Decommissioning of North Sea oil and gas facilities

An introductory assessment of potential impacts, costs and opportunities

Background report phase 1
Living North Sea Initiative

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Introduction, objectives and scope

The implicit rationale of the current OSPAR regulation on decommissioning of offshore installations is that it is worthwhile to spend more than 50 billion Euros on removing almost all offshore installations to shore for dismantling and waste handling. Within the Living North Sea Initiative, we take a closer look at this assumption from an ecosystem perspective. What is the expected effect of full removal of oil and gas installations and transportation to shore on the North Sea ecosystem? And what would be the effects of alternative scenarios that might lead to a reduction in costs?
To answer these questions, we establish in Phase 1 facts, uncertainties and knowledge gaps surrounding the decommissioning of North Sea oil and gas facilities. Current regulation is not leading in this screening assessment: we have widened our scope in order to seek for new options. This report focuses on the decommissioning process itself: its potential impacts on health, safety and the environment and the associated costs. Also, we look into the size of cost savings that could potentially be realised by leaving in place more oil and gas structures than is currently allowed for.
The aim of this report is to provide a common knowledge base on the different decommissioning options for offshore installations and their physical, chemical and economic impacts for all participants in the stakeholder process.

Decommissioning

This report focuses on the two extreme options for offshore installations: *leave in place* and *retrieve to shore*. In both cases we assume that the topside is removed to shore and the wells are plugged and abandoned. Other options like partial removal and toppling in place are discussed when appropriate. *Drill cuttings* and *pipelines* have been considered as well, albeit in less detail.

Criteria

The criteria that are covered in this report are*: environmental impacts*; *health and safety* impacts on personnel and shipping; and *financial costs*. As environmental impacts we assessed toxic substances, waste, energy and emissions to air. Impacts on biodiversity have not been treated *in extenso* as these are discussed in detail in a separate report (IMSA 2011c). A weighing of the different impacts lies outside the scope of this report. Such a multi-criteria analysis will be performed in Phase 2 of the project and would use the knowledge from all four background reports.

Key Findings

Installations

	Retrieve to shore	Leave in place	Assessment
Environmental impacts[1]			
Toxic substances	The treatment of hazardous waste onshore potentially leads to emissions of contaminants to land, air or water and occupational health risks.	Potential contaminants in and on a structure that is left in situ have a minimal, yet long-term environmental impact. Most of the contaminants that are released into the marine environment are predicted to stay below concentration levels that are considered detrimental to human health and marine life.	In both cases the impacts of toxic substances appear to be small and manageable.
Waste and resources	Most materials will be recycled. Limited possibilities for reuse of materials and equipment. The residual waste stream (<10%) ends up in landfills. Visual impact of demolition yards might be a concern.	From a material scarcity point of view there is no significant impact.	Retrieval to shore has a larger negative impact than a leave-in-place scenario.
Energy	Large energy requirement stems from marine operations with large case-by-case differences (5-57 GJ/ton for jackets). Recycling requires approximately 9 GJ/ton.	Within the LCA approach, replacement energy of material should be accounted for: 25-30 GJ/ton.	Energy impact is significant in both cases. Large uncertainties preclude general differentiation between options and extrapolation to all North Sea installations.
Emissions to air	Marine transport leads to relatively large emissions of greenhouse gasses and other emissions to air.	Emissions stemming from replacement of material have relatively smaller emission factors.	Depending on the energy assessment, emissions to air could be larger for the retrieve-to-shore than the leave-in-place scenario.
Health and Safety			
Personnel	Removal of steel jackets and footings leads to additional risks for personnel of the same order of magnitude as topside removal or more. For concrete substructures, the additional risks may be unacceptable high.	Top-side removal poses significant, but manageable risks comparable to what is acceptable in the industry.	Leaving in place poses a significant, but acceptable risk on personnel health and safety. Risks increase for total removal, but will be manageable for steel structures. With concrete substructures, this might pose unacceptably high risks.
Shipping	No impacts	Collisions with (fishing) ships might be a major risk in the North Sea for densely trafficked areas.	The leave-in-place scenario might not be possible in densely trafficked areas.
Financial costs			
Jacket removal[2]	Removing the jackets of all North Sea structures will cost approximately €9 billion. This estimate has an uncertainty of ±50%.	Negligible costs. However, when derogated with relocation to a different location, e.g. artificial reef, unknown additional costs arise.	The leave-in-place scenario gives rise to a cost saving of €1-9 billion compared to removal. Relocation of the jackets makes the lower range of this estimate more likely.

1. Seabed clearance and marine-growth removal are treated in *Chapter 6*. As these effects are not considered to be the main environmental impacts, they have not been included in this table.
2. The difference between the two cases has been narrowed down to and is dominated by jacket removal. Full cost analysis is addressed in *Chapter 8.*

Drill cuttings

Drill cuttings piles may be contaminated with hazardous chemicals that slowly release into the marine environment. Leaving drill cuttings in place is currently the preferred method in the decommissioning of a field provided that the pile has been surveyed, characterised and assessed against OSPAR thresholds. Many studies and stakeholder consultation processes have been carried out in order to assess the potential impacts from drill cuttings to the marine environment and to agree on a preferred management option. These studies and consultation processes have resulted in an agreed position of both industry and regulators: it aims at reducing the pollution by hydrocarbons and other substances from drill cuttings piles to a level that is not significant and defines acceptable thresholds of contamination. In 2009 the OSPAR Commission concluded that since no major impacts on the marine environment had been detected, no OSPAR measure had to be developed at that time.
Our research on the environmental impacts of drill cuttings piles does not indicate that alternative approaches to this issue are needed at this time.

Pipelines

The OSPAR Convention does not cover pipeline decommissioning. North Sea countries define their own policies for the pipelines at their continental shelves. In most cases, leaving the pipelines on the seabed is the currently preferred decommissioning option. Trenching of the pipes is possible to prevent possible interactions with other sea-users.
Our research indicates that the impact of possible releases of chemicals from pipelines into the marine environment is small. The assessment for the energy requirements and emissions to air cannot be made due to the same large uncertainties that were found for the decommissioning of installations (see above). Costs of removal are assessed to be large.

Conclusions

The relative order of a number of impacts can be given with reasonable certainty. When an installation is left in place, a number of potential benefits can be expected in terms of reduced costs, reduced risks to personnel health and safety, and reduced impacts from waste handling. The differences between decommissioning options for the other environmental impacts are likely to be small.

With reasonable certainty

- Cost savings are possible when a leave-in-place scenario is chosen over retrieve to shore.
- These savings will be smaller if structures are not left in-situ, but relocated.
- For concrete installations, a leave-in-place scenario in many cases will be the only acceptable case considering the risks to personnel.
- A leave-in-place scenario of steel structures has a substantially lower risk of potential life loss or injury of personnel.
- A leave-in-place scenario will present higher risks of collision with (fishing) ships in densely trafficked areas.

- The impact of toxics released to the environment is small and manageable in both cases.
- A leave-in-place scenario reduces potential waste handling issues resulting from handling large waste streams, like visual pollution and landfilling.
- Both options require a large total energy use resulting in greenhouse gas emissions and other emissions to air.

With higher uncertainty

- Cost estimates are highly uncertain: a margin of ±50% should be assumed.
- Energy use of decommissioning operations, particularly marine vessel movements, is uncertain. Since this is the dominant term in an LCA, a preference for either option based on total energy requirement cannot be given.
- The uncertainty in energy assessment causes potentially even larger errors in the assessment of emissions to air.

Further research

In order to assess the "win-win" possibilities a better estimate of potential cost savings is required, possibly with a wider scope than jackets alone.
In order to perform a multi-criteria analysis better quantitative insight into a number of impacts is necessary. In particular health and safety risks relating to shipping collisions, and the total energy requirement with the associated emissions to air need to be analysed in more detail.

1. Introduction

Since the 1970s, the offshore oil and gas industry in the North Sea has played a major role in the economic development of the surrounding countries. In the coming decades the producing fields will become depleted and platforms and infrastructure will be abandoned.

Current policies and regulations demand complete removal (decommissioning) of structures and transportation to shore, unless derogation is approved under OSPAR Decision 98/3 (Oslo Paris Convention), based on technical complexity, safety and environmental issues.

This decommissioning process implies large-scale removal, cleaning, demolition, and reuse, recycling or disposal of oil and gas installations. In this field of work, a new industry sector is developing, with high expectations regarding employment and profits. Large investments are needed in order to get ready for the amount of work projected, such as investments in heavy lifting vessels, onshore waste treatment facilities and other infrastructure.

Taking structures onshore is technically complex, implies specific environmental and human safety risks, and is costly. Until now, research suggesting that current regulation might not be entirely rational seems to have failed in challenging the dominant truth that "full removal is the best option for the ecosystem/environment". In this study we compare the decommissioning options for offshore structures, "total removal" and "leave in place", in terms of environmental impacts, health & safety risks and costs.

This report looks into the environmental and technical cost aspects of decommissioning and functions as a baseline introduction to all stakeholders.

1.1. Problem definition

From an environmental and socio-economic point of view, it is questioned if complete removal (the decommissioning strategy according to OSPAR 98/3) is necessarily the best option in most cases. With this in mind, current regulation is not specifically leading in this screening assessment: we take on a new approach to seek for new options.

This report provides the background information to answer the following questions:

- What decommissioning options are preferential from an environmental, financial and technical (safety) perspective?
- What could be gained (if anything) by taking a different approach to decommissioning than is currently demanded by OSPAR and national regulations?
- What would be key elements of a new approach to decommissioning; criteria and categories for choice of decommissioning options; issues to be resolved; knowledge gaps?

1.2. Background

The North Sea ecosystem is rather unique in that it is a large area of shallow sea (apart from the most northern part) with large parts of sandy substrate. This has not always been the case, though. Only a few centuries ago, the southern North Sea contained significant areas of hard substrate, in the form of boulders from the ice ages, old surfacing peat layers and large oyster banks. Although this situation has dramatically changed (mainly as a result of fishing but also by natural processes such as erosion), hard substrates still significantly contribute to the biodiversity of the system. Ecosystem structure and functioning are further determined by factors such as water temperature, salinity, currents and human activities.

For centuries the people of the North Sea have benefited from the services offered by this ecosystem, such as: food, energy, transport, a stable, comfortable climate. The growing intensity of human activities – in particular fisheries, toxic emissions and an excess discharge of nutrients from land-based sources – has caused a decline in ecosystem quality over the past decades ("The North Sea ecosystem", LNS128, IMSA Amsterdam, 2011a). In the coming years the intensity of several human activities is expected to increase. Warming waters and acidification resulting from climate change further increase the pressure on the North Sea. Although relatively little is known about ecosystem *functioning* ("The North Sea ecosystem", LNS128, IMSA Amsterdam, 2011a), these developments suggest that the risk of a deteriorated ecosystem functioning and loss of ecosystem services is real. Until now, measures to protect and improve the quality of the ecosystem are not progressing fast enough to be able to halt this trend.

An integral, long-term strategy to assess, potentially restore and revitalise the North Sea ecosystem is a challenge. Many governmental institutions are working hard to design such a strategy, both at national and super-national level. But the process of setting up an integrated management strategy for the North Sea that addresses all the major drivers of ecosystem decline, currently seems to get stuck in stalemates between potential winners and potential losers. The strategy should fill in the lack of knowledge and should aim for consensus about what are the measures that will really lead to improvement of ecosystem quality – and what are the potential effects of new human activities such as the construction of offshore wind parks.

Within the current discourse, there is continuous competition for space and money in a zero-sum game: none of the current users of the North Sea ecosystem services wish to give up their historical rights, whereas the sustainable use of the North Sea demands a gradual transition to different fisheries practices, renewable energy sources, cleaner shipping, protection of sub-ecosystems of particular value and a continued reduction of land-based discharges.

Our Living North Sea Initiative is exploring opportunities to turn the current zero-sum game into a positive-sum game that will help increase societal support for measures that lead to substantial improvement of the ecosystem quality. In the first place we explore the opportunities for using the decommissioning of the more than 500 North Sea oil and gas installations that are becoming redundant as a catalyst for the required change.

In the current discourse, the "dominant truth", in the terminology of Jørgen Randers[1], is that the current OSPAR regulation on decommissioning of offshore installations is adequate. That dominant truth implies that it is assumed to be worthwhile spending potentially more than 50 billion Euros on removing almost all offshore installations to shore for dismantling and waste handling. Within the Living North Sea Initiative, we first take a closer look at this assumption from an ecosystem perspective. What is the expected effect of full removal of offshore oil and gas installations and transportation to shore on the North Sea ecosystem? And what would be the effects of alternative scenarios that might lead to a reduction in costs?

In Phase 2, we plan to analyse, through a multi-criteria model, the opportunities for ecosystem restoration that might arise from alternative uses of some of the billions of Euros that are now reserved for the decommissioning of oil and gas installations. Depending on the outcome of these assessments, the Living North Sea Initiative will set out designing a new positive-sum game for the North Sea; a new game that allows all stakeholders to jointly support measures that facilitate a rapid transition to a sustainable use of this precious ecosystem.

This report is one of four background documents resulting from the first phase of the Living North Sea Initiative, the inventory phase:

- The North Sea ecosystem; Background report Phase 1 Living North Sea Initiative (LNS128, IMSA Amsterdam, 2011a)
- Decommissioning of North Sea oil and gas facilities – An introductory assessment of potential impacts, costs and opportunities; Background report Phase 1 Living North Sea Initiative (LNS200, IMSA Amsterdam, 2011b)
- Ecosystems associated with North Sea oil and gas facilities and the impact of decommissioning options – With attention for local and regional effects; Background report Phase 1 Living North Sea Initiative (LNS214, IMSA Amsterdam, 2011c)
- North Sea legal and policy framework – A dynamic document; Background report Phase 1 Living North Sea Initiative (LNS130, IMSA Amsterdam, 2011d).

1.3. Study approach and objectives

In this study the focus is on knowledge building through data collection (desk research) and interviews, resulting in various baseline reports identifying facts about which there is primarily consensus, uncertainties and knowledge gaps.

Central to the study is an integral approach to North Sea decommissioning, looking at the whole system instead of considering each country's continental shelf separately. We look into a variety of criteria to determine possible impacts of decommissioning options, with a more detailed study of costs and environmental impact.

[1] Randers is professor of climate strategy at the Norwegian School of Management, where his work is concentrated on climate issues, scenario planning and system dynamics. He served as deputy director general of the World Wildlife Fund International. He has authored and co-authored several books and articles, notably the 'Limits to Growth' (1972) with updates in 1992 and 2004.

This study, together with the baseline studies on the North Sea ecosystem and the ecosystems on and around offshore oil and gas installations, will form the basis for the development in Phase 2 of a multi-criteria model on macro-scale: the intention is to be able to design optional strategies for categories of North Sea installations, without having to discuss each individual installation in detail.

This study aims to:
- provide a common knowledge base for stakeholders;
- present a general screening of financial costs;
- present an overview of publicly available technical, ecological and financial data on the status and developments with regard to the decommissioning of the oil and gas infrastructures in the North Sea;
- present selected data and lessons learnt from completed decommissioning cases and additionally from cases that are in preparation;
- present and identify different options for decommissioning versus current decommissioning methods and instruments, including risks and opportunities;
- provide an inventory and interpretation of the opportunities for the second-life use of installations offshore and onshore.

1.4. Report outline

This report is for internal use only, whereby the phrasing “internal” refers to all parties involved in project activities (sponsors, partners, key experts, reviewers). If the sponsors and partners of the Living North Sea Initiative decide to continue into the next phase, the report will serve as input for discussions with a wider group of stakeholders.

Chapters 2 to *4* serve as a general introduction into the decommissioning issue and might be skipped by readers that are already well familiar with this topic. In *Chapter 5* a general description of practice and technologies is given with a definition of the different cases. The different impacts are discussed in the ensuing chapters: environmental impacts (*Chapter 6*), health and safety (*Chapter 7*), and financial costs (*Chapter 8*). Finally, *Chapter 9* presents conclusions and recommendations.

2. The global decommissioning issue

Oil and gas production covers about 60% of the world's current energy need. It has brought many benefits to society and it has a significant impact on our environment in terms of climate change and local pollution with oil and toxic substances. Though new reserves are still being discovered, the larger fields are being depleted or are no longer profitable, and both oil and gas productions are reaching their peaks. Society has to make a transition to new energy sources. As a result of depletion of oil and gas fields, the decommissioning of oil and gas facilities – especially offshore – is a growing issue. The process is driven by a) reservoir production rates; b) the field lifetime; and c) the operating lifetime of the production facilities. The latter can potentially be upgraded to meet appropriate standards, but is, in the end, limited. The mean operating lifetime of an offshore production platform is estimated at twenty to thirty years.

The first offshore oil production activities already started in the nineteenth century in the Caspian Sea, in Japan and along the coasts of California and Virginia. The first offshore structures were accomplished in the beginning of the twentieth century, developing from shallow coastal waters to further seawards on the continental shelves. In the 1940s the industry developed in the Gulf of Mexico, followed by the Persian Gulf, the Venezuela shelf and off the coast of California. In the 1970s the industry grew fast. Large-scale offshore oil and gas exploration occurred worldwide. Many of the currently used facilities were installed in the 1970s or 1980s and have now reached an age of about thirty years. Consequently, in the next decades, the decommissioning of oil and gas facilities will become an urgent issue (Patin, 1999).

Nowadays, the offshore infrastructure has expanded to over 7000 facilities worldwide, comprising many different types and sizes of installations. The deepest platform is a floating spar construction in the Gulf of Mexico (2438 m water depth). The deepest non-floating structure is the Petronius Platform also in the Gulf of Mexico (531 m).

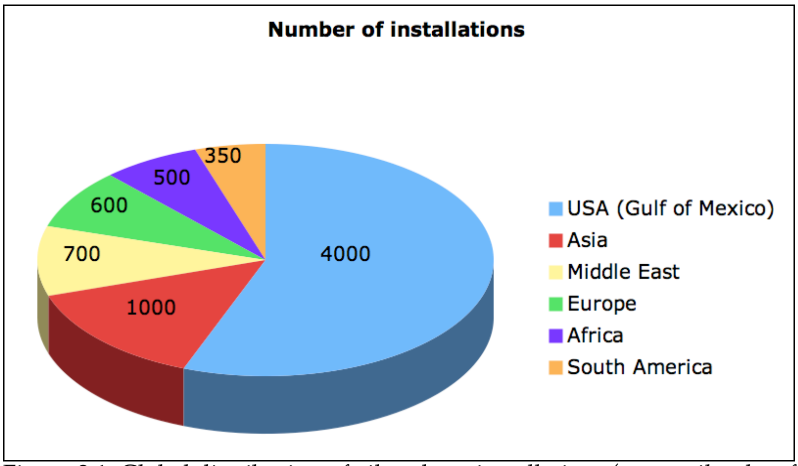

Figure 2.1. Global distribution of oil and gas installations (www.oilandgasforum.net).

In the Gulf of Mexico over 2000 decommissioning projects have been successfully completed, with an abandonment average of 125 structures annually. About 10% of the decommissioned installations were donated to artificial reef programs, while the other 90% were brought onshore for dismantling (Kaiser, 2005). The decommissioned installations at a depth of up to thirty metres are almost always removed to shore. Approximately 85% of the platforms at a depth of 61 to 121 metres were only partially removed or toppled (Schroeder & Love, 2004; Kaiser & Pulsipher, 2005).

In the Asia-Pacific region only 74 installations were totally removed and sixteen partially removed by 2009, despite the fact that 48.1% are more than twenty years old and 11.8% more than thirty years old (Twomey, 2010).

In the North Sea about 60 installations have been removed, including the famous Brent Spar that became world news in 1995, due to opposition of Greenpeace to Shell's plans for disposal at deep sea.

In general the UNCLOS (United Nations Convention on the Law of the Sea) and IMO (International Maritime Organization) regulations are leading and all materials need to be removed: i.e. complete removal of all structures in water depths less than 100 metres and weighing less than 4,000 tons (since 1989). Most regions have additional regulation on top of the IMO agreement, i.e. OSPAR 98/3.

Despite a clear regulatory framework, discussions about the best-fit solutions for removal and disposal of the structures are ongoing. The scope of the process, the high costs, the environmental and social impact, and the complexity of planning all contribute to strongly differing viewpoints among experts and stakeholders (Cripps & Aabel, 2002; Ekins *et al.*, 2005; McGinnis *et al.*, 2001).

3. The North Sea oil and gas industry

3.1. North Sea

The Greater North Sea, as defined by OSPAR, has a surface area of about 750,000 km^2 and a volume of about 94,000 km^3. The basin is deepest in the northern region (> 100 m) and becomes shallower to the south (< 50 m). The central part has depths varying from 50 to 100 metres (Figure 3.1).

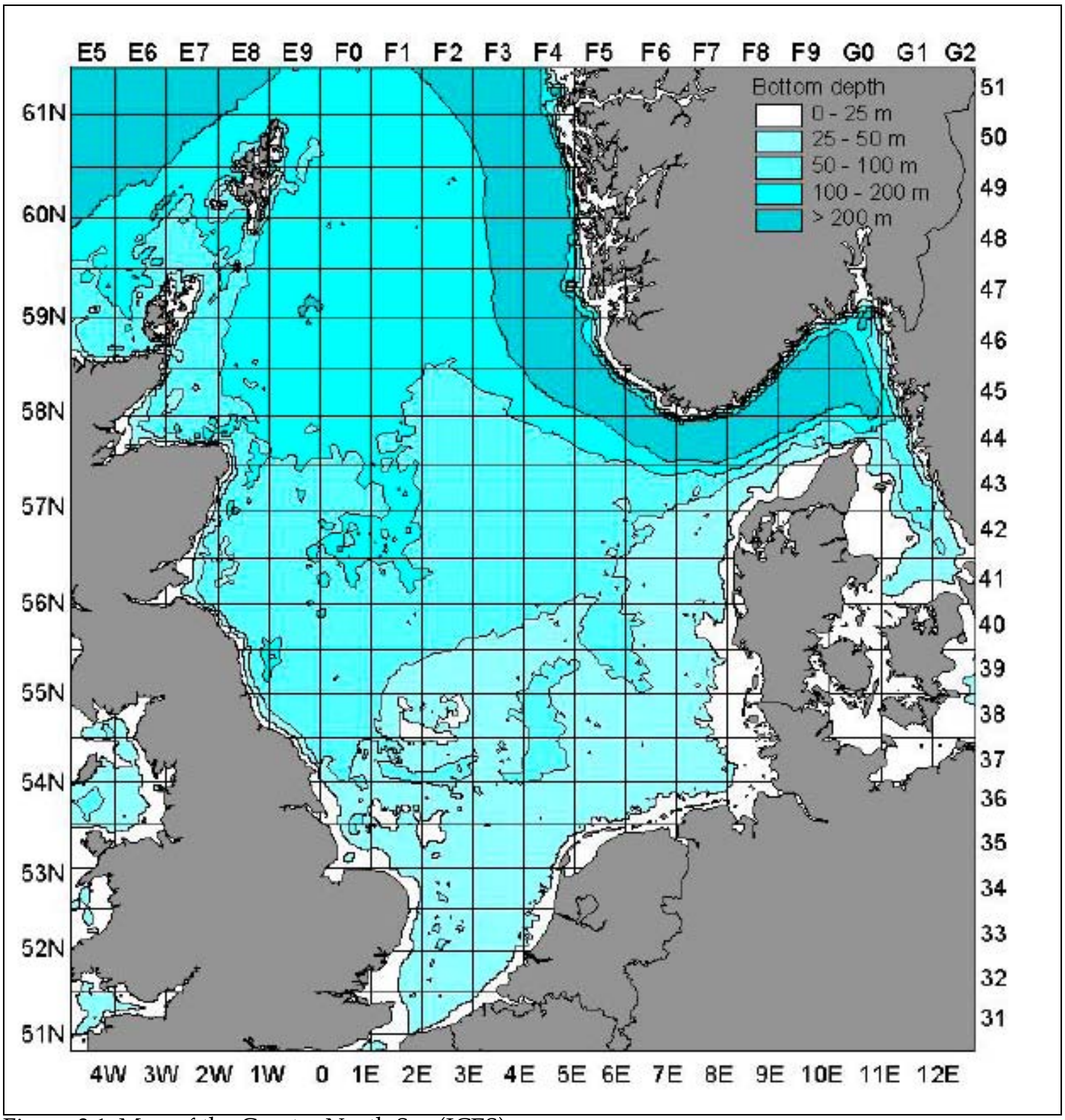

Figure 3.1. Map of the Greater North Sea (ICES).

The sedimentary environment at the sea bottom of the North Sea is dominated by muddy sands, sands and gravely sands and has several muddy habitats. Harder grounds (e.g.

boulder fields) occur in the German Bight and off the coasts of Scotland, Orkney and Shetland.

The northern North Sea (NNS) has some deep parts on the Norwegian side: the Norwegian trench reaches to 270 metres and the Skagerrak to 700 metres. In the NNS region mainly fine-grained muddy sediments occur and especially in the deeper parts the grain size becomes very fine. The NNS contains parts of the Norwegian and the British continental shelves. These coasts typically are mountainous with rocky shores and islands, and deep fjords.

The central North Sea (CNS) is the region north of the Dogger Bank, including the Danish continental shelf and parts of the British and Norwegian continental shelves. The southern North Sea (SNS) includes the Dutch continental shelf, the largest part of the German continental shelf and about a quarter of the British continental shelf. It includes the Dogger Bank, which is a shallower zone with depths ranging from 15 (SW) to 36 metres (NE). It is not a sand bank, but a large shallow plateau. The substrate of the SNS mainly consists of sands and gravel deposits and has overall not much hard substrates. The Cleaver Bank is one of the few areas that contain gravels and coarse sands (BGS, 2001; Smits *et al.*, 2005; Lindeboom *et al.*, 2008).

About 200 million people live in the vicinity of the North Sea, with seven countries directly adjacent to it: the UK, Norway, Denmark, Germany, the Netherlands, Belgium and France. The economies of these countries are strongly connected with three main offshore activities. Firstly, the shipping industry is very intensive and eleven of the twenty largest EU ports are situated at the North Sea. Container transports, ferries and roll on/roll off vessels are the most important shipping activities. Secondly, the commercial fisheries and aquacultures are highly significant to some of the countries (among which Denmark and the UK), although they do not contribute much to the EU gross domestic product (about 1%). Fisheries have declined with 25% from 2000 to 2006, but intensive beam and trawl fisheries are ongoing and still lead to overexploitation of several commercial species. Thirdly, the offshore oil and gas industry in the North Sea produces roughly 80% of the EU's and Norway's combined production (Lindén *et al.*, 2009).

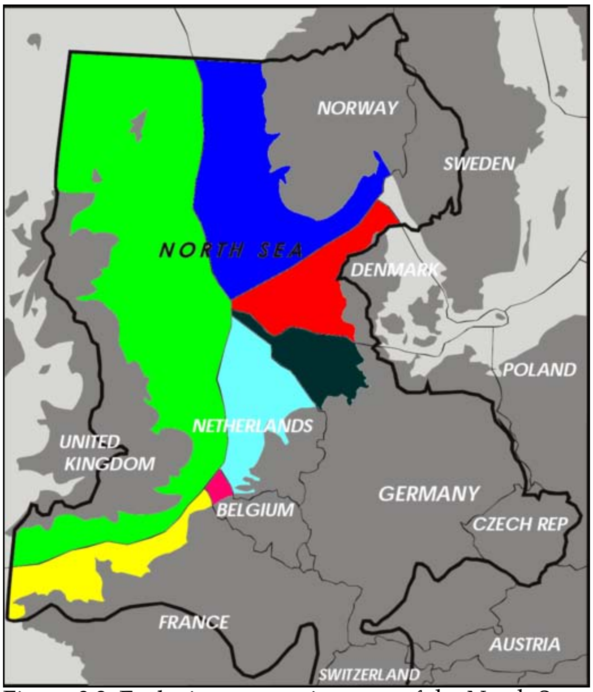

Figure 3.2. Exclusive economic zones of the North Sea (Wikimedia Commons, 2008).

3.2. Oil and gas developments

The development of the North Sea as an oil and gas region only took off seriously after the global oil crisis in 1973, but has its origin in the first commercial oil extraction in 1851, onshore in Scotland. Some years later also in Germany oil resources were discovered onshore. It took another fifty years to find the first gas reserves, again onshore in Germany (1910). In the 1960s first seismic surveys at the British continental shelf started, but offshore exploration did not receive much attention until 1969, when the oilfields of Ekofisk (Norway) and Montrose (UK) were discovered. In the following two years also the Forties and Brent oilfields were drilled.

Norway has the largest reserves, estimated at 54% of the oil and 45% of the gas reserves of the North Sea. The UK is second, with a share of about 30% of the oil reserves. The UK is one of the few countries that became self-sufficient in energy needs. In the early 1980s it even became a net oil exporting country, followed by gas exports about ten years later. Due to decreasing oil and gas production in the North Sea, the UK is an energy importer again since 2004, after two decades of self-sufficiency (Mearns, 2010; www.eia.doe.gov).

The majority of the Dutch offshore fields contain natural gas (~90%). The Netherlands is the second largest gas producer in Europe, after Norway and followed by the UK. The Danish oil and gas industry is exclusively offshore and dominated by oil production: 195 oil wells versus 63 gas wells (DEA, 2007). Since the 1990s Denmark is self-sufficient in its energy supply, also investing heavily in offshore wind energy in the past decade. Germany has a limited offshore oil and gas industry, with only one platform for gas and a single oil field: Mittelplate.

By 2010 the North Sea accommodated approximately 300 oil and gas fields (see Figure 3.3), with an infrastructure of over 5,000 wells, more than 500 platforms, and 10,000 kilometres of pipelines.

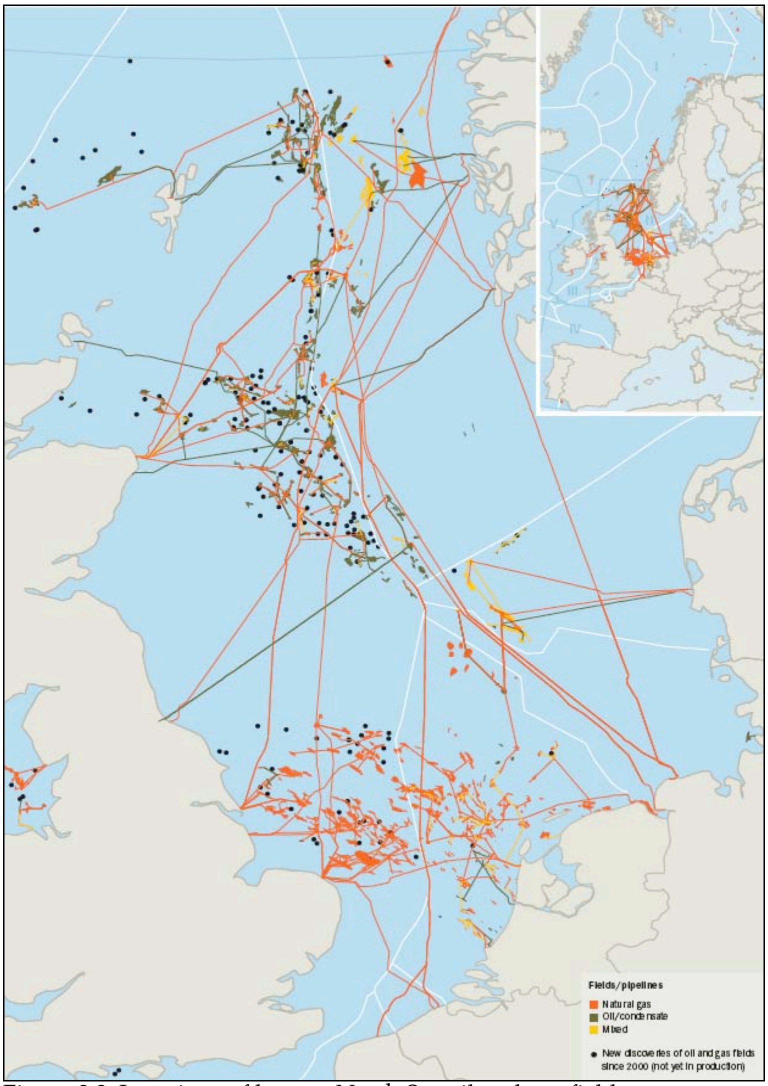

Figure 3.3. Locations of known North Sea oil and gas fields;
green indicates the oil fields and orange the natural gas fields (OSPAR, 2010).

The oil production peaked in 1999 with six million barrels a day. At that time it represented 9% of the global oil production. The UK peaked in 1999, Norway in 2001 and Denmark in 2003. In 2007 this OSPAR region had a total oil production of 205.4 million tons equivalent and a gas production of 172.8 tons equivalent. It is estimated that about half of the reserves have been extracted and that in 2020 production will be at one third of the 1999 peak. The current decrease in production is accompanied with an increase in installations, indicating a trend towards the development of smaller fields (Regional Development Agency, 2008; OSPAR, 2010).

The decline in oil and gas production in the North Sea will have a large impact on the economies of especially the UK and Norway. It is estimated that about 440,000 people in the UK, 75,000 people in Norway and 16,000 in the Netherlands are directly or indirectly employed by oil and gas companies (OGUK, 2010; Nogepa, 2008). The more important operating companies are BP, Shell, ConocoPhillips, Chevron, Total, Statoil and ExxonMobil. And there are many contracting parties, delivering offshore and onshore services for the oil and gas industry, such as Aker, Heerema, and AF Decom (www.subsea.org).

Cooperation within the sector is streamlined by branch organisation such as Oil and Gas UK, OLF (Norway), NOGEPA (the Netherlands) and DEA (Denmark). The national governments are involved in the development of the oil and gas industry, having the responsibility for activities at their continental shelves. For more information on this topic see report "North Sea legal and policy framework" (LNS130, IMSA Amsterdam, 2011d).

3.3. Decommissioning process in the North Sea

In the North Sea decommissioning is still a relatively new activity in comparison to the Gulf of Mexico. Only a limited number of fields have been decommissioned (see Figure 3.4). The industry has started to build up experience, but is still immature and is still preparing for the enormous task of the coming decades. The timing of decommissioning is uncertain as the focus is on extending production. It is also complex, depending on many factors such as oil prices and technological innovations. Investments are postponed, due to market uncertainties[2]. The importance of a well-developed supply chain is recognised, but the urgency is not yet large enough (OGUK, 2010).

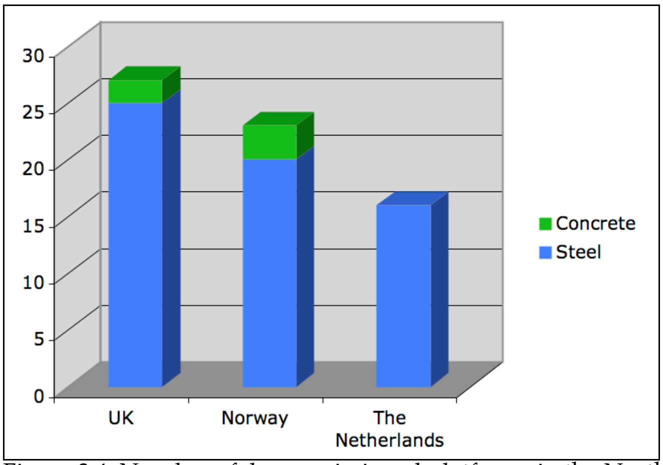

Figure 3.4. Number of decommissioned platforms in the North Sea, according to OSPAR (2010).

Many believe a decommissioning peak to be inevitable. Regulations oblige operators to remove the facilities after cessation of production. The current delays in decommissioning may increase the risk of a peak.

[2] Structures are not left unnecessarily and there are procedures on how to maintain an installation that is no longer in production.

For the surrounding countries decommissioning does not only imply costs for the operators, but also for society. Governments have committed themselves to the development of the industry, including the decommissioning activities. The decommissioning costs are largely tax-deductible. The latter will have impact on budgets of governments, based on current tax laws: 50 to 80% of potential decommissioning costs will be on the account of national governments ("North Sea legal and policy framework", LNS130, IMSA Amsterdam, 2011d). The UK estimates the total decommissioning costs for its continental shelf at GBP 27 billion (OGUK, 2010). Compared to the 2005 estimates of the Scottish Enterprise of GBP 15.47 pounds, the cost estimates have increased rapidly. The increase in costs also reflects the markets and is not just limited to decommissioning uncertainty – for instance if you look at services required for any oil & gas operation, costs have increased by approximately a factor of 1.7 since 2005 (Upstream Capital Cost Index). Figure 3.5 shows the North Sea decommissioning scope of costs per country.

Moreover, an increase in decommissioning costs is accompanied by a decrease in income from the oil and gas industry at the North Sea. Government income and the contribution to national income and employment by this industry will substantially diminish over the coming decades. These developments may have a significant effect on the economies of both countries and in particular on specific regions (i.e. Aberdeen and Stavanger) that are now substantially depending on the oil and gas industry.

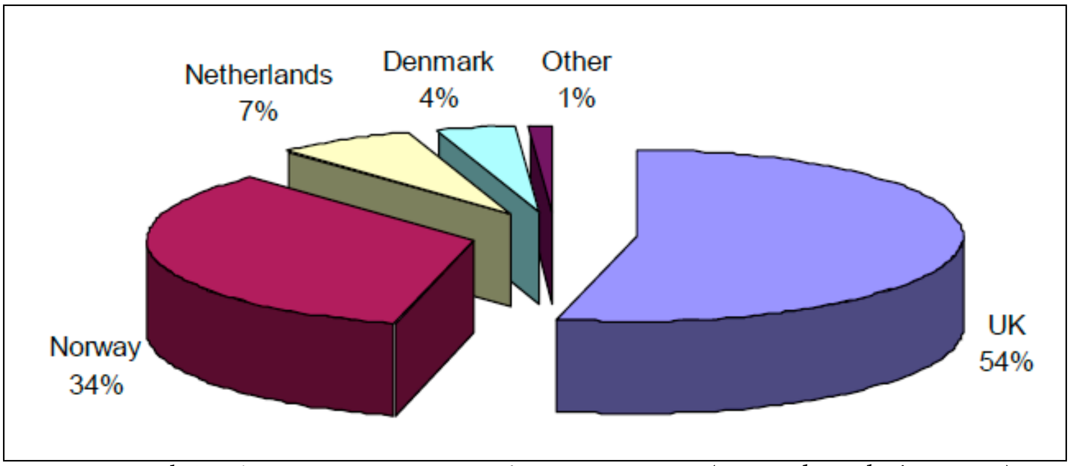

Figure 3.5. North Sea decommissioning scope of costs per country (www.akersolutions.com).

4. Oil and gas facilities in the North Sea

4.1. Infrastructure

In this paragraph we give a short overview of the infrastructure associated with the oil and gas industry in the North Sea. In the following paragraph (4.2) we elaborate on the fixed platforms, which are the structures that are assessed for possible decommissioning alternatives in Chapters 5, 6 and 7.

4.1.1. Facilities

As indicated in Chapter 2, there are many different facilities for offshore oil and gas production. Due to depths and rough weather conditions, the platforms in the central and northern North Sea are in general relatively large, varying from 40 to 300 metres in height. In the southern North Sea the platforms are much smaller, standing in water depths from about 15 to 50 metres. (In comparison: The Eiffel tower stands 324 metres and weighs 7,300 tons, excluding the foundation.)

In this analysis we use data provided by OSPAR (2010). These data sets may be incomplete or contain uncertainties. In an industry that is rapidly developing and on which the available information is scattered, we have to accept small deviations in our figures. The table below gives an overview of the main structures in the region.

Table 4.1. Overview of oil and gas facilities in the North Sea, according to OSPAR (2010).

Country	Fixed steel	Gravity-based	Floating	Subsea
Norway	58	9	11 (1 concrete)	191
United Kingdom	243	10	26	321
The Netherlands	134	1	0	21
Denmark	53	1	0	1
Germany	2	0	0	0
Total	490	21	37	534

- We distinguish two groups of fixed platforms: the concrete gravity-based platforms and the fixed steel ones. These form the focus for this study. In the next paragraph (4.2) we describe the details of these kinds of platforms.

In this report we do not include, for reasons given below, the decommissioning options and criteria for the floating platforms, the subsea systems and the platforms that contain storage tanks or cells.

- Floating platforms can be of concrete or steel. There is only one floating concrete structure on the Norwegian continental shelf. In the UK all structures are of steel. Decommissioning of these systems needs other technology than that of the fixed platforms. Examples of floating systems are the Brent Spar and Hutton TLP, both large, unusual structures that have been decommissioned in the UK already (www.oilandgasuk.co.uk).

- Subsea structures include drilling templates, production manifolds, wellheads, protective structures, anchor blocks, anchor chains, risers and riser bases (Scottish Enterprise, 2005). The use of subsea structures for satellites with connections to existing fixed platforms is increasingly applied in offshore fields. The subsea structures are relatively small, over-trawlable and easy to lift. Decommissioning of these structures is more straightforward in technology and instruments and thus costs, but often divers are needed for securing the lifting systems, which leads to higher safety risks.

- Some of the fixed and floating platforms have storage units. An example is the decommissioned Brent Spar. In case of floating structures these are often called FPSO (floating production, storage and offloading). Some structures in the North Sea have storage capacities. Decommissioning options of these storage cells and their substances are considered on a balanced assessment of impacts. Modern gravity-based structure storage cells are often designed to be refloated and brought back to shore.

4.1.2. Wells and drill cuttings piles

There are more than 5000 wells in the North Sea. When wells are drilled through the seabed, the drill bit cuts the rock; the fragments formed are called drill cuttings. In the North Sea the cuttings consist of sandstone, shale, limestone, anhydrite and/or chalk. During drilling a liquid mud is used to carry the rock fragments to the surface, to cool the drilling bit and to maintain the pressure in the well. This drilling mud is a complex mixture of chemicals that meets the needs of the drilling activity. The muds and cuttings are separated from each other, in order to reuse the drilling muds for new drilling activities (Gerrard *et al.,* 1999).

Three types of muds are used offshore: oil based muds (OBM), synthetic based muds (SBM) and water based muds (WBM). The cuttings used to be discharged at the seabed underneath or adjacent to the platforms, accumulating into drill cuttings piles. In the central North Sea discharge sizes vary from 5,000 to 25,000 tons. In the northern North Sea much larger sizes of piles occur. The largest pile has a volume of about 66,000 m^3.

In the northern region the total volume of drill cuttings piles is estimated at about 1.3 million m^3 distributed over 102 individual piles with an estimated total mass of 2 to 2.5 million m^3. In these deep parts the piles remain on the seabed, while in the southern North Sea they get easily dispersed by wave and tidal action. In this region the piles are smaller and oil-based muds less abundant (Wills, 2000; ALTRA, 1996). The spreading by the energetic tidal regime enhances the rate of degradation of the muds.

Although the mud has been separated from the cuttings, the piles still contain mud that adheres to the cuttings. Both OBM and SBM contain high levels of hydrocarbons, which are toxic to the local marine life. The WBM is less toxic. It mainly consists of water and fine-grained sediments, but may still contain free oil, dissolved aromatic hydrocarbons, heavy metals and radionuclides. Degradation of the muds occurs very slowly, especially when buried. The top layer (6 to 8 cm) decomposes, being exposed to chemical, physical and biological processes. Degradation rates amount to 400 to 600 years.

In 1996 OSPAR prohibited the discharge of OBM contaminated cuttings piles, which largely put an end to use of OBM. Leaving the cuttings in place in their present form is permitted under the UK Department of Trade and Industry guidelines. Many studies have since then been carried out, mainly by the UK and Norway, to assess the potential impacts from relocation of drill cuttings to the marine environment, e.g., UKOAA JIP on cuttings-pile management (UKOOA, 2002) and studies on the cuttings piles of Ekofisk and Albuskjell (OSPAR, 2009) and NW Hutton (CEFAS, 2001). Industry has also set up several consultation processes with other North Sea stakeholders, including governments, NGOs and fisheries, to come to an acceptable process for the management of drill cuttings.

These studies and consultation processes resulted in an agreed position of both industry and regulators. This position is detailed in OSPAR Recommendation 2006/5, which aims at reducing the pollution by hydrocarbons and other substances from drill cuttings piles to a level that is not significant and defines acceptable thresholds of contamination. In another update assessment in 2009 the OSPAR Commission concluded that since no major impacts on the marine environment had been detected, no OSPAR measure had to be developed at that time.

4.1.3. Pipelines

Estimates of OSPAR (2000) indicate a total of rigid and flexible pipelines of approximately 10,000 kilometres. This infrastructure consists of over 1.7 million tons of steel and 2.2 million tons of concrete on the seabed. The coverings consist of tar (~ 5,100 tons) and asphalt (~ 62,000 tons). To protect the steel from corroding, anodes of aluminium (~ 10,000 tons) and zinc (~ 6,500 tons) are added.

Pipeline decommissioning is subject to different considerations than that of platforms. The OSPAR Convention does not regulate the abandonment of pipelines and North Sea countries define their own policies for the pipelines at their continental shelves. In most of the North Sea countries, with the exception of Denmark, industry is required to start a comparative assessment process in consultation with other stakeholders of the North Sea. During this process environmental impact, complexity, safety to users and operators, and costs are examined and balanced to determine the best environmental practice. Chapter 5 describes the available options for pipelines and describes the general practice.

The pipelines differ in diameter and thickness (see annex III). Part of the infrastructure is buried in the seabed; part is on top of it. Especially in the southern North Sea there are smaller pipelines, which are buried to keep them in place. For decommissioning, the smaller, flexible pipelines can be reeled. Less flexible pipelines need to be cut before transport, which can be done by vessel or by making the parts buoyant (Cox & Gerrard, 2001).

4.2. Main elements of fixed concrete and steel platforms

The fixed platforms can be based on steel or concrete legs – or both – which are directly anchored onto the seabed. We distinguish three main elements: a) the topside or the above-water "deck" of the platform, b) the substructure or jacket holding the topside and c) the footing, pinned into the seabed and carrying both jacket and topside.

- Topsides vary in weight from 100 to 40,000 tons. They accommodate equipment, such as injection and gas compressors, gas turbine generators, pipings and drilling rigs. The manned platforms also contain accommodation for the personnel. Some of the topsides are fit for reuse onto another jacket, but in general reuse is low, as the topside legs need to be connected to the jacket structure, which often differs in design.

- The steel jackets in the North Sea are built with one up to eight legs and vary in weight from several hundreds of tons up to 20,000 tons and some even more. It is a space-framed design with tubular members, used in waters with depths up to about 400 metres. Worldwide this type of platform is mostly used (~ 95%). To protect the jacket from corrosion, cathodic protection is applied by attaching sacrificial anodes of aluminium and zinc. Typically they are about 5% of the jacket weight. Paints and coatings are used on the above water parts of the jackets (splash zones) to protect the steel against corrosion.

- Most of the concrete platforms have a base caisson and shafts that support the topside. Common designs are: Condeep design (one, two, three or four columns), Andoc design (four columns) or sea tank (two or four columns). They need less maintenance than the steel jackets. Fourteen of the concrete platforms in the North Sea have storage capacities, the largest ones allowing two million barrels to be stored offshore (OGP, 2003).

- The footings are the lower portion of the jackets. They are pinned into the jacket and through the seabed. They can reach up to 40 m above the seabed (NW Hutton) and they can penetrate 100 m into the seabed. They often represent 50% of the substructure weight.

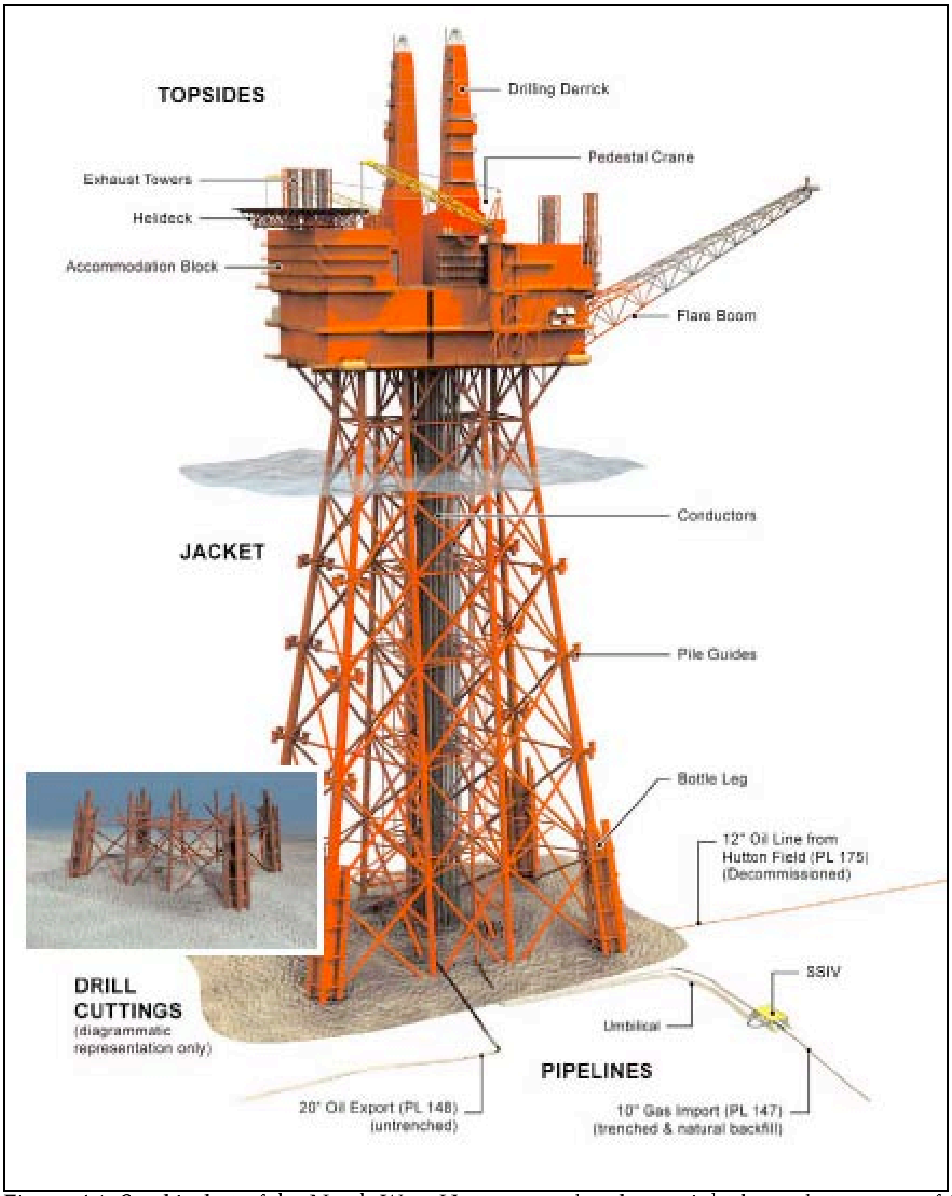

Figure 4.1. Steel jacket of the North West Hutton: an ultra-large eight-legged structure of 17, 000 tons, 144 m of height and with a footing of 40 m above the seabed (BP, 2005).

The costs of platform removal increase with weight and size, due to decommissioning equipment and complex technological solutions. Modern jackets up to 100 m are often installed as a single piece and are most likely removable in one piece. Above 100 m the jackets will need to be cut into smaller pieces for removal, which will add to cost. (The figure of 100 m is simplified; options differ per installation (personal comment)).

In this report we categorise the steel platforms according to the weight of their jackets (Table 4.2), because platforms tend to get larger and heavier with increasing depth. We have used data from OSPAR (2010) and other studies on decommissioning platforms in the North Sea (e.g. Scottish Enterprise, 2005). Next to this, OSPAR applies weight considerations for its derogation regulations. Attention needs to be paid to platforms with jackets that are taller than 100 metres: when decommissioned the jacket cannot be removed in one piece.

Table 4.2. Categories of platforms, classified by jacket weight

Platform group	Weight (tons)
Small steel	0 – 2,000
Large steel	2000 – 10,000
Ultra-large steel	> 10,000
Concrete	> 15,000

The majority of the concrete structures weigh between 15,000 and 350,000 tons (21 pieces). Three structures weigh more than 350,000 tons, all located in Norway. Based on these numbers the structures at the continental shelves of the North Sea can be subdivided as in Table 4.3.

Table 4.3. Overview of platform types per country (OSPAR, 2010; input from Shell UK, Shell Norge and EBN).

Country	Small steel	Large steel	Ultra-large steel	Concrete	Total
Norway	9	42	7	9	67
United Kingdom	162	50	31	10	253
The Netherlands	125	7	2	1	135
Denmark	46	7	0	1	54
Germany	1	0	1	0	2
Total	343	106	41	21	511

In the following chapters we categorize the platforms to define decommissioning scenarios at the macro-level of the North Sea. Categorization is done according to type/size and location of the platforms. As indicated in Chapter 3, we consider three main regions of the North Sea: the northern (NNS), central (CNS) and southern (SNS) region. This subdivision only roughly coincides with the subdivision presented in the other baseline reports (LNS128, IMSA Amsterdam, 2011a; LNS214, IMSA Amsterdam, 2011c). We use the partition in blocks used by the oil and gas industry. The central North Sea is in the north bounded by blocks 1 to 3 (UK) and 30 to 32 (Norway) and in the south by blocks 34 to 39 (UK) and A/B (the Netherlands).

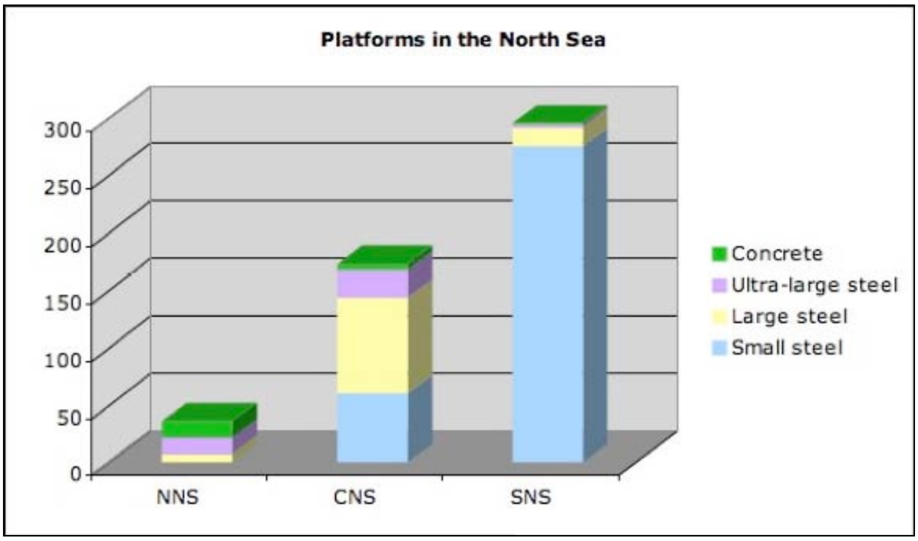

Figure 4.2. Occurrences of platform types in the NNS, CNS and SNS (according to OSPAR database).

4.3. Lifetime of platforms

As mentioned in Chapter 2, the design lifetime of a production platform is about 20 to 30 years. There are many platforms in the North Sea, though, that have their lifetime extended after thorough reassessment. One of the more extreme examples of exceptions to this mean lifetime is the Leman Alpha platform. This particular installation has a total of 42 production years to date. In general, to extend lifetime, thorough inspections and monitoring of the structure's strength and condition are needed before the life of the platform can be prolonged. And due to safety reasons this lifetime may be limited. Figure 4.3 schematically shows the expected ages (annotation x- axis) of the number of platforms (annotation y-axis) in the North Sea.

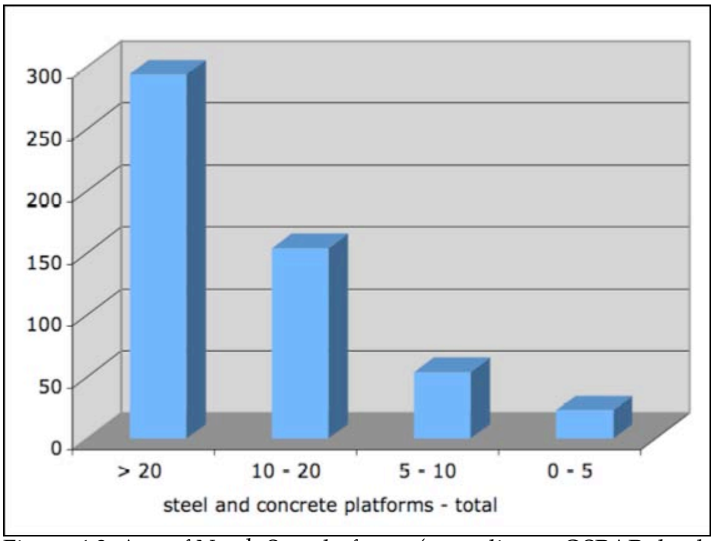

Figure 4.3. Age of North Sea platforms (according to OSPAR database).

X – age of platforms

Y – number of platforms

5. Decommissioning practices and technologies

This chapter deals with the most important practices and technologies for decommissioning. For a brief insight into relevant regulations, see Annex VII.

5.1. Decommissioning process

Based on Picken (1995) & Ekins et al. (2006), unless indicated otherwise.

In this section we describe possible options for the decommissioning of installations with a focus on those aspects that are relevant to the analysis of costs, environmental impact, health and safety. Theoretically a large number of decommissioning options can be envisioned. Picken (1995) discerns fifteen possible operations and four different endpoints for steel jackets alone. Not all combinations of activities, however, make sense from a technical perspective. This is mainly determined by the type of structure (small steel, large steel, ultra-large steel or concrete based) and by the location in the North Sea. Secondly, laws and regulation exclude a number of decommissioning options, described in the law and regulation report ("North Sea legal and policy framework", LNS130, IMSA Amsterdam, 2011d).

In paragraph 5.2 we define three main decommissioning options. This pre-selection is done to simplify the analysis in later chapters. In the next phase of the project a larger spectrum may be used. First, a schematic overview of the general steps involved in decommissioning is given in Figure 5.1. This flowchart is used as a general framework to discuss various alternatives in the following chapters and shows where the focus of the report is placed.

When production has ceased an oil or gas installation can be mothballed – i.e. prepared for future use – for several years. This option is chosen when better circumstances to continue production later are anticipated, e.g. an increase in oil price or certain technical developments. Alternatively an installation can be mothballed to await a new function, e.g. as a station for CO_2 storage (see Annex V for a list of options). Finally, an installation can be mothballed, because the equipment necessary to dismantle it is not available (see Chapter 8.7: decommissioning time scale). Independent of the type of lifetime extension, however, at some point in time the facility must be decommissioned.

We discern three distinct parts of the field that need to be dealt with: the pipelines, the drill cuttings piles and the installation itself. The latter consists of a topside which is either placed on steel jackets or has a concrete gravity base. Depending on which decommissioning option is chosen, part of the structure or the entire structure is removed and disposed of. When (part of) the structure remains in situ, it can either be left standing or be toppled. Depending on the materials, the remains will disintegrate over a long time period (>100 years).

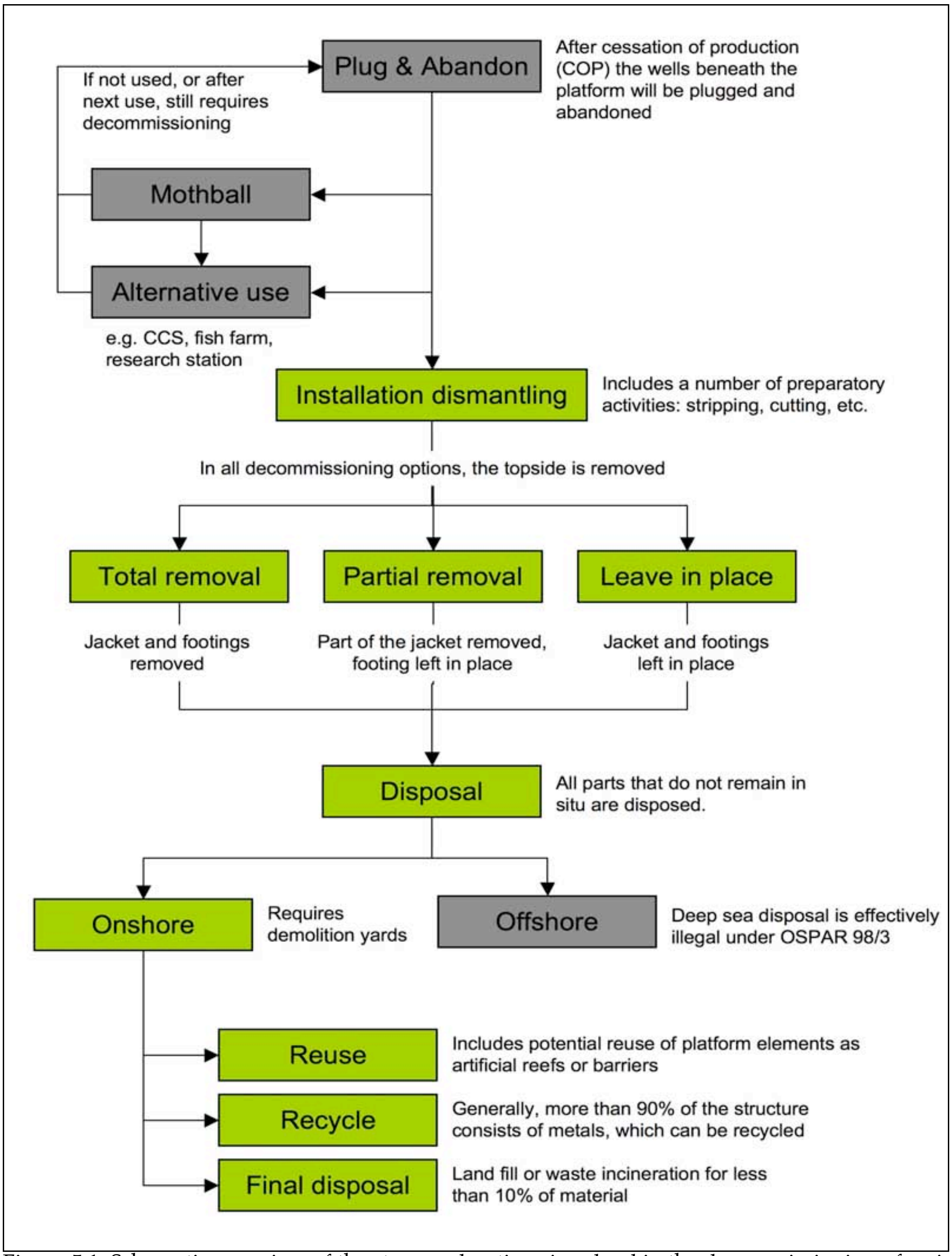

Figure 5.1. Schematic overview of the steps and options involved in the decommissioning of an installation. Drill cuttings and pipelines are treated in the text. The green boxes indicate steps and options that are most relevant to this report. The grey boxes are provided for context, but will not be discussed at length.

For disposal a number of options are available: the structure can either be towed onshore to a demolition yard for further processing or be deposited in an offshore location. When disposed onshore, part of the installation can be reused or recycled while the rest is treated as waste and either incinerated or brought to a landfill site. Offshore disposal, currently forbidden under OSPAR regulations, entails towing parts of the structure to a selected deep-sea site where it will further disintegrate. Alternative reuse of platform structures includes the use as artificial reefs or barriers. In that case a structure is towed to shallower waters, where it provides a solid substrate for an artificial reef. For transfer to a shallow reef, it is possible that structures are grouped to maximise the ecological benefits and minimise transfer costs. The collection of platforms, such as is done in the Gulf of Mexico, enables large reefs and can be implemented to protect Marine Protected Areas (MPAs) from illegal fisheries.

5.2. Main options for decommissioning

5.2.1. Activities common to all options

A number of activities are common to all variants and will therefore not influence the choice between different decommissioning options.

The *wells* have to be closed off, irrespective of the decommissioning option. This involves plugging the wellbore with concrete to avoid future leaking of oil or gas. It takes seven to fourteen days per well, and costs are estimated at a mean of € 1.5 million per well in the southern North Sea (personal information). This figure could be too low for the central and northern North Sea and especially for HPHT wells (High Pressure High Temperature), for which the costs may be as high as € 10 million per well and even examples of € 15 million per well are known.

The plugging should be done carefully: one of the main environmental risks of decommissioning is future oil spill after the wells have been closed off and abandoned (e.g. caused by geological pressures or subsidence).

It is furthermore assumed that in all cases a basic *clean-up of hydrocarbons* from the structure's oil and gas systems (including storage tanks) is performed. Also debris from the immediate surface of the seabed (i.e. not including the drill cuttings pile) will be removed in all variants.

Although it might be considered an option to leave the topside in place, *it is assumed here that in every disposal variant, at least the topside is removed*. According to Ekins *et al.* (2006), all parties seem to agree that for topsides, removal to shore is the only scenario worthy of serious consideration.

Finally for all options, *deep-sea disposal is not considered* here. When disposing at deep-sea, the collection of structures does not have the same positive impact as in shallower areas with higher productivity (see "Ecosystems associated with oil and gas facilities and the impact of decommissioning options", LNS214, IMSA Amsterdam, 2011c). Moreover, it is not likely that governments will allow this option, in view of the Brent Spar experience (Ekins *et al.*, 2006).

5.2.2. Description of main decommissioning options

In Table 5.1 we give a short definition of the three main decommissioning options. This section focuses on options for the dismantling of the installation itself (topside, steel jacket, footing). Drill cuttings and pipelines are discussed separately.

Table 5.1. Overview and description of the decommissioning options for dismantling the structure

Option	Platform*	Description	Endpoints
Leave in place	C, S	The entire installation without the topside is left in place. For this option the integrity of the structure is an important issue. Disintegration of the structure at the shorter (steel) or longer term (concrete) is inevitable. The presence of anodes can enlarge the lifetime, but not prevent collapse.	In situ
Partial removal	S-L	Partial removal is only considered for steel structures and is thought to be too hazardous, as human safety is severely at risk, for concrete structures. After removal of the topside, the jacket is cut to a certain height: either to the footing or to a height that leaves at least a 55 m clear water column. The latter in agreement with the IMO guidelines that specify the requirements for unobstructed passing of ships.	Bottom: In situ Top: onshore disposal with possible reuse offshore (artificial reef)
Total removal	C, S	This option involves removal of the topside, of the jacket and conductors, and of the footing from the sediment. Parts of an installation that are under the seabed and concrete anchor foundations that do not present an obstacle to fisheries do not have to be removed. Concrete structures will be refloated and towed to shore.	Onshore disposal (all structures) with possible reuse offshore (artificial reef)

* C = Concrete, S= All Steel, S-L = large and ultra-large steel platforms

Next to the options discussed above, there is an option to topple the structure in place. Toppling the structure means the topside is removed to shore after which the jacket is knocked over, by cutting the piles or by using explosives. The toppling of the structure is done under controlled conditions, after which it is left at the seabed. This option is only considered for larger steel structures that allow a water column of 55 m after toppling. IMO regulations demand a 55-m clear water column to allow unobstructed passing of ships.

5.2.3. Options for topside removal

After surveying and making an installation safe (upgrading, installing utilities), contractors start removing the topside. This can also include offshore cleaning activities.

There are two main methods for topside removal: modular and piece small[3]. For modular dismantling, the topside is separated offshore in large units that can be lifted off by crane, usually in the form of reverse installation. This requires cutting operations and vessel operations. The modules are removed using large semi-submersible crane vessels (SSCV). Provided the capacity of the lift vessel is large enough, it is also possible to lift the entire topside in one go. This might require extra reinforcement of the structure.

[3] Piece small operations mean that the structures are decommissioned offshore and shipped to shore via supply vessels for further processing, segregation and waste management.

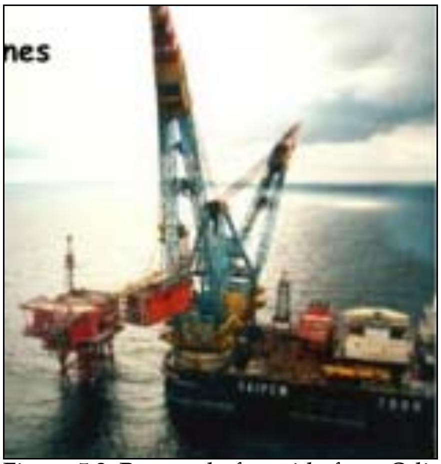

Figure 5.2. Removal of topside from Odin platform.
The 7,700 tons topside is lifted module by module.
Source: Kirsting (Aker Solutions). Presentation for the
Oil and Gas UK decommissioning seminar 12 June 2008.

In the case of offshore piece small dismantling, the topside is stripped down entirely by a workforce living on a (temporary) platform. The topside is cut to pieces that are small enough for onward transportation using the platform's crane and standard supply vessels. This requires a lot more time and cutting operations, but reduces or eliminates the need for large offshore crane vessels. It also allows removing more contaminants offshore by the operator instead of removing these onshore by a contractor.

5.2.4. Options for steel jackets

Apart from leaving the steel jackets in situ, they can be totally removed, partially removed or toppled in situ.

Total removal

Depending on the crane capacity, the legs are either removed in one piece or first cut to smaller pieces. They are then lifted and transported to shore. Alternatively the jackets can be refloated. This requires substantial additional buoyancy. On Frigg, for instance, to remove 9000 tons additional buoyancy tanks had been constructed, which themselves weighed 5000 tons.
In all cases, the jacket need to be severed from the seabed or from its footing. When one-piece removal is not an option, additional cuts need to be made. Under water, steel could be severed either by shearing, explosive cutting, diamond wire or abrasive water jetting (see Figure 5.3).

Figure 5.3. Abrasive waterjet cutting.
Presentation for the Oil and Gas UK decommissioning seminar 12 June 2008.

Partial removal

Partial removal of the jacket would involve removing the upper part of the structure to provide a draft for shipping of at least 55 m. Cutting above the footing and leaving the footing in situ is also considered a partial removal. Activities include cutting the steel legs and lifting and removing the top-part as described above for total removal.

Toppling

The procedure for toppling a steel jacket entails partial cutting of the underwater structure, so that it would fall, or could be pulled over, onto the seabed. The main aim of this operation would be to provide the required 55 m clearance for navigation above any remains on the seabed. Before OSPAR 98/3 there was a major research effort on toppling conducted for NW Hutton, but since then it has not been an acceptable option, as leaving a jacket behind on the seabed was considered as dumping.

5.2.5. Options for concrete gravity-based platforms

This paragraph is based on OGP report #338 (2003)

The early installations installed in the 1970s with a concrete substructure were not designed to be removed after abandonment. Although later concrete installations include provisions for future removal, the extent of possible obstacles and hazards that might occur during decommissioning may not have been appreciated fully in the original design. For ultra-large steel installations and concrete gravity-based structures, derogation under OSPAR 98/3 may be considered.

Many concrete structures provide storage facilities for oil at an offshore location. Oil-storage capacities are typically in the range of 400,000 to 2,000,000 barrels. A leave-in-place variant may require flushing and cleaning of these storage tanks to reduce the content of hydrocarbon and other contaminants to an acceptable level. Furthermore the topside would have to be removed as described in Chapter 8.3.

The total removal of concrete gravity bases would involve freeing them from the seabed (by breaking the suction that exists between the base of the structure within the skirt and the seabed), and refloating them by deballasting the storage compartments. Theoretical calculations have shown that this is possible, but no such exercise has yet been undertaken.

Partial removal of a concrete gravity base is theoretically possible, but presents so many technical difficulties and hazards that so far it has not been considered a serious option.

5.2.6. Options for pipelines

This section is based on NPD (2000), Ekins et al. *(2005), and Picken (1995)*

This category includes export pipelines and infield lines. The latter may be split in a steel and flexible category. OSPAR 98/3 does not cover pipelines and regulators consider them on a national basis, case by case. Next to leaving the pipelines in situ, they could be trenched, covered or buried out of regard for other sea users. Alternatively, the pipelines and cables could be removed, i.e., lifted and recovered for the purpose of reuse, recycling or deposit.

Current practice for decommissioning in the North Sea is to consider a comparative assessment between options to determine the most appropriate solution for regulator approval. Smaller lines are typically trenched or buried to provide protection and avoid/minimise buckling risks during operation.

Leaving in place as is

This option requires no other measures than purging, flushing if needed, plugging and securing of the free ends. However, out of regard for other users of the sea, it may be desirable to keep some control over pipeline degradation. Exact knowledge on the course of degradation is lacking and will depend among other things on the materials, the presence of protective anodes and the amount of coverage. Degradation and final collapse will most likely occur at different places during a long course of time. The experience with operating pipelines that lie on a sandy seabed shows that most of them tend wholly or partially to “burrow down on their own”. Pieces of broken pipeline will be a hindrance in areas where productive fishing with bottom gear like trawl and seine net takes place.

Leaving in place with safeguarding measures

Pipelines laid on the surface of the seabed or remaining partially exposed in unfilled trenches, could be buried completely to eliminate any potential interactions with other users of the sea. Two main methods are available: 1) covering with gravel and/or rock and 2) burial. For the second method a trench is excavated in which the pipe is placed. This trench will fill with natural covering over the course of a few years. If natural backfilling does not take place or takes too long, natural sea bottom masses can be ploughed back.

Recovery

All flexible and some rigid lines could be retrieved by a reversal of the laying process, with the pipe either wound on to very large reels on the deck of a vessel, or cut into appropriate lengths as it is hauled in over the stinger. Such an operation would require a pipe-laying vessel or similar to work down the pipeline route, deploying an anchor pattern at frequent intervals to hold the vessel in place while the pipe is retrieved. The steel in pipelines can be remelted and recycled once the concrete and asphalt have been removed. Pipelines, especially gas pipes, can be used as conduits for cabling after they have been cleaned from hydrocarbons.

5.2.7. Options for the treatment of drill cuttings

Drill cuttings piles are the solid waste discharges that were created during drilling of the wells. These piles are contaminated with hydrocarbons and often contain traces of heavy metals, PCBs and naturally occuring radioactive material from the bed and cap rock.

The UKOOA (2002) report identifies a number of management options for drill cuttings piles. The choice for a certain option will depend on the nature and volume of the hydrocarbons within the particular pile, the local hydro-geographical situation, and the local facilities available for supporting a particular option.

The industry currently assesses the issue of drill cutting removal case by case. There are different options to deal with drill cuttings piles: 1) *leave in place* (uncovered, covered, dispersed) or 2) *remove from the seabed* (re-injection, treatment on land). At present the drill cuttings are most often left in place, since this is considered the best available environmental option. A selection of the potential treatment options for drill cuttings, which are taken into consideration, is discussed below. Offshore bioremediation is not considered here, as this option is considered not attractive for practical reasons (Ekins *et al.*, 2006,; UKOOA, 2002).

Leaving in place

Drill cuttings can be left in place or be covered with sand, concrete or textile matting. Degradation is slow, especially when buried and anaerobe conditions apply. It can take hundreds of years before the OBMs in larger cuttings piles will degrade. Leaving the drill cuttings in place, the contaminants will degrade naturally, which is considered sound from an environmental perspective. It may raise issues of extra costs, long-term monitoring, liability and public perceptions. Whether it is acceptable to leave the drill cuttings piles in place mainly depends on future uses of the seabed.

Removal from seabed

Total removal of the drill cuttings from the seabed can be achieved by either pumping or dredging. The simplest treatment would be to landfill the solids. However, as discussed in Chapter 6, this might not be what is considered best environmental practice (UKOOA, 2002). Lakhal (2009, p. 119) mentions some options for reuse of cuttings (road surfacing, construction materials, source of fuel), but these are at present not financially viable and therefore very uncommon. (Assessments on waste, landfill, recycling and incineration can be found in Chapter 6.7 on “Waste and resources management”.)

With *re-injection* drilling wastes (fluids and cuttings) are injected back into the sub-surface. This technology is not applied often and might not be possible for all platforms. In the UK it would be considered unacceptable to transport material to another platform for re-injection. Re-injection is considered as technically feasible for fresh cuttings, but possibly not for older drill cuttings piles. It involves grinding the cuttings and preparing a fine slurry which is then pumped down wells, prior to their abandonment. The process is performed entirely offshore and produces little if any waste (Picken, 1995).

5.3. Disposal options

The parts of the structure that are removed from the seabed could potentially be disposed of onshore or offshore. The latter is effectively forbidden under OSPAR regulations.

5.3.1. Onshore

Onshore demolition is carried out in so-called demolition yards. An overview of current demolition yards around the North Sea is given in Table 5.2.

Table 5.2. Overview of current demolition yards around the North Sea

Country	Location	Contractors	Capacity (tons/year)
Norway	Eldøyane	Stord Aker, Scanmet	50,000
	Vats, Vindafjord	AF Decom	
	Lyngdal	Lyngdal Recycling	
United Kingdom	Lerwick, Shetland	Veolia, Peterson SBS	20,000 – 30,000
	Peterhead		
	Teesside (TERRC)	Able Group	
	Wallsend (North Tyneside)	Veolia, Peterson SBS	
The Netherlands	Vlissingen	Hoondert	
	's Gravendeel	Hapo	

Future expansion of demolition yards

In Norway Lutelandet offshore will be constructed. The UK has several options but all are uncertain: Dales Voe, Nigg, Loch Kishorn (west), Middlesborough, Great Yarmouth, etc. Scottish Enterprise has bought twelve hectares of coastal land in Peterhead, north of Aberdeen, in May 2010, which may be used as a demolition yard in the future. In the Netherlands there are plans for yards in Delfzijl, Port of Rotterdam (Henk Poot) and in IJmuiden (ROS Holland).

The current Norwegian waste handling capacity is sufficient to handle offshore installations until around 2020. After 2020 the amount of waste material to be handled is expected to increase to such an extent that major investments need to be done in improving current waste handling facilities and in building new ones. Uncertainties about the need are substantial: the exact time of abandonment depends on various factors (oil price, technology development, etc.); and waste handling facilities in other parts of the North Sea, e.g. in the Netherlands, are uncertain (KLIF, 2010).

Demolition yards and recycling capacity are not yet expected to be of influence on the decommissioning peak. The eventual shortage of demolition yards is not considered to be a showstopper in current studies: the peak will, among other things due to this potential shortage, spread itself out, sites could be reinstalled, ship building yards can easily be transformed and expertise can be bought in. Demolition yards are therefore not likely to be a constraint; the major concern remains the heavy-lift market.

5.3.2. Offshore

- Material destined for offshore reuse (artificial reef) could be transported to the selected site by refloating and towing, by barge, or on the deck of a lifting vessel. Final release at the site could be accomplished by various means. The reader is referred to the report on "Ecosystems associated with North Sea oil and gas facilities" (IMSA Amsterdam, 2011c) for more information.

5.4. Vessel operations

The types and numbers of vessels that would be required to complete any of the foregoing operations will vary from structure to structure and from one option to another. During decommissioning, marine operations will take place at the site of structures, along the pipelines and at any location for offloading materials to the shore.

The vessels that are likely to be used at one time or another during operation would include heavy lift vessels, semi-submersible crane vessels, barges and tow boats, supply boats and dive vessels

Table 5.3. Main categories of decommissioning vessels

Type	Activities	Capacities (approximates)
Construction vessel	Subsea installations, ROV operations, deck space, often multiple cranes.	230 tons bollard pull. Deck load 15-20 mt/m^2.
Support vessel (equipment)	Installation, testing and maintenance. Heave crane(s).	Lifting 100 – 400 tons.
Crane vessel	Loading, balancing.	Tandem lift of 9,000 short tons max. Deck load of 8,000 tons max.
Tug	Transport (towing).	160 tons bollard pull.
Barge	Transport.	8,000 – 130,000 tons.

The availability of heavy lift vessels is expected to become critical for the decommissioning of the largest structures. There is only a limited number of these vessels, and there are concerns that not enough capacity will be built before the decommissioning peak sets in. Therefore it might occur that a platform cannot be decommissioned in the preferred way at the preferred time. This implies that a platform will either have to be mothballed or be dismantled in smaller units. The consequences for the decommissioning costs will be discussed in Chapter 8.

5.5. Experiences with decommissioning in the North Sea

Table 5.4 shows what is decommissioned already in the North Sea (OSPAR, 2010).

Table 5.4. Overview of structures decommissioned (OSPAR, 2010).

Country	Small steel	Large steel	Ultra-large steel	Concrete	Total
Norway	6	12	2	3	23
United Kingdom	21	2	2	2	27
The Netherlands	16	-	-	-	16
Denmark	-	-	-	-	0
Germany	-	-	-	-	0
Total	43	14	4	5	66

In this study we use two cases to learn from the considerations that were made on the main criteria of technology, environment, safety and costs. All these structures are ultra-large steel or gravity-based concrete platforms that were considered for derogation to OSPAR 98/3.

Table 5.5. Overview of the decommissioning programs of selected cases (see annex II for more information).

Facility	Decommission category	Topside	Jacket	Footing	Drilling muds	Pipelines
NW Hutton	Partial removal	Removal to shore	Removal to shore	Cut off to 40m, left in situ	OBM, left in situ.	Left in situ
Frigg	Partial removal	Removal to shore	Steel jackets: Removed to shore. Concrete substructures: left in situ.	Removal (of steel jacket footing) to shore	WBM, left in situ. Only 2 wells drilled. OBM, cleaned and disposed on seabed	Left in situ

6. Environmental impacts

All decommissioning options have an environmental impact. Leaving structures in situ per definition leads to emissions to water. Even if all contaminants were to be removed, the disintegration of the structure itself over time will release substances to the marine environment. On the other hand, if all man-made structures were recovered to shore, there would still be impacts from the onshore waste handling and the emissions to air from disposal activities. Thus, irrespective of the scenario chosen, there will always be a non-zero environmental impact.

However, an important distinction exists between removal to shore and options that leave some part of the structure in the marine environment: removal gives more control over the way contaminants are released into the environment and means dealing with the environmental impacts in a timeframe of a few years. Leave-in-situ scenarios mean less controllable potential environmental hazards for hundred years or more. For these and other reasons, environmental NGOs like Greenpeace are against leaving man-made structures in the marine environment even if in quantitative terms the environmental risks are of the same order of magnitude as total-removal scenarios. Oil and gas production companies will in many cases – for liability reasons – prefer to clean up as well to prevent future damages and the associated bad press this might generate.

This chapter discusses the main environmental impacts related to the decommissioning activities "total removal" and "leave in place": toxic substances in/on the structure; drill cuttings piles; marine growth on the structure; seabed clearance; energy use and (greenhouse gas) emissions; waste and resources management. Please, take note that possible positive environmental impacts of a leave-in-place scenario are not treated here. The biodiversity effects of (removal of) the ecosystems that have developed on and around the structures are dealt with separately in much more detail in the report "Ecosystems associated with North Sea oil and gas facilities and the impact of decommissioning options" ("Ecosystems associated with North Sea oil and gas facilities and the impact of decommissioning options", LNS214, IMSA Amsterdam, 2011c).

The different environmental impacts and risks are difficult to establish with high certainty for all biological hazards and only crude estimates are available for greenhouse gas emissions. To complicate matters further, the impacts are mostly incomparable: hydrocarbon residues leaking from drill cuttings will have a small, but long-term, local impact on marine ecology, whereas the CO_2 emissions during decommissioning activities have an impact on the global climate. Finally, there is no generally accepted method that allows comparison of environmental criteria with cost or health and safety risks.

6.1. Contaminants from the structure

There are different types of toxic wastes present on the structure elements of platforms. The types and amounts of contaminants on platforms are always uncertain and need to be determined on a case-by-case basis (KLIF, 2010, p. 16).

Many types of contaminants are present on the topsides and in accompanying equipment. For all decommissioning options it is assumed that topsides and associated equipment are removed and that components that are left in place are cleaned. The following paragraph, therefore, only discusses hazardous wastes that are found on or near the structure elements and which are potentially left in place.

Sacrificial anodes

The jackets and footings are protected against corrosion by cathodic protection provided by sacrificial anodes. The anodes are either welded onto the jacket legs or placed on the seabed and connected to the jacket legs by copper wire. The anodes are made from zinc or aluminium and contain traces of contaminants, including bismuth, cadmium, copper, indium, lead, iron, mercury, silicon and titanium (Picken *et al.*, 1997, p. 10).[4]

The sacrificial anodes emit zinc or aluminium to the water. Over the last ten years the use of mixed anodes or aluminium anodes was stimulated, which has led to a decrease in zinc of about 35% (Oranjewoud, 2008). Combined with the figures for the Dutch continental shelf of 2001 (URS) it is estimated that per platform, depending on the amount of anodes needed (related to amounts of steel), per platform 52 to 88 kg zinc is released annually (IMSA Amsterdam, 2011, p. 12).

During production the anodes already cause emissions of zinc and aluminium and other contaminants to the surrounding seawater. These emissions will continue to take place if the platforms are abandoned and left in place. Marine organisms living near the anodes have already adapted to these emissions during the operational phase of the platforms. The average sacrificial rate of anodes is estimated at 4%/y (URS, 2001, p. 77). The release of zinc and aluminium and other contaminants will be highest during the first 20 years of abandonment, after which the emissions will steadily decrease. After approximately 40 years all the anode material will have dissolved (Picken *et al.*, 1997, p. 10).

The environmental effects of the contaminants are highly dependent on concentrations of contaminants, dispersion and fate of contaminants and on the specific ecosystems in which release takes place. The contaminant concentrations will decrease with increasing distance from the site of deposition. Peak concentrations of contaminants, however, would be very low, even near the deposition site. Zinc and aluminium will dissolve in seawater and will be dispersed over a wide area. The remaining flocs will be essentially inert (Picken *et al.*, 1997, p. 4). There will be some effects on local organisms, but the impact is expected to be low. Marine organisms living near the anodes have already adapted to these emissions during the operational phase of the platforms.

[4] For anodes that consist for 95% of aluminium and 4% of zinc.

Potential environmental impacts of the dissolution of sacrificial anodes can be prevented by removing them. This enables recycling of the aluminium and zinc. Especially zinc has high economic value. An integrated assessment for potential removal of the anodes, however, is needed to compare the environmental impacts and the benefits of removal with health and safety risks and costs.

Radio-active waste

On some of the adjacent tanks, pipelines and process systems of Oil & Gas structures in the North Sea radioactive waste is found. In many geological formations naturally occurring radioactive material (NORM) is found, e.g. low concentrations of radium. Oil and gas drilling brings the NORM to the surface where it ends up in scales and sludges on and within drilling and processing equipment, mainly in the piping systems, tanks and well casings. At the equipment of oil installations larger amounts of radioactive material are found than at gas equipment, since the radioactive scale is combined with deposits of barium sulphate from seawater breakthrough in produced water (KLIF, 2010, p. 17).

The NORM scale is removed and disposed of either offshore or onshore. KLIF has calculated, based on Norway's finished decommissioning projects, that large platforms generate between one to three tons of radioactive material dependent on their size. It is expected that 288 tons of radioactive scale will come of the platforms and steel structures which will be decommissioned in respectively Norway and UK between 2010-2020 (KLIF, 2010, p. 18). Most of the scales and sediments will have activity concentrations above 10 Bq/g (KLIF, 2010, p. 19). There are no such data about the platforms of other North Sea countries or the platforms that will be decommissioned after 2020.

Common methods for removing NORM-contaminated scale are high-pressure water jetting, mechanical scraping or scrubbing, chemical cleaning or sandblasting (KLIF, 2010, p. 15). The radioactive substances have to be stored, handled and disposed of carefully to prevent that workers in the oil and gas or waste and recycling industry are exposed to high radioactive concentrations. In Norway new regulations on NORM came into force on 1 January 2011 (KLIF, 2010, p. 7). The NORM has to hand over to facilities that are permitted to handle and store radioactive waste. Table 6.2 shows the difference between the environmental impacts of contaminants on the structure for the decommissioning options of "total removal" and " leave in place".

UKOOA (2002) concluded that the presence of NORM and other contaminants was not likely to result in adverse effects on biota present in the water column. Picken (1995) quotes a significant body of research that shows that in general there is no deleterious effect to be expected in populations of marine organisms. Further research on food chain impacts is needed (Ekins, 2005, p. 426).

Hydrocarbons

Large amounts of residual oily sludges often remain in tanks, pipelines and process systems (Lakhal *et al.*, 2009, p. 121). If these components are not cleaned properly, they can be released in the seawater, also releasing polycyclic aromatic hydrocarbons (PAHs). Components that are left in place have to demonstrate an acceptable impact over a range of categories of contaminants. Hydrocarbons (as well as other categories of contaminants) have to be cleaned to the degree where defined threshold levels are not exceeded. The hydrocarbon residuals are treated onshore. The organic material in hydrocarbons is destroyed by thermal technologies (Lakhal *et al.*, 2009, p. 119).

Paints and coatings

Few platforms have any anti-corrosion coating although some have a coating or cladding in the splash-zone where corrosion rates are highest (Picken, 1995). Different types of coatings are applied to protect the structure elements. Some of these contain toxic substances, e.g. bitumen, asbestos, PCBs, heavy metals (lead, barium, cadmium, chromium, copper, zinc) , epoxy-based and vinyl paintings (to prevent corrosion), organotins (to prevent biofouling) (KLIF, 2010, p. 28). Emissions from paintings are mainly an issue when structure elements are removed, since toxic waste gases can be released when painted elements are heated or combusted. This will mainly cause occupational health issues (KLIF, 2010, p. 28). If the structure elements are left in place, the paints will gradually wear, slowly releasing toxic substances in presumably very low concentrations.

Steel corrosion

When the sacrificial anodes are consumed or removed the steel parts of the platforms will start to corrode. The jacket of platforms consists of tubes, which are constructed of steel plates that are rolled up and welded together. The greater part of the jacket is constantly below sea level and is therefore most susceptible to corrosion by salt water. The structures will become weaker and weaker and begin to collapse. In time the steel structures will fall apart in small pieces of iron oxide that will settle on the seabed. It is estimated that it might take more than 500 years for all the steel to fully corrode (Picken *et al.*, 1997, p. 4).[5]

The greater part of the steel structures is made of iron, which is extremely insoluble in seawater. The corrosion product has 1.9 times the volume of the original steel structure elements. Since the corrosion products of steel are insoluble and inert, they are not likely to give rise to cumulative effects at the structure's endpoint or beyond it, save for changes to the physical characteristics of the sediment caused by the deposition of flakes and particles of iron oxide (Picken *et al.*, 1997, p. 4).

[5] The average free single-sided corrosion rate for steel in seawater is between 0.08 and 0.3 mm/yr (UKOOA, 1995). Corrosion, however, is unpredictable. Steel corrosion rates depend on several factors, including temperature, oxygen concentrations, combination with other metals and the effects of marine growth at the structure.

Summary of impacts

Table 6.2. Environmental impacts of contaminants on the structure for the decommissioning options of "total removal" and "leave in place"

Contaminants	Total removal	Leave in place
Anodes	Recycling of aluminium and zinc is possible. The impact is mainly in energy and emissions to air (discussed in paragraph 6.5)	When leaving the structure elements in place, the dissolution of the sacrificial anodes will result in emissions of aluminium, zinc and copper. An integrated assessment is needed to decide whether it is necessary to avoid potential environmental impacts by removing the anodes.
NORM	Basic cleaning of structure elements takes place offshore. NORM scale is removed and disposed of either offshore or onshore. *Environment*: marine organisms are to a certain agree better adapted to radioactive material since these substances are naturally occurring in seawater in very low concentrations. *Health*: Onshore handling and disposal increases occupational health risks. During scrapping radioactive particles can be transported through the air. Protective clothing reduces risk of breathing.	If left in place, basic cleaning of NORM scale present in equipment and process systems takes place, meaning that the environmental & health impacts will be similar to "total removal".
Hydrocarbons	Basic cleaning takes place of components that are left in place. Hydrocarbon residuals are treated onshore and destroyed by thermal technologies. (The impacts of hydrocarbons in drill cuttings are discussed in 6.4.)	If left in place, basic cleaning and removal of hydrocarbons present in equipment and process systems takes place, meaning that the environmental impacts will be similar to "total removal".
Paints, coatings	If structure elements are removed, this will pose occupational health issues onshore when painted components are heated or combusted and toxic waste gases are released.	When the structure elements are left in place, the paints will gradually wear. Toxic substances will be released over time in very low concentrations and are not expected to harm the marine environment.
Steel	Recycling of steel structure elements is possible. The impact is mainly in energy and emissions to air (discussed in paragraph 6.5)	When the steel structure elements are left in place, they will slowly corrode and eventually fall apart into small flocs of iron, which will settle on the seabed. These corrosive products are not toxic, but may cause physical hindrance to other users, e.g. trawling fisheries. Potential impacts can be avoided by keeping the old safety zones in place.

6.2. Marine growth

In this paragraph we will discuss only those issues related to marine growth that are not covered in the ecosystems report (IMSA Amsterdam, 2011c). In particular effects on biodiversity are not covered here. This paragraph focuses on the *removal* of marine growth and the environmental implications.

After installation the submerged part of the platform structure is increasingly covered with marine growth. This has negative effects on the stability of the structure by loading and on the integrity of the material by corrosion. To protect the structures from marine growth and to avoid overloading anti-fouling paints and other anti-fouling systems are used. The structures are also regularly cleaned with freshwater or chlorinated water to remove the marine growth. The first forms of marine growth, however, return within days or weeks.

Marine growth removal

When platforms are decommissioned the marine growth has to be removed and disposed of. Several techniques are employed to remove marine growth including: 1) manual cleaning, 2) water jetting, 3) hydraulic powered cutters or brushes and 4) clean and paint machines (Iberahin, 1996, p. 93). Sometimes a small fraction of the marine growth is removed offshore prior to removal of the structure, if cutting tool access is required. Full removal of marine growth can be either onshore or inshore. Onshore removal is the most common practice. Removal onshore can cause air quality issues due to the odor of decaying organic matter, but these issues are transient and manageable. In Norway marine growth is sometimes also removed *inshore* prior to arrival at the demolition site. In more enclosed, waters, however, where there are smaller water masses and little water renewal excessive loads of organic material and oxygen depletion on the seabed may be the result.

Disposal of the material *onshore* and composting and landfilling is a possibility (KLIF, 2010, p. 25) but the disposal costs are high. Of the Ekofisk platforms, for instance, 7,000 tons of marine growth on jackets and 3,700 tons on tanks had to be removed (Ekins *et al.*, 2005, p. 37 and 39). All of this organic material needed to be landfilled. Alternative uses of marine growth are also possible but uncommon. The waste stream is sometimes used for soil remediation. It can be used as a nutrient source for bio-remediation of oil-contaminated soil. In the UK, marine growth is sometimes used to break down heavy clay land (Oil & Gas Journal, 1997).

Energy use of decommissioning

As already mentioned in Chapter 5, the marine growth forms an extra load during decommissioning activities. Especially the shell bands are of heavy weight. The organic material can contain a lot of water, of which part can dry rather rapidly, i.e. sea cucumbers, and soft corals (Klif, 2010). The total amount of marine growth on the UK platform Maureen, that was towed to Norway for dismantling, for instance, was 1,700 tons wet weight. After exposure to air the marine growth loses typically 70-90% of its water content resulting into 230-450 tons that still had to be removed (Rogaland Research, 2001, p. 2).

Platforms with extensive marine growth are confronted with added mass. Lifting and transportation of platforms with the additional weight of marine growth requires more energy and causes higher emissions of CO_2.

Summary of impacts

Table 6.3. Environmental impacts of marine growth removal for the decommissioning options “total removal” and “leave in place”. Biodiversity impacts are treated in a separate report (IMSA 2011c).

Environmental impact	Total removal	Leave in place
Contaminants	Marine growth may contain different contaminants, like PCBs. The contamination levels are in general too low to have significant impacts on the marine environment. Final disposal offshore or inshore is favourable since the marine growth decomposes naturally in this environment.	Most contaminants are contained by marine organisms and will gradually degrade. This process might even be enhanced by bioremediation caused by the marine growth.
Organic loads	In shallow waters the disposal of marine growth can result in excessive loads of organic material and oxygen depletion on the seabed. At open sea this will not cause problems.	No impact
Odour	Onshore storage and disposal of marine growth causes a strong smell and air quality issues due to decaying organic material.	No impact
Invasive species	Most of the marine growth decays soon after the structures have been lifted out of the water. The risks of spreading invasive species are more prevalent with shipping than with the removal of structures or removal of marine growth.	On site abandonment of platforms does not pose an extra biofouling risk, since the organisms living on or near the structures were already present during operation.
Energy use & emissions	Marine growth increases the total weight of the structure (up to 30%). Lifting and transporting platforms with additional weight requires more energy and causes higher emissions of CO_2.	No impact

6.3. Drill cuttings

Around the platforms often drill cuttings piles are found, which are the result of well drilling. The drill cuttings contain different types of contamination, mostly toxics used during the mining process. It should be addressed here that currently and in the past work is being or has been done by industry, government and stakeholders to come to a mutually acceptable process for determining appropriate outcomes for this issue. As previously described in Chapter 4.1.2. OSPAR Recommendation 2006/5 states that the pollution by hydrocarbons and other substances from drill cuttings piles should be reduced to a level that is not significant. The management of drill cuttings is considered case by case. When an installation is decommissioned, the drill cuttings are screened and an assessment of the best environmental practice is made. Leaving the drill cuttings in place is in general considered the best available environmental option if assessment meets OSPAR threshold.

If the platform is totally removed, potential future trawling by fisheries may whirl up drill cuttings and thereby cause spreading of toxic substances into the water phase. The results of the Fisheries Research Services study (FSR-ML 2000), which measured the effects of interaction of fishing gear with drill cuttings, indicated, however, that the dispersal of contaminated cuttings arising from over-trawling will not be of measurable environmental significance. Contaminants in the drill cuttings will be spread, but the concentrations will not be high enough to pose ecological threats to the marine environment (OSPAR, 2009, p. 6). Hence, the risks of over-trawling are small. If the platform is left in place this will even reduce the risk of leakage of contaminants by over-trawling, due to the visible presence of the jacket above the surface and potential restrictions on seabed use.

Table 6.4 compares the environmental impacts related to drill cuttings for the decommissioning options "leave in place" and "total removal". It is assumed that for both options the drill cuttings are left in place.

Table 6.4. Impacts of drill cuttings for the decommissioning options "total removal" and "leave in place".

Impacts	**Total removal**	**Leave in place**
Leakage of contaminants	Whirling up of drill cuttings during removal of the platform might cause a sudden release of toxic substances in seawater and physical smothering of benthic organisms due to movement of sediments and fluids. These effects are currently prevented by removing cuttings piles close to the footing or by cutting the footing.	The leave-in-place option implies the smallest risk of spreading of toxic substances into the water phase. The drill cuttings remain concentrated and very slowly degrade (100-300 y).

6.4 Seabed disturbance

Current decommissioning regulations require that wells are permanently plugged and abandoned and that the seafloor is (more or less) cleared of all obstructions created by the operations (Kaiser & Pulsipher, 2009). It may be valuable to clear the seabed entirely to leave a pristine marine environment or to make future uses of the seabed, like trawling fisheries, possible. An entirely clear seabed can only be achieved by removing the drill cuttings, detaching the (concrete or steel) footing of the seabed, removing cables and pipelines lying on or buried in the seabed and clearing other types of debris. These clearance activities would have their own environmental impacts, e.g. higher energy use, higher emissions and larger risks of leakage of contaminants.

A clean seabed has no particular environmental benefits. From an ecosystem perspective one might even argue that a clean seabed creates a less diverse ecosystem as substrate for marine growth is removed. From a cost perspective it is favourable to leave as much of the elements in or on the seabed in place. Minimizing seabed clearance could, however, become a spatial issue, when it is desired to enable other future uses of the seabed, like trawling fisheries, defense, sand extraction and carbon storage. Remaining elements might physically hinder them.

6.5. Energy requirements

This chapter builds on two broad assessment reports: one by Ekins *et al.* (2005) which focussed on the British oil and gas sector and a 1995 report by Picken *et al.* for the UKOOA. In the text we will simply refer to these studies as Ekins and Picken.

The energy requirements for a decommissioning scenario form important parameters in an environmental impact assessment. As energy requirements can be expressed as fuel requirements, saving energy means saving fuel. Therefore, the scenario with the lowest energy requirement will also have the lower cost component for fuels. As a next step in the assessment the greenhouse gas emissions and other emissions to air will be calculated that are associated with all individual energy consuming processes.

Relevant to the operators is the actual energy consumption for a specific decommissioning variant. This is the sum of all direct energy uses in dismantling / disposing a platform and for disposing or recycling the materials ($E_{con} = E_{dir} + E_{rec}$). For an environmental impact assessment, the broader, global perspective of a life cycle assessment (LCA) is taken. The total energy consumed in a decommissioning variant should then include the theoretical amount of energy that is required to replace all materials that are not recovered (E_{rep}).

Figure 6.1 illustrates the comparison between leaving part of a structure on the seabed in comparison with a variant where that same structure is retrieved to shore for further processing (recycling). If the actual energy consumption ($E_{dir}+E_{rec}$) is smaller than the energy required to reproduce that same amount of material from raw materials (E_{rep}), then “recovery” performs better than “leave in place” in terms of energy use. However, when $E_{dir} + E_{rec} > E_{rep}$ the energy balance favours a leave-in-place scenario.

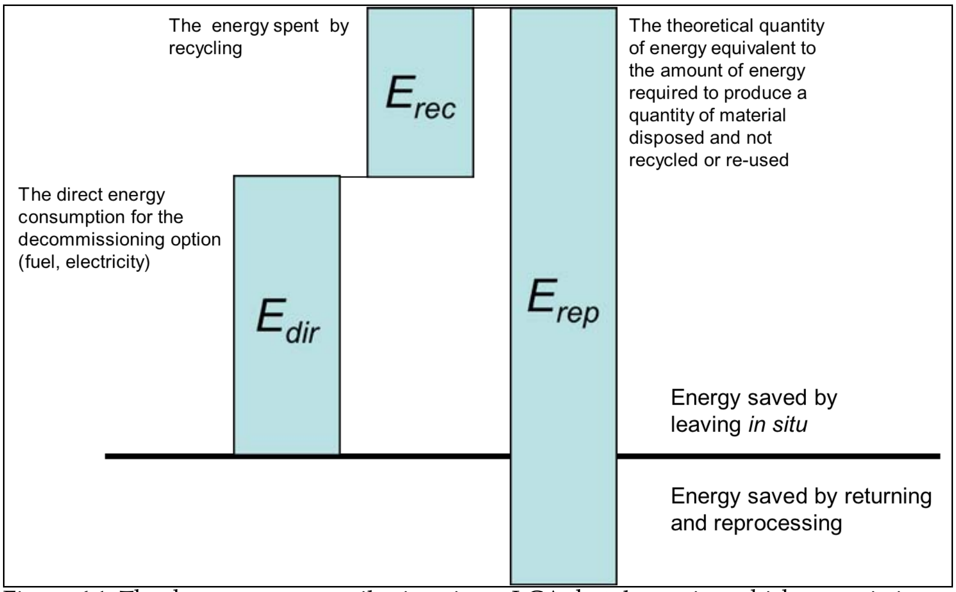

Figure 6.1. The three energy contributions in an LCA that determine which scenario is most energy-efficient. If $E_{dir}+E_{rec}-E_{rep} < 0$ then energy is saved by recovery; otherwise, leave in place is preferred from an energy perspective.

Compared to LCAs for consumer products, the following LCA results might at first glance appear strange. Typically, consumer product LCAs reveal that transport has a small, but significant contribution to the total energy use of approximately 10%. The nature of the decommissioning process implies that the energy for all transport movements is much higher, 50% or more, and therefore might dominate the analysis.

At the same time, the decommissioning process contains many unknowns, especially when it comes to comparison of different platforms. Calculations for the energy consumption therefore have uncertainties in the order of 30-40% (Ekins). The uncertainty in emission data is not given, but it can be assumed that this is even higher. It should also be pointed out that the data used for this chapter are all based on *projections* for the energy use. To the best of our knowledge, there is no data available on energy usage during an actual decommissioning project.

6.5.1. Methodology

The determination of the energy requirements and emissions for a decommissioning variant is done using the principles of LCA. The material and energy flows for different options are determined for the entire life cycle. This requires a clear definition of the boundaries and scope of the LCA. Ekins defines the following boundaries for the analysis.

Temporal boundaries

The starting point for the analysis is after shutdown (cessation of operation of the installation), with all the required tasks that are similar in all decommissioning options (see Chapter 5.2.). The endpoint is defined by the material endpoints of all the decommissioned and input parameters. For all decommissioning options, the fuels that are used have their endpoint in the gaseous emissions of CO_2, SO_2, and NO_x. Other emissions, such as methane or particulate matter have not been considered. For a leave-in-place scenario the temporal boundaries include monitoring and surveying for an ongoing period (operational and maintenance costs). For a removal option, the endpoint is defined when the material has been returned to its recycled and usable form, or treated as waste.

Spatial boundaries

The spatial boundary of the analysis is defined by earth's outer atmosphere. Impacts were thus considered on a global scale, as is appropriate when the aim is to properly account for material, waste, and emission streams.

Direct energy consumption

Direct energy consumption stems from dismantling, sea transport and onshore activities (demolition, onshore works and transport). A minor contribution is related to the extra material (steel) that is used in the decommissioning process, e.g. for reinforcements. The fuel needed for survey missions when part of the structure remains on the seabed can be neglected (see below).

Material recycling and replacement

The environmental impact due to the materials of the platform is strongly dominated by the energy requirements for the production of steel. Platforms in general and jackets in particular consist for more than 90% of steel. Since steel can be recycled for 98% or more (KLIF, 2010), the recycling (E_{rec}) and replacement (E_{rep}) contributions are almost entirely determined by the energies required to produce steel. Steel production is energy intensive and according to the World Steel Association, primary steel production requires 19.8 – 30.9 GJ per ton of steel, depending on the specific process. Secondary steel production, i.e. recycling from scrap, requires much less energy: 9.1-12.5 GJ/ton.

6.5.2. Assumptions and limitations

The most important limitation for the Living North Sea project is that the results of case studies for specific platforms cannot be used to draw conclusions for the entire North Sea. Ekins shows for a number of parameters (jacket mass, water depth, cuttings pile volume) that Case Study A is indeed representative for large steel structures on the British continental shelf (UKCS). The results however cannot be extended to structures that are either much smaller or larger. More importantly, the energy and emission impact from the dismantling process itself contains too many uncertainties to allow extrapolation to the impacts on the North Sea. Neither Picken nor Ekins describes the assumptions underlying the dismantling process: how many ships, lorries and other equipment needed during what period. In the absence of these details it is impossible to assess how representative the presented cases are for all of the North Sea platforms.

Picken does give energy and emissions estimates for the decommissioning of all North Sea platforms, but in the light of the widely varying energy and emissions estimates given below (Table 6.5), we consider this fifteen-year old estimate as too uncertain to be a basis for the present discussion.

Here, as elsewhere in the report, the concrete-based structures will not be considered, as these are likely candidates for derogation under OSPAR 98/3 for technical, financial, and health and safety issues. As there is no energetic benefit in recycling concrete over de-novo production, the total energy requirement will be dominated by the fuel requirements for ships and lorries. Hence, also from an energy, resource and emissions point of view, leaving in place will be strongly preferable over a return and reprocess option.

The leave-in-place scenario of Ekins does not include further monitoring or maintenance. Picken does take survey and monitor missions explicitly into account. However his calculations for a leave-in-place scenario are based on the assumption that the topside is left in place, which then is visited once a month by helicopter over a period of 100 years. In this report, it is assumed that the topside will be removed in all scenarios. Although toppling or removal scenarios that do not clear the seabed would still require some form of surveying and monitoring, the frequency of such missions will be much lower and be carried out by boat. Picken estimates that surveying all toppled or partially removed structures in the North Sea requires 157,000 GJ per year, corresponding to 16 Kton CO_2 emissions per year.[6] Compared to the other contributions, the survey impact can be neglected.

[6] The TER for survey liabilities in the minimum compliance option is 15.7×106 GJ for the entire North Sea (Table 8.12, Picken 1995) and 1.6×106 ton CO_2 equivalents. This value is integrated over a time period of 100 years (Table 8.3, Picken 1995). Hence, the annual values for surveys are those given in the text.

Materials that are brought onshore can be reused, recycled, landfilled or incinerated. As the energy and emissions contributions are dominated by the metal content of the platform, incineration plays a negligible role in the waste-handling process and is not covered here.

6.5.3. Comparison of scenarios

In order to compare scenarios, energy data from several sources have been analyzed in terms of the three energy contributions: direct, recycling and replacement. When necessary, data were converted to the same units and expressed relatively to the mass of the structure in question. We compare Case Study A (CSA), a large-steel, deep-water structure studied in depth by Ekins (Ekins, 2005 and references therein) to the estimates made for the structures on the Frigg field (Total, 2003) and the indefatigable field (Shell, 2007). The latter structures are representatives of a smaller, shallow-water class of platforms. For comparison some general estimates are furthermore provided on E_{dir} and E_{rep} that were used for the case studies presented by Picken; together with general material parameters for some metals (Ekins).

Table 6.5 summarises the results for the relative energy costs for decommissioning. Only Ekins provides all the data that is required for an LCA; the other reports mention only one or two of the relevant energy parameters. Nevertheless, all data combined provide a reasonably coherent picture.

As could be expected, there is reasonable agreement on the energy cost for recycling and replacing part of the structure. As more than 90% of the weight of the structure is determined by steel, the values for E_{rec} and E_{rep} are close to those for standard steel: 9 and 25 GJ/ton respectively. Only for topsides, somewhat larger deviations from these numbers are possible, because there the fraction of steel can be smaller.

Very large deviations are observed for the direct energy costs. E_{dir} ranges from values of 5 GJ/ton or lower (Picken) to values as high as 60 GJ for the topsides of the M and N structures in the indefatigable field. Looking only at the steel jackets, energy use lies somewhat closer together, but the differences still span a large range. The reason for these large differences must be sought in platform specifics and logistic choices: how the platform is dismantled will determine what vessel movements are required.

Since the underlying calculations are not provided, it is impossible to understand why removing a relatively light jacket from shallow water (indefatigable platforms) requires at least four times more energy per ton of structure than the dismantling and retrieval of the much heavier DP-jacket from the Frigg field. The same holds for the estimates of Picken that form the lower boundary of this range. This might point out the fact that the amount of work required for decommissioning has been underestimated in the 90s, but without the details this cannot be concluded with certainty.

Table 6.5. The relative energy cost for returning and reprocessing part of a platform with respect to leaving that part in situ. Negative numbers indicate energy savings as a result of returning and reprocessing. Positive numbers are an energy cost. The input energies consist mostly of the fuel used for transport and cutting. The material difference is the difference: recovered – replaced material.

	Weight (ton)	**Depth (m)**	***E**direct* **(GJ/ton)**	***E**recycle* **(GJ/ton)**	***E**replace* **(GJ/ton)**
Case Study A (Ekins, Table 6.1-6.4)					
Topside	20,520	140	17.3	9.6	25.6
Jacket	10,200	140	15.9	9.2	32.7
Footing	11,300	140	13.4	9.0	27.9
Frigg (Table 7.2 & 8.2)					
QP-Topside	3,639	100	14.0	8.2	
QP-Jacket	5,490	100	17.6	7.9	
DP1-Jacket	7,600	100	16.8	8.8	
DP2-Topside	5,479	100	8.6	8.5	
DP2-Jacket	14,407	100	9.6	8.4	
Indefatigable field (Appendix D, Installation reversal with HLV)					
J-K-L Topsides	1,448-3,000	31	24-30	16-32	
M-N Topsides	495-522	31	60-63	7-9	
J-K-L-M-N Jackets	637-1,273	31	33-57	9	
Case studies Picken, Table 8.15 & 8.16					
Total removal by cutting and lifting	~30,000		4.37		27.57
Total removal by floating and wet-tow	~30,000		1.97		26.10
Partial removal	~30,000		4.37		30.25
Toppling *in situ*	~30,000		5.06		
Metals (Ekins, Table 3.6; data Source: IP 2000)					
Standard steel				9	25
Low alloyed steel				9	32
High alloyed steel				9	56
Aluminium				15	215
Copper				25	100

From Table 6.5 it can be concluded that E_{dir} is the decisive factor in judging decommissioning options from an energy perspective. There appears to be relative agreement on the other two components E_{rec} and E_{rep}: their difference is approximately 14 GJ/ton in most studies. This implies (see Figure 6.1) that when the direct energy costs are more than 14 GJ/ton, it would be better to leave the structure in place. From CSA and Frigg data, one would conclude that within the uncertainties there is no compelling energy argument for a preference for either scenario. Using the data from Picken would suggest that recovery is more favourable, whereas the data from the indefatigable field points towards leaving in place.

In the absence of better validated estimates, an assessment of decommissioning options based on energy has to be postponed. This has double consequences: firstly, it means that an energy assessment for the entire North Sea cannot be made. Although the energy difference between a leave-in-place and a retrieval scenario might turn out to be small per ton of structure, multiplied for the weight of all platforms the outcome could be substantial. Secondly, without good estimates for energy, the value of the assessment for emissions to air will be based on even shakier grounds.

6.6. Emissions to air

The total energy requirement is related to the emissions to air through the emission factors of all emitting sources in the decommissioning scenarios. These emission factors are determined largely by fuel efficiency for CO_2 and SO_2, whereas NO_x emissions are determined amongst other things by engine design (temperature) and the presence of emission control measures such as DeNOx catalysts. Generally, emission factors for transport modes (vessels, lorries) are larger than those required for material production. The recycling or primary production of metals takes place in energy efficient industries that often have several air emission control measures in place. The shipping sector, by contrast, is still quite polluting, although new regulations increasingly limit also the emissions of ships.

Given these general trends for emission factors, emissions from direct energy use will weigh in more strongly than emissions related to material recycling or replacement. Therefore, even when the LCA shows that bringing a platform to shore for reprocessing saves energy, the assessment based on emissions may conclude that a leave-in-place scenario would be preferred. This is indeed what Ekins finds in his study.
A few observations regarding the emissions to air will serve to put this assessment in perspective. First of all, as noted before, the large uncertainties in the energy assessments are enlarged for the emissions assessment. Secondly, there is no generally accepted method to weigh the impact of all emissions to air. Some gasses enhance the greenhouse effect (CO_2, methane, NO_x); others have a more local effect on air quality (SO_2, particulate matter and also NO_x). Thirdly, the emissions resulting from decommissioning activities strongly depend on the practices of the service companies: use of low-sulphur fuels, lower cruising speed, improved logistics etc. can significantly diminish the impact of the operations.

Pipelines

For pipelines, Ekins considers a number of decommissioning options that will be briefly and qualitatively discussed. As a reference case all pipelines are left in situ with no remedial action. This turns out to be the best option both in terms of energy and emissions. Recovery and recycling of the material does not outweigh the energy and emissions associated with the vessel movements. However, for this assessment the same type of assumptions has been used as for the platforms themselves and, as shown above, there are large uncertainties connected to these numbers. As further alternatives, leaving in place with remedial action (to minimize interactions with trawlers) and trench-and-bury are considered. From an energy and emissions standpoint, the first would be strongly preferred.

Drill cuttings

Because there is no valuable material to recover from drill cuttings, it is easily understood that leaving in place would be the best option in terms of energy and emissions. According to Ekins, the following energy and CO_2 costs are associated with the alternatives for drill cuttings.

Table 6.6. The direct energy costs and CO_2 emissions associated with alternatives for the 40,000-ton drill cuttings pile of Case Study A other than leaving them untreated on the seabed.

	E_{dir} (GJ/ton)	CO_2 (ton/ton)
Excavate and leave	0.8	0.06
Cover and leave	4.7	0.35
Remove and treat onshore	8.4	0.72

It should be realised that even if energy requirements and CO_2 emissions for these alternatives might appear modest if expressed per ton material, for a typical drill cuttings pile this amounts to a significant amount of energy and CO_2. Returning the drill cuttings to shore would furthermore mean waste treatment on land of materials that represent no economic value and are potentially hazardous.

6.7. Waste and resources management

From a waste and resources perspective, the main question is how much material can be reused or recycled when it is brought onshore. Here the environmental impact is assessed in terms of environmental impact of waste handling decisions. The energy aspects of recovery have been discussed in the previous paragraph. Figure 6.1 provides a high view of the material flows for different options. This diagram shows the actual material flows (solid lines) and the "virtual" material and energy flows (dashed lines), which would have been required, in the absence of recovery, to achieve the same material endpoint (Ekins 2006).

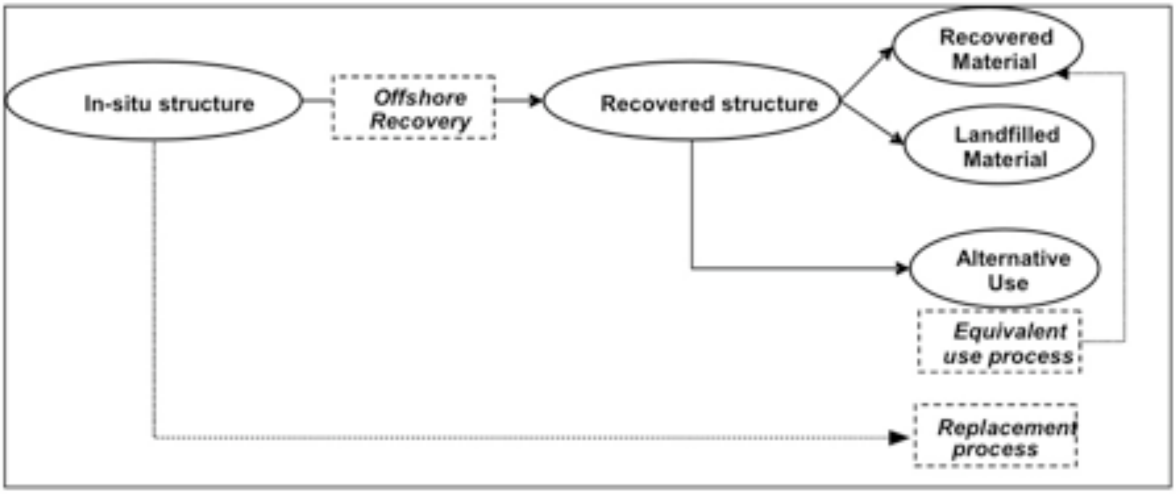

Figure 6.1.

Decommissioning and waste handling inshore and onshore make intensive use of coastal and harbour areas, which may have aesthetic impacts (landscape pollution) and spatial impacts (conflicts with other users).

Reuse

Here, we consider some second-life options for equipment from the installation and the structure itself. Reuse of jackets as artificial reefs is an option that is available in partial- and total-removal scenarios. This might benefit marine life in a number of ways as described in the report “Ecosystems associated with North Sea oil and gas facilities” (LNS214, IMSA Amsterdam, 2011c).

Motors, turbines, cranes, pumps and other such equipment from a platform could be sold. Most of this equipment is present on the topside. In practice, however, reuse is not of much significance because much of this type of equipment is old and out-of-date. Some parts of the structure might be reused in the petroleum industry or for other purposes. The steel column from the Frigg platform has been reused as a breakwater at Tau, while the topside has been used as a training centre for offshore personnel. Again, the market for reuse of installations appears to be small. Concrete substructures might find reuse as foundations for e.g. bridges or wind turbines. These options were considered for the Frigg decommissioning project, but were not economical. There was also a great deal of uncertainty about the practical aspects of using the structure in such ways (KLIF, 2010).

Recycling

Most metals in the structures can be recycled cost-effectively and with a high recovery. Approximately 90% of all metals present in North Sea platforms is steel (Picken 1995), which can be recycled for 98% (KLIF, 2010). Jackets consist almost entirely of metals. Recycling metals is to be preferred over producing metals from raw materials, because of the smaller energy requirements and hence lower CO_2 footprint (see previous paragraph). From a perspective of material scarcity there is no urgent reason to recover the metals present in the offshore structures: compared to the global, annual production of steel, copper, aluminium and zinc, the total quantities present in the North Sea platforms represent only a minute fraction.

For the non-metals, less information is available. In absolute numbers, the non-metal materials of offshore platforms in the North Sea are dominated by concrete: over 3 million tons in structures and almost 5 million tons in pipelines. Concrete cannot be recycled as concrete, but can be recycled as hard core. In energy terms, the savings due to recycling are small (Picken, 1995). As concrete can be produced abundantly, recycling is not a consideration in choosing a decommissioning option.

Landfilling and waste incineration

The materials and equipment that are brought onshore and that cannot be reused or recycled will be disposed in either landfilling sites or incinerated in waste incineration facilities. This waste stream can be classified in four types: inert, non-hazardous, putrescible and hazardous/difficult. The inert category cannot be incinerated and must be landfilled. The inert category contains non-recycled metals, concrete and mineral wool. Non-hazardous materials (e.g. plastics and rubbers) and putrescible waste (wood) can be either landfilled or incinerated. The hazardous category requires specific treatment for each substance. Drill cuttings would form a separate category if these were to be disposed of onshore. This is not discussed here.

According to Picken (1995), the residual waste stream (i.e. not recycled or reused) from all British platforms is approximately 1 million m^3. The pipelines in the British sector represent a similar residual waste volume. This is assuming a decommissioning option with steel platforms, where the topsides are removed and returned to land, and the jacket either toppled or partially or totally removed in accordance with present IMO guidelines. For concrete gravity bases, only the topsides are removed and returned to land. Picken furthermore assumes that 85% of all metals are recycled. Under these assumptions, more than 80% of the residual waste volume is inert and requires landfilling. Approximately 8% is hazardous waste and another 8% is non-hazardous. The amount of putrescible waste is negligible.

Generally, to dispose materials in landfills is the least favourable option from an environmental perspective. The main environmental impacts of landfilling are leaching and landfill gas. Even if the materials are inert, there is the loss of void space and the impact of lorries for transport.

A small fraction of the solid waste could be burned instead of landfilled (plastics, wood, rubber). If this incineration takes place in a modern facility with low emissions to air and efficient recovery of energy, this method is to be preferred over landfilling from an environmental standpoint.

7. Health and safety

Decommissioning of offshore platforms poses considerable health and safety challenges. Activities such as the lifting of heavy structures and diving, for instance, create significant risks of fatal injuries or serious accidents for the personnel. The industry addresses these health and safety issues for its own personnel, using the general principles of risk management. The option of not or partially removing a structure, however, poses a risk to a wider community, such as the risk of collision between the remaining platform and ships. The risk to personnel and the risk of collision have been identified as the principle health and safety issues. They will be discussed in this paragraph for the various decommissioning options. Environmental issues, as discussed in Chapter 6, pose comparatively small threats to human health and safety for all decommissioning options and are, therefore, not considered here.

7.1. Risk acceptance principles

To estimate health and safety impacts associated with various types of offshore activities, the oil and gas industry applies a risk assessment. Personnel risks are expressed by the chances of fatality or serious injury for an individual. For each type of activity a Fatal Accident Rate (FAR) or Serious Injury Rate (SIR) can be estimated. For example, for offshore activities in the Pacific region, SIR was estimated to be three injuries per 10 million hours of exposure. The corresponding FAR is four fatal accidents per 100 million hours of exposure. Diving activities are orders of magnitude more hazardous with 2000 serious injuries per 10^6 hours and 600 fatal accidents per 10^8 hours (Twachtmand Snyder & Byrd, 2003).

To calculate the total risk involved in a specific decommissioning scenario, individual risk rates are multiplied by the estimated time involved. The product of FAR with time involved is called Potential Loss of Life (PLL). The PLL can be used as a relative measure to compare different decommissioning options, showing which methods involve more risk to personnel than others. To use PLL as an absolute standard leaves one with the normative question: what kind of risk is still acceptable? According to industry standards, the risk of fatality for an individual should be as low as reasonably practicable (Bemment, 2001) and not exceed $1x10^{-3}$ per year (Total, 2003).

If a platform is not dismantled to a safe distance below sea level, a long-term safety and health risk remains for collision with a fishing or cargo vessel. The chance of such an incidence is expressed as a yearly frequency of collision (Marin, 2005). However, quantitative information on the possible effects of such a collision (life loss, serious injuries, etc.) has not been found.

7.2. Assessment of health and safety risks for personnel

Generally, the lowest risk to personnel safety results from minimizing the amount of offshore work. The operations themselves carry an inherent safety risk, and this can be aggravated by the possibility of adverse weather conditions and/or breaking off parts of the structure.

For the different options considered here, a number of activities have to be carried out in all cases: removing the topside, isolating the installation from the hydrocarbon source (see Chapter 5), and transportation and disposal of parts of the installation. The types of hazards that arise from these activities are summarized in Annex IV (types of hazards). The differences in terms of health and safety for personnel are found in the amount and manner of decommissioning.

Table 7.1. Overview of risk to personnel per decommissioning option

Option	Risk to personnel
Leave in place (base case)	This can be considered the base case, and only involves the removal of the topside and the isolation from the hydrocarbon source. Risks of topside removal depend on the size of the topside and whether or not it can be removed in one piece, in combination with the removal technology. Generally, a reverse installation sequence is considered to have the smallest risks with PLLs between 0.02 and 0.05. The offshore part of the work typically poses more than 80% of the risk, the remainder stemming from onshore disposal.
Topple in place	This option poses additional risks during the toppling of the jacket. This might require divers[7] who cut the piles, after which the jacket is toppled. Apart from the diving activities, which generally have large accident rates, there is the risk that the structure collapses in an uncontrolled manner. The chances of the latter might be small, but the effects can be large. For the North Sea platforms no detailed risk assessments for this option appear to be made.
Partial removal	Compared to the base case, this option poses the extra risks related to partial removal of the jacket. The jacket is dismantled to a depth that allows safe passage of the largest ships (-55 m). For steel substructures it involves cutting the jacket, lifting the top part(s) and moving them onshore for further processing. This is associated with additional PLLs comparable to the base case, stemming almost exclusively from the offshore activities. For concrete substructures the risk analysis is of an entirely different order. Underwater cutting of reinforced column walls would be extremely hazardous. The long period required to complete such an operation enhances the risk of failure during the cutting operation. Solving such situations is again extremely hazardous. Overall, cutting down a concrete substructure to provide a draft of 55 m is the most dangerous option of all, and has a ten to thirty times higher predicted number of fatalities than the base case (Total, Frigg Field 2003). Also in an absolute sense such risks are clearly higher than what is acceptable for offshore activities.
Total removal	For small steel substructures this alternative is hardly different from the partial removal option. With larger jackets, risks increase as multiple cut and lift operations will be required. Compared to a structure at 60 m depth, the complete removal of a structure at 200 m gives a four times higher risk of fatalities. By hopping the jacket parts into shallower water locations, larger fragments can be removed at once and cutting activities can be done in open air. In this way diving hours are limited and risks are significantly reduced (Twachtmand Snyder & Byrd 2003). For a concrete substructure, total removal would involve refloating and towing it either onshore or to a deepwater location. Both options are relatively safer than partial removal, but still present predicted numbers of fatalities that are five to ten times higher than the base case. These relatively high figures are a consequence of the fact that these structures were not designed to be refloated. The risk of structural failure during the refloating, towing or demolition is considerable (Total, Frigg Field, 2003).

[7] Divers are not a necessity in subsea activities: NW Hutton did not use any.

7.3. Assessment of health and safety risks associated with remaining structures

If a platform is left in place as a structure above sea level, the risk of collision with a ship remains for the entire period that it stays in place: 150–200 years for steel structures and 400–600 years and possibly longer, for concrete elements. In all other variants, it is assumed here that the platform is decommissioned in such a way to provide a draft of -55 m, thereby avoiding the risk of collision with a ship altogether. A special case is a decommissioning scenario in which a number of dismantled structures are sunk in one place to create an artificial reef. Health and safety risks for such a scenario are discussed later.

Protruding structures

In discussing collision risks, each platform should be evaluated separately, as traffic patterns on the North Sea are highly location dependent (Figures 7.1 and 7.2). In this report an average picture is sketched, leaving a detailed analysis for Phase 2. The North Sea is one of the most densely trafficked seas in the world and over the years there has been a considerable amount of ship-ship collisions. Ship-platform collisions in contrast are a relatively rare phenomenon. A risk assessment is therefore based on the modelling of collision frequencies.

An assessment of collision risks for decommissioned platforms will be based on the collision risks between ships and current platforms. For current platforms, collisions may occur with either visiting vessels or passing vessels. The first ones are related to field operations. These activities will halt after decommissioning. The remaining risks therefore are only with passing vessels. Two types of incidents are generally discerned: ramming and drifting, with different probabilities and causing different damages.

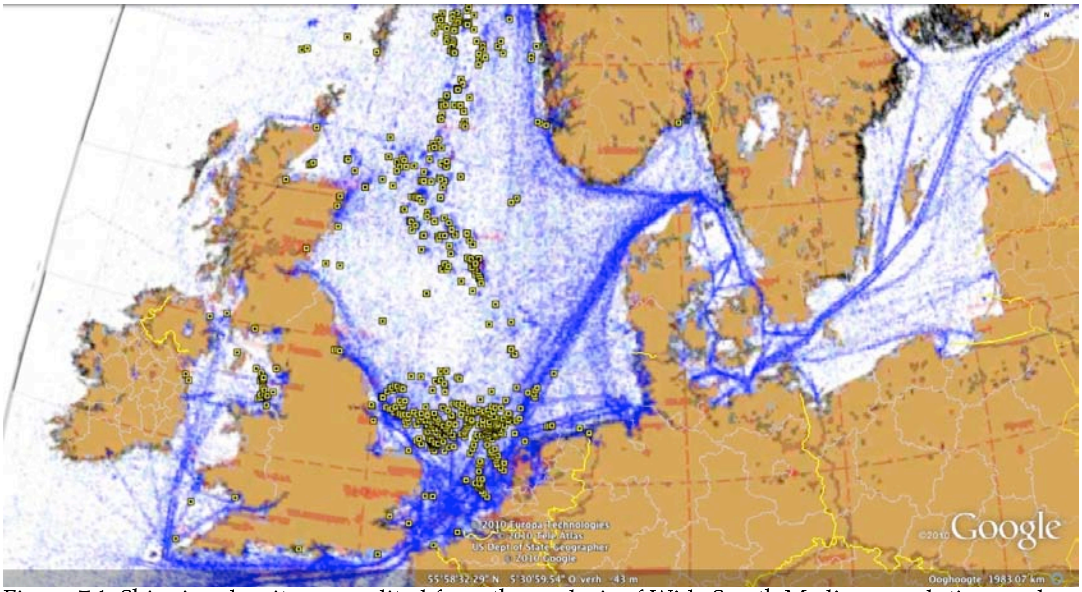

Figure 7.1. Shipping density map edited from the analysis of Wide Swath Medium resolution mode products from the Advanced Synthetic Aperture Radar (ASAR) instrument on ESA's Envisat satellite between 2002 to 2009 (http://www.esa.int/esaEO/SEMBDI0OWUF_index_1.html - subhead3) and Google maps.

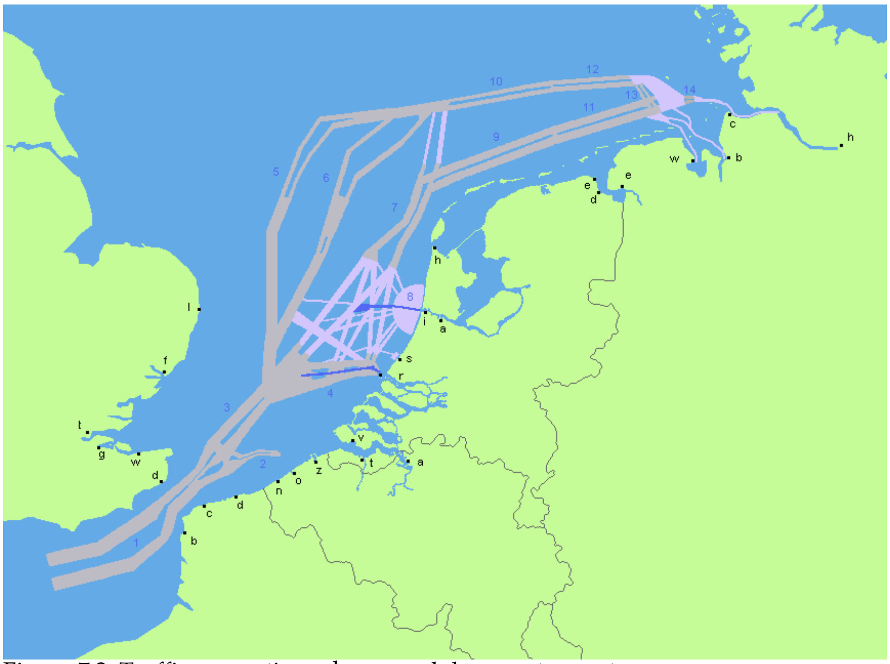

Figure 7.2. Traffic separation scheme and deep-water routes (http://nl.wikipedia.org/wiki/Verkeersscheidingsstelsels_op_de_Noordzee).

Based on worldwide data, the collision frequency with a passing ship was $2.5x10^{-4}$ per installation per year for the period 1990-2002. For the British continental shelf the frequency of recorded collisions that resulted in actual impact is an order of magnitude higher: $2.2x10^{-3}$ of which 31% are categorized as accidents. A large fraction (46%) involved fishing vessels (OGP, 2010). In a more theoretical approach (Van der Tak, 1995) it was found that collision frequencies for the British and Dutch sectors are approximately the same, whereas the chances of a ship-platform collision are much lower for the Danish and Norwegian sector, in line with the observed traffic patterns (Figure 7.1). Locally, of course, collision risks with passing vessels can be higher if the platform is located near a shipping lane (Figure 7.2). Collision risks with decommissioned platforms might be expected to increase over time: as the structure degrades, its visibility – both on radar and to the naked eye – decreases. These risks could be managed by technical measures increasing the visibility of degraded structures. How this would influence the collision risk, however, cannot yet be quantified.

Having established that significant collision risks for decommissioned platforms will remain for an extensive period, the question of impact to health needs to be answered. Existing literature is of little guidance here, since available risk assessments consider mainly the effects of a collision for the operator's personnel and material damage to the platform. An estimate of the impact on the shipping side has not been found, but can be developed qualitatively. These possible impacts can be expected to increase over time as the decommissioned platform loses its structural integrity.

The most likely collisions will be with fishing ships, as these are numerous and will not follow predetermined routes. Not all collisions, however, will lead to serious injuries or fatalities. It seems unlikely that decommissioned structures pose a health and safety risk to the fishing community that is larger than what is acceptable for an industry used to working in hazardous conditions. The second group to consider are merchant ships. Here the effect of a collision strongly depends on the type of ship and its cargo. A collision might lead to the release of hazardous cargo: explosive, toxic or otherwise. This not only poses a threat to the ship's personnel; it may have environmental consequences that could lead to health risks for a wider community. Structures in or near shipping lanes are therefore to be removed entirely without exception under IMO regulations (Article 3.7 of resolution A.672(16), 1989). Finally, there are minor categories of vessels, such as naval traffic and recreational shipping. The first is expected to be well equipped with sufficient personnel on watch, which makes collisions very unlikely. Submarines are a possible exception (see below). For recreational vessels the collision risk and impact can be expected to be approximately equal to that of fishing ships.

Vessel movements that are needed for monitoring of the decommissioned structure will form a special category. The risks associated with this activity will be comparable to the risks that are associated with field related vessel movements for current unmanned platforms. As the number of vessel movements will be much lower for a decommissioned structure, the number of possible accidents will be lower as well. The effects of a collision on the other hand could be more severe with the structure loosing its integrity over time.

Submerged structures

All submerged structures might pose a health and safety risk to submarine traffic. Although there is only a limited number of such vessels active in the North Sea, it has been noted that it is often difficult for submarines to detect platforms as they do not have a lookout. Navigation is therefore entirely dependent on electronic navigation aids and sonar. It has been noted that detection of a platform can be a problem then, since it does not emit much sound in the water.

For other vessels submerged structures only pose health and safety risk when they block passage. Such a situation might occur when decommissioned platforms are towed to a designated (shallow) location to form an artificial reef. Provided such an area is well marked on maps and with buoys, the risks will be in the same order of magnitude as those of any other shallow area.

Excluded area

Decommissioned structures, whether in situ or towed to a different location (reef), occupy a certain area that is no longer available for other activities. As there is a considerable risk for collision between ships in the already crowded North Sea (Figure 7.1), any structure taking up space can increase the risk of ship-ship collisions. This risk is likely to be small: the total area taken by platforms is about 400 km^2 on a total North Sea area of 750,000 km^2. Furthermore, structures in or near shipping lanes are to be removed entirely without exception under IMO regulations.

Assessment of health and safety risks associated with degradation

As a decommissioned platform ages, it will degrade and eventually collapse – the latter most probably in bad weather conditions. Although the process is inevitable, the chance of human presence within a risk radius of 500 m is expected to be small.

A larger, indirect risk is thought to be associated with collapse or degradation of the part of the structure that is above sea level. When this occurs, the visibility of the structure is lost and chances of collision with a passing vessel increase. Deterioration of a structure will therefore require some additional navigation measures to mitigate risk of collision (eg buoys).

7.4. Health and safety in relation to other criteria

There is a strong correlation between the individual risk to personnel during offshore operations and the cost for decommissioning. The risks to personnel are linearly related to the time spent on decommissioning activities. In general the same holds for the costs to perform offshore activities. Therefore a risk assessment for offshore operations in terms of "potential loss of life" will generally lead to conclusions that are in line with an economic assessment.

A more complex correlation with health and safety issues is the link to environmental issues: what's bad for the environment will through some mechanism (e.g. through the food chain) end up impacting human health.

8. Technical cost

In this chapter we provide an overview of decommissioning costs and potential savings that might be realised through a different approach to decommissioning than is allowed for within the current regulation. The cost overview is prepared at a screening level and the numbers come with a range of uncertainties. In the assessment of potential cost savings, we limit ourselves to a comparison of the extreme options of full removal (current regulatory demand) versus leaving in place. We make this limitation, as detailed data allowing for comparison of more specific options is not available and because we expect both environmental and cost benefits to be significantly reduced as soon as an installation is moved from the place where it currently stands.

In order to assess potential cost savings, we analyse differences per region, per platform category and per installation element. This chapter highlights only technical costs directly associated to the decommissioning process. Savings in non-technical costs that might be realised as a result of the Living North Sea Initiative building a new consensus on preferable decommissioning options are not included, though these might potentially exceed the technical costs. Also, we do not include potential cost savings that could be realised by creating new business from platforms being left in place. That way, we try to ensure that our eventual estimate of potential cost savings is relatively conservative.

As the scope of this report is limited, we point out there are aspects that need in-depth attention in the next phase, Phase 2.

- Further research, as is currently set up by Oil and Gas UK (OGUK), will provide a basis for a more detailed assessment of specific decommissioning options in Phase 2.
- In the next phase, it will also be assessed who benefits and how to allocate part of the potential benefit with the objective to improve the ecosystem quality status of the North Sea. Phase 2 will focus on developing a vision and programme for a sustainable North Sea, incl. funds needed, that creates wins for all stakeholders.
- Leave in situ would lead to cost savings. If regulation changes for this benefit, a discussion will be started on the criteria that should be used in decision making about which installations could best be left in place when derogated. This will include spatial aspects, ecosystem value, environmental criteria and learnings from experiences in the Gulf of Mexico, Japan and Brunei.
- Tax legislation is an important element for the decision-making on decommissioning and also in the division of cost savings. Tax legislation is briefly touched upon, more in extenso in the legal background report ("North Sea legal and policy framework", LNS130, IMSA Amsterdam, 2011d), and needs further and in-depth attention in Phase 2.

Note: All sums referring to decommissioning costs are in 2009 money unless otherwise mentioned. Sums are in British Pounds (GBP) or in Euros.

Disclaimer: All costs are estimates based on publicly available but limited data and have mainly been retrieved from OGUK[8] and OSPAR. Costs mentioned should be treated as rough estimates. The numbers are estimated on a 50/50% (P50) basis, meaning that it could turn out 50% cheaper or 50% more expensive, whilst in reality individual platform costs will have a range of outcomes – some higher, some lower. Costs are presented as money of the day.

8.1. Decommissioning scope North Sea

The decommissioning process in the North Sea has been addressed in Chapter 3.3, where the immaturity of the market, timing and tax regulation were mentioned. We continue here with a focus on cost. The costs and timing of decommissioning vary widely. They depend on several factors, such as the installations' physical condition, production levels, location, water depth, type of platform, size and weight of structure, complexity, age of installation, number of wells, availability of contractors, technological drilling developments, market conditions, weather, case-by-case approach, new production techniques, regulation, tax regimes and probably most important: energy prices.

The total decommissioning spending for the entire North Sea is estimated (2010) at more than € 53 billion (Table 8.1). A third of this total is scheduled to take place before 2020. This cost estimate does not include the removal of installations that are applicable for derogation under OSPAR 98/3, nor does it include the removal of all pipelines. The inclusion of removal of any of these items would dramatically increase the estimated costs.

Table 8.1. Decommissioning cost estimates per country (2010).

Country	NO	UK	NL
Estimates 2010	€ 20.5* billion	€ 29 billion	€ 3 billion**

* Decommissioning costs, excluding heavy concrete installations. (Klif, 2010).
** This figure excludes the plugging & abandonment of the wells. On the Dutch continental shelf there are 450 wells. Plugging and abandonment costs average € 1.5 million per well. This would add another € 675 million (derived from personal communication). Plugging and abandonment of wells in other regions is said to cost up to € 10 million per well.

Table 8.2 shows the main market segments that account for 92% of the total spent. In order to estimate costs directly related to the removal of platforms, the costs of removing pipelines and subsea installations and of well plugging and abandonment are excluded, as shown in the fourth column.

8 The OGUK Decommissioning Insight 2010 document was an initial attempt to regionalise and segmentise a single cost data point collected through an annual operator questionnaire conducted by OGUK. The data provided by the operators is in the main not a project estimate, has not been subjected to any cost risk assessment analysis and is at best "order of magnitude".

Table 8.2. Market segmentation of (only) UKCS decommissioning Market 2011-2050. Column "spent" is based on OGUK (2010) Decommissioning Insight.

Segmentation (92% of total estimated spending)	**Spent in million**	**Share in total cost**	**Cost if excluding pipeline, subsea and cost for well plugging and abandonment**
Subsea	£ 500	2.0%	()
Project management	£ 2.500	10.0%	£ 2,500*
Decommissioning programme	£ 330	1.3%	£ 330
Operations	£ 3,450	13.9%	£ 3,450
Wells plugging and abandonment	£ 4,000	16.1%	()
Conductor removal	£ 1,100	4.4%	£ 1,100
Topsides cleaning	£ 1,250	5.0%	£ 1,250
Pipelines cleaning	£ 650	2.6%	()
Topside removal	£ 4,300	17.3%	£ 4,300
Jacket removal	£ 4,300	17.3%	£ 4,300
Onshore disposal	£ 720	2.9%	£ 720
Pipeline decommissioning	£ 1,550	6.2%	()
Survey & monitoring	£ 250	1.0%	£ 250
Total	£ 24,900	100%	£ 18,200
Euro	€ 29,050	Δ € 7.816	€ 21,233

*Although the cost of *Project Management* would in reality be lower for jacket removal only, we kept this cost segment the same in order to reduce complexity.

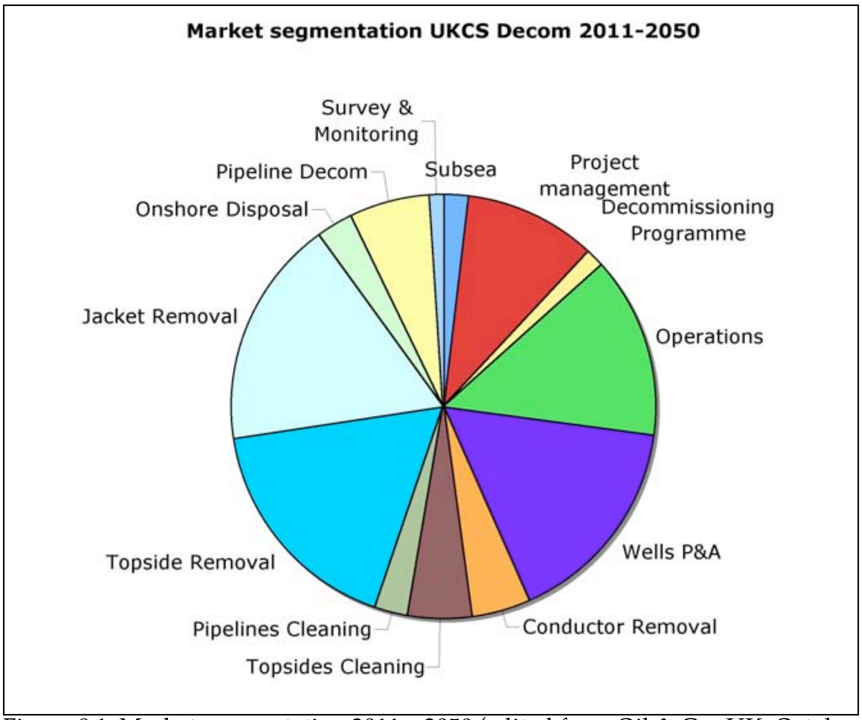

Figure 8.1. Market segmentation 2011 – 2050 (edited from Oil & Gas UK, October 2010).

Figure 8.2 shows the percentages of the excluded segments.

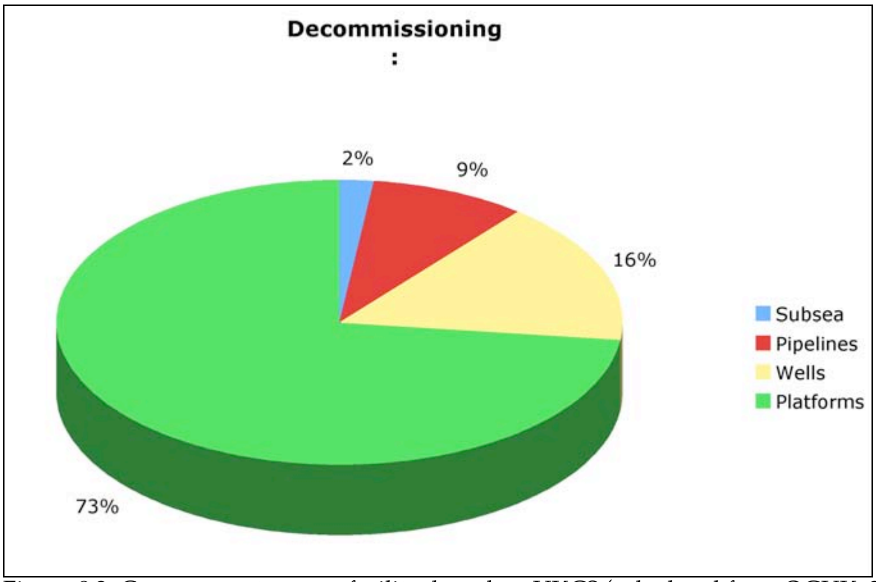

Figure 8.2. Costs percentage per facility, based on UKCS (calculated from OGUK, 2010).

8.2. Regional spread: central and northern versus southern North Sea

Decommissioning costs per installation are considerably higher in the central and northern North Sea (CNS and NNS) than in the southern North Sea (SNS). This is primarily due to the number of large platforms with substantial sub-structures, the deeper waters and the rough weather conditions. Installations in the CNS and NNS comprise 44% (GBP 12 bn) and 34% (GBP 9 bn) of the total estimated British continental shelf spending, compared to the SNS at 15% (GBP 4 bn) (Rigzone 17/06/10). The complex nature of the CNS/NNS means that a relatively smaller number of installations (than in the SNS) account for around 80% of the total estimated decommissioning costs.

The nature of decommissioning projects in the SNS implies that the majority of costs concern operations, project management, jacket and topside removal, and the plugging and abandonment of the wells. These segments make up to more than 75% of the costs per installation. Moving to the north, the majority of costs still focuses on jacket removal (approx. 20%), topside removal and operations, but within these expenses the percentages shift. Topside removal and wells plugging and abandonment take a larger share of the pie. So does the jacket removal (approx. 21%), due to increased water depth, many more High Pressure High Temperature (HPHT) fields and partly due to higher transportation costs. In the CNS and NNS vessels have to sail many more kilometres than in the SNS, because of the larger distance to the coast and the sail back and forth several times. Also, the vessel will spend more time on cutting and moving the larger topsides and the jackets.

The average cost of removing a steel installation in the CNS and NNS is around € 75 million. In the SNS, the average costs of removal of installations is approximately € 20 million. Ultra-large steel platforms (all situated in the CNS and NNS) start at € 100 million. For large concrete structures costs start at around € 300 million, but vary extremely. Taking out the concrete structures in the Brent field, for example, is estimated to exceed GBP 1 billion per installation in costs. Table 8.3 provides an overview of cost estimates used here in relation to size (weight) of the installations.

Table 8.3. Categorical total removal decommissioning costs of installations in the North Sea

Category	Weight range in tons	Ranges of costs for total removal (million €)
Small	0 – 2,000	10 – 30
Large	2,000 – 10,000	50 – 100
Ultra large	> 10,000	100 – 200
Concrete		300 – 700

* Average taken from OSPAR inventory offshore structures (in 98/3 derogation category list).
** Due to great uncertainty, costs exclude wells plugging and abandonment and the mentioned figures should be treated as directional estimates at best.

Figure 8.3 differentiates the costs per country, which shows that more than 50% of the costs are for the UK.

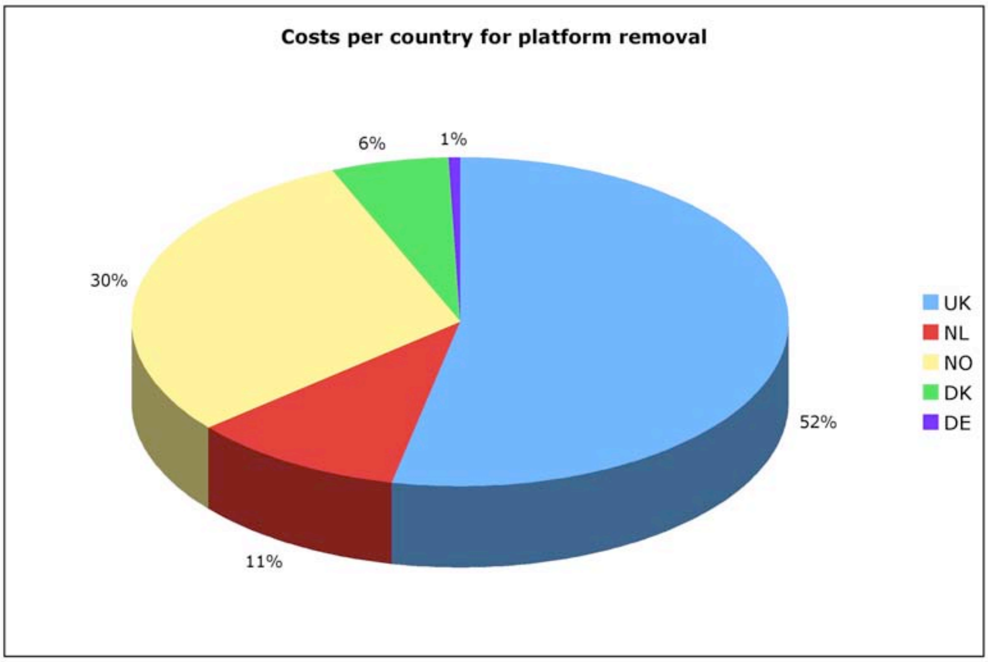

Figure 8.3. Costs for platform removal based on best estimates (see Figure 8.2.) Note: similar to estimates of Aker solutions (Chapter 3.3)

8.3. Basic assumptions in calculating potential cost saving of leave-in-place option

Leaving platforms in place is within current OSPAR regulation generally not an option. Exceptions to this rule are the derogations mentioned in OSPAR Decision 98/3, applying to gravity-based concrete structures and some steel jackets of more than 10,000 tons. Considering the conclusions of the previous chapters that full removal of platforms does not necessarily provide a substantial environmental or ecosystem advantage above the leave-in-place option, it is worthwhile to look further into the extent to which a leave-in-place scenario would save costs.

The leave-in-place option is in some places not practical due to spatial planning and safety issues: interference with shipping lanes, military zones, etc., but also liability issues and high costs associated with monitoring or maintenance could make it unattractive to leave a structure in place. These considerations are not taken into account in this paragraph, as they will have to be dealt with on a case-by-case basis.

The calculation of potential cost savings is based on the subdivision of costs presented in Chapter 8.2. (see Table 8.2 and Figure 8.3). In general, four core elements account for over 65% of the total decommissioning costs: topside removal, jacket removal, operations and well plugging and abandonment. Below, we briefly discuss three of these elements to understand their relevance to decommissioning costs in a leave-in-place scenario as compared to a full-removal scenario.

Plugging and abandonment

Wells must always be plugged and abandoned, regardless of the decommissioning option. It is expected that in the future the plugging and abandonment of wells will increasingly influence the decommissioning costs. The current percentage of costs is estimated at 16%. Operators expect this to be on the low end and expect wells plugging and abandonment to rise to over a third of the future spending and maybe even up to 50% of the costs. The variation in cost estimates depends on the integrity of the wells: casings deteriorating, casing cement not blocking the path from the reservoir as designed, condition of cement and steel. Leakages could add up to extra costs. To avoid the escape of hydrocarbons, all well perforations must be sealed, gaps between pipes and casing squeezed shut and the wellheads plugged with concrete. Because a platform can have many wells branching from it, the plugging and abandonment can take months or even years.
Plug and abandonment costs are estimated at about € 1.5 million per well in the SNS (information derived from personal communication). But in de CNS and NNS the plug and abandonment cost can rise up to € 10 million and even € 15 million per well.

In a leave-in-place scenario, there are no savings to be expected in wells plug and abandonment costs.

Removal of topsides

Removal of the topsides comprises approximately 19% of decommissioning costs, 16% in the SNS up to 23% in the CNS and NNS. These costs are highly dependent on contractors, ship availability, technical complexity, weather and the physical condition of the topside after many years at sea. After cessation of production, operators seek for cost advantages in the decommissioning process. When the market is tight, mothballing platforms can be advantageous. To mothball a small platform will cost around GBP 500,000 per year; for a large platform that could be up to GBP 1.25 million per year. These mothballing costs consist of navigation aids, safety and critical equipment maintenance and regular integrity checks (four times a year). Mothballing costs need to be seen in the light of what it costs to heavy lift an ultra large topside and jacket, which can be as much as GBP 100 - 150 million.

In the calculation of cost savings we assume that topsides are also removed in a leave-in-place scenario. Leaving the topside in place generally has a neutral to negative impact on the environment (no significant benefits, whereas large amounts of material is lost to recycling or reuse), whereas it poses significant safety risks as the topside deteriorates.

Jacket removal

The costs related to removal and disposal of the jacket can be a substantial portion of the overall costs of decommissioning. They are estimated to account for 16 to 25% of the total removal costs of the installation, in most of the cases differing between 16% in the SNS and 21% in the CNS and NNS. The diversity and range of complexity of facilities makes the removal alternatives differ: not one removal technique will be most appropriate or cost-effective in all cases (MMS, The Politics, Economics, and Ecology of Decommissioning Offshore Oil and Gas Structures, 2001, Byrd). Removal in one piece has the advantage of requiring the least amount of offshore work and consequently the least energy and the lowest costs. This method is generally only practical for the smaller topsides (<5,000 tons). Anything where more ship movements are required leads to increased costs and environmental impact.
Single lifts should now be possible until depths of nearly 100 m, but this figure is also a simplifying assumption for cost screening: there are and will be exceptions (personal communication). The transportation to the onshore facilities represents another significant portion of total removal costs. Distance to shore and facility determine the size of costs.

For the partial removal scenarios the cost of jacket removal vary. The costs associated with leaving jackets in place have a limited impact on operational cost. This also accounts for other sub-scenarios such as toppling, partial removal/and relocation. Actually, cutting, lifting and moving the jacket to another location cannot be regarded as a cost saver in relation to complete removal. A scenario where the jacket is toppled would reduce the maximum lift requirement. Toppling the jacket can be done by winching the structure onto its side. This scenario could reduce the costs by 50% in relation to the costs of total removal (MMS, 2001; SapuraAgercy, 2010, Iwaki Platform, Japan).

Leaving the jacket in place would lead to cost reductions in the components of jacket removal, onshore disposal and project management. On the other hand, costs of survey and monitoring are likely to rise. To keep it simple and avoid overestimation of cost savings, we only consider the component of jacket removal as a cost-saving factor.

Derogation and cost reduction

Some structures, for example, can presumably not be taken out due to safety risks in relation to technical impossibilities. Technically speaking, it will be often not be possible to take away gravity-based structures. Removal is thus not included in industry cost, as it is already acceptable to leave the structures in place. It is estimated that removal of large concrete gravity-based structures, which are currently eligible for derogation, could cost an excess of GBP 7.5 billion.

Does the leaving in place of – part of – platforms lead to cost savings? This chapter explores the opportunities. Cost savings are expected to be possible only by leaving the structures in place. Cost savings will diminish once structures are being moved, because then a large part of the costs are sunk (personal communication). The leaving in place of parts of large steel installations could potentially form a cost win; small steel is not expected to be that beneficial, unless left wholly in place, especially not when towing to reef areas is involved. As mentioned, a question for Phase 2 will be if newly derogated platforms are likely to remain in situ or be removed.

Generally concrete structures are subject to the OSPAR 98/3 derogation - allowing for a leave-in-place solution - so these costs are not included in cost-saving calculations. In addition to this, it can be considered that several gravity-based and steel structures are expected to have their decommissioning programmes for leaving in place submitted/ approved before the 2013 OSPAR review.
An overview of OSPAR inventory of offshore structures (in 98/3 derogation category) is presented in annex VIII.

8.4. Influence of the price of steel on decommissioning

Reuse or recycling is typically included in the decommissioning costs (onshore disposal). In principle, there is an income side to this element too in the form of the price paid for the steel that is offered for recycling. Despite the large amounts of steel involved, a steel recycling benefit is not a significant cost driver. It is included in disposal cost calculation. Figure 8.4. is based upon the OSPAR offshore installation database and provides an impression of the amount of steel that will eventually come onshore if all platforms are removed and transported to shore in accordance with current regulations.
If all of the steel is brought onshore (4,265,189 tons), the steel is worth GBP 853 million (steel price estimated at GBP 200 per ton), on a total North Sea decommissioning market of at least GBP 50 billion (less than 2%).

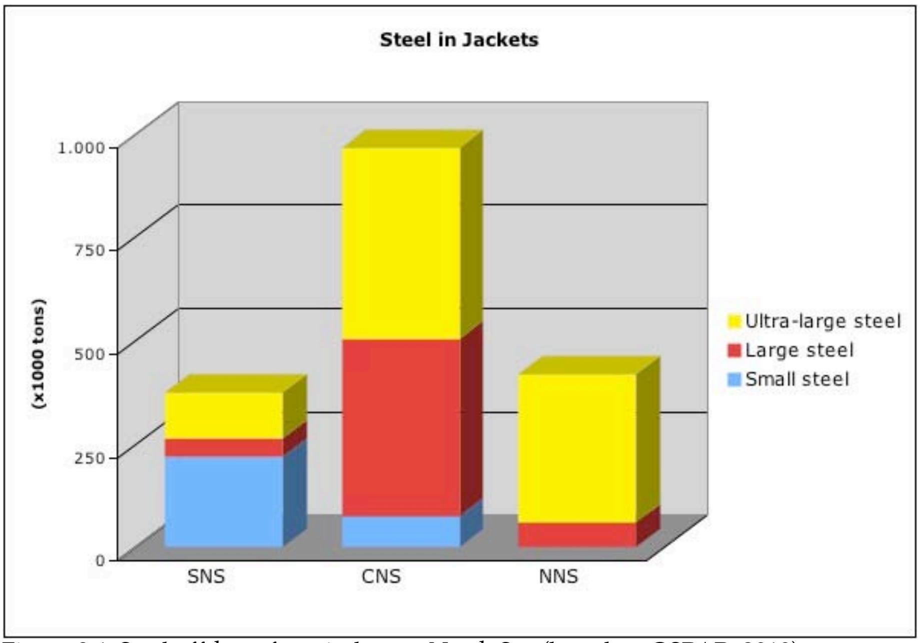

Figure 8.4. Steel offshore from jackets at North Sea (based on OSPAR, 2010).

Figure 8.5 shows recycling revenues when only the North Sea jackets are taken into account.

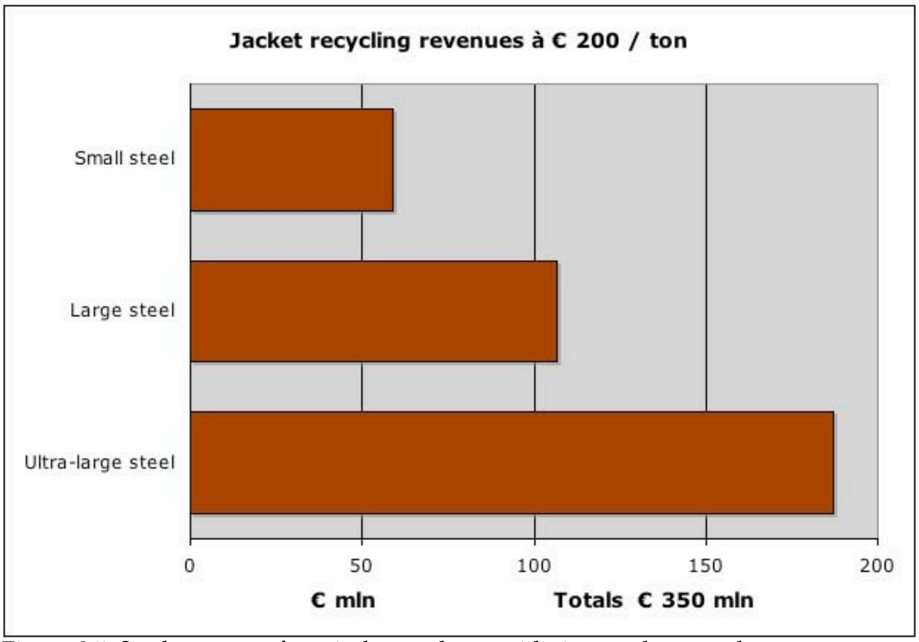

Figure 8.5. Steel revenues from jackets only, considering total removal.

In the decommissioning figures that are generally available, the net costs of dismantling include the credit for recycling. The revenues for recycled steel should be subtracted from cost savings associated with the leave-in-place option.

8.5. Scenarios

This paragraph proposes several scenarios to put opportunities of cost savings into perspective. The scenarios are built on figures derived from available but limited actual data produced by others, mainly OGUK and OSPAR. Please note that the figures are indicative. They have been simplified and assumptions have been made, as it is impossible to assess all platforms in case-by-case scenarios.

The basic facts are mentioned in Table 8.4. This table divides the platforms in the North Sea into four categories with different weight ranges and defines average decommissioning costs.

Table 8.4.

Category	**Weight range in tons**	**Cost range for total removal (million €)**	**Average cost* of total removal (million €)**
Small steel	0 – 2,000t	10 - 30	€ 20
Large steel	2,000 – 10,000t	50 - 100	€ 75
Ultra large steel	> 10,000t	100 - 200	€ 150
Concrete	> 15,000t	300 - 700	€ 500

* Costs exclude well plugging and abandonment, and the numbers mentioned should be treated as directional estimates at best.

In Table 8.5 the total removal costs have been calculated (excluding costs of well plugging and abandonment) of all installations per country, by taking the averages of the cost ranges from Table 8.4.
Table 8.6 shows the total cost of total removal of all platforms per category.

Table 8.5. The total removal cost, excluding well plugging & abandonment.

	# platforms					**rough**	total cost removal platforms				
	UK	NL	NO	DK	DE	**€ mln**	UK	NL	NO	DK	DE
Small	162	125	9	46	1	**20**	€ 3.240	€ 2.500	€ 180	€ 920	€ 20
Large	50	7	42	7		**75**	€ 3.750	€ 525	€ 3.150	€ 525	€ -
Ultra large	31	2	7	0	1	**150**	€ 4.650	€ 300	€ 1.050	€ -	€ 150
Concrete	10	1	9	1		**500**	€ 5.000	€ 500	€ 4.500	€ 500	€ -
sum	253	135	67	54	2						
						Total(rounded)	€ 16.640	€ 3.825	€ 8.880	€ 1.945	€ 170

Table 8.6. Total cost of total removal of all platforms per category.

Category	**# Platforms**	**Total removal cost (mln)***
Small	343	€ 6,860
Large	160	€ 7,950
Ultra large	41	€ 6,150
Concrete	21	€ 10,500
Total	511	€ 31,460

* Numbers shown exclude costs of well plugging and abandonment. Total removal costs, including costs of well plugging and abandonment, are estimated to exceed € 50 billion.

The following graphs visualise the information given in the table of scenarios. Figure 8.6 shows a column chart of all platforms per category in the North Sea and their total cost of removal versus the potential cost savings when leaving the jackets in place.

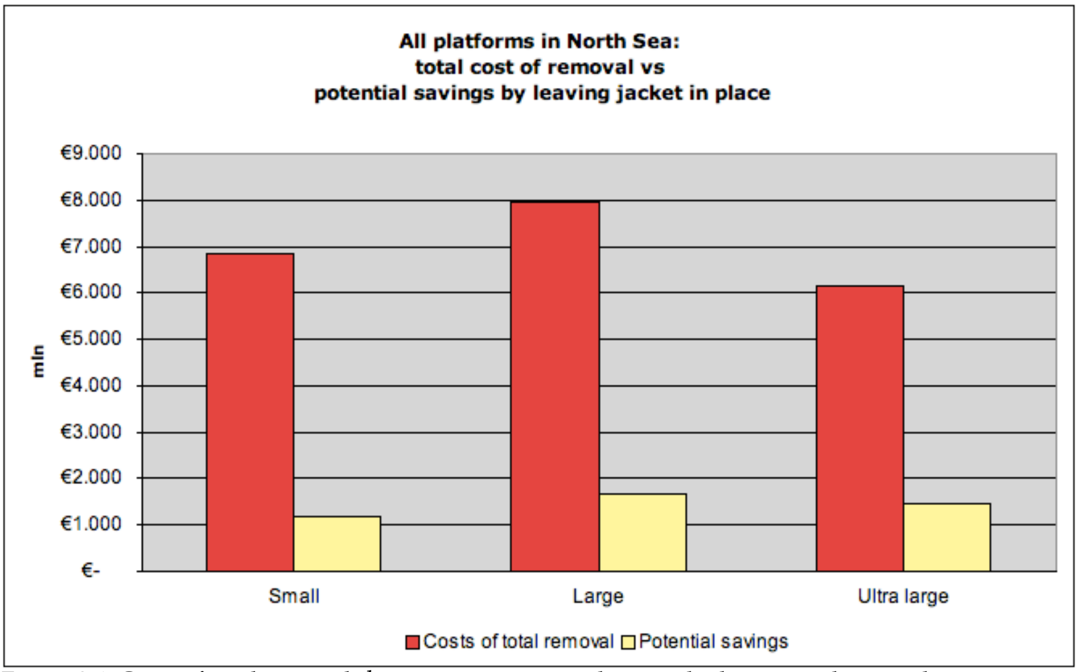

Figure 8.6. Costs of total removal shown versus potential saving by leaving jackets in place, per category.

Figure 8.7 shows the data for costs of total removal versus potential cost savings by leaving jackets in place for the UK only.

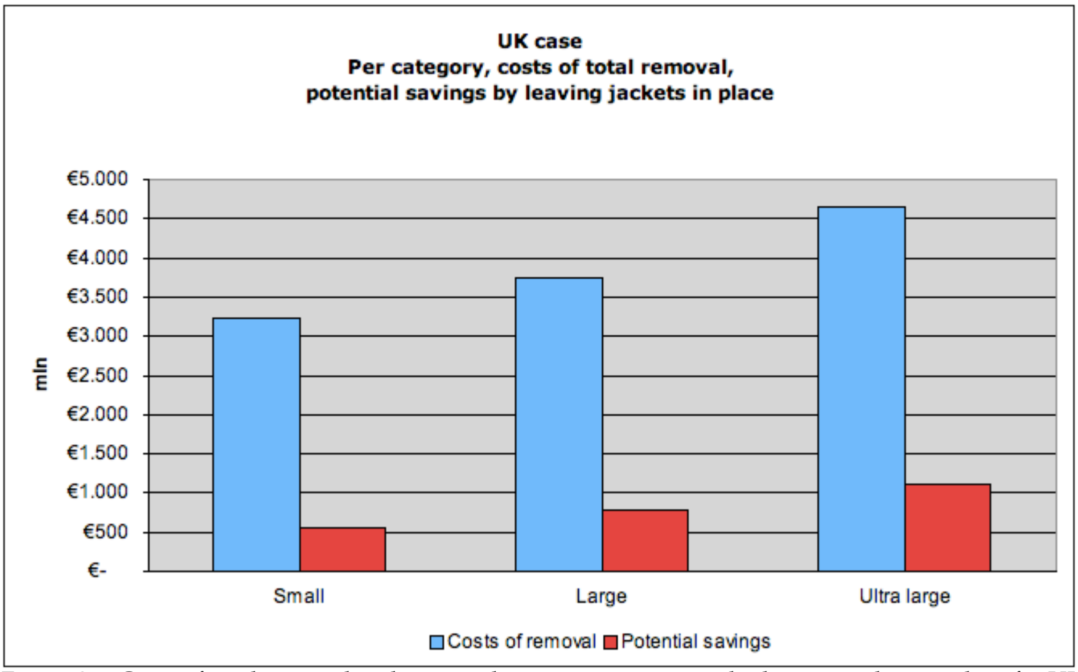

Figure 8.7. Costs of total removal and potential savings per category by leaving jackets in place for UK only.

Figure 8.8 shows the potential savings per country.

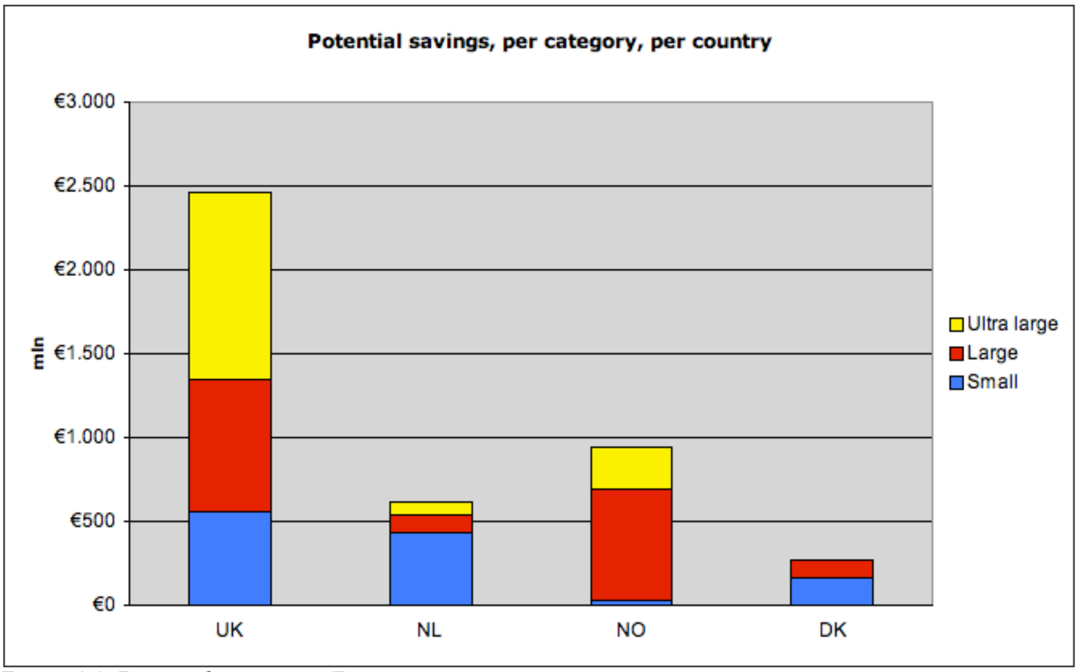

Figure 8.8. Potential savings in Euros per category per country.

Figure 8.9 shows a graph of the shares of total removal cost per category.

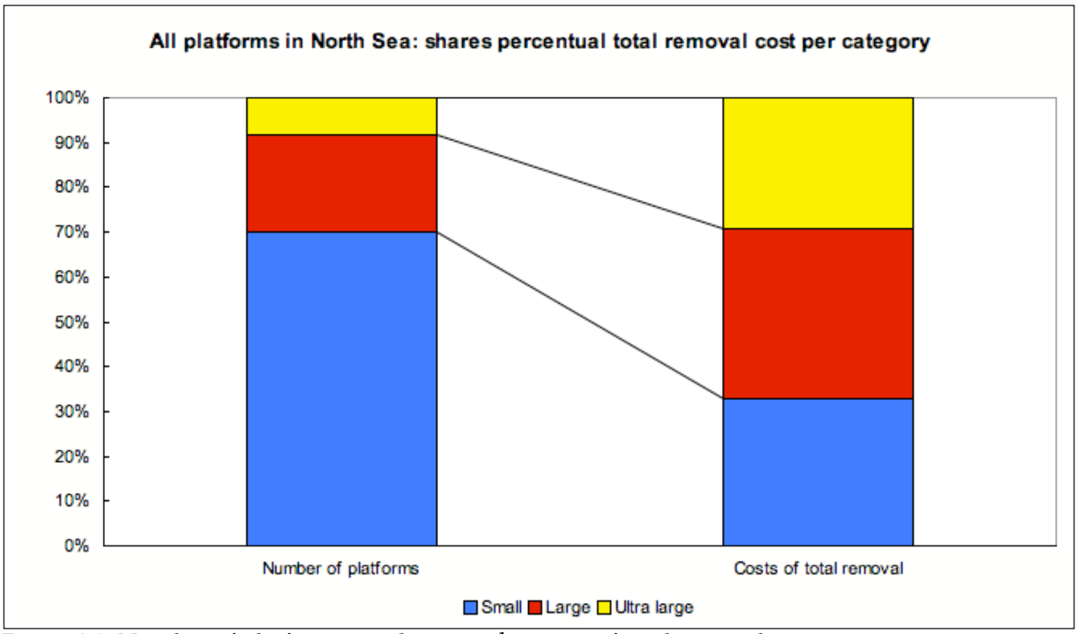

Figure 8.9. Number of platforms in relation to their cost of total removal

Decommissioning of platforms always demands a case-by-case approach, as each platform is uniquely built in its own settings and location. Despite this insight, we calculate below potential cost savings for different variants of the two extreme scenarios of full removal and leave in place. As mentioned, it is assumed that the topsides are always removed.

Consequently, they have been left out and the assessment simplifies the calculations by only working and counting with the jackets of the structures. Table 8.7 provides five scenarios that show directional outcomes of total cost savings. The costs of jacket removal have been estimated (of the total removal cost) and averaged at 17.3% for small jackets in the SNS and at 21% for large and 24% for ultra-large jackets in the CNS and NNS. These figures are derived from OSPAR Offshore database and the Oil & Gas UK – 2010 Decommissioning Insight report.

Table 8.7. Scenarios on potential cost savings leaving jackets in place versus the total removal of the jackets.

	Scenario Total removal			Scenario 1			Scenario 2			Scenario 3			Scenario 4			Scenario 5		
	#Jackets left in place	Rest total removal	*savings € mln*	#Jackets left in place	Rest total removal	*savings € mln*	#Jackets left in place	Rest total removal	*savings € mln*	#Jackets left in place	Rest total removal	*savings € mln*	#Jackets left in place	Rest total removal	*savings € mln*	#Jackets left in place	Rest total removal	*savings € mln*
Small	0	343	*€0*	10	333	*€35*	25	318	*€87*	75	268	*€260*	170	173	*€588*	343	0	*€1.187*
Large	0	106	*€0*	10	96	*€158*	30	76	*€473*	50	56	*€788*	106	0	*€1.670*	106	0	*€1.670*
Ultra large	0	41	*€0*	20	21	*€720*	30	11	*€1.080*	41	0	*€1.476*	41	0	*€1.476*	41	0	*€1.476*
sum(rounded)	0	490	*€0*	40	450	*€900*	85	405	*€1.600*	166	324	*€2.500*	317	173	*€3.700*	490	0	*€4.300*

It must be noted here that the number of oil and gas facilities in the North Sea is measured differently. Figures here are provided by OSPAR (2010), totalling 490 fixed steel jackets. The OGUK counts many more installations, even 630 just on the British continental shelf[9]. Therefore, the amount of savings in Table 8.7 is on the low side when compared to the amount with OGUK figures. Relating to the latter, the outcome of savings in scenario 5 would more or less be in the magnitude of € 9 billion.

Gravity-based structures have been excluded in relation to current regulation and therefore cannot be added to savings. The decommissioning of GBS is not anticipated to be feasible with current industry expectations.

As mentioned in Chapter 8.3 several steel structures might have their decommissioning programmes for leaving in place submitted/ approved before the 2013 OSPAR review. Therefore these structures (considered for derogation) should not feature in any future overall industry cost savings. To simplify this screening, however, we have not left these potential derogations out. For now, they are included in the savings. After the OSPAR 98/3 review in 2013, more accurate sums can be made.

The scenarios provide insight into the potential savings if a number of jackets are left in place. This number depends on the criteria applied and the acceptability of leaving them in place for various other stakeholders. The calculations show cost savings in the different categories. It must be taken into account that the figures are about jackets only. The sum would be larger if other segments of the structure are left in place and are taken into account as well.

[9] Oil & Gas UK - 2010 Decommissioning Insight, p.2

8.6. Risks and opportunities to take into account

It has become clear that there are many challenges in the decommissioning sector. This paragraph briefly touches on a number of issues that need to be addressed in the next phase of our exploration of an alternative decommissioning scenario.

- A major challenge ahead for the decommissioning sector is the abandonment planning. Planning can be beneficial: combine the abandonment of several platforms and the costs will go down. The industry can work together. Planning the abandonment to a large extent in advance and allowing the contractor a work period of several years will also bring down the costs. With the current business-as-usual policy of decommissioning, a bottleneck in the planning seems to arise, which will increase costs. There are currently too little offshore contractors with heavy lifts. A peak is predicted this decade around 2018 for both the CNS and the NNS as well as for the Dutch SNS. The peak is a bottleneck, but as it is recognised, an industry effort of mitigating and smoothing by mothballing redundant platforms can be expected. The main problem will be the availability of the heavy lifts. At this time there are only two ultra-heavy lifter companies (Heerema and Saipem) for very large lifts of up to 10,000 tons. There is one extra heavy lifter planned (Allseas) and one proposed (GM Lifter). The heavy lift vessel that services the decommissioning market will also be used to install new infrastructures. Grouping redundant installations ready for decommissioning could be cost-effective.

- Tax legislation is an important element for the decision-making on decommissioning and on the perceived cost savings. UNCLOS actually entails the legal basis to raise tax. On the basis of UNCLOS, the North Sea has been divided into maritime zones. The North Sea countries all know – in different varieties – a system in which costs for decommissioning are tax deductible: Norway for around 80%, UK between 50 to 70%, Netherlands for around 50% and Denmark for around 50 to 70% (see "North Sea legal and policy framework", LNS130, IMSA Amsterdam, 2011d). This has an impact on the mentioned savings, as these are not all industry-based: governments benefit (>50%) from decommissioning cost savings as well.

- In the decommissioning programmes in the Gulf of Mexico some 90% of the installations are moved to shore. About 10% of the installations are left at sea, but not in situ: they are transferred to reefing locations. For Phase 2 research is to be done on how this could potentially apply to the North Sea. The question would remain if many installations are likely to be left in place when derogated. Should they be towed to other locations (relocated positions)? If so, what is then the impact on the estimated cost savings? This in analogue to an example, the Iwaki installation in Japan, which was decommissioned and toppled in 2010 to meet IMO regulation (-55 m water clearance) at about half the cost of total removal (personal information).

- Do the new and smaller operators have sufficient reserves to make up for future decommissioning costs and/or for possible accidents? Are they capable of fulfilling future decommissioning obligations? In the Netherlands this liability issue is "organised" when the transfer to the new owner takes place. This means that the former owner, the new owner and the Dutch State arrange, secure and legally bind on how to anticipate on the future decommissioning costs. As the new owner takes over, future responsibility cannot be carried back upon the former owner(s), unless agreed otherwise. In the UK this could be very different: future costs may be carried back onto the former owner when the new owner cannot cover them.

- If licensees mean to leave (part of) their structures at sea, the future responsibility and ownership of the platform must be planned. Currently, it could be presumed that licensees, even without OSPAR 98/3 legislation, want to decommission their platforms, as they form a liability at sea. Who will want to be responsible after cessation of production and after all measures have been taken for leaving the platform behind? New legislation must be formulated, defining new ownership and procedures thereto, before licensees will leave anything behind. In analogue to the Gulf of Mexico the liability is transferred to the state. This issue also relates to other North Sea spatial planning discussions, such as shipping, renewable energy, military zones, sand and gravel extraction, fisheries, nature, and marine protected areas.

9. Conclusions

9.1. Environmental impacts of decommissioning

The different environmental impacts of the two decommissioning options of "leave in place" and "total removal" are summarised in Table 6.5. Further research is needed to be able to compare and rank these different types of environmental impacts; both in terms of *type* of impact (e.g. energy versus material) and *duration* of impact (temporal effects versus long-term risks) and to make an overall environmental analysis of the decommissioning options.

Contaminants

When topsides are removed and basic cleaning of the structure takes place, the contaminants on the structure and adjacent equipment left in place have a minimal, yet long-term environmental impact. Further assessment is needed on the removal of anodes. When removed for onshore waste handling and recycling, contaminants present in and on jackets and footings have to be taken into account, e.g. residual NORM and toxic substances present in coatings. This is mainly an occupational health issue.

Marine growth removal

Effects on biodiversity are covered in a separate report (IMSA 2011c). If a structure is removed, marine growth needs to be disposed of as well, causing potential issues with contaminants present in the marine growth; the organic loads might cause oxygen depletion when the structures are in shallow waters; onshore storage and disposal of marine growth can cause odour issues. Compared to shipping the spreading of invasive species caused by removal of the installation is a minor issue. Finally, marine growth increases the weight of structures, causing higher energy requirements and higher emissions to air.

Drill cuttings

When drill cuttings are left in place and stay undisturbed, they have a small local environmental impact on seabed communities. Most contaminants will gradually degrade over time. From an energy and emissions perspective drill cuttings are best left in place.

Seabed clearance

A clear seabed has little environmental benefits and is only preferred if future uses of the seabed require a clear seabed. Assessing the environmental impact of pipeline removal would also require an energy assessment. Here, the same uncertainties apply as found for the installations (see below).

Total energy requirement

The analyses of the energy and emissions impacts of a number of case studies show that there is a very large spread in the estimates of the direct energy requirement. Clearly these projections should be used with great care in assessing which decommissioning scenario is to be preferred. We do find reasonable agreement on the energy involved in recycling and reproducing the materials. The difference is approximately 14 GJ/ton, meaning that any structure for which the direct energy costs (excluding recycling) are substantially higher than 14 GJ/ton is better left in place.

Emissions to air

Emissions associated with direct energy use (vessel movements) have higher emission factors than those associated with material production. Therefore, not removing a structure might produce less emissions even though the corresponding energy use is larger. It should be noted, however, that the large uncertainties present in the energy assessment will be enlarged by the calculations of emissions. No information was found on specific measures that could reduce emissions during a decommissioning operation (type of fuel, cruising speed, logistic optimisation, etc.)

Waste and resources

When retrieved to shore, most material will be recycled. Currently, there appear to be limited possibilities for reuse of material and equipment. Most of the materials that are brought onshore and cannot be reused or recycled are inert. This residual waste stream (<10%) ends up in landfills. The visual impact of demolition yards might be a concern. Leaving in place has no significant impact from a material-scarcity point of view.

9.2. Health and safety impacts of decommissioning

In general, risk assessments have been made for operational platforms with a focus on the health and safety of the operator's personnel. As a choice for leaving a structure (partly) in place is considered, long-term health and safety risks for the wider community need to be taken into account as well. For densely trafficked areas a leave-in-place scenario might not be possible.

Health and safety issues for personnel related to decommissioning

- The risk of decommissioning platforms with steel substructures is manageable and poses hazards that are comparable to what is acceptable in the industry.
- Generally, for steel substructures, the safest option is to leave the structure in place, whereas total removal or toppling poses the highest risks. Risks associated with partial removal lie somewhere in between.
- With concrete substructures health and safety risks for personnel could be higher than acceptable in the industry. Depending on the details, leaving the structure in place often is the only acceptable option from a health and safety perspective.

- For concrete substructures, the second-best option is to re-float them and tow them for disposal at a deep-sea location or onshore. Partial removal that involves cutting of the concrete columns is the most dangerous option.

Health and safety issues for ships

- Health and safety issues from collisions depend strongly on the location of the decommissioned platform.
- A quantitative risk assessment for longer-term risks of collision is missing.
- Collision incidents with remaining structures are most likely with fishing ships, but the consequences from a collision with merchant ships could be more far-reaching.
- When the structure has been degraded to a point that the part above sea level is lost, lack of visibility becomes an issue and special measures are required.

9.3. Technical cost

On the basis of the assessment in this report the following conclusion may be drawn:

- The total decommissioning spending for the North Sea is currently indicatively estimated at approximately € 53 billion.
- The development of the market segment of well plugging & abandonment can have an increasing impact on the cost side. As this plugging & abandonment will always have to be done, it is not of influence on potential cost savings of a leave-in-place scenario.
- The decommissioning peak could sort itself out by mothballing platforms and by increasing market developments in the decommissioning industry.
- The larger and heavier the jacket, the more costs can be saved.
- When taking all categories into account, a range from € 1 billion to 9 billion cost savings can be realised if the leaving-in-place scenario is an option (only jackets accounted for). This should be seen as an estimate. It should be noted that the costs and savings are related to a time range, i.e. over the next 40 years.
- Legislation change is needed to be able to follow up on the scenario outcomes. Developing legislation on the structure ownership and liability issues will need special attention.
- A steel-recycling benefit is not a significant cost driver and is included in disposal cost calculation.

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Annex I. Maps of oil and gas facilities in the North Sea

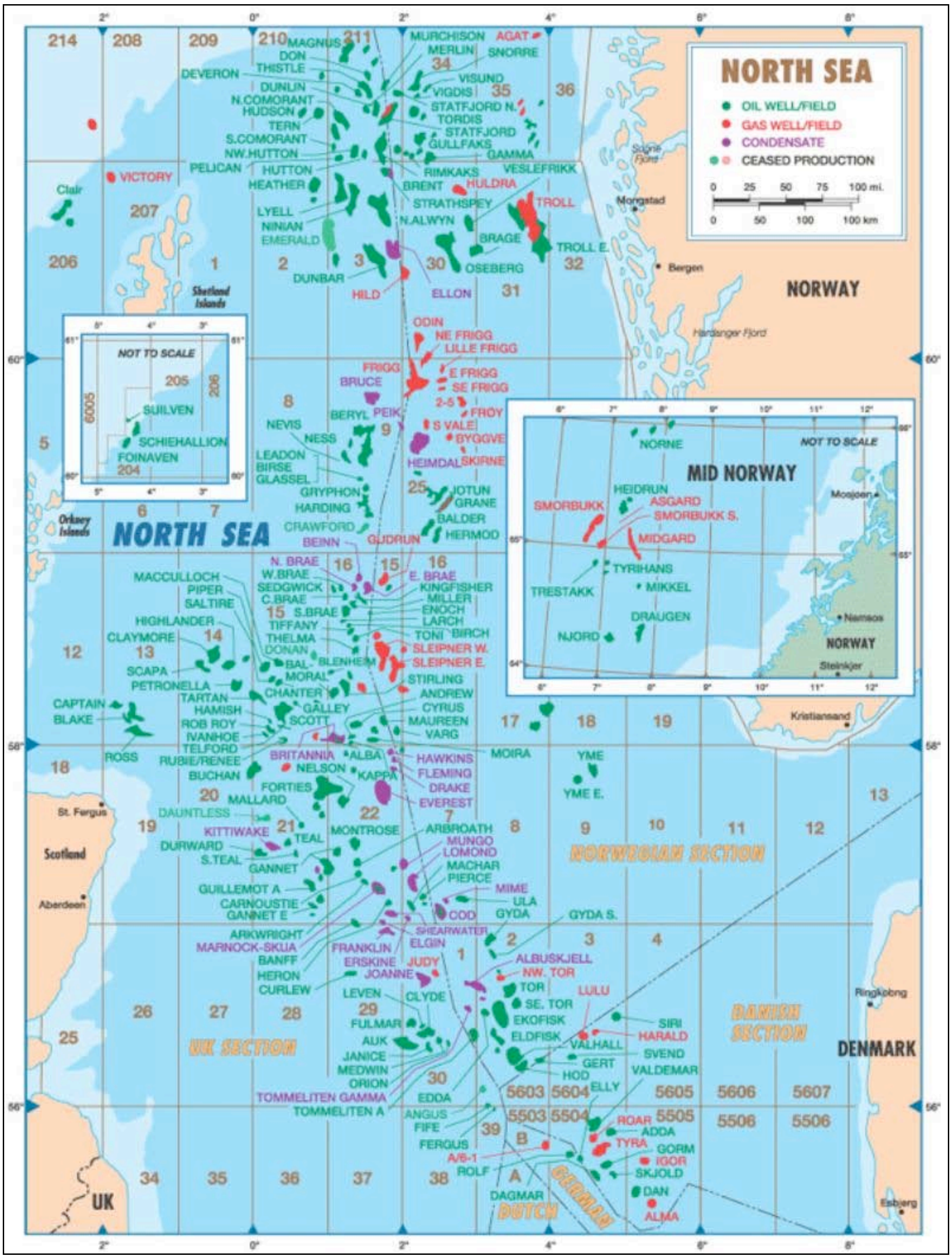

Figure I-a. Map of the central and northern North Sea with oil and gas installations plotted (WorldOil.com).

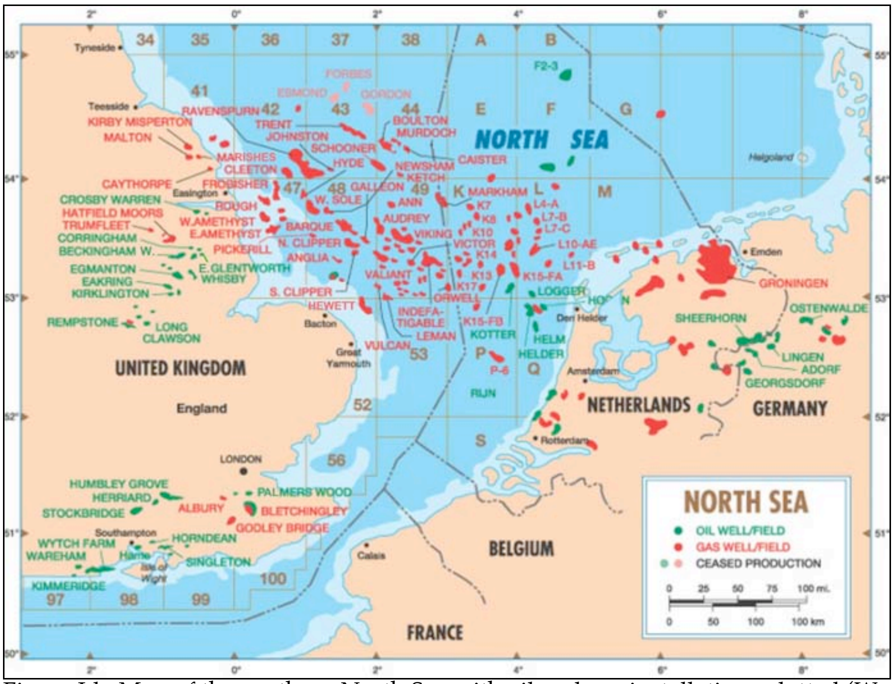

Figure I-b. Map of the southern North Sea with oil and gas installations plotted (WorldOil.com).

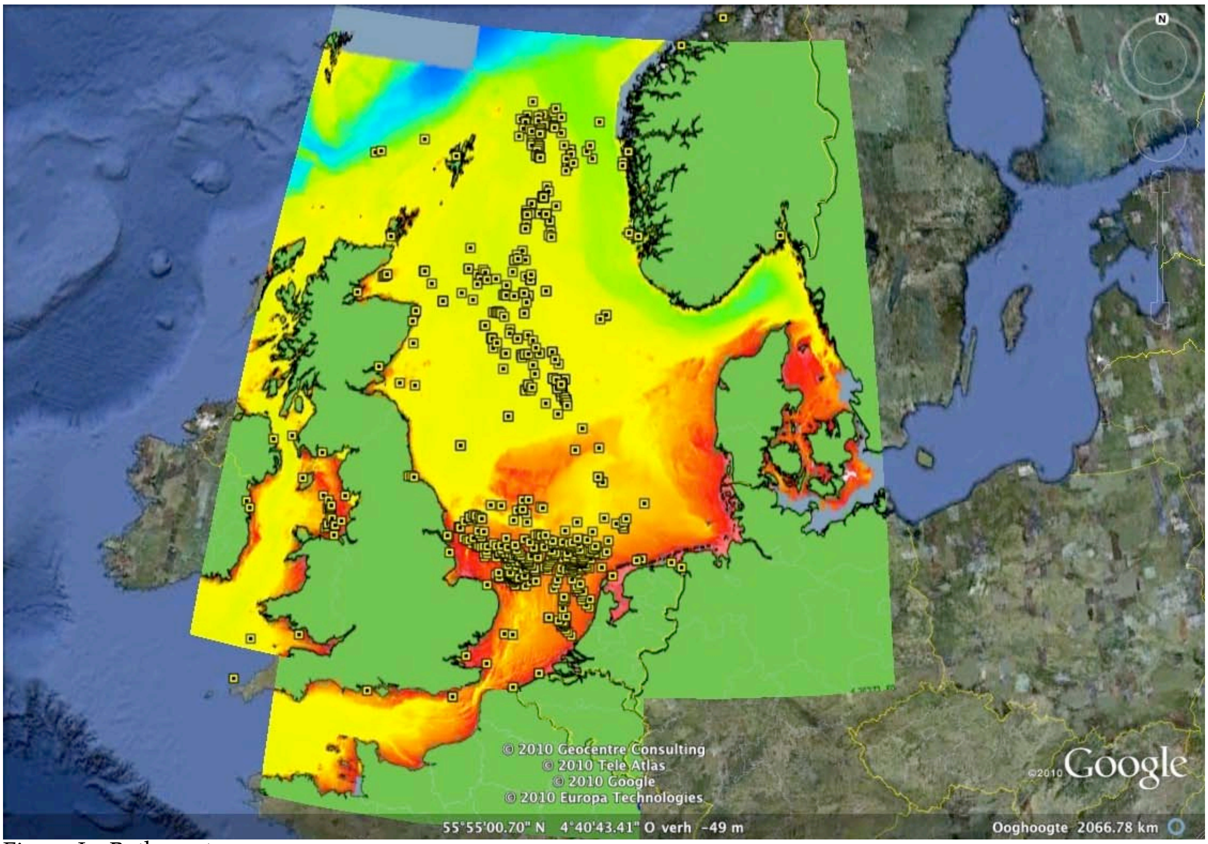

Figure I-c Bathymetry.

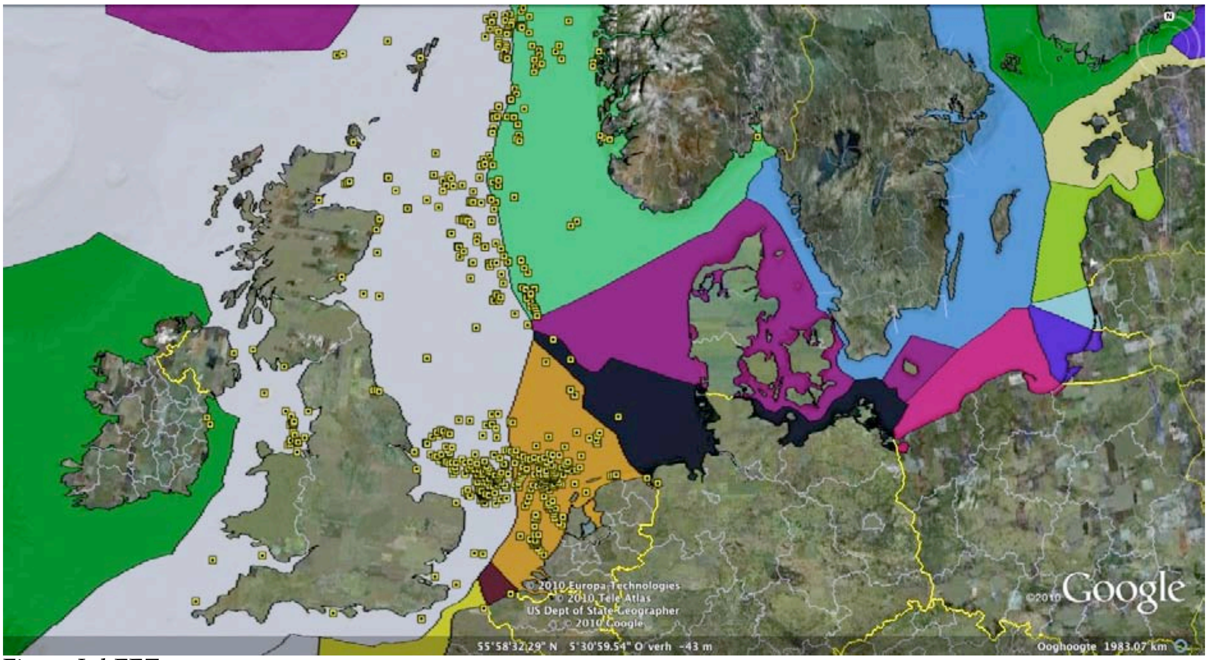

Figure I-d EEZ.

Annex II. Cases decommissioning North Sea

Cases:
A. North West Hutton
B. Frigg

A. North West Hutton

A.1. Facts of North West Hutton installation

Location	Block 211/27a, NNS, located 130 km north ast of the Shetland Islands, UK.
Timeline	Installed 1981, cessation of production 2003, decommissioning programme 2006, topside removed 2009.
Operations	Integrated oil and gas drilling, production processing and accommodation facilities.
Field owners	Amoco Exploration Company 25.8% (operator), CIECO E&P 25.8%, Enterprise Oil 28.4%, Mobil North Sea 20%.
Contractor	Heerema
Depth	144 m
Substrate	Sand, silt and very stiff to very hard clay.
Marine value	Typical of large areas of the NNS. Marine mammals have been sighted and a variety of seabirds use the area for feeding and breeding (May and June). Coral *Lophelia pertusa* (EC Habitat Directive protected) grows on the jacket structure. No designated conservation areas or vulnerable species in the area.
Economic value	Moderate economic value for fishing activity, which is generally low compared with other areas of the North Sea. Commercial shipping traffic: the majority is directly associated with oil and gas activity.
Structure	Large steel platform; total of 37,000 tons.
Topside	Total topside weight: 20,000 tons; over 97% of the topside weight comprises carbon steel.
Jacket	Eight legs; x-braced steel space frame fixed to the seabed; 17,500 tons including the weight of the piles and the steel template of 290 tons fixed on the seabed; ~100 tons of cement grout around the base of the legs (result of repairs during installation).
Footing	Extends 40 m above seabed; comprising 5.5 m diameter legs; accounting for ~50% of the total weight of the jacket.
Gas pipeline	~13 km; trenched to a depth of 0.45 m below the seabed at the time of installation; currently fully trenched along 100% of its length; buried along approximately 73% of its length.
Oil pipeline	Not trenched and lies on the seabed.
Drill cuttings	Maximum depth of 5.5 m in the centre; rapidly thins to approximately 1.5 m around the jacket legs; extends to between 20 m and 70 m beyond the jacket legs; surface area of ~0.02 km^2; total volume of the pile including the seawater is ~30,000 m^3; consists predominantly of rock (48%) and seawater (45%); residual material (7%) is the oil for drilling fluid and small amounts of chemicals used in the drilling operations.

A.2. Decommissioning status

The decommissioning programme (approved April 2006 by DTI) requires:

Topsides and jacket	Completely removed for recycling onshore
Jacket footing	Left in place, including the piles for fixation to seabed (OSPAR derogation)
Drill cuttings pile	Left in place (to allow the seabed to recover naturally)
Oil pipeline	Trenched and buried
Gas pipeline	Left in place (already trenched)

- OSPAR Decision 98/3 allows derogation for all of the footings of steel installations weighing more than 10,000 tons and placed in the maritime area before 9th February 1999.
- In 2009 the topsides were removed. The other activities include the jacket lift preparation and removal, the disposal of topsides and jacket, pipeline trenching and burial activities, and subsea surveys. Total decommissioning costs are estimated at GBP 250 million.

- Studies conducted by Fairfield's engineers revealed that the field area can be redeveloped and that the remaining estimated reserves of the field could be tapped. In September 2009, Fairfield Energy made an agreement with the field owners to acquire a package of assets in the British North Sea, including the North West Hutton field.

A.3. Assessment of disposal alternatives

Studies evaluating the potential reuse in the present location show that this is not feasible, due to the remote northern location and extreme weather conditions. Possible reuse of the platform at another location is not feasible due to the age and condition of the equipment. In the absence of such opportunities the only alternative is to consider decommissioning the facility.

Topside

Various removal methods are possible, but reverse installation is considered to be the preferred option, due to higher safety risk and as yet unavailable single-lift technology. The former accommodation block is now used as offices on the yard.

Jacket

The technical considerations and possible derogation led to three options for decommissioning the jacket:

Summary of jacket and footing options	Jacket and footing removal	Jacket and footing partial removal	Jacket removal to -100 m to top of the footing
Probability of loss of life No. of Lost Time Injuries (LTI)	14% 16	13% 15	5% 6
GHG CO_2E in tons	42,000	44,000	38,000
Total Energy requirement GJ	520,000	568,000	559,000
Persistence yrs	None	> 500	> 500
Impact on fisheries	None	No-go fishing area	No-go fishing area
UK employment impact man/years	196	Not studied	66
Technical risks of failure	45% (damage to footing, cutting difficulty and complexity)	70% (cutting bottles is high technical risk)	23% (cutting difficulty and complexity

1. Safety risk: full or partial removal of the jacket footing would involve an unacceptable level of safety risk, particularly for the divers who would be required for key parts of the operation. The risk of someone being killed during full removal operations (1 in 7 chance = 14%) is much higher compared to removal to the top of the footing (1 in 20 chance = 5%). For partial removal of the footing it is 13%.
2. Technical risk: risk of project failure for partial and full footing removal was 70% and 45% respectively, which is (unacceptably) high compared to removal to the top of the footing (23%).

3. Potential risk for fisheries (trawling): leaving the footing in place and partial removal would result in the continued exclusion of a small area of the seabed for fishing activities.

The North West Hutton jacket is removed down to the top of the footing and returned to shore for reuse or recycling. The footing structure remains in situ. The assessment of full removal indicated that the most significant risks were associated with the removal of the footing and the lower-most section of the jacket.

Drill cuttings piles

The cuttings pile consists of about 30,000 m^3 of oil-based and water-based drill cuttings together with seawater, covering a relatively small area of around 0.02 km^2.

Re-injection options are not legal and there is no onshore treatment facility that is commercially available to treat the drill cuttings.

The technical uncertainty for removal is reflected in the much higher costs and in safety exposure; the risks are nearly ten times greater than the in-situ options.
The recommended option is therefore to leave the pile in situ to recover naturally. This is also the best environmental option.

Pipelines

The options studied for the pipelines were: leave in situ on the seabed; trench and bury to below the seabed; and recovery of the pipelines.

Technical and safety consideration: all of the options are feasible, although there is almost a ten-fold increase in the safety risk associated with the recovery options.
Trenching and burying is the best solution as it achieves a lower operational safety risk and energy use and minimises risk to other sea users.

A.4. Environmental impact

Footing

The leave-in-situ option would have the least environmental impact. There is no over-riding environmental imperative for removal, and to remove them completely would incur associated risks due to the need to remove at least 90% of the cuttings pile.

Drill cuttings

a. Best option is to leave the pile in place to allow the seabed to recover naturally. The materials within the pile and the immediate surrounding area will, however, remain for a long period: 1,000 to 5,000 years.

b. The environmental assessment showed that, in spite of predicted longevity of the pile in situ, the impact would be minimal and recovery of the seabed would proceed, albeit very slowly.
c. Recovery to shore would ultimately involve the use of valuable landfill capacity.
d. Removal and transport to shore followed by treatment and disposal would have a negative impact on communities due to the large movement of materials and landfill capacity.

Pipelines

a. Environmental concerns: not any associated with the pipeline decommissioning options, as these involve relatively minor localised disturbance for trenching or removal.
b. Potential hazards and environmental impacts of recycling and disposal: for the pipeline removal option there are, e.g., the potential loss of the concrete coating to the sea as the pipeline is lifted, the removal of the concrete, and hazards from the corrosion coating system during cut-up/disposal. The predicted deterioration of the pipelines indicates that they could remain for at least 300 years.

A.5. Costs

Total costs: GBP 250 million (2010 money and risked). The costs have exceeded the initial budget of GBP 160 million (2004 money and unrisked), but not one on one comparable.

A.6. References

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B. Frigg

B.1. Facts of Frigg Field

Location	Boundary between UKCS (Block 10/1) and NoCS (Block 25/1), Frigg is 190 km from the Norwegian coast and 360 km from the British coast. Treaty between UK and NO confirms that 60.82% of the resources are located on the Norwegian side of the border.
Timeline	Production started 1977 and stopped October 2004. Construction of the platforms began in 1973. Cessation between 2004 and 2012.
Field	Quarters Platform (QP), Treatment and Compression Platform 2 (TCP2), Treatment Platform 1 (TP1), Concrete Drilling Platform 1 (CDP1) and Drilling Platform 2 (DP2). Drilling Platform 1 (DP1) steel structure was damaged during installation in 1974.
Field owners	No: TOTAL Norge 47.13%, Norsk Hydro 32.87%, Statoil 20%; UK: TOTAL UK 100%.
Contractor	Aker Kvaerner
Depth	100 m (water); reservoir depth: 2,000 m.
Substrate	Ecocene sand, Frigg Formation, olive-gry coloured fine sand 90%, small amounts of pelite and medium sand.
Economic value	The Frigg area is today regarded as of medium importance to the fisheries. Assuming that this situation is unchanged, the impact of leaving the substructures in place has been assessed by DNV to be "small negative" to "moderate negative", due solely to their potential obstruction to fishing activity in the area. The Norwegian Institute of Marine Research has noted that after 30 years of operation the Frigg Field installations have become part of the ecosystem. It is therefore their opinion that leaving the three concrete substructures in place will not harm the fishery resources or other marine fauna. There is a low level of shipping in the vicinity of the Frigg Field, with no major shipping routes passing within 10 nautical miles. The statistical probability of a collision by fishing vessels or passing vessels has been judged by navigation experts to be low.
Liability	Remains with licensees and the question of long-term residual liability should be discussed and agreed with the present owners and authorities in order to make suitable arrangements.
Integrity	In the next 100 years, very little physical damage to the three Frigg Field concrete substructures is predicted. After that time corrosion of the horizontal reinforcement in the splash zone is likely to give rise, initially to spalling of the concrete, and later to local damage, which may be expected in roughly 100 to 150 years. The overall integrity of the structures will however not be affected. The columns of TCP2 and TP1, and the walls of CDP1, are predicted to remain in place for 500 to 800 years before collapsing. The above-water deterioration of all three structures will take place relatively slowly and the navigation aids may be expected to remain in place for several hundred of years.
Structure jackets	Two are of steel and three of the substructures are made of concrete.
Topside facilities	Five topsides, total weight: 45,100 tons.
Jacket	Removed: three steel substructures (jackets), total weight: 20,000 tons. Left in place: three concrete substructures, after removing external steel works. Navigation aids installed on each substructure. Total weight: 809,000 tons.
Pipelines	All pipelines were cleaned and every well plugged during 2004. All the infield and interfield sea lines, umbilicals and cables have been removed within the 500-metre zone where they could have created potential obstruction for any bottom-trawl fishing in the future.
Drill cuttings	Leave in place: drill cuttings on the seabed accumulate (max. 20 cm thick). They derive from the topmost level of a well and contain no petroleum residues or polluting chemicals.

B.2. Decommissioning status

The whole removal operation is due to be completed in 2012. Navigation aids will be installed on each substructure.

All topsides and steel jackets (DP2, QP, DP1, TCP2, CDP1, TP1)	Removed and disposed onshore
Concrete platform substructures (TCP2, CDP1, TP1)	Left in place after removing as much of the external steelwork as is reasonably practicable
Drill cuttings pile	Left in place
Infield pipelines and cables	Removed and disposed onshore

B.3. Assessment of disposal alternatives

The general principle has been adopted that if reuse is not possible, either at the current location or at another site, then as much of the equipment and materials as practicable will be recycled. The assessment process is based upon the waste hierarchy, which values reuse above recycling, and disposal onshore above disposal at sea.

B.4. Summary of disposal alternatives

A number of possible non-oil and gas uses for the platforms have been evaluated including: deep-water disposal, cutting to -55 metres, leave in place, reuse potential, artificial reefs, wind generators, on-land disposal. The feasibility of many of the options is technically uncertain and none of the arrangements are judged to be economically viable. No potential reuse application has been identified for the three Frigg Field steel substructures at another location. The three Frigg Field substructures would have some potential for reuse at another location, if it were possible to refloat and relocate them without undue technical risk or risk to personnel. These reuse options involve great technical uncertainties, and none were regarded as financially viable. After an overall assessment, including environmental impact assessment performed by Det Norske Veritas, the owners recommended that the concrete structures should be left in place, suitably marked, while the topside facilities were removed and brought to shore for disposal.

B.5. Comparison of disposal alternatives and their environmental impacts

Deepwater disposal

Deep-water disposal will eliminate major environmental impacts onshore during the deconstruction phase. But society's general aversion to offshore dumping makes this alternative unattractive.

Leave in place

The energy consumed to prepare the three concrete substructures to be left in place is significantly less than the energy to remove and deconstruct them, which is equivalent to running more than 105,000 family cars for one year. The emissions of carbon dioxide, nitrogen oxides and sulphur dioxide to atmosphere are approximately 5% of the equivalent values for on land-disposal of the concrete substructures.

Reuse potential

An option is to use the concrete substructures as bridge foundations for fjord crossings. Such a use has the potential to provide cost savings on the bridge construction cost. The substructures could also be incorporated into some form of quay foundation or be used as landfill for industrial purposes. The feasibility of such schemes depends upon the ability to safely refloat the substructures and on the particular site conditions where they would be reused. However, the risks associated with refloating the Frigg Field concrete substructures are many times higher than acceptable. No arrangement to reuse the facilities at their present location has been identified which is both technically feasible and economically viable at the present moment. The uncertainties inherent in trying to refloat the concrete substructures mean that it is not possible to reuse them at another location.

Artificial reef

The studies show that none of the alternatives are likely to have a great enhancement effect on pelagic fishery, or a significant positive impact on the total marine environment. The establishment of an artificial reef is only considered to be a favourable option if clearly positive effects can be shown. It is concluded that the use of the installations as artificial reefs is not a desirable reuse alternative.

Wind generators

The study has shown that it is technically feasible to supply power from wind-generators located at the Frigg Field to other platforms in the same general area of the North Sea. The price of electricity generated by offshore wind power systems at Frigg has been estimated to be considerably higher than the cost of electricity generated offshore from the combustion of hydrocarbons. It is judged that electricity generated by offshore wind-generators located on the Frigg Field installations would not be competitive in the energy market, even if the cost of production could be significantly reduced. The cost uncertainties associated with the conversion and maintenance of the ageing Frigg installations and their logistical support, also plea strongly against their use as wind generators. It should be noted that any consumer of wind generated electrical power would need to install and maintain a back-up source of power for times when there is insufficient wind to meet the required power demand. The export of wind-generated electricity from Frigg to shore is not economically viable due to the high transmission cost (Frigg is 190 km from the Norwegian coast and 360 km from the British coast).

On-land disposal

The concrete platforms represent the technically most difficult challenges, as they were not designed for removal at the time of construction. The concrete cut from the substructures would be crushed onshore to allow recovery of the steel and concrete. The steel would then be sent for re-smelting whilst it is anticipated that the crushed concrete would be reused or disposed of in landfill. Environmental studies have shown that unlike steel structures, the significant energy consumption (and consequent discharges of CO_2) required to bring ashore and the recovery of the steel embedded within offshore concrete substructures, generally exceeds the energy consumption and discharges required to replace that steel using iron ore.

B.6. Summary of environmental impact

The principle has been: reuse before recycling and recycling before landfill. About 80% of the material has been disposed of, and the reuse percentage is 97.8%.

The energy consumption and the CO_2 emission during the work necessary for removal and on-land disposal of the three concrete substructures is shown, compared with equivalent values if they are left in place after removal of the external steelwork.

Concrete substructures	Leave in place	Removal and onshore disposal
Energy consumption	178,000 GJ	4,033,000 GJ
CO_2 emission (in tons)	13,750t	265,000t

A comparison of the environmental impacts of different decommissioning options for the three concrete substructures taken together has been made and the main parameters are given.

The following table presents a summary of the environmental impact of alternative disposal arrangements for all three concrete substructures (TCP2, CDP1 and TP1).

	A: Refloat, tow to shore, demolish and dispose on-shore	B: Remove external and internal steelwork, refloat and dispose at deep-water location	C: Remove internal and external steelwork and cut down substructure to provide a clear draft of 55 m	D: leave in place removing as much external steelwork as reasonably practical
Total energy (million GJ)	4.0	2.2	3.1	1.0
CO_2 emissions (1000t)	265	108	168	14
Physical impact environment	Moderately negative	Moderately negative	Large/moderately negative	Moderately negative
Aesthetic impact	Moderately negative	None/insignificant	None/insignificant	None/insignificant
Material management	Moderately positive	None/insignificant	Small/positive	None/insignificant (small positive)
Littering	None/ insignificant	None/insignificant	Small/negative	Small/negative
Impact on fisheries	Moderately positive	Moderately positive	Moderately negative	Moderately negative
Free passage at sea	Moderate positive	Moderately positive	Moderately positive	Moderately negative

B.7. Costs (2002 money)

The interest of each licensee in the Frigg licences will be the basis for the allocation of disposal costs.
The estimated total cost of the recommended disposal arrangements for the Frigg Field is 3483 MNOK/£266.3 m. The total cost of the work necessary for removal and on-land disposal of the three concrete substructures is estimated at 8418 MNOK /£ 643.6 m (€ 1027 m).

Estimated costs for different Frigg Field Decommissioning Alternatives

Recommended decommissioning arrangement: Remove all 5 topsides and 3 steel substructures and dispose onshore. Leave 3 concrete substructures in place after removing external steel work. Remove all infield pipelines and cables and dispose onshore. Leave drill cuttings in place.	3483 MNOK / GBP 266.3 m
Removal of concrete substructure: Remove all 5 topsides and 3 steel substructures and dispose onshore. Refloat 3 concrete substructures, tow to shore and dispose onshore. Remove all infield pipelines and cables and dispose onshore. Leave drill cuttings in place.	11273 MNOK / GBP 861.8 m
Cut down concrete substructures: Remove all 5 topsides and 3 steel substructures and dispose onshore. Cut down the 3 concrete substructures to provide a clear draft of 55 m for shipping. Remove all infield pipelines and cables and dispose onshore. Leave drill cuttings in place.	10417 MNOK / GBP 796.4 m

B.8. References

- http://www.kulturminne-frigg.no/index.asp?mid=133
- http://www.total.no/en/default.aspx?channel=64592ff6-9a3e-48e5-b35a-7b8e80d63505
- Frigg Field Cessation Plan – TOTAL E&P NORGE AS
- Norsk oljemuseum
- OGP_2003_Disposal of offshore concrete gravity platforms in the OSPAR Maritime Area
- TOTAL: From a Chinese butterfly to nails
- TOTAL 2002 Frigg Field Concrete Substructures

Annex III. Pipelines North Sea

Pipeline	Trajectory	Length	Diameter	Substances	Operator
Europipe I	Runs from the Draupner E riser platform in the North Sea to a receiving terminal at Dornum on the German coast.	716 km	40 inches	Gas	Gassco
Europipe II	From the Kårstø processing complex north of Stavanger to the receiving facilities at Dornum in northern Germany.	658 km	42 inches	Gas	Gassco
Franpipe	From the Draupner E riser platform in the North Sea to the receiving terminal at Port Ouest in Dunkerque on the French coast.	840 km	42 inches		Gassco
Frostpipe	From the Lille-Frigg and Frøy fields in the Frigg area to Oseberg.	82 km	16 inches	Oil	TotalFina Elf
Haltenpipe	From the Heidrun field in the Norwegian Sea to Tjeldbergodden in mid-Norway.	250 km	16 inches	Gas	Gassco
Langeled	From Nyhamna at the west coast of Norway via Sleipner in the North Sea to Easington in UK. The world's longest export pipeline.	1200 km		Gas	Norsk Hydro
Norne Gas Transport System	Ties the Norne field in the Norwegian Sea into the Åsgard Transport pipeline.	126 km		Gas	Gassco
Norpipe	From Ekofisk to the Teesside export port in Britain.	335 km	34 inches	Oil	Phillips
Oseberg Transport System – OTS	Crude from Oseberg, Veslefrikk, Brage, Frøy and Lille-Frigg is piped to Sture near Bergen.	115 km	28 inches	Oil	
Sleipner Condensate	From the Sleipner fields to Kårstø north of Stavanger for processing.	245 km	20 inches	Condensate	Statoil
Troll oil I	From Troll B to Mongstad near Bergen, reaching a depth of more than 500 metres in the Hjelte Fjord.	86 km	16 inches	Oil	Statoil
Troll oil II	From Troll C to Mongstad. Daily capacity of 315,000 barrels in November 1999	82 km	20 inches	Oil	Statoil
Ula Transport	From Ula and Gyda to Ekofisk, and on through Norpipe Oil.		20 inches	Oil	Statoil
Vesterled	From the Heimdal Riser platform to St Fergus in the UK	361 km	32 inches		Gassco
Zeepipe	From the Troll Gas processing plant at Kollsnes near Bergen to the Sleipner area and from the Sleipner area of the North Sea to a receiving terminal at Zeebrugge in Belgium.	814 km	40 inches	Gas	Gassco
Åsgard Transport	Flexible risers from the floating Åsgard B gas platform tie into an export riser base on the seabed		42 inches	Gas	Gassco

Source: www.subsea.org

Annex IV. Types of hazards

Generic hazardous operations include:

- Well plugging and abandonment
- Cutting of conductors and appurtenances
- Disconnecting, purging and sealing pipelines and risers
- Removal of pipelines, risers and associated substructures
- Making process trains safe
- Final shutdown
- Dismantling of topsides
- Dismantling and removal of jacket
- Complete removal
- Loading to means of transport and fastening down
- Unloading from means of transport
- Disposal

Hazards arising during offshore installation decommissioning

- Installations must be isolated from sources of hydrocarbons
- Wells must be plugged and sealed
- Pipelines must be isolated and ultimately disconnected
- Processing plant must be emptied of hydrocarbon liquids and gases, usually by draining, venting and purging with inert gas or water

Hazards arising during offshore installation dismantlement

- Residues could ignite flammable atmospheres, generating significant explosions or flash fires during thermal cutting or grinding.
- There could be exposure to harmful substances during the breaking up of plant or during entry into vessels.
- Asbestos could be a hazard.
- Large objects could be dropped.
- Fixed systems for fire and gas detection, alarms and firefighting equipment will become progressively unavailable.
- The means of escape, evacuation and rescue (EER) will similarly become progressively unavailable, with consequent reduction of access to and egress from the installation.
- Risk to divers during intervention to attach, manipulate, place, survey, strengthen etc.

Hazards arising during offshore installation disposal

- Contamination of toxic substances during transportation to disposal site (Bemment, 2001).

Annex V. Second-life options for disused offshore installations

Alternative uses for oil and gas platforms that are no longer in use depend on factors such as location, water depth, structure condition, local environmental conditions, economics, and meteorological conditions. This annex aims to demonstrate some potential uses of disused offshore installations. It is by no means exhaustive.

Marine conservation

Disused offshore installations may be good locations for protecting and preserving ecosystems in the North Sea. In the LiNSI report "Ecosystems associated with North Sea oil and gas facilities and the impact of decommissioning options" their ecological value is discussed in some detail. Further research on the ecosystems services of the areas around platforms would be needed, but there are signs that these areas could function as MPAs, due to the fact that they have not been fished for several decades and provide hard substrate vertically in the water column.

Fisheries

Disused offshore oil and gas installations may be interesting for sports fisheries and commercial line fisheries. In fact, in the Gulf of Mexico the idea of leaving in place of platforms has been initiated by this sector.

Long lining is used to capture both demersal and pelagic fishes including swordfish and tuna. It involves setting out a length of line, possibly as much as 50-100 km long, to which short lengths of line, or snoods, carrying baited hooks are attached at intervals. The lines may be set vertically in the water column, or horizontally along the bottom. The size of the fish and the species caught are determined by hook size and the type of bait used. Although it is a selective method of catching fish, long lining does pose one of the greatest threats to seabirds. A range of practical measures has been developed to help prevent seabirds from being hooked and drowned on long-lines.

Maricultures

Aquaculture is a term used to describe the farming of marine and freshwater organisms. Mariculture only refers to the farming of marine organisms; it can be further defined as open mariculture (or semi-culture) where organisms are farmed in a natural environment, such as mussels, and closed mariculture (or intensive mariculture) where organisms are farmed in closed environments as used for some finfish such as halibut.

Mariculture is a specialized branch of aquaculture involving the cultivation of marine organisms for food and other products in the open ocean, an enclosed section of the ocean, or in tanks, ponds or raceways which are filled with seawater.

A specific possibility would be the installation of mussel seed collectors. In the Netherlands there are initiatives to catch mussels in open sea, including the Voordelta. Benefits of catching mussels in open sea are fewer problems with ecological support due to the larger flux of nutrients in the coastal zone. Also, there is less hindrance for other users than at the Oosterschelde or Wadden Sea. Downsides are turbulent circumstances, which would require robust structures and a new type of harvesting ships. Currently, Imares (NL) is doing research on international developments in the field of mussel seed collection. This spring a workshop will be held. A pilot is foreseen where synergy with mariculture and disused offshore oil and gas installations would be addressed.

Recreation

Some recreational activities may be developed at disused offshore oil and gas installations, such as hotel/restaurant, diving, bird and sea mammal watching or a combination of these functions.

Morris Architects has designed an Oil Rig Platform Resort and Spa. This Houston-based architecture and design firm won the grand prize in the Radical Innovation in Hospitality design competition.

Figure VI-a. Oil Rig Eco Resort, Morris Architects.

In Sabah, Malaysia, the Seaventures Dive Resort is a hotel and scuba diving centre, which was transformed from an old oil rig. The resort is located near Sipadan, a world-famous dive site at the Celebes Sea that borders Malaysia, Indonesia and the Philippines. The rig was bought in Singapore and then towed to Borneo waters where it was converted into a unique diving hotel.

Figure VI-b. Seaventures Oil Rig, Malaysia.

Offshore energy

New alternative energy production solutions are entering the North Sea and offer possibilities for an energy transition which could include: optimized utilization of offshore energy resources, enhanced oil/gas recovery, in-situ electricity production and CCS; wind, wave, water, current, tidal and osmotic energy, bio-energy from sea organics, ocean thermal energy conversion (OTEC); compressed air energy storage (CAES), water energy storage and hydrogen; interconnection and "super grid". Until now, offshore wind energy production and planning is commercially and technically the most developed alternative energy source in the North Sea. Oil and gas installations (and related infrastructure) could be reused for these new forms of energy production.
They might provide service platforms for wind (parks), wave energy installations, carry solar panel arrays, give access to geothermal energy and natural gas storage and CCS.

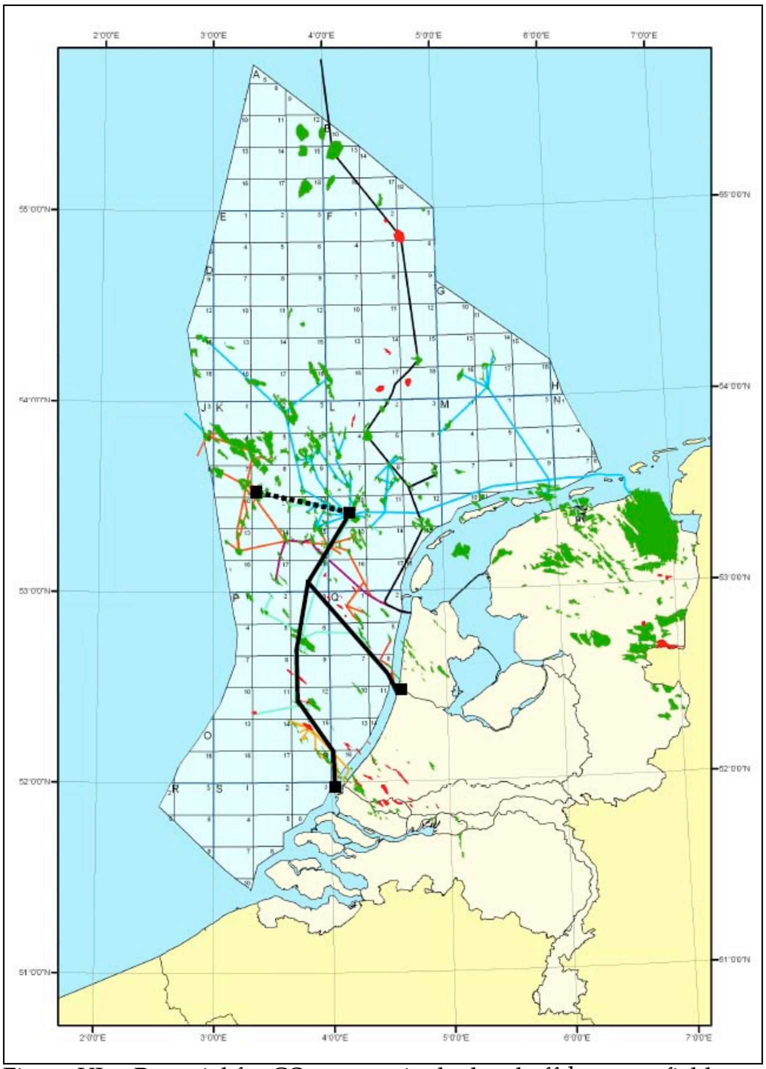

Figure VI-c. Potential for CO_2 storage in depleted offshore gas fields on the Dutch Continental Shelf (Nogepa, 2008)

Ocean instrumentation

Disused offshore oil and gas installations may serve scientific purposes. The locations of offshore facilities give excellent access to the North Sea. Research and monitoring activities on and around platforms could (and in some cases: should) be done.

Other business purposes that may be taken into consideration include navigation beacons for the shipping industry or fisheries, or communication hubs.

Other uses

Disused offshore oil and gas installations may serve military purposes as well.
Ideas have even been raised to turn them into prisons (Shell UK Limited, 2007, page 30).

Annex VI. Glossary of acronyms and terms

Biota	Living organisms.
CCS	Carbon capture and storage.
CNS	Central North Sea.
EIA	Environmental impact assessment.
FPSO	Floating production, storage and offloading units
IMO	International Maritime Organization.
LARP	Louisiana Artificial Reef Program.
MPA	Marine protected area, protected area whose boundaries include some area of ocean.
NNS	Northern North Sea.
OBM	Oil-based muds, drilling muds of which the base fluid is a petroleum product.
OSPAR	Oslo Paris convention for the protection of the marine environment of the North-East Atlantic.
Pelagic	Concerning any water in the sea that is not close to the bottom or near to the shore.
SBM	Synthetic-based muds, drilling muds of which the base fluid is of synthetic composition.
SNS	Southern North Sea.
UKCS	United Kingdom Continental Shelf.
UNCLOS	United Nations Convention on the Law of the Sea.
WBM	Water-based muds, drilling mud of a mix of water, clays and other chemicals to create a homogenous blend.

Annex VII. Regulations

Decommissioning in the North Sea is governed by international, regional and national regulations. Most important are UNCLOS, IMO and OSPAR regulations dealing with decommissioning obligations and derogations, as well as liability regulations for abandoned wells and structures left in place. These will be discussed here briefly. Also, the issue of liability will be addressed. For further background, please consult the law and regulation report (LNS130, IMSA Amsterdam, 2011d).

VII.1. Regulations on decommissioning obligations and derogations

Article 60 UNCLOS

Being the basic international legal framework, the United Nations Convention on the Law of the Sea (UNCLOS, 1982) defines the rights and responsibilities of nations in their use of the world's oceans. Article 60 provides coastal states an exclusive right to construct or authorize the construction of artificial islands and installations in the coastal state's exclusive economic zone, which may extend beyond the continental shelf. Article 60 (3) of UNCLOS permits the *partial* removal of structures, provided that IMO criteria are met.

IMO guidelines and standards 1989

The IMO Guidelines and Standards for the removal of Offshore Installations (Resolution A.672(16) adopted by IMO Contracting States in 1989, set out conditions for removal of installations with the aim of protecting navigation and the safety of other legitimate users of the sea. In essence the guidelines suggest that where complete removal is not possible, partial removal should leave an unobstructed water column of 55 metres (*Disposal of disused offshore concrete gravity platforms in the OSPAR Maritime Area, OGP, 338, Feb. 2003, p. 10*). The IMO standards state that installations weighing less than 4,000 tons should be removed, with specific differences for disused installations before and after 1998.

OSPAR Decision 98/3

For the North Sea, OSPAR 98/3 sets the following requirements – more stringent than the IMO Guidelines – for disused offshore installations. All topsides shall be removed for reuse or recycling, and all steel jackets weighing less than 10,000 tons shall be removed. Decision 98/3 does provide, on a case-by-case basis, a mechanism of derogation where there may be practical difficulty in removing installations, i.e. the footings of large steel platforms weighing over 10,000 tons, the concrete gravity-based platform substructures, or concrete anchor bases and other structures with significant damage or deterioration (which would prevent removal).

Removal and derogations in practice

Since the ban on dumping of disused offshore installations in 1999, 122 offshore installations have been brought ashore for disposal. In this period, permits have been issued for four concrete substructures and the footing of one large steel structure to be left in place. The decommissioning of the Frigg field is one example. Derogations from the dumping ban may be considered for 59 steel installations with a substructure of more than 10,000 tons, and 22 gravity-based concrete installations (OSPAR QSR 2010).

The decommissioning of oil and gas facilities is carried out for two main reasons:
1) cessation of production, when oil or gas exploration and production from the field is no longer beneficial; and 2) the integrity of the structure or elements: most platforms are built to last approximately 25 years. The integrity of offshore structures is discussed in Chapter 4. The period between cessation of production and abandonment differs per country. In the Netherlands platforms may be left in place after cessation of production if the operator commits himself to high maintenance standards.

Liability

All those with a financial interest in an oil and gas installation have a residual liability for anything left in situ. In the event of the ownership being passed on, perhaps to new entrants and smaller operators, new owners may be asked to give financial security to old owners, because, in the event of new owners going out of business, liability can revert to former owners. If a party wishes to end their liabilities in the asset, a government will only agree to this if appropriate external financial security is agreed within the partnership (Ekins *et al.,* 2006).

The liability for an offshore installation remains with licensees. The question of long-term residual liability should be discussed and agreed with the present owners and authorities so that suitable arrangements are made. The owners of installations at the time of decommissioning will normally continue to be the owners of any residues, unless otherwise agreed with the authorities. Further details on liability issues may be found in the report on the law and regulation work stream.

Dominant in the discussions on decommissioning in the North Sea is long-term liability for abandoned wells and structures left in place. Operators are not keen on long-term responsibilities. Also from a societal point of view it would be desirable for an infinite institution (i.e. government) to be liable.

The Louisiana Reef Programme (LARP) requires a state fishing management agency to accept liability for the structure. The state assumes ownership of the structure after it has been donated to the reef program and is responsible for the cost of buoy construction and replacement, operation and liability in perpetuity. The donor and other participants constructing a reef are absolved from liability provided the terms and conditions of the reef permits are met (Kaiser, 2005).

Annex VIII. OSPAR Inventory of offshore installations in 98/3 derogation category

OSPAR INVENTORY OF OFFSHORE STRUCTURES (in 98/3 derogation category)							
Name	**Water Dept (m)**	**Operator**	**Weight sub-structure (tonnes)**	**Name**	**Water Dept (m)**	**Operator**	**Weight sub-structure (tonnes)**
Fixed Steel - Substructure >10,000 tonnes				**Floating Steel - Substructure >10,000 tonnes**			
							-
Harding Platform	111	BP	88000	Durward FPSO - Glas Dowr	89	Hess	110000
Murchison	156	CNR	44300	Ross FPSO Bleo Holm	110	Talisman	105000
Ninian Central	135	CNR	43700	Hutton; TLP	150	Maersk Oil	51693
Magnus	190	BP	35057	Snorre A	335	StatoilHydro	40560
Ninian Central	135	CNR	31500	Leadon FPSO	119	Maersk	22811
Thistle A	160	Lundin Oil	31500	Veslefrikk B	176	StatoilHydro	22600
Brage	137	StatoilHydro	26000	Asgard C	290	StatoilHydro	22500
Piper B	146	Talisman	22555	Gallery FPF	147	Talisman	18800
Tern	167	Shell	20500	Emerald FPF	155	MSE	18800
Cormorant north	160	Shell	20052	Troll C	339	StatoilHydro	17900
Britania Platform	148	BOL	20000	Ivanhoe; AH001	142	Hess	16400
Ekofish 2/4-K	74	ConocoPhillips	19820	Visund FPU	331	StatoilHydro	16000
Clyde	81	Talisman	19400	Asgard B	300	StatoilHydro	14800
Brae B	102	Marathon	18900	Kristin	360	StatoilHydro	14400
Heather A	144	Lundin Oil	18700	Fife FPSO	69	Hess	10500
Brae A	112	Marathon	18600				
Alwyn north NAA	125	Total E&P	18500	**Gravity-based Structures**			
Oseberg B	110	StatoilHydro	18000				
Grane A	127	StatoilHydro	17500	Statfjord B	145	StatoilHydro	743000
Hutton NW	144	BP	17500	Troll A	302	StatoilHydro	656000
Tiffany	125	CNR	17500	Gullfaks C	217	StatoilHydro	652600
Eider	159	Shell	17100	Statfjord C	146	StatoilHydro	641000
Alba northern	140	Chevron	17000	Statfjord A	145	StatoilHydro	579000
Claymore A	111	Talisman	17000	Ekofish 2/4-T	74	ConocoPhillips	510000
Scott JD	142	Nexen	16130	Frigg (UK) CDP1	112	Total E&P	418000
Heimdal	120	StatoilHydro	16032	Frigg - MCP01	94	Total E&P	386000
F2-A-Hanze	42	Petro-Canada	16000	Ninian Central	135	CNR	384000
Saltire A	143	Talisman	15000	Gullfaks A	134	StatoilHydro	347000
Miller	103	BP	14830	Oseberg A	110	StatoilHydro	321000
Alba nort NAB	125	Total E&P	14500	Cormorant south A	155	Shell	294655
Piper Alpha	144	Talisman	14300	Brent C	142	Shell	287542
Brent A	142	Shell	14225	Gullfaks B	142	StatoilHydro	269000
Forties FB	106	Apache	14152	Frigg TCP2	102	TotalFinaELF	261000
Forties FC	106	Apache	14152	Dunlin A	151	Fairfield	228611
Forties FD	106	Apache	14152	Draugen	251	Shell	210000
Oseberg C	109	StatoilHydro	14100	Sleipner A	82	StatoilHydro	205000
Tartan A	142	Talisman	14090	Beryl A	119	ExxonMobil	200000
Beryl B	119	ExxonMobil	13250	Brent D	142	Shell	177809
Fulmar A	83	Talisman	12400	Brent B	142	Shell	165664
Forties FA	106	Apache	12310	Syd Arne	60	Hess Denmark	112800
Morecambe CPPI	32	HRL	11754	F3-FB-1	42.3	NAM	60500
Ekofisk 2/4-J	80	ConocoPhillips	11535	Ravenspurn (NTH):CPP	45	BP	38500

Frigg DP2	97	TotalFinaELF	11200					
Gaviota	105	Repsol Inv.	10500					
Other Structures					**Floating Concrete Structures**			
Maureen A	94	ConocoPhillips	92000		Heidrun	345	StatoilHydro	290000
Mittleplate A	2	RWE-DEA	75400		Troll B	325	StatoilHydro	125000