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ABSTRACT

Decommissioning of offshore installations on the Norwegian Continental Shelf (NCS) is not a new industry, but apart from the vast Frigg and Ekofisk I projects, it has seen little activity in the years since the production from oil and gas fields started to decline. However, decommissioning is set to grow steadily in the coming years as more and more fields' running costs surpass their revenues. Cost estimation for decommissioning is a major challenge in the petroleum industry, and is notoriously difficult, due to the great uncertainties concerning the condition of the facility and the scope of work for the project.

As far as the authors are aware, no scientific papers have examined probabilistic modelling for decommissioning cost estimation on the NCS. Cost engineers mostly rely upon historical databases, which some insiders have described as out of date. Also, the uniqueness of each field in the North Sea makes benchmarking challenging. This thesis uses probabilistic modelling to attempt two things:

1. Estimate the decommissioning cost of a facility on the Norwegian Continental Shelf
2. Estimate the decommissioning cost of all infrastructure on the Norwegian Continental Shelf

Using a mostly self-compiled database of installations on the NCS and their associated subsea equipment, cost data for facilities previously decommissioned and those soon to be decommissioned were gathered for use as inputs to a Monte Carlo cost simulation model. The model shows sufficient accuracy to be used for cost estimation in future decommissioning projects.

Besides probabilistic modelling, other approaches to estimating the cost of decommissioning the entirety of Norwegian offshore petroleum infrastructure have been applied: through analysis of operators' Asset Retirement Obligations, and through a comparative analysis of the decommissioning scope in the UK and Norway along with the estimated future decommissioning expenditure in the UK.

In addition, the actual cost to the Norwegian government has been studied, as its direct and indirect ownerships in oil companies entails a higher coverage of the costs than what is apparent.

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We would also like to thank Stig Paulsen and Tore Gabrielsen at Wintershall for providing useful insights.

Interviews have been conducted with several companies and organizations involved in offshore decommissioning. We are extremely grateful for the time they have taken from their schedules to give interviews for this thesis. The insight gained from these interviews has provided a much higher level of knowledge than could have been obtained solely through literature studies.

Last but not at all least, we would like to thank our supervisor Finn Harald Sandberg for his sage advice and contributions. His support has lifted the thesis to a higher level.

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ABBREVIATIONS

ARO	Asset Retirement Obligation
AtoN	Aid to Navigation
BAT	Best Available Technology
BEIS	Department of Business, Energy and Industrial Strategy
BEP	Best Environmental Practice
CALM	Catenary Anchor Leg Mooring
CoP	Cessation of Production
DECC	Department of Energy and Climate Change
EIA	Environmental Impact Assessment
FPSO	Floating Production Storage and Offloading
FPU	Floating Production Unit
FSO	Floating Storage and Offloading
FSU	Floating Storage Unit
GBP	Pounds sterling
HLV	Heavy lift vessel
HSE	Health, Safety and Environment
IOR	Increased Oil Recovery
LAT	Lowest Astronomical Tide
LTI	Lost Time Injury
MDR	Modular Drilling Rig
MGBP	Million Pounds sterling
MNOK	Million Norwegian Kroner
MODU	Mobile Offshore Drilling Unit
MPE	Ministry of Petroleum and Energy
MSF	Module Support Frame
MW	Megawatt
MWA	Mid-Water Arch
NCS	Norwegian Continental Shelf

NOK	Norwegian Kroner
NPD	Norwegian Petroleum Directorate
NPT	Non-Productive Time
NUI	Normally Unmanned Installation
OPEX	Operating expenditure
P&A	Plug and Abandonment
PLEM	Pipeline End Manifold
PLET	Pipeline End Termination
POB	Personnel on Board
PSA	Petroleum Safety Authority
R&D	Research and Development
SIMOPS	Simultaneous operations
SLV	Single Lift Vessel
SSHTV	Semi-Submersible Heavy Transport Vessel
WBS	Work Breakdown Structure
WoW	Waiting on Weather

INTRODUCTION

Problem Background

Several installations on the NCS have exceeded their profitable life cycle or are on the verge of doing so. In accordance with Norwegian laws and regulations, these facilities must be removed unless they meet certain criteria. The scope of removing all installations is considerable and carries significant costs. Cost estimation for decommissioning has proven to be notoriously difficult, due to a vast number of variables and the uniqueness in design of each offshore facility [1].

Wintershall Norge sought to examine which methodologies or approaches could be applied to improve decommissioning cost estimation accuracy. Currently, the industry uses historical data from databases to estimate costs. Probabilistic modelling has not been widely applied thus far but has seen successful application in the plugging and abandonment of wells.

The initial objective of this thesis was an invitation from Wintershall Norge to develop a framework for an estimate of the decommissioning cost of an oil and gas field, to assist Wintershall in improving initial stage cost estimation methodology in decommissioning and to assess the potential for cost reductions in decommissioning in the years to come.

The prime objective of this thesis is to develop a model for early stage cost estimation, to test and evaluate this model and to investigate how decommissioning expenditure can be reduced.

In the review of the relevant literature on decommissioning cost estimation it became clear that no scientific papers have attempted to estimate the cost of the total scope of decommissioning in Norway. A choice was made to expand the model for decommissioning cost estimation, to test it rigorously and, if the model produces results that seem credible, to apply the cost estimation model on the full scope of decommissioning in Norway.

A note from the authors: A number of data files are enclosed in this thesis, showing methods and calculations for inputs. Several additional files have been withheld due to confidentiality. Additional information regarding these files may be given by request to the authors, at runevikane@gmail.com or pdallen00@gmail.com.

Problem Formulation

How can a model for decommissioning cost estimation be developed, how does the model perform, what are the model's predictions on the decommissioning cost of oil and gas fields in Norway and how can the cost of decommissioning be reduced?

Methodology

Data Collection

- Examining publicly available sources: industry reports, news reports, academic papers and journals, presentations from conferences. Lack of available data on decommissioning meant that this part of the work accounted for approximately sixty to seventy percent of total hours.
- Acquiring cost data from operator companies and removal contractors: Extensive efforts were made to initiate a dialogue with oil companies involved in decommissioning. Twenty-three companies or organizations were contacted with requests for cost data under condition of confidentiality and anonymization of data. Three of these agreed to supply cost information, either in the form of detailed estimates prior to decommissioning or actual costs after completion of a project.
- Semi-structured interviews with industry professionals: decommissioning personnel from six of the aforementioned companies and organizations agreed to be interviewed in order to gain insight into the challenges of decommissioning and estimation of its costs. These were conducted in an informal manner to gather opinions on improvement potential for the industry and to provide a first-hand account of decommissioning projects. The interviewees were in executive positions in major petroleum industry companies with extensive experience in decommissioning. The interviews took a semi-structured form, with a list of pre-prepared questions. The

interviews also allowed time for general discussions. The average interview time was two and a half hours.

- Presentations from industry professionals: two presentations were attended – one on decommissioning of a platform and one on plug and abandonment of wells.

Data Analysis

A database was compiled with all information deemed relevant to cost scope in a decommissioning project. Data was examined to look for correlations between physical properties and costs using simple Excel tools.

Metrics for each phase of decommissioning were compiled using average values of cost data. These were in the form of either cost per ton of material, cost per well plugged, cost per pipeline decommissioned, or percentage of total cost. Due to many data sources having dubious reliability, the metrics were provided to industry professionals for verification. Some agreed that some of the numbers were in the correct range, whereas others could not be verified due to confidentiality. These metrics were compared with yearly reports from the UK oil industry and proved to be approximately correct assuming costs are higher in Norway.

Project Scope and Delimitation

As mentioned, there is a lack of publicly available data. Necessary assumptions have been made where no information is available, or where the research required has been beyond the scope of the thesis. Some data has been gathered from the UK petroleum industry, as there is more publicly available information there. This was deemed acceptable as the industries share the same body of water and therefore to an extent share the supply chain, although the UK's industry is more mature. The differences in the two nations' petroleum industries has been accounted for, such as the UK sector's installations being larger in number but smaller in size and water depth, and costs for some parts of decommissioning being lower [2].

THEORETICAL BACKGROUND

The theoretical background has two sections: A section on decommissioning and a section on cost estimation.

Decommissioning

Decommissioning of an offshore hydrocarbon producing facility sees similarities and differences from its installation; the main difference being that a decommissioning project has a generous time frame for completion, whereas time is truly of the essence for installation of a facility, where the strive toward “first oil” drives the project. Legislation states that facilities must be removed entirely but does not dictate when. This is up to the operator. There are grounds for both decommissioning in a near time frame, and for deferring the decommissioning until a later date. Disused facilities with minimal maintenance will be more expensive to decommission at a later date, due to deterioration of facilities, outdated documentation and data, and uncertainty on changes in market conditions and regulations for decommissioning infrastructure. On the other hand, there are incentives to postpone the removal of disused installations to minimize costs. Anticipation of new technology to make decommissioning less costly, or new methods to recover resources previously thought unreachable, may make companies delay the removal of installations [3]. In any case, at some point the cost surpasses the gains from postponing abandonment, and removal must commence.

To illustrate the relative cost of decommissioning, one may look at the Norwegian Petroleum Directorate’s (NPD) yearly reports, where decommissioning costs as a portion of total exploration, development and operation costs are shown for 23 fields in Figure 1 [4].

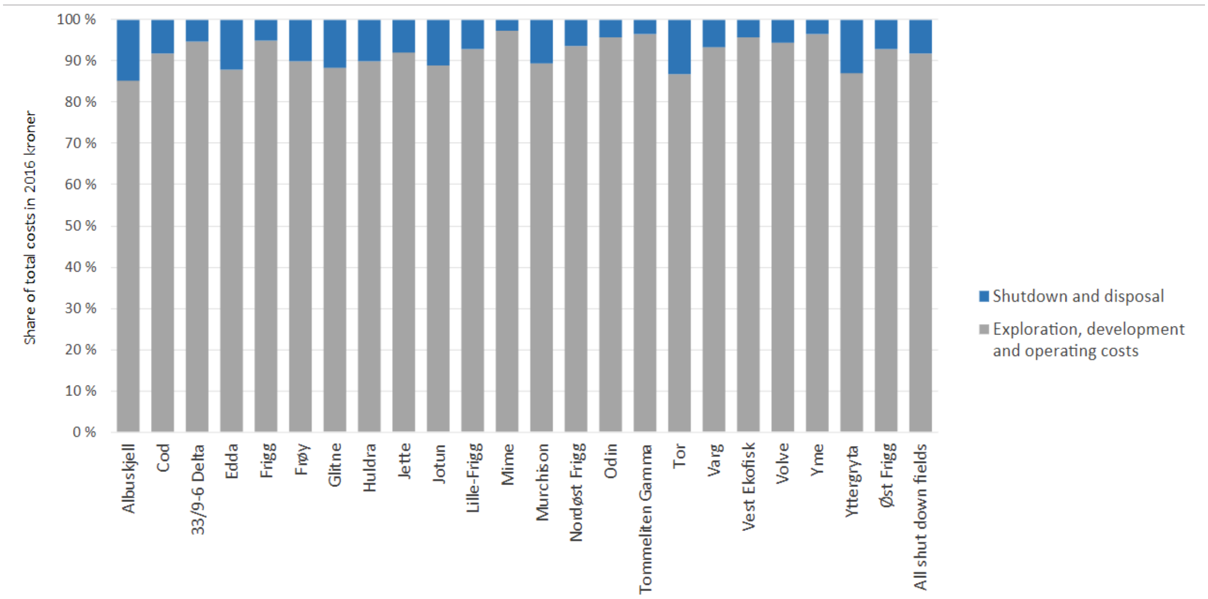


Figure 1: Decommissioning costs as a portion of total field costs [4]

The average cost as a share of total is 8.2 percent. Total expenditure in petroleum activities for the 23 fields above until December 31st 2016 is 428 billion NOK (2016). Total decommissioning costs for these fields are therefore

$$428 \times 8.2\ \% = 35.096$$

billion NOK, or 35.74 billion NOK in 2017 money. There are also figures for total decommissioning expenditure for the years 2007 – 2016, and prognoses for the years from 2017 – 2022 [5]. These show a total of 53.597 billion in decommissioning costs from 2007 – 2016 (5.36 billion on average per year), and an estimated 37.32 billion (6.22 billion on average per year) from 2017 – 2023.

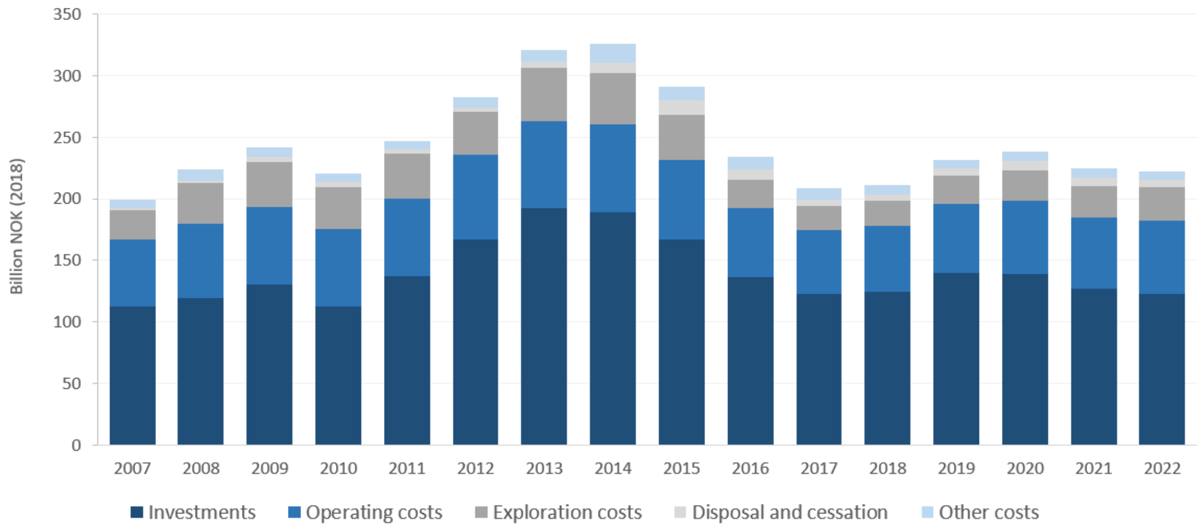


Figure 2: Past and future costs

Factors Influencing the Optimal Timing of Decommissioning

Operators must consider several factors before making the decision to start the decommissioning process. In this section some of these factors will be explained in greater detail.

The operators on the NCS must choose between different projects every year and usually have three options. They can choose to go ahead with the project, postpone the project or abandon the project [6]. Abandoning the project is not an option when it comes to decommissioning, but the other two options apply.

One of the most common approaches used to value and to prioritize between projects is to estimate the Net Present Value (NPV) of different projects and choose the projects that maximize NPV.

NPV is used to find the project with the highest profits but may also be used to find the project with the smallest loss – therefore it may be applied for decommissioning.

The NPV is the present value of the discounted cashflows of a project – the discount rate used by companies is usually their cost of capital. A key issue is whether the company is forced to abandon or postpone other projects to have the capacity to perform decommissioning.

The price of capital differs between the operating companies. One way of estimating a suitable discount rate is using the Capital Asset Pricing Model (CAPM). When the operator is financed by equity and debt in combination, the Weighted Adjusted Cost of Capital (WACCA) method can be used to calculate the average cost of capital [6].

These calculations are the foundation of an estimate of the NPV for a decommissioning project. Decommissioning projects are not optional and must be performed. The only option is to postpone the projects and a key issue is how long these projects will be postponed by rational profit-maximizing owners. Decommissioning projects will be postponed until the estimated annual operating expenses (OPEX) are equal to the discounted benefits from postponing decommissioning cost one more year.

That means it can be rational for the operating companies to continue production even if OPEX exceeds revenues.

There are a lot of variables in this calculation and the operators try to find the exact time when the actual and potential benefits of postponing the decommissioning project is equal to the profit of operating the field further using historical production costs, oil price futures, predictions of future production and estimates of the price of capital.

Other factors that may influence the timing of decommissioning is that the cost of decommissioning may be lower in the future due to new technology. It might be expensive to be an early mover and the benefits from waiting can be significant.

Another factor that may influence decommissioning are the fluctuations of the market price for Heavy Lift Vessels (HLV), Single Lift Vessels (SLV) and the rates for the rigs used to perform some of the plug and abandonment (P&A) of oil and gas wells. The operating companies would ideally prefer to undertake the decommissioning in periods with relatively low demand and thus low rates.

A key issue in the calculations of the NPV of an offshore development is the potential for new discoveries that may increase future profitability. New small to medium scale oil discoveries are usually extracted using existing infrastructure when that is the most profitable option. These potential revenues may be incorporated in the calculations of the NPV of a project.

The theory of real options applies to these problems and gives further insight in the analysis of the optimal time to decommission a field but is beyond the scope of this thesis.

The Decommissioning Process

The following section describes the decommissioning process, divided into work breakdown structures (WBS) used in Oil & Gas UK's *Guidelines on Decommissioning Cost Estimation 2013* [7]

Table 1: Decommissioning WBS

Operator Project Management	Facility Running/Owner's Costs	Wells Abandonment	Facilities/pipelines making safe	Topside Preparation	Topside Removal	Substructure Removal	Onshore Recycling and Disposal	Subsea Infrastructure	Site Remediation	Monitoring

Operator Project Management: This is the first step in a decommissioning project, however it continues until the end of the project when the facility is removed and the seabed is approved clear. It includes stakeholder engagement and decommissioning program preparation, and generally follows the same routines as similar engineering projects.

When the final decommissioning decision is made, the first engineering studies are performed to ascertain the scope of work. This will often involve subcontractors, as early involvement of vendors reduces risk and enables more precise cost estimation [8].

Facility running/owner's costs/Post-CoP OPEX: During the decommissioning process, the installation must still be run, and processes must be maintained. The most expensive of these functions is the running of the drilling facilities and its associated equipment. Other systems to be run include safety mechanisms, accommodation and amenities, processing of remaining production from wells, logistics, power generation, and waste treatment. The cost is usually counted from Cessation of Production (CoP), where wells are no longer producing, but are not yet permanently plugged. As the installation enters the “cold” stage, where excess hydrocarbons in platform equipment have been removed, and major power sources have been shut down, costs decrease. Finally, when the installation enters the ‘Normally Unmanned Installation’ (NUI) stage, where there are no personnel living on the platform, costs are minimal. At this stage, minimal upkeep is required as the facility (or at least the topside) is to be removed promptly.

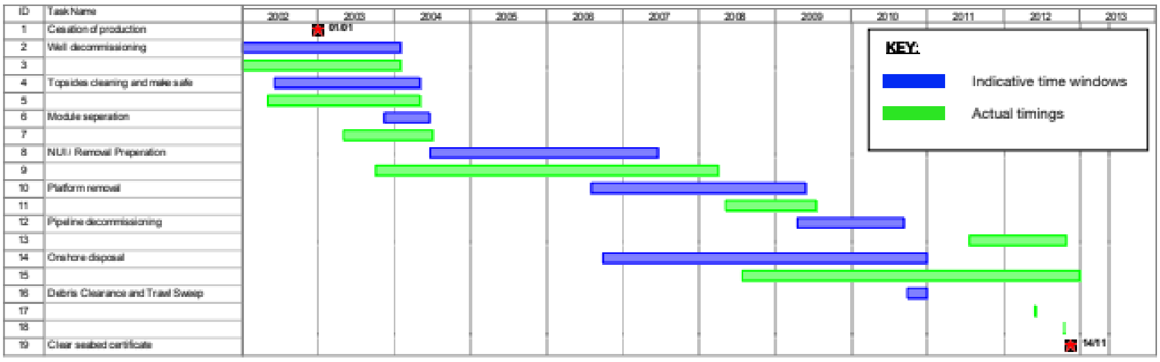


Figure 3: Gantt chart showing the phases of decommissioning. In this figure, facility running costs will incur until approximately mid-2004 [9]

Plug and abandonment of wells: As wells produce fewer and fewer hydrocarbons, they must be plugged in accordance with regulations.

The most costly part of a decommissioning process, well abandonment has been studied extensively in recent years. For non-platform wells, the main element of this most expensive activity is the day-rate of external rigs/vessels. New technologies have been developed to reduce the time spent per well [10], and there has been a shift toward more use of vessels rather than rigs in the last ten years. Also, a campaign approach, where performing plug and abandonment (P&A) on a phase-by-phase basis rather than well-by-well, has seen costs decline.

Plug and abandonment is undertaken using the same facilities used to drill wells, so wells scheduled for abandonment are usually divided into two main categories: where a drilling facility is readily accessible, and where there is not. Those without drilling capacity are usually subsea wells, or platform wells where the drilling facility is in a non-operable state or has been decommissioned previously. Where there is no drilling capacity, a rig or vessel must be mobilized to perform P&A. For subsea wells this can be either a drilling rig (jack-up or semi-submersible), a riser-less well intervention vessel (RLWI), or in some cases a drillship. For a platform with no integral rig/derrick, a modular drilling unit may be installed, or a jack-up rig will skid a moveable derrick over the well deck of the platform. The day-rates for these installations are high, so the crux of the operation is the time spent on each well. For a platform with drilling capability, time is also of the essence – there are high operating costs, along with costs of drilling crews. Downhole operations are generally the same for platform and non-platform wells [11]

Wells may have been only temporarily abandoned if there may be a future re-entering of a well, or permanently abandoned, where the well is regarded as sealed eternally (in practice 600-700 years) [11] A common method of describing the phases in plugging a well is Oil & Gas UK's cost estimation guidelines for well abandonment [12]. This approach divides well abandonment in three phases, and four classifications of complexity. The three phases are:

1. Reservoir abandonment: pumping of kill fluid, installation of mechanical plugs
2. Intermediate abandonment: removal of tubing and upper completion (everything above production packer), logging of existing cement, installation of permanent barriers.
3. Wellhead removal: removal of conductor, casing and wellhead. Conductor and casing are removed using either explosives, cutting tools, or abrasive water jets

The four classifications of complexity are:

0. No work required – a plug and abandonment may already have been completed
1. Simple rig-less abandonment – using wireline, pumping, crane, jacks. Subsea wells will use RLWI vessels
2. Complex rig-less abandonment: Using coiled tubing, hydraulic work-over unit, pumping, crane, jacks. Subsea wells will use heavy-duty well intervention vessels with riser

3. Simple rig-based abandonment: requiring retrieval of tubing and casing
4. Complex rig-based abandonment: May have poor access and poor cement requiring retrieval of tubing and casing, milling and cement repairs.

Depending on the complexities, different vessel types are used. The following describes the main type of vessels used for P&A:

RLWI vessel: hulled vessels used for light well intervention operations, using wireline or coiled tubing. The most pertinent difference between these vessels and rigs is the lack of a riser, so there is no sealed conduit between the reservoir and the interface. Recent studies have shown that RLWI vessels may also be used for phase 3 operations [13]. RLWI vessels have lower day-rates than rigs and can move swiftly between P&A locations.

Figure 4: RLWI vessel [14]

Drilling rig: either a semi-submersible, jack-up rig or a modular drilling rig (MDR) assembled on a platform can be used to perform P&A work, usually the cementing work and the pulling of conductor and wellheads. Jack-up rigs can be used on both subsea wells and platforms, as the drilling unit can be extended from the platform on a cantilever above the drilling floor of a platform. Semi-subs are used where no platform infrastructure is above the wells, whereas modular drilling rigs require a platform to be installed on. If the facility still has its integral rig assembly intact, this may also be used, though it may need to be refurbished. Semi-submersibles and jack-ups are collectively known as Mobile Offshore Drilling Units (MODU). Most jack-ups have a maximum operating depth of 150 metres.

Figure 5: Semi-submersible drilling rig [15]

Figure 6: Jack-up rig with derrick cantilevered over a wellhead platform [16]

Figure 7: Archer MDR installed on the Heimdal platform [17]

Wells are generally unique, and well conditions can vary greatly, which affects the scope of work required to effectively prevent leaks from the well in accordance with NORSOK standards. In addition to challenges due to depth, reservoir characteristics, formation characteristics, pressure and temperature, other unforeseen issues may arise during the well's lifetime. Cementing may have been poorly done or has deteriorated, there may be issues in removal of tubing and casing strings, and there may be a lack of proper data on the well.

Issues with cutting and pulling casing can be resolved using several techniques:

Where obstructions are present in the annulus, **section milling** [10] is an effective, yet time consuming and complex solution. A milling tool is lowered into the wellbore and rotated using hydraulic force. This extends blades which grind away casing, cement, and anything else in the section of the borehole, leaving an entirely open section of the well. This must be cleaned out to remove the milled material (cement, swarf, etc.) The section is then cemented.

Figure 8: Section milling (left), where cement and casing are ground away by hydraulic extended blades. Underreaming (right) grinds away more formation to expose fresh formation for better cement bonding [18]

An alternative to section milling is **Perforate, Wash and Cement** (PWC). This tool assembly blows holes in casing using explosives. The firing assembly is then dropped into the borehole. The perforated section is then washed, and cement is squeezed through the perforations, creating a formation to formation barrier, meaning barriers across the entire cross-section of the well, including borehole and annuli. Depending on whether one wishes to retrieve equipment, use of PWC can reduce the number of trips downhole significantly. According to industry professionals, use of PWC can save up to 10 days of work per well [19]

Cement has certain limitations, as it can crack and create leak paths when temperatures or pressure changes [10]. **Formation as barrier** is a cost reducing method of providing an external barrier. This has yielded savings of up to 20 million NOK per well [20]. The creeping of the natural formation against casing, seen as a major issue in development wells, can actually be beneficial in well abandonment, as this saves a great deal of cementing work.

Regulations and guidelines for P&A

The guidelines for the permanent plug and abandonment process are dictated in chapter 9 of the NORSOK standard *D-010 – well integrity in drilling and well operations* [21].

Permanent plug and abandonment is defined as the complete and indefinite cut-off of fluid flow from a well, both to the external environment and between well sources, with no intention of re-entering the well at any time. The permanent well barrier must have the following properties:

- Integrity for a significant, foreseeable future period
- Materials used must not deform over time, be invulnerable to effects from hydrocarbons, hydrogen sulphide and carbon dioxide, and be able to bond with steel casings
- The well barriers must withstand impacts and loads
- Must be impermeable
- Must be of an approved length – at least 100m, or 50m inside a casing if a mechanical plug is used
- Must be in an approved position in the well – as close to the inflow source as possible
- Must extend across the entire diameter of the well – casing, all annuli, and from the outer casing to the formation
- Testing, such as logging and pressure testing must be performed to verify the integrity of the well

If abandonment is only temporary as opposed to permanent, a maximum time of 3 years may pass until the well is either re-entered or permanently abandoned. Otherwise, the well must be monitored.

There are different types of well barriers:

- Primary well barrier: initial barrier against inflow
- Secondary well barrier: back-up to primary well barrier

- Barrier between reservoirs: prevents flow between formations
- Open hole to surface well barrier: hinders inflow from surface after removal of casings

Facilities/pipelines making safe: Making safe of topsides consists of removal of hazardous materials, disconnection and physical isolation of equipment and waste management [2]. If the platform has been idle or in a cold phase for a long period of time with no maintenance, refurbishing of infrastructure is required. It is often part of a Decommissioning Services Contract, which may also include topside preparation. Making safe of facilities is often performed in the same operation as pipelines making safe, as the capacities required for these operations are similar. It also entails making the platform safe for hot work, (i.e. cutting and welding), and hook-down – preparing electrical, utility and process circuits for the removal of the topside. Waste material must be transported onshore for processing and disposal.

Topsides preparation: Depending on removal method, the topside of the facility must be prepared for removal. Preparations for lifting operations of topsides are complex, as rigorous surveys and tests must be performed to ensure structural integrity. The three main options for removal of topsides – piece small, module based/reverse installation and single lift – all present challenges and require different procedures prior to removal.

- Piece small removal requires the lifting on board of cutting machines and containers for material, and extensive safety measures for personnel working on board
- Module based removal requires separation of modules and attachment of pad eyes for lifting, in addition to studies of integrity and strengthening of modules
- Single lift removal requires extensive studies of the structural integrity of the entire topside

Personnel aboard the facility require temporary utilities (power, air, water). If these utilities are not in place, they must be installed or refurbished. Other activities include dropped object surveys and subsequent remedial actions.

Topsides removal: One of the most challenging aspects of decommissioning is the removal of the topside facilities. Three main options for removal are available:

Single lift: Removal of the entire topside after making safe and cutting of connections to substructure. For large topsides this option is constrained by the limited supply of single lift vessels (SLV) and bears a high degree of uncertainty as to whether the structure has sufficient structural integrity. Extensive work must be performed to ensure the structure does not disintegrate during the lift. Some topsides on the NCS are beyond the maximum lifting capacity of SLV's.

Figure 9: Allseas' Pioneering Spirit

Module based/reverse installation: The topside is removed module by module, usually in the reverse order of installation. Cutting must be performed to separate the modules. Modules are either transferred to barges or loaded on the lifting vessel itself.

Figure 10: HMC Hermod removing a derrick from North-West Hutton [22]

Piece small: One or more excavators are lifted onto the platform deck and cuts the platform into smaller pieces using specialized cutting tools. The pieces are sorted into containers, which are lifted onto vessels for transport ashore.

Figure 11: Piece small removal [23]

Substructure removal: The regulations for removal are governed by the OSPAR convention [24], which may, under certain circumstances, grant exemptions from the regulations if a set of criteria are met. If a substructure weighs more than 10 000 tons in air, and was installed before February 1999, the footings (described in next section) of the substructure may be left in place, due to the high risk and high costs of removal.

Concrete substructures are granted OSPAR derogations due to the lack of sufficient technology for removal of these structures.

Whether or not derogations are granted, the jacket can be removed in a single lift, or cut into pieces using an ROV and several available cutting technologies, such as abrasive water jets, explosives, or diamond wire cutting. The substructure is then lifted onto a barge, wholly or in sections, or transported by the lifting vessel itself to shore for recycling or disposal. Another option is attachment of buoyancy tanks to the jacket legs, cutting the legs at a given point, and de-ballasting the tanks. The substructure is then towed ashore, as seen in Figure 12.

Figure 12: Flotation and removal of Frigg DP-2 jacket [25]

Removal of floating installations: floaters takes three forms:

- Hulled type floaters, such as floating production, storage and offloading vessels (FPSO), floating storage and offloading vessels (FSO) floating storage units (FSU), and floating production units (FPU).

Figure 13: The Alvheim FPSO, a typical hull-shaped FPSO [26]

- Some FPSO's have a cylindrical design reminiscent of spar platforms, such as Goliat and Aasta Hansteen.

Figure 14: The Goliat FPSO under transport by Dockwise [27]

- Rig-type floaters, which are usually semi-submersible rigs modified and moored for permanent residence and production. Jack-up rigs are sometimes also used for this purpose. In this thesis tension-leg platforms (TLP) also fall into this category, as it is assumed these will be removed and disposed of in much the same way as production semi-submersibles.

Figure 15: Visund A: a semi-submersible style production platform [28]

It is also assumed that the majority of floaters will be removed by tugboats to a disposal yard after preparation and disconnection from moorings and risers. However, in some cases, semi-submersible heavy transport vessels (SSHTV) may be an option, see Figure 14. As of 2018, two hulled floaters have been decommissioned, but were towed to international ship breaking yards [29] [30]. Therefore, it is unclear if disposal of hulled floaters will be undertaken at the standard disposal yards, or if a dry-dock will be required.

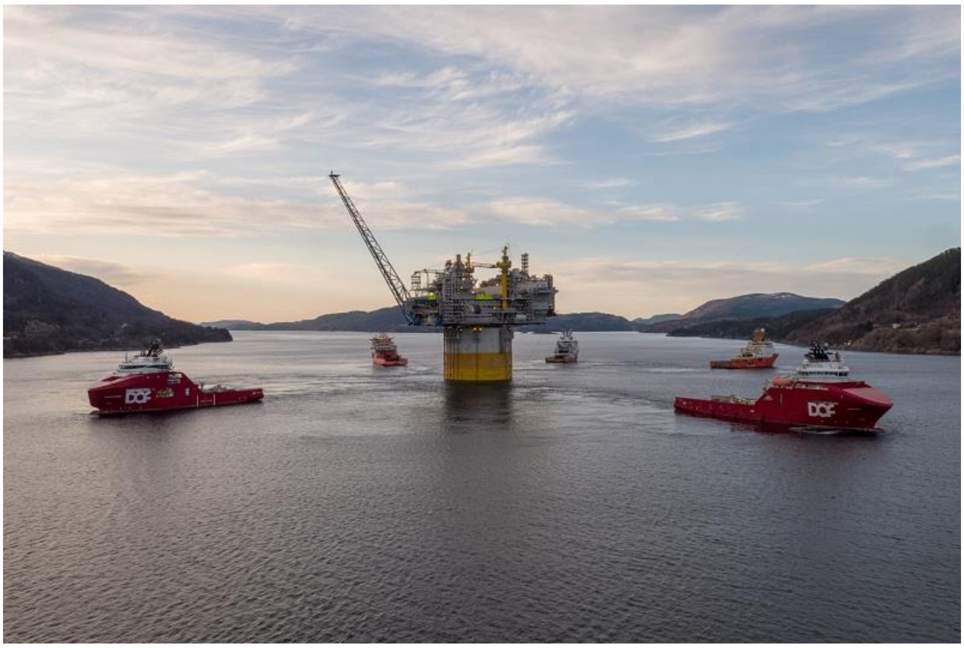


Figure 16: Aasta Hansteen platform transport by tugboats [31]

<u>Onshore disposal and recycling:</u> The removed infrastructure is taken ashore to a disposal yard for further dismantling. If module-based or single lift removal has been used, some equipment may be re-used. Otherwise, the material is further cut up, sorted and recycled or disposed of. Depending on removal method, there may still be hazardous materials in the facility, and must therefore be disposed of.

In Norway, there are several options for depositing the material onshore [32]

- AF Miljøbase Vats (Rogaland)
- Lutelandet Offshore AS (Sogn og Fjordane)
- Lyngdal Recycling AS (Vest-Agder)
- Kværner Stord (Hordaland) - includes GMC Decom (formerly Scandinavian Metal), recently acquired by Kværner [33]. This facility can process 60 000 tons of material a year.

There are several yards in the UK, however, these yards do not have deep water capacity at time of writing.

Subsea Infrastructure removal: The seafloor surrounding a facility contains a large amount of installations and components to be removed or secured for abandonment.

- Subsea production equipment: X-mas trees, templates, manifolds, PLET's PLEM's, SSIV's and flexible risers are among the range of equipment on the seafloor.
- Subsea fastening equipment: Riser bases, MWA's, and mooring systems.
- Pipelines: The Norwegian government's guidelines on pipeline decommissioning state that as long as pipelines do not pose a hazard to other marine activities, they may be left in place. However, they must be scoured, cut and plugged. If they are an obstruction to marine activities, they may be removed, trenched (buried) or rock-dumped.
- Cuttings pile: If the facility is a drilling platform, there may be a large pile of drilling cuttings around the base of the platform. During the early stages of drilling, cuttings will have been transported from the bore to the seabed. These cuttings may contain fluids hazardous to the local environment. OSPAR recommendation 2006/5 affirms that studies should be carried out to ascertain whether any harmful compounds are contained in the cuttings pile, and their annual fluid loss to water column and persistence. If these values are above defined limits, they must be removed. However, previous decommissioning programs have shown that cuttings piles usually have fluid loss/persistence values below the OSPAR limits.

- Mattresses, concrete blocks, grout bags: Used to cover pipelines and other fragile seafloor infrastructure to protect them from dropped objects, these mattresses must be removed. Two of the most common alternatives are subsea baskets and speed loaders [34].

Figure 17: Subsea mattresses [25]

Site remediation: After removal of all or most of the infrastructure, any remaining miscellaneous objects must be removed. Trawl surveys are completed to verify that there are no hazards to fishery, and cuttings piles are removed or buried if applicable.

Monitoring: The operator of a field has a continuing liability for the field, and if any infrastructure or cuttings piles are left in place, they must be monitored at intervals to verify that they no longer pose a hazard to marine life or activity. Any facilities above sea-level that are left behind must have an aid to navigation (AtoN) to warn shipping of its presence, and this must be maintained in perpetuity or until removal.

Figure 18: Installation of AtoN on the concrete legs left behind after the decommissioning of Frigg [35]

Legislation

In this section, an overview of relevant regulations, guidelines and standards are presented.

Decommissioning is considered a petroleum activity, but when the facility in question is moved to a removal vessel, it is considered a maritime activity. Disposal and recycling is further regulated by separate legislation [36].

OSPAR

The Convention for the Protection of the Marine Environment of the North-East Atlantic, also known as the Oslo Paris Convention or OSPAR, is the most widely used legislative framework with regards to abandonment of offshore facilities. There are other regulative organizations, but OSPAR's statutes are the most stringent, making them the primary source of regulations to abide by. In Norway, OSPAR's rules are enforced by the Norwegian government, which is the contracting party to the convention.

Relevant statutes of the convention are decision 98/3 and recommendation 2006/5:

OSPAR decision 98/3: Decision 98/3 [24] of the OSPAR convention dictates regulations for the disposal of disused offshore facilities.

Paragraph 2 states: *The dumping, and the leaving wholly or partly in place, of disused offshore installations within the maritime area is prohibited.* In practice this means all offshore facilities must be removed and brought to shore.

However, paragraph 3 states that derogations from paragraph 2 may be made under the following criteria, specified under Annex 1 of the decision:

- The facility is a steel installation weighing more than 10 000 tons in air, excluding topside
- The facility is a gravity based concrete installation
- The facility is a floating concrete installation
- Any concrete anchor-base which results, or is likely to result, in interference with other legitimate uses of the sea.

If any of the aforementioned criteria are satisfied, a permit may be issued for the following alternative disposal options:

- If all or part the footings of the facility's substructure were placed in the environment before February 9th, 1999, the footings (see Figure 19) may be left in place
- A concrete installation may be dumped at sea or left wholly or partly in place
- If significant structural damage or deterioration of the facility can be demonstrated, which may pose great risk and endure high costs during removal, recycling or disposal, a facility may be dumped at sea or left wholly or partly in place.

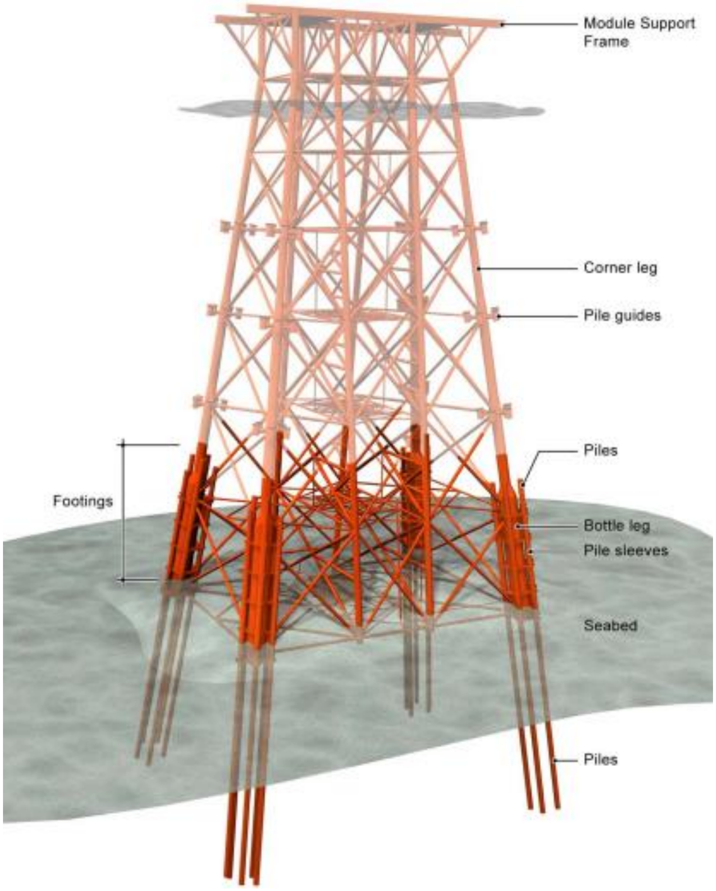


Figure 19: Steel jacket with footings indicated [37]

A detailed comparative assessment and stakeholder consultation must be completed if the concerned party is to be granted a derogation.

If derogations from the OSPAR-decision are granted [24], the jacket may be cut above the footings. The footings are defined as

Those parts of an installation which:

1. *Are below the highest point of the piles which connect the installation to the seabed*
2. *In the case of an installation built without piling, form the foundation of the installation and contain amounts of cement grouting similar to those found in footings as defined in 1.*
3. *Are so closely connected to the parts mentioned in 1. and 2. above as to present major engineering problems in severing them from those parts.*

Cutting above footings may be performed at the most convenient section for accessibility of cutting equipment and where the fewest cuts are required, at a minimum of 55 metres below lowest astronomical tide (LAT).

Figure 20 illustrates the possible outcomes in an OSPAR derogation process for a steel jacket.

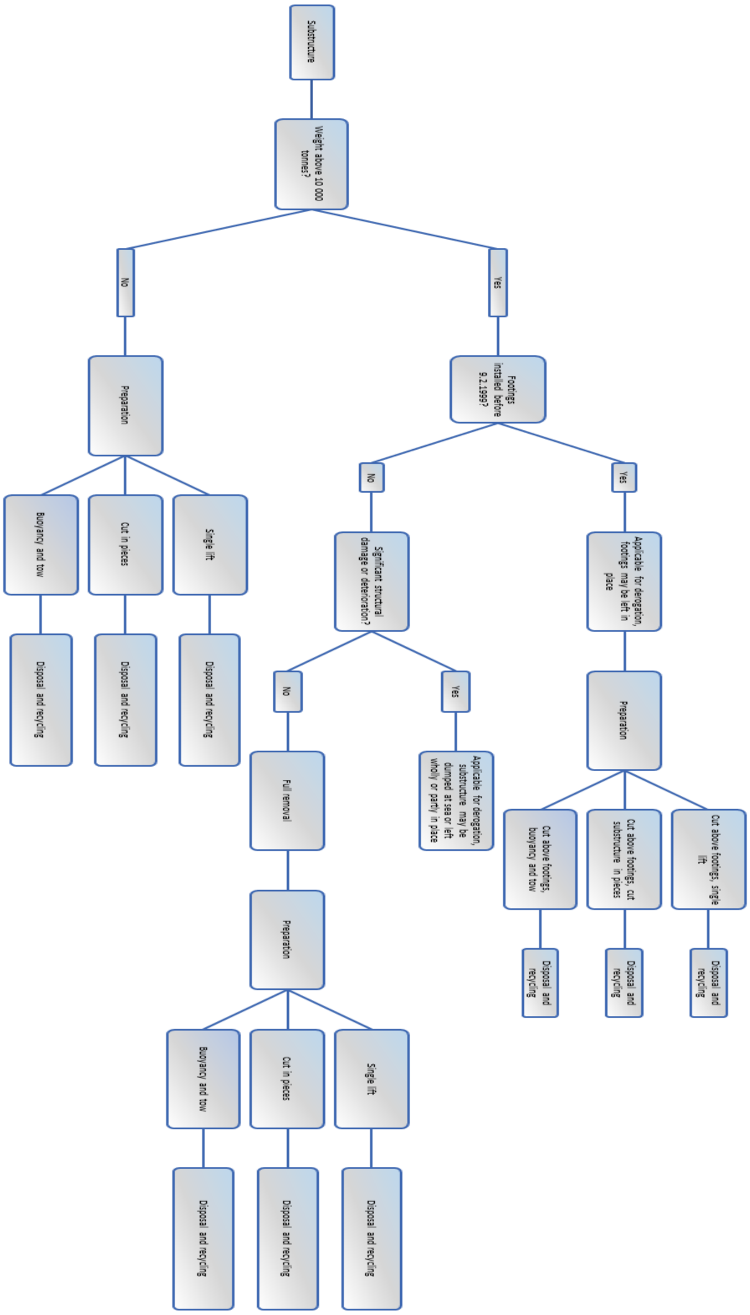


Figure 20: OSPAR steel jacket derogation process

Paragraph 7 states that as more experience and industry knowledge is attained, the OSPAR commission shall strive towards amendments to Annex 1 to reduce the scope of possible derogations under paragraph 3. This entails that more stringent regulations may apply in the future, resulting in higher costs and more complex decommissioning operations.

OSPAR recommendation 2006/5 [38]: has a stated purpose to *reduce to a level that is not significant, the impacts of pollution by oil and/or other substances from cuttings piles.* The process is divided into two stages.

- Stage 1 is a screening of the cuttings pile to investigate piles which require further examination. Where water-based drilling fluids were used and no other discharges (meaning discharges which contain either chemicals on the OSPAR list of chemicals for priority action or radioactive substances) have contaminated the cuttings, no further investigation is necessary. Where organic-phase drilling fluids (OPF) were used and discharged or other discharges have contaminated the cuttings pile, a process of assessing rate of oil loss to the water column and persistence over the area of seabed contaminated are assessed. If the prescribed limits of 10 tons per year and 500 km^2 per year are exceeded, stage 2 should be initiated at a time to be determined by the contracting party.
- Stage 2 requires a study to determine the best available techniques (BAT) and best environmental practice (BEP) regarding further action for the cuttings pile. When assessing BAT and BEP, the following options should be considered:

    - Onshore treatment and reuse
    - Onshore treatment and disposal
    - Offshore injection
    - Bioremediation in situ
    - Covering in situ
    - Natural degradation in situ

A comparative assessment should be made, considering the potential impacts of the proposed disposal method.

In practice, cuttings piles are often left in situ (meaning left in place), as this is the best BEP. Disturbing the cuttings pile may create a large dispersion of chemicals harmful to local marine habitats. The BEP of leaving the cuttings pile in situ also coincides with the application for derogation of removal of jacket footings, as removal of the footings will disturb the cuttings pile.

Figure 21 shows the options in evaluating seafloor materials.

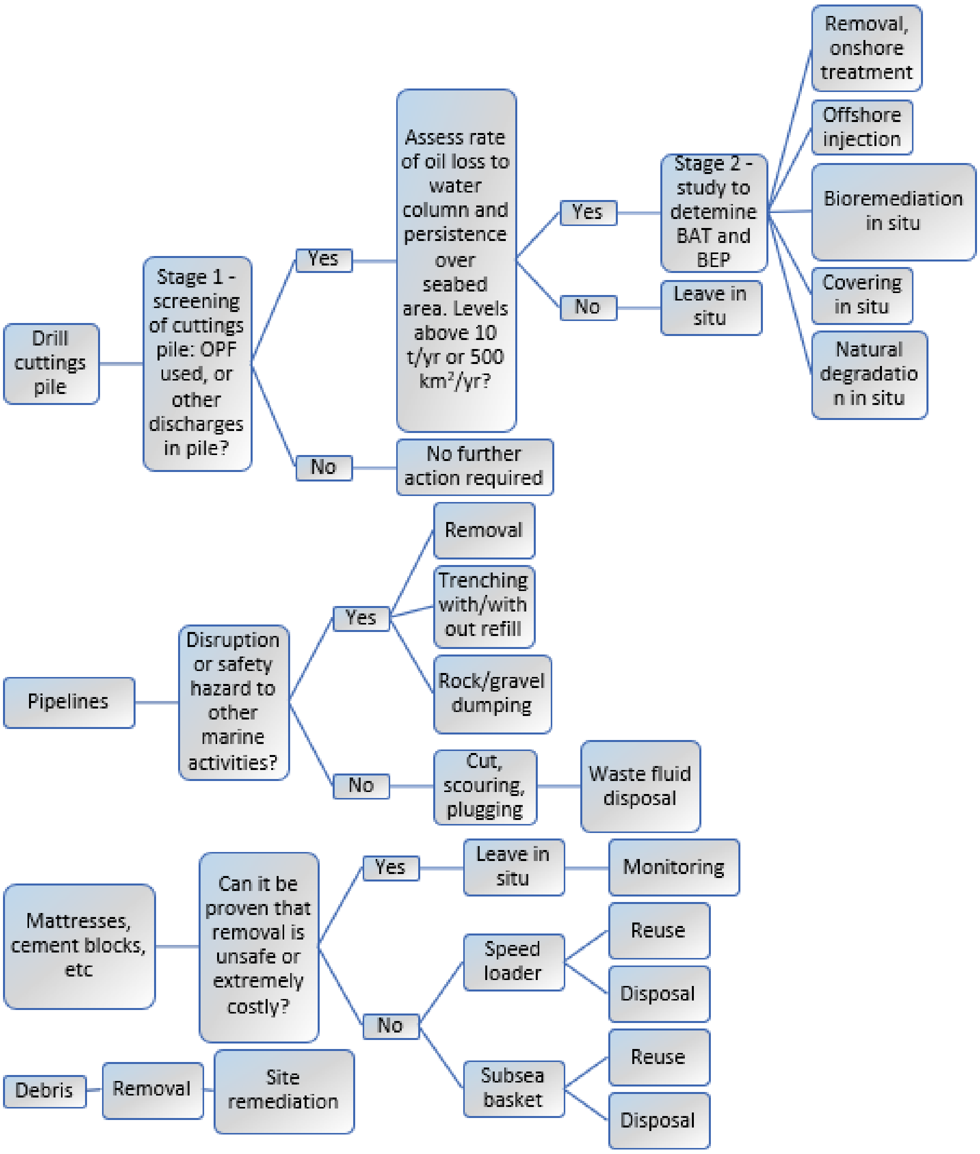


Figure 21: Subsea equipment removal process

Other legislation

Petroleumsloven (Petroleum Act) [39]:

- Paragraph 5-1 states that when production on an oilfield nears cessation, an extensive plan for decommissioning, including recommended actions for disposal, shall be submitted to the Ministry of Petroleum and Energy (MPE). The plan shall be submitted between two to five years before a license expires or is relinquished, or when a facility will no longer be used. The plan contains two parts: the *Disponeringsdel,* reviewed by the Norwegian Petroleum Directorate (NPD) and the Petroleum Safety Authority (PSA) and the *Konsekvensutredning*, reviewed in public hearing by stakeholders such as fisheries associations and environmental agencies.
- Permission for any intentional discharges during decommission must be granted by the Norwegian Environment Agency, a department of the Ministry of Climate and Environment (Klima- og miljødepartementet, KLD).
- The licensee is obligated to draft several options for disposal methods, as stated in paragraph 5-1 of the Petroleum Act.
- A key principle for the approval of a decommissioning plan, is that all hydrocarbon resources have been extracted profitably. The decommissioning process must also be within acceptable HSE boundaries and must not infringe on other users of the maritime area.
- The MPE passes a resolution on the disposal process, as dictated in paragraph 5-3 of the Petroleum Act. The resolution may differ from the licensee's proposed plan.

Petroleumsforskriften (petroleum regulations): Paragraphs 43 - 45 state that the plan shall contain two parts, a plan for disposal and an impact assessment plan [40]

- The disposal plan describes the technical and financial aspects of the cessation project.

- The impact assessment assesses consequences of the decommissioning process.

The MPE makes the final judgment on the decommissioning process, with feedback from other government departments such as the NPD and the PSA.

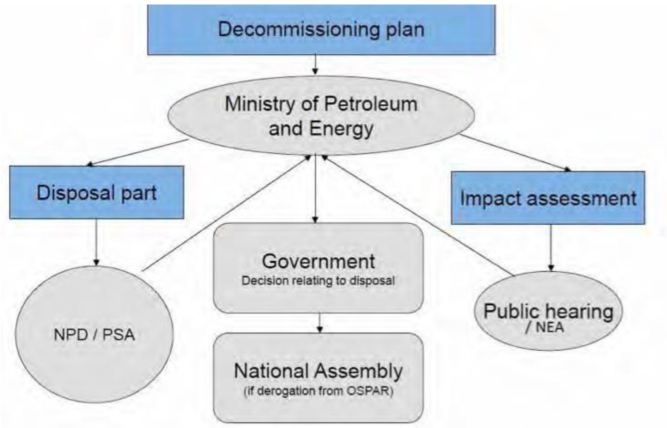


Figure 22: Approval and hearing process for decommissioning programs [41]

<u>Pipelines:</u> The OSPAR convention does not include regulations for the removal and disposal of pipelines. In a government white paper [42], guidelines are provided for this procedure. It states that pipelines and cables can generally be left in situ provided they do not cause disruptions or safety hazards to other maritime activities, particularly bottom trawling. However, decommissioned pipelines must be scoured of hydrocarbon residue and scaling of other materials and monitored for future hazards.

Decommissioning Contracts

Decommissioning contracts are usually divided into four components – Engineering, Preparation, Removal and Disposal. A common form of contract is the EPRD contract where all four components are assembled as a complete integrated contract. The management of the decommissioning project is then performed by a single contractor, using subcontractors for lower-level work packages as required. EPRD contracts are in the form of a lump sum contract, where the EPRD contractor controls most of the processes in the work. The EPRD format may be divided – a common division is an EPR contract where the D-portion, disposal, is completed in a separate contract.

EPRD contracts may be developed for removal of an entire installation, or only parts of it.

Due to the large scope in an EPRD contract, a limited number of suppliers have the experience and capacity to offer the entire range of work required in a decommissioning project.

Cooperation and partnership between contractor and operator and between sub-contractors is crucial during decommissioning. For example, hook-down and topside preparation must be completed before arrival of the topside removal vessel. Removal contractors are usually given a removal time window, which provides contingencies for poor weather and allows the removal contractor to plan and coordinate around other obligations. However, they will have a deadline for removal as the facility owner incurs costs of upkeep, and the disposal yard will anticipate the arrival of the facility within a given time frame.

Examples of EPRD contracts:

Removal of 10 platforms on the Ekofisk field: [43]

- Operator: ConocoPhillips
- EPRD contractor: Heerema Marine Contractors (also performs heavy lifts and removal)
- Sub-contractors: AF Decom (disposal, topside preparation), AAK, Oceaneering, Scanmudring, IKM plus several more

Removal of Valhall QP: [44]

- Operator: Aker BP
- EPRD contractor: Allseas via Excaliber Marine Contractors (also performs heavy lifts and removal)
- Sub-contractors: Aker Solutions (offshore preparations), Kværner Stord (disposal)

Removal of Frigg platforms: [45]

- Operator: Total E&P Norge
- EPRD Contractor: Aker Solutions
- Sub-contractors: Saipem UK (heavy lifts and removal)

- SONSUB and Deepocean were awarded separate contracts for removal of steel from the concrete substructure and cutting of sealines.

Risk-sharing in contracts: Ideally, contract risk is borne by the party which is better suited to manage the loss in case of overruns. The compensation format must account for uncertainties in the project and lack of information on the condition of the facility. Performance risk is allocated to the contractor, whereas market and incident/insurable risk is placed at the operator [8].

One of the main issues in decommissioning contracts is the uncertainties in the extent and type of hazardous waste on an installation. Treatment of hazardous waste carries a high cost [46], and unexpected finds of hazardous material beyond that detailed in surveys will increase costs further. Disposal contractors may use reimbursable contract formats for hazardous waste treatment in the event of uncertainties in the amount or type of hazardous waste [47].

There has been a discussion on the need for standard decommissioning contracts on the NCS [48] [46] [49]. Decommissioning contracts were previously based on standard traditional development and installation EPCI (engineering, procurement, construction and installation) contracts. Contract specialists agree that separate standard terms for decommissioning contracts should be developed. Differences in development and abandonment of an oil field lie in that development is often operator driven, whereas abandonment is often contractor driven [50]. Development projects have strict timeframes, as production must be initiated as soon as possible, whereas decommissioning projects are often postponed to mitigate the effects of cost overruns – a balance between the costs of running the facility and taking on the abandonment expenditure must be found.

As the Norwegian decommissioning market is in its relative infancy, with significant growth in the coming years, one may consider which terms should apply for regulation of decommissioning in a prudent way. As the contract scope revolves around the removal of an installation, very much the opposite of typical construction contracts, the NF (*Norsk Fabrikasjonskontrakt*) or the NTK (*Norsk Totalkontrakt*) standards may be unsuitable. The principle of standard contract terms and agreed documents however, will reduce transaction costs from negotiations with several bidders during tendering processes. Standard agreed documents also improve clarity in the terms, so vendors may require less risk coverage [48].

The scope of a decommissioning contract sees two extremes: the operator may request a price for the removal of a platform, with a minimal level of detail on the scope of work. This places the risk in the hands of the contractor, as unforeseen elements in the work are not accounted for in the contract. At the other end, the operator may assemble a detailed specification on the removal process. In this case the operator carries the risk. Usually contracts are placed somewhere in between these extremes. The remuneration for risk is defined by the level of detail in the contract.

The EPRD format, contracting most of the work to a single contractor and paid by lump sum, places risk in the hands of the contractor. This also incentivizes efficient completion of the work scope. Handling of hazardous materials may be recompensed by unit rates.

The pertinent issue in a contract's terms are how these terms may affect the cost estimation of the decommissioning project. The level of detail in the as-is condition of the facility, and the amount of access to the facility and its documentation granted to subcontractors play a major part in the precision of cost estimation.

Health, Safety and Environment

The cost of decommissioning is the focal point of this thesis, and the different projects have been evaluated solely on financial performance according to budget so far. An evaluation of the cost of a decommissioning project should be accompanied by an evaluation of the performance in Health, Safety and Environment.

Health and Safety:

The Petroleum Industry has a strong focus on health and safety in general. In the decommissioning phase there are a multitude of risk factors that are not encountered under normal operations.

In most of the reports studied in relation to this thesis there is a strong focus on health and safety, and no Close Out report is complete without a summary of the health and safety statistics.

In the following section some decommissioning projects have been evaluated on their health and safety performance.

The H7 removal project [51]**:**

The platform is owned by Gassled and operated by Gassco. Equinor was the technical operator on behalf of Gassco. The EPRD contract for H7 was awarded to AF Gruppen. In the process of removing the H7 topsides and jacket a total of 165 000 manhours were used.

During the whole project there were only two minor injuries. One person stumbled on deck, and one person had a finger injury.

The H7 disposal/recycling project [52]**:**

The whole disposal/recycling process was undertaken by AF Gruppen with no fatalities and no Lost Time Injuries (LTI).

Regardless of the financial outcome this is a project with an excellent performance with regards to health and safety.

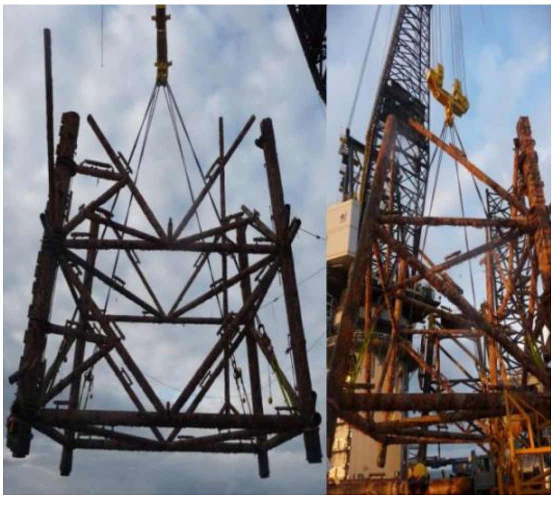


Figure 23: Transferral of the H7 jacket to land [51]

The B11 removal project [53]**:**

The platform is owned by Gassled and operated by Gassco. Equinor was the technical operator on behalf of Gassco. The EPRD contract for B11 was awarded to AF Gruppen.

The project had no fatalities and no LTI's for the entire project and received a safety award in 2016.

Regardless of the financial outcome this is a project with an excellent performance with regards to health and safety.

The Ekofisk 2/4 S jacket removal project [54]**:**

The platform is owned by Gassled and operated by Gassco. Equinor was the technical operator on behalf of Gassco. The contract for the removal of the jacket was awarded to Saipem.

The project took a total of 171 319 manhours and there were no fatalities and no LTI's

Regardless of the financial outcome this is a project with an excellent performance with regards to health and safety.

The Maureen disposal/recycling project [55]**:**

The Maureen platform was a platform on the UK Continental Shelf (UKCS). The platform was refloated, towed to Stord and finally disposed/recycled in 2001. The platform was one of the giants in the UK, so this was a project with a large scope. The Maureen decommissioning was a project haunted by both fatalities and injuries.

According to the newspaper *Dagbladet* [56] there were 2 fatalities, 5 serious injuries and one situation with an unacceptably high risk of a major explosion with multiple fatalities.

According to Dagbladet an integral report concluded that, at least for some key managers in Aker Stord, keeping the Maureen project on schedule and within budget had a higher priority than health and safety on this specific project. In the aftermath several key managers lost their jobs and new integral routines concerning risk were implemented. According to the top management in Aker Stord the poor performance with regards to HMS was due to a subculture in part of the company; It did not represent the company culture [56].

This is unacceptable and even though this seems to be one of the more successful decommissioning projects financially, the project did not perform acceptably with regards to safety.

The Frigg decommissioning project:

This is a decommissioning project with an enormous scope and should not be compared with the projects mentioned above. It included the topside preparation, removal and disposal/recycling of 5 topsides and 3 jackets.

According to the Frigg Close Out report's safety section there were a total of 8 LTI injuries [25]. For a project of this magnitude that can be considered a commendable outcome.

Regardless of the financial outcome this is a project with a very good performance with regards to health and safety.

Frigg MCP-01 [57]**:**

This Frigg platform was singled out for a separate decommissioning program. The decommissioning only included the topside. Aker Offshore Partner was awarded the main decommissioning contract for the removal and disposal/recycling of the topside. The project included a total of 1 933 400 offshore hours without any serious LTI's.

At Aker's onshore disposal yard, a total of 13 LTI incidents were registered, but none of the incidents caused severe or debilitating injuries.

Table 2 presents an overview of safety incidents on selected decommissioning projects:

Table 2: Overview of LTI's on selected decommissioning projects

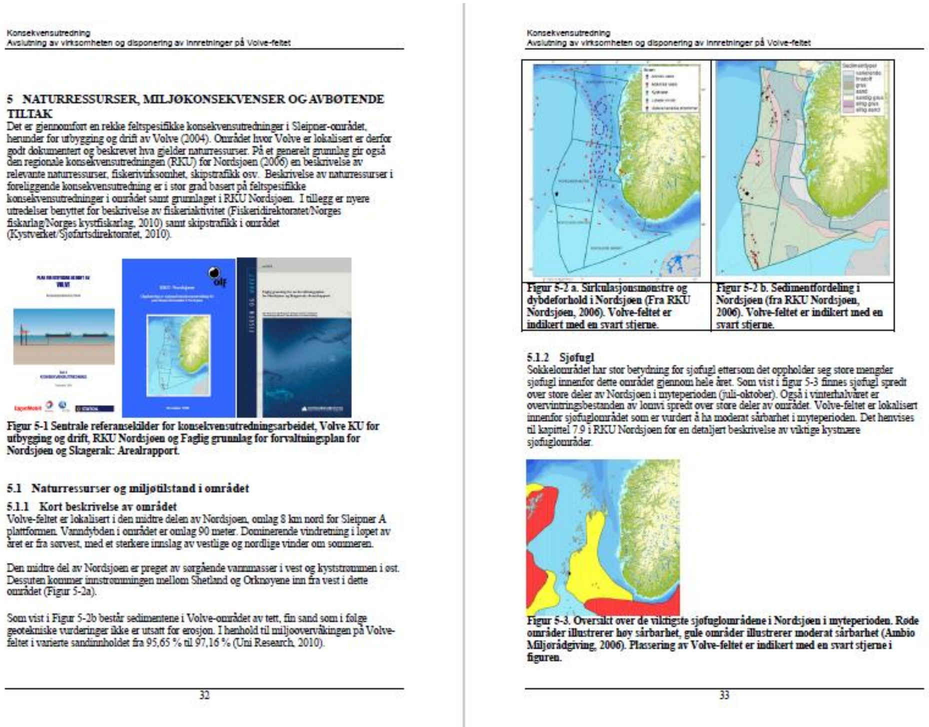
Project	Phase	Operator	Contractor	LTI
H7 removal	Removal	Gassco	AF Gruppen	0
H7 disposal and recycling	Disposal/recycling	Gassco	AF Gruppen	0
B11 removal	Removal	Gassco	AF Gruppen	0
Ekofisk 2/4 S jacket removal	Removal	Gassco	Saipem	0
Maureen disposal/recycling	Disposal/recycling	Phillips Petroleum	Aker Stord	5 + 2 deaths
Frigg decommissioning	All	Total	Aker Kværner	8
Frigg MCP-01	All	Total	Aker Kværner	13

Environment:

The decommissioning projects evaluated in this thesis are very complex in nature and involve a multitude of hazardous operations and a range of hazardous materials.

The environmental risks in the processes of cleaning and making safe a platform, in plugging and abandoning the wells, in removing, demolishing and recycling the platform are so numerous that environmental issues are to be expected. But in the literature review for this thesis very few, and only minor, incidents were encountered. This is a credit both to the regulators, to the professionals that perform the planning and engineering of the decommissioning projects and to the operators, contractors and subcontractors that are involved in the execution of the decommissioning projects. Given the risks involved, some accidents are to be expected, but the environmental track record of decommissioning in Norway looks strong.

The decommissioning programs and the Close Out reports related to decommissioning show a prioritized focus on environmental hazards and the results are evident. The high rate of recycling at Norwegian disposal yards is further evidence of the rigorous environmental regulations in place, as shown in numerous presentations.



Konsekvensutredning
Avslutning av virksomheten og disponering av innretninger på Volve-feltet

5 NATURRESSURSER, MILJØKONSEKVENSER OG AVBØTENDE TILTAK

Det er gjennomført en rekke feltspesifikke konsekvensutredninger i Sleipner-området, herunder for utbygging og drift av Volve (2004). Området hvor Volve er lokalisert er derfor godt dokumentert og beskrevet hva gjelder naturressurser. På et generelt grunnlag gir også den regionale konsekvensutredningen (RKU) for Nordsjøen (2006) en beskrivelse av relevante naturressurser, fiskerivirksomhet, skipstrafikk osv. Beskrivelse av naturressurser i foreliggende konsekvensutredning er i stor grad basert på feltspesifikke konsekvensutredninger i området samt grunnlaget i RKU Nordsjøen. I tillegg er nyere utredelser benyttet for beskrivelse av fiskeriaktivitet (Fiskeridirektoratet/Norges fiskarlag/Norges kystfiskarlag, 2010) samt skipstrafikk i området (Kystverket/Sjøfartsdirektoratet, 2010).

Figur 5-1 Sentrale referansekilder for konsekvensutredningsarbeidet, Volve KU for utbygging og drift, RKU Nordsjøen og Faglig grunnlag for forvaltningsplan for Nordsjøen og Skagerak: Arealrapport.

5.1 Naturressurser og miljøtilstand i området

5.1.1 Kort beskrivelse av området

Volve-feltet er lokalisert i den midtre delen av Nordsjøen, omlag 8 km nord for Sleipner A plattformen. Vanndybden i området er omlag 90 meter. Dominerende vindretning i løpet av året er fra sørvest, med et sterkere innslag av vestlige og nordlige vinder om sommeren.

Den midtre del av Nordsjøen er preget av sørgående vannmasser i vest og kyststrømmen i øst. Dessuten kommer innstrømmingen mellom Shetland og Orknøyene inn fra vest i dette området (Figur 5-2a).

Som vist i Figur 5-2b består sedimentene i Volve-området av tett, fin sand som i følge geotekniske vurderinger ikke er utsatt for erosjon. I henhold til miljøovervåkingen på Volve-feltet i varierte sandinnholdet fra 95,65 % til 97,16 % (Uni Research, 2010).

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Konsekvensutredning
Avslutning av virksomheten og disponering av innretninger på Volve-feltet

Figur 5-2 a. Sirkulasjonsmønstre og dybdeforhold i Nordsjøen (Fra RKU Nordsjøen, 2006). Volve-feltet er indikert med en svart stjerne.	**Figur 5-2 b. Sedimentfordeling i Nordsjøen (fra RKU Nordsjøen, 2006). Volve-feltet er indikert med en svart stjerne.**

5.1.2 Sjøfugl

Sokkelområdet har stor betydning for sjøfugl ettersom det oppholder seg store mengder sjøfugl innenfor dette området gjennom hele året. Som vist i figur 5-3 finnes sjøfugl spredt over store deler av Nordsjøen i myteperioden (juli-oktober). Også i vinterhalvåret er overvintringsbestanden av lomvi spredt over store deler av området. Volve-feltet er lokalisert innenfor sjøfuglområdet som er vurdert å ha moderat sårbarhet i myteperioden. Det henvises til kapittel 7.9 i RKU Nordsjøen for en detaljert beskrivelse av viktige kystnære sjøfuglområder.

Figur 5-3. Oversikt over de viktigste sjøfuglområdene i Nordsjøen i myteperioden. Røde områder illustrerer høy sårbarhet, gule områder illustrerer moderat sårbarhet (Ambio Miljørådgiving, 2006). Plassering av Volve-feltet er indikert med en svart stjerne i figuren.

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Figure 24: Excerpt from the Volve Environmental Impact Assessment describing marine wildlife in the area [58]

A summary point is that even though this thesis has a strict emphasis on cost estimation and budget performance, there are several other important criteria that must be included in the evaluation of decommissioning projects. HSE is most definitely among the key criteria.

In the process of writing this thesis, the authors were invited to visit Kværner's Demolition Yard at Stord to gain insight into disposal and recycling of offshore facilities, and conduct interviews with disposal professionals. A concluding lesson from that trip is that the strong focus on health, safety and environment that permeate the entire demolition and recycling process is probably the main reason why so few reports of accidents have been encountered in the literature study.

Cost estimation

As mentioned, the decommissioning industry is still in its infancy, with a large degree of uncertainty and risk involved. A study of cost estimation data versus actual costs shows considerable overruns in the vast majority of projects, with an average overrun of 50 percent. Whether estimates are intentionally modest is unclear; underestimating asset retirement obligations has certain financial benefits, as these liabilities may be viewed debt in the eyes of investors.

Observations on Budgeting in Decommissioning

This section details a range of previously decommissioned facilities and their associated costs.

Frigg field, Norway [25]**:**

Frigg DP1, the wreck of a jacket intended to be the substructure of a drilling platform

Frigg DP2, a drilling platform with a steel jacket

Frigg TCP2, a treatment, compression and production Condeep (deep-water concrete substructure) platform

The project included:

Removal and disposal of the DP Jacket,

Cleaning, removal and disposal of the DP2 topside

Removal and disposal of the DP2 jacket

Cleaning, removal and disposal of the TCP2 topside

Removal and disposal of the external steelworks on the TCP1 substructure

Decommissioning of the infield pipelines and export lines

Seabed clean-up

The P&A of the wells on DP2 are exempt from both the budget and the actual costs.

The two platforms and the jacket on the Norwegian side of the border and three of the four Frigg platforms in the UK were part of a combined decommissioning program. The decommissioning program in its entirety and the Close Out report for the Frigg decommissioning program is publicly available as the Frigg Field is a development on both sides of the border.

The information from the Close Out report shows that the decommissioning of the three offshore structures on the Norwegian side were budgeted to cost 2 170 million NOK (2010) in the decommissioning program but ended up costing a total of 3 287 million NOK (2010).

This represents a budget overrun of 51.5 %.

There are many possible explanations for this overrun. The Frigg Decommissioning was one of the first major decommissioning projects on the NCS, and the lack of experience made budgeting very challenging. The project tried new and untested methods for decommissioning. One example is the use of buoyancy tanks as the chosen method of refloating the DP2 jacket. Another example is the DP1 jacket; it was accidentally dropped on the seafloor during installation and due to the resulting lack of structural integrity it had to be cut into small sections and picked up piece by piece off the sea floor.

These factors increase the complexity of the project, but that is no excuse for underbudgeting; at best it is part of the explanation.

Another fact that should be mentioned is that Aker Offshore Partner who was awarded the fixed price EPRD contract for all the platforms both in Norway and in the UK took a hit on the project [23].

The contract was won by Aker Offshore Partner on a fixed price format, and both Aker Stord and Aker Maritime Partners participated as subcontractors in the project. As the project unfolded, it became more complex than expected at the outset [59].

This indicates that the project was even more over budget than what is stated in the Frigg Close Out Report. Aker had to cover some of the budget overruns connected to engineering, removal and disposal due to the fixed price contract, even though the operator Total agreed to cover some of the cost overrun [60].

To sum up the evaluation of this project, the original budget from the decommissioning program turned out to be far too low. The official overrun was around 50 % and the actual overrun including the losses Aker incurred was even higher.

Due to the lack of available information from the NCS, the authors decided to gather information on decommissioning projects on the UKCS. The regulations in the UK are similar to Norway's, and the operating environments are comparable, especially in the Central and Northern North Sea.

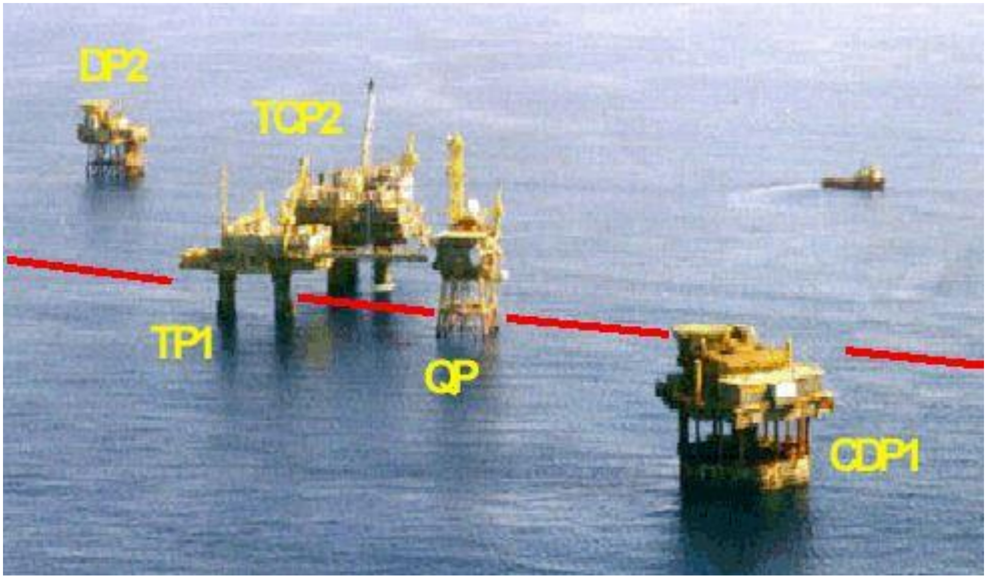


Figure 25: The Frigg field with the UK-Norway border illustrated by the red line [61]

Budget Overruns in the UK

In the UK there are some decommissioning projects of particular interest concerning budgeting and actual cost in the decommissioning programs and Close Out reports.

The decommissioning projects with full information on both decommissioning program budget and actual cost from the Close Out reports are:

<u>Frigg Field UK</u> [25]

The part of the Frigg field on the UKCS consisted of:

Frigg CDP1:

A drilling platform with a concrete substructure. The topside weight was just under 5 000 tons and the substructure weighed in at over 400 000 tons including ballast.

Frigg QP

A jacket platform with a total weight of just over 8000 tons containing the control center and the living quarters.

Frigg TP1

A treatment platform with a topside weight of around 8 000 tons and a substructure weighing in at over 160 000 tons including ballast.

Frigg MCP-01 was also located on the UKCS but is treated as a separate decommissioning project.

The scope of the Frigg decommissioning project on the UKCS consisted of the following:

- Project management
- Engineering
- Field running cost after COP
- Cleaning/making safe, topside preparation, removal and disposal/recycling of the Frigg CDP1 topside
- Cleaning/making safe, topside preparation, removal and disposal/recycling of the Frigg QP topside
- Removal and disposal/recycling of the Frigg QP jacket
- Cleaning/making safe, topside preparation, removal and disposal/recycling of the TP1 topside
- Decommissioning of pipelines and control lines

- Seabed clean up

The budget for the project in the decommissioning program was 1911 million NOK (2010)

The actual cost from the Close Out report was 2710 million NOK (2010)

This represents a budget overrun of 41.8 %.

As mentioned above for the Norwegian part of the Frigg field, the overrun was probably even higher, but Aker covered some of the cost overrun.

Frigg MCP-01 [57]**:**

This was a manifold and compression platform and one of UK Frigg platforms.

The platform had a concrete substructure weighing 386 000 tons including ballast and a topside weight of 13 500 tons. The platform topside was removed between 2004-2009 and the external steelwork on the substructure was removed as part of other removal operations in 2010. The actual cost in the Close Out report covers making safe and cold, topside removal and disposal, removal of a riser and post removal activities. The budgeted cost was 86.01 million Pounds (2004) and the actual cost was 211.5 million Pounds (2014). Converted to NOK and adjusted for inflation to 2017 that converts to a budgeted cost of 1344.3 million NOK (using an exchange rate of 1GBP = 12 NOK for the 2004 figure, as stated in the Frigg decommissioning program) and the actual cost converts to 2 363.5 million NOK using actual exchange rates and adjustment for inflation.

This represents a budget overrun of 75.8 %.

As mentioned above for the Norwegian part of the Frigg field, the overrun was probably even larger, but Aker covered some of the cost overrun.

North West Hutton [37]**:**

North West Hutton was one of the giants in the UK with a total design weight of 36 630 tons. North West Hutton was a modular jacket platform with drilling, production, processing and quarters.

The decommissioning project was a full decommissioning project covering P&A of 40 wells, topside cleaning and preparations, the removal and disposal of topside and jacket down to footings, transport to shore and onshore recycling/disposal, decommissioning of pipelines, seabed clean-up and monitoring program.

The platform ceased producing in 2003 and was removed in 2008-2009.

In the decommissioning program the budget for the whole decommissioning project was 160 million GBP (2014). The actual cost ended up being 246 million GBP (2014) [9].

This represents a budget overrun of 53.8 %.

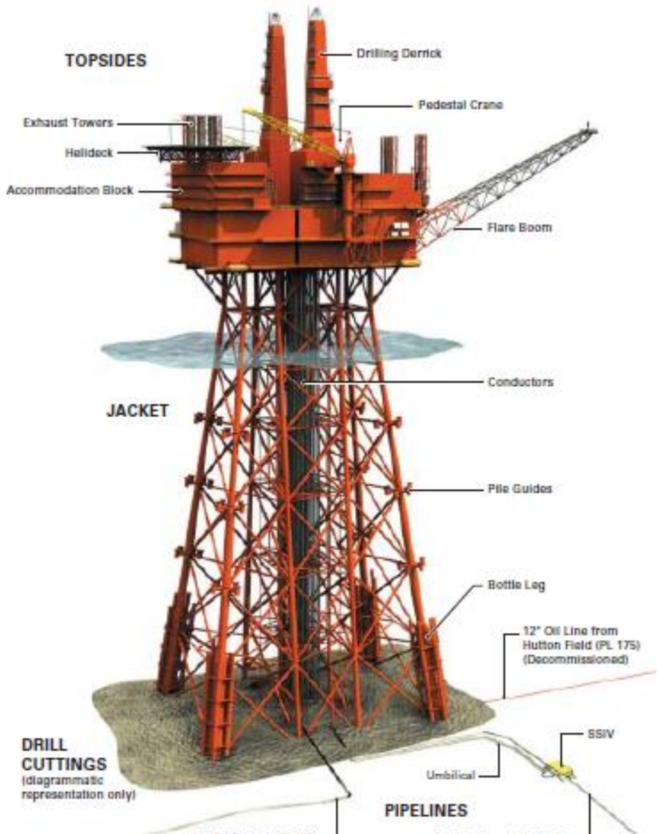


Figure 26: North West Hutton [37]

Indefatigable field:

The Indefatigable field consisted of 6 small jacket platforms with a total weight of 12 548 tons including all 6 topsides and jackets. The platforms ceased production between 2006-2008 and were removed between 2009-2011. The platforms had a total of 32 wells, but P&A was not included in the decommissioning program and the Close Out report.

The scope of the work included in the decommissioning project was the full decommissioning of the six platforms in the Indefatigable Field.

Budgeted cost was 61.3 million GBP (2003) and the actual cost was 154.8 million GBP (2014) [62].

After converting to NOK and adjusting for inflation to 2017 value, the budgeted cost was 927 million NOK and the actual cost was 1729.7 million NOK.

This represents a budget overrun of 86.6 %.

Camelot CA:

The Camelot decommissioning project is an example of a minor development consisting of the cleaning, removal and disposal of Camelot CA, a small jacket platform, with a total weight of just under 2000 tons, P&A of 6 wells, the removal of 22 concrete mattresses and the decommissioning of the gas export pipeline and the infield pipelines and control lines.

The project had a budget of 31.4 million GBP (2013) and the actual expenditure ended up at 37.3 million GBP (2013) [63].

This represents a budget overrun of only 18.8 %

Maureen:

The Maureen decommissioning project is the only example from the North Sea where a gravity-based substructure and its topside have been refloated as one unit. The Maureen platform was a drilling, production and accommodation platform with a unique design. It was a jacket platform with 3 storage cells attached to the jacket. The total weight of the platform was 111 750 tons, including just over 50 000 tons of orecrete as ballast in the storage cells. The removal of the platform was undertaken by refloating the whole structure using the storage cells as buoyancy and towing it to shore. The P&A of the 23 wells were not included in the decommissioning program since a majority of the work had already been done.

The scope of the Maureen decommissioning project was as follows:

- Cleaning of and making safe topsides
- Cleaning the ballast water from the storage cells
- Refloating the whole platform
- Towing the platform to shore
- Disposal /recycling of the platform on shore
- Removal of drilling template
- Removal of 2 docking piles and 4 mooring piles
- Decommissioning of pipelines
- Removal of equipment associated with the Moira subsea development
- Seabed clean-up

The budget of the Maureen decommissioning project was 150 million Pounds (2001) which is equal to 2636 million NOK (2017) [64].

The actual cost of the Maureen decommissioning project was 225 million dollars (2001) [65], excluding the disposal/recycling. The contract value for disposal/recycling, awarded to Aker Stord, was 700 million NOK (2001) [66]. This equals 3446 million NOK (2017).

This represents a budget overrun of 30.7 %.

Fife, Flora, Fergus and Angus [67] [68]

This is a subsea field in the UK developed using the FPSO *Uisge Gorm.*

The field consisted of 11 wells – 8 producers and 3 injectors.

The decommissioning project was carried out between 2008 (CoP) and 2014 (removal of the last subsea structure)

The scope of the project was:

- Disconnection of *Uisge Gorm*
- Removal of subsea facilities
- Removal of pipelines
- P&A of 11 wells
- Seabed clearance
- Transport of pipelines and facilities to shore
- Disposal and recycling onshore

The budget was 220.5 million pounds (2014)

The actual cost was 265.9 million pounds (2014)

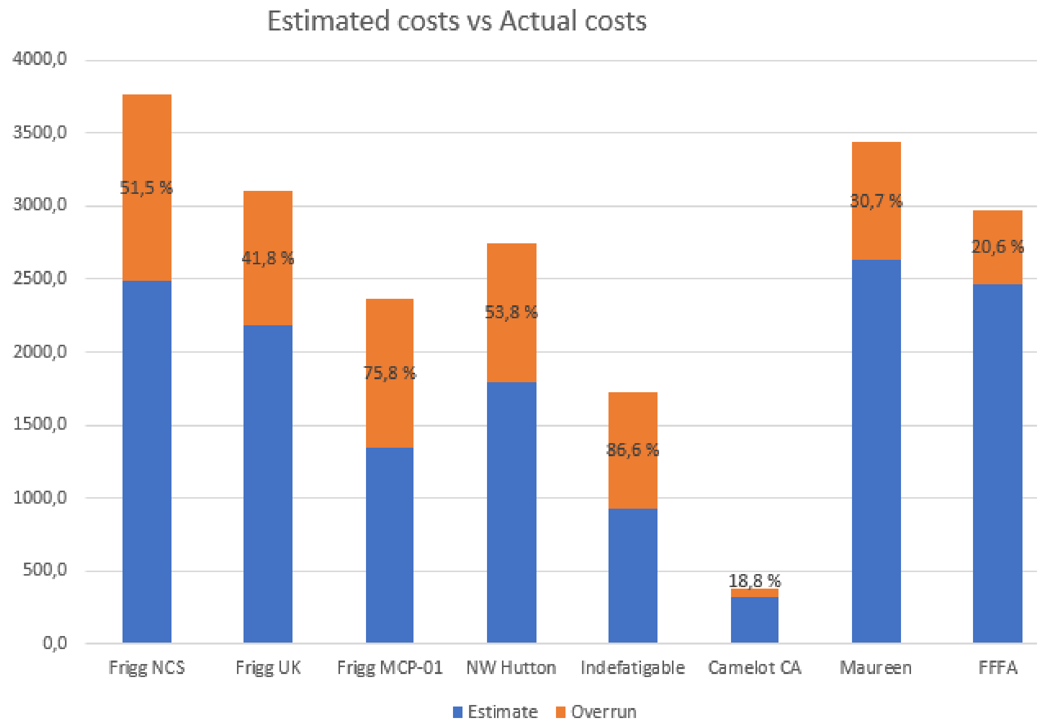
This represents a budget overrun of 20.6 %.

__Summary:__

The average overrun on the decommissioning projects for the 12 jackets, the 15 topsides and the one subsea development using FPSO listed above ended up at 47.4 %.

Due to lack of data, it is unclear in which phases of decommissioning the overruns are incurred.

Table 3: Overview of decommissioning cost overruns



From these findings one thing is evident: budgeting and cost estimation for decommissioning projects is difficult to get right. In the discussion section the root causes of the underbudgeting is investigated further.

Budgeting and Cost estimation in the Early Stages of Decommissioning

In the analysis of budgeted cost compared to actual cost in decommissioning projects, the finding was clear. Operators seem to systematically underestimate the actual cost of decommissioning.

It is imperative to find the root causes of these findings, but initially it is useful to look at some of the characteristics of a decommissioning project.

Complexity

Decommissioning projects are inherently complex and achieving the objective involves a range of different disciplines cooperating to undertake a multitude of tasks in succession.

Decommissioning projects like the decommissioning of Frigg field and Ekofisk I are examples of projects defined as megaprojects according to the article *What You Should Know About Megaprojects, and Why: An Overview* by Bent Flyvbjerg [69]. This is due to the combination of the projects' vast complexity and the cost of over a billion dollars. Most of the decommissioning projects studied in this thesis are either major projects that share a lot of characteristics with megaprojects or are in fact megaprojects.

Uncertain time frame

There is a high level of uncertainty regarding both the start date and the duration of decommissioning projects. The oil price, among other factors, influences the choice of CoP date. Projects will often drag out in time, and for some offshore structures more than 10 years pass between CoP and full removal, such as with Frigg. It is challenging to budget for a project when there is deep uncertainty related to both start date and duration.

Scope not clearly defined at the outset

The lack of information about the scope of decommissioning projects at the outset makes cost estimation demanding. One challenge might be poor documentation – as one industry insider stated in an interview, "we are working with hand-written notes by Mobil from the seventies". Another issue might be poor data on the structural integrity of the offshore structure. Another example can be poor information on the prevalence of hazardous materials like asbestos or low-radioactive materials in the offshore structure. The condition of the wells that are to be plugged are sometimes unknown, which makes cost estimation highly challenging.

External factors

Weather is a factor in decommissioning and can easily make a project much more expensive if conditions are poor. Also, legislation and regulations might change over time making the project more demanding – paragraph 7 of OSPAR decision 98/3 states that as experience and technology in decommissioning improves, stricter criteria for granting derogations shall be implemented [24].

Immaturity of Technologies

In decommissioning, a whole range of different methods have been tested with varying results. Testing new and/or immature technologies can be very expensive. One example might be piece-small on a large platform. Another example might be the use of buoyancy tanks in the transport of jackets to shore. One industry professional stated in an interview that there is a "race to be second" – to not be the first to try out new methods and technologies due to the high risk, but to quickly implement it if proven successful.

Inexperience in project teams and engineering

The operating companies and the decommissioning industry in Norway has not undertaken many projects yet and lacks experience. Inexperience can lead to poor budgeting.

Low degree of transparency in Decommissioning increases the risk of making poor choices when choosing the preferred method for decommissioning

The lack of transparency in the decommissioning industry increases the risk of making the same mistakes over and over. In more transparent industries the lessons learned are shared and the whole industry is aware of best practices. This is not the case in decommissioning.

Principal-agent problem

There are two varieties of the principal-agent problem in decommissioning relevant to the thesis. One is present both in Norway and in the UK, and the other is only present in the UK.

Both in Norway and in the UK the management group of the operating companies have incentives to make the future liabilities seem as low as possible. Future liabilities influence stock prices, and the lower the future liabilities seem, the higher the stock price. The stock price is an important factor in assessing how the management group performs, and in many cases part of the remuneration of the managers is through stock options. This gives the decision makers an incentive to make sure that future liabilities are on the optimistic side (read: underestimated) and can be one of the reasons that decommissioning is systematically underestimated.

The other principal-agent problem is present only in the UK but works through the same mechanism.

The article *Decommissioning Liability in the UK and Relief under the Finance Bill* [70] is the basis for the following paragraph.

When a UK field approaches the decommissioning stage, UK regulators demand that all field owners appropriate a letter of credit to ensure that the field owners are financially able to cover their share of the decommissioning costs. This letter of credit must be obtained from a third party and there are costs associated with acquiring it. The higher the estimated decommissioning costs are, the higher the cost. This is another mechanism through which the principal-agent problem might lead to a systematic underbudgeting of decommissioning projects.

The operating companies are required to hand in their best guess for the actual costs in the decommissioning programs, but the principal-agent problem brings incentives to hand in a more optimistic version of the decommissioning budget.

There are a multitude of other factors that cause difficulties when estimating the cost of a decommissioning project, so the above is by no means the sole reason for estimating errors. However, it should be evident that cost estimation for decommissioning projects is a challenging discipline.

In Flyvbjerg's article [69], which is the basis for the following section, it is stated that megaprojects often end up with cost overruns in excess of 50 %. Flyvbjerg points to "optimism bias" as one of the key factors contributing to cost overruns. Another key contributor is what Flyvbjerg describes as "uniqueness bias". Planners and managers tend to categorize their project as "…singular, impeding learning from other projects".

The lock-in to one specific concept in an early phase is another pitfall according to the article. Principal-agent problems are also mentioned as a potential problem. A central issue pointed out by Flyvbjerg is that cost estimates are often deterministic in nature. A probabilistic approach would serve the megaprojects better given their overexposure to so-called *black swans*. The contingencies in the cost estimates of megaprojects do not account for the risk of unplanned events due to the complexities in the project. A consequence of the factors above and other factors not mentioned is that cost estimates for megaprojects have a high risk of being too low.

In Flyvbjerg's article "*the iron law of mega projects"* is presented:

"Over budget, over time, over and over again"

According to Flyvbjerg, only one in ten megaprojects is on schedule, one in ten is on budget and one in ten delivers the expected benefits. That makes a megaproject that is on schedule, on budget and deliver the expected benefits a rare breed indeed.

In general, decommissioning projects deliver the expected benefits from the projects. The regulators require a decommissioning program to be handed in for all decommissioning projects except some of the minor ones. In the decommissioning programs the different concepts are explored and evaluated reducing the risk of choosing the wrong concept.

Most of the root causes for cost overruns of megaprojects are relevant for decommissioning projects. All operators should take note of the pitfalls mentioned in Flyvbjerg's article and keep them in mind throughout the decommissioning project's lifecycle.

Top-Down Versus Bottom-Up

A key distinction in cost estimation is the top-down and the bottom-up estimation methodology.

In a top-down approach an aggregated number of some sort is collected from prior comparable projects and an expected cost per unit is calculated. The result may be called a norm or a metric in cost estimation literature. This aggregated number may be the total cost for the whole project or it may be the aggregated numbers on a high level of the work breakdown structure. This approach is much less labor-intensive for the cost estimators and, though some precision is lost, this approach is common in cost estimation in early phases of projects. Another key issue is that this approach does not require the same insight in the specifics of the project.

The top down-methodology can prove quite precise if the historical data used as the basis of calculating the norms/metrics is precise and there is sufficient data. The choice of contingency is at the estimator's discretion and is often based on historical data on the uncertainty of final cost.

A pitfall of top down cost estimation is that some detail is lost, and the full scope of the project may not be captured in the budget. In later stages of the project when the scope of the project is well defined a higher level of accuracy may be reached using the bottom-up methodology. In this approach the project is partitioned using a WBS on a detailed level. Each activity is divided into job packages and the estimator will calculate the expected cost of each work package. The final budget will be the sum of all the work packages the project is comprised of.

This approach requires detailed knowledge of the scope of work of each activity and of the cost of all the input factors. To create an estimate with this level of detail is labor intensive and requires estimators with a broad skillset. The estimates carrying this level of detail are more precise but are usually not performed at the initial stages of a project. They are usually done when a project is close to a decision gateway where it is either rejected or approved by management.

The choice of contingency is at the estimator's discretion and is often based on historical data on the track record of estimates of final cost compared to actual cost.

One of the most important motivations for developing a budget is to use it as decision support at the gateways of the project. This is less important for decommissioning projects due to the limited alternatives open to management. A decommissioning project can bring forward the execution stage or it can be postponed, but it cannot be rejected. This has implications for the choice of cost estimation strategy. Some detail is lost in top-down budgeting, but it generally carries less cost. If a top-down budget is deemed sufficiently precise, this should be the preferred choice in the early stages of decommissioning cost estimation.

Risk is a central element in all modeling and Monte Carlo simulations (discussed further down) try to include risk in the estimates. But not all risk factors are easily included in the projects.

In the article by Flyvbjerg [69], the author cites *The Black Swan: The Impact of the Highly Improbable* by N.N. Taleb [71], and states that

> *…megaprojects have an overexposure to so-called "Black Swans", i.e. events with massively negative outcomes.*

This risk is not easily included in cost estimates. One striking example is the Deepwater Horizon blowout and resulting oil spill, another is the Fukushima disaster. In these incidents, several highly unlikely scenarios happened to occur simultaneously, with an extremely low combined probability. Events such as these are extremely unlikely, but the consequences are extreme. These outliers are inherently difficult to model.

Deterministic Versus Probabilistic

A deterministic approach to cost estimation means that the expected cost of each element in a project is estimated separately and an expected cost is calculated for each element. The final cost estimate is the sum of all the cost elements. The estimator may add a contingency to the final sum to account for the uncertainty in the estimate, but the final cost estimate is a fixed number.

The probabilistic approach is very different. This approach to estimation tries to model the uncertainty attributed to each element in the process and consequentially the uncertainty in the outcome. The cost of each element varies but it is not random. Using historical data and theoretical approaches, a probability distribution can be developed, and the actual cost of the element will be a random number from the cost element's probability distribution.

The distribution of the project's cost is determined by the probability distributions of all the cost elements. A distribution for the final cost estimate can be calculated using this approach, and the key attributes of the estimate can be presented. Those may be: Expected value, standard deviation, P10, P50, P90, and so forth. The P50 value is the output value where 50 percent of the simulation results are above this value and 50 percent of the simulation results are below. The P10 value is the output value where 90 percent of the simulation results are above this value and 10 percent of the simulation results are below. The P90 value is the output value where 10 percent of the simulation results are above this value and 90 percent of the simulation results are below.

The Monte Carlo approach results in an estimate that carries a lot more information about the inherent uncertainty of the project.

One challenge may be defining the distribution of all the sub-elements. A common approach is to use historical data to establish a lower and an upper bound and use the average as the distribution center. If there is sufficient historical data, the exact distribution for the cost of each element may be established. In many cases a triangular distribution is chosen for ease of estimation.

The distinction between deterministic and probabilistic cost estimation is not exclusive to bottom-up estimation. It applies to top-down estimation as well. A common approach in probabilistic cost estimation is the use of Monte Carlo-simulation.

Monte Carlo Simulation

The modelling of outcomes of cost estimation requires a probability simulation, and due to the large number of uncertainties in the model, a Monte Carlo simulation is a fitting approach [6]. The Monte Carlo method is a computational technique used to model uncertainty in a system by generating random variables. The variables are based on a specific distribution, such as a triangular distribution. The probability of different outcomes in a system is influenced by many random variables, and the probabilities are interconnected, making it a highly complex system.

The model assigns probability distributions to each variable. Random numbers from the probability distributions are used to determine the outcome of each simulation, and many simulations are performed. The most likely outcome will be approximated by the outcome that occurs the most in the simulations, due to the large number of simulations which should indicate a real-life situation. The large number of simulations is the essence of the Monte Carlo model.

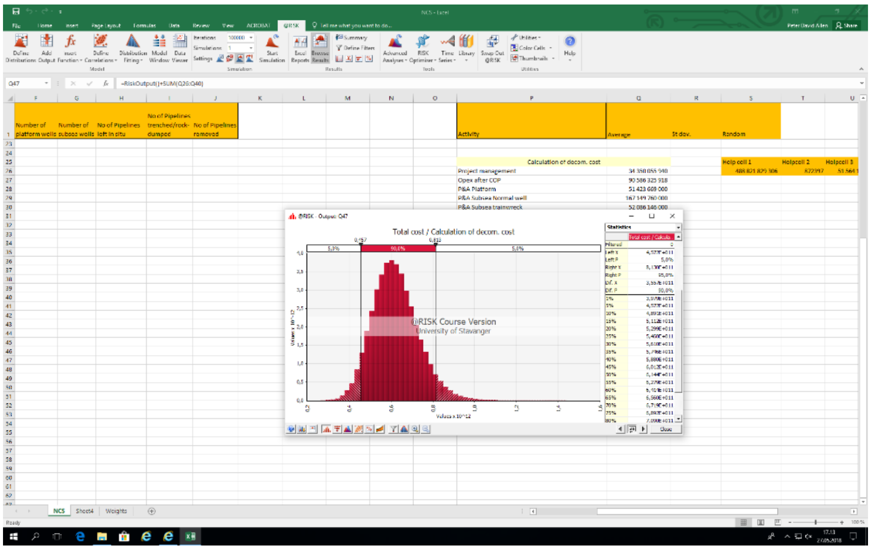


Figure 27: A Monte Carlo simulation using Excel and @Risk

As mentioned, use of bottom-up cost estimation approach requires considerable experience in the industry and in-depth knowledge of the activities and equipment on an installation. It also requires access to historical cost databases. As the authors do not possess any of these, this method is beyond the scope of the thesis. However, an overview of this cost estimation approach is presented.

Cost breakdown for cost estimation is based on the NORSOK Z-014 [72] standard and the internationalized ISO 19008 [73] standard. These form a standard cost coding system (SCCS) that classifies costs, durations and quantities related to offshore petroleum activities. The standard is made up of three annexes – Physical Breakdown Structure, Standard Activity Breakdown, and Code of Resource. The three annexes are further broken down into hierarchical levels as one delves deeper into the details of the structure and the work associated with its activity. The different components in each level are assigned a letter or a number. Each component then has its own unique code.

- Physical Breakdown Structure, PBS: defines the physical and functional components of an installation. Regarded as the **where** of the activity

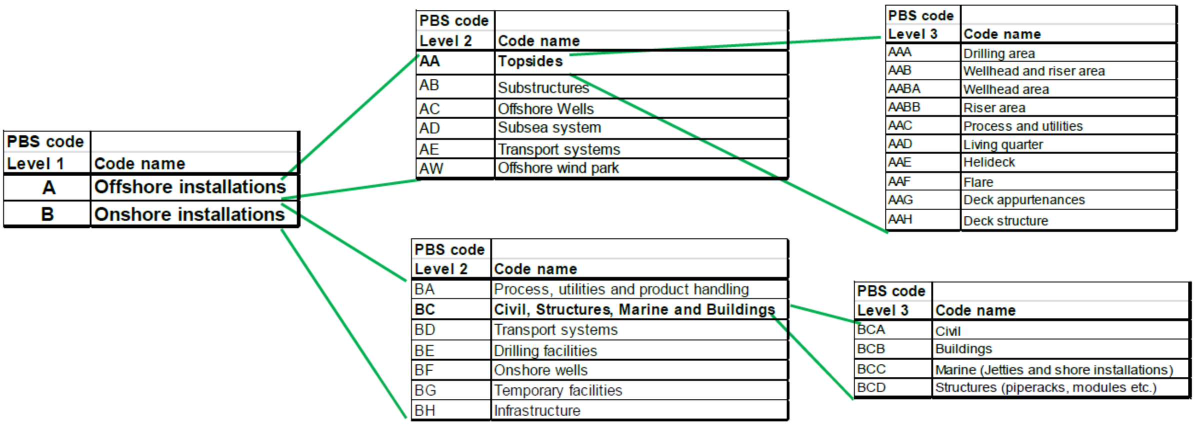


Figure 28: Example of PBS breakdown [74]

- Standard Activity Breakdown, SAB: breaks down the activities in a project, such as project management, engineering, procurement, construction and operation. Regarded as the **when** of the activity

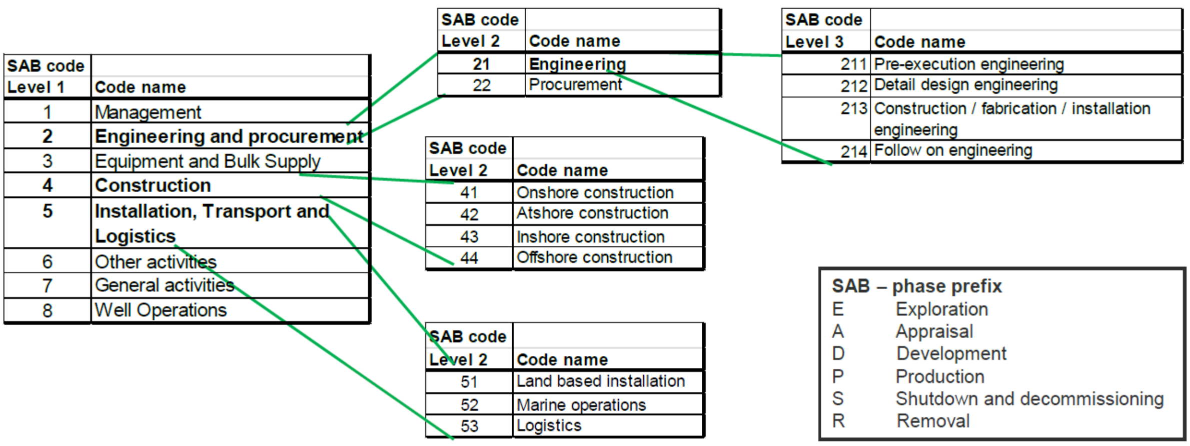


Figure 29: Example of SAB breakdown [74]

- Code of Resource, COR: classifies project resources, generically categorizing them according to primary, secondary and tertiary levels of resource. It is intended to provide codes to classify the complete scale of resources required in developing off- and onshore installations. Regarded as the **what** of the activity

COR code Level 1	Code name
COR code	**Code name**
A	General costs
E	**Equipment**
B	Bulk materials
K	Engineering personnel
R	Engineering overheads
L	Direct labour
M	Indirect labour
C	Construction overheads
H	Company personnel
Q	Company personnel overheads
S	Unit work
X	Marine operations and logistics
Y	Land based plant and equipment

COR code Level 2	Code name
EA	Architectural equipment
ED	Drilling equipment
EE	Electrical equipment
EG	Heating, ventilation and air conditioning (HVAC) equipment
EJ	Instrumentation equipment
ER	**Mechanical equipment**
ES	Safety/escape and firefighting equipment
ET	Telecommunication equipment
EU	Subsea equipment
EV	Mooring and marine equipment
EY	Transfer and control equipment

COR code Level 3	Code name
ERC	Miscellaneous mechanical equipment
ERD	Drivers and power transmissions
ERF	Heaters, boilers, furnaces and flares
ERH	Heat transfer equipment
ERK	Compressors, blowers and expanders
ERM	Material and product handling equipment
ERN	Mechanical equipment – solids
ERP	Pumps
ERT	Storage tanks/containment equipment – atmospheric
ERV	Vessels and columns – pressurised
ERX	Miscellaneous package units

Figure 30: Example of COR breakdown [74]

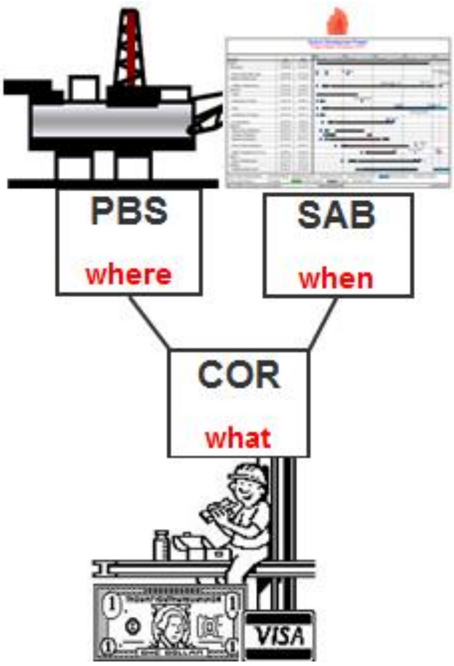


Figure 31: Illustration of the three classification structures [74]

Combining the three classification structures with associated costs gives a cost estimate for a work package in a WBS. The figure below shows an example of a cost structure. The PBS code ABAD indicates the following:

- First letter A: offshore installation
- Second letter B: substructure
- Third letter A: steel jacket
- Fourth letter D: Piles

The SAB code 4132 indicates the following:

- 4: construction
- 1: onshore construction
- 3: fabrication
- 2: Installation/assembly/erection

The COR code LN indicates:

- L: direct labor
- N: structural direct labor

79	ABAD	ABAD Piles	322	322 Contractor provided bulk	BQE	BQE Piles	1.01.02.01.02	PILES Material Procurement	LEVEL 5	1 100 057
80							1.01.02.02	JACKET MATERIALS SHIPPING & FREIGHT	LEVEL 4	304 962
81	ABA	ABA Jacket	3	3 Equipment and Bulk Supply	AEC	AEC Freight	1.01.02.02.01	JACKET Materials Shipping to Fab Yard	LEVEL 5	304 962
82							1.01.02.03	JACKET FABRICATION	LEVEL 4	8 318 611
83	ABAA	ABAA Jacket structure	4132	4132 Installation/assembly/erection	LN	LN Structural direct labour	1.01.02.03.01	JACKET Fabrication	LEVEL 5	4 722 266
84	**ABAD**	**ABAD Piles**	**4132**	**4132 Installation/assembly/erection**	**LN**	**LN Structural direct labour**	**1.01.02.03.02**	**JACKET Piles Fabrication**	**LEVEL 5**	**904 478**
85	ABA	ABA Jacket	418	418 Weighing, seafastening and load-out	LN	LN Structural direct labour	1.01.02.03.03	JACKET Loadout, Weighing & Seafastening	LEVEL 5	1 224 782
86	ABA	ABA Jacket	41	41 Onshore construction	CAA	CAA Construction management	1.01.02.03.04	JACKET Fabrication Yard Management	LEVEL 5	1 467 085
87							1.01.02.04	JACKET Management & Engineering (EPC)	LEVEL 4	1 315 819
88	ABA	ABA Jacket	21	21 Engineering	KA	KA Engineering management and administration	1.01.02.04.01	JACKET Project Management (EPC)	LEVEL 5	1 162 077
89	ABA	ABA Jacket	212	212 Design engineering	KZ	KZ Multidiscipline	1.01.02.04.02	JACKET Design Engineering (EPC)	LEVEL 5	153 742
90							1.01.02.05	JACKET GENERAL SERVICES	LEVEL 4	229 048
91	ABA	ABA Jacket	7	7 General activities	AC	AC Insurance	1.01.02.05.01	JACKET Insurance	LEVEL 5	229 048
92							1.01.02.06	JACKET TRANSPORT	LEVEL 4	1 708 240
93	ABA	ABA Jacket	526	526 Transport	XS	XS Heavy transport vessels	1.01.02.06.01	JACKET Transport Barge	LEVEL 5	1 708 240
94							1,01.03	WP 3 - INSTALLATION OF DECK, JACKET / OFFSHORE	LEVEL 3	76 277 597
95							1.01.03.01	INSTALLATION OF DECK, JACKET & PILES	LEVEL 4	20 247 609
96	ABA	ABA Jacket	523	523 Installation	XC	XC Lifting vessels	1.01.03.01.03	Heavy Lift Vessels JACKET	LEVEL 5	13 498 406
97	AA	AA Topsides	523	523 Installation	XC	XC Lifting vessels	1.01.03.01.04	Heavy Lift Vessels DECK	LEVEL 5	6 749 203
98							1.01.03.02	BULK SUPPLY, TRANSPORT & INSTALLATION OF OFFSHORE	LEVEL 4	35 965 595
99	AEAAA	AEAAA Production/trunk line	322	322 Contractor provided bulk	BY	BY Pipeline bulk	1.01.03.02.01	PIPELINE Misc. Materials Procurement	LEVEL 5	3 898 042
100	AEAAA	AEAAA Production/trunk line	5241	5241 Pipelaying	XD	XD Pipelaying vessels - S-lay	1.01.03.02.03	PIPELINE Installation	LEVEL 5	22 693 750

Figure 32: Example of usage of the SCCS

AACE Cost Estimate Classification System

AACE International's cost estimate system [75] provides guidance on applying estimate classification principles to project cost estimates. It maps the phases and stages of project cost estimating with a generic project scope definition maturity and quality matrix. The system is used in conjunction with stage-gate scope development and decision-making processes. Table 4 illustrates the cost estimate classes and their corresponding maturity levels.

Table 4: AACE Cost Estimate Classification Matrix [75]

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

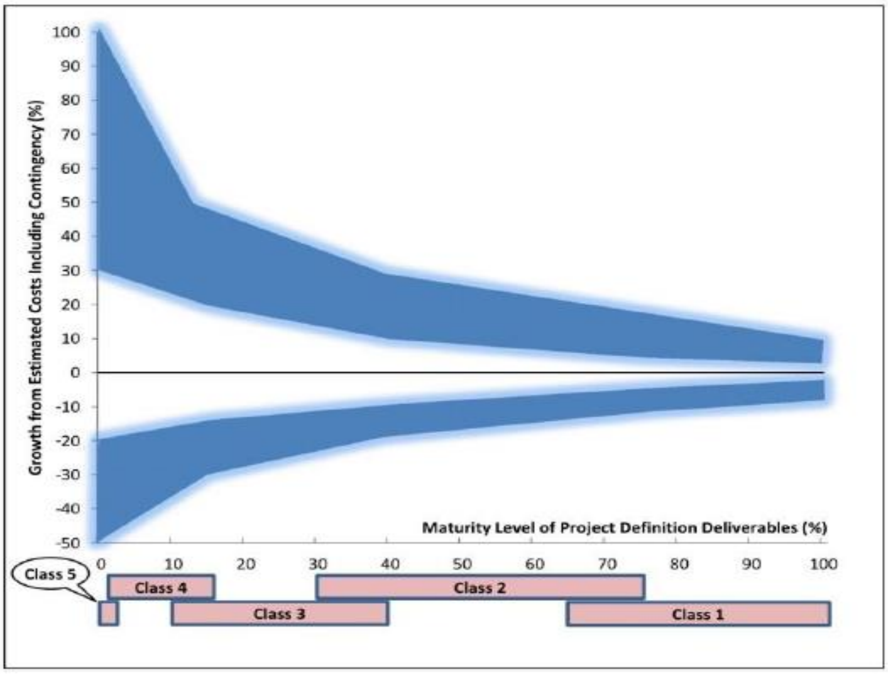


Figure 33: Variability of accuracy ranges [75]

The cost estimator determines the estimate class based on the maturity level of the project definition, which is in turn based on the status of key planning and design deliverables.

Use of metrics in decommissioning

Several metrics can be used for cost estimation of decommissioning:

- Cost per ton removed, cost per well plugged
- Time per activity
- Scope, such as number of operations required

BP's Win Thornton has presented the use of metrics in decommissioning [76]. This thesis attempts cost estimation in the same fashion, based on cost per ton removed, cost per well/pipeline, and cost per transport of floating installation. Figure 34 presents examples of metrics from Thornton's presentation.

OGUK WBS	Scope	Data Source	Basis of Estimate	Metric/NORM	Estimate	%
Operator Project Management			Compay Project Team (6% PMT & 1% Studies)	7%	£20,000,000	7%
Facility Running/Owner Costs			P&A 50% wells preCOP	80% final year OPEX	£40,000,000	14%
Wells Abandonment	20 wells	region well inventory	P&A 50% wells preCOP with exisitng rig. No refurb req'd	£4MM/well	£80,000,000	29%
Facilities/Pipelines Making Safe			50% prep time SIMOPS with P&A	5% of removal costs	£5,500,000	2%
Topsides Preparation	20,000 Te	Photo & OSPAR database	50% prep time SIMOPS with P&A; modules have all lifting aids in place	5% of removal costs	£5,500,000	2%
Topsides Removal			reverse installation of modules and backload to HLV for transit	£3,500/Te	£70,000,000	25%
Substructure Removal	18,000 Te		derogation of jacket footings and single lift of top section to shore	£4,000/Te	£40,000,000	14%
Topsides & Substructure Onshore Recycling	30,000 Te	assumed weight removed w/derogation	backload to disposal site, demo & recycle	£150/Te	£4,500,000	2%
Subsea Infrastructure	20" 3rd party gas; 16" 3rd party oil	Pipeline database	Obligation to clean & disconnect	£5MM/pipeline	£10,000,000	4%
Site Remediation	0 M3	region inventory	No drill cuttings or debris		£0	0%
Monitoring			two inspections (1@5 yrs & 1@10yrs) as part of industry program	£1MM/inspection	£2,000,000	1%
				Totals	£277,500,000	100%

Figure 34: Examples of metrics for decommissioning [76]

RESEARCH METHODOLOGY

This section details the methods used for the development of this thesis: how information was gathered, examined, scrutinized, analysed, processed and presented. Based on the availability and amount of data, a combined quantitative-qualitative method was chosen, where select cases of decommissioning were examined to find the most pertinent factors that guide cost estimation and their effects on the decommissioning process. Data was compiled to develop cost metrics for phases of decommissioning, which were further used to build a cost estimation model. Through discussions with the industry and studies of prior publications, other goals of the research were established – to determine the total cost of decommissioning for the entire NCS using the model. The Norwegian government is obligated to cover most of the decommissioning costs and it was deemed beneficial to provide estimates toward the total expenditure, as this can provide a sense of the scope of the future decommissioning industry. This can act as a stimulus for increased funding of R&D in decommissioning, thereby reducing costs, maximizing domestic supply chain efficiency, improving HSE and minimizing energy use.

The main challenge of decommissioning cost estimation is the immense amount of variables on different oil and gas installations - to name a few: water depth, weight, age, accuracy of documentation, risk level, removal method, installation design, number of jacket legs, cuttings pile constituents, accommodation configuration, vessel and rig demand, well structure, spread rates, market volatility, supply chain utilization, level of experience, rate of deterioration and scope of maintenance performed.

Analysis of the gathered information:

A database was compiled, where a range of different values were gathered, mostly pertaining to costs and removal methods. As the work progressed, it became clear that a wider range of data was necessary to examine correlations and trends in projects. The database was expanded and developed throughout the work on the thesis as new information was discovered, almost until the deadline for hand-in. Costs were examined to compile metrics on the different phases of decommissioning. These metrics were then used for cost estimation modelling.

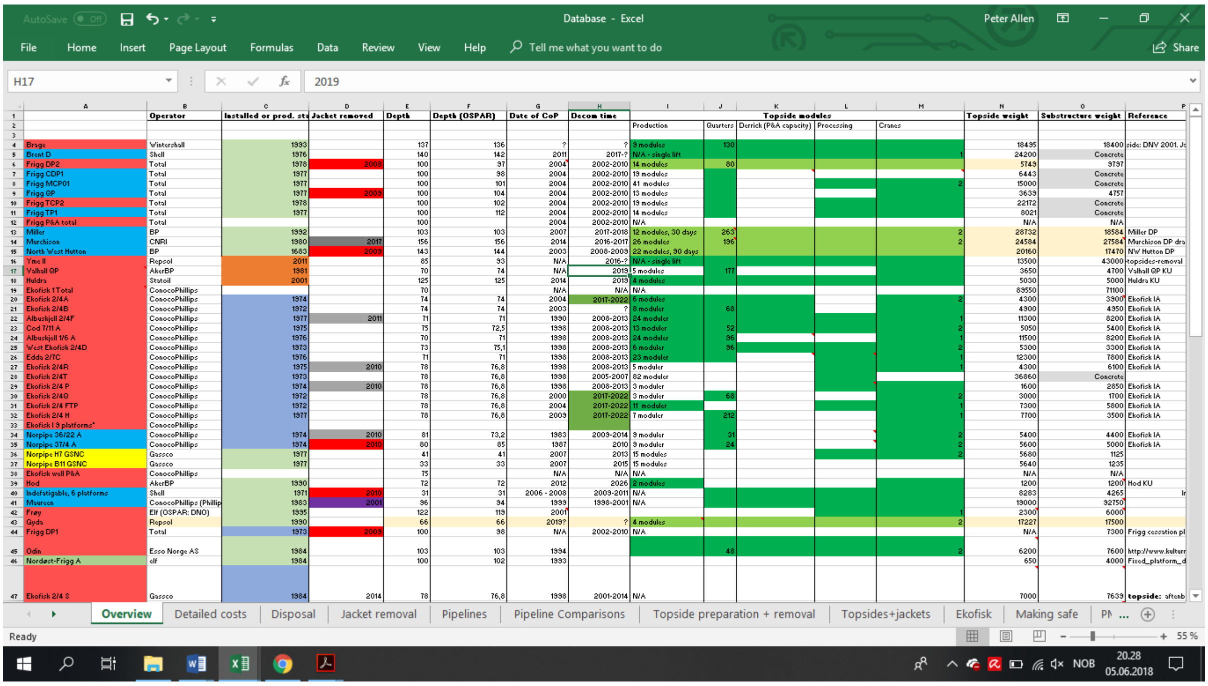


Figure 35: Database of field properties

The oil and gas industry is, as most industries, highly reluctant to share development project cost figures in the public domain. This is to be expected, as a firm's competitive advantage may be dependent on corporate secrecy. This approach also carries over to decommissioning projects – decommissioning obligations are viewed as liabilities, so cost estimates are naturally restricted information. Actual costs are also kept confidential for many reasons, chief among them to maintain reputation amongst stakeholders. Cost estimation methodology and actual cost information is highly challenging to obtain for independent researchers. However, some information is publicly available, mostly from **decommissioning programs, Close Out reports** and **impact assessments**. These three types of documents constitute a significant portion of the information used in this thesis.

- **Decommissioning program:** A plan for the decommissioning of an asset on the UKCS, whose main component is a comparative assessment of removal methods and cost-benefit analyses of these. These reports are published to inform all affected stakeholders in an oil or gas development. The programs contain high-level cost estimates, however the majority are redacted and provided separately to the

Department of Energy and Climate Change (DECC) / Department of Business, Energy and Industrial Strategy (BEIS). A small portion have uncensored cost estimates, and these have been used as a basis for cost analysis in this thesis. The structure of the cost numbers has posed challenges, as they are often detailed as one lump sum, or divided in segments that do not correspond to commonly used Work Breakdown Structures for decommissioning, such as those used in Oil & Gas UK's *Guideline for Decommissioning Cost Estimation* [7]. For example, topside removal and disposal may be listed as one cost, whereas they are separate in the Oil & Gas UK guidelines. In another report, subsea infrastructure removal and site remediation may be classified as the same cost.

- **Close Out reports:** an after-action report from a decommissioning process, usually published for projects in the UK sector, where all activities performed are described in varying detail. Costs are often reported, but as with decommissioning programs they are often segmented in differing formats, making cost breakdown analysis challenging.

- **Impact assessments:** For the Norwegian sector, one of the main sources of information is the *Konsekvensutredning*, or Environmental Impact Assessment. The konsekvensutredning is a part of the decommissioning plan (*avviklingsplan*), along with the *disponeringsdel* [40]. The disponeringsdel is similar to the UK's decommissioning program but is not released to the public. The konsekvensutredning details environmental effects of the decommissioning process, and is, in some cases, publicly available online or by request to the government. A portion of the konsekvensutredning's have cost estimation figures. Again, costs in these publications are often broken down in segments that do not correspond to guidelines used in WBS's but can still be used as cost data.

Apart from these main sources, information has been gathered from a wide range of other sources, such as information on projects from collaborating companies, news articles, annual reports from decommissioning vendors, semi-structured interviews with industry professionals, and publicly available databases. The use of news articles as a source, although highly unreliable, was deemed necessary due to the lack of publicly available information. In the majority of cases where news articles were used, secondary news sources were consulted to judge the accuracy of figures.

Literature study

In the initial stage of the thesis work the main priority was to gain further insight into all aspects of decommissioning. More than 100 scientific articles, reports and other publications were reviewed – though they are not referenced in this thesis, these sources form the foundation of the thesis. The following list details some of the main sources for this foundation

- Dr. Techn. Olav Olsen: *Markedsrapport Knyttet til Avslutning og Disponering av Utrangerte Innretninger* [77] - This is a market report that describes the decommissioning projects that have been executed, presents an overview of the status quo in decommissioning as of 2018 and presents a forecast of future decommissioning.
- Oil & Gas UK: *Decommissioning Insight 2015, 2016, 2017* [78] [79] [2] - An annual report on the status of decommissioning, with ten-year forecasts on upcoming decommissioning scope.
- Win Thornton: *The Case for Metrics* [76] - A presentation showing how metrics for cost estimation can be developed and applied.
- Oil and Gas Authority: *UKCS Decommissioning – 2017 Cost Estimate Report* [80] - A report detailing future costs of decommissioning on the UKCS. The report uses probabilistic Monte Carlo modelling to present a total estimate.
- Thomas Øia, Jon Oscar Spieler: *Plug and Abandonment Status on the Norwegian Continental Shelf* [11] - This thesis describes the scope of P&A on the NCS, and has been used for insight into the scope of decommissioning on the NCS and as a source of information on the specifics of P&A.
- Olav Fjelde: *Time Estimation of Future Plug and Abandonment Operation at Brage Field* [81] - This thesis contains in-depth analysis of the P&A operations on a specific field, and has provided information on P&A duration
- Mats Mathisen Aarlott: *Cost Analysis of Plug and Abandonment Operations on the Norwegian Continental Shelf* [82] - This thesis has given additional insight in cost

analysis of P&A on the NCS and P&A methodology. It has also provided useful information on the specifics of P&A cost components and the scope of P&A on the NCS.

- BP Valhall P&A Team: *Valhall DP P&A Project: The Project That Has It All* [83] - A presentation on the P&A of highly complex wells. Provides insight into the complexities and challenges of P&A, along with cost data
- Tim Croucher: *Decommissioning and P&A in the Future* [84] – A presentation on P&A at the Ekofisk field, illustrating learning effects

The following theses and doctorates provided additional insight on cost and duration of P&A:

- Fredrik Birkeland: *Final Field Permanent Plug and Abandonment – Methodology Development, Time and Cost Estimation, Risk Evaluation* [85]
- Emil Mikalsen: *A Rigless Permanent Plug and Abandonment Approach* [86]
- Jon Oscar Spieler: *Utilization of Purpose-Built Jack-Up Units for Plug and Abandonment Operations* [11]
- Moeinikia, Fatemeh: *Rigless P&A Technology Availability and Cost Effectiveness of Rigless P&A Operations* [87]

Anonymous sources: Where access to confidential cost data has been granted from operating companies, platform names have been anonymized in the form *Platform NN1, platform NN2*, and so forth. Interviewees have been kept anonymous.

Cost data were converted to Norwegian Kroner by using the corresponding exchange rate in the year the data was recorded, retrieved from [88], and adjusted to 2017 values using CPI values from [89].

Table 5: Exchange rates and CPI

Year	Consumer Price Index	Exchange rate GBP	Exchange rate USD
2017	105,5	10,6386	8,263
2016	103,6	11,3725	8,3987
2015	100	12,3415	8,0739
2014	97,9	10,369	6,3019
2013	95,9	9,1968	5,8768
2012	93,9	9,2199	5,821
2011	93,3	8,9841	5,6074
2010	92,1	9,3402	6,0453
2009	89,9	9,8052	6,2817
2008	88	10,3304	5,6361
2007	84,8	11,7237	5,86
2006	84,2	11,8141	6,418
2005	82,3	11,7111	6,445
2004	81	12,3401	6,7372
2003	80,7	11,567	7,0824
2002	78,7	11,9461	7,9702
2001	77,7	12,9414	8,9879
2000	75,5	13,3129	8,8058
1999	73,2	12,6252	7,8047
1998	71,5	12,5007	7,5465
1997	69,9	11,5958	7,0788

The data gathered on each part of the WBS is presented in the next section. Averages and standard deviations were gathered from each part and refined based on judgments on each individual project's characteristics.

Table 6: Work Breakdown Structure elements

Operator Project Management	**Facility Running/Owner's Costs**	**Wells Abandonment**	**Facilities/pipelines making safe**	**Topside Preparation**	**Topside Removal**	**Substructure Removal**	**Onshore Recycling and Disposal**	**Subsea Infrastructure**	**Site Remediation**	**Monitoring**

A Monte Carlo simulation model was compiled, using the @Risk excel add-in from Palisade Software, and used to estimate the cost of a typical North Sea oil platform. It was then used on 24 other facilities. This is detailed in the section *Estimation of Single Platforms.*

The model was developed using the following steps:

1. Definition of model: the model was developed for cost estimation, based on parameters such as cost per ton removed, cost per well plugged, percentage of total expenditure, and probability of encountering problems when plugging a well.

2. Data gathering: as detailed in previous sections, data on the costs and physical properties of a number of oil and gas fields were gathered.

3. Defining input distributions: Most of the parameters are assigned a triangular distribution. The normal distribution is disregarded as it will produce negative values in simulations, however the average and standard deviation has been used as a basis or indicator of the values of the mode, minimum and maximum values of the triangular distribution. The number of subsea problem wells is assigned a binomial distribution.

The triangular distribution is a simple probability distribution where only three parameters are required: the lowest possible outcome, the highest possible outcome, and the most likely outcome, known as the mode.

For the model, averages and standard deviations were calculated for each metric. The average was used as a basis for calculating the most likely outcome. The average in a triangular distribution can be calculated using the following equation:

$$\frac{min + mode + max}{3} = average$$

The mode can thereby be calculated:

$$(3 \times average) - min - max = mode$$

Finding the minimum and maximum possible outcomes was found based on the standard deviations and by examining the collected data.

Modifications were made to the triangular distributions for the cost of subsea wells and the cost of complex / "train wreck" subsea wells. These distributions are combined to overlap, to ensure a continuous cumulative distribution.

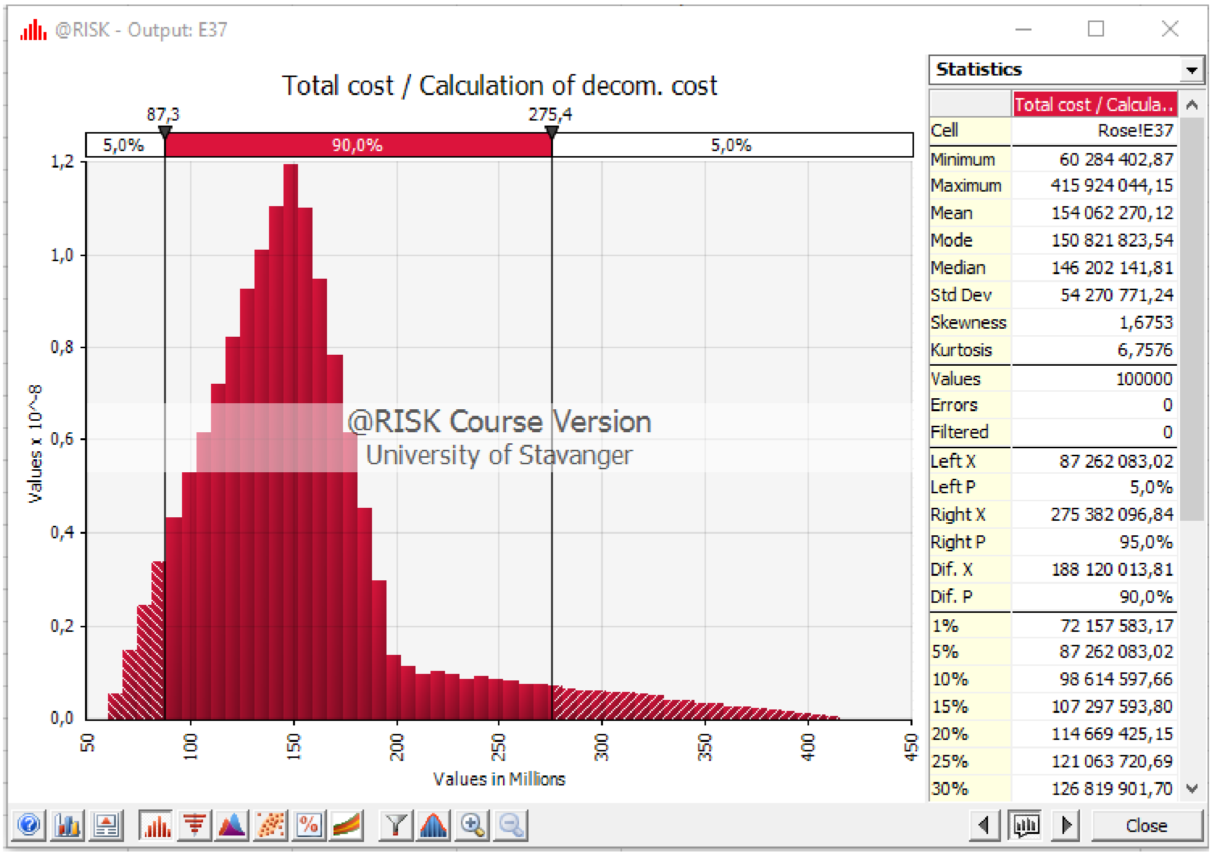


Figure 36: Distribution for subsea train wreck well costs

A major part of the workload related to this thesis has been data collection. Sufficient data is a requirement for estimating an adequate metric, and the collection and assessment of this data has been highly prioritized. Data sources with cost numbers have been emphasized, and those without have been studied for insight and understanding.

Table 7 illustrates the fields where pertinent information was found. The properties of more than 80 installations are directly used as sources for metrics. In addition, information presented in *Decommissioning Insight* has been used [78] [79] [2].

Table 7: Overview of fields and type of data gathered

Installation	Disposal	Jacket removal	Topside preparation	Making safe	Remediation	Monitoring	Pipelines	Project Management	Operator's cost post CoP	Subsa Infrastructure	Platform P&A Cost	Platform P&A Duration	Subsea P&A Cost	Subsea P&A Duration	Complex subsea P&A	Estimated cost	Actual cost
Brage																	
Frigg DP2																	
Frigg TCP2																	
Statfjord C SPM																	
Veslefrikk A																	
Veslefrikk B																	
Platform NN1																	
Platform NN2																	
Platform NN3																	
Platform NN4																	
Platform NN5																	
Platform NN6																	
Yme I																	
Valhall DP																	
Valhall QP																	
Huldra																	
Ekofisk 1 Total																	
Ekofisk 2/4A																	
Ekofisk 2/4B																	
Albuskjell 2/4F																	
Cod 7/11 A																	
Albuskjell 1/6 A																	
West Ekofisk 2/4D																	
Edda 2/7C																	
Ekofisk 2/4R																	
Ekofisk 2/4T																	
Ekofisk 2/4 P																	
Ekofisk 2/4Q																	
Ekofisk 2/4 FTP																	
Ekofisk 2/4 H																	
Frøy																	
Gyda																	
Frigg DP1																	
Odin																	
Hod																	
Ekofisk 2/4 S																	
Volve																	
Varg A																	
Jotun B																	
Rev																	
Øst-Frigg																	
Glitne																	
Tommeliten Gamma																	
Brent A																	
Camelot CA																	
Leman BH																	
Kittiwake Loading Buoy																	
Thames AP																	
Thames AW																	
Thames AR																	
Horne & Wren (Thames area)																	
Norpipe 36/22 A																	
Norpipe 37/4 A																	
Indefatigable, 6 platforms																	
Maureen																	
Frigg CDP1																	
Frigg MCP01																	
Frigg QP																	
Frigg TP1																	
Miller																	
Murchison																	
North West Hutton																	
Fife, Flora, Fergus, Angus (FFFA)																	
Annabel & Audrey																	
Rose																	
Tristan NW																	
Gawain (Thames area)																	
Wissey (Thames area)																	
Orwell (Thames area)																	
Markham Stamford																	
Arthur (Thames area)																	
Norpipe H7 GSNC																	
Norpipe B11 GSNC																	
Decom Insight		27						80	79								

Table 8: Fields studied where no data was gathered

Installations where no information was found
Statfjord A
Ekofisk 2/4 G
Heimdal HMP
Yme II
Nordøst-Frigg A
Mime
Lillefrigg
Brent D
Brent A, B, C
Ninian North
Brae A, B, Brae Central, West Brae
East Brae and Braemar
Jackie
Bains
Windemere
Welland
IVRR
Schiehallion & Loyal
Rubie & Renee
Leadon
Viking
Athena
Janice, James & Affleck
Ettrick and Blackbird
Vulcan UR, Viscount VO & Vampire OD
Markham ST-1
Audrey
Ann & Allison
Atlantic and Cromarty
Linnhe
Don
Stamford
Merlin
Osprey

Table 9: Key to types of fields

NCS
NCS, subsea wellheads only
UK
UKCS, subsea field
Germany

The second part of the thesis expands the model to estimate the cost of decommissioning all current infrastructure on the NCS.

ESTIMATION OF SINGLE PLATFORMS

The following section describes the data gathered on each phase of decommissioning, and their input for estimation metrics. It then shows the model development and its verification on a number of installations.

Phase 1: Project Management

Project management and engineering costs have been estimated. This is often expressed as a percentage of total decommissioning cost. A number of decommissioning projects' percentages of total have been examined. It is unclear which activities constitute this portion in the individual cases, however mostly it comprises contractual review, documentation reviews, engineering analysis, operational planning and contracting. It is assumed that project management costs include project management costs for P&A.

Ekofisk I: the removal of the topsides of the Ekofisk I complex took place in three phases: the Ekofisk Tank topside was removed in 2008, and nine topsides were removed in 2009 – 2013:

- 2/4 D
- 2/4 P
- 2/4 R
- Norpipe 36/22 A
- Norpipe 37/4 A
- Albuskjell 2/4 F
- Albuskjell 1/6 A
- Cod 7/11 A
- Edda 2/7 C

The remaining five (2/4 A, B, H, Q, and FTP) are in the process of being removed, with EPRD contracts for all except 2/4 B awarded to the Heerema – AF Decom consortium [90] . Project management and engineering included both the contractor's administration of the project and ConocoPhillips' input as field operator for the project. Engineering design was expected to be performed dually by the operator and an engineering firm, and included structural analysis, temporary support structure planning, strength estimations, and marine operations planning.

The impact assessment listed estimated project management costs of 350 million NOK (1998) for the 15 topsides, and 160 million NOK for the 14 jackets [91], which equates to 516 million NOK and 236 million NOK in 2017, respectively. Total estimated costs of topside and jacket removal were 7.9 billion NOK in 1998. Combined percentage of total cost equates to 6.5 percent. These cost estimates assume that P&A of the 112 wells on the complex has been completed, and pipelines disconnected.

Figure 37: The Ekofisk field centre [92]

Varg: The Varg field is an oilfield employing water and gas injection, comprising an FPSO, Petrojarl Varg, connected to a wellhead platform, Varg A, which is a NUI [93]. Production commenced in 1998, and decommissioning work began in 2015, starting with the removal of Petrojarl Varg [94].

The estimated cost of project management is 90 million NOK (2013), or 99 million NOK in 2017. The total decommissioning cost was 1.72 billion NOK, or 5.2 % [93]. If the project management cost does not account for P&A (950 million NOK), the percentage is 11.7 %

Veslefrikk: A steel jacket wellhead platform connected to a semi-submersible production platform. Veslefrikk produces oil and a small amount of gas [95].The facilities were installed in 1989 [96], and a tentative shut-down date was set for 2020 [97].

Project management cost estimates are 115 million NOK, out of a total 2650 million NOK, or 4.3 %. If one assumes that project management does not account for the P&A work (1.05 billion NOK), the percentage is 7.2 % [97].

Figure 38: Veslefrikk A and B [98]

Camelot CA: A small steel platform in the Southern North Sea, Camelot A was shut down in 2009, and removed in 2012 [63]. The decommissioning work included removal of the CA platform, and surveys of the Camelot CA and CB pipelines. Project management costs were 1 million GBP, out of a 16.3 million GBP total decommissioning cost, or 6.1 %. If the project management does not cover the P&A work (7.5 million GBP), the percentage is 11.4 %.

Rev: A subsea development comprising 4 installations – a Pipeline End Manifold (PLEM) and three templates with one to two X-mas trees each with protective infrastructure. Production was initiated in 2009, and Cessation of Production (CoP) is planned in 2020. Cost estimates for project management are 37 million NOK out of 798 million NOK total [99], or 4.6 %. If P&A is considered a separate activity, with a listed cost of 598 million, project management constitutes 18.5 % of the total.

Other sources: Information obtained from an operating company for an installation decommissioned in the past decade showed project management costs of 12 % [100]

An anonymized Plan for Development and Operation (PDO) stated project management costs of 210 million NOK against a total of 2.2 billion NOK [101], or 9.5 % if P&A project management is disregarded.

A large variation in project management proportions of total costs is apparent in the examination. An average percentage of 6.1 is revealed, when assuming P&A project management is included in decommissioning project management, and 9.6 % if not. This indicates that if P&A project management is included in total project management, the fractional costs are 33 % higher.

There is a large variation in the properties of the sample units, and the origins of cost figures – some are cost estimates from before the installation was even built, whereas others are actual costs. One may also assume there are differences as to which activities are included in the project management scope.

There is an indication that the estimates may be sound, as Oil & Gas UK's *Decommissioning Insight* lists a percentage of 7 for platforms in the Northern North Sea [78], whereas BP's metrics are 7 % [76]. These are based on UK activity.

Consolidating the data gathered, an average of 6.1 % of total costs was calculated. Discussion with project managers revealed that there is a large variation in what constitutes project management [102] – e.g. whether sub-contractor project management is included, and whether P&A project management is included.

Phase 2: Facility Running/Owner’s Costs/Post-Cop OPEX

Decommissioning executives at BP operate with a Post-CoP OPEX of around 80% of the actual OPEX in the year prior to CoP [76]. This is on an installation where half the wells have been plugged prior to CoP. It is assumed that this cost is a per-year cost and runs until the installation reaches NUI-status.

Data gathering has revealed the following information:

- An anonymized platform had running costs of 29 % of total decommissioning costs [103].
- An anonymized decommissioning project was revealed to have facility running costs of 12 % of the total. This was a steel jacket platform removed in recent years [104].
- *Decommissioning Insight* 2016 states that facility running/owner’s costs for several platforms to be decommissioned in the next 10 years as 16 % [79]. This number was weighted in the average as it pertains to a large number of installations.

A metric of 16 % for facility running costs was developed, taking a weighted average of data gathered.

An issue arose when examining post facility running costs: drilling facilities would have considerably larger costs than other types of facilities. For the cost estimation simulation, assumptions were made that non-drilling and processing facilities would have minimal running costs compared to those facilities involved in P&A activities, where the majority of systems must be kept running.

Phase 3: Well Plugging and Abandonment

The literature is scarce on actual cost of P&A of platform wells and the information that has been shared is usually related to the duration of P&A per well rather than the cost per well.

In this segment a short summary of the sources that may be used as a basis for an estimate of P&A expenditure for platform wells is presented. Platform wells are usually defined as wells where the wellhead is on an installation above sea-level. In this thesis, the definition is modified to mean wells where the platform's drilling equipment is functioning at the time of P&A.

Figure 39: Platform well X-mas tree

In the presentation *Decommissioning – The case for metrics* [76] by Win Thornton, VP of Decommissioning in BP, a metric for estimation of P&A cost is presented. According to the presentation a fair estimate for P&A per platform well is 4 million GBP (2016) which is around 46.314 million per platform well converted to 2017 NOK.

Metrics can also be inferred from estimates presented in the impact assessment (*konsekvensutredning*) section of *Avviklingsplan.*

Platform well P&A estimates in Norway:

Veslefrikk:

This field development is located at a depth of 185 meters.

The impact assessment for the Veslefrikk field operated by Equinor present an estimate of 1 050 million NOK (2016) for the P&A of the 23 wells [97]. Converted to 2017 NOK per well that transfers to:

$$\frac{\frac{(1050 \times 105.5)}{103.2}}{23} = 46.76 \text{ million NOK per well}$$

Platform NN1:

An anonymized platform with P&A of 20+ wells had an estimated cost of 45.313 million NOK per well [103].

Brage, bottom-up estimate:

Note: For sake of order, all well abandonment and decommissioning costs referred to in this thesis are based on public information. Any number calculated, or given, should not be considered as having its origin from, or being approved by Wintershall.

In the master thesis *Time Estimation of Future Plug and Abandonment Operation at Brage Field* by Olav Fjelde [81], the author presents an estimate of the expected duration of the P&A operation. The P50 estimate presented is 1090 days, which is very close to 3 years.

In the master thesis *A Rigless Permanent Plug and Abandon Approach* by Emil Mikalsen [86], the metric used by Equinor for the cost of the crew and equipment required to perform P&A using a platform derrick is presented. According to this thesis Equinor calculates P&A cost for platform wells by multiplying the expected duration with a day-rate of 1.1 million NOK (2012) which is 1.236 million NOK per day converted to 2017 NOK.

Information from the industry has confirmed that this figure is still a fair estimate, but marginally on the low side. The assumption in this thesis is that the current cost per day is around 1.3 million NOK. This does not include the running cost of the platform while performing P&A.

Combining the information from the two sources results in an estimate of:

$$1090\ days\ \times 1.3\ million \frac{NOK}{day} = 1\ 417\ \text{million NOK}$$

This is a fair estimate, but the estimate can be further refined.

In the calculation of expected time in Fjelde, the estimate of 1 090 days is calculated using a deterministic approach.

The estimate of the total P&A duration has omitted the impact of Non-Productive Time (NPT), Waiting on Weather (WoW), the learning effect and the impact of unexpected events.

Average numbers for NPT and WoW based on data for 26 platform wells from Rushmore is presented in Fjelde's thesis. WoW on a platform is given as 2.4 % and NPT is 20.6 %. The effective time while performing P&A is 77 %.

According to the presentation *Valhall DP P&A Project: The Project that has it all* by BP [83], this P&A operation, which included P&A of 13 wells using a jack-up rig, experienced 2623 hours of NPT in a project where the total hours worked were 16 156. This represents 14.0 % NPT.

According to Mats Mathisen Aarlott in his thesis *Cost Analysis of Plug and Abandonment Operations on the Norwegian Continental Shelf* [82], an estimate of 20 % for NPT corresponds well with earlier literature.

Final field permanent plug and abandonment - methodology development, time and cost estimation, risk evaluation by Fredrik Birkeland [85] uses 2.2 % as an estimate for WoW related to platform well P&A.

Sources in the industry have provided information on the NPT metric used in the operators own estimates, and a value of 15 % is considered reasonable [105].

As a way of refining the estimated duration of P&A for the Brage field the following estimates are used:

An estimate for **WoW of 2.3 %** and an estimate for **NPT of 15 %.**

The final effect that should be accounted for is the learning curve, also called the learning effect. This is the effect of small incremental refinements in methodology or in execution which result in significant efficiency gains in P&A campaigns. Part of the efficiency gains stem from the fact that the formation and the reservoir is similar for wells in the same field development. There can be additional efficiency gains from well campaigns if several of the wells in the campaign are similar in design.

It is challenging to pin down a number for the efficiency gains, but several sources refer to this effect and the importance of addressing it in the more extensive P&A campaigns. The following illustration can be found in the presentation *Valhall DP P&A Project: The Project that has it all* by BP [83]. The figure illustrates the falling trend of duration per well over time.

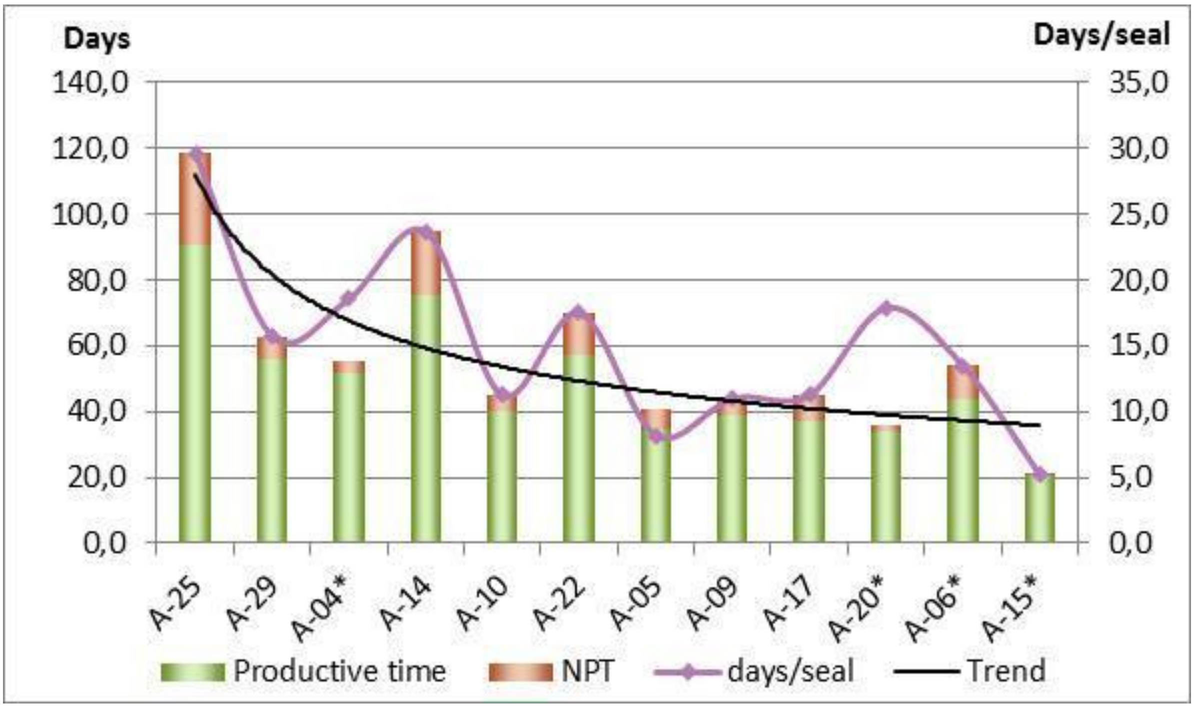


Figure 40: The learning curve illustrated in BP's Valhall P&A project [83]

A similar illustration with even more pronounced learning effects is found in *Decommissioning and P&A in the future* by Tim Croucher, ConocoPhillips [84].

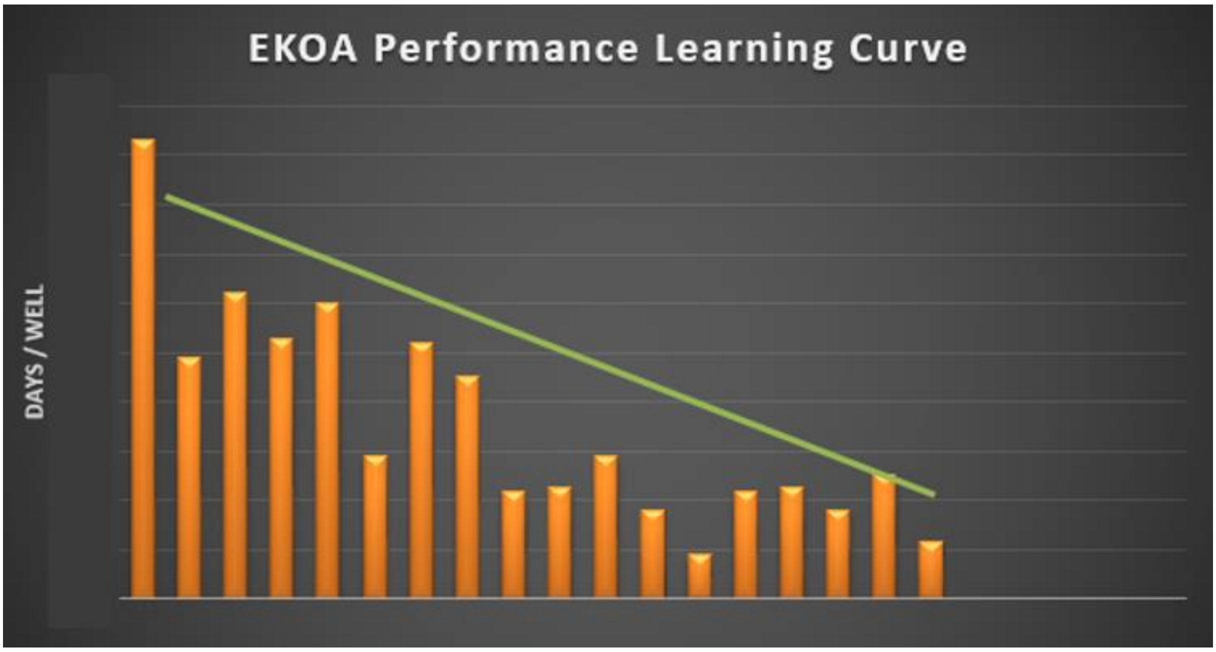


Figure 41: Learning effects in P&A at Ekofisk [84]

The effect is described in detail in the article *Integrating Learning Curves in Probabilistic Well-Construction Estimates* [106] by Jablonowski et. al. The effect is described further in *Rigless P&A Technology Availability and Cost Effectiveness of Rigless P&A Operations* [87].

The 40 wells at the Brage field consist of 20 wells that are similar in design according to Fjelde. The P&A of these wells are estimated to require 29 days per well.

In this thesis the learning effect has been included in the following way:

An average learning effect of 20 % is assumed for the 20 wells that are similar in design and will benefit fully from the learning effect. An average learning effect of 10 % is assumed for the 20 wells that are less similar in design and will benefit partially from the learning effect.

The resulting total effect from the Learning curve can be calculated in the following manner.

$$\frac{((20\ \% \times 20 \times 29) + (10\ \% \times (1090 - [20 \times 29])))}{1090} = 15.32\ \%$$

Unexpected events can cause significant delays and when the P&A scope consists of 40 wells one should expect the unexpected. The P&A operations are complex and the data on the wells are usually not exhaustive. In P&A terminology some wells are labeled “train wrecks” [107] and can cause considerable delays. The number of thinkable and unthinkable events that may cause delays should be accounted for. In deterministic approaches to cost estimation the solution is generally to add a contingency; the appropriate contingency should be based on a large sample of historical data. According to sources in the industry [108], approximately one well in seven is considered a train wreck and results in increased P&A expenditure compared to the deterministic estimate. A contingency of 20 % to account for all unexpected events, including potential train wrecks and potential black swans, is included in the estimate.

The resulting cost estimate for Brage is as follows:

$$\frac{Duration\ in\ days \times day\ rate\ of\ P\&A\ crew \times (1 - learning\ effect) \times (1 + contingency)}{1 - NPT - WoW}$$

$$\frac{1\ 090 \times 1.3 \times (1 - 0.1532) \times (1 + 0.20)}{1 - 0.023 - 0.15} = 1\ 741.111\ \text{million}$$

This is an estimate for 40 wells, so the resulting cost per well is **43.528 million per well**.

There is considerable uncertainty in this estimate, as should be evident from the explanation of the basis for the estimate above. The estimate is a best guess based on available information and is in line with other metrics and estimates.

Average cost of platform well P&A in Norway

The average cost of P&A based on the three estimated averages above:

Veslefrikk: 46.314 million per well

Platform NN1: 45.313 million per well

Brage: 43.528 million per well

$$\frac{46.314 + 45.313 + 43.528}{3} = 45.052$$

Results in **45.052 million NOK per well.** This will be the average for platform well P&A in this thesis.

Platform well P&A in the UK

In Thornton's presentation [76], a metric for estimation of P&A cost is presented. According to the presentation a fair estimate for P&A per platform well is 4 million GBP (2016) which is around 46.314 million per platform well converted to 2017 NOK.

The regulations for P&A are different in the UK compared but the metric provided by Win Thornton is useful as a reference point and corresponds well with the metric estimated in this thesis.

Estimation of the Cost of P&A for Subsea Wells in Norway

Subsea wells are usually defined as wells where the wellhead is placed on the seafloor. In this thesis however, the definition is modified to mean both seafloor wells and topside wells where there is no existing drilling equipment available to perform P&A, so that an external drilling facility must be brought in to perform P&A.

Valhall:

Data is available for the P&A of 13 wells that were plugged by the jack-up Maersk Reacher between July 2014 and August 2016 [109].

According to [83], the formation and the reservoir at Valhall is very complex and the wells are old with multiple issues. The wells are platform wells, but the platform no longer has an integral rig, so a separate rig must perform the actual plugging.

The P&A of these 13 wells resulted in savings of 210 million USD (2016) which was 35 % of the original budget. That means the budget for the 13 wells was 600 million USD and the actual cost was 390 million USD. That represents an average cost of 30 million USD per well (2016).

That translates to an estimated cost of 256.582 million NOK (2017) per well.

Figure 42: Maersk Reacher jack-up performing P&A on Valhall DP [110]

Rev:

The Rev field consists of 4 subsea wells. From the Impact Assessment the estimate for P&A is 593 million NOK (2014) [99].

That translates to an estimated cost of 159,759 million NOK (2017) per well.

Varg:

This field consisted of 8 subsea wells that were plugged in 2017-2018 by Rowan Stavanger [111]. The estimated cost was 950 million NOK (2014) [93].

That translates to an estimated cost of 127.969 million NOK (2017) per well. The actual cost is unknown.

Estimate based on duration and assumptions on rig-rates and rules of thumb:

In this thesis the rig-rate is assumed to represent 50 % of the cost related to rig-based P&A.

The average duration of P&A for subsea wells is estimated to 32.87 days per well in the *duration of P&A* section, described next.

The current day-rate for jack-up rigs on the NCS is just over 200 000 USD but the market is recovering from a period with very low rates. The average day-rate for jack-up rigs is therefore assumed to be 250 000 USD.

An estimate of the cost of rig-based P&A can be calculated based on these assumptions using the following formula

$$\frac{Day\ rate\ in\ USD \times exchange\ rate \times average\ duration\ in\ days}{Cost\ of\ rig\ as\ fraction\ of\ total\ P\&A\ expenditure}$$

$$\frac{250\ 000 \times 8.263 \times 32.867}{0.50} = 135.790\ \text{million NOK}$$

The estimated cost of P&A for subsea wells is 135.790 million NOK. This corresponds well with the cost estimates for subsea well P&A from impact assessments on the NCS.

The Valhall wells are not representative for subsea wells and are disregarded in the calculation of normal subsea wells. However, the cost is indicative of how expensive a train wreck/highly complex subsea well can be.

The cost estimates for the 12 subsea wells on the NCS considered normal subsea wells and the 15 subsea wells where P&A cost has been estimated by the authors based on an estimate of duration, an assumption about rig-rates and an assumption on the rig-rate's fraction of total P&A cost is the basis for the subsea well P&A metric average.

The estimated P&A expenditure is:

$$\frac{(159.759 \times 4) + (127.969 \times 8) + (135.790 \times 15)}{4 + 8 + 15} = 137.024$$

The metric average for subsea well P&A for normal wells in this thesis will be **137.024 million NOK.**

The standard deviation of this estimator cannot be calculated due to the use of aggregated numbers.

The standard deviation for normal subsea wells is assumed to be similar to the standard deviation of platform well duration. There may be a wider variation due to subsea well P&A being more weather-sensitive, but due to lack of data on this subject the standard deviations are assumed to be the same.

The standard deviation for normal subsea wells is **20 % which translates to 27.405 million**.

Calculation of standard deviation of wells is demonstrated in the section *The Standard Deviation of P&A Duration per well based on P&A duration estimates.*

Subsea wells in the UK

Rose:

In the decommissioning program for the Rose subsea installation in the UK there is an estimated cost for the P&A of a single subsea well. The cost is 10 million GBP (2015) [112].

That translates to an estimated cost of 130.2 million NOK (2017) per well.

This number corresponds well with the metric calculated for subsea well P&A in this thesis.

Figure 43: A number of subsea wells surrounding a central manifold [113]

Average cost of complex ("train wreck") subsea wells

The wells on Valhall are considered complex wells primarily due to the many pressure zones in the formation and the number of plugs required for P&A on Valhall is above average [83].

The average cost of P&A for subsea wells on Valhall will be used as the metric average for complex subsea well P&A in this thesis.

The average cost of complex subsea wells in Norway is **256.6 million NOK.**

The average extra cost of each of the wells on Valhall is

$$256.582 - 137.024 = 119.558\ million$$

Due to lack of information, these wells were the only input available to the average.

Information from the industry has indicated that the industry's rule of thumb for train wrecks is that approximately one in seven subsea wells are train wrecks [102].

One in seven wells will be the metric for the prevalence of complex wells/train wrecks in this thesis.

Assuming 1 in 7 wells is a train wreck, or is as complex as the Valhall wells, one should add 1/7 of the difference to the estimate.

That leads to an estimated cost per subsea well of

$$137.024 + \frac{119.558}{7} = 154.104$$

The estimated average P&A cost for all subsea wells on the NCS is 154.104 million NOK

Duration of P&A

The following section includes actual and estimated durations for platform and subsea wells on both NCS and UKCS and attempts to pinpoint the expected duration of P&A for the two well classes in this thesis.

<u>Subsea wells:</u>

Glitne [114]**:** 7 subsea wells; 6 producers and 1 injector

RLWI phase 82 days

Rig phase: 130

The average P&A duration is **30.29 days per well.**

Varg:

P&A of 8 subsea wells

The P&A was completed in two separate campaigns.

The Maersk Giant performed the downhole plugging of 8 wells and a complete P&A for one of the 8 wells in 2016 and the estimated time to perform the job was 153 days [115].

The Jack-up Rowan Stavanger completed the pulling of tubing, casing and conductors for the 7 wells that were partially plugged and abandoned and the full P&A scope for the remaining 8 wells on the Varg field in 2017-2018. The estimated time for the Jack-up Rowan Stavanger for the Varg P&A was 208 days [116]. However, the actual time used was 128 days [117].

$$\frac{(153 + 128)}{8} = 35.125$$

The actual duration for the P&A procedure cannot be calculated due to lack of data. However, the estimated time for the P&A of these 8 wells using actual duration where available is **35.13 days per well.**

$$\frac{(30.286 \times 7) + (35.125 \times 8)}{7 + 8} = 32.867$$

The weighted average duration for P&A of subsea wells in Norway based on these number is 32.87 days per well.

Equinor P&A 2016:

In 2016 Equinor performed campaigns completing P&A on 9 wells on the Volve platform and 6 wells on the Huldra platform in addition to some single wells [118]. According to the article there were 6 single wells and the total was 18 wells. These numbers cannot all be correct. After further research it was confirmed in the presentation *P&A Experience and Cooperation* by ConocoPhillips, AkerBP and Equinor [119], that Equinor in fact plugged on 9 wells on Volve, 6 wells on Huldra and 3 single wells in 2016.

According to an article interviewing Pål Hemmingsen, Project Manager P&A technology strategy in Equinor and according to [119], the average P&A duration per well for the wells that underwent P&A in 2016 was 17.8 days per well. For comparison the average number in 2014 was 34 days per well. The reduction was in large due to better planning, a focus on expenditure and applying best practices throughout the P&A process. P&A is a priority in Equinor's cost reduction program STEP [120] - Equinor's goal was to cut both the cost and the time of P&A by 50 % in the 2016 well P&A campaigns and that was accomplished.

The 15 wells on Volve and Huldra are all platform wells, but P&A was performed using jack-up rigs and thus the wells are defined as subsea wells in this thesis. Due to insufficient data on how much of the total P&A scope that was performed by the jack-up rigs and how much of the scope that was done using wireline operations before the jack-up rigs arrived, the duration data for these wells are not included in the subsea well P&A duration calculations. Either way, the P&A duration achieved by Equinor in 2016 was impressive and represents the technical limit for rig-based P&A duration in Norway with existing technology. If these results can be replicated the expected duration for subsea P&A in this thesis are on the high side.

In a longer perspective Equinor aims to be able to perform P&A using only 1 week per well [121].

Platform wells

UK Platforms:

North West Hutton: 40 platform wells

Calculations of average P&A time are shown in the enclosure *North West Hutton P&A.* In the analysis the wells that underwent phase 1 before year 2000 are excluded in the phase 1 analysis and in total duration due to insufficient information. Average time for phase 1 and phase 2 is calculated, and the average total P&A duration for the wells where the whole P&A scope was done in 2002 and 2003.

The standard deviation for phase 2 was also calculated, but some of the duration data are inconclusive due to simultaneous P&A processes and duration data is only available on phase 2. The standard deviation calculation is not considered sufficiently accurate due to these issues.

The calculation of average time per well P&A is based on the numbers that are not inconclusive, and this calculation is a good indication of P&A duration on platform wells on the UKCS

The average duration of plugging the 24 wells that underwent the full P&A scope from 2002-2004 was 11.3 days, the average duration of pulling tubing, casing and conductor was 6.0 days. The average time for full P&A was 17.3 days [37].

Murchison: 33 platform wells, 1 subsea well

RLWI phase: 205 operational days between October 2013 and 2014 [122].

Rig phase: 655 between June 2014 and 31. of March 2016 (It is assumed it started on the 15th of June) [123]

The average P&A duration is 25.3 days per well.

Note: For sake of order, all well abandonment and decommissioning costs referred to in this thesis are based on public information. Any number calculated, or given, should not be considered as having its origin from, or being approved by Wintershall.

<u>**P&A Duration estimates**</u>

Brage:

Note: For sake of order, all well abandonment and decommissioning costs referred to in this thesis are based on public information. Any number calculated, or given, should not be considered as having its origin from, or being approved by Wintershall.

In Fjelde's thesis [81], the author presents an estimate of the expected duration of the P&A operations on Brage. The P50 estimate presented is 1090 days, very close to 3 years.

The average P&A duration is **27.2 days.**

Platform NN1:

The expected duration of P&A for platform NN1 with more than 20 wells is 35 days per well without considering the learning effect [100].

When a learning effect of 14 % is included the estimated time per well is 30.1 days.

The Standard Deviation of P&A Cost per Well Based on P&A Duration Estimates

Due to lack of data a choice has been made to develop an estimate of the standard deviation of P&A cost by calculating the standard deviation of P&A duration. Duration of P&A is a very good estimate of cost of P&A, as the most important cost factors are rates for rigs and vessels and labor cost which is dependent primarily on duration.

There are some fixed costs like the mobilization fee for the vessels, but the P&A cost has a very high correlation with duration.

In Fjelde [81], an estimate of P&A duration on the Brage field is presented. This thesis is the result of a detailed analysis of a possible P&A strategy on the Brage field and the required duration. In the thesis the results of Monte Carlo simulations for each well category is presented, and based on the P50 estimates for each well, the standard deviation for the 40 wells is calculated. The standard deviation of the duration in percent is the chosen estimate for the standard deviation of P&A cost per platform well. The standard deviation of the estimated P&A duration per well is 17.6 %.

Note: For sake of order, all well abandonment and decommissioning costs referred to in this thesis are based on public information. Any number calculated, or given, should not be considered as having its origin from, or being approved by Wintershall.

The authors have been given access to information on estimated duration for 20+ wells on an anonymized platform from an operating company (note: this company is not Wintershall), NN1, on the NCS. Based on this information the standard deviation of the P&A duration has been estimated and the estimated standard deviation of P&A duration in percent is used as an estimate of P&A cost.

From platform NN1, with more than 20 wells, the standard deviation of the expected duration of P&A per well is 23.2 %

The average standard deviation is

$$\frac{17.6\ \% + 23.2\ \%}{2} = 20.4\ \%$$

Based on the calculations above a choice has been made to assume a standard deviation for the estimated cost of P&A for platform wells of 20 %. This has been used as an indication of credible triangular distribution parameters.

Standard deviation of complex subsea wells

The duration of P&A for 12 of the 13 wells from the P&A campaign on the Valhall field in 2014 – 2016 is found in the presentation *Valhall DP P&A project: The Project that has it all* [83]. The exact time for each of the wells can be found in a bar chart in the presentation, also shown in Figure 40.

The average duration and the standard deviation of the duration is calculated based on these numbers. The duration of P&A is considered a good estimator of the cost of P&A. A choice was made to use the standard deviation of the duration of P&A for complex subsea wells/train wrecks as an estimator for the standard deviation of the cost of P&A for complex subsea wells/train wrecks. The number that is used as an estimator is the fraction of the standard deviation divided by the average duration.

For the standard deviation of subsea train wreck wells, the average duration of P&A on Valhall's wells was calculated as 57.4 days, with a standard deviation of 26.89 days. To estimate a standard deviation of cost, standard deviation as a fraction of average was used.

$$\frac{26.89}{57.4} = 46.83\ \%$$

The calculations are shown in the enclosure *Standard deviation for duration of P&A of complex subsea wells and train wrecks.*

As a percentage of total, this means the standard deviation of complex subsea wells can be assumed to be

$$46.83\ \% \times 256\ 582\ 000 = 120\ 157\ 351\ \mathrm{NOK}$$

Cost Per Day

In a presentation at the 2016 Plug & Abandonment Forum, it is stated as a general rule that rig cost makes up approximately 40-50 % of P&A [124].

According to Øia and Spieler, the rig rate represents around 50 % of P&A expenditure in rig-based P&A [11].

In the thesis *Utilization of Purpose-Built Jack-Up Units for Plug and Abandonment Operations* by Spieler [125], the author states that, after discussions with various parts of the industry, there is a consensus on the rule of thumb that the rig-rate represents around half the costs related to rig-based P&A.

In this thesis the rig-rate is assumed to be 50 % of the P&A cost when performing P&A.

Rig rates:

The rig-rates have decreased significantly from the historical top in 2014-2015 and are expected to rise in the coming years. The next section is based on *Market Insight December 2017* by UK Oil & Gas [126].

- The average rate for a standard jack-up in the North Sea in 2017 was 70 000 USD per day which translates to 578 410 NOK (2017)

- The historical top was in January 2015 with 165 000 USD which translates to 1 405 464 NOK (2017). That represents a drop in the jack-up rig-rate of 58.8 %

- The average rate for a standard semi-submersible in the North Sea in 2017 was 115 000 USD which translates to 950 245 NOK (2017).

- The historical top was in April 2014 with 385 000 USD which translates to 2 614 580 NOK (2017). That represents a drop in the semi-submersible rig-rate of 63.7 %.

- The day-rates for jack-up rigs are significantly lower on the UKCS due to its generally shallower waters. The actual rates presented in the article are not applicable to the NCS, but the volatility of the day-rates applies to the NCS.

Phase 4: Topsides Making Safe

Frigg MCP-01 [57]**:** The platform had been in NUI-status since 1992 and the two 32” pipelines passing through the facility were routed to pass through the bottom part of the substructure. The topsides associated with the pipelines were then cleaned and shut in. The result of this work was that 40 % of the structure was no longer in use.

The make safe work for the removal of MCP-01 took place in 2004-2005 and was completed by Total themselves, using a variation of the operations and maintenance program. All process equipment was prepared to present it as clean and hydrocarbon free. Utilities were shut down and isolated and essential access routes were identified and made safe. A survey was carried out to identify hazardous materials. The work was completed within time and budget constraints.

The final cost of making safe was 4.85 million GBP (2011), or 49,2 million NOK (2017). Cost per ton is 3634 NOK.

Figure 44: Frigg MCP-01 [127]

Data from anonymous sources:

A platform decommissioned in recent years had a topside making safe cost per ton of 7000 NOK [128]

Another recently decommissioned platform had a topside making safe cost of 5900 NOK per ton [129]

Other sources of make safe data are *Decommissioning Insight*, where numbers from 5400 – 5700 NOK per ton are reported [78] [2]

A wide range of numbers are observed from the gathered data. Factors that affect cost are uncertainties on remaining hydrocarbons, uncertainties on amounts of hazardous materials, number of modules, complexity of equipment and quality of documentation on the facility.

Phase 5: Topside Preparation and Removal

A selection of topsides which have been removed or are due to be removed are presented:

Frigg TCP2 [25]**:** All information is from the Frigg Close Out report, unless otherwise stated. TCP2 was a treatment and compression platform installed in 1977 and removed in the period 2005 – 2007. The platform was attached to three concrete legs. A combination of reverse installation and piece small methods was used, removing 18 modules and a bridge to TP1 using the HLV Saipem 7000 and shipping the modules to Aker Stord. The heaviest lift of the operation was the Module Support Frame (MSF), weighing 8 500 tons. This was at the limit of S7000's lifting capacity, using both cranes. Therefore, the MSF had to be transferred to a separate barge. The MSF was then shipped to Shetland for disposal and recycling. A total of 22 736 tons were removed. 26 heavy lifts were performed over 49 days. 288 000 offshore man-hours were used, equalling 13 man-hours per ton removed [45].

The cost for the removal of TCP2 was 1 428 million NOK (2010), 1625 million NOK in 2017. This included the removal of steelwork from the concrete substructure by Deepocean and onshore disposal at Aker Stord. Cost per ton removed is 72 000 NOK (2017).

Frigg TP1 [25]**:** All information is from the Frigg Close Out report, unless otherwise stated. TP1 was a treatment platform on the UK sector, installed on two concrete legs in 1974. The removal campaign took place from 2005 to 2009, where 505 tons, or 6 %, were removed by piece small, and the remaining 7500 tons were removed in a reverse installation by S7000, shipping the modules to Aker Stord. 10 lifts were completed over 14 days, and 233 000 manhours were spent removing the topside, equalling 29 manhours per ton removed.

The cost for the removal of the topside was 846 million NOK in 2010, or 970 million NOK in 2017. Cost per ton removed is 120 000 NOK. The large cost per ton may be due to changes in lifting schedule priorities [23].

Frigg CDP1: All information is from the Frigg Close Out report, unless otherwise stated. Frigg CDP1 was a drilling and production rig on the UK sector, installed in 1977 on a Doris concrete substructure design. Activities on the platform ceased in 1990, with no maintenance performed between cessation and removal. This necessitated a significant amount of work to make the platform safe for topsides removal. In addition, removal took place during winter months, with 20 % downtime due to WoW. A combination of piece small and reverse installation was used, placing all removed items on the deck of S7000 before being transported to shore at Aker Stord. 23 lifts were performed over 24 days, and 310 000 manhours were worked, at 52 manhours per ton removed. The operation required 145 days of flotel use, and 154 days of other vessels [45].

The total weight removed from CDP1 was 6 443 tons, at a cost of 629 million NOK (2010). This equates to 720 million NOK in 2017, and 112 000 NOK per ton.

Frigg MCP-01 [57]**:** All information is from the MCP-01 Close Out report, unless otherwise stated. Frigg MCP-01 was installed in 1976 and used as a manifold/pigging and recompression installation. From 1992 it served solely as an interface for some third-party gases with periodic maintenance. By 2003 its condition had deteriorated considerably, and plans were made to decommission the platform. Operations started in July 2006 and were completed in 2009. The contract was a fixed price contract with a provision for reimbursement of additional recognised costs, awarded to Aker Offshore Partner.

The scope of work for the removal of the topside grew in complexity, as the platform was constructed without decommissioning in mind.

45 % of the topside was removed by the piece small method, using excavators equipped with hydraulic shears. The excavators required support decks which had to be engineered and fabricated. This, along with the many modifications performed over the years, meant a large portion had to be done manually by rope access and some scaffolding. The amount of removal work done manually grew by 300 %.

The remaining 55 % was removed by the lifting of entire modules, sometimes several modules in one lift.

Flotels were used as accommodation in the offshore work, and later in the removal process personnel lived aboard the HLV Saipem 7000. In the early phases personnel with limited offshore experience were used, requiring additional supervision.

An additional crane was installed on MCP-01, which along with a pre-existing crane performed more than 16 000 lifts.

The material removed was initially to be shipped to Greenheads Base in Shetland, but due to limited water depth at quayside only 5400 tons were moved here. The remainder was shipped to Aker Stord.

Removal required 29 heavy lifts, taking place over 31 days. 1.2 million manhours were spent on the operation, at 88 manhours per ton removed. 1126 vessel days were used in addition to 457 days of flotel use [45].

The final cost of the topside removal was 196.25 million GBP, whereas the original estimate was 68 million GBP. This equates to 132 400 NOK per ton (2017), where total tonnage removed was 15 100.

Ekofisk 2/4 S: A riser platform for the Statpipe pipeline's connection to Ekofisk with a 7 000 ton topside [130], installed in 1984. Shut down in 1998 and removed in 2001, the topside was taken to Lyngdal Recycling for disposal. [131] The cost of removal was approximately 136 million NOK (1999) [132], or 28 000 NOK per ton.

Ekofisk 2/4 T: Designed to store oil, the Ekofisk tank was installed in 1973, and its topside removed in 2008. The topside weighed 36 860 tons and was removed piece small by AF Decom in the period from 2005 to 2008. This contract was reported to be worth 400-440 million NOK [133] [134] , but it is unclear whether this included the actual removal of material to shore. Final weight removed was 25 000 tons [135]

Ekofisk I: The removal of the 15 topsides is an ongoing project, with four remaining platforms scheduled to be removed in the next few years [136] . The platforms were installed between 1972 and 1974. Due to seabed sinkage a new network of platforms was commissioned. The old platforms comprise many types of facilities, with topside weights ranging from 1700 (2/4 P) to 36860 tons (Ekofisk Tank). The majority of topsides were removed module based, apart from Ekofisk Tank which was removed entirely piece small by AF Gruppen, using excavators lifted aboard the facility [135]. A total of 126 410 tons will be removed, at an estimated 1999 cost of 4070 million NOK (2700 for preparation, 820 for removal and 550 for transport). This equals 46 400 NOK per ton (2017).

Anonymous sources: In data received from operating companies, two topsides removed during the past decade studied revealed cost-per-ton values of 24 600 NOK [100].

The topside removal operations mentioned cover module-based, piece small and combinations of these. Projects that were both over and under budget are represented. As the Ekofisk project contained 15 platforms, this cost per ton was weighted accordingly.

Phase 6: Jacket Removal

The time between topside removal and jacket removal varies greatly – in some cases they are removed in the same operation, in others there may be a long deferral. This is due to several factors such as the benefits of postponing decommissioning operations, constraints on removal operator availability, and differences in maintenance requirements between topsides and jackets.

The method for removal of jackets is dependent on depth, weight, diameter of struts, OSPAR derogation approval and supply-chain constraints.

Options for removal are piece small – cutting the substructure into sections manageable for the designated lifting vessel, single lift, and re-floating. Other options, such as re-use and toppling/leaving in place are not examined, as there is a minimal demand for used steel jackets and leaving in situ is not permitted in the North Sea, unless significant structural damage or deterioration can be demonstrated.

An issue in removal of jackets is the presence of cuttings from drilling activities. Studies of decommissioning programs and Close Out reports show that cuttings piles very rarely yield fluid loss levels beyond OSPAR recommendation 2006/5 levels [38] and can therefore be left in situ. However, they may be a hindrance in cutting of piles for jacket removal.

Several platform jackets have been examined, with a wide range of weights, water depth and removal methods:

Huldra [137]**:** Jacket installed in 2000 at a depth of 125 metres with a weight of approximately 5200 tons and a height of 154 metres. The four legs are secured to the seafloor by two 96" piles on each leg. These will be cut from the inside 1-5 metres under the seabed, and the resulting pits will be rock-dumped. Dredging will be required to uncover the lower portions of the substructure. An HLV will remove the jacket in a single lift, contracted to HMC, with the removal work taking place in 2019. The estimated cost is 60 % of the total decommissioning cost of 336 million NOK (2012), or 226 million NOK in 2017. This equals 45 000 NOK per ton.

Figure 45: The Huldra platform [138]

Camelot CA [63]**:** Installed in 1989 at a depth of 11 metres and removed in 2012 using a single lift. The jacket piles were cut 3 metres below the seabed, and the substructure shipped to the Netherlands. Jacket removal costs amounted to 6.3 million GBP, or 63.7 million NOK in 2017. This is a cost per ton of 106 000 NOK (2017).

Frigg DP1 [25]**:** The following information is taken from the Frigg Close Out report, unless otherwise stated. Frigg DP1 was planned to be the first installation on the Frigg field. However, the ballast tanks collapsed during installation resulting in an impact on the seabed. The substructure was damaged beyond safe use. Due to uncertainties in the structural integrity of the jacket, single lift removal was not a feasible option. A spreader frame was installed to ease work in the splash zone. The top section, approximately a third of total weight, was removed by *Saipem 7000.* The middle section was cut into smaller pieces by ROV and placed in seabed baskets which were later removed by *S7000.* The bottom section was removed in two parts by *S7000*. A significant amount of seabed debris was also removed. Total weight removed was 7364 tons, at a 2017 cost per ton of 89 400 NOK.

Anonymous source: A jacket removed in the past twenty years had a removal cost per ton of 93 505 NOK [139].

Large variations in depth, jacket weight, timeframe and work performed on jackets makes comparison of removal projects challenging. *Decommissioning Insight* gauges a cost of 4700 GBP per ton, but this cost could increase to as much as 8000 GBP per ton for the most complex operations in the northern North Sea [2].

Combined Topside and Substructure Removal

Many sources report topside and jacket removal costs as a combined cost. This is to be expected, as the majority of decommissioning contracts engage a single contractor to remove the entire platform.

Varg: The following information is gathered from the Varg impact assessment [93]. Removal of both jacket and topside has an estimated cost of 330 million NOK (2014, 355 million in 2017). The monotower weighs 5.2 tons and the topside weighs 880 tons, for a combined weight of 6080 tons. This equates to a cost per ton of 51 600 NOK, when average disposal cost per ton (detailed in the next section) is subtracted.

Figure 46: The Varg A platform with Petrojarl Varg FPSO in the background [115]

Hod: The following information is gathered from the impact assessment for Hod [140]. Hod is a normally unmanned wellhead platform remotely operated from the Valhall field. Hod lies in the southernmost region of the NCS, at a depth of 72 metres. The topside has no processing facilities as production is sent to the Valhall field. Topside weight is 1180 tons and jacket weight is 2400 tons. The platform is scheduled to be removed around 2022, along with facilities at the Valhall field. Cost estimates are 600 million NOK (2014), of which 40 % is removal costs. This equates to a 2017 removal cost per ton of 72 200 NOK.

Leman BH [141]**:** One of four platforms in the Leman B complex, which is part of the wider Leman gas field. Leman BH is a living quarters platform linked by a bridge (removed previously) to Leman BT, a gas transport platform. The topside, weighing 1039 tons, sits on a four-legged fixed steel jacket weighing 566 tons which includes the four jacket piles. Both topside and jacket will be removed by single lift and taken to disposal yards in the UK or the

Netherlands. Based on cost estimates of 13.8 million GBP (2017). Subtracting an expected removal cost per ton of 6 900 NOK, cost per ton in 2017 is 84 600 NOK.

Anonymous source: A platform removed in recent years showed a cost per ton of 55 450 NOK per ton (2017) [100].

Phase 7: Subsea Infrastructure

Pipelines

The extent of removal of subsea pipelines is governed by the report *Stortingsmelding 47* [42], which states that pipelines may be left in situ, provided they do not hinder other marine activity. If they prove to be a hindrance, they must be trenched or covered. Pipelines must also be thoroughly cleaned.

As of January 2000, there were 9 300 kilometres of pipelines connected to Norwegian oil and gas fields, of which 7 400 kilometres are export pipelines and the rest are facility (infield) or intrafield pipelines. Approximately a third of export pipelines and 77 % of infield pipelines are trenched, covered or rock dumped.

To gain insight into the costs of decommissioning pipelines in the North Sea, several pipelines were studied. The available options in pipeline decommissioning are [142]:

- Leaving in situ: this approach may be taken if the pipeline does not cause hazards for fishing activities. If so, the only work to be undertaken is cleaning of the pipeline, cutting of end(s), plugging of open ends, and monitoring. The end of the pipeline, where it connects to the installation, will usually be removed. The length of this end varies by field layout.
- Rock-dumping: covering the pipeline with rocks to protect trawling nets from snagging. Completed by a rock-dumping vessel.
- Trenching: creates a depression in the seabed along the pipeline’s axis, lowering the pipeline below seabed level. Backfilling is an option, where displaced seabed is pushed back into the trench, covering the pipeline. If no backfilling is performed, it is assumed

the trench will backfill naturally through shifting of seabed. Recommended burial depth is 0.6 metres.

- Removal: partial or full removal of pipeline.

A part of pipelines is making safe, where a thorough survey of the pipeline is completed, aiding in decision-making for the best decommissioning approach.

All available decommissioning programs and Close Out reports from the UKCS were studied to gather data, and the same was done with impact assessments from the NCS. Eighteen documents were shown to have relevant information, such as comparisons and cost estimates for the different approaches. In addition, the following documents were studied:

- *Brent Fields Pipelines Decommissioning Technical Document* was studied for information on Brent A's PL050 pipeline [143].
- Comparative Assessment reports on the *Ann & Allison* [144], *Rose* [145] and *Markham-Stamford* [146] fields were studied for information on the pipelines of these fields.

	Gas	Oil	Number of pipelines	Diameter	Weight	Total length	Length removed	Weight remo	Sections leng	Concrete coati	Trenched len	Mattresses (tons	SSIV weight	Cost per pipeline (2017 MNC	S
Full removal															
Frigg infield pipelines NCS	1	0	4	3 - 26		2602								52,5	
Frigg infield pipelines UKCS	1	0	4	3 - 26		1990								52,5	
Brent Apha PL050	1	0	1	28		3000								98,7	
Ann & Allison PL 947	1		1	12		41800								9,4	
Ann & Allison PL 948			1			17600								8,0	
Ann & Allison PL 1099			1			15100								5,6	
Tommeliten Gamma			2	6-8										27	
Hod			2	4-12										16,2	
Huldra 8"	Condensate		1	8		16000								134,8	
Huldra 22"			1	22										89,9	
Rose															
Annabel & Audrey PL 496, PL 497	1	0	2	3 - 20		2 x 16900								130,9	A
Annabel & Audrey PL575	1	0	1	8		492								5,3	A
Annabel & Audrey PL576	1	0	1	4		650								3,2	A
Annabel & Audrey PL 723, PL724	1	0	2	3-14		2 x 4400								21,8	A
Annabel & Audrey PL 2066	1	0	1	10		17800								50,7	A
Annabel & Audrey PL 2067	Meg+un	0	1	4,5		13400								37,8	A
Markham-Stamford PL 2567, PL 2568			2	5 - 6		7400 + 7700								165,4	S
Markham-Stamford PL 992, PL 993	1		1	2 - 12		2 x 5480								27,8	M
Partial removal															
North West Hutton PL147	1	0		10	2532	13000	73			13000	0	760	84	51,8	
North West Hutton PL148	0	1		20	5300	12085	670	224	12	12085	0	300		103,6	
Rose	1			10			200					116		78,1	
Rose Umbilical							148								
Annabel & Audrey Gas + methanol line	1	0	2	3 - 20		16900	155							1,54	
Annabel & Audrey PL575	1	0	1	8		492								2,9	
Annabel & Audrey PL576	1	0	1	4		650								2,9	
Annabel & Audrey PL 723, PL724	1	0	2	3-14		2 x 4400	2 x 262							3,8	
Annabel & Audrey PL 2066	1	0	1	10		17800									
Annabel & Audrey PL 2067	Meg+un	0	1	4,5		13400									
Markham-Stamford PL 2567, PL 2568			2	5 - 6		7400 + 7700								147,1	S
Markham-Stamford PL 992, PL 993														17,4	M
Leave in-situ															
Indefatigable PL80	1	0		20		3880	0	0		13000	13000			20,7	
Indefatigable PL81	1	0		24		9140	0	0						20,7	
Huldra 8"				8		16000								67,4	K
Huldra 22"				22		700								33,7	
Camelot CA PL 624	1	0		12		14424	0					2 of 7 removed		23,8	
Camelot CB PL 878 flexible	1	0		6		1226	0					8 of 10 removed		23,8	
Ann & Allison PL 947	1	0				41800									

Figure 47: Sample of pipeline database compiled for this thesis

Due to lack of available data, costs were compiled by comparison of each decommissioning option, such as rock-dumping as a percentage of full removal cost.

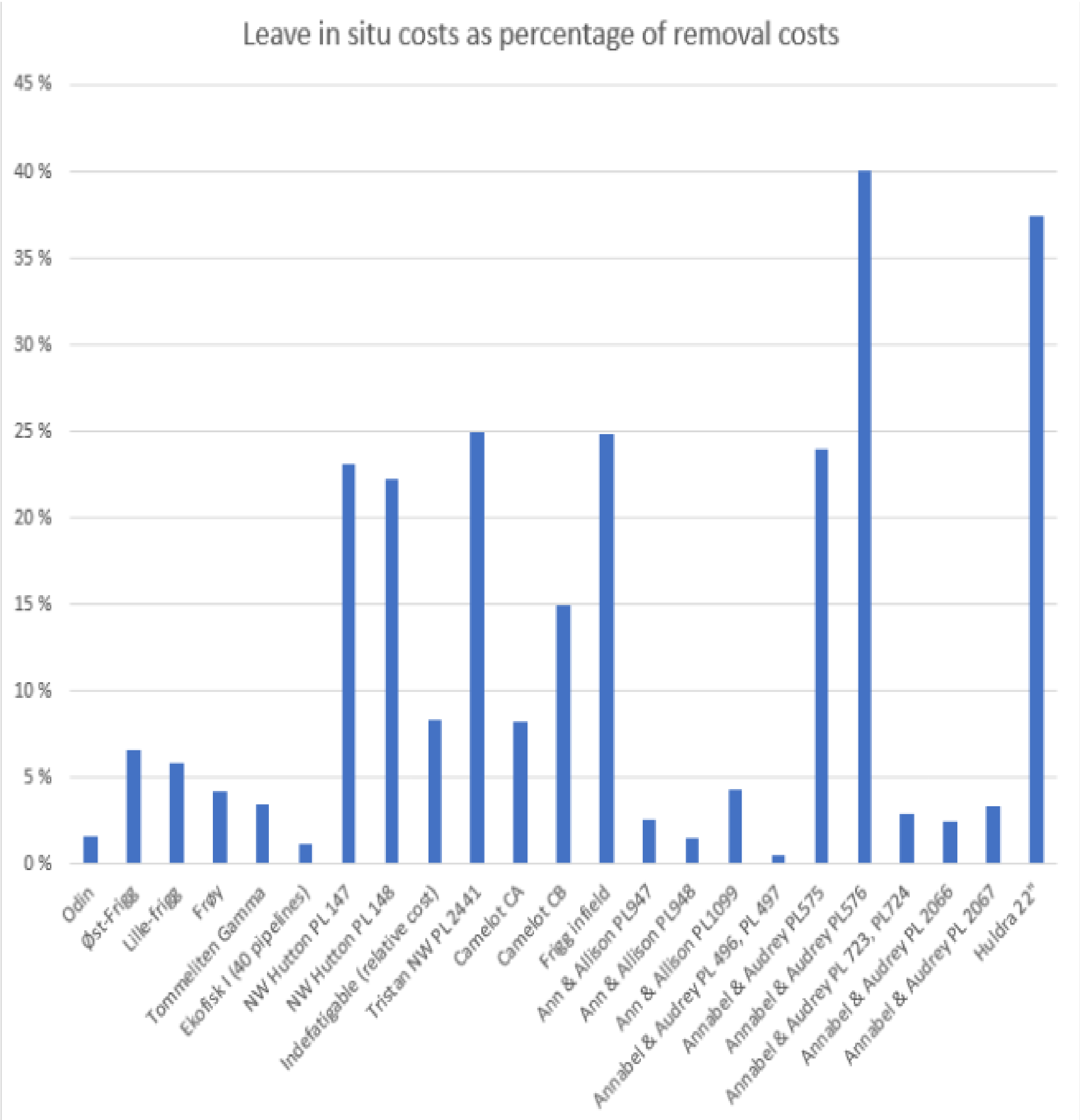


Figure 48: Infield pipeline leave in situ costs as percentage of removal costs

Rock-dumping: The cost to rock-dump the Odin pipeline was 79 % percent of the cost of full removal, and 17 % for Brent Alpha's PL050 pipeline.

Figure 49: Rockdumping of pipeline

Trenching, no backfill: The cost of trenching the Odin pipeline was 29 % of the full removal cost, 16 % for Øst-Frigg's pipeline, 88 % for Frigg's infield pipelines and 48 % for Frøy's water injection pipeline.

Trenching with backfill: The cost of trenching and backfilling the Odin pipeline was 44 % of full removal cost, 46 % for Øst-Frigg's pipeline and 33 % for North West Hutton's PL 148 pipeline.

Using the data, three cost sub-categories were devised:

- Cost to leave a pipeline in situ
- Cost to trench or bury a pipeline. Analysis indicates that the costs of these options are similar and they are therefore combined.
- Cost to remove a pipeline

The calculations of pipeline costs are undertaken in a separate unpublished document. The average cost of leaving a pipeline in situ is 24.52 million NOK. The average cost of removal of a pipeline is 72.05 million NOK. From the gathered data costs of trenching and rock-dumping appear to be similar. As little data is available, the costs of these operations were calculated as an average percentage of the cost to remove a pipeline: 43.2 %. The cost to trench/rock-dump a pipeline is calculated as

$$43.2\ \% \times 72.05 = 31.24 \text{ million NOK}$$

Subsea equipment not including pipelines (X-mas trees, templates, manifolds etc.)

For subsea development fields and tie-backs, the regular cost per ton approach was used. This revealed, as expected, large variances in cost per ton for removal and disposal. This could be attributed to differences in depth, and total number of installations removed. Assuming the cost of leaving a pipeline in situ is 24.5 million NOK per pipeline, this cost was subtracted from the removal cost for each subsea field unless pipeline decommissioning costs were stated explicitly. The following cost data were discovered:

Rev [99]**:** At a depth of 85 metres, removal of the three structures at Rev was estimated at 139 million NOK (149.8 million NOK in 2017). Subtracting the costs of decommissioning two pipelines, total cost is 100.8 million NOK (2017). The total weight of the infrastructure is 619 tons including 329 tons of mattresses; cost per ton removed is 162 828 NOK.

Yme I [147]**:** Comprised of two production areas, Yme Gamma, located at the production platform Maersk Giant, and the satellite field Yme Beta. At Yme Beta there were four X-mas trees, two protective structures, and two templates. At Yme Gamma there was a drilling template to be removed. Assuming risers at Yme Gamma were removed previously, total weight removed was 766 tons, at a cost of 15.4 million (2017) or 20 000 NOK per ton.

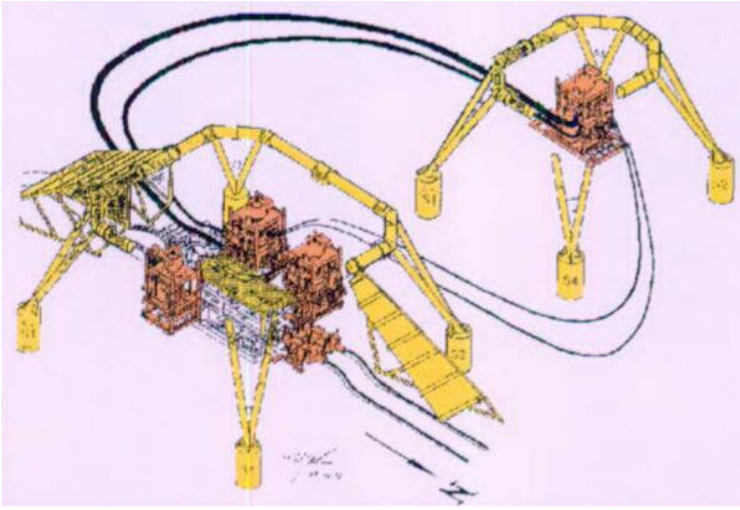


Figure 50: Subsea wells at Yme Beta

Volve [58]**:** Comprised of a jack-up rig, Maersk Inspirer, connected to the FPSO Navion Saga. Approximate weight of subsea material was 3200 tons at a depth of 80 metres, and included drilling template, Subsea Isolation Valve (SSIV), and numerous smaller pieces of mooring equipment. Removal of the materials with an estimated cost of 175 million NOK (192.5 million NOK in 2017), gives a cost per ton of 40 300 NOK.

Tristan NW [148]**:** A small gas field at a depth of 36 metres, the DSV *Bibby Topaz* completed the removal work in 2010. Equipment removed included a wellhead, two well casings and four spool pieces, 408 tons of concrete mattresses and five tons of grout bags. Total weight of steel was 43.8 tons. Final cost of the operation was 2.9 million GBP or 31 million 2017 NOK. This amounts to 67 900 NOK per ton [149].

Arthur [150]**:** A gas field in the Southern North Sea, tied back to the Thames platform. The field consisted of four structures: three wellheads and a manifold, all with protective structures. In addition, 87 tons of mattresses and 73 tons of frond mats are scheduled for removal or have been removed. The total weight to be removed was 591 tons, at a 2015 estimated cost of 3.5 million GBP, or 77 108 NOK per ton.

Gawain [151]**:** Comprised of four single subsea installations: three wells and a manifold with protection frames, tied back to the Thames platform. Total weight removed is 719 tons, including mattresses, costing an estimated 4.6 million GBP (2015). This equates to a cost per ton of 83 300 NOK.

Wissey [152]**:** A single wellhead with protection frame tied back to the Thames platforms. Weight including mattresses is 352 tons with a cost of 3 million GBP for removal and disposal, or 111 000 NOK per ton.

Thames complex [153]**:** The system comprising 4 wellheads and a template with protective frames, tied back to the Thames platform, the removal cost is estimated at 6 million GBP (2015). This equates to 65.1 million 2017 NOK, or 55 400 NOK per ton.

Orwell [154]**:** Three subsea wells, five manifolds and a template are to be removed. The total weight is 1100 tons including mattresses. The cost is estimated at 5 million GBP (2015), or 175 700 NOK per ton (2017)

Rose [112]**:** a single wellhead, X-mas tree and protective frame at a depth of 30 metres [155], Rose is estimated to cost 13 million GBP (2015). Subtracting costs for umbilical and pipeline removal (2.63 and 3.38 million GBP respectively), the cost for removing 91 tons of equipment is 175 700 NOK per ton.

Phase 8: Disposal and Recycling

When offshore installations are brought to shore, several alternatives are available for disposal and recycling. The removal method will govern these options.

- Piece small removal produces scrap metal in containers which may be recycled.
- Module-based removal presents options for re-sale of equipment, and perhaps entire modules.
- A topside removed by single lift can be reused entirely. However, this is a rarely used option due to the extensive work required prior to resale and the continuing liability after. Single lift removal also offers alternatives for making safe – some of the facility may be cleaned onshore, reducing costs. However, an entire topside may present challenges in demolition due to the height of the structure.

The type of module will affect the time and work scope. For example, a living quarters module will take longer time to process due to the larger variation in types of materials in these structures [19]. This is evident in the disposal of Frigg QP, where only 88.8 % of materials were recycled as opposed to almost 100 % on the other Frigg installations [25].

Assumptions made:

- Most of the cleaning work has been completed offshore in DCS contracts
- Method of removal is reverse installation/module-based removal
- Resale value of scrap metal is considered an integrated part of the disposal contract

The following table provides an overview of some of the data gathered to develop a metric for disposal:

Table 10: Overview of disposal costs

Name	**Weight removed**	**Cost**	**Timeframe**	**Cost MNOK (2017)**	**Cost per ton**	**Disposal site**
Miller	30 855 [156]	200 MNOK [157]	2016 – [156]	200	6 482	Kværner Stord [157]
Huldra	10 600 [137]	88.6 [137]	2019 – 2020	99.5	9 391	AF Miljøbase Vats [158]
Hod	4 170 [140]	5 % of 600 MNOK [140]	2026 - [159]	32.3	7 753	
Camelot CA	1 912 [63]	1.5 MGBP [63]	2012 [63]	15.2	7 937	Netherlands [63]
Statfjord C Single-Point Mooring	8 000 [160]	49 MNOK [161]	2012 [160]	55.4	6 926	AF Miljøbase Vats [160]
Veslefrikk A&B	45 052 [97]	275 [97]		280	6 216	

Recycling provides opportunities for disposal yards. Disposal contractors such as Kværner and AF Decom have achieved recycling rates of up to 98 % on average for disposal of offshore installations [162] [135]. The resale value of both equipment and scrap steel incentivizes high recycling rates. Scrap steel prices can vary between 500 and 3000 NOK per ton. This will provide considerable extra income for disposal contractors and will affect the price per ton disposal contractors will charge for recycling.

Phase 9: Site Remediation

The final stage of the removal process is the seabed clean-up – removal of material on the seafloor and subsequent over-trawl surveys to ensure any infrastructure left in situ does not pose a hazard to marine activities or the environment.

Common seabed debris may be mattresses and grout bags used for covering pipelines, various dropped objects, pipeline infrastructure not removed during pipeline decommissioning, and cuttings piles.

Gathering data from publicly available sources, a selection of seabed clearance and monitoring operations have been reviewed.

Frigg: SONSUB Ltd was awarded the clean-up contract in April 2006 as a lump-sum contract for both pipeline/cable removal and seabed clean-up [23]. Two campaigns were performed, in 2008 and 2010 [25]. 270 tons of material were identified and removed using a construction type vessel, echo sounders and ROV [163] [25]. The cost for the NCS-portion of seabed clearance was 61 million NOK and 49 million NOK on the UKCS [25]. Drill cuttings from the DP2 platform contained mostly water-based fluids, meaning cuttings could be left to degrade naturally [25]. A substantial clear-up operation around the DP1 platform was required due to the amount of debris from the impact.

Frigg MCP-01 [57]**:** A Close Out report of the MCP-01 cessation revealed a post-decommissioning clean-up cost of 5.4 million GBP (2013). The seabed clearance was performed by DOF after topside removal had been completed and 641 items with a weight of

100 tons were removed from the seabed. The concrete base structure of MCP-01 is still in place.

Ekofisk: The seabed clean-up operation is currently ongoing, at an estimated 1998 cost of 66 million NOK [91] adjusted to 97.4 million NOK in 2017.

Table 11: Overview of site remediation costs

	Water depth (m)	Year completed	Remediation cost	Total cost	Percent of total
Frigg NCS	100	2008, 2010	61 MNOK	3287 MNOK	1.9
Frigg UKCS	100	2008, 2010	49 MNOK	2710 MNOK	1.8
Frigg MCP-01	100	2011	5.4 MGBP	211.5 MGBP	2.6
Ekofisk 1	75		66 MNOK	6900 MGBP	1.0

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Phase 10: Monitoring

Monitoring must be completed at regular intervals after final seabed clean-up. This consists of visual inspections of equipment left on the seafloor, testing of cuttings piles, and trawl-over tests to confirm that the equipment does not present a hazard to fisheries. Time between surveys is usually at the operator's discretion, based on results of previous surveys.

Assuming 2 surveys at intervals of five years [142] , the following costs were compiled:

Table 12: Overview of monitoring costs

	Decommissioning end	Cost per survey	2017 cost per survey
Thames Complex		0.5 [153]	6.5
Thames Horne & Wren		0.5 [164]	6.5
Rose	2015	0.5 [112]	6.5

Model Development

The inputs to be simulated in the Monte Carlo estimation model are the aforementioned elements from the WBS in addition to a number of extra inputs which provide more detail.

The extra inputs and their distributions are:

- The number of train wrecks among the wells to be plugged. Given a binomial distribution
- The cost of a train wreck well. Given a triangular distribution
- Cost to leave a pipeline in situ. Given a triangular distribution
- Cost to trench or rock-dump a pipeline. Given a triangular distribution
- Cost to remove a pipeline. Given a triangular distribution

Various judgments and assumptions were made for each installation, such as:

- Whether making safe costs could be disregarded or minimized since the majority of work may have been completed outside the scope of the decommissioning project in question, such as on several of the Frigg platforms [57].

- Weight removed may differ from weight delivered to disposal yard. Marine growth on substructures can weigh several thousand tons, as seen in most of the literature studied, however as this growth dries out it will weigh considerably less, as stated by a disposal yard contractor [19]. For simplicity the weight removed including marine growth has been used both for estimating removal cost per ton and disposal cost per ton.

Table 13: Data gathered on marine growth

	Installed/start	Depth	Removed	Years of u	Design Topside	Design jacket	Removed Topside	Removed jacket	Marine growth	Growth per ton
Frigg DP2	1978	100	2008	30	5749	9797	4002	11122	300	0,031
Frigg QP	1977	100	2009	32	3639	4757	3063	5243	250	0,053
Miller	1992	103		25	28732	18584	28732	18584	1657	0,089
Murchison	1980	156	2017	37	24584	27584	24584	14854	2394	0,087
Yme II	2011	93		6	13500	43000	13500	N/A	300	0,007
Valhall QP	1981	74		36	3650	4700	3800	5063	151	0,032
Huldra	2001	125		16	5030	5000			350	0,070
Hod	1990	72		27	1200	1200	1180	2437	85	0,071
Indefatigable, (	1971	31	2010	39	8283	4265	12341		278	0,065
Maureen	1983	94	2001	18	19000	92750	19000	97250	650	0,007
Gyda	1990	66		27	17227	17500	17227	11050	1200	0,069
Frigg DP1	1973	98	2009	36	N/A	7300		7364	300	0,041
Varg A	1998	84		19	878	3611	878	5200	580	0,161
Jotun B	1999	127		18	8467	6010	8467	8310	1000	0,166
									Average	0,06771

- When examining pipeline decommissioning, judgments were made on lumping together several small parallel pipeline pieces and umbilicals as one pipeline for simplification. Lengths and diameters have been disregarded, and superficial cost-per-pipeline data have been used, due to time constraints and lack of data.
- In several attributes cost estimation for removal has been based on 'weight removed' rather than the more realistic 'number of lifts'. This is due to scarcity of information on number of lifts. 'Man-hours required' has been disregarded due to scarcity of information on cost of man-hours for different categories.
- Whether facility running costs/post-COP OPEX could be disregarded on installations that had been shut down long before removal, or for other reasons may incur minimal or no facility running costs.

Each of the WBS categories of decommissioning are represented. The average and standard deviation of each phase has been calculated. The categories are given triangular distributions as this best represents cost. A guiding principle been that the average in the triangular distribution is equal to the average calculated from the data. The standard deviation has been an important input in deciding the minimum and maximum of the distribution.

Next, the parameters for the platform are developed. The following are used:

- Weight topside
- Weight substructure
- Weight subsea infrastructure
- Number of platform wells
- Number of subsea wells
- Number of pipelines left in situ
- Number of pipelines trenched/rock-dumped
- Number of pipelines removed
- Where applicable, transport cost for removal of floating installations

The model is run with 100 000 iterations (random number generations).

Simulations were run on fields where decommissioning cost estimates and/or actual decommissioning costs are known. For these platforms an effort was made to gather the required input data to run the simulations.

Table 14: Overview of fields simulated in model

Platform	Weight Topside tons	Weight jacket removed tons	Weight subsea infrastr.	Number of platform wells	Number of subsea wells	No of Pipelines left in situ	No of Pipelines trenched/rock-dumped	No of Pipelines removed
Ekofisk 1 minus Tank	89550	71100	0	0	0	40	0	0
Ekofisk 2/4 S	0	11280	0	0	0	0	0	0
Ekofisk 2/4 Tank	25000	0	0	0	0	0	0	0
Frigg NCS	25435	19225	0	0	0	0	0	2
Gyda	17227	11050	90	32	0	2	0	0
Hod	1180	2437	533	0	0	2	0	0
Huldra	5030	5000	0	0	7	1	1	0
Jotun B	8467	8310	4250	21,2	0	6	0	0
Valhall QP	3800	4960	0	0	0	0	0	0
Varg A	878	5780	2010,5	0	8	1	0	2
Veslefrikk	5752	11800	4900	23	0	2	0	0
Volve	0	0	3200	0	6	2	0	0
Norpipe B11 GSNC	6606	2694	0	0	0	0	0	0
Rev	0	0	619	0	4	2	0	0
Frigg UKCS	16949	5821	0	0	0	0	0	3
Frigg MCP01	15100	0	256	0	0	0	0	0
Indefatigable, 6 platforms	8283	4260	90	0	0	5	0	0
Miller	28732	18584	485	15	7	0	0	0
North West Hutton	19227	9200	603,5	33,6	0	2	1	0
Thames AW, AR, AP	8929	4099	1367,8	5	4	5	0	0
Fife, Flora, Fergus, Angus (FFF	0	0	8940,72	0	12	11	0	8
Rose	0	0	507,9	0	1	2	0	0
Platform NN1								
Platform NN2								
Platform NN3								
Platform NN4								

Monte Carlo simulation

The motivation for undertaking the following simulations is to produce simulation results that can be a basis for the verification of the cost estimation model developed in this thesis.

The different cost components were analysed for each field with regards to the different cost components. For example, if no P&A was to be performed there would be minimal or no Post-CoP OPEX. The same applies for quarters platforms, and fields that have been shut down for a long time before removal. The following details which assumptions have been made for each field, to make the modelling costs resemble the costs stated in the gathered information.

- Ekofisk I (minus Ekofisk tank): site remediation, monitoring and post-CoP OPEX were disregarded
- Ekofisk Tank: site remediation, monitoring and post-CoP OPEX were disregarded
- Frigg, Norwegian platforms: making safe, post-CoP OPEX disregarded in accordance with decommissioning program cost overview
- Hod: P&A was not included in the estimate from the impact assessment, and was therefore removed from inputs
- Huldra: No post-CoP OPEX, as a separate rig will perform P&A [137]
- Jotun: A modular rig installed on the platform will perform P&A [165]. Post-CoP OPEX is therefore incurred.
- Valhall QP: Post-CoP OPEX disregarded, as this is a quarters platform
- Varg A: Post-CoP OPEX disregarded, due to wells being treated as subsea wells with a separate rig performing P&A.
- Veslefrikk: Site remediation and monitoring costs disregarded, as these costs were not included in the impact assessment. This facility has a floating production unit connected, the semi-submersible Veslefrikk B. Therefore, extra costs were added for the tow-away and disposal/recycling of this facility.
- Volve: Wells counted as subsea wells with no post-CoP OPEX. The full cost may be less as the field may receive generous day rates for the Maersk Inspirer jack-up's P&A completion.
- Rev: No post-CoP OPEX, or making safe, as this is a subsea-only field.
- Frigg MCP-01: Post-CoP OPEX disregarded, due to minimal costs. There were no wells associated with the facility and it had been largely made safe years prior to removal.
- Indefatigable: P&A costs not included in cost reports. Post-CoP OPEX disregarded.
- Rose: Subsea-field only – post-CoP OPEX disregarded.

Validation and verification of model

The cost estimation model used in the Monte Carlo simulation must be validated and verified to uncover the precision of the model, and to which degree it can be trusted.

According to the article *Validation and verification of Simulation Models* by RG Sargent [166], one way of verifying a model is to test it against other models.

All operators on the NCS have their own decommissioning cost estimation models. Testing the estimates from the Monte Carlo model developed by the authors against real estimates from different operators is one way of validating the model. The cost estimation model in this thesis is constructed for decommissioning cost estimation on the NCS and is validated using decommissioning cost estimates presented by operators and actual decommissioning costs.

A cost estimation model should ideally be developed using only part of the data available. Then the output of the model is tested on actual cost data that have not been used in the creation of the model. In the construction of the cost estimation model in this thesis it was decided that this approach is not feasible. Due to lack of data, all available data is needed to estimate the metrics used in the cost estimation model. There are only three Norwegian installations where the total decommissioning cost estimate is publicly available which are not used as inputs in the model. Three installations is considered too small a sample to credibly validate the model, and the model is tested on the three installations grouped together with all other installations on the NCS where the total decommissioning cost estimate is available.

The estimation model in this thesis versus other decommissioning cost estimates

The Monte Carlo simulations carried out by the authors produced estimates for 26 installations on 10 fields where the decommissioning cost estimates are public knowledge. The results are listed in the table on the following page.

Table 15: Deviation from estimates

Installation	P50 estimated by Monte Carlo	P10	P90	Total cost estimated by operator	% deviation from estimate	Used as input to the model	Operator cost estimate within P10 to P90 range
Ekofisk 1 excl. Tank	13 173 456 769	1 059 280 022	16 874 709 046	9 976 000 000	32,1 %	Y	Y
Ekofisk 2/4 Tank	2 038 220 503	1 410 671 021	2 951 103 261	1 680 600 000	21,3 %	Y	Y
Frigg NCS	3 570 227 672	2 708 182 687	4 607 705 714	2 443 500 000	46,1 %	Y	N
Gyda	4 530 310 236	3 456 830 335	5 854 387 408	5 682 000 000	-20,3 %	Y	Y
Hod	395 345 444	318 644 606	489 106 774	646 600 000	-38,9 %	Y	N
Huldra	2 022 015 332	1 643 784 443	2 397 356 983	2 261 500 000	-10,6 %	Y	Y
Jotun B	3 372 572 333	2 657 417 217	4 256 973 449	3 692 500 000	-8,7 %	N	Y
Valhall QP	681 322 540	514 582 154	879 338 385	949 500 000	-28,2 %	N	N
Varg A	2 184 721 389	1 770 752 186	2 579 172 034	1 892 500 000	15,4 %	Y	Y
Veslefrikk A	3 598 865 959	2 851 370 046	4 535 256 590	2 698 600 000	33,4 %	Y	N
Volve	1 364 783 072	1 055 780 303	1 665 768 320	1 210 100 000	12,8 %	Y	Y
Norpipe B11 GSNC	909 386 426	677 968 110	1 218 403 110	1 123 535 676	-19,1 %	N	Y
Rev	814 094 661	606 701 503	1 001 205 244	859 900 000	-5,3 %	Y	Y
				Average	2,3 %		
				Standard deviation	26 %		

Average difference between the P50 cost estimates produced by the model developed in this thesis and the estimates presented by the operators on the NCS is 2.3 % meaning estimates are marginally on the high side.

The average precision of the model seems to be high. The standard deviation is 26 % which tells us that the estimates produced by the model in this thesis in some cases produces estimates that are relatively far from the operators own estimates.

On average the model fits very well and some variation in the estimates is to be expected.

Another observation is that for 9 of the 13 estimates the operator's estimate is within the P10 to P90 range. Ideally more of the operator estimates would have been within the P10 to P90 range, but the estimates that are outside the range are in most cases just outside the range and would have fitted within a P5 to P95 range.

The model developed in this thesis seems to estimate average decommissioning cost with a high level of accuracy, and even though there is some variation, these results go a long way toward validating the model.

The estimation model in this thesis versus actual decommissioning cost figures

The estimates produced by the model developed in this thesis have also been tested against actual decommissioning expenditure from decommissioning projects on the NCS where cost is known. The results are listed in the table below:

Table 16: Overview of deviations from actual costs

Installation	P50 estimated by Monte Carlo	P10	P90	Total cost estimated by operator	Actual cost	% deviation from actual cost
Frigg NCS	3 570 227 672	2 708 182 687	4 607 705 714	2 443 500 000	3 559 100 000	0,3 %
Platform NN2						2,9 %
Platform NN3						11,4 %
Platform NN4						7,1 %
					Average deviation	5,4 %
					Standard deviation	4,8 %

One of the decommissioning projects where cost is known is the decommissioning of the three Frigg structures on the NCS. For these three platforms the estimate produced by the authors is 0.3 % above actual cost.

The authors have been given access to actual cost for three other decommissioning projects under condition of anonymization. When including the three Frigg platforms, the 4 estimates produced by the authors are on average 5.4 % above actual cost with a standard deviation of 4.8 %. The fact that actual cost data for decommissioning is only available for four fields and 6 platforms is an issue, and ideally more actual cost data should be obtained to verify the model further. However, based on the available data the model developed in this thesis performs very well.

The precision of the estimates produced by the model in this thesis is excellent compared to actual cost, and the variation is within acceptable levels by a decent margin.

It is worth noting that some of the metrics used in the model development have been created using data from some of the platforms above. But as illustrated in Table 7, a total of 75 installations have contributed directly with data for the metrics in the cost estimation model. On top of that an unknown but considerable number of installations have contributed with additional data through Decom Insight Reports by UK Oil & Gas. The impact of the data from the individual installations listed in the Table 7 in the determination of the metrics is within acceptable levels.

The results described in the section above should be sufficient to validate the Monte Carlo Model presented in this thesis, and the authors feel confident that the estimates produced by the model give a fairly precise indication of actual total decommissioning cost on the NCS at current.

UKCS

The model was also tested against estimated and actual cost on the UKCS. The results are described in the table below.

Table 17: Overview of deviations from UK costs

Installation	P50 estimated by Monte Carlo	P10	P90	Total cost estimated by operator	Actual cost	% deviation from estimate	% deviation from actual cost
Frigg UKCS	2 051 003 838	1 569 892 453	2 685 631 233	2 016 000 000	2 843 100 000	1,7 %	-27,9 %
Frigg MCP01	1 294 341 375	914 094 336	1 844 857 923	1 062 800 000	1 985 547 404	21,8 %	-34,8 %
Indefatigable	1 145 405 873	891 949 233	1 464 002 497	927 000 000	1 729 730 000	23,6 %	-33,8 %
Miller	6 661 548 297	5 350 779 411	8 273 107 366	3 452 000 000		93,0 %	
North West Hutton	4 765 521 831	3 643 498 605	6 161 549 661	1 657 421 853	2 548 286 000	187,5 %	87,0 %
Thames AW, AR, AP	2 635 390 503	2 169 652 687	3 197 251 506		1 251 249 148		110,6 %
FFFA	3 703 884 824	3 000 533 465	4 425 647 941	2 463 855 513	2 971 152 748	50,3 %	24,7 %
Rose	293 948 970	234 374 537	379 161 144	312 448 000		-5,9 %	
					Average	53,1 %	21,0 %
					Std dev	67,9 %	64,7 %

The estimation model developed in this thesis estimated on average 53.1 % above estimated cost and 21 % above actual cost for the 20 installations in the 8 fields listed above. The standard deviation is very high, indicating that the model's precision is does not predict decommissioning cost sufficiently accurate for the UKCS.

The data suggests that decommissioning cost metrics are different on the UKCS compared to on the NCS. The authors suspect that different regulations and practices when it comes to P&A is the main contributor.

The results presented above support the assumption that the unit cost of decommissioning is higher in Norway than in the UK and suggest that decommissioning cost in the UK is around 15 % lower on average than in Norway.

ESTIMATION OF THE NCS

The following section details the cost estimation of the decommissioning of all infrastructure on the NCS. First, the Monte Carlo estimation of the total cost is presented. To validate the estimate, total decommissioning costs are calculated through operator ARO liability estimates. Another validation is developed by calculating total decommissioning weight and comparing it to the UKCS's total weights and cost estimates for decommissioning this weight. Lastly, the share of decommissioning costs covered by the Norwegian government is calculated.

Monte Carlo Estimate

Estimating the cost of decommissioning the entire current NCS infrastructure was developed from the calculation of the following parameters:

1. The total weight of all platforms and floaters. Fixed concrete substructures were disregarded as it is assumed these will be left in situ
2. Removal cost of steel floaters
3. Transportation cost of concrete-base floaters
4. The number of wells to be plugged and abandoned and their classification
5. The total weight of subsea infrastructure, including concrete mattresses and mooring systems for floaters
6. The total number of pipelines to be decommissioned

Total Weight of Platforms and Floaters

The calculation of total weight of fixed platforms is detailed in the section *The Weight of Structures on the NCS Including New Structures After 01.01.2015 Based on OSPAR Data*. Refinements were made, so that bridge structures and separate flame towers were separated as the site remediation and monitoring cost of these structures is included in the cost of their respective associated facility.

As part of the calculation of the weight of the structures on the NCS, the floaters were investigated. Four floaters were not registered with weight in the OSPAR data.

Where the floaters that were not registered with weight and where information on weight could not be found, an attempt was made to find information on the displacement and the deadweight of each vessel. The lightweight tonnage has been estimated by subtracting the deadweight tonnage from the displacement for 2 of the FPSO's. The lightweight tonnage is used as an estimator for the weight of the 2 vessels [167].

For the remaining FPSO's an assumption has been made. The average weight of the 9 FPSOs, 1 FPU and 1 FSO where information on weight is available/has been calculated, is used as an estimate of the weight of the 5 FPSO's and 1 FSO with unknown weight. The estimate used is 38 081 tons.

Estimation of Removal Cost for Steel Floaters

These vessels normally need to be transported ashore from the fields using tugboats. Some unconventional FPSO's have been transported using semi-submersible transport vessels like Dockwise Vanguard for long distance transportation [168]. An example of conventional hulled FPSO transport is that of Armada Intrepid, formerly known as Schiehallion FPSO, which was transported from the Netherlands to Indonesia using Dockwise Vanguard [169]. These examples are for long distance transportation only.

The distance installations need to be towed and the time required will vary. Other variables are the vessel's drag depending on how hydrodynamic the vessels are and the weight of the towed vessel.

Data has been gathered on typical transport of FPSO's:

- One article indicates that two tugboats are required with one additional tugboat in backup when moving the Schiehallion FPSO [170].
- The towing of the SPAR-platform Aasta Hansteen required five tugboats [171].

The following 3 articles carry information from executed projects on the number of tugboats required and distance traveled per day.

- The towing of the FPSO Sevan Hummingbird from Rotterdam to the UKCS required 2 tug boats and the average speed was 9 knots [172] . That translates to approximately **400 km per day.**
- Towing the Petrojarl Knarr the 16 000 miles from South Korea to Norway required 3 tug boats and took 61 days. The average speed while towing was 10.74 knots [173]. That translates to **477 km per day.**
- The towing of the FSU Heidrun B the 11 000 miles from South Korea to the Heidrun field took 51 days and required 2 tugs. The average speed while towing was 10 knots [174]. That translates to **444 km per day.**

The towing of the five described facilities required a total of 15 tug boats – an average of 3 tug boats per vessel. The average distance traveled per day for the 3 projects where average towing speed is known is **440 kilometers.** The mobilization/demobilization fee and day-rate for tugboats is based on information from the industry.

To calculate transport costs for the FPSO, FSU and FPU vessels several assumptions must be made.

1. Average distance for the vessel to be towed is assumed to be approximately 900 km
2. Average number of tugboats required is assumed to be 3
3. Average mobilization fee and demobilization fee is 1 million NOK each
4. Average day-rate for a tugboat is 500 000 NOK

This leads to an average cost of transporting an FPSO to shore of 9 million NOK.

$$3 \times \left(1 + 1 + (2 \times 0.5)\right) = 9$$

An estimated cost of 9 million NOK is the value used for transportation to shore for floaters on the NCS.

Estimation of Transportation Cost for Floaters with Concrete Substructure

The two floaters with concrete substructures in Norway are much heavier than average floating structures. Floaters on the NCS weigh on average 38 081 tons.

- The Troll B platform is 160 901 tons, which is 4.22 times heavier than the average floater.
- The Heidrun TLP is 355 000 tons which is 9.32 times heavier than the average floater.

The magnitude of transport resources required increases. It is assumed that there is more hydrodynamic drag on these four-legged concrete structures. Therefore, the number of tugs required to transport these platforms is higher and the average speed under tow is lower.

In this thesis the transportation cost for the Troll B platform is assumed to be twice that of other floating structures since the distances from Troll B to the potential demolition yards in the UK or in Western Norway are relatively short.

That translates to a cost of 18 million NOK.

The distance Heidrun TLP will need to be towed is around the assumed average length. The transportation cost for the Heidrun TLP is assumed to be 6 times higher than for other floaters in this thesis.

That translates to a cost of 54 million NOK.

The Number of Wells in Norway

The number of wells that must be plugged and abandoned in Norway is an essential input in calculations of total decommissioning expenditures. The following section seeks to clarify both the current and the future scope of P&A in Norway.

- The NCS has approximately 3 000 wells according to an article by *Teknisk Ukeblad* [175].
- In a presentation from June 2013 the chairman of the P&A Forum stated that the number of wells in Norway is 2 880 [176].
- Another source of information is Øia and Spieler [11]. The number of wells in Norway where the P&A process has not started is 2 410 per 28th of February 2015.

These numbers are mutually exclusive and attaining a correct number of wells to undergo P&A is crucial to the estimate of total decommissioning cost. The decision was made to investigate further and decide which source is the most credible. The analysis involved examining information on all development wells on the NCS on the 3rd of May 2018 using a downloaded database from the NPD [177].

This list was sorted before further analysis [178] [82].

Table 18: Overview of well status

CLOSED	513
DRILLING	11
JUNKED	40
ONLINE/OPERATIONAL	1671
P&A	299
PLUGGED	2043
PREDRILLED	39
SUSPENDED	27
WILL NEVER BE DRILLED	51
NO CATEGORY	81
TOTAL	4775
TOTAL W/O EXCLUDED WELLS (IN YELLOW)	4632
TOTAL ALREADY P&A	2382
TOTAL TO BE P&A	2250

- The category *Closed* describes wells that have been closed for a shorter or longer period.
- The category *Drilling* describes wells that are being drilled or are undergoing P&A at present. These wells are disregarded as their status when drilling has ended is unknown.
- The category *Junked* describes wells that are finished due to technical issues. No further P&A is required on these wells.
- The category *Online/Operational* are wells that are ready for production or are currently producing or injecting.
- The category *P&A* are wells that are plugged and abandoned from fields that are closed.

- The category *Plugged* describes wells that are P&A from fields that are not closed. The category also describes wells with sidesteps where the well has only undergone phase 1 and phase 2 of P&A. Phase 3 will be performed at a later stage when the sidestep has undergone phase 1 and phase 2.
- The category *Predrilled* describes wells that have been predrilled.
- The category Suspended describes wells that have been temporarily abandoned. These wells require all 3 phases of P&A.
- The category *Will never be drilled* is disregarded as these are wells that were planned at some point in time but were never carried out.
- The wells that do not belong to any category are disregarded as no information is available on the status of these wells.

In this thesis it is assumed for simplicity that the wells that have undergone P&A are the wells in the categories *Junked, Plugged* and *P&A.* The total number of wells in these categories is 2 382.

The wells that have not been plugged are the categories *Closed, Online/Operational, Predrilled* and *Suspended*. The total number of wells in these categories is 2 250.

Calculations for the above numbers are shown in the enclosure *Norwegian wells 03.05.2018.*

These numbers are different from the numbers in Øia and Spieler. The reason is partly that new wells have been drilled and that some wells have undergone P&A since the 28th of February 2015. Another reason is that Øia and Spieler include exploration wells in the analysis of the wells on the NCS.

Analysis of a list of exploration wells downloaded from NPD on the 24th of May 2018 show that a total of 178 exploration wells belong to the three categories *Reclass to Development*, *Reclass to Test* and *Suspended*. These wells are not plugged and abandoned and could be included in the wells that will undergo P&A in the future given that the choice was made to include exploration wells in the analysis.

For comparison with Øia and Spieler, the total number of wells to be plugged including exploration wells are 2428 wells.

$$2\,250 + 178 = 2\,428$$

The number of wells that required phase 3 P&A according to Øia and Spieler was 2 159 on the 28th of February 2015. Approximately 3.25 years have passed since Øia and Spieler's number was calculated.

The annual increase would be 83 wells per year.

$$\frac{2\,428 - 2\,159}{3.25} = 83$$

The average annual number of wells drilled were 159 wells per year in the years between 2000 and 2017, as shown in the enclosure *Norwegian wells 03.05.2018.*

According to *Decommissioning Insight 2017*, the number of wells to be plugged and abandoned in Norway between 2017 and 2025 is 300, and the average number of wells that require P&A per year is 37.5. That means that the net increase of wells each year is 122.

According to Øia and Spieler, 37 % of all wells are sidetracks, which does not add new wellheads, and 63 % are new wells. Using this as an estimate for new wells, only 63 % of the net increase is new wellheads. That leads to an estimated annual increase of 77 wells per year

$$122 \times 0.63 = 77$$

Given that approximately 3.25 years have passed since Øia and Spieler collected their data, an estimate of the number of wells to undergo phase 3 P&A per May 2018 would be 2 409

$$2\,159 + (77 \times 3.25) = 2\,409$$

This number is very close to the actual number calculated using well statistics from NPD of 2 428.

$$2\ 250 + 178 = 2\ 428$$

After this analysis the conclusion is that the numbers Øia and Spieler present in their thesis are credible and can be the foundation of the calculations in this thesis. Given that the thesis' focus is on development wells only, and that the number of wells to undergo phase 3 corresponds closely with Øia and Spieler's numbers, a decision has been made to use the number 2 250 as the number of development wells to undergo full P&A on the NCS as of the 3rd of May 2018.

According to Øia and Spieler, the number of wells that must undergo phase 1 and phase 2 is higher than the number of wells that must undergo phase 3 abandonment, and a total of 2 159 wells require phase 3, while 2 410 wells require phase 1 and 2 424 wells require phase 2.

For phase 1 that represents a number that is 11.63 % higher

$$\frac{(2\ 410 - 2\ 159)}{2\ 159} \times 100\ \% = 11.63\ \%$$

For phase 2 that represents a number that is 12.27 % higher

$$\frac{(2\ 424 - 2\ 159)}{2\ 159} \times 100\ \% = 12.27\ \%$$

Given the lack of information on which wells have undergone phase 1 and 2, these percentages are assumed to be good estimates for the current proportion. An average of a 12 % higher number is used for both phase 1 and phase 2 for simplicity.

According to Øia and Spieler, the wellbores that have not been plugged and abandoned are 44 % subsea wells and 56 % platform wells. Phase 3 abandonment represents only about 3 % of the total P&A duration for subsea wells. As duration is a good estimate for cost in P&A, it is assumed that phase 3 represents 3 % of the cost.

For platform wells there is no similar available information on the fractional duration of phase 3, but an assumption is made that phase 3 represents 3 % of the time on platform well P&A as well.

The total scope of P&A can now be calculated to 2 512 wells.

$$2\ 250 + (2\ 250 \times 12\ \% \times 97\ \%) = 2\ 512$$

Given the assumptions that there are approximately 12 % more wells that need phase 1 and phase 2 abandonment, and that these phases represent approximately 97 % of the cost, the estimate of the number of wells on the NCS to be plugged and abandoned is 2 512.

As mentioned, according to Øia and Spieler approximately 44 % of the remaining wells that are not yet plugged and abandoned on the NCS are subsea wells and 56 % are platform wells.

According to Aarlott [82], 42.35 % of the remaining wells on the NCS are subsea wells and 57.65 % are platform wells.

This thesis will assume 43 % subsea wells and 57 % platform wells. Using this assumption for the distribution between platform wells and subsea wells leads to the following numbers:

Total number of subsea wells set for future P&A are 1 080.

Total number of platform wells set for future P&A are 1432.

A note on exploration wells: The data on all exploration wells were downloaded from the webpages of NPD 24th of May 2018 [179] and the wells that require P&A were singled out.

They belong to the categories *Reclass to dev*, *Reclass to test* and *In suspension*. In total there were 178 wells in these three categories that require P&A. The number was calculated for comparison with estimates in other sources on the number of wells that require P&A including exploration wells on the NCS. The calculations are shown in the enclosure *Exploration wells in Norway 24.05.2018.*

Exploration wells are omitted from the cost estimates of wells that require P&A in this master thesis.

Further refinements:

In this thesis the assumption so far has been that all platform wells will be plugged and abandoned using the integral rig.

The reality is more complex.

- On some platforms the rig is in operation and the P&A procedure can begin at any time.
- On some platforms the rig can be reactivated, sometimes at great expense.
- On some platforms the integral rig has been removed.
- On some platforms the wells were originally drilled using a Modular Drilling Rig (MDR) that was removed after the initial drilling. These platforms no longer have an integral rig.
- On some platforms the integral rig is so poorly maintained it is inoperable and cannot be repaired. These platforms no longer have an integral rig.
- On some platforms the wells were predrilled and the platforms do not have an integral rig.
- Floating installations on the NCS require a complex categorization to fit the Monte Carlo model. Judging by study of PDO's and other documentation on the floaters on the NCS, it is assumed only two will plug their own wells: the two TLP's Heidrun and Snorre A. These installations have platform wells with rigid risers and assumed functioning integral rigs – they will therefore complete P&A on these wells, incurring Post-CoP OPEX costs. The categorization of floating installations has been illustrated in Figure 51 :

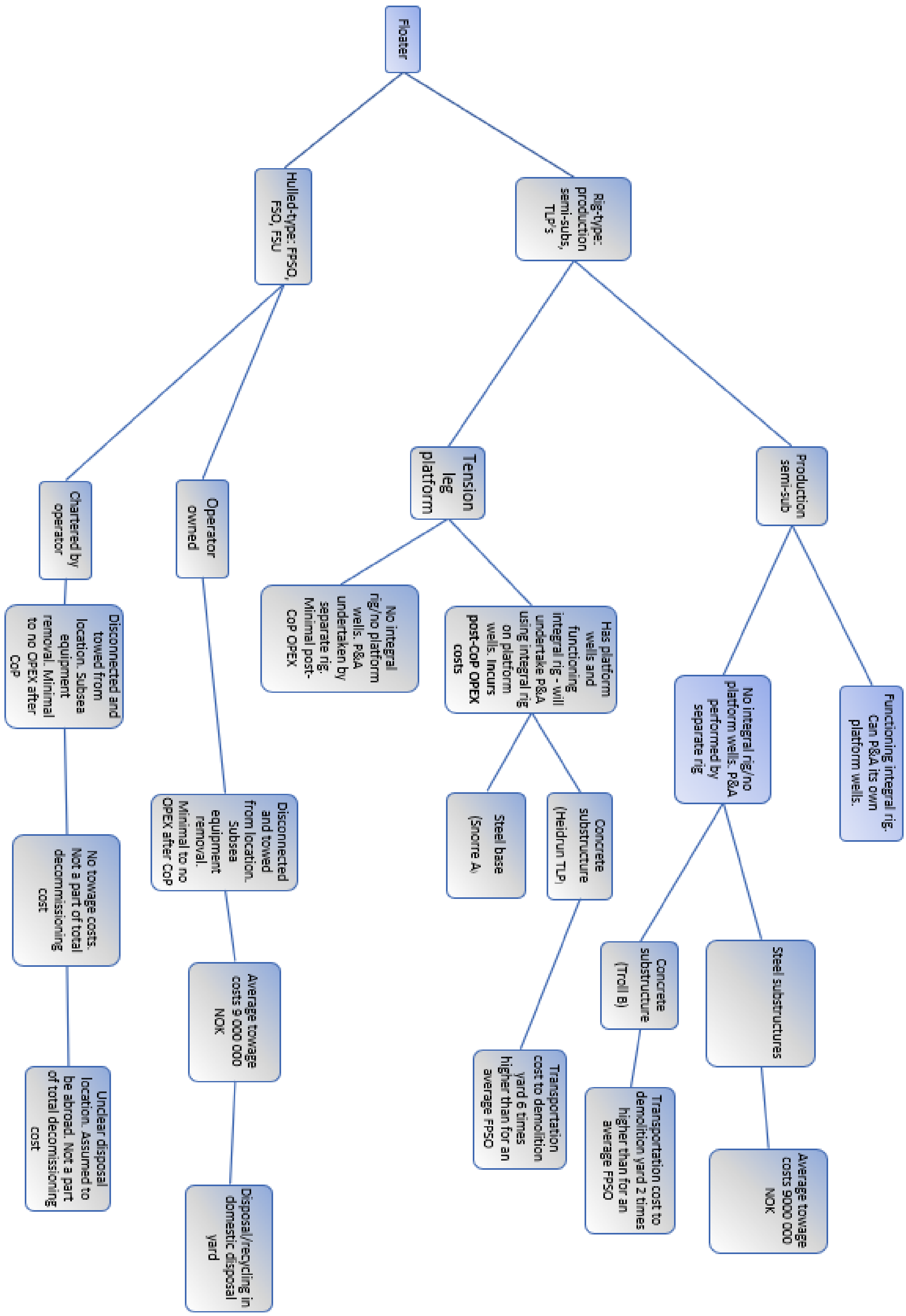

Figure 51: Classification of floating installations

For the platforms where the integral rig is removed, where an MDR was used originally, where the integral rig is inoperable and cannot be repaired and where the platform has never had a drilling rig the options are limited. The P&A can be carried out using an MDR, a jack-up rig or a new rig can be constructed on the platform. According to Archer, the day-rates for modular rigs are around 50 % of the day-rate of standard jack-ups [180]. These rigs can perform P&A on platforms without functioning derricks in deep water and are an alternative to jack-up rigs in shallow waters. The main advantage of modular rigs is the relatively reasonable day-rate compared to jack-ups. According to *Digital Energy Journal*, the day-rate for a modular rig is generally 40 % lower than for jack-up rigs [181].

Advantages of MDR's:

- The ability to perform P&A in waters too deep for conventional jack-up rigs or where the bottom conditions are unsuitable for jack-ups.
- They can perform P&A with a lower number of Personnel on Board (POB) than other alternative rigs [182].

Drawbacks of MDR's:

- The assembly and disassembly time needed. The first rig up of the Archer Topaz rig took 37 days [183].

Day rate:

The modular rig Archer Topaz is one example of a modular rig. This rig closed a 34-month contract with Equinor on the Heimdal field for an estimated 115 million in 2014 [182].

- That translates to 780.979 million NOK (2017).
- The number of days in 34 months is set to 1035 days.
- The contract represents a day-rate of **755 000** NOK per day or 91 000 USD.

Another contract for the modular drilling rig Archer Emerald that was later terminated by Talisman Sinopec Energy UK had a contract value of 96 million USD (2014) for a 2-year period

[184]. That translates to 651.947 million NOK (2017). The 2-year period is assumed to be 731 days.

- The contract represents a day rate of **892 000 NOK** per day or 108 000 USD.
- The average day rate is **823 500 NOK**, which translates to 100 000 USD.

Jack-up rig rates are currently around 200 000-250 000 USD per day in the North Sea [185] [185] [186], so the assumption that jack-up day-rates are twice the MDR day-rates is justifiable. For platforms where an MDR can be installed and operated, an MDR is the less expensive option in most cases.

The number of platform wells which require an MDR or a jack-up to execute P&A operations is difficult to estimate. According to *Decom Insight 2016* the percentage of platform wells without integral rigs to be plugged and abandoned in Norway in the next 10 years is 32 % [79]. According to *Decom Insight 2017* the percentage of platform wells without integral rigs to be plugged and abandoned in Norway in the next 9 years is 47 % [2]. According to *Norwegian Continental Shelf Decom Insight 2016* by UK Oil & Gas the percentage of platform wells without integral rigs to be plugged and abandoned in Norway in the next 9 years is 61 % [187].

These numbers make it difficult to say something conclusive on the proportion of platform wells in Norway that can be plugged using the integral rig. Future trends in rig maintenance will be important and it is challenging to say whether the fields that are being plugged in this 10-year period is representative. It is safe to assume that the wells on Ekofisk are heavily represented in the statistics in these reports. These platforms are assumed to have non-functioning derricks, requiring an external rig for P&A.

In this thesis it is assumed that 68 % of the platform wells on the NCS will be plugged using integral rigs and 32 % will have to be plugged using jack-ups or MDR's.

According to *Decommissioning insight 2016* modular rigs are a sought-after technology on the NCS [79], due in part to its deep waters. There are limits to the depths a jack-up can operate in, and the jack-ups for deep water have higher day-rates.

In this thesis it is assumed that half the platform wells on platforms without an integral rig will be plugged using MDR's and half will be plugged using jack-ups. That means that 16 % of platform wells will be plugged using MDR's and 16 % will be plugged using jack-ups. The 16 %

of platform wells that will be plugged using jack-ups will be treated as subsea wells in this thesis.

The day rate for MDR's is assumed to be half the day-rate for jack-ups. For simplicity in later modeling the 16 % of the platform wells that are assumed to be plugged and abandoned using an MDR is distributed to the 2 main categories and 8 % of these wells are treated as platform wells to be plugged using the integral rig and 8 % of these wells are treated as subsea wells.

The distribution of wells into the categories subsea wells and platform wells to be plugged and abandoned using the platform's integral rig is illustrated in Figure 52.

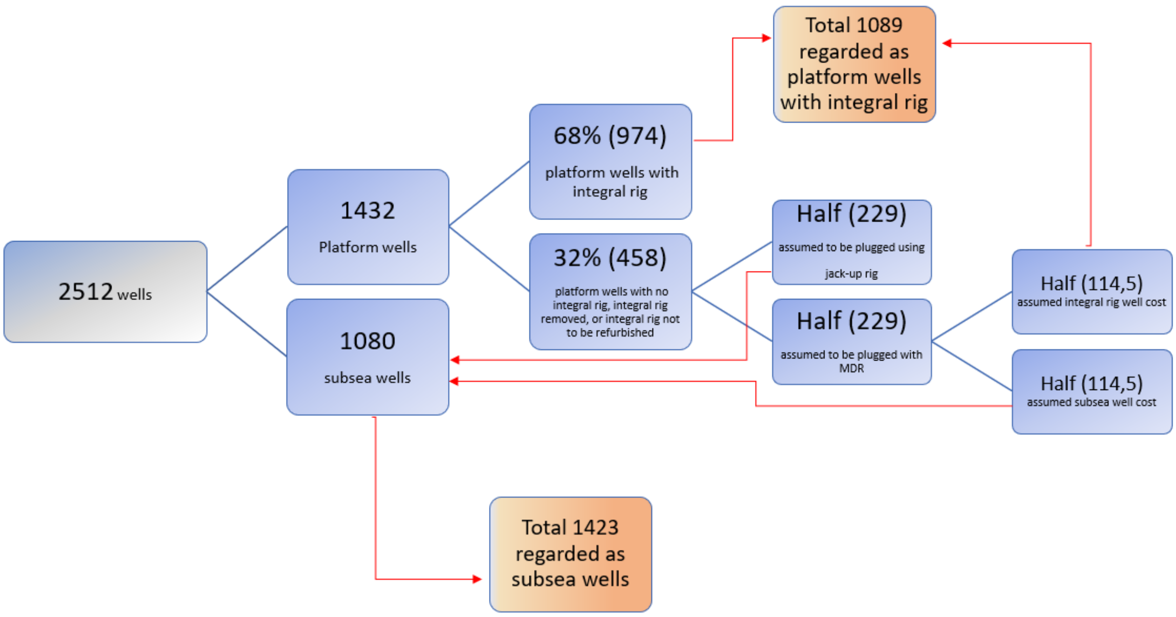

Figure 52: Simplification of well categories

The total number of wells treated as platform wells plugged using the integral rig will be **1089** in the later analysis. The total number of wells treated as subsea wells will be **1423** in the later analysis.

Estimated future development

The number of wells will change over time. In the enclosure *Statistics on the number of new development wells in Norway 03.05.2018,* future drilling of wells is analyzed.

The calculations also indicate that the total number of wells that require P&A currently increases by approximately 159 wells per year, and that 37 wells will be plugged each year. The same fraction of wells treated as subsea wells and platform wells is assumed for the new wells.

Applying the assumptions and estimates above to the annual increase in wells, the 159 new wells each year is divided into an increase of 90 subsea wells and 69 platform wells per year

Applying the assumptions and estimates above to the annual net increase of wells, the net increase of 122 new wells each year is divided into a net increase of 69 subsea wells and 53 platform wells per year.

Calculation of Subsea Equipment on the NCS

To calculate the amount of subsea equipment on the NCS, the following assumptions were made:

1. A subsea field is defined as a field which includes a minimum of one subsea tree or template. Although fields with no subsea trees do contain subsea equipment such as SSIV's and drilling templates, the weight of this equipment is minimal and therefore disregarded. There are approximately 87 fields on the NCS that can be considered subsea fields according to the definition used in this thesis.

Every field on the NCS is unique with large variations in amount of infrastructure. Some fields include only a single subsea tree, whereas fields such as Johan Castberg may have up to 10 000 tons including anchoring equipment [188], or in excess of 26 491 tons as seen on the Troll fields, calculated in the enclosure *Weight of the Troll Subsea Infrastructure.* Therefore, broad assumptions were made to generalize for the entirety of the shelf.

The records of equipment are found in a separate file compiled by the authors.

The main components examined were:

- **Subsea X-mas trees:** Studying literature, an assumed average weight of 51.4 tons was calculated [67] [189] [99]. As mentioned it is assumed there are 1 423 subsea wells on the NCS.
- **Templates:** Typical subsea templates, used for assembling several subsea trees, generally have four tree slots, but may have more, such as Ormen Lange's eight-tree templates [190]. An average weight of 310.5 tons per structure was calculated, and 283 templates were recorded. With 87 subsea fields, this amounts to 3.25 templates per field.

Figure 53: Subsea template with protective structure [191]

- **Manifolds**: These structures combine the flows from several sources for more efficient use of piping. These will also vary greatly in size and weight. Many templates are combined manifold/template solutions. A total of 21 pure manifolds was recorded, with an average weight of 650 tons. With 87 fields containing subsea equipment, this amounts to 0.241 manifolds per field.

Figure 54: Subsea manifold [192]

- **PLEM:** Pipeline End Manifolds collect flow from several lines at their termination point to deliver a single flow to an installation. An average weight of 61 tons was calculated. With one PLEM assumed per subsea field, this amounts to 87 PLEMS.

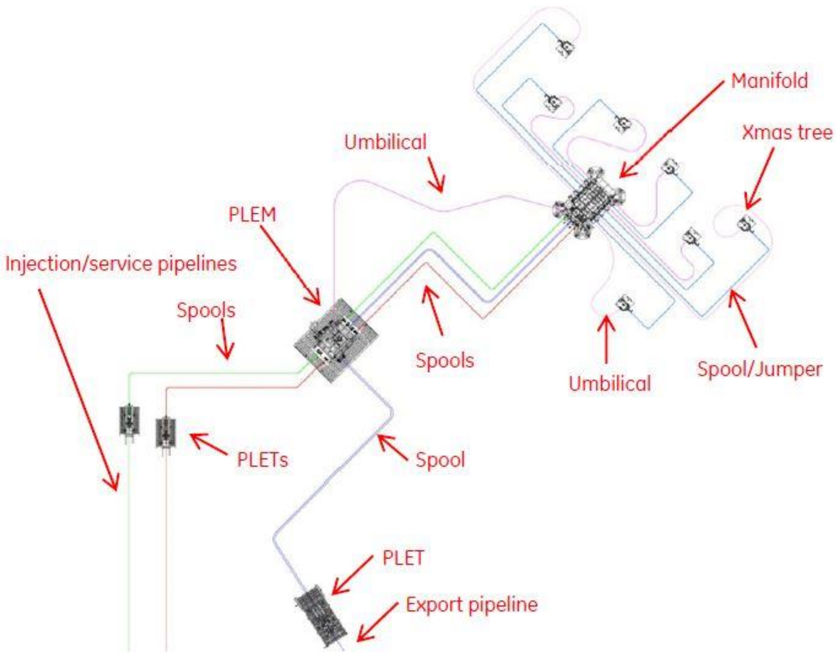

Figure 55: Typical subsea field layout showing PLEM's and PLET's [193]

Figure 56: PLEM [194]

- **PLET:** Pipeline End Terminations are at the end of a pipeline to transfer flow to smaller lines. Calculated average weight of a PLET is 10 tons.
    - Assumption: one PLET per pipeline per subsea field. Assuming three pipelines per subsea field, this amounts to 261 PLET's.

Figure 57: PLET [195]

- **SSIV:** Subsea isolation valves are used to stop incoming flows to a facility. An average weight of 15 tons was found.
    - Assumption: 2 SSIV's per field, revealing a total of 174 SSIV's

Error! Reference source not found. sums up subsea equipment. Due to lack of detail in r eports and schematics, it is assumed that this only accounts for 75 % of the actual amount of subsea equipment

Table 19: Overview of subsea equipment

Equipment	Weight	Number	Total weight	Weight per field
Subsea tree	51.4	1423	73 142.2	840.7
Template	310.5	283	87 871.5	1010
Manifold	650	21	13 650	156.9
PLET	10	261	2610	30
PLEM	61	87	5307	61
SSIV	15	174	2610	30
Subtotal			185 190.7	2128.6

Assumptions were made that miscellaneous equipment on all fields not accounted for in the main categories amounts to an average of 25 % of the total weight of subsea equipment. This includes equipment disregarded due to lack of data such as jumpers, spools, SDU's, pig loops, choke modules, T-connections, Y-connections, UTA's and drilling templates, and equipment recorded from the literature, listed in Table 20. The list also includes equipment from the categories above which were considered too large to include in calculations of averages.

Table 20: Miscellaneous subsea equipment

Gullfaks C compression	1 070
Trestakk misc. equipment	1 250
Troll Pilot	350
Knarr template end Tow Head	550
Knarr FPSO end Tow Head	440
Oseberg-Y pipeline coupling	481
Snorre UPA Template	3 700
Tordis SSIV	1 245
Åsgard gas compression	4 800
Ormen Lange PLEM	350
Ormen Lange Template	4 600
Ormen Lange Manifold	1 105
Heidrun drilling template	2 250
Ormen Lange PLET	1 220
Sum	23 411

The weight of the subsea equipment in the main categories, is assumed to comprise 75 % of all subsea equipment, and weighs 185 190 tons. The remaining weight of other material is accounted for by the equipment mentioned above. This remaining 25 % is one third of 75 %.

$$\frac{185\ 190.7}{3} = 61\ 730.2 \text{ tons}$$

23 411 tons of this is accounted for, the remainder is from unidentified equipment.

$$61\ 730.2 - 23\ 411 = 38\ 319.2 \text{ tons}$$

The total amount of equipment is

$$185\,190.7 + 61\,730.2 = 246\,920.9 \text{ tons}$$

Subsea equipment on the NCS is estimated to be 246 921 tons.

Mattresses: Stabilization features constitute a considerable amount of seabed infrastructure and requires thorough planning to execute. Such is the scope of the challenge that several technical innovations have arisen to meet the requirements of this seemingly insignificant portion of decommissioning [34]. Several decommissioning programs were examined, where average weight per mattress and number of mattresses were recorded. This resulted in an average mattress weight of 6.7 tons, with 58 mattresses per field. This was adjusted to 100, as most of the data was found in UK fields, and it was assumed that Norwegian fields would have more mattresses due to larger amounts of subsea infrastructure. Calculations are performed in a separate document.

It is assumed that not only subsea fields use mattresses, as these are used to protect pipelines, which are present in all fields. With approximately 120 producing fields assumed to be using mattresses, this amounts to 80 400 tons of mattresses on the NCS.

Adding mattresses to the total equals 327 321 tons of subsea equipment and mattresses

$$246\,920.9 + 80\,400 = 327\,321\ tons$$

Calculation of Pipelines on the NCS

The pipeline network on the NCS stretches over the waters of five countries. To estimate pipelines, field schematics and illustrations were examined, and PDO's were studied. The final number counted was 493. This does not include smaller lengths such as spool pieces and jumpers. Assuming a considerable number of pipelines have not been accounted for, the number is adjusted to 610. Adding the export lines (30 gas pipelines and 10 oil/condensate lines), the final number is 650. *Decommissioning of Pipelines in the North Sea Region* states that there are 2 500 individual pipelines, umbilicals and power cables in the North Sea [142]. As umbilicals and power cables have been disregarded in this thesis, and assuming the UKCS has more pipelines than the NCS due to having more installations, the number seems credible.

An analysis of recorded pipeline data showed the following information:

1. 91.4 % of pipelines will be left in situ. Small sections may be trenched or rock dumped
2. 3.45 % of pipelines will be trenched or rock dumped entirely
3. 5.17 % of pipelines will be removed

The 40 transport and export pipelines are assumed to be left in situ.

Calculation of floater subsea equipment on the NCS

Floaters include hulled FPSO/FSO/FSU type vessels, floating cylindrical-type platforms and Tension Leg Platforms. These commonly have subsea equipment deemed necessary to include in a separate section. In this section, total weight of the floaters' associated subsea equipment will be estimated.

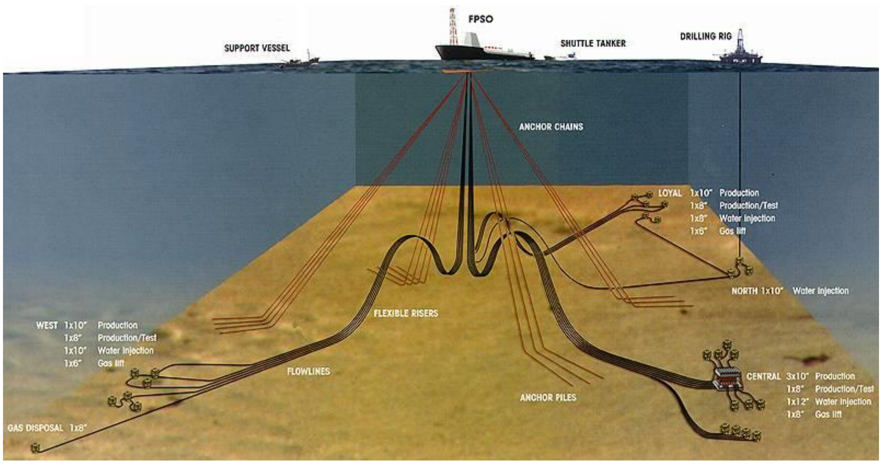

Figure 58: Typical FPSO subsea field layout [196]

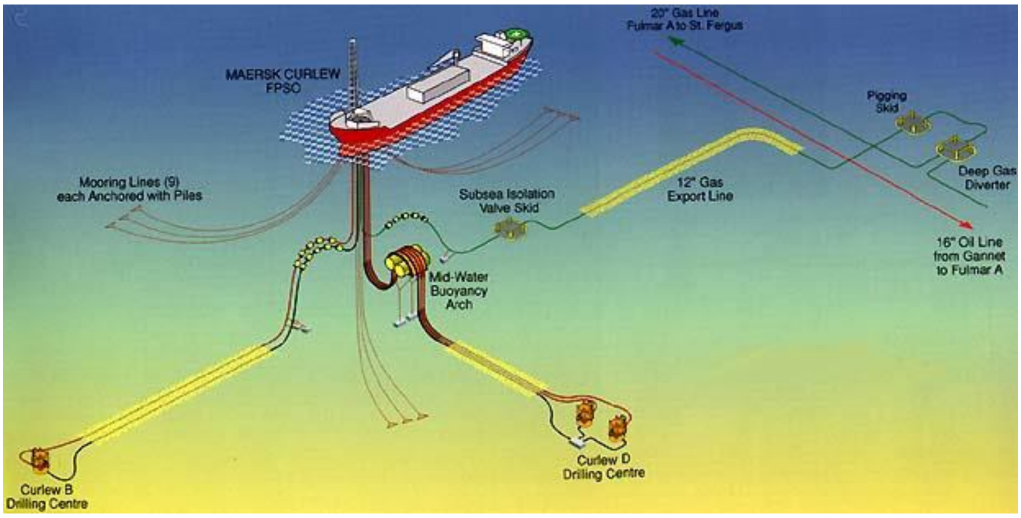

Figure 59: Typical FPSO subsea field layout [197]

- **Anchors and anchor lines:** Data on several suction anchors was compiled, revealing an average weight of 1 051 tons of anchors per floater. Further, data on anchor lines was gathered, weight per metre was calculated, and calculations were performed to find weight in air. A total of 5 040 tons of anchor lines per floater was calculated. This amounts to a total of 6 091 tons of anchors per floater. The calculations are performed in a separate document.
- **Flexible risers:** used to bring well flow up to floating installations. Varg's four 1 400 metre risers have a weight of 890 tons, revealing a weight per riser of 222.5 tons [93].
  - Assumption: 12 flexible risers per floating installation, calculated from an average of collected data. Many of the fields in the collected data are not representative of typical floaters, so the number was adjusted to 9. This amounts to approximately 2 000 tons of riser per floater. The calculations are performed in a separate document.

- **Riser base:** anchoring systems for flexible risers on floating installations. An average weight of 187 tons was calculated.
  - Assumption 1: there is a multitude of technologies for fastening risers. Studying documentation revealed that riser bases and MWA's appear to be the

most widespread equipment used. Therefore, it is assumed 50 % of floating installations use riser bases. The remainder use MWA's for riser fastening.

- Assumption 2: an average of 2 riser bases per floater is used.

- **Mid-water arches (MWA):** buoyancy tanks used to hold flexible risers in place. Tethered to a weight at seabed. These have an average weight of 350 tons.
  - Assumption 1: 50 % of floaters use MWA systems for securing risers, with two MWA's per installation. This amounts to 27 MWA's in total.

Table 21: Summation of subsea equipment for floaters

Equipment	Weight	Number	Total weight	Weight per floater
Anchors and lines			164 459,7	6 091.1
Flexible risers	222.5	216	48 060	1 780
Riser base	187	27	5 049	187
MWA	350		9 450	350
Subtotal			227 018.7	8 408.1

It is assumed the equipment mentioned above constitutes approximately 75 % of all subsea floater equipment. The remaining 25 % consists of miscellaneous equipment such as Submerged Turret Loading (STL) systems used on FSU's and FSO's [198] and Submerged Turret Production systems (STP). These, and other miscellaneous equipment, are challenging to find in reports and documentation. Below is a list of some of the miscellaneous equipment found:

Table 22: Miscellaneous subsea equipment associated with floaters

Troll ERS	4 000
Troll PRS	200
Troll RSS1	4 000
Troll RSS2	2 800
Aasta Hansteen Anchors	2 465
Jotun moorings	3 288
Martin Linge FSU STL	500
STL Navion Saga	140
Heidrun TLP tethers	30 500
Snorre A TLP tethers	4 176
Sum	52 069

This miscellaneous equipment and other unidentified equipment makes up the remaining 25 % of the subsea floater equipment.

$$\frac{227\ 018.7}{3} = 75\ 672.9 \text{ tons}$$

The miscellaneous weight unaccounted for is

$$75\ 672.9 - 52\ 069 = 23\ 603.9 \text{ tons}$$

Total weight is

$$227\ 018.7 + 75\ 672.9 = 302\ 691.6 \text{ tons}$$

This section explains the modifications of the model for estimation of the entire NCS. Three parameter types are described:

- Decommissioning cost categories
- Total numbers
- Infrastructure types

The section describes how each of these categories are combined to contribute toward the decommissioning total.

Refinements to the model were made to enable cost estimation of all infrastructure on the NCS. An aspect of the model requires detailed explanation: the estimate of OPEX after CoP. As described earlier, the metric for this expense is calculated as a **percentage of the total cost**, which presents certain challenges: the costs of decommissioning several types of infrastructure do not "contribute" to this total cost from which this percentage is calculated. The following section describes how the different decommissioning parameters are handled in their contribution towards the post-CoP OPEX total, henceforth known as **PCOT**.

Decommissioning cost categories

The following describes how costs are calculated for each category.

Project Management: this phase is calculated as a percentage of total costs. To find this total, all costs are summed together. And a percentage of this total is taken.

OPEX after CoP: This phase is also calculated as a percentage of total costs. The amount of facility running costs applicable to each facility varies greatly. The model attempts to recreate this by using help cells where the costs applicable to the total from which the percentage is taken (PCOT) are formulated

- P&A platform wells: all costs of platform wells contribute to the PCOT.

- P&A Subsea Normal wells: in the *Number of wells in Norway* section, 974 wells are initially counted as platform wells, plus half of the wells plugged using MDR, for a total of 1 089. The other half are considered subsea wells. Subsea wells are not considered to incur post-CoP OPEX expenses: it is assumed they have minimal to no operational expenses after shutdown. However, in the model, MDR wells are considered to incur post-CoP OPEX, so **all** wells plugged by MDR are included to estimate Post-CoP OPEX of wells. Of the subsea-MDR wells this is

$$\frac{114.5}{1\ 423} = 8\ \%$$

  Summarized: 8 percent of the subsea wells' abandonment costs are assigned to PCOT.

- P&A subsea train wreck: As with normal subsea wells, 8 % of these costs contribute to PCOT.
- Topside making safe: All costs except those for making safe of floaters contribute to PCOT.
- Topside preparation and removal: All costs contribute to PCOT
- Jacket removal: All costs contribute to PCOT
- Disposal and recycling: Costs of disposal of total topside weights, total jacket weights and the weights of floaters with Post-CoP OPEX (Heidrun TLP and Snorre A) contribute to PCOT.
- Pipeline left in situ, trenched/rock-dumped and removed: 40 % of these costs are considered to contribute toward the PCOT, as they are associated with a facility with post-CoP OPEX. The remainder are connected to a subsea field with no post-CoP OPEX.
- Subsea infrastructure: It is assumed 40 percent of subsea equipment (not including anchors, risers and moorings associated with floaters) is tied back to a fixed installation

$$\frac{40\ \%\ \times 327\ 320.9}{630\ 012.5} \approx 20\ \%$$

This is approximately 20 % of total subsea equipment. The cost of removal of this is part of a facility with post-CoP OPEX, and therefore contributes to the PCOT.

- Site remediation: The clean-up cost of the seabed around all fixed installations, plus Heidrun TLP and Snorre A contribute toward the PCOT, as all these sites have post-CoP OPEX. The remaining 75 do not.
- Monitoring: Costs of post-decommissioning seabed monitoring around all fixed installations, plus Heidrun TLP and Snorre A contribute toward the PCOT, as all these sites have post-CoP OPEX. The remaining 75 do not.
- Transport floaters: Only one floater's removal cost contributes to the PCOT, Snorre A.
- Transport concrete floater without derrick: Troll B has no post-CoP OPEX, so transport cost does not contribute to the PCOT.
- Transport TLP with derrick: Heidrun TLP has post-CoP OPEX, and its transport will therefore contribute toward the PCOT.

<u>P&A Platform:</u> The number of platform wells is multiplied by the cost per well.

<u>P&A subsea normal wells:</u> The total number of wells minus the number of train wreck wells.

<u>P&A subsea train wreck:</u> A one in seven binomial distribution, multiplied by train wreck cost.

<u>Topside making safe:</u> The sum of total topside and floater weight multiplied by the making safe cost per ton.

<u>Topside preparation and removal:</u> The total topside weight multiplied by cost per ton.

<u>Jacket removal:</u> Total jacket weight multiplied by cost per ton.

<u>Disposal and recycling:</u> Total weight of topsides, jackets and floaters, except floaters not owned by operator, as these are assumed to be towed to foreign ship breaking yards.

<u>Pipelines:</u> Using the count mentioned earlier (91.4 % left in situ, 3.1 % trenched/rock-dumped, 5.5 % removed), these were multiplied with the total pipeline count of 650.

<u>Subsea infrastructure removal and disposal:</u> Total weight multiplied by cost per ton.

Site remediation: The total number of sites counted were multiplied with the cost per site remediation. Site remediation was disregarded for separate flame towers, bridge structures etc, as these costs are included for their associated platform.

Monitoring: the total number of sites counted were multiplied with the cost per monitoring. Monitoring was disregarded for separate flame towers, bridge structures etc, as these costs are included for their associated platform.

Transport floaters: 19 floaters are owned by the operator, and towing costs are therefore included.

Transport concrete floater without derrick (Troll B): towing costs assumed to be twice that of other floaters.

Transport TLP with derrick (Heidrun TLP): Towing costs assumed to be six times that of other floaters.

Total numbers

The category list of total numbers resembles the model for estimating single platforms, but with some new categories: *Weight of floaters to be decommissioned* and *Number of fields to monitor and remediate.*

- Weight topside to be removed:
    - The topsides of all fixed steel platforms and concrete GBS platforms
    - Loading systems, as these have similar properties to platform topsides
- Weight jackets:
    - The weights of all steel jackets on the NCS.
- Weight floater to be decommissioned:
    - Total weight of all floaters except those not owned by operator, as the removal costs of these floaters are assumed covered by the owner. However, the

subsea equipment removal, site remediation and monitoring costs will contribute to the total

  - Only those floaters owned by operators contribute to topside making safe and disposal costs

- Number of fields to be remediated and monitored:

  - Counting the exact number of fields on the NCS is challenging – in some cases subsea tieback fields are counted as part of the parent field, in others not. Examining databases from OSPAR and the NPD, a decision was made to add 50 fields that will require site remediation and monitoring. These 50 fields were found by studying the NPD's fact pages and assessing all fields, including those shut down but not decommissioned and those not yet developed. Though this total is more than the actual number of fields, there are several facilities per field, each with their own remediation and monitoring. The assumptions in this approach are backed up by the fact that several facilities on the same field may be far apart from each other.

- Weight subsea infrastructure: The total of subsea equipment from subsea fields and from floaters
- Number of platform wells: 1089 wells
- Number of subsea wells: 1423 wells
- No. of pipelines left in situ: 598, or 91.4 % of total
- No. of pipelines trenched/rock-dumped: 20, or 3.45 % of total
- No. of pipelines removed: 32, or 5.17 % of total

Infrastructure types

The total decommissioning expense on the NCS was calculated by arranging decommissioning into different facility types. The following categories were estimated, and the assumptions made for each category is listed below:

- Fixed steel jacket platforms:
    - Total weight and total number are gathered from *The weight of structures on the NCS including new structures after 01.01.2015 based on OSPAR data.*
    - Assumptions were made on platforms that had been shut down for a time before removal and their OPEX. An analysis of these installations is undertaken in a separate document. Some fixed platforms will not be in operation after CoP and that has an impact on the cost estimates for decommissioning. In this thesis an attempt has been made to single these platforms out. The platforms that instantly stand out as platforms that will not require OPEX after CoP are quarters platforms. These platforms are only used for accommodation and the platforms do not need to stay in operation after accommodation is no longer required. The platforms that have accommodation as their sole function on the NCS are all part of larger field developments, and these platforms are expected to be in service until the last platform in the field development is made cold.

      The only exception among the quarters platforms is the Valhall QP platform. This platform is expected to be decommissioned in 2019 and a replacement quarters platform has already been installed on the Valhall field.

      Another example of platforms that do not incur any OPEX after CoP are the two booster platforms Draupner E and Draupner S. These platforms will have minimal running costs after close-down.

      These are the only fixed platforms without OPEX after CoP that have been identified.

      The total weight of these three fixed platforms is 19 462 tons.

That is around 0.2 % of the total weight of the fixed platforms that will be decommissioned on the NCS, and the running costs are only 16 % of that sum if the thesis metric is applied.

Omitting the OPEX after CoP for these platforms will change the cost of decommissioning the category *Fixed Steel Jacket Platforms* by around 0.03 % and the total cost of decommissioning by even less. A choice has been made to assume that all fixed platforms have OPEX after CoP for simplicity.

- Concrete GBS topsides
  - Total weight and number is collected from *The weight of structures on the NCS including new structures after 01.01.2015 based on OSPAR data*
  - Concrete substructures are assumed left in situ. In the future, new technology may enable removal, but its costs cannot be determined
- Offshore loading systems
  - The loading systems are considered topsides, as they have many of the same properties as a topside. Their total weight contributes toward the cost for topside making safe and topside preparation and removal.
- Heidrun TLP
  - Due to the weight of this facility, towing costs are assumed to be 6 times higher than for regular floaters
- Snorre A
  - The facility will sustain regular tow-away costs
- Troll B
  - Has no functioning derrick and will therefore sustain minimal to no post-CoP OPEX
  - Towing costs will be twice that of regular floaters

- Site remediation and monitoring costs do not contribute to the PCOT

- Steel floaters owned by operator
  - No Post-CoP OPEX
  - Site remediation and monitoring does not contribute to the PCOT

- Steel floater not owned by operator
  - No Post-CoP OPEX
  - No towage costs
  - Site remediation and monitoring does not contribute to the PCOT

- Subsea infrastructure
  - It is assumed 20 % of this equipment will be removed as part of the decommissioning program of a fixed structure. This percentage will therefore contribute toward the PCOT

Monte Carlo simulation

Using the numbers developed in the previous sections, the simulation was run with 100 000 iterations and resulted in a total cost of **571.191 billion NOK** (2017). The division of costs according to the UK Oil & Gas WBS is shown in Figure 60.

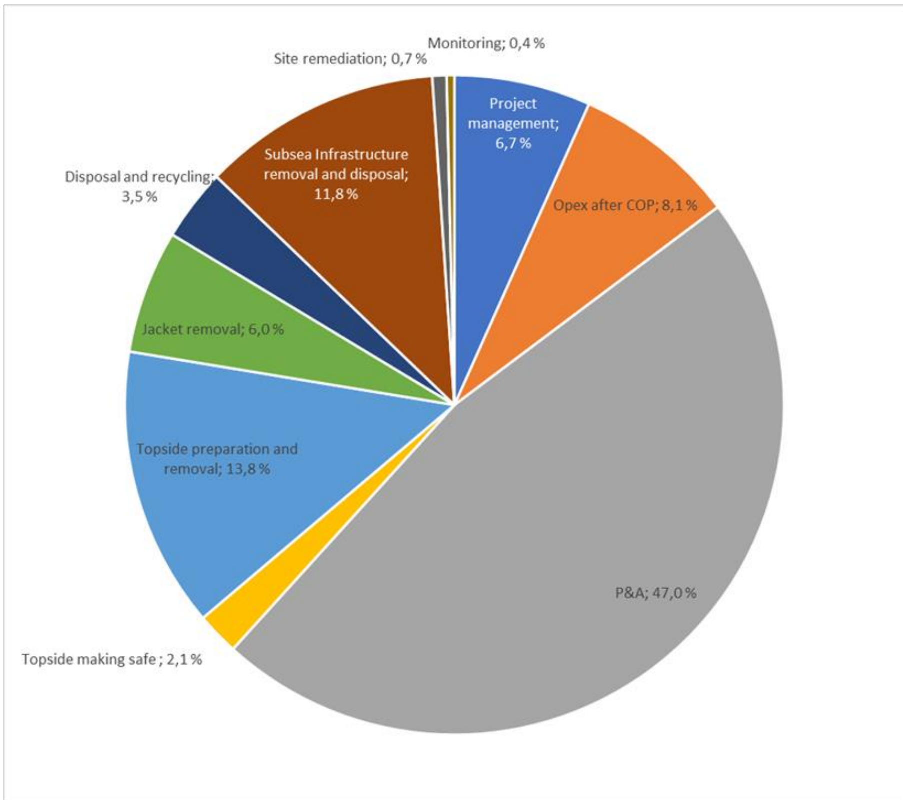

Figure 60: Division of costs by Oil & Gas UK WBS category

The P50 estimate represents the value in the simulation where 50 % of the simulated total costs are below this number and 50 % are above. The P10 and P90 range for the estimate is 486.2 to 661.8 billion NOK. The meaning of this range is that in the simulation 80 % of the simulated total costs were within this range

Other even wider intervals can also be constructed, but one of the pitfalls of Monte Carlo analysis is to place too much emphasis on the simulation results in the tail ends.

A P5 to P95 range may be constructed and the resulting interval based on the Monte Carlo simulation is 462.9 to 688.4 billion NOK. This range is from 19 % below the P50 estimate to 20.5 % above the P50 estimate.

Assigning Monte Carlo estimates to AACE estimate classes is a challenging task, but the range of the P5 to P95 estimate indicates that the precision of the Monte Carlo estimate is comparable to at least a Class 4 estimate and possibly even a Class 3 estimate in the AACE classification.

Error! Reference source not found. shows the minimum, maximum and P1 to P99 values from t he simulation, and Figure 61 illustrates the range of the simulation.

Table 23: Min, max and P-values from the simulation

Min	334 300 000 000
P1	423 000 000 000
P5	462 900 000 000
P10	486 200 000 000
P15	502 100 000 000
P20	514 300 000 000
P25	525 500 000 000
P30	535 400 000 000
P35	544 700 000 000
P40	553 600 000 000
P45	562 300 000 000
P50	571 200 000 000
P55	579 600 000 000
P60	588 500 000 000
P65	597 600 000 000
P70	607 500 000 000
P75	618 100 000 000
P80	630 000 000 000
P85	644 100 000 000
P90	661 800 000 000
P95	688 400 000 000
P99	739 400 000 000
Max	857 000 000 000

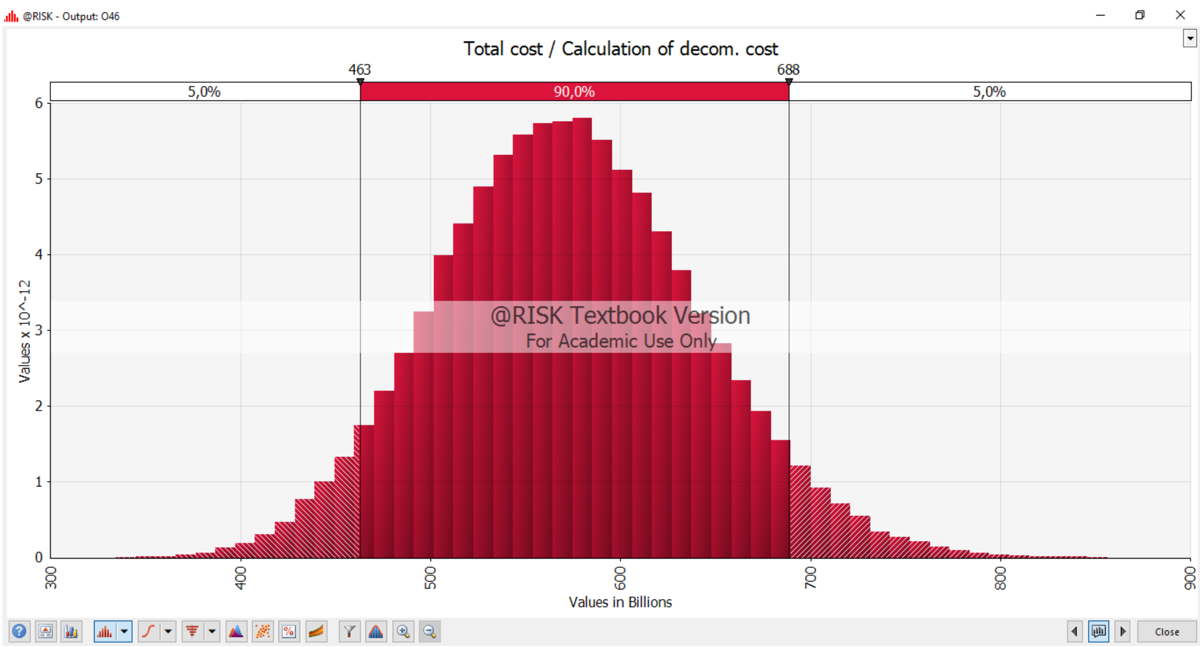

Figure 61: Simulation result range

Comparing the result to *Decommissioning Insight 2017*'s cost breakdown for the next ten-year period shows close similarities in cost distribution:

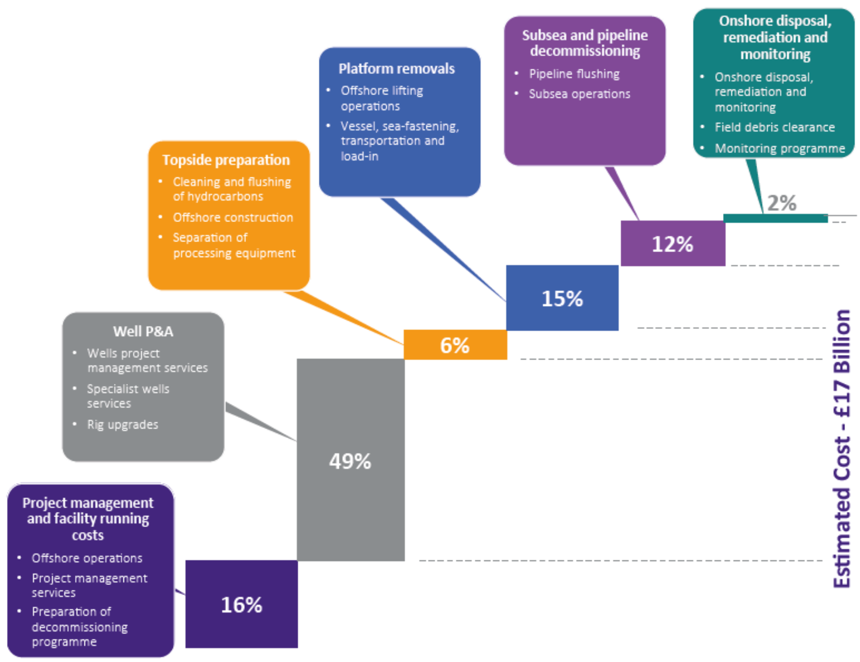

Figure 62: Decommissioning Insight cost breakdown [2]

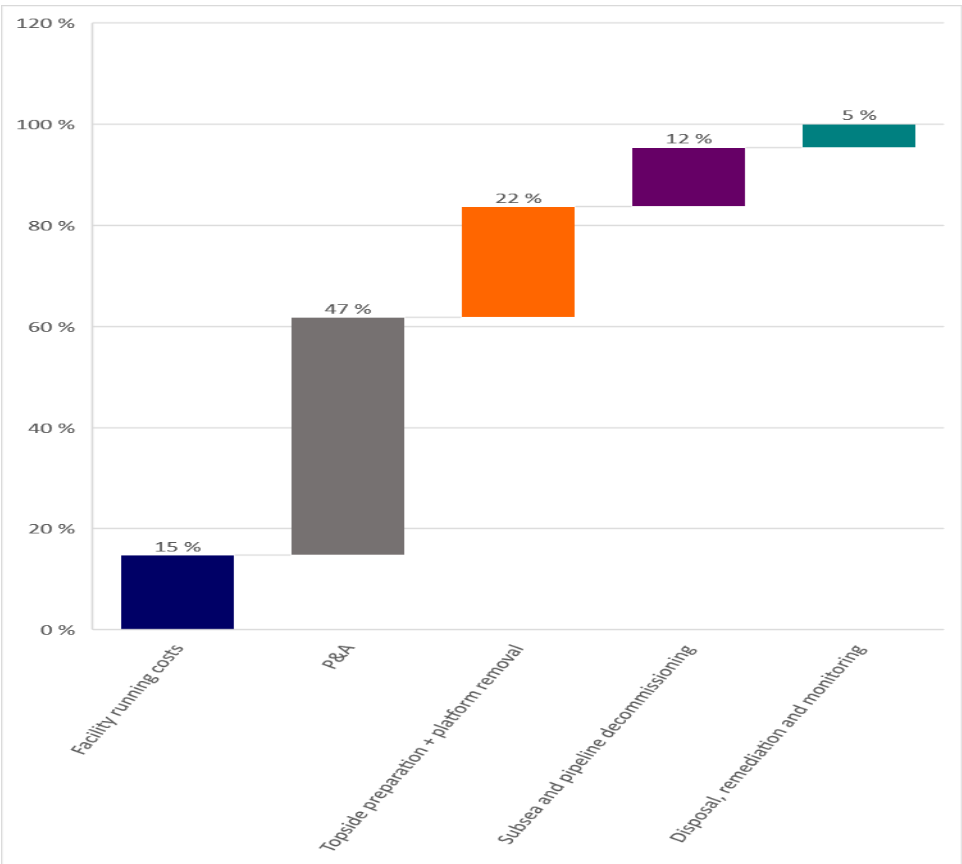

Figure 63: Cost breakdown comparison to Decommissioning Insight 2017

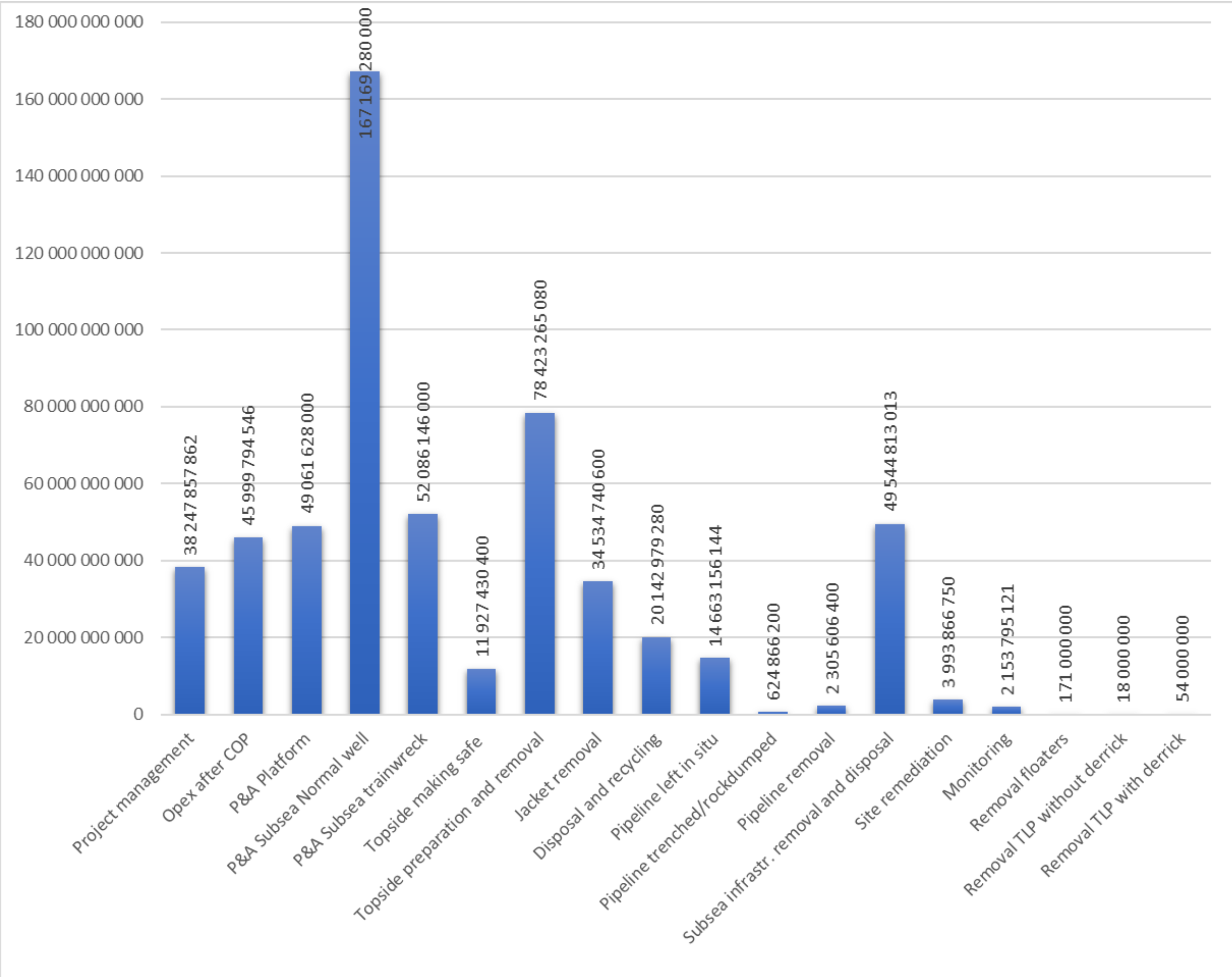

Figure 64: Cost categories

Figure 64 shows the cost breakdown of all categories. As expected, P&A makes up the majority of costs, with topside preparation and removal being the second-largest expense. Due to lack of data preparation and removal have been lumped into a single category. Jacket removal makes up six percent, or 34.5 billion NOK. Removal costs may change substantially in the future, as discussed in the later section *Market Analysis of Single Lift and Heavy Lift Vessels*.

Facility running costs during decommissioning may also see changes, as more effective strategies are employed, and widespread SIMOPS-techniques are utilized.

Removal operations will see a low degree of domestic supply chain usage, as all major removers are foreign companies. One of the phases of decommissioning with high domestic supply chain usage, is disposal and recycling – the Norwegian demolition yards are favorable due to their deep-water access capacity. The estimated total value of the market is 24.12 billion NOK.

$$Disposal\ and\ recycling\ of\ structure\ material + (cost\ per\ ton\ of\ disposal\ and\ recycling \times tons\ of\ subsea\ equipment)$$

$$(3.5\ \% \times 571.2\ \text{billion NOK}) + \left(6\ 560\frac{\text{NOK}}{\text{ton}} \times 630\ 613\ \text{tons}\right) = 24\ 124\ 560\ 000\ \text{NOK}$$

An important aspect of future decommissioning costs is the type of rig used for P&A, as this is the most cost-sensitive part of decommissioning. Figure 65 illustrates the segmenting of rig types for future P&A. As shown, 72 % of wells will be plugged by MODU, indicating that costs may vary significantly due to rig-rate volatility.

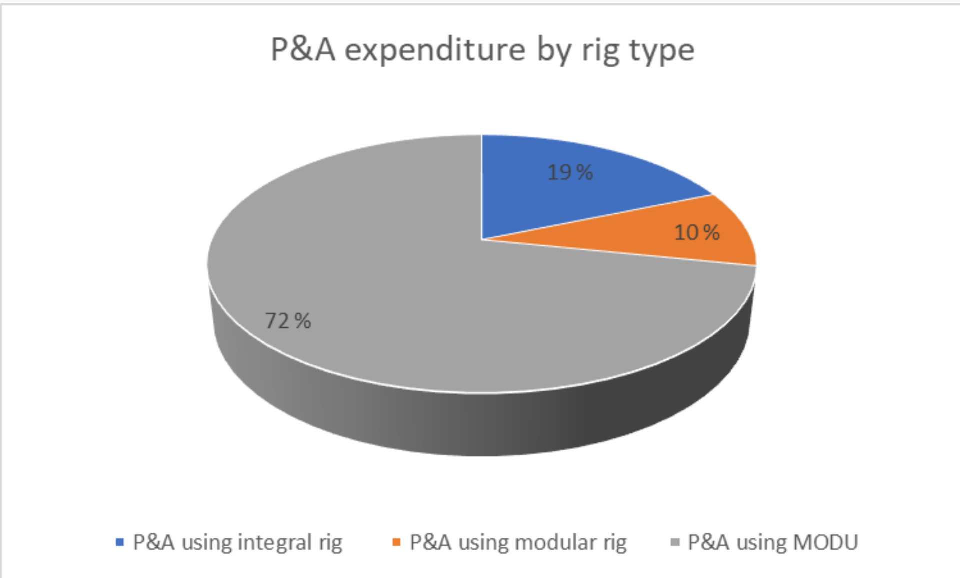

Figure 65: P&A expenditure

Limitations to the Model

The estimates in the thesis rest on a multitude of assumptions. These assumptions are necessary, but detail may be lost as a result. In this section the weaknesses of the thesis are analyzed in further detail, with a focus on the implications of some of the main assumptions.

Exchange rates:

Throughout the thesis annual average exchange rates are used in conversions of currencies. Due to the broad variations in exchange rates this is a source of uncertainty.

Inflation:

The inflation rates used in this thesis is the average inflation, not the industry specific. This is done for simplicity, but the inflation rate used may not be the most suitable.

Conversions of currency:

When discounting historical figures to present value the choice was made to convert the currency to NOK in the year the figure is reported and use Norwegian inflation rates in the discounting to present value. This may lead to inaccuracies. Another approach could have been to use the inflation rate in the country where the figure is from and convert the present value.

Deciding on the actual year a figure is from:

Which year the figures are from is difficult to pinpoint in many of the sources in this thesis. A choice has been made to use the date of publishing for the source as reference date. In many cases this is not correct, and in the conversions to present value this lead to inaccuracies.

The use of contract values:

Several sources in this thesis are news articles reporting on contract values. The actual contracts may contain information that gives a better understanding of the actual expected cash flows resulting from the contract. Potential contingencies, amendments and variation orders might have an impact on the final contract value.

Platforms that are partially decommissioned:

A choice has been made to treat platforms that are partially decommissioned as platforms where no decommissioning has been undertaken. The reasoning behind this assumption is that it is very challenging to find out exactly how much of the decommissioning scope that has been completed in the ongoing projects.

Fixed cost:

In most of the categories in the WBS there is both variable and fixed cost components. Most decommissioning projects require the assistance of vessels, and for vessels there is usually a mobilization fee. This is a fixed cost and is not dependent on the weight of the structure or the number of wells.

In the cost estimation model in this thesis all costs are considered variable for ease of modeling. This choice lead to underestimation on installations with low weight or a low number of wells.

OPEX after CoP:

Ascertaining which platforms have OPEX after CoP has been challenging. Some platforms do not have an integral rig and need the assistance of a modular rig or a jack-up rig to perform P&A. This will affect the OPEX after CoP. It is unclear how great these costs are, and for which platforms these costs are greatest.

Rig reactivation:

The state of the integral rig will affect decommissioning expenditure. According to sources from the industry the cost of reactivating an integral rig that has been out of use for a long period and has not been maintained properly can be up to 50 million USD. That is a significant figure and should ideally have been included in the model. But the authors are not privy to information on the actual state of integral rigs on the platforms on the NCS. Part of this cost component has probably been captured in the operators own estimates of P&A expenditure.

Rig rates:

Rig rates are one of the key factors influencing rig-based P&A cost, which is the main component of P&A expenditure. The assumption of average long-term rig rates for jack-ups of 250 000 USD per day can be questioned, and the effect of changing the assumed rig rate is substantial. Around 50 % of rig-based P&A is rig rates. Around 72 % of P&A is performed by MODU. Around 47 % of decommissioning expenditure is P&A. From these numbers, the sensitivity of decommissioning expenditure can be calculated. The sensitivity is around 0.17 which means that the effect of an increase in rig rates by 1 % corresponds to an increase in decommissioning expenditure by 0.17 %.

In this thesis rig rates for jack-ups is assumed to be 250 000 USD per day. A long-term average rate of 300 000 USD per day could just as easily have been chosen.

The effect of a 20 % increase in rig rates, based on the sensitivity calculation above would be a 3.4 % increase in decommissioning expenditure.

Metric for pipelines:

The pipelines on the NCS differ in length from the shortest infield pipelines measuring less than a kilometer to the export gas pipelines where 7 of the pipelines measure more than 500 kilometers. Decommissioning these pipelines is a major undertaking, and there is little data on the cost.

Changes in regulations:

The cost of decommissioning depends on the regulations governing decommissioning. Changes in P&A regulations or in the regulations for decommissioning of gravity-based concrete installations can have a severe impact on decommissioning expenditure.

Removal of floaters:

There is little available information on the removal and decommissioning of floaters. Several assumptions have been made on costs, such as towage, make safe and disposal. The uncoupling of TLP tethers are known to be complex and demanding operations but have been disregarded due to lack of information on this procedure.

Platform well P&A:

No data has been found on the cost of plugging complex platform wells. The data gathered is assumed to be an average where the cost of complex/train wreck wells is incorporated.

Subsea infrastructure:

The data on subsea equipment has been amassed into two broad categories. There are large variations in weights and amount of infrastructure, but it is believed the averages compiled are representative. Finding exact values on the weights of each field is highly challenging. In many cases, simple illustrations and schematics with low levels of detail have been used to estimate the subsea infrastructure of each field.

Condition of platform

The age and physical state of the installation is a significant factor in cost. This has been disregarded to a large extent due to lack of information.

New infrastructure on the UKCS since 2015

It is assumed that the amount of decommissioned infrastructure in the UK is the same as the amount of newly developed infrastructure in the same time frame. This may be inaccurate, but updated information is scarce.

P&A

- Platform wells plugged using external rigs have been treated as subsea wells in the thesis for simplification and because they use much the same type of rigs. In reality, the plugging of subsea wells actually requires more use of rigs.
- The assumption that 68 % of wells will be plugged by integral rig is uncertain. Different reports state very different figures.

Exact number of fields

The exact number of oil and gas fields in Norway is unclear – for example, in some databases all subsea fields tied back to a surface installation are considered part of said installation. In others, each subsea field is considered a separate field. Another example is fields containing several platforms such as Statfjord, Gullfaks, Troll, etc. Whether these fields should be regarded as a single field is hard to judge. From a decommissioning point of view, they may be viewed as individual fields if they are to be decommissioned separately.

Correlations

Due to lack of data, the decision was made to disregard possible correlations between decommissioning phases. The most obvious correlation is found between post-CoP OPEX and P&A – many complex wells in a project will entail a long post-shutdown running time for a facility.

Depth

Depth is most certainly an important factor in decommissioning cost. Analyses have been attempted to find a possible depth point where costs increase substantially, with no conclusive results.

VALIDATION AND DISCUSSION OF RESULT USING COMPARATIVE ANALYSES

The result of the analysis should ideally be compared with other estimates of decommissioning expenditure for the NCS, but no prior estimates have been published. The decision was made to investigate other approaches toward establishing estimates of decommissioning expenditure for the NCS, and after careful deliberation two alternative methods were developed.

Decommissioning Expenditure Estimated Using Extrapolation of Oil Companies' ARO Liability Estimates

Petoro

One way of obtaining an estimate for the decommissioning liabilities on the NCS is to take the estimate of liabilities calculated by Petoro and divide it by Petoro's share of the Norwegian petroleum production.

From Petoro's annual report for 2017 the decommissioning liabilities of Petoro are estimated to 67.647 billion NOK (2017) [199]. In the calculation of this number Petoro use a discount rate equal to the coupon rate of Norwegian government bonds with a matching duration.

Petoro's share of the Norwegian oil production in 2017 was 24.11390 % [200]:

$$\frac{Petoro\ production}{Total\ production}$$

$$\frac{64.51902854}{237.7269583} = 0.27139971 = 27.139971\ \%$$

This can be used as an estimator of Petoro's share of future decommissioning cost.

An estimate of the total decommissioning cost is

$$\frac{67.647}{0.27139971} = 249.252$$

The estimate of Norwegian decommissioning liabilities based on Petoro's estimate of ARO liabilities lead to an estimated **249 billion NOK** in total decommissioning expenditure.

Petoro participates in 40 fields on the NCS as of the 31st of December 2017. Whether the licenses of Petoro are a good representation of the whole NCS is an open question. It should also be mentioned that petroleum equivalents are used in the calculation. There might be differences in decommissioning cost per oil equivalent of gas, condensate and oil.

Equinor

Equinor's estimate of decommissioning liabilities on the NCS is presented in the *Decommissioning Portfolio Update* presented in March 2018 at the 18th Norwegian Petroleum Conference [201].

Equinor's estimate is that the decommissioning of the 48 platforms Equinor operates will cost $25 billion USD. Converted to NOK using the average exchange rate for 2017 of 8.2630 that equals 206.575 billion NOK.

Using the production from Equinor-operated oil fields' share of Norwegian petroleum production (shown in the enclosure *Equinor-operated fields' share of Norwegian petroleum production*) as an indicator of the Equinor operated fields' share of Norwegian decommissioning liabilities we can reach an estimate of Norway's total decommissioning liabilities.

The Equinor operated fields represent 68.68126 % of Norwegian petroleum production

$$\frac{206.575}{0.6868126} = 300.773$$

The estimate of Norwegian decommissioning liabilities based on Equinor's estimate of ARO liabilities lead to an estimated **301 billion NOK** in total decommissioning expenditure.

Aker BP

Aker BP's production represents 3.904225 % of the total production in Norway in 2017, according to calculations presented in the enclosure *The government's share of Norwegian petroleum production.*

In Aker BP's annual report for 2017 [59], the provision for abandonment liabilities per 31st of December 2017 was 3 043 884 USD. That translates to 25 151 613 NOK. Using this estimate and dividing it by Aker BP's share of total production results in the following estimate:

$$\frac{25\ 151\ 613}{0.03904225} = 644\ 215\ 254$$

The estimate of Norwegian decommissioning liabilities based on Aker BP's estimate of ARO liabilities lead to an estimated **644 billion NOK** in total decommissioning expenditure.

Discussion

The estimates of total decommissioning expenditure based on the estimates of Equinor and Petoro are similar and there is a reason for that.

Petoro does not calculate decommissioning costs in-house. They rely on the estimates produced by the field operators. The fields Equinor operate represent 2/3 of the production on the NCS. Without examining the issue in detail, it stands to reason that on most of the fields where Petoro is a license owner, Equinor is the operator. The result is that the estimates of future liabilities in Equinor and Petoro have considerable overlap.

Aker BP's numbers should also be commented on. It is not specified in Aker BP's Annual Report of 2017, but it is assumed that the decommissioning liabilities for Johan Sverdrup are included in the calculations. This field represents a major part of Aker BP's reserves, but the field is not due to produce first oil until Q4 2019.

Presumably, Aker BP has included a major future liability for decommissioning of a field that does not contribute to production today. This will affect the extrapolated estimate of total decommissioning expenditure and will lead to an overestimation of decommissioning expenditure using the methodology applied in this section.

The effect is offset by a reduction in estimated costs for Aker BP's facilities. Aker BP states that experience from past and current projects, especially with regards to P&A justifies reducing the estimated expenditure.

Norwegian Decommissioning Expenditure Estimated Based on Decommissioning Expenditure Estimates for the UK

An alternative method of establishing an estimate of the total cost of decommissioning on the NCS is by combining information from UK Oil & Gas Authority's recent estimate of the total decommissioning cost on the UKCS with an estimate of the scope of decommissioning of the NCS compared to the scope on the UKCS based on total weight. This approach requires compensations in numbers due to difference in regulations.

Comparative analysis of decommissioning scope on the NCS versus the UKCS

The most recent numbers on the weight of Norwegian offshore installations are from the report *Markedsrapport knyttet til avslutning og disponering* [77]. In this report the estimated weight as of December 31st 2017 for different offshore structures is presented.

However there seems to be some discrepancies between the number in that report and those in the report *Decommissioning in the North Sea – Review of Decommissioning Capacity,* prepared by Arup and commissioned by Decom North Sea and Scottish Enterprise [202], which is referenced as the source of the information.

Markedsrapport knyttet til avslutning og disponering states that the total weight of steel jackets is 675 000 tons and the total weight of topsides both from gravity based concrete substructures and from steel jackets is 985 000 tons. The reference for these numbers is

Arup’s report. The report continues to state that the weight of floaters with a steel hull is 715 000 tons.

However, the Arup report presents the following numbers:

The aggregated numbers for fixed and floating steel infrastructure in Norway has a total substructure weight of 675 000 tons a total topside weight for fixed **and floating** structures of 985 000 tons.

These reports are conflicting, as the aggregated steel weight from the reports differ by as much as 715 000 tons for the same structures. The decision was made to perform new calculations based on a list of all offshore structures and their weight published by OSPAR in its database of installations in the North Sea [96]. Analysis of the raw data brought forth the conclusion that *Markedsrapport knyttet til avslutning og disponering’s* numbers are the most credible, but the updated version compiled in this thesis is considered more precise.

The most recent data available from OSPAR are from 2015, but the numbers have been modified by the authors to include fixed and floating offshore structures that started producing after January 1st 2015 and offshore structures where the PDO has been approved and the offshore structure is under construction.

In the following section a number of assumptions have been made:

1. It is assumed that gravity-based concrete substructures applicable for derogation will be left in situ. Experience so far indicate this is a fair assumption.
2. It is assumed that floaters with a concrete substructure will be taken to shore and decommissioned and that the cost of decommissioning the substructure of a concrete substructure is the same as decommissioning a steel substructure from a floater. There is no experience data related to removal of concrete substructures in the North Sea.
3. It is assumed that all steel floaters will be made safe and disposed of in the same manner as fixed structure topsides.

Recent reports indicate that the steel floaters owned by third parties will most likely be decommissioned in the same way as conventional vessels – by the lowest bidder internationally. Two examples of this have been uncovered. The North Sea Producer, owned by Maersk, operated at the MacCulloch oil field on the UKCS [203]. This FPSO is currently being demolished at a beach in Bangladesh [30].

Another example is the FSO Navion Saga, owned by Teekay Offshore Partners, which operated on the Glitne field for over a decade. The Navion Saga was recently reported to be on its way to India for demolition [29].

So far very few steel floaters have been decommissioned and they are normally reinstalled on new fields. But only a small fraction is owned by third parties, and the fraction may be similar in Norway and in the UK, so the assumption only has a very small impact on the comparison.

4. Another assumption is that the proportion of pipelines and subsea structures in Norway compared to the UK is proportional to the fraction of the total weight of fixed and floating structures that will be decommissioned in the two countries.

   A result of these assumptions is that the steel jackets, the topsides of both steel and gravity-based substructures, all floaters and the number of wells is central in estimating the total scope of decommissioning.

5. It is assumed that well P&A represents 50 % of total decommissioning cost.
6. It is assumed that no new structures have been added in the UK after 2015. This assumption is inaccurate, but the UKCS is a more mature region and the number of new offshore structures installed in the UK in the last three and a half years and the structures which are currently under construction are disregarded in the following discussion. The structures that were decommissioned after 2015 are also disregarded and these two categories partially cancel each other out.

   Recent and planned developments on the UKCS are considered beyond the scope of this thesis.

The Weight of Structures on the NCS Including New Structures After 01.01.2015 Based on OSPAR Data

This section details the gathering of weight data on all structures on the NCS. The data is information registered by OSPAR on the weight of all installations on the NCS, supplemented by data from several other sources where the OSPAR data was inadequate. This data is compiled in a separate document.

The structures on the NCS have been divided into several categories, primarily motivated by the requirements for the input data used in the estimation of total decommissioning expenditure on the NCS.

The weight in each category has been divided into the subcategories *closed down*, *decommissioned* and *operational*. The category *closed down* represents all platform that are not currently in production, but where the decommissioning process is not yet finished. For simplicity all structures in the categories *closed dow*n and *operational* are considered not decommissioned even though some of the structures in the *closed down* category is partially decommissioned.

Fixed steel:

The first category is fixed steel platforms. These are fixed platforms with steel jackets. The platforms where data on weight was missing were investigated and weight was added. The platforms that have not been installed yet, are under construction or are at a stage of the planning process where sufficient information on the structure is known have been added to the list. For the 5th platform on the Johan Sverdrup field that is currently in the planning stage, the weight of the steel jacket is assumed to be equal to the average weight of the four other steel jackets.

The total weight of the subcategory *not decommissioned* is used in the Monte Carlo simulation for total decommissioning expenditure.

Floating concrete:

The two floating concrete platforms have been divided into 2 categories with one platform each. Those are floating concrete with derrick (a TLP but regarded as a floater for simplicity) and floating concrete without derrick. The reasoning behind creating these subcategories is the requirements of the input data in the estimation of total decommissioning expenditure. The concrete floaters without derrick will not have OPEX after CoP.

Figure 66: The Heidrun TLP [204]

Figure 67: Troll B [205]

Floating steel:

This category is a complex category that includes floating structures in the categories FPSO's (hull-type and cylindrical spar-type), FSO's, FSU's, FPU's, steel TLP's and production semi-subs.

These floating structures will be decommissioned in different ways. After conferring with key decision-makers in the industry it became clear that steel floaters owned by the operators will be decommissioned in the same manner as steel platforms. They will be taken to shore for disposal/recycling. The floating steel structures that are commissioned by the operators but are owned by third parties is a different matter. Evidence suggest that these floating structures will most likely be decommissioned by the lowest bidder internationally. The vessels owned by third parties have been examined and singled out in a separate document and the weight of these structures is omitted in the total floating steel weight to be decommissioned. The vessels where no weight information was available have been assigned the average weight calculated in a separate document.

Figure 68: The Heidrun B floating storage unit (FSU) [206]

Figure 69: The Hanne Knutsen, which has been converted to an FSO for the Martin Linge development [207]

<u>FPSO, FSO, FSU, FPU and Semi-sub:</u>

All the floating steel structures except the TLP Snorre A are assumed to not have drilling capacity. That means that these platforms will be removed and a MODU will complete the P&A procedure. This means that these floating structures will have minimal to no OPEX after CoP.

<u>Steel TLP with Derrick:</u>

The Snorre A TLP has an operational derrick and is assumed to perform the P&A from the TLP platform before leaving the field. This is the only steel floater assumed to have OPEX after CoP.

Gravity Based Concrete:

This category includes most of the giants on the NCS. As mentioned, the concrete substructures will be left in situ.

The topsides of these structures are assumed to be removed and recycled/disposed of ashore and the total topside weight of not-decommissioned platforms with concrete substructure has been calculated.

Figure 70: Draugen concrete gravity-based platform [208]

Subsea:

In this category few structures are registered with weight in the OSPAR data and several fields are omitted. To remedy the inadequate data a decision was made to perform a separate analysis on the weight of subsea equipment on the NCS. This analysis is described in detail in the section *Calculation of Subsea Equipment on the NCS* on page 142.

Other:

In this category all the structures registered are loading systems. After some research it was uncovered that several of the structures that were registered as operational are in fact already decommissioned. The four Submerged Turret Loading (STL) systems have been treated with the subsea equipment and were omitted from the category in the OSPAR data. The only structures left among the operational structures in the other category is the four Offshore Loading Systems (OLS). The weight of three of these is unknown, but they are assumed to be equal to the weight of the Statfjord B OLS.

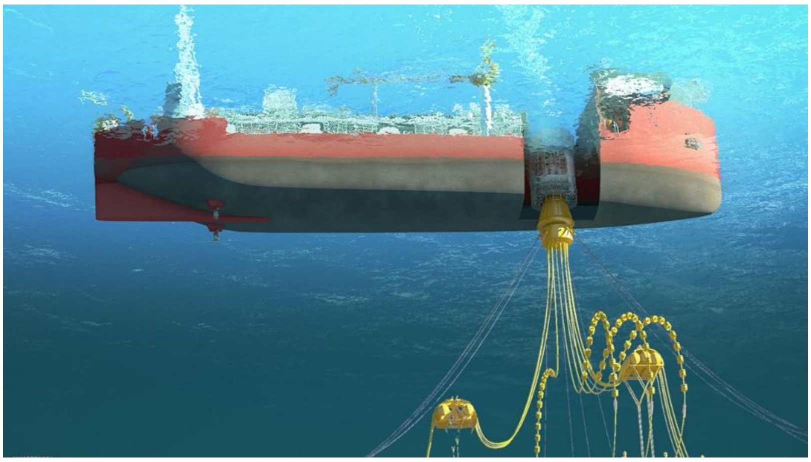

Figure 71: Submerged Turret Loading System (STL) [209]

Figure 72: Statfjord C with the loading system in the foreground [210]

Fields that started production after 01.01.2015 and planned new developments

The data from OSPAR only includes offshore structures that were in production as of 01.01.2015. To get an impression of the actual scope of decommissioning on the NCS, an attempt has been made to include all structures that have come into production since 01.01.2015, all structures that are currently being constructed or installed and all structures where the PDO has been approved, handed in or is expected to be handed in shortly.

The data has been compiled as an attempt to create an exhaustive list of structures on the NCS that will require decommissioning in the future. The aim is to register all structures, but some structures might have escaped the authors' attention.

The structures where sufficient information is available have been added to the list of structures on the NCS published by OSPAR in 2015. The subsea developments have not been investigated in detail but are listed to show the high level of activity on the NCS at present.

Summary of total weights on the NCS

The total weight of steel jackets is **630 150** tons.

The total weight of topsides from both fixed concrete and fixed steel substructures is **1 143 856** tons.

The steel from fixed steel platforms and topsides of concrete substructures is **1 774 006** tons.

In Norway concrete substructures from floaters to be decommissioned is **428 559** tons.

In Norway the weight of topsides from concrete floaters is **87 342** tons.

In Norway the weight of steel floaters to be decommissioned is **1 047 482** tons.

The sum of all floaters is **1 563 383** tons.

Weights on the UKCS

The same assumptions apply to the UKCS, but the numbers are from 2015 [211].

- In the UK, the weight of steel from jacket platforms and concrete substructures is 2 978 128 tons.
- In the UK, the weight of steel floaters to be decommissioned is 1 811 469 tons. Many UKCS floaters do not have recorded weights – an average weight has been applied to these. A similar approach to floaters on the NCS has been taken for floating installations on the UKCS, as shown in the enclosure *Ospar Calculation of weight of offshore structures in the UK.* Based on the data from OSPAR [211], the weight of all structures on the UKCS was sorted into sub-categories and added together. For floating structures in the categories FPSO, FSU, FPF, jack-up and the CALM buoy that did not have weight registered are all given a weight equal to the average of all the floaters that have weights registered. The average weight for all floating structures with known weight is 46 347 tons. This is the estimated weight for the floating structures with unknown weight. This weight is comparable to the average weight of a floating structure in Norway and the fact that the weights are similar adds credibility to the estimates.
- In the UK, the weight of concrete substructures from floaters to be decommissioned is 0 tons.

Several offshore structures have been decommissioned between 2015 and 2017 in the UK and there are few new developments. A point worth mentioning is that it seems OSPAR changes the status of a platform from the category *closed down* to the category *decommissioned* when a Close Out report has been sent in and accepted by the authorities.

The proportion of the total weight in Norway compared to the UK for each category is:

Steel jacket and topsides:	59.6 %
Steel floaters:	86.3 %
Proportion of total steel weight:	69.7 %

When it comes to wells, Norway has, according to *Offshore Engineer* [107] – approximately 3000 wells whereas the UK has 5000 wells.

The number of wells in Norway is investigated further in the section *The number of wells in Norway* on page 131 but the information in the Offshore Engineer article is assumed to be comparable for scale.

The Norwegian number of wells to be permanently plugged and abandoned is around 60 % of the UK number. It is assumed that the cost of P&A on the UKCS is 75 % of the P&A cost on the NCS due to less stringent regulations on well P&A in the UK.

The cost of P&A in Norway compared to the UK is set as 80 % of UK costs:

$$\frac{3\ 000}{5\ 000 \times {}^{3}\!/_{4}} = 80\ \%$$

Assuming P&A expenditure represents 50 % of all decommissioning expenditure, and assuming total steel weight is an estimator of the other 50 % of the expenditure, the cost of decommissioning in Norway compared to the UK can be calculated in the following way:

$$Fraction\ of\ P\&A\ cost \times impact\ of\ P\&A + fraction\ of\ steel\ weight \times impact\ of\ steel\ weight$$

$$80\ \% \times 0.50 + 69.7\ \% \times 0.50 = 74.85\ \%$$

These calculations support the assumption that total decommissioning expenditure on the NCS is roughly 75 % of the total expenditure in the UK.

A cost estimate for the total scope of decommissioning in the UK, Oil & Gas Authority UK's *UKCS Decommissioning – 2017 Cost Estimate Report,* was published in 2017 [80].

The report states that the total cost of decommissioning in the UK had a P50 estimate of 59.7 billion Pounds in 2016, a P10 estimate of 44.5 billion Pounds and a P90 estimate of 82.7 billion Pounds [80].

This equates to a P10 – P90 range of between 515 - 957 billion NOK with a P50 estimate of 691 billion NOK (2017).

The comparison of the scale of the decommissioning scope on the NCS versus the UKCS lead up to the following estimate. Decommissioning expenditure on the NCS can be estimated to 75 % of the P50 estimate in the UK. The resulting P50 estimate of future decommissioning liabilities in Norway is 518 billion NOK.

UK Oil & Gas state that a cost reduction of 35 % should be attainable in decommissioning. The analysis of actual cost compared to cost budget (*observations on budgeting in* decommissioning, page 41) points to an average cost overrun of 50 % on decommissioning projects compared to initial budgets.

If the ambitious target of a cost reduction of 35 % is reached both in the UK and in Norway, the Norwegian decommissioning expenditure will end up at approximately 337 billion NOK, using the P50 estimate and assuming a cost reduction of 35 % is realized.

Assuming no cost reduction and an average cost overrun of 50 %, the P50 estimate for Norwegian decommissioning expenditure is 777 billion NOK.

These estimates are constructed using P50 estimates only, and an even broader range could be constructed by combining adjusted P10 and P90 estimates.

Using the P90 estimate of decommissioning liabilities in the UK, and assuming the scope of decommissioning in Norway is approximately 3/4 of the scope in the UK, the cost reduction is not realized and an average cost overrun of 50 % occurs, the estimated decommissioning liabilities are as high as 1077 billion NOK.

Using the P10 estimate of decommissioning liabilities in the UK, assuming the scope of decommissioning in Norway is approximately 3/4 of the scope in the UK, assuming the cost reduction is realized and assuming an average cost overrun of 0 % the estimated decommissioning liabilities are as low as 251 billion NOK.

Figure 73 summarizes the cost estimates developed in the previous sections.

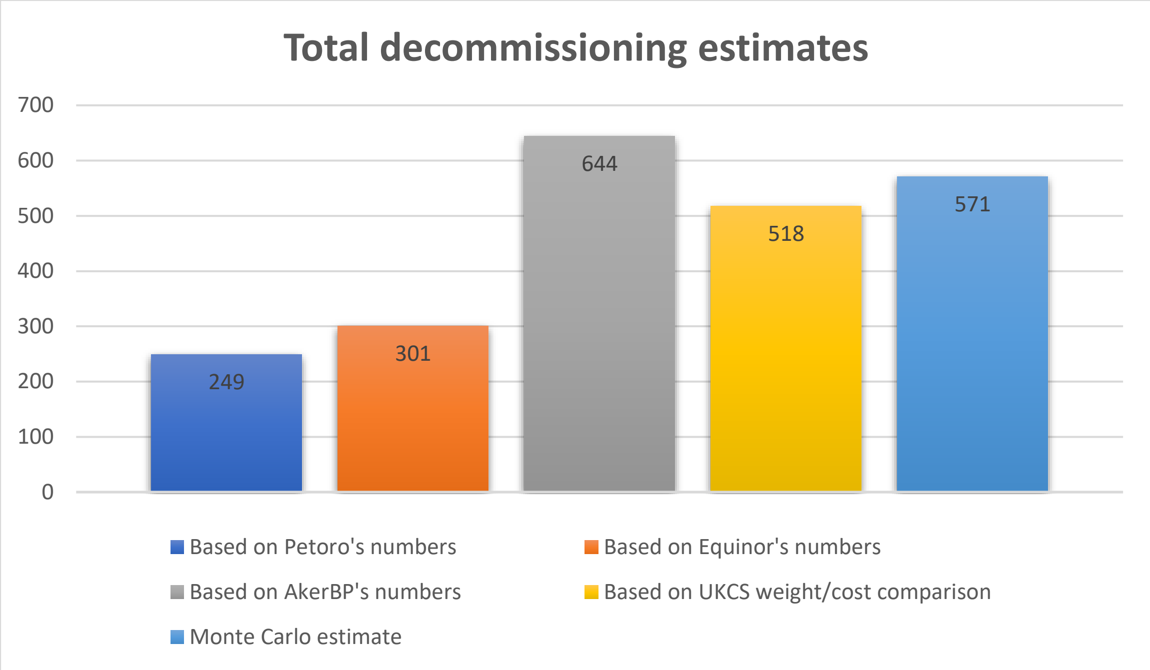

Figure 73: Overview of estimates from different sources

The total decommissioning cost estimate from the Monte Carlo simulations is **571.191 billion.** This number seems to be of the correct scale as shown in Figure 74.

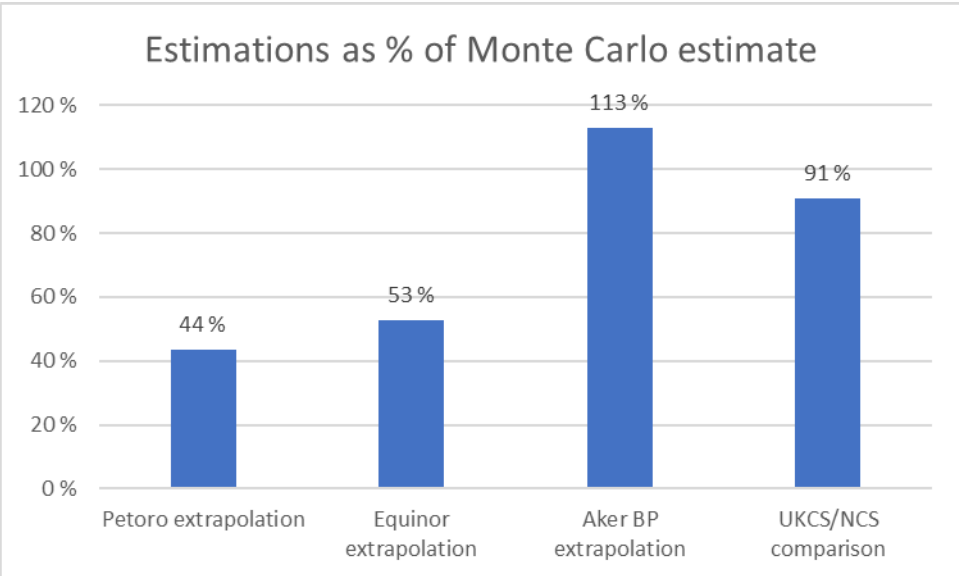

Figure 74: Estimates as percentages of Monte Carlo result

The number corresponds well with the comparative estimate of decommissioning cost on the NCS based on the P50 estimate for total cost of decommissioning on the UKCS, with a deviation of only nine percent.

A point worth noting is that the minimum result in the Monte Carlo simulation using 100 000 iterations was 334.3 billion NOK, which is above the extrapolated total cost estimates based on Equinor and Petoro's ARO estimates.

The Aker BP extrapolation should not be given much weight as it is an extrapolation developed based on numbers from an operator with only a minor market share. The extrapolations based on Petoro and Equinor's ARO estimates are around half of the Monte Carlo estimate. This implies that the Monte Carlo estimate is over target but warrants further analysis. According to Equinor, the ARO estimates are mainly based on high level, immature estimates. Equinor have recently completed successful P&A campaigns with significant cost reductions. These successes may have influenced the P&A-portion of their cost estimates. The numbers may also be attributed to anticipation of savings potentials through new technology or improved contracting practices.

The estimate developed through the UKCS comparison is believed to be the most credible, as extrapolation of petroleum companies' ARO estimates assumes that the company in question's methods are applied to the entire NCS, which may be a questionable assumption. The comparison approach is also the closest to the Monte Carlo estimate and validates it adequately as it is also based on a Monte Carlo analysis of weight to be removed.

Comparison of P&A estimates

The cost estimate of the full scope of well P&A in this thesis is 268.5 billion NOK, or 47 % of the total.

Few attempts have been made to estimate the total cost of P&A in Norway, but there is one source of information that this estimate should be compared to.

In their Bachelor thesis Øia and Spieler estimated the cost of performing P&A on all wellbores on the NCS in 2015. Their most likely estimate was 441 billion NOK (2015), which is 465.3 billion NOK (2017).

An outline of their assumptions deserves mentioning.

In their thesis Øia and Spieler make a series of assumptions:

- All wells on platforms are assumed to be plugged and abandoned using an integral derrick.
- The day rate for performing P&A on a platform all costs included is assumed to be 400 000 USD (2015) per day. This is 3 407 186 NOK (2017)
- The day rate for performing P&A with an RLWI) all costs included is assumed to be 450 000 USD (2015) per day.
- The day rate for performing P&A with a MODU with all costs included is assumed to be 700 000 USD (2015) per day.
- The day rate for performing P&A with a Light Construction Vessel (LCV) with all costs included is assumed to be 150 000 USD (2015) per day.
- Assumptions have also been made concerning the expected P&A duration for different categories of wells.
- The most likely P&A duration for platform wells that do not require section milling is assumed to be 39 or 40 days depending on the P&A method chosen.
- The most likely P&A duration for subsea wells that do not require section milling is assumed to be between 39 and 44 days depending on the P&A method chosen.
- Section milling has been assumed to be required on 25 % of all wells on the NCS.
- The number of wells on the NCS that require phase 1 and phase 2 P&A, as it is defined in their thesis, is assumed to be 2 410 and 2 424 accordingly.
- Phase 1 and phase 2 represent more than 97 to 99 % of the P&A duration according to Øia and Spieler. That means that the number of wells that require phase 3, which is wellhead removal, can be ignored for simplicity. The phase 1 and phase 2 durations are similar, so for simplicity the number of wells on the NCS in Øia and Spieler's thesis is approximately 2 410. This includes both development and exploration wells.

Assumptions made in this thesis:

- In this thesis only 68 % of all platform wells are assumed to be plugged and abandoned using the integral rig. The other 32 % are treated as subsea wells.
- The day rate for performing P&A on a platform is assumed to be 1 300 000 NOK in this thesis.
- The day rate for RLWI and LCV is not stated in this thesis.
- The day rate for jack-up rigs is assumed to be 250 000 USD in this thesis.
- The average P&A duration for normal platform wells is assumed to be 28.2 days
- The average P&A duration for normal subsea wells in this thesis is assumed to be 32.87 days
- Wells that require section milling and complex wells represent 1/7 of all wells in our thesis
- The number of wells that require P&A on the NCS is assumed to be 2 512 in this thesis.

As can be seen the assumption in this thesis are quite different from the assumptions in Øia and Spieler's thesis. The assumptions that should lead to a higher estimate in this thesis are the fact that the number of wells that are treated as subsea wells is higher and that the total number of wells that require P&A is higher.

The other assumptions in this thesis should lead to a lower estimate. The rig rates were historically high in the start of 2015 and have dropped considerably since. Another point worth mentioning is that as many as one in four wells is assumed to require section milling in Øia and Spieler's thesis, a much higher fraction than what is assumed in this thesis.

The total effect of all the differences in assumptions is hard to establish, but the reduction in rig rates is of particular importance.

The net effect of all the differing assumptions is a significant reduction in the estimated P&A expenditure in this thesis compared to Øia and Spieler.

Which of the assumptions that best represent future P&A expenditure is debatable, but the general cost reduction in the oil and gas industry in recent years should lead to a reduction in future P&A expenditure if the cost reduction is considered permanent.

As mentioned in the discussion of rig-rates in the section *Limitations to the model* on page 167, rig rates are stated as 50 % of P&A expenditure and P&A performed by MODU represents 72 % of total P&A costs. That means that an increase of 1 % in rig-rates for MODU will increase P&A expenditure by 0.36 %. The bottom line is that most of the differences in P&A expenditure can be explained by differing assumptions on rig rates.

The Norwegian Government's Exposure to Decommissioning Costs

The final cost of decommissioning In Norway is hard to estimate precisely, but it will be counted in hundreds of billions NOK.

When evaluating decommissioning expenditure, it is of vital interest to uncover where the bill eventually ends up. As mentioned, the license-owners on the NCS pay a marginal tax of 78 % through an ordinary tax of 23 % and a special tax of 55 % as of 2018 [212].

The Norwegian petroleum tax system is neutral, i.e., the government covers 78 % of the expenditure related to decommissioning directly through tax exemptions.

The remaining expenditure is split between the owners on the NCS.

However, the Norwegian government has several roles in the Norwegian petroleum industry. They are the regulator, a direct license owner through Petoro, a direct owner through Equinor and Aker BP and an indirect owner through the *Government pension fund global* and the *Folketrygdfondet*.

In the enclosure *The government's share of Norwegian petroleum production*, an estimate of the Norwegian government's share of the decommissioning expenditure is calculated based on the direct and an indirect ownership as license holder or shareholder. The spreadsheet is shown in Table 24.

Table 24: The government's share of Norwegian petroleum production

Selskap	Sum Oil equivalents (Mill. Sm³ o.e.)	Ownership Government Pension Fund Global 31.12.2017	Comment	Ownership Folketrygdfondet 31.12.2017	Comment	Direct Ownership 31.12.2017	The Governments Total Ownership 31.12.2017	Estimated Share of Total Production (Mill. Sm³ o.e.)
A/S Norske Shell	10,01300341	2,19 %	*Ownership through the parent company Royal Dutch Shell PLc*	0,00 %		0,00 %	2,19 %	0,219284775
Aker BP ASA	9,281395456	0,65 %	*The Petroleum Fund owns 2,17 % of BP p.l.c. which owns 30 % of Aker BP through the subsidiary BP Global Investments limited*	6,01 %	*Owns 4,35 % directly and 1,664 % through a 4,16 % ownership in Aker ASA which owns 40 % of Aker BP through their subsidiary Aker Capital ASA*	0,00 %	6,665 %	0,618605007
CapeOmega AS	0,0679606	0,00 %		0,00 %		0,00 %	0,00 %	0
ConocoPhillips Skandinavia AS	7,733692497	0,92 %	*Ownership through the parent company ConocoPhilips*	0,00 %		0,00 %	0,92 %	0,071149971
DEA Norge AS	3,403064538	0,00 %		0,00 %		0,00 %	0,00 %	0
Eni Norge AS	7,134812124	1,42 %	*Ownership through the parent company ENI SpA*	0,00 %		0,00 %	1,42 %	0,101314332
Equinor Energy AS	76,31294268	0,00 %		3,56 %		67,00 %	70,56 %	53,84641236
ExxonMobil E&P Norway AS	10,05245372	0,87 %	*Ownership through the parent company ExxonMobil Corp*	0,00 %		0,00 %	0,87 %	0,087456347
Faroe Petroleum Norge AS	0,602359468	0,00 %		0,00 %		0,00 %	0,00 %	0
Idemitsu Petroleum Norge AS	1,976582148	1,33 %	*Ownership through the parent company Idemitsu Koran Co Ltd*	0,00 %		0,00 %	1,33 %	0,026288543
INEOS E&P Norge AS	2,972044711	0,00 %		0,00 %		0,00 %	0,00 %	0
KUFPEC Norway AS	0,908542913	0,00 %		0,00 %		0,00 %	0,00 %	0
LOTOS E&P Norge AS	0,957878496	0,60 %	*Ownership through the parent company Grupa Lotos S.A.*	0,00 %		0,00 %	0,60 %	0,005747271
Lundin Norway AS	5,111559611	0,22 %	*Ownership through the parent company Lundin Petroleum AB*	0,45 %	*Ownership through the parent company Lundin Petroleum AB*	0,00 %	0,67 %	0,034247449
Neptune Energy Norge AS	4,701186994	0,00 %		0,00 %		0,00 %	0,00 %	0
OKEA AS	0,016852553	0,00 %		0,00 %		0,00 %	0,00 %	0
OMV (Norge) AS	4,68154013	1,07 %	*Ownership through the parent company OMV AG*	0,00 %		0,00 %	1,07 %	0,050092479
Pandion Energy AS	0,2239899	0,00 %		0,00 %		0,00 %	0,00 %	0
Petoro AS	64,51902854	0,00 %		0,00 %		100,00 %	100,00 %	64,51902854
PGNiG Upstream Norway AS	1,137695382	0,24 %	*Ownership through the parent company Polskie Gornictwo Naftowe i Gazownictwo SA*	0,00 %		0,00 %	0,24 %	0,002730469
Point Resources AS	2,717129114	0,00 %		0,00 %		0,00 %	0,00 %	0
Repsol Norge AS	1,809784562	1,29 %	*Ownership through the parent company Repsol SA*	0,00 %		0,00 %	1,29 %	0,023346221
Spirit Energy Norge AS	4,071227082	1,06 %	*The Government Pension Fund Global owns 1,53 % of Centrica PLC which owns 69 % of the parent company Spirit Energy AS*	0,00 %		0,00 %	1,06 %	0,042979944
Total E&P Norge AS	12,427323	1,79 %	*Ownership through the parent company Total SA*	0,00 %		0,00 %	1,79 %	0,222449082
VNG Norge AS	0,221715091	0,00 %		0,00 %		0,00 %	0,00 %	0
Wintershall Norge AS	4,671193583	2,54 %	*Ownership through the parent company BASF SE*	0,00 %		0,00 %	2,54 %	0,118648317
Sum Oil Equivalents	237,7269583							119,9897811
Share of Norwegian production owned by Pet	27,139971 %							
Share of Norwegian production owned by Equ	32,101089 %							
Share of Norwegian production owned by Ake	3,904225 %							
Share of Norwegian production owned directly or indirectly by the Norwegian Government through Statoil and Petoro	49,790500 %							
Share of Norwegian production owned directly or indirectly by the Norwegian Government	50,473780 %							
Estimator for the Norwegian Governments share of the Decommissioning Expences	**50 %**							

The computation of the Norwegian government's ownership is straightforward, but the link to decommissioning cost requires an explanation. Field-specific decommissioning costs are not available, and it is beyond the scope of this thesis to attempt a calculation of these. However, it is fair to assume that there is a strong correlation between the license-holders' and the shareholders' share of the total Norwegian petroleum production and their share of the total decommissioning cost. The decommissioning cost per oil equivalent produced will of course vary broadly, but as aggregated numbers for the whole NCS, these variations will cancel out and the share of current production is assumed to be a good estimator of the share of decommissioning costs.

Calculations show that the direct and indirect ownership of the Norwegian government, both as a license holder and as a shareholder, amounts to 50.47378 % of the oil and gas production on the NCS.

A data-file showing per-company production as of December 31st 2017 is directly available at [213].

Information concerning the ownership of shares through the Norwegian Petroleum Fund and the Folketrygdfondet and the direct ownership of the Norwegian government have been combined to show the government's total ownership on the NCS.

To identify each company's parent company, all the operators on the NCS were investigated and the parent companies, if any, were identified and researched further.

The ownership structure of Aker BP is the most complex, and a figure has been created to illustrate the ownership structure of this company.

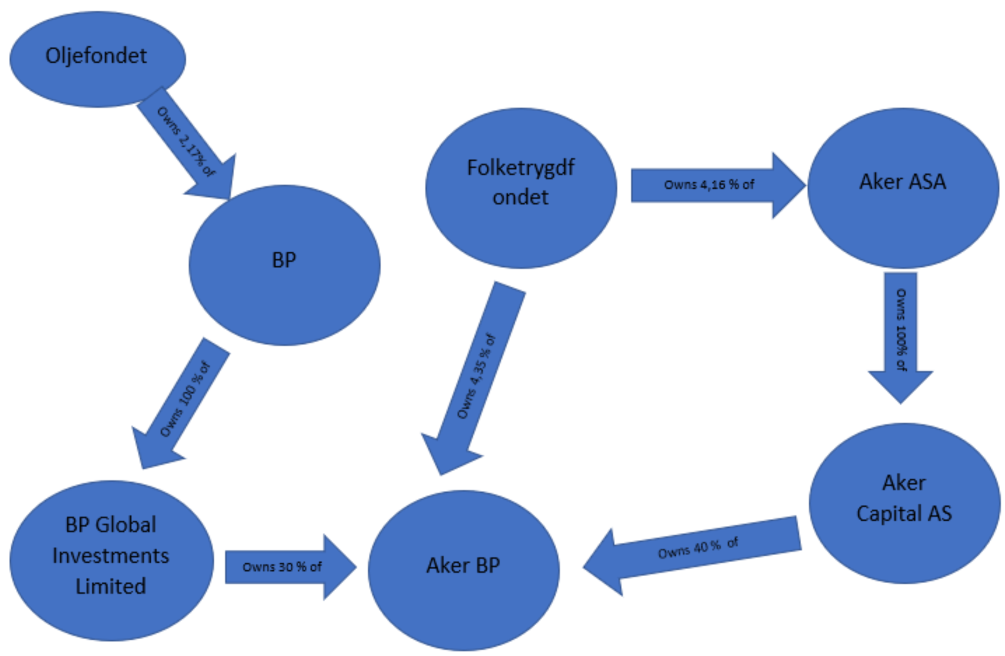

Figure 75: Ownership of Aker, BP and subsidiaries

The uncertainty linked to the estimator is considerable. The Norwegian government owns approximately 98.65 % of its share of the Norwegian oil production through Petoro and Equinor. It is challenging to generalize on the characteristics of the licenses owned by Petoro and Equinor, but it is striking that Equinor's experience with decommissioning is limited so far. This is an indication of Equinor's preference for larger field developments, presumably with a longer life span and a lower decommissioning cost per oil equivalent produced. Another reason is that Equinor has been successful in the exploration of additional resources that increase the life span of the aging fields. This is an indication that the estimate developed for governmental ownership might be on the high side, since field decommissioning cost as a fraction of field reserves decreases as the field increases.

A central observation is that the decommissioning obligations for the licenses owned by Equinor and Petoro are far away time-wise. Petoro's fields have an average expected close-down year of 2034 according to calculations in the enclosure *Average close-down time for Petoro's Licenses.* The information concerning remaining production periods of Petoro's licenses is available at Petoro's website [214].

For Equinor this information is not available as they are an international company with foreign licenses, so an aggregated number would not be as relevant for the NCS.

An advantage of being a late mover in the decommissioning process is that Equinor and Petoro will benefit from lessons learned and new technology when the bulk of their decommissioning is expected to take place. This effect is hard to put a number on, but it will probably be substantial, and might shift the governments fraction of the decommissioning expenditure through direct and indirect ownership significantly.

The Norwegian government's estimated share of the Norwegian petroleum production is 50.47 %.

The estimator of the Norwegian governments total share of decommissioning expenditure, both as a direct and indirect owner used in this paper is 50 %, but an argument can be made for a minor reduction of the estimator for the reasons listed above.

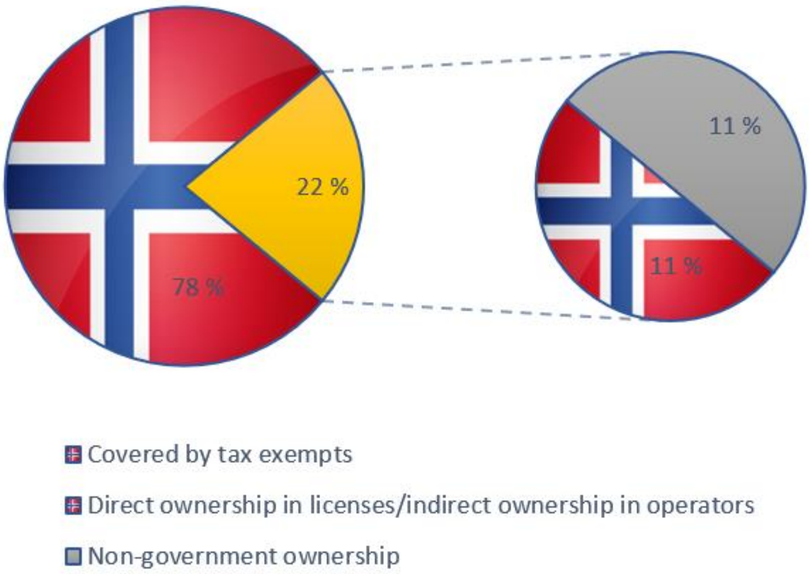

Figure 76: Government's share of decommissioning expenditure

To sum up the discussion of the Norwegian government's share of future decommissioning expenditure, we estimate that the government will cover 78 % of the decommissioning cost through tax exempts and 50 % of the remaining cost as a direct or indirect owner.

This constitutes 89 % of the total expenditure related to decommissioning on the NCS.

One of the consequences of the Norwegian petroleum tax law is that the government must take an active role in decommissioning. There is a significant risk of underinvestment in R&D related to decommissioning, primarily because the oil companies only keep 22 % of the potential cost reductions.

Another implication is that the government should consider being more active in their ownership management in Equinor, and make sure that Equinor prioritizes R&D in relation to decommissioning and be an advocate for increased transparency to ensure all operators in Norway are aware of best practice and lessons learned.

Market Analysis of Single Lift and Heavy Lift Vessels

An important element in the cost of decommissioning is the availability of removal vessels. This section describes the current and future market for HLV's and SLV's.

In 2016 a potential gamechanger in platform installation and removal was introduced. The following information is from Allseas' website [215]:

The SLV *Pioneering Spirit*, formerly known as *Pieter Schelte,* is a pipelaying and offshore installation and removal vessel owned by Allseas. The ship is capable of lifting topsides weighing as much as 48 000 tons and jackets up to 20 000 tons.

The vessel is twin-hulled, 382 meters long and 124 meters wide. The single lifts are performed using a 59-meter wide and 122-meter long slot at the bow of the vessel. The *Pioneering Spirit* positions itself so that the platform is in the slot and uses horizontal lifting beams to lift the topside from its substructure.

If the waters surrounding the contracted disposal yard are too shallow, the *Pioneering Spirit* can transfer its load to the barge *Iron Lady*, also owned by Allseas, which can operate in more shallow waters. A point worth noting is that the *Iron Lady* can only operate in relatively calm seas.

Pioneering Spirit commenced operations in 2016 with the record breaking single lift removal of the 13 500 ton Yme topsides. In April 2017, the *Pioneering Spirit* performed another record breaking single lift, removing the Brent Delta topside, weighing 24 000 tons.

In 2019 the Pioneering Spirit plans to break the record again in the installation process of the topside of the Johan Sverdrup processing platform. The estimated weight of the topside is 26 000 tons [216] [217].

At present the vessel is unique and there is no competition in the single lift market for the heaviest topsides and jackets.

Saipem's *S7000* and Hereema's *Thialf* are heavy lift vessel that can compete with the *Pioneering Spirit* for small and medium sized topsides and jackets. For larger offshore structures, the only alternative to the *Pioneering Spirit* is module-based reverse installation or piece-small removal. This implies that Allseas can choose to strategically price the *Pioneering Spirit's* services at a price just below the alternative, which in most cases is module-based reverse installation.

An interesting question is whether new entrants to the SLV market, and the increased competition this will bring forth, has the potential to reduce removal cost. The *Pioneering Spirit* is an expensive vessel. The total development and construction cost is 2.6 billion EUR (2016) [218], which is around 24.6 billion NOK (2017). This represents a substantial investment, and for Allseas it is essential that the day-rates are high enough to give the company a reasonable return on their investment.

Allseas are already planning to build a new and even larger SLV, *Amazing Grace* and construction may begin as soon as 2021 [219]. This is a clear indication that Allseas is satisfied with the return on their investment in the Pioneering Spirit.

At present, the market for SLV's must be characterized as a monopoly with Allseas as the only supplier. However, the HLV's are imperfect substitutes. They can get the job done, but for the larger removal projects they will need to remove the platforms using reverse installation of the modules. The consequence of reverse installation is that a much larger portion of the work must be performed offshore, and that the duration of the project will increase. These factors will both increase cost.

Another type of vessels worth mentioning are Semi-Submersible Heavy Transport Vessels (SSHTV). *Dockwise Vanguard* is the largest and is owned by a subsidiary of Boskalis. This vessel has potential uses in the removal of steel floaters in The North Sea – it can carry vessels up to 110 000 tons [220]. There are other smaller SSHTV's such as the MV *Blue Marlin* which also has potential in steel floater removal.

Assuming the FPSO's will be demolished/recycled in Norway or in the UK, these ships will probably not be an alternative. If the FPSO's cannot sail using their own engines they can be towed the relatively short distances to shore.

The HLV Market

The market for HLV's is itself an oligopoly with a very limited number of suppliers. The key suppliers are Heerema Marine Contractors, Saipem and McDermott, but McDermott operates mainly in the Gulf of Mexico.

Table 25: Overview of lifting vessels

Heavy Lift Vessels

Existing

Owner	Name	Lift Capacity (tons)	Lift Capacity Tandem (tons)
Saipem	Saipem 7000	7000	14000
Heerema	Thialf	7100	14200
Heerema	Balder	3629	6300

Under construction

Owner	Name	Lift Capacity (tons)	Lift Capacity Tandem (tons)
Heerema	Sleipnir	10000	20000
Shandong Twin Marine	2 Lifting and 1 Transporting Vessels [221]		34000

When the Heerema *Sleipnir* comes into service in 2019 there will be increased competition in the singe lift removal of topsides and jackets. With a lifting capacity of 20 000 tons in tandem lifts, the *Sleipnir* will be able to compete with the *Pioneering Spirit* on more projects.

The 3 vessels under construction from Shandong Twin Marine will increase competition further. They have a combined lifting capacity of 34 000 tons and can presumably compete with the *Pioneering Spirit* for most contracts.

From the list of the largest HLVs it is evident that this is a classic case of oligopoly with only two service providers and three vessels in the market. These vessels compete for contracts with the only SLV in the world.

In oligopolies, the suppliers have significant market power and the HLV market has seen some instances of collusion [222]. In 1997, Heerema was sued by the United States Department of Justice for conspiracy to suppress and eliminate competition in cooperation with McDermott and Saipem. Heerema pled guilty and agreed to pay a fine of 49 million USD. In 1998 a Saipem official failed to appear in court in the US in a related case. In 1999 the vice president of Business Development and Strategic Initiatives in McDermott pled guilty to violating the Sherman antitrust act. In May 2000 the former president in McDermott was indicted for bid-rigging.

This is clear evidence that collusion between the oligopolists has occured in the past.

There is no evidence to suggest that it is still happening, but oligopolies are susceptible to collusion and the market should be monitored closely by consumers of their services.

Another key factor is that prices will vary considerably depending on the market conditions. When demand is high, the day-rates can increase sharply. The reasoning is simple enough. If three of the four providers are tied up in existing contracts, the market is in effect a monopoly and the supplier can set the market price. This will lead to steep increases in day-rates in peak periods and deep plunges in times of overcapacity.

This effect is dampened by the fact that timing is less critical in decommissioning than in commissioning. The trend in the decommissioning industry is to agree on windows in the contracts. A removal contract may state that the topside and jacket may be removed at any time over a four-year duration. This flexibility reduces decommissioning cost and it reduces risk in making the future revenues more predictable for the HLV providers operating in what is traditionally a spot market.

Market conditions may create bargain opportunities for the buyers of HLV services, and operators should monitor the market closely and be ready to seize the opportunities.

Another issue worth noting is the articles that have recently featured in Norwegian newspapers on issues concerning worker’s rights and minimum wages aboard the HLV *Thialf* [223]. According to the article the workers earn as little as 29 NOK per hour and will regularly have to work 12 hour shifts in 12-week rotations. These practices are not in line with Norwegian regulations. It is debatable whether Norwegian regulations apply to the HLV’s operating in the North Sea, but bad press is a concern for all operators and should be avoided. This is an area that should be watched closely by operators hiring HLVs. If operators are concerned about their public image, minimum wages and worker's rights should be stipulated in the contracts.

Decommissioning is still in its relative infancy in Norway and the activity level will increase. New entrants to the market will increase the competition and should lead to reduced day-rates for SLV's and HLV's and reduced decommissioning expenditure. It should also reduce the variability in prices and thus make cost estimation less challenging.

DISCUSSION

The Government's Role in Decommissioning Cost Reduction

The Norwegian petroleum Tax Regime and the direct and indirect ownership of the Norwegian government has been a success story and contributed to the prosperity of the Norwegian state. However, it has some ramifications to be aware of. The Norwegian government covers 78 % of decommissioning expenditure directly through tax exempts. In effect the Norwegian government covers 89 % of the decommissioning costs due to direct ownership of licenses and direct and indirect ownership of companies that are operators or license holders on the NCS. Since the decommissioning process on the shelf is more technologically challenging, governed by stricter regulations and is more cost intensive than in most other areas of the world, considerable benefits may be had from R&D and innovative technology.

This is a classic case of positive externalities. Operators are responsible for the undertaking of decommissioning, but on only cover 22 % of the expenses. The fact that the government is owner and shareholder in companies on the NCS does not change the fact that the operator covers 22 % of the cost and receives 22 % of the potential savings related to decommissioning. The Norwegian government stands to reap 78 % of the benefits from efficiency gains and new and more customized technologies used in decommissioning.

Decommissioning is a classic example of an area where there is a significant risk of underinvestment in R&D.

The case can be made that the same effect applies to petroleum production since the government through the neutral petroleum taxation receives 78 % of the profits from oil production as well.

However, there are some significant differences.

Equinor, which in its infancy was 100 % Norwegian government-owned, was an early mover on the NCS and invested significantly in R&D related to offshore petroleum production and broke new ground. The other operators and license holders on the NCS benefited from the

R&D undertaken by Equinor and consequently the government received larger tax revenues from the petroleum industry in the following years, in part due to efficiency gains and increased oil recovery adapted by all operators on the NCS.

Today Equinor as a company has a different agenda and is not the extended hand of the Norwegian government in the same way. Equinor has an obligation to all shareholders to maximize profits, and the Norwegian government is no longer the only shareholder. In the case of decommissioning, Equinor is a late mover and even though it is by far the largest operator on the NCS, the company has limited experience with decommissioning. Equinor has been able to prolong the life of most of the fields where Equinor is the operator primarily through Increased Oil Recovery (IOR) and discoveries of new resources near existing infrastructure.

That is an impressive feat, but one consequence is that Equinor to some degree has postponed R&D related to decommissioning. There has been some R&D related to P&A, for example in the use of formation as barrier at Huldra [224].

But research into decommissioning has not been a top priority for Equinor so far and the other operators on the NCS do not have the same incentive to engage in R&D specifically related to decommissioning on the NCS since they have few licenses in Norway compared to Equinor.

As in all cases where positive externalities are present, a key role of the government is to ensure that subsidies are in place to increase the production of the good with positive externalities to the level that is most beneficial to the society. In other words: The Norwegian government needs to find a way to ensure that companies and research institutions invest in R&D related to decommissioning.

One example of research in the field is the research program at SINTEF called Economic analysis of coordinated plug and abandonment operations (ECOPA). It has received a total of 8 million NOK in governmental funding from 2015-2018 for research related to P&A [225].

Demo 2000 is another example of governmentally funded R&D in the petroleum industry. It has contributed between 50 -225 million NOK each year between 2012 and 2017, and in 2017 the total contribution was 150 million NOK [226] [227]. However, only a small proportion of the research done under the DEMO 2000 umbrella is applicable to decommissioning.

It is fair to say that research into the area of decommissioning is grossly underfinanced, and the government should make this a priority in the coming years.

It is possible for the Norwegian government to be a more active owner in Equinor and advocate prioritization of R&D in decommissioning. As a majority owner in Equinor, the Norwegian government has considerable weight, and can influence the company through several channels.

An increase in R&D related to decommissioning is beneficial to the society and, as for many products with positive externalities, the facilitation of, and if necessary, the subsidization of R&D by the government is crucial to achieving the desired level of R&D in the decommissioning area.

The role of the Government as regulator

The Norwegian regulators have chosen to accept that the *Disponeringsdel*-section of the *Avslutningsplan* (decommissioning program) is exempt from the public in its entirety. This is a choice that has serious ramifications and this section is dedicated to the analysis of the justification for and the consequences of this choice.

In the process of writing this thesis the most striking experience was the discovery of how extremely limited the publicly available information concerning the cost of decommissioning was. The information on how the decommissioning was performed in some cases had similarities to a black box, with a platform on the NCS as input and a few thousand tons of rebar as output with close to no information about the processes between these stages.

It is apparent that historically very little effort has been made by regulators to ensure that the information about the decommissioned structures from the NCS is publicly available, with the honorable exception of the Norwegian Petroleum Museum, which has made a great effort in documenting and recording the history of the petroleum industry in Norway.

The only information that, at least in theory, is publicly available are Environmental Impact Assessments. But these reports are not publicly available in the general sense. They are only available by request from the government through the portal www.einnsyn.no, and at times the number of seemingly identical documents to search through in the portal is somewhat like looking for the proverbial needle in the haystack.

Another issue is the fact that there is no generally accepted standard for cost breakdown. Some of the operators on UKCS and NCS use the cost breakdown structure recommended by UK Oil & Gas or a similar breakdown, but others have chosen their own generic cost breakdown structures. Benchmarking of projects becomes very challenging due to these practices. This is a striking contrast to the regime in the UK where a substantial part of the information contained in this thesis is gathered.

Initially it is useful to look at how the Oil & Gas industry is organized in the UK and in Norway.

Figure 77: Overview of regulatory authorities. Note: the UK's Department of Energy and Climate Change has recently restructured to the Department of Business, Energy and Industrial Strategy (BEIS) [228]

State Participant

The figure above is from the report *Netherlands Masterplan for Decommissioning and Reuse* [228] and presents most of the key stakeholders in decommissioning in the UK, the Netherlands, Norway and the US.

In Norway, Petoro has a similar role to EBN in the Netherlands, while there is no direct state ownership of production licenses in the UK.

In the Netherlands, EBN has a very active role and is behind a promising recent initiative that could potentially reduce decommissioning cost substantially.

Petoro has a very different role and its main priority is toward EOR, IOR and maximizing revenues from their license portfolio. Petoro could have assumed a much more active role in decommissioning but has chosen not to. This may be due to resource constraints or it may be due to decommissioning being underprioritized.

In the report *Riksrevisjonens undersøkelse av myndighetenes arbeid for økt oljeutvinning fra modne områder på norsk kontinentalsokkel* [229], the Supreme Audit Institution (SAI) concludes that Petoro, due to capacity constraints, has chosen to prioritize the major mature fields where Petoro has ownership interests and the minor fields close to them. According to the report, it is doubtful whether Petoro is fully capable of making sure that the resources from the government's direct ownership in Petoro is managed according to the instructions.

When resources are scarce, decommissioning may be under-prioritized or handled perfunctorily. The priorities of Petoro are in all likelihood prudent – the effect of a 1 % increase in petroleum revenues is much larger than the effect of a 1 % decrease in decommissioning expenditure. The bottom line is that if the funding of Petoro is insufficient for it to perform all its functions satisfactorily, increased funding should be prioritized.

The consequence is that the owner of licenses representing around a quarter of Norwegian petroleum production is near invisible on the decommissioning arena. That is a striking contrast to EBN which has a very proactive approach to decommissioning. The Netherlands' petroleum industry has more mature field developments, but the total scope of decommissioning in the Netherlands is much smaller than its Norwegian counterpart. According to the report *Netherlands Masterplan for Decommissioning and Reuse* [228], the total decommissioning liabilities in the Netherlands are 6.7 billion GBP (2016) which translates to 63.4 billion NOK (2017). That is presumably around 10-20 % of the decommissioning liabilities in the Norwegian petroleum industry. This makes the contrast between EBN and Petoro even more noteworthy.

Regulators

In the UK the regulator is the Department for Business, Energy and Industrial Strategy (BEIS). The equivalent in Norway is a duality consisting of the PSA and the MPE. The regulatory role of the PSA is, according to their website, to supervise safety, emergency preparedness and the working environment in Norwegian petroleum activities offshore and on land [230]. The PSA has a supervisory responsibility for cessation and removal activities in Norway. The PSA, in their own words, has a role both as a guide-dog and a watchdog. Some of the key responsibilities of the PSA is to maintain an ongoing dialogue with the industry, to share knowledge and experience and to facilitate continuous improvement.

In the research for this thesis little information was found on the PSA's active involvement on the decommissioning arena when it comes to ongoing dialogue, the sharing of knowledge and experience and the facilitation of continuous improvement.

According to the article *The North Sea's $100 Billion Decommissioning Challenge* by Boston Consulting Group [231] which is presented in detail in appendix 1, a central observation is that more collaboration among operators, especially in the case of P&A, can potentially reduce cost considerably. But collaboration comes hard to highly competitive operating companies in the oil industry.

One example of collaboration is the decommissioning platform initiative instigated by EBN, a state-owned license holder in the Netherlands equivalent to Petoro in Norway. The initiative is an attempt to create a common platform for the government, the operators and other stakeholders. A key objective is to help the operators collaborate, to reduce cost and to promote nationwide sharing of lessons learned in decommissioning. This initiative shows promise and should be monitored closely by the Norwegian authorities.

Licensing Authority

The NPD has, among several other responsibilities, the role of licensing authority on the NCS.

Initially it is useful to inspect the role the NPD has been given by the Norwegian government. According to information found on their website, they are a governmental specialist directorate and administrative body and the NPD reports directly to the MPE [232].

In their own words

> *"The Norwegian Petroleum Directorate's primary objective is to contribute to the greatest possible values for Norwegian society from the oil and gas activities through efficient and responsible resource management".*

To achieve their objective the NPD has identified 4 key functions:

1. *The NPD is to be an adviser to the MPE through its professional integrity and interdisciplinary expertise.*
2. *The NPD has a national responsibility for data from the Norwegian continental shelf. The NPD's data, overview and analyses constitute a crucial factual basis on which the activities are founded.*
3. *The NPD shall be a driving force for realising the resource potential by emphasising long-term solutions, upside opportunities, economies of scale and joint operations, as well as ensuring that time-critical resources are not lost.*
4. *In cooperation with other authorities, the NPD is to ensure comprehensive follow-up of the petroleum activities.*

The tools employed by the NPD to fill their functions and achieve their goals is the development of frameworks, the stipulation of regulations, and decision-making in areas where it has been delegated authority. To be fair, the NPD is the orchestrator behind several very useful initiatives in the field of decommissioning and some of the initiatives deserve some attention in this thesis.

The most recent initiative is the commissioning of the report by Dr. Techn. Olav Olsen, *Markedsrapport knyttet til Avslutning og Disponering* [77], which is a market report of decommissioning in Norway. The report was published in the spring of 2018 and is an insightful summary of the decommissioning industry in Norway.

There are two other reports that deserve mentioning. The first one is the report *Disposal of concrete facilities* [233], published by the NPD. This report is thorough and insightful and is the standard text on decommissioning of concrete installations. Another report where the

NPD has contributed is the report *Decommissioning of Offshore Installations* [36]*,* published by the Climate and Pollution Agency. These reports are very informative and may help educate researchers, students and the public on the topic of decommissioning.

Other reports that should be mentioned are *Utredning om tekniske utfordringer knyttet til transport, mottak og disponering av betonginnretninger ved land* by AF Decom Offshore [234], commissioned by the NPD and the report *Utredning av miljøkonsekvenser ved disponering av betonginstallasjoner* by Multiconsult [235], where the NPD contributed.

The NPD also has a section on their webpage dedicated to decommissioning and has published selected statistics from decommissioning.

When it comes to the role of the NPD in actual decommissioning processes, sources in the operating companies in the industry have stated that the dialogue with the NPD in determining the optimal concepts for decommissioning is constructive and founded on a desire to find the optimal solution.

However, there are some areas where the NPD has considerable potential for improvement. Before delving into those areas, it is enlightening to study how the Oil and Gas Authority in the UK fills the mandate given to them by the government.

In the UK all decommissioning program drafts, all approved decommissioning programs and, perhaps most significantly, all Close Out Reports are publicly available on the UK Oil & Gas homepage [236].

A Close Out Report is a report that sums up the essentials of the decommissioning process:

- *What was done in the decommissioning of the facilities?*
- *How did the project perform compared to schedule?*
- *How does the actual cost of the decommissioning project align with the initial budget (In many cases the budget and the cost summary are provided separately to BEIS)?*
- *What were the most important lessons learned in the project?*

The comparative assessments for pipelines and for a range of other activities are also made publicly available.

It should be evident that the information described above is instrumental in establishing a benchmark in decommissioning and in establishing best practices. The readily available information on lessons learned in previous projects make decommissioning projects much easier to plan and execute, especially for the operators new to decommissioning projects.

This is a stark contrast to the current situation in Norway. It has been difficult for the authors to assess how the NPD fulfills its mandate simply because so little information is publicly available concerning the NPD's approach to decommissioning.

Insiders in the petroleum industry acquire access to information through channels such as *Performance Forum* [237] and through decommissioning programs from fields where they are among the license owners. There are presumably informal channels as well, where personnel that have participated in or managed decommissioning projects exchange information and lessons learned.

This is crucial information to the operators in the petroleum industry, but also to the academic community.

To researchers, information on cost and lessons learned in Norway is very scarce. The lack of available information in the field of decommissioning diverts research to other fields.

When it comes to information flow to potential new entrants in the decommissioning industry, the NPD shares so little information that potential new entrants to the decommissioning industry are hesitant to enter the industry. The report published by NPD in 2018 is a step in the right direction but is too little too late.

There are several commendable reasons for withholding some information from the public and some of the information on cost is too sensitive to be publicly available.

However, the documents that are allegedly public should at the very least be readily available to the public. Impact assessments related to decommissioning are meant to be publicly available but are very difficult to access. Some of the Norwegian sector's impact assessments can be found online, but far from all. At the very least these documents should be made available by the NPD.

Close out reports in Norway summarizing lessons learned are not publicly available in Norway. These reports are crucial to transfer of knowledge and establishment of best practice and should be made available to all interested parties.

Appendix 1 provides a summary of some of the most important lessons learned encountered in the research for this thesis. This section should be educational both for insiders in the decommissioning industry and other interested parties.

In the following section a considerable part of the information is based on confidential interviews with insiders in the decommissioning industry. The information has been gathered in numerous interviews, motivated primarily by the lack of transparency in Norway with regards to decommissioning.

One of the roles of the NPD is to supply the operators with the data, overview and analysis to build a solid foundation for the operators to carry out decommissioning cost efficiently. In this area the NPD does not perform to the same standards as in other areas. The operators are to a large degree forced to rely on historical data from previous decommissioning projects where the company either was the operator or one of the license owners. There are some informal contact points between the operators and some exchange of lessons learned in these forums. But the flow of information is far from perfect.

Another area where the NPD has improvement potential according to sources in the industry, is in decommissioning projects where there is a potential to generate economies of scale in collaboration between two or more decommissioning projects from different operators. The NPD should take an active role in these projects and facilitate collaboration. The NPD does not perform to its usual high standards in this area today.

According to sources in the industry the NPD is far from proactive when it comes to assisting and advising operators in their decommissioning projects. The operators are forced to take the initiative and actively involve the NPD in the decommissioning projects. Ideally the NPD can take a more active role in future projects and ensure that the decommissioning projects move in the right direction.

The question of who is responsible for the lack of transparency in decommissioning is an open question. The government sets the rules the NPD are required to follow with regards to decommissioning. At the same time the NPD has an advisory role when the government makes decisions related to decommissioning. The NPD should advise the government to change procedure and/or regulations and increase the transparency in the industry. Whether the NPD has already taken that stance, and the MPE has chosen not to heed the advice, is not public knowledge. If that is the case the NPD are free of blame.

The MPE has the final word in the important decisions in the petroleum industry. Based on advice from the NPD and the PSA, the MPE seeks to regulate the petroleum industry in Norway in all areas. One of those areas is decommissioning and making sure that installations are decommissioned in a responsible way whilst minimizing cost is central.

Recommendations

- The MPE should instruct the NPD to assess whether the current level of transparency is sufficient, and at least instruct the NPD to make all publicly available information accessible on NPD's homepages.
- The MPE should also assess whether Petoro has sufficient funding to fill its mandate, and if not ensure increased funding.
- The MPE should ensure increased funding for R&D in decommissioning and facilitate the research.
- The MPE should instruct the NPD to be more proactive with regards to decommissioning.

The rules and regulations that govern the Norwegian oil industry at present have been constructed as a collaborative undertaking by the stakeholders mentioned above. It is crucial that the laws, legislations, guidelines, regulations and recommendations that govern decommissioning are strict enough to make sure that decommissioning is executed in the proper manner, but not too strict. The cost escalates when new and more strict regulations are introduced, and it is vital to avoid overregulation in this area. It is a collective responsibility, involving all regulators, to achieve the adequate level of regulation.

Increased transparency in the industry will most likely reduce decommissioning expenditure in the long run, and the choice of making information inaccessible to the public must be based on sound reasoning. Increased transparency is probably beneficial to the society, who are set to pay 89 % of the decommissioning expenditure through tax exempts. The negative consequences for operators, contractors and subcontractors should be manageable.

CONCLUSIONS AND RECOMMENDATIONS FOR FURTHER RESEARCH

Conclusion

The thesis has shown that probabilistic modelling of decommissioning cost can provide sound results. The cost estimates produced by the model have been verified using cost estimates and actual costs of several completed, ongoing and future decommissioning projects. These verifications show that the model is an adequate tool for an early-stage estimate of the cost of decommissioning a petroleum platform.

The model has been expanded for use in estimating the total decommissioning expenditure of current NCS infrastructure. This provides an insight to the magnitude of work to be completed, and the considerable cost for operators as well as the Norwegian government. This also shows opportunities for the supply chain, and the potential for innovation.

The estimated P50 cost of decommissioning the current infrastructure is 571 billion NOK. As demonstrated in the analysis, the Norwegian government's coverage of this expenditure is beyond the 78 % presumed by most researchers. Through direct and indirect ownerships of companies and licenses on the NCS, the actual figure is 89 %. The scope of decommissioning sees a steady increase – an estimated 159 new wells will be drilled each year for a net increase of 122 wells and estimated P&A costs of 15 billion NOK.

The model estimate is approximately twice the size of estimates based on extrapolation of ARO liabilities and Equinor and Petoro's portion of total production, but quite close to Aker BP's estimates. The comparison to UK Oil & Gas' P50 estimate for UKCS total decommissioning, adjusted for the NCS's lesser scope, is 518 billion NOK – not far off the Monte Carlo estimate.

The UKCS comparison estimate adds credibility to the model estimate. The estimates extrapolated from Equinor and Petoro's numbers may have included the benefits from expected technological advances, which has been beyond the scope of this thesis.

There are significant gains to be made through collaboration in decommissioning. The relative immaturity of the industry and lack of experience has resulted in large project uncertainty and cost overruns are common. There are many pitfalls, and practices to mitigate their effects are presented.

Key external factors are the removal vessel and rig markets. Future developments in the heavy lift/single lift industry have been examined, and cost savings may be achieved through increased competition in this industry. The impact of rig-rates on decommissioning cost has also been examined.

The Norwegian government's role in decommissioning is dual-faceted – they are both owners and regulators. Comparison with the involved government bodies in neighboring countries shows that there is a significant potential for improvement. This thesis argues for greater focus on decommissioning from regulators, increased R&D and most importantly, greater transparency.

The Norwegian government should make increased collaboration in decommissioning a top priority – after all, they will carry the lion's share of the expenditure.

Recommendations for Further Research

- Examine man-hours used combined with weight removed to add another dimension to cost estimation. This was considered, and attempted, but ultimately dismissed due to lack of data.
- More extensive research on pipeline decommissioning. Broad simplifications and assumptions have been made on this aspect of decommissioning due to lack of time and data. Lengths, diameters, age and amount of scaling are parameters that can be analysed.
- The cost-effect of the lack of transparency in the decommissioning in Norway could be investigated.
- The potential benefits of developing a decommissioning strategy and roadmap similar to the Dutch EBN/NOGEPA initiative.

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Note: various sources in this thesis are anonymous. They will be made available to academic evaluators by request and on agreement of confidentiality/non-disclosure.

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https://www.slideserve.com/amato/skarvfeltet-lokale-ringvirkninger-i-nordland
https://www.tu.no/artikler/heder-for-tyrihans/252566
https://www.tu.no/artikler/ormen-lange-et-unikt-undervannsarbeid/261959
https://www.wintershall.no/fileadmin/assets/05_Documents/05.4_Other_PDFs/FINAL__Konsekvensutredning.pdf
https://www.wintershall.no/projects/maria.html
https://www-onepetro-org.ezproxy.uis.no/download/conference-paper/OTC-8084-MS?id=conference-paper%2FOTC-8084-MS
https://www-onepetro-org.ezproxy.uis.no/download/conference-paper/OTC-8084-MS?id=conference-paper%2FOTC-8084-MS
https://www.norwep.com/www.intsok.com/index.php//content/download/33625/243754/version/4/file/Statoil+JC+Tove+Lind+-+norwep_nettverksm%C3%B8te_08.02.18_final.pdf
norskpetroleum.no/en/facts/field/islay

The SSCV Saipem 7000 docked at Mekjarvik, Norway, May 6th 2018. S7000 is a mainstay of the North Sea decommissioning industry. Photo taken by the author

APPENDIXES

Appendix 1: Compilation of Lessons Learned from the Literature

Decommissioning on the NCS should build on lessons learned in the industry. The foundation of this thesis has been a comprehensive study of literature, including Close Out reports, presentations by industry executives, academic research articles and studies by consulting firms – all valuable sources of learning and directions on how to reduce the cost of decommissioning. One of the most important contributors to cost reduction in any industry is the ability to learn from mistakes. In an immature industry like offshore decommissioning mistakes will be made, but the mistakes need not be repeated.

Perhaps even more important is the ability to learn from the successes. These projects should be the benchmark and should represent the best practice in the industry.

In this section the most pertinent and prevailing lessons learned and the main cost drivers and causes for cost overruns are structured and presented.

The lessons learned that are adaptable to the format are presented in a lessons learned matrix.

Main Sources:

- Operators
- Subcontractors
- Foreign branch organizations
- Independent consultants and advisors
- R&D (Academics, pilots)

Main channels:

- Decommissioning Close Out reports
- Other Close Out reports
- Reports from branch organizations

Main areas:

- Project execution
- Concept choice
- Contractual arrangements
- P&A
- Project management
- Collaboration

Key:

Table 26: Color key for lessons-learned table

	Legend
	Operator
	Contractor
	Trade association
	Consultancy firm

Sources:

1. Frigg Close Out report [25]
2. Frigg MCP-01 Close Out report [57]
3. North-West Hutton Close Out report [9]
4. Indefatigable Close Out report [62]
5. Fife, Flora, Fergus and Angus Close Out report [68]
6. Road Testing a Decommissioning Cost Reduction Opportunity Tool [238]
7. Prinsipper for vurderinger og problemstillinger knyttet til fjerning av Frigg [239]
8. Frigg Cessation Project, Jean-Claude Berger, Total SA [240]
9. Frigg Decommissioning, Onshore Disposal, Michael Oram – Total SA [241]
10. H7 Platform Removal Project Presentation - Vidar Eiken, Equinor [51]

11. Dunlin Decommissioning Project Update, Fairfield Energy [242]
12. Brent Project Update [243]
13. Frigg Decommissioning – Contracting Process [244]
14. Decommissioning of Frigg and MCP-01 – A Contractor View [23]
15. Ekofisk 2/4 S Jacket Removal, Saipem [54]
16. Decommissioning Experience – Onshore Process, Veolia Peterson [245]
17. Royal Academy of Engineering – Decommissioning in the North Sea [1]
18. Decommissioning Insight 2017 – UK Oil & Gas [2]
19. McKinsey, From Late-Life Operations to Decommissioning – Maximizing Value at Every Stage [246]

Sources	Project execution	Concept choice	Contractual arrangements	P&A	Project Management	Collaboration
Frigg close out report Norway	The main reason for the cost overrun stems from delays in the topside preparation phase, due to unforeseen hindrances in the operation. This resulted in increased use of flotel and other support vessels.				The main reason for the cost overrun stems from delays in the topside preparation phase, due to unforeseen hindrances in the operation. This resulted in increased use of flotel and other support vessels.	
Frigg close out report UK		Change in removal method in the middle of operations is a poor strategy, as demonstrated on Frigg CDP-1 topside and QP jacket. Proper FEED reduces the probability of changes during operations. If a change must be made at a late stage, it will increase cost considerably			Change in removal method in the middle of operations is a poor strategy, as demonstrated on Frigg CDP-1 topside and QP jacket. Proper FEED reduces the probability of changes during operations. If a change must be made at a late stage, it will increase cost considerably	
Frigg MCP-01 close out report	Operators must be aware of their responsibility to fully complete topside preparation before the removal contractors begin their work. Strategic partnerships with vendors of topside preparation services and prudent risk-sharing and incentives for alignment of goals in DSC contracts can be very beneficial.	Use of new techniques should require pre-qualification. The additional planning and engineering could be detrimental to the project scope.	Reporting of all contractual issues, be it safety, technical or contract related, should be provided by all parties to a contract.		The importance of a thorough preparation, planning and engineering phase prior to actual offshore work should not be underestimated. It should be on a par with construction industry standards.	Reporting of all contractual issues, be it safety, technical or contract related, should be provided by all parties to a contract.
	There should be a system in place for records of the installation, and ease of access to said information. This may not be an issue for newer platforms in the digital age, but older infrastructure requires stringent upkeep of data. This will save considerable resources in the preparatory work.				Decommissioning projects are complex in nature and thorough planning is of the essence. Simultaneous operations are prevalent and a project manager's physical presence at the site is beneficial	
	The HLV/SLV market is limited – decommissioning projects must be worked around the vessels' schedules and operating windows. In the future, the market will likely become even more constrained as the number of projects increases. Planning must revolve around the vendors.				Access to cranes and the reliability of these is a vital component of removal work. Planning should take this into account, in the same way availability of accommodation for decommissioning personnel is. Management of storage space and lay-down areas is key in the preparation and removal process. This should be a part of FEED.	
	Utilize the experience and knowledge of the operating crew on the platform in the decommissioning process. They know their platform. An argument for not delaying the decommissioning process, as crews may have moved on to other employment opportunities.				Labor is a limited resource. Decommissioning has not been appealing career path for engineers, due to the erratic frequency of decommissioning projects. However, there is a lack of personnel with skills in several disciplines required for efficient decommissioning	
North West Hutton close out report	Challenging soil conditions on the sea bed can be a challenge in relation to pipeline decommissioning and may cause cost overruns.					Difficult to perform cost estimation correctly in the initial phases due to lack of available benchmarking data.
Indefatigable close out report	Contaminated waste water after flushing was injected to the reservoir though an injection well. That was a success.	The two small platforms Inde Juliet and Inde Kilo were singled out for piece small due to the number of modules and the relatively low total weight. The concept choice of piece small for these platforms proved to be both safe and efficient But the total number of man hours related to topside removal for these two platforms was exceeded by over 50 % so labeling the topside removal method as efficient may be challenged.	To minimize cost, according to Shell, it was a priority in the project planning phase to facilitate for maximum flexibility in schedule for the contractors in their project execution. The facility removal contract awarded was due to take place between 2008 -2012. This high level of flexibility reduced the cost of removal.			
Fife, Fergus, Flora and Angus close out Report	Subsea mattresses structural integrity should be evaluated before making a decision on removal strategy.			Injection of liquids after flushing can cause problems in the P&A campaign		
	Proper and updated information about the installations are essential			For well P&A the retrieval of the tubing and the logging of the cement is crucial to assess the potential need for section milling and to verify that the well is plugged according to the regulations.		

Sources	Project execution	Concept choice	Contractual arrangements	P&A	Project Management	Collaboration
Road testing a Decommissioning cost reduction opportunity tool by Win Thornton, BP				Plug and abandonment should be performed with formation as part of barrier when adequate clay is present.	The post CoP unmanned period should be minimized.	
				The number of well barriers should be as low as the regulations allow.	The transfer of duty holder in the cleaning and preparation phase could reduce cost.	
				P&A should be performed in campaigns if possible.	During topside preparation flotels are more cost efficient than HLVs.	
				LWIV should be preferred over conventional rigs for subsea well P&A.	There are cost reduction opportunities arising from facilities applicable for derogation, and these should be taken advantage of.	
				P&A should be started well in advance of CoP to help reduce post CoP Operational Expenses (OPEX)		
Total E & P Norge: Prinsipper for vurderinger og problemstillinger knyttet til fjerning av Frigg	Welding of new material to old structures is a challenge.					
Frigg Cessation Project, Jan Claude Berger – Total SA		The development and application of four new technologies was successful, but pilots usually do not reduce cost, rather they increase the cost of a project. Untested technologies are nearly always more expensive.				
Frigg Decommissioning: Onshore disposal, Michael Oram – Total SA			The contract with the onshore disposal/recycling contractor included reimbursement of extra cost when handling hazardous material. This gave the contractor incentives to find and register hazardous waste properly and disposing of it in a safe and efficient way.			

Sources	Project execution	Concept choice	Contractual arrangements	P&A	Project Management	Collaboration
H7 Platform Removal Project presentation, Vidar Eiken – Equinor	Number of lifts and efficient utilization of cranes are essential to decommissioning projects				It takes some time to warm up a new crew.	
					Weather can be a challenge, especially for the smaller lifts	
					The weights of the modules and components are quite often uncertain. The weights of the components need to be calculated or a contingency must be added.	
					ROV's experience low visibility in shallow waters with high currents	
					Dredging can be time consuming and proper equipment is key	
Dunlin decommissioning project update, Fairfield Energy			Revisit existing commercial agreements. This include renegotiating contracts with service providers if possible			
Brent project update, Shell	A lesson learned from topside preparation on Brent Delta was that some teams perform better with regards to execution, efficiency and delivery and that incentives are important	Single lift works and the conservativism regarding the use of single-lift technology seems unfounded.		It is crucial to start P&A before CoP.	The important milestones are hydrocarbon free and demanned.	Collaboration between the decommissioning project, operations and well should be a high priority.
	Another lesson was that the MSF strengthening was too complex and that a reduction in lift points from 8 to 6 is acceptable.	The concept single-lift minimizes offshore exposure and reduce the scope of the project.		Treat each well individually and optimize solution.	It is imperative to down man as soon as possible after P&A.	
	Keeping a high reliability on the utility functions such as cranes, power, HVAC and safety systems is crucial.	If you choose a new technology, plan well ahead		New technology and new techniques are reducing P&A duration and thus reducing OPEX after CoP.		
	CoP reduce some risk and the maintenance can be reduced about 20 % after CoP.	Monitor the market conditions closely and take advantage of opportunities that arise		There is a significant learning effect when it comes to conductor recovery.		
		Secure early input from the suppliers of decommissioning services on alternative solutions.				
Frigg decommissioning – contracting process			Pre-qualification and tender processing could be shortened as the market establishes.		A system of collecting documentation on the installation to be removed proved very useful for the engineering phase of the project.	Pre-basic engineering studies prior to basic engineering involved all major players experienced in offshore construction and marine activities, giving valuable input to basic engineering studies
			Due to the many uncertainties and subsequent risk, lump-sum contracts were deemed inefficient. Lump-sum contracts may not incentivize HSE performance.			

Sources	Project execution	Concept choice	Contractual arrangements	P&A	Project Management	Collaboration
Decommissioning of Frigg and MCP01 – A Contractor View	Prior to arrival of HLV, it is vital to avoid delays in preparation. Significant cost increases will be incurred if extra days are required for lifting.	The heavy lift method, lifting an entire or several modules at once, becomes less desirable the more connections there are between modules			One of the main lessons learned from Frigg is that engineering must commence while the platform is still operational and there is easy access to facilities in order to document as-is condition	Timing is in fact equally important in a decommissioning project as in a development project, even though there is no reservoir income to be generated. The large number of subcontractors, each with their own operating windows, requires project discipline. Concept and FEED studies are crucial.
	Frigg MCP01 had a schedule overrun of 10 months, from the initial schedule of 5. This was mostly due to late access to the platform for surveys, discovery of hydrocarbons in a lot more of the infrastructure than expected, the need to use manual cutting instead of excavators, and insufficient laydown areas. This resulted in the mobilization of an extra flotel.	Cutting before heavy lifts may take longer than expected. Diamond wire saws may get stuck, however, improved shimming techniques alleviated this issue.				
		Horizontal jacking by a few centimeters proved successful and was simpler than vertical jacking. Jacking is a method of checking if a module is in fact loose from the structure and is performed before heavy lifts.				
	10% of the offshore hours were safety related – compiling SJA's, HAZIDS, etc., and extensive safety training.	Piece small removal requires adequate space for excavators to operate and a temporary deck must be constructed. This proved to be an extensive task which caused some delays. Excavator use requires a large safety zone for falling objects, causing working space constraints, hindering manual removal SIMOPS. Overall, there were mixed experiences using piece small removal on the Frigg decom project – the disadvantages outnumbered the benefits.				
		The removal of the DP2 jacket, using attached buoyancy tanks, was a success. However, the engineering and building of the buoyancy tanks themselves ran over budget				
Ekofisk 2/4 S jacket removal, Saipem		Simultaneous subsea work from more than one vessel is undesirable.			Important lessons learned was that using actual models of the structures in the planning phase is beneficial	
		Existing documentation is essential when preparing a decommissioning project.			Change management is central in decommissioning and must be dealt with efficiently and correctly	
					Dangerous to perceive decommissioning as reverse installation as that is not always the case.	
					A good client contractor relationship is essential to achieve the desired outcome.	

Sources	Project execution	Concept choice	Contractual arrangements	P&A	Project Management	Collaboration
Decommissioning experience – Onshore Process, Veolia Peterson					Early engagement between offshore removal and onshore disposal/recycling crew	
					Uncertain schedule can lead to difficulties onshore	
					Change management is important; there are always some surprises.	
					Photo books compiled during offshore removal proved invaluable	
					Tidal ranges are challenging with regards to load-in and must be planned for	
Royal Academy of Engineering, Decommissioning in the North Sea	The learning curve is substantial in decommissioning – lessons learned and focused campaigns may reduce cost by 10 – 15% for successive facilities.	The cost of innovation is high – there will be a so-called "race to be second".				
	Project failures are costly not only for the companies involved, but for the reputation of the entire decommissioning industry.					
	After the implementation of the OSPAR regulations, (post February 1999), design of installations has had decommissioning in mind. However, the numerous modifications performed throughout installation lifetime may not. This adds complexity to the decommissioning scope.					

Sources	Project execution	Concept choice	Contractual arrangements	P&A	Project Management	Collaboration
Decommissioning Insight 2017, UK Oil & Gas		A campaign-based removal approach, potentially including more than one operator, will reduce mobilization cost for the HLV/SLV per structure.	Entering into contracts where several decommissioning activities are bundled into a single contract can reduce cost.	Late-life production should be combined with decommissioning activities to reduce decommissioning duration. In the UK some operators plan to perform P&A on 75 % of the wells before CoP.	Late-life production should be combined with decommissioning activities to reduce decommissioning duration. In the UK some operators plan to perform P&A on 75 % of the wells before CoP.	A campaign-based removal approach, potentially including more than one operator, will reduce mobilization cost for the HLV/SLV per structure.
			Tender processes where the removal method is left open may reduce cost by letting the market divulge the most cost-efficient removal method.	Performing well P&A in campaigns reduce the mobilization cost per well and take full advantage of the so-called learning effect, which is defined by *Decommissioning Insight* as a process where "…incremental improvements in technique can be cascaded across the campaign". Operators report on savings per well of more than one-third in some of the cases where P&A is campaign-based.	Maintenance strategies should be adapted to the changing requirements as a field development get close to CoP. Some equipment may be redundant and other equipment will soon become redundant. That should be accounted for in the maintenance program and maintenance expenditure should be reduced in the period prior to CoP. According to Decommissioning Insight 2017 an optimized maintenance strategy could lead to substantial cost reductions.	
			Flexibility regarding the actual removal date can reduce cost and facilitate increased competition as more vessels are available when the date is not set.			
				A risk-based approach where the P&A strategy is tailor made for each well has been shown to reduce cost for some operators.	Deciding on a CoP date well in advance will improve the Decommissioning planning process. But fluctuating oil and gas prices, new technological advances in Increased Oil Recovery (IOR) and regulatory approval processes may present serious obstacles in the planning process.	
				Cooperating with other operators in multi-operator P&A campaigns can reduce cost.	Deciding whether to stay with a field to the end or to transfer the operatorship in the final stages is an important and difficult decision that should be made on a case to case basis.	
				Investing in new technology can potentially lead to substantial reductions in P&A expenditure. There are several promising technologies that should be developed further.		
				P&A should be performed in the correct order. Minimizing the total distance travelled by the derrick and performing P&A on the least productive wells first will reduce cost and increase revenues.		
				Using rig-less methods or using modular rigs has the potential of saving costs.		
				Removing subsea infrastructure prior to subsea well P&A can save time and money.		
				Using rig-less methods to set plugs, perform logging and assess well conditions in the P&A planning phase for subsea wells give important inputs and help operators choose the optimal P&A strategy.		
				Networking and sharing lessons learnt between operators can potentially reduce P&A expenditure.		Networking and sharing lessons learnt between operators can potentially reduce P&A expenditure.
McKinsey, From late-life operations to decommissioning – maximizing value at every stage					Pooling resources can improve project economics. An analysis by McKinsey showed that costs can be reduced by 25-30% by pooling resources for 4 subsequent decommissioning projects. Mobilization costs were divided by 4, PM and engineering costs were reduced by 40%, and a learning curve effect reduced the final costs by 10%.	

Reports on lessons learned from miscellaneous sources:

Lessons learned that do not easily fit into a matrix

The North Sea's $100 billion decommissioning challenge, Eric Oudenot, Phillip Whittaker and Martha Vasquez, Boston Consulting Group [231]

In their article the authors make an insightful analysis of the challenges related to decommissioning based on their extensive experience as management consultants in the oil industry.

Six areas are pointed out as keys to success in decommissioning:

Strategy and roadmap:

Development of a decommissioning strategy and company-wide alignment around the company's vision for decommissioning and a roadmap describing how to get there. Taking advantage of lessons learned in previous decommissioning projects is central in the development of the strategy. According to the authors a successful decommissioning strategy includes a detailed database, a model for forecasting and a dedicated decommissioning team.

Data availability and quality:

The data on the installations and the wells in the North Sea is the basis for proper decommissioning planning, but there are several challenges related to this crucial component in decommissioning planning and forecasting. Some of the challenges are lack of centralization and different formats. Another issue is that some of the data are of low quality and at times the quality of the data is unknown. Experience shows that cleaning the data and making it available in central databases is a sound investment and make the planning and forecasting less challenging.

Cost estimating methodology and accuracy:

The decommissioning estimates in the early stages of decommissioning projects have a poor track record and as a rule of thumb the expenditure in decommissioning projects end up well over budget.

One of the root causes is the lack of experience in decommissioning and the resulting lack of proper benchmarks in most operating companies. A higher level of transparency and more collaboration between the operating companies could alleviate these challenges. In most cases the industry has the required experience, but individual companies may not have the required experience in the decommissioning area. Due to lack of experience many projects are handled as unique cases, when in fact they are typical decommissioning projects.

Due to the low number of projects that have been carried out in decommissioning the authors point out the importance of taking advantage of experience in decommissioning worldwide and construct a global decommissioning database.

Technical standards:

BCG points out that in some cases the chosen concepts in the decommissioning projects overshoot the target. One example is well P&A where the chosen designs in some cases far exceed the regulatory requirements. Another example is the case of derogation applications, which allow for exceptions to be made if the installations meet certain criteria. Some examples are concrete substructures and jackets with a dry weight above 10 000 tons. According to the article the operators in some cases choose not to apply for derogation even if that is a realistic option and has the potential to reduce decommissioning cost considerably.

Organization and team:

The operators in the North Sea area differ considerably in how they organize decommissioning activities but there are some common traits. All the organizations have a dedicated multidisciplinary team at the core, but the size of the organizations and how they are organized differ.

A central issue in building up a decommissioning team is to attract the right people. Decommissioning projects require team members with strong technical and nontechnical skills and the competition for talents with these skills is fierce. Putting together the right team is challenging. The trend is that operators are now defining decommissioning as a career path.

Contractors:

The growing decommissioning market has received a lot more attention in the last years and is attracting new players who see the potential in decommissioning. This will probably promote more competition and reduce decommissioning costs. New business models, novel contractual arrangements and integrated offerings has changed the relationship between operators and contractors. Joint ventures and duty-holder service contracts are more prevalent. Pre-FEED decommissioning service contracts are also emerging. These trends have the potential to transform the decommissioning industry and reduce costs.

Decommissioning Costs Can Be Reduced [247]

A 60 000 boe field which reduces decommissioning costs by 50 % can increase its overall lifetime NPV by 13 %. Many of the cost drivers may be mitigated in the early stages of a project, where scope is defined. The following cost drivers in each phase of decommissioning are identified:

Phase	**Cost driver**
Preparation, project management	Number of methodology, safety and IA studies
Post-CoP operations	Number of personnel required to support safe operations
Engineering down	Disposal route for hazardous material
Removal of hydrocarbons and cleaning	Standard for hydrocarbon-free post-removal
Cutting of pipes, steel and cables for removal	Size and duration for cutting team
Lifting and removal	Duration of HLV/SLV, support vessel use
Onshore disposal	Location, capacity of onshore disposal yard

Design phase cost reductions:

- Self-contained section of the accommodation module with its own utilities for a decommissioning team. This simplifies the planning and sequencing of removal of quarters modules
- The wellhead deck should be designed with capability of bearing the load of a coiled-tubing rig, giving flexibility in the choice of P&A equipment
- The emergency generator should be capable of generating 1.5 MW of power, so the main generator can be decommissioned
- The design life for facilities should be CoP date plus five years to allow time for decommissioning work
- Easy access to the structure from the sea, so the helideck may be decommissioned at any time
- Efficient hazardous waste removal will aid shutdowns and decommissioning
- Placement of pad-eyes for installation should consider decommissioning, and design for extra strength to account for added weight through platform life
- Use of other materials in gratings that do not deteriorate as quickly

Oil & Gas UK, Decommissioning Contract Risk Allocation [248]

Contractual agreements:

The top risks in decommissioning contracts, when examining impact and controllability, are:

- WoW
- Restricted access to structure
- Uncertainties in volume of drill cuttings pile and content
- Unknown obstructions to pilings cut location
- Changes to removal requirements beyond original scope of work
- Availability of lifting vessel that has been contracted within the agreed period

Risk reduction:

- Early engagement with removal contractors helps towards developing a clear scope of work
- Cleaning the facility to an agreed level of cleanliness mitigates potential pollution risks
- Data uncertainties of the redundant structure can be reduced through more robust data management and documentation process
- Surveying the redundant structure before removal

Risk allocation:

- Pollution risks should remain with the operator when removing a potentially contaminated redundant structure
- Ownership of the structure should be transferred between the operator and the disposal contractor, with the removal contractor only providing a service to remove but not accepting ownership.

Contract type:

- Removal contractors prefer the operator led reimbursable type contract to the lump sum EPRD contract
- In EPRD contracts, operators felt WoW risk should be equally shared between operators and removal contractors, whilst removers felt this risk should be borne by the contractor.
- In EPRD contracts, removers felt the risks in changes to removal requirements beyond the original scope of work should be carried by operators, whilst operators considered that this risk should be shared, but mostly owned by the operator

Suggested areas for contract consideration:

- Large execution windows for removal contractors, where the removal contractor informs the operator when the work can be performed

ABB, Offshore Oil and Gas Decommissioning, 2015 [249]

Project management:

A survey of operators was undertaken, examining the importance of various aspects of decommissioning versus the operators' confidence in their capability in that aspect. The most important aspects, which also had a low level of knowledge, were found to be:

- Financial viability of piece small/piece large removal – there is a lack of benchmarking for piece small removal, and uncertainties in costs of labor, productivity of labor, effects of offshore conditions, cost of vessel hire and cost of decontamination
- Knowledge of contractors – there is a limited number of contractors with experience in offshore demolition
- Health and safety management – collaboration between contractors and operators, to establish common HSE policies is vital
- Environmental management – a clear description of both piece small and piece large removal methodologies must be shared as a standard amongst operators.
- Technical feasibility
- Contractual arrangements for piece small/piece large – the simple contract format when using piece large removal may not be adequate for alternative removal methods.
- Knowledge of technologies available for piece small/large – operators acknowledge they are unaware of the capabilities and technologies that exist in onshore demolition.
- Managing waste and recycling effectively onshore – demonstration of how this is managed is required to provide confidence that it will not become an issue during implementation

Significant cost drivers have been identified: flights to and from installations, accommodation costs and poor productivity due to constraints of weather, safety systems, etc. There is a desire to minimize the amount of work performed offshore. A concept of walk to work vessels has been discussed, with labor transported by ship. These vessels could provide accommodation, craneage, load handling and essential platform services that would allow for early shutdown of platform systems.

Concept choice for removal:

Advantages and disadvantages of different removal methods:

Piece small	
Advantages	**Disadvantages**
Heavy lift vessels not needed, providing greater flexibility around timescales	More decontamination work must be completed to avoid spills of hazardous waste
No long term delays	More hours must be worked offshore
Can start during late life	High number of vessel trips to shore
Sorting of materials can be done offshore	Complexities in timing of decommissioning of essential life support services
Re-sale/re-use items can be removed at an earlier stage and be delivered to end-user sooner	Challenges in working space for equipment and sorting of waste
Greater flexibility in choice of disposal yard	Lack of cost certainty, potential for escalation of costs
	Increased risk of dropping items to seabed

Modular removal	
Advantages	**Disadvantages**
Wider range of HLV's are now available, allowing greater flexibility Smaller number of lifts are required, reducing time offshore Modules only have to be separated for lifting, reducing preparation time and risk of loss of containment Modules can be lifted in a single campaign, reducing risk of delays from WoW Using a support vessel to transport workers is potentially cheaper than flying the workforce to platform Less lifts means less risk of damage to equipment to be re-used/re-sold	Lifting points on modules must be reinstalled or retested The platform may have been significantly modified since original construction. Some equipment may need to be removed to obtain a suitable centre of gravity Depending on the size of the platform and the HLV cranes, the HLV may need to reposition for some lifts Ease of jacket lift depends on installation method – may need strengthening if it is to be tipped for transport to shore

Single lift	
Advantages	**Disadvantages**
The same vessel may be used to remove both topside and jacket Fewer lifts, and no module separation required Less cleaning required, reduces risk of loss of containment Fewer labor hours offshore means less exposure to risk Greater cost certainty	Limited number of SLV's available Additional running costs due to platform being in cold "lighthouse state" for an extended period prior to removal A considerable amount of work may be required to strengthen the topside prior to removal Flare may have to be removed in sections Limited number of yards able to receive heavy integrated decks Jacket may require structural stiffening to prevent collapse when lowering onto transport vessel

Cost estimation:

A calculation of the strategy that offers best value needs to be carried out for each individual asset; there is no one size fits all solution. Many factors come into effect, such as:

- Location of platform
- Original construction type
- Space available
- Equipment/processes on board
- Time of year demolition is taking place
- Age of individual equipment
- Availability of removal methodology
- Distance from site to disposal yard