



Cost Overruns and the Subsequent Performance of Developments on the Norwegian Continental Shelf

How have oil and gas field developments with large cost overruns in investments on the Norwegian continental shelf performed over time?

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This thesis was written as part of the Master of Science in Economics and Business Administration at NHH. Please note that neither the institution nor the examiners are responsible – through the approval of this thesis – for the theories and methods used, or results and conclusions drawn in this work.

Disclaimer:

This thesis was written as part of the Master of Science in Economics and Business Administration at NHH. Please note that none of the oil companies, which have provided us with confidential information through their Plans for Development and Operation, have validated or contributed to any of the analyses or results, hence the results and analyses are done by the authors and any conclusion drawn is based on these analyses.

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Executive Summary

This report provides an analysis and evaluation of how oil and gas field developments on the Norwegian continental shelf perform over time, after occurring significant cost overruns in initial investments.

The analyses are mainly quantitative, and methods used include calculation of net present values, internal rates of return, and break-even prices of the licenses. The report then looks into how these have developed over the lifetime of the developments. Other analyses, such as variance analyses, were used to look at how different factors affected the deviations from PDO and the change in net present value.

The results of the licenses analyzed show that they manage to keep a positive NPV, but longer production time causes lower internal rates of return for three of the fields, and higher break-even prices for all of them. What causes the NPVs to stay positive is mainly the strong increase in oil and gas prices over the period from approval of the PDO till 2013. Without this effect, all the licenses would be worse off than in the PDO. All the licenses failed to meet the expected costs on operational expenses, based on the prolonged lifetimes, and the capital expenses increased significantly as well.

The report finds the companies are too optimistic when estimating the production profile, operating costs and capital expenses. They are also strongly dependent on the rise in oil and gas prices, which is the main reason for their successes.

The recommendations given in the report are to put more effort into estimating operational expenses, lifetime of the field, capital expenditure, and the sensitivity to the oil and gas prices. This is to reduce the errors from estimations, and thereby be closer to the actual NPV, IRR and B/E-prices from the project.

Limitations to the report are that only a small number of licenses were analyzed, only licenses with cost overruns were included, all the fields were around 20 years old, and the interrelation between oil and gas prices, capital investments, and daily and total production makes it hard to identify which factor initially drives the costs and revenues, and with which magnitude.

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1 Introduction

1.1 Problem Statement and Hypotheses

How have oil and gas field developments with big cost overruns in investments on the Norwegian continental shelf performed over time?

Hypotheses:

- Cost overruns undermine the net present value
- The positive market development compensates for the cost overruns
- Prolonged lifetime for a field will have a positive effect on the total production of petroleum products
- Estimated ultimate recoverable reserves (URR) in the PDOs are too optimistic
- Higher capital costs lead to a higher degree of URR because of investments in technology and more effective and bigger equipment

1.2 Motivation

Revenues from the petroleum industry contributed 23% of the value creation in Norway in 2012, more than twice as much as the land industries. By the end of 2012 there have also been invested more than 3 000 billion kroner in the petroleum industry (Ministry of Petroleum and Energy, 2013). The comparative size of the petroleum sector can be seen in figure 1, which clearly shows the magnitude of the industry in economic terms relative to the rest of the Norwegian economy.

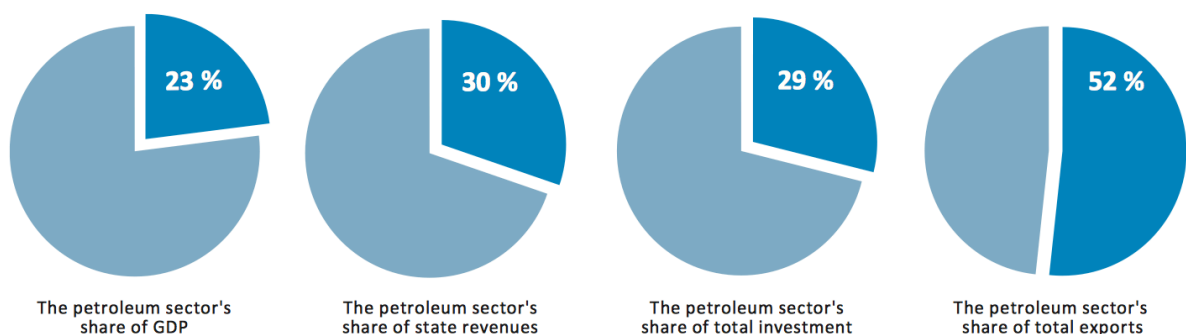


Figure 1 - Macroeconomic indicators for the petroleum sector 2012 (Norwegian Petroleum Directorate, 2013)

Because of the special tax and the big numbers, costs and revenues from this sector are very important for the Norwegian national budget, and therefore Norwegian society, and the recent focus

on cost overruns makes for an interesting topic. As many of the industry's costs generate tax refunds, the Norwegian people are indirectly paying for this meaning that every Norwegian is affected by these cost overruns. Discovering where these costs occur and maybe finding that they also produce other advantages, is not just interesting for us and the oil companies, but also the Norwegian government, and everyone affected by their decisions regarding regulation of the petroleum industry.

When a development on the Norwegian continental shelf goes over budget, 89.2% of the investments are paid for indirectly by the tax payers in Norway. The Norwegian government wants to make sure the oil industry uses less money than they have done recently so, by shifting more of the risk to the companies, the government predicts these entities will become more cost aware (Riise, 2013).

Some say the reasons for the high cost overruns are due to the use of international yards (Lindeberg, 2013), but a report ordered by the Norwegian Petroleum Directorate in 2013, "Vurdering av gjennomførte prosjekter på norsk sokkel", drew another conclusion. It concluded that the cost overruns using international yards are due mostly to faults and shortcomings in the contracts and lack of follow-up by the operators (Lindeberg, 2013). The high demand from suppliers after the financial crisis also led to contracts that were more expensive because many of these used prices reflecting then current market values (Økland, 2013).

Internationally, this topic is also highly relevant, as the 20 biggest development projects within oil and gas, recently completed, had an average cost overrun of 65%, totaling around 440 billion Norwegian kroner (Endresen & Ånestad, 2013). Out of 300 megaprojects around the world (budgets over 1 billion US dollars), 65% did not meet the targets set for costs, profits, schedule and/or performance. The reason to consider these megaprojects is the increasing trend of global projects to be of this magnitude, especially in capital intensive industries such as oil, coal, copper and iron (Merrow, 2011). These types of projects are especially important for the societies in which they originate, as they create a lot of jobs, and also keep the prices of raw materials, such as oil, down to a certain level. If a project fails, the consequences may be catastrophic for the companies involved, and thereby also the local societies in which these projects are developed. Another good reason to look at this topic is the fact that very little is really written about it (Merrow, 2011).

Many of the oil and gas companies operating on the Norwegian continental shelf are criticized for going over budget, these same companies generating large cost overruns. The report "Vurdering av gjennomførte prosjekter på norsk sokkel", pointed to four important factors for the project

execution to go well: thorough project development, a clear contract strategy, thorough pre-qualification of suppliers, and finally a consistent follow-up of the project by the operator (Lindeberg, 2013). We have looked at one aspect of this topic frequently not discussed in recent reports or articles, namely the NPV of projects with cost overruns. It seems the extra costs may also be directly related to unexpected further investments, or adjustments, as the project goes along. These will generate higher costs, but, to get a nuanced picture, we will look at the new NPV of the project to see if these cost overruns also resulted in higher incomes. This needs to be considered to either support current reports on the topic, or to show why some of the recent conclusions might need further discussion.

1.3 Scope and Structure

The thesis has a quantitative focus, on the effects of the cost overruns and the financial performance of the fields. By using a wide range of analysis we have completed a thorough analysis of each field. By identifying how the different costs and revenue components have affected the updated NPVs of the fields we have analyzed what areas have been the most crucial for the new updated valuations.

The thesis presents this by first considering the theoretical frameworks and empirical aspects for valuing an oilfield on the Norwegian continental shelf in chapter 2. After introducing the different theoretical frameworks we give reason for the decided theoretical frameworks chosen, which is followed by an empirical presentation of what has been done earlier and what new perspectives this report will provide. In chapter 3 we present the different data sources and the different fields we are analyzing, in detail. This is followed by a thorough analysis of each field using the presented frameworks and presentation of the considerations taken in different parts of the analysis. All of the findings are summarized at the end of chapter 4 before they are discussed in chapter 5. This makes the basis for our conclusion in chapter 6, which also considers the validity of our results and what possible implications this has for future developments on the Norwegian continental shelf.

1.4 Methodology

We have chosen a quantitative method to investigate the problem statement. By using quantitative data presented in the PDO from diverse operators and in the Wood Mackenzie (WM) Global Economic Model 4 (GEM) we have conducted valuations of the fields using the Free Cash Flow to Firm method (FCFF). The PDOs and GEM represent the estimates prior to the development of each field, followed by updated estimates for the fields. After we identified both the old and updated valuations, we used the analysis and updated numbers to identify the sources of deviation and how

they have affected the valuations. We also used different financial performance measurements such as net present values, IRR and change in B/E-prices to identify the financial performance of the fields. . We also conducted variance analysis to identify how the fields performed relative to their initial estimates, which helps to identify sources of deviation in support of the valuation breakdown analysis.

2 Theoretical Perspective and Empirics

2.1 Choosing the Valuation Method

In order to determine the success of the developed oil fields there are some aspects we need to consider. Considering the profitability of a developed oil field can be done several ways. A valuation of the developed oil field after knowing the specifics, such as cash flows, oil and gas production, CAPEX and OPEX, compared to the initial estimated value will show how the development performed relative to the expectations. This will show how the profitability of the development has changed. In order for us to value the oil field we need to assess how to do so by considering different valuation techniques.

2.1.1 Valuation Theory

Discounted Cash Flow Methods

Free Cash Flow to Firm

This method uses an asset's expected future cash flow as the basis for its value, where the value is the present value of all future cash flows. Because of this we need to 1) create a prognosis for the future cash flows, 2) estimate the weighted average cost of capital (WACC) and 3) discount all the future cash flows to present values (Kaldestad & Møller, 2012). These three steps value the asset, and include the cash flows available to all investors; equity holders, debt holders and any other non-equity investors. An asset's WACC is decided by the blended capital costs of all investors (Koller, Goedhart, & Wessels, 2010). To value a company's common equity we can follow a four-step process (Koller, Goedhart, & Wessels, 2010).

1. Value the company by discounting the free cash flow from operations at the WACC
2. Identify and value non-operating assets. The sum of these assets and the value of operations equals the enterprise value (EV)
3. Identify and value all debt and other non-equity claims against the EV
4. Subtract the value of debt and non-equity claims from the EV to find the value of the common equity

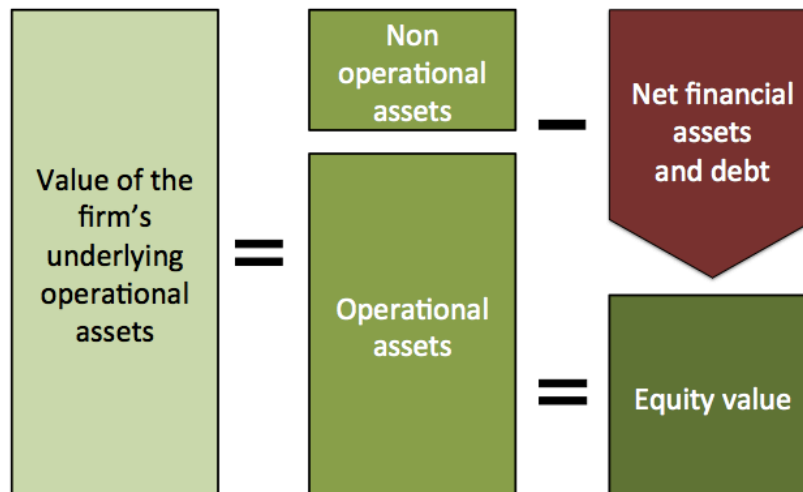


Figure 2 - Asset valuation (Kaldestad & Møller, 2012)

A great advantage with this is that it does not rely on different accounting standards such as IFRS and GAAP. Dealing with different accounting standards can make the valuation too complex, making the valuation incorrect. This has made the model a favourite among practitioners and academics (Koller, Goedhart, & Wessels, 2010). A drawback with this method is that it is normally much more time consuming to perform than other valuation techniques. In addition the valuation is sensitive to inputs such as growth rate, discount rate and margins, whose changes can change the valuation dramatically even though the change is well within the reliability requirements.

Adjusted present value (APV)

This method values an asset by discounting its cash flows as if it is unlevered and adding value of the tax shield to get the levered value. The APV approach could be used when the overall risk of an asset is independent of the choice of leverage, which is true as long as the debt to value ratio is kept constant. This approach has its advantage when the debt capacity is known (Berk & DeMarzo, 2011).

Free cash flow to equity (FCFE)

FCFE is the free cash flow available to equity holders, after taking into account all payments to and from non-equity holders. Because of this we need to discount the cash flow by the equity cost of capital. One of the drawbacks of both the FCFE and APV method is that if the debt to equity ratio is expected to change over time, the risk of the equity will change, thus changing the cost of capital. Because of this we will need to compute the project's debt capacity to determine interest and net borrowing to make decisions regarding the capital structure (Berk & DeMarzo, 2011). The method could be advantageous if the asset's capital structure is complex and we do not know the market value of the other securities financing the asset.

Valuation Multiples

The principle behind valuation multiples is that we can estimate the value of an asset through the value of other comparable assets. Assets that will generate the same cash flow in the future should have the same price, also known as The Law of One Price, which says that a good must sell at the same price in all locations. This is based on the perception that arbitrage possibilities will ultimately eliminate all price differences. Using this principle we can assume that assets with expected similar cash flows should have about the same expected value. So if you know the price of one asset, you can use this to determine the value of another similar asset by using comparable ratios between value and a measure of a firm's scale.

A multiple is an expression of the market value of an asset relative to a key statistic that one can assume to relate to the value of the asset. The statistic needs to bear a logical relationship to the market value that can be observed. It must actually be seen as the driver of the observed market value. There are two basic types of multiples, equity and enterprise multiples, which need to use statistics that are related to either enterprise or equity. Example of an enterprise multiple could be EV/EBITDA, while market capitalization/cash earnings and market capitalization/book value are examples of equity multiples (UBS Warburg, 2001). For oil and gas companies a possible valuation multiple may be USD per barrel of oil equivalent (boe).

The important thing is to find a multiple that is useful for the purpose (Berk & DeMarzo, 2011). Using the multiple valuation method gives us what we could say is the closest to a sales price of an asset among the different valuation techniques. It is an easy and effective way to make a valuation, but demands that it is possible to find comparable assets with known prices. Since it is often hard to find good comparable assets, one would often settle for rough estimates of comparable assets (Kaldestad & Møller, 2012).

Option Valuation

Options can be used to value flexibility for an asset (Koller, Goedhart, & Wessels, 2010). Managers' flexibility could be quite valuable for both stake- and shareholders when they are faced with strategic or operating uncertainty. In the oil industry the uncertainty is especially high during exploration, field development and initial production phases of an oil field. The Norwegian government could also demand overcapacity on platforms and developments to enable possible future successful explorations to connect to the present development. One reason may be that the costs of future developments of successful explorations nearby will decrease dramatically, making smaller fields more profitable and development of these more likely. This can be a source of value which traditional DCF valuation does not take into account, and because of this underestimate the value of

the asset. When including the value of real options you find the value of future cash flows in a static scenario and the value of flexibility (Kaldestad & Møller, 2012).

$$V_0 = V_{\text{asset}} + \text{present value of flexibility}$$

The value of the flexibility may occur because of some other events. An example from an upstream project may be the production capacity. If anticipated production is 10.000 barrels of oil per day, it can still pay off to have a higher capacity because of the uncertainty of the production level. In this case we will have a real option in terms of potential higher daily production. In this case the real option will not have a value unless actual production is higher than 10.000 barrels per day as shown by the illustration below.

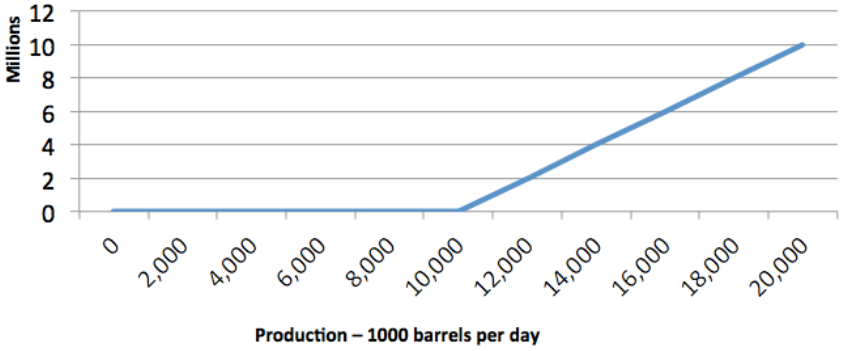


Figure 3 - Pay off real option

The three main categories of real options are (Kaldestad & Møller, 2012):

1. The possibility to defer a project
2. The possibility to expand an investment or to expand the business
3. The possibility to abandon or cancel a project or investment within a relatively short time frame

To value a real option we can use the discrete binominal process presented by Cox, Ross and Rubinstein (1979). The model assumes that the value of an asset will either increase or fall each time period. The model can be illustrated with a tree diagram showing the different values depending on the outcome in previous steps. This model is often referred to as binominal trees where the branches illustrate the values of the different outcomes as shown below.

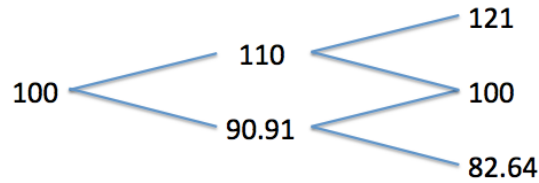


Figure 4 - Binominal tree

The method can seem simple, but it is an effective, and quite intuitive, tool to illustrate the effect of sequential events or factors that will influence the value of an option. The current value reflects the current price of the option, which will reflect the expectations regarding the future. This can be very illustrative for the valuation of an oil field where more information will be accumulated over time and drilling operations which gives strong indications whether a field is commercially viable or not.

Cost-Based Valuation Methods

This method is based on the idea that an asset is not worth more than its replacement cost, since a rational buyer will not be willing to pay more than it costs to make it (Kaldestad & Møller, 2012). The cost of reproducing the asset must be based on current prices at the valuation time, but the value must be adjusted for age, technical development and impairments.

Break-Up Valuation

This valuation method values an asset by the market value of all its individual and underlying assets, less net financial debt and deferred taxes on sold assets. This method values the assets as if they were for sale today, based on observed transactions of similar assets, while the DCF (DCF) method value each asset based on future income. Because of this the method does not take into account the current use of the assets. This method is suitable under three scenarios (Kaldestad & Møller, 2012):

1. A market for the assets exists
2. The asset's value is independent of the business
3. The profitability of the asset is low

2.1.2 Which Valuation Model is Best Suited?

As we have demonstrated, there are several valuation techniques for valuing an asset. In order to find the most suitable valuation technique we need to weigh the strengths and weaknesses of the different techniques to find the most appropriate for valuing an oil field.

Discounted Cash Flow Models

The different DCF methods have different strengths and weaknesses. One of the common weaknesses is that the valuations are subject to subjective perspectives that can influence the value

to a large degree. The margins, growth rate, and discount rate used will influence the value significantly. A DCF valuation method is usually split in two, an explicit forecast period for the cash flow, and continuing value from the end of the explicit period and until eternity.

The FCFF method includes the value of any tax shield by taking it into account by using an after-tax discount rate. The method assumes that the asset will hold a constant debt to equity ratio, since a change of the ratio will alter the cost of capital and hence the discount rate. An important advantage of this method is that by using WACC as the cost of capital we do not need to know how the constant debt to equity ratio policy is implemented to make the capital budgeting decisions (Berk & DeMarzo, 2011).

The APV method is well suited when the debt to equity ratio is kept constant. Since the value of an oil field will vary quite heavily with changes in the oil price, it is necessary to rebalance the debt to value ratio quite often in order for the ratio to stay constant. This will cause a lot of down payment and debt issuing which can be quite costly. We do not think it is likely that oil firms and financing institutions will prefer this kind of financing, making the APV method not appropriate for valuing an oil field.

Because the FCFE valuation method is dependent on the risk of the equity and the asset's debt capacity this method can be more complex than the FCFF method, without making it a better or a more robust valuation. It is not likely that the financing situation of an oil field is so complex that the FCFE method makes up for the additional workload that this method will cause compared to the FCFF method.

Based on these evaluations the most appropriate DCF model to use for a valuation of an oil field will be the FCFF method.

Multiples

One drawback by using multiples is that they do not take the specifics of an asset into account. However this technique is quite effective and easy to understand. In the oil industry, using different multiples can be used to compare different oil fields. Multiples can be related to the volume of oil equivalents (o.e.) discovered in the field such as price per boe and the phase the field is in, such as exploration or producing. In a report from Swedbank First Securities (Swedbank First Securities, 2014) regarding Lundin Petroleum, an analysis overview regarding all the oil fields is presented in the "sum of all parts" section of the analysis. Here the fields are presented with a USD per boe multiple. The grouping clearly shows that the more secure and the further into development a field is, the higher the USD/boe multiple is. Roughly speaking the multiple will be in the range of 0.5-5 USD/boe

for fields with proven oil reserves, 5-10 USD/boe for fields that have approved PDO, and from 10-20 USD/boe for fields in production. The value of the field will also be adjusted for the probability of successful exploration and production. The multiples are also dependent on the cost structure of the field. If there are higher costs or investments per boe the multiple is likely to be lower than for fields with lower costs and investments.

A change in the multiple will have the same direct impact on the valuation of the field, making the choice of multiple important for valuing the field. A multiple of 5 or 6 USD/boe could both be good, but will give a difference in value of 20%. Such multiples are typically used to analyze merger and acquisition transactions to see what prices are paid for similar fields.

A multiple valuation would not enable us to identify the impact of different value drivers on the value of the field. When also considering the unique characteristics of each oil field and the impact of a small change in multiples, we feel that this valuation method will not be applicable for a good and thorough valuation in our case.

Options

All of the three main categories of real options are relevant for valuing planned developing of oil fields. A binominal tree can be very illustrative for the value development of an oil field as the project progresses. The value could then be influenced by decisions made, creating a decision tree. As the work with the license progresses we can identify changes in the value. For example is it naturally to think that if an exploration well is dry this may cause the value of the field to drop, while a hit would increase its value. However this may not be the case for drilling exploration wells. Drilling operations not only give answers to the well being dry or not, but collect a multitude of data during the drilling period, well beyond the confirmation of the deposit. They can provide indications regarding the likely existence, size, and/or quality of deposits in related geological structures, and provide more accurate estimates of drilling costs and operating conditions in the general vicinity, which can be valuable for future planning. Because of this the value of drilling again, even though the first (or later) well was unsuccessful, might be significant undervalued by using the traditional binominal process (Smith, 2005).

However, we feel that this is not the main value of an oil field, but rather an extra dimension of value that should be added to the development of the field, especially prior to the development. Since we will look at oil fields after they have been developed we will not focus on real options.

Cost-Based and Break-Up Valuation

Since an oil field cannot be reproduced, the cost-based method will be useless in valuing an oil field. When it comes to the three scenarios where the break-up valuation method is suitable, the characteristics of an oil field makes this technique not applicable for our valuation.

How to Value an Oil Field

We will focus on a DCF model to determine the value of oil fields. As we have seen from PDOs, DCFs are used to estimate the net present value of the oil fields. Although there are a few variations within the DCF methods, we assume that the firms have used the FCFF method since this reflects the cash flow that the field is expected to generate to its licensees. This is also what it says in the guidelines from NPD (Norwegian Petroleum Directorate, 2000).

Each production licence on the Norwegian continental shelf is licensed to two or more licensees, where one licensee has the main responsibility for the daily work on the licence, referred to as the operator. The operator reports to all of the licence's licensees, referred to as partners. This organizing of the licences makes it a lot like an ordinary subsidiary, with two or more companies as parent companies, which gives the licence its own financial statement. Because of this it is natural to value the licence as a separate entity using the FCFF, where the firm is the licence, as the DCF method.

2.2 Valuing an Oil Field on the Norwegian Continental Shelf

2.2.1 Using the Free Cash Flow to Firm method

In *“Valuation – Measuring and managing the value of companies”* by McKinsey & Company the term Enterprise DCF is used. This model is quite similar to the discounted free cash flow-model presented by Kaldestad & Møller (2012), because they both use a company's cash flow to value it. However the main difference is that McKinsey's Enterprise DCF valuation method is a residual model. This implies that it focuses on the profitability of an asset and return on invested capital instead of cash flows. To use residual methods we would need to define the invested capital from the balance sheet. For our valuation the balance sheet needs to be reorganized in order to group the assets and debt into operational and financial assets.

In order to make a thorough valuation using DCF to firm, we need to reorganize the balance sheet, make explicit projections and estimates regarding the future cash flow for a given time period (typically 3-10 years or a cycle in a cyclical industry), estimate a continuing value to account for the value creation after the explicit prognosis period, and estimate the discount rate for all cash flows.

How all of this is done will be very different when valuing an oil field compared to a fast moving consumer goods company. The main difference is the projection of the future income and costs. Because oil field income will be decided by the market price of oil, and how much oil the field is producing.

Reorganizing the Balance Sheet

The purpose of reorganizing the balance sheet is to enable us to identify the value of the equity. By switching focus from credit and financing situation, we want to focus on what is operational and pure financing related assets and debt in the balance sheet. Operational assets (and debt) can be defined as production assets and other balance sheet items that are a part of the operation. Organizing the balance sheet like this makes it possible to show which items generate yield in the operating result, instead of showing the separate items in the financial statement. The present value of all future cash flows that the operational assets generate is the value of the equity. Financial assets and debt can be identified as those items that could be sold off without influencing the daily operations. By identifying the financial assets and debts we can calculate the net financial assets, which we then can deduct from the value of the operational assets to find the value of the equity (Kaldestad & Møller, 2012).

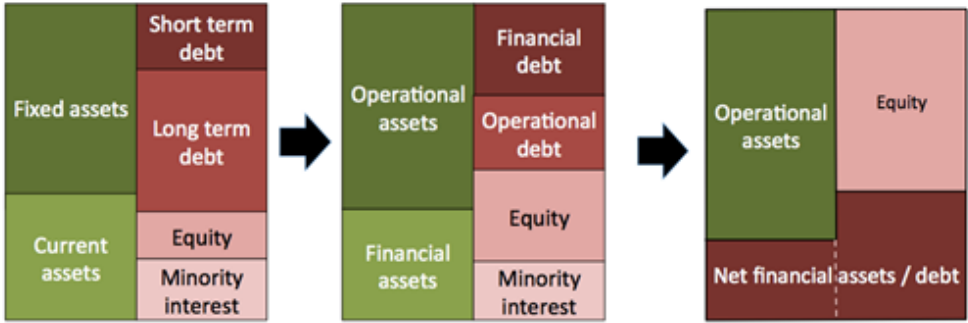


Figure 5 - Reorganizing the balance sheet for valuation purposes (Kaldestad & Møller, 2012)

Explicit Forecast Period

The cash flow forecast period includes forecasts for income statements, balance sheets and cash flow budgets, often with separate modeling of taxes and investments in operational assets (Kaldestad & Møller, 2012). The forecast period is often based on a historical and strategic analysis.

The historical analysis will also show what has been accomplished earlier, previous investments, what commitments that exists, historical development in cash flow, and correlations between activity and investments in fixed assets and working capital (Kaldestad & Møller, 2012). It will also involve making corrections of recurring items and other events that will not occur later to make the financial reports more suitable for forecasting. The purpose of the corrections and the historical

analysis is to get a clear picture of the past in order to understand where we are now, and to understand where we can go and how to get there in the future.

Since we have decided to use the FCFF method, we will need to separate cash flows from operations and financial activities. Since we want to find the value from operations of an oil field we need to focus on the items that are included in the operations. However, an oil field on the Norwegian continental shelf will not have a lot of financial activities, assets and debts directly since two or more oil companies own it. The reason is that an oil field is by definition an operating asset for the oil companies. The owners finance the oil field directly, so there is not much reason for an oil field to have its own financial activities.

When analyzing an oil field, or any other asset, time series analysis can be helpful. Locating trends can be very helpful for finding areas where the asset's trends are favorable or unfavorable. When we find such trends we can compare them to peers and get a better understanding of the trends; what causes them, how long will they last and what is the impact of it. Trend analysis is especially important for cyclical industries. When an asset experience these natural fluctuations it is important to have a trend analysis that covers a long enough time period to identify a cycle. For cycles we need to estimate an average for the cycle, while a trend should not be adjusted to an average.

Market Conditions

A strategic analysis is often used to supplement a historical analysis, creating better understanding regarding the activities performed and the strategic position of the asset. This helps us to get a better understanding regarding how the assets earn money and create value in the industry they operate within (Kaldestad & Møller, 2012). However, this will not be applicable for valuing an oil field. When we are valuing an oil field the knowledge and estimates regarding the current and future market conditions are much more important for the value of the oil field.

The value of an oil field is affected by both internal and external factors. Internal decisions regarding development, concept choices and the production of oil and gas will have a significant effect on the value. By making the right choices internal decisions can cut costs and increase production. The value can increase significantly. Including the internal factors within a company affecting the value, external conditions and factors will also have a significant impact on the value of an oil field. The company needs to make assumptions about these conditions for the future, such as oil and gas sales prices, tariffs, exchange rates, inflation rate, taxes and norm prices. As well as these assumptions, there might be some global events affecting these factors, which are hard or impossible to foresee. These might include economic downturns, trade embargos, wars or OPEC decisions. All of these

events will affect the oil prices, and possibly legislation, market conditions or national taxation decisions as well. Included in the market conditions, political factors and risk need to be assessed. The risk of changes due to political circumstances, which may cause changes in government regulations, may be quite different from one area to another and needs to be accounted for by the licensees. Because of differences in the political climate and political risks companies seek to diversify their portfolio to minimize the risk (Ministry of Trade, Industry and Fisheries, 2001).

The company needs to base the investment costs on standard cost coding systems, and also make a CO₂ tax profile that depend on production and the tax rate of CO₂. Since there are many uncertainties in the cost estimate as well, the companies need to make a 10/90 and 90/10 confidence level estimate as well as specifying the exchange rate they have used (Norwegian Petroleum Directorate, 2000).

Descriptions of all the economic aspects need to be included in the PDO. The calculations should be shown before and after tax, and all variables should be based on statistical expectations. The assumptions for the economic parameters also need to be documented (Norwegian Petroleum Directorate, 2000). From the guidelines to PDO, issued by the Norwegian Petroleum Directorate in 2000, it states in paragraph 3.5.1 that:

“Central variables are

- Prices and price trends of products sold,
- Currency exchange rates,
- Inflation,
- Requirements in relation to return,
- Oil, gas, condensate and NGL sales (volumes),
- Gas purchases,
- Net income from tariffs,
- Investments,
- All operating costs, including tariffs for transportation and processing of petroleum as well as other
- Services, CO₂ tax etc.,
- All essential conditions for tax calculations, including assumptions on financing,
- Final disposal,
- Any credits in relation to income, expenses, taxes etc. included in the calculations.”

Continuing Value

For oil fields we know that their lifetime is limited. None of them will continue to produce oil into eternity since oil is created over millions of years. Because of this, oil companies create production profiles for the oil field when estimating the development. However, for assets with an “unlimited”

life, or a lifetime that cannot be defined, we reach a state that we cannot predict future cash flows with high certainty. From this moment we assume that the cash flow will continue forever, creating a continuing value using the Gordon growth model, which is a perpetuity formula. The explicit forecast period until this time should last for at least one cycle for cyclical assets, or until the assets reach a “*steady state*”. After the explicit forecasting period we will not be able to account for changes so it is important that the forecasting period is long enough so that we can assume that it will not change (Koller, Goedhart, & Wessels, 2010). The growth cannot by definition be larger than the growth in the economy. The reason is that if we assume that an asset has a higher growth rate than the economy into eternity, the asset will take over the economy, which will not happen. In a typical valuation, the continuing value of an asset will often make up a large portion of the total value of the asset (Kaldestad & Møller, 2012).

For an oil field, the case of a continuing value is not applicable due to decrease in daily production and eventual closing of the fields. Because of this we will need to have a much longer explicit forecast period than what would be the case for an ordinary company. In our valuation we will use the estimated production volumes for an oil field’s lifetime as the starting point for income and costs.

Discount Rate

The purpose of the discount rate is to identify the alternative cost of capital for investors and to visualize the time value of money; money now is worth more than money later, given inflation. The discount rate represents what an investor could expect to get in return of an alternative investment with the same risk.

A traditional way to find the discount rate is by using the WACC method. This method represents the average capital cost for all investors. This is important when using the FCF method since the cash flow is available to all investors. To find an asset’s average cost of capital we need to identify its capital structure, the nominal tax rate and the cost of equity and debt (Berk & DeMarzo, 2011). The cost of capital 1) must include the opportunity cost for all investors, 2) must include the weight of each security’s return by its target market-based weight, 3) incorporate any financing-related benefits or costs, such as tax interest shields, not included in the free cash flow or value them separately using APV, 4) must be based on the same expectations regarding inflation as those embedded in the cash flow forecast, and 5) need to match the duration of the securities used to estimate the cost of capital with the duration of the cash flows (Koller, Goedhart, & Wessels, 2010).

However, calculating the “correct” discount rate is extremely difficult, and at the same time very important for final value of the asset. The discount rate is based on different parameters that are

calculated with some uncertainty. Because of this we can find an uncertainty interval of discount rates that will give large differences in the valuation of the asset.

Since our valuation will be a comparison between the estimates provided in the PDO, and what the net present value is considering the updated cash flows, we chose to use the same discount rates as in the PDOs. Each license has several partners, which will compute their own discount rates depending on their financial situation. Since we are considering the partners of the fields as one unit, we will need to find discount rates that will fit with these owners' discount rates. However, since our thesis will focus on the performance of the developments, we should also consider the Norwegian government as a stakeholder. Since we would like to make comparisons between the fields as well, we need similar discount rates to make the analysis and comparisons valid. Because of this we will not compute any discount rates, but use those explicitly stated in the PDOs.

2.2.2 Distinct Rules and Policies in the Petroleum Industry

Taxation of oil and gas companies is done according to the Norwegian law of petroleum taxation, Petroleumsskatteloven, and applies to exploration, production, processing and pipeline transportation of petroleum (Ministry of Finance, 2013a).

Taxation of oil and gas companies is based on corporate taxation, but because of the much higher return, there is a special tax for petroleum upstream industry in addition to the ordinary company tax in Norway (Ministry of Finance, 2013d). This special tax rate is set by the government each year (Ministry of Finance, 2013a). The current special tax rate is 51%, while the company tax rate is 27%. Since we will benchmark the net present value of the fields compared to PDO we need to have the same assumptions and expectations for tax rates, as was the case on the timing of the PDO. The historical tax rates have been 50% on special tax and 28% on company tax. By using the historical tax rates we avoid including changes in net present value that can be caused by changes in tax rates.

Historically, closure and abandonment costs have been deductible just as other costs. Deductions are not given on allocations for abandonment costs. Instead, the government gives subsidies for the removals, and these subsidies are not taxable (Ministry of Finance, 2013b). The law for subsidies given for removal of installations from 1986 says the subsidy should equal the effective tax over the life time of the field. The rate of the subsidy is effective tax over the taxation basis, and only years with positive income is included (Department of Finance, 1986). There are three ways of aligning the costs of abandonment with income over the years, the most common is building up the abandonment costs by expensing the costs over the life time of the installation (Jan Samuelsen, 2002). This is also the way we are going to do this in our analysis.

The uplift is a share of the oil companies' income that they do not need to pay taxes on. It is subtracted before the special taxes are done to make sure the normal returns are not submitted to special taxes. The rate is now at 5.5% of the cost price of depreciable operating assets. The uplift can be done every year for 4 years after the investment (Ministry of Finance, 2013d). This gives an incentive to oil companies to invest, as they do not have to pay the full tax. The response to the change in 2013, from 7.5% to 5.5% makes proof of how important this uplift is. Higher taxes mean lower results after tax, so this has even delayed planned developments, such as Johan Castberg (Helgesen, 2013).

Oil and gas companies in Norway gets the taxation value of exploration expenses back the next year given deficits. To give new companies the same tax treatment as established ones, the rule that losses can be carried forward from previous years was made (Ministry of Finance, 2013d).

Expenses from exploration wells are put in the balance sheet until they know whether the deposits of oil and gas are commercial or not. If the field is commercial, the expenses are put in with the development costs of the oil field. However, if it is not commercial, the expenses in the balance sheet are impaired (Deloitte Global Services Limited, 2005). Gas and oil reserves that have been discovered cannot be put in the balance sheet, but if they buy reserves from another company, the value of the reserves goes into the balance sheet as the historical cost from the purchase.

In accounting for oil and gas companies, depreciations of pipelines and production installations and facilities are done by the units-of-production method. The oil or gas company can use P90 secure reserves, or P50 secure and probable reserves. This method is used because the lives of the investments are mainly determined by the time it takes to clear the resources. Tax depreciation usually uses balance depreciation, which gives a temporary difference (Ministry of Finance, 2000). Production facilities and pipelines can be depreciated over 6 years, and this is usually done (Ministry of Finance, 2013d).

Table 1 - Special petroleum tax (Ministry of Finance, 2013d)

Sales income
- Operating costs
- Depreciation
- Net financial costs
- Losses carried forward from previous years
= Ordinary tax base taxed at 27%
- Uplift (investment-based "supplementary depreciation")
- Unused uplift carried forward from previous years
= Special tax base taxed at 51%

Other costs for oil and gas companies are CO₂-taxes and area fees (Ministry of Finance, 2013d). Finally, the Norwegian petroleum price council, Petroleumsprisrådet, sets the norm price used for taxation purposes. The price is supposed to reflect the trading value in the market. This is done quarterly to find the correct norm price for each day of the previous quarter (Ministry of Petroleum and Energy, 2014).

Financial costs can be deducted. These include interest costs and currency losses less currency gains. This is multiplied by 50% and the taxable value of the assets assigned to the license as of December 31st, divided by average interest-bearing debt (Ministry of Finance, 2013a).

The removal costs must be allocated in the accounts, but the company will not get deductions for these costs until the removal happens (Norsk RegnskapsStiftelse, 2013).

2.2.3 Changes in Distinct Rules and Policies Since 1995

The Norwegian government sets the special tax rate each year. This has been 50% since 1995, but was changed to 51% for the year of 2014 at the same time as the ordinary tax rate was reduced from 28% to 27%.

In 2004 the Norwegian law of petroleum taxation changed to equate the differences between established and new companies on the Norwegian continental shelf. Prior to 2004 companies needed to be in a tax position in order to be able to deduct exploration costs. The law changed so that the companies which were not in a tax position could demand the tax value, 78 percent, of the exploration costs paid back from the government (Ministry of Finance, 2004a).

Prior to 2002 losses could only be carried for 15 years, but due to changes in the legislation losses from 2002, losses could be carried indefinitely with interest (Ministry of Finance, 2013b).

When it comes to abandonment costs, as of the 15th of June 2002, companies were also required to use a present value technique (Financial Accounting Standards Board, 2001). The law on abandonment costs was repealed as of 27th of June 2003 (Department of Finance, 2003), but we will again use the regulations that took place in 1995 for our analysis.

The rate at which the companies can do uplifts has been changed a few times since 1995. In 1995, this rate was 5% of cost price for depreciable operating assets, and could be done every year for 6 years (Lovdata, 1995). On the 5th of May 2013 the rate at which the companies can do uplifts was changed from 7.5% to 5.5% of the cost price of depreciable operating costs, effective 1st January 2014 (Ministry of Finance, 2013b). As the number used in 1995 was 5% over 6 years, this is also what

we will use in our analysis. The changes of this parameter should not be included when we look at why there have been higher costs.

The regulations for norm prices have not been changed since 1995 (Norges Lover 1685 - 1995, 1995).

IFRS 6, which makes it possible to put expenses from exploration wells in the balance sheet until they know whether the resources are commercially viable, was issued in 2004 (IFRS Class, 2007). Before this law, these expenses were charged to the accounts regardless of the results from the exploration well (Ministry of Finance, 2004b)

The paragraph in the Norwegian law on petroleum taxation on depreciations has been changed since 1995 (Norges Lover 1685 - 1995, 1995), adding a sentence that says the company may depreciate certain investments over just 3 years. This only applies for production, pipeline transportation, and processing of gas to Finnmark, Kåfjord, Skjervøy, Nordreise or Kvænangen (Ministry of Finance, 2013b). Since this is not relevant for any of the fields we are looking at, we do not need to take this into account in our calculations.

2.2.4 Variance analysis

Variance analysis is the process of examining the variance between actual and budgeted costs and revenues to determine why the budgeted results were not met (Ventureline, 2014). Because of this it can be a useful tool for performance measurement and financial management. How deep and detailed the variance analysis should be depends on the needs of management. The point of it is not to analyze everything in depth, but rather to find which areas to focus the analysis on after doing a cost-benefit assessment. It is often possible to split the deviations to an extraordinary detail level for variance analysis, but since this may not be desirable or required, management needs to decide what detail level is wanted (Shank & Churchill, 1977).

No matter how a budget or financial statement is built, the purpose of the variance analysis is to quickly identify the significant differences between the budgets and the results. By quickly identifying these, managers can address them and implement actions to correct them early in the process (Hoff & Bjørnenak, 2013). In our case we will not use the tools of variance analysis as a management tool, but only for analysis purposes. By using variance analysis we will identify areas where cost estimations and budgets have not complied with the results generated from the operations. By identifying the areas with significant variances we can establish what areas operators on the Norwegian continental shelf, and the Norwegian government, need to strictly focus on when considering developing oil and gas fields. The deviations the variance analysis identifies can often be separated into two different groups, controllable and uncontrollable deviations. Controllable

deviations are those deviations that the developments in our case can influence, while uncontrollable deviations are not under control by the developments. An example for a controllable deviation can be the daily production volumes, while the oil and gas prices are uncontrollable deviations.

Static Budget and Static Budget Variance

The static budget is created prior to the budget period, based on current knowledge and information. Because of this there will not be done any changes, regardless of actual volume, sales or prices, during the period. The static budget variance will therefore be the difference between the static budget and the real result. A positive budget variance means that the result is better than originally expected, and may be caused by higher revenues, lower costs or any combination of these.

$$\text{Static Budget Variance} = \text{Real} - \text{Budget}$$

Flexible Budget

The static budget variance can be further analyzed to a deeper level by using the flexible budget. A flexible budget is a budget that shows the budgeted revenues, costs, and results, with the real sales and production volumes (Hoff & Bjørnenak, 2013). One could say that the flexible budget shows how the budget would be if the management creating the original static budget were able to predict the sales volume. Since the volume cannot be predicted with 100 % accuracy the flexible budget needs to be created after the budget period. The flexible budget adjusts the budgeted posts that are influenced by changes in real sales volume or other activities. The flexible budget will then show what the income and costs should be, based on the real activity level, so that we can compare it with the real numbers (Hoff & Bjørnenak, 2013). After creating the flexible budget we can do further analysis by analyzing the flexible budget variance and sales volume variance to get a better understanding of what is creating the differences.

$$\text{Flexible Budget} = \text{Budget} * \frac{\text{Real Production}}{\text{Planned Production}}$$

Sales Volume Variance and Flexible Budget Variance

The sales volume variance will show the differences caused by changes in the sold volume. Any changes in sold volume compared to the budgeted volume will cause the flexible budget to change. So the sales volume variance will show changes in the flexible budget caused by new sale volume and is a relatively basic analysis that does not provide a lot of new detailed information.

$$\text{Sales volume variance} = (\text{real production} - \text{budgeted production}) * \text{budgeted sale price}$$

The flexible budget variance can however be more detailed and give more detailed information regarding the variances. The reason is that we can now compare the real numbers and the budgeted numbers based on the same activity level (Hoff & Bjørnenak, 2013). Regarding the flexible budget variance, we can split it into two aspects, revenues and costs. For the revenues the flexible budget variance analysis will identify the sale price volume variance, visualizing the effect that changed prices have had on the result (Hoff & Bjørnenak, 2013).

$$\text{Sales price variance} = (\text{real sale price} - \text{budgeted sale price}) * \text{real sales volume}$$

If the business does not have the market power to influence the market prices, this variance should be categorized as a non-controllable variance, which will be the case for oil companies on the Norwegian continental shelf where none of the operators have the power to set the price.

Analyzing the costs however can be a more comprehensive task. By going one level deeper into the budget and financial reports, we can find the variances for individual line items such as direct materials, direct labor, as well as variable and fixed manufacturing overhead variances. The variable costs can often also be analyzed even further measuring prices and efficiency variances (Horngren, Datar, & Rajan, Cost Accounting: A Managerial Emphasis, 2011). For our analysis we will stop at the second level due to limitations in the dataset.

The level of the analysis defines how detailed the analysis is, and also how detailed your information needs to be.

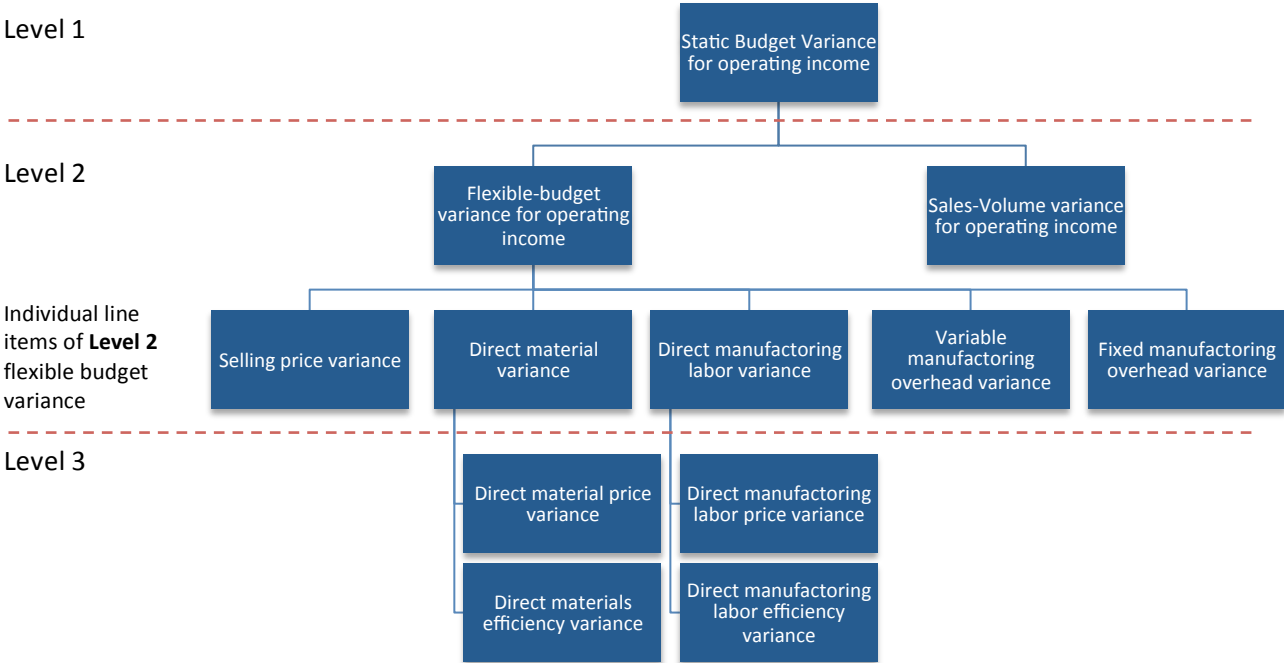


Figure 6 – Illustration of different levels in the variance analysis (Horngren, Sacramento State)

2.2.4 Performance Measurements

Break-even analysis

A break-even analysis is a method that assesses the importance of the uncertainty of important drivers of value in a project (Berk & DeMarzo, 2011). For oil and gas companies the oil and gas prices are crucial for the net present value of the fields. Because of this the B/E-price is calculated in all of the PDOs for our fields to identify the sensitivity a development has to changes in the oil price. When there is uncertainty regarding an input in the capital budgeting decision or process, a B/E-analysis can help to visualize how much these parameters can change for the project to have a net present value of zero, which is the B/E-level (Berk & DeMarzo, 2011). In a B/E-price analysis the idea is to identify the price that will make the net present value of the project equal to zero. This will tell the decision makers how wrong they can be regarding the price before the project is unprofitable.

The B/E-analysis is not only used for the price, it can be calculated for a wide range of parameters such as units sold and cost of goods. The B/E-level is found by taking one parameter at a time and identifying at what level the net present value of the project is zero, given that every other assumption stays the same. The analysis does not have to be on a net present value basis, it can also be done quite easily in terms of accounting standards for instance, but this would not include the opportunity cost of the capital employed (Berk & DeMarzo, 2011). Because of the large CAPEX related to developing oil fields we will focus on a B/E-price analysis that considers the net present value of the projects.

Internal Rate of Return

The IRR is actually a B/E-analysis as well. The reason for this is that the IRR identifies what the actual costs of capital of investors can be before the project becomes unprofitable for the investors. It is the interest rate that sets the net present value of the cash flows equal to zero. It is useful for investors or decision makers because it provides useful information regarding the sensitivity of a project's net present value to errors in the estimate of its cost of capital (Berk & DeMarzo, 2011).

Based on this, a rule known as the 'internal rate of return investment rule' has been developed: *"Take any investment opportunity where the internal rate of return exceeds the opportunity costs of capital. Turn down any opportunity whose internal rate of return is less than the opportunity cost of capital."* (Berk & DeMarzo, 2011). This rule is based on the idea that if the average return on the investment opportunity (i.e. the IRR) is greater than the return on other alternatives in the market with equivalent risk and maturity (a project's cost of capital) you should welcome the investment opportunity. The problem with this rule is that it does not guarantee to work for a stand-alone

project unless all of the negative cash flows of the project precede its positive cash flows. Because of this there are some pitfalls of the rule, such as delayed investments, multiple internal rates of return and non-existent internal rates of return (Berk & DeMarzo, 2011). When a field is developed, the largest investments are during the first years, causing a negative cash flow. Then, as the investments go down, and the production reaches a "steady state", the cash flow turns positive. Finally, the daily production gets very low, and they decide to plug and abandon the field. During these last couple of years, the cash flow is negative again. When we do our analyses, we just need to make sure that this is really the case.

2.3 What Has Been Done Earlier

2.3.1 Theory: Valuation of Oil Companies and Oil Fields

This section looks at how oil companies and oil fields have been valued before. There is little to find about this in academic literature, so the discussion is mainly based on findings in reports and articles written by people doing these valuations before. The valuation is based on estimated resources and the probability of recovering this oil or gas. These estimates give an estimated profitability, and uncertainty of profitability (Norwegian Petroleum Directorate, 2010). The value of the company as a whole is then based on its reserves, its URR, and the commodity prices, but the primary value is based on present and future cash flows and earnings (Kaiser & Yu, 2012).

Regarding previous valuations of oil fields, there are a few different ways of doing this. Except for using the net present value of the estimated future cash flow, one way this has been valued is through real options. The real options contribute to creating an added value to the project, compared with using net present value. This gives the oil companies the possibility of looking at the value when undertaking change (Horngren, Sacramento State). It gives a strategic flexibility that you will not get by using only the net present value analysis (Skjørestad, 2011). Because of the complexity of an oil field though, the model needs to have clear definitions.

The most common way of valuing oil companies has been through a net present value analysis. As analysts lack necessary data or resources to do so in some instances, they often use relative valuation. When valuing the company as a whole, using net present value and free cash flows as measurements has been criticized because the industry is capital intensive and large investments are needed before production can start. In this period, they get tax refunds on the exploration costs even though the revenue from production is marginal (Gjøen, 2007). Financial ratios may also be insufficient in looking at valuing a company, but is widely used. Reinvestments in E&P (exploration and production) oil companies is important for future growth, and big reinvestments tomorrow may

show artificially low returns for a longer period of time (Gjøen, 2007). Because it is hard to determine the company value, analysts recommend using different methods and comparing these. For example, using multiples such as EV/EBITDA, EV/Production, EV/2P, P/CF and EV/DACF, and compare these with each other. Because of high debt levels, differences in commodity prices, differing taxes for different countries, and possibilities of having production from undeveloped fields in the future, each method can give a different answer, and it is recommended to use more methods (Dumont, 2011).

Since there are so many different variables when calculating the value of an oil company, using more than one method is recommended. This is also what we see in the market. Analysts often use cash flow to find net present value of the company, but because so little data is available, combined with high uncertainty, they also need to use multiples. In some cases they also use real options because of the changing conditions for developing an oil field.

With the above, we end up with several different values, and we need to look at the industry as a whole, comparing our analysis with the sales value of recently sold wells. Even this comparison with recently sold wells is not to be fully trusted, as each oil field differs in some way, but using all these methods gives us the best estimate for the company value (Investing Sidekick, 2013).

2.3.2 Empirics: What Drive Costs – Reasons for Cost Overruns

Costs of an activity or an area of the business are driven by cost drivers. The cost drivers are the units that change the total cost of the activity or area. It may for example be the numbers of operations, the time used, or the kilometers driven. Traditional systems are good to use for volume-related operations and products. The “correct” cost driver may be hard to find though. For indirect costs, the cost drivers can be multiple different drivers, set up costs, or production scheduling costs. One way to handle this is to use activity based costing, where you identify all the activities and their costs, and assign the activities to the products by measuring the amount of activities used (Drury, 1992).

For an oil field, these costs may for example vary on field location, when considering logistics and transportation, the cost of workforce, security and the type of offices and housing required (Inkpen & Moffet, 2011). Other factors that may vary the costs are contract types, order complexity, and ambiguities. Most of the cost overruns which occur to these examples are when the need of more time, more workers, more materials, more expensive materials, or adjustments to new technology is present. This is also evident from the reports discussed in part 2.3.3.

2.3.3 Empirics: Cost overruns on the Norwegian Continental Shelf – Reports from the Norwegian Petroleum Directorate

The Norwegian Petroleum Directorate has published two reports regarding cost overruns on the Norwegian continental shelf. The first was published in 1999 (Kaasen, et al., 1999) and the second, and most recent one, was published late 2013 (Norwegian Petroleum Directorate, 2013d).

These reports have a lot in common regarding their scope. They have analyzed several oil fields, with and without cost overruns, and tried to find patterns that can explain why some developments experience cost overruns, while others do not. The analysis has a strong qualitative focus; focusing on the quality of work in the initial phases, contract strategy, prequalification of suppliers and operator's monitoring and follow-up on suppliers.

The report produced by the Investment Committee (Kaasen, et al., 1999) found four main reasons to explain cost overruns for projects on the Norwegian continental shelf. These are:

The Basis for Decision Making, Budget, Understanding of Risk

The majority of the projects and their PDOs were unrealistic, and too optimistic. Due to the trends in the market, in addition to little maturation of the projects, this explained most of the cost overruns.

Drilling and Complementation

This item accounts for one third of total increase in costs for PDO. This is due to rough planning in the initial phases, combined with a high demand during this period for mobile drilling rigs that met the requirements for the Norwegian continental shelf.

Technology

Changes in technology during the same period caused more uncertainty. These combined with a shortage of prequalified suppliers who understood the oil industry's complexity, quality needs and regulations, led to critical under-estimation in the budgets.

Project Execution

One of the reasons we see cost overruns is that the time estimated for use during execution is too short, the actual execution being even shorter than estimated. Finally, if just one of the phases gets delayed, the overlaps between phases cause the following ones to be delayed as well. Because of these there are limited possibilities to solve unpredicted trouble in one phase without affecting later phases that, once initiated, cause higher costs and delays. The elements, although contributing to improvements such as new collaboration forms with suppliers, also led to cost overruns.

During the last period the operators have changed from single element contracts to contracts for the total delivery. The suppliers previously had total responsibility for the project execution. The suppliers previously were familiar with single element contracts, but now did not have the necessary experience to handle the responsibility of the whole project execution. There apparently has not been any knowledge transfer flowing from the operators to the suppliers regarding project execution, so there is no question that the suppliers have had difficulties delivering a complete project, hence the cost overruns.

In addition, a higher activity level on the Norwegian continental shelf has probably led to higher costs, relative to the budgets. The report however identifies that it is likely that the foundation for the cost overruns was laid in the early phases of the projects. The scarcities of resources, and competencies, have in addition made it hard for operators and suppliers to complete the projects as effectively as possible.

New report, familiar results

The results in a report from 2013, "Vurdering av gjennomførte prosjekter på norsk sokkel", coincide to a fairly large degree with the results of the Investment Committee of 1999. All the projects that experienced cost overruns had a severe lack in the initial engineering work. By initial engineering work we mean the engineering that is executed prior to the PDO and prior to the procurement and construction. This is important because deficiencies and defects early in the engineering process will spread into the future project work. Because of this the project is dependent on thorough initial engineering work to complete the project on time, without cost overruns and according to quality requirements. Projects with deficiencies during the initial engineering work often experience the need for changes during the construction phase, where significant parts need to be redone, which has led to major cost overruns and delays. The changes identified in the design are not major so that the final production facilities and capacities change little from PDO, making the different plants comparable.

For several of the projects, deficiencies regarding the prequalification of suppliers and their sub-suppliers have led to cost overruns. Since the operator will not be able to follow up all deliveries during the construction they need to prioritize which areas to follow up on their own. The analysis indicates that introduction of new technology does no longer cause severe delays nor cost overruns. The reason is that operators have identified introduction of new technology as a high-risk area, which needs to be monitored and followed up. However, it seems the operators too often trust that the suppliers are able to meet the required specifications and that, if these suppliers use sub-suppliers, the latter are able to meet the required specifications. So if the deliveries do not meet the

required specifications a lot have to be done all over, which can lead to adverse effects on progress and costs (Norwegian Petroleum Directorate, 2013d).

In addition to thorough initial engineering work, contracts need to be designed in a way to encourage cost effective progress and quality, while at the same time enabling operators to monitor, control and implement corrective measures during production. Because of this the operators need to handle the challenges different types of contracts entails to ensure the needed progress and quality (Norwegian Petroleum Directorate, 2013d).

2.3.4 Empirics: Costs of Drilling and Well Operations

Costs of drilling and well operations have more than doubled during the period from 2000 to 2010 (Reiten, et al., 2012). These costs constitute about half of the costs related to total field development costs, and the average cost for drilling a production well from a mobile offshore unit was in 2010 more than 500 million NOK (Rosendahl, 2012). Because of the size of these costs, it is crucial for the value creation to have cost effective drilling and well operations. Statoil, a major player on the Norwegian continental shelf, has estimated that there is a large potential for enhanced oil production. To utilize this potential, drilling and well operations are necessary. The high cost of these operations can make it difficult to realize the potential of increased production. Due to the high cost level, a high production efficiency and utilization of rigs is necessary to reduce the costs of a drilling, or well operation (Reiten, et al., 2012). However there is not only a cost consideration. A good and correct drilling is necessary to get a good production, so there is a need to make a tradeoff between speed and quality (Osmundsen, Roll, & Tvetervås, 2010).

The total costs related to a drilling and well operation on the Norwegian Continental Shelf are approximately 40% or higher than the costs for the same operation on the UK continental shelf. The main reason for this is the costs related to rig hire combined with operating costs on the Norwegian continental shelf. These high operating costs reflect the 50 000 to 75 000 USD higher per day costs for personnel on the Norwegian versus the UK continental shelf (Reiten, et al., 2012).

The flow of mobile offshore units between the Norwegian continental shelf and its North Sea neighbor countries is low. The same cannot be said for areas outside the Norwegian continental shelf where the flow seems to be good and without any significant constraints. Companies that operate on both the Norwegian and UK continental shelf refrain from moving mobile offshore units between the continental shelves. The reason is the fear of, and risks of, high costs and delays. The operators also find that very few units are suitable for operations on the Norwegian continental shelf without high modification costs due to Norwegian regulations (Reiten, et al., 2012).

Reiten, et al. (2012) find that a lot of newly built offshore units from foreign shipyards need modifications before they can operate on the Norwegian continental shelf. This is especially the case when the activity levels are high, and it is necessary to use players that are not familiar with the regulations for the Norwegian continental shelf. The article argues that this can lead to cost overruns, but a new report did not find data that could support this statement (Norwegian Petroleum Directorate, 2013d).

2.3.5 Empirics: Oil and Gas Megaprojects

Megaprojects are defined as projects with capital investments exceeding 1 billion USD. Compared to non-oil and gas projects upstream megaprojects seem to perform quite poorly and be more fragile. A project's success is considered by how well the project performs compared to promises made during financial investment decisions (FID). Analysis shows that the larger the project (initially planned investment) is, the less likely it is that a project will be successful (Morrow, I and Gas Industry Megaprojects: Our Recent Track Record, 2012).

While non-oil and gas megaprojects' success rate stays approximately the same, at 50%, even as they grow in size and difficulty, upstream megaprojects fall to a 22% success rate. Taking into account that most projects, independent of sector, with a scope of 300 to 600 million USD are successful, this is a dramatic fall in success rate (Morrow, I and Gas Industry Megaprojects: Our Recent Track Record, 2012). Even though these project developments can be called failures, it does not necessarily mean that they are unprofitable, but it is natural to think that their net present value can suffer from it.

The successful projects had on average lower costs than budgeted, were delivered on time, were cost effective, had an average schedule, and they all produced as promised. The failed projects on the other hand were badly overrun, very expensive, quite late in delivery and two-thirds of them had production failures. Of the failed projects, 64% experienced serious and enduring problems with production during the first two years of production (Morrow, I and Gas Industry Megaprojects: Our Recent Track Record, 2012). Morrow points out that the seven main reasons for megaproject failure are greed, schedule pressure, not enough details in the deals being made, not enough money and time spent upfront, cuts in costs during the project, expectations that the contractors are carrying the risk when they are really not, and finally the firing of the project manager (Morrow, 2011). As for megaprojects in the gas and oil industry, the main reasons are front-end loading, turnover of project managers, and overly aggressive planning as described in the following paragraphs (Morrow, 2011). The production attainment ratio of produced oil and gas, which is the actual production to forecast at FID, is the single largest driver to return on investment for these projects. So these projects could experience a large hit to their net present value if the production attainment is low.

A report addressing oil and gas megaprojects from the audit and advisory firm EY (EY, 2013) supports these findings. In their dataset they found that 57% of the projects with updated cost data experienced cost overruns, with an average cost overrun of 65% (Endresen & Ånestad, 2013), while 64% experienced schedule delays.

In the article *“Oil and Gas Industry Megaprojects: Our Recent Track Record”* (Morrow, I and Gas Industry Megaprojects: Our Recent Track Record, 2012) there are three major factors that can explain why upstream megaprojects have a lower success rate than non-oil and gas projects;

1. Front-end loading of projects is much more important for upstream megaprojects. Front-end loading is often a three-stage process; business case development and appraisal, scope development, and front-end engineering design which includes execution planning. Upstream megaprojects are particularly sensitive to the front-end loading work, and as the completeness degrades cost overruns mount quickly.
2. Turnover of project leadership also damages the projects' outcome; for example, changing the project director is associated with a 30% decline in probability of achieving a successful project. When a project has done a good job with the front-end loading, the project director is likely to succeed nearly two-thirds of the time, compared to less than one-third if there is a turnover of the project director. For other industrial megaprojects the decline in success rate is only 5%, which is not statistically significant (Morrow, I and Gas Industry Megaprojects: Our Recent Track Record, 2012). This shows that non-oil and gas megaprojects are not as sensitive to a change of project director as upstream megaprojects. This position is important for upstream projects because the project director is often the glue between the different functions in a large company. If the project director is replaced, the glue dissolves, and the coherent whole that the project leader may have created between the different functions disintegrates.
3. Outside the E&P industry, a project's duration is often set close to the industry average of executed projects. Among upstream projects 54 % are schedule driven, meaning that the project is instructed to minimize the time to first production or set a schedule that is at least 15% less than the industry average of similar projects. The result however is that when one tries to achieve unobtainable speed, the quality of the work that goes into successful projects erode. To be able to master the excellence of speed, a seamlessly integrated organizational structure within the project is needed.

2.4 What has not been done?

We have looked at articles and reports addressing the reasons for cost overruns, and how to avoid them, but we have not found any literature or other sources where the current NPV of a development on the Norwegian continental shelf, or internationally, has been compared to the NPV calculated in the PDO. We will do this to see if the cost overruns could have caused higher revenues and that possibly the cost overruns do not really cause a much lower NPV. A deeper analysis is also relevant to look at how oil or gas reserves, the production profile, input prices, and recovery rate changes the NPV. This way, we will be able to show where the costs occur and how possible benefits emerge with the extra costs. This should be of interest for both for oil companies and for the government to consider which measures needs to be implemented, both regarding project management for the company, and also possible regulations from the government.

We also could not find anything addressing changes to the cash flows following cost overruns. The cash flow can be changed because of investments in newer technology than planned and also in more operating wells. We think this is essential for analyzing cost overruns, to show a slightly new point of view. It now becomes relevant to split the cash flow into smaller parts to see where the effects are more significant.

2.5 What New Perspectives and Knowledge will this Report give?

The empirical and academic studies we have found tend to have a strong qualitative focus. We try to deepen the understanding provided by these reports by focusing on the quantitative effects of the cost overruns by using valuation and budget analysis.

By valuing the fields in an order reflecting the expectations in the PDOs, and by the updated numbers, we have uncovered how the fields have performed financially, even though they have all experienced significantly higher investments than expected in the PDOs. By identifying how the different areas of the operations have affected the valuation, we wanted to uncover where the operations may have been successful and where they have experienced problems. The valuation analysis is supplemented by a variance analysis to look at how the fields have performed relative to their budgets, which expands our understanding from the valuation done by NPV analysis. By uncovering the different value drivers of the fields, and their performance relative to the budgets, we have unveiled some areas that later master theses or other reports can focus on to give a more detailed analysis of the underlying reasons for the deviations.

3 Data

3.1 Introducing the Norwegian Continental Shelf

In 1958, few believed that there was coal, oil or sulfur to be found on the Norwegian continental shelf (Norsk Olje og Gass, 2010). After the gas discoveries in Groningen in 1959 though, people started to talk about finding hydrocarbons in the North Sea. Just three years later, Phillips Petroleum contacted the Norwegian authorities, and asked for exploration permits in the North Sea. This was the start of the Norwegian oil and gas age.

Agreements made between Norway and the United Kingdom, and later in 1965 Norway and Denmark, to split the continental shelf by the median line principle, insured there would be less conflict surrounding newly discovered resources (Ministry of Petroleum and Energy, 2013).

By 1963, companies were given permissions to do seismic analysis, and the first exploration well was completed in 1966 (Ministry of Petroleum and Energy, 2013). The well was dry, but in 1968, Phillips Petroleum published a press release confirming findings of hydrocarbons in one of their wells. Before this, in 1967, Balder was drilled. It was not seen as commercially interesting at that time, but the area was explored further, and the PDO was approved in 1996.

By the fall of 1969 Ekofisk, one of Norway's biggest oil and gas discoveries was found (Norwegian Petroleum Museum). Production from Ekofisk started in 1971, and many bigger discoveries were made in the years that followed. Since most participating companies were foreign, in 1971 the Government's industry committee stated some guidelines for future Norwegian oil politics, saying that oil should primarily be landed in Norway, so that a new industry could be established in Norway. The following year, the Norwegian Petroleum Directorate was created, and Statoil as a state oil company (Norwegian Petroleum Museum).

During the middle of the 1970's, the world was struck by an oil crisis following wars in the Middle East, and subsequent reduced oil production. This led to higher prices and a certainty that Norwegian developments would now likely pay off. In 1979 the production from Statfjord also started (Norwegian Petroleum Museum).

In 1980, the first blocks north of 62nd latitude were awarded. This was a controversial decision because of the fisheries (Norwegian Petroleum Museum). In 1981 the first discovery on Haltenbanken was made, and throughout the 80's, more discoveries were made in the Norwegian Sea (e.g. Åsgard, Draugen and Heidrun).

On the 1st of January 1985, the participant rate from the government was split in two, one part tied to Statoil, and one tied to the State's Direct Financial Interest (SDFI). It is a portfolio where the Norwegian government owns interest in E&P licenses on the Norwegian continental shelf. In 2001, Petoro was established to keep running the SDFI (Ministry of Petroleum and Energy, 2013). Very low oil prices from 1986 on, and the CO₂ fee introduced in 1991 in Norway, led to big technological developments, and Norway became one of the leading countries in oil and gas explorations. By 1998, the Norwegian oil wealth, counting the estimated reserves on the Norwegian continental shelf, was estimated to 1 000 billion Norwegian kroner (Norwegian Petroleum Museum). Because of new found resources and a strong increase in oil prices, this has risen significantly, and by December 2nd 2013 the Norwegian oil fund passed 5 000 billion NOK in size (Dagens Næringsliv, 2013).

Since the beginning in the 1960's, this industry has created values of more than 12 000 billion kroner, and by 2012 it accounted for 23% of the GDP in Norway. The industry is vast and capital intensive, and as of 12/31/2012, more than 3 000 billion kroner have been invested in exploration, development, infrastructure and land facilities in Norway (Ministry of Petroleum and Energy, 2013).

These big numbers also invite for big cost overruns to be done, but even though some projects have had big overruns, most projects are within the +/-20% uncertainty of PDO (Norwegian Petroleum Directorate, 2013d). With these big overruns though, we have chosen a few projects to have a closer look at.

3.2 Why we have Chosen these Licenses

We have already limited the topic of our report to only look at developments on the Norwegian continental shelf. This is because of the high relevance to the Norwegian economy and society, as well as the relevance of the topic in Norway today. We also chose to have three to five fields, so that we could compare the findings, and see if there are any common tendencies. By using developments from different companies, with different solutions we hoped that we could find both tendencies and differences between them.

When choosing the fields to look at, we had several aspects in mind. We wanted to compare the NPV we get from the PDO to a new calculation of NPV after several years of production. Since the PDOs are not official, we also considered it more likely to get access to the data if the field were some years old, since it probably makes them less sensitive. However it was also important for us to look at fields that are still relevant, with up to date technology. We therefore started our selection by looking at all fields that were developed between 1990 and 2005.

Of these fields, we also needed to find only those who had considerable cost overruns, and were still operating. Since we also wanted to make sure the fields were somewhat comparable to each other we needed to take into account which year they started production, in what year the PDO was sent in and approved, and that the present accumulated CAPEX of the field was above one billion USD, defining the project as a megaproject.

Criteria:

- PDO was approved between 1990 and 2005
- Cost overruns for developing the field according to PDO
- Still operating
- Accumulated CAPEX above 1 billion USD

By grouping developments that met our criteria of when they sent in their PDOs and started production, we tried to ensure that the decisions to develop these oil fields were made with the same expectations of the market conditions and the market place. We therefore grouped developments which had their PDO approved within two years of each other, then looked at each of these segments. We found the CAPEX of the fields in WM's GEM, and were finally left with Åsgard, Oseberg Øst, Jotun, Varg and Balder; all these meet our criteria. For these fields PDO was approved between 1996 and 1997, production started during the time frame of 1998 till 1999, the technology was relatively new, the market conditions were pretty much the same, and they are all still operating (Norwegian Petroleum Directorate, 2014c).

Since no oil field will be identical we still have some challenges when comparing the developments. The differences could be as follows: whether they are oil or gas intensive, the size of the initial investment, how the field was developed, the ocean depth, the depth of the reservoir, and the reservoir's temperature and pressure. When comparing the different developments we need to be aware of the differences between the developments and fields since these items can have a significant impact on the investments, revenues and operating costs.

After identifying which fields fit our criteria, we contacted the individual operators and the Norwegian Ministry of Petroleum and Energy. This secured access to different sources of data that we could use in our analysis. From these we got PDOs, Starting propositions and impact assessments for the different fields. After assessing the data received we decided to exclude Balder from our analysis due to its close connection to Ringhorne. This connection is so close that we are not able to distinguish costs and revenues between Balder and Ringhorne in our dataset.

3.3 Presentation of data sources

We have used several sources for our analysis, however there are a couple of sources that have been used more comprehensively throughout our analysis. Since these sources are not available for the average reader we have chosen to present these briefly.

3.3.1 Wood Mackenzie Global Economic Model

The GEM by the consulting and research company WM is an effective valuation tool for upstream assets and portfolios around the world. It is used for market valuation, M&A transactions, benchmarking, fiscal analysis and negotiations (Wood Mackenzie, 2014a). The model allows you to customize asset and company data, prices and fiscal models to generate valuation based on your own assumptions. The reason for this is that it is built on the robust proprietary data of WM and supported by their analysts. WM gathers information from a wide range of sources such as regular meetings and conversations with key players, which is then analyzed to produce independent insight (Wood Mackenzie, 2014b).

In our own valuation model, we will use GEM as a database for updated real costs and estimates for the future (2014 onwards) regarding such items as production, costs, and investments. This will then be compared to the valuation based on the PDO, which will be used as the benchmark.

3.3.2 Plan for Development and Operations

The Norwegian government must approve the PDO and operations in order for a company to be allowed to develop an oil field. The operator has the responsibility for producing the PDO, which is often done in close cooperation with the rest of the licensees, before it is sent to the government for approval.

In a PDO we can typically find information regarding geological conditions, the reservoir, installation and equipment for production, costs and schedule, HSE, organization and execution, removal of the installations, and economic and area analysis.

For our analysis some parts of the PDO are more relevant than others. We will especially focus on costs and schedule, removal of the installations and the economic analysis. The PDO is not available to the public and we signed confidentiality agreements to be granted access. Because of this, our analysis will need to aggregate data to ensure the confidential data in the PDOs. We acknowledge that it would be beneficial to use publicly available sources, but due to the lack of detailed public sources, we have chosen to stay with the PDOs.

The PDOs are much more detailed than publicly available information. Because of this we do not need to make assumptions regarding decisions and considerations that have been included in the PDO when we are benchmarking, which is a great advantage for the validity of our results.

3.3.3 Storting Propositions

Depending on the size of the CAPEX of the development the Ministry of Energy and Petroleum or the Storting may approve the PDO. Currently (March 5th 2014) PDOs with CAPEX above 10 billion NOK need to be approved by the Storting, while smaller developments can be approved by only the Ministry of Energy and Petroleum. The Ministry of Petroleum and Energy generate the Storting propositions through their recommendation regarding the development, and under what criteria they made their recommendation. These propositions do not focus on the quantitative parts of the PDO, but rather focus on the qualitative parts and assessments of the PDO. This process is done by focusing on Norway as an oil and gas nation, and how these developments will advance the country as such. How the development will link to other fields on the continental shelf and a focus on environmental issues are included. By emphasizing production, transport, environmental, and development solution issues, the propositions will give us a better understanding of the field developments.

3.3.4 Impact assessments

The impact assessments conducted prior to the PDO emphasize the effects a possible development has on the environment, society, the fishery industry, and assessments regarding different development solutions. The social consequences focus on the economic effects directly from the field and the spillover effect it has on the oil and gas industry and the rest of the country. The impact assessments consider a wide range of qualitative data, providing good insight into possible challenges regarding the development that we can investigate further if our findings from the analysis suggest so. In addition, these assessments provide some quantitative data regarding the investments, and costs of the development, that can be used for further analysis.

3.3.5 Differences between Wood Mackenzie and Plans for development and Operations

A main difference in our data sources is the type of data they contain. While the impact assessments and Storting propositions to a large degree are qualitative, the WM database is a purely quantitative data source. The PDO on the other hand fits in the middle of these, with different chapters focusing on both qualitative and quantitative sides of the development. The qualitative data sources will help us get a better understanding of the developments, giving us a better understanding of data such as drilling programs, areas of uncertainty and risk and the concept solution. So the qualitative sources are to a large degree complementary and are not contradictive of one another.

The quantitative data sources are also complementary, but differ largely due to the time frame in which they were created. The data and estimates in the PDO are created prior to the development of the fields. Because of this, the data only represents the best estimates of the real production, revenues, costs and capital investments. On the other hand the data from WM GEM is updated twice a year, with updated estimates for the future and real numbers from the past. Since the PDOs are quite old, and the data from WM are quite new, we are able to use the differences between them to determine how good the estimates were, and how accurate the profitability is likely to be when compared to the estimates once deciding to take on the project.

However, the comparison between the WM database and the PDO is not straightforward. The parameters such as costs, revenues, production and CAPEX are not grouped in the same manner. Because of this we have grouped these to facilitate benchmarking and comparison between the updated data from WM and the estimated data from PDO.

Specific assessments regarding the analysis

The CAPEX is stated differently in the PDOs and the WM GEM. The PDOs grouping can be seen in chapter 3.4 while WM has a different grouping. In WM the CAPEX is given in these posts:

- Processing Facilities
- Processing Equipment
- Subsea
- Drilling
- Offshore Loading
- Pipeline
- Terminal
- Other

When comparing WM figures with the PDO figures we have chosen just to look at the total, as it is not possible for us to make a consistent breakdown of the numbers.

All the fields valued and analyzed are subject to Norwegian tax authorities and taxation laws. However, there could be permanent and temporary differences between them, which we are not aware of, that can influence both the tax and paid taxes, which in turn can influence the present value of the fields after taxes. Our analysis shows that our present values before tax equals the values found in the PDOs, but there are differences after taxes. This may be caused by the timing of paid taxes, other temporary and permanent differences, and other assumptions, of which we are

unaware. Because of this, we have considered numbers from PDOs and WM as subject to taxation, and are following the Norwegian law of petroleum taxation as it was in 1995.

Some of the developments are financed using debt, which will cause the field to pay interest rates on the loan, reducing the taxable result. Since financing is not considered in the WM model, we would normally need to consider how the interest rates have been during the period used, and what they are expected to be in the future, which could deviate from the assumptions in the PDOs. However, we have chosen to let the interest rates and down payment period follow the expectations in the PDO, but letting the CAPEX affect the size of the loan since there is made assumptions that a certain part of the investments would be financed using debt.

Some of the fields produce only oil, some only gas, and some produce both, so we need to use a measure for volume that takes this into account for the variance analysis. We have found the real volumes using standard cubic meters of o.e.s for all the petroleum resources being produced.

3.4 Strengths and weaknesses of the data material

Our analysis is based on several sources of information. The main sources are WM's GEM, Plans for Development and Operations and published reports (PDO). We have also looked into impact assessment studies and Storting propositions, but found the data to be secondary to the PDOs, and have focused on the data presented in the latter.

GEM is software developed by the consultant and analysis firm WM. They gather information from a wide range of sources and use these to create both estimates for the future and reports on the past for individual oil companies and oil fields. We have no opportunity to assess the sources used by WM. The company is well known, and this program is frequently used in the oil industry on a global basis. Because of this we consider the data to be of a strong and good quality, and the best available source without gaining direct access to the internal financial statements of each field. This data is also the most reliable data we can get our hands on for financial data after the PDO and after many years of production. Because of this, our updated analysis will be based on this dataset.

The PDOs for the different fields are quite detailed, but the information found in them is confidential. Because of this the data presented will need to be aggregated so that detailed confidential information is not published.

The different sources of data seem to be good individually, but for our analysis it is also important that they are comparable and compatible to each other. Since we will present aggregated data in our analysis, and some of the data that is presented to us is aggregated, we need to make sure that they

are aggregated in the same manner. Where it was not clear how the data was aggregated, we clarified this by contacting the different publishers of data, which gave us a better foundation to compare the data. Based on this information, calculations, and educated guesses, we have identified which costs were included and where. We have done so by taking all information into account and comparing previous years where we have solid data, and are happy to see that we get comparable aggregated data.

3.5 Presentation of each License

3.5.1 Jotun

The field

Jotun was discovered in 1994 on production license 103 B and 027 B in the central part of the North Sea. Esso Exploration and Production Norway AS, which was the interim operator, applied for development of the field with its PDO, which was approved on June 10th 1997. The field started production on October 25th 1999.

At the time of PDO, Esso Exploration and Production Norway AS and Enterprise Oil Norway AS were the operators of PL 103 B, and Norske Conoco AS, Statoil AS (named Den norske stats oljeselskap at the moment), Amerada Hess Norge AS, and The State's direct financial interest were the licensees. Currently (February 13th 2014) the operator is ExxonMobil Exploration and Production Norway AS, and additional licensees are Det norske oljeselskap ASA, Dana Petroleum Norway AS, and Faroe Petroleum Norge AS (Norwegian Petroleum Directorate, 2013b).

The field has been developed with a combined accommodation, production, and storage vessel (FPSO), and a wellhead facility. Jotun is integrated with Balder and Ringhorne, processing gas from Balder and oil from Ringhorne. The Jotun oil is recovered with pressure support, using gas in all the producing wells. The gas that is processed at Jotun is exported via Statpipe to Kårstø, while the oil is exported via the production vessel and to tankers on the field. The field is in its tail phase and 97% of the well stream is water (Norwegian Petroleum Directorate, 2013b). A small oil field, Jette, is now tied into Jotun, using some of its production capacity. Jotun, which was expected to stop producing in 2015 (Norwegian Petroleum Directorate, 2014c), is now expected to produce until 2021 (Norwegian Petroleum Directorate, 2013b).

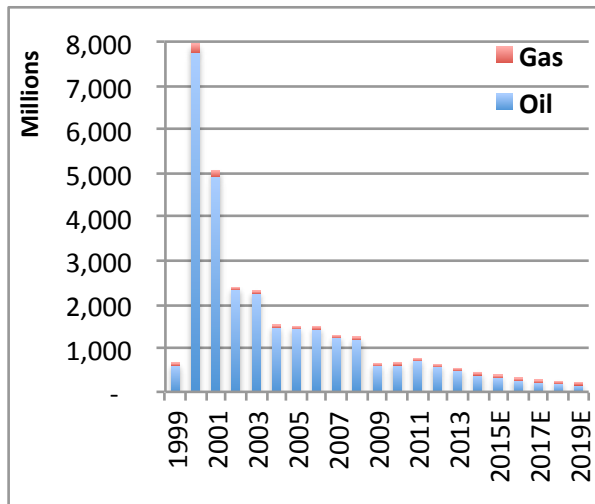


Figure 7 – Revenues NOK'96 - Jotun

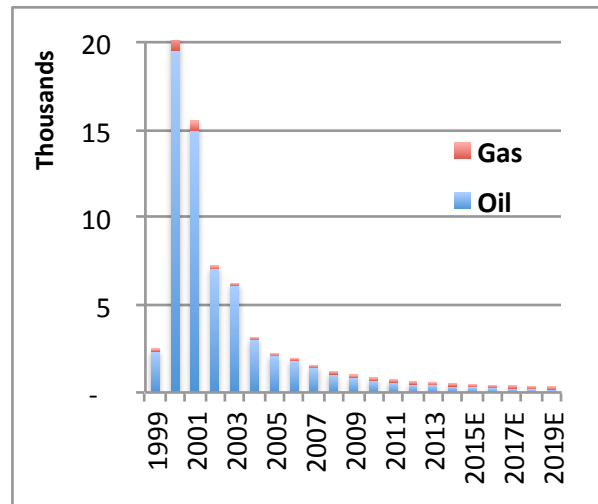


Figure 8 - Production Profile SM³ Oil Equivalents per day, Jotun

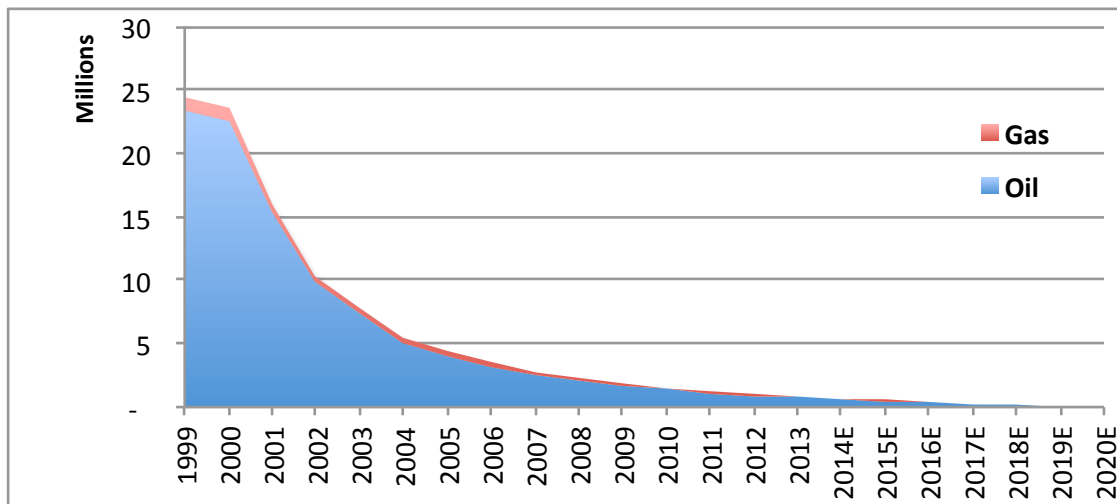


Figure 9 - Remaining Resources SM³ Oil Equivalents, Jotun

Table 2 - Reserves and production Jotun

Recoverable reserves		Estimated production in 2013
Identified	Remaining (as of 31.12.2012)	
23.4 million Sm ³ o.e. oil	0.7 million Sm ³ o.e. oil	Oil: 0.12 million Sm ³ o.e.
1.1 million Sm ³ o.e. gas	0.2 million Sm ³ o.e. gas	Gas: 0.00 Sm ³ o.e.

(Norwegian Petroleum Directorate, 2013b)

Cost overrun

Table 3 - Cost overruns Jotun

Key elements	PDO	CCE2*	Increase	Increase	WM**	Increase
	Billion 98-NOK	Billion 98-NOK	Billion 98-NOK	Percent	Billion 98-NOK	Percent
Date of source	Jan. 1997	Feb. 1999			Nov. 2013	
Administration and project planning	0.508	0.646	0.137	27%		
Platform	4.139	4.717	0.578	14%		
Modifications	0	0	0	-		
Subsea constructions	0.416	0.567	0.151	36%		
Marine operations	0	0	0	-		
Assembly and commencement	0	0	0	-		
Drilling and completion	1.135	1.149	0.014	1%		
Miscellaneous	0	0.125	0.125	-		
SUM	6.199	7.204	1.005	16%	7.929	28%

* Last controlled cost estimate prior to NOU 1999:11 report and prior to production start (Kaasen, et al., 1999)

** Data from the Wood Mackenzie license Global Economic Model 4

The cost overrun for Jotun prior to the report published February 19th 1999, eight months prior to production start, was 1,005 million NOK in total, or 16% above the estimates in the approved PDO. Our estimated final costs for the planned development were 27.9% above the PDO that was approved by the Norwegian government. In the report the operator states that there were several reasons for the cost overruns.

The platform accounts for about half the cost overruns and it is mainly due to underestimation, and increased weight of the topside, in addition to some further development of the design. For the subsea construction underestimation and further development in the design has caused the cost overruns, while cost of administration and project planning has increased because of contractual complexity, long distances, extended project period and closer follow-up of contractors (Kaasen, et al., 1999).

3.5.2 Varg

The Field

Varg was discovered in 1984 on production license 038 in the central part of the North Sea. The operator, Saga Petroleum AS, applied for development of the field with its PDO, which was approved May 3rd 1996. The field started production on December 22nd 1998.

At the time of PDO, Saga Petroleum AS and Statoil AS (named Den norske stats oljeselskap at the moment) were the licensees after Saga had bought Esso's share in 1994 (Norwegian Petroleum Directorate, 2014a). Currently, on February 13th 2014, the Operator is Talisman Energy Norge AS, and additional licensees are Petoro AS and Det norske oljeselskap ASA.

The field is developed with a production vessel that has integrated oil storage connected to the wellhead facility Varg A. The decommissioning plan for the field was approved in 2001, with scheduled end of production in the summer of 2002. However, because of new measures, the lifetime of the field was prolonged and the field is now expected to produce until 2021. Drilling campaigns to optimize the recovery have been successful, and several new production wells are planned for the future. The recovery takes place using gas and water injection. The field has only produced oil so far and used the gas as injection to support the recovery. In the future it is expected that the gas will be exported via the CATS pipeline system to the UK (Norwegian Petroleum Directorate, 2013e).

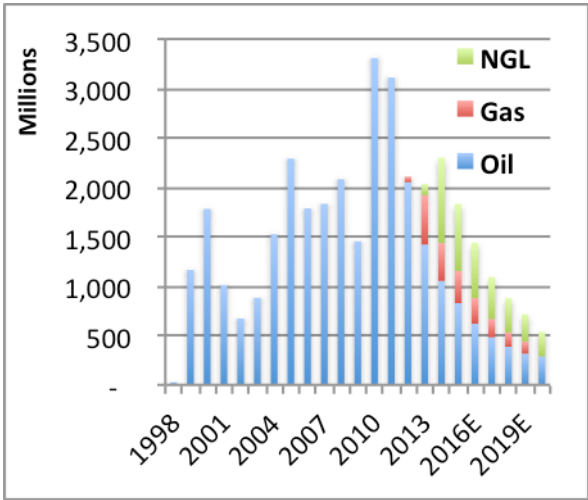


Figure 10 – Revenues NOK'95, Varg

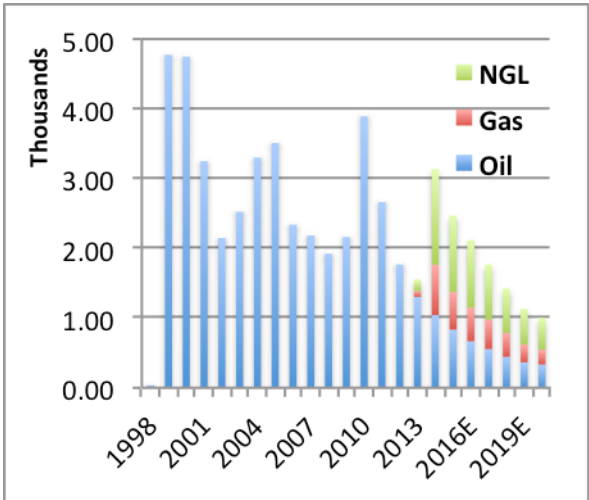


Figure 11 - Production Profile SM³ Oil Equivalents per day, Varg

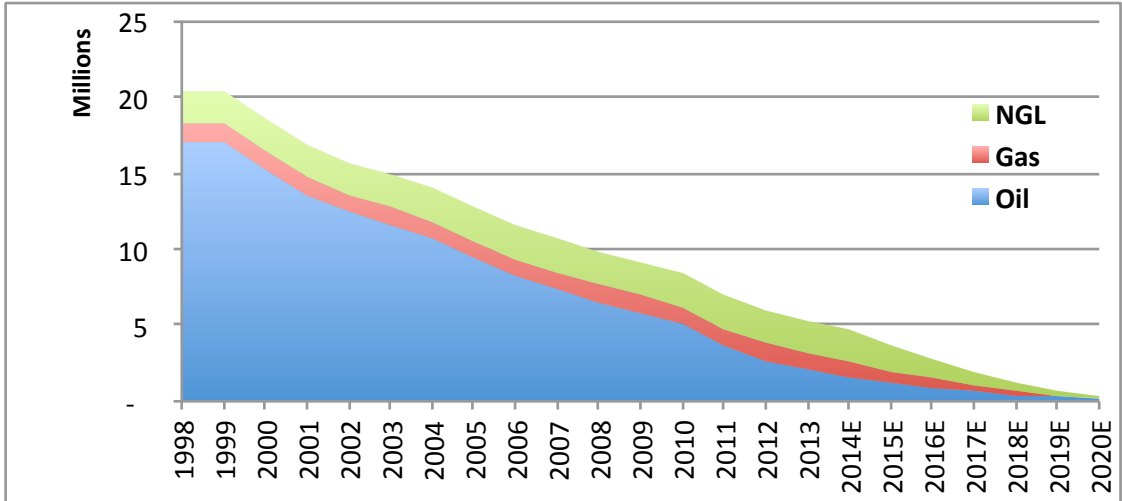


Figure 12 - Remaining Resources SM³ Oil Equivalents, Varg

Table 4 - Reserves and production - Varg

Recoverable reserves		Estimated production in 2013
Identified	Remaining (as of 31.12.2012)	
16.4 million Sm ³ o.e. oil	1.4 million Sm ³ oil	Oil: 0.52 million Sm ³ o.e.
1.1 million Sm ³ o.e. gas	1.1 million Sm ³ o.e. gas	Gas: 0.02 million Sm ³ o.e.
1.9 million Sm ³ o.e. NGL	1.9 million Sm ³ o.e. NGL	NGL: 0.038 million Sm ³ o.e. NGL

(Norwegian Petroleum Directorate, 2013e)

Cost Overrun

Table 5 - Cost overruns Varg

Key elements	PDO	CCE5*	Increase	Increase	WM**	Increase
	Billion 98-NOK	Billion 98-NOK	Billion 98-NOK	Percent	Billion 98-NOK	Percent
Date of source	Jan. 1996	Feb. 1999			Nov. 2013	
Administration	0.168	0.300	0.133	79%		
Platform (Varg A and B)	1.994	2.055	0.061	3%		
Modifications	0	0	0	-		
Subsea construction	0.158	0.173	0.015	9%		
Marine operations	0.025	0.133	0.108	432%		
Assembly and commencement	0.037	0.140	0.103	278%		
Drilling and completion	0.553	0.835	0.282	51%		
Miscellaneous	0	0	0	-		
SUM	2.935	3.636	0.701	24%	4.114	37%

* Last cost control estimate prior to the NOU 1999:11 report (Kaasen, et al., 1999)

** Data from the Wood Mackenzie license Global Economic Model 4

The estimated cost overrun on Varg prior to the report published in February 1999 was 700 million NOK in total, which is 24% above the estimates in the PDO that was approved by the government. Our estimated final costs for the planned development were 37% above the PDO that was approved by the Norwegian government. According to the operator the initial cost overruns reported in 1999 was caused for several reasons.

Drilling and complementation became more expensive due to changes in the drilling program, lower rig efficiency and increased drilling and complementation time, delayed installation and drilling start, as well as higher rig rates.

Administration costs increased by 133 MNOK, 79%, due to higher degree of follow-up on the production facility, caused by lack of follow-up from their suppliers. Because of inadequate technical definitions and late arrival of the drilling rig and the production facility the marine operations increased by 107 MNOK.

3.5.3 Oseberg Øst

The field

Oseberg Øst was granted as production license 53 as early as in 1979. It is located just east of Oseberg, in the northern parts of the North Sea. Statoil AS (named Den norske stats oljeselskap a.s at that time) is now the operator, as it was in 1979. The discovery on this field was done in 1981, and in 1982 the operator became Norsk Hydro, which continued until Statoil became operator again in 2007. The PDO was not approved until October 11th 1996 though, and production started as late as May 3rd 1999.

The other licensees are Petoro AS, Total E&P Norge AS, and ConocoPhillips Skandinavia AS. At the time of PDO the licensees were Den norske stats oljeselskap a.s, Norsk Hydro Produksjon AS, Elf Petroleum Norge AS, Saga Petroleum Norge AS, Mobil Development Norway AS, and Total Norge AS (Norwegian Petroleum Directorate, 2014).

The sea depth where the facilities are located is about 160 meters, and the reserves are at 2700-3100 meters depth.

This field has been developed with an integrated, fixed facility with accommodations, drilling equipment, and first stage separation of oil, water and gas. The oil is recovered with pressure support using gas and water. The oil then goes through pipelines to the Oseberg field center. It gets processed and transported from there to Stureterminalen. There is also some gas in the license, but this is mainly used as injection for pressure support, and as fuel gas (Norwegian Petroleum Directorate, 2013c)

The field has prolonged its initial production period till 2031, and they are expecting to recover another 7.9 million Sm³ as of December 31st 2012 while they are also working to improve their drilling operations.

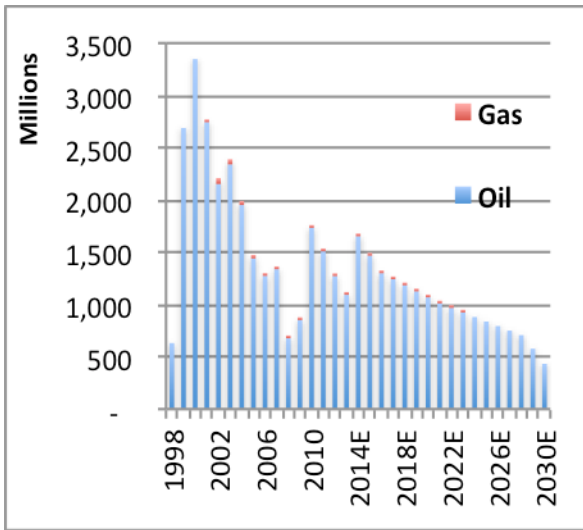


Figure 13 – Revenues NOK'96, Oseberg Øst

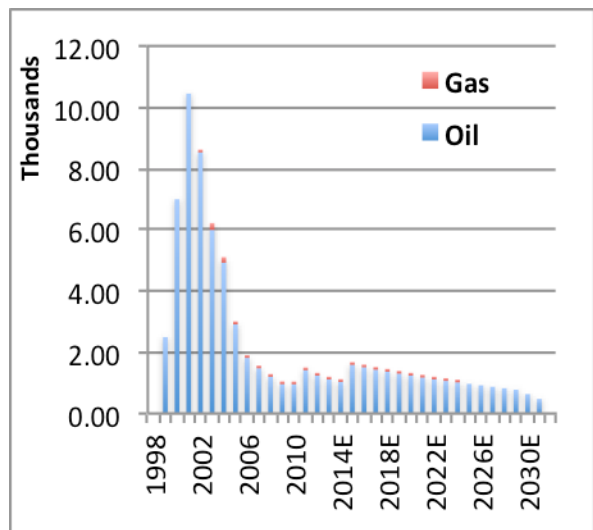


Figure 14 - Production Profile SM³ Oil Equivalents per day, Oseberg Øst

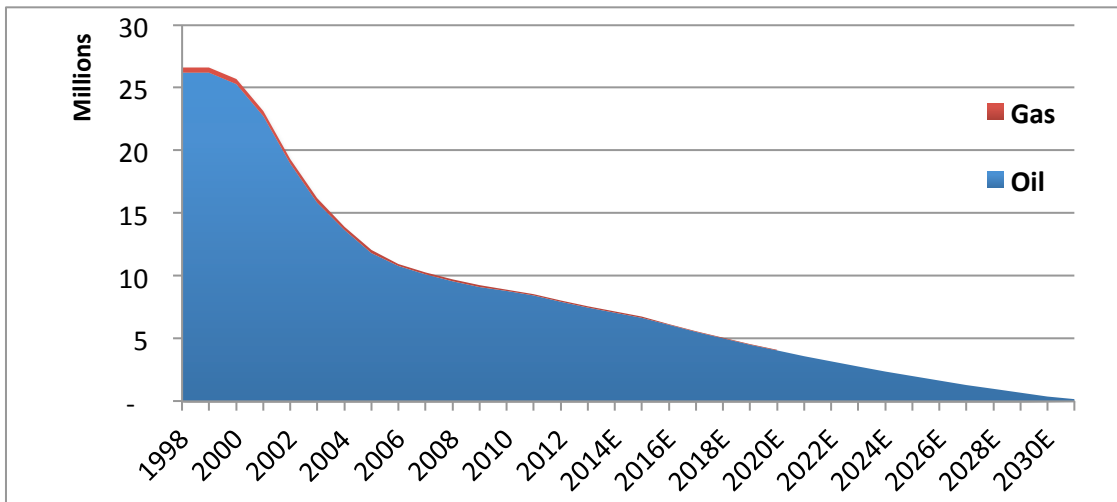


Figure 15 - Remaining Resources SM³ Oil Equivalents, Oseberg Øst

Table 6 - Reserves and production Oseberg Øst

Recoverable reserves		Estimated production in 2013
Identified	Remaining (as of 31.12.2012)	
26.7 million Sm ³ o.e. oil	7.9 million Sm ³ o.e. oil	Oil: 0.41 million Sm ³ o.e.
0.4 million Sm ³ o.e. gas	0.1 million Sm ³ o.e. gas	Gas: 0.00 Sm ³ o.e.

(Norwegian Petroleum Directorate, 2013c)

Cost overrun

Table 7 - Cost overruns Oseberg Øst

Key elements	PDO	CCE5*	Increase	Increase	WM**	Increase
	Billion 98-NOK	Billion 98-NOK	Billion 98-NOK	Percent	Billion 98-NOK	Percent
Date of source	Apr. 1996	Feb. 1999			Nov. 2013	
Administration and project planning	0.247	0.297	0.050	20 %		
Platform	1.595	1.936	0.340	21 %		
Modifications	0.118	0.088	0.029	-25 %		
Subsea constructions	0.267	0.192	-0.075	-28 %		
Marine operations	0.180	0.267	0.087	48 %		
Assembly and commencement	0.064	0.175	0.111	173 %		
Drilling and completion	1.016	1.334	0.318	31 %		
Miscellaneous	0	0.008	0.008	-		
SUM	3.488	4.298	810	23 %	4.581	31%

* Last controlled cost estimate prior to NOU 1999:11 report and prior to production start (Kaasen, et al., 1999)

** Data from the Wood Mackenzie license Global Economic Model 4

The cost overrun on Oseberg Øst prior to the report, which was published February 19th 1999, barely three months prior to production start, was 810 million NOK in total, or 23% above the estimates in the approved PDO. Our total estimated final costs of the planned development were 31.8% above the PDO that was approved by the Norwegian government. We have set the cut off for the initial investments according to the PDO to be all investments from 1996 and through 2000.

Much of the cost increase of the platform is due to a heavier body, but also because of underestimation and deficiencies. Of the cost overrun on drilling and completion, some costs have been used to increase the daily production, and URR. New information during the development of the field, and delayed completion, has also caused cost overruns on assembly and commencement (included in the drilling and completion from WM). Marine operations have also increased, but WM also does not have this specified (Kaasen, et al., 1999).

3.5.4 Åsgard

The field

Åsgard is an oil, gas and condensate field consisting of 6 licenses; production license 62, 74, 94, 94B, 134 and 237. It is centrally located in the Norwegian Sea and is developed through two phases, the first one being the fluid phase in 1999 and the second one being the gas export phase, which started in 2000. The field consists of discoveries on Midgard, Smørbukk and Smørbukk Sør. Midgard was discovered in 1981, Smørbukk in 1985, and Smørbukk Sør in 1985. The PDO for the joint field was

approved June 14th 1996, and production started May 19th 1999. Today, as was true in 1996, the operator is Statoil Petroleum AS, and the other licensees are Petoro AS, Eni Norge AS, Total E&P Norge AS, and ExxonMobil Exploration & Production Norway AS (Norwegian Petroleum Directorate, 2014b).

The sea depth where the facilities are is from 240-300 meters, and the reserves are at different depths for the different discoveries, the deepest discoveries being as deep as 4850 meters.

The field has been developed with subsea wells tied to an FPSO (floating production, storage and offloading) vessel called Åsgard A, and a floating semi-submersible platform which processes gas and condensate, Åsgard B. There is also a storage vessel tied to Åsgard B to store condensate. Gas from Mikkel also gets processed at Åsgard, and injection gas is transported to the Tyrihans field (Norwegian Petroleum Directorate, 2014b). The recovery of each discovery also differs. Smørbukk Sør recovers its resources through the use of gas injections, while Smørbukk uses both depressurization, and injections of surplus gas. Midgard uses depressurization only. The oil and condensate from the field is transported by tankers, while the gas gets transported through pipelines to Kårstø.

Most of the production wells on Åsgard are drilled, and they are actively looking for ways to increase URR with more wells and sidetracks. They have also discovered new segments with hydrocarbons that are being considered as possibilities for longer production. The remaining reserves as of December 31st 2012 are 18.6 million Sm³ oil, 84.1 billion Sm³ gas, and 16.8 million tons of NGL.

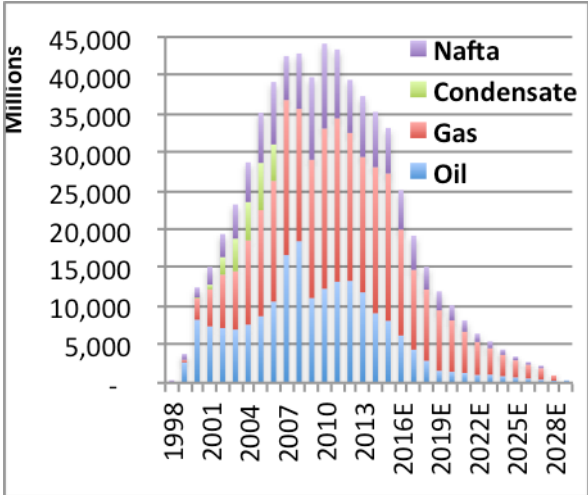


Figure 16 – Revenues NOK'95, Åsgard

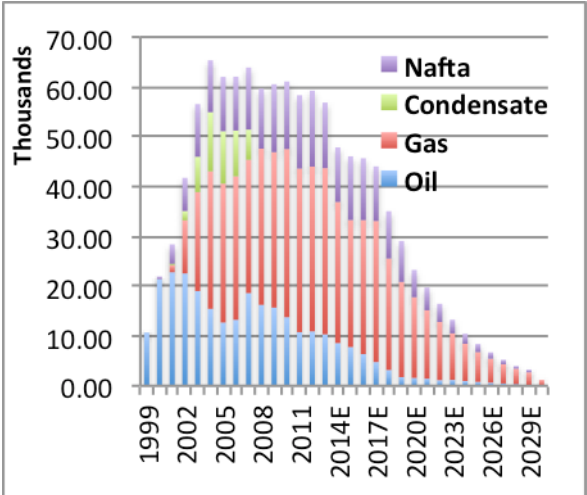


Figure 17 - Production Profile SM³ Oil Equivalents per day, Åsgard

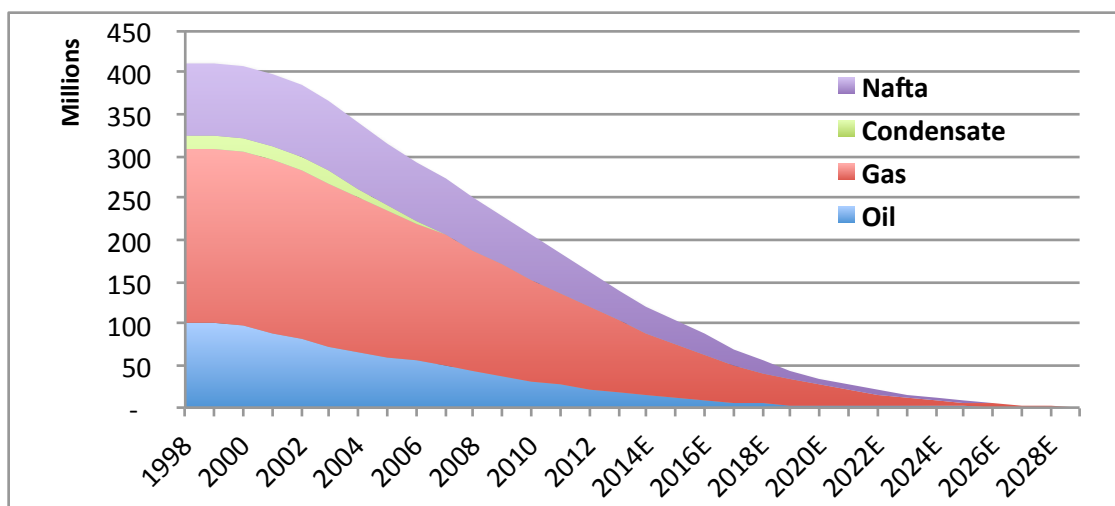


Figure 18 - Remaining Resources SM³ Oil Equivalents, Åsgard

Table 8 - Reserves and production Åsgard

Recoverable reserves		Estimated production in 2012
Identified	Remaining (as of 31.12.2011)	
103.8 million Sm ³ o.e. oil	25.9 million Sm ³ o.e. oil	Oil: 4.99 million Sm ³ o.e.
200.6 million Sm ³ o.e. gas	89.3 million Sm ³ o.e. gas	Gas: 11.83 million Sm ³ o.e.
73.7 million Sm ³ o.e. NGL	35.5 million Sm ³ o.e. NGL	NGL: 4.29 million Sm ³ o.e.
16.1 million Sm ³ o.e. condensate	-	-

(Norwegian Petroleum Directorate, 2012)

Cost overrun

Table 9 - Cost overruns Åsgard

Key elements	PDO	CCE5*	Increase	Increase	WM**	Increase
	Billion 98-NOK	Billion 98-NOK	Billion 98-NOK	Percent	Billion 98-NOK	Percent
Date of source	Des. 1995	Feb. 1999			Nov. 2013	
Administration and project planning	3.996	5.248	1.251	31%		
Platform	9.994	11.558	1.564	16%		
Modifications	0	0	0	0		
Subsea constructions	3.693	5.312	1.619	44%		
Marine operations	2.327	2.764	0.438	19%		
Assembly and commencement	0.136	0.199	0.063	47%		
Drilling and completion	7.162	10.417	3.255	45%		
Miscellaneous	1.219	1.469	0.250	21%		
SUM	28.524	36.967	8.443	30%	48.887	71,4 %

* Last controlled cost estimate prior to NOU 1999:11 report and prior to production start (Kaasen, et al., 1999)

** Data from the Wood Mackenzie license Global Economic Model 4

The cost overrun on Åsgard prior to the report, which was published February 19th 1999 and three months prior to production start, was 8.443 billion NOK in total, or 30% above the estimates in the approved PDO. Our estimated final cost, with a cut off including the investments in 2002 when all the planned wells were drilled, were 75.9% above the PDO that was approved by the Norwegian government.

Much of the cost overrun on Åsgard A is due to work being handled by Aker Stord instead of Hitachi Zosen, increased weight on the platform, more risers than estimated, and increased injection of produced water and gas. Åsgard B also underestimated the cost of the topside, and generated higher costs on the structural support. Åsgard C was first considered for purchase, but instead became a leased property.

The subsea constructions also increased costs because of the increased number of risers, and their larger dimensions, while the drilling costs increased for several different reasons: use of a rig with much higher daily rates, rebuilding the rig, longer time for completion of wells, and the wells being harder to complete than anticipated (Kaasen, et al., 1999).

4 Data Analysis

4.1 Considerations Regarding the Valuation Model

Our valuation model is based on cash flows to the firm, discounted at different discount rates that coincide with the discount rates used in the PDOs, these being used to compare our updated valuations to the original valuations in the PDOs. To accomplish this we have created a valuation model, this model being used to create new financial statements for the income statement and cash flow statement, and the required balance sheet items, such as accumulated uplift and depreciation. We have used the available data from the PDOs, and used the assumptions made in the PDOs throughout the valuation where we do not have any updated information. This can be related to financing decisions where some of the initial CAPEX are financed by debt with a given grace and down payment period. The specific assumptions and considerations used are presented in the valuation analysis of each field.

Regarding the cash flow, we have made assumptions that the cash flow from the items in the income statement will occur the same year as the revenues and costs occur. All the numbers are considered in real terms since the PDOs operate with real numbers in NOK'96 or NOK'95. Because of this we have converted all the nominal monetary numbers into the deflated real values of NOK'95 or NOK'96 to enable us to make the comparison between the PDO and updated numbers. All of the discount rates are in real terms as well, and the same sizes as in the PDOs.

When conducting the updated valuation of the fields, we have used all of the updated numbers. Over time the fields have experienced several changes and investments that were not anticipated in the PDO, making the field different from the initial development. Despite this we have chosen to include all these changes because we do not have data that would enable us to identify exactly how this has affected costs and production for each year. The differences this have made on the valuation of the fields will be very hard, if not impossible, to identify. However, we feel that it would be naive to not expect unforeseen changes in technology, for instance, which can increase the recovery rate and hence the economic value of the field. We need to be aware of this source of uncertainty when conducting our analysis in order to avoid false conclusions. This uncertainty and the impact of it will be further discussed in the part of criticism to our data.

We have seen that on an after-tax valuation the timing of the tax payments has an impact on the value of the field. After speaking with industry sources we have found that oil companies pay 50% of their expected taxes upfront (the same year as the income occur), and the rest the following year.

The fields are valued on an unconsolidated tax basis, meaning they are valued as stand-alone projects. This affects the timing of the uplift, and losses need to be carried forward reducing future taxable results. The present value would be higher if we valued the consolidated fields assuming that a negative profit would decrease tax payments in other areas or from other fields as would be likely for established oil companies with other producing oil fields.

4.2 Considerations Regarding the Variance Analysis Model

The variance analysis model is constructed in accordance with the theory presented in chapter 2.2.4. For the revenues this is quite straight forward given that we have the produced volumes for each of the petroleum products being produced. For the costs this is more complex. Given our datasets we cannot effectively identify the cost drivers. The datasets also group the OPEX in different ways making a detailed and correct analysis of the operating costs difficult. We find that a detailed analysis would demand many assumptions, which we will not know if correct or not. Because of this we have chosen not to complete a detailed analysis of the operating costs since a more detailed analysis would just lead to more uncertainty regarding our findings. Because of this we feel that a correct analysis on a more aggregated level is the better for our analysis.

The only area in which the PDOs and the data from WM are comparable regarding costs is transportation costs. These are often given in both the PDOs and the WM, but not for all products. So where it is possible and meaningful we have analyzed the variance for these costs using the produced volumes as the cost driver for transportation of petroleum.

In terms of deciding production volumes, the different fields produce a variety of petroleum, such as oil, gas and condensate, which needs to be considered. We have chosen to define production as standard cubic meters of o.e.s produced. Because of this we have converted the production using the following table:

Table 10 - Conversions to standard cubic meter of oil equivalents (Norwegian Petroleum Directorate, 2009).

1 standard cubic meter of o.e.	=	1 Sm ³ of oil
1 standard cubic meter of o.e.	=	1 Sm ³ condensate
1.9 standard cubic meter of o.e.	=	1 ton of NGL
1 standard cubic meter of o.e.	=	1000 Sm ³ of gas

As for the costs we have also decided not to include extra-ordinary cost groups that were not included in the PDO, such as leasing costs for the Jotun development caused by the sale of the Jotun FPSO, which was not anticipated in the PDO.

For the flexible budget covering OPEX, we have had to consider the mix between fixed and flexible costs for each field. The flexible budget in the variance analysis is most suitable when analyzing cost groups with clear cost drivers. Because of this the analyze method is often used for individual products or processes based on the production. Since we will analyze the OPEX for the whole field, the production volume might not be the only factor to calculate the flexible budget for OPEX. After talking to industry sources and considering the GEM database, we have concluded that not all OPEX are fixed, but that there are a large number of fixed annual costs as well. Because of this we will need to consider the operating years of the field when calculating the flexible budget as well. When we have done this, we have identified the relative lifetime of the field, which is the new updated lifetime of the field, compared to the expected lifetime in the PDO.

We have identified, in GEM, how the costs for each field are distributed between fixed, variable and transportation, if the transport costs are supplied in GEM or PDO. We have excluded leasing costs and tariff receipts. The leasing costs are excluded since these costs occur after the sale of production and processing facilities. Otherwise they would need to carry these ownership expenses as capital costs instead of as operational costs. We see the sale of these assets as a pure financial decision between owning and leasing them, and the operator has done what seems most profitable for the field. These should therefore not affect the fixed operational costs. The tariff costs are excluded since the fields, which have these costs, receive revenue to cover them so these are not borne by the field, but by other fields which use the processing and production facilities of the field.

We have found that the different fields have these mixes of operational cost structure and updated expected lifetime compared to original lifetime in the PDOs:

Table 11 - Cost distribution and lifetime of fields

	Share of Fixed Costs	Share of Flexible Costs	Lifetime		
			PDO (years)	Updated (years)	Deviation
Jotun	38.0%	62.0%	14	33	24 %
Varg	63.1%	36.9%	17	21	283 %
Oseberg Øst	63.1%	37.0%	6	23	136 %
Åsgard	44.6%	55.4%	31	31	0 %

Based on these shares we have calculated the flexible budget as a result of the new expected lifetime of the field and the URR of the field using the following formula:

$$Flexible\ Budget = New\ Budgeted\ Fixed\ Costs + New\ Budgeted\ Variable\ Costs$$

$$Flexible\ budget = (PDO * Fixed * Lifetime) + (PDO * Flexible * Updated\ Production)$$

Where:

- PDO = Budget OPEX in the PDO
- Fixed = Share of fixed costs for the field
- Lifetime = Relative change in lifetime from the PDO
- Flexible = Share of flexible costs for the field
- Updated Production = Updated production for the field in standard cubic meters of o.e.

4.3 Considerations Regarding the Break-Even Price Analysis

When calculating the B/E-prices, both for the PDOs and with the updated numbers, we needed to assess the production. For Jotun, Varg, and Oseberg Øst, almost all the value comes from the oil production. The relative value of the oil production compared to the gas production is so much bigger that when calculating the B/E-prices we have let the gas prices remain unchanged since it is the oil price that drives the value of the field. We have chosen to do it this way after talking to industry sources regarding how they treat such analysis. For Åsgard the case is quite different with gas being the main revenue source, where it counted for approximately 65% of the total revenues in the PDO. Even after the oil price has increased significantly and the field has produced more liquids, the total revenue share of gas is 47%. Because of this we needed to consider the correlation between these prices when calculating the B/E-prices for the field. The same industry sources we spoke with earlier have informed us that, when a field produces significant volumes of gas as well as oil, the gas price cannot be neglected. In the industry, the norm is to assume a correlation of one between the oil and gas price, letting the gas price be a function of the movements in the oil price. We considered computing the real correlation between the oil and gas price in the given period, but found this to be unnecessary. The reason is that we assume that the original B/E-price is computed according to the industry norm, and if we change the way the B/E-price is calculated we would not be calculating it consistently. We also expect the gains from this to be quite low in terms of what extra it will bring to our analysis and that it might just add extra uncertainty.

4.4 Conclusions Regarding Hypothesis

- *Cost overruns undermine the net present value*

Saying that the cost overruns undermine the net present value in itself is true, but looking at what happens with these overruns, that is, higher production, URR and prolonged lifetimes, makes the total net present value higher for all the fields we have been considered.

We may therefore say that the direct effect of this hypothesis is true, but the indirect effect depends on how the cost overruns are spent, and what the results are of this spending.

- *Positive market development compensates for the cost overruns*

The results clearly indicate that the increased oil and gas prices have had a significantly positive effect on the value of the fields, the increases being the single most important positive factor for changes in the net present value of the fields. The market development has, in the case of our analyzed fields, more than compensated for cost overruns.

- *Prolonging the lifetime of a field will have a positive effect on the ultimate recoverable reserves*

We have seen that of the three fields with prolonged lifetime estimates, two of them have increased their URR. The fields with increased URR show that production in the early years was lower than expected, but higher in the end, while the opposite was true for Jotun, this being the only field with lower production. This seems to indicate that lower production in the early years is compensated for by increased production over a prolonged lifetime. A prolonged lifetime does not necessarily lead to a higher NPV of the production profile, being the production was much lower than estimated for the first years, and that the prolonged lifetime is more of a result of increased drilling operations, which in turn increases the URR.

- *Estimated ultimate recoverable reserves in the PDOs are too optimistic*

Jotun is the only field with a clearly lower URR than estimated in the PDO, while Oseberg Øst, Varg, and Åsgard, have a higher URR than estimated. For Oseberg Øst and Varg, the URR is clearly increased due to prolonged lifetimes, but this is not the case for Åsgard. It seems from our results that Åsgard is the exception, and that the other fields have had overly optimistic production estimates. With only three of the four fields complying with our hypothesis, we cannot declare this to be true on a general basis. A potential reason why Åsgard deviates may be that it is largely a gas field compared to the other fields. This has implications on how much can be done to production since overall capacity is affected by infrastructure and transportation capacity, thus making it harder to adjust a gas field than an oil field.

- *Higher capital costs lead to higher URR as a result of investments in technology and more efficient equipment*

We see that all our fields have significantly higher CAPEX related to drilling costs than was expected in the PDOs, both while developing the field according to the PDO, and after completing the development. Taking the prolonged lifetime and increased URR into consideration, this implies that the fields have made investments in drilling in order to increase URR. However, this is the only factor indicating that increased investments lead to higher URR. We also see that production during the

first years was worse for Varg, Oseberg Øst, and Åsgard than was anticipated in the PDOs, which indicates that cost overruns for developing the fields does not necessarily lead to increased URR.

4.5 Analysis of the fields

4.5.1 Jotun

Valuation of Jotun

The valuation analysis of the development of the Jotun field has shown that the deviation between the estimated net present value of the field in the PDO and our updated valuation (after 15 years of production) is not significant. Before taxes, the deviation is in the interval of -1.6% and 2.5% from PDO depending on the discount rates, which we would categorize as hitting target regarding the initial valuation in the PDO. The discount rates used are the same as in the PDOs, which we presented in chapter 2.2.1 on page 19. After taxes, the results are not quite the same, but the deviation is not dramatic. With variances in the deviation between 10.9% and -11.6%, depending on the discount rate, we would still say that the net present value found in in the PDO is acceptable. All of the internal rates of return (IRR) are quite acceptable for investments with an expected present IRR of the project of 16.3% after taxes compared to 19.0% in the PDO, and 36.3% before taxes compared to 38.5% in the PDO. The updated IRR shows that the return is acceptable. The timing of the tax payments causes the relatively large difference of the present values after taxes between the different discount rates. This indicates that the higher CAPEX that occurred in the beginning of the development had a larger overall impact as the discount rate increases, and the value of later cash flows declines. The analysis shows that the IRR, after the cost overruns, was significantly more damaged than the updated IRR shows, but still acceptable. This is because Jotun produced significantly more oil than estimated in the early years of its lifetime.

Our conclusion is that even though the development experienced severe cost overruns, the value of the field was not damaged much during its lifetime. To explore what caused these differences, we conducted a more comprehensive and detailed drill down analysis.

A B/E-analysis regarding the oil price for Jotun shows that the field needed a significantly higher oil price than was expected in order to make a profit from the operations of the field.

Table 12 – NPV before tax – Jotun (MNOK'96)

Updated present value before unconsolidated tax			Deviation from PDO before tax	
Discount rate 1	0%	13,009	-213	-1.6%
Discount rate 2	7%	7,613	155	2.1%
Discount rate 3	10%	5,980	144	2.5%

Table 13 – NPV after tax – Jotun (MNOK'96)

Updated present value after unconsolidated tax			Deviation from PDO after tax	
Discount rate 1	0%	4,202	412	10.9%
Discount rate 2	7%	1,753	-25	-1.4%
Discount rate 3	10%	1,048	-137	-11.6%

Table 14 - Internal Rate of Return - Jotun

Internal Rates of Return					
	PDO	After cost overrun		Updated	
	IRR	IRR	Deviation	IRR	Deviation
Before tax	38.5%	28.6%	-9.9 pp	36.3%	-2.2 pp
After tax	19.0%	14.5%	-4.5 pp	16.3%	-2.7 pp

Table 15 - Break-even prices – Jotun (USD'96)

B/E-Price (7% discount rate) in USD'96					
	PDO	After cost overrun		Updated	
	B/E-Price	B/E-Price	Deviation	B/E-Price	Deviation
Before tax	\$10.70	\$12.49	16.7%	\$16.19	51.3%
After tax	\$11.56	\$13.52	17.0%	\$23.22	100.9%

Net Present Value Breakdown Analysis

As we can see from the waterfall chart, the revenues, operation expenditures, and CAPEX, have been higher than anticipated in the PDO. While higher revenues would lead to a higher net present value, the increased expenditures have the opposite effect of decreasing the value. The increase in CAPEX over the lifetime of the development is in large part due to higher costs for processing facilities, and for a more comprehensive drilling program than planned in the PDO. In the period from 2002 to 2006, well after the development was finished, eight new wells and several observation wells were drilled. None of these were specified in the PDO. A possible reason for this may be that the field produced a lot more than expected in the year 2000, and only a bit more in 2001, before it had a severe decrease in production volume.

The difference in operating costs may be a result of factors not specified in the PDO. These could be the costs of processing and transporting petroleum from other fields, also leasing costs, none of which was included in the PDO. The costs of processing and transporting for other fields are covered by those fields, and are specified in other revenues that offset these costs. The unexpected leasing costs were incurred after receiving capital for the sale of Jotun FPSO in 2003. It becomes obvious that

revenues received from this sale, and the tariffs are slightly higher than the increased costs of the aforementioned activities.

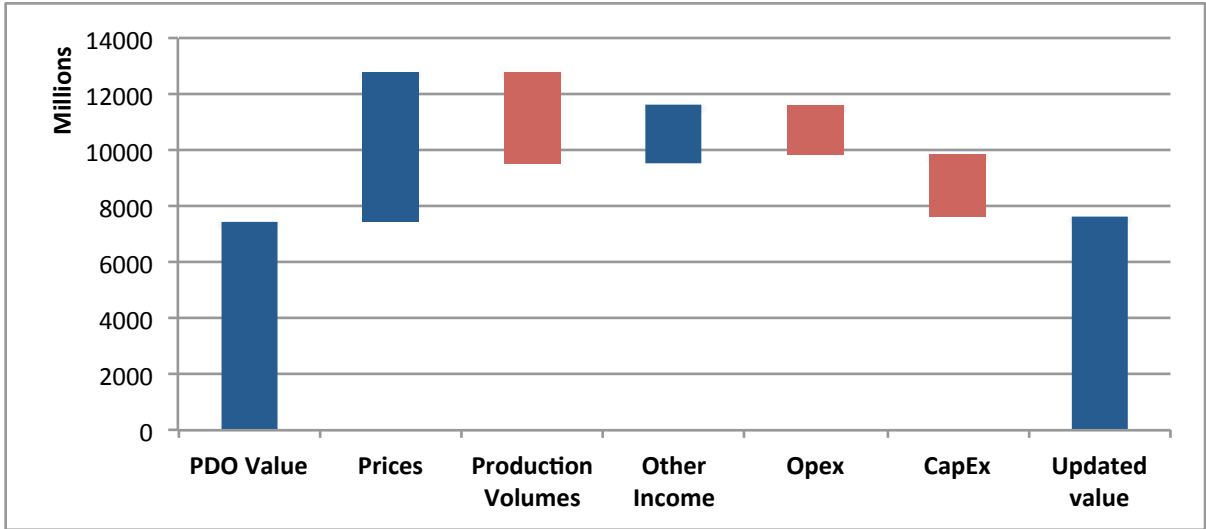


Figure 19 – NPV analysis of cash flow components at 7 % discount rate pretax – Jotun (96’NOK)

When looking at the core activity of the development, production, and processing of petroleum, the picture is quite remarkable. The analysis shows that the production volumes have been significantly lower than what was expected in the PDO. The effect of the lower production volumes has a significant impact on the value of the development. The results of this are a reduced value of the field totaling approximately one third of the initial PDO value. However, as the oil prices over this period were so much higher than expected, the result more than offset the effects of lower production levels. Our analysis shows that the positive effects of higher prices roughly offset the negative effect of lower production volumes and higher CAPEX. We have also seen that although the

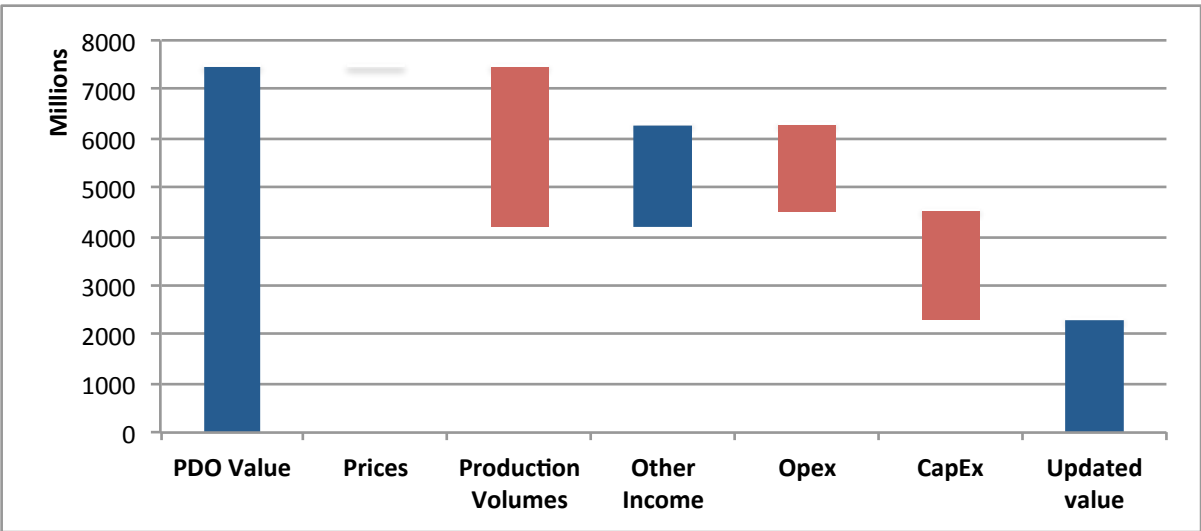


Figure 20 - NPV break down analysis isolating the price effect – Jotun (NOK’96)

field has produced some gas, the relative value and volume of this is so low that the effect on the value of the field is negligible.

Our analysis, illustrated in figure 20, clearly shows how significant the impact of higher oil prices has been on the value of Jotun. When isolating the valuation from the price effect, the updated value of the field drops to about one-third of the estimated PDO value.

Variance Analysis

Static budget variance

The static budget variance of the operating costs, and revenue streams, shows the deviations between the budget and the updated numbers. The analysis shows that the field has experienced a significant increase in revenues, but also a large negative effect concerning CAPEX, resulting in an overrun of 3.027 MNOK'96. Taking into account the CAPEX being much lower than the revenues, we can say that this is a relatively larger deviation. The analysis also shows that the field had somewhat

Table 16 – Static budget variance analysis – Jotun

<i>Numbers in MNOK'96</i>	Budget	Static Budget Variance	Updated
Revenues	26 167	4 011	30 178
Opex	6 309	- 236	6 545
Transport costs	236	10	226
CapEx	5 909	- 3 027	8 936
Total	13 713	758	14 471

larger operating costs than expected, while the transportation costs were lower. These results indicate that the total revenue stream of the field changed little over its lifetime, even though there were some changes to the cost, and revenue streams. To identify what caused these changes we will need to make a more comprehensive analysis using a flexible budget.

Flexible budget

A more detailed variance analysis of revenues and costs of Jotun helps us gain a better understanding of the performance of the field. When considering the revenues, we can see that the revenues from production and sale of gas were about 82% higher than expected in the PDO. The reason for this is that both the production and gas prices have been higher than expected. The relative size of gas revenues compared to those of oil are however so small that the focus for Jotun should be on the revenues from the oil production.

The variance analysis confirms the findings of the valuation analysis, indicating that the production volume has had a significantly negative impact on the revenues through the sales volume variance. The flexible variance shows the price variance as very positive; the price variance showing the oil prices as 50% higher than expected, given the updated production volumes.

The variance analysis for operating costs excluded the tariff costs and leasing costs, since these were not included in the PDO, in order to get a comparable dataset. The analysis shows that the operating costs are approximately as high as estimated in the PDO. However, when adjusting the budget for the updated production volume of standard cubic meters of o.e.s, we see that the costs run about 39% higher than in the flexible budget. This indicates higher costs than expected. A large part of the annual costs of operating an oil field could be classified as fixed. If the annual costs were to a large degree fixed, we would expect the operating costs to be higher than indicated by the production volume described in the flexible budget, if the field is expected to produce five more years than estimated in the PDO. This is because the annual costs would not be severely affected by production volumes. Considering this, it appears the updated operating costs are lower than PDO estimates. Transportation costs are also lower than expected in the PDO, both as total costs, and especially so when considering updated production volumes.

The most important conclusion discovered by this analysis is that the field failed to produce the oil volume as planned, but that revenues were maintained by significantly higher oil prices.

Table 17 – Flexible budget variance analysis – Jotun

<i>Numbers in MNOK'96</i>	Updated	Flexible variance		Flexible budget	Sales volume variance		PDO budget
Revenues							
Oil	29 171	10 081	53%	19 090	- 6 523	-25%	25 613
Gas	1 007	336	50%	671	118	21%	554
Total revenues	30 178	10 417	53%	19 762	- 6 405	-24%	26 167
Costs							
Opex	6 545	609	10%	5 936	- 373	-6%	6 309
Transport Opex (gas)	226	60	-21%	286	50	21%	236
Total costs	6 771	549	9%	6 222	- 323	-5%	6 545

4.5.2 Varg

Valuation of Varg

Our updated valuation of Varg has significant deviations from the valuation in the PDO. This is not surprising since the field was expected to produce until 2003, but has had its lifetime prolonged until at least 2021. The cash flows from the field have been significantly higher than expected, but over a much longer period of time than the expectations. Over the lifetime of Varg, the total cash flow in our updated valuation is 10 900 MNOK'95 compared to 3 106 MNOK in the PDO. However, since these cash flows are expected to occur over a much longer period, the overall net present value is not necessary positive. When considering the net present value, the field has a positive deviation, before taxes, at a 7% discount rate. After taxes however, the field has a negative deviation compared to the PDO at both the 7% and 10% discount rates. The full picture seems to indicate that, since a larger part of the revenue in the updated analysis compared to the PDO occurs later, higher discount rates makes the project less profitable than estimated in the PDO.

We can also see that the updated IRR from the project has almost been cut in half from the PDO, both before and after taxes. This is due to the higher CAPEX, increased OPEX, and lower production volumes than those expected in the first phase of the field's production. Taking into account that there is no IRR after the cost overruns, when considering the original development, we see that the field has performed worse than planned. The large reductions in the IRR are not satisfying when considering the overall performance of the field.

The B/E-prices, both before and after taxes, have almost tripled in the updated valuation when compared to the PDO. The reasons for this may be the same as those outlined above for the decrease in the IRR. The B/E-prices are also almost twice as high as the expected oil prices in the PDO, clearly indicating that this field would not been considered commercially viable at the time of the PDO.

Table 18 – NPV before tax - Varg (MNOK'95)

Updated present value before unconsolidated tax			Deviation from PDO before tax	
Discount rate 1	0%	10 900	7 794	251.0%
Discount rate 2	7%	2 659	952	55.8%
Discount rate 3	10%	1 151	-139	-10.8%

Table 19 – NPV after tax - Varg (MNOK'95)

Updated present value after unconsolidated tax			Deviation from PDO after tax	
Discount rate 1	0%	4 596	3 196	228.4%
Discount rate 2	7%	513	-66	-11.4%
Discount rate 3	10%	-244	-578	-173.3%

Table 20 - Internal rate of return - Varg

Internal Rates of Return					
	PDO	After cost overrun		Updated	
	IRR	IRR	Deviation	IRR	Deviation
Before tax	27.1%	NA*	NA*	13.9%	-13.2 pp
After tax	15.4%	NA*	NA*	8.9%	-6.5 pp

* Varg does not have an IRR after the cost overruns due to negative IRRs only

Table 21 - Break-even prices - Varg (USD'95)

B/E-Price (7% discount rate) in USD'95					
	PDO	After cost overrun		Updated	
	B/E-Price	B/E-Price	Deviation	B/E-Price	Deviation
Before tax	\$10.47	\$18.31	74.9%	\$29.75	184.1%
After tax	\$10.77	\$22.03	104.6%	\$32.25	199.4%

Net Present Value Breakdown Analysis

As we can see from the waterfall chart, there are numerous items that add up to the change in net present value. First we see that production has been beneficial while operating costs and CAPEX have been unfavorable. The field has produced more oil than was expected in the PDO, and has also begun to produce and export gas and NGL, something not included in the PDO estimations. Gas exports were presented as a possibility for the field when considering how areas close to Varg developed, but the economic potential of this was not presented in any quantitative way. Because of this the value analysis of gas and NGL export cannot be split into production and prices, as we do with oil. The oil production has been larger than expected, leading to an increased value. However, we see that the single most important factor to the valuation of the field is the oil prices, which have been significantly higher than the expectations in the PDO.

The total effect of the increased oil prices of approximately 7 500 MNOK'95 by itself constitutes three times the original valuation of the field. This is probably one of the reasons why the field has had its lifetime prolonged so much as it has.

Other income consists of sales of the Varg facilities, which, although generating revenue, also increased costs since these facilities were then leased back to the field.

The OPEX having such a negative impact on the valuation of the field should not be surprising when considering that the production lifetime of the field has been prolonged from 6 to 23 years. When also considering the increased costs incurred from leasing and processing petroleum from other fields, which are then offset by other revenues, this result is to be expected.

The CAPEX of the field has been significantly higher than the PDO estimate. The large change in the CAPEX is due to cost overruns in the development of the field, and large investments in drilling activities, during the time period 2003 through 2013.

When excluding the effect oil prices have had on the value of the field, we can clearly see that this project would not be a profitable one without the high prices. However, we cannot predicate this result if the prices were to stay at the lower level outlined in the PDO. Since the field would have had many years of negative cash flow at that price, it is likely that the operations would have been shut down much earlier than what is the case now.

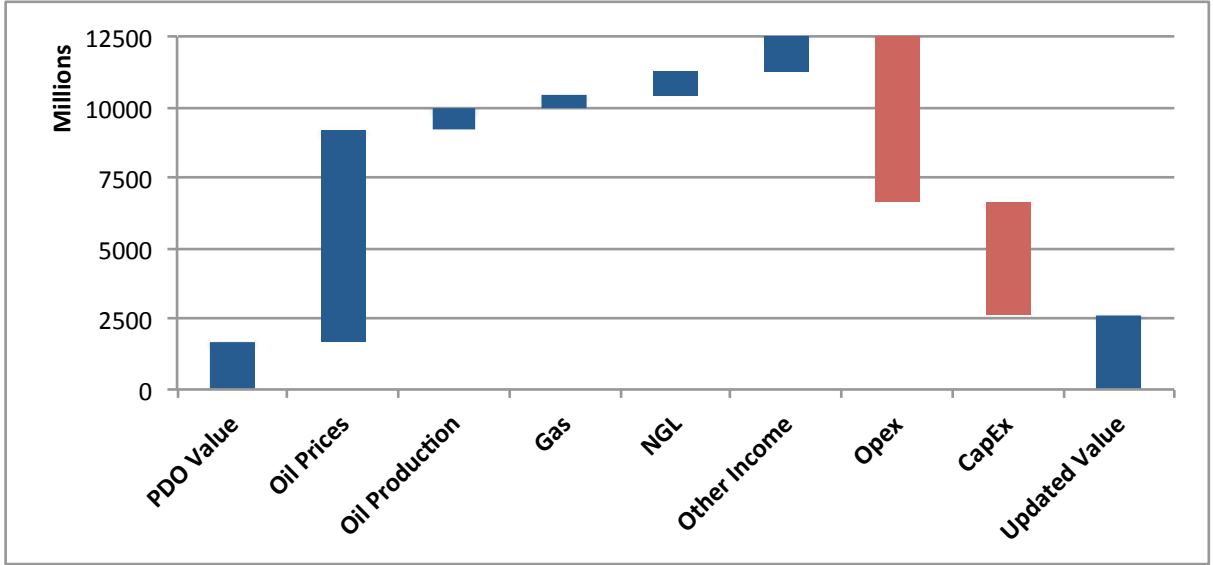


Figure 21 - NPV break down analysis at 7 % discount rate pretax – Varg (NOK'95)

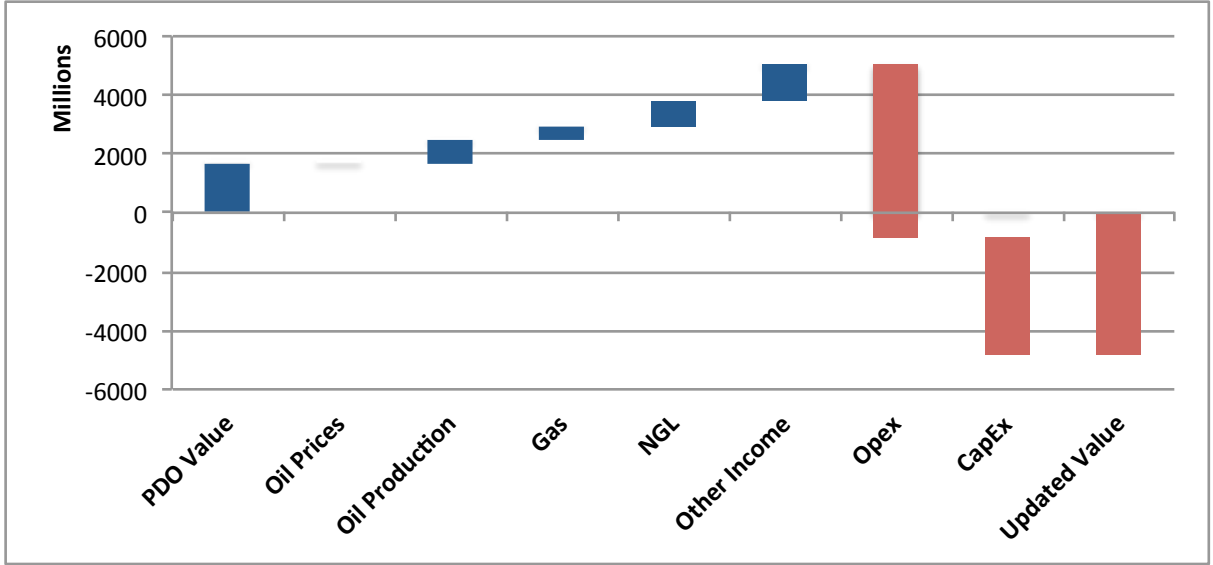


Figure 22 – NPV break down analysis isolating the price effect pretax– Varg (NOK'95)

Variance Analysis

Static budget variance

The static budget variance regarding the operating revenues, costs, and CAPEX show that the field had significantly higher revenue streams over this period than estimated in the budget, but also higher costs and investments. The picture then emerges that the higher revenues have occurred over a significantly longer period. Since the field has prolonged its lifetime, we could also expect that the operating costs and CAPEX increase. However, we can see that the changes in the revenues are much larger than the changes in operating costs and CAPEX. To find out why, we have split this into a more comprehensive analysis using flexible budget analysis.

Table 22 - Static budget variance analysis – Varg

<i>Numbers in MNOK'95</i>	Static Budget	Static Budget Variance	Updated
Revenues	6 737	23 606	30 342
Opex	1 692	- 6 307	7 999
CapEx	3 073	- 4 779	7 852
Total	1 972	12 520	14 491

Flexible Budget

A more detailed variance analysis of the field consists of considering the revenues from oil production and the operating costs. The reason for this is that these are the only numbers in which the data from the PDO and the GEM coincide. The production and export of NGL and gas was not anticipated in the PDO, while other cost groups, such as transportation of oil, is not specified in enough detail to analyze.

When analyzing the revenues from oil production, we can see that the field is expected to produce a significant larger volume than estimated in the PDO. However we can also see that increased oil prices during this period have had a significantly larger impact on the revenues. Our analysis indicates that a good job was done with controllable deviations of production volumes, and that a windfall arose with the development in the oil prices. What must be considered is that, while the total production volumes have been larger, these figures are also a result of greatly prolonging the field's lifetime. The actual production volume for the initial years, as planned in the PDO, was lower than the estimated volumes. When considering this it is likely that the increased production over the prolonged lifetime of the field is a reflection of increased oil prices.

In analyzing the operating costs, we see that when adjusting for the increased production volumes, we expect the operating costs to be higher than the PDO. However, by looking at the flexible variance we see that the operating costs have been significantly higher than what we would expect considering the production. A possible reason for this is that the URR has not increased as much as the lifetime of the field. When a considerable share of the field’s costs are fixed, a prolonged lifetime relative to the production volume may cause higher operating costs that this analysis will not capture when adjusting the flexible budget for the production volume of standard cubic meters of o.e.s.

Table 23 - Flexible budget variance analysis – Varg

<i>Numbers in MNOK'95</i>	Updated	Flexible variance		Flexible budget	Sales volume variance		PDO budget
Revenues							
Oil	30 342	19 136	171%	11 206	4 470	66%	6 737
Costs							
Opex	7 999	2 683	50%	5 316	3 624	214%	1 692

We see that Varg has prolonged its lifetime, increasing its production relative to the PDO estimates and that the OPEX are larger than what we would expect. The field would not be profitable if it was not for the increased oil prices in the period and the field would probably not be developed if the B/E-price after completing the development were known in advance of the development of the field.

4.5.3 Oseberg Øst

Valuation of Oseberg Øst

The updated valuation of Oseberg Øst after 15 years of production shows that the net present value is much higher than what was estimated in the PDO. This is true both before and after taxes, and with a 7% discount rate, which we are focusing on for our analysis, the net present value before taxes is about twice that originally estimated.

On the other hand, the updated IRR shows lower returns, which may be the result of higher costs, something we will look into. The project is still quite profitable both before and after taxes, and the IRR is not significantly lower. The IRR after cost overruns was, however, lower than the estimated IRR in the PDO, and in the updated IRR. This may be explained by the increased URR compared with the PDO. However, without exploring details, it seems the project has done quite well, with much higher returns than estimated, and almost reaching the same rate of return as they had in their prognosis.

The B/E-price however shows a different picture, with the updated B/E-price before taxes being over twice as high as that estimated in the PDO, and almost a tripling after taxes. This shows that the project needed a significantly higher oil price to be profitable compared to that estimated in the PDO.

The total picture however seems to be that even though we know from earlier reports that there have been serious cost overruns, the value has actually gone up, so it is still a very profitable project.

Table 24 – NPV before tax - Oseberg Øst (MNOK'96)

Updated present value before unconsolidated tax			Deviation from PDO before tax	
Discount rate 1	0%	17 509	12 235	232.0%
Discount rate 2	7%	5 925	2 974	100.8%
Discount rate 3	10%	3 895	1 631	72.0%

Table 25 - NPV after tax - Oseberg Øst (MNOK'96)

Updated present value after unconsolidated tax			Deviation from PDO after tax	
Discount rate 1	0%	7 285	5 295	266.1%
Discount rate 2	7%	2 016	1 135	128.9%
Discount rate 3	10%	1 061	516	94.8%

Table 26 - Internal rate of return - Oseberg Øst

Internal Rates of Return						
	PDO		After cost overrun		Updated	
	IRR	IRR	Deviation	IRR	Deviation	
Before tax	29.3%	22.6%	- 6.7 pp	25.8%	- 3.5 pp	
After tax	16.5%	13.8%	- 2.8 pp	15.8%	- 0.7 pp	

Table 27 - Break-even prices - Oseberg Øst (USD'96)

B/E-Price (7% discount rate) in USD'96						
	PDO		After cost overrun		Updated	
	B/E-Price	B/E-Price	Deviation	B/E-Price	Deviation	
Before tax	\$10.11	\$11.50	13.8%	\$22.32	120.8%	
After tax	\$10.17	\$11.57	13.8%	\$28.95	184.7%	

Net Present Value Breakdown Analysis

We found when looking closer at our analysis of Oseberg Øst that both capital and OPEX were higher than in the PDO. Together with a lower production volume than planned, the updated

value is lower than in the PDO, but higher oil and gas prices contributes a great deal to a higher net present value in the end.

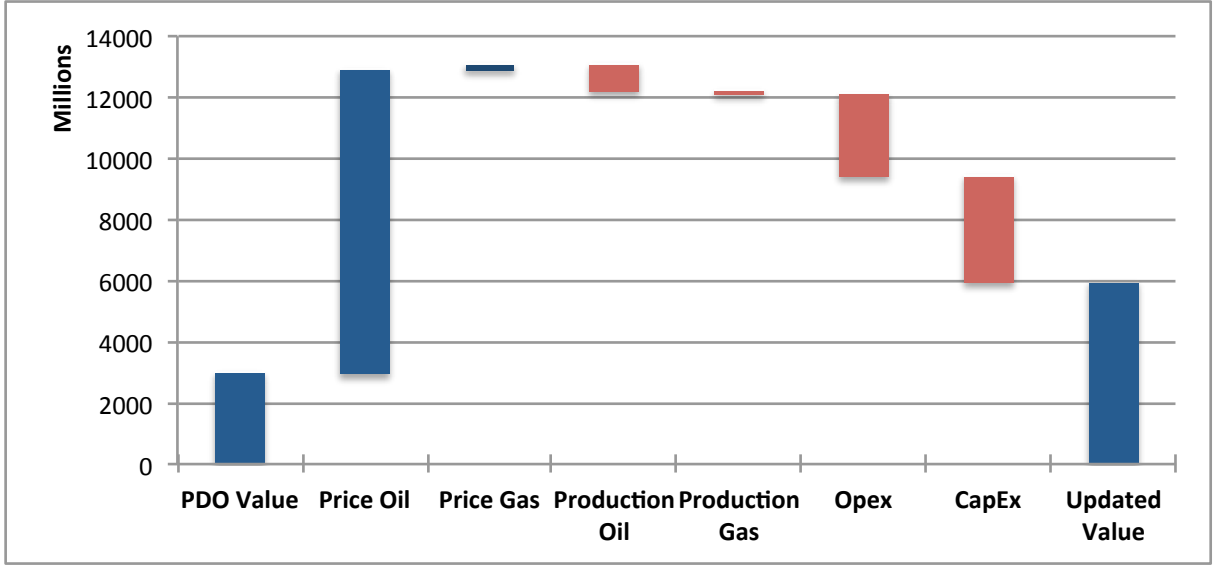


Figure 23 - NPV break down analysis at 7 % discount rate pretax – Oseberg Øst (NOK'96)

The higher capital costs are caused by considerably higher costs for platforms and drilling. As we see from the chart above, this has not increased the present value of the production volumes compared with the PDO, but seems to have lowered the OPEX. The OPEX here include the abandonment costs as well, but they would still be higher than budgeted even if they were not included. That the OPEX have been higher than estimated in the PDO implies that the costs have been higher, or that the licensees where not able to operate as effectively as they first assumed. The much higher revenues due to higher prices are caused by the fact that the oil price has been

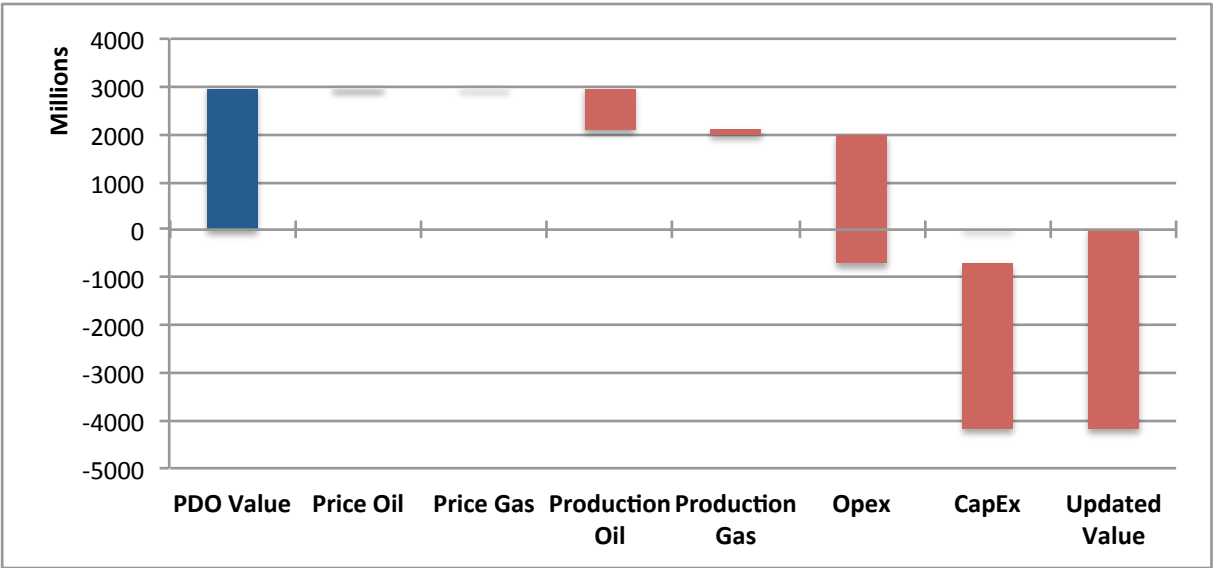


Figure 24 - NPV break down analysis isolating the price effect pretax – Oseberg Øst (NOK'96)

higher than the estimated \$15 all but one year. It has actually been as high as 5 times the price given in the PDO (in real '96 USD).

A chart where we do not include the positive effect of the price shows how much worse the development really performed. If the price had stayed at a stable \$15 in real 1996 figures, the net present value would have been negative 4 billion kroner.

With this price, the development would have been a disaster for the licensees, making the project very unprofitable.

Variance Analysis

Static Budget Variance

An overview of the variances shows how the revenues have actually tripled compared with the budget, but it also shows how the operational costs, transportation costs and capital costs have been much higher than budgeted. The total value is still just below 40% of the revenues. Since this is over a longer time frame though, the IRR is lower, as shown earlier in the analysis. What is worth mentioning is that the OPEX excluding the transport costs, have risen dramatically relative to the revenues.

Table 28 – Static budget variance analysis – Oseberg Øst

<i>Numbers in MNOK'96</i>	Budget	Static Budget Variance	Updated
Revenues	14 049	30 381	44 429
Opex	2 680	- 8 634	11 314
Transport costs	2 275	- 931	3 206
CapEx	3 570	- 8 235	11 805
Total	5 524	12 580	18 104

Flexible Budget Variance

The flexible budget variance gives a more comprehensive analysis of each post. The revenues have gone up, but as we see from table 29, it is mainly due to higher oil prices. The gas price has also been higher than in the PDO, but with a very low production volume, it does not contribute as much in actual numbers. The higher production of oil towards the end of the period we are looking at makes a positive sales volume variance, but as we saw from the waterfall chart, the total effect on the valuation of the field is negative with a 7% discount rate due to the fact that the production is lower in the first years than budgeted. This negative effect weighs heavier than

the later positive effect when we use this discount rate. The much higher revenues, which gives a higher net present value of the project is therefore mainly due to the change in oil prices.

Table 29 –Flexible budget variance analysis – Oseberg Øst

<i>Numbers in MNOK'96</i>	Updated	Flexible Variance		Flexible Budget	Sales Volume Variance		PDO Budget
Revenues							
Oil	43 970	27 897	174%	16 073	2 343	17%	13 731
Gas (1996-2007)	229	229	-	0	0	-	0
Gas (2008-)	231	159	221%	72	246	-77%	318
Total	44 429	28 284	175%	16 145	2 096	15%	14 049
Costs							
Opex	11 314	6 197	121%	5 117	2 437	91%	2 680
Total Transport Opex	3 206	588	22%	2 619	344	15%	2 275
Total	14 521	6 785	88%	7 736	2 781	56%	4 955

We have looked at the operating costs without the transport expenses, as the latter are more directly tied to production than the rest of the operating costs. As we see from table 29, the operational costs are expected to rise slightly with the change in production, creating the flexible budget. Since the field mainly produces oil, most of the transportation costs are in the transport of the produced oil even though we do not have these numbers analyzed individually. However, we can see that the main reason is the flexible variance. The costs on OPEX have actually been 121% higher than the flexible budget would suggest. The transport OPEX is not that far off the expected costs with a bit higher production, but it still has an increase of 22% from the flexible budget to the updated value found with updates up until November 2013.

Summary Oseberg Øst Analysis

The field has been close to meeting their production targets, but with much higher operational costs and capital costs, they would have had a strong negative net present value if it was not for the much stronger oil price than expected in the PDO. This is not something they can control, contrary to operational and CAPEX, and gives a poor impression of the project as a whole.

4.5.4 Åsgard

Valuation of Åsgard

When analyzing Åsgard with our valuation model, and the actual numbers from WM with estimates from 2013 on, the net present value becomes over 300% higher than the PDO estimates, before and after taxes and regardless of discount rate. The deviation actually rises with increased discount rates. The IRR was also as high as 28.6% before taxes, showing this was actually a very profitable project.

The IRR of the project after taxes is also as high as 17.7%. Even though the initial capital costs were higher than expected, this showed to be a very profitable project. The IRR before taxes were also significantly higher than the IRR in the PDO. This implies that the project has been a success in economic terms and quite profitable. If it was not for the increased production, and higher prices of oil and gas, this may not have been the case. The analysis also shows that the IRR, after cost overruns, were significantly lower than both the updated IRR, and that estimated in the PDO. This shows that the IRR associated with the cost overruns was severely damaged by the cost overruns, but that market conditions and production has been very favorable for the development of the field.

Table 30 - NPV before tax - Åsgard (MNOK'95)

Present Value after unconsolidated tax (MNOK'95)			Deviation from PDO after tax	
Discount rate 1	0%	115 776	87 358	307%
Discount rate 2	7%	34 021	26 553	356%
Discount rate 3	10%	18 901	15 762	502%

Table 31 - NPV after tax - Åsgard (MNOK'95)

Present Value before unconsolidated tax (MNOK'95)			Deviation from PDO before tax	
Discount rate 1	0%	463 445	357 374	337%
Discount rate 2	7%	147 709	114 746	348%
Discount rate 3	10%	92 767	72 677	362%

Table 32 - Internal rate of return - Åsgard

Internal Rates of Return					
	PDO	After cost overrun		Updated	
	IRR	IRR	Deviation	IRR	Deviation
Before tax	21.9%	15.2 %	- 6.7 pp	28.6%	+6.7 pp
After tax	13.2%	10.3 %	-2.9 pp	17.7%	+4.5 pp

Table 33 - Break-even prices - Åsgard (USD'95)

B/E- Price (7% discount rate) in USD'95					
	PDO	After cost overrun		Updated	
	B/E-Price	B/E-Price	Deviation	B/E-Price	Deviation
Before tax	\$10.90	\$12.61	15.7%	\$13.31	22.1%
After tax	\$12.37	\$14.69	18.8%	\$15.83	28.0%

Net Present Value Breakdown Analysis

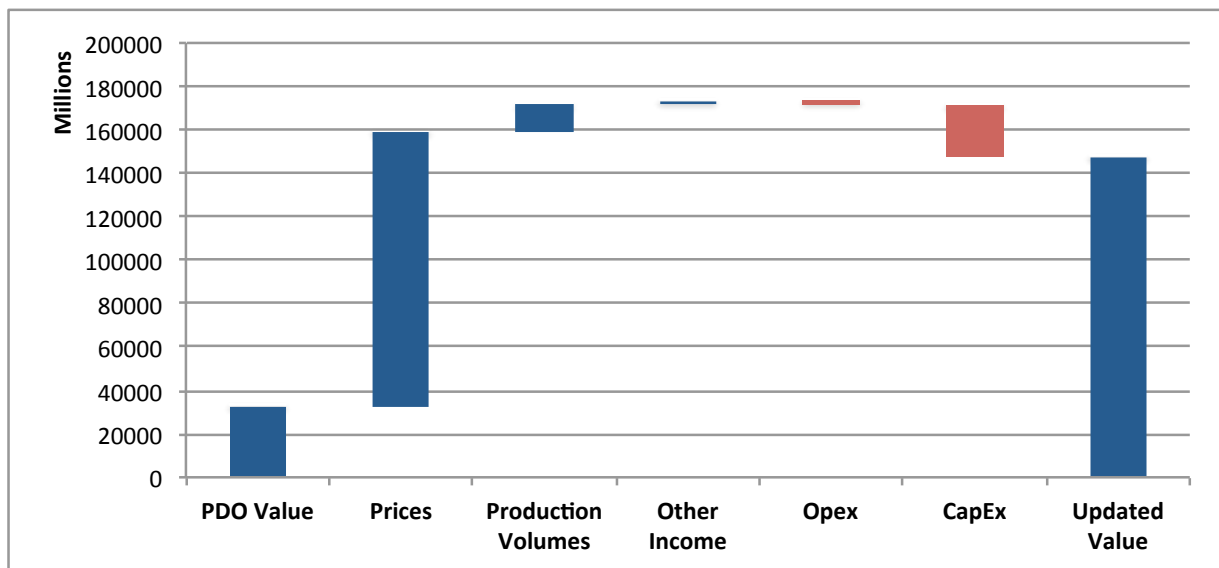


Figure 25 –NPV break down analysis pretax – Åsgard (NOK'95)

As we see from the chart, with a 7% discount rate the updated value of the project is much higher than the PDO value. This is mainly due to higher revenues.

As was mentioned in the report *“Analyse av investeringsutviklingen på kontinentalsokkelen”* from the Ministry of Petroleum and Energy, there have been cost overruns in the CAPEX, but these are more than outweighed by the extra earnings. The CAPEX cost overruns are primarily due to underestimating costs, but also to changes in production capacity and recovery strategy. As of 2013, the total number of wells that were planned in the PDO are still not completed (Statoil, 2013), but more opportunities in the existing field are being sought. The change in production capacity can somewhat be seen in the higher net present value given by this section.

There has not been more drilling than originally planned, but higher investments subsea and on the rig, as well as high cost overruns on the drilling sections, has resulted in much higher CAPEX. The negative effect of OPEX is only 1%, which can be split into the sales volume variance of 12.2% higher costs and the flexible variance of almost the same in negative numbers. This is given the assumption that the OPEX is dependent on production, and is highly correlated with this. Since the production is not far from what was expected in the PDO, this makes sense.

The much higher revenues are somewhat due to more investments, which resulted in somewhat higher URR, but are mainly due to much higher sales prices than anticipated. As can be seen from figure 26, the production volume has also had a positive net effect to some extent; however, for gas

and condensate this is actually negative. Considering price on the other hand, this has been much higher than was expected in 1995, so the revenue effect is significant.

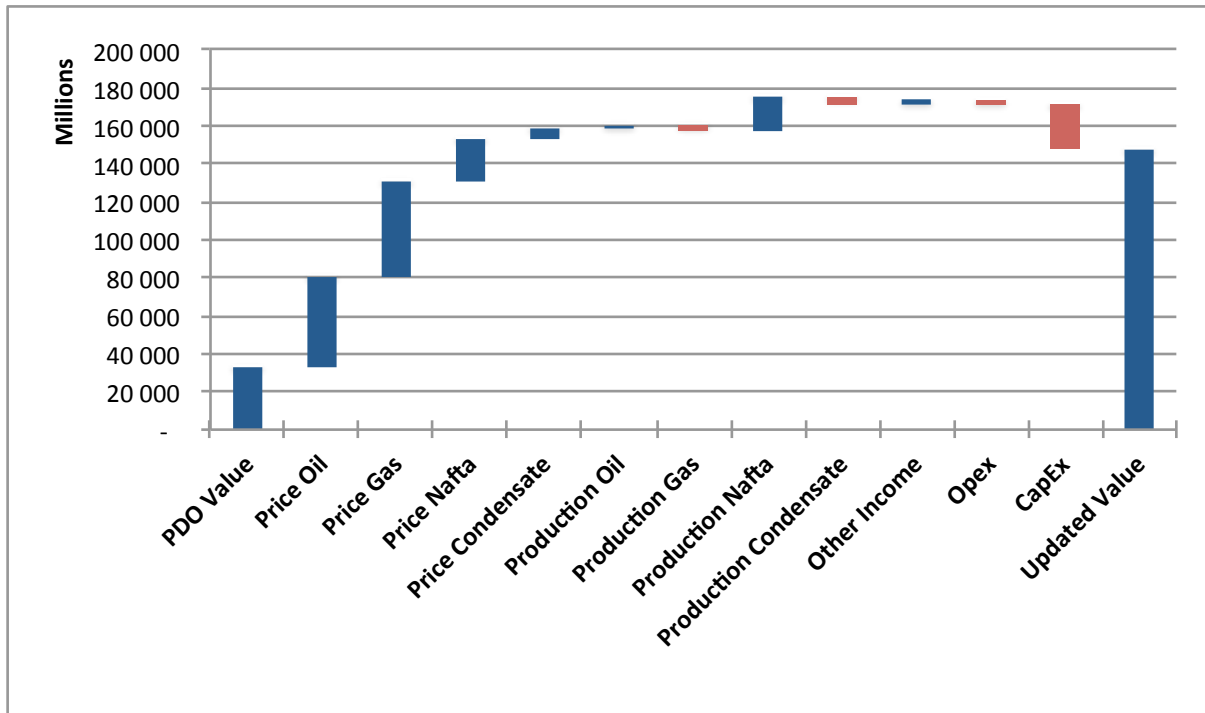


Figure 26 – NPV break down analysis at 7 % discount rate pretax – Åsgard (95'NOK)

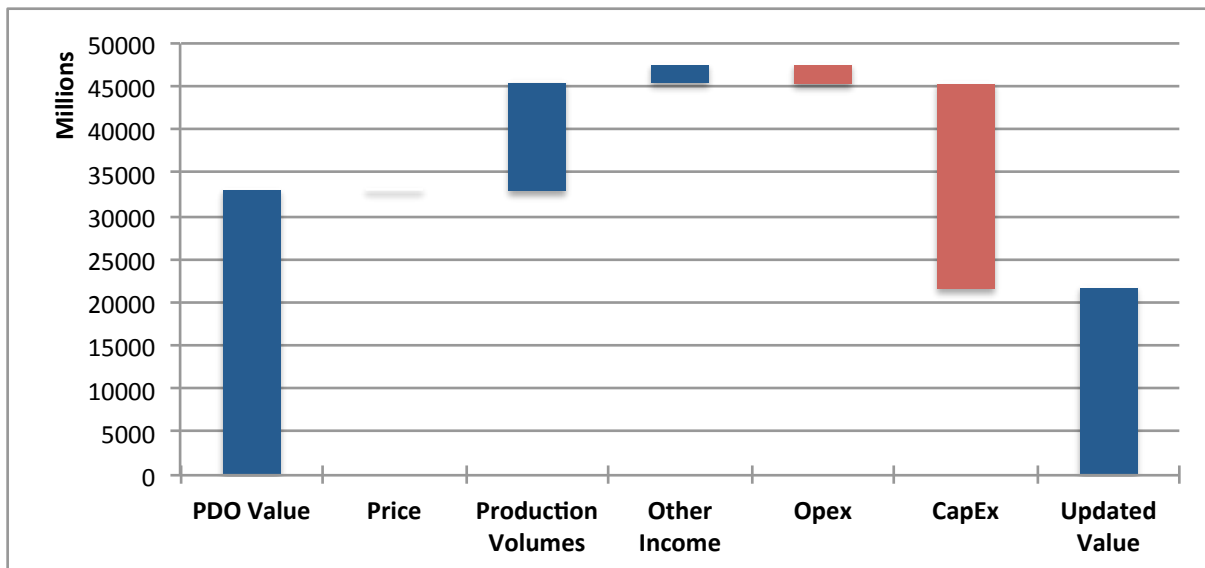


Figure 27 – NPV break down analysis isolating the price effect pretax – Åsgard (NOK'95)

When considering the development as a whole, the project is very profitable, and gives a net present value much higher than was expected in the PDO. Once again, this is mainly due to higher sales prices. If this were not the case, the updated value would have been lower than in the PDO. This shows that the extra CAPEX during the development period have not been matched with higher URR

or lower OPEX. Without the higher gas and oil prices, this project would have been far worse off than shown in the PDO.

Variance analysis

Static Budget Variance

The static budget variance shows what we already know, the revenues are much higher than the PDO, the OPEX slightly lower and the CAPEX higher than in the PDO, but the total effect is a very high positive difference between the numbers of today compared with the PDO. Here we have also looked at the transport cost by itself, which shows that this actually lowers the OPEX somewhat.

Table 34 - Static budget variance analysis - Åsgard

<i>Numbers in MNOK'95</i>	Budget	Static Budget Variance		Updated
Revenues	239 778		410 024	649 802
Opex	44 734	-	4 677	49 411
Transport costs	55 084		3 589	51 495
CapEx	33 884	-	58 624	92 508
Total	106 076		350 313	456 389

Flexible Budget Variance

Looking more into the details of the variances, we look at the results from the flexible budget variance.

Table 35 - Flexible budget variance analysis - Åsgard

<i>Numbers in MNOK'95</i>	Real	Flexible variance	Flexible budget	Sales volume variance	PDO budget
Revenues					
Oil	195 704	127 276	186%	68 429	52 102
Condensate	23 098	11 352	97%	11 747 -	27 996
Nafta	125 456	71 430	132%	54 026	4 116
Gas	305 543	166 199	119%	139 345 -	155 565
Total	649 802	376 256	138%	273 546	239 778
Costs					
Opex	49 411	1 498	3%	47 913	44 734
Transport Opex	51 495 -	4 065	-7%	55 560	55 084
Total	100 906 -	2 567 ■	-2%	103 473	99 818

As in the waterfall analysis, we see that the higher revenues are caused both by production volumes and the sales price, but mostly by the sales price. Åsgard has produced three different liquids over time, as well as producing gas. The prices of these resources have risen significantly over the past decades. While the license used \$16, \$16.8 and \$17.6 per barrel of liquids for the future, the prices have gone upwards almost every year since 1995, and the prices in 2013 were closer to \$75 per barrel (USD'95). Even though WM assumes the price will go down to around \$60 per barrel, the effect is strongly positive for the net present value of the license. For gas the same result appears; where \$2.92 per thousand cubic feet of gas was assumed. Up until the year 2000, the price was actually lower than this, but production had not yet started. From 2000 on, the price rose to around \$8 by 2013 (USD'95). Again, WM assumes the price will go down a bit, but will stay at around \$6.8 in 2019, then increase slowly over the years to come. This also gives a much higher net present value for the project.

With regards to oil production, this started out lower than PDO expectations for the first 5 years, but every year after that, it has been higher than the PDO, producing a net present gain here as well. Updated Nafta production has actually been higher than in the PDO for the whole period, also leaving an extra positive value. Regarding condensate and gas production, some years have seen higher production than in the PDO, but several more years showed lower production than expected. Not surprisingly, this contributes negatively to the net present value.

As we looked at OPEX and the transport costs specifically, it was not possible to get all the information needed to perform a complete analysis as to regards of the price of transporting each resource. The total number still shows that increased total production have pulled costs up, while updated oil prices have reduced OPEX. OPEX as a whole went slightly up, caused mainly by higher production.

The results of our analysis show that the field has done better than planned, but this is mainly due to the higher oil and gas prices. If this had not been the case, the net present value would have been reduced by about 30% from the PDO.

4.6 Summary of results

Valuation

Considering the four fields we have been looking at, all of them end up with a positive net present value, even though they had great cost overruns. For Jotun and Varg, updated net present value was close to the same as in the PDOs, but for Oseberg Øst and Åsgard, the new valuation from our analysis is a lot higher. Even though the valuation has not decreased for any of the fields, a common

finding is longer production times, so, the IRR for Varg, Jotun and Oseberg Øst has gone down, showing the return to be lower than estimated in the PDO. For Åsgard, the IRR has gone up, but since this is a very large field, also much larger than the other fields, the positive change in oil prices has had a much greater impact on the value.

The B/E-price for each of the projects has gone up as a result of the higher costs and lower and slower production of oil and gas. For Varg and Oseberg Øst, which both prolonged their lifetime significantly without raising the URR as much, relatively seen, the B/E-price has close to tripled, from around \$10 to close to \$30 after taxes, with a 7% discount rate. For Jotun, which has not prolonged its lifetime more than four years, the B/E-price has almost doubled, while for Åsgard it has only risen by 28% compared with the PDO. This lower growth is due to the fact that Åsgard has much higher URR which then generates higher revenues, even though the price is not that high. Because of this high URR, it does not need a similar increase in price to cover the extra costs occurred on CAPEX, and occurring in its OPEX. We still see though, that the B/E-prices for each of the projects have gone up, compared with the PDO, making the projects less attractive.

Net Present Value Breakdown Analysis

The production figures, and the updated estimates we have from November 2013, show that Jotun is the only one of our developments with lower production volumes than the PDO. However, we also see that the impact on the valuation of Oseberg Øst with the change in production profile is negative, indicating that the effect of later cash flows from slower production is larger than the effect of increased URR. So, except from Jotun, the projects have produced more than estimated. For Varg and Oseberg, this is due to the prolonged lifespan. Had they stopped production the year they originally planned, URR then would also have been lower than estimated. Åsgard is the only one which has done slightly better, and that only after spending extra capital on equipment to better the URR and cost overruns. All in all, the production estimates in the PDOs seem to have been too optimistic.

What has had a strong positive effect on all the projects has been the oil and gas price changes we have seen after the millennium. The valuations of all developments are higher than in the PDOs, this being mainly caused by higher sale prices, a variable existing outside the companies' control. All the projects would have been worse off than estimated in the PDOs had they not experienced the positive effect of oil and gas price hikes. For Oseberg Øst and Varg stable oil and gas prices would have been disastrous, as they would have become unprofitable, and most likely forced to close down earlier than anticipated.

The OPEX for each field has had an overall negative effect on the valuation, compared with the PDOs, showing that the operations have been more expensive than budgeted. For Varg and Oseberg Øst, this is not a surprise as they both have prolonged their lifespan greatly. When only looking at the years they originally planned to be operative, however, the OPEX is higher than budgeted, without considering any additional production years. A common thread seems to be that the projects were unable to operate within their budgeted OPEX. Considering that the production on three of the fields were lower than estimated for the budgeted years, we would expect the OPEX to be a bit lower than budgeted. This is not the case, and gives reason to look further into the operational cost overruns.

The CAPEX for each field has also gone up. This was one of our conditions for looking at the developments, and is still an interesting factor to consider in the valuation. We have found the cost overruns on each of the licenses to be even higher than what was reported in 1999, making the value of the field lower. The cost overruns on CAPEX had already occurred prior to production start, and have been quite significant for all of the fields. However, later investments have caused this cost overrun to be quite severe. These overruns have not shown a positive effect on the production rates compared with the PDO projections, therefore the cost overruns are likely to be more closely related to errors, wrong estimations, and schedule delays. This conclusion was also reached by the report published in 1999 by the Directorate of Petroleum and Energy.

All in all we have seen the field values increasing due to higher prices of oil and gas. Overall production has been lower, or close to target, however both CAPEX and OPEX have had a negative effect on the valuation of the fields. Without the much higher oil and gas prices, none of the projects would have reached their targets from PDO.

Variance Analysis

Static Budget Variance

The revenues for all of the fields have gone up, substantially for Åsgard, Oseberg Øst and Varg. We also see that the CAPEX have increased strongly for all the fields. The OPEX were stable for Jotun, while they increased slightly for Åsgard, and significantly for Varg and Oseberg Øst. Since both Varg and Oseberg Øst prolonged their production period, we would expect their OPEX to go up, but the slight increase for Åsgard and Jotun cannot be explained by extra URR. Looking behind these numbers, we argued earlier that the OPEX for Oseberg Øst and Varg would be higher than budgeted even without a prolonged production time. The rise in revenues has been higher than the increase in capital and operational costs for all fields, leading to a higher positive cash flow than budgeted.

Flexible Budget Variance

Looking deeper into the variances for each field we see that URR has contributed both negatively and positively to the value of the field, but the effect is not as big as the effect from prices. Splitting the effects into smaller parts shows that the price of oil and gas is by far the most important factor for the new value, causing it to be higher than in the PDO. The flexible variance supports this finding.

The flexible variance analysis shows that Åsgard is the only field that has an acceptable deviation from the flexible budget. Oseberg Øst and Varg have significantly higher costs than what we would expect given their new lifetime, production, and mix of operating costs. Oseberg Øst is 121% above the flexible budget, while Varg is 50% above. This indicates that there are some problems relating to the operational costs of these fields especially, which will be discussed in the next chapter.

5 Discussion

Cost overruns, looking at the report, our analysis and GEM

As we chose only fields with considerable cost overruns, we are not surprised that the CAPEX are higher than budgeted. We did however have some challenges when considering the effect of higher CAPEX. The drilling costs on some of the fields kept rising far beyond the commencement of production, even after the planned number of wells were drilled, implying that some of the cost overruns came not only from extra investments, but also from overruns relative to the original PDO. When making a comparison between the PDO and what we believe were the actual costs for the planned development, we had to make a cut-off on investments based on the specific number of wells that were drilled, and when we saw a decline in actual investments, this suggesting the field was done with that specific phase.

When analyzing the performance of the fields with the updated numbers, including all CAPEX, and then comparing them with the PDO estimates, one issue is that we are no longer comparing two identical factories. Because of this, we could not fully predict how the field would have performed with the original design. We have taken this information into account when considering the analysis of the fields.

One group of CAPEX that we have seen change significantly from the PDO estimates is in the drilling costs of the fields. This category accounts for 49%-84% of the total investments after PDO completion for the fields. Based on new knowledge, it may be desirable to increase drilling, thus making the field more profitable. This would of course only be valid if the resulting increase in revenue surpasses actual costs of expansion. Since the oil price has increased significantly during the

last decades and is significantly higher than the expectations in the PDOs it has become more lucrative to increase the recovery rate, and thus it is likely to assume that the willingness to pay for drilling operations has increased. Given this assumption, it is difficult for us to determine the share of the drilling costs that are caused by weak well performance compared to the expectations in the PDOs, and those mitigated by increased oil prices, which increases the revenues of each barrel of oil produced.

All four fields have significant increases in drilling costs compared to the PDO. The updated drilling costs for the fields are 101% above PDO for Jotun, 739% for Varg, 503% for Oseberg Øst and 389% for Åsgard. This is evidence that all of the developments have significantly underestimated the potential drilling costs incurred during the projected lifetime of the field. It is interesting that Jotun is the field with the lowest increase in drilling costs and that it is the only field of the four that is expected to produce less petroleum products than estimated in the PDO, even though it has increased its lifetime. The fact that these cost overruns happen both prior to finishing what was planned in the PDO, and also appearing after the completion of this phase, suggests that the overruns are caused by several factors: bad initial planning, project adjustments being needed, and opportunities for further investment being discovered as the project unfolded. Since a large part of the cost overruns came so late, it may also be that the licensees saw that oil price had increased considerably, making it more profitable to produce just a bit more than originally planned for the PDO. It is also a circular problem, because higher investments put higher demand on suppliers, so that the prices go up. Jotun, being the only field investing the majority of its drilling costs in development according to PDO, accrues 47% of total drilling costs after PDO completion. For the other fields, the share of drilling costs spent after completion of development, according to the PDOs, ranged from 69% to 77%.

The estimated lifetimes of the fields have also changed since the PDO estimates, except for Åsgard. The lifetime of Åsgard is easier to estimate, because it is primarily a gas field, and there are more constraints on the capacity coming from production, infrastructure, and transportation capacity. Jotun has prolonged its lifetime by 24%, Varg with an originally estimated lifetime of 6 years, increased by 283%, and Oseberg Øst by 136%. Unfortunately we cannot decide how and if the increased drilling costs have been financially justified by these prolonged lifetimes. It is, however, likely that some of the fields have prolonged their lifetime significantly because of the increase in oil and gas prices since the millennium change. This has made it more profitable to increase recovery rate, by producing lower volumes during the later years as well, thus prolonging their lifetime, and possibly also justifying the increased drilling costs.

After conducting our analysis however, we feel that one likely explanation for the increased drilling costs comes from poor production performance compared to the PDOs, especially during the first couple of years. These poor results have led to a more comprehensive drilling program over time in order to recover the identified resources. As the oil prices have increased significantly after the millennium, this increased the profitability of recovering the oil, further increasing the above effect. We therefore see a higher URR, but with lower production each year than estimated in the PDOs.

What is quite remarkable is that none of the four fields we have analyzed anticipated further drilling costs once the initial drilling connected with establishing the field had ended. The PDOs show that operators expect there to be a period during the development of the field when CAPEX is high, but that this period tapers off rapidly after initiating the development; this phase typically lasts for 5 years for the larger fields. After this period there are no expectations of high drilling costs, if any at all, but we have seen from GEM that all of the fields have had significant drilling costs after completing the development according to PDO.

Our analysis indicates that the projects fail in at least one of two places, either at the recovery estimates in the PDOs, or when considering the profitability of conducting further drilling operations. If the drilling operations completed have been necessary to be able to produce the achieved production volumes, estimates of the production profile in the PDO seem far too optimistic.

Valuation, including net present valuation, internal rate of return and break-even prices

Of our four licenses, only Åsgard and Oseberg Øst outperform the PDOs' net present value estimates. Their valuations show a significant increase from the PDO, this being due to increased revenues, and will be discussed later. Varg performs better than the PDO with low discount rates, but perform much weaker with higher discount rates. This comes from lower production in the early years, and a prolonged lifetime, coupled with lower yearly production rates than the PDO. Jotun hits the PDO estimate before taxes, with only small deviations from the PDO, but the after tax numbers show higher deviations. This is because of delayed production start, and the production profile being higher for two years before normalizing below the estimates. The earlier heavy tax load also decreases the value of the field.

Internal Rate of Return

When calculating the IRRs, and the B/E-prices for the licenses, we see that the valuation of the fields does not show the whole picture. The IRR of Oseberg Øst, Varg, and Jotun have actually declined, while it has increased for Åsgard. We have seen that all the fields except for Åsgard have prolonged their lifetime, and that Varg, Oseberg Øst, and Åsgard, have increased their URR. Taking into account

that Jotun has produced less than planned, it seems that the reason for the decline in these fields' IRRs is that the URR are spread across more years of production, with a larger share of the production than estimated in the later years of their lifetimes. Jotun is the only field to produce less than expected in the PDO, but Jotun is also the only field that has produced more than estimated in the early years of production. Because of this, the impact on its IRR is smaller. Varg has had the most dramatic fall in IRR, being cut almost in half between PDO and our updated numbers. This dramatic reduction makes us wonder if this project is commercially viable, or at least if this was a project that would have reached development having the knowledge we have today. Our thoughts are that it would not have been developed. Åsgard, which is the only field with increased IRR, is the only field that has not changed its estimated lifetime. Åsgard have on the other hand managed to increase its URR, which will have a positive effect on the IRR everything being equal.

All four fields have experienced increased oil and gas prices, which have had a positive effect on their IRR. These fields have also experienced cost overruns in their development, this having a negative effect on their IRR. Taking the quite large increase in petroleum prices into account, it is likely that the cost overruns to some extent are compensated in the internal rate by the increased petroleum prices, but in total there are more factors that have a negative effect on the IRR, than factors that have a positive effect.

Break-Even Prices

For all of the fields in our analysis we see that the B/E-prices have increased compared to the PDOs. As we chose only fields with cost overruns, it is not surprising that the B/E-prices also increased just after completing development according to the PDO. Some of the increase is due to increased CAPEX, some is due to increased OPEX, and some due to lower production profiles. The remarkable finding is that Varg's B/E-price, after considering the cost overruns, is higher than the assumed sales price of oil in the PDO. This is not the case for any of the other fields. When the B/E-prices are above the expected sales prices, it is a clear indication that the project will be unprofitable and would not be conducted or developed. For Varg this would probably mean that the development would be delayed until the oil prices had increased, or costs could be brought down.

When considering the updated B/E-prices for the fields, after including all costs, we see that only Åsgard has a B/E-price that is lower than the expected oil price in the PDO. This shows that if there had not been any change in oil prices, none of the three first projects would be profitable, and Åsgard, with multibillion revenues, is just above this B/E-price. Some of the increase in B/E-prices may however be an indirect result of increased oil prices. The large increase in oil prices made investments that increased URR more lucrative, which in turn prolonged the lifetimes of the fields

and which would likely have had an effect on the costs, increasing these as well. Increased URR for some of the fields is a factor that will reduce the B/E-price since costs can be distributed over a larger volume. This applies to all of the fields except for Jotun. It is then remarkable that Jotun has a smaller increase in the B/E-price than both Varg and Oseberg Øst. A possible explanation to this may be the fact that Jotun experienced significantly higher production the first two years than expected, which may have a beneficial effect on B/E-prices when cash flows are discounted, even though Jotun produced less than expected during its lifetime.

The prolonged lifetime of Jotun, Varg and Oseberg will also result in higher operating costs for the fields. This will have a disadvantageous effect on the B/E-prices that will make them increase if the URR is not high enough. It is not likely that the production is at a high enough level to offset the effect of increased OPEX considering the initial B/E-prices. This is because the lifetime has been prolonged with low production volumes. But, the oil prices in these periods are much higher than what was expected in the PDOs, so the operations are profitable in present values even though increased operating costs have a negative effect on the B/E-prices.

For Åsgard, the increase in B/E-price is the lowest as they have a very high URR securing a high revenue flow, even though the price of oil is not that high.

Breakdown analysis

The breakdown analysis of the NPV clearly shows how the different revenue sources and cost groups have affected the net present value of each field from the PDO valuation until the updated valuation. The most significant effect is the increased oil prices during the period, which have proven to be several times higher than expected in the PDOs. All four fields experienced increased prices, but Jotun has gained the least of the fields because it produced most of its URR in the first couple of years of its lifetime, when oil prices had not yet significantly increased.

When we excluded the effect of the oil price, and let everything else be as it turned out in reality, we found that only Åsgard and Jotun would have experienced a positive valuation. However, this is a simplified analysis since we assume that the operators would have made exactly the same decisions regardless of the development of the price. This assumption cannot be correct, since the development in oil prices have such great importance for the profitability in the industry. The analysis does however visualize the effect the oil prices have had on the valuation of the fields. Three of the fields would have experienced several years of negative cash flows if it were not for the increased oil and gas prices. It is very likely this would have reduced the lifetime of the fields. Jotun would probably have been closed in 2006 with a positive net present value, while Oseberg Øst would

most likely been closed the same year, only with a negative NPV. Varg would have suffered from increased CAPEX, and low production volumes, compared to the estimates in the PDO, and would have only experienced a couple of years of positive cash flow before closing down with a negative valuation for the project as a whole. Åsgard on the other hand would be a profitable project with the PDO prices. It has, however, quite large CAPEX throughout its lifetime, and with significantly lower oil prices, we suspect that some of the CAPEX would not have been made since some of the drilling operations would probably have been unprofitable.

All of the fields have experienced significantly higher CAPEX during their lifetimes. The largest share of these costs was related to drilling costs, which we assume were incurred to enhance the recovery rate, and to increase URR. It is our belief that a large part of these drilling costs would not have been incurred if not for the increased oil and gas prices, since the profitability of increased URR would not have been as great as it is today. This would in turn have reduced the URR of the fields, which would then affect the revenues, and the CAPEX.

We have seen that a large part of the increased OPEX occur in the fields with increased lifetimes, while Åsgard, which has had no change in its lifetime, has experienced only a small change in OPEX. Jotun on the other hand with only small change in its lifetime, but has experienced quite an increase in OPEX. A large part of this increase is due to leasing and tariffs costs. The leasing costs are due to the sale of the Jotun FPSO, while the tariff costs are covered by tariff revenue. Based on the above, it seems the operators are good at estimating the OPEX of their respective fields, especially since Oseberg Øst and Varg experienced increased OPEX due to prolonged lifetimes. Some of the increased operating costs can also be traced back to higher prices of oil and gas this leading to higher demand from suppliers, which again drives prices up.

Variance analysis

Static Variance

The static analysis showed that the revenues were higher than budgeted for all the licenses. Varg, Oseberg Øst, and Åsgard, had an increase of 350%, 216% and 170% respectively, while Jotun had the smallest increase of only 15%. As we have seen from the valuation of these fields, most of this growth is due to the increased prices of petroleum products. Except for the increased revenues, the only other positive deviation from the budgets is Åsgard's transportation costs, which are lower than expected. All the fields have experienced unfavorable CAPEX as previously discussed and presented, and we see that all the fields have had unfavorable development in OPEX, with the updated numbers

exceeding the budgeted numbers. The only field that does not experience a deviation above 10% is Jotun.

Flexible Budget Variance

By using the variance analysis technique, we have illustrated how the production of each field has been compared to their PDOs. As we have seen, both Oseberg Øst, and Varg, have managed to increase their URR, while increasing their lifetimes as well. We also see that the URR have not increased as much as we would expect from the increase in lifetimes. A more thorough analysis, showing the deviations each year, shows that all the fields, except for Jotun, produced less than estimated in the first five years after production start. This has a negative impact on the present value of the fields, since high production at the start would give higher revenues with lower discount rates. It also shows that the operators overestimated the potential production from the fields, especially during the plateau phase of the fields' lifetimes. The production volumes have decreased in the early years of production while URR have increased, with the exception of Jotun.

The progression of a larger share of production moving towards the tail-end phase of the fields has actually been lucrative for the fields thanks to the increase of oil and gas prices. The prices have risen by several hundred percent during this period, which is much more than the deviation between the estimates and the real production. The effect of the increased prices has been very strong as we can see both from the valuation and variance analysis.

How strong the effect of the increased oil price has been, is affected by both the assumptions regarding the oil price and how the production profile has changed. The price effect on Jotun's revenues is much smaller than it is for the other fields. This is due to the production profile of Jotun, with a large share of its production being prior to the sharp rise in oil prices. Where Varg and Oseberg Øst have had a price effect on their revenues of 171% and 175% respectively, Åsgard has had an effect of 138%. The main reason for this is that Åsgard produces significantly more gas than the other fields and that the gas price has not increased as much as the oil price. Since Varg and Oseberg Øst almost exclusively produce oil, the effect of the higher oil prices is much greater when their lifetimes have been prolonged as much as they have.

After adjusting the flexible budget for variable and fixed costs we see a mixed picture. Åsgard made quite good estimates in their PDO, and the deviation from the flexible budget is only 3%. For Jotun the deviation is only 10%, which is a bit over the flexible budget but not so significant that it poses a large threat to the profitability of the field. However, for Varg and Oseberg Øst, the deviations seem to be quite significant. Oseberg Øst's OPEX are 121% above the flexible budget, while the deviation is

50% above for Varg. This is a considerable deviation from the plan and could have a severe impact on the fields' profitability. These two fields are also the fields that have experienced the longest prolonging of their lifetimes. When the lifetime have been prolonged by as much as 283% for Varg it is natural to assume that a total cost for a longer timeframe is more difficult to estimate than it is for a shorter timeframe. Considering this, it is notable that Oseberg Øst that has the highest deviation. Following a doubling of its lifetime, and a prolonging its lifetime by two years more than Varg, we should not focus too much on the percentage change in lifetime between these two fields. Since the fields have prolonged their lifetimes so much, a possible reason for the increased operating costs may be that since the facilities were not planned to last for as long as they now are expected to, the costs of operating "old fashioned" facilities may be more costly. We do not have any data that suggest that this is the case, but it might be. Another reason for this may be that as the production volume goes down, the fields produce more water alongside the production of oil and gas. When the fields are in the tail-end phase they start to produce more water along with the production of oil and gas. Assuming that the fields use the same amount of resources and variable costs per unit of liquid, and that the liquid flow through the pipes is constant during the fields' lifetime, no matter how much of it is oil or water, the costs per barrel of oil will go up. Since the fields produce more water, the total costs per barrel would go up if the variable costs only depend on the liquid flow through the pipes. Since we do not know the share of oil (or gas) versus water we cannot analyze how this would influence the flexible budget and thus the operator's performance.

6 Conclusion and Results

6.1 Conclusion

Our analysis shows that all the fields we have looked at performed better than the PDO in terms of the NPV with a 7% discount rate before taxes. This is despite the fact that they have had great cost overruns. But, the B/E-prices have risen for all the fields, and the IRR has decreased for all the fields except for Åsgard. Even though B/E-prices have increased after completing the initial development, they are lower than expected sales prices in the different PDOs, except for Varg. This shows that three of the fields would be profitable projects despite the cost overruns everything else being equal. For Varg we found that the B/E-price after finishing the development according to PDO was higher than the estimated price. With this in mind, Varg should not have been developed, had they known the actual costs, and assumed the same oil and gas prices as they did.

When we exclude the effect of the higher oil prices, we found that only Åsgard and Jotun would experience positive net present values. Even though this is a simplified analysis, it visualizes the immense effect of the oil prices on the fields' valuations. It also shows that Åsgard is the only field that we would say had been a success, regarding profits earned, even if oil and gas prices had not gone up as much as they did.

We see that a large part of the cost overruns concern the drilling operations to finish the fields according to the PDOs. In addition we see that far more comprehensive drilling operations after completing the development, according to the PDO, have inflicted large CAPEX on all of the projects. The most remarkable discovery is that none of the fields had anticipated any large, if any at all, drilling costs after completing the development according to the PDOs. Considering the actual production volumes, the job done to estimate these figures seems to have been poor. All of the fields, except for Jotun, generate less than estimated in the first years of production and have a much lower plateau level of production, and enter a higher share of production in the tail-end phase of the fields.

The drilling operations conducted after completing the development according to the PDO is a clear indication of failed estimates for drilling operations, which have resulted in extra drilling operations to better the URR. The drilling operations, production volumes, and oil and gas prices need to be considered as interconnected. Lower production volumes would induce more drilling operations to improve the well performance, which in turn would increase production, while increased oil and gas prices would increase the profitability, making it more attractive to increase the URR. What we see is

that Varg, Oseberg Øst, and Åsgard, have experienced low production in the start of their lifetime, but as oil prices increased the fields developed more comprehensive drilling operations. We do not know how the prices and production volumes independently have contributed to the increased drilling costs, but it is clear that the estimated production profiles in the PDOs are far too optimistic given the performance of the wells and the drilling operations. This is especially true for the production in the plateau phase of the field. Since this is in the earlier stages of the fields' lifetime, the production will have a great impact on the NPV of the fields.

In our opinion, the increased URR and the prolonged lifetime of the fields are results of the increased oil and gas prices and the more comprehensive drilling operations. The analysis shows that if the oil and gas prices had not increased, the fields would not have prolonged their lifetimes as much as they have. The increased URRs are also a result of the prolonged lifetimes, so if the fields had closed down earlier, URRs would be much lower than the PDO estimates. For Varg and Oseberg Øst, it would actually not be profitable to operate with the prices expected in the PDO. But, as the operators saw the higher oil and gas prices, the production continued. Some of the licenses would be better off stopping production earlier than estimated had the oil and gas prices not gone up, due to negative cash flows from the revenues being lower than OPEX.

The revenues for all fields have gone up compared with the PDO, and this mainly due to the higher oil and gas prices. The production had a positive effect for two of the fields, but also a negative effect for the other two. The higher oil and gas prices have also been key to saving all the fields in regard to covering the higher operational and CAPEX. The higher OPEX are mainly due to prolonged lifetimes of the fields. However, we see that for both Varg and Oseberg, the OPEX are high above the flexible budget, which takes into account the production volumes, lifetime, and the mix of variable and fixed costs. This shows that these fields have not been able to manage their operations according to their budgets. It is our belief that since these fields have prolonged their lifetimes significantly, they have experienced higher operational costs. A prolonged lifetime also makes it harder to estimate the operational costs, but we see that the fields are underestimating once again.

Of the fields analyzed Åsgard is the field that has performed the best, with higher URR for two out of four products, and hitting budget on OPEX. However, we have seen that the production estimates seems to have been too optimistic in the early phases of the field's lifetime before it started to produce more than anticipated after a while. During this period the field had significant drilling costs that may have increased the URR. This has been very profitable for the valuation of the field. So even though Åsgard has performed quite well compared to the other fields, it seems as if also Åsgard has had a too optimistic production profile.

The major similarity between the fields is the dependency of the oil price for the fields' valuation. A second common factor seems to be the difficulty of estimating the lifetime and production profile of the different fields. A field's lifetime is affected by both the production in previous years, and the commodity prices, where increased prices can make it very lucrative to prolong the lifetime of a field even with low production volumes. Finally, the drilling costs after the field is developed according to the PDO, is significant.

6.2 Validity of the Results

The results of our valuation models correspond to the valuations in the PDOs, which are done by three large, international, independent and well-known oil and gas companies. Because of this we feel that the results from the analysis with updated numbers, which are gathered in the same manner as with the PDO numbers, are comparable to the PDO valuations. We have also seen that the cash flows in our valuation models are equal to the cash flows in the different PDOs, ensuring correct results for each in the valuation models after using updated numbers.

The flexible budget picture is more fragmented. In the income parts of the analysis, the only place where there may be some fault is when a field has produced other petroleum products than anticipated in their PDO. Thus, they have not made an assumption on price for the corresponding product. Because of this we left it out of our analysis regarding the flexible budget for revenues if this was the case.

The OPEX are more difficult to evaluate and be one hundred percent certain about the analysis. This is because we do not know with complete confidence that production of oil and gas is the cost driver of the variable costs. This has implications when analyzing the results, and has been discussed in the previous sections. Since the variable costs of the different fields may be differently affected by the production volume, it is hard to argue that the findings of this part of the analysis are valid for other fields. We chose to split the OPEX into one part dependent on the production volume, the other part being fixed, so that it increased with a longer production period when looking at the flexible budget. For the transport costs, the data only depended on production for the different liquids or gases.

In the majority of the analysis, it is hard to generalize our findings to apply to other fields. Considering that we have only analyzed fields with cost overruns means that we cannot with certainty say that our findings are applicable only to fields with cost overruns, or not. Taking into account that the PDOs are almost 20 years old there is uncertainty regarding how production is today since a lot has changed during this time period.

Another factor that needs to be addressed is that we have only looked at megaprojects. If we had included smaller projects, we might have seen that the cost overruns on CAPEX would have been more severe for the total project. Since smaller projects are likely to have fewer resources to recover, these projects are more exposed to cost overruns in terms of their profitability.

6.3 Findings and Implications for Further Analyses

We have some interesting findings and take-aways for operators and stakeholders on the Norwegian continental shelf from these analyses. This can be especially interesting for megaprojects in the future, such as Johan Sverdrup.

Our analyses indicate some key areas for operators to focus on. These are the OPEX, lifetime estimation, CAPEX and a field's sensitivity to the oil and gas price. We have seen that two of the fields have significant higher operating costs than what we would expect given the lifetime of the fields, and the production volumes. We do not have available data that can identify how the costs have developed for the different areas and costs of operations, so this is something that the operators, or others with access to a more comprehensive financial statement of the fields, should work on to identify. Identifying more precisely where the increased costs occurred can be crucial to increasing the performance of operations. For Johan Sverdrup this could be essential to keeping the costs down, as it will operate for several years, and it is likely to meet changes in the production profile and lifetime. With these variables they will meet changes in operational costs, and should spend time gathering the best estimates possible in order to not be surprised by big cost overruns at a later date.

The lifetime and production profile estimates for the different fields seem to be quite inaccurate. The tendency of a lower production rate with decreased share of the production in the early years of production, and an increased share in the later years of production, will have a negative effect on the valuation of the fields, everything else being equal. Since it seems that the production profiles have been rather optimistic, the operators should try to be more critical with the production profile, and consider the effect on the valuation of a more prudent production profile. Johan Sverdrup, which will produce from several wells, and with a high URR, will need to think about this, because overestimating the early years' production could mean hundreds of millions in overestimation of the NPV of the field.

All of our fields had significant cost overruns since this was a criterion when we chose our fields. We have found that the fields still had significant drilling costs even after completing the development according to the PDOs. We have not seen any indications in the PDOs of the fields expecting such

comprehensive drilling programs even after completing the development for production. The government that approves the PDOs should address this since it will have a significant effect on the valuation of the fields and the taxes to be paid to the Government. Not only should they look at the percentage of costs occurring in the comprehensive drilling program, but the absolute value in kroner, as Johan Sverdrup for instance will have a considerable amount invested in the drilling program included in the PDO.

We have also seen in the post millennium period that the oil and gas prices have had an increased effect on the NPV of the fields. The developed fields sell their petroleum products in the commodity markets and have a low or non-existing power to influence the prices, so the effect from the commodity prices on the NPV is probably going to stay strong. Because of this the fields' B/E-price needs to be considered when considering developing a field to ensure that the fields can handle a decrease in the oil price. So both the operators and the Government should try to take measures that can decrease the B/E-prices, which will both increase the profitability of the fields; and the taxes paid by the fields.

Current and future development should be careful with assuming the same appreciation of oil and gas prices as we have seen over the last decade. The oil prices have increased from around 20 USD per barrel to above 147 (114 USD in 1996 terms) USD at the most. The last couple of years the technology have introduced more and more shield gas and oil, which have significant higher B/E-prices than conventional oil and gas, but where production can be closed and opened far more easily than for conventional oil and gas. This implies that if the prices increase significantly, we can expect a surge in the production of shield oil and gas, which in turn will have a negative effect on the prices due to increased supply. Due to this, assuming large future appreciations in the oil price should be done with caution.

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Abbreviations

Abbreviation	Meaning	Page
APV	Adjusted present value	9
B/E	Break-even	7
boe	Barrel of oil equivalent	10
CAPEX	Capital expenses	8
CCE	Cost control estimate	44
DACF	Debt-adjusted cash flow	28
DCF	Discounted cash flow	10
E&P	Exploration and production	30
EBITDA	Earnings before interest, taxes, depreciation and amortization	30
EV	Enterprise value	25
FCFE	Free cash flow to equity	9
FCFF	Free cash flow to firm	6
FID	Financial investment decisions	32
FPSO	Floating production, storage and offloading	43
GAAP	Generally accepted accounting principles	9
GDP	Gross domestic product	37
GEM	Global Economic Model 4	6
HSE	Health, safety and environment	39
IFRS	International financing reporting standards	9
IRR	Internal rate of return	7
NGL	Natural gas liquids	18
o.e.	Oil equivalent	13
OPEX	Operational expenses	8
PDO	Plan for Development and Operations	4
SDFI	Stat's Direct Financial Interest	37
URR	Ultimate recoverable reserves	4
WACC	Weighted average cost of capital	8
WM	Wood Mackenzie	6

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