Foreign & Commonwealth Office
Oil and Gas Decommissioning
From the UK’s North Sea to the
Brazilian Atlantic
Implementation of the Regulatory
Regime

Final  |  25 April 2017

This report takes into account the particular instructions and requirements of our client. It is not intended for and should not be relied upon by any third party and no responsibility is undertaken to any third party.

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## Document Verification

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# Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Introduction</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>The Decommissioning Process: scope of the engineering work</td>
<td>5</td>
</tr>
<tr>
<td>2.1</td>
<td>Introduction</td>
<td>5</td>
</tr>
<tr>
<td>2.2</td>
<td>Well abandonment</td>
<td>7</td>
</tr>
<tr>
<td>2.3</td>
<td>Running, making safe &amp; preparation</td>
<td>9</td>
</tr>
<tr>
<td>2.4</td>
<td>Topside and substructure removal</td>
<td>10</td>
</tr>
<tr>
<td>2.5</td>
<td>Subsea site remediation &amp; monitoring</td>
<td>14</td>
</tr>
<tr>
<td>3</td>
<td>Decommissioning Programme and Derogation Approval: the UK approach</td>
<td>16</td>
</tr>
<tr>
<td>3.1</td>
<td>Introduction</td>
<td>16</td>
</tr>
<tr>
<td>3.2</td>
<td>Decommissioning Programme</td>
<td>17</td>
</tr>
<tr>
<td>3.3</td>
<td>Derogation approval</td>
<td>23</td>
</tr>
<tr>
<td>4</td>
<td>Safety Management</td>
<td>27</td>
</tr>
<tr>
<td>4.1</td>
<td>Introduction</td>
<td>27</td>
</tr>
<tr>
<td>4.2</td>
<td>Safety Case Principle</td>
<td>27</td>
</tr>
<tr>
<td>4.3</td>
<td>Goal-Setting</td>
<td>28</td>
</tr>
<tr>
<td>4.4</td>
<td>Implementation of Regulation</td>
<td>29</td>
</tr>
<tr>
<td>4.5</td>
<td>Structure of a Safety Case Document</td>
<td>29</td>
</tr>
<tr>
<td>4.6</td>
<td>Operational Considerations</td>
<td>31</td>
</tr>
<tr>
<td>4.7</td>
<td>Significant Lessons Learnt</td>
<td>35</td>
</tr>
<tr>
<td>5</td>
<td>Environmental Management</td>
<td>37</td>
</tr>
<tr>
<td>5.1</td>
<td>Introduction</td>
<td>37</td>
</tr>
<tr>
<td>5.2</td>
<td>Strategic Environmental Assessments</td>
<td>37</td>
</tr>
<tr>
<td>5.3</td>
<td>Environmental Impact Assessment</td>
<td>39</td>
</tr>
<tr>
<td>5.4</td>
<td>Stakeholder Engagement</td>
<td>42</td>
</tr>
<tr>
<td>5.5</td>
<td>Environmental Management Systems</td>
<td>44</td>
</tr>
<tr>
<td>5.6</td>
<td>Other Key Assessments and Consents</td>
<td>45</td>
</tr>
<tr>
<td>5.7</td>
<td>Post-decommissioning</td>
<td>48</td>
</tr>
<tr>
<td>6</td>
<td>Waste Management</td>
<td>50</td>
</tr>
<tr>
<td>6.1</td>
<td>Introduction</td>
<td>50</td>
</tr>
<tr>
<td>6.2</td>
<td>Regulatory regime and general strategy</td>
<td>50</td>
</tr>
<tr>
<td>6.3</td>
<td>Waste management at decommissioning</td>
<td>57</td>
</tr>
<tr>
<td>7</td>
<td>Other North Sea Regulatory Regimes</td>
<td>64</td>
</tr>
<tr>
<td>7.1</td>
<td>Introduction</td>
<td>64</td>
</tr>
<tr>
<td>7.2</td>
<td>Norway</td>
<td>64</td>
</tr>
</tbody>
</table>
1 Introduction

Context

Arup has been commissioned by the Foreign & Commonwealth Office (FCO) to deliver the commission ‘Oil and Gas Decommissioning - UK North Sea to Brazilian Atlantic’ (‘The Project’). The Project is commissioned to the benefit of Brazil’s National Agency of Petroleum, Natural Gas and Biofuels (ANP).

Brazil are anticipating that there will be an increase in offshore Oil and Gas (O&G) decommissioning in the coming years as elements of Brazilian O&G infrastructure reaches the end of its useful life. There is currently legislation which covers decommissioning, and ANP are currently focused on developing their regulatory structure and processes in order to manage an increase in decommissioning activities.

This report is the second of three reports delivered by Arup, to share lessons learned from the North Sea. The first report focuses on the legislation around decommissioning. This second report focuses on the more practical aspects with experience from decommissioning, including a number of case studies. The final report delivers a framework describing the considerations which should be made at a national level when developing a decommissioning strategy.

The scope

The North Sea is a much older O&G basin than the Brazilian basin, and as such has had more experience in decommissioning O&G infrastructure. The purpose of the Project is to deliver a comprehensive overview of UK Continental Shelf (UKCS), and other North Sea O&G Decommissioning Regulation. This includes a review of both formal and informal methods of influencing the industry which will inform the Brazilian O&G Regulator in the review of their own approach to regulating decommissioning.

Despite the differences between the Brazilian and North Sea markets and infrastructures, much experience can be shared to give an insight into the challenges and approaches to offshore O&G decommissioning. The Project seeks to provide insight into the conditions which have influenced the regulatory approaches and lessons learnt by the UK industry, to allow ANP to make informed decisions when considering the relevance to their own regime.

The deliverables

In addition to a number of workshops and meetings the main written deliverables for the Project are three reports as follows:

1. Description of the Regulatory Regime – Provides a detailed understanding of the overarching framework of policy and legislation and informal approach which has been developed to influence the delivery of O&G decommissioning activities in the UK.
2. **Implementation of the Regulatory Regime** – Provides a detailed understanding of how the regime is implemented in the UKCS including full description of the informal mechanisms by which frameworks are implemented and delivered through regulation, by which organisations, and how projects are delivered as a result of this regulation. A comparison is provided between the differences in approaches taken by the other main North Sea countries including Norway, Denmark and the Netherlands.

3. **Decision Making Framework** – Develops a decision-making framework which ANP (or another O&G regulator) could use to develop their approach to developing their influencing and delivery of frameworks for O&G decommissioning. This final deliverable is not specific to Brazil, but rather a generic framework, which can be applied by any country looking to develop a decommissioning regime.

This report is the output of deliverable 2 – the Implementation of the Regulatory Regime.

**The Prosperity Fund**

The Project is supported by the UK Government’s Prosperity Fund [1]. This global fund promotes the economic reform and development needed for growth in partner countries, including Brazil, and creates opportunities for international business, including opportunities for UK companies.

**Decommissioning in Brazil and the UK**

There are many differences between the decommissioning markets in Brazil and in the North Sea. In Brazil, the decommissioning industry is at a significantly earlier stage than the North Sea, and the asset base is much younger. Although some early decommissioning works have taken place, there is limited experience in undertaking significant programmes.

The physical nature of the Brazilian basins is different to that of the North Sea. Most of the Brazilian resource is in much deeper water of between 300 to 2,500 metres (m), compared to a maximum depth of approximately 725 m in the North Sea (Norway). The average water depths in the North Sea are much shallower at 127 m for the overall basin. As a result, the Brazilian infrastructure is biased towards floating facilities rather than the fixed steel installations of the North Sea.

While the Brazilian Atlantic currently has a small number of operators, of which Petrobras is the most dominant, the makeup of the North Sea operators is generally dominated by a much larger number of smaller private sector companies. The operator landscape in Brazil is currently more analogous to the early stages of North Sea operations. The Brazilian landscape may change as Petrobras consider divesting some of their more mature assets.
Structure of the report

The report is structured as follows;

**Section 2:** Provides an overview of the typical scopes of work which must be undertaken by an operator during decommissioning of an offshore asset.

**Section 3:** Describes the key regulatory approvals that a UK operator must obtain to carry out the decommissioning work described in Section 2 – or to obtain derogations (i.e. exemptions) from these activities.

**Section 4:** Describes the UK regulatory regime which underpins the management of safety during a decommissioning project and how the legislation applies to the planning and delivery of a decommissioning project.

**Section 5:** Describes in detail the UK regulatory approvals process for the management of the environmental aspects of decommissioning, including the approaches to considering and managing environmental impacts during the planning and delivery of a decommissioning project.

**Section 6:** Describes the UK regulatory process that must be followed to manage the disposal of typical decommissioning waste streams, and the waste disposal supply chain in the UK, and the legislation which governs the processes.

**Section 7:** Provides an overview of the key regulatory differences between the other non-UK North Sea regulatory regimes including Denmark, Norway and the Netherlands.

**Section 8:** Provides a number of decommissioning industry case studies describing the engineering and environmental approaches and challenges to decommissioning

**Section 9:** An overview of the responses to a survey completed by UK operators providing their view on the approaches to O&G decommissioning regulation in the UK.

**Section 10:** Provides insight into the key learning points from the approach to regulation in the North Sea which are likely to be of relevance to the development of regulation in the Brazilian Atlantic.

A glossary of terms, abbreviations and acronyms is provided after section 10.
Contributions

To develop Section 7 of this report a number of consultations were held with regulators from outside of the UK, including:

The Norwegian Ministry of Petroleum and Energy (MPE)
The Dutch Ministry for Economic Affairs & Energie Beheer Nederland (EBN)

Separate consultations were also carried out with nine operators in the North Sea to develop the operator insight described in Section 9. The operators who participated include:

Shell
Hess
BP
Marathon Oil

Chevron
CNR International
Centrica
Repsol
2 The Decommissioning Process: scope of the engineering work

The scope of work in decommissioning an offshore asset includes the plugging of wells and the making safe and subsequent removal of all parts of an installation, unless approvals are granted to leave any aspects in situ.

The offshore operations are typically complex and result in a lengthy sequence of resource-intensive offshore operations which will draw on many aspects of the O&G supply chain.

The first steps typically include the plugging and abandonment of wells which can be a complex process highly dependent on the age and condition of the well. Topsides and foundation assets can then be surveyed, made safe and cleaned prior to dismantling and removal to shore. There are a number of dismantling/removal options available to operators. Depending on the nature of the asset, its proximity to shore, the water depth and other variables, detailed review is required to select the optimal offshore process.

Once removed, the operator is obliged to provide the authorities with survey data to confirm that all assets have been removed and that no hazards remain. If any materials have been left in place, long-term seabed monitoring may be stipulated by the authorities.

2.1 Introduction

The decommissioning process from initial planning to final removal can be broken into distinct phases with significant activity occurring at each phase. This section reviews these phases in more detail to highlight the skills, infrastructure and supply chain required for each stage.

The Work Breakdown Structure (WBS) described in Report 1 is used as a framework to describe these tasks. The WBS process can be applied to all offshore assets – ranging from the decommissioning of very large concrete gravity base structures to the removal of smaller subsea components such as pipelines and manifolds.

To provide an understanding of the sequences, the activities are illustrated on a programme in Figure 2, which shows the lifecycle of a decommissioning project.

In this section of the report, the following operator-led steps are described:

- Well abandonment
- Running, making safe and preparation for dismantling
- Removal of topsides and substructures
- Site remediation and monitoring
- Reuse and recycling (this is covered in Section 6)
Figure 1. Oil&Gas UK Work Breakdown Structure for decommissioning

Figure 2: Example timeline of decommissioning activities
2.2 Well abandonment

Plugging & Abandonment (P&A), also known as well abandonment, is the process in which a well is isolated and sealed from the reservoir permanently. This is the most costly part of decommissioning and must be carried out using a method which assures protection of the downhole and surface environment in perpetuity. The skills, infrastructure and supply chain required for these tasks are illustrated in Figure 3.

Figure 3. Well abandonment supply chain

The principle of well abandonment is to insert a number of plugs into a disused well, to create impermeable barriers. These plugs are typically constructed from cement, injected into the borehole to create a plug approximately 100ft in length, at a prescribed depth. The plugs must ensure good bonding with the bore of the well.

Depending on the complexity of the operation, this process can be carried out from a vessel or rig. The complexity will be dictated by the integrity and age of the well, along with details of the local geology and details of any residual pipework or cabling. If the well is characterised as “simple” then the plugging can most likely be carried out from a vessel, but if the well is “complex” then a rig with specialist equipment may be required. The process can be time-consuming and expensive – particularly if a production rig associated with the well does not have any well intervention equipment and specialist equipment must be installed.
Figure 4. Illustration of plugged well
2.3 Running, making safe & preparation

A number of activities are required in preparation for removal. These are generally referred to as: running, making safe and preparation.

To minimise the amount of hazardous waste, all equipment must be cleaned before removal and decommissioning. This includes removal of hydrocarbons, asbestos, chemicals and other hazardous waste, which may be carried out by specialist cleaning teams. Any waste streams, including spent cleaning fluids, must be captured and disposed of in line with waste management regulations (see Section 6).

**Topsides**

Topsides infrastructure must be cleaned of hydrocarbons to a level that meets the requirements of the removal method and contractor. For those methods that do not involve breaking of any containment of the original hydrocarbon envelope, a lower level of cleanliness may be acceptable. Dismantling using onsite demolition is likely to require a higher level of cleaning.
Pipelines

More information on the criteria for removal of infrastructure can be found in Section 2.4, and the assessments that are undertaken to support decision making are found in Section 3.2. In principle the following apply:

- If the pipelines have been buried or are expected to be naturally buried sufficiently over time and cannot be recovered safely or efficiently, then they can be left in situ once safely isolated, provided this has been agreed by the regulator.

- Smaller pipelines with a diameter less than 16 inches, flexible flow lines and umbilical lines which have not been buried or trenched are expected to be removed from the site.

- All pipelines must be isolated from the installation equipment by ‘air gapping’ i.e. physical separation between the pipeline and other equipment.

- Equipment that is to remain in-situ, must be cleaned to an agreed specification which must demonstrate that any residual contamination would not cause concern to the eco-system in which it remains.

A key pre-requisite to this stage is gaining a thorough understanding of the scope of the asset, and the health of individual components. It is common for platforms, pipelines and other assets to have been updated and modified during their operational life. This should be reflected in the operator’s records, but older components may have suffered from corrosion and wear. Detailed surveys (sometimes component-by-component) may be required to gain a full understanding of the integrity of each component prior to preparation for dismantling.

2.4 Topside and substructure removal

The activities that fall under this phase include removal preparation (which may include making reinforcements to structures to be lifted), the general management of removal vessel operations, offshore fastening of components and considering of transportation routes to shore and loading procedures.

There are a number of methods for removal of topsides and substructures/jackets of an installation, which are described in Section 2.4.1. The asset can then be transported to shore on a barge or specialist transportation vessel. The overall skills, equipment and supply chain are illustrated in Figure 6.
The location of the asset will to a certain degree inform the removal method, as a greater distance from shore will require vessels and crews to work with a greater autonomy from onshore support, and water depth will dictate what class of underwater tools are used. For example, deeper water operations will preclude the use of divers, and necessitate the use of Remotely Operated Vehicles (ROVs) which in turn may require specialised surface vessels for launch, operation and recovery of the ROVs.

This sensitivity can be observed by considering the Norwegian and Netherlands sectors which have similar numbers of installations. However, because of greater depths and distances from shore in the Norwegian waters, more capable vessels and tools are required for decommissioning much larger, heavier structures and as a result forecast costs are very different to decommissioning in the Netherlands sector.

2.4.1 Topsides removal

Generally, there are three methods to remove the jackets and topsides of an installation. In practice, removing a large installation would require a combination of two or more of the following:

1. **Reverse of Installation**: Most large platforms were assembled as a series of modules lifted into place by a Heavy Lift Vessel (HLV), which typically with a lift capacity up to 14,000 tonnes. This process can be used in reverse, removing decommissioned modules one by one. However significant preparatory works are required to separate the modules and to ensure structural integrity both of the modules as they are lifted, and of the structures that remain, as the centre of gravity changes.
2. **Single Lift**: Smaller assets are candidates for removal in a single lift with an HLV. Specialist Single Lift Vessels (SLV) with very large lift capacity of between 25,000 – 48,000 tonnes are emerging in the market with the capacity to remove the much larger, multi module assets in one lift. As with reverse of installation, significant preparatory works, including strengthening of the structure, are required to facilitate this method.

3. **Demolition in-situ**: A team of specialists with industrial demolition machines and hydraulic shears can be brought to the platform when still offshore to dismantle the asset over an extended time period, shipping waste streams to shore. There is limited preparatory work required for this option, but may require more people offshore for a longer period.
2.4.2 Substructure removal

Jacket removal can make use of the same techniques as topsides removal, although demolition in-situ would require divers and ROV systems to cut the jacket into manageable pieces which would then be lifted to the surface.

A more straightforward opportunity is to dismantle the jacket in varying sized elements depending on the size and design of the original jacket. This technique is commonly known as cut and lift, illustrated in Figure 10.

There are some innovative solutions which have demonstrated jacket recovery, including using buoyancy tanks to float the structure, allowing it to be towed ashore for inshore dismantling.
2.5 Subsea site remediation & monitoring

Figure 11: Subsea and Site Remediation Key Aspects Summary

2.5.1 Site Remediation

Site remediation activities assure that, once the asset has been removed, the seabed is substantially clear of debris and that no items remaining pose a threat to other users of the area. Typical activities include pile management, clearing decommissioned oilfield debris (with a 500 m zone and 200 m corridor around pipelines. Over-trawl surveys must be carried out to confirm that any debris remaining on the seabed does not pose a threat to fishermen.
2.5.2 Monitoring

A post-decommissioning environmental seabed sample survey should be undertaken, typically to monitor levels of contaminants in the surrounding sediment. Operators should develop their survey strategy in consultation with the regulator. Details of the survey strategy should be included in the DP. Subsequent surveys may be needed sometime after the post decommissioning sampling to monitor changes in the surrounding environment since the decommissioning activity. The timing of further surveys will typically be risk-based and will be informed by the results of the initial surveys and what issues were highlighted at that stage.
3 Decommissioning Programme and Derogation Approval: the UK approach

The UK has prescriptive legislation in place which defines how an operator should go about the process of applying for permissions to cease production and commence decommissioning of an asset.

This process includes the submission of specific documentation (a Decommissioning Plan) 3 to 5 years ahead of cessation of production (CoP) of hydrocarbons. This document is to be submitted to BEIS for review and consultation with other stakeholders prior to any revisions and formal approval. The stakeholders primarily include environmental agencies, as well as OSPAR if derogations are being sought to leave assets in situ.

The process also dictates that comparative assessments should be used as tools for the bulk of decision-making to ensure that all decisions are made through thorough consideration of all options, and with consideration of the technical, environmental and financial consequences.

3.1 Introduction

This section describes the key regulatory approvals that a UK operator must obtain to carry out the decommissioning work described in Section 2.

Decommissioning activities include a range of approvals which are described in more detail in the first report in this series, Description of the Regulatory Regime. A summary of the wider process can be found in Figure 12 and sets out the following:

Identifying liabilities for decommissioning - Section 29 notice. Requires the licensee(s) to submit a costed DP. Usually required at early stages when the field commences operation.

Securities Review and Approval. When the liability has been identified through the Section 29 notice, the licensee must then demonstrate that they have the securities in place to cover the identified cost.

Cessation of Production (CoP) Approval. Approval is sought from the OGA to stop production on a field. The licensee must demonstrate that the field has maximised its economic recovery, before the CoP approval will be granted.

Decommissioning Programme (DP). Must be submitted to BEIS and include a detailed programme for decommissioning, including environmental impacts and H&S considerations.

Derogation Approvals. As set out in the OSPAR Decision 98/3, this is required if an installation is to be left in-situ. The application must be supported by a comparative assessment showing the analysis behind the request to leave in-situ.

More detail is provided in the following sections on The Decommissioning Programme and Derogation Approvals process.
3.2 Decommissioning Programme

What does a DP seek to achieve?

The Petroleum Act 1998 [2] provides the BEIS Secretary of State (SoS) with power to require Section 29 notice holders to submit a detailed and costed DP for the notice holder’s assets.

The DP sets out the approaches, programmes and costs of the decommissioning options and the associated environmental impacts. The programme must be approved by BEIS prior to decommissioning commencing.

This obligation to seek approval for a DP ensures that activities are carried out in a responsible way. The DP must demonstrate that the decommissioning process is delivered with acceptable impacts to the environment, with consideration to cost.

Who submits the DP?

Where an asset has multiple Section 29 notice holders, all of the parties share the obligation to submit a DP. In practice it is expected that a single point of contact is provided, acting on behalf of all the notice holders of the asset. In most circumstances this party is the operator who has responsibility for day-to-day management of the installation.

What is the scope of a DP?

The scope of the infrastructure contained within an application is currently not determined in guidance from BEIS. However, it is the preference that DPs are submitted for the entire field including all infrastructure and assets [3]. The
complexity of boundaries of licences, ownership and timescales for the phased
retirement of a field can make the production of a single DP challenging. As a
result a single application is not always practicable.

The DP can present a number of alternatives for carrying out decommissioning.
For example it may consider alternative methods for removing topsides and
transporting these to shore. The DP is generally produced prior to finalising
detailed design and as such requires some optionality in order to ensure that
options to reduce costs through the procurement process are maintained. All
potential options should be considered and assessed in the DP.

A DP should identify all items of equipment and materials that have been installed
(e.g. installations, subsea equipment, wells, pipelines) or have accumulated (e.g.
drill cuttings) at the site. In addition, with the exception of items left downhole,
the programme should clearly specify any infrastructure to remain in situ.

The guidance notes from BEIS provide information on what should be included in
a DP [4]. BEIS have also published streamlined DP templates for applications [5]
[6]. The operators may produce a DP using their own format as long as it is
ensured that the aspects identified by BEIS have been addressed.

**How are environmental impacts considered?**

Although there is currently no statutory requirement to undertake an EIA at the
decommissioning stage, BEIS have determined that a DP will nevertheless need to
be supported by an EIA. The Environmental Statement (ES) submitted under the
EIA regulations for the development licence before production commences,
requires the applicant to consider the long term impacts of the development and
these include the impacts arising from decommissioning. However, in the light of
the lengthy period of time between project sanction and decommissioning, the
requirement for a detailed assessment is deferred until closer to the time of actual
decommissioning and is submitted as part of the DP [6].

The EIA will form part of the DP and should assess the impact of the project on
the marine and terrestrial environments. The EIA should include information on
the energy balance and emissions of the options considered and take account of
requirements under the EU Habitats & Birds Directives. See Section 5 for further
details on EIA in relation to decommissioning.

The other bodies listed in Table 1, Section 4.5 of Report 1 may act as either
statutory or non-statutory consultees on the DP and will review the EIA associated
with the DP in great detail. This consultation is likely to start informally early in
the DP process and, as the programme develops and documents are issued, BEIS
will formally request advice/opinion from Statutory Consultees and others prior to
approving the DP.
What are the timescales for the delivery of a DP?

The UK does not have a policy to compel operators to remove infrastructure in a prescribed timescale, unlike the Gulf of Mexico’s ‘Idle Iron,’ policy [7]. BEIS guidance notes [4] state:

‘The Government aims to ensure the orderly decommissioning of offshore infrastructure in a timely and efficient manner, in line with the UK’s international obligations and domestic legislation. BEIS’s expectation is that the removal of redundant installations, including subsea equipment, will be carried out as soon as reasonably practicable. At the same time we recognise that disused facilities including pipelines may represent important UKCS infrastructure and provide the means for the further development of hydrocarbon reserves, the storage of carbon dioxide or hydrocarbon gas.

Where a specific opportunity has been identified deferral of decommissioning can be considered. The timing of decommissioning will also be influenced by market factors and vessel availability and there may be benefits from coordinating offshore work with other projects being undertaken in a similar timescale. This may involve agreeing that decommissioning work can be conducted during a window of opportunity, possibly spread across two or three seasons.

In general, though, in view of the UK’s obligations under OSPAR, DECC (The department of energy and climate change) expects the removal of disused installations not to be delayed unless a robust case demonstrates there is a specific reuse opportunity or other justifiable reasons for deferring decommissioning.’

As such, the operator is expected to provide a delivery programme for decommissioning in their DP, which will have some flexibility to allow for contracting timescales. Agreed timescales in a DP can be varied on agreement with the SoS through BEIS.

In practice, operators are sometimes motivated to delay some aspects of decommissioning activities, particularly removal, in order to defer the costs. The timing of CoP approval and DP submission has allowed some flexibility in this regard. There are examples of programmes which have had significant time periods between CoP and the final removal of assets.

What is the process and timing for producing a DP

The guidance notes from BEIS [4] provide a flow chart of a typical programme indicating what is expected to take place at each stage of the programme. The duration for production and approval of the DP will vary depending on the nature of the infrastructure and complexity of the programme. While BEIS guidance [4] requests operators to engage up to 3 years in advance of CoP and 5 years in the case of potential derogation cases, the duration can be much shorter or longer depending on the complexity of the programme.

The time frame of each stage will vary significantly with some activities lasting a few weeks and others requiring years of development. This flow chart is
summarised in Figure 13, with each stage described in more detail in the section that follows.

**Stage 1**

Early discussions are held between the operator and BEIS to ensure that timely action is being taken by the operator, and that the decommissioning process is well understood. The onus rests with the operator to initiate these discussions in a timely fashion, observing the 3-year and 5-year guidance.

At the same time the OGA will endeavour to maintain a more general dialogue with the operator on their future UKCS plans in order to understand the likely timing of CoP from their fields and the implications for decommissioning of the infrastructure.

The operator will be asked to outline the likely timetable of future events to form a basis for agreement as to when more detailed discussions should commence and what documentation should be prepared in advance.

**Stage 2**

This stage involves more detailed discussion of an operator's decommissioning proposal and the consideration by BEIS and other interested parties of a consultation draft of the DP.

Of particular note at this stage is the consideration of any derogation case under OSPAR Decision 98/3. The inclusion of a derogation case requires more focus on comparative assessments and post-decommissioning monitoring.

DP templates for both derogation and non-derogation programmes are available from BEIS [5] [6]. Every DP submitted for review should include these headings:
<table>
<thead>
<tr>
<th>Introduction</th>
<th>Environmental Impact Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Executive Summary</td>
<td>Interested Party Consultations</td>
</tr>
<tr>
<td>Background Information</td>
<td>Costs</td>
</tr>
<tr>
<td>Description of items to be decommissioned</td>
<td>Schedule</td>
</tr>
<tr>
<td>Inventory of materials</td>
<td>Project Management and Verification</td>
</tr>
<tr>
<td>Removal and disposal option</td>
<td>Debris Clearance</td>
</tr>
<tr>
<td>Selected removal and disposal option</td>
<td>Pre and Post Decommissioning Monitoring and Maintenance</td>
</tr>
<tr>
<td>Wells</td>
<td>Supporting Studies</td>
</tr>
<tr>
<td>Drill Cuttings</td>
<td></td>
</tr>
</tbody>
</table>

After submission on an agreed date, the document will undergo a review process during which BEIS and statutory consultees will consider the draft. BEIS aim to complete this phase within ten weeks. This may take longer, particularly for derogation case projects.

Transparency and openness is an important aspect of any decommissioning decision. At the same time as submitting the programme for government consideration, the operator will be required to carry out consultations with interested parties. The extent of these consultations will be determined by the particular circumstances of the case. In all cases the operator will be asked to undertake statutory consultations as provided for in the Petroleum Act 1998 [2] as well as providing opportunity to the general public to respond. In addition to holding meetings with consultees the operator will announce its proposals by placing advertisements in local media and will publish the proposal online with hard copies available on request. The consultation period will usually last for 30 days within the ten week period.

Following consultations, BEIS will collate all comments and concerns that consultees have raised and will submit a written response to the operator for consideration in a subsequent draft of the DP. In most cases only one draft report is formally submitted however revisions of some sections of the programme may be required to produce the finalised version for stage 3.

Where appropriate, consideration of the draft DP will run in parallel with:

- Consideration by OGA of the CoP document
- Consideration by the HSE of the Dismantlement Safety Case
- Consideration of any environmental permits or consents
- Consideration of any onshore disposal consents or licences which may be necessary, including any transfrontier shipment of waste issues

**Stage 3**

Once the draft and consultation periods are completed, the SoS for BEIS send a formal letter to the operator, requesting a final DP for approval. The operator responds by submitting the programme with a formal letter from each party with
obligations stating that this programme has been submitted on their behalf. The SoS will formally approve the programme and publish the approval online.

Stage 4

Once the DP has been approved, the decommissioning work can be carried out in accordance with the agreed programme.

This stage covers the period from implementation of the approved DP up to the completion of site surveys. The programme will specify the arrangements by which BEIS will be kept informed of progress and, where appropriate, will indicate the milestones at which progress will be reviewed. Any revisions to the programme will be subject to SoS approval in accordance with the provisions of the Petroleum Act 1998.

At the conclusion of Stage 4 the operator will be required to satisfy BEIS that the approved programme has been implemented. This will normally involve the submission of a close-out report within four months of the completion of offshore work, including debris clearance surveys and post-decommissioning surveys.

Stage 5

The final stage will require the operator to implement arrangements for monitoring, maintenance and management of the decommissioned site and any remains of installations or pipelines that may exist. The extent of survey and monitoring that is required is agreed during the DP and will depend on the extent of any infrastructure left in situ.

There is no prescribed programme for monitoring but a suitable monitoring regime would be agreed with BEIS who will consult with other government departments, agencies and stakeholders with a relevant interest.

How does the DP interface with OSPAR Decision 98/3?

The base case for decommissioning assumes the total removal of all installations (topsides and substructures). The majority of installations will fall into this category.

For installations which are eligible for a derogation, and where an operator seeks to leave infrastructure partially or wholly in situ, a comparative assessment must accompany a derogation application as part of the DP. Should derogation of an installation have been approved by OSPAR, it will then be necessary to address the environmental impacts of alternative disposal options as part of the Comparative Assessment. However, in the majority of cases total removal applies and a Comparative Assessment is not required. It will only be necessary for the EIA to address the impacts of the proposed decommissioning activity on the environment.

Comparative assessments are also undertaken to support any applications to leave pipelines or drill cutting piles in situ.
3.3 Derogation approval

A small proportion of offshore installations are eligible for a derogation under OSPAR decision 98/3 [8]. These may apply to leave an installation partially or wholly in place. This includes substructures for the following offshore installations:

- All or part of the footings of a steel installation weighing more than 10,000 tonnes placed in the maritime area before 9 February 1999
- A concrete installation or a concrete anchor base
- Any other disused offshore installation to be dumped or left wholly or partly in place, when exceptional and unforeseen circumstances resulting from structural damage or deterioration, or from some other cause presenting equivalent difficulties, can be demonstrated

Generally, derogation can only be approved if enough justification is provided to suggest that the complete removal of the asset will be technically challenging, cause a detrimental impact to the surrounding environment or pose a significant H&S risk. The OSPAR Decision 98/3 Annex 2 Assessment Framework states that the data used in the comparative assessment should be sufficiently comprehensive to enable a reasoned judgment on the practicability of each of the disposal options considered, and allow for an authoritative comparative evaluation. In summary:

- The conclusions shall be based on scientific principles
- It will be possible to link the conclusions back to supporting evidence and arguments
- Documentation shall identify the origin of data used

What is the purpose of a comparative assessment?

The objective of any comparative assessment is to identify all removal options, comparing the features, benefits, drawbacks and risks to identify the “most preferred” option. In derogation cases, the comparative assessment conclusion should justify why derogation is preferable to complete removal and demonstrate that there are significant reasons why complete removal is not the optimal choice.

What else is comparative assessment used for?

In addition to derogation cases, in the UK comparative assessments are also used to identify the preferred options for the following infrastructure:

- All pipelines being decommissioned under the Petroleum Act 1998
- All drill cuttings piles that are not screened-out at Stage 1 of OSPAR Recommendation 2006/5
Who reviews the comparative assessment and what is the criteria?

The assessment must be submitted to the OSPAR executive and contracting parties for review. It is then the responsibility of BEIS, as the contracting party for the UK, to facilitate this. However, BEIS will ask the operator to support the assessment by providing supporting information. This supporting information must be provided with the DP submitted to BEIS.

Comparative assessment criteria

BEIS provide guidance on the assessment criteria for comparative assessment [4], with additional guidance having also been developed by Oil & Gas UK (O&GUK) [9]. The BEIS guidance sets out the main criteria that should be considered, with suggestions on sub-criteria. It is up to the operator to decide which sub-criteria are appropriate. These are summarised in Table 2.

Table 2: Criteria matrix for a comparative assessment

<table>
<thead>
<tr>
<th>Main Criterion</th>
<th>Sub-Criterion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Safety</td>
<td>Risk to personnel</td>
</tr>
<tr>
<td></td>
<td>Risk to other users of the sea</td>
</tr>
<tr>
<td></td>
<td>Risk to those on land</td>
</tr>
<tr>
<td>Environmental</td>
<td>Marine impacts</td>
</tr>
<tr>
<td></td>
<td>Other environmental compartments (including emissions to the atmosphere)</td>
</tr>
<tr>
<td></td>
<td>Energy/resource consumption</td>
</tr>
<tr>
<td></td>
<td>Other environmental consequences (including cumulative effects)</td>
</tr>
<tr>
<td>Technical</td>
<td>Risk of major project failure</td>
</tr>
<tr>
<td>Societal</td>
<td>Fisheries impact</td>
</tr>
<tr>
<td></td>
<td>Amenities</td>
</tr>
<tr>
<td></td>
<td>Communities</td>
</tr>
<tr>
<td>Economic</td>
<td>Cost Estimates</td>
</tr>
</tbody>
</table>

The derogation comparative assessment document must include all options available for decommissioning of the installation in addition to the derogation option that the operator is proposing, in addition to estimated timeframes for each option. Typically this would include:

- Complete removal to land
• Partial removal to land
• Leave wholly in place
• Disposal at sea

The BEIS guidance states that for derogation cases:
• The impact of each option should be assessed using established methodologies
• The preferred option should be selected by focusing on the matters where the impacts of the options are significantly different
• The means used to reach the conclusion should be described

If the comparative assessment of the options identifies two or three matters that show a significant difference, judgement will need to be exercised as to which should be given the greatest consideration.

**What are the main phases of the comparative assessment?**

The comparative assessment process follows a prescribed process across a number of stages illustrated in Figure 14.

<table>
<thead>
<tr>
<th>Scoping</th>
<th>• A description of all assets to be assessed, the method of assessment and a confirmation of the criteria and boundaries of the comparative assessment is considered.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Screening</td>
<td>• At the screening stage unfeasible options are removed to produce a short list of options for comparative assessment. The potential reuse of assets must be considered.</td>
</tr>
<tr>
<td>Preparation</td>
<td>• Prior to the assessment, studies are conducted looking at technical, safety, and environmental aspects. This allows a well-informed comparative assessment to be carried out.</td>
</tr>
<tr>
<td>Evaluation</td>
<td>• The assessment of confirmed options is carried out, judging against the key criteria and sub-criteria aspects.</td>
</tr>
<tr>
<td>Recommendation</td>
<td>• Using results from the evaluation stage, a preferred option is recommended with an explanation of pros and cons for each option including options that are not recommended.</td>
</tr>
<tr>
<td>Review</td>
<td>• Drafts of the assessment are sent to identified key stakeholders for comment.</td>
</tr>
<tr>
<td>Submit</td>
<td>• The comparative assessment report is submitted to BEIS for approval.</td>
</tr>
</tbody>
</table>

Figure 14: Comparative assessment process flow chart
How are comparative assessments verified?

BEIS guidance states that in addition to stakeholder engagement it is important that the studies, and the assessment processes, which support the chosen decommissioning option are subject to independent expert verification. The purpose of this verification is to confirm that the assessments are reliable, unbiased and that there is no requirement to verify the final means of weighting or balancing the options, and that the process is transparent. This may involve the establishment of an independent review panel to evaluate the scope, quality and application of the work undertaken.

Experts in particular fields may be engaged to evaluate and confirm specific aspects of the project. BEIS may itself engage consultants to test particular aspects of the decommissioning proposals or to confirm that accepted practices and methodologies have been used.

How long does a comparative assessment take?

Depending on the scale and complexity of the project, the operator should provide adequate time for the scoping, screening and preparation phases of the comparative assessment process. This will ensure the evaluation phase is adequately informed and the evaluation is carried out at the appropriate level.

It is anticipated that for derogation candidates the scoping, screening and preparation stage will take minimum 12 months; and the evaluation, recommendation, review and submit stages will take 6 months.

Surveys may be required to gather asset data and inform the evaluation stage of the comparative assessment and these surveys should be initiated early in the process.
4 Safety Management

The management of safety in the UK O&G industry has been subject to significant changes since 1992, when the concept of a “safety case” was introduced in the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations. This method of governance covers all aspects of operations, including decommissioning.

Although the Major Accident Hazard (the presence of hydrocarbons) is much reduced during decommissioning, the safety management framework does not change.

Other regulations stipulate the use of a number of tools and methodologies for risk assessment and risk management during operations. Again, these methodologies are equally applicable to decommissioning and often involve review by the Offshore Safety Directive Regulator (OSDR) prior to commencing any work offshore.

4.1 Introduction

This section provides an overview of the key regulatory structure and processes relating to health and safety (H&S) management of O&G decommissioning activities. The principal requirements of the UK offshore Safety Case regulations are described, along with a review of how the regulator reviews and approves the relevant documentation. An overview of risk assessment approaches commonly used offshore is also provided, along with key lessons learnt by the industry.

4.2 Safety Case Principle

Fundamental to offshore O&G H&S governance within the UK is the principle of the “safety case”. For all aspects of the lifecycle of an asset, the operator is required to prepare and maintain the case that the design, construction, operation and decommissioning of an O&G installation is safe. This concept is not unique to offshore installations and is frequently deployed for similar purposes in the nuclear and rail industries.

A safety case is defined as ‘A structured argument, supported by a body of evidence that provides a compelling, comprehensible and valid case that a system is safe for a given application in a given operating environment’ [10].

The UK Safety Case regulations were initially considered following the recommendations of the Cullen Report into the Piper Alpha disaster in 1988. The primary aim of the regulations, introduced in 1992, was to reduce the risks from major accident hazards to the H&S of the workforce employed on offshore O&G installations or in connected activities.

The regulations were updated in 2005, and a further update was issued in 2015 as the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, known as SCR 2015 [11]. This latest update includes the requirement of Directive 2013/30/EU on the ‘safety of offshore oil and gas operations’ [12]. This directive came about following the 2010 Macondo disaster in the Gulf of Mexico.
SCR 2015 came into force on 19 July 2015 and covers O&G operations in the territorial sea adjacent to Great Britain and any designated area within the UKCS.

The primary aims of these regulations are to:

- Reduce the risks from major accident hazards to the H&S of the workforce employed on offshore installations or in connected activities;
- Increase the protection of the marine environment and coastal economies against pollution and ensure improved response mechanisms in the event of such an incident.

A Safety Case must demonstrate compliance with the ‘relevant statutory provisions’ (RSPs), notably:

- The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 (DCR) [14];
- Offshore Installations and Pipeline Works (Mgt & Admin) Regulations 1995 (as amended) (MAR) [15].

Other supporting RSPs are listed in Appendix 1.

4.3 Goal-Setting

UK Health & Safety law is based on a ‘goal-setting’ regime, rather than a prescriptive approach. Goal-setting sets out the objectives to be achieved, but leaves the operator with considerable freedom as to how these goals are achieved.

Duty holders for O&G installations must:

- Identify hazards;
- Undertake risk assessment, determining the consequences and likelihood of those hazards being realised;
- Establish suitable procedures and measures to control those risk.

Goal-setting allows duty holders to choose the most appropriate methods or equipment available to meet the safety case requirements and there is industry and Health & Safety Executive (HSE) guidance available which describes good practice in how the regulatory requirements are achieved.

The desired outcome of goal-setting is to reduce risks to As Low As Reasonably Practicable (ALARP). This does not mean that risk must be eliminated but that risk should be reduced to an acceptable, or tolerable level where the cost of further risk reduction would be ‘grossly disproportionate’ to the benefit realised.

To understand ALARP, it is first accepted that risk is an inevitable part of operations and everyday life, and that people accept a level of risk. If the level of risk is fairly low, i.e., a risk that is acceptable in day to day life, then that can be
termed broadly acceptable. If the risk is high, then it is deemed to be an intolerable risk.

It is in between these levels of broadly acceptable and intolerable that most offshore installations (and many onshore) operate. This is where the risks are deemed to be tolerable if the risks have been reduced to ALARP.

Goal-setting regulation encourages innovation and continuous improvement in risk management as it avoids the ‘tick-box’ approach of more prescriptive regulatory systems where it can be assumed that if all boxes are ticked, then safety has been achieved. This would rely on the regulatory system being comprehensive and adequate to cover all installations and technologies. As new technologies are introduced, regulation based on prescription may not be adequate.

### 4.4 Implementation of Regulation

All O&G fixed installations operating in the UKCS require a Safety Case under SCR 2015. The Safety Case document must outline all potential hazards that have been identified and the preventive measures that have been implemented to control the potential risks. The Safety Case also provides an overview of the safety management system in use on the installation to demonstrate that the controls are applied effectively. The Safety Case document is developed and enforced by the operator of the installation.

In the context of decommissioning, regulation 20 of SCR 2015 states that the operator of a fixed installation in external waters must ensure that it is not dismantled unless:

- The operator has prepared revisions to the current Safety Case, containing the particulars not contained in the current safety case for that installation;
- The operator has sent a version of the current Safety Case which incorporates the proposed revisions, showing clearly where they are to be made, to the Health and Safety Executive (HSE) at least three months (or such shorter period as the competent authority may specify) before the commencement of the dismantling;
- The HSE has accepted those revisions to the current Safety Case.

Hence decommissioning of a fixed installation requires a revision of the Safety Case to take account of the new hazards and risks arising from the change in activities. As plant is progressively decommissioned, the operational status and risk profile of the installation will change.

### 4.5 Structure of a Safety Case Document

The Safety Case is designed to provide documentary evidence to demonstrate that:

- The arrangements within the installation’s Health Safety Security and Environment (HSSE) Management System are adequate to ensure that the duty holder’s HSSE Policy and Technical Standards and relevant statutory...
requirements are complied with in relation to the installation and any activity connected with it;

• All hazards which could give rise to a Major Accident\(^1\), or the need for evacuation, escape or rescue have been identified and their risks to persons (workers and/or members of the public) and the environment evaluated;

• Measures have been, or will be, taken to reduce the risks to persons and the environment affected by those hazards to ALARP;

• Appropriate Performance Standards\(^2\) have been established for the Safety and Environmental Critical Elements\(^3\) (SECE) required to manage the identified Major Accident hazards and Environmental Events, and appropriate schemes and performance standards are in place for the assurance and verification of the SECE’s.

A Safety Case is generally structured around the following six sections:

• Safety and environmental criteria;
• Installation description;
• Safety and Environmental Management Systems;
• Control of major accident hazards;
• Justification for continued safe operation;
• Combined operations.

These sections are generally structured in a document with an introduction and executive summary. A Safety Case should be a living document and must be maintained and updated throughout the life cycle of the installation.

The Safety Case must be revised in the event of any significant change in circumstances including but not limited to; major modifications to the installation, management systems, organisation, operations, activities, the environment or industry guidance, changes in local community population or adjacent land-use, lessons learned, etc.

Due account should also be taken of technological advances that may present improved techniques for risk reduction or render current techniques obsolete.

The duty holder (i.e. the operator of any production installation) must undertake a thorough review of a Safety Case at least once every five years. The need to update and re-issue the Safety Case should be based on the outcomes of the

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\(^1\) A Major Accident is defined as an occurrence (including in particular, a major emission, fire or explosion) resulting from uncontrolled developments in the course of the operation of any establishment and leading to serious danger to human health or the environment, immediate or delayed, inside or outside the establishment, and involving one or more dangerous substances.

\(^2\) A Performance Standard is a statement, either qualitative or quantitative, of the performance required of a system or item of equipment. The Performance Standard is used as the basis for managing hazards through the life-cycle of the installation.

\(^3\) Safety and environmental-critical elements are defined as such parts of an installation or its plant (including computer programmes), (a) the failure of which could cause or contribute substantially to a major accident; or (b) a purpose of which is to prevent, or limit the effect of, a major accident.
review. The review should include a Major Accident Hazard review and use this to define a more detailed scope of work as required to confirm the validity of, or update to, the Safety Case. As part of the thorough review, all of the original supporting documents (including Hazard Identification [HAZID], Hazard and Operability Studies [HAZOP], risk assessments etc.) should be confirmed as appropriate to remain in place, or else shall be updated to reflect changes.

Development of new Safety Cases and revisions of existing Safety Cases must include consultation with relevant staff from the installation.

4.5.1 Regulatory Review

The review process is generally the same for submissions of new Safety Cases and existing Safety Cases. Submissions are made electronically to the Offshore Safety Directive Regulator (OSDR). The regulator undertakes an initial review, and then allocates sections of the document to internal topic specialists as required. OSDR can, if necessary, request further information from the duty holder.

The duty holder will revise the Safety Case if required following review and the updated Safety Case will then be filed in both electronic and paper format with:

- The OSDR
- The duty holder’s corporate centre
- The duty holder’s Offshore Installation Managers
- The duty holder’s Health, Safety & Environment (HS&E) Manager
- The duty holder’s Installation HSE Advisor.

4.6 Operational Considerations

In order to manage the operation of an installation safely and effectively, the duty holder must have an effective Safety and Environmental Management System (SEMS) in use on the installation. This is typically an integral part of the overall Management System put in place by the duty holder. The SEMS is generally based on the Plan, Do, Check, Act process utilised in various international standards such as ISO 80001 or ISO 14001. A typical SEMS content is included in appendix 2.

4.6.1 Risk Assessment and Supporting Studies

The Health & Safety at Work Act 1974 is the over-arching legislation for all H&S regulation in the UK. This act requires employers and employees to prevent exposure to risks in the workplace ‘so far as is reasonably practicable’. In order to prevent exposure to risks, as far as is reasonably practicable, it is necessary that risks are understood and robustly assessed. Risk assessment is therefore a fundamental part of UK H&S law.

Risk assessment has five fundamental steps:

1. Identify the hazards
2. Determine who may be harmed, and how
3. Evaluate the risks, decide on precautions
4. Record significant findings
5. Review the assessment as work progresses, and update as necessary

During planning of any operations, a number of standardised tools and methodologies are available to enable the understanding and assessment of hazards and risks. The most commonly used methodologies are described below.

**Management of Change**

An installation’s SEMS will include a Management of Change (MoC) process. This process should be applied to any dismantlement phase of the installation.

As part of the MoC process, Hazard Identification and Risk Assessment (HIRA) will be applied to changes as required. HIRA will include task risk assessment, Permit to Work and the Safe Isolation & Reinstatement of Plant. To support the HIRA, HAZID, Environmental Issues Identification (ENVID) and HAZOP studies may be required. The HAZID and ENVID studies should determine how detailed any further risk assessment such as HAZOP and quantitative risk assessment should be.

Risk assessments should therefore, be carried out, and where necessary recorded, and are a key part of the MoC process and Safe System of Work (SSoW).

**Safe System of Work**

A Method Statement or SSoW is required under the Health and Safety at Work Act 1974 for all workplaces. The aim of the SSoW is to provide all necessary information so individuals can carry out work in a safe manner. The SSoW must be easily accessible by staff and ready for inspection, therefore a copy must be kept within the operational area at all times. It is the responsibility of project management to ensure that all staff have read through the SSoW and are aware of their specific roles.

A typical SSoW can include information such as work sequencing, H&S contact details, details of the supervisors on site and waste management information as well as descriptions of all equipment to be used during operations and a log of all relevant certificates and inspections.

**Permit to Work**

In environments where the work being carried out has been identified as high risk, a system of safety procedures and strict control measures must be agreed upon before the work is permitted to begin. This is known as a ‘permit to work system’.

The aim of permit to work systems is to minimise the risk of a major incident occurring by reducing the risk of human failures by ensuring that all staff carrying out the work are trained to a high level and are managed by responsible people with sufficient experience in the high risk environment. Work identified as high risk cannot be carried out without a permit to work.
The permit to work is a methodology that must be followed throughout operations and is informed by earlier risk assessments of the work being executed. The permit to work should provide information of all operations, how they will be carried out and how all safety procedures will be implemented.

**Safe Isolation and Reinstatement of Plant**

High standards of isolation and reinstatement controls are a requirement in major hazard industries such as the offshore O&G industry. Failures during these operations are one of the main causes of loss of containment incidents and are one of the most significant failures that can result in a major incident if not correctly controlled.

The HSE provides guidance notes outlining industry good practice when performing isolation and reinstatement operations [16]. Keys factors to achieve good practice include intelligent design principles, the consideration of human factors when performing operations and using a comprehensive component selection tool.

**Hazard Identification and Risk Assessment**

Hazard Identification and Risk Analysis (HIRA) is a collective term that includes all actions involved in identifying hazards and evaluating risk at installations, to make certain that risks to employees, the public or the environment are consistently controlled within the organisation’s risk tolerance. These studies typically address three main risk questions to a level of detail commensurate with analysis objectives, life cycle stage, available information and resources. The three main risk questions are:

- **Hazard** – What can go wrong?
- **Consequences** – How bad could it be?
- **Likelihood** – How often might it happen?

Tools and studies which may be employed are described below.

**Hazard Identification (HAZID)**

The objective of a HAZID procedure is to identify main hazards, to review the effectiveness of selected safety measures and, where required, to expand the safety measures in order to achieve a tolerable residual risk. HAZID studies use appropriate guidewords to facilitate the study, and are typically led by a trained and experienced facilitator.

**Hazard and Operability (HAZOP)**

A HAZOP is a structured analysis of a system, process or operation, carried out by a multi-disciplinary team. The HAZOP team, using guidewords and parameters (e.g. high pressure) as prompts, determines potential deviations from a design intent, and the potential consequences of those deviations (e.g. vessel failure). It then looks to what safeguards are built into the design which will mitigate against the deviation, and also identifies further action required where such safeguards are inadequate or non-existent.
HAZOP requires an experienced facilitator in order to achieve a comprehensive output.

**Simultaneous Operations (SIMOPS)**

Simultaneous Operations occur when two or more activities are being executed in the same location at the same time, often with different contractors working on different scopes of work. When this situation arises, a SIMOPS plan is typically prepared to develop a suitable hazard and risk management plan. SIMOPS plans do not need to be presented directly to the regulator, however the regulator may request to see these and other plans, procedures etc. during inspection visits.

**Combined Operations (COMOPS)**

Combined Operations (COMOPS), where two Safety Cases may be involved, for example when an external drilling rig is operating on a platform, must be submitted to the regulator prior to the commencement of the COMOPS. The notification should be accompanied by a COMOPS bridging document which describes the arrangements for the execution of the COMOPS [17].

A COMOPS notification is assessed by the regulator in a similar manner to the Safety Case. However, the time required for this review would typically be significantly less.

**TASK Risk Assessment**

A TASK card is a tool used by workers on site to actively assess their surroundings to ensure they are operating in a safe environment and have all the necessary protective equipment.

The TASK card is based on the phrase ‘Think first, Act safe, Stop if hazardous, Keep safe’ and contains a flowchart with a series of questions that the worker must ask themselves to ensure that are adequately prepared to begin work. The card includes questions such as:

- Are all risk assessments and method statements up to date and available?
- Do you have correct PPE?
- Do you know the emergency escape route?
- Are all hazards identified in the risk assessment being sufficiently controlled?

Once the card is completed and the workers are satisfied with the work environment, the entire team must all sign the TASK card before work can commence.

**Environmental aspects identification (ENVID)**

An Environmental aspects identification (ENVID) review is a tool used to identify environmental aspects of a project in relation to its surrounding environment in order to develop plans to mitigate potential impacts.

An ENVID review will identify hazards and will provide recommended mitigations at an early stage of a project’s design. This allows the project to
comply with all relevant legislation and minimise the risk of hazards and environmental impacts that the design may have on the surrounding environment.

The review is completed by a team with relevant experience who look at the proposed design concept and consider all hazards which could potentially develop, and how these hazards could be removed or reduced.

### 4.6.2 Emergency Response

Regulation 7 of the Management of Health and Safety at Work Regulations 1999 requires that employers draw up emergency procedures [18]. Regulation 8 of PFEER builds on that requirement in order that duty holders develop an emergency response plan for offshore installations [13]. Regulation 8 further requires that the emergency response plan is tested ‘by practice and otherwise’.

Installations will have existing emergency response plans, but these will require updating and testing due to the different conditions applicable to decommissioning, such as different numbers of persons on board. Due to the fact that differing conditions will exist on the installation as decommissioning progresses, it is likely that emergency response plans will require updating as circumstances change.

### 4.7 Significant Lessons Learnt

Thanks to the removal of the majority of hydrocarbons from offshore installations prior to the commencement of dismantling, the potential for Major Accident Hazards is significantly reduced.

Operators are not obliged to declare the detail of safety issues in decommissioning close-out reports. Hence there is limited information about specific events but broad themes have been identified:

- Particular attention should be paid to the management of contractors, as it is likely that significant numbers of different contractors will be used and coordination of work may be complex, leading to the increased potential for incidents. Pre-qualification processes for contractors need to be robust to ensure they are competent to carry out the work safely.

- Guidance from Department of Energy and Climate Change (DECC) (Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998) [4], recommends the use of Quantitative Risk Assessment\(^4\), although the value of this is questionable given that the principal major hazards, hydrocarbons, have been removed from the installation and incidents become more occupational. This has been seen and the majority of incidents relating to dismantlement have been in the slip, fall and trip categories, i.e., occupational risk.

\(^4\) Quantitative Risk Assessment is most commonly used in process industries to quantify the risks of Major Hazards. This will typically rely on assigning typical failure rates to specific components to identify their probability of failure, and then assessing the potential consequences of that failure.
• Asbestos is highly likely to be present on old installations, and asbestos surveys and removal plans should be undertaken.

• The management of Naturally Occurring Radioactive Material (NORM), already a well-documented challenge in the O&G industry, can become a greater challenge during decommissioning as the recovered volumes are far greater than during exploration and production.

• Some paints have been found to contain isocyanates. These can be liberated by mechanical or flame cutting and require the use of Respiratory Protective Equipment which may not be typical of Personal Protective Equipment (PPE) during exploration and production.

• There have been incidents where dismantling activities have resulted in dropped objects during both the lifting of supplies on/off the installation and the removal of pipework and structures. All lifting operations should be covered by adequate lifting plans prepared by competent personnel. This would be typical of normal operational practice but the use of structural engineers to review significant lifting operations is essential, as the dismantlement methodology may not reflect the original construction methodology, and require strengthening of components prior to removal.

• If a significant period of time has passed between CoP and dismantling, with limited maintenance then access structures such as walkways, ladders and gangways may require integrity assessment to confirm that they still provide a safe method of access to all areas of the asset.

In summary, the majority of Major Accident Hazards are absent when dismantlement commences, but the level of individual risks from occupational and health hazards has a different profile, and is in some cases greater.
5 Environmental Management

Environmental management is enforced through a suite of legislation/regulation implemented by government departments and agencies.

Environmental Impact Assessments (EIAs) are undertaken for planned decommissioning activities and as a tool to be used in Comparative Assessment (CAs). The EIA requires a number of topics to be assessed and highlights any mitigation measures to be carried out during the decommissioning. The EIA forms part of the DP submission, submitted by operators.

When the decommissioning is being carried out an Environmental Management System (EMS) is set up to monitor and make sure all the precautions and permits highlighted in the EIA are carried out.

Depending on local conditions and circumstances further assessments might be necessary if protected species are affected by any of the decommissioning activities.

5.1 Introduction

This section addresses in detail the UK regulatory approvals process for the management of the environmental aspects of decommissioning. Environmental considerations are a key requirement throughout the lifecycle of an O&G field, including the decommissioning phase. Measures should be implemented to ensure that the marine and terrestrial environment, habitats and species do not face significant consequences from decommissioning work or any of the activities associated with it. These considerations are enforced in the UKCS through various European directives, transposed into UK law, which sets requirements for both the UK Governments and licence holders.

Environmental assessment of O&G licensing is delivered through Strategic Environmental Assessments (SEAs) from the UK Government, and, for operations and decommissioning through Environmental Impact Assessments (EIAs) carried out by operators and approved by BEIS and other bodies.

5.2 Strategic Environmental Assessments

SEAs are carried out by the UK Government to assess whether a rolling programme of O&G licensing rounds and hence developments in the UKCS should be undertaken. This is a requirement of the European SEA Directive (2001/42/EC) [19] and implemented through the Environmental Assessment of Plans and Programmes Regulations 2004 [20]. Although the Directive was not incorporated into UK law until 2004, the requirements of the Directive have been applicable to O&G projects and other marine energy projects since 1999.

The Directive requires the full lifecycle of a plan or programme to be considered, so for O&G operations, the environmental impacts of decommissioning is included. The SEAs set the precedence for what environmental work must be carried out as a minimum for certain areas of the investigated programme. To date 11 O&G and latterly Offshore Energy SEAs have been carried out covering almost the entire UKCS. This is shown in Figure 15.
Figure 15: Map of previous UK SEAs.

The 2016 UK Offshore Energy SEA [31] notes that ‘Decommissioning programmes will require EIA, which should include the following relevant information:

- All potential impacts on the marine environment, including exposure of biota to contaminants associated with the installation, other biological impacts arising from physical effects, conflicts with the conservation of species, with
the protection of their habitats, or with mariculture, and interference with other legitimate uses of the sea.

- All potential impacts on other environmental receptors, including emissions to the atmosphere, leaching to groundwater, discharges to surface fresh water and effects on the soil.
- Other consequential effects on the physical environment which may be expected to result from the option.

The SEAs undertaken to date and the information collected as part of the baseline studies, provides an important framework for subsequent development specific EIAs. It provides contextual information for DP EIAs.

### 5.3 Environmental Impact Assessment

An EIA involves assessing the environmental impacts of a proposed project or activity. The conclusions of the assessment are recorded in an ES, which for a decommissioning project, forms part of the DP submitted to BEIS for approval.

The European Commission (EC) introduced the Directive on the Assessment of the Effects of Certain Public and Private Activities on the Environment (85/337/EEC) in 1985 as a Europe-wide procedure [21]. It was put in place to ensure that the environmental consequences of projects are identified and assessed before authorisation for development is given.


Although there is currently no statutory requirement to undertake an EIA at the decommissioning stage, BEIS have determined that a DP must be supported by an EIA. The EIA will form part of the DP and should assess the impact of the decommissioning activities on the environment.

Guidance from BEIS [4] confirms the following should be included in the DP EIA:

- All potential impacts on the marine environment, including exposure of biota to contaminants associated with the installation, other biological impacts arising from physical effects, conflicts with the conservation of species, with the protection of their habitats, or with mariculture, and interference with other legitimate uses of the sea.
- All potential impacts on other environmental compartments, including emissions to the atmosphere, leaching to groundwater, discharges to surface fresh water and effects on the soil.
- Consumption of natural resources and energy associated with re-use and recycling.
- Other consequential effects on the physical environment which may be expected to result from the option.
- Potential impacts on amenities, the activities of communities and on future uses of the environment.
Requirements under the EU Habitats & Birds Directives may also be dealt with as part of the EIA if there are significant issues. This happens through submission of a separate Habitats Regulations Appraisal (HRA). This is explained in more detail in Section 5.6.3.

In order to undertake an EIA, it is necessary to provide specialists with details of the proposed methodology for undertaking the decommissioning including quantification of emissions to air, land, fresh and sea water. If the exact methodology is not known or a Comparative Assessment is being undertaken, as will be required for pipelines, then the EIA should look at all methodologies and receptors using a standardised EIA process. When creating a baseline for the EIA the importance of access to previous environmental surveys and understanding of the historic use of the area should not be underestimated for instance, accurate knowledge of the content of any drill cuttings pile.

Receptors can broadly be broken down into three main groups – physical, biological and human. Examples of the topics to be included are shown in Figure 16.

<table>
<thead>
<tr>
<th>Physical</th>
<th>Biological</th>
<th>Human</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marine</td>
<td>Marine</td>
<td>Marine</td>
</tr>
<tr>
<td>Oceanography</td>
<td>Nature Conservation</td>
<td>Recreational Users</td>
</tr>
<tr>
<td>Bathymetry</td>
<td>Ornithology</td>
<td>Military</td>
</tr>
<tr>
<td>Geology</td>
<td>Benthic environment</td>
<td>Aviation</td>
</tr>
<tr>
<td>Geophysical Processes</td>
<td>Fish and Elasmobranch</td>
<td>Commercial Shipping</td>
</tr>
<tr>
<td>Terrestrial</td>
<td>Marine Mammals</td>
<td>Commercial Fisheries</td>
</tr>
<tr>
<td>Geology</td>
<td>Terrestrial</td>
<td>Other sea users</td>
</tr>
<tr>
<td>Landforms</td>
<td>Nature conservation</td>
<td>Both</td>
</tr>
<tr>
<td></td>
<td>Birds</td>
<td>Socio-economic</td>
</tr>
<tr>
<td></td>
<td>Mammals</td>
<td>Atmospheric</td>
</tr>
<tr>
<td></td>
<td>Flora and fauna</td>
<td>Emissions</td>
</tr>
</tbody>
</table>

Figure 16: General environmental assessment topics

The EIA should go through a scoping phase to focus time and resources on those receptors or features deemed to be a risk of a ‘significant impact’ by activities planned under the DP. Depending on the scale of decommissioning, an official EIA scoping document may not be released by operators in the UKCS. However, stakeholder engagement will help to focus the EIA on the relevant receptors and pathways. An effective scoping exercise should also be able to scope out non issues and record the reasons why.
In the UKCS to date, environmental assessment of decommissioning activities starts from the base case that most installations will be removed due to the OSPAR 98/3 recommendation. This means that the aspects of the EIAs considering installations focus on assessing the impacts from the operations associated with the decommissioning activities and not comparing the impacts of leaving installations in place versus removal. This type of assessment known as a ‘Comparative Assessment’ is described in Section 3.3, and is applied to installations eligible for a derogation, pipelines, and drill pile cuttings.

The type of potential impacts identified during the EIA will vary across geographical areas however most EIAs identify similar issues such as those described below. A drill cuttings pile study, if appropriate, will be required and future management of drill cuttings piles fully described in the EIA. Generally impacts are localised to the location of the facility or infrastructure being decommissioned and the reuse, recycling or disposal sites onshore.

**Seabed:** The seabed is likely to be disturbed through removal of structures and placing of equipment. This in turns impacts upon the benthos which lives on or in the seabed. Levels of disturbance to the seabed will vary according to the scale of the decommissioning activities. Leaving pipelines or other infrastructure in place will have impacts on the seabed over a longer time period. The seabed may also be contaminated by drill cutting piles or other historic discharges.

**Marine Mammals, Fish and Shellfish:** Impacted through underwater noise and general risk to water quality through planned or accidental discharge of chemicals, oils and other substances. Increased vessels in some sensitive areas may be an issue due to increased risk of vessel strike.

**Ornithology:** Minimal direct risk to seabirds unless there is an accidental event resulting in unplanned discharges of oil or other substances. For onshore works disposing of or reusing materials may increase environmental risks to birds.
**Commercial Fisheries:** Commercial fishermen are mostly concerned about the long term impacts of leaving infrastructure in place in relation to safety and the entanglement risk. There is also a risk of contaminating a catch should a net be trawled through areas of contaminated seabed. There may also be greater or extended geographical restrictions for all shipping in a sea area whilst the decommissioning activity is taking place.

**Atmospheric Emissions:** Atmospheric emissions associated with the use of vessels and equipment offshore and from processes to re-use or recycle materials onshore can be considerable depending on the scale of the decommissioning.

The EIA should also identify any mitigation measures or best practices that will be in place for the decommissioning activities to reduce impacts. These will then be taken forward, usually through the EMS or other system used to manage the physical decommissioning activities.

The EIA should also set out the planned monitoring relevant to the EIA including types of surveys, frequency, any planned analysis and how the monitoring plan will be reported, including timescales. Ideally monitoring should be planned to answer specific questions such as what are the contaminant levels in sediments surrounding the drill cuttings pile.

### 5.4 Stakeholder Engagement

Engaging with stakeholders and responding to their comments is an important aspect of the environmental assessment, especially when considering the human impacts. Consultations must be carried out with statutory consultees, stakeholders and the public, as is set out in BEIS DP guidance.

A programme of stakeholder engagement works will be identified and may include websites, workshops, dedicated meetings for specific topics and specific groups and is usually recorded in a stakeholder engagement report appended to the DP. This report should summarise the main concerns raised by stakeholders and how these have been addressed, or the reasons they are not addressed clearly explained.

Statutory consultees tend to be government advisors or bodies that represent other sea users for instance:

- Environmental Agencies (Advisors to Government) including Joint Nature Conservation Committee (JNCC), Scottish Natural Heritage (SNH), Natural Resources Wales (NRW), English Nature (EN), Scottish Environmental Protection Agency (SEPA)
- Marine Water Quality and Fisheries including Centre for Environment, Fisheries and Aquaculture Science (CEFAS) and Marine Scotland Licensing (MS-LOT)
- Health & Safety - UK Health & Safety Executives (UK HSE)
- Shipping Safety including Department of the Environment, Transport and the Regions (DETR) and The Marine Coastguard Agency (MCA)
Other consultees, while they are not statutory, are effectively treated as statutory consultees during the consultation process:

- Commercial Fisheries Representatives including National Federation of Fishermen’s Organisations (NFFO), Scottish Fishermen’s Federation (SFF), Northern Ireland Fish Producers’ Organisations (NIFPO) and Anglo-North Irish Fish Producers Organisation (ANIFPO)
- Shipping Safety including Northern Lighthouse Board (NLB) and Trinity House

Stakeholders are any individual or organisation affected by the decommissioning activities and could include:

- Other local infrastructure owners
- Oil companies, telecoms cable operators, electrical cables
- Shipping Representatives
- Chamber of Shipping (CoS)
- Non-government organisations including Greenpeace, WWF, Friends of the Earth, Royal Society for Protection of Birds (RSPB), MCS, WDC
- Recreational Users including individual sports fishermen, Royal Yachting Associations (RYA)

Statutory consultees will be sent the DP (or a link to it) by BEIS and formally asked for their comments which BEIS take into account when making a decision on whether to accept the DP or not.

As with statutory consultees, stakeholders may also submit their comments on a DP to BEIS and BEIS should consider these when making a decision on the DP.

**Case Study: Shell Brent**

As part of the decommissioning of the wider Brent Field in the North Sea, and particularly the Brent Delta topside removal, Shell set up a number of tools and processes for undertaking a long-term consultation programme. This programme included five main elements which were set out in their DP [23].

- A public website, [www.shell.co.uk/brentdecomm](http://www.shell.co.uk/brentdecomm).
- A regular e-newsletter, available from the website
- Stakeholder dialogue meetings including, to date, 12 wide-ranging stakeholder meetings in London and Aberdeen and five specific meetings of a working group looking at options for the management of the GBS cell sediments.
- One-to-one meetings with individual stakeholders or stakeholder organisations.
- Presentations at conferences and meetings.
5.5 Environmental Management Systems

In order to ensure commitments made in the DP are carried forward to the operational stage, an Environmental Management System (EMS) of some form will be required. The OSPAR Recommendation 2003/5 [24] was put in place to promote the use and implementation of Environmental Management Systems (EMS) by the offshore O&G industry. An operator’s EMS is the key tool for implementing the environmental mitigation and requirements set out in an EIA.

BEIS requires all operators of offshore Licences to have an EMS in place [25]. The leading accreditation systems for EMSs are:

- BS EN ISO14001: 2004 Environmental Management Systems
- European Eco-Management and Audit Scheme (EMAS)

For operators who do not have an EMS which has been accredited to ISO 14001 or is registered to EMAS, BEIS requires a number of actions to ensure full compliance with the requirements of BEIS licence applications.

The aim is to ensure that all UK operators have systems and procedures to identify, monitor and control the environmental aspects associated with their exploration and production activity.

According to BEIS EMSs should:

- Be implemented at a strategic level and integrated into corporate plans, and policies. Top-level commitment is required, so that senior management understands its role in ensuring the success of an EMS.
- Identify the organisation’s impacts on the environment and set clear objectives and targets to improve its management of these aspects and improve the organisation’s overall environmental performance.
- Be designed to deliver and manage compliance with environmental laws and regulations on an ongoing basis, and to quickly initiate corrective and preventative action in cases of legal non-compliance.
- Deliver good resource management.
- Incorporate assured performance metrics that demonstrate the above, that can be communicated in a transparent manner.
5.6 Other Key Assessments and Consents

Agreement of the DP by BEIS allows the operator or designated organisation to move forward with the physical act of decommissioning under a broad envelope of activities however, other consents will be also be required to manage activities at sea and on land.

5.6.1 BEIS Permitting

Once the DP is approved BEIS continues to permit physical activities in the marine environment. Over the years a system of minimising duplication has been developed where an operator can submit one ‘Master Application Template’ (MAT). This contains general information relating to the relevant operation type, including an EIA, if required.

Subsidiary Application Templates (SATs) must be submitted for decommissioning activities such as proposed pipeline operations, well operations, use of chemicals, discharge of oil and other substances, Consent to Locate (i.e. temporarily place a structure on the seabed) and for geological surveys. The MAT can support a number of ‘Subsidiary Applications’ for specific approvals under a variety of applicable environmental legislation.

The MAT/SAT process allows for detailed examination of proposed activities at sea and allows BEIS to ensure commitments made in the DP EIA are implemented.

Under the Offshore Petroleum Activities (Oil Pollution Prevention and Control) (Amendment) Regulations 2011 [26], an OPPC permit is also required from BEIS for any material being discharged or re-injected that has been contaminated by hydrocarbons from the reservoir. The OPPC Regulations include the concept of “release” to cover all unintentional emissions of oil that occur through accidental spills / leaks or non-operational discharges with intentional emissions called “discharges”.

Under the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 [27], all operations carried out on or in relation to an offshore installation or pipeline (including decommissioning) which may present a risk of marine pollution by oil must be covered by an Oil Pollution Emergency Plans or OPEP which must be approved by BEIS.
5.6.2 Marine Licence

A marine licence is required for decommissioning activities where anything is temporarily placed on the seabed, left in-situ, permanently removed, or for the use of explosives. It can be applied for individual activities or for a group of activities and depending on the scale of activities an EIA may be required. Licences will be time limited but operators will be able to apply to renew licences that cover a range of activities. The Marine Licence allows for a level of detail and scrutiny beyond that provided in the EIA of the actual planned activity at sea.

The legislation implementing Marine Licences varies across geographical regions and according to the activities taking place. Some activities are regulated by BEIS, others by the Marine Management Organisation (MMO) under the Marine and Coastal Access Act 2009 [28] and others by Scottish Government under the Marine (Scotland) Act 2010 [29].

Decommissioning activities need to be completed in line with any conditions included within the Marine Licence. For instance, that marine mammal observers will be used during certain operations. The regulators will require records to show Marine Licence conditions have been adhered to and have the powers to inspect and audit operations.

5.6.3 Protected Sites and Species- The Habitat and Birds Directives

In addition to the general protection afforded to the environment through EIAs, other European Directives provide enhanced protection for species and habitats of particular European importance including specific habitats such as sandbanks or reefs and some seabirds and marine mammal species.


These Directives specify that where a plan or project is likely to have a significant effect upon a protected site, either individually or in combination with other projects, the Competent Authority, in this case BEIS, must complete an Appropriate Assessment (AA). The AA must look in detail at how the projects may adversely affect the integrity of the protected area and associated features. The information to allow the Competent Authority to undertake an AA is often supplied by the applicant in the form of a Habitats Regulations Assessment (HRA).

Where an AA has been carried out and results show adverse effects upon a site, consent will only be granted if there are no alternative solutions or where there are imperative reasons of over-riding public interest (IROPI) for the development and compensatory measures have been secured.

In order to minimise impacts to European Protected Species (EPS), a group of birds and mammals identified by the EU as in particular need of protection, an EPS disturbance licence may also be required. The administration of the EPS Licence is the responsibility of regional governments across the UK, and there are
some variations in the specific requirements across the UKCS. An EPS Licence will be required for any ‘deliberate disturbance’ of marine mammals resulting from decommissioning activities.

5.6.4 Non-Native Species

The North Sea and waters around the UK have few invasive species, but do have set processes and guidance for how to handle non-native species (NNS). A number of international and European agreements and regulations set out the framework for how NNS, The International Convention for the Control and Management of Ships’ Ballast Water and Sediments (BWM Convention), aims to stop the spread of potentially invasive aquatic species in ships’ ballast water. The convention entered into force on 8th September 2017 as part of the International Maritime Organisation’s (IMO) part of the United Nations (UN).

In line with EU member state requirement, the UK has also developed a Great Britain Invasive Non-native Species Strategy [32], which sets out requirements for terrestrial, freshwater and marine environments. Further guidance for the management and monitoring of the NNS is set out by local agencies including Scottish National Heritage (SNH) [33]. The SNH guidance also sets out a method for developing the biosecurity control measures that should be applied to reduce the likelihood of introducing NNS. Detailed description of the method and examples can be found in Appendix B of the guidance document [34].

Figure 18: Five step method for preventing NSS
5.6.5 Convention on International Trade in Endangered Species (CITES)

CITES (the Convention on International Trade in Endangered Species of Wild Fauna and Flora) is an international agreement between governments. Its aim is to ensure that international trade in specimens of wild animals and plants does not threaten their survival. In the UKCS, the cold water coral Lophelia Pertusa is known to exist on some offshore installations. If the coral is present and the installation upon which it is located is to be returned to shore or across state boundaries it will be necessary to discuss with the Department for Environment Food and Rural Affairs (DEFRA) the requirements for a CITES certificate.

5.6.6 Environmental Research

Through the SEA process and other research groups, BEIS have embarked on a programme of research to increase our understanding of the environmental impacts of O&G activities. Recently much of this research has been managed through the SEA process. O&GUK also put significant effort into research and development of the evidence base to support EIA and other permitting requirements.

In 2011 and 2012, O&GUK led the ‘Decommissioning Baseline Study’ Joint Industry Project (JIP) to gather knowledge and experience around the decommissioning of offshore structures and pipelines. The environmental workstream within the JIP identified that gaps exist in the data set used to describe the influence of man-made structures on the North Sea ecosystem. In response to this a long-term and scientifically-led JIP was launched in 2013 to improving scientific knowledge across all aspects of the ecosystem. This led to the Influence of Structures In The Ecosystem (INSITE) JIP, which was backed by eight energy companies as sponsors, who all committed to proactively engage with stakeholders and make all the findings of INSITE publically available. Their current research include measuring shadow effects, reef effects, ecological effects and much more.

This is described in more detail in Case Study 2 – The INSITE Project.

5.7 Post-decommissioning

After assets have been removed or left in-situ, as per the approved DP, a number of survey and monitoring requirements remain with the operator in perpetuity. The specific requirements must be agreed with BEIS, and will depend on local conditions. As part of the post-decommissioning process some key compliances must be met by the operators, including:

- Where pipelines or any part of any installation are left in-situ, location data and surveyed depths are to be submitted to the UK Hydrographic Office. Navigation aids and markings must be installed and maintained for any remains that project above the sea surface.
• Following removal of debris, an independent verification survey is required. This is often known as an over-trawlability survey and conducted by a fishing vessel towing fishing gear across the seabed.

• Post-decommissioning environmental seabed sampling surveys will be undertaken to monitor levels of hydrocarbons, heavy metals and other contaminants. The survey strategy will have been summarised in the EIA and agreed with BEIS and their scientific advisors through the DP approvals process.

The requirement for monitoring is set in perpetuity in the UK, although the scope of monitoring is reviewed on a regular basis with BEIS. The DP sets out the initial post removal surveys to be carried out between the DP approval and submitting the close-out report. After this stage, any further surveys are agreed with BEIS at the point of reporting back on the previous survey. The key requirement is that once a survey has been carried out, the operator consults with BEIS to agree next steps.

5.7.1 Close-out Report

To report on the conclusion of asset decommissioning and removal, a close-out report is submitted to BEIS within four months of completing the offshore works. The report allows the operator to confirm to BEIS that the requirements set out in the DP have been carried out as described and agreed. The report will include results of the debris clearance and post decommissioning surveys, as well as explaining any major variations from the DP. The close-out should summarise the following:

• Information on the outcome of the DP as a whole.

• The results of debris clearance and any monitoring undertaken. Any independent verification should be included.

• The results of the post-decommissioning environmental sampling survey. If necessary update the schedule for future environmental monitoring or monitoring of items left in place with reasons for the changes.

• Measures taken to manage the potential risks arising from any legacies, confirmation that mariners’ charts are updated with the location of any items left in-situ and, that installation of navigational aids has taken place.

• Provide high level summary of actual costs and a general explanation of any difference against forecast costs.

The close out reports are used by BEIS to influence policy and regulation development and broaden the decommissioning knowledge base.
6 Waste Management

Waste management is a key challenge in decommissioning to make sure waste is minimised, materials are reused in the best way possible, or disposed of in a safe manner.

A number of international regulations put in place robust requirements of transparency on the registration and movement of waste, and hazardous wastes in particular. This is key to limiting the ‘dumping’ of dangerous materials, and ensures that the originator of the waste takes responsibility and accountability of waste disposal.

For movement and treatment of waste within the UK, a Duty of Care applies to both hazardous and non-hazardous wastes. For hazardous waste, consignment notes provide an audit trail. For non-hazardous wastes this is achieved through the use of waste transfer notes. This arrangement allows the regulatory authorities to ‘audit’ regulatory compliance.

For international movements of waste, transboundary consignment notes fulfil the same function as WTNs. These are governed by OECD Guidance and require consent documentation and permits to travel with a waste consignment, to audit the waste and its destination as it moves across borders and different authorities.

6.1 Introduction

This section describes the UK regulatory process that must be followed to manage the disposal of waste at various phases of the decommissioning process. Waste handling and processing is associated with several stages of the decommissioning process. Waste management can also be considered part of environmental considerations, but are described in detail in this section, as the processes follow distinct element of legislation.

6.2 Regulatory regime and general strategy

The international ‘Basel Convention on the Control of Transboundary Movements (TBM) of Hazardous Wastes and their Disposal 1992’ sets out strict regulation for any TBM of hazardous waste. The main objectives of the convention are to:

- reduce TBM of hazardous waste;
- to ensure treatment and disposal takes place as close as possible to their source of generation; and
- to minimise the generation of waste.

Over 170 countries have signed up to the convention across the world [35].

Following the 1992 Basel Convention, the Organisation for Economic Co-operation and Development (OECD) has been developing a Control System for Waste Recovery (Decision C(2001)107) [36]. The control system aims to facilitate the trade of recyclable goods in an environmentally friendly way. This is to ensure that the full value of materials is utilised, while trading these goods with consideration of the environment. This Decision prohibits the export of hazardous wastes to non-OECD members, for disposal or recovery. A guidance manual has been developed to guide the members in how best to follow the process [35].
The UK regulatory regime was established by the Control of Pollution Act 1974. This was further strengthened with the introduction of the Environmental Protection Act 1990 [37], which replaced much of the 1974 Act. The Act initially focused on disposal of waste, but since the EC Framework Directive on Waste (Directive 75/442/EEC, amended as Directive 2006/12/EC and Directive 2008/98/EC) [38] [39], the scope of the regulatory regime has expanded to include storage, treatment, recycling and transport of waste. Oversight of the regulatory requirements set out in the 1990 Act has been delegated to each devolved administration within the UK5.

The 1990 Act sets out the primary legislation, though much of the legislation that impacts on operators is secondary legislation i.e. regulation, provided for in the primary legislation. The most influential secondary legislation includes the Duty of Care (DoC) discussed below and forms part of Section 34 of the Act, and Waste Management Licencing regulations of 1994 [40].

6.2.1 Duty of Care

With the Environmental Protection Act 1990, a ‘Duty of Care’ (DoC) was introduced under Section 34 [37]. Any individual or organisation who imports, produces, carries, keeps, treats or disposes of waste is subject to the DoC. Its purpose is to avoid waste being handed over to entities that do not have the appropriate licences to handle the waste, including consideration of the final destination and how it is treated. This obligation is imposed by means of a clear audit trail from waste production through to disposal, executed by means of Waste Transfer Notes (WTNs).

The DoC requires organisations and individuals to take all reasonable and applicable measures to:

- Ensure that waste is handled by those with the necessary permits and licences
- Ensure that waste is stored and transported appropriately and securely so it does not escape
- Complete WTNs to document transfers, and to follow the shipment at all points

This DoC ensures that operators are obligated to check that waste recipients at any stage of the chain are accredited to handle the given types of waste. This encourages self-regulating, where waste producers are responsible for making the necessary checks. A breach of the DoC is a criminal offence, with a penalty of up to £5,000 for smaller offences or an unlimited amount for more serious offences [4].

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5 For England this is the Environment Agency (EA); for Scotland this is the Scottish Environmental Protection Agency (SEPA); for Wales this is Natural Resources Wales (NRW); and for Northern Ireland this the Northern Ireland Environment Agency (NIEA).
6.2.2 Waste strategy and principles

UK decommissioning guidance requires that decisions are consistent with the hierarchy principles for all waste types, as seen in Figure 19. In line with this waste hierarchy, OSPAR recognises re-use of installations as the preferred decommissioning option.

BEIS wish to encourage the re-use of facilities wherever this is practical. It is therefore expected that the DP should demonstrate that the potential for re-use has been fully examined. Although hazardous wastes can be destined for landfill under certain circumstances, all crude oil and petroleum products are not [41].

The description of the preferred decommissioning option which is put forward with the decommissioning plan should also include clear indication of how the principles of the waste hierarchy will be met. This includes the extent to which the installation or any part of it, including the topsides and the materials contained within it, will be re-used, recycled or scrapped.

Figure 19: The waste hierarchy by DEFRA [42]

In some cases, thermal destruction (high temperature incineration without energy recovery), chemical treatment or biological treatment may be justified for particular wastes. This could be due to contamination or the nature of the substances in the oil which prevents recycling or recovery. This might be the case if the oil is contaminated with very hazardous materials like PCBs, which are subject to mandated waste management arrangements, or other materials that render recovery impractical.

6.2.3 Waste types

Waste can be considered as one of two categories: non-hazardous waste, typically just referred to as waste, or as a more specific hazardous waste.

In the UK, waste is considered hazardous when it contains substances or has properties that might make it harmful to human health or the environment. A comprehensive technical guidance note from the Environment Agency (EA) sets
out how waste should be assessed to determine whether it is classified as hazardous or not [43]. This definition applies to all UK industries, not just O&G.

Hazardous waste is classified by reference to a List of Waste (LoW) types mixtures e.g. oil/water, hydrocarbon/water. These waste types must either display one of a separately listed set of hazardous properties e.g. corrosive; or contain any of the constituents on a third list e.g. mercury/mercury compounds and have hazardous properties (in this case ‘toxic’). The properties are defined by regulation along with a determining methodology. The governing legislation is the European Hazardous Waste Directive (91/689/EEC) [44].

NORM waste is subject to further regulations and is discussed in more detail in Section 6.2.4.

Metal wastes typically contribute the greatest volume of material from offshore decommissioning and are divided into ferrous metals and non-ferrous metals, to distinguish the metals into those which includes the presence of iron i.e. ferrous. Ferrous metal waste is typically more valuable, and present in much greater volume than non-ferrous.

The flow of the material and the associated considerations that must be considered depending on the waste types are shown in Figure 20. This illustrates the flow of waste from a typical platform and the importance of keeping waste ‘clean’ from contamination.

Figure 20: Onshore processing flow diagram
6.2.4 NORM

The management of NORM is a well-documented challenge in the O&G industry, particularly when it comes to decommissioning. When considering decommissioning activities, the challenge commences at the cleaning and making safe stage, as NORM can be present in:

- produced water which is a derivative product from O&G processing
- scale which may have built up in pipes or process equipment
- solid or semi-solid wastes (known as sludge) from drilling or O&G processing
- pigging debris resulting from the cleaning of pipelines [45]

Where NORM is present this will require treatment such as de-scaling to decontaminate the material or equipment. Figure 21 shows a schematic of systems in the offshore platform environment, illustrating the occurrence of NORM during exploration and production processes.

![Figure 21: Schematic of where NORM can occur in the offshore E&P environment.](image)

**EU Legislation**

The management of NORM has traditionally been driven by the nuclear industry, and its regulators. In particular, the International Commission on Radiological Protection (ICRP) sets the international standards and recommendations for radiation exposure for the public. O&G industry workers are considered members of the wider public whose annual exposure must be monitored and limited. These recommendations have been implemented in the International Atomic Energy Agency (IAEA) Basic Safety Standards (BSS) [46], which are largely harmonized...
with Europe by means of EU Directive 2013/59/Euratom [47]. This directive lays down basic safety standards for protection against the dangers arising from exposure to ionising radiation.

Although the O&G industry was not initially a main objective of this legislation, the IAEA BSS does consider O&G industry workers to be members of the population whose annual exposure must be monitored and limited. Moreover the EU includes the O&G industry in a “list of 16 distinct industrial sectors involving NORM.” Nonetheless, legislation within the EU varies from country to country and it should be noted that the UK’s strategy is subject to ongoing review.

**UK legislation**

Under the UK regulatory regime, radioactive waste is not a 'controlled waste' and is regulated separately under the Radioactive Substances Act 1993 (RSA) [48]. This Act covers the holding of radioactive materials as well as the accumulation and disposal of radioactive waste.

Additionally, the UK is a signatory of the OSPAR Convention on the protection of the North East Atlantic [49] and the UK subscribes to the OSPAR Radioactive Substances Strategy [50].

This is enacted in the UK through the 2009 UK Strategy for Radioactive Discharges [51], which sets out how the UK implements the objectives of the OSPAR strategy. The scope of the discharge strategy considers both aerial and liquid discharges, from decommissioning as well as from operational activities.

The objectives of the UK Discharge Strategy are to ensure:

- Progressive and substantial reductions in radioactive discharges;
- Progressive reductions in concentrations of radionuclides in the marine environment resulting from radioactive discharges, such that by 2020 they add close to zero to historic levels;
- Progressive reductions in human exposures to ionising radiation resulting from radioactive discharges, as a result of planned reductions in discharges.

Another relevant publication is the OSPAR Offshore Oil and Gas Strategy [52]. This states that OSPAR will review the disposal of all NORM, where appropriate to develop management measures to reducing the amount of disposal. This is achieved through the consideration of specific activity scales and when required, development of management measures to reduce the discharges of radioactive substances from offshore O&G activities. At the OSPAR Offshore Industry Committee (OIC) 2013 it was agreed that it was necessary to determine if there is any impact of NORM discharges on the marine environment, before OIC make any decision on whether to develop management measures concerning NORM.

**Discharge of NORM to the environment**

Under Sections 13 and 14 of the Radioactive Substances Act a certificate is required for the accumulation and disposal of liquid radioactive waste. Operators
must apply for the necessary certificate five months prior to the expected disposal. Some offshore radioactive wastes may be exempt from registration due to their low levels of radioactive activity. Wherever waste is oil contaminated, an Oil Pollution and Prevention Control (OPPC) Permit under the OPPC 2005 Regulations [53] will also be required prior to discharge. These permits and certificates are issued under authorisation from the local governmental Environmental Agencies, e.g. SEPA, EA, NRW and NIEA, depending on the geographical location within the UK.

**Permanent disposal of NORM**

Given the long lifetime of NORM, the provision of long term disposal options that provide adequate protection to both human health and the environment over comparable timescales needs careful consideration. A typical range of disposal options is illustrated in Figure 22. These are illustrative only and each disposal option would have its own requirements for risk assessment and permitting, depending on the ultimate disposal location, and the relevant governing Authority.

In 2014, it was identified that the UK’s strategy for the management of NORM required review and that the regulatory framework should be reformed to ensure that it is clear, coherent and effective [51].

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**Figure 22: NORM disposal options**
6.3 Waste management at decommissioning

6.3.1 Planning for decommissioning

In the preparation for decommissioning of an asset, it is essential to have accurate information of what materials make up the assets in order to develop the most appropriate waste strategy. In developing such a register, distinction should be made between different types of materials. Materials used in construction of the asset (e.g. steel, concrete etc.), which may become waste on ‘demolition’, are distinct from operational waste associated with the asset's operation (e.g. drilling fluids, catering waste). This distinction should be maintained as a continuous process while the platform is on operation, so a clear register is available once decommissioning needs to be undertaken.

The European Waste Catalogue provides a list of definitions and codes for classifying wastes, for which the UK Government also provides guidance [54]. This system provides a standardised method to identify the type of waste, to ensure consistency across the EU. This catalogue is also known as the ‘List of Waste’ (LoW).

The inventory and mapping of all wastes should be completed offshore, prior to removing or demolishing components. In doing so identification and quantity of materials is required, such as:

<table>
<thead>
<tr>
<th>Table 3: Construction materials and deconstruction wastes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon steel</td>
</tr>
<tr>
<td>Alloy and stainless steel</td>
</tr>
<tr>
<td>Aluminium</td>
</tr>
<tr>
<td>Cement</td>
</tr>
<tr>
<td>Copper</td>
</tr>
<tr>
<td>Glass reinforced plastic</td>
</tr>
<tr>
<td>Iron</td>
</tr>
<tr>
<td>Non-ferrous metals</td>
</tr>
<tr>
<td>PVC</td>
</tr>
<tr>
<td>Plastics and rubber</td>
</tr>
</tbody>
</table>

Residual waste from operations must also be required, as it is essential for the cleaning and making safe of assets prior to removal. Typical types of residual waste include:

<table>
<thead>
<tr>
<th>Table 4: Residual operational wastes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrocarbon sludge</td>
</tr>
<tr>
<td>Chemicals</td>
</tr>
<tr>
<td>Plastics and rubber</td>
</tr>
<tr>
<td>Diesel</td>
</tr>
<tr>
<td>Heating and cooling medium</td>
</tr>
<tr>
<td>Hydraulic oil</td>
</tr>
<tr>
<td>Seal Oil</td>
</tr>
<tr>
<td>Asbestos</td>
</tr>
<tr>
<td>Mercury</td>
</tr>
</tbody>
</table>

An asset operator’s EMS should provide the required tools for continuously recording any waste or dangerous materials that might be stored or dumped from a
platform. More information on the requirements around EMS can be found in Section 5.5.

Although inventorising takes place offshore, regulation of most of these waste materials does not begin until the wastes are onshore. Despite this, personnel on offshore platforms have to ensure that the different wastes are appropriately segregated to allow for appropriate treatment when onshore. This was previously a statutory requirement in the UK for large construction projects and is still regarded as good practice. This inventorising provides a further means of documenting how waste is managed and, importantly, collates metrics in relation to waste accumulation at source.

6.3.2 Preparation for removal

Prior to the actual removal of topsides, substructures and any associated subsea infrastructure, assets must be cleaned and prepared for the removal.

The disposal of waste from offshore installations or vessels is covered by the Merchant Shipping Regulations 2008 [55]. This regulation set out general prohibition against the overboard disposal of all types of garbage waste from vessels and offshore installations. This therefore required the operators to have a full register of the wastes on a platform.

Waste streams are identified, segregated and removed for safe disposal by specialist contractors licensed for this purpose. These activities include:

- Draining all fluids from the structure
- Removal of asbestos
- Removal of Low Specific Activity (LSA) scale
- Removal of waste electrical and electronic equipment (WEEE)
- Demolition, segregation, transportation and storage

Common methods for removing scale are high-pressure water jetting and mechanical scrubbing, both of which could result in pollutants being released (e.g. trace metals, LSA scale). In some cases chemical cleaning methods will have to be used.

The materials used in the construction of the modules will typically vary by age – many older modules (>30 years) may have asbestos which is now a prohibited material. Gas processing pipework and other equipment from some gas fields can occasionally have compounds of mercury entrained in the steelwork, which is very difficult and hazardous to remove.

This highlights the fact that, if not properly managed, decommissioning activities can result in contaminated waste streams.

6 LSA is a generic term for low level radioactive materials. NORM is a subset of LSA and is a naturally occurring form of low level radioactive material. The two terms are often used interchangeably.
6.3.3 Removal and shipment to shore

Once preparation is completed the full removal of the asset can take place. This will require moving the asset either to a new location for reuse, but is more likely to be to an onshore site for recycling.

While wastes generated from the operation of O&G platforms may be exempt from the scope of the European Waste Shipment Regulation (WSR) [56], decommissioned installations are not exempt [4]. Given the highly specialised nature of waste shipment controls, operators planning to carry out any decommissioning must contact the relevant Environmental Agency for permitting.

Movement of waste from the UKCS to other EU Member States and Non-Member States, are deemed as TBM. These movements are subject to Transfrontier Shipment of Waste Regulations 2007 [57], as well as the ‘DoC’ described in Section 6.2.1.

Operators must take the appropriate measures to ensure that TBM of hazardous – and other wastes are only allowed if one of the three following conditions is met [58]:

the State of export does not have the technical capacity and the necessary facilities, capacity or suitable disposal sites in order to dispose of the wastes in question in an “environmentally sound manner”; or

the wastes in question are required as raw material for recycling or recovery industries in the State of import; or

the TBM in question is in accordance with other criteria decided by the Parties (such criteria will normally be found in the decisions adopted by the Conference of the Parties).

The Transfrontier Shipment of Radioactive Waste and Spent Fuel Regulations 2008 [59], governs the shipment of NORM and disused radioactive sources to authorised storage facilities. NORM is discussed in more detail in Section 6.2.4.

6.3.4 Near shore and onshore handling

Once material is destined for the UK shores, a number of rules and processes must be followed, depending on the destination of the material.

Disposal of materials onshore must comply with the relevant health, safety, pollution prevention and waste requirements in part I and II of the Environmental Protection Act [37]. As previously stated, there are limitations in terms of what waste can be transferred across national borders. While waste that requires disposal cannot be shipped outside of the UK, waste destined for recovery can.

Waste disposal routes must be identified prior to generation of waste to ensure that wastes can be safely, efficiently and legally disposed of. This ensures that unexpected ‘orphan’ wastes do not arise and create a disposal issue.

The graphic below illustrates the skills, infrastructure and supply chain involved in the near shore and onshore aspects of decommissioning.
Figure 23. The skills, infrastructure and supply chain involved in the near shore and onshore aspects of decommissioning

To ensure that the national industry will be able to cope with the demands from decommissioning, it is important that the supporting infrastructure is in place. This is not the responsibility of the operators, but is key to ensuring a healthy industry and supply chain that can meet the demands of the future.

**Yard Preparedness**

Yards where offshore material will be offloaded are an important aspect of the decommissioning and recycling process in the UKCS. They must ensure appropriate quay side conditions for receiving installations, as well as appropriate onshore connectivity to recycling and disposal facilities.

From the waste management perspective, for an onshore yard to be considered fully prepared for receiving and managing decommissioned materials it must fulfil the following criteria:

- The dismantling site must be constructed appropriately to contain hazardous spill-off
- Any hazardous spill-off must be contained
- Proximate to licenced contractor to cut and sort metal into ferrous and non-ferrous, and waste into hazardous and non-hazardous. Waste contractors must have access to transport waste metals to waste treatment and disposal facilities (e.g. smelters, foundries, other recycling facilities or landfill)
- The yard operator must maintain an audit trail of all materials from receipt to final destination.
Monitoring the movements

Before the onshore movement can commence the national authorities must issue a consent for the waste in question. As the materials are moved between locations, the tracking procedures set out by the OECD system require all movement to be documented. This process is set out in Figure 24, which illustrates which documentation must travel with the waste shipment [36]. This documentation will include all the necessary consents and any conditions that might have been issued with the consent. This waste is then monitored as it moves across national boundaries and local agencies will verify the waste movement.
Figure 24: Main stages of the OECD control procedures

Onshore recycling and landfill disposal

All operators of waste sites have a responsibility to ensure waste is as described in WTN and is acceptable under the terms of their permit. Landfill operators have additional responsibilities regarding waste acceptance criteria (WAC), which are used, in part, to differentiate between different classes of landfill. For example,
the WAC generally addresses the leachability of pollutants and dictates groundwater protection measures which may be required.

The operators of landfill sites are therefore responsible for inspecting the waste on receipt to ensure that the waste conforms to the description provided in the transfer documentation. Should the shipment not conform to the description, the waste consignment will be refused. The waste description must therefore follow the LoW definitions [60].
7 Other North Sea Regulatory Regimes

All countries around the North Sea – the UK, Norway, Denmark and the Netherlands – have distinct regulatory regimes which govern O&G activities within their territorial waters. All of these countries have provisions for decommissioning to be regulated, although to varying degrees of detail – generally commensurate with the size of the industry, and depending on the state’s level of involvement in field licences.

Although there are differences in how prescriptive the legislation is in each country, one common feature is that practice in all countries ensures that all relevant stakeholders are consulted as part of the process of applying for permissions. This has the benefit of streamlining the overall process, particularly in terms of engaging with all agencies & bodies who have an interest in environmental management.

Another common feature is that all states have some degree of financial liability, either through direct liability as a result of shared field ownership, or by means of tax rebates or by means decommissioning expenses being tax deductible.

7.1 Introduction

The four countries most active in exploiting O&G reserves in the North Sea are the UK, Norway, Denmark and the Netherlands.

While this report is mainly focused on the regulatory regime in the UK, this section provides a summary of the regulatory regimes in Norway, Denmark and the Netherlands. This includes a high level overview of the key legislation set out to govern decommissioning, key approvals the operators must seek, liabilities relating to decommissioning, and any significant differences between the regimes.

The findings are based on publically available information as well as consultations held with the Norwegian and Dutch regulators.

7.2 Norway

Norway’s O&G industry was initiated with the discovery of the large Ekofisk field in 1969 [61].

Today there are approximately 120 installations in the seas surrounding Norway, less than a third of the number of installations in UK waters. The Norwegian Sector has deeper water and more exposed metocean conditions when compared to the southern areas and as a result the platforms tend to be larger and heavier. Norway also has a larger percentage of heavy concrete gravity base infrastructure when compared to the rest of the North Sea.

This infrastructure is estimated by the Norwegian Petroleum Directorate (NPD) to cost around 170 billion Norwegian Kroner (NOK) to decommission, excluding concrete facilities [62].

To date around 15 platforms have been decommissioned in Norway. This is relatively low considering the market size and compared to the UK where around 45 platforms have been decommissioned [63]. Most of the decommissioning activity took place in the early 2000s and more recently in 2012.
7.2.1 Regulating bodies

Norway’s central regulating body for the O&G industry is the MPE. The MPE are responsible for the review and granting of approval for decommissioning, exploration and production activities. The NPD acts as a technical advisor to the MPE. Some responsibilities are designated to the NPD, for example legislation from 2003 sets out the responsibilities of the NPD more clearly [64]. This states; ‘The Norwegian Petroleum Directorate shall evaluate cessation/decommissioning plans and follow up the Ministry's disposal decisions, thus contributing to the selection of optimum solutions for disposal of installations after production has ceased.’

The Norwegian government’s involvement in the industry is implemented in a number of ways. The state-owned Petoro looks after the State’s Direct Financial Interest (SDFI) as a licensee or joined partner on O&G licences across the Norwegian Continental Shelf. Petoro is a licensee on around a third of all O&G reserves, and is also the largest owner of pipelines in Norway [65]. Furthermore the state has a 67% ownership stake in Statoil, with the remaining shares publicly listed on the Oslo and New York stock exchanges [66]. The state’s interests in Statoil is managed by the MPE.

Parties involved

As part of the decommissioning process two public consultations are usually held. The first of these concerns the impact assessment scope and allows stakeholders to comment on the methodology of the upcoming assessment. Following this a public consultation is held on the final impact assessment and the proposed operations required for the decommissioning work.

In decommissioning cases where derogation is being proposed, the MPE will tend to take the decision to the Norwegian Parliament, following their initial review of the proposed programme.

A number of other public authorities are also involved in specific stages of the decommissioning process. These will respond and review specific parts of the application. These include:

- Coastal Authority
- Radiation Authority
- Petroleum Safety Authority
- Environmental Authority
- Administration of Trade and Fisheries
- Ministry of Labour
- Ministry of Climate
- Ministry of Finance
7.2.2 Key legislation & approvals

The Petroleum Act 1996 [67] is the key legislation governing the Norwegian O&G industry. Prior to the Petroleum Act 1996 there was no specific legislation governing decommissioning. The Petroleum 1996 Act sets out the rules governing CoP and decommissioning, including notice periods and liabilities. This Act also confirms that liability for any environmental pollution associated with a licence’s infrastructure falls on the licensee regardless of fault.

The Petroleum 1996 Act requires licensees to submit a Decommissioning Plan (DP) to the Ministry between two and five years before the expected CoP date. The DP is to consist of two parts:

- an impact assessment and;
- detailed plans for the installation after CoP, including potential re-use, removal or abandonment.

Unlike the UK regime, the DP is the first approval to be sought followed by an application for CoP, once the DP has been approved. As in the UK, the impact assessment covers environmental, technical, commercial, safety and societal aspects. In cases where derogation is considered, the application for this must be proposed at the DP stage and will be reviewed by the MPE, and approved by the Norwegian Parliament.

In addition to the direct laws on decommissioning stipulated the Petroleum Act 1996, there are additional Norwegian policies and Acts which indirectly relate to the decommissioning of installations in Norwegian waters. These include:

- The Pollution Control Act 1981 [68] (relating to permits for demolition and recycling);
- The Planning and Building Act 2008 [69];
- Public Services Act 2011 [70]; and
- Legislation relating to Radioactive Material [71].

Removal requirements

Topside and substructures are generally treated in a similar manner to the UK, in line with OSPAR decision 98/3.

As opposed to the UK regime, pipelines and manifolds and other subsea steel in Norwegian waters can be assumed to be left in-situ, rather than removed.

Pile cuttings are typically left in place, in line with OSPAR regulations which stipulate that cuttings piles may be left in place if the hydrocarbon release from the pile is below a specified threshold.

The table below illustrates the legal requirements and recommended best practice regarding the removal of infrastructure in Norway.
Table 5: Removal requirements in Norway

<table>
<thead>
<tr>
<th>Work Breakdown Structure</th>
<th>Sub section</th>
<th>Ospar 98/3 and 2006/5</th>
<th>Norway</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Removal to land</td>
<td>Derogation possibility</td>
</tr>
<tr>
<td>Running Making safe and preparation</td>
<td>Large Diameter pipelines, trenched or buried pipelines</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Small Diameter pipelines not buried/trenched</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td></td>
<td>Mattresses &amp; Grout Bags</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Topside and Substructure Removal</td>
<td>Topside Facilities</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Steel (Less than 10,000 tonnes)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Steel (More than 10,000 tonnes installed before 9th February 1999)</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td></td>
<td>Steel (More than 10,000 tonnes installed after 9th February 1999)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Concrete Gravity Base</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Subsea and Site Remediation</td>
<td>Sub-sea Installations (Templates, Manifolds, Well heads)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Drill Cuttings</td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>

Key:
- Not specified in legislation or guidance
- X Preferred option in legislation or guidance

7.2.3 Liabilities and securities

Under the current regime operators are liable in perpetuity for the monitoring of their decommissioned assets, and addressing any required remedial works as is the case in the UK.

The Norwegian legislation does not require operators to demonstrate that they have financial securities in place for future decommissioning work. However, a number of other principles are in place to mitigate against the risk of an operator not having the financial standing to meet their liabilities:

At the time of submitting a Plan of Development and Operation (PDO) for a new field development, due diligence is carried out on the applicant to ensure that they are of sufficient financial standing.

Norwegian regulations discourage the establishment of special purpose vehicles, or company subsidiaries for operating assets. This ensures that the decommissioning liability generally rests with a substantial O&G corporation,
rather than with a smaller entity which may not have sufficient financial resources for decommissioning activities.

7.2.4 Expected future changes

As discussed above operators are liable in perpetuity for the monitoring of their decommissioned assets. Some consideration has been given to the possibility of changing this regime, as concrete foundations may have a lifetime that would far exceed the lifetime of a commercial O&G company. It could therefore be reasonable for the Government to become the long term guardian of such assets.

It has also been noted that although the decommissioning approvals process stipulated by the Petroleum Act 1996 is appropriate for large projects, there may be scope for streamlining of the approvals process for the decommissioning of smaller, less complex installations.

In recent years, more thought has also been given to the timing of the decommissioning of fields with long tail production. In these cases, short term market fluctuations could impact on the decision and long term financial viability of a field. It is important to the regulator that the long term benefit to society remains a key focus, through maximising value of production. This thought process is analogous to the MER strategy in the UK.

7.3 The Netherlands

The Dutch O&G industry was initiated with the discovery of a very large onshore gas field near Groningen in 1959, the largest gas field in Europe.

Around 150 platforms are operating in the Dutch North Sea, slightly more than in the Norwegian sector. Despite this, the total Dutch decommissioning expenditure is expected to be much lower. This can be attributed to the Dutch platforms being situated in shallower waters and hence being generally smaller, lighter and less expensive to remove to shore.

The latest decommissioning cost estimate amounts to €6.7 billion, based on today’s market environment [72]. The Dutch state is expected to be liable for about €5 billion of this total [72].

To date, 23 fixed steel installations have been decommissioned. It is notable that for 11 of these, the steel substructures were reused for new development activities [73].

7.3.1 Regulating bodies

The Dutch decommissioning regulatory regime is not as prescriptive as in the UK or other North Sea countries. The main regulator is the Ministry of Economic Affairs (MEA), who issue exploration and production licences as well as being responsible for the approval of any decommissioning activities.

The state is, through MEA, the single owner of EBN which is a licence participant on gas and oil field licences awarded in the Netherlands. A minimum 40% state
participation is mandatory through EBN, which provides the government with indirect control and influence in the industry [74].

State Supervision of Mines (SSM) oversees the compliance with statutory regulations applicable to mineral exploration, extraction, storage and transport of minerals. The SSM is the enforcing body under the MEA, focusing on health, safety, the environment, and effective extraction of resources. They have a compliance role, and monitor the licence holders and operators to ensure adherence to both E&P and decommissioning regulations.

**Parties involved**

Other key regulatory bodies relevant to decommissioning include:

- The Ministry of Infrastructure and Environment, who have specific authority over the installation and removal of pipelines;
- The Ministry of Finance;
- Authority for Nuclear Safety and Radiation Protection (in cases where NORM is present)

### 7.3.2 Key legislation & approvals

The Dutch Mining Act 2003 [75] is the core legislation in place through which E&P and decommissioning are regulated. The associated Mining Decree 2003 [75] and Mining Regulation 2003 [75] also cover aspects of decommissioning, including DP content requirements and waste disposal guidance.

Unlike in the UK or Norway, the process for obtaining DP approval is not defined in guidance and the process is typically a consultative process between the operator and the authorities.

The 2003 Act prescribes that ‘*O&G installations must be removed, including debris and other materials at or immediately near such installations*’ [75].

Operators who are considering decommissioning of installations must consider the following in their DP:

- Prepare an update to the installation’s Safety Case;
- Draft plan for removal of the asset;
- Adhere to regulations stipulated in the Nuclear Energy Act in decommissioning cases where NORM is present [76].

For P&A of wells, 8 weeks’ notice must be given to the MEA prior to the anticipated start of the campaign, and a further notice must be given 24 hours prior to works commencing. Once a well has been decommissioned a close-out report is to be submitted to the MEA, to describe how the well has been decommissioned.
Removal requirement

Topside and substructures are generally treated in a similar manner to the UK, in line with OSPAR decision 98/3.

However, operators’ liabilities in relation to subsea infrastructure are different to those in either the UK or in Norway.

The majority of pipelines installed before December 2015 is assumed to be left in-situ, though the MEA may request complete or partial removal in certain circumstances. In particular, the MEA generally request that pipelines located in the zone between the 20 m water depth contour and 12 NM territorial limit are removed. This policy is to allow for other activities such as offshore wind farm development or sand dredging. The MEA estimate that out of a total of 2,700 km pipelines laid on the seabed, 300 km are estimated to require removal when decommissioned.

Following stakeholder discussions and the new regulations in 2015, all pipelines installed from 2015 onward must be removed when decommissioned although there is scope for an operator to make a case to leave these in-situ. The table below illustrates the legal requirements and recommended best practice regarding the removal of subsea infrastructure in the Netherlands.

Table 6: Removal requirements in the Netherlands

<table>
<thead>
<tr>
<th>Work Breakdown Structure</th>
<th>Sub section</th>
<th>OSPAR 98/3 and 2006/5</th>
<th>The Netherlands</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Removal to land</td>
<td>Derogation possibility</td>
</tr>
<tr>
<td>Running Making safe and preparation</td>
<td>Pipelines between the 20 m water depth contour and 12 NM territorial limit</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Mattresses &amp; Grout Bags</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Topside and Substructure Removal</td>
<td>Topside Facilities</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Steel (Less than 10,000 tonnes)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Steel (More than 10,000 tonnes installed before 9th February 1999)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Steel (More than 10,000 tonnes installed after 9th February 1999)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Concrete Gravity Base</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Subsea and Site Remediation</td>
<td>Sub-sea Installations (Templates, Manifolds, Well heads)</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Drill Cuttings</td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>
Key:

- Not specified in legislation or guidance
- Preferred option in legislation or guidance

### 7.3.3 Liabilities and securities

The obligation to remove infrastructure rests with the current or last known operator. Unlike in the UK the liability for decommissioning cannot revert to previous licence holders.

The Netherlands has a significant difference in their treatment to liabilities when compared to the rest of the North Sea. There is no liability in perpetuity for wells or platforms. Once wells have been plugged and abandoned, and platforms removed, the field licence is to be returned and the licensee is assumed to be clear of their obligations.

However, there is a liability in perpetuity for any pipelines left in-situ which are required to be monitored. Annual monitoring is prescribed, although there is a general move towards biannual and risk-based monitoring.

Where a joint venture owns the licence, all parties remain jointly and severally liable, even if the joint venture itself has been dissolved.

Although securities are typically not required to be held, the MEA may require securities in the event that the obligations for the licensee need to be enforced i.e. if the licensee is in breach of their obligations [74].

### 7.3.4 Expected future changes

In December 2016 a decommissioning masterplan was developed for the industry by EBN and MEA [73]. This sets out the future direction and how the government could guide the industry to be more collaborative and more efficient in undertaking future decommissioning. It provides a ten step plan illustrating how to prepare the industry and regulator for the upcoming increase in decommissioning activities.

These steps include establishing a new organisation, the National Decommissioning Platform (NDP). This entity will encourage information sharing and collaboration across stakeholders, including EBN, other private licence holders, operators and the wider supply chain. The NDP’s role is envisaged as initially acting as an industry facilitator to develop best practice and standards. This role may evolve over time, and consideration is being given to them taking a more involved execution role. As a decommissioning delivery unit they would specialising in undertaking and delivering the decommissioning, working with the supply chain.

The MEA has also taken a role in incentivising innovation in the industry, with projects looking at improving P&A techniques, and identifying alternative uses of decommissioned installations.
7.4 Denmark

Denmark has been active in O&G exploitation since the first production of hydrocarbons started in the Danish North Sea in 1972 [47].

Today it has the least number of installations in the North Sea, with approximately 50 installations. There is only one concrete gravity based structure, with the remainder constructed using steel jackets. Only a small number of subsea wells exist in Denmark, with the majority of wellheads co-located with platforms.

The Danish waters are comparatively shallow when compared to the other North Sea geographies so the installations tend to be relatively light. The Danish installations are also the youngest of the overall North Sea asset base.

No publically available research has been done to forecast the total value of the decommissioning market in Denmark at present. It would be expected that this changes as more assets move closer to end of life and CoP.

To date no Danish offshore assets have been fully decommissioned, but some assets have ceased production and will be removed if no further discoveries are made in the area [48].

7.4.1 Regulating bodies

The responsibility for the licencing and approval of O&G activities in Denmark rests with the Ministry of Energy, Utilities and Climate (MEUC). Within the MEUC, the Danish Energy Agency (DEA) is the responsible authority for reviewing and approving decommissioning plans and granting the rights for CoP.

The North Sea Fund (Nordsøfonden) is the state owned company, through which all state participation is facilitated. It is also part of the Danish Underground Consortium (DUC) which owns 15 of the 19 licence fields in the Danish North Sea [77]. Ownership of the DUC is shared by Mærsk Oil, Shell, Chevron and, the North Sea Fund who hold a 20% share. [78].

Parties involved

When issuing a decommissioning plan to the DEA, operators considering decommissioning are required to consult with environmental, waste and safety regulators, prior to removing installations including:

- The Ministry of Environment and Food of Denmark (MEFD) and its Environmental Protection Agency (EPA), is responsible for the environmental and waste management of the O&G industry.
- The Danish Working Environment Authority (WEA) supervises the H&S safety aspects of offshore installations in Danish waters.

7.4.2 Key legislation and approvals

The Subsoil Act 2011 [79] and Offshore Safety Act [80] are the key pieces of legislation governing the decommissioning of installations. The Subsoil Act
prescribes that a field licence must define both cost of decommissioning installations and how installations will be removed once they become obsolete. Furthermore, as of July 2015, a proposed amendment to the Subsoil Act states that all new licence applications must include a full DP, and all existing licence holders in the Danish North Sea must submit DPs for their assets before July 2018 [81].

As part of the decommissioning process, operators must seek approval from the DEA for CoP. Even temporary CoP can only be approved by the DEA. Should the DEA not approve the request (e.g. if the State considers that significant reserves may be orphaned), then Section 33 of the Act allows the State to take over the licence and continue operation.

The process for submission, review and approval of a decommissioning plan has not yet be defined in official guidance.

Operators are also required to consult with the environmental & waste regulator (EPA) and the safety regulator (WEA) for relevant approvals to remove installations. Environmental considerations are set out in a number of legislations including:

- Subsoil Act 2011 [79]
- Continental Shelf Act 2005 [82]
- Marine Environment Protection Act 2005 [83]
- Environmental Protection Act 2015 [84]

**Removal requirements**

Topside and substructures are generally treated in a similar manner to the UK, in line with OSPAR decision 98/3.

There is currently no specific Danish legislation stating the requirements for removal of any infrastructure other than OSPAR 98/3. This may change as Denmark experiences more decommissioning and develops more of an evidence base which might support alternative approaches, as has been witnessed in other countries. The table below illustrates the legal requirements and regarding the removal of subsea infrastructure in Denmark.

Table 7: Removal requirements in Denmark

<table>
<thead>
<tr>
<th>Work Breakdown Structure</th>
<th>Sub section</th>
<th>Ospar 98/3 and 2006/5</th>
<th>Denmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Running Making safe and preparation</td>
<td>Large Diameter pipelines, trenched or buried pipelines</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Small Diameter pipelines not buried/trenched</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Mattresses &amp; Grout Bags</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
7.4.3 Liabilities and securities

As is the case in Norway, the financial capacity of an E&P licensee must be confirmed at the point of application for a field licence. The DEA is the responsible authority for reviewing any securities or parent company guarantees provided at this stage.

DPs prepared by an operator must include cost estimations of the full decommissioning. Moreover it must include information on when and how financial securities will be put in place to cover the expected decommissioning cost. The DEA also has the power to require additional securities to be held.

As is the case in the UK, the liability for decommissioning is passed onto any new holders of a production licence and assets. Should the current holder fail to meet the liabilities for decommissioning, this will revert to the previous owner [79].

7.4.4 Expected future changes

Although wells have been plugged and abandoned, no installation decommissioning projects have yet been undertaken in Denmark. As a result, it is reasonable to assume that the processes and regulatory regime may evolve in the future.
7.5 Summary overview

With regard to the removal of infrastructure, the requirements and processes vary between countries. This variability is clear in both how responsibilities are delegated and in the removal requirements for subsea infrastructure that is not covered by the OSPAR 98/3 and 2006/5 regulations, which all four countries are signatories to. Table 8 illustrates some of the key points of decommissioning and how these differ and are similar between the countries.

Table 8. Comparison of key decommissioning aspects.

<table>
<thead>
<tr>
<th></th>
<th>United Kingdom</th>
<th>Norway</th>
<th>Netherlands</th>
<th>Denmark</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Main regulator</strong></td>
<td>Department of Business Energy and Industrial Strategy (BEIS)</td>
<td>Ministry of Petroleum and Energy (MPE)</td>
<td>Ministry of Economic Affairs (MEA)</td>
<td>Ministry of Energy Utilities and Climate (MEUC)</td>
</tr>
<tr>
<td><strong>Delegated authorities</strong></td>
<td>BEIS are responsible for approving DPs, while other areas are delegated to the Oil and Gas Authority (OGA) and, the Health &amp; Safety Executives (HSE).</td>
<td>MPE is responsible for reviewing and approving licences, some areas are delegated to the Norwegian Petroleum Directorate (NPD).</td>
<td>MPE is responsible for reviewing and approving licences, some areas are delegated to the State Supervision of Mines.</td>
<td>Danish Energy Authority (DEA)</td>
</tr>
<tr>
<td><strong>State ownership of fields</strong></td>
<td>None</td>
<td>Direct licence ownership through Petoro, which is wholly owned by the Government which also holds a 67% ownership in Statoil.</td>
<td>Direct licence ownership through Energie Beheer Nederland (EBN), which is wholly owned by the Government. A minimum of 40% of a licences must be offered to EBN, to enable state participation.</td>
<td>Direct Licence ownership through the North Sea Fund which is wholly owned by the Government. The North Sea Fund owns a 20% share in Danish Underground Consortium (DUC) which holds 79% of licences.</td>
</tr>
<tr>
<td>Physical environment</td>
<td>United Kingdom</td>
<td>Norway</td>
<td>Netherlands</td>
<td>Denmark</td>
</tr>
<tr>
<td>----------------------</td>
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<td>--------</td>
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<td>---------</td>
</tr>
<tr>
<td></td>
<td>Both shallow waters with lighter steel structures in the SNS and large deep water concrete and steel installations in the NNS. Both platform and subsea wells are in operation across the UKCS.</td>
<td>Mainly large concrete and steel installation in deep waters, both subsea and topside wells are used across Norwegian waters.</td>
<td>Shallow water and light steel installations, both subsea and platform wells.</td>
<td>Shallow water and light steel installations, mainly only platform wells.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Planning for decommissioning</th>
<th>United Kingdom</th>
<th>Norway</th>
<th>Netherlands</th>
<th>Denmark</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Firstly a CoP application is submitted, followed by a DP. The DP can be submitted before CoP approval.</td>
<td>Firstly a DP is submitted between two to five years before expected CoP. This is then followed by a formal CoP application once DP is approved.</td>
<td>No set order, planning is a consultative process between the operator and the authorities.</td>
<td>DP must be submitted with the field development licence application. CoP is then applied for closer to the time of decommissioning.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Requirements of the Decommissioning Plan (DP)</th>
<th>United Kingdom</th>
<th>Norway</th>
<th>Netherlands</th>
<th>Denmark</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>An EIA is submitted alongside the DP. This includes both environmental and societal impacts. Comparative assessment to be undertaken as justification for the preferred decommissioning option.</td>
<td>The DP must include 1) Impact Assessment covering aspects such as environment, technical, societal etc. 2) Detailed disposal plan for the installation.</td>
<td>The DP should consider an updated safety case, a draft removal plan, and any detailed requirements from the Nuclear Energy Act where NORM is present.</td>
<td>A DP must be provided at the development phase and include information on estimated costs and removal plans.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Comparative Assessment (CA)</th>
<th>United Kingdom</th>
<th>Norway</th>
<th>Netherlands</th>
<th>Denmark</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CA to be undertaken as justification for the preferred decommissioning option if substructures are proposed to be left in situ in line with the requirements of OSPAR. This is only for substructures which are eligible for derogation. CA is also used as a tool for any pipelines which are proposed to be left in situ.</td>
<td>CA to be undertaken as justification for the preferred decommissioning option if substructures are proposed to be left in situ in line with the requirements of OSPAR. This is only for substructures which are eligible for derogation.</td>
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</tr>
<tr>
<td>Requirement for consultations as part of decommissioning</td>
<td>United Kingdom</td>
<td>Norway</td>
<td>Netherlands</td>
<td>Denmark</td>
</tr>
<tr>
<td>----------------------------------------------------------</td>
<td>----------------</td>
<td>--------</td>
<td>-------------</td>
<td>---------</td>
</tr>
<tr>
<td>Statutory consultations are required once the draft DP has been submitted to BEIS. A list of statutory consultees is supplied by BEIS, and must be given 30 days to review the draft DP. Public information about the DP must also be published in national and local press, as well as on the internet. BEIS will also publish the DP on its website. Public consultations may also be required where derogation is proposed.</td>
<td>Two public consultations are held. Firstly on the scope of the proposed Impact Assessment and secondly on the final Impact Assessment and the proposed decommissioning works. Where derogation is proposed the decision goes to Parliament for the final approval.</td>
<td>Not specified in legislation or guidance.</td>
<td>Not specified in legislation or guidance.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Securities for decommissioning costs</th>
<th>United Kingdom</th>
<th>Norway</th>
<th>Netherlands</th>
<th>Denmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Not required by default. Due diligence is carried out at development stage into licensees financial standing. If considered insufficient, provision for a security can be required.</td>
<td>Licence holders are liable in perpetuity, and any previous licence holders take on the liability should the current holder default.</td>
<td>Licence holders are liable in perpetuity, and any previous licence holders take on the liability should the current holder default.</td>
<td>Liability for installations is with the current or last known licence holder. Pipelines left in-situ have liabilities in perpetuity, whereas abandoned wells have no ongoing liability once authorities have approved the decommissioning of the site.</td>
<td>Licence holders are liable in perpetuity, and any previous licence holders take on the liability should the current holder default.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ongoing liabilities post decommissioning</th>
<th>United Kingdom</th>
<th>Norway</th>
<th>Netherlands</th>
<th>Denmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Licence holders are liable in perpetuity, and any previous licence holders take on the liability should the current holder default.</td>
<td>Licence holders are liable in perpetuity, and any previous licence holders take on the liability should the current holder default.</td>
<td>Liability for installations is with the current or last known licence holder. Pipelines left in-situ have liabilities in perpetuity, whereas abandoned wells have no ongoing liability once authorities have approved the decommissioning of the site.</td>
<td>Licence holders are liable in perpetuity, and any previous licence holders take on the liability should the current holder default.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Removal requirements</th>
<th>United Kingdom</th>
<th>Norway</th>
<th>Netherlands</th>
<th>Denmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Topsides follow OSPAR 98/3 regulations. Smaller pipelines should be removed, and larger pipelines can be left in-situ.</td>
<td>Topsides follow OSPAR 98/3 regulations. Pipelines left in-situ as default.</td>
<td>Topsides follow OSPAR 98/3 regulations. Pipelines left in-situ, unless removal is requested by the MEA.</td>
<td>Topsides follow OSPAR 98/3 regulations. Removal requirements for pipelines is not defined in legislation or in any guidance.</td>
<td></td>
</tr>
</tbody>
</table>
One of the main differences can also be seen in the sequencing of the various requirements such as the DP or a CoP application and when these might take place and in which order. Figure 25 illustrates and compares the varying order and sequencing across the four countries.

Figure 25: Sequencing of decommissioning - international comparison
8 Case Studies

8.1 Case study 1 - Decommissioning of NWH

Introduction

The decommissioning of the North West Hutton platform is a useful example project which demonstrates a number of key features of the UK decommissioning process:

- An application for CoP was submitted to DECC in May 2002, with approval granted in June 2002.
- A DP was submitted to DECC in January 2005, and approval was granted on 12th April 2006. This included:
  - A removal plan for the topsides and jacket foundation.
  - A comparative assessment to support a derogation from OSPAR 98/3 to leave the foundation footings in situ.
  - A comparative assessment to support leaving the cuttings pile in situ.
  - Comparative assessments to support leaving two major lengths of pipelines in situ, and to recover only certain elements.
- Removal activities were carried out offshore between 2006 and 2012, in a number of resource-intensive operations using a variety of tools and techniques.
- During the pipeline decommissioning works, unexpected findings required a change to the DP which was discussed with DECC and approval for the change granted in February 2012.

Overall the programme took longer than planned and resulted in higher costs than forecast. The operator submitted a close-out report to DECC which provides insight into these over-runs.

Asset description

North West Hutton (NWH) was a large production platform which began operating in 1983, and ceased production in 2003. The platform was operated by Amoco, a subsidiary of BP. At the time of decommissioning, other field owners included Cieco, Enterprise Oil and Mobil North Sea.

The platform was constructed on steel jacket foundations weighing 17,500 tonnes, situated in 143m of water in the Northern North Sea. During its operating life, the platform produced 128 million barrels of oil from 40 wells.

Overall, the decommissioning requirements were typical of many North Sea installations, with a number of wells, pipelines, subsea equipment and a cuttings pile to consider for decommissioning, along with the jacket and topside.
Figure 26. Illustration of North West Hutton

Decommissioning of the asset was carried out in a number of phases: [85]

- Plugging and abandonment of wells
- Topside decommissioning and recovery to shore
- Jacket decommissioning and recovery to shore
- Pipeline decommissioning
- These activities are described in more detail below.

**Well P&A**

The first package of offshore work was completing the plugging and abandonment of 40 wells. A total of 16 of these had been plugged and abandoned previously and the remaining 24 were dealt with in two distinct phases:

Each well is isolated from the reservoir using three separate cement plugs, two set deep in the well and a third approximately 500m below sea level. Any fluids removed from the wells during this phase were pumped back into the reservoir, or taken to shore for appropriate treatment and disposal.
In the second phase, all conductors and other components linking the well to the platform were removed from each well. In addition, the well conductors were removed to 3m below the seabed wherever possible, noting that this could not be achieved on some wells (e.g. because the cuttings pile prevented access).

All components and material recovered during this phase of work was returned to shore for recycling or disposal as appropriate.

**Topside and jacket removal**

A total of 28,427 tonnes of material was recovered to shore. The topsides were removed using the reverse installation method using a HLV to lift sections of the platform onto barges for towing to shore. This operation lasted 117 days in summer 2008.

![Figure 27. Removal of topside modules from NW Hutton in 2008.](image)

The jacket decommissioning was completed in 2009 over 100 days by cutting the jacket into sections subsea and lifting them to barges for towing to shore. A total of 58 lifts were carried out and a variety of cutting techniques used.
The footings of the jacket (everything below 95 m of water depth) were left in situ, as agreed following comparative assessment to achieve derogation from OSPAR 98/3. This resulted in a seabed obstruction which is marked on the appropriate charts as an obstruction to be avoided. The footings are subject to an inspection regime, with periodic visual surveys to be conducted of the footings and cuttings pile, with a timeline agreed with BEIS. Early surveys will provide baseline data which will determine the frequency and scope of future surveys.

**Cuttings Pile**

A comparative assessment was carried out to review all options for handling the drill cuttings pile. It was concluded that the pile should be left in situ.

**Pipelines**

A number of concrete coated pipelines, flexible pipelines, umbilicals and mattresses were all decommissioned. A total of 534 m of pipelines and umbilicals were recovered and 86 subsea mattresses were recovered. In 2012, all smaller diameter pipelines (less that 10” diameter) were recovered. A larger, 20” diameter, pipeline was trenched to a depth of approximately 0.6m. The trench was left open and surveys since then have confirmed that the natural movement of seabed sediment has buried the pipeline.

During the pipeline trenching, one section was noted to be very close to an adjacent operating platform. A potential collision between the vessels carrying out the work and this platform was identified as a hazard. Through a change in the
DP, it was agreed with BEIS that this section of pipeline could be left untrenched to reduce the risk of collision.

Also during this phase of work, it was noted that a 120m pipeline element was absent from the pipelines. It was concluded that this must have been removed during an earlier phase of work, during the platform’s operational life.

Trawl tests were carried out to confirm that no hazards to fishing remained around the pipelines. Seabed sampling surveys were carried out in 2013 to gather a baseline of the environment post decommissioning. This survey was specified in the DP and is a requirement of OSPAR Recommendation 2006/5. Results showed that the seabed is recovering from hydrocarbon contamination. [86]

**Cost & Duration**

The total cost of decommissioning NW Hutton was £246m, approximately 50% more than initially estimated. This large discrepancy was attributed to the lack of benchmark cost data at the time of the estimation, and some offshore operations taking longer than planned, resulting in delays and changes in techniques. In particular, pipeline cutting and trenching activities required the development of new tools and procedures once the work had commenced and the planned tools were found to be inefficient. In addition, a decision was made to delay the pipeline works so that they aligned with other offshore work in the area, to achieve cost efficiencies. Overall, the decommissioning offshore operations lasted 2 years longer than planned.
8.2 Case Study 2 – The INSITE project

Introduction

To develop a robust programme of research on decommissioning, stakeholders in O&G in the UKCS have learnt that collaborative projects driven jointly by industry, regulators and their advisors have added considerable value to the pool of knowledge. These have proven to be more valuable than projects driven solely by either industry or government. It has been possible to maximise the value of research results by:

- working on projects collaboratively,
- agreeing a scope of work that responds to questions on decommissioning issues raised by a large number of stakeholders, and
- pooling collective knowledge to manage ongoing projects.

Previous examples of this type of Joint Industry Programmes (JIPs) include the Atlantic Frontier Environmental Network (AFEN) a group set up when exploration was commencing in new areas of the Atlantic Frontier [87]. Another example is the worldwide Sound and Marine Life project, a JIP consisting of multinational companies, advised by experts from around the world who have undertaken extensive research on the issues of underwater noise and impacts on marine mammals [88].

INfluence of man-made Structures In The Ecosystem (INSITE)

In 2011 and 2012, O&GUK led a ‘Decommissioning Baseline’ JIP to gather knowledge about the decommissioning of offshore structures. One of the findings of the project was that gaps existed in the evidence base to describe the influence of man-made structures on the North Sea ecosystem. This finding was identified as a high priority and in 2014 a significant longer-term JIP known as INSITE – INfluence of man-made Structures In The Ecosystem was set up ‘To provide stakeholders with the independent scientific evidence-base needed to better understand the influence of man-made structures on the ecosystem of the North Sea.’

Specifically, projects within INSITE will broach 2 key themes of effects and connectivity, to establish:

- The magnitude of the effects of man-made structures compared to the spatial and temporal variability of the North Sea ecosystem, considered on different time and space scales; and
- To what extent, if any, the man-made structures in the North Sea represent a large inter-connected hard substrate system.

The intention is that a better understanding of the effect of man-made structures on the North Sea will provide better baseline data to better inform any decision making processes being used during decommissioning planning. The influence of the connectivity of man-made structures is to be understood by taking an ecosystem-based approach to determine their cumulative effect and to compare
this with effects of other stressors of the North Sea region, e.g., river and atmospheric pollution, and climate change.

The JIP participants are: BP, Centrica, CNR International, ExxonMobil, Marathon Oil, Shell, Talisman–Sinopec and Total. For the first phase of investigations, £1.8m of funding has been put forward for individual projects. INSITE’s projects are focused on the area known as ‘Region II, The Greater North Sea’ under OSPAR’s definition.

This is the region which has the most man-made structures in it. The structures of greatest interest are steel and concrete installations, pipelines and renewable energy structures. Shipwrecks are also relevant as these provide useful data about the deterioration of structures over time.

Currently, eight projects are being undertaken, by research institutions in Germany, the Netherlands, the UK, Belgium and Norway. These first-phase projects commenced in 2015 and are expected to complete in late 2017. These projects are:

• Understanding the influence of man-made structures on the ecosystem functions of the North Sea
• Assessing the Ecological Connectivity between man-made structures in the North Sea
• Coupled Spatial Modelling – trophic effects due to structures and habitat change in the North Sea
• Reef effects of structures in the North Sea: Islands or connections?
• Measuring the shadow effect of artificial structures in the North Sea on the surrounding soft bottom community
• Appraisal of network connectivity between North Sea subsea O&G platforms
• Man-made structures and Apex Predators: Spatial interactions and overlap
• Influence of Man-Made Structures in the ecosystem: Is there a planktonic signal?

On conclusion of these projects, the JIP will review the outcomes and determine if further funding can be made available for subsequent phases of research, again with the objective of improving scientific knowledge across all aspects of the ecosystem.
9 Operator Insight

Consultations with operators were undertaken to provide the industry’s view of the approaches to regulation in the North Sea. Operators were asked to respond with their general view of the industry, impact of OSPAR Decision 98/3, the decommissioning approval process, MER UK policy and the OGA, and the costs of decommissioning.

Nine operators, who collectively operate 25% of the UK North Sea assets, responded to the survey. These operators represent a diverse set of infrastructure ownership, organisation scale and interests. While their responses provide a useful perspective on the view of the industry, their views are likely to be biased by commercial interests.

The industry survey shows a number of areas where the operators are in strong agreement including their view that OSPAR Decision 98/3 requires review. However, there are a significant number of issues where there is not a common industry view, and there is ongoing debate on the best approach for the industry.

9.1 Introduction

A consultation exercise was undertaken in order to provide insight into the operators’ views and opinions of how well O&G regulation in the North Sea is aligned with the interests of the industry.

Operators were asked to respond to a questionnaire focused on five main topics which included:

- The general state of the decommissioning industry
- The impact of OSPAR Decision 98/3
- The UK decommissioning approval process
- The MER UK policy and the role of the new OGA
- The costs of decommissioning and provision of security

The operators were presented with a number of statements and asked to state their opinion in terms of their agreement with the statement ranging from: strongly agree, agree, neutral, disagree, strongly disagree.

A total of 17 operators were asked to participate in the survey, and nine responses were received including the following operators:

- Shell
- Hess
- BP
- Marathon Oil
- Chevron
- CNR International
- Centrica
- Repsol

These operators represent a broad range of interests in the UK North Sea. The contributors collectively operate just over 25% of the above sea installation in the

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7 One operator remained anonymous
UKCS. They have portfolios of varying scale from a few assets in an individual field to many tens of installations across many fields. They operate both gas and oil installations in the deeper waters of the northern North Sea, and in the shallower waters of the southern North Sea. Their portfolios includes small light installations and large steel and concrete installations. While some have delivered major decommissioning projects, some have much less experience in implementation and are focused on the planning stages.

It should be noted that while the responses provide some interesting insight into the industry’s views, the sample size is relatively small in absolute terms. As such there are some limitations in how the data can be interpreted. It is also worth noting that the operators’ views are likely to be biased by their own commercial interests, and may not always align with the views of a regulator, which must take a broader view.

The full responses to the questionnaire can be found in Appendix A.

### 9.2 General state of the industry

The statements in this section refer to the operators’ general view on the success of regulation, how well aligned it is with the interests of industry.

The responses suggested that there was a general view that the regulation of decommissioning has improved and benefited from experience, but that the industry was much less certain that regulation is well aligned with the industry’s interests, with the majority of respondents being neutral or disagreeing on this point.

Only 33% of respondents viewed that the UK’s approach was best practice and could be effectively applied in a different region. There is a possibility that this is due to the fact that some operators’ views that the UK’s regime is more onerous than the internal legislative requirements, with 45% of respondents agreeing to that statement.
9.3 The impact of OSPAR Decision 98/3

The survey responses suggested that the operators had some concerns regarding the benefits of OSPAR Decision 98/3 and its impact on the industry.

The operators were not clear on its environmental benefits and 67% do not believe that it delivers environmental benefits that would not be otherwise achieved. 78% felt that it created an excessive financial burden for both operators and taxpayers.

Rather counterintuitively only 22% of operators felt that there would be significantly more installations abandoned offshore without OSPAR Decision 98/3. This could be due to concerns relating to liabilities in perpetuity.

The vast majority, 89%, felt that the UK should challenge OSPAR Decision 98/3 to allow more flexibility, and 67% agreed that they required more environmental evidence to back up this challenge. There was a lack of consensus if OSPAR Decision 98/3 was likely to become more stringent in future. One operator
commented that OSPAR Decision 98/3 was a response to a local political issue and the “rigs to reef” strategy applied in other regions should be considered.

9.4 The UK decommissioning approval process

The questions in this section refer to the DP, derogation approval and CoP approval process and the consideration of technical, environmental, commercial and H&S impacts in the decision making process.

A small majority of respondents agreed that the approvals process is logical and easy to understand, the industry was generally split on agreement that the processes for submitting and approving a DP, derogation approvals, and CoP approvals are clear and efficient.

The vast majority of respondents, 89%, agreed that operators gave appropriate consideration of technical, environmental, societal, safety and commercial criteria, and a small majority, 56%, agreed the regulator did the same.
Generally, respondents felt that H&S, and environmental/societal aspects were prioritised appropriately during the process with 67% agreeing with these statements. No respondents agreed that commercial aspects were prioritised appropriately.

There was a generally positive response to questions relating to positive engagement with the industry. The vast majority think the operators undertake appropriate stakeholder engagement, and a small majority agree that the stakeholders engage productively, and are engaged at an appropriate time.
9.5 The MER UK policy and the role of new OGA

In this section the operators were asked about their views on the MER UK policy objectives, the roles of the regulator, and the interaction of decommissioning.

The respondents were generally positive that the policy objectives are clear and that the MER UK objectives are clear and aligned with the interest of the industry.

There was less agreement that the regulatory bodies have clearly assigned roles and are sufficiently resourced with only 22% of respondents agreeing on that point. This is potentially as a result of the newly formed status of the OGA and the developing nature of its role.

There was some concern that the MER UK policy creates conflicts between operators with 44% agreeing with that statement.
The industry was split on agreement if the ‘domino effect’ existed, and if premature decommissioning of some installations could impact on other operators. However, a small majority agreed the MER UK was compatible with cost-effective decommissioning.

The respondents were not very clear if the current regime would deliver the necessary framework for decommissioning with only 22% agreeing. They were not generally clear on the role of the OGA, only 22% confirming it was clear, which is possibly not surprising due to its developing nature. One operator commented that the OGA has not yet developed plans that fulfil the potential of its remit, and that the OGA’s thinking is not distinctive enough.

The industry was generally in agreement that the OGA’s role in fostering collaboration was important with 78% in agreement and, that they were carrying out that role effectively, with 67% in agreement.
9.6 The costs of decommissioning and provision of security

Operators were asked questions on the industry’s ability to estimate costs, the likely trends for costs and on the provision of securities and their impact on operators and the tax payer.

The operators were generally neutral or disagreed with the statement that the regulator has under-predicted decommissioning costs. This appears to contradict the conventional wisdom that the industry has historically underestimated costs and that the outturn costs may be significantly more than expected. Operators may be biased in their response to support the regulator’s current view on costs.

There is a very strong agreement that the industry is not yet estimating costs in a standardised way with 89% of respondents agreeing with this point.

Responses were mixed on the question whether securities were appropriate to protect the public sector from exposure to costs, and on the view that the requirements for securities created an onerous burden on the operator. Two operators commented that the Section 29 obligations had the unintended
consequence of inhibiting transfer of assets to those best placed to execute cost-effective decommissioning.

Q5.2 The provision of securities is appropriate to protect the public sector from exposure to the costs of decommissioning in the case of default.

There was limited agreement that it was better to delay decommissioning to take advantage of technology improvements and there was limited agreement that it is better to decommission quickly to reduce OPEX and move onto new projects.

Q5.4 The provision of securities creates an overly onerous burden on operator.

There is a lack of agreement regarding the statement the tax regime meets the needs of the industry, with one operator commenting that PRT tax relief should be available on whole field life history to encourage a transfer of assets to those best placed to execute cost-effective decommissioning.
Q5.5 The tax regime for decommissioning meets the need of the industry.

<table>
<thead>
<tr>
<th>Response</th>
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<tr>
<td>Strongly agree</td>
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<tr>
<td>Agree</td>
<td>22.2%</td>
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<tr>
<td>Neutral</td>
<td>11.1%</td>
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<tr>
<td>Disagree</td>
<td>33.3%</td>
</tr>
<tr>
<td>Strongly disagree</td>
<td>11.1%</td>
</tr>
<tr>
<td>Cannot answer</td>
<td>11.1%</td>
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</tbody>
</table>
10 Insight Summary

This document, and the previous report, has described the framework and implementation of the UK and North Sea O&G decommissioning regulatory regime, considering the external factors which have influenced its development. This section draws out the key issues which have influenced policy makers when developing and implementing the regulations.

10.1 Maximising Economic Recovery (MER)

The UKCS is classed as a ‘super mature’ basin, with first production commencing 50 years ago. Its regulatory regime has evolved and adapted to meet the changing needs of the industry and market conditions. At the start of the decade, in the face of declining production, UK Government identified the need to carry out an audit of how the regulatory framework was aligned with the current market conditions.

In February 2014 the UKCS Maximising Recovery Review (“Wood Review”) was published [89]. This concluded that UK O&G regulation required a major overhaul to meet the demands of a maturing basin.

In this review, it was proposed that the industry was too focused on achieving MER for individual assets and fields, and that there was little co-operation or collaboration between operators. The report concluded that while that strategy was appropriate for the early exploitation of the North Sea, involving a few larger operators and larger fields, it was no longer appropriate for the current market conditions.

Decommissioning was identified as a potential threat to achieving MER for the following reasons:

1. Decommissioning costs increase overall because of the aging of the infrastructure and hence increase the burden on the UK tax payer or increase the financial burden on operators

2. The costs of decommissioning deter new exploration by operators, and prevent ongoing exploitation of the UK’s resources

3. Decommissioning of infrastructure is undertaken by an individual operator (acting in its individual commercial interest), but has a greater harmful effect on the value of O&G extraction being undertaken by other operators because critical shared infrastructure is removed. In effect, decommissioning is “premature” from a UK perspective

The report concluded that to achieve MER for the UK as a whole it would be necessary to ensure co-operation between operators to exploit the marginal fields, using interconnected infrastructure. Without this intervention there remained a risk that reserves would be left in place through premature decommissioning of critical assets.

The report made a number of recommendations including the requirement for the UK Government to commit to the new strategy for MER UK. These
recommendations were largely accepted by UK Government and have been incorporated in current policy and legislation.

The MER UK Strategy is legally binding on “relevant persons” which include the OGA and licensees. The “Central Obligation” of the Strategy requires that “relevant persons must, in the exercise of their relevant functions, take the steps necessary to ensure that the maximum value of economically recoverable petroleum is recovered from the strata beneath relevant UK waters.” Hence this strategy obliges all stakeholders to maximise the expected net value of economically recoverable petroleum from relevant UK waters, not the volume expected to be produced.

Although the UK is the only North Sea country to have enacted this form of policy in legislation, MER is a topic of discussion elsewhere too. For example, as highlighted in section 7.3.4., the Netherlands have also started developing a more structured approach to try and inform the industry as decommissioning activities become more prominent. The new NDP will be set up to foster increased collaboration across the industry, but may also evolve into a more executive role as the regime changes.

10.2 Impact of OSPAR on Regulation

OSPAR Decision 98/3 prohibits dumping offshore installations or leaving them in place (either partly or wholly) in the North East Atlantic. This sets a stringent minimum requirement for national regulators in determining the approach to decommissioning, with little room for interpretation at a national level.

OSPAR Decision 98/3 was implemented following the contentious Brent Spar case, where Greenpeace launched a high profile campaign objecting to Shell’s proposals to dispose of infrastructure at sea. The case caused a highly emotive response from the general public including consumer boycott of Shell’s products. Shell were widely criticised in the press for their lack of regard for the environment and prioritisation for profits.

Within the UK and beyond, debate on OSPAR Decision 98/3 continues, with a diversity of views on the efficacy of the decision. Not all environmental groups support Greenpeace’s conclusion that infrastructure left at sea has a net negative environmental impact. Some bodies promote the benefits of habitat creation, or object to the removal of habitats created from a lifetime of operation of the assets. The technical capability of the supply chain to remove infrastructure and increased safety risk profile associated with removing assets is also subject to debate.

Within the UK, significant proportion of the cost of decommissioning is met by the tax payer. As such there is active debate about the socio-economic impacts of removing platforms and whether the impacts are commensurate with the environmental benefits.

As there are still gaps in the evidence about these impacts, and it is sometimes difficult to establish which approach offers the best compromise of the environmental, economic, and safety considerations, the industry and UK regulators are working together to fill these evidence gaps. However, the
contentious history of the decision has created a challenging environment for robust scientific debate.

Decision 98/3 is reviewed on a periodic basis to examine the technical capability of the industry and growing evidence base. The result of the reviews may conclude that the requirements to remove infrastructure become more stringent. For example, it could extend to pipelines and subsea infrastructure, or the derogation cases may be reduced in scope. There is no facility within the current framework to make the requirements less stringent. This would require a new Decision which would need to be agreed by all signatories.

Currently, the UK regulators are primarily focused on ensuring the status quo is maintained with respect to the scope of Decision 98/3. At the time of writing, it is considered unlikely that it will be relaxed significantly in the near future. This is partly because a number of the other OSPAR signatories, many who have significantly less O&G infrastructure than the UK, are not supportive of a change.

Decision 98/3 does not apply to subsea infrastructure and pipelines which is considered at the discretion of the individual nations. The UK allows operators to provide evidence on a case by case basis regarding the decommissioning of subsea infrastructure and pipelines.

10.3 Market Structure & Transparency of Rules

The manner by which decommissioning is regulated varies across the North Sea O&G producing countries. This is a result of various factors such as;

- Market maturity,
- Physical nature of the infrastructure,
- Market structure e.g. level of public and private ownership, and
- National policy objectives.

Market maturity is reflected in the varying levels of legislation in different countries. For example, countries that have had limited or no decommissioning experience, such as Denmark, have relatively little guidance and specific legislative requirements in place. Conversely, the UK, which has a much older asset base, more decommissioning activity under way and greater experience, has a much more developed approach to regulation.

Regulation also takes different forms as industry structures and ownership change. Under nationalised industries and close government control, industries are largely self-regulated or this function is undertaken by relevant Government departments that are both the owner and the regulator. At this stage requirements and guidance are less transparent. Where markets are more liberalised and privatised, the regimes tend to be more transparent and prescriptive.

For commercialised and liberalised markets such as the UK, where private sector interest exists, transparency of regulatory rules and the processes that accompany them is essential. Where these are not transparent, regulatory interventions and subsequent regulatory actions can be questioned through the courts and the
effectiveness undermined. Transparency and clarity is also necessary if government wishes to attract private sector investment into the sector.

How clearly and transparently this process is expressed in the regulatory instruments is therefore an important factor influencing the effectiveness of the regime. Ambiguities or confusions in process inevitably lead to ineffective regulation.

10.4 Liability and Securities for Decommissioning

UK Government estimate the total costs of decommissioning of the UKCS O&G infrastructure at £47 bn [90]. Identification of the parties responsible and liable for decommissioning, and ensuring they are able to meet the costs of decommissioning is a critical activity to ensure that the public sector is not exposed to the significant risks and costs associated with decommissioning.

However, overly onerous requirements with respect to establishing liabilities and securities can have negative impacts on the overall market function which do not align with MER UK policies. This can be either by dis-incentivising new exploration and production, or by supressing the transfer of assets, which could result in premature decommissioning.

Managing the public’s exposure to the risk of any unexpected decommissioning costs is a recurring policy objective across the North Sea countries. All countries allow for the regulator to make itself comfortable that the licence holder should be able to meet the costs of carrying out the decommissioning works. In addition the regulator may request securities to be put in place should they consider that the particular licence holder does not have sufficient financial standing to execute the future decommissioning works.

A significant challenge with respect to assessing the financial standing or appropriate security is the ability to accurately predict the costs of decommissioning. Historically, cost estimates have under-estimated the actual cost of asset decommissioning. This is largely attributable to a lack of precedents on which to base estimates and operational difficulties which have arisen because of the poor or unknown condition of assets. To allow for this uncertainty, UK requires that, should securities be in place, these cover 100% of the latest cost estimate, and that cost estimates are repeated every 3 years. In addition, the UK regulator is seeking to standardise cost estimation methods, to carry out their own estimates, and to publish cost metrics to improve transparency.

10.5 Suitability of Liability in Perpetuity

Across all North Sea countries ongoing liabilities post decommissioning have been considered in their legislation. Most countries have prescribed in legislation that the liability for any damage to the natural environment, arising from wells or any assets left in situ, will rest with the field licence holder in perpetuity. This obligation on the licence holder ensures that the cost of any interventions and remediation activities do not rest with the state which could have a negative impact on MER.
There are some exceptions, for example in The Netherlands where the licence holder is not liable for wells after decommissioning has been carried out and approved by the relevant authority. Once wells have been plugged and abandoned, and platforms removed, the field licence is to be returned and the licensee is assumed to be clear of their obligations.

There is some anecdotal evidence that there is growing doubt that a corporation such as an O&G operator is an appropriate choice as perpetual guardian of a site, well or in-situ asset. The implication of this is that the state may be better positioned to take on this role, although this principle is not formally reflected in any North Sea country.
# Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>AA</td>
<td>Appropriate Assessment</td>
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<td>ANP</td>
<td>Agencia Nacional do Petroleo</td>
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<td>BEIS</td>
<td>Department of Business, Energy and Industrial Strategy</td>
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<td>BSS</td>
<td>Basic Safety Standards</td>
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<td>CoP</td>
<td>Cessation of Production</td>
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<td>DEA</td>
<td>Danish Energy Authority</td>
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<td>DECC</td>
<td>Department of Energy and Climate Change (now BEIS)</td>
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<td>DEFRA</td>
<td>Department for Environment Food &amp; Rural Affairs</td>
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<td>DoC</td>
<td>Duty of Care</td>
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<td>DP</td>
<td>Decommissioning Programme</td>
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<td>DUC</td>
<td>Danish Underground Consortium</td>
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<td>EA</td>
<td>Environmental Agency</td>
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<td>EBN</td>
<td>Energie Beheer Nederland</td>
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<td>EC</td>
<td>European Commission</td>
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<td>EIA</td>
<td>Environmental Impact Assessment</td>
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<td>EMAS</td>
<td>European Eco-Management and Audit Scheme</td>
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<td>EMS</td>
<td>Environmental Management Systems</td>
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<td>EPA</td>
<td>(Danish) Environmental Protection Agency</td>
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<td>ES</td>
<td>Environmental Statement</td>
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<td>H&amp;S</td>
<td>Health and Safety</td>
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<td>Abbreviation</td>
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<tr>
<td>HAZID</td>
<td>Hazard Identification</td>
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<td>HAZOP</td>
<td>Hazard and Operability Study</td>
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<td>HLV</td>
<td>Heavy Lift Vessel</td>
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<td>HSE</td>
<td>Health &amp; Safety Executives</td>
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<td>IAEA</td>
<td>International Atomic Energy Agency</td>
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<td>ICRP</td>
<td>International Commission on Radiological Protection</td>
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<td>INSITE</td>
<td>Influence of Structures In The Ecosystem</td>
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<td>IROPI</td>
<td>imperative reasons of over-riding public interest</td>
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<td>JIP</td>
<td>Joint Industry Project</td>
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<td>LoW</td>
<td>List of Waste</td>
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<td>LSA</td>
<td>Low Specific Activity</td>
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<td>m</td>
<td>metres</td>
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<td>MEA</td>
<td>Ministry of Economic Affairs</td>
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<td>MEFD</td>
<td>Ministry of Environment and Food of Denmark</td>
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<td>MER</td>
<td>Maximising Economic Recovery</td>
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<td>MEUC</td>
<td>(Danish) Ministry of Energy, Utilities and Climate</td>
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<td>MPE</td>
<td>(Norwegian) Ministry of Petroleum &amp; Energy</td>
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<td>NDP</td>
<td>National Decommissioning Platform</td>
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<td>NIEA</td>
<td>Northern Ireland Environmental Agency</td>
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<td>NOK</td>
<td>Norwegian Kroner</td>
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<td>NORM</td>
<td>Naturally Occurring Radioactive Materials</td>
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<td>Abbreviation</td>
<td>Description</td>
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<td>NPD</td>
<td>Norwegian Petroleum Directorate</td>
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<td>NRW</td>
<td>Natural Resources Wales</td>
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<td>O&amp;G</td>
<td>Oil and Gas</td>
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<td>O&amp;G UK</td>
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<tr>
<td>OECD</td>
<td>Organisation for Economic Co-operation and Development</td>
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<td>OGA</td>
<td>Oil and Gas Authority</td>
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<tr>
<td>SEA</td>
<td>Strategic Environmental Assessment</td>
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<td>SoS</td>
<td>Secretary of State</td>
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Glossary of terms

Cessation of Production
The termination of hydrocarbon production from a field or specific well. This can be due to technical, safety or economic reasons.

The Crown
A single entity that represents the legal embodiment of executive, legislative and judicial governance within the United Kingdom and its territory.

Decommissioning (or Abandonment) Programme
A legally required document that outlines the key decommissioning aspects for the installations of a field. Must be submitted to and approved by the SoS.

OSPAR Commission
A commission established to protect the marine environment of the North East Atlantic. 15 governments participate in the commission. OSPAR decision 98/3 legislation is ratified by the OSPAR commission.

Department of Business, Energy, and Industrial Strategy (BEIS)
The O&G regulator in the UK. BEIS replaced DECC (Department for Energy and Climate Change) in July 2016.

Derogation cases
A proposal developed with the aim of seeking derogation approval, an exception to the OSPAR 98/3 removal criteria for offshore installations. These require approval on a domestic and international level.

Legislation
A directive placed by a government or governing body on either an industry or country. This must be complied with in order to remain within the legal requirements of that country or industry.

Act
A piece of primary legislation.

Bill
A proposed Act that has not yet been approved by the House of Commons and House of Lords, as well as the formally receiving Royal Assent.

Regulation
A regulation refers to a specific requirement that can take on various forms, such as industry specific regulation or broader in scope.
Abandonment retirement obligation
A legal obligation to retire an asset once it has reached the end of its life. The method and cost of retiring the asset will depend on the available options at the time of retirement.

Cold stacking
A cost reduction technique that involves shutting down an installation and removing all personnel from it. Equipment within the installation is prepared for long term inactivity.

Comparative assessment
A technique used to compare the similarities and differences between two or more decommissioning options. A comparative assessment is a legal requirement to support derogation cases and pipeline decommissioning approvals.

Concrete gravity base
Large substructures primarily constructed from concrete that are fixed to the seabed and which support a topside with production facilities.

Consultation
The process of formally discussing activities with an expert in a particular field.

Decommissioning Relief Deed
A financial mechanism developed by the HM Treasury to provide certainty of available decommissioning financial relief for licensee holders.

Decommissioning Security Agreement
An agreement to provide certainty over decommissioning liabilities of O&G field developments. The agreement identifies the liabilities of all parties associated with a field.

Defer
To put off or delay an action or activity until a later date.

Derogation
An exemption from a rule. Derogation approval must be granted by a relevant authority.

Drilling rig
A specialised structure designed to drill wells for exploration, appraisal, injection and production.

Environmental Impact Assessment
An assessment of the complete environmental effects of a project that is currently being developed. These form part of a project’s environmental statement.
Environmental Statement
A legally required report that provides publicly available environmental and planning information about a planned project. Environmental statements are submitted alongside planning applications.

Field development plan
A document that outlines the estimated production and economic activity of a hydrocarbon field. These are developed by the licence holder and are submitted to the authority for formal approval.

Fixed Steel
The most common form of offshore structure used in the petroleum industry. A fixed steel structure (often called a Jacket) fixes to the seabed and is primarily made of steel.

Foreign & Commonwealth Office
A ministerial department of the government that promotes the United Kingdom’s interests overseas. The Foreign & Commonwealth Office are responsible for the UK prosperity fund.

Framework
A tool developed from previous experience that is comprised of a set of rules and procedural steps.

Habitat Regulation Appraisal
An assessment of a project that will potentially affect the habitat of the area. This appraisal is carried out by a competent authority under domestic and EU habitat regulations.

Health and Safety Executive
A non-departmental public body of the UK that operates as the watchdog for work related, H&S regulations. The health and safety executive provide guidelines on all H&S legislation and regulations.

Hydrocarbon envelope
The temperature and pressure parameters of a particular hydrocarbon, indicating the critical phase points (shown in a phase diagram).

Hydrocarbon-free Installation
An installation that, after isolation and cleaning, no longer contains any hydrocarbons in its storage, production or processing equipment.

Low Specific Activity (LSA) scale
A radioactive deposit that accumulates inside of pipelines and other production equipment consisting of carbonates and sulphates.
Maximising Economic Recovery
A strategy developed by the UK government and implemented by the OGA. The strategy focuses on the overall economy of the petroleum industry in the UKCS and is a result of the 2013 Wood Review.

Mergers & Acquisitions
A term used to refer to the consolidation of companies and their assets.

Metoecean
The combined wind, wave, tidal and climate conditions at a specific location. These conditions can be estimated using a statistical analysis of previous metoecean conditions.

North Sea
A marginal sea of the Atlantic Ocean located between the United Kingdom, Scandinavia, Germany, The Netherlands, Belgium and France. The UKCS is located in the North Sea.

Oil and Gas Authority
A regulator for both onshore and offshore hydrocarbon operations in the United Kingdom. The OGA became a statutory corporation in 2016 as a result of the Wood Review with an aim of delivering the MER UK strategy.

Operator
The company responsible for the exploration, development and production of a field licence.

Opex
Operating expenditure. The operating and maintenance costs of a project.

Oversupply
Oversupply occurs when hydrocarbon production exceeds the current market demands for hydrocarbon, resulting in an abundance of available supplies.

PIG
A maintenance tool to ensure pipelines run smoothly. A pig can be configured to scrape the insides of a pipeline, pushing debris ahead. A pig can also be used for inspection purposes.

Plays
A group of oil fields or potential sites in a single region that all fall under the same geological formations. Commonly used when talking about hydrocarbon exploration.

Post-Decommissioning Monitoring
An inspection of the installation site after all proposed decommissioning activity has been completed to ensure that all agreed work has been completed to the agreed standard.
**Regulatory Regime**
A system of regulations and the means to enforce them, usually established by a government to regulate a specific activity.

**Reserves**
The amount of hydrocarbons anticipated to be commercially recoverable from a field.

**Secretary of State**
The title given to a cabinet minister in charge of a government department. In this context, the department of Business, Energy and Industrial Strategy is the most relevant. A DP must be formally approved by the BEIS SoS.

**Section 29**
A section of the UK petroleum act 1998 that grants the SoS the ability to serve mandatory decommissioning notices to field licensees.

**Securities**
A deposit or pledge that serves as a financial guarantee of fulfilling a legal obligation.

**Stakeholders**
A group, organisation or company that has an interest or concern in an area or industry. Stakeholders can have commercial, environmental and social interests.

**Topsides**
The upper part of an oil platform above the waterline where accommodation, storage and hydrocarbon production modules are located.

**Transportation tariffs**
A system of prices, or rates which are collected for allowing the movement of hydrocarbons through a pipeline network. Tariffs will likely be a burden on operators who wish to move resources from their field through a third party’s pipeline to an onshore refinery for processing.

**Treasury (HM Treasury)**
The UK government economic and finance ministry which sets the UK’s economic policies.

**UNCLOS**
The United Nations Conventions on the Law of the Sea is an international agreement that defines the rights and responsibilities of using the world’s oceans.

**Well Plugging and Abandonment**
The operation of permanently isolating and shutting in a well after production is concluded.
Work breakdown structure

A structure of decommissioning categories developed by O&G UK in their decommissioning cost estimate guidelines. The breakdown structure is used to categorise work activities and estimated expenditures.
Bibliography


Appendix 1 Relevant UK Health & Safety Statutory Provisions

The following is an indicative list of relevant statutory provisions which a Safety Case must demonstrate compliance with:

- The Health and Safety at Work Act 1974
- The Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015
- The Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995, as amended by SCR 2005 and SCR 2015 (PFEER)
- The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 (DCR)
- The Offshore Installations and Pipeline Works (Mgt & Admin) Regulations 1995 (as amended) (MAR)
- The Dangerous Substances and Explosive Atmospheres Regulations 2002
- The Management of Health and Safety at Work Regulations 1999
- The Work at Height Regulations 2005
- The Provision and Use of Work Equipment Regulations 1998
- The Personal Protective Equipment at Work Regulations 1992 (as amended)
- The Confined Spaces Regulations 1997
- The Diving at Work Regulations 1997
- The Pipelines Safety Regulations 1996
- The Control of Noise at Work Regulations 2005
- The Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989
- The Health and Safety (Consultation with Employees) Regulations 1996 (as amended)
- The Ionising Radiations Regulations 1999
- The Control of Substances Hazardous to Health Regulations 2002 (as amended)
- The Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995
- The Control of Vibration at Work Regulations 2005
- The Electricity at Work Regulations 1989
- The Manual Handling Operations Regulations 1992 (as amended)
- The Health and Safety (Safety Signs and Signals) Regulations 1996
• The Offshore Installations and Pipeline Works (First Aid) Regulations 1989
• The Control of Asbestos Regulations 2006
• The Chemicals (Hazard Information and Packaging for Supply) Regulations 2009
• The Control of Lead at Work Regulations 2002
• The Placing on the Market and Supervision of Transfers of Explosives Regulations 1993
• The Health and Safety (Display Screen Equipment) Regulations 1992 (as amended)
• The Working Time Regulations 1998
• The Health and Safety Information for Employees Regulations 1989
• The Supply of Machinery (Safety) Regulations 2008
• The Equipment & Protective Systems Intended for use in Potentially EA Regulations 1996
Appendix 2. Typical SEMS Content

The table below is a typical table of contents of an offshore installation’s Safety and Environmental Management System.

1.0 Introduction
1.1 Introduction
1.2 How to use the SEMS
1.3 SEMS Philosophy (Plan, Do, Check, Act)
1.4 Principle health, safety and environmental policies and documents:
   1.3.1 Duty Holder HSE Policy Statement (Section 2 Health and Safety at Work Act 1974)
   1.3.2 Corporate Major Accident Prevention Policy
   1.3.3 Operational Safety Case
   1.3.4 Duty Holder Quality Policy
   1.3.5 Asset Integrity Management Policy
   1.3.6 Environment Policy
   1.3.7 SEMS Document (Reg. 8 OSCR 2015)

1.5 Legal Framework for safe operation of an FPSO in the UKCS

2.0 Planning For Safe Operation and Environmental Protection (“Plan”)
2.1 Organisational Planning, Command and Control
   2.1.1 Organisation and Responsibilities:
      • Senior Management - Management (Board of Directors)
      • Operations:
         ➢ Installation Organisation – Operations Corporate
         ➢ Installation Organisation – Operations Onshore
         ➢ Installation Organisation – Operations Offshore
         ➢ Installation Organisation – Technical Authorities
      • HSSEQ (Operations) - HSSEQ Operations (Corporate)
   2.1.2 Leadership and Commitment
   2.1.3 Policy and Objectives
   2.1.4 Command and Control (duties, areas of authority and responsibilities)
   2.1.5 Integration of the SEMS with the Corporate Management System
   2.1.6 Communication and workforce involvement
      2.1.6.1 Workforce involvement in the development of the CMAPP, SEMS and Safety Case
      2.1.6.2 Onshore Communication
      2.1.6.3 Offshore Communication
      2.1.6.4 Emergency Communication
      2.1.6.5 Safety Committees/meetings
      2.1.6.6 Safety Representatives
      2.1.6.7 Client interface/bridging arrangements
      2.1.6.8 Tripartite consultation
      2.1.6.9 Reporting
      2.1.6.10 Whistleblowing
   2.1.7 Contractor Management
      2.1.7.1 Contractor Companies
      2.1.7.2 Effective Contractor Management
      2.1.7.3 Effective Purchasing and Procurement (the corporate MS)
   2.1.8 Documentation and HSSEQ Document Control
• Arrangements for preparing and submitting documents under the relevant statutory provisions
• Document control

2.1.10 Regulatory Compliance
2.1.11 Required Behaviours/safety and environment culture

2.1.12 Personnel:
2.1.12.1 Recruitment and Selection
2.1.12.2 Competence Assurance and Training
2.1.12.3 Drills and exercises
2.1.12.4 Staffing arrangements
2.1.12.5 Medical Arrangements

2.1.13 Organisation and resources for implementation of the CMAPP
2.1.14 ISO Certifications

2.2 Summary of Operational Planning

Overview of organisational planning in relation to the following:
• Command and Control
• Permit to Work (Organisation)
• HSSEQ Programme
• Offshore Safety Objectives and Targets
• Project HSSEQ Plans
• Emergency Response
• Maintenance and verification
• Inspection
• Environmental Management Objectives and Targets
• Environmental Aspects and Impacts
• Oil Pollution Preparedness Plan (OPEP)
• Review and reporting

2.3 Hazard Identification and Risk Assessment
2.3.1 Preparation and Development of the Safety Case.
2.3.2 Corporate Major Accident Prevention Policy
2.3.3 MAH Identification process (e.g. HAZID and ENVID).
2.3.4 Project Hazard Identification and Risk Assessment.
2.3.5 Safety Studies
2.3.6 Risk Criteria
2.3.7 Risk Assessment (qualitative to full QRA)
2.3.8 ALARP Methodology
2.3.9 Ongoing hazard identification
2.3.10 Unplanned escape of hazardous substances
2.3.11 Management of Safety and Environmental Critical Elements

Design Envelope and commissioning
2.3.12 Design of Marine Systems
2.3.13 Design of Plant and Equipment
2.3.14 CRIOP and Human Factors in Design
2.3.15 Loss of Containment (HID OIG - Inspection of Loss of Containment (LOC).
2.3.16 Hydrocarbon Release Reduction Plan
2.3.17 Pipelines
2.3.18 Commissioning

3.0 Implementation and Control (“DO”)

3.1 Procedures common to all operational and maintenance tasks and activities
3.1.1 Control of Major Hazard Risks during normal operations (CMAPP)
3.1.2 Plan, Do, Check, Act philosophy
3.1.2 Integrated safe system of work
3.1.3 Permit to Work
3.1.4 Operational Risk Assessments
3.1.5 Inspection of Operational Risk Assessments/Inspection of Control of Work arrangements
3.1.6 PFEER Assessment
3.1.7 PFEER Reg 5 Assessment including toxic and asphyxiating gases.
3.1.8 Procedures and Work Instructions
3.1.9 Task Support Tools
3.1.10 Supervision
3.1.11 Support and Advice
3.1.12 Task Performance
3.1.13 Management of Change (incorporating design, material, procedure and management changes).
3.1.14 Human Factors in Operations
3.1.15 Contractor Management
3.1.16 Contractor interfaces and third party equipment
3.1.17 Hardware and equipment conformance

3.2 Specific Operational Tasks and Activities
3.2.1 Permitted Operations
3.2.2 Lifting Operations
3.2.3 Marine Operations
3.2.4 Operation of Facilities
3.2.5 Diving Operations
3.2.6 Hot work
3.2.6 Confined spaces
3.2.7 Working at height
3.2.7 Combined Operations
3.2.8 Simultaneous Operations
3.2.8 Helicopter Operations
3.2.9 Maintenance

3.3 Emergencies and Emergency Management
3.3.1 Introduction
3.3.2 Identification and Assessment of Potential Emergency Scenarios
3.3.3 Emergency Response support facilities and resources.
3.3.4 Emergency Information and Communication
3.3.5 Emergency Shutdown
3.3.6 Fire Fighting (covering deluge, monitors and systems)
3.3.7 Evacuation, Escape and Rescue
3.3.8 Emergency Response and Ongoing Review
3.3.9 Maintenance of Control Systems Following Evacuation
3.3.10 Oil Pollution

3.4 Asset Integrity Management
3.4.1 Maintenance Management System
3.4.2 Corrosion Management
3.4.3 Ageing and Life Extension (ALE) Management

3.5 Occupational Health and Safety
3.5.1 COSHH
3.5.2 Noise
3.5.3 Scaffolding
3.5.4 PPE
3.5.5 Ergonomics and human factors
3.5.6 Provision of information to staff and contractors
3.5.7 Provision of medical support
3.5.8 Health risk assessments and checks
3.5.9 Illness
3.5.10 Stress
3.5.11 Medical emergencies
3.5.12 Evacuation
3.5.13 Hygiene
3.5.14 Weather working procedures

3.6 Verification and Examination
3.6.1 Safety and Environmental Critical Elements (“SECEs”)
3.6.2 Performance Standards
3.6.3 Verification scheme

3.7 Notifications
3.7.1 Design Notification
3.7.2 Material Change to Safety Case
3.7.3 Combined Operations (COMOPS)
3.7.4 RIDDOR
3.7.5 EU Reporting Requirements

4.0 Environmental Management
4.1 General Requirements
4.2 Environmental Policy
4.3 Planning
4.4 Environmental Aspects
4.5 Legal and Other Requirements
4.6 Objectives, targets and programmes
4.7 Implementation and Operation
4.8 Resources, Roles, responsibility and Authority
4.9 Competence, Training and Awareness
4.10 Communication
4.11 Documentation
4.12 Control of Documents
4.13 Operational Control
4.14 Emergency Preparedness and response
4.15 Checking
4.16 Monitoring and Measurement
4.17 Evaluation of Compliance
4.18 Non Conformity, Corrective Action and Preventive Action
4.19 Control of records
4.20 Internal Audit
4.21 Management review

5.0 Monitoring, Audit and Investigation (“CHECK”)
5.1 Data collection/integrity of data
5.2 Ongoing Safety Assurance
5.3 SEMS Risk Management and Safety Case (including thorough review/updating)
5.4 Active Monitoring
5.5 Incident and hazard/near miss Notification
5.6 Reporting
5.7 Incident Investigation
5.8 Safety and Environmental Performance Measures, Performance indicators and PSPIs
5.9 Maintenance Management System Audit & Security
5.10 Audit Arrangements (internal and external)
5.11 Quality Assurance programme
5.12 Environmental Monitoring and Measurement
5.14 Evaluation of Compliance
5.15 Nonconformity, Corrective Action and Preventive Action
5.16 Control of Records and Documentation
5.17 Regulatory compliance register

6.0 Review, Lessons Learned and Positive Action (“ACT”)
6.1 Regular review of SEMS and CMAPP
6.2 Management/Board Review
6.3 Process (Technical) Safety Review
6.4 Environmental Review
6.5 Tripartite Consultation
6.6 Continuous Risk Reduction
6.7 Process and operational status monitoring and handover
6.8 Management of operational interfaces
6.9 Operational readiness and process start-up
6.10 Worker involvement
6.11 Lessons learned
6.12 Positive action/action tracking
6.13 Amending Procedures
6.14 Competency and Training