet and interview the people with the best knowledge about arctic oil. These are found within oil companies, brokerage firms and suppliers to the offshore industry. After the initial empirical research we decided that the best way to conduct the research and solve the objective was to perform a case study in order to evaluate the economics in one specific setting. This had to be the most-likely-to-occur scenario which is of interest to the project sponsor. The decision to use a case study as our research method was made after understanding the actual problem, the great complexity of the arctic. We understood that we had to rely on empirical research to a great extent, all of which the case study was well suited for.[12] After deciding that a case study would be the best way to estimate the entry level oil price for arctic resources, a suitable theoretical framework was built, a framework that could be used to structure and analyse the cost drivers for arctic production. The theoretical framework was then used to build a model that would evaluate the entry level oil price for the arctic case study. During the process the DrillMAX Ice has been kept in mind and the investigated case has the environmental characteristics where she can perform.

[12] Yin (2003), p. 13

The empirical research has mainly been conducted in Aberdeen in Scotland, Calgary in Canada and Houston in the USA. The travelling allowed us to meet the best in the business face to face for interviews and discussion since those cities have a high presence of oil companies, brokerage firms, contractors and industry linked people.

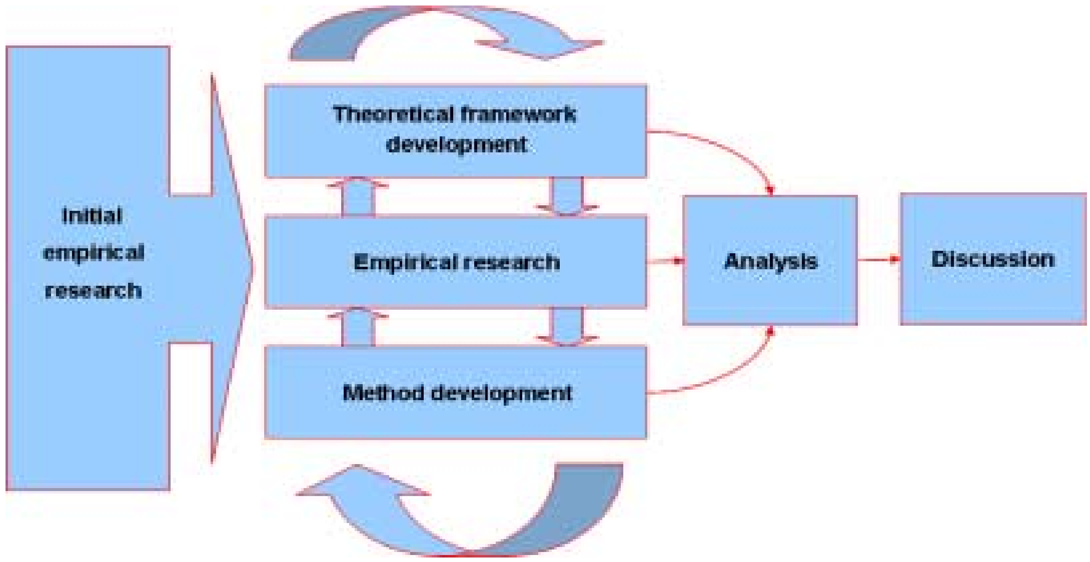


Figure 2. The working process used in the thesis. Theoretical framework, empirical research and method development have performed iterative

2.2 The case study

A case study is suitably conducted when "a how question is being asked about a contemporary set of events, over which the investigator has little or no control".[13] Hence, the case research method is suitable in this study since we, the authors, have no control of the events occurring in the arctic region regarding resource extraction.

Case studies are particularly suitable when the research can be considered complex in its nature. Usually a case study allows the authors to describe and understand in depth a system or organisation which can hardly be investigated by other research methods. [14]

The case study has forced us to iteratively search for cost drivers associated with the offshore industry applicable to the arctic. The case study in itself is a method where a phenomena or event is investigated in its real life environment and hence suitable for this study.[15] We have throughout the process simultaneously been collecting empirical data and building the theoretical framework that supports our case analysis. This has made us deeply understand and describe the complex system of the offshore system which indeed the case study supports better than many other research methods. The offshore case investigated in this thesis is predicted on benchmarks and peers of other previous and occurring offshore cases. This kind of data has been of great aid to understand the industry and the offshore system. This data has made it possible to make the assumptions for the case.

[13] Yin (2003), p. 9
[14] Backman (2008), p. 55
[15] Backman (2008), p. 55

2.2.1 Qualitative and quantitative

The use of mathematics, measurements and statistics are usually referred to as a quantitative method while use of the qualitative method refers to the use of verbal formulations such as interviews and reports. Even if a study is characterised by one paradigm, it does not exclude the use of another method.[16]

In this thesis the information and data is generally gathered from reports and papers about the arctic offshore industry and interviews with key specialists in the industry. Through reports and papers knowledge about existing technologies and learning from previous arctic offshore projects was obtained. Through the interviews an overview of possible arctic development concepts and knowledge concerning future technologies have been obtained. Many costs could be quantified by interviewing industry experts. The informal discussions with personnel at the Stena Drilling office in Aberdeen have also contributed to a great extent to the understanding of the complex offshore industry, especially when it comes to drilling.

One direct observation[17] has been performed aboard an icebreaker for two days in order to collect in-depth knowledge about the arctic climate, icebreaker technology and ice management. In a case study these ways of finding data are commonly used.[18] Some of the data collected and analysed are statistics from previous and occurring cases, but the majority of estimations and assumptions in the case are drawn in a qualitative way by interviewing personnel in the industry and investigating several other cases through archival records and documentation, i.e. reports. The qualitative data has later been analysed, measured and calculated. Hence the report is of qualitative paradigm character with some use of quantitative methods.

2.2.2 Interviews

The case study is usually to a great extent based on interviews and they are considered one of the major sources for data collection. The interviews in this study can distinctively be divided into three under groups; the ones held in-house at Stena Drilling and the mother company Stena AB, the oil companies, and lastly other companies related to the industry, such as suppliers to the oil companies or brokerage firms.

Early in the process the empirical data research of written material was complimented with interviews mainly conducted with personnel from the Stena group or Stena consultants, that are specialists within different fields relevant to the thesis. With many of these personnel the interviews were conducted ad hoc and open-ended[19] during longer periods. These interviews gave a good insight into the industry as a whole and helped to generate ideas of how we could reach our objectives.

Later in the process as more knowledge was gained we conducted several interviews with specialists from oil companies and related companies to gain knowledge about up to date offshore arctic agenda. The specialists have usually been involved in arctic

[16] Backman (2008), p. 33
[17] Yin (2003), p. 94
[18] Regnell & Runesson (2006), p. 34
[19] Yin (2003), p. 90

projects to some extent and these interviews were more focused[20]. During these interviews bits and pieces were gained and these together could be used to build up assumptions and estimates in the case.

The interviews have mainly been conducted in a face-to-face environment and were all of a non-rigid character and more guided conversations rather than structured inquiries, all in line with case study research method.[21] This was to avoid manipulating the interview subject in any certain direction, but rather to let the subject articulate freely on his area of expertise and get a better flow in the discussion. In order to guide the interview towards a satisfying direction, the subject was supplied with predetermined discussion topics and leading questions in order to allow for preparation for the interview.

Many of the interview subjects have been experts in a specific technology or geographical field and hence relatively subjective. To avoid bias, the focus was to find interview subjects covering the whole range of expertise regarding both technological and geographical view. The data was later analysed and converted to a more subjective view and we tried to lay the "puzzle" of all subjective views in order to make our own more subjective view. We have tried to see beyond the subjectivity of the interviewee and to a great extent only used the subjective facts that came out of the interviews.

2.2.3 Other sources

Beside the reports, interviews and observations, other published sources have been used to complement and validate the information as well as creating a theoretical framework, which laid the structure for our developed model. Documentation of similar cases as this one have been studied, such as Hibernia and Hebron offshore fields, as well as newspaper clippings, administrative documents and other reports.[22] The documentation has mainly been used to create a good picture and overview of the case as well as to validate the interviews to get a more objective picture.

Archival records, material with a more scientific approach, listings and statistical records[23] are used to estimate and make assumptions. We have used maps and charts to understand the geography and also service and organisational records to understand the fundamentals of the offshore hydrocarbon exploration and production.

[20] Yin (2003), p. 90
[21] Yin (2003), p. 89
[22] Yin (2003) p. 87
[23] Yin (2003) p. 88-89

2.2.4 Theory and empirical research

Deductive reasoning uses theories, hypothesises and question formulations to create a truth, while the inductive reasoning rather confirms and creates hypothesises or theories by empirical data analysis. The qualitative approach usually favours the inductive reasoning.[24]. The deductive research derives conclusions and hypothesis by scanning theory and testing these in an empirical way. Thereafter theories are supported or criticised[25]. The inductive researcher is the opposite of the deductive. No theoretical framework or literature is needed but instead observations about the world lead to conclusions and new theories.[26] Abductive reasoning involves finding suitable theories to an empirical observation, sometimes called theory matching. Case studies often use abductive research methods.[27] The difference between abductive and inductive is that the inductive approach starts with an empirical approach without any theoretical framework. While the abductive approach simultaneously starts with empirical observations and theoretical framework. Both the inductive and abductive methods aim to develop theory while the deductive aims to test theories or hypothesis.[28]

The approach of this thesis is more abductive than inductive which means that theoretical frameworks were developed simultaneously to empirical data collection. The theoretical framework that is applied to the case study is matched to suit the empirical data that was gathered. This abductive process started in an empirical observation that resulted in a theoretical model suggestion that combined two existing theoretical models that together formed a new tool that was applied to further empirical data in order to analyse a case study. This made it possible to estimate an entry level oil price for our case study. To some extent this thesis is also deductive, since the theoretical frameworks that were developed in the abductive process of the thesis also are tested and criticised in the conclusion of the thesis.

The case study performed is largely predictive[29] where the description of the facts is used as the base for the case. Simultaneously, we look at other cases which are used as proxies and hence we have used a more explanatory[30] approach.

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[24] Backman (2008), p. 54
[25] Kovacs, G. & Spens, K. p. 132
[26] Kovacs, G. & Spens, K. p. 133
[27] Kovacs, G. & Spens, K. p. 136
[28] Kovacs, G. & Spens, K. p. 139
[29] Yin (2003), p. 6
[30] Backman (2008), p. 54

3 Theoretical framework

This chapter presents the theoretical framework used as a base for the case study. Two models originating from theories are described. The theoretical framework with the models is necessary to enable a more constructive analysis of the empirical data later presented in the thesis.

3.1 The chain of activities and its costs

To evaluate the economics of an investment one has to look at the fundamentals of the costs. Organisations all have different activities performed that are consistent with costs. To gain competitive advantage or develop a framework for investments it is crucial to understand which the activities are and how they are interrelated to each other. The network created of the activities within an organisation is often referred to as a value chain, originally introduced by the well-known economist Michael Porter. All organisations have unique value chains but the fundamentals are basically the same with a few distinctions. Stabell & Fjeldstad have written an article about the distinctions with take-off in the value chain which is very suitable for this study since one type of distinction presented is adjusted to suit the upstream petroleum industry. Few other theoretical models can describe this industry in-depth as this model is able to, but to understand the model employed later on in the thesis it is crucial to understand the value chain.

3.1.1 Introduction to the value chain

Michael Porter is one of the early describers of a set of activities that together creates value for a customer within an organisation. He describes a series of primary and secondary activities that together creates value to a firm which he refers to as a value chain. The value chain is embedded in a system together with other firms' value chains since all organisations are to some extent dependent on connections and networks with other organisations to survive and to realize business. The concept relies on the closely coordinated and cooperative networks between organisations which compete with other similar chains. This interrelated system is referred to as a value system. [31] [32] [33]

The trends in recent years have been on outsourcing activities not considered the core activity in many organisations, why it is becoming very important to look beyond the own organisation to secure liable suppliers and distributors to the own organisation. [34] When evaluating the cost of a product it is important to not exclude any factors affecting the product's cost, but a too detailed breakdown of the cost can also confuse more than benefit. Only activities representing a significant or growing proportion of cost should be included.[35]

The value chain is meant to work as a model for the organisation in order to see the critical activities performed and is not meant to reflect the actual flow of material. This implies an easier understanding of the activities and the organisations as a whole,

[31] Christopher (1998), pp. 12-13
[32] Huemer (2006), p. 134
[33] Skjott-Larsen (2007), p.17-18
[34] Christopher (1998), p. 116
[35] Stabell & Fjeldstad (1998), p. 417

which makes improvements easier to recognise in order to gain competitive advantage.[36] The generic value chain consists of five primary activities which are:

- Inbound logistics
- Operations
- Outbound logistics
- Marketing
- Service

To gain competitive advantage by utilising the concept of the value chain a firm can analyse differences in the activities costs in the chain towards competitors or other benchmarking methods. It is important to compare historical data, but also to analyse future trends if possible, to get an accurate analysis.[37]

3.1.2 The value chain, shop and network

Stabell & Fjeldstad have in their report *Configuring value for competitive advantage: on chain, shops, and networks,* developed and clarified some obscurities with the traditional thinking of a value chain. To do an analysis of the value chain and decompose the activities it is important to understand the activities characteristics, regarding cost and value creation.

Porter claims that the generic value chain with the value creation is valid for all industries, but that the specific activities performed within a firm are dependent on the industry the organisation are active in.[38] Stabell & Fjeldstad have as supervisors of the value chain in several industries often faced problems applying the generic value chain. The traditional value chain applies well onto a traditional manufacturing firm, but the typology and the value creation logic is not applicable for many other firms such as service companies. The five generic activities presented in the typical value chain are difficult to apply and analyse in a number of industries and causes more obscurity than clarity.[39]

When considering a service company such as a bank or an insurance firm the application of the five generic activities are not very suitable. For example, what activities are associated with inbound and outbound logistics in an insurance firm, and which are associated with operation. Since the activities are supposed to reflect the value creation, the value chain is suitable when analysing manufacturing firms which focuses on unit costs, but the primary activities must be switched to something more suitable when analysing firms such as service companies.[40]

Other issues arise when considering the upstream petroleum exploration industry and oil field development. Factors such as technological development, field size and different technological solutions applicable to different fields will not be high-lighted in the generic value chain and its activities. Rather than just the inbound and outbound logistics and the operational production the value creation of a petroleum explorer and

[36] Stabell & Fjeldstad (1998), p. 417
[37] Christopher (1998), p. 116
[38] Stabell & Fjeldstad (1998), p. 413
[39] Stabell & Fjeldstad (1998), pp. 413-414
[40] Stabell & Fjeldstad (1998), p. 414

field developer much depends on the finding of a large oil field and the chosen production concept. If applying the generic value chain, the value creation logic of some major factors affecting the petroleum business would be absent.[41]

The issues highlight the need for other tools for analysing such industries such as the petroleum industry and the service sector. To manage the issues described above, Stabell & Fjeldstad present two other alternatives to the generic value chain and its value creation logic. Hence the value chain is only one of three generic value configurations, which in total are the value chain, the value shop and the value network.

The value chain is applicable to the traditional manufacturing firm while the value network creates value by facilitating relationships and network with its customers such as banks and insurance companies. Value shops are referred to as firms creating value by mobilising resources and focus their activities on solving a customer problem.[42] Figure 3 shows the distinction of the three value configurations.

	Chain	Shop	Network
Value creation logic	Transformation of inputs into products	(Re)solving customer problems	Linking customers
Primary technology	Long-linked	Intensive	Mediating
Primary activity categories	• Inbound logistics • Operations • Outbound logistics • Marketing • Service	• Problem-finding and acquisition • Problem-solving • Choice • Execution • Control/evaluation	• Network promotion and contract management • Service provisioning • Infrastructure operation
Main interactivity relationship logic	Sequential	Cyclical, spiralling	Simultaneous, parallel
Primary activity interdependence	• Pooled • Sequential	• Pooled • Sequential • Reciprocal	• Pooled • Reciprocal
Key cost drivers	• Scale • Capacity utilization		• Scale • Capacity utilization
Key value drivers		• Reputation	• Scale • Capacity utilization
Business value system structure	• Interlinked chains	• Referred shops	• Layered and interconnected networks

Figure 3. The three generic value configurations[43]

Hence the traditional value chain analysis is transformed into an analysis with its starting point on the value configuration. Dependent on the value creation logic and technology in the analysed firm, one of the three configurations should be applicable to the firm.[44]

[41] Stabell & Fjeldstad (1998), p. 414
[42] Stabell & Fjeldstad (1998), pp. 414-415
[43] Stabell & Fjeldstad (1998), p. 415
[44] Stabell & Fjeldstad (1998), pp. 414-415

3.1.3 The value shop

The value shop relies on intensive technology to solve a customer or client problem. It is the problem needed to be solved that sets the requirement of the activities that needs to be in place to solve the problem. It also sets the order and the combination of the activities. In comparison to the chain which has a fixed setting of activities performed, the shop schedules activities and sets the resources needed purposely and appropriate for the problem faced. The value shop customises its resources and activities dependent on the problem presented and hence the matching between the problem and the problem-solving activities and resources are crucial for the organisation and management. Unlike a value chain, the problem-solving activities like process development are considered primary activities rather than supporting activity. The industries which utilise intensive technology to solve customer needs are professional service firms such as engineering, medicine, law and architecture firms. These firms are most applicable to the value shop configuration.[45]

The value creation logic in a value shop is to develop an existing state to a more desired one. This is done by solving the problem faced during the development. The intensive technology used is hence directed towards the problem and should finally change the state to a more desired one of the object which is of value for the customer or client. The object can be human, such as transforming a sick person to a healthy one, or it can be a site or system, like in the case of the petroleum industry or the architect, where the architect firm changes a site by raising a building.[46]

Usually the problems faced for firms active in a value shop are somewhat standardised, but the value creation process is organised to manage unique cases which require specialist knowledge in many activities in the value shop. The activities in every new case are performed cyclical and iterative rather than linear. During the process new data will appear and confirm, reject or reform the hypothesis and other activities needs to be put in place to solve the problem. The process can also be interruptible and come to a halt if new data makes a problem insolvable or reveals that the problem is already solved or that no problem occurred, such as the case of when a person goes to a doctor and gets the diagnosis that the person is healthy.[47]

The iterative process also implies that the process is sequential and a high degree of interdependence between the activities. To generate a solution to a certain problem it is critical to understand the requisite of the problem. A proper definition of the problem is hence vital for all subsequent activities in order to put a solution in place. To acquire information of the problem, the value shop often uses a standardised procedure to frame the problem correctly.

[45] Stabell & Fjeldstad (1998), pp. 420-421
[46] Stabell & Fjeldstad (1998), pp. 420-421
[47] Stabell & Fjeldstad (1998), p. 422

In a value shop there are five generic primary value shop activities. The category of activity is divided into some distinctive and specific firm activities dependent on the industry the firm is active in. The primary activities are:

- **Problem-finding and acquisition.** Activities associated with recording, reviewing and formulating of the problem to be solved and choosing the overall approach to solving the problem
- **Problem-solving.** Activities associated with generating and evaluating alternative solutions.
- **Choice.** Activities associated with choosing among alternative problem solutions.
- **Execution.** Activities associated with communicating, organising, and implementing the chosen solution.
- **Control and evaluation.** Activities associated with measuring and evaluating to what extent implementation has solved the initial problem statement.

To the primary activities comes supporting activities like human resources management, procurement and technology development which generates little value to the customer but is crucial for the competitive advantage. Figure 4 shows the concept of a generic value shop. [48]

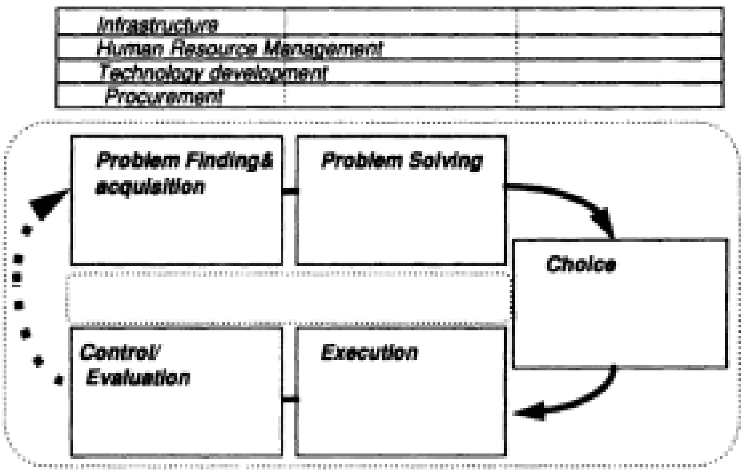

Figure 4. The value shop diagram[49]

3.1.4 The value shop and the upstream petroleum industry

The value shop concept is applicable to the upstream petroleum industry since the petroleum industry utilises intensive technique to solve problems related to exploration and development of oil fields for a customer, the oil company. All fields are unique and in need of a unique concept with different technologies in order to develop the field from a non-producing state to a producing state. At value shops, the technology is directed to bring changes to an object, and in the petroleum industry the object is the oil field site. The advance technology utilised has the ability to change the field to make it profitable, i.e. create value through the commercialisation of the field.[50]

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[48] Stabell & Fjeldstad (1998), p. 422
[49] Stabell & Fjeldstad (1998), p. 424
[50] Stabell & Fjeldstad (1998), pp. 420-421

The upstream offshore industry requires interplay between several specialist firms which all utilise their speciality of intensive technologies. Field development includes activities like exploration, feasibility studies, construction work and many other activities, of which many are performed by different operators and suppliers to the oil company developing the field. The process takes the form of spiralling activity cycles where the previous cycle's problem-solving and hence the solutions chosen sets the requirements for the next cycle. [51]

In the value shop and the petroleum industry, the choice is considered of less importance in terms of effort and time, but has a great impact on the value. Figure 5 relieves the concept of the upstream petroleum industry with the search-active petroleum exploration and the more design-focused field development in the wheel-in-wheel spiralling activity cycle. As can be seen in the figure below, the two cycles differ somewhat in between even if they both belong to the shop concept due to the problem-solving emphasis and the cyclic and iterative process. [52]

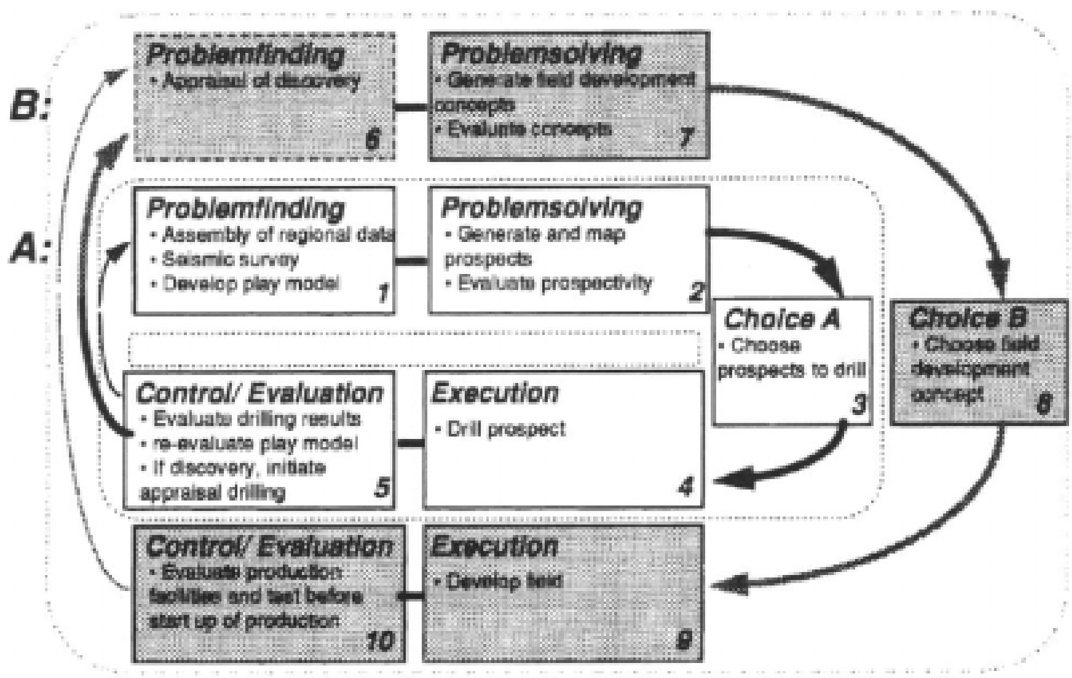

Figure 5. Value shop diagram for a (A) petroleum explorer and (B) a field developer[53]

The petroleum exploration cycle, A, illustrates that the problem-finding activity is divided into more distinct activities aiming to identify an area with potential hydrocarbon findings. The problem-solving activity aims to generate and evaluate the prospects found in the area and hence lays the ground for the choice where a decision of what prospects there are to drill if there are any at all.

[51] Stabell & Fjeldstad (1998), p. 422
[52] Stabell & Fjeldstad (1998), pp. 424-425
[53] Stabell & Fjeldstad (1998), p. 425

The field development cycle, B, has a different focus and different activities under the primary activity categories. The problem-finding activity is much dependent on the data collected from the exploration phase, and focuses on appraisal of the discovery, while the problem-solving uses the appraised data to form a concept for the development.[54]

There are several other factors affecting the cost for the upstream petroleum than the more operational factors described through the value shop. There are also costs associated with royalties, taxes and governmental participation, and this cost varies dependent on the location. [55]

3.2 Investment decision

When making an investment decision there are some certain rules and models that are applicable in order to get a proper view of the investment and to get a fair estimation of the outcome. Given all future revenues and the cost of all activities in a value chain, shop or network it is possible to calculate the value of the investment in today's value in order to compare different alternatives. Actual figures of capital differ in time and an important factor is the present value of the capital invested. Therefore it is important to understand the principles of present value of capital.

3.2.1 Present value

In general, one dollar today is worth more than one dollar in a year. If the dollar is invested the value of the dollar can grow to a bigger amount in a year. The difference of the value of one dollar today and the value in one years time due to investment is called the time value of money. When comparing money today with the money in a certain period of time there is a need to know the interest rate, i.e. the rate of which the money grows. By depositing money into a risk-free account at a certain interest rate, the value of the money grows without the investor taking any risk. This rate is called the risk-free interest rate, r_f, since there is no risk of lending the money to the bank. Hence the exchange of one dollar today is $(1+ r_f)$ dollars in the future, but also $(1+ r_f)$ dollars in the future is one dollar today. To determine the present value, PV, of money flowing in or out, called cash flow, C, in the future one hence need to divide the amount by $(1+ r_f)^n$ to get the amount in today's value where n is the time. Since the interest rate usually is determined on an annual basis, the time is usually in years. [56]

3.2.2 Discount rate

When making an investment the lowest acceptable rate of return is the risk free interest rate which is the interest rate at which capital can be lent or borrowed without any risk over a certain period of time. If the risk-free interest rate is not returned on the investment, the investor benefits more from investing the money in a savings account or in a government bond which is considered risk-free. The premiums investors are paid in terms of rate above risk free rate are due to risk, arbitrage or imperfect markets. For example, if the risk free interest rate is 5% the value of USD 100 today is worth USD 105 in one year time. It is also the opposite way around when analysing future cash flows. USD 105 in one year time is worth USD 100 today. The

[54] Stabell & Fjeldstad (1998), p. 424
[55] Johnston (2003), p. 4
[56] Berk, J. & DeMarzo, P (2007) pp. 51-52

rate demanded from the investment is called the discount rate. Hence the discount rate for a risk-free investment is the risk free interest rate.[57] But there are more factors included. Consider a firm which has received their capital from owners and banks: When the firm makes investments which are not risk-free the owners demand a higher rate of return than the risk-free interest due to the correlation between risk and return. To decide the actual discount rate of an investment the company need to consider the rate of return the investors are expecting due to the risk. The investors are expecting a risk premium above the risk-free interest rate due to the risk of a failure of the investment which would leave them without any return, or less in return, than they invested. Hence, if there is any risk at all, the discount rate will be higher than the risk-free interest rate.[58]

In a perfect market, the discount rate is equal to the weighted average cost of capital (WACC). The WACC reflects the return required from both depth holders, i.e. normally banks, and the equity holders which are the stock holders. The return required by banks might differ some in comparison to the requirements by the stock holders. The WACC also depends upon the ratio between capital from equity and capital from depth. This ratio is called the dept-to-equity ratio. Assume a firm has 40 % bank loan, i.e. depth capital, and 60 % capital from stock investors, i.e. equity capital. This would imply that the WACC would be 0.4 * bank interest rate + 0.6 * the return expected by the stock holders, and hence the depth-to-equity ratio plays an important role due to the difference in expected return from equity holders and depth holders. [59]

3.2.3 Cash flow

In general, cash flow is the difference in cash flowing in and out of a firm, organisation or person. If considering a firm, the inflow is usually the revenue by selling goods or service. The inflow occurs when the customer actually pays for a service or for goods, i.e. giving the firm cash, or transferring money to the firm's account.[60]

The outflow is the opposite of inflow, hence when cash is leaving the firm. The costs are in general of two different kinds, capital costs and operating costs. Capital costs are associated with the equipment needed to produce the product or service, while operating costs are the expenses for consumables, personnel and other expenses to keep the production up.[61]

[57] Berk, J. & DeMarzo, P (2007) p.53
[58] Berk, J. & DeMarzo, P (2007) p.68
[59] Berk, J. & DeMarzo, P (2007) p.259
[60] Berk, J. & DeMarzo, P (2007) p.84
[61] Berk, J. & DeMarzo, P (2007) p.33

3.2.4 Net present value

When making an investment, it is important to know when in time the cash flow occurs in order to move the cash flow in time to the right period. It is also important to know the risk of the project to determine the risk premium and thereby the discount rate. When knowing the actual cost and benefits of the investment and when they occur it is possible to calculate the net present value, NPV, which is defined as follows:

NPV=PV(benefits)-PV(costs)=PV(benefits-costs)=PV(all investment cash flow)

If C_n represents the cash flow the year n, the net present value is calculated as follows:

$$NPV = C_0/(1+r)^0 + C_1/(1+r)^1 + C_2/(1+r)^2 \ldots + C_n/(1+r)^n$$
$$= \sum (C_n/(1+r)^n),$$

with n growing from 0 to n.[62]

In the discount rate the risk is included, and also covers the expectations the company's shareholder has regarding their return, hence the profit made on the investment. This implies that an investment with positive NPV is profitable to realise. If there are several options available with the same discount rate, the investment relieving the greatest NPV is the most profitable project. The NPV decision rule is stated as:

When making an investment decision, take the alternative with the highest NPV. Choosing this alternative is equivalent to receiving its NPV in cash today.[63]

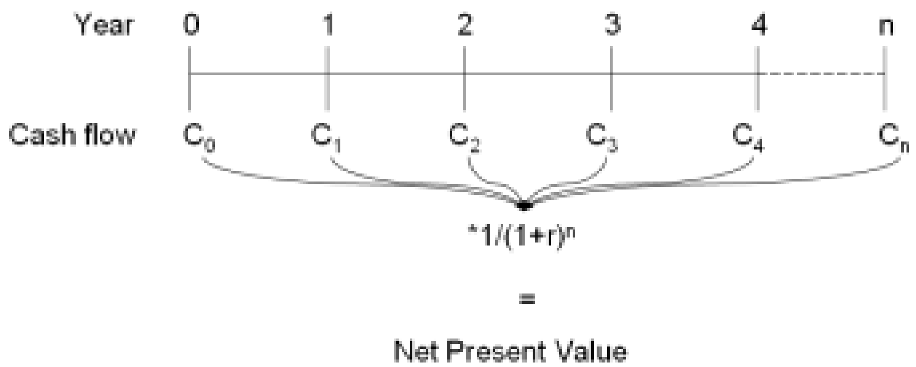

Figure 6. Visualisation of the net present value method

[62] Berk, J. & DeMarzo, P (2007) p.92
[63] Berk, J. & DeMarzo, P (2007) p.55

3.2.5 Project analysis

When making an investment and evaluating its profitability, the firm should maximise the NPV. To calculate the NPV the cash flows and the discount rate needs to be chosen for the project. It is generally difficult to estimate the discount rate and the cash flow, and the factors are usually significantly uncertain. To manage the uncertainty with the factors there are some helpful methods that improve the picture of an investment.[64]

One important tool is the sensitivity analysis which is a method where the NPV is broken down into components and tested individually. By varying the components it is possible to investigate how they affect the NPV and to what extent. By using this method it is also possible to put up a base case, best case and worst case, using the factors uncertainty. Consider that a store should most likely be able to sell 100 units of a product normally. The 100 units would be the base case. In a bad market, the store would only sell 70 units, and in a good 130 units. The 70 and 130 units would then represent the worst case and best case. With the sensitivity analysis it would then be able to calculate the NPV with all these scenarios and see the effect of it.[65]

In reality, a change internally or externally of the firm affects more than just one factor and brings changes to several parameters. By analysing the effect on the NPV by changing several factors is called a scenario analysis. For example, might an increase of price per unit affect the amount of units sold, and a downturn in the market might affect both the sale amount of units sold and cost of capital. Hence the scenario analysis tool gives a good view of how a change, internally or externally, might affect the investment in general.[66]

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[64] Berk, J. & DeMarzo, P (2007) p.196
[65] Berk, J. & DeMarzo, P (2007) p.197
[66] Berk, J. & DeMarzo, P (2007) p.198

4 Gold Digger model

This chapter presents a merger of the two theoretical models presented in chapter 3. The theoretical models will be analysed and modified to better suit the objective of this thesis.

4.1 Introduction to the Gold Digger model

The Gold digger model is built on the value shop model and the net present value model and aims to calculate an entry level oil price.

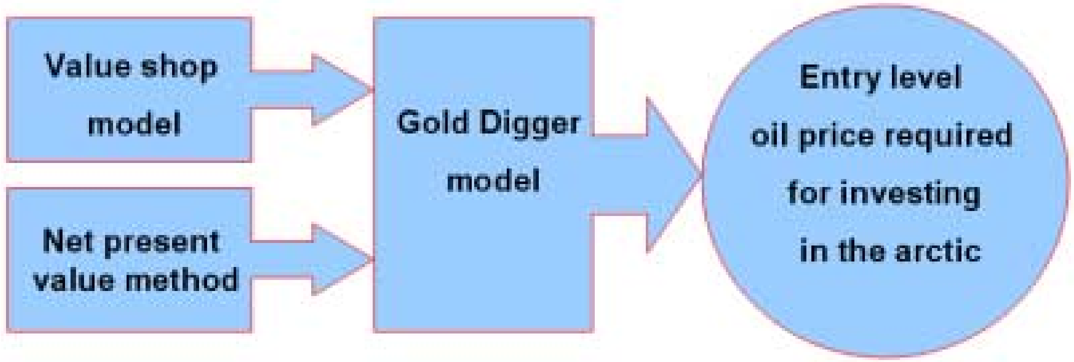

Figure 7. The Gold Digger model is created out of two theoretical models and calculates the entry level of oil price required for investing in the arctic

The Gold Digger model's ultimate area of utilisation is to be a guide for estimating the entry level oil price of oil in a not yet fully explored or developed field and hence, the model is best applicable to a case such as an area available for bidding or recently leased out. The case field is then evaluated by two main steps in the model which are crucial for the estimation.

1. Find the cost drivers for the field and the actual cost for each one of them
2. Discount the cost to present time in order to calculate a entry level oil price per barrel

The first step in the model is based on the model developed by Stabell & Fjeldstad, the value shop concept for the upstream petroleum industry described in the theoretical framework chapter, with a very important distinction - the first step of the Gold Digger model is predictive rather than descriptive. In the value shop model for the upstream petroleum industry, the concept is to describe the activities as they come, but in the Gold Digger model, the concept is to make assumptions of the future activities and technologies to be utilised in order to build a future, non-existing concept of exploration and production. The concept is supposed to reflect the potential of the field and technologies believed to be in place in the future. These technologies, assumed to be used in the exploration phase and the field development phase are the primary cost drivers in the model.

The second part of the model uses the estimated cost for the cost drivers, hence the technologies assumed to be used to explore and develop the field and their operating expenses, and discounts the costs and revenues to present time using a modified net present value model. To get the extraction cost per barrel of oil the net present value is set to zero, and the oil price to the unknown factor. This will bring the minimum oil price required for the oil company to consider the investment as profitable. Figure 8 shows the concept of the model and how the model is employed.

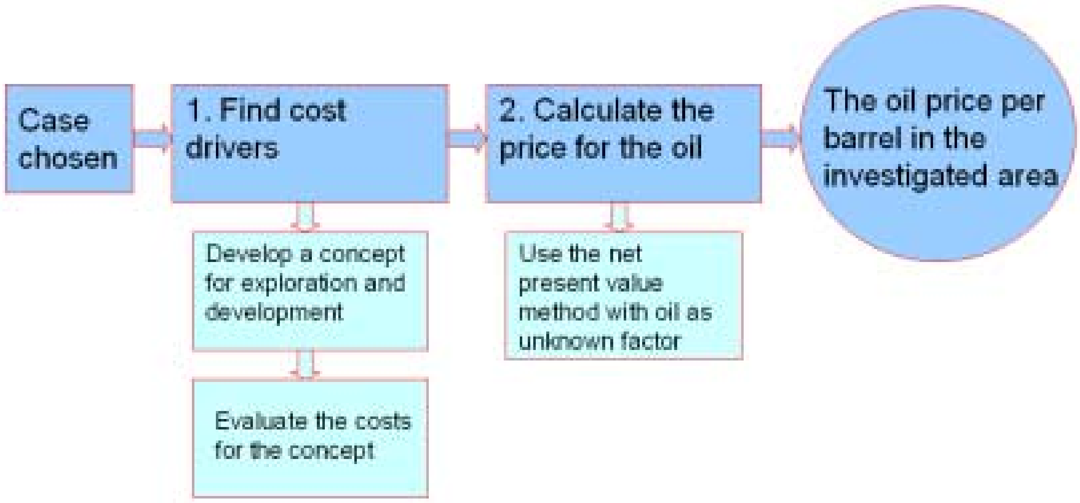

Figure 8. The concept of the Gold Digger model and how it is utilised to calculate the oil price required to enter the arctic

4.1.1 Step 1- Find the cost drivers

The Stabell & Fjeldstads model for a value shop for the petroleum field explorer and developer is partly used to identify the cost drivers for both the petroleum field explorer and field developer. Some parts of the model are well suited for the purpose of building a concept which the technologies used in the value shop of the upstream petroleum industry. While the value shop model for the upstream petroleum industry is used to describe the flow of activities creating value for the industry, the Gold Digger model utilises some parts of the model to find the relevant activities assumed to be realised in a specific case.

The parts utilised from the value shop model are the problem-finding, problem-solving and choice for both the petroleum exploration industry and field development industry. The parts execution and control/evaluation is impossible to apply since the case is of a predictive character and no execution or control/evaluation will occur during the exercise of the model. One step has been added to the model under choice which is cost of choice, this is necessary as the first step of Gold digger aims to quantify the cost of the cost drivers analysed when performing the first two steps of the model. Part from this distinction, all activities performed under the primary activities will be employed in the assumption of the technologies used in the case. This implies that the process will be a wheel-in-wheel process starting with finding the cost drivers for the exploration phase. This cycle ends with finding the costs for the chosen concept. Next the field development cycle starts which also ends with estimating the cost of the chosen concept. Figure 9 is a flowchart of the activities in step 1 of the Gold Digger model.

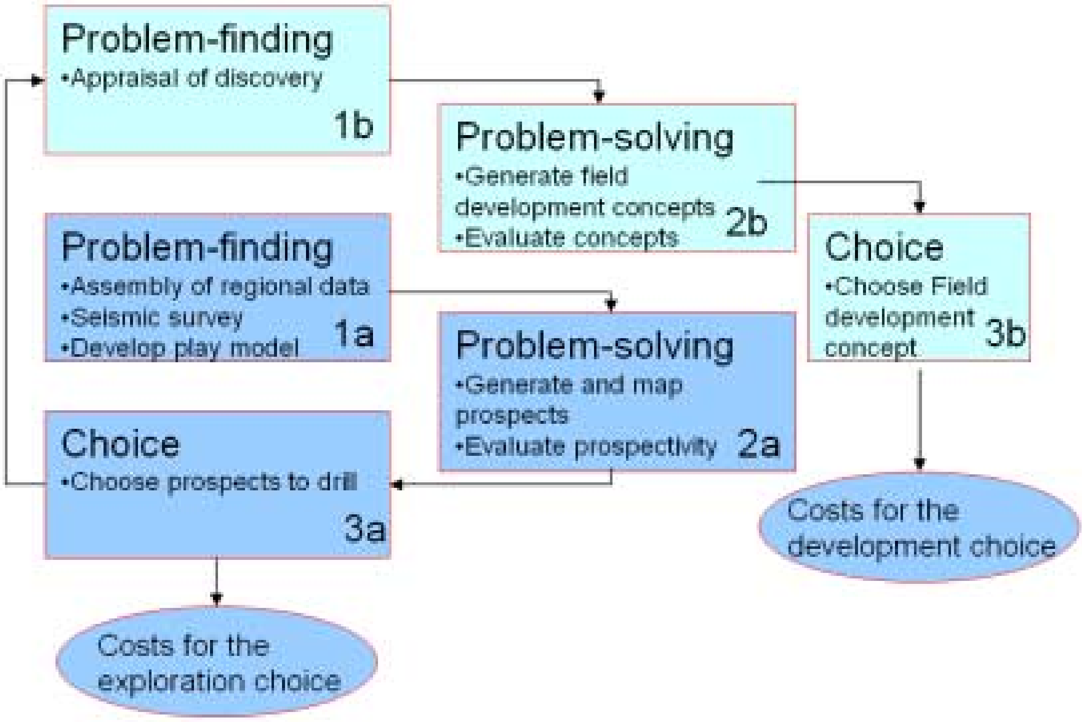

Figure 9. Flowchart of step 1 in the Gold Digger model

All a-boxes represent the offshore petroleum exploration industry while all b-boxes represent the field development industry. Starting with box 1a, the problem finding for the exploration industry sets the prerequisite for box 2a, the problem solving, which eventually leads to a choice in box 3a. The same procedure is utilised in the b-boxes. After every choice, the costs are calculated or estimated with basis of data at hand. These are the costs which are ready to be adapted and worked through in step 2.

Since it is important to know when the costs occur in time, a field profile estimating the length of the field life, production decline rate and the output per year is completed.

4.2 Step 2-Calculate the entry level price of oil

The net present value model is a tool for analysing investment opportunities when both costs and revenues are known, and when it is known when in time they occur, as described in the theoretical framework chapter. The objective with this study is not to answer the question of whether a certain investment is profitable or not, but rather put an estimate on the minimum oil price required to make investments in oil production in the arctic region profitable. For an investment to be attractive the net present value must be above zero, otherwise the investment is unbeneficial for the firm, and the revenues do not cover the cost of debt and equity. The Gold Digger model's step 2 is a modified version of the net present value model with the oil price as the unknown factor instead of the net present value. In the Gold Digger model's step 2 the net present value will hence be set to zero to get the minimum price for the oil, the entry level oil price. All input assumptions to the Gold Digger step 2 are received from the Gold Digger model's step 1– cost estimations for the choices of exploration and development concepts. The discount rate is directly estimated in step 2 but when in time the costs that occur are received from the production profile from step 1.

The Gold Digger model's step 2 is hence structured in revenues, capital costs and operating costs originating from the estimations done in step 1.

In the Gold Digger model the total NPV should be zero and therefore the PV(costs) are equal to the PV(revenues). The revenues are equal to *oil price * volume*.

$$NPV=0=PV(benefits)-PV(costs) \rightarrow PV(costs) = PV(benefits) \rightarrow$$

$$PV(costs) = P*V_0 /(1+ r)^0 + P*V_1 /(1+ r)^1 + P*V_2 /(1+ r)^2 \ldots\ldots + P*V_n /(1+ r)^n$$

with n growing from 0 to n.

n is the number of year the field is active, r is the discount rate, P is the oil price and V the yearly volume of oil produced in the field. Since all factors but the oil price is known and since we have one equation with one unknown factor, the oil price will be calculated by breaking out the oil price P by dividing PV(costs) with PV(volume). We assume a constant oil price to simplify the model.

$$P = PV(costs) / [V_0 /(1+ r)^0 + V_1 /(1+ r)^1 + V_2 /(1+ r)^2 \ldots\ldots + V_n /(1+ r)^n]$$
$$= PV(costs) / PV(Volume)$$

Step 2 hence discounts the costs and the volume to present time and divide them with each other which gives the entry level oil price.

With the formula the oil price is easily calculated with MS Excel, and table 1 shows the concept of the calculation.

Table 1. The concept of the Gold Digger model's step 2 calculation in MS Excel

Year	0	1	2	....	n
Yearly oil production volume (million barrels)					
Discount yearly volumes--> PV(volume)					
Capital costs					
Exploration					
Development					
Distribution					
Operating costs					
Total Yearly Cost					
Discount total yearly costs--> PV(costs)					
PV(cost) / PV(volume) = OIL PRICE					

The last part of the model's step 2 will be to perform a sensitivity analysis and a scenario analysis as they are described in the theoretical framework chapter, but instead of observing a changing NPV, the oil price is the factor that will be set to change. The sensitivity analysis will benefit mostly by revealing which factors make the biggest impact on the oil price, such as the discount rate (WACC), prices on commodities or operational factors and a changing decline rate and production.

It will also benefit through eliminating the uncertainty in the estimations done in step 1 of the Gold digger model. The estimations of the costs will be done with present and historical data and the exact development of the prices due to market changes or other factors are impossible to predict.

The sensitivity analysis will be done by changing the major factors by adding and deducting value from them individually and calculating the new oil price that the changes in the factors bring. It will then be visualised in a diagram showing the factors span versus the oil price span.

The scenario analysis has a similar setup. A description of why the scenario might occur, which factors it might change and to what extent the factors are changed will be performed. The oil span will be presented in tables.

5 Canadian Beaufort Case Study

This chapter presents the empirical data of the offshore exploration and development industry. It uses the step 1 of the Gold Digger model to analyse the empirical data to generate and evaluate the cost drivers for the EL449 field. The analysis generates a choice suitable for the EL449 field and the costs associated with the choice.

5.1 Case background

On the 2nd of June 2008 one of the super major oil companies British Petroleum (BP) made a commitment to spend approximately USD 1.2 billion in the EL449 field in the Canadian Beaufort Sea and thereby won the licence to explore, develop and produce it. This is the highest bid ever made in the region. Just a year earlier Exxon Mobile made a bid of USD 585 Million in the region for the block just next to BP's, which is the next highest bid in the area.[67] If BP decides not to do any investments in the field during the next years a penalty fee of 25% of the commitment has to be paid to the Canadian government.[68]

The field, EL449, is located approximately 140 km offshore in the Beaufort Sea from the nearest coastline of Canada. See figure 10 for the licensed areas in the Beaufort Sea. The total size of block EL449 is circa 2024 km^2 and lies next to two other BP blocks considered not to have the same resource potential since the winning bid was much lower, USD 15 and USD 1 million respectively.[69]

2D-seismic had previous been performed by a company called GX Technologies. This geological survey was probably a part of the decision base for the choice to invest in the licence. The high commitment reflects the high level of oil price at the time and the speculation in a potentially very large oil field. Altogether this implies that the companies believe the area has great potential for future oil or gas production.[70]

After an interview with Mark Stanley at BP, a future exploration, production and distribution case was taking shape. The fact that the field is likely to be explored and due to the high bid reflecting the high potential of reserves in the block makes it interesting to use this licence area as a base for a case when assessing the economics in offshore arctic oil fields. The sea depth is challenging since the major part of the field is greater than 140 meters which makes it appealing from an unexplored frontier point of view.

[67] Shepherd, R. (03/02/2009)
[68] Ramsey-Lewis, K. (05/03/2009)
[69] Indian and Northern Canada Affairs (05/03/2009), http://www.ainc-inac.gc.ca/nth/og/le/mp/bsmd/bsmdwinbid2008pg.pdf
[70] Stanley, M. (09/03/2009)

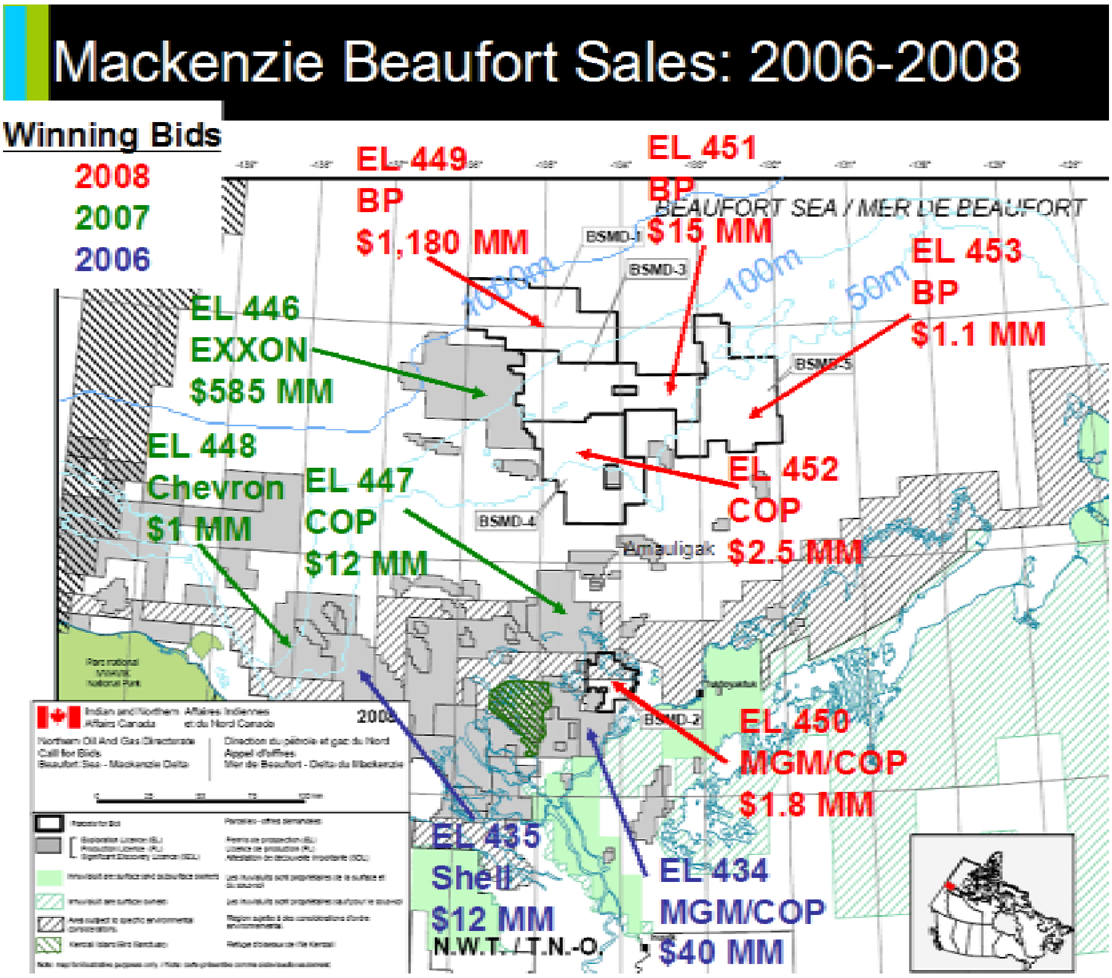

Figure 10. Licensed areas in the Beaufort Sea[71]

5.2 Problem Finding - Exploration

Exploration for oil is the process of detecting and determining the potential and productivity of an oilfield in order to lay the ground for rational investment decisions. The exploration process consists of geological seismic studies and drilling of exploration wells. The cost of exploration gradually increases as it proceeds and can be terminated at certain milestones and be viewed as a sunk cost. The first step of exploration is generally the seismic studies. The goal of a seismic study is to obtain definitive geological data and assess the geological structure for potential to find a reliable and economic recoverable pool of resource.[72] This activity can last from weeks to several months.[73] Drilling is the final stage of the exploration process.[74]

The problem finding process aims to analyse the regional data, the seismic survey and to develop a play model in order to plan and execute the exploration drilling. The regional data consists of an analysis of the potential in the region and the potential resources in the region. Since the arctic in itself is an environment of extreme

[71] Indian and Northern Canada Affairs (05/03/2009), http://www.ainc-inac.gc.ca/nth/og/le/mp/bsmd/bsmdwinbid2008pg.pdf
[72] Babusiaux et al. (2007) p. 77
[73] Frederking (1984), p. 393
[74] Babusiaux et al. (2007) p. 77

character it is of even greater importance to understand the fundamentals of the climate and the complications that follow.

5.2.1 Assembly of Regional data

Oil Potential

The total potential for the Canadian Beaufort Sea is 7 billion barrels of recoverable oil.[75] This study researches block EL449 straddling the Kopanoar and Deep Marine plays which both show great potential for undiscovered oil, see figure 11.

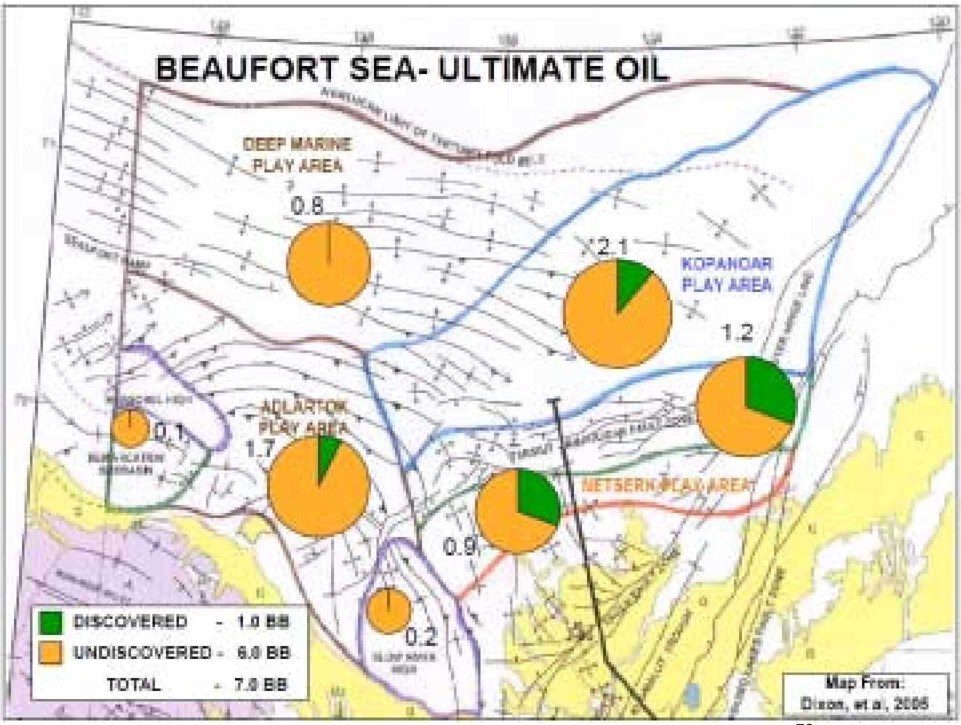

Figure 11. Recoverable Oil in the Canadian Beaufort Sea[76]

The Kopanor area is believed to have approximately 2.1 billion barrels of oil and only a small fraction of it is discovered. The Deep Marine play area is totally undiscovered and believed to consist of 0.8 billion barrels of oil.[77] The estimations are recoverable oil and reached by investigating geological foundations in the different areas. When knowing the geology, geologists look at other areas which have the same characteristics and where oil has been found earlier. If the data shows that the geology has characteristics as other areas where hydrocarbons have been formed it is likely is has in the area surveyed too. An estimation of the composition of the hydrocarbons has to be done, i.e. if it is oil or gas. The recovery factor also has to be estimated in order to decide the amount of recoverable resources. This is done by investigating other fields developed in the past with similar geology and economics. [78]

[75] Drummond (2008), p. 27
[76] Drummond (2008), p. 27
[77] Drummond (2008), p. 27
[78] Shepherd, R. (10/03/2009)

Sea Depths
The sea depth in block EL449 is varying as can be seen in figure 12. The south-east corner is the shallowest with less than 100 metres and even down to approximately 75 metres, while the deepest parts are in the north-west corner with sea depths over 1000 metres.[79]

Figure 12. The depth of the EL449 field

Environmental complications
The arctic is a relatively unexplored frontier as mentioned earlier. This is due to the extreme conditions that make it complicated to operate in the area. The arctic is a big geographical area with differing environment conditions depending on location and which time of the year it is. When operating in the arctic the major factor affecting the operation is ice conditions but also low temperatures, long periods of darkness and isolation are factors of importance.[80] The analysis of ice conditions, temperatures and daylight are critical when evaluating different exploration and production scenarios for block EL 449. Therefore the environment in the Canadian Beaufort is described below.

Ice conditions
The analysis of ice conditions is critical when evaluating different exploration and production scenarios. The ice type and the ice dynamics are the fundamentals for such analysis. In the arctic sea, the majority of the ice is formed by the freezing of sea water. The sea ice is classified according to age in first year ice and multiyear ice. The second type of ice is glacial ice that is created from ice break-up on glaciers. This type of ice usually occurs in the form of icebergs or more rarely as ice islands.

Sea ice is hence formed by the cooling and freezing of the ocean.[81] *First year ice* is formed the present season. The salinity of first year sea ice is 5% and the salt content influences the strength of the ice.[82] The characteristic of this ice is that it is less stiff than multiyear ice and is easier to break with ice breakers or other vessels. The thickness is usually no more than 2 metres. First year ice is present in the Canadian Beaufort Sea during the winter and parts of the summer. Normally the sea opens up in June or July and first year ice starts to form in September or October.[83]

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[79] Lowings, M. (29/01/2009)
[80] Frederking (1984), p. 393
[81] Frederking (1984), p. 393
[82] Frederking (1984), p. 393
[83] Lowings, M (29/01/2009)

So called pressure ridges can form when ice sheets collide and erode against each other.[84] [85] The erosions occur due to wind or currents.[86] Those pressure ridges can become much thicker than the sheet it is made from and may cause problems for a vessel trying to pass it.[87] [88] In some areas it is believed that the pressure ridges can reach down to the seafloor in areas with a sea depth up to 50 metres.[89] See figure 13.

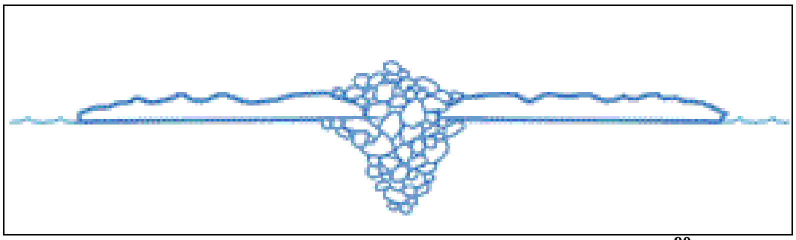

Figure 13. A conceptual picture of pressure ridges[90]

Sea ice or first year ice that survives one or more melting season is termed *multiyear ice*. The melt water during the melt season flushes much of the brine out of the ice which results in a lower salinity content of approximately 1%-3%. This makes multiyear ice very stiff compared to first year ice and therefore a greater problem for vessels operating in the ice.[91] It can also become very thick, especially during the winter time. In areas like in the Beaufort the multiyear ice thickness ranging from 3 metres and upward, and up to ten meters has been recorded.[92] [93] Multiyear ridges have been recorded as big as 11 meters high and 31 meters deep.[94]

Icebergs are usually compact glacial ice and can be of many different sizes and shapes. They originate from a glacier or an ice shelf where a perennial snow field exists.[95] Only about ten percent of the iceberg is visible above the sea level. See figure 14 for the iceberg routes in the arctic.

[84] Lowings, M (29/01/2009)
[85] Liljeström, G. (25/02/2009)
[86] Frederking (1984), p. 389
[87] Lowings, M (29/01/2009)
[88] Liljeström, G. (25/02/2009)
[89] Paulin (2008), p. 155
[90] Environment Canada Greenlane (15/03/2009),
http://ice-glaces.ec.gc.ca/App/WsvPageDsp.cfm?ID=10164&LnId=7&Lang=eng
[91] National Snow and Ice Data Center (15/03/2009),
http://nsidc.org/seaice/characteristics/multiyear.html
[92] Paulin (2008), p. 155
[93] Frederking (1984), p. 389
[94] Frederking (1984), p. 390
[95] Frederking (1984), p. 390

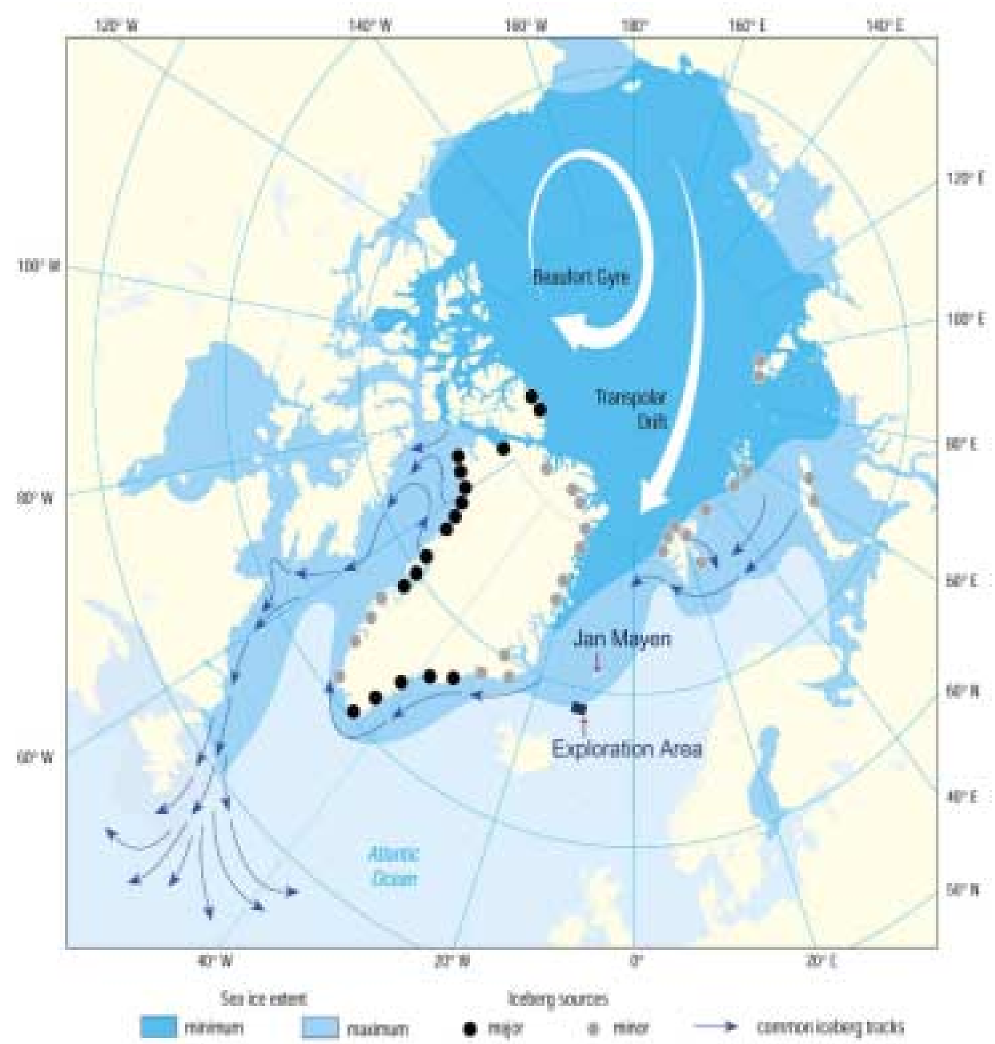

Figure 14. The origin of icebergs and their routes[96]

In the Canadian Beaufort Sea pack ice is rotating clock-wise in the Beaufort Gyre. This moves on and off the shelf during the summer and winter and consists of multiyear ice floes, pressure ridges and smaller floes of second year ice. The speed of ice floes varies from 0.06 m/s nearshore and 0.08 m/s offshore. Glacial ice in the form of ice shelf or ice island fragments is possible in the Canadian Beaufort Sea, but very rare.[97]

[96] Lowings (2008), p. 12
[97] Lowings, M. (29/01/2009)

Table 2. A summary of the ice occurring in the Beaufort Sea

Sea Ice	Parameter	Average annual value	Range in annual values
Occurrence	First ice	September	
	Last ice	August	
Ridges (first year)	Sail height	5m	3-6m
	Keel depth	25m	15-28m
Multiyear ice	Floe thickness	5m	0-10m
Ice movement	Speed nearshore	0.06m/s	
	Speed offshore	0.08m/s	

The ice conditions in the arctic are becoming milder due to changes in climate [98] as can be seen in figure 15. The figure shows a comparison of the ice sheet in the northern hemisphere on the 1st of September 1979 and the same date in 2007. This implies a longer ice free season in the Canadian Beaufort as well as less multiyear ice floes.[99] The open water season is approximately 90 days.[100]

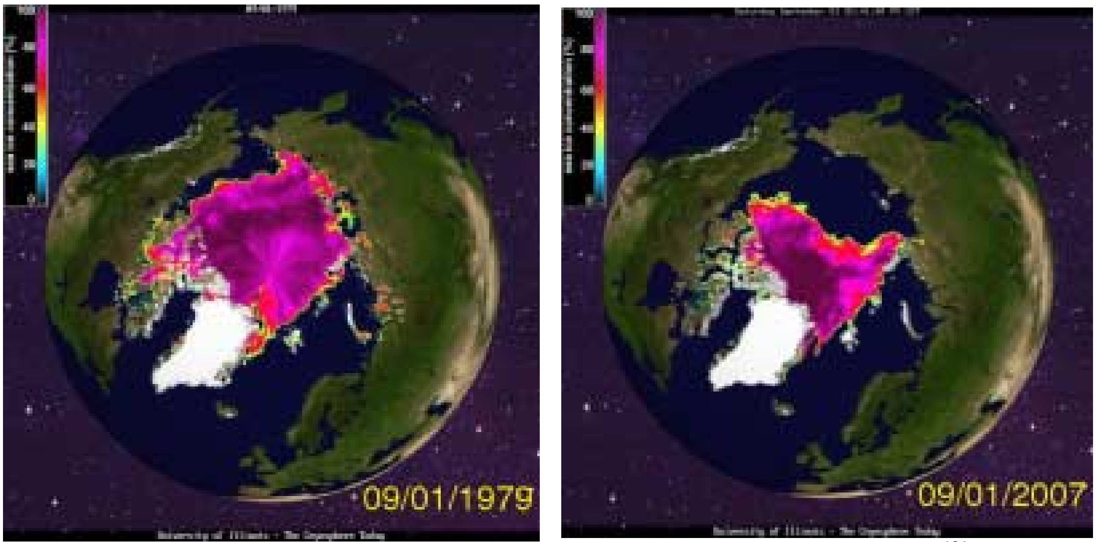

Figure 15. Ice concentration 1 September 1979 and 1 September 2007 [101]

Temperature

The temperature in the arctic is another important factor affecting the operations in the area. In figure 16 mean daily temperatures are presented between January 1 2000 and October 1 2006. Data is collected at Alert, Nunavut station at 82 degrees longitude in the Canadian Beaufort Sea by National Climate Data and Information Archive. The figure shows high temperatures of slightly over 13 degrees and low temperatures of -45.5 degrees. Linear regression analysis shows that the trend is warmer temperatures. These extreme temperatures have to be taken into consideration when designing structures for exploration and development.

[98] Lowings, M. (29/01/2009)
[99] Lowings, M. (29/01/2009)
[100] Stanley, M. (09/03/2009)
[101] The Cryosphere Today (10/03/2009), http://arctic.atmos.uiuc.edu/cryosphere/archive.html

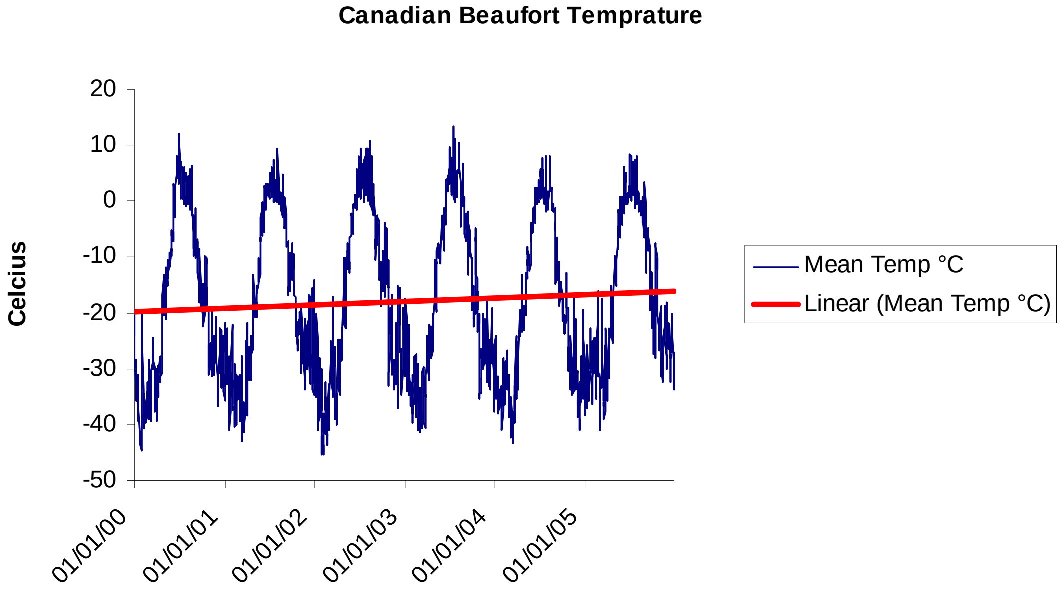

Figure 16: Mean daily temperature at Alert from 2000 to 2006[102]

Daylight

The last major factor is the daylight. The further north one travels the longer the nights are in the summer and the shorter the days are in the winter. The sun does not rise above the horizon for more than four months during the winter season in the Canadian Beaufort Sea. On the other hand the sun provides 24 hours of daylight during the summer months.[103] This is illustrated in figure 17.

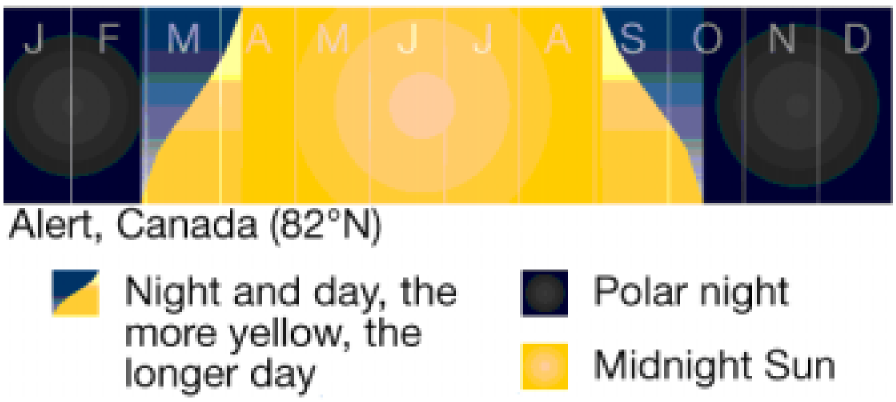

Figure 17: Daylight in Alert, Canada, next to the Beaufort Sea.[104]

[102] National Climate Data and Information Centre (12/03/2009), http://www.climate.weatheroffice.ec.gc.ca/climateData/hourlydata_e.html?timeframe=1&Prov=NU&StationID=1731&Year=2009&Month=3&Day=22

[103] National Climate Data and Information Centre (12/03/2009), http://www.climate.weatheroffice.ec.gc.ca/climateData/hourlydata_e.html?timeframe=1&Prov=NU&StationID=1731&Year=2009&Month=3&Day=22

[104] UNEP/GRID-Arendal (12/03/2009), http://maps.grida.no/go/graphic/extreme-days-and-nights-daylight-variation-in-the-arctic-reykjavik-murmansk-and-alert

5.2.1.1 Summary regional data

Table 3. A summary of the regional data

Oil Potential	• Kopanoar – 2.1 MBO recoverable • Deep marine play – 0.8 MBO recoverable
ICE	The first ice starts forming in September and Last ice is averagely recorded in August. In the area both first year ice and multiyear ice is occurring as well as ice ridges. Generally experts believe that the open water season is generally 90 days.
Temperature	The temperature varies from minus -45.5 to 13 Celsius. The trend is towards a warmer climate.
Daylight	• Summer – 24 hours of daylight • Winter – 0 hours of daylight

The potential of 0.8 to 2.1 MBO of recoverable oil is considered to be large and motivates further survey. This is proven by BP intentions to conduct 3D seismic in the summer of 2009.[105] The extreme conditions discussed will make the exploration and development concepts more complicated than in other places since the structures and concepts must be capable of coping with the extreme environments.

5.2.2 Seismic Survey - Canadian Beaufort Sea

Oil and gas is found in sedimentary basins. Therefore the exploration is targeting to analyse the structures in order to evaluate the potential sedimentary basins.[106] One method to do so is the reflection seismology, seismic. It is based on waves sent through the ground caused by explosions or heavy mass falling on the ground. The vibrations created by these actions are travelling in all directions when they meet geological layers. Some of these waves are reflected and travel back to the surface while others manage to continue without being reflected. The seismic survey company places sensitive receptors that record the waves that are reflected back to the surface. The first waves to arrive are the ones that have been reflected first, and then the ones reflected in the next geological layer are recorded and so on. The elapsed time between the waves is sent out from the transmitter to it hits the receiver is measured and thereby can be determined at what depth certain geological structures occur. By changing the position of the receivers and transmitters the geologists can build up a two dimensional picture of the subsurface geology. For seismic exploration offshore, the transceivers are pulled behind a ship.[107] The vessel is towing air guns and steamers that contain receivers or hydrophones a few meters below the water surface. The airguns send waves periodically that are reflected back to the steamer.[108] When conducting 3 dimensional studies of the underneath structures the transceivers are placed in layers in order to construct an image of the substratum in volume.

[105] Stanley, M. (09/03/2009)
[106] Theodoropoulos (2008), p.80
[107] Theodoropoulos (2008), pp.82-83
[108] Schlumberger website (14/03/2009),
http://www.glossary.oilfield.slb.com/DisplayImage.cfm?ID=213

Most often, simple 2-dimensional technology is used in the first phase to make analysis that will support further investment decisions. For EL 449 a two dimensional seismic has already been shot. The traditional 2-D seismic survey is often conducted regionally or over a large sparsely sampled area.[109] The next step is often to shoot 3 dimensional seismic. The 3-D seismic studies are often being concentrated to much smaller areas. 3-D seismic can provide even better analysis for making further investment decisions and if 3-D seismic shows good results, a decision is often made to continue with exploration drilling which is often the last activity of exploration.[110]

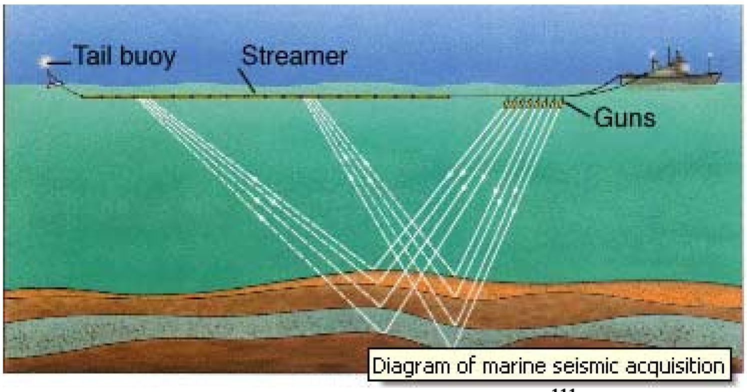

Figure 18. The concept of seismic[111]

Due to the extreme conditions in the arctic, marine offshore seismic is complicated. The steamers are sensitive to ice and can only operate in open water conditions, which is normally only 90 days if no ice pack floes are disturbing the operations. The likely scenario when shooting seismic in the Canadian Beaufort would be to prepare a fleet of seismic vessels and icebreakers to enter and wait for the open water to come. The entering will probably be through Bering Strait since this gateway to the Canadian Beaufort Sea opens from ice earlier than the North West passage.[112] If not all information about the formation is gathered a second attempt will probably have to be performed. If no information is gathered at all, it will be necessary to perform new attempts during a second season. It is a 25% probability that seismic gives all data needed in one season, and 75% risk that they need another season to gather the data.[113]

[109] Paulin (1997), p. 7
[110] Stanley, M. (09/03/2009)
[111] Schlumberger website (14/03/2009), http://www.glossary.oilfield.slb.com/DisplayImage.cfm?ID=213
[112] Stanley, M. (09/03/2009)
[113] Stanley, M. (09/03/2009)

5.2.3 Cost; Seismic in the Canadian Beaufort Sea

Since 2-D seismic already has been acquired in EL 449, it can be viewed as sunk cost and we will therefore neglect this cost. Before drilling commences it is necessary to invest in a 3-D seismic survey to increase the success rate for exploration drilling. We assume that 3-D seismic will be performed during the summer season of 2009. The estimate case is to go there and wait for the ice to disappear from the area. The chances of a successful seismic depend on the ice conditions. The probability chart can be seen in Table 4. The cost for one season is estimated to be USD 50 million[114] while the total cost statistically is 25%*$50+75%*$100 = USD 85.7 million.

5.2.4 Develop play model

Once the Seismic has been shot a crucial step in the exploration process is the evaluation of the data. If data from the 3-D seismic survey shows good structures for oil, the next step is to commence a drilling program in order to be gain further information about the formations. We assume that good structures for oil are found and that the 3-D seismic shows five structures that are to be exploration drilled, see figure 19. The five pools is a fair assumption considering the size of the block.[115] Each structure will be drilled with two exploration wells which will together add up to ten exploration wells which will be tested. Two exploration wells per structure was chosen as an assumption since there is a fifty percent probability of striking oil when 3-D seismic has been shot.[116]

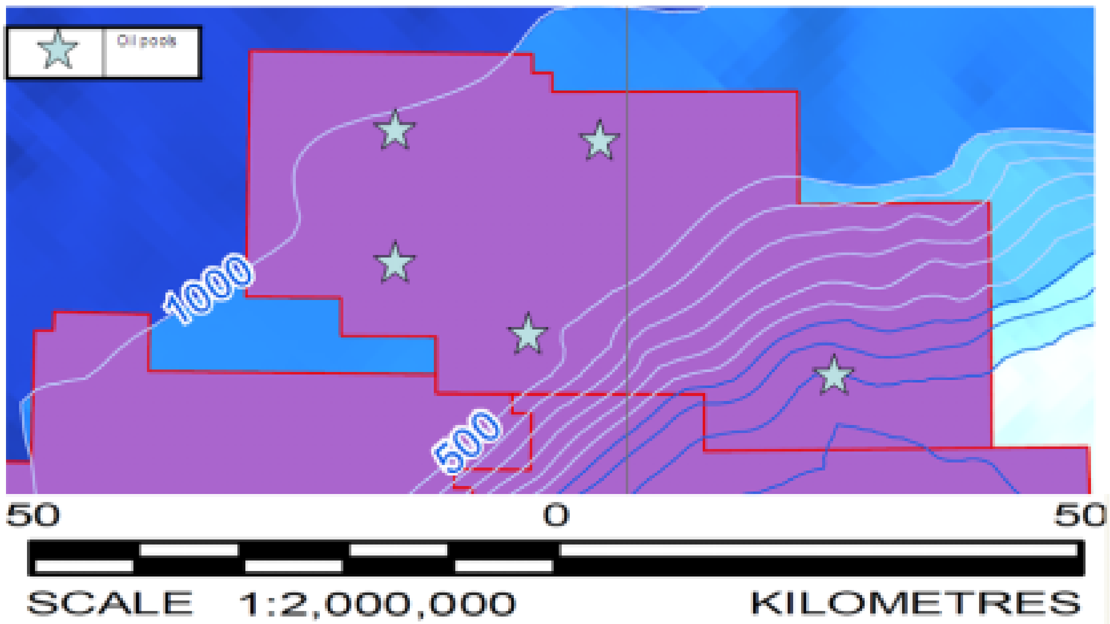

Figure 19. Assumed structures for Cases EL 449

[114] Stanley, M. (09/03/2009)
[115] Shepherd, R. (10/03/2009)
[116] Shepherd, R. (10/03/2009)

5.3 Problem solving – Exploration

Problem solving aims to find means to answer the problems that were found in the problem finding. These basic problems to solve are how to drill the prospects in the complicated environment that the Canadian Beaufort offers. Therefore a presentation of drilling technologies applicable in the case area is presented below. Also an evaluation of these technologies has been made, which will provide an analysis for the choice of technology and thereby the cost.

5.3.1 Concept generation - drilling

Drilling aims to give information about the target formation by penetrating up to ten kilometres below the surface or seabed. Drilling in the Canadian Beaufort Sea is special due to the ice conditions and extreme temperatures. Depending on which structure is used for drilling, the length of the season is longer or shorter. Using a highly flexible structure generally shortens the season and by using a more stable fixed structure one could operate all year around. The dilemma for drilling is that the units are generally wanted to be re-usable or expendable which makes the design difficult. The flexible and floating units existing today cannot operate all year in a climate prevailing in the Beaufort Sea. However, generally there are three main categories of systems suited for those projects; artificial islands, Gravity based structures (GBS) and floating structures. [117] The structures presented below are possible options for exploration drilling.

5.3.1.1Artificial Islands

Artificial islands was the first platforms used in the Beaufort in the 1960's and 1970's when arctic exploration for oil and gas begun. Primarily gravel islands were used.[118] The gravel islands have also been used as production structures.[119] The constructions of the islands have been made during the winter by offloading granular over the ice or during the arctic summer months by dredging. The materials used for these constructions range between gravel, sand, silt or mixtures. Slope protection has been made out of, poly-filter cloth and sandbags, concrete units, rock fill and sacrificial beaches. The design has to take the working area needed, ice action, wave action and geo technicalities into account. The advantages of these structures are year around drilling and the major disadvantage is the limitation of depth. The deepest granular island was Issugnak 0-61 in 19 meters depth which took three seasons to complete and required 5 million cubic meters of fill.[120] The other form of artificial island is the grounded artificial ice island. Grounded ice islands are constructed by artificial ice built up on top of the natural ice in order to increase the ice sheet thickness until the ice grounds the sea bed. The contact with the seabed eliminates the movement of the structure; any movement will damage the drill string. The oil company Amoco oil built the artificial ice island Mars. The island was completely made out of spray ice at 7.6m water depth. The platform was 330 meters in diameter, required 1 million cubic meter of pumped water and a 45 days construction program.[121]

[117] Frederking (1984), p. 390
[118] Paulin (2008), p. 118
[119] Paulin (2008), p. 118
[120] Paulin (2008), p. 130
[121] Paulin (2008), p. 122

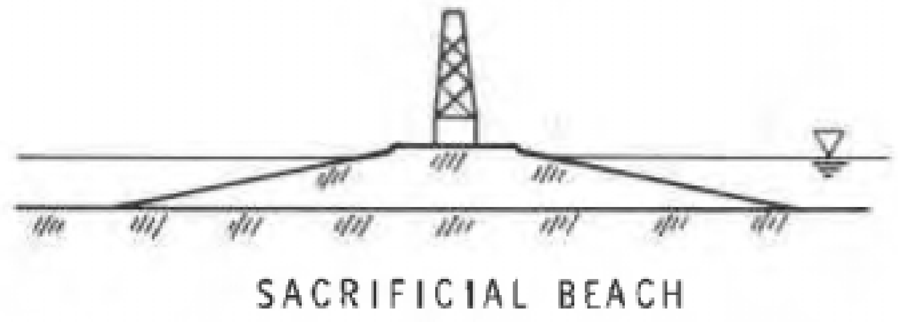

Figure 20. The concept of a sacrificial beach.[122]

5.3.1.2 Gravity Based Structures

There are several gravity based structures (GBS), also called bottom founded structures, available for exploration in the arctic. The GBS structures can have different shapes; it can be cylindrical, conical or caisson, see figure 21. The idea of the GBS was to be able to reach further depths than were possible from the artificial island. These gravity based structures were constructed by building an underwater caisson that was then filled with dredged materials. This technology allowed good stability with less material fill than artificial islands. These structures were not truly mobile as the structure had to be adjusted for different depths.[123]

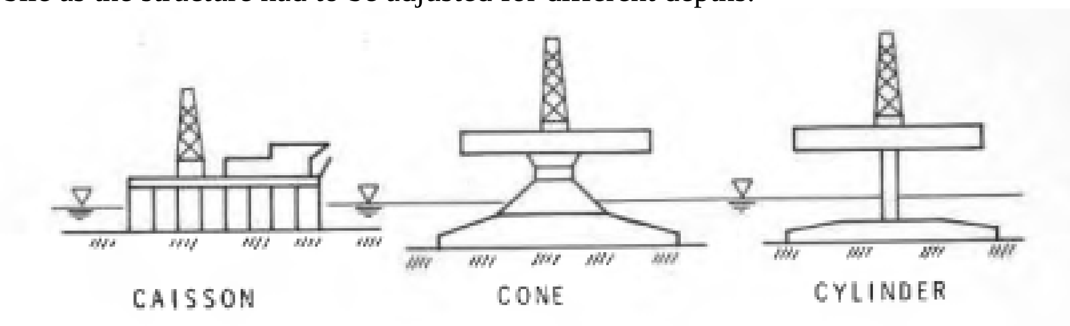

Figure 21. The concept of gravity based structures.[124]

The cylindrical type of GBS was firstly studied by the oil company Esso to operate in a water depth of up to 20 meters. It was a 24 meter long structure with a cylinder of 9 meters and 97.5 meter diameter base. It was planned to operate all year around and constructed of steel. The structure was capable of coping with ice loads of 135 MN which is equivalent of a 14 meter first year pressure ridge. The structure was designed in a way that allowed it to disconnect and slide if it would fail to resist the ice load. This included ice monitoring and blow out preventions to permit safe abandonment. The structure was never built.[125]

The conical type is a variation of the cylinder proposed by Esso. The structure was to be operating in depths between 10 and 41 meters and had a 45 degree conical collar to make the ice bend. The structure was 43 meters in height and had a base of 107 meter in diameter. Both the collar and base were ballasted with water. The cone position

[122] Frederking (1984), p. 394
[123] Paulin (2008), p. 110
[124] Frederking (1984), p. 394
[125] Frederking (1984), p. 395

could be manipulated by 13 meters in order to be able to break ice both downwards and upwards. The structure was designed for a maximum of a 125 MN ice load which is equivalent of approximately 14 meter pressure ridge. The structure was never built.[126] Another structure was also designed by the oil company Gulf that had a mixed design between cone and cylinder which allowed water depths between 20 and 50 meters. It was designed to sustain first year ice, ridges and multiyear ice flows. It was never built.[127]

The caisson structure has been developed by the oil company Dome petroleum. A former tanker was used to build a barge which was 162 metres long and 53 metres wide and had a strengthened hull to be able to cope with ice pressures.. It was operating in 25 meters of water.[128]

One of the most recent is the caisson GBS which is still in operation is the Molikpaq. The Molikpaq was designed for arctic use in Canadian waters and has later been modified for use in Sakhalin oil fields outside Russia.[129] The core of the structure was filled with sand surrounded by a steel structure. The structure had outside dimensions of 110 meters on the sea bed and 86 metres at the deck. The height of the Molikpaq is 33.5 meters and the depth employed is approximately 20 meters.[130]

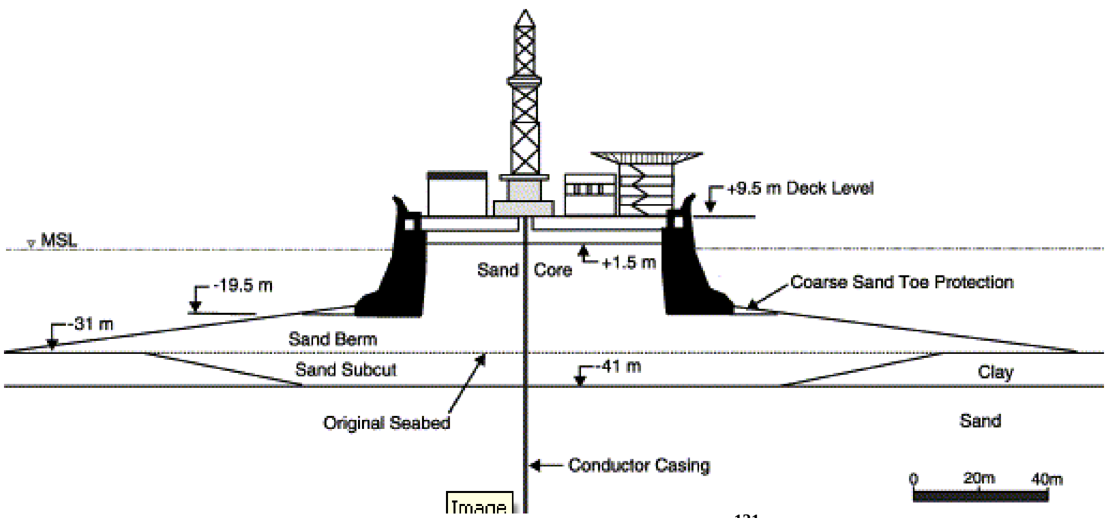

Figure 22. The concept of Molipaq[131]

[126] Frederking (1984), p. 396
[127] Frederking (1984), p. 397
[128] Frederking (1984), p. 398
[129] Sakhalin Energy (20/03/2009), http://www.sakhalinenergy.com/en/project.asp?p=paa_platform
[130] ScienceDirect (20/03/2009), http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6V86-48BTY91-1&_user=745831&_rdoc=1&_fmt=&_orig=search&_sort=d&view=c&_acct=C000041498&_version=1&_urlVersion=0&_userid=745831&md5=55b92ad7ab93d74811f1f896c948a490#bbib2
[131] ScienceDirect (20/03/2009), http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6V86-48BTY91-1&_user=745831&_rdoc=1&_fmt=&_orig=search&_sort=d&view=c&_acct=C000041498&_version=1&_urlVersion=0&_userid=745831&md5=55b92ad7ab93d74811f1f896c948a490#bbib2

5.3.1.3Floating structures

There are several existing floating structures, both moored and dynamically positioned. Dynamically positioned floating structures are better suited for larger sea depths. Moored structures are better suited for shallower waters and can tolerate greater ice pressures. It is dependent on ice conditions and sea depth when choosing which system to use. At first drilling operations in the Canadian Beaufort Sea were performed during the summer and early fall seasons by moored drill ships. Later operations developed capabilities to maintain position in different ice pack conditions thanks to improved ice management, this extended the season beyond the open water season. The technologies for floating structures are presented below.

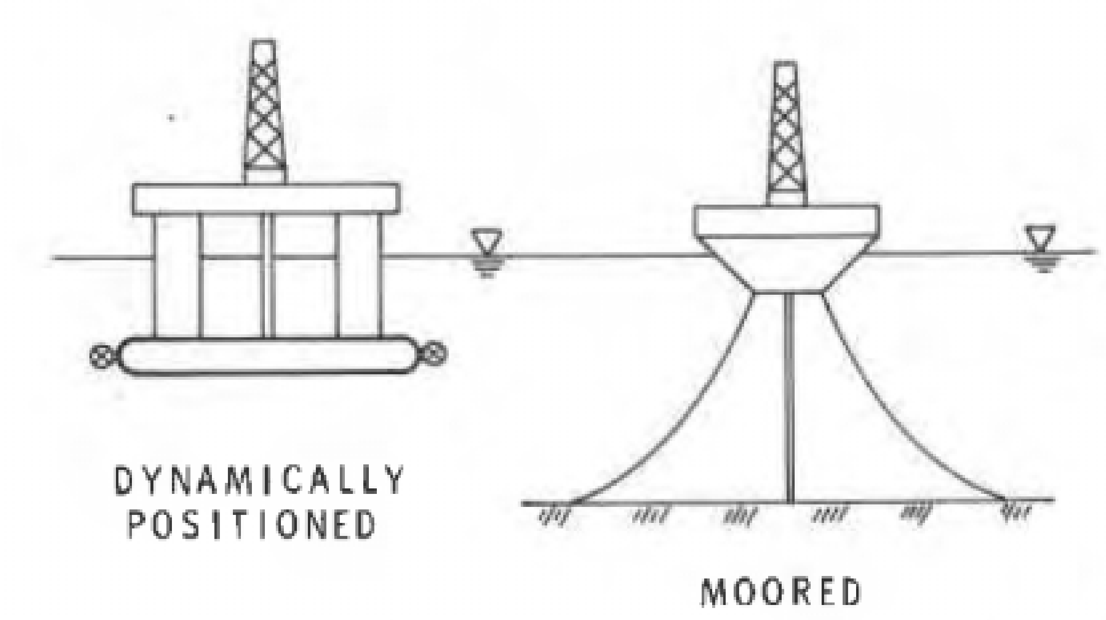

Figure 23. The concept of floating structures for exploration drilling[132]

Dome Petroleum brought in a total of four ice strengthened drillships. These operations were at first only allowed to operate during the summer but as ice management was improved the ships stayed until November.[133] The drillship Explorer III was an eight point wire moored Donheiser Marine, Super Class 1AA, designed to resist loads up to 5794 tonnes.[134] The drillships were supported by icebreakers; these would break oncoming ice and thereby reduce size and pressure of the ice flowing toward the ships.[135]

[132] Frederking (1984), p. 394
[133] Frederking (1984), p. 400
[134] Paulin (2008), p. 134
[135] Timco & Frederking (2009), p. 22

Figure 24. The Dome petroleum's Explorer III[136]

The Kulluk is a moored floating exploration structure that was designed in order to extend the drilling season, and allowed drilling operations to begin in the spring and continue until the early winter months. The Kulluk therefore operated in a harsher environment and more difficult ice conditions than the drillships. The Kulluk was designed by Gulf.[137] It is a conical drilling unit in order to minimise the icebreaking forces of different directions.[138] It is designed to operate in depths of 24 – 55 meters. The shape is an inverted cone with a 30 degree slope and an outer diameter of 81 metres. The structure is moored by twelve mooring lines that can sustain a pressure of 1.2 meters of ice. During operations the Kulluk is assisted with two to four icebreakers of CAC2 class during operations when heavy ice-packs were present (CAC2 being the Canadian Ice Class needed to be allowed to pass North West passage[139]) and two supply ships.[140] Occasionally the vessel operated in unbroken ice, though normally there was ice management present.[141] The Kulluk had a maximum length season of 160 days.[142]

[136] Paulin (2008), p. 134
[137] Frederking (1984), p. 401
[138] PAULIN (2008), p. 135
[139] Karlqvist (2006), p. 86
[140] Frederking (1984), p. 401
[141] Paulin (2008), p. 134
[142] Childs (2007), p. 1

Figure 25. The Kulluk being transferred through ice[143]

The latest up to date technology in arctic drillship technology is the Stena DrillMAX Ice that will be completed in 2011. This will, according to Stena Drilling Limited, be the first ultra deepwater drillship for arctic conditions in the world with dynamic positioning. Dynamic positioning means that no anchors are needed as thrusters under the ship holds it in position over the well. The drillship is under construction for Stena Drilling Limited by Samsung Heavy Industries in Korea and is based on previous drillship design but is ice strengthened.[144] The ship is capable of operating on sea depths ranging from 140 to 1800 meter.

[143] Ocean Arctic (20/03/2009), http://oceanarctic.com/Images/KullukKuvlumNov92.jpg
[144] Stena DrillMAX Ice prospect (2007)

Figure 26. Stena DrillMAX Ice[145]

5.3.1.4 Future technologies

One potential future technology that would be highly applicable to arctic conditions is a seabed rig. The company Seabed Rig AS in Stavanger is developing an innovative seabed rig that will carry out drilling operations from the seafloor. By doing so the window of drilling is very much prolonged since there is now risk of ice pulling the rig out of place. The rig is unmanned and fully automated with robotics. The operations are controlled from a man to machine computer system aboard a ship supporting the rig. The rig is lowered through a moon pool, a hole in the transporting vessel's hull, of 7.2 x 7.2 m to the seabed and is then connected to the vessel with an umbilical coil containing power, communication, cement and mud flow, the umbilical can easily be disconnected in case of ice danger for the vessel. The umbilical will allow a 100 metre movement of the controlling vessel, which is generous. The rig will be prefilled with a 3000 metre drill pipe, drill parts and other equipment. Robots working on the deck inside the rig will assist the operation.[146] The rig is designed to drill in sea depths from 50 metres upwards. The development project is partnered by Statoil Hydro, Norwegian Research Centre and Innovation Norway. The concept is in phase 1 of 3 and the product is planned to reach the market in 2013. In theory the rig will be capable of year-round drilling.[147]

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[145] Stena Drilling Limited website (01/04/2009), http://www.stena-drilling.com/sub.asp?m=drilling&p=ice
[146] Seabed rig website (02/04/2009), http://www.seabedrig.com/default.asp?cat=5
[147] Haughom, P. (02/04/2009)

Kilde: Seabed Rig AS

Figure 27. The Seabed Rig concept[148]

5.3.1.5 Ice Management and Supply Vessels for Canadian Beaufort

An icebreaker is a ship designed to break ice in making way for other vessels. The sizes and the ice thickness they can handle vary. Icebreaker Oden, owned by the Swedish authority Sjöfartsverket, is a multi-purpose icebreaker with very good abilities and can easily make it way to the North Pole. Oden has an Ice Class of DNV 1A1 and CAC2, which allows her to go through the North West passage. When operating in the arctic it will always be required for icebreaker assistance – probably in more ways than one, dependent on the conditions. Icebreakers could, in the case of not needing to perform ice management, work as a supply ship for the operating team.[149]

Always when operating offshore there is a need of supplies and support to the well, independent on which state the well is in, i.e. drilling, development or production. The supplies are carried by supply vessels that can carry pipes and other supplies to the drill spot, lay pipes on the sea bed or carry out some ice management such as dragging away ice bergs or breaking ice floes into thinner ice. When operating in climates like the Canadian Beaufort Sea there is a need for ice strengthened supply vessels. The Viking class vessels, partly owned by Rederi Transatlantic AB, are such vessels.

[148] Seabed rig website (02/04/2009), http://www.seabedrig.com/default.asp?cat=5
[149] Liljeström, G. (25/02/2009)

Figure **28**. The Viking class ship Tor Viking[150]

5.3.2 Evaluation of concepts - drilling

Below is a compilation of the alternatives there are for exploration drilling. The alternatives are evaluated by the length of the season they can operate, which sea depth they can handle, if they are mobile and if they are dependent on Ice management.

Table 4. Compilation of exploration drilling alternatives

Exploration Structure	Length of Season	Sea depth	Mobility / Ice Management
Artificial Islands	12 months	19 m	NO / NO
Ice Islands	?	7.6 m	NO / NO
GBS Cylinder	12 months	?	NO / NO
GBS Conical	12 months	41 m	NO / NO
GBS Caisson	12 months	25 m	NO / NO
Drillship moored Explorer	5 months		YES / YES
Moored Kulluk	5-6 months	24-55 m	YES / YES
DrillMax Ice	?	140 – 1800 m	YES / YES
Seabed Rig	12 months	50 – ?m	YES / YES
Ice management and Supply vessels	**Length of season**		
Oden ice breaker	12 months		
Viking supply vessel	12 months		

All platforms described in the chart above are capable of operating in the harsh environment that drilling operations will face in the Canadian Beaufort Sea. Depending on where in the Canadian Beaufort Sea operations take place different structures will be better suited. In very shallow water of just a few metres near shore the ice islands will be best suited. These can be constructed in a relatively short period of time and function well. As the water is getting a little deeper the drilling should take place from artificial islands but these are relatively time consuming and material consuming to build when compared with the Ice Islands. In waters of 25 to 41 meters GBS structures will be the best option from an operational approach since these can operate the whole year around. The downside of using GBS structures are the inflexibility of these structures. The alternative to use a GBS for these depths would be to use a Kulluk-like construction or a moored drillship like the Explorer III. The trade off using these floating structures is the extra cost for ice management and the shortened drilling season. For deeper exploration drilling the only structures available are the DrillMAX Ice drillship and the futuristic Seabed Rig. The DrillMAX Ice is

[150] Viking Supply Online (02/04/2009), http://www.vikingsupply.com/vess_tor_spec.asp

planned to reach the market in 2011 which gives it a first mover advantage, but due to the design it can only operate in a season similar to the Kulluk. The structures suitable for operations in EL449 are hence the DrillMAX Ice and the Seabed Rig due to the sea depths (greater than 140m) of the licence. The Seabed Rig is far from being completed and is therefore not a realistic option to use in the case since technological uncertainty is too big. However, when the Kulluk was operating it needed assistance of two ice breakers and two supply ships. A good ice management solution for the floating structures would therefore be to use two icebreakers like Oden and two supply vessels of Viking class.

5.4 Choice - Exploration

We will assume that the DrillMAX Ice will be employed in this case since the only other optional technology for the EL449 is the Seabed Rig which is too far away in time and reality. In addition to the drillship, two icebreakers of Oden class and two supply ships of Viking class will be employed. We assume that the number of drill ships available is not a critical factor. Therefore we further assume that drillships will be employed for ten exploration wells during a period of two years meaning five wells per season.

5.4.1 The costs per well

The cost per well is basically driven by the chartering cost, bunker cost and material costs. Below is the total assumed exploration well costs.

Total well cost

Charter cost	123,691,711
Bunker costs	20,452,608
Materials	8,238,064
total well cost	**152,382,383**

The chartering cost is driven by the kind of structures and ice management which is employed and for how many days. In appendix II all assumptions regarding days of mobilisation and days of operation are shown. The bunker cost is based on the consumed amount of fuel oil and the price of the fuel oil. The assumed price is a mean of several years of oil prices, and is available in appendix VII. The material costs are based on the materials needed to drill the well and the price of those materials. The assumptions regarding these costs are available in appendix II and appendix VII.

5.5 Problem Finding - Development

Development problem finding is associated to evaluate the field profile in order to be able to solve the problem of extracting the oil in the ground. Therefore the first step after the exploration phase is to use the information gathered during the exploration phase to make an appraisal of the discovery. This case uses existing pool peers to make assumptions that will work as estimates in order to conclude a field profile, hence be able to determine the most optimal way to develop the field matching to the size and behaviour of the field.

5.5.1 Appraisal of discovery

In order to be able to appraise the discovery and to determine the production profile one must know the field size, the productivity of the field including peak production output and the decline rate. When this is established it is possible to evaluate the number of producing years for the field. Since very little offshore drilling and production has occurred in the Canadian Beaufort Sea the case assumptions are based on work done by specialists and pools that are economically recoverable and producing in areas similar to the one studied.

5.5.1.1 Field size

All fields have unique characteristics. When assessing the size of the fields in EL 449, the assumptions are based partly on the work of the scientist Kenneth Drummond. Below is a diagram that shows what is believed to be the recoverable sizes of the top 20 oil fields in the Beaufort Sea. The largest is approximately 500 million barrels of oil recoverable.[151] This implies approximately 2 billion barrels of oil in place at 25% recovery rate, which is approximately the industry average.[152] The recovery rate is dependent on many variables, such as economics, pressure in the field, the viscosity of the oil and how much effort is done to enhance recovery. Generally, recovery rates are lower in the fields operated by international oil companies and higher in national oil companies. The national oil companies have greater incentives to enhance the recovery since it is considered a national strength to be able to be independent from foreign suppliers of oil.[153] The rationale behind lower recovery rates of privately owned fields is to produce quick cash flows and maximum returns on capital investment made in the field.[154]

[151] Drummond (2008), p. 28
[152] Shepherd, R. (10/03/2009)
[153] Shepherd, R. (10/03/2009)
[154] Shepherd, R. (10/03/2009)

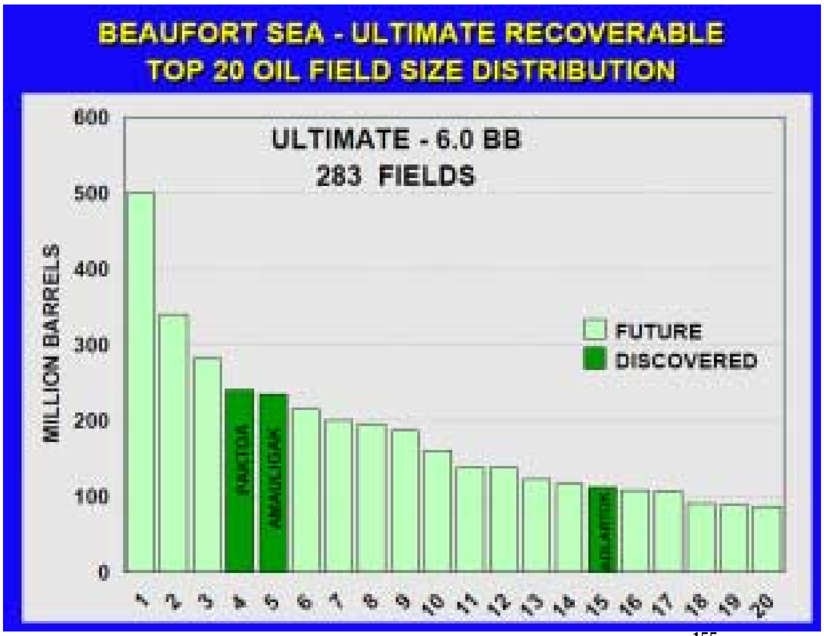

Figure 29 Field size distribution in the Beaufort Sea[155]

After the exploration phase, the oil company operating in the field can make a better estimation of the reserves in place and reserves recoverable after testing the well and the composition of hydrocarbons and water flowing from it.[156] In order to make a field economical and motivate investments in EL449 it is likely that the operator has to find very large fields to motivate further investments. Mark Stanley at BP states that BP will not go for something small and that BP believes in the great potential of EL449.[157]

The field size assumptions for the case are based on a combination of the statement from BP and Kenneth Drummond's estimations. When combining these statements it is clear that the biggest of the top 20 fields will likely be produced. This determines a size of 500 million barrels of recoverable oil in EL449.

5.5.1.2Productivity of EL449

The field life and the production profile are closely correlated in an offshore field and depend on several factors. The amount of reserves in place together with the recovery factor decides the recoverable resources in place. The major factors deciding the field life and the production profile are the recoverable resources in place together with the decline rate and peak production of the field.

Peak production

The peak production of a field is the highest rate of output during the life time of the field. The peak production of the field is much dependent on the pressure of the field and the viscosity of the oil. In almost all fields, the peak production occurs very early in the field life, usually just after one year of production, and a larger field like a 500 million barrels of oil field may achieve a long-lasting peak production occurring over several years.[158] The peak production is an average of the output per day during a

155 Drummond (2008), p. 28
156 Shepherd, R. (10/03/2009)
157 Stanley, M. (09/03/2009)
158 Babusiaux et al. (2007) p. 108

calendar year. It takes time to build up production in a new larger field since there are multiple producing wells and complex processing systems to activate even if some wells have been pre-drilled.

To make relevant assumptions for the case of EL449 it is vital to study the production profiles of peer fields. The Hebron and Hibernia fields of the east coast of Canada are two offshore fields. Hebron has 400 – 700 million barrels of recoverable oil in place and an estimated peak of around 150 000 barrels per day[159]. Hibernia was originally estimated to produce 615 million barrels of recoverable oil and to reach a peak production of 135 000 barrels per day.[160] In Hibernia more reserves have been found and production of 706 million barrels is now proven.[161] The peak production is slightly over 200 000 barrels per day.[162] To make assumptions for the EL449 case study, the average 1000 barrels of oil of peak production per million barrels of recoverable oil is calculated on the three peers. This multiple is then multiplied with the estimated 500 million recoverable barrels of oil estimated for the case and results in 146 300 barrels of peak production. This is rounded up to 150 000. See table 6.

Table 5. The peak production versus recoverable oil in Hibernia, Hebron and the case EL449

	Hibernia original estimate	Hibernia today	Hebron estimate	Case estimate
Recoverable oil (million barrels)	615	706	400	500
Peak production (barrels)	135,000	200,000	150,000	146,300
Peak production per recoverable barrel	220	283	375	293

The first year production estimation is half of peak production, 75 000 barrels per day on average due to less production during the start-up. This is mainly due to the number of wells completed in the first year. The peak production is estimated to be maintained for four years due to added production of one pool each year during the first four years of production.

Decline rate

The decline rate is the rate at which production declines each year after peak production and is expressed in percent terms as an average value even if the rates vary during the life of the field. This rate depends much on the extra production wells drilled during the field life but also on the number of injection wells drilled which are used to increase the pressure in the field. The extra production wells together with the injection wells will lower the decline rate but also enhance the recovery factor.[163]

In Hibernia, development drilling of both production wells and injection wells has occurred and the peak production was estimated to occur over several years.[164] From a production forecast dating back to 1997 we can calculate the expected decline rate in Hibernia at 17% until the field is no longer economically viable. The Hibernia field is estimated to be operative for 18 years.[165]

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[159] Offshore Technology (11/04/2008), http://www.offshore-technology.com/projects/exxon_hebron/exxon_hebron1.html
[160] The Free Library (11/04/2008), http://www.thefreelibrary.com/Hibernia+Project+on+Track+for+Success-a019954583
[161] Canada-New Foundland and Labrador offshore petroleum board (11/04/2008), http://www.cnlopb.nl.ca/pdfs/estrr_hib.pdf
[162] One Ocean (12/04/2008), http://www.oneocean.ca/hibernia.htm
[163] Babusiaux et al. (2007) p. 108
[164] Canada-New Foundland and Labrador offshore petroleum board (11/04/2008), http://www.cnlopb.nl.ca/news/d1997_01_en.shtml
[165] One Ocean (12/04/2008), http://www.oneocean.ca/hibernia.htm

Assuming that EL449 will have the same life time as Hibernia of 18 years and assuming that the cumulative n production over these years will be 500 million barrels of oil and that the peak production will be for four years before decline starts, shows in a calculation that 16.3% must be the assumed decline rate for EL449. This base case assumption is not far from the 17% decline rate in Hibernia.

5.5.2 Production profile of EL 449

Now when the recoverable oil, peak production and decline rate has been estimated it is possible to make a production profile for the EL449 field, see figure 30.

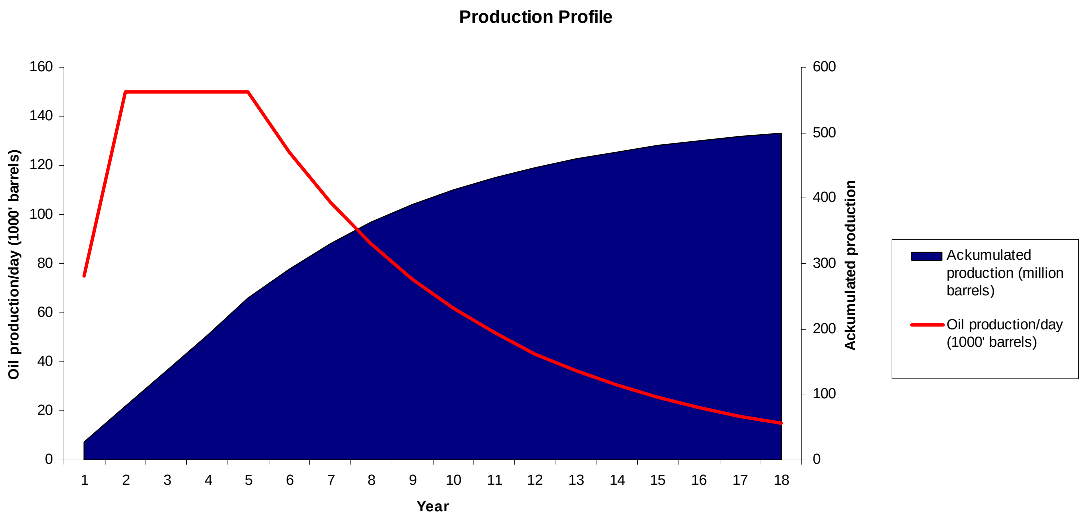

Figure 30. Estimated production for the EL449

The estimation is based on the factors estimated above. Below is a summary of the assumptions presented. The characteristics of the EL449 field are estimated to be approximately:

Table 6. The estimated characteristics of the EL449 field

Production profile	
Field size	500 MBO
First year production	75 000 BOP
Peak production	150 000 BOP
NBR of years of peak production	4 YEARS
Decline rate	16.30%

5.6 Problem solving - Development

When the field characteristics are estimated there is a need for generating and evaluating technological concepts for the number of wells, production and distribution, which has to match and correspond to the uniqueness of the field as well as the environment discussed earlier in this chapter. Since all fields have a unique character, most of the production facilities have to be purpose built or modified for the specific field.[166] Problem solving therefore aims to solve the problem by generating and evaluating development concepts of how to extract the oil in the ground based on the characteristics that were determined in problem finding.

There are several factors deciding which structures and production systems could be used in order to produce the field EL449. During the development phases, production and injection wells are drilled by drillships or from the platform in order to enhance recovery and maintain a good production profile. The injection wells are used to inject water or gas to increase reservoir pressure, and thereby enhance the recovery factor.[167] When drilling from the platform the length of directional wells is limited to approximately 10 km.[168]

When the wells are drilled, they are connected by pipes or flowlines to a production system. The system makes a first separation of the wellstream flowing from the well, usually consisting of oil, gas, condensate and water solution. The processing system is situated on a production structure of a different kind. If it is shallow enough, the structure can be placed on the sea bed, and in deeper water, the system is buoyant. The production system together with the structure can usually store some oil while waiting for offloading.[169]

5.6.1 Generation of field development concepts

The definition of the field development concept includes how many wells are needed to be drilled to be able to extract the oil, what structures are available to produce the field and what means of transport can be used in order to distribute the oil to the market.

5.6.1.1Number of wells

In reality all oil fields are different and therefore the number of wells needed to reach the oil is difficult to estimate. Assumptions concerning the number of wells are based on statistical data over previously developed offshore deepwater oil fields. Richard Shepherd at the energy consulting firm Petrologica have provided data over the number of wells drilled versus the activated reserves over a number of fields. This serves as a proxy showing the number of wells drilled per field, given the size of the field.

[166] Alsaker, E. (13/03/2009)
[167] Babusiaux et al. (2007) p. 77
[168] Shepherd, R. (10/03/2009)
[169] Shepherd, R. (10/03/2009)

Table 7. Deepwater oil fields [170]

YEAR	MBO of recoverable	Number of production wells	Reserves per well
1996	663	17	39
2003	300	28	11
2004	2,012	67	30
2005	1,290	45	29
2007	2,205	72	31
2008	2,300	78	29
2009	600	44	14
Total	9,370	351	26.7

Table 8 reveals that on average there are 26.7 million barrels of recoverable oil in a typical well. Not only production wells need to be in place, but also injection wells in order to increase the pressure in the field. In Hibernia there are today (2009-04-03) 30 production wells and 25 injection wells.[171] A simplified approximation is a 1-to-1 ratio between production wells and injection wells and is quite typical in the industry, even if fields producing both gas and oil usually have more producing wells than injection wells, see appendix XI.[172]

5.6.1.2Production Concepts

There are many different production concepts applicable for offshore production. In this paragraph technologies that are suited to withstand the extreme environment present in the arctic are presented.

Gravity base structures

Gravity base structures (GBS), sometimes called bottom founded structures, are big structures made of steel or concrete standing on the sea floor with a production system on top of the platform, this is called the topside. Usually a GBS is also equipped with a storage facility and can also be equipped with a drilling rig, which can be used to drill extended development wells. All of the GBSs are custom built for the specific area they operate in and they all have very different features.[173] Figure 31 shows the concept of the GBS in Hibernia.

[170] Shepherd, R. (10/03/2009)
[171] Canada-New Foundland and Labrador offshore petroleum board (11/04/2008), http://www.cnlopb.nl.ca/pdfs/estrr_hib.pdf
[172] Shepherd, R. (10/03/2009)
[173] Paulin (2008), pp. 25-42

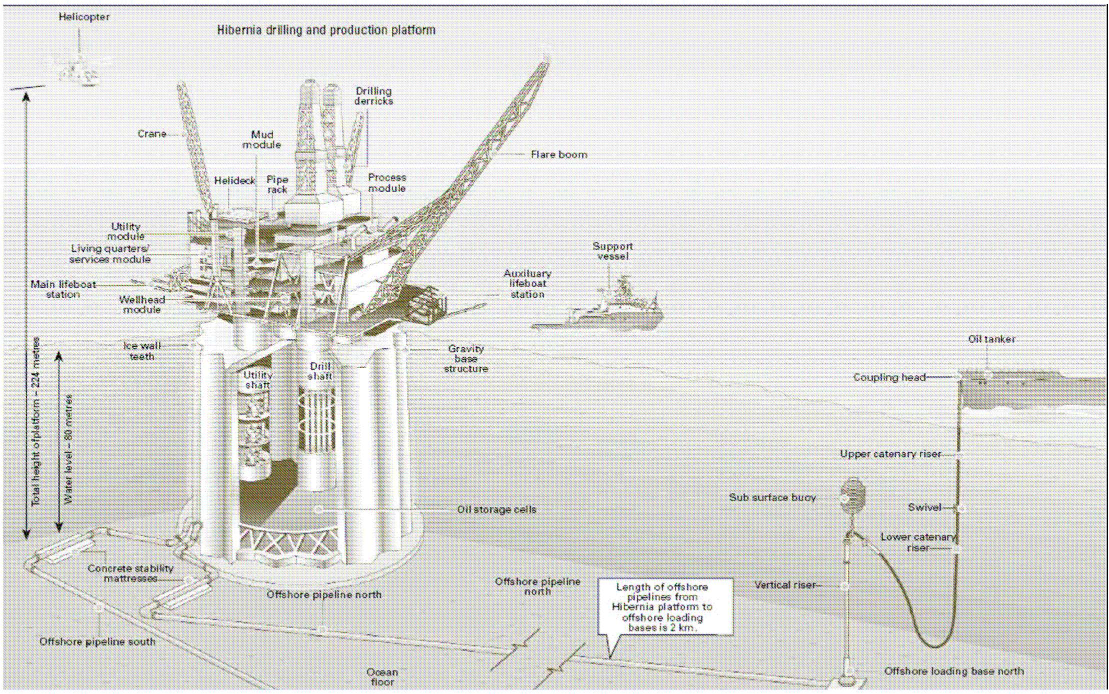

Figure 31. The concept of a gravity base structure of concrete. This is operating in Hibernia, east cost of Canada[174]

Traditionally a GBS is constructed of concrete but new engineering technologies have made it possible to manufacture them out of steel to make them more resistant.[175] None of these steel structures have yet been built but the engineering firm CJK Engineering with John Fitzpatrick believes that this concept is the best suited for the Beaufort area where the climate is extremely severe.[176] A suitable construction would be the steel stepped gravity platform. Such a structure is suitable for water depths around 100 metres and is capable of resisting ice loads from first year and multi-year ice occurring in the Beaufort Sea. Figure 32 shows the concept developed by John Fitzpatrick.

[174] Paulin (2008), p. 37
[175] Paulin (2008), p. 41
[176] Fitzpatrick (2008), p. 5

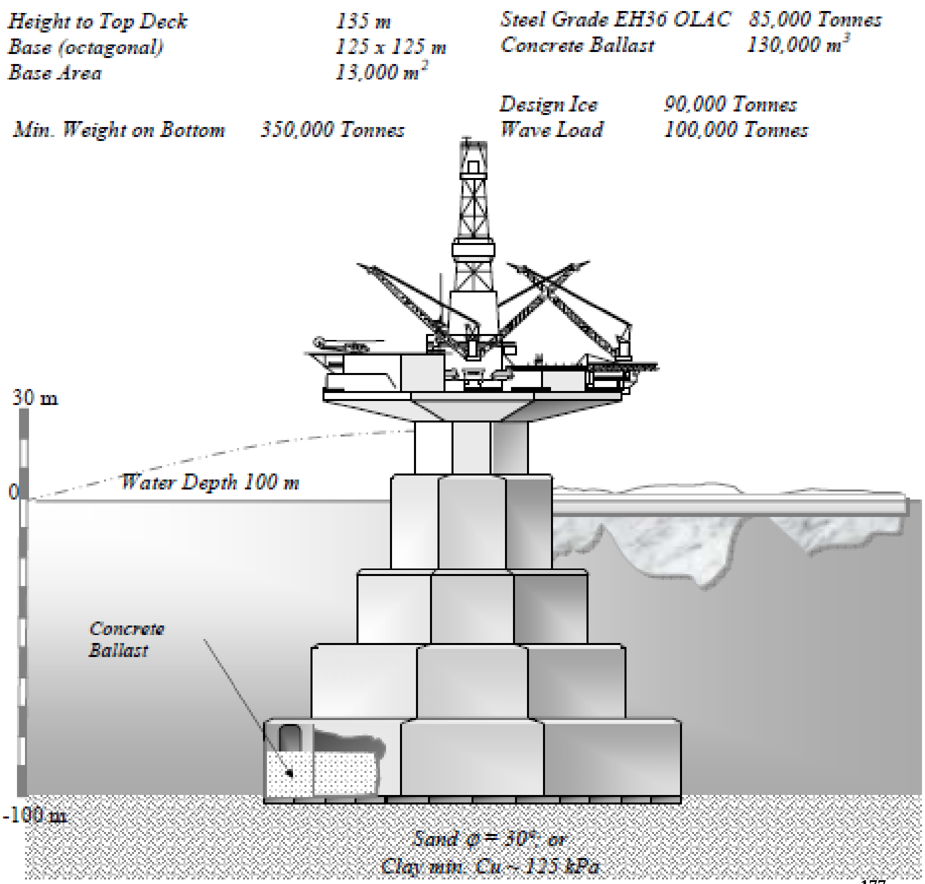

Figure 32. CJK Engineering's model of a steel stepped gravity platform[177]

Tension legged platform

In the Canadian Beaufort Sea, a Tension legged platform (TLP) could be used. The structure is a buoyant floating unit, tightly moored to the sea bed with several wires. The structure is hence suitable for depths of greater than 200 metres down to approximately 1000 metres. John Fitzpatrick from CJK Engineering has developed a TLP suitable for the Canadian Beaufort Sea, designed to manage the great ice loads in the area. See figure 33.

[177] Fitzpatrick (2008), p. 23

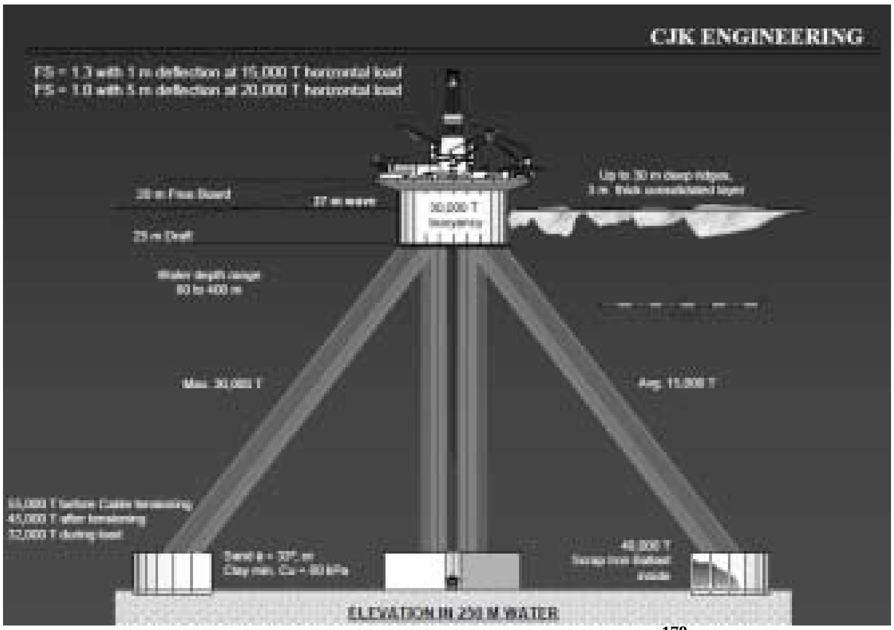

Figure 33. The concept of an arctic TLP[178]

Jack Up

The jack up structure is a fixed, permanent platform made up from a framed structure of steel, see figure 34.

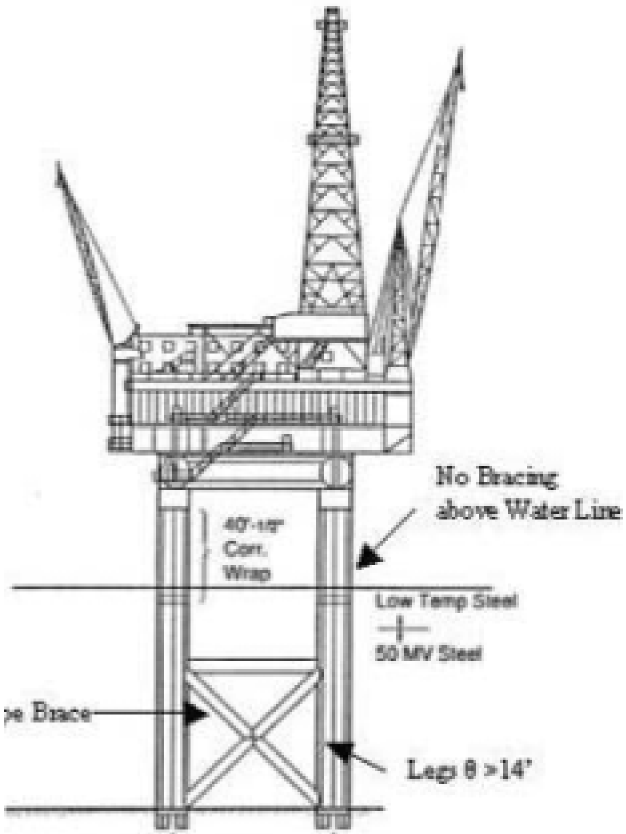

Figure 34. Jack-up structure designed for the Cook Inlet[179]

[178] Fitzpatrick (2008), p. 30
[179] Paulin (2008), p. 41

It is the most commonly used fixed platform in the world since it combines the mobility of a floating platform with the properties of a fixed platform with wave resistance and certain ice load resistance. The sea depth the jack-ups can operate in range from 10 metres to approximately 150 metres. There are jack ups used in the arctic climate such as in the Cook Inlet[180], but there is no jack-up developed for a climate occurring in the Beaufort Sea.[181]

Floating production, storage and offloading unit
A Floating production, storage and offloading unit (FPSO) is usually a rebuilt tanker with a production system installed on top. If the FPSO operates in an area which is severe, it is usually designed to be able to easily disconnect from the flowlines and the mooring system in case of an emergency.[182] Figure 35 shows the concept of the FPSO in White Rose field in the east coast of Canada where icebergs are present.

Figure 35. The concept of White Rose FPSO with a tanker loading oil[183]

When operating in an extreme, harsh environment, the existing technology might not be strong enough, and purpose built structures will be necessary.

In the Goliat field, in north Norway, there is a concept for a round-shaped FPSO handling much harsher environments than any FPSO existing today.[184] See figure 36 for the Goliat concept. The negative aspect of the FPSO, even though it is ice strengthened, is that it will be extremely difficult to fix the position of the structure during production in heavy ice floes. FPSOs are likely to be used in areas where ice bergs are occurring but are too weak to withstand extreme ice floes such as the ice floes in the Canadian Beaufort Sea.[185] Therefore it is not likely that year around

[180] Paulin (2008), p. 41
[181] Shepherd, R. (10/03/2009)
[182] Offshore Technology (11/04/2008), http://www.offshore-technology.com/projects/white_rose/
[183] Offshore Technology (11/04/2008), http://www.offshore-technology.com/projects/white_rose/
[184] Offshore Technology (11/04/2008), http://www.offshore-technology.com/projects/goliat/
[185] Lowings, M. (29/01/2009)

production can be performed using FPSO in the EL449. The sea depth range using a FPSO depends on the system used.

Figure 36. The Goliat FPSO concept[186]

Sub-sea production system

One possibility is to produce on the sea bed and tie the oil to shore by pipe. Today, the only existing sub-sea production system is in the Norwegian field Snöhvit where the sea depth ranges from 250 to 345 metres. This system has no complementary unit above the sea level, and all activity occurs on the seabed. The concept is that the first refining of the gas and fluid occurs in a facility fixed on the platform and thereafter pumped in pipelines to the shore where it is further processed. Figure 37 shows a picture of the development in the field.

[186] Offshore Technology (11/04/2008), http://www.offshore-technology.com/projects/goliat/goliat1.html

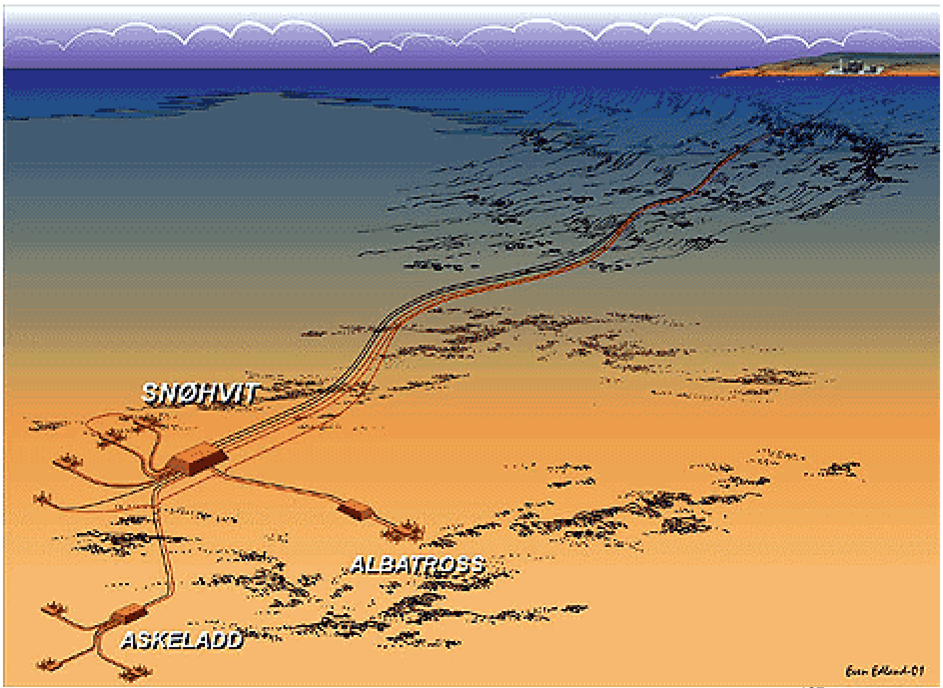

Figure 37. The Snöhvit field in Norway with subsea solution[187]

The concept is believed to have a great potential in the future for production in areas where no floating platform can perform due to heavy ice loads and the harsh environment. The negative aspect is that it cannot be maintained during long periods due to ice conditions, and consequences of a breakdown can therefore be very severe. Such risks are due to risk of leakage and the extremely large sunk cost if production is disrupted in the winter when it not is possible to access the structure. [188] [189]

Manifolds and flowlines

Independent of the choice of platform concept there is likely a need to connect the wells with a production system. To connect the flowing wells to the production system, manifolds are used to gather the flowing oil from nearby fields' wellheads. Dependent on the output from the wells, different systems have to be in place. The manifolds handle various kinds of output or input from the production wells and injection wells, and the diameter of the flowline connected to the manifolds has to correspond to the same flow. Flowlines and control umbilicals must also be laid to both injection wells and production wells. This implies that to every manifold there will be three flowlines, one for the oil output and one each for water and gas injection. To this a control line has to be laid out to each manifold.[190] Figure 38 pictures the concept of wellheads connected to manifolds and hence to collecting manifolds transporting the hydrocarbons to an FPSO in the Norwegian field of Alvheim.[191]

[187] Offshore Technology (11/04/2008), http://www.offshore-technology.com/projects/snohvit/snohvit5.html
[188] Offshore Technology (11/04/2008), http://www.offshore-technology.com/features/feature1412/
[189] Nellany, P. (12/03/2009)
[190] Nellany, P. (12/03/2009)
[191] Shepherd, R. (10/03/2009)

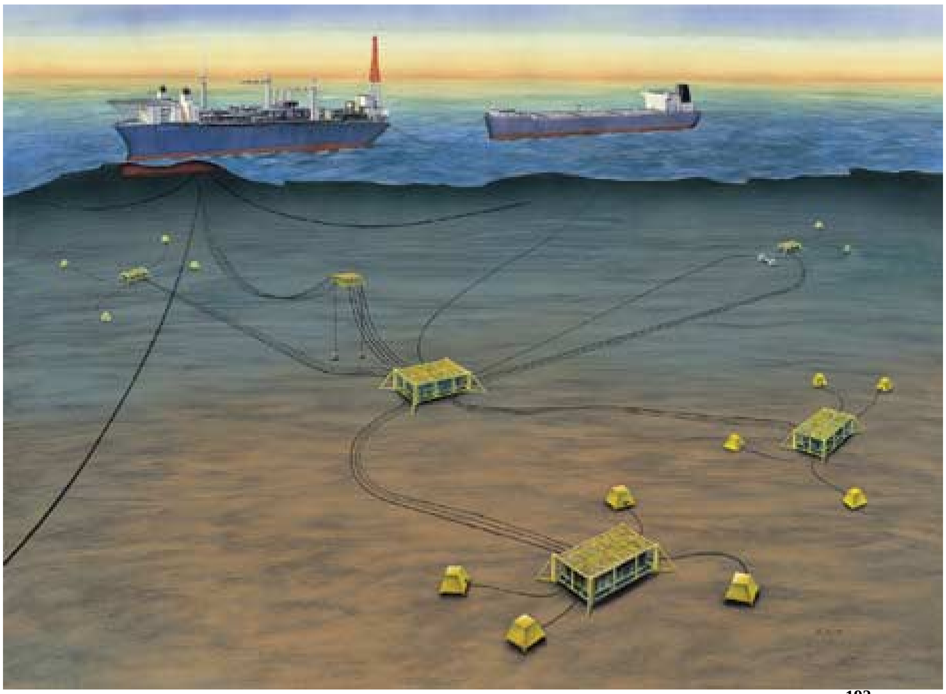

Figure 38. The concept of wells and manifolds tied back to an FPSO[192]

If there are wells drilled from a platform, those wells do not need any flowlines or manifolds since those wells will be directly connected with the platform.[193] The maximum reach of the extended reach drilling from the platform is approximately 10km.[194] With today's technology, the maximum length between a manifold and a collecting manifold or the production platform is approximately 25 km, which implies that if the wells are more than 25 km from the platform, another manifold has to be put out in order to transport the oil to the platform.[195]

5.6.1.3Distribution concepts

Distribution to market means that the oil has to be carried to a point where it can easily reach the market system and be traded. The positions for these kinds of hubs are differing to which geographical region you are operating from. Generally there are two ways of transporting the oil to market. The use of a shuttle tanker or pipeline are the alternatives of transportation. Usually when the distances are long, it is easier and more economically feasible to use a shuttle tanker for the loading. A pipeline implies great capital cost and is of no use when a field is abandoned. A shuttle tanker is not purpose built and hence easier to relocate.[196]

Shuttle tankers

The RN-Arkengelsk is an example of an arctic tanker. The vessel is 170 meters long and 30 meters wide and can load 25 000 tons of oil. The tanker is designed to operate in extreme ice conditions of arctic seas with more than one metre thick ice. The tanker is owned by the Russian oil company Rosneft.[197] No tanker has today been operating

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192 Offshore Technology (11/04/2008), http://www.offshore-technology.com/projects/alvheim/
193 Shepherd, R. (10/03/2009)
194 Allen et al. (1997), p. 12
195 Nellany, P. (12/03/2009)
196 Lowings, M. (29/01/2009)
197 Rosneft website (11/04/2009), http://www.rosneft.com/news/news_in_press/03092008.html

in the extreme winter climate of the Canadian Beaufort and it is not likely that this tanker, even though it can handle more than one meter thick ice, will withstand the multiyear ice and pressure ridges that are present in the Canadian Beaufort Sea during winter time. Therefore the length of the operating season is assumed to be less than a year when using shuttle tankers.

Figure 39. The Rosneft arctic shuttle tanker[198]

Pipeline

To this day, pipelines have been operational in the arctic, though only in shallower waters. One big challenge and also an extra cost is that pipelines have to be trenched for protection due to ice gouging, especially in waters of 20 to 40 meters depth.[199] Trenching and pipeline installations in arctic waters will require the use of floating vessels and have to this day not been done, but the technology exists and during the ice free period this is definitely possible.[200] [201]

[198] Rosneft website (16/04/2009), http://www.rosneft.com/news/news_in_press/03092008.html
[199] Paulin (2008), p. iv
[200] Paulin (2008), p. v
[201] Nellany, P. (12/03/2009)

5.6.2 Evaluation of concepts – Development

Below is an evaluation of all the alternatives for development concepts. The concepts are presented in the categories number of wells, production concept and distribution concept.

5.6.2.1Number of wells

The estimation of the field size of 500 million barrels of oil recoverable, together with data from the energy consulting firm Petrologica showing that the reserves per production well is approximately 26.7 million barrels of oil, gives the assumption that the EL449 field will be in need of 500 divided by 26.7 which is equal to roughly 20 production wells. This is what we estimate in the EL449 field. Knowing that a common ratio between the production wells and injection wells is approximately 1-to-1, we assume another 20 injection wells have to be drilled. We will estimate that the wells will be clustered together in groups of 4 production and 4 injection wells per cluster and we assume the clusters are evenly spread out over the area of EL449 which measures 2024 km^2,see figure 40. This implies five separate pools of oil in the field with 4 production wells and 4 injection wells in each one of them. We assume to develop one cluster per year from the first year of production.

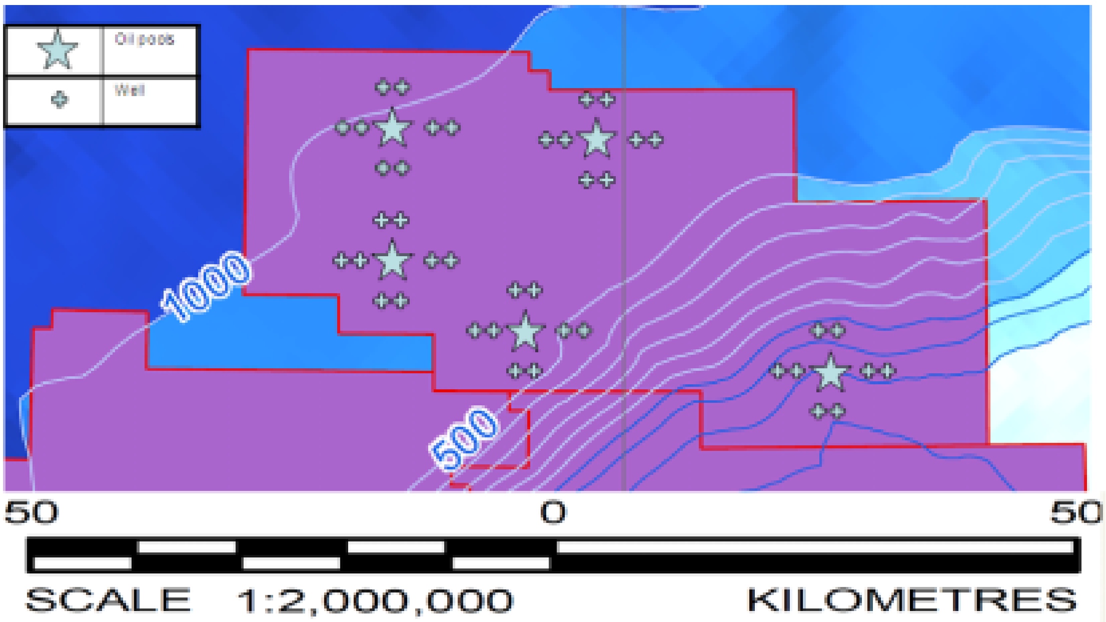


Figure 40. Assumed drilling in the EL449

5.6.2.2Production concepts

Below in table 9 all viable arctic production concepts are presented in a summary. Further we also compare and analyse the viability of the different concepts

Table 8. Summary of the production concept evaluated.

Production concept	Managing ice in	Sea depth	Ice Management
GBS	Yes	50-200 m	NO
TLP	Yes	200-1000 m	NO
Jack-up	No	10-150	Yes
FPSO	No	-	Yes
Sub-sea production system	Yes	250-345	NO

The FPSO and Jack-up are with existing technology probably not viable choices for year-round production in the Canadian Beaufort Sea due to dense first year ice and multiyear ice floes, these choices will also have to be assisted by ice management during the season of operations. Therefore these two options are ruled out of the case. This leaves the choice of using Sub-sea production systems, GBS or a Tension legged platform. The Sub-sea might at first glimpse look like a very good option since it would be protected from the ice loads by being situated on the sea bed, but at the same time this possesses the possibility of a great threat. For example, if there is service or maintenance work required, this cannot be performed during the winter season because of the ice, and the operator will have to wait until summer before repair work can begin. Leakage might also cause an environmental disaster.

The two remaining structures considered for use in arctic environment are the TLP and the GBS structures. The difference between these options is that the GBS structures are more suitable for shallower waters and the TLP more suitable for deeper waters, see figure 41 below. The GBS structure is suitable in water depths of circa 100 metres while the TLP is more suitable in deeper waters.

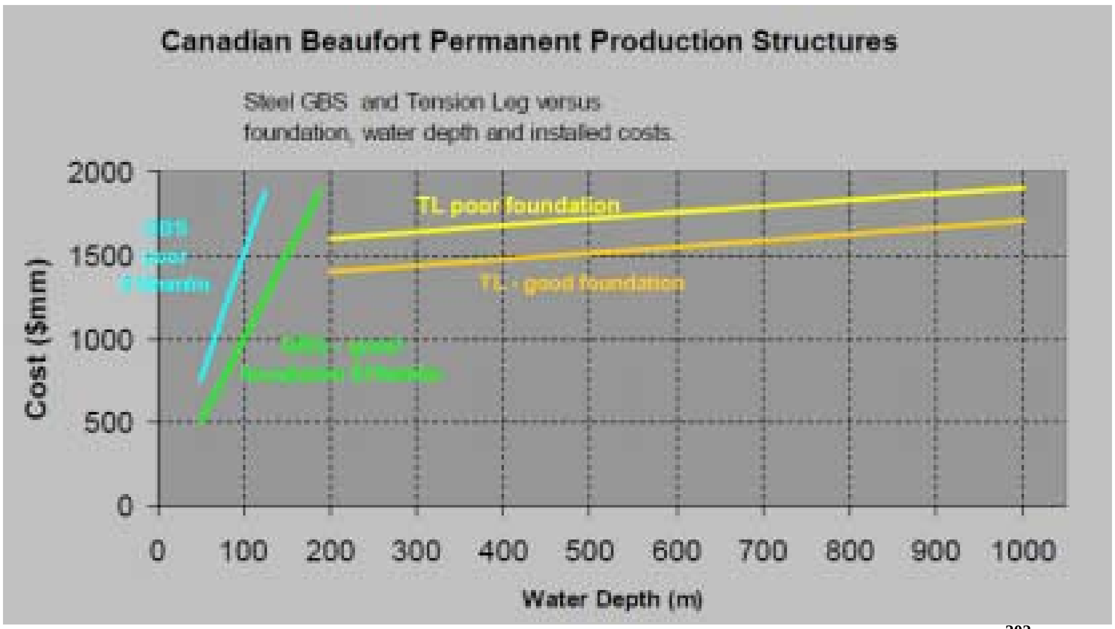


Figure 41. Cost versus water depths of Offshore Structures In Ice Environments. [202]

[202] Fitzpatrick (2008), p. 4

This leaves us with two real production scenarios to evaluate. One is to place a TLP in the middle of EL449 and the second would be to place a GBS structure on the 100 meter shelf in the South East corner of EL449. Independently of solution the oil will be tied-backed to a production platform by subsea manifolds and flowlines. The upside of using the TLP is that it would mean that more wells could be drilled from the platform by using extended reach drilling and thereby lowering the drilling cost. The downside of the TLP is that people in the industry do not believe it is a viable solution. Bill Scott at Chevron and Mark Stanley at BP believe that the GBS structure is a more viable choice for EL449 because of the technological uncertainty of the TLP's ice resistance capabilities.

5.6.2.3Distribution

In the arctic Beaufort Sea, a pipeline is in many cases more feasible than a shuttle tanker. This area of the Beaufort Sea is only free from ice during a limited number of months a year and tankers are in need of icebreaker assistance during most of the year. This is in itself expensive, and in some periods it might not even be possible to go by tanker at all.[203] A pipeline is much more capital intensive than using shuttle tankers but the operating cost of the pipeline is much lower than for using shuttle tankers. Generally, if the distance is very long, a pipeline is a less attractive option due to the high capital cost and inflexibility in comparison to the tankers. On the other hand, pipelines are considered to be a safer way of transporting oil.[204] Tankers also disturb the natural environment in the arctic, creating unnatural ice free waters which create problems for wildlife and hunting.[205]

Table 9. Summary of the distribution options

Option	Year around operations	Pros	Cons
Pipeline	YES	• Low operating cost • Safe	• Capital intensive • No reallocation possibility
Shuttle tanker	NO (uncertain)	• Reallocation possibility	• High operating cost • Oil spill risk • Environmental disturbance

5.7 Choice – Development

The first assumption is that a GBS structure will be placed on the 100 metre shelf in the south east corner of EL449, see figure 42. When possible drilling would be carried out from the GBS. The maximum reach from the GBS is assumed to be 10km. This implies it can cover an area of $\pi*10^2$ equal to 314 km^2 or approximately 15% of the

[203] Lowings, M. (29/01/2009)
[204] Nellany, P. (12/03/2009)
[205] Shepherd, R. (10/03/2009)

EL449 area of total 2024 km^2. This implies that if the GBS is placed close to the pool in the south east corner then wells can reach and cover that pool. This implies that the GBS will drill 4 production wells and 4 injection wells. The probability is that it will probably drill many more wells to enhance recovery since the rig on the platform is in place at all times. Drillships will be used where the GBS is out of reach. This implies 16 wells for production and 16 wells for injection will be drilled by drillships. In total, this implies at least 8 wells drilled from the GBS, and 32 from drillships.

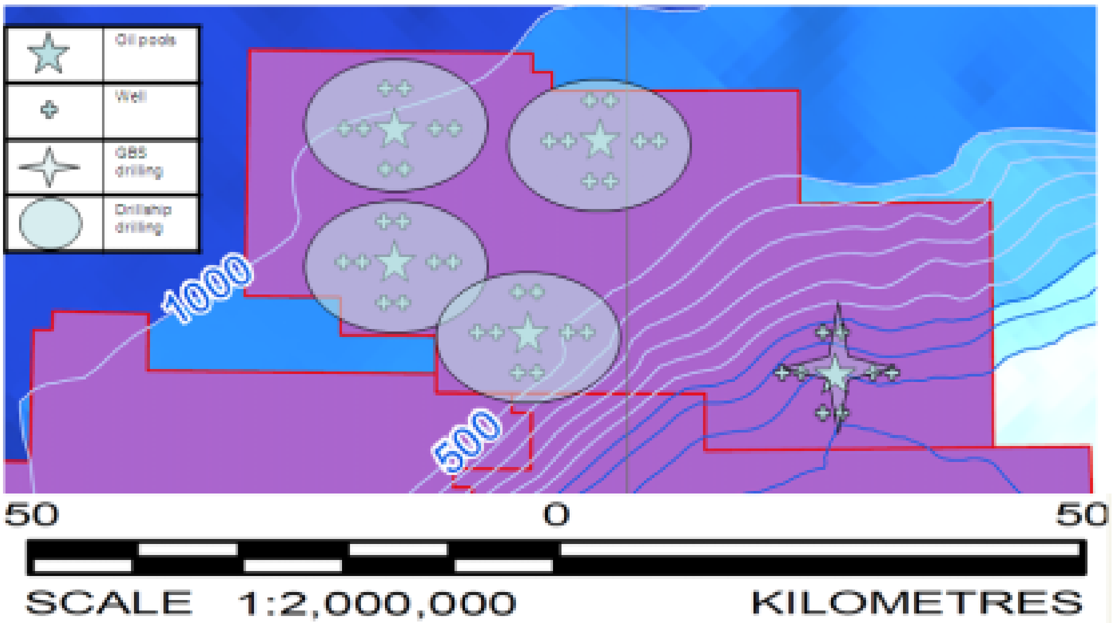


Figure 42. The EL449 field with the drilling assumption

We assume a scenario where the five oil pools are spread over the whole area of EL449. In this case, flowlines will measure a total distance of 65 km from the producing manifolds to the collecting manifold. Thereafter, the oil will pass in flowlines from the collecting manifold to the GBS. Firstly, there is the production flowline in which the oil is tied back to the GBS, then there are two flow lines for injection of gas and water going out from the GBS to the injection wells, and also a control line to the each manifold. Therefore in every line presented in figure 43 there are three flow lines plus a control line.

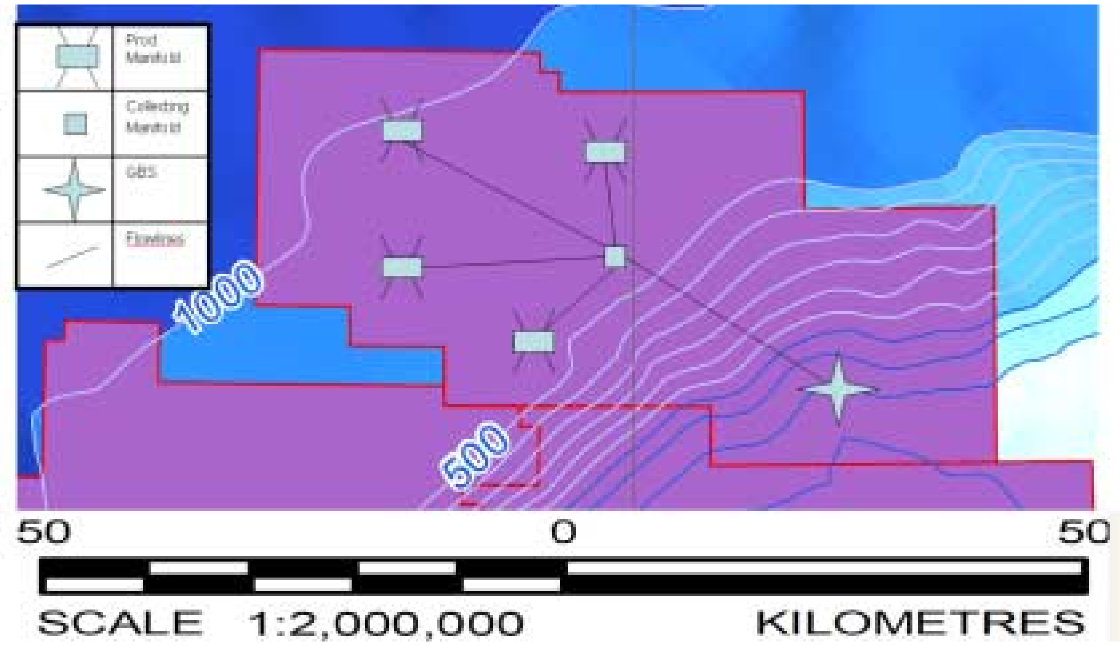


Figure 43. The EL449 field with a production system in place

In the EL449 field, we assume that pipeline will be laid to Prudhoe Bay and there connected to the Trans Alaskan oil pipeline to Valdez. Once in Valdez it can be considered to be at the market. Along the way, the pipeline will be laid at various water depths and as long as the water depth is beyond 50 metres, it does not have to be trenched. The only distance the water depth is shallower than 50 metres is the last distance just before Prudhoe Bay. The total distance of pipeline required to Prudhoe Bay is 606 km whereof approximately 100 km must be trenched which implies an extra cost.

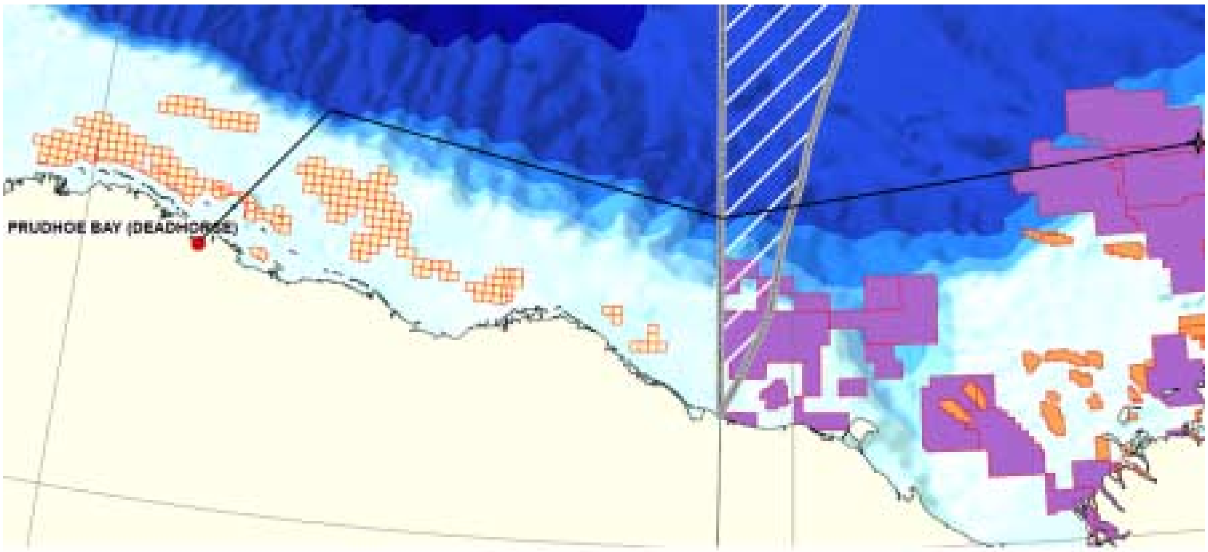


Figure 44. The pipeline from EL449 to Prudhoe Bay

5.7.1.1Development costs

The development costs are based on the use of a GBS platform capable of drilling. The estimated cost of such a platform is USD 2.3 billion including the topsides. These costs have been assumed by John Fitzpatrick for the platform and the topside cost is estimated by a specialist from Shell.[206] [207] The cost of production includes capital costs for drilling, production systems and pipelines plus the operating cost for running the platform, wells and pipelines together with the management cost. This includes labour cost, maintenance, transport of people and equipment to and from the platform and all other cost related to the daily management. This cost includes the cost for drilling from the platform if the platform is equipped with a drill rig. In 2007 the annual operation cost reached USD 404 million at Hibernia.[208] This can be considered to be a good proxy for the EL449 field too since the production system is quite similar to Hibernia. The GBS investment is expected to occur the year after drilling and testing has been done, and construction work will occur over a period of two years. Thereafter production is ready to take place.

The cost for subsea tiebacks with flow lines and manifolds have been evaluated with the firm Technip which specialises in that kind of work and are available in appendix V and appendix VII. The subsea work will be spread out over a four year period since we are assuming that one pool will be drilled each season and that drilling will constantly occur from the platform.

Gravity Based Structure

CAPEX	
Platform	1,000,000,000
Topsides	1,300,000,000
Total	**2,300,000,000**

OPEX	
Prod. & GBS Drilling	404,000,000

Subsea

CAPEX	127,091,680

The drilling of development and injection wells will be spread out over a four year period. Each season there will be 8 wells drilled, which implies that one pool will be activated per year the first four years. The wells are very similar to exploration wells and we have only assumed some extra time for completion of the wells. The pool on which the GBS structure is standing will be drilled from the GBS structure and this cost will be included in the operating costs of the GBS. The table below shows a single well cost which itself is sensitive to whether or not the well can be completed in a single short drilling season for a mobile drilling unit.

Development Drilling

Total well cost

Charter cost	128,201,086
Bunker costs	21,198,240
Materials	8,238,064
total well cost	**157,637,390**

[206] Fitzpatrick (2008), p. 23
[207] Stanley, M. (09/03/2009)
[208] Canada-New Foundland and Labrador offshore petroleum board (11/04/2008), http://www.cnlopb.nl.ca/pdfs/project_benefits.pdf

The cost of building the pipeline is estimated to USD 3.1 billion and is evaluated by generating peers. These are calculated by the cost per km and by the thickness of the pipe. Assumptions are available in appendix VIII.

Pipeline Costs

EL 449 Pipeline Cost	Length	Diameter	Cost USD
Non Dredged	501	36	980,097,268
Dredged	105	36	2,161,062,750
Total			**3,141,160,018**

6 The NPV calculus-step two in Gold Digger

This chapter applies step 2 of the Gold Digger model in order to make a calculus of the oil price required to reach a net present value of zero. The discount rate is first discussed and analysed before the base case is calculated. To get a broader view and eliminate some uncertainty, sensitivity and scenario analysis will be performed.

6.1 Discount factor

In a perfect market the discount rate used to discount future cash flows to present value should be equivalent to the weighted average cost of capital (WACC), but it is more complicated than that since all projects have different risks. These risks should be reflected in the discount rate. Exploration projects tend to have high discount rates because of the uncertainty of success. Therefore the discount rate varies in the industry. The extremes of historical discount rates are ranging from 5 to 25%. The lower rates have historically been used in times of low inflation and low cost of capital from debt holders and equity holders. The higher rates tend to be used in high-risk projects and times of high inflation.[209] There are generally two methods for estimating the discount rates of today. One is to use the WACC formula and calculate the discount rates for a number of companies and use the average as a proxy. This is not likely to be successful other than in the theory. In reality it is very difficult to estimate the cost of equity. The other method is to conduct interviews and ask a number of oil companies which discount rates are being used when evaluating projects; this will be qualitative data estimation.

The exact discount rates used by certain oil companies are confidential and hard to reach. Still, after a number of interviews with several firms active in the industry a range of discount rates were obtained. Table 11 presents the results from the interviews with four different firms having knowledge of the discount rate.

Table 10. Discount rates for oil projects

Discount Rates (WACC)	
Firm	**Discount rate (%)**
BP - James Trantham	7.5
Chevron - Alan Tritthardt	7.5
Chevron - Alan Tritthardt	12.5
Encana - Dave Fryett	10
Fearnleys - Jacob Brechan	8
Fearnleys - Jacob Brechan	10
Average	**9.25**

In present time the oil firm seems to apply a discount rate ranging from 7.5 to 12.5% depending on the cost of capital and the risk of the project. The Average number is hence the 9.25 which we believe is a good assumption to use in the base case.

[209] Fryett, D. (03/03/2009)

6.2 Base Case

The base case of the Gold Digger analysis is based on the assumptions made in chapter 5. In the economic model the field life is divided into four different phases, exploration, start-up, peak production and decline. See table 12. The years are defined from 0 to end of field life 22 years.

Capital costs

During the *exploration phase* capital costs are generated by 3-D seismic survey and exploration drilling. The time plan is to the end of year 0 have commenced and finished the 3-D seismic survey. During year 1 and 2 the plan is to drill a total of 10 exploration wells. See table 12. The drilling schedule is a variable assumption since both exploration and injection wells may well be spaced out over a longer period depending both on ice conditions and the requirement to add injection wells as reservoir pressure changes over time. Likewise, the pre-production phase may well be stretched out by several years during the host government's permitting and approval process, a major factor in the North American arctic, both onshore and offshore.

During year 3 the *start up phase* begins, the capital cost is driven by the construction of the GBS, Pipeline and drilling of production and injection wells as well as subsea works. During year 5 the first two pools are drilled, one from the platform and one from drills-ships, at first the GBS is expected to begin producing at 50 % of peak production during year 5 which is also the last year of the *start up phase*. When both the pools are fully developed we are assuming that *peak production phase* will start in year 6. See table 12. *Peak production phase* starts in year 6 and lasts for 4 years. It is mainly the drilling of development wells, injections wells and subsea work that drives the capital costs during this period. See table 12.

Operating costs

As production starts in year 5 operating costs due to production and drilling from the platform is added to the total cost. See table 12.

Table 11. The Gold Digger model's step 2 – base case

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	n
	EXPLORATION			START UP			PEAK PRODUCTION				DECLINE				
Oil production/day (1000' barrels)	0	0	0	0	0	75	150	150	150	150	126	105	88	74	62
Decline (%)	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*
Yearly oil production (million barrels)	0	0	0	0	0	27	55	55	55	55	46	38	32	27	23
Ackumulated production (million barrels)	0	0	0	0	0	27	82	137	192	246	292	331	363	390	412
Revenues															
Capital costs															
Exploration															
3-D Seismic	87.5														
Exploration well		762	762												
Development															
GBS structure with topside				2300											
Production wells						788	788	788	788						
Injection wells						788	788	788	788						
Subsea						32	32	32	32						
Distribution															
Pipeline				3141											
Operating costs															
Production						404	404	404	404	404	404	404	404	404	404
Total cost	88	762	762	5441	0	2012	2012	2012	2012	404	404	404	404	404	404
PV(cost)	**-88**	**-697**	**-638**	**-4173**	**0**	**-1293**	**-1183**	**-1083**	**-991**	**-182**	**-167**	**-153**	**-140**	**-128**	**-117**
PV(volume)	**0**	**0**	**0**	**0**	**0**	**18**	**32**	**29**	**27**	**25**	**19**	**15**	**11**	**9**	**7**
PV(income)	**0**	**0**	**0**	**0**	**0**	**981**	**1796**	**1644**	**1504**	**1377**	**1055**	**809**	**620**	**475**	**364**

Revenues

During the last year of the *start up phase* revenues will be generated at 50 % level of peak production which is equivalent to 75 000 BPD. During year 6 as the *Peak production phase* is entered we are assuming that 150 000 BPD will be produced at the same level for 4 years. When entering the decline phase in year 10 a decline rate of 16.3% is assumed. This is the revenue side of the model. Yearly production times the oil price gives the model the USD revenues.

Assumptions

Oil in place	2,000
Recovery factor	25%
Recoverable oil	500
Days of operation	365
Peak production	**150,000**
Decline rate	**16%**
Cost manipulation	**0%**
Discount rate	**9%**
Well Scenario	**50**
Exploration wells	10
Nbr of years for exploration drilling	2
Production wells	20
Injection wells	20
Nbr of years for development drilling	4
oil price	**55.8**
NPV check	*0*

The results

The Gold Digger model then calculates the Net Present Value, by subtracting the costs from the revenues. Thereafter we have tested at what oil price the Net Present Value is zero. The Net Present Value is a function of the oil produced times the price of oil minus the all costs then discounted to year zero. In the function the oil price is X and NPV is equal to zero, thereby we are able to calculate the oil price. As we tested the base case an oil price of USD 55.8 reflects the entry barrier level.

6.3 Sensitivity analysis

The Gold Digger model analysis reflects an entry level price of USD 55.8. This is a relevant level based on that all assumptions made in the case are correct. In order to analyse the sensitivity of different assumptions and to provide an oil price spread for a more qualitative analysis a sensitivity analysis of the assumptions is provided. To analyse what factor affects the entry level price most significantly, a sensitivity analysis can be seen in figure 45. The red line reflects the base case of USD 55.8.

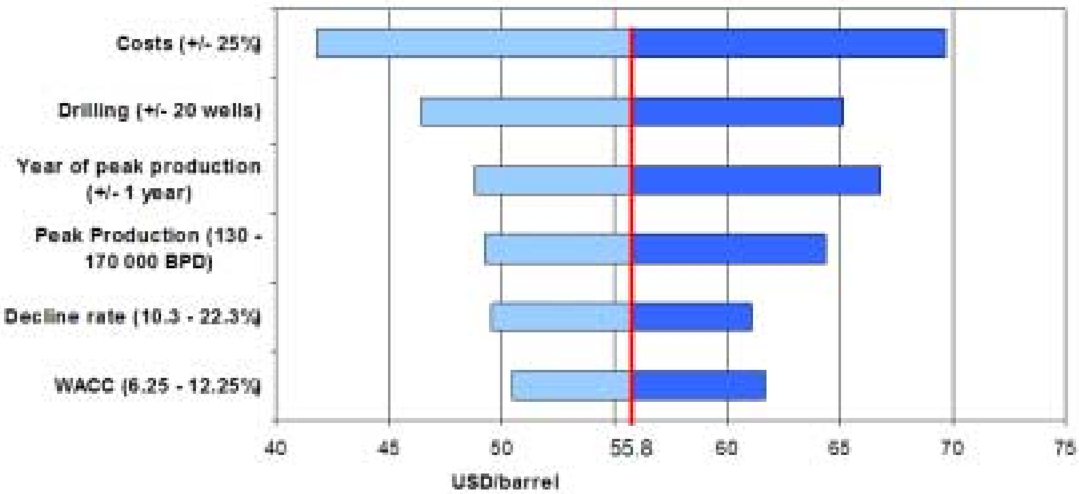


Figure 45. The spread of entry level oil price with the sensitivity analysis

Costs

We have found cost to be the truly significant factor for upstream petroleum projects. By varying the costs by adding or removing 25 % we found that this factor gives the most significant variation of the entry level oil price, spreading from USD 41.8 to 69.7. The costs are very uncertain factors which are difficult to predict and therefore it is important to analyse a rather large spread of the costs. Hence we choose +/- 25 % as the spread. The future of the cost structure is dependent on many factors such as the market development for commodity prices and the development of costs of investments in the offshore industry.

Drilling

Drilling costs is the second most significant cost. By reducing or increasing the number of wells necessary to be drilled by a drillship by the number 20, the entry price of oil will range from USD 46.4 to 65.1. This large price spread can be explained by the high well cost combined with drilling in the arctic environment. The well cost is mainly driven by the drilling structure and mobilisation costs. Extra wells might be needed to be drilled during the exploration phase if more wells than normal are dry, or during the development phase to improve the recovery factor. In contrast, fewer wells might be enough if it turns out that the exploration drilling is successful or that the oil is easy to recover which might lead to less injection wells or production wells.

Years of peak production
The number of years the field is able to hold the peak production is significant for the entry level of oil price. Adding or removing one year from the base case of four years of peak production will make an oil price spread of USD 48.8 to 66.8. The time of peak production is an effect of the size and characteristics of the field and the viscosity and quality of the oil. A large field with oil of proper quality might have a peak production lasting longer than a smaller field with poorer oil quality. The spectrum of three to five years of peak production eliminates some of the uncertainty caused by the field characteristics.

Peak Production
Exactly how many barrels per day that will be extracted is a difficult factor to predict. It depends on the characteristics of the field such as well pressure and viscosity of the oil. If the pressure in the field is high, the peak production will be higher as the case in Hibernia which had a higher output per day than planned. But if the pressure is low, the peak production might be lower than planned. We have a base case of 150 000 barrels per day which is the assumed to be the most likely scenario, and the sensitivity analysis is set to range from 130 000 – 170 000 barrels per day to eliminate the uncertainty. With a peak production of 130 000 barrels per day an oil price of USD 64.3 reflects the entry level. If the peak production is 170 000 barrels per day, the entry level oil price is USD 49.2.

Decline rate
The base case assumes a decline rate of 16.3% and in the sensitivity analysis decline rate of +/- 6% has been tested. Even though a wide range of decline rates have been tested, the entry level oil price does not face any major fluctuations. The entry level oil price ranges between USD 49.6 to USD 61.1. However it is important to take the decline rate into consideration since it is difficult to predict. As the case with peak production, the decline rate is heavily dependent on the characteristics of the oil pools found and how they are treated. If the pressure is low, the oil company operating the field might choose to raise the pressure in the pools by utilising injection wells.

WACC
We believe that the WACC is considered to be more certain as we have qualitative and quantitative data of which discount rates are currently being used by oil companies. We have set a base case of 9.25 and analysed the consequences when the WACC is ranging +/- 3% - units from the base case, hence from 6.25 to 12.25%. A low WACC requires an entry level oil price of USD 50.5, and a high WACC implies an entry level oil price of USD 61.7. The WACC does hence not affect the entry level of the oil price as significantly as the previous factors.

6.4 Scenario analysis

In the sensitivity analysis above we analysed five different assumptions and their respective impacts on the entry level oil price, we found that all five assumptions analysed had an impact. The five different assumptions can be categorised into two different categories that both have an effect on the economics of the EL 449 case. The first category is connected with macro economics and the future of market uncertainties. The second category is connected with the field production profile. In order to further analyse these two different categories, different scenarios within each category have been analysed below.

6.4.1 Market uncertainty scenarios

	WACC/Cost scenario - Oil price - Production 150 000		
55.8	-25.0%	0.0%	25.0%
6.3%	37.9	50.5	63.1
9.3%	41.8	55.8	69.7
12.3%	46.3	61.7	77.1

In order to analyse the market uncertainty scenario, a three by three matrix consisting of different scenarios for WACC and Cost was designed. The cost scenario tested was +/- 25 % and the WACC scenario was +/- 3 %. The base case is in the middle of the matrix and is based on the base case assumptions made in the case. These are assumptions based on the market situation of today or one year backwards. The main difficulty in using historical data is that the market changes all the time. The costs for upstream exploration and development are correlated with the oil price, see figure 41. As oil price increases the industry is motivated to make new investments and demand for contractor's increases very quickly. On the other hand, supply of contractors is limited and develops much slower than demand. The prices that oil companies must pay their contractors increases as demand rises. When oil prices peaked in 2008 the cost for expenditure was a record high, see figure 41. Today the oil price is much lower and we believe that prices will, in the short term, come down. On the other hand, as the price of oil today is low and little investment in upstream development is being made it is likely that a shortage of oil supply could be an issue in the long term. Such a shortage of supply would result in a higher oil price and thereby increase the upstream costs.

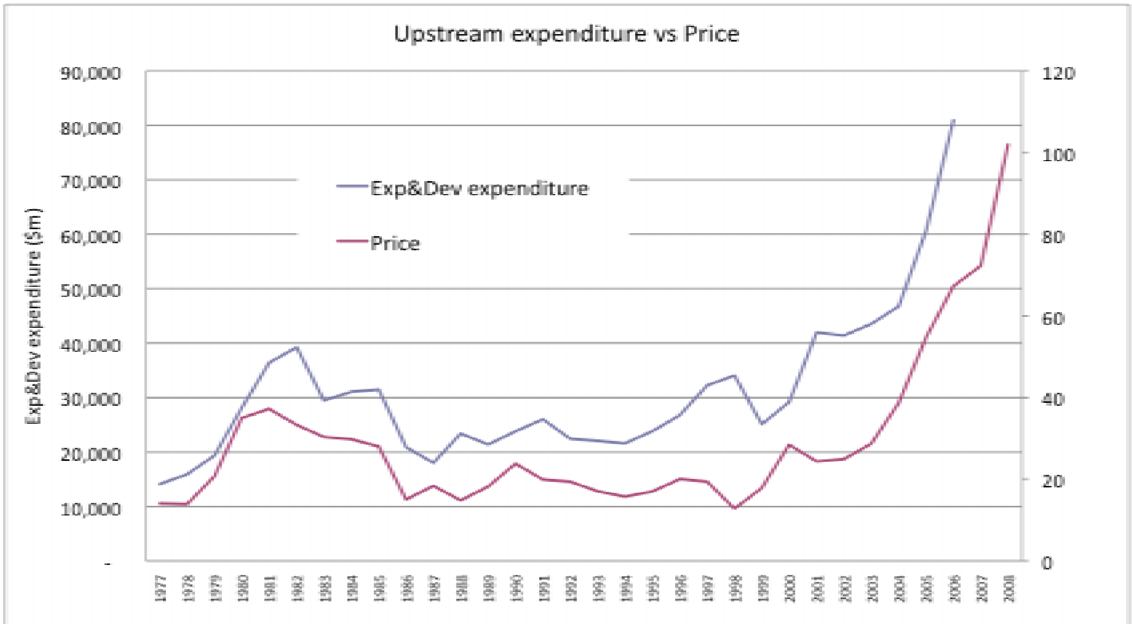


Figure 46. The oil rice versus the exploration and development expenditures[210]

The WACC is depending on the cost of capital from debt and equity and the balance between these. If we for the purpose of the analysis exclude the balance since it is

[210] Shepherd (2008), p. 8

irrelevant due to that we are not analysing a specific firm, the factors that are deciding the future of the WACC is the cost of debt and equity. The cost of debt and equity is very much dependent on the economic climate. Today, capital is relatively inexpensive because many central banks and governments are trying to stimulate the economy. If the economy is over stimulated and a situation of inflation should arise the central banks will try to hold capital in. This is done by raising the cost of debt by raising the interest rate. In a situation of further dampened economic climate, debt is likely to be even cheaper.

Table 12. Scenario analysis dependent on market uncertainty

		COST		
		LOW	MID	HIGH
WACC	LOW	Low oil price and further economic stimuli	Today's oil price and further economic stimuli	High oil price and further economic stimuli
	MID	Low oil price, in the short term cost should come down	BASE CASE	High oil price, on a longer term prices are likely to increase.
	HIGH	Low oil price and increased capital cost due to inflation	Today's oil price and increased capital costs due to inflation	High oil price and increased capital cost due to inflation

We believe that the low cost scenario is more likely on a short term since we have had such a steep price fall in oil since the start of 2008. This leaves the industry with an over-supply of contractors. The WACC is more difficult to predict as it is harder to analyse the fundamental consequences of the financial crises and the consequences of the governmental stimulation packages. Depending on the actions of the government the WACC will go up or down. In case the economic stimulation continues the WACC should remain on today's levels or even come down further. If the inflation scenario would arise, the WACC will increase due to raised interest rate and expected return on equity due to increased risks. The price spread for the low to high WACC is approx USD 10 and the price spread for low and high cost scenarios are closer to USD 30, hence the macro factor of future oil price is more important. However, we also believe that the price of oil in the longer term will come up because the fundamentals of supply and demand are pointing in a direction of supply shortage in the coming future. In the long-term we also believe that the WACC should increase some since the cost of capital is today historically low due to financial stimuli packages performed by governments.

6.4.2 Oil field characteristics scenarios

This scenario focuses on the characteristics of the oil field. In analysis three, factors that are impacted by the production profile are analysed, the decline rate, peak production and number of wells needed to be drilled.

The number of wells that are needed to be drilled in total are dependent on the characteristics of the field. If the productivity per well is low, many more wells will be needed to be drilled in order to maintain a high production rate. Also, if the pressure in the field is lower than expected, additional injection wells may be needed to enhance the recovery factor. On the contrary, the opposite scenario can be applied if fewer production and injection wells than has been assumed in the base case are needed should the oil be easier to recover than expected.

The peak production has economic impact but the exact number of barrels per day that will be extracted is a very uncertain factor. It depends on the characteristics of the field such as the oil pool pressure and the viscosity of the oil. If the pressure in the field is high, the peak production could be above the base case level, as was the case in Hibernia, which had a higher output per day a few years after production start than was first assumed. On the other hand if the pressure is low, the peak production might be lower than planned.

As in the case with peak production, the decline rate is heavily dependent on the characteristics of the oil pools found and how they are treated. If the pressure is low, the oil company operating the field might choose to raise the pressure in the pools by increasing the pressure by injection wells. If the pressure is good and the size of the pool is big, the decline rate will be lower.

The base case used is the most likely to occur and implies an entry level oil price of USD 55.8. If the pools have a less good characteristic than expected, such as more viscous oil and smaller pool sizes, both require more wells to be drilled, less peak production and an increased decline rate, this can have negative impact on the economics. Then a higher entry level oil price is needed to make the project economical. The worst scenario is a peak production of 130 000 barrels per day, a decline rate of 22.3% and the need for 70 wells to be drilled by drillship in order to extract the oil. This requires an oil price of over USD 82.3 for the project to be profitable.

On the other hand, , the situation could be the opposite. If the findings are bigger than expected than in the base case due to natural pressure and pool size, and the viscosity of the oil is more satisfying than expected, the case could be the opposite meaning greater peak production, less decline rate and even fewer wells needed to be drilled. The best case scenario, with only taking the field characteristics into consideration, would imply 30 drilled wells from drillship, 170 000 barrels of oil peak production and decline rate of 10.3%. This case would imply an entry level oil price of approximately USD 36.4. Obviously the oil companies do not believe in this best case because then the firms would have already invested since this scenario's oil price is much lower than the present oil price which would have motivated investments, which as of today has not yet happened.

Table 14 shows the different scenarios regarding the oil field characteristics. At today's oil price of little more than USD 50, the oil companies require large fields which can embrace a high peak production and a low decline rate. A large peak production of 170 000 barrels per day can make a field profitable at today's oil price even if many wells (50) have to be drilled, given that the decline rate is not higher than 16%. The decline rate, which makes the lowest impact on the required oil price, can still make a field profitable if less wells (30) need to be drilled. However, a low peak production and a high decline rate, i.e. a smaller field than the base case, might require an oil price of USD 58,7 to USD 82,5 higher than today's oil price. This means that in order to make the project economic a large field with good production characteristics is required as well as an expectation of an oil price at least double the long term historic average in real terms. In other words, for the companies to go ahead with the project they must believe in large resources in terms of peak production and that are not too complicated to produce in terms of number of wells and decline rate.

Table 13. Oil price affected by decline rate, peak production and wells drilled

	Decline rate/Peak production - Oil price - 30 wells		
46.4	130,000	150,000	170,000
10%	47.6	41.2	36.4
16%	53.5	46.4	40.9
22%	58.7	50.8	44.9

	Decline rate/Peak production - Oil price - 50 wells		
55.8	130,000	150,000	170,000
10%	57.2	49.6	43.7
16%	64.3	55.8	49.2
22%	70.5	61.1	53.9

	Decline rate/Peak production - Oil price - 70 wells		
65.1	130,000	150,000	170,000
10%	66.8	57.9	51.1
16%	75.1	65.1	57.5
22%	82.3	71.4	63.0

6.4.3 Worst Case and Best Case

The worst case and best case scenario is used to give an analysis of the economics of arctic oil based on the case of EL449. The best case assumes that all is in favour for arctic production. The field is producing 170 000 BPD, the decline rate is only 10.3 %, the discount rate is 6.25 %, the costs are down 25 % from the base case and the total number of wells drilled from drillship is only 30. In addition, peak production is maintained for five years. The best case is not very likely but we believe that it shows a good floor of where the economics in the arctic environment should be. The worst case is that exploration and development ends up much more expensive due to that we have increased all factors, the field is producing only 130 000 BPD, the decline rate is 22.3 %, the discount rate is 12.25 %, the costs are up 25 %, the number of wells is up 70 and the time of peak production is only three years. The best case illustrates an entry price level of USD 22.0 and the worst case illustrates an entry level of USD 138.6. Our analysis is that the reality is probably closer to the worst case than the best case, as we would probably otherwise see more activity in arctic regions which we do not see at the present time. The oil price is as of today (2008-05-06) USD 53 and that is likely to be below the entry level oil price.

Best case	**Base case**	**Worst case**
22.0	55.8	138.6

7 Theoretical discussion

This chapter aims to discuss the theoretical models that have been used in this case study.

7.1 Theoretical framework

This thesis objective is more of an empirical character than theoretical. Still, the theoretical models, value shop model and net present value model, are the tools that were needed to perform this case study and needed to be able to structure and analyse the empirical data.

However, the theories used are of good quality and very generic in form. The value chain theoretical model is frequently used to describe how firms create value, and the development of the value chain to value shop by Stabell & Fjeldstad can basically just be seen as an extension of the value chain model aiming to best describe a certain type of industry, like the upstream petroleum industry.

Even if this study is performed as a case study, which usually does not test a theory, this has been done by using parts of the theories and rebuilt them to suit our purpose.

7.2 The Gold Digger model

The thesis delivers a model development by merging and rebuilding two theoretical models to answer the objective of the thesis. The first objective of this thesis is to develop a model that can evaluate arctic offshore field concepts and estimate the cost drivers in order to calculate an entry level oil price. In chapter 4, this model is developed by rebuilding the value shop model for upstream petroleum industry from describing the predictive, and also by redesigning the NPV model to break out the unknown factor oil price and setting the NPV to zero. By combining the two models into the Gold Digger this objective is reached. Since there is no generic tool for this purpose before the Gold Digger model was developed, and we found the model very satisfying when it was tested during our research in the economics of arctic oil, we are certain that the model development has been made successfully. We believe this model can be used in other cases for solving similar objectives. It would be interesting to apply the model to several more cases to test it more extensively in order to make further improvements of the model.

The estimations and calculations in the model in a generic form are quite simple, but when applied to a case it is getting more complex. The most time consuming part is the empirical research needed to perform step 1. To develop a concept suitable for a specific area puts high demand on understanding the area’s characteristics and the environment surrounding it. To estimate the cost for the concept is also very difficult due to market changes and the fact that not all concepts are built and need to be purpose developed. In such a case, the cost estimations can beneficially be taken from another similar site and used as a proxy.

Step 2 in the Gold Digger model utilises an economic NPV model purpose built in MS Excel and developed by us in order to calculate the entry level of oil price when all cost drivers are known, part from the oil price. The model is carefully prepared to be a user friendly model with all cost drivers and cells linked to the calculation in order for future users to utilise it without needing to be professionals in Excel. This also makes it easy to change the assumptions and calculate different scenario outcomes.

The two models complement each other very well and we are very satisfied with the outcomes and analysis that have been realisable thanks to the model developments. Even though the models have been satisfactory for us we have some further improvements and comments, especially in the value shop for the upstream petroleum industry model by Stabell & Fjeldstad.

7.2.1 The Stabell & Fjeldstad model

The value shop model, or more specifically the value shop model for an oil exploration and field development company developed by Stabell & Fjeldstad has been used as a base for finding the cost drivers in this thesis and hence an extremely important part of the study. Generally, the model is satisfying and we are confident that all major cost drivers are recognised when using the rebuilt predictive parts of the two cycles in the model. The model follows the process of exploration and development and therefore the structure of the empirical data is more consistent and pedagogical to read and to analyse. The distinction between the exploration phase and the development phase is good and necessary since the two phases are significantly different from each other and also dependant on each other. Even if we are generally satisfied with the model there are a few improvements we would like to make that would have improved the work process in this thesis.

The model does not specifically include distribution, therefore we placed distribution of oil under the development circle, but in harsh and severe climates like the arctic, we believe that the distribution requires a deep investigation and generation of transportation concepts in itself. Therefore we would like to see the distribution as another, third cycle in the model. We also feel that much work had to be invested in order to structure the development phase in a pedagogic manner due to disorder in that chapter. We believe that by breaking out distribution into a paragraph of its own this disorder would be minimised naturally and the researcher would have to consume less time on structural work. The distribution is consistent with significant costs and should also therefore be better highlighted in the model. By breaking out the distribution the cost drivers and the costs of distribution will be better and more clearly highlighted to the reader. This will also go better with step two in the Gold digger model since the more the costs are segmented in the NPV analysis, the easier and more pedagogic the economic model will be to use and to analyse. As the model is, it does not take the distribution to the market into consideration at all. After being active in the industry for more than four months we have been in contact with many experts and specialists in the oil upstream industry - the distinction in the upstream petroleum industry between exploration, development and distribution is rather a rule than a norm. Furthermore, the development concept you choose is dependent on the findings in exploration, and the distribution you choose depends on the development concept choice. Hence we think another third cycle with distribution would be a great contribution to the model.

Secondly, the seismic survey is included in the problem finding of the exploration circle. Many times when a predictive analysis is being made, the seismic survey has not yet been conducted. In some cases such as in the arctic the equipment and technology needed for a seismic survey have to be tailored exclusively to the present environment. Therefore we found that the exploration circle can be divided into two circles. This would highlight the seismic survey better. The argument against such a proposition could be that the seismic survey could be viewed as a part of assembly of regional data. This is true but creates disorder in the structure and makes it less easy to analyse and understand the text. We see that by breaking out the exploration circle into exploration phase 1 (Seismic) and exploration phase 2 (Drilling) the model would be improved structurally and pedagogically. Another argument for breaking out exploration into two circles is that the seismic is dependent on the regional data and the drilling is dependent on the results of the seismic. The seismic survey is also a major milestone in the exploration phase, if the seismic shows good structures it makes sense to go ahead with drilling, but if seismic doesn't show good results the next circle should not be continued. Therefore it makes sense to break out seismic in order to represent the critical decision point that it actually is in the process.

The improvements with two extra circles in the value shop model would influence the Gold Digger model's step 1 as well, since the Gold Digger model's step 1 is exclusively built on the value shop model. Figure 47 shows an improved step 1 of the Gold Digger model that would have eliminated the disorder and made the structure and analysis even easier for us in this study.

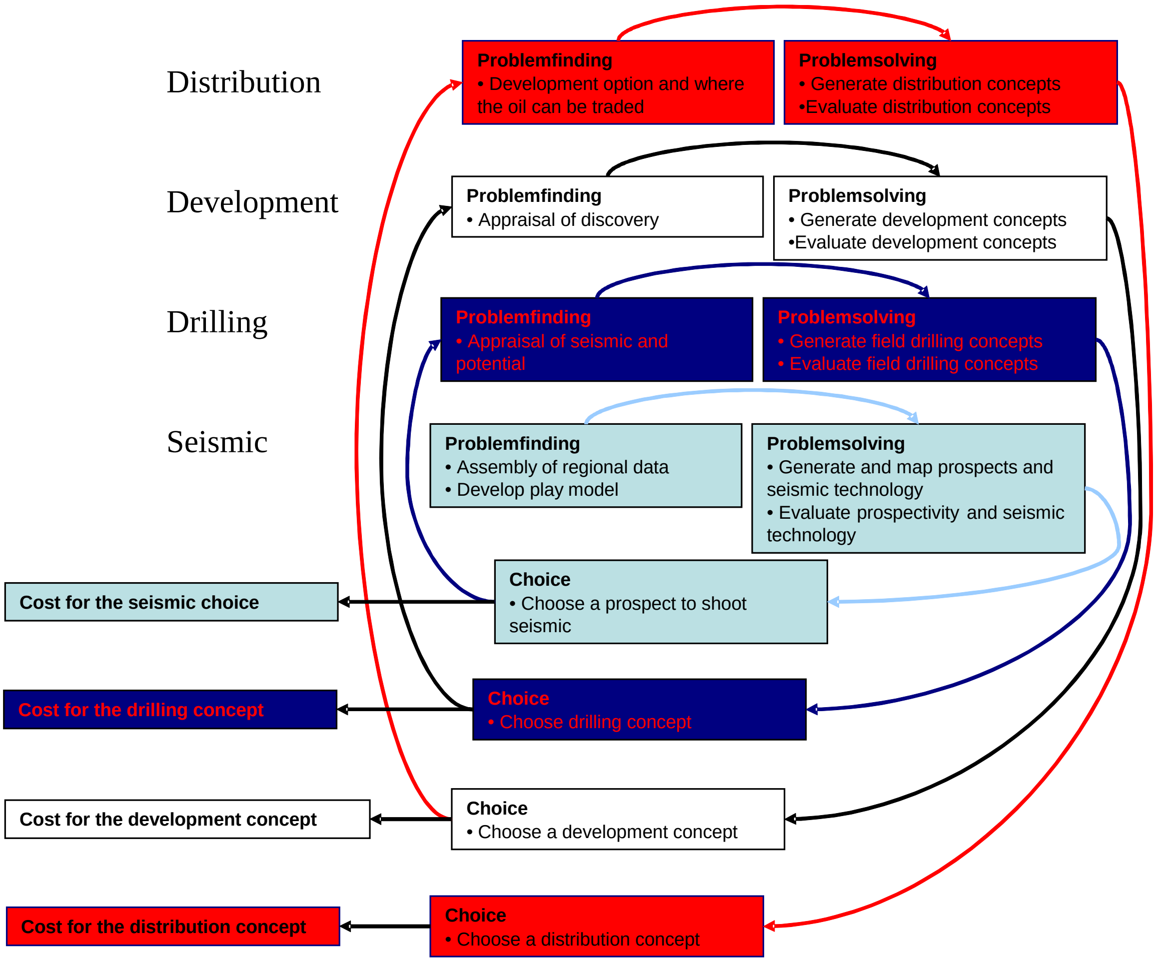


Figure 47. Recommendation of improvements of the Gold Digger model's step 1

8 Conclusions

This chapter aims to address the major conclusions that we have been able to make theoretically and empirically. The conclusions are based on three defined objectives.

Develop a model for evaluating arctic offshore field concepts and estimating the cost drivers of the concept in order to calculate an entry level oil price at which oil firms can beneficially invest in the arctic production.

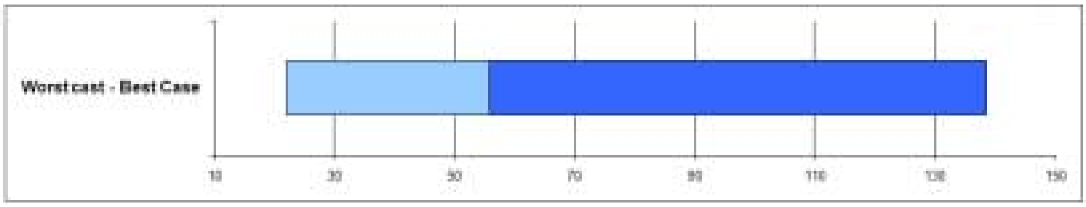
This objective was reached in an iterative process where empirical data and theoretical models were studied simultaneously. It was clear to us after the initial empirical work that we needed some theoretical models that could work as a base to help build up the structure for our empirical data. It was decided after much reading that a redesigned predictive version of Stabell & Fjellstad's value shop model would work as a suitable structure for our technological cost driver analysis, and thus the first half of the objective was answered. In interviews and in written material we understood that the NPV method was commonly used in the upstream petroleum industry in order to evaluate investment opportunities. We used our financial knowledge to find the suitable theoretical references for describing such a model and then redesigned it in order to be tailored to our needs, hence using input from the cost driver analysis and setting the NPV to zero and oil price to the unknown factor. By combining the value shop concept together with NPV modelling we designed a functional model named Gold Digger for the objective. We have also found the need to do some improvements to the value shop model in order to work in a predictive manner. We have also found the need to recommend future users of the model to add circles for seismic and distribution in the Gold Digger model's step 1, in order to enhance the structure.

Describe necessary technologies applicable in the arctic for extracting oil and delivering it to the market.

The model was used and tested by conducting a predictive case study of an arctic project. The case study was mainly chosen as our method since all oil fields have very different characteristics and it is therefore practically impossible to create a general view of the economics of arctic oil. Instead it is more creative to build up a realistic case which can then be analysed from different scenarios in order to evaluate the economics of arctic oil. The structure of the case was partly based on Stabell & Fjellstad's value shop, and when building up the case necessary technologies were presented and analysed. We found that the most suitable way for exploration in the short term is to use an arctic drillship with technology that exists today. In the medium term we found that seabed based rigs are likely to enter the market for drilling and could open opportunities. Whatever technology used, ice management will be necessary in all exploration activities. We also found that a major cost driver for the well cost in the arctic is the mobilisation cost. The development of the field is most likely done from a GBS, TLP or subsea. In the short term we found that the GBS is the most commonly used structure in arctic environments. In the mid to longer term the TLP or subsea technology might develop to be the leader. The TLP allows production from greater water depths but the technology is questioned. The subsea has been realised for gas production of the coast of Norway but the safety and risks must be carefully evaluated before placing such a production system in heavily ice infested waters where it will be extremely hard to perform maintenance work during the winter.

Apply the developed model to a case study in order to find an entry level oil price for the case study.

In order to find the entry level oil price for our case we used all the input that was found in the cost driver analysis in step 1 of the Gold Digger model. All assumptions that were made for the NPV model in the second step of the Gold digger model was hence very carefully researched, therefore we can claim that our case study holds a high validity. The outcome of the analysis was that a base case assumed an entry level oil price of USD 55.8 per barrel of oil in order for the case to be economical. We analysed the case with sensitivity analysis and scenario analysis in order to test in what span the entry level oil price should be within. We found that in the best case, assuming a large field, low decline, low costs, little drilling and a low WACC, the very lowest entry level oil price is USD 22.0. If assuming the worst, hence a small field, high decline, high costs, much drilling and a high WACC, the entry level oil price is USD 138.6. We believe that in reality the entry level oil price is more towards USD 138.6 than 22.0. This can be proven by the fact that no offshore production in the Canadian Beaufort is taking place and the oil price is above USD 22.0 as of today.



8.1 The easy oil is coming to its end

In the beginning of this thesis we stated that the time of the easy oil is coming to an end. This is true. In the Canadian Beaufort, oil companies have made commitments to invest billions of USD and there are many other arctic areas that are about to be explored. We can conclude that the next frontier of arctic oil will be difficult to access and will be extremely expensive to extract. This tells us that the oil we are consuming today is cheap. The cost of all future supply of oil will increase and hence the marginal cost of the oil will also increase. This will in the longer term push the price of oil to higher levels and step by step open up new frontiers for oil supply.

8.2 Further research

The topic of oil and new oil fields are highly up-to-date and changes in the industry regarding costs and prices happen rapidly. In our analysis we take different scenarios into account regarding price changes and other economic factors but this could be further investigated and analysed with more scenarios and other factors included. The creation of a dynamic model which includes the cost trends and their correlation to the oil price would help to an even better understanding of the oil price required for entering the arctic. The creation of such a model would require in-depth investigation of the trends of all cost drivers used in this study and could be the objective for further studies. This would include investigation of rig rates and construction of production platforms in correlation to oil price and demand. Trends on offshore/onshore oil exploration would be necessary, but also analysing steel prices in correlation to supply, demand and market changes.

We have used a fixed oil price in our analysis which not is completely realistic. The analysis of the future oil price and the average annual growth of the price would improve the analysis. Such a study would include the trends for world market oil price and an analysis of the future trends regarding supply and demand.

The WACC is another factor which could be further investigated in order to develop trends of a possible future. This would imply an analysis of the risks in different projects, the stock holder's expected return and an analysis of the interest rates and debt-to-equity ratios.

More scenarios would give more accurate view of the costs for operating in the arctic and to what price it is beneficial to enter it and can be a subject for further studies. Also to evaluate more proxies and peers would be of interest of investigating since it would imply more accurate costs.

We believe it would be very illuminating to set the costs and the whole case study scenario against known projects in other frontier areas, especially deep water, to show how large or small the Arctic premium is over other areas. It would also be useful to compare this case study with other different Arctic environments such as the Barents Sea, West Greenland and the Russian east coast north of Sakhalin which all are highly prospective areas.

Lastly it would be good to run the whole model for an Arctic gas field since gas is believed to be an important Arctic resource in the future.

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10 Appendices

Appendix I. The Gold Digger Model

Assumptions

Oil in place	2,000
Recovery factor	25%
Recoverable oil	500
Days of operation	365
Peak production	**150,000**
Decline rate	**16%**
Cost manipulation	**0%**
Discount rate	**9%**
Well Scenario	**50**
Exploration wells	10
Nbr of years for exploration drilling	2
Production wells	20
Injection wells	20
Nbr of years for development drilling	4
oil price	**55.8**
NPV check	*0*

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
	EXPLORATION			START UP			PEAK PRODUCTION				DECLINE												
Oil production/day (1000' barrels)	0	0	0	0	0	75	150	150	150	150	126	105	88	74	62	52	43	36	30	25	21	18	15
Decline (%)	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*	*-16%*
Yearly oil production (million barrels)	0	0	0	0	0	27	55	55	55	55	46	38	32	27	23	19	16	13	11	9	8	6	5
Ackumulated production (million barrels)	0	0	0	0	0	27	82	137	192	246	292	331	363	390	412	431	447	460	471	480	488	495	500
Revenues																							
Capital costs																							
Exploration																							
3-D Seismic	87.5																						
Exploration well		762	762																				
Development																							
GBS structure with topside				2300																			
Production wells						788	788	788	788														
Injection wells						788	788	788	788														
Subsea						32	32	32	32														
Distribution																							
Pipeline				3141																			
Operating costs																							
Production						404	404	404	404	404	404	404	404	404	404	404	404	404	404	404	404	404	404
Total cost	88	762	762	5441	0	2012	2012	2012	2012	404	404	404	404	404	404	404	404	404	404	404	404	404	404
PV(cost)	**-88**	**-697**	**-638**	**-4173**	**0**	**-1293**	**-1183**	**-1083**	**-991**	**-182**	**-167**	**-153**	**-140**	**-128**	**-117**	**-107**	**-98**	**-90**	**-82**	**-75**	**-69**	**-63**	**-58**
PV(volume)	**0**	**0**	**0**	**0**	**0**	**18**	**32**	**29**	**27**	**25**	**19**	**15**	**11**	**9**	**7**	**5**	**4**	**3**	**2**	**2**	**1**	**1**	**1**
PV(income)	**0**	**0**	**0**	**0**	**0**	**981**	**1796**	**1644**	**1504**	**1377**	**1055**	**809**	**620**	**475**	**364**	**279**	**214**	**164**	**126**	**96**	**74**	**56**	**43**

Appendix II. Exploration

Total well cost

Charter cost	123,691,711
Bunker costs	20,452,608
Materials	8,238,064
total well cost	**152,382,383**

Drillship and Ice Management

	Operation	Mob. in	Mob. out	Tot days per exp. well	Charter rate	Charter cost	Bunker use	Bunker cost	Bunker cost/day	Bunker cost
Drillship	67	30	30	127	675,000	85,632,723	100	461	46,062	5,843,602
Supply vessel 1	67	30	30	127	50,000	6,343,165	50	461	23,031	2,921,801
Supply vessel 2	67	30	30	127	50,000	6,343,165	50	461	23,031	2,921,801
Ice breaker 1	67	30	30	127	100,000	12,686,329	75	461	34,547	4,382,702
Ice breaker 2	67	30	30	127	100,000	12,686,329	75	461	34,547	4,382,702
					975,000	123,691,711			161,218	20,452,608

Material Costs

Section nbr	Tot. casing tonnes	Tot. casing cost	Mud m^3	Mud cost	Cemente m^3	Cemente cost
1	31	91,608	66	131,339	26	2,649
2	218	654,528	343	685,069	553	55,256
3	354	1,062,992	341	682,788	676	67,555
4	631	1,894,059	175	349,774	411	41,145
5	511	1,532,749	15	29,288	181	18,138
Total	1,745	5,235,935	939	2,817,385	1,847	184,743

Drilling Assumptions

Sea depth	1000	m
Drilling speed < 2100	10	m/s
Drilling speed 2100 - 4300	7	m/s
Drilling speed > 4300	5	m/s
Joint speed	60	sections/h
Speed for run in hole	700	m/h
Riser speed	50	m/h
Time required to prepare BOP	8	h
Time required to run BOP	24	h
Time required to test BOP	12	h
Time required to do logging	36	h
Time required to do circulation	3	h
Time required for cementing	6	h
Time required to test casing	6	h
Time required to drill out shoe	2	h
M/U time	4	h

Drilling Operations General Assumptions

Section nbr	Depth	Drilled	Hole size	Casing size	Casing weight(kg/m)	Tot. casing tonnes	Cemented volume	Cemente m^3	Mud volume m^3
1	1100	100	36	30	305	31	20	26	66
2	2100	1000	26	20	198	218	419	553	343
3	4300	2200	18	13 3/8	107	354	512	676	341
4	6600	2300	12	9 5/8	113	631	312	411	175
5	7000	400	9	7	85	511	137	181	15
						1745	**1399**	**1847**	**939**

Appendix III. Exploration Drilling

Drilling Operations Time

	Operation	Time Hrs
1	Set drillship DP on location	24
2	**M/U 36" BHA. Tag seabed, Drill ca1000m-1100m**	**10**
3	Circulate clean . Wiper trip. POH	3
4	M/U Guide base, conductor housing & 30" casing. RIH	3
5	Cement 30" casing,POH stinger	7
6	M/U 26" BHA & RIH	4
7	**Drill 26" hole from 1100m to 2100m**	**100**
8	POH	2
9	M/U 18 3/4" BHA, 18 3/4" csg hngr, & run 20" casing	21
10	RIH	1
11	Circulate clean .	3
12	Cement 20" casing to seabed	6
13	Prepare BOP	8
14	Run subsea BOP's and Riser	20
15	Rig up surface equipment and test BOP	15
16	M/U with 17 1/2" BHA. Test casing. Drillout shoe	15
17	**Drill 17.1/2"hole from 2100m to4300m**	**316**
18	POH	6
19	Logging well	36
20	Wiper trip	12
21	M/U 18.3/4", 13.3/8" csg hngr, & run 13.3/8" casing.	41
22	RIH	1
23	Cement 13.3/8" Casing	6
24	M/U with 12.1/4" BHA. Test casing. Drillout shoe	18
25	**Drill 12.1/4" hole from 4300m to 6600m**	**460**
26	POH	9
27	Logging well	36
28	Wiper trip	19
29	M/U 18-3/4" x 9.5/8" csg hngr, r/u & run 9.5/8" casing.	42
30	RIH	1
31	Cement 9.5/8"casing	6
32	M/U with 8.1/2"" BHA. Test casing. Drillout shoe	42
33	**Drill 8.1/2" hole from 6600m to 7000m**	**80**
34	Logging well	36
35	Wiper trip	20
36	MU 7"liner	7
37	RIH on drillpipe,hang of in 9.5/8" casing at6500m.	10
38	Cement 7" liner	6
39	POH	9
	Total Days	**61**

40	**[1] DST / Production Test, Single Zone**	
41	RIH bit/scrapers, Circulate well to completion brine,POH	23
43	M/U TCP guns to DST assembly	4
44	R/U & run DST test string	10
46	Set packer / landout subsea BOP's & test	6
47	N/U flowhead & production equipment	6
49	Open circ.valve,circulate drillpipe to light brine,close valve	6
50	Perforate well	1
52	Perform clean up & flow well	12
53	Flow well at reduced rate	12
55	Perform build up test	12
56	Flow well at maximum rate	12
58	Perform build up test and collect samples	12
59	Unseat production packer & kill well	6
61	R/D test equipment & pull test string & BOP's	20
	Total Days	**5.92**

Appendix IV. Development

Gravity Based Structure

CAPEX	
Platform	1,000,000,000
Topsides	1,300,000,000
Total	**2,300,000,000**

OPEX	
Prod. & GBS Drilling	404,000,000

Subsea

CAPEX	127,091,680

Development Drilling

Total well cost

Charter cost	128,201,086
Bunker costs	21,198,240
Materials	8,238,064
total well cost	**157,637,390**

Appendix V Development Drilling

Drillship and Ice Management

	Operation	Mob. in	Mob. out	Tot days per exp. well	Charter rate	Charter cost	Bunker use	Bunker cost	Bunker cost/day	Bunker cost
Drillship	71	30	30	131	675,000	88,754,598	100	461	46,062	6,056,640
Supply vessel 1	71	30	30	131	50,000	6,574,415	50	461	23,031	3,028,320
Supply vessel 2	71	30	30	131	50,000	6,574,415	50	461	23,031	3,028,320
Ice breaker 1	71	30	30	131	100,000	13,148,829	75	461	34,547	4,542,480
Ice breaker 2	71	30	30	131	100,000	13,148,829	75	461	34,547	4,542,480
					975,000	128,201,086			161,218	21,198,240

Material Costs

Section nbr	Tot. casing tonnes	Tot. casing cost	Mud m^3	Mud cost	Cemente m^3	Cemente cost
1	31	91,608	66	131,339	26	2,649
2	218	654,528	343	685,069	553	55,256
3	354	1,062,992	341	682,788	676	67,555
4	631	1,894,059	175	349,774	411	41,145
5	511	1,532,749	15	29,288	181	18,138
Total	1,745	5,235,935	939	2,817,385	1,847	184,743

Drilling Assumptions

Sea depth	1000	m
Drilling speed < 2100	10	m/s
Drilling speed 2100 - 4300	7	m/s
Drilling speed > 4300	5	m/s
Joint speed	60	sections/h
Speed for run in hole	700	m/h
Riser speed	50	m/h
Time required to prepare BOP	8	h
Time required to run BOP	24	h
Time required to test BOP	12	h
Time required to do logging	36	h
Time required to do circulation	3	h
Time required for cementing	6	h
Time required to test casing	6	h
Time required to drill out shoe	2	h
M/U time	4	h

Drilling Operations General Assumptions

Section nbr	Depth	Drilled	Hole size	Casing size	Casing weight(kg/m)	Tot. casing tonnes	Cemented volume	Cemente m^3	Mud volume m^3
1	1100	100	36	30	305	31	20	26	66
2	2100	1000	26	20	198	218	419	553	343
3	4300	2200	18	13 3/8	107	354	512	676	341
4	6600	2300	12	9 5/8	113	631	312	411	175
5	7000	400	9	7	85	511	137	181	15
						1745	**1399**	**1847**	**939**

Appendix VI Development Drilling Operations

Drilling Operations Time

	Operation	Time Hrs
1	Set drillship DP on location	24
2	**M/U 36" BHA. Tag seabed, Drill ca1000m-1100m**	**10**
3	Circulate clean . Wiper trip. POH	3
4	M/U Guide base, conductor housing & 30" casing. RIH	3
5	Cement 30" casing,POH stinger	7
6	M/U 26" BHA & RIH	4
7	**Drill 26" hole from 1100m to 2100m**	**100**
8	POH	2
9	M/U 18 3/4" BHA, 18 3/4" csg hngr, & run 20" casing	21
10	RIH	1
11	Circulate clean .	3
12	Cement 20" casing to seabed	6
13	Prepare BOP	8
14	Run subsea BOP's and Riser	20
15	Rig up surface equipment and test BOP	15
16	M/U with 17 1/2" BHA. Test casing. Drillout shoe	15
17	**Drill 17.1/2"hole from 2100m to4300m**	**316**
18	POH	6
19	Logging well	36
20	Wiper trip	12
21	M/U 18.3/4", 13.3/8" csg hngr, & run 13.3/8" casing.	41
22	RIH	1
23	Cement 13.3/8" Casing	6
24	M/U with 12.1/4" BHA. Test casing. Drillout shoe	18
25	**Drill 12.1/4" hole from 4300m to 6600m**	**460**
26	POH	9
27	Logging well	36
28	Wiper trip	19
29	M/U 18-3/4" x 9.5/8" csg hngr, r/u & run 9.5/8" casing.	42
30	RIH	1
31	Cement 9.5/8"casing	6
32	M/U with 8.1/2"" BHA. Test casing. Drillout shoe	42
33	**Drill 8.1/2" hole from 6600m to 7000m**	**80**
34	Logging well	36
35	Wiper trip	20
36	MU 7"liner	7
37	RIH on drillpipe,hang of in 9.5/8" casing at6500m.	10
38	Cement 7" liner	6
39	POH	9
	Total Days	**61**

	Permanent Completion-Development well	
62	RIH bit/scrapers, Circulate well to completion brine,POH	26
63	M/U TCP guns to a permanent packer,RIH on electric line	8
64	M/U and run the completion string and land off in packer	47
65	Close BOP rams,test tubing and annulus,open BOP rams	6
66	Pull tubing back ca 1000m,install SSSV,space out subsea tubing h	12
67	RIH completion tubing,land in subsea wellhead	2
68	Run wireline,open circulating valve,circulate completion to ligh	6
69	Wireline Instal plug in tubing hanger	2
70	Release BOP pull marine riser and BOP,set back BOP.	24
71	Set back BOP	8
72	Pick up the Subsea tree,prepare to run on production riser.	8
73	Run Xmas tree on production riser to sea bed.	24
74	Land Xmas tree on wellhead-establish hydraulic conection to co	12
75	Rig up wireline, pull plugs,check SSV and drift completion	24
76	Perforate well	2
77	Clean up well and flow through test seperators	12
78	Close SSSV,close valves on Subsea tree,disconnect prod.riser LMR	6
79	Pull and laydown production riser	20
80	Run Xmas tree cap on drillpipe ,instal same POH	4
	Total Days	**10.54**

Appendix VII. Drilling Materials and Bunnker Costs (Explorationa and Development

Materials Assumptions

Cement water mix	44	l/100kg
Steel price	3000	$/tonnes
Cement price	100	$/tonnes
Mud price	2000	$/m^3

Bunker Cost Input

2000: /MTD	279.5
2001: /MTD	241.25
2002: /MTD	230.75
2003: /MTD	279.5
2004: /MTD	377
2005: /MTD	533.5
2006: /MTD	608.5
2007: /MTD	662.56
2008: /MTD	949.47
2009; JAN-MAR: /MTD	444.19
Average	**460.622**

Appendix VIII. Development Subsea

Item	Weight/length/time/number [tonnes]/[m]/[day]/[-]		Unit price [USD]		Cost [USD]
Procurement and onshore subcontracts					
Project Management and Engineering	230	work days	12,000	/ day	2,760,000
90 km 8-inch injection pipelines (8/16-inch wall thickness)	64	tonnes / km	3,000	/ tonne	17,280,000
65 km 10-inch carbon steel pipeline (7/16-inch wall thickness)	70	tonnes/km	3,000	/ tonne	13,650,000
25 km 24-inch carbon steel pipeline (8/16-inch wall thickness)	192	tonnes/km	3,000	/ tonne	14,400,000
Spoolbase activities for 8-inch and 10-inch pipeline (fabrication, field joint coating, general costs)	155	km	120,000	/ km	18,600,000
8 8-inch spoolpieces (35 m each)	64	tonnes / km	3,000	/ tonne	53,760
16 10-inch spoolpieces (35 m each)	70	tonnes/km	3,000	/ tonne	117,600
2 24-inch spoolpieces (35 m each)	192	tonnes/km	3,000	/ tonne	40,320
8-inch pipeline heads (pig launchers & receivers, pigs)	4		50000		200,000
10-inch pipeline heads (pig launchers & receivers, pigs)	4		60000		240,000
24-inch pipeline heads (pig launchers & receivers, pigs)	2		90000		180,000
Control umbilicals including subsea control system components (Subsea Umbilical Termination Units - SUTA, Subsea Distribution Units – SDU)	90	km	200000	/ km	18,000,000
Manifolds	4		250000		1,000,000
Main manifold	1		400000		400,000
Installation and offshore subcontracts					
Reel-lay vessel (8-inch and 10-inch pipeline)	50	days	300,000	/ day	15,000,000
S-lay vessel (36-inch pipeline)	9	days	450,000	/ day	4,050,000
Support vessel with Work class Remote Operated Vehicles (ROV's) for tie-ins, pre-commissioning	80	days	150,000	/ day	12,000,000
Survey vessel	80	days	110,000	/day	8,800,000
Platform operations (umbilical pull-in, leaktest)	80	days	4,000	/ day	320,000
Total					**127,091,680**

Appendix IX. Distribution – Pipeline

Pipeline Costs

EL 449 Pipeline Cost	Length	Diameter	Cost USD
Non Dredged	501	36	980,097,268
Dredged	105	36	2,161,062,750
Total			**3,141,160,018**

Pipeline Peers

Non Dredged Pipeline Be	Length	Diameter	Cost USD	Cost/km	Cost per km and diam	Source
Nord Stream, Baltic Sea	1,220.0	45.4	4,865,870,000.0	3,988,418.0	87862.808	www.nordstream.com
Langeled, North Sea	1,200.0	44.0	2,484,533,000.0	2,070,444.2	47055.549	www.subsea.org
Second Interconnector Pipe	195.0	30.0	289,322,000.0	1,483,702.6	49456.752	www.subsea.org
Blue Stream	1,218.3	48.0	3,400,000,000.0	2,790,834.9	58142.395	www.offshore-technology.com
Tecnip specialist	606.0	36.0	636,772,500.0	1,050,779.7	29188.325	interview
Mean					**54341.166**	
Dredged Pipeline Benschmarks						
Hebron - Hibernia	40.0	?	823,262,000.0	20,581,550.0		www.offshore-technology.com

Tecnip Pipeline Assumption

Item	Weight/length/time/number s]/[m]/[day]/[-]		Unit price [USD]		Cost [USD]
Nbr of km	606	km			
Procurement and onshore subcontracts					
Project Management and E	230	work days	12000	/ day	2,760,000
606 km 36-inch injection pip	288	tonnes / km 1)	3000	/ tonne	523,584,000
2 36-inch spoolpieces (35 m	288	tonnes/km 1)	3000	/ tonne	864,000
36-inch pipeline heads (pig	2		120000		240,000
Installation and offshore subcontracts					
S-lay vessel (36-inch pipelin	151	days	450000	/ day	67,950,000
Mobilisation, demobilisation	2		427500	/ day	855,000
Transit 5)	20		495000	/ day	9,900,000
Construction vessel with W	10	days	150000	/ day	1,500,000
Mobilisation, demobilisation	3		142500	/ day	427,500
Transit	20		165000	/ day	3,300,000
Survey vessel for touchdow	151	days	110000	/day	16,610,000
Mobilisation, demobilisation	2		104500	/ day	209,000
Transit	20		121000	/ day	2,420,000
Trenching vessel with trenc	21	days	140000	/ day	2,940,000
Mobilisation, demobilisation	1		133000	/ day	133,000
Transit	20		154000	/ day	3,080,000
Sub-total (excl. pre-commissioning & transits)					**636,772,500**

Appendix X. WACC

Discount Rates (WACC)

BP	7.5	James Trantham
Chevron	7.5	Alan Tritthardt
	12.5	
Encana	10	Dave Fryett
Fearnleys	8	Jacob Brechan
	10	
Average	**9.25**	

Appendix XI. Production wells versus injection wells in oil and gas fields. Data from www.offshore-technologies.com

Field name	Production wells	Injection wells
Ettrick Field, United Kingdom	3	4
Hibernia Field, Canada	30	25
Glitne, North Sea Northern, Norway	5	2
Clair Field, Shetlands, United Kingdom	15	9
Jotun, North Sea Northern, Norway	11	8
Visund, North Sea Northern, Norway	13	8
Oseberg Sør, North Sea Northern, Norway	16	14
Tot	93	70
Ratio	1.3	