Evaluation of projects implemented on the Norwegian shelf

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1 Introduction

Reference is made to the inquiry from the Ministry of Petroleum and Energy (MPE) of 13 March 2013, requesting that the Norwegian Petroleum Directorate (NPD) conduct a review of projects where production has recently started, or should have started, and that have an investment scope exceeding NOK 10 billion. The review will include all projects with an approved development plan in the years 2006 to 2008.

This report summarises the NPD's response to the request.

The main objective of the project review has been to understand the reasons why licensees do or do not succeed in implementing projects on time, with quality and costs in accordance with the plan for development and operation (PDO) and in turn using this to highlight important lessons and experience transfer to other projects. A secondary goal has been to provide a description of the actual cost development and implementation time for each project, as well as to describe the project experiences, including causes of deviations in implementation time and costs in relation to the PDO.

It has been important to limit the task to a manageable, but representative selection. By taking a basis in the framework provided in the assignment from the MPE, the scope is limited to review of the following projects: Skarv, Yme, Valhall Redevelopment (VRD), Tyrihans and Gjøa. These are projects with a PDO approved in the period 2006 – 2008, and with investments exceeding NOK 10 billion. The projects are distributed among three operators and represent significant variation in development concepts. The selection includes both projects implemented with significant time and cost overruns, as well as projects implemented in accordance with the PDO, with regard to both time and costs. The Yme project is included in this connection because, while the original investment estimate in the PDO was less than NOK 10 billion, the final investments for the project exceed NOK 10 billion. Tyrihans is also included as the approval date by the Storting (Norwegian Parliament), 2 December 2005, was near 2006.

The development of costs and time, as well as causes and experiences are based on the operator's reports at the request of the NPD. Meetings have also been held with the relevant operators. A basis is taken in the estimates in the PDO. The most important reasons for overruns are described, as well as lessons learned from the projects. The NPD's overall assessment is provided in Chapter 5.

2. Summary

Most projects on the Norwegian shelf end up with development costs within the uncertainty range indicated in the PDO. Despite this, there are major cost overruns from the development projects overall. This is mainly caused by a few projects with substantial overruns. These projects are therefore responsible for most of the overall change in relation to the PDO estimates. However, major overruns in oil and gas projects are not unique to the Norwegian shelf. Recent studies reveal the same development internationally, both with regard to costs and implementation time.

The Skarv, Yme and Valhall VRD projects have experienced considerable overruns in both costs and implementation time. The costs for the Tyrihans and Gjøa projects also ended up higher than the unbiased estimate in the PDOs, but were still within the indicated range of uncertainty. The completion of these projects was in line with the implementation time in the PDOs.

The review shows that some important factors need to be in place in the operator’s project management in order to ensure successful implementation of the projects as regards time, costs and quality. Several of these factors are crucial in any project context, and are already known. The Investment Commission, appointed in 1998, highlighted the same factors in the report "Analyse av investeringsutviklingen på kontinentalsokkelen" (NOU 1999:11) *<Analysis of investment development on the continental shelf – Trans.>*.

Thorough, high quality work in the early phase is crucial for the rest of the project implementation to succeed. Several projects in this review have, for various reasons, been governed by schedules that are too ambitious from start-up of the project. Time allocated for early phase work has been insufficient. For several projects, Front-End Engineering Design (FEED) has not been sufficiently completed before project sanctioning. This has resulted in implementation of construction and procurement on a deficient basis. There are also examples of important new information not being taken into consideration as it would have resulted in a restart of the front-end engineering, thus delaying the project. There are also examples of operators lacking an internal decision programme for sufficient maturing of projects. There have thus been unclear quality requirements in the decision basis for the project sanctioning.

It is important that the projects have a clear contract strategy which helps ensure quality and progress. The operator’s follow-up and prequalification of suppliers must be clearly included as part of the operator’s contract strategy. The projects that succeeded with project implementation in this review cite these as important criteria for success. In major projects, the operator will not be able to carry out close follow-up of all parts of the project. There must therefore be certain prioritisations with regard to follow-up areas, while the rest of the project should undergo extensive prequalification of suppliers and sub-suppliers. This will reduce the risk of replacing suppliers along the way, that suppliers go bankrupt, that the quality of deliveries is not as expected, and that central technology elements are not delivered in accordance with expectations.

This review does not provide a basis for concluding that there is a correlation between the cost overruns and the geographical location of the fabrication site. Faults and defects in relation to contract specifications are, in the NPD's assessment, primarily caused by the operator's deficient follow-up of the project. This will apply whether the faults are caused by poor quality or the suppliers' potential deficient understanding of Norwegian standards and regulations.

A high activity level has resulted in increased prices for input factors and scarcity of certain resources. For projects that have experienced difficulties, a high activity level has therefore had an amplifying effect. A high activity level has resulted in tighter conditions for the project implementation and, according to the NPD, is a contributing cause of the major time and cost overruns incurred in some of the projects in this review.

3. Implementation of offshore oil/gas projects

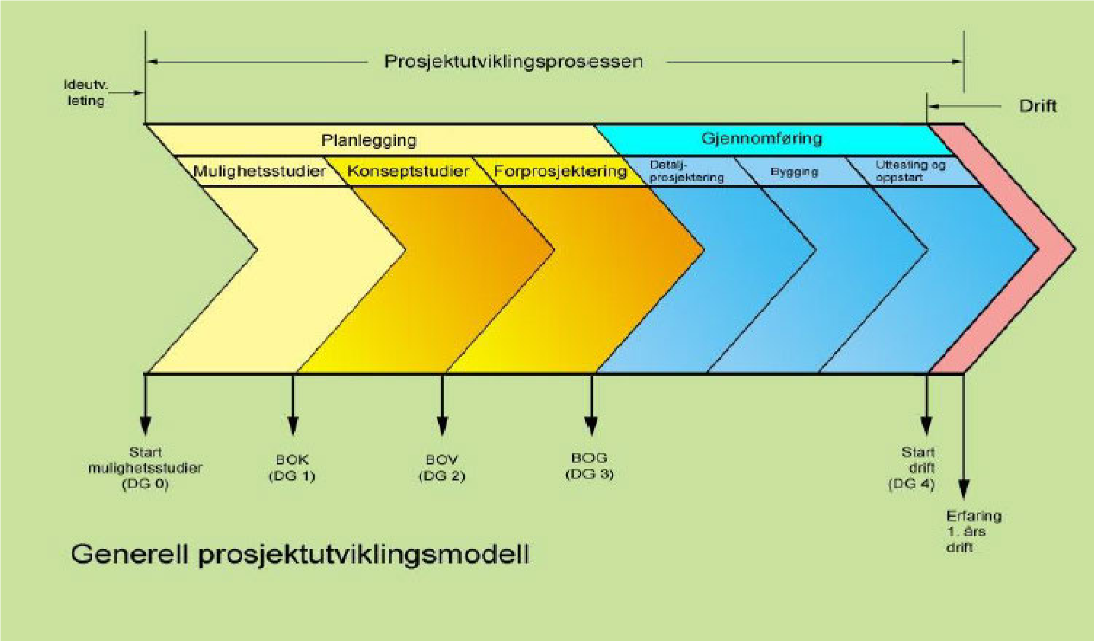
Offshore oil/gas projects are generally divided into a planning phase and an implementation phase. The final work scope is prepared in the planning phase, an implementation plan is established, a contract strategy is laid, tenders from suppliers are obtained and a contractor is chosen. An important part of the planning phase is preparing good, realistic estimates for implementation times, performance and cost requirements. Through feasibility studies, concept studies and front-end engineering design, the project is matured up to a level of detail which forms the basis for a potential decision regarding development. The front-end engineering design forms an important basis for the PDO application to the authorities.

Major offshore oil/gas projects comprise several independent activities, and a successful result is contingent on all involved parties completing their deliveries on time. Activities take place at different geographical locations and extensive communication and sound cooperation between players is vital.

A common project implementation model used on the Norwegian shelf involves multiple decision points along the way during the project's lifetime. Various forms of quality assurance are carried out prior to these decisions, both internal and external. Internal quality assurance comprises technical quality, as well as multidisciplinary and commercial quality of the project based on empirical data from other projects the operator has insight into. External quality assurance can include external benchmarking and peer reviews as contributions toward improvements, as well as to ensure good ownership of the project in the entire partnership.

The authorities' "Guidelines for PDO and PIO (Plan for Installation and Operation), focus on planning, organisation and implementation of development projects. The guidelines state that a schedule must normally be submitted for the development and that the project should be assessed to the extent that all investment elements can be estimated with reasonable certainty before the PDO is sent to the authorities.

Project management is defined as the systems needed to prepare the plans, follow-up to ensure that the plans are realised and potentially make corrective measures along the way. The project implementation must be focused toward completion at the right time and within a given cost framework.



text in figure:
Prosjektutviklingsprosessen = Project development process
Ideutv. = Idea development
Leting = Exploration
Drift = Operation
Planlegging = Planning
Gjennomføring = Implementation
Mulighetsstudier = Feasibility studies
Konseptstudier = Concept studies
Forprosjektering = Front-End Engineering Design
Detaljprosjektering = Detail engineering
Bygging = Construction
Uttesting og oppstart = Commissioning and start-up
Start mulighetsstudier = Start feasibility studies
Start drift = Start operations
Erfaring 1. års drift = Experience 1 year of operation
Generell projektutviklingsmodell = General project development model

Figure 3.1 General project development model

3.1 Responsibilities

When awarding a production licence, the Ministry will appoint or approve an operator (Section 3-7 of the Petroleum Act (PA)). The operator is responsible for daily management of the joint venture's activities, including implementation of individual projects (cf. Article 3).

The licensee is the party awarded rights according to the individual licence (Section 1-3 of PA) and has overall responsibility for prudent operation of the petroleum activities.

According to current statutes, the licensee is subject to a special follow-up duty (the “supervisory duty”). In accordance with Section 10-6, last subsection, the licensee is required to ensure that everyone that performs work for the licensee complies with the provisions stipulated in or in pursuance of the Act. The licensee (normally the operator) also, by involving other participants in the activity, has direct management and control of the performance of the overall activity through e.g. stipulating requirements, terms and conditions or framework for quality and efficiency.

On behalf of and according to instructions from the other licensees in the licence, the operator is responsible for daily management of the activity. The operator therefore has a special responsibility for ensuring that the overall activities take place in a prudent manner and in accordance with the applicable rules at any given time. The other licensees (the joint venture individually and jointly) must, e.g. through audits, ensure that the operator is fulfilling its special operator duties, and facilitate the operator's work through budgets and decisions, etc..

Licensees' supervisory duty will mainly be related to ensuring that the operator fulfils its obligations. In practice, this will entail the licensee ensuring that the operator and other participants in the activity have a satisfactory management system, have a satisfactory organisation, possess sufficient capacity, address problem areas on which the authorities place particular emphasis, obtain necessary permits and consents, etc.

The responsibility for ensuring compliance with the regulations is a general and comprehensive follow-up duty when carrying out all petroleum activities. The licensees' follow-up duty entails that the licensee, before and during signing of the contract, as well as when implementing the activity, shall verify that all participants are competent and qualified to conduct petroleum activities.

Pursuant to the Agreement concerning petroleum activities (Article 11), all licensees must contribute in the strategy work with a focus on goals, choosing the course and monitoring the entire activity. The operator is required to make regular reports to the management committee regarding the status, nonconformities and measures.

The licensees are required to contribute to management and control of the joint venture's activities. In development cases, the licensees therefore have a responsibility to actively use the various companies' experience and expertise to improve and verify the quality of the projects. Important milestones and decisions relating to continuation must be made by the licensees. This applies for decision points during the planning phase, as well as for status reviews and decisions regarding potential corrective measures during the implementation phase.

3.2 Project follow-up

The preconditions for a project to succeed with implementation in accordance with both the time and cost framework are established in the planning phase. The project basis must contain both realistic plans with built-in flexibility and a realistic budget with a buffer to accommodate changes. Another important precondition is that the contracts entered into with suppliers contain precise descriptions of the work scope. This will promote good communication and reduce the potential for misunderstandings between the parties. Another precondition is that both the operator and supplier, as well as sub-suppliers, have the necessary expertise.

For offshore projects on the Norwegian shelf, the operator always has overall responsibility for daily management and project implementation, and it is therefore a precondition that the operator has sound project implementation expertise, including knowledge of requirements on the Norwegian shelf. Furthermore, the operator is responsible for ensuring suppliers also have the necessary expertise. This is the operator’s responsibility regardless of the contract type chosen. Expertise, and thus quality in all stages, will be an important success criterion for a project.

Project follow-up during the implementation phase will mainly mean following up contractual factors, ensuring sound cost and progress control, managing the engineering work, following up the construction work, conducting procurement/material management and quality assurance. How these tasks are distributed between operator and supplier may vary, and this is regulated in different types of contracts. Regardless, the operator will have the overall responsibility on behalf of the licensees, and must ensure progress and costs are in accordance with the plans, as well as ensure the quality of the deliveries.

The implementation phase is divided into detailed engineering, construction and commissioning/start-up. The final basic drawings for the construction are prepared during detailed engineering. More exact calculations of weights, space and material needs are made, and procurement of materials starts.

3.3 Cost estimation

The costs of submitting a PDO/PIO are estimated. An estimate must take project uncertainties into account. The costs are therefore estimated within an interval with a certain degree of confidence. More detailed engineering is required to achieve greater certainty in the estimates. There will always be balancing of considerations as to how certain the estimates need to be to form the basis for a decision.

For example, a project can be estimated as costing NOK 100 +-20% within an 80% confidence interval. This means that if we implement such a project many times, in 8 out of 10 cases (80%) the costs will be between NOK 80 and 120.

The guidelines for PDOs/PIOs state that the operator must present an unbiased estimate that is estimated with reasonable certainty. To illuminate the uncertainties around this estimate, estimates with a 10/90 and 90/10 confidence level must also be presented. These estimates indicate what the project will cost in the 10% best and 10% worst outcomes of the sample space.

3.4 Contract types

A project can be divided up in several different ways. The degree of follow-up work on the part of the operator and contractor will vary, depending on the type of contract chosen.

The parts of a project that are included in one and the same contract will vary from project to project and operator to operator.

Table 3.3. Normal main activities included in contracts for offshore projects (English/Norwegian).

	English	Norsk
E	Engineering	Prosjektering
P	Procurement	Innkjøp
C	Construction	Konstruksjon
I	Installation	Installasjon
C	Commissioning	Uttesting
H	Hook up	Sammenstilling
F	Fabrication	Fabrikasjon

Putting together different parts of a project into one single contract (total contract) entails that one primary supplier will handle the interfaces between the various deliveries. One of the advantages of this type of contact is that it is simpler to have overlapping activities. The contractor can then e.g. determine independently how much engineering needs to be completed before construction can start and procurement of equipment and bulk materials should be initiated.

An important purpose of the Norsok process (from the first half of the 1990s), was e.g. to focus on the possibilities of reducing implementation time in projects and standardising requirements. Design-build contracts became an important step in achieving this. In the time following Norsok, design-build contracts in various forms have been the dominant contract type on the Norwegian shelf. However, there have been some recent examples that indicate that the industry sees advantages of returning to use of more divided contracts. This is so that they can govern when to start activities, as well as to better utilise the strongest sides of the various suppliers.

EPCI contracts are currently commonly used for pipelines, cables and subsea installations. One contractor is assigned overall responsibility from engineering to installation. This contract type is less common for platform contracts since installation is a highly plan-sensitive activity. Installation on the Norwegian shelf is only possible during a brief weather window in the spring-summer seasons. The operator often wants to be in charge of this. Installation vessels are often a scarce resource, and if installation does not take place as planned, delays may become considerable.

EPCH contracts are very frequently used for platforms on the Norwegian shelf. The contractor will normally coordinate the various parts of the work so that construction, for example, can start before engineering is completed. This facilitates e.g. good possibilities for procurement of equipment and bulk material at the optimal time. This entails a potential for reducing the project's overall implementation time.

Changes will normally occur during a contract. How they are handled in a specific contract type must be clearly defined in advance between the operator and contractor.

In certain cases, installation can also be included in the contract. This means that the supplier is also responsible for installation out on the field.

Dividing the contract into two parts where one part is engineering and one part is construction leads to more interfaces for the operator, but also leads to the operator having more control over the project. By dividing the project in this manner, the operator will have a greater possibility of choosing the best supplier for engineering and the best supplier for construction and fabrication. In this connection, it is important to achieve good communication between the EP and FC contractors.

There are many different types of compensation, all of which distribute risk between the operator and supplier in different ways. There are three main types of compensation used for projects on the Norwegian shelf:

1. With a fixed-price contract, the cost of the project is negotiated before the contract is signed. All implementation risk is then placed on the suppliers. With this type of contract, the operator can generally use less resources for cost follow-up since the cost is already determined. The disadvantage of this contract type is that it provides little opportunity for changes. If the operator wishes to make changes along the way, they often turn out to be time-consuming and costly.
2. This contract type is the most common on the Norwegian shelf. Rates and norms are negotiated to be used in calculating the project costs. The customer is responsible for the scope of the project and therefore assumes the risk associated with changes and developments in the project. The supplier is responsible for the rates and norms stipulated in the contract, this entails that the supplier must assume the risk related to efficiency and productivity.
3. With this type of the contact the supplier is paid by the hour. The operator then assumes risk related to productivity, in addition to risk related to the work scope.

3.5 Cost development in projects on the Norwegian shelf

Below is a list of projects under development as presented in the 2013 fiscal budget (ref. (8)). Looking at all projects, the increase in relation to PDO/PIO is more than NOK 49 billion. This indicates that projects on the Norwegian shelf in recent years have generally become more expensive than the unbiased estimate submitted in the PDOs/PIOs.

Table 3.1 Cost changes for projects with an approved PDO between 2007 and 2012. The table is from Storting Proposition 1 S (2012-2013). The figures may deviate somewhat from what follows in the further review due to project development in the past year.

Project	PDO/PIO approved	PDO/PIO estimate	New estimates	Change	Change %
Atla	2011	1 382	1 382	0	0%
Brynhild	2011	4 227	4 579	352	8%
Edvard Grieg	2012	24 205	24 205	0	0%
Ekofisk Sør	2011	28 022	27 237	-785	-3%
Eldfisk II	2011	37 987	37 893	-94	0%
Gaupe	2010	2 828	2 376	-453	-16%
Goliat	2009	30 942	37 142	6 200	20%
Gudrun	2010	20 592	18 976	-1 616	-8%
Hyme	2011	4 593	4 780	187	4%
Jette	2012	2 590	2 909	319	12%
Kårstø Expansion Project 2010	2008	6 675	6 297	-378	-6%
Knarr	2011	11 437	11 527	90	1%
Martin Linge	2012	25 641	25 641	0	0%
Marulk	2010	4 162	4 476	314	8%
Oselvar	2009	4 937	5 120	183	4%
Skarv	2007	35 632	47 162	11 530	32%
Skuld	2012	9 895	10 147	253	3%
Stjerne	2011	5 263	4 976	-287	-5%
Valemon	2011	26 329	26 880	551	2%
Valhall Redevelopment	2007	25 163	46 727	21 564	86%
Vigdis Nordøst	2011	4 194	4 467	273	7%
Visund Sør	2011	5 296	5 208	-88	-2%
Yme	2007	4 894	14 114	9 220	188%
Åsgard Compression	2012	15 661	17 693	2 031	13%
Total		342 547	391 914	49 366	14%

The selection of projects assessed in this report represent a large part of the changes during the period. Together, Yme, Skarv and Valhall Redevelopment represent 86% of the changes. Gjøa and Tyrihans differ from the other projects as there were only minor changes as regards costs and the start-up date.

Table 3.2 Cost changes for Gjøa and Tyrihans

Project	PDO/PIO approved	PDO/PIO estimate	New estimates	Change	Change %
Gjøa	2007	31 239	35 135	3 896	12%
Tyrihans	2005	14 059	16 627	2 568	18%
Total		45 298	51 762	6 464	14%

Adding a range of uncertainty in the PDO estimates which, according to the authorities' PDO guidelines, must be estimated with reasonable certainty, reveals a more differentiated picture. By using an uncertainty range of 20%, which is commonly used by operators at the time of PDO/PIO submission, only three of the projects are outside the estimated costs submitted in the PDO/PIO.

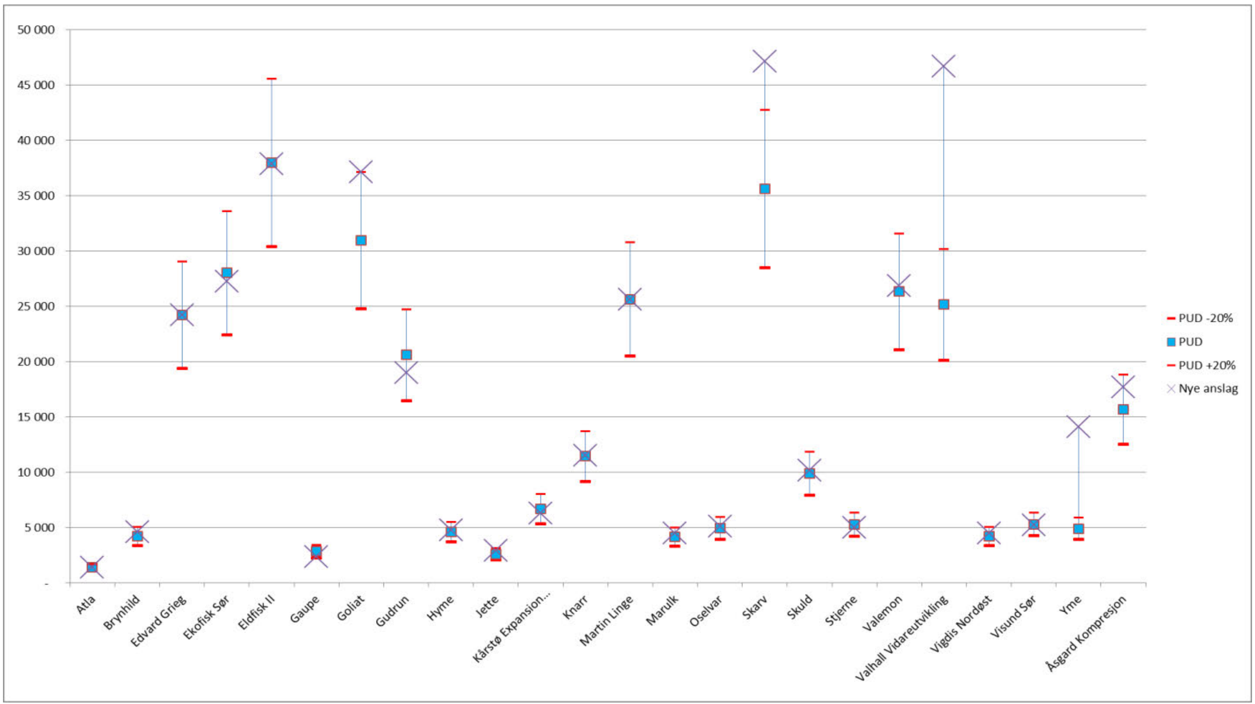


Figure 3.2 Cost estimate in PDO with uncertainty range and cost development

It also becomes clear that a few projects represent the majority of the change in relation to PDO/PIO estimates. At the same time, very few end up with final costs below the unbiased estimate. Overall, this results in the substantial total change described in the 2013 fiscal budget.

3.6 Cost development in major international projects

Research in implementation of major projects within other industry branches (transport sector, defence projects, etc.) generally shows that major projects frequently experience considerable cost overruns and delays (ref. 12).

Overruns in major oil and gas projects are also a challenge internationally. The EY auditing and consulting company has carried out an analysis of the 20 largest upstream investment projects within the oil and gas industry that were recently approved for development (ref 9). The analysis shows that, on average, these projects have experienced overruns of 65 per cent. The overruns for these projects total USD 76 billion, or about NOK 440 billion. This results in average overruns of about NOK 22 billion per project.

EY's study (ref. 9) generally focuses on projects with investment budgets exceeding USD 1 billion (357 projects) within oil and gas activities (LNG, pipeline projects, refining and upstream). It shows that a substantial number of the projects experience major cost overruns and delays. Of the 357 projects included in the study, updated cost estimates have been acquired for 194 of the projects. Of these, cost overruns are reported in 57% of the projects. Of the same 357 projects, information on project progress has been received from 227 projects, of which 64% report delays. Cost overruns and delays have been observed within all types of oil and gas projects, but upstream projects have the highest percentage.

The study also geographically distributes the projects in the areas Africa, Asia/Pacific Ocean, Europe, Middle East and America. The percentage of projects that experience cost overruns and delays is relatively similar for all regions.

Another study carried out by IPA (Independent Project Analysis) ref. (10), concludes that 22% of major oil and gas projects (with investment costs exceeding USD 1 billion) succeed with project implementation. In this study, a project will fail if either the cost growth is higher than 25%, cost growth is higher than 25% of the industry average, implementation time is exceeded by 25%, implementation time is more than 50% of the average in the industry or if major and lasting production problems are experienced in the first two years following start-up. All major projects in the study have low success rates. The oil and gas projects, with a success rate of 22%, have the worst result. The corresponding success rate for all mega-projects regardless of industry is 35%, while all projects regardless of size have a success rate of just over 50%.

3.7 Investment Committee

The Investment Committee was appointed by the Ministry of Petroleum and Energy on 29 August 1998 to analyse investment development on the continental shelf on the basis of major cost overruns in several projects. The Committee's report is the most recent and most extensive analysis of cost overruns on the Norwegian shelf, with a review of 13 of the projects approved by the authorities in the period 1994 – 1998. The Committee highlights four main causes of cost overruns for the projects in the report:

1. ***Decision basis, budget, risk understanding***

"The Committee believes the majority of PDO estimates from the period have been unrealistic for reasons that can be attributed to underlying factors that distinguished the period. Facilitation of the decision basis and decision process was often characterised by exaggerated optimism on the basis of positive trends, general unrealistic ambitions regarding significant further improvements and a deficient understanding of the uncertainty in fragile project maturing and introduction of new elements. A significant part of the cost overruns must be attributed to these general and often contributory reasons for unrealistic budgeting."

2. ***Drilling and completion***

"Drilling and completion of production and injection wells accounts for one-third of the overall cost increase. In the Committee's opinion, this striking factor is primarily related to the operators' insufficient detailed planning of the drilling and completion operations when preparing the PDO. All operators have noted reservoir complexity and technologically advanced wells as important characteristics in the drilling operations… The large number of subsea wells in the projects from the period have resulted in a considerable demand for mobile drilling rigs. Nearly all rig capacity that meets the quality requirements for the Norwegian continental shelf has been used. In this situation, the industry has struggled to maintain a sufficiently high and steady level of expertise. The strong demand has resulted in unusually high rates, also for rigs that must eventually be considered older, which has contributed to the cost increase."

3. ***Technology***

"A technology shift has taken place through the projects in the period, particularly with regard to production drilling and well completion and floating production facilities with subsea wells. The implementation of new technology has introduced considerable uncertainty factors which have not been sufficiently noted in budgeting and implementation of the projects. This particularly applies within the drilling and floaters areas" … "several projects experienced challenges with deliveries from new suppliers to the offshore industry, the shipyards. Several hulls were delivered to hook-up workshops in Norway with a considerable scope of outstanding work. This was caused by deficient qualification of these suppliers, underestimating follow-up needs, problems in applying the offshore industry's change mechanisms in another industry and a failure in the shipyards' understanding of complexity, quality requirements and applicable regulations, as well as in their ability to deliver. The

players thus underestimated the problems associated with exploiting the advantages that were presumably entailed by use of shipyards."

4. Project implementation

The project implementation in the relevant projects is characterised by a short project implementation time where the time in both the phase prior to start-up of the project and during the actual project has been reduced. A number of the elements that have contributed to the improvements have, however, also contributed to the overruns… there has been a pronounced transition during this period from an implementation model with many individual contracts to the full-range deliveries. The suppliers have had experience with the individual elements in these contracts, but not with the total project management which was previously the operator's responsibility. There has been no special experience transfer from operator to supplier in this area, and there is no doubt that the suppliers have experienced problems in implementing the overall deliveries as efficiently as assumed… as regards activity level, the indications are that the activity level has been significant for the cost increase. It is probable that the basis for the cost increase was laid early in the project, and this was amplified by the fact that expertise and resource scarcity has made it difficult for the operators and suppliers to implement the projects as efficiently as possible."

The quotes were obtained from the Summary in the Committee's report NOU 1999:11 "Analyse av investeringsutviklingen på kontinentalsokkelen" *<Analysis of investment development on the continental shelf – Trans.>*.

4. Project review

This chapter contains a review of each project. The review emphasises development in costs and implementation time compared with the plans in the PDO, causes of the development, as well as potential lessons learned from the projects. The review is mainly based on information received from the operators both in the form of written replies to the NPD's requests, as well as in meetings with the NPD.

4.1 Gjøa

4.1.1 Project description

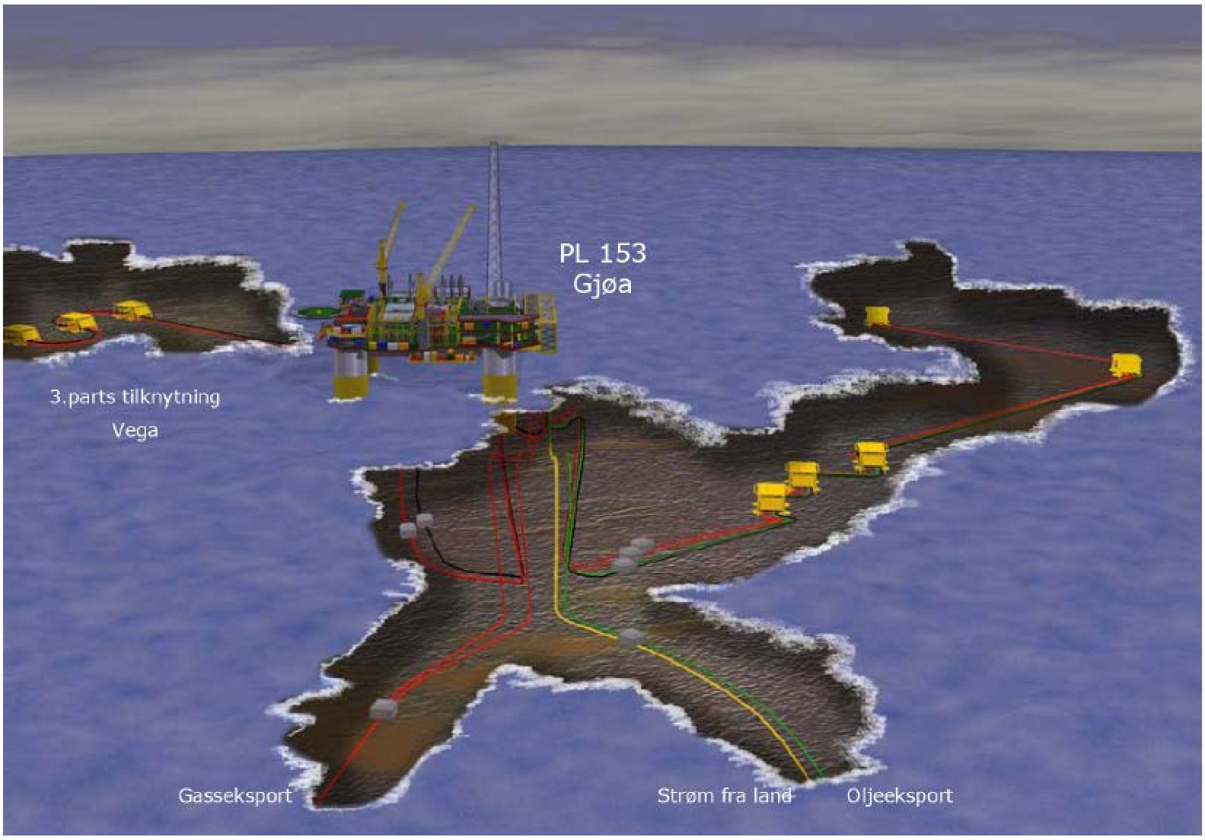
Gjøa is located in blocks 35/9 and 36/7, approx. 65 km southwest of Florø, 70 km northeast of Troll B and 80 km northeast of Kvitebjørn. Gjøa is located entirely in production licence 153.

Statoil was the operator in the development phase, while Gaz de France is the operator in the operations phase.

In the PDO, recoverable reserves were estimated at 13.2 MSm^3 oil and condensate and 39.7 GSm^3 gas.

The field is developed with a semi-submersible production platform. Four subsea templates with a total of 13 wells will be connected to the production platform. The Gjøa facility will receive most of its power supply from shore. The Vega and Vega Sør fields are tied in to the Gjøa facility. Gjøa is produced with natural depressurisation. Stabilised oil is exported by pipeline to Troll oljerør II <*Troll Oil Pipeline II – Trans.*> and on to Mongstad. Rich gas is exported by pipeline to St. Fergus via the FLAGS pipeline system.

Licensees June 2013	
GDF Suez E&P Norge AS	30%
Petoro AS	30%
Statoil Petroleum AS	20%
A/S Norske Shell	12%
RWE Dea Norge AS	8%



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3. parts tilknytning Vega – Third party tie-in Vega
Gasseksport – Gas export
Strøm fra land – Power from shore
Oljeeksport – Oil export

Figure 4.1 Gjøa development concept

4.1.2 Brief description and status

The application for development and operation of Gjøa was submitted to the MPE on 15 December 2006 and approved by the King in Council on 11 May 2007. In the PDO, Gjøa's production start date was in October 2010, and Gjøa has been producing since 7 November 2010.

Some of the key contracts in the project included: Aker Kværner had an EPCI contract for the production facility. FMC had an EPC contract for the subsea facilities, Transocean had contractual responsibility for drilling and completion, ABB had an EPCI contract for the power cable from shore and NKT had an EPC contract for the flexible risers. The production facility's deck was built by Aker Kværner Stord, the living quarters was built by Leirvik Modul Teknologi (EPC) and the jacket was built by Samsung Heavy Industries in South Korea (FC contract).

4.1.3 Development in project costs and implementation time

Table 4.1 Cost development for the Gjøa project from PDO to completion, * Vega's share of the investment estimate approx. NOK 2.2 billion.

	MNOK (2012) PDO	MNOK (2012) Completion 2012	MNOK (2012) increase	% increase
Pre-PDO investments	308	286	-22	-7%
Project personnel and studies	2 988	2 580	-408	-13%
Production platform - topsides	12 336	15 198	2 862	23%
Production platform - hull	1 456	1 129	-327	-22%
Export pipelines	3 882	3 868	-14	0%
Subsea installations	4 282	4 750	468	11%
Drilling and wells	5 987	7 324	1 337	22%
Total *	31 239 *	35 135	3 896	12%

The Gjøa project had a cost increase of NOK 3 307 million compared with the unbiased estimate in the PDO. However, this is still within the PDO estimate's uncertainty margin of 20%. The largest growth was within drilling and wells, as well as within the deck facility (topsides) of the production facility.

Less than 50% of the total budget was covered by contracts entered into before the PDO was submitted.

100% of FEED was completed when the PDO was submitted.

4.1.4 Project experience

Though this project also experienced cost overruns in relation to the expected estimate in the PDO, the project was a success overall. Start-up only one week behind schedule, as well as a final cost of 10% over the estimate in the PDO is within the uncertainty range described in the PDO plans.

The cost for drilling and wells was one of the parts of the project with the largest increase in relation to the estimate in the PDO. An important reason for the increase was that the original estimated number of days needed for drilling and completion of the wells was too optimistic. With a basis in experience from surrounding fields, the estimates for the number of days was increased significantly after the PDO. The increase was also caused by design changes along the way. For example, it was discovered during the process that sand screens had to be installed instead of the original design with liner and oriented perforations. Furthermore, some of the segments to be drilled turned out to be dry. These planned producers therefore had to be plugged before the next well could be drilled, which also led to a cost increase.

The weight of the topsides was increased by 3 000 tonnes compared with the estimate in the PDO. The topsides costs also increased.

Engineering took longer than planned, and greater resources than assumed were needed. It was more difficult than expected for the supplier to recruit sufficient personnel with experience for the project. The engineering work took place partly in Oslo and partly in Mumbai (India). It took time to establish an efficient cooperation between the two engineering offices, which contributed to reduced efficiency in the beginning.

Another cause of the weight increases was that several of the sub-suppliers focused on delivering on time and at the agreed cost, at the expense of maintaining sufficient focus on keeping the weights within the estimates. The weight therefore increased overall, which had to be offset with other measures.

Late in the project it was discovered that many of the fittings being used on the platform were of poorer quality than what was required. Due to too many incoming orders, the sub-supplier of these fittings had increased capacity in its facility by simplifying and thus breaching the set procedure for heat treatment of the pipes for increased strength. This led to impaired quality and all fittings had to be replaced. The replacement task was extensive, and made a considerable contribution to the cost increase for the topsides. Using incentives, a joint willingness to solve the problems was achieved, thus avoiding major delays in the project.

Construction of the jacket in Korea took place in accordance with quality, costs and the schedule. The hull supplier was required to review the engineering work Aker had carried out, and therefore visited with Aker in Oslo prior to starting up to ensure Aker's design and Norwegian standards were completely understood. Pre-fabrication meetings were also held with the supplier and sub-suppliers to ensure the sub-suppliers had a sound understanding of the requirements. This was important to achieve the desired quality and progress.

Having a well-defined work scope, as well as being able to handle changes in an orderly manner was very important to achieve a good result in the construction contract with Samsung. With a well-defined work scope, the operator was able to limit the changes along the way to a minimum. Only one major change was implemented along the way during construction. Despite this, when the change was described in detail and handled in an orderly manner, Samsung was able to complete the delivery on schedule and at a lower cost than the operator had budgeted for.

The operator had a team with both technical and commercial expertise for follow-up of the construction contract with Samsung. They also hired a local company to follow-up specific quality requirements. This company worked at the construction site to inspect the quality of the work being carried out. Prior to the construction, these personnel also visited Norway to familiarise themselves with Norwegian requirements and standards.

After the start-up in November 2010, vibration problems were discovered in the gas export risers. This resulted in significantly lower gas export for 2011 than planned. The riser was replaced around the turn of the year 2011/2012.

According to information from the operator, the partnership was active in the project. Besides active participation and input at licence meetings (TC/MC), as well as joint workshops during the project, the other licensees carried out a PEER review on the operator's geology and reservoir work. "Value Improvements Processes" (VIP) were carried out with participation from the entire licensee group where proposed improvements were included in the project. Shell's system for maturing and project status was adopted and used in the project. In addition to Statoil's internal benchmarks, the other licensees carried out their own, independent benchmarks. Statoil, as the operator during the development phase, had a close cooperation with the operator for the operations phase (GdfSuez) and GdfSuez personnel participated in Statoil's development team. The project had a quality and safety supervisor from Shell.

4.1.5 Lessons from the project

A key lesson from the Gjøa project is the importance of maintaining a focus and control over the uncertainty associated with the reservoir. All licensees agreed at an early stage on the best strategy for draining the resources in the best possible manner. When this decision was made, it was also important that all licensees were able to stand by this decision without having to renegotiate along the way.

The right decisions at the right time are necessary to achieve a successful project. The crucial factor is then being able to prepare a sufficient basis for making these decisions. Having the right personnel in the key disciplines for all phases of a project will ensure this. This is particularly important during an early phase of the project as decisions that are not optimal could delay the project and lead to additional problems along the way.

To ensure the right quality is delivered for construction, it is very important to have a dedicated follow-up team with the correct expertise at the construction site. If external personnel will be used to assist in the follow-up work, it must be ensured that they have extensive knowledge of Norwegian regulations and standards.

Prequalification of relevant suppliers for the project was a key activity in order to succeed with a good project implementation on Gjøa. In general, the operator succeeded by using companies that were able to deliver in accordance with the requirements stipulated by the project. The sub-supper of fittings in the Gjøa project had previously been qualified through the operator's extensive system for prequalification of suppliers. Due to a high activity level, the sub-supplier did not use the same procedures used when the operator carried out the prequalification. This shows that prequalification of suppliers provides no guarantee for good deliveries, but is still an important contribution in reducing project risk.

4.2 Skarv

4.2.1 Project description

Skarv is located in production licences 212, 212B, 262 and 159 and is situated in the Norwegian Sea about halfway between Norne and Heidrun. The development is a unitisation of the 6507/5-1 (Skarv) and 6507/3-3 (Idun) deposits. The 6507/5-3(Snadd) deposit is included in Skarv, but is not yet part of the development. Water depth is between 350 – 450 metres. Recoverable reserves have been estimated at 43.4 GSm^3 gas and 15.5 MSm^3 oil and 5.6 mill. tonnes NGL.

The field is developed with a floating production storage and offloading installation (FPSO). Five subsea templates are tied in to the ship. The oil is buoy-loaded onto tanker ships, while the gas is transported via an 80 km pipeline to Åsgard Transport.

The PDO called for 16 wells, seven oil producers, five gas producers and four gas injectors. The plan is to return the gas injectors to gas producers during the late phase of the field's lifetime.

Licensees June 2013	
Statoil Petroleum AS	36.17%
E.ON E&P Norge AS	28.08%
BP Norge AS	23.84%
PGNiG Norway AS	11.92%

BP is the operator for development and operation of the field.

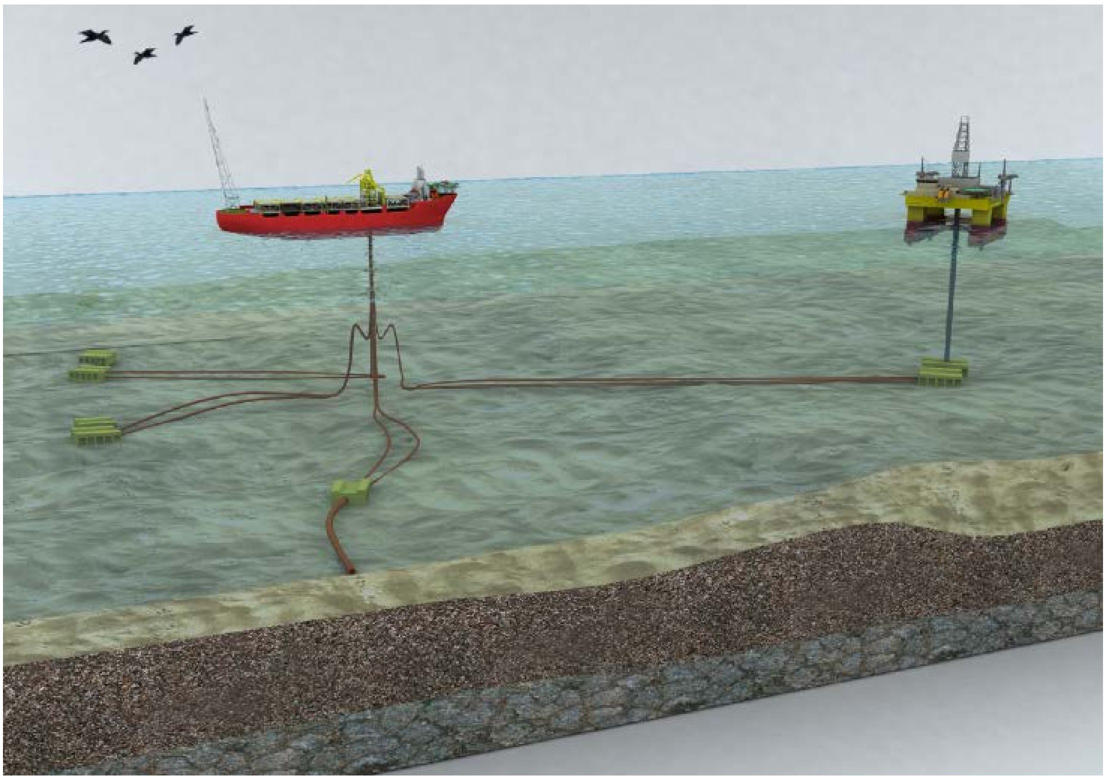

Figure 4.2 Skarv development concept

4.2.2 Brief description and status

The application for development and operation of Skarv was submitted to the MPE on 29 June 2007 and approved by the King in Council on 9 November 2007. The project consisted of two main elements:

- Drilling and wells, which includes lease of a drilling rig and costs of well materials.
- Facilities, which includes a production facility, subsea templates including pipelines and umbilicals and gas export pipelines.

The production facility was manufactured by Samsung in South Korea via an EPC contract, the turret was manufactured by SBM in Singapore as a sub-contract for the production facility. The subsea equipment was built by Vetco.

Skarv has been producing since the turn of the year 2012/2013.

4.2.3 Development in project costs and implementation time

Skarv FPSO was impacted by major cost increases and a very delayed start-up.

Table 4.2 Cost development for the Skarv project from PDO to completion

	MNOK (2012) PDO	MNOK (2012) Completion (June 2013)	MNOK (2012) change	% change
Project Management Team/ Owners' costs	4 987	6 509	1 522	31%
Engineering, procurement & construction management	1 412	1 779	367	26%
FPSO Hull & Living Quarters, Marine operations	3 772	3 485	-287	-8%
FPSO Topsides Fabrication, Integration, Control system & Major Equipment	6 438	9 994	3 556	55%
Turret & Mooring System	2 289	2 765	476	21%
SURF (Subsea Production System, Umbilicals, Risers & Flowlines)	7 391	10 882	3 491	47%
Gas Export Pipeline	2 101	1 721	-380	-18%
Drilling & Completions	6 651	9 248	2 597	39%
Total	35 038	46 379	11 341	32%

Drilling of production wells started in 2010. The production ship was completed and installed on the field in August 2011. Skarv was scheduled to start producing in August 2011, but due to major delays for various reasons, production did not start until the turn of the year 2012/2013.

50% of the total budget was covered by contracts entered into before the PDO was submitted.

59% of FEED was completed when the PDO was submitted.

4.2.4 Project experience

The operator notes deficient follow-up of the turret constructed in Singapore as a main reason for the overruns. One month was set aside in the original plans for mechanical completion at Stord following transport from South Korea before the ship went out to the field. The production ship arrived at Stord according to the plan, and at this time the licensees still maintained the planned production start-up date. However, several leaks were discovered in the turret that needed to be repaired, and the time at Stord was extended to five months. This delay also led to missing the planned weather window for pulling in risers. More faults and deficiencies were discovered during this period in the crane vessels that were be used in connection with the offshore installation. However, a decision was made to keep the installation vessels at the field so they could use “good weather periods” for installation work. However, there were very few of these periods, so pulling in risers during autumn and winter was not possible. Having specialised vessels remaining idle on location is costly.

The operator experienced the greatest challenges during the construction phase in connection with building the FPSO and understanding of Norwegian working environment requirements. Neither the supplier nor operator had a sufficient focus on these requirements at an early stage in the construction phase. Faults and deficiencies were therefore discovered late, and it became challenging and cost-intensive to comply with requirements.

The consequences of the Norwegian Working Environment Act, particularly with regard to use of overtime, were miscalculated in the operator’s early estimates. This led to work performed in Norway becoming more personnel-intensive than assumed in the PDO.

The delayed commissioning was worsened by the operator not being granted an exemption for using 25 reversible beds, as was planned.

Several equipment packages were ordered early due to long delivery times. However, engineering was not sufficiently completed when the equipment was ordered. This led to many changes along the way, which in turn led to cost overruns and delays.

The operator was early in securing a rig for drilling wells. Rates for this new rig were used as a basis for the estimates at an early phase. It turned out after a short while that this rig would not be finished in time, and the operator therefore decided to terminate the contract with the rig supplier. By signing a new contract with another supplier, the operator ensured the wells would be drilled on time. The new contract was more expensive than the original and led to increased drilling costs.

According to information from the operator, the project and project progress were regularly reviewed with the other licensees. Until start-up of the field, all-day workshops were held every three months prior to the technical committee meeting, relating to cost development and further plans. Meetings were also held in the licensee group to address specific technical issues. Technical expertise from the operator, as well as other licensees, participated in these meetings. Internal benchmarking was carried out based on the operator’s project experience data and from use of consultants. There were no personnel from the other licensees in the project organisation.

4.2.5 Lessons from the project

The operator experienced many problems with equipment packages and their quality. Some equipment packages turned out to be so important to follow up with regard to time, quality and cost that they should have been excluded from the contract with the main contractor and followed up directly by the operator. This should have been done from the beginning.

The project experienced major delays and cost overruns due to deficient vessels. In hindsight, this could have been avoided with more time set aside for prequalification of companies and quality control of the vessels prior to entering into the installation contracts.

Putting all marine operations under one contract turned out to be a successful action according to the operator. There are many operations that need to be performed simultaneously, and coordination of these activities is therefore important. The fact that one supplier handled all interfaces between these operations simplified prioritisation of the operations.

Involving operations personnel early in the project is generally very important to achieve a facility which facilitates sound operations. The operator also involved operations personnel in this project, but inadequate continuity of operations personnel during the construction phase was unfortunate. Several of the requests from the operations personnel during the construction phase were therefore not sufficiently anchored in the project management and resulted in some cases of additional work and cost increases.

The project experienced several suppliers being unable to deliver what they had promised. Decisions were therefore made along the way to replace suppliers and terminate some of the contracts. Had this not been done, the delays and cost overruns would have been even greater. According to the operator, the ability to be bold enough to replace suppliers along the way was important for realisation of the project, and was thus an important lesson learned.

During construction of the platform, the operator had many discussions with the contractor regarding change orders. Having a strong commercial team at the construction site thus turned out to be very valuable. Many of the proposed changes were communicated at an early stage and the final cost was far lower than had the change orders been accepted uncritically.

Another lesson is that the accommodation needs in connection with offshore hook-up and completion should have been taken into consideration to a greater extent when the final bed capacity at the ship (FPSO) was determined.

4.3 Tyrihans

4.3.1 Project description

Tyrihans consists of Tyrihans Nord and Tyrihans Sør and is located in blocks 6406/3 and 6407/1. The field is located in the southern part of Haltenbanken, 40 km southeast of Kristin and 170 km from Vikna on the border between Nord-Trøndelag County and Nordland County.

Tyrihans is part of production licences 073, 073B and 091. Statoil is the operator on the field. Total recoverable reserves were estimated at 29 MSm³ oil and 34.8 GSm³ gas in the PDO.

The field is developed with a subsea production facility tied in to Kristin for processing of the wellstream and Åsgard B for import of gas for gas injection.

In the PDO, the plan was for Tyrihans to be developed with 12 wells distributed over five templates. Of these, 11 were scheduled to be drilled by 2011 and one in 2015.

Production started as planned in July 2009.

Licensees June 2013	
Statoil Petroleum AS	58.84%
Total E&P Norge AS	23.15%
Exxon Mobil Exploration & Production Norway AS	11.79%
Eni Norge AS	6.23%

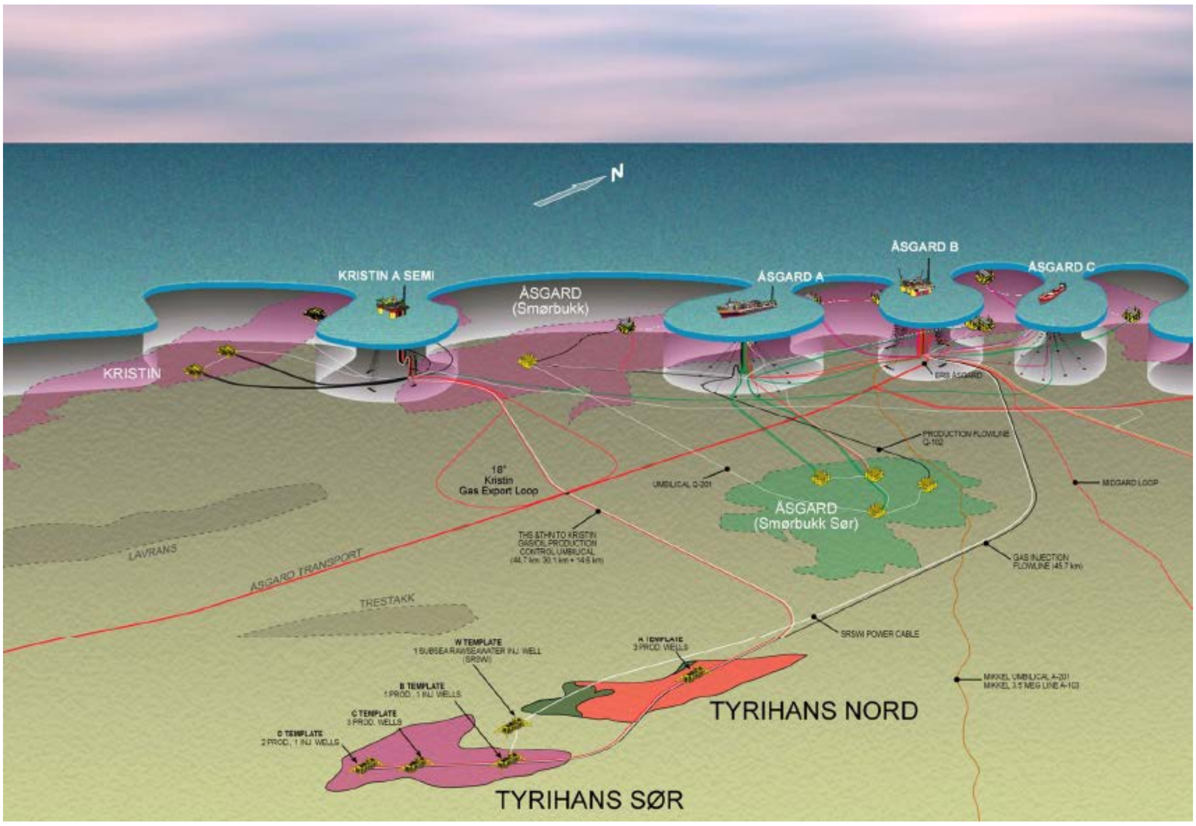

Figure 4.3 Tyrihans development concept

4.3.2 Brief description and status

The application for development and operation of Tyrihans was submitted to the MPE on 11 July 2005 and approved by the King in Council on 2 December 2005.

A large part of the Tyrihans development was based on use of new technology that had to be qualified. This primarily applied to the subsea production systems, where subsea pumps were chosen for injection of raw seawater. This had not previously been done on the Norwegian shelf. Aker was awarded the contract for delivering these pumps. FMC had the EPC contract for the subsea facility. An advanced control and workover system was subject to qualification here. Nexan had a contract for delivery of the umbilical and DEH (direct electrical heating). DEH also required qualification as this was used on pipelines over longer distances than ever before for Tyrihans. Acergy had a contract for installing pipelines. Reinertsen was awarded an EPC contract for necessary modification work on Kristin, and a contract was signed with Transocean Arctic for drilling the wells.

Production started as planned in July 2009 with production from four wells.

4.3.3 Development in project costs and implementation time

Table 4.3 Cost development for the Tyrihans project from PDO to completion

	MNOK (2012) PDO	MNOK (2012) Completion (Sept. 2013)	MNOK (2012) Change	% change
Project management	198	180	-18	-9%
Insurance	218	219	1	0.5%
Modifications Åsgard	390	251	-139	-36%
Modifications Kristin	692	1353	661	96%
Low pressure separator Kristin	468			
Subsea prod. system	5595	7248	1653	30%
Drilling/completion	6498	7377	879	14%
Total	14 059	16 627	2 568	18%

Eleven wells have been drilled in Tyrihans as of September 2013. The PDO estimate assumed that 11 wells would be producing by 2011, i.e. two years after production start-up and that the 12^{th} well would be drilled in 2015. Drilling of the wells has taken somewhat longer than planned. The reason for this was that most of the production wells were optimised with a significantly longer horizontal section in the reservoir which has, however, turned out to be beneficial for the recovery. Tyrihans is now planning to have more wells than assumed in the PDO with an expected higher recovery rate.

An estimated 10% of the total budget was covered by contracts entered into before the PDO was submitted.

100% of FEED was completed upon PDO submission.

4.3.4 Project experience

Important development elements with new technology were identified early on as one of the major risks in the project. To achieve sound project control over these key elements in the development, the operator chose to enter into direct contracts with the suppliers of these equipment components. This e.g. related to deliveries of both subsea pumps for injection of raw seawater and deliveries of pipes with direct heating. In retrospect, this is considered a successful strategy. Furthermore, the scope of work was well-defined in the PDO, which was an important reason why there was only one change after the PDO was approved.

Due to a clearly identified risk picture and a focus on qualification of new technology, this part of the project proceeded as expected. It was more challenging to get all necessary deliveries in place at the right time so as to not inhibit progress.

The cost increase for the subsea facility was mainly caused by an increase in key input factors due to a major increase in the activity level in the period 2005/2006.

For the Kristin modifications, the cost increase was e.g. caused by a significantly higher number of engineering hours than assumed, and that the weights increased to twice the estimate. Initially, it was not assumed that there was major risk associated with implementation of the modification on Kristin. It was not considered to be critical, and the work therefore did not start immediately after the PDO was approved. However, the operator sees in hindsight that the complexity and scope of modification work on Kristin was underestimated and that this work could well have started earlier. Modification work simultaneously with operations on Kristin was more complicated than previously assumed. Efforts required to achieve the planned production start-up contributed to cost increases.

The progress in the engineering was deficient and ended up behind schedule. The modification work therefore started before the drawing basis was sufficiently completed. This e.g. resulted in some work being done in the incorrect order and having to redo the same work. The reason for the problems was primarily that the supplier lacked personnel with sufficient experience to perform the engineering as planned. There was a high activity level in the industry and thus difficult to increase staffing through recruitment or loan of personnel from partners, which was a precondition when entering into contracts.

According to information from the operator, the licensee group was highly involved and contributed in a constructive manner through the licence meetings (TC/MC) both during the planning and implementation phases. A review was carried out during the implementation phase of the scope of work on topsides with associated plans. The entire licensee group participated in this. There were no formal benchmarks in the project beyond assessing the Tyrihans project against others based on the steep price development the project experienced in 2006 and 2007. No personnel from the licensees participated in the operator's project organisation.

4.3.5 Lessons from the project

Tyrihans was a successful project delivered at the expected cost and time. The project experienced some challenges along the way, but was still able to stay within the planned implementation time and budget. The most important lessons learned from the project are:

Implementation of the subsea facility aspect of the project went according to plan. An important success factor was that the implementation took place based on a well-defined scope of work in the PDO. There was only one significant change during the construction phase.

Qualification of new technology was identified early on as one of the largest risks in the project. The operator therefore chose to remain in control of choosing important new technology and entered into direct contracts with suppliers of these technology elements. This was successful and deliveries in these parts of the project took place according to plan.

Understanding and maturing of the scope of work of a modification was underestimated in the project. This should have been assigned greater focus, and it should have been confirmed that the supplier had sufficient personnel resources for good engineering prior to entering into contracts.

Good interaction between the various disciplines in the company is crucial. Operation of the Kristin field in parallel with modification work resulted in challenges along the way with regard to prioritisation of personnel and offshore bed capacity.

4.4 Valhall Redevelopment (Valhall VRD)

4.4.1 Project description

The Valhall field is located in blocks 2/8 and 2/11 in the southernmost part of the Norwegian continental shelf. BP is the operator of the field.

The first platforms on the Valhall field were installed in 1981, and started producing in 1982. The field has subsequently been developed in multiple phases. The first phase consisted of a processing platform, a drilling platform and a living quarters platform. A wellhead platform and a water injection platform were subsequently installed on the field.

Redevelopment of the field comprises installation of a new process platform and extensive modification work on the existing platforms for extended operations and adaptation to future production on the field. The remaining reserves on the field are 41.5 million Sm3 oil, 6.9 billion Sm3 gas and 2.2 million tonnes NGL.

Licensees June 2013	
Hess Norge AS	64.05%
BP Norge AS	35.95%

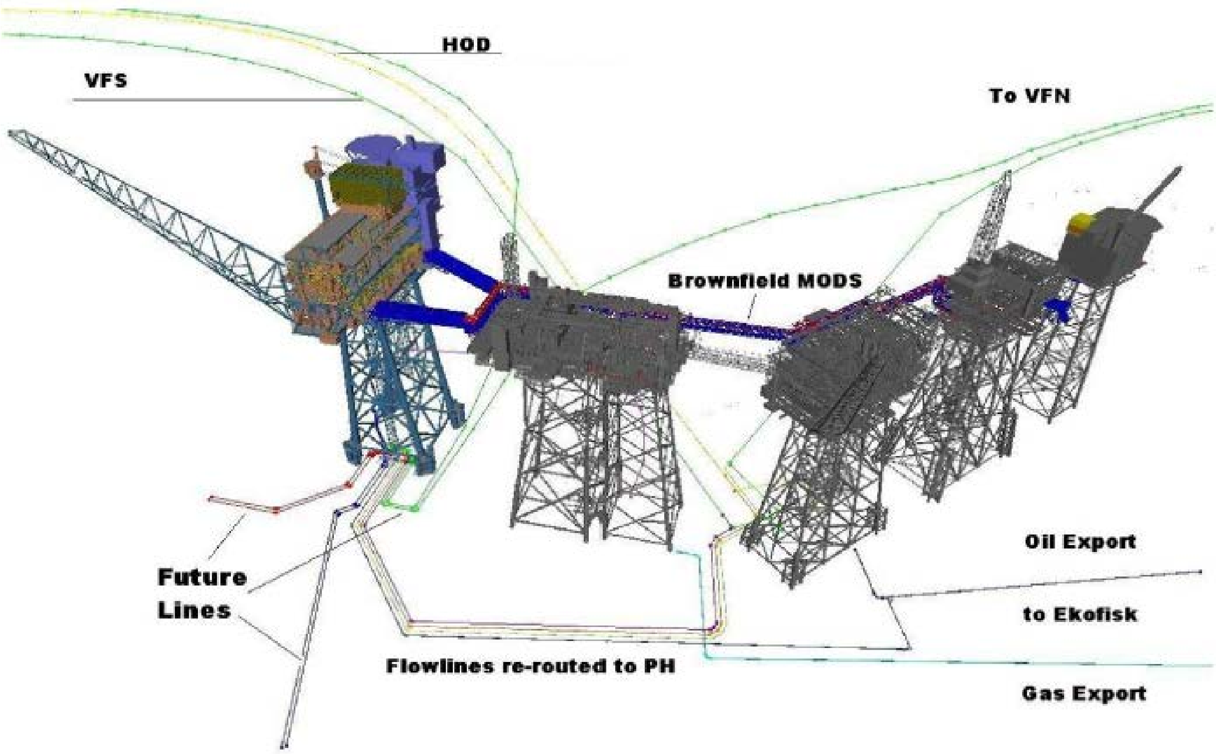

Figure 4.4 Valhall Redevelopment concept

4.4.2 Brief description and status

The application for development and operation of Valhall VRD was submitted on 22 March 2007 and approved by the King in Council on 25 May 2007.

Valhall VRD was first initiated due to subsidence and expiry of the design lifetime of the existing field centre. Furthermore, there was a need for a facility more adapted to the future needs on the field. The project was complex as it included both newbuilds, a considerable modification of the existing facility, as well as new technology in connection with transition to electricity from shore. In addition, it was assumed that the project would be carried out with simultaneous operations at the existing facility. The project consisted of a new steel platform resting on the seabed for production and accommodation, connected by gangway to the existing Valhall centre. The project included a conversion from gas-generated power to power from shore via a DC interconnector from Lista.

Engineering was carried out by Mustang (US). The new platform was mainly built at four different locations: The living quarters module in STL (UK), the jacket at Aker Verdal, construction and hook up of the deck facility at Heerema (Holland). Furthermore, ABB was responsible for power from shore and Subsea7 was responsible for all pipe work. About 45% of the contracts went to Norwegian suppliers.

Following considerable delays and cost overruns, production from the new field centre started on 26 January 2013.

4.4.3 Development in project costs and implementation time

Table 4.4 The cost development for Valhall VRD from PDO (2007) to completion in 2013

	MNOK (2012) PDO	**MNOK (2012) Completion (May 2013)**	**MNOK (2012) Change from PDO**	**% Change from PDO**
Project owners	2 098	2 101	3	0%
Ready for Operations	807	1 000	193	24%
Topsides	5 322	7 691	2 369	45%
Structure	620	689	69	11%
Power from Shore	1 841	2 067	226	12%
Living Quarters	833	1 903	1 070	128%
Safety Automation Systems	440	618	178	40%
Transport and installations	584	552	-32	-5%
Subsea pipelines	642	1 262	620	97%
Brownfield Modifications	1 482	3 137	1 655	112%
Hook Up and Commissioning	720	5 503	4 783	664%
Project Handover		567	567	
Un-Allocated provision		-2 205	-2 205	
TOTAL	15 391	24 887	9 496	62%
Well costs Valhall Redevelopment	3 277	13 986	10 709	327%

The expected start-up in the PDO was November 2010, i.e. a project implementation time of three years and eight months. However, the actual start-up was in January 2013 which results in a total project implementation of five years and nine months. The project was therefore two years and one month delayed in relation to expected start-up in the PDO. The field was shut down for six months in connection with hook up and commissioning of VRD. The planned shutdown in the PDO was three months.

40% of the total budget was covered by contracts entered into before the PDO was submitted. 100% of FEED was completed when the PDO was submitted.

4.4.4 Project experience

A powerful wave hit the field centre at Valhall in November 2006, causing considerable damage to both the production facility and living quarters platform. Several lifeboats were also torn off the facility. Due to this incident, the operator pushed forward the Valhall VRD plans, and the project was under major pressure to be carried out quickly. The project was therefore schedule-driven from the start. Too little time and too few resources were used in the early phase of the project. This led to underestimating dimensions and the weight of the new platform, which was first discovered late in the detail engineering phase. For example, in FEED it was concluded that the platform could be lifted in place in two lifts. Late in the detail engineering phase this was changed to five lifts, which entailed completely different requirements for time and resource use in the hook up and commissioning phase than previously assumed. Another indication that sufficient time was not allocated in the early engineering phase was that a very high number of change orders were initiated during the implementation phase of the project.

The results of a new Valhall reservoir review were also published in the early phase of the project (late 2006). This concluded that the future potential at the field was far smaller than previously assumed. Consequently, Valhall VRD should, based on this, have been subject to an audit both with regard to dimensions and thet design lifetime it was constructed for. However, it was considered that there was not enough time for this, and the plans were therefore continued as they were.

Valhall VRD was designed for a 40-year lifetime as a long production period was originally expected. A 40-year lifetime generally sets higher requirements for material qualities than is the case for a 25-year design lifetime. These materials are more expensive, and some areas require more special expertise for processing in the construction phase. A far tighter market than assumed in the PDO resulted in the project experiencing a general scarcity of expertise. This was particularly evident in areas where special expertise was required. For example, there was a lack of qualified welders that could weld titanium. It was challenging for the suppliers to deliver equipment with sufficient quality. A tight market in combination with special design requirements therefore contributed to cost increases, quality issues and delays.

Though the operator chose many experienced and recognised equipment suppliers, there was a high degree of flaws and inadequacies in many equipment packages. This was in part caused by deficient quality follow-up of the sub-suppliers. The quality inadequacies were discovered late, and entailed correction work and detailed mechanical completion, which in turn impacted final commissioning and start-up.

The company responsible for construction of the new living quarters module went bankrupt before the work was completed. BP then had to go in and secure operations until completion. This was both resource-intensive and costly for the project.

The challenge of offshore hook up and commissioning/start-up simultaneously with operation of existing facilities was underestimated in the PDO. Simultaneous operations also made all necessary modification work on existing facilities considerably more challenging than assumed in the PDO. Prioritisation of the limited bed capacity became a source of continuous discussion between the project and operations organisation. Use of a flotel that was not permanently anchored contributed further complications. This was far more weather-sensitive than a permanently anchored flotel and resulted in the flotel being disconnected for large parts of the time. Completion of the project therefore took longer than estimated.

The increase in well costs is caused by development in reservoir understanding and a much greater need for wells than assumed in the PDO. The costs associated with drilling and completion of the individual wells was also higher than expected.

According to information from the operator, frequent updates were provided with reviews of the project status in the partnership. Formally, this took place in the quarterly licence meetings (TC, MC). The partnership also supported the work by making the companies' experts available to the project prior to decision points during the project. The operator carried out a benchmark of the project based on project experience data, as well as using external consultants. Many senior personnel from Hess participated in the project organisation, e.g. as "PH Offshore Delivery managers" and "Hook Up and Commissioning managers".

4.4.5 Lessons from the project

Too little time was spent at the early phase of the project. The project should have incorporated the new reservoir information and conducted a new design review which could have entailed changes in the topsides weight, size, requirements for design lifetime, number of change orders along the way and offshore hook up. The fact that the project was driven by an implementation plan from the start was unfortunate and had major consequences in the further project implementation.

Follow-up of quality in large equipment packages was inadequate. The lesson learned is that the operator should have had a more direct supervision of fabrication of the large equipment packages, including the work from the sub-suppliers.

The challenges in connection with modification work, hook up, completion and start-up of new facilities, in parallel with maintaining operations of existing facilities, was underestimated. This was very complex and the need for offshore bed capacity was underestimated.

4.5 Yme

4.5.1 Project description

Yme is located in blocks 9/2 and 9/5 and is situated approx. 100 km from the Norwegian coast. Water depths at Yme are between 77-93 metres. Yme was originally developed and operated by Statoil up to 2001 when production ceased. The plan was for Yme to be the first field to be reopened on the Norwegian shelf.

Talisman is the operator of the field.

The licensees planned to develop Yme with a mobile production facility with storage. This is the same concept used on the Siri field in the Danish sector. In principle, this is a jack-up platform over a storage tank on the seabed.

The Yme PDO called for a development with 12 wells – seven producers and five injectors. The recoverable reserves are 14.1 million Sm3 oil. Planned production start was in February 2009.

Licensees June 2013	
Talisman Energy Norge AS	60%
Lotos Exploration and Production Norge AS	20%
Wintershall Norge AS	10%
Norske AEDC A/S	10%

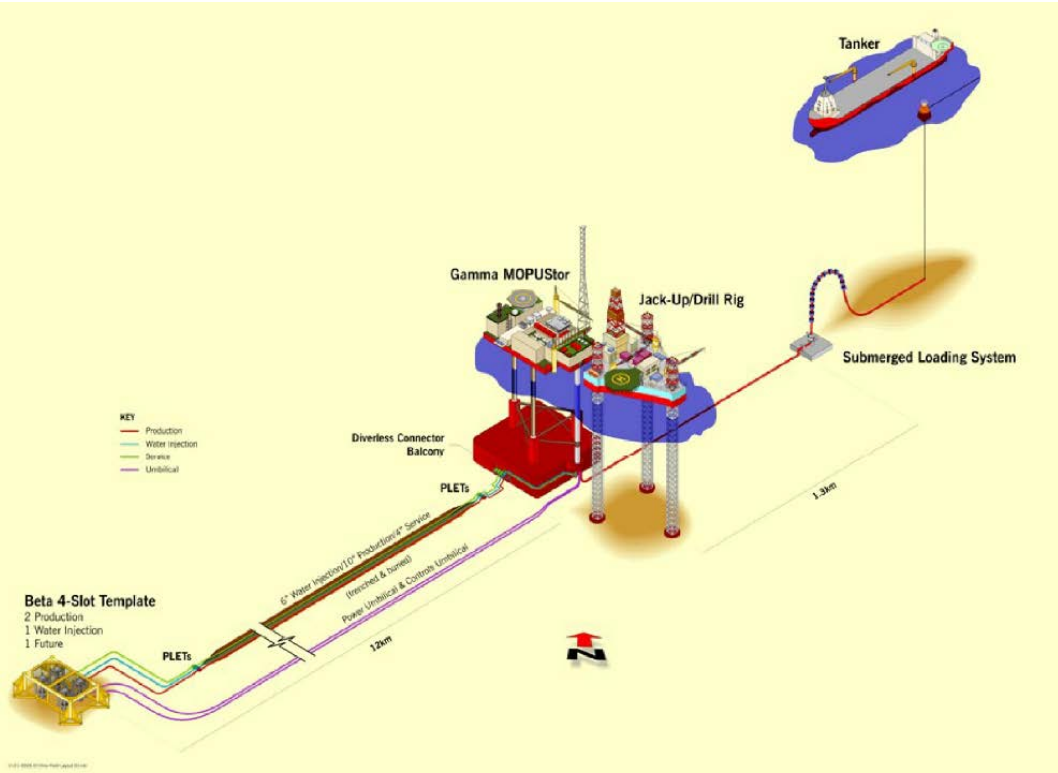

Figure 4.5 Yme development concept

4.5.2 Brief description and status

The application for development and operation of Yme re-development was submitted to the MPE on 9 January 2007 and approved by the Government on 11 May 2007. The project consisted of three main elements:

- Drilling/completion of production and injection wells
- Subsea production facilities, including pipelines and umbilicals
- Construction of a leased mobile production unit with storage (MOPU)

For the MOPU, an EPCIC contract was signed with Single Buoy Moorings Inc. (SBM), which would also be the owners of the facility. The Yme licensees were then to pay rent to SBM under a so-called Bareboat Charter agreement throughout the field's lifetime.

The storage tank was installed on the field in the summer of 2008, followed by start-up of drilling and well completion. The subsea production facility, pipelines and umbilicals were completed in 2009 according to schedule. As regards the MOPU, however, it was installed offshore almost three years later than planned – in the summer of 2011. Significant faults and defects were identified on the MOPU in parallel with the installation offshore. This caused an increase in the completion work offshore and the MOPU delays continued. In July 2012, the operator decided to remove personnel from the MOPU due to the discovery of significant structural design faults, in addition to cracks in the foundation which fastened the MOPU to the storage tank on the seabed. In December 2012, the owner, SBM, decided to scrap MOPU. Therefore, the project as described in the 2007 PDO will never be realised. On this basis, the licensees have applied to the Ministry of Petroleum and Energy (MPE) for approval of deviations from the PDO in order to replace the MOPU with an alternative production facility.

4.5.3 Development in project costs and implementation time

	MNOK 2012 at PDO	MNOK 2012 Dec. 2012	MNOK 2012 increase	% increase
Wells	3076	4299	1223	+40%
Subsea facility	1159	1350	192	17%
Mobilisation and insuring facilities	209	3595	3386	1620%
Project management	450	2315	1865	414%
Total	4894	11558	6664	136%

Table 4.5 Cost development for the Yme project from PDO to cessation

An additional production well was drilled compared with the number of production wells described in the PDO. The planned wells were somewhat more expensive due to the drilling of extra sidetracks to adjust for coal formations that were encountered. Moreover, the cost estimate in the PDO had a limited contingency for dealing with unforeseen incidents.

Including such a contingency is common practice when estimating costs, and the drilling cost estimate was therefore rather optimistic.

The increase in "Mobilisation & insuring facilities" is linked to direct financial contributions to SBM during the course of the construction phase in order to enhance progress and quality. These were either direct intervention payments from the operator/licensees or payments pursuant to "Side Agreements" to the contract negotiated because interim progress and deliveries were not in accordance with the main contract. These factors were not incorporated in the PDO assumptions and were not included in the cost estimate. Therefore, this portion of the costs was estimated at a relatively small amount in the PDO.

The cost development in Project management is also linked to the fact that the operator identified an increased need for own follow-up during the construction process, as well as that the duration of the project became much longer than estimated in the PDO. This caused an increase in the operator's project follow-up costs.

The total project implementation from start-up of detail engineering to production start was estimated as two years and four months in the PDO. Six years and three months into the project, the licensees decided to halt the project even though it was not completed.

About 2% of the total budget was covered by contracts entered into before PDO submission.

Large parts of the necessary FEED documentation were not complete when the PDO was submitted.

4.5.4 Project experience

Drilling/completion of the subsea facilities was completed without major time and cost overruns. Therefore, the further description of project experience will focus on the design and construction of the MOPU production unit. It was this part of the project that caused substantial additional work, delays and cost overruns.

Hindsight reveals some crucial errors in judgement in the important early phase of the project. The project was considered to be economically marginal, and it could only become financially robust through a development with little extra cost exposure in the early phase. In terms of value, it was considered better to distribute the costs over the field's lifetime. The economic lifetime of the project was also very uncertain, and the licensees therefore decided in the early screening phase to base the development solution selection on a leased concept. This thus became a normative assumption for further realisation of the project.

The operating company generally had little development experience and had not yet implemented a good internal decision system with sufficient quality assurance and maturing of projects up to final project approval, in line with the established industry standards in this area. While the operator had involved Norwegian employees with development experience from other projects on the Norwegian shelf in the Yme project, the operator only had experience from developments in the UK sector going back to 2003, and no development experience as operator on the Norwegian shelf. A leasing concept with a lump sum EPCIC contract therefore appeared attractive, as the responsibility under the contract for the entire project implementation, from engineering, procurement, building the installation to commissioning, rested with the contractor.

In general, there were few bidders in the tender process. In practice, SBM emerged as the only real candidate. After a review of all bidders, the others were either considered to be unqualified or were eliminated from the list for other reasons.

The possibility of carrying out well intervention was an important criterion for selecting the development solution. SBM's MOPU solution would provide both "dry" wellheads and oil storage, and was thus regarded as being more attractive than the other leasing options. SBM owned Gusto engineering, the developer of the MOPU concept. This concept had also been used by Statoil on the Danish Siri field, and was therefore regarded as being well-suited for petroleum activity on the Norwegian shelf as well. SBM was the world's largest operator of FPSOs, and the company also had good HSE statistics. Moreover, the company also had experience with several shipyards in Asia.

Based on this, there was a great deal of confidence that SBM could deliver according to the bid it had submitted, in spite of the fact that SBM also lacked experience in implementing major construction projects entailing building according to Norwegian requirements. Although the licensees had identified the supplier's lack of experience with Norwegian offshore projects as an implementation risk, critical questions surrounding this factor were not granted sufficient weight in the licensees' selection of contractor.

The contract entered into with SBM was characterised by considerable optimism. Far too little consideration was given to the possibility that everything might not go according to plan. SBM owned the facility. The most important incentive SBM had was to complete engineering, procurement, fabrication and construction so that the field could start up and the company could start to collect rental income. Therefore, from the very beginning, the project was driven by the desire to achieve completion at the earliest possible date (schedule-driven). This was a poor point of departure for achieving good project quality. The consequences for the Yme project were insufficient allocation of time for both completion of the FEED phase or detail engineering prior to fabrication. The detail engineering started before the FEED phase was completed, and fabrication and procurement were initiated far too early in relation to completion of detail engineering. In short, this led to a lot of futile fabrication work that had to be done over. This led to schedule delays, cost overruns, and a significant increase in the weight of the facility. The deck facilities on MOPU had an overall weight increase of 39%.

Prior to the PDO, the operator had identified that lack of compliance with Norwegian regulatory requirements and standards could pose an important risk for project implementation. Several measures were therefore instituted in the form of seminars, courses, as well as follow-up of the contractor's engineers with a view toward reducing this risk. However, these measures fell short. A lack of understanding of Norwegian regulations and NORSOK standards was a pervasive problem through the entire construction phase, and was the reason why much of the work had to be done over. This lack of expertise and understanding was a problem both on the part of the contractor as well as subcontractors. More and more nonconformities were uncovered as the production unit was gradually completed. In general, there were nonconformities in all system areas, with a particularly high number within working environment and technical safety. According to the contract form selected, there should, in principle, have been no need for extremely vigilant follow-up by the operator throughout the project. The operator had established a small project follow-up team consisting of experienced Norwegian professionals in Abu Dhabi with the aim of following the MOPU completion process. As more and more nonconformities were uncovered, the operator had to send an increasing number of its own staff and hired personnel to follow up the project. This resulted in higher follow-up costs, as well as uncovering even more nonconformities. One problem was that many nonconformities were discovered at such a late stage that much of the work was already completed. Another problem was the ability to ascertain a correct picture of the scope of these nonconformities. The contract form, with SBM as owner of the facility, restricted the operator's opportunity to carry out inspection, intervention and follow-up of the subcontractors, and to influence the solutions chosen during the process.

According to the contract, potential nonconformities uncovered during the construction phase were to be corrected. Therefore, many of the discussions between operator and contractor related to agreeing on what needed to be corrected. Furthermore, the operator's perception was that the supplier's incentive to complete the delivery would be seriously impaired if they were to cover correction of all of the defects free of charge. Several economic incentives (direct intervention payments to subcontractors, resource support (personnel/equipment/flotel) for the supplier's completion and formalised "side arrangements" to the contract) to improve progress and changes. In retrospect, the conclusion is that these measures were ineffective as regards ensuring both progress and adequate quality, as the incentive schemes themselves quite often resulted in disputes between supplier and operator.

The production facility therefore left the yard in Abu Dhabi, bound for the Rosenberg shipyard, with quite a number of defects. The work that, according to the contract, should have been completed in Abu Dhabi thus had to be completed in Norway, at a substantially higher cost level. The scope of work now also proved to be considerably greater than previously assumed. However, in order to avoid additional delays, a decision was made to put the production facility out on the field before winter set in, even with a considerable number of defects and flaws (approx. 74% completed). Work that should have been completed on land had to be completed offshore, with even higher costs.

In July 2012, the operator made the decision to remove personnel from the MOPU due to the discovery of significant structural flaws and cracks in the foundation that fastened the MOPU legs to the storage tank on the seabed. The MOPU owner (SBM) declared the unit to be scrap in December 2012.

According to the operator, all important decisions in the production licence were processed in ordinary (and extraordinary) committee meetings, and resolutions were made either in the management committee or through License to share (L2S). The frequency of meetings in the licence was ramped up as the challenges in the project unfolded. In an early phase of the project, an exchange of information/experience was carried out between the Yme project and Dong for the purpose of benchmarking costs and the implementation plan for the Yme topside vis-à-vis the Siri topside on the Danish sector. Late in the project, in the spring of 2012, the other licensees called for a project audit. The final report was presented on 10 July 2012, and the operator's comments regarding this were issued on 12 August 2012. The platform had been de-manned at this time.

4.5.5 Lessons from the project

The most important lessons from this project are linked to the decisions made in the early phases of the project. The project got off on the wrong foot, and the remainder of the time since was largely spent on trying to rectify this. The operator is currently working on an in-depth review of the project so as to extract maximum lessons learned. Based on the information the NPD has received, some of the most important lessons are listed below:

1. More work in the early phase of the project
   - Have an internal system in place to ensure maturing and quality towards final project approval
   - Allow sufficient time to complete the FEED phase prior to PDO submission and detail engineering
   - Perform thorough work as regards assessing contractors' quality, experience and expertise
2. Avoid the EPCIC – lease contract form. It would have been better if the operator was the owner of the facility during construction. After completion, the facility could have been sold, if applicable, and then leased back in for the operations phase.
3. Use the contract to its fullest extent in the project implementation. Set the standard early in the project as regards ensuring deliveries in accordance with contract stipulations.
4. Place much greater focus on project follow-up. Ensure own expertise in Norwegian regulations, in addition to project follow-up experience and capacity.

5. The Norwegian Petroleum Directorate's assessments

5.1 Comparative causes of the development

Based on the project review, the NPD has identified deficiencies in the following areas of project implementation. These are regarded as being main causes of the time and cost overruns. The following aspects are key as regards success in implementing major projects:

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

A high level of activity in this period has resulted in a tight market for all of the projects. This has led to a scarcity of resources and expertise, and has driven up prices for all input factors. This has contributed to amplifying the negative effects as regards progress and costs in the project. However, the review also includes examples of projects that have been completed on time and in accordance with cost estimates, in spite of implementation in a much tighter market than was presumed in the PDOs. What these projects have in common is that the aforementioned factors have largely been properly dealt with.
A high activity level means tighter conditions for project implementation and, in the opinion of the NPD, constitutes a contributing cause of the schedule and cost overruns incurred in some of these projects.

Below is the NPD's assessment of this, related to the review of the discussed projects.

The operator's work in the early phase
A conclusion for all of the projects with major time and cost overruns reviewed in this report is that there have been significant deficiencies in the early engineering work. In this context, this means all engineering that takes place prior to the PDO and before procurement and construction start. In this context, it is also a fundamental precondition that the licensees and the operator, in particular, have a good internal decision program for maturing the projects in an early phase. Through such a system, demands will be placed as regards a sufficient level of engineering and cost estimation as the project is gradually matured towards final approval. This will ensure a minimum quality standard for a decision basis for project approval.

Deficiencies and flaws in the early engineering will be transmitted on through the project work. Thorough front end engineering design work is thus essential in succeeding with completing the project on time, according to the cost estimate, and in compliance with quality requirements. Several projects have been driven by a far too ambitious implementation plan from the very start, and have therefore also shortened the time spent on early phase work. For example, this has meant that FEED has not been 100% complete when the PDO was submitted, or that equipment has been ordered and construction work commenced before necessary engineering was completed. In other cases, new information that could have impacted the preconditions for the project has not been taken into account as the project was already well underway. Experience indicates that projects with deficient early phase work have experienced a substantial need for changes along the way in the construction phase. Significant parts of the work have had to be done over, which has resulted in major overruns and delays.

Prequalification of suppliers

For several of the projects with major overruns, the causes can be traced to deficiencies in prequalifying suppliers. In major offshore projects, the operator has no chance of following up all deliveries, and must therefore prioritise which areas should be subjected to operator follow-up. Thorough prequalification of the companies that are to deliver to the project in terms of previous experience (quality, delivery security), financial strength, etc. could reduce the risk of problems along the way, and thus also the need for follow-up. This review shows that the operator, in several cases and to a far too extensive degree, and without necessary verification, has relied on the contractor's ability to deliver according to the requirement specifications, and furthermore, that these contractors also deal with subcontractors that can live up to this. The consequences if this fails is that much of the work must be done over, with detrimental effects on both schedules and costs.

Contract strategy

It is important that the project has a contract strategy that ensures cost-effective progress and quality, including the operator's opportunity for follow-up, verification and corrective measures along the way. The contract strategy should reflect the key risk elements in the project, and should also be viewed in context with the operator's direct follow-up and prequalification of suppliers. The review has shown that the operator should consider taking on a greater direct contract responsibility as regards deliveries of major key equipment packages in the projects.

For many projects, design and build contracts have resulted in both time and cost savings compared with previous sequential contract forms. This contract form will also be important in the future. Use of this contract strategy will be crucial, particularly for many of the smaller operators on the Norwegian shelf. Therefore, in the NPD's opinion, vigilant follow-up of the challenges associated with design and build contracts will be particularly important. This applies particularly to factors associated with the process of selecting contractor/ subcontractors, and requirements related to the operator's follow-up of construction according to quality requirements and Norwegian regulations.

Several of the projects reviewed here contain elements of new technology. However, this has not been identified as a cause of cost overruns or project delays. In the projects reviewed here, central technology qualification elements have been identified early in the process as high-risk elements for the project, and have thus received operator focus. This has led to direct operator follow-up of contracts and technology qualification.

Operator's follow-up of the projects

In the projects reviewed, the NPD does not consider there to be a basis for concluding that there is a direct correlation between the overruns and the geographical location of the fabrication sites. Understanding of NORSOK standards and Norwegian regulatory requirements is a greater challenge in international shipyards compared with those located in Norway. The operator therefore has a special responsibility to follow this up. Conducting courses in Norwegian standards and safety requirements is important, but not sufficient. It must be followed up throughout the entire construction period. In those cases where faults and deficiencies in fabrication are caused by inadequate understanding of NORSOK, this is, in the NPD's assessment, about the operator's deficient follow-up of the construction work in relation to what is specified in the contracts. Correspondingly, it applies to those cases where the cause of overruns is often due to a deficient work quality. A recurring cause of project overruns is deficient deliveries in relation to the contract. This is about inadequate fulfilment of Norwegian standards, as well as inadequacies in relation to other quality requirements in the projects. In the NPD's assessment, this is largely caused by the operating companies lack of personnel with sufficient experience and expertise to follow up the requirements and project progress.

It will be important to find the correct balance between the contractual responsibility assigned to the contractor and the operator's actual opportunities for follow-up. In this case, Yme differs from the others with a "turn-key EPCI contract"» for construction of an installation that would in turn be leased by the operator. In reality, the contractor built its own facility in this case, and it became challenging for the operator to provide sufficient input in the contractor's work during the construction phase. These types of solutions entail very special follow-up challenges, that, in the opinion of the NPD, should be considered carefully before such contracts are signed.

The projects in this review are primarily developments of new fields. However, the Valhall VRD project stands out being a redevelopment project for an operating field. Newbuilds in combination with major modification work at facilities in operation entail special requirements for planning and coordination. Estimation of costs and the time spent on modification work on existing facilities is associated with major uncertainties and is therefore particularly challenging. In the NPD's assessment, it will be particularly important in these types of projects to conduct thorough early phase work which includes detailed planning of the activities. With regard to the fact that redevelopment of operating fields could become relevant on several fields, it will be important to learn from the projects that have been carried out.

5.2 Comparison with factors noted by the Investment Committee

The NPD's summary of the causes of the project development in the five projects reviewed here, is very similar with the causes determined by the Investment Committee in 1998 (see Ch. 4). Then, as now, it was noted that the basis for the cost increases arose at an early stage of the projects. Exaggerated optimism, unrealistic ambitions and inadequate understanding of uncertainty, as well as insufficient time set aside for the planning phase before project start-up, were noted as reasons for this. This largely corresponds with the conclusions in the NPD's review.

Deficient qualification and follow-up of suppliers and sub-suppliers was also noted by the Investment Committee as another important reason for the development. This is also noted in the NPD's review. In 1998, the transition to design and build contracts represented new and inadequate knowledge in the supplier industry, with regard to this being identified as an important cause. Today, 15 years later, it should be expected that the knowledge regarding these issues has improved. However, it appears that several of the projects have experienced troubles with some of the same challenges. Correspondingly, the issues regarding use of traditional shipyards for offshore construction projects have long been known. Our review therefore attributes these issues to the operator's deficient prequalification and follow-up of suppliers.

The industry underwent a technology shift during the period which the Investment Committee examined, particularly within transition to floating solutions and subsea wells. A corresponding shift has not been identified in the projects reviewed here. New technology elements appear to be safeguarded well in the projects. New technology has therefore not been identified as a cause for the overruns with regard to time and costs in the projects reviewed here.

The activity level was also considered to be high during the period which the Investment Committee examined. It was concluded that there were indications that the activity level was significant for the cost increase, but that the main reasons for the increases were other fundamental factors in the project implementation. This corresponds with what the NPD has identified in this review based on the current high activity level.

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