Study on Decommissioning of offshore oil and gas installations: a technical, legal and political analysis

Final report

Luc Van Nuffel
Pavla Cihlarova
Oana Forestier
Hans Bolscher
Colin Howes
John Morgan
Steinar Nesse
Mark Purcell
Rob Beks
Jens Lovgren Frandsen

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Trinomics

DNV

Contact: Dr. Jörg Köhli

E-mail: joerg.koehli@ec.europa.eu

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Directorate-General for Energy
Directorate B — Internal Energy Market
Unit B4 — Energy Security and Safety

Contact: Dr. Jörg Köhli

E-mail: joerg.koehli@ec.europa.eu

European Commission
B-1049 Brussels

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ACRONYMS

AACE:	Association for the Advancement of Cost Engineering
ALARP:	As Low as Reasonably Practicable
ARO:	Asset Retirement Obligation
BAT:	Best Available Technology
bbl:	Barrel
BEIS:	Business, Energy and Industrial Strategy (UK)
BREF:	Best Available Techniques Reference Document
CA:	Comparative Assessment
CCS:	Carbon Capture and Storage
CNS:	Central North Sea (UK)
CoP:	Cessation of Production
DCENR:	Department of the Environment Climate and Communications (Ireland)
DEA:	Danish Energy Agency
DGSAIE:	Ministry of Economic Development
DSA:	Decommissioning Security Agreement
DSMA:	Decommissioning Security Monitoring Agreement
EA:	Environmental Appraisal
EBN:	Energie Beheer Nederland
EEA:	European Economic Area
EEZ:	Exclusive Economic Zone
EIA:	Environmental Impact Assessment
ELD:	Environmental Liability Directive
EU OAG:	European Union Offshore Authorities Group
FPSO:	Floating Production Storage and Offloading
FSU:	Floating Storage Unit
HHRM:	Hellenic Hydrocarbon Resource Management (Greece)
IFC:	International Finance Corporation
IMO:	International Maritime Organisation

IADC:	International Association of Drilling Contractors
IOC:	International Oil Company
IOGP:	International Oil and Gas Producers
GBS:	Gravity Base Structure
HELCOM:	Helsinki Convention Committee
MCA:	Multi Criteria Analysis
MCDA:	Multi-Criteria Decision Analysis
MiSE:	Ministry of Economic Development (Italy)
MPE:	Ministry of Petroleum and Energy (Norway)
MS:	Member State (of the EU)
MSCC:	Medium and Small Cap Companies
NCS:	Norwegian Continental Shelf
NEA:	Norwegian Environment Agency
NEBA:	Net Environmental Benefit Analysis
NGO:	Non-Governmental Organisation
NNS:	Northern North Sea (UK)
NOGEPA:	Netherlands Oil and Gas Exploration and Production Association
NPD:	Norwegian Petroleum Directorate
NSOAF:	North Sea Offshore Authorities Forum
OGA:	Oil and Gas Authority (OGA UK)
OGD:	Oil and Gas Denmark
OPRED:	Offshore Petroleum Regulator for the Environment and Decommissioning (UK)
OSD:	Offshore Safety Directive (2013/30/EU)
OSPAR:	Oslo-Paris Convention
P&A:	Plug and Abandonment of wells (or well decommissioning)
PDO:	Petroleum Deposit
PIO:	Plan for Installation and operation (Norway)
RoMH:	Report of Major Hazards
RtR:	Rig to Reef
SAC:	Special Area of Conservation

SNS:	Southern North Sea (UK)
SPA:	Special Protection Area
UKCS:	UK Continental Shelf
UNCLOS:	United Nations Convention on the Law of the Sea
UNMIG:	National Mining Office for Hydrocarbons and Georesources (Italy)
USD:	US Dollar
WFD:	Waste Framework Directive

EXECUTIVE SUMMARY

Background and Legal Challenges

Decommissioning offshore oil and gas infrastructure is the process of permanent resealing of wells such that remaining hydrocarbons cannot leak to the sea, or move between different rock strata, and the removal of offshore oil and gas infrastructure from the marine environment with the objective of leaving a clean sea-bed where technically possible, environmentally beneficial, and with the minimum risk to the safety of personnel involved in the decommissioning operation. Other than long-term environmental monitoring, decommissioning is the final stage in the lifecycle of an oil and gas production installation.

The Offshore Safety Directive (2013/30/EU) sets a legal framework for the safe decommissioning of offshore installations with respect to major (safety) hazards and the environmental impact that may follow such a major hazard event and the requirement for permanent sealing of the wells from the installation and the environment, but it does not explicitly address the overall aims of decommissioning and any remaining longer-term environmental effects if all infrastructure is not removed. There is no EU legislation on offshore oil and gas decommissioning specifically, although decommissioning is a 'project' as defined in the EIA Directive (2014/52/EU) and so falls within its scope and also under the scope of other EU environmental legislation, such as the Environmental Liability Directive (2004/35/EC) and the Marine Strategy Framework Directive (2008/56/EC to assess the pressure and impacts of this human activity on the marine environment). Collectively, under this legislation, the physical process of decommissioning is well-regulated, but EU legislation does not directly cover the principle aims of decommissioning that are in country-specific legislation, or in international conventions such as the Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR).

Given the above, the European Commission, through DG ENER, has commissioned Trinomics and DNV to carry out a technical, legal and political analysis of decommissioning of offshore oil and gas infrastructure in the EU to identify where potential gaps in the current decommissioning legislative framework exist and whether EU regulation on decommissioning is warranted.

Decommissioning in the EU, UK and Norway

In the EU, UK and Norway, a growing number of offshore oil and gas installations are reaching the end of their economically productive life and are entering the process of decommissioning. The main reasons for decommissioning an oil or gas field are either that its production is decreasing, making operating costs too high to sustain further operation, or that technical conditions require shut-down and it is considered uneconomic to upgrade the infrastructure to continue production of the remaining resources. Decommissioning is also expected to accelerate due to the shift from fossil fuels to renewable and low-carbon energy sources. Although decommissioning in the EU will not be completed until at least 2050, the costs are high now and it is estimated that €4.8bn will be spent in the EU-27 on decommissioning of oil and gas infrastructure in 2020-2030. Given this high level of activity and its impacts, the Commission has prioritised this study to investigate the adequacy of EU legislation.

Decommissioning is a relatively mature activity in the UK and Netherlands with some projects having also been carried out in Italy, Denmark and Norway. Other EU countries have little to no experience and a minimal decommissioning legislative framework due to their small offshore industry.

While there is no specific EU legislation that covers the principles that must be met in decommissioning offshore oil and gas infrastructure, UNCLOS and IMO conventions require installations (not including pipelines and drill cuttings) to be fully removed to allow safe navigation of shipping and other uses of the sea. Regional Seas Conventions are in place for the North Sea (OSPAR), Mediterranean Sea (Barcelona), Black Sea (Bucharest) and Baltic Sea (Helsinki). However, only OSPAR establishes criteria for derogation from complete removal, and only for large fixed installations.

Within OSPAR, to enable signatory countries to decide whether a derogation is appropriate, there are well-used decision processes and administrative structures. The other regional sea conventions are less well-developed and do not have specific provisions for removal of oil and gas structures. As such there are no common principles for the removal of oil and gas infrastructure from EU controlled waters.

From consideration of legislation in place and practices across the EU, UK and Norway, it is possible to define good practice in relation to removal of oil and gas infrastructure. This is presented below along with the potential environmental impact from structures that can be left in-situ and the reason they are not removed (albeit almost each one needs to be assessed by the Operator separately).

Infrastructure	Quantity in EU-27	What is left in-situ?	Long-term Environmental Impact of leaving in-situ	Other Options	Reason for leaving in-situ
Facility Topsides	> 300	Nothing – fully removed.	n/a	Re-use in oil and gas application. Re-purposing for alternative offshore use.	n/a
Steel Sub-structure (non-derogable)	> 300				
Floating Structures	Tens				
Subsea Structures	Thousands			None	n/a
Wells	Many thousand	Sealed subsurface wellbore.	Potential failure of sealing system and leak of reservoir contents.	None	n/a
Steel Sub-structure above IMO weight and age limit	Zero	Upper section (to -55m MSL) is removed leaving lower part of jacket, or footings.	Minimal as remaining material is steel. Impact on local fishing due to snagging.	Remove to deepest depth possible with available technology. Full removal.	Cost and personnel risk.
Gravity Based Structures (GBS)	Nether-lands (1) Denmark (1)	The whole GBS, which is then monitored.	Minimal, though see below for the GBS contents. Impact on local fishing due to snagging.	Full removal of GBS. Removal of GBS legs only.	Technically not feasible to safely destruct a GBS.
GBS Cell Contents	As above (contents are mainly ballast).	Hazardous waste is removed, but can be challenging to remove it all.	As the cell degrades it will gradually leak and slowly release contaminants into the sea with an impact on the local area.	Cleaning of GBS and removal of hazardous waste. Full removal of cell (and GBS).	Cost and personnel risk.
Drill Cuttings	Many	Cuttings left in place unless need to be disturbed to remove the jacket.	Potential for oil to seep from the cuttings.	Removal	Removal likely to have a greater environmental impact than leaving in-situ.
Pipelines	Many	Pipeline left in-situ and filled with inhibited water.	Potential for small amounts of oil, or other contaminants to seep into the environment once pipeline degrades, but at a level most likely well below that permitted in produced water in production operations.		
Mattresses (pipeline protection)	Many	Left in-situ if the associated pipeline is left.	Possible plastic from the material that holds the mats together.		

To decommission an offshore oil or gas field, all wells are decommissioned using a process in the industry known as ‘plug and abandonment’ (P&A). Well decommissioning isolates the reservoir from the marine environment through the placement of two or more cement barriers in the well bore. This can be demonstrated to provide isolation in the short to medium term.

However, the long-term integrity (in terms of the need to ensure that the well is sealed ‘in perpetuity’) of well P&A barriers is not proven. Monitoring of the wellbore above or between the barriers is not realistic as this would require the intermediate barriers to have a through barrier penetration, which introduces a potential leak path. Thus, a failure may only be apparent when a release to the marine environment is. Well intervention would be required to remediate such a release, particularly if sensitive environmental receptors were at risk. The development of a well intervention plan, well P&A design and project execution would be technically challenging, time consuming and expensive.

Completely filling a well with cement would minimise the risks but is prohibitively expensive and cement has its own environmental impact. The balance between this cost and the risk of failure has been considered in regional practices for well abandonment, and it is considered that ensuring that this balance is right is a key environmental target. This needs to be tempered by the fact that by analogy with onshore well decommissioning (no releases from >1,000 decommissioned wells in Europe), such a release is considered unlikely and would be small as the flow path through a failed barrier resulting from cracking or channelling in the cement is likely to be very limited. The proportion of offshore decommissioned well stock in the total well portfolio is rising, although it is still a small percentage and there is little leak data from decommissioned wells to draw upon, with no published data from long term decommissioned wells (>ca 30 years).

Stakeholder Input

A key input into this assessment are the opinions of NGOs, authorities and industry bodies gathered through a questionnaire. Some excerpts of responses are given below as they summarise important points that align with or influence the identification of shortcomings and potential improvements in EU legislation that are considered in this analysis:

- All responders that provided feedback on the major aims of EU decommissioning legislation, agreed that protection of the environment should be a major objective of such legislation, while many of the responders, both industry and NGOs, also noted that the environmental risk cannot be reduced to zero;
- No responder identified a specific environmental standard that would assist in the consideration of how to seal and abandon a well, or whether oil and gas infrastructure could, in some cases, be left on the seabed after decommissioning;
- Where mentioned, responders stated that it should not be the public purse that paid for decommissioning; the “polluter pays” principle was cited;
- No responder suggested that the current regime did not work and many responders considered that decommissioning was adequately covered in existing legislation and conventions (e.g. OSPAR, Barcelona). National authorities from Italy, Denmark and the Netherlands stated that the current regulatory regime in their countries worked well and change was not required. Authorities from Norway and the UK did not reply, but industry bodies that represent operators in these countries replied in the same way (the majority of decommissioning in Europe will occur outside the EU, i.e. in the UK and Norway);
- Authorities from some Member States with a smaller oil and gas industry, or with less experience in decommissioning stated that additional EU legislation would be beneficial to clarify the responsibilities of the different concerned parties; and
- Regarding long term liability after licensee monitoring finishes, almost all responders stated that the state should be responsible, though only after rigorous analysis of the decommissioning process and status by the country’s competent authorities.

Analysis Outcomes

Nine shortcomings were identified in the current EU regulatory framework for decommissioning with a number of potential measures to resolve each, of which four were considered for implementation in new EU legislation:

- Decommissioning principles are not well-established in law outside of the OSPAR region;
- The long-term integrity of wells that are decommissioned is not known and, while there is no reason to expect any future issues, they are sealed to differing standards in different countries as there are no EU wide common requirements;
- There is a potential environmental hazard from wells or infrastructure left in-situ decades into the future and so long-term monitoring principles need to be defined; and
- Currently, where national regulation of long term liability exists, the licence holder is required to indefinitely retain adequate financial provisions for the remediation of any environmental impacts after decommissioning. However, in the long term there is the risk that the licence holder entity ceases to exist exposing Member States to financial risks from remediation of incidents. EU regulation should adequately consider these long term potential exposures.

Each of the potential options to address these identified shortcomings were subject to an impact analysis, which resulted in the following proposed measures:

It is proportionate and appropriate for the EU to define Offshore Oil and Gas Decommissioning Principles in a Directive. This could be a new Directive, or appended to the Offshore Safety Directive, though their scope and aims would be significantly different. Introducing a common set of principles across the EU, would provide a more harmonised legal framework and would in particular benefit the EU Member States with limited decommissioning experience. The Offshore Safety Directive was approved and implemented within 2 to 3 years and if the same timescale was achieved for a decommissioning directive, it would be enacted before the majority of installations in the EU enter decommissioning**. The new Directive could define the following principles**:

Infrastructure should be removed from the seabed such that it does not create a long-term hazard. Drill cuttings, pipelines, mattresses and umbilicals should be removed, and only considered for leaving in situ if removal is likely to present a safety or environmental hazard greater than that from leaving in situ. If left in-situ, pipelines must be flushed to a standard that meets agreed oil (and other hazardous materials) in water targets. Criteria for leaving large sub-structures in-situ should be appropriate to the EU asset base and technical capacity and capability available to oil and gas operators and Member States. As an example, derogation criteria for large sub-structures to remain in-situ are included in OSPAR Decision 98/3 and include cleanliness, weight and age criteria.

Environmental Risk Assessment is required to justify any infrastructure left in-situ, and a Member State may decide to adopt a generic assessment covering the majority of drill cuttings, pipelines, mattresses and umbilicals.

A national competent authority (most likely already existing) should review and approve or reject the assessment for leaving infrastructure in-situ (including the ERA).

Re-use of infrastructure needs to be considered before it is decommissioned.

For infrastructure to be left in-situ, acknowledgement that this is appropriate is required from all concerned Member States' Competent Authorities sharing a sea with that infrastructure. A consultation process to address objections and to develop a mutually agreeable solution between all parties will be required. If an agreement is not reached through the consultation process, then mediation by the European Commission may be considered.

Member States should determine how Long-Term Monitoring of Decommissioned Infrastructure is achieved once a steady state environmental condition has been reached at a decommissioned site, potentially decades after decommissioning. Monitoring could remain the responsibility of the licence holder, but, as the volume of decommissioned infrastructure under survey will increase with time (see estimated numbers in EU-27 in table above), single wide area surveys commissioned by the national Competent Authority may become more efficient to deliver and would ensure fuller and more consistent coverage than those of individual surveys of small areas by multiple licence holders. Also, critically, licence holders are likely to gradually cease to exist. As this proposed measure would only take effect after a number of decades, it does not need to be in place immediately, allowing Member States to consult on their arrangements for long term monitoring and how robust and practical current methods for monitoring are over multi-decade timescales and how industry is charged for this monitoring effort.

Appropriate **Common Well Decommissioning Requirements** complementary to the principles of the proposed Directive on Decommissioning could be developed by a technical committee with in-depth experience of well decommissioning. Well decommissioning requirements are currently developed by the oil and gas industry; some regimes, such as the UK, Norway and Netherlands, are mature, while most other Member States do not have specific requirements. A set of minimum well decommissioning requirements would provide a common basis across EU Member States for the environmentally critical process of sealing a well for geological time. Good practice well decommissioning guidance is present in the North Sea and the North Sea Offshore Authorities Forum (NSOAF) is developing common decommissioning guidance for use in the North Sea based on practices from the UK, Norway and Netherlands. This guidance could be implemented or used as the basis for an EU best practice guidelines.

Inclusion of requirements on the scope and acceptance of Comparative Assessments in the Directive was also considered, but these assessments are common across many industries and it was not considered feasible to create oil and gas specific requirements.

Other measures were considered, but these are generally managed by the industry, or Competent Authorities without the need for new EU legislation and include:

- Decommissioning knowledge transfer;
- Post-decommissioning short term monitoring arrangements; and
- Collaboration on decommissioning activities.

1. Scope and objectives

1.1. Background

In the EU, UK and Norway, an increasing number of offshore oil and gas operations are approaching cessation of production and decommissioning as further exploitation of the reservoirs is no more economically viable. Decommissioning is expected to accelerate due to the ongoing shift from fossil fuels to renewable and low-carbon energy vectors and the resulting decreased demand for oil and natural gas. To decommission an offshore oil and gas production field, the wells must be permanently resealed such that remaining hydrocarbons cannot leak to the sea, or move between different rock strata and infrastructure on the seabed must be completely removed, or, if any of it remains in-situ, it must not present a long-term environmental hazard. Other than any long-term environmental monitoring of decommissioned wells and infrastructure left in-situ, decommissioning is the final stage in the lifecycle of an oil and gas installation.

The Offshore Safety Directive (2013/30/EU) (OSD) sets a legal framework for the safe decommissioning of offshore installations with respect to major (safety) hazards and the environmental impact that may follow such a major hazard event, but it does not address any potential longer-term effects. It also covers the requirement for the concerned licensees to have sufficient funding to carry out their operations, including decommissioning. EU Member States (including the UK being an EU-member at that time) have implemented the Directive and an analogous legal framework exists in Norway.

Decommissioning is a ‘project’ as defined in the EIA Directive (2014/52/EU) and so falls under its remit. Decommissioning is also subject to other EU environmental legislation, such as the Environmental Liability Directive (2004/35/EC), the Marine Strategy Framework Directive (2008/56/EC) and the Habitats Directive (92/43/EEC).This means that an environmental assessment of decommissioning must be developed for decommissioning options considered and subsequently chosen and that the impacts and pressures of any decommissioning activities have to be assessed. Decommissioning projects in many Member States and in the North Sea have already been completed or are currently ongoing or planned and, with these assessments being carried out and subsequent monitoring happening, the impact of the actual process of decommissioning on the environment is well-understood. Broadly, it is managed in a similar way as to how environmental impact during production operations is prevented.

EU legislation does not directly cover any longer-term impact from oil and gas infrastructure that is decommissioned, but left in-situ, and does not provide associated requirements such as monitoring and liability. National rules and legislation cover this in the concerned countries, and also international conventions such as the North Atlantic (OSPAR), Mediterranean (Barcelona) and Baltic (HELCOM) conventions, with varying degrees of effectiveness and coverage.

1.2. Objective of the study

To consider whether the lack of specific EU legislation regarding decommissioning needs resolving, the European Commission, through DG ENER, has commissioned Trinomics and DNV to complete this study to:

- Identify current practices and issues relating to decommissioning by:
    - analysing the scope of current and future offshore oil and gas decommissioning in the EU, the UK and Norway;

  - reviewing the EU, national and international legal instruments and requirements relating to decommissioning that are in place, and analysing their practical implementation;
  - identifying potential significant technical challenges in the decommissioning of wells and oil and gas production infrastructure, and in the dismantlement of installations;
  - identifying any applicable guidelines and best practices for decommissioning;
- Examine environmental and financial implications resulting from decommissioning, particularly those associated with the potential for environmental damage in the long term, e.g. decommissioned wells, infrastructure left in-situ;
- Assess the potential need for update of the legal framework for decommissioning within the EU and identify and evaluate potential options for updating EU legislation; and
- Identify best practice in international or national regulatory regimes that can be recommended and/or used as a basis for potential changes in EU legislation or guidelines.

1.3. Emphasis of the study

Decommissioning is the last stage in the lifecycle of an oil and gas asset. The legislation in place at the EU, international and national level for decommissioning is broadly similar to that in place for production operations albeit the hazards are altered. For example,

- the process of plugging and abandoning a well to decommission it has less risk than its original drilling due to the fact that the well is a known entity and, to decommission it, no drilling of rock is carried out and there is no risk of encountering new hydrocarbon bearing strata;
- decommissioning of topsides process systems and subsea infrastructure have the potential to release contaminants to the environment but follow similar processes to those applied by an operator during major maintenance activities and are generally well described by existing procedures; and
- final removal of a structure has the potential to result in major accident hazard and in the release of contaminants into the environment. Identification, assessment, mitigation and control of major accident hazards is required under the Offshore Safety Directive and decommissioning and removal operations are covered by this Directive. Elimination, mitigation and control of releases to the environment are required under the Environmental Impact Assessment Directive and other instruments.

Therefore, while this study describes and assesses the current procedures and status of decommissioning in the concerned European countries involved in decommissioning, the emphasis of the study is consideration of potential EU legislation on the end state of a decommissioned oil and gas asset i.e.

- The way in which the wells are decommissioned (plugged and abandoned[1]); and
- Infrastructure that, after due consideration by regulatory authorities, may be left in-situ.

as these are areas where additional EU level action could have the greatest added value.

[1] Well Decommissioning or Plug and Abandonment (P&A) is the oil and gas industry terminology for the process of preparing a wellbore to be shut in and then permanently isolating it from both geological zones with flow potential and the wider external environment. In most cases, a series of cement plugs is set in the wellbore, with an inflow or integrity test made at each stage to confirm isolation.

In tandem with this, the study considers monitoring arrangements required over decades for decommissioned oil and gas fields and financial liability should any further remediation be required.

1.4. Methodology and report structure

This report has been prepared by independent experts in oil and gas decommissioning practices and related legislation and regulation and presents the results of the study in the following structure:

- Data gathering and analysis of the current status and expected development of decommissioning in the EU, UK and Norway (Section 2);
- Analysis of the regulatory framework for decommissioning in the EU, UK and Norway (Section 3);
- Section 4 covers the environmental impact of leaving infrastructure in-situ (as permitted within the regulatory frameworks) including for how wells are plugged and abandoned, the potential impact of this on the environment and how decisions to leave in-situ are made;
- Section 5 introduces best practice applied to the main steps in decommissioning;
- Identification of weaknesses and shortcomings and identification of potential measures to resolve them (Section 6); and
- The measures that are considered to be amenable to EU legislation are taken forward to the impact analysis in Section 7;

Finally, Section 7 provides the conclusions of the impact analysis, proposes the introduction of a new EU Directive on Decommissioning and common well decommissioning guidance, and provides draft texts for consideration by DG ENER.

The overall methodology has been to gather data to feed into the identification and analysis of potential improvements considered for legislative changes. Another key input into this process are the opinions of stakeholders gathered through a detailed questionnaire sent to NGOs, authorities and industry bodies. 0 provides an extensive summary of their responses and lists the respondents. Some excerpts are given below as they summarise important points from the stakeholders' feedback that align with or influence the identification of shortcomings and potential improvements that are considered in the analysis:

- All responders that provided feedback on the major aims of EU decommissioning legislation, agreed that protection of the environment should be a major objective of such legislation, while many of the responders, both industry and NGOs, also noted that the environmental risk cannot be reduced to zero;
- No responder identified a specific environmental standard that would assist in the consideration of how to seal and abandon a well, or whether oil and gas infrastructure could, in some cases, be left on the seabed after decommissioning;
- Where mentioned, responders stated that it should not be the public purse that paid for decommissioning; the "polluter pays" principle was cited;
- No responder suggested that the current regime did not work and many responders considered that decommissioning was adequately covered in existing legislation and conventions (e.g. OSPAR, Barcelona). National authorities from Italy, Denmark and the Netherlands stated that the current regulatory regime in their countries worked well and change was not required. Authorities from Norway and the UK did not reply, but industry bodies that represent operators in these countries replied in the same way (note that, as described in Section 2.3 and in Appendix C, the majority of decommissioning in Europe will occur outside the EU, i.e. in the UK and Norway);

- Authorities from some EU-countries with a smaller oil and gas industry, or with less experience in decommissioning stated that additional EU legislation would be beneficial to clarify the responsibilities of the different concerned parties; and
- Regarding long term liability after licensee monitoring finishes, almost all responders stated that the state should be responsible, though only after rigorous analysis of the decommissioning process and status by the country's competent authorities.

This report is kept deliberately short, concentrating on describing the current situation and shortcomings and then taking forward these shortcomings into the identification of potential measures to address them, and finally the impact analysis of selected measures. It is backed up by detailed descriptions and analyses presented in several appendices that are referenced as relevant. In addition, 0 contains six case studies of decommissioning projects and examples of cases outside of Europe where decommissioning liability has had to be taken up by the State. **Bold text** is used in the report to emphasise key aspects.

2. Offshore oil & gas infrastructure decommissioning

2.1. What is decommissioning?

Decommissioning is the clean-up, dismantling, removal and disposal or recycling of infrastructure related to an oil or gas producing asset at the end of its operational life. Decommissioning consists of a series of key steps:

1) permitting and regulatory compliance

   field, asset and condition data is gathered and preliminary environmental and condition surveys are conducted to identify decommissioning requirements, identification and selection of methods, and development and submission of the preferred decommissioning plan and programme to the regulatory authorities.

2) well decommissioning

   the production reservoirs are isolated from the rock strata above them and the wider external marine environment through the placement of barriers (or plugs) in the well. Well tubing and casing is removed where required, and conductors and wellhead structures are recovered.

3) topsides and pipeline preparation for removal from site/leaving in-situ

   topsides production equipment and pipelines are cleaned of hydrocarbons to agreed standards, hazardous materials are removed or securely contained, and structures prepared for removal or in situ abandonment.

4) removal of topsides and jacket

   the topsides are removed by single lift, reverse installation or piece-small methods and jackets cut and lifted.

5) onshore dismantling and disposal

   the removed structures are transported to a shoreside reception facility for re-use, or cleaning and dismantlement for recycling and disposal.

6) offshore site clearance

   the site is surveyed after decommissioning is complete and residual debris is removed.

7) ongoing monitoring

   wells and any infrastructure left in-situ is periodically surveyed to identify changes in its condition or the surrounding environment that might adversely impact the marine environment or users of the sea.

These steps are often carried out discretely and often with periods where no activity is occurring, particularly between topsides and pipeline preparation, decommissioning, and topsides and jacket removals. As such, decommissioning is not as time dependent as other offshore projects and can typically range from 2 years to 10+ years from conception to conclusion depending on its complexity.

Three areas of decommissioning take up ~80% of the total cost (in descending order of cost):

- decommissioning of the wells;
- installation removal, particularly of fixed topside and steel jacket structures; and
- operational costs to maintain assets in a suitable condition for decommissioning.

2.2. What are the main issues?

The majority of oil and gas production in Europe is considered mature and either approaching or in the end of life phase. Decommissioning activity is already underway in many EU countries (and the UK and Norway) and is likely to accelerate over the period 2020-2030, as production declines and becomes increasingly uneconomic.

There is a large and varied inventory of oil and gas infrastructure in the marine environment including fixed structures ranging from a few hundred tonnes to many hundred thousand tonnes (in the case of concrete Gravity Based Structures (GBS)), floating production units, subsea tie-backs, pipeline transportation systems of varying diameters and lengths, and wells of differing depths and complexity. A small proportion of these have been fully decommissioned. However, these are mostly sub-sea production systems, and simple fixed production systems such as UK SNS and Dutch gas producing assets. A smaller number of large structures from the UKCS and Norway have been decommissioned, and it is from these projects that much of the learnings in decommissioning have come from to date. These **larger structures, parts of which may remain in place after decommissioning, and the reliability of the seal of a decommissioned well, present the most significant potential long term environmental impact**.

The hazard associated with large structures left in-situ, or disposed of as part of a rig to reef (RtR) policy, will diminish over a long timescale as there is a finite inventory of material in place that is slowly broken down in the marine environment. The hazard associated with a decommissioned well remains, as there is the potential for failure of the barriers in the well over time that may result in a significant release from the reservoir. Ensuring the seal is as permanent as realistically possible is critical in avoiding long-term environmental impact.

Society generally expects that the seabed should be returned to its original condition and so **a robust and transparent decision-making process is essential in developing public trust and acceptance of any decommissioning solution that leaves materials in situ**.

In a recent report[2], Wood-Mackenzie estimated that $85bn will be spent globally on decommissioning offshore oil and gas infrastructure in the period 2019-2028, of which 43% ($37bn) will be spent in the North Sea basin. It is estimated that **$75bn will need to be committed to decommission the current European offshore oil and gas infrastructure** by 2050. It is hence important for authorities to have a good understanding of this cost and how it may impact the taxpayer.

Most countries have some fiscal exposure to oil and gas decommissioning, both through the loss of tax income from production and through tax relief to oil and gas operators that are decommissioning. Operators or licensees carry the responsibility for decommissioning costs, but there are examples outside of Europe where the State had to pay for decommissioning as the licensee had been liquidated and could no longer be held liable for the costs (see Appendix 0). Requirements in the Offshore Safety Directive reduce this risk in the EU, but **the financial responsibility for any longer-term environmental liability is less well-defined despite the 'Polluter Pays' principle**.

Many of the European countries with offshore oil and gas production are now having to **resource or re-align regulatory and oversight bodies to effectively administer and adequately regulate decommissioning** activities within their jurisdiction to ensure licence holders' compliance with international, EU, regional and national legal and environmental obligations.

[2] OGUK, Decommissioning Insight Report, 2020

2.3. Overview of the offshore oil and gas industry in the EU, Norway and the UK

Table 1 summarises the offshore oil and gas industry in the EU, Norway and the UK; further details are provided in Appendix B and Appendix C. The European offshore oil and gas industry is dominated by the UK and Norway. Within the EU, the Netherlands, Denmark and Italy have significant offshore oil and gas assets, while some other EU-countries have small offshore activities, though Romania and Croatia have multiple assets. The whole industry is mature with decommissioning having commenced in many areas. Some EU-countries with a coastline have no offshore oil and gas industry.

Table 1: Overview of Offshore Oil and Gas Fixed and Floating Structures in the EU, Norway and the UK

Parameter	UK	Norway	Netherlands	Denmark	Italy	Croatia	Spain	Romania	Germany	Ireland	Greece	Poland
First production	1965	1971	Late 1960s	1972	Mid 1960s	1968	1983	-	1987	1978	-	-
Number of fields	364	114		20	55							
Field locations (Maximum water depth of above water structures)	North Sea (186m) West of Shetland (150m - 300m) Irish Sea (138m)	Norwegian and North Sea (378m)	North Sea (51m)	North Sea (68m)	Adriatic Sea Medi-terranean	Northern Adriatic	Gulf of Biscay Medi-terranean	Black Sea	Wadden Sea	Celtic Sea	Aegean Sea	Baltic Sea
Number of structures currently operating or shut down awaiting decommissioning (fixed and floating)	306	114	117	~60	116	19	1	11	1	1	3	1
Number of structures partly or completely removed or disposed of (fixed and floating)	89	55	31	3	23 (RtR) 8	-	-	-	1	2 (in progress)	-	-
Number of well structures [1]	500	500	16	-	-	-	-	-	-	-	-	-
Type of installations	GBS Fixed steel Floating steel	GBS Fixed steel Floating steel	GBS (1) Fixed steel	GBS (1) Fixed Steel	Fixed steel Floating Steel	Fixed steel	Fixed steel	Fixed Steel	Drilling & production island	Fixed steel	Fixed Steel	Fixed Steel
Length of offshore pipeline(km)	> 10,000	~10,200	~3,000	>1,800	> 1,000		-	-		~200	~10	-
Total number of wells drilled	> 7,800	~ 7,000	680	~300	~715	51	-	-	30	90	-	-

[1] – Includes well templates and other subsea installations currently operating or shut down awaiting decommissioning

The tables below expand on the offshore oil and gas industry picture in each concerned country. Further details on each country's regulatory framework are provided in Section 3 and further detailed in Appendices B and C.

Table 2: Overview of Offshore Oil and Gas Industry Maturity and Metrics in the EU, Norway and the UK

Parameter	UK	Norway	Netherlands	Denmark	Italy
Industry Maturity & Size	• Multi Basin • Well developed • High % Late Life • Significant decommissioning underway	• Multi Basin • Well developed • Life Extension • Some decommissioning (mostly subsea developments)	• Single Basin • Well developed • High % Late Life • Re-use focus • Decommissioning underway	• Single Basin • Well developed • Life Extension • No significant decommissioning	• Multi Basin • Well developed • High % Late Life • No significant decommissioning
Metrics	364 Fields 306 Structures 500 Subsea Installations 89 Decommissioned >7,800 wells drilled Multiple GBS Fixed and Floating Steel >10,000km pipeline	114 Fields 114 Structures 500 Subsea Installations 55 Decommissioned ~7,000 wells drilled Multiple GBS Fixed and Floating Steel >10,000km pipeline	117 Structures 16 Subsea Installations 31 Decommissioned 680 Wells GBS (1) Fixed Steel ~3,000km pipeline	20 Fields 60 Structures Decommissioned 300 Wells GBS (1) Fixed Steel >1,800km pipeline	55 Fields 116 Structures 31 Decommissioned (23 Rig to Reef) 715 Wells Fixed and Floating Steel >1,000km pipeline

Parameter	Croatia	Spain	Romania	Germany	Ireland	Greece	Poland
Industry Maturity & Size	• Medium • Developed • No significant decom	• Small • Developed • All in decom	• Small • Developed • No significant decom	• Small • Developed • Partial decom	• Small • Developed • In decom	• Small • Developed • No significant decom	• Small • Developed • No significant decom
Metrics	19 Structures 51 Wells Fixed Steel	3 Fields (2 storage) Fixed Steel	11 Structures Fixed Steel	2 Fields; 30 Wells 1 Decom Production Island	2 Fields; 90 Wells Fixed Steel 200km p/l	1 Field Fixed Steel	1 Field Fixed Steel

2.4. Decommissioning cost

2.4.1. Introduction

The cost of decommissioning is significant for the concerned licensees albeit one that can be estimated and accounted for in advance. Indeed, one of the requirements of the OSD is for licensees to have sufficient funds available to finance their operations, including decommissioning of assets. This cost is borne by the industry, though tax rebates are available in some countries. The industry therefore seeks to drive down the costs through, for example:

- more efficient well decommissioning;
- preference for single lift of topsides and jackets over reverse installation, modular removal, or piece small removal;
- campaign strategies for multi-well decommissioning and asset removals; and
- cooperation between different licensees in wider, multi-operator campaigns.

Cost is a consideration in terms of the development and production of the decommissioning solution, i.e. whether any infrastructure is left on the seabed and the extent to which the well bore is filled with cement to provide a seal that prevents hydrocarbons being released. Filling the entire well with cement to make the seal longer would be prohibitively expensive and have an environmental impact through the increased use of cement and the additional rig time required to do this, but may not materially improve the sealing of the well. This cost and the environmental requirement to seal the reservoir drive the standards covering well decommissioning. Pipelines are often left in-situ as they can be flushed clean to a relatively high standard and their removal is expensive and environmentally damaging in the short-term.

Structures that are eligible for derogation from removal under OSPAR would be expensive to completely remove though there may be an environmental benefit in doing so.

Detailed decommissioning cost information is given in 0 and a summary of the main decommissioning drivers of total cost and timing is provided below.

2.4.2. Main cost drivers

OGUK has produced a report[3] on the decommissioning activity in the UK for the remainder of this decade including the cost of decommissioning in key stages, which is applicable to most decommissioning projects. The concluding overview table is presented below, which shows that almost half of the overall cost is associated with P&A of the wells, with 1% on site remediation and 0.4% on post decommissioning monitoring.

	1 Project Management	2 Post-CoP Running Costs	3 Well Decommissioning	4 Facilities & Pipelines Permanent Isolation & Cleaning	5 Topsides Preparation	6 Topsides Removal	7 Substructure Removal	8 Topsides and Sub-structure Onshore Disposal	9 Subsea Infrastructure	10 Site Remediation	11 Post-Decommissioning Monitoring	
Proportion of Overall Ten-Year Expenditure (£MM)	7%	9%	49%	3%	3%	8%	6%	2%	11%	1%	<1%	TOTAL
Northern North Sea & West of Shetland	£389.04	£520.75	£2,940.09	£241.40	£193.39	£703.01	£265.59	£123.96	£519.68	£39.14	£14.35	£5,950.40
Central North Sea	£418.52	£672.60	£3,162.60	£95.90	£183.65	£300.47	£247.17	£147.19	£786.15	£39.49	£19.50	£6,073.25
Southern North Sea & East Irish Sea	£191.15	£176.22	£1,287.77	£87.90	£105.20	£253.84	£417.00	£94.23	£316.61	£94.23	£25.53	£3,049.69
TOTAL	£998.71	£1,369.57	£7,390.46	£425.20	£482.24	£1,257.32	£929.76	£365.38	£1,622.44	£172.86	£59.38	£15,073.34

2.4.3. Total cost estimates

An overview of the offshore oil and gas infrastructure planned to be decommissioned up until 2030 and the associated costs is presented below.

Table 3: Extent and cost of decommissioning from 2020 to 2030

Country	Cost €		Wells	Topsides Tonnes	Tonnes Substructure
UK	**€17bn**		1,616	568,000	372,000
Norway	**€9.7bn**		250	77,000	108,000
Netherlands	**EU Total €4.8bn**	€2.6bn	470	132,000	184,000
Denmark		€0.4bn	90	33,000	40,000
Italy		€1.4bn	380		
Other EU MSs[4]		€0.4bn			

The cost in each country is a reflection of the number of assets in these areas and, generally, their increasing complexity from South to North with deeper water, harsher environmental conditions (larger jackets) and greater propensity for oil fields in Northern Europe.

[3] OGUK, Decommissioning Insight Report, 2020

[4] Decommissioning is currently underway or planned in Spain and Ireland. The Bulgarian facilities are shut down awaiting decommissioning and no decommissioning is planned in Romania, Germany or Poland at this time. No formal decommissioning cost estimates are available for these areas.

All the cost estimates and projections are highly sensitive to factors not directly in control of regulators and operators, such as demand levels and commodity prices for oil and gas, that can influence the future value of an asset and the continuing economic viability. This can directly impact decision making around the timing for cessation of production and the start of decommissioning.

2.4.4. Expected decommissioning timing

The main reasons for decommissioning an oil or gas field are either that its production is decreasing, making operating costs too high to sustain further operation, or that technical conditions require shut-down and it is considered uneconomic to upgrade the infrastructure to continue production of the remaining resource. Operators take a risk-based approach to determining Cessation of Production, that will involve scenarios with a number of different commodity price predictions. When a field no longer forecasts a positive monetary return within the analysis period, the operator will apply for CoP to the national Competent Authority.

Decommissioning programmes are then developed and submitted to the concerned regulator for approval. The timing of the delivery of the decommissioning proposal varies from country to country; in countries with a more mature industry the regulator expects to engage with an operator from 2 years up to 6 years prior to a CoP application. This generally allows sufficient time for organisation and agreement of the Decommissioning Programme between the regulator and operator, and an efficient transition from production, through CoP, and into decommissioning. It also provides the regulator with a ‘look ahead’ at the potential profile of assets entering decommissioning and the likely cost estimate on a year-on-year basis. In countries with a less mature offshore hydrocarbon industry, this process is in general not so well-established and assets can have production suspended suddenly, or continue for a period of sub-economic production, while decommissioning programmes are developed and approved.

In the UK, decommissioning is now established and the number of assets entering decommissioning is steadily rising. The UK is expected to lead demand for decommissioning services in Europe through the 2020s when more than 80 fields may enter CoP and see decommissioning commence, a trend to continue through the 2030s.

In Norway, decommissioning has been forestalled by life extension of most of the large fields. As a consequence, most decommissioning in Norway will take place from the 2030s through the 2040s, with only sporadic decommissioning activity amongst the large fields and a concentration on sub-sea production removals in the 2020s.

In the Netherlands, the most recent report[5] anticipates that 60% of the current installations will be decommissioned in the period up to 2030, with the remaining 40% decommissioned in the period 2030-2040. Denmark anticipates decommissioning to begin toward the end of the 2020s and continue through the 2030s, with only very few fields remaining in production by 2040.

The decommissioning data on other EU-countries is less detailed. In particular, Italy and Croatia have uncertain decommissioning profiles at present, but given the age and maturity of the installations in Italy, it is anticipated that many of them will enter decommissioning during the late 2020s and through the 2030s. Croatia is expected to have increasing decommissioning activities through the 2030s. The other EU-Member States with offshore oil and gas installations have only small offshore fields that will not significantly impact the overall decommissioning activities across Europe.

[5] Nexstep, Re-use & Decommissioning Report, Innovation & Collaboration, 2020

3. Legal Framework for decommissioning of offshore oil and gas assets

3.1. International and regional legal instruments

At the international level, the three instruments outlined below advocate complete removal of structures in all but exceptional cases. This framework is enacted at the regional level by sea-specific conventions of which the **OSPAR Convention for the NE Atlantic is an example of regulatory good practice**. A summary of the relevant instruments, applicable to those states that have ratified them, is given below (see Appendix A for further details).

Table 4 Overview of relevant international and regional legal instruments

International		
International Maritime Organisation (IMO) and its Guidelines	**UN Law of the Sea Convention ('UNCLOS')**	**London Convention & London Protocol**
• In its full name, Guidelines & Standards for the Removal of Offshore Installations & Structures on the Continental Shelf & in the Exclusion Economic Zone (EEZ); • Presumes full removal of installations or structures, but allows case by case exceptions: o >75m water depth & >4,000 tonnes in air, excluding deck and superstructure; o In place after 1st Jan 1998, if >100m water depth and >4,000 tonnes in air; o Removal is technically not feasible or safe, or has excessive cost (cost element not applied in OSPAR); o No adverse impact of structure on navigation or environment; o Reefing away from shipping lanes, if beneficial; and o Min. 55m water clearance, or clearly marked. • All post 1st Jan 1998 structures must be designed for full removal. and • All EU Member States are members of the IMO.	• Requires installation removal for 'safety of navigation' with 'due regard' for fishing, environmental protection & rights of other States; and • EU-wide ratification.	• Regulates dumping, or leaving in situ, waste at sea; • Provides for guidelines for assessment of leaving platforms or other man-made structures at sea; • Used by national authorities responsible for regulating dumping of wastes; and • Ratified by Belgium, Denmark, Germany, Finland, France, Greece, Hungary, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain and Sweden.

Regional			
OSPAR Convention (NE Atlantic, North Sea)	**Barcelona Convention (Mediterranean)**	**Helsinki Convention (Baltic Sea)**	**Bucharest Convention (Black Sea)**
• OSPAR Decision 98/3 forbids dumping and leaving (wholly or partly) in place disused of offshore installations. It does not cover pipelines or wells; • Allows for derogations and requires Comparative Assessment (CA) to be carried out; • Decisions on derogations can be discussed before the OSPAR Offshore Committee; • Derogation requirements & CA open to interpretation by Competent Authority; • Unclear on long term monitoring arrangements; • Full assessment process for all CA options not followed; and • Regular deliberations to consider whether the approach of Decision 98/3 addresses removal of structures adequately OSPAR Recommendation 2006/5 reduces pollution impact from oil in cutting piles but not from other materials. 2 stage assessment process – generally, leave in situ decision.	• 1994 Offshore Protocol requires removal but ratification is not universal; • 2003 Guidelines align to OSPAR, but non-binding. Authorities can set their own criteria for operators; • Leave in-situ (including RtR) option not excluded; and • 2016 Action Plan seeks common standards & guidelines.	• HELCOM Recommendation 14/9 recommends complete removal and well P&A; • Few oil and gas requirements published; and • Operators to apply 'zero discharge' principle – installations should be removed, dismantled in an environmentally friendly manner.	• Aims to prevent, reduce and control pollution in general terms only; • Does not address O&G decommissioning requirements; and • National competent authority and operators agree on case-by-case basis.

A key finding of the legal analysis of the above instruments (details are provided in **0**) is that the **enforcement of international and regional (environmental) conventions is problematic.** Despite the fact that most of the instruments addressed above are of binding nature and often include enforcement mechanisms, it remains at the discretion of sovereign states whether they choose to become a party to (and to ratify) certain conditions within them. Also, even after state ratification, international environmental law is generally based on a state's compliance with, rather than enforcement of, conventions.

3.2. EU legislation

The five directives that are most directly relevant for offshore oil and gas infrastructure decommissioning are summarised below. The only Directive that directly addresses decommissioning of offshore oil and gas structures is the Offshore Safety Directive (OSD). It requires that all major hazards through the lifecycle of the asset are identified and managed so that the risk from operations is 'as low as reasonably practicable' (ALARP), which includes major hazards arising during decommissioning. However, the OSD only considers major hazards to safety and, once the facilities are removed, or decommissioned, the OSD ceases to apply. Thus, the OSD applies to decommissioning up to the point that the safety risk is removed and does not address the long-term risks to the environment, or the monitoring of assets left in situ, following decommissioning. The OSD requires that licence holders demonstrate sufficient financial resources to remediate potential consequences resulting from their assets and operations, including in decommissioning. However, it does not consider events following decommissioning.

In terms of any long-term environmental impact as needs to be considered for the leave in-situ options in Table 9, the Environmental Liability Directive and the Environmental Impact Assessment Directive are the most relevant. The latter governs the framework for assessing different decommissioning options and the former covers any on-going liability, though this is not well-defined in the long term when the original operator and hence potential 'polluter' may no longer exist (e.g. due to bankruptcy or liquidation). Summaries of the relevant EU directives are represented below (see **Appendix A** for further details).

Table 5 Overview of relevant EU legislation

Offshore Safety Directive (OSD)

- Sets requirement for safe decommissioning.
- Licence transfer process requires sufficient funds to cover cost of decommissioning.
- Licensees are financially liable for major event mitigation & remediation, but the Directive is not explicit about post-decommissioning events.
- It does not address long term liability.

Marine Strategy Framework Directive (MSFD)

- Requires protection and restoring, with ultimately the prevention of risks to marine biodiversity, marine ecosystems, human health or legitimate uses of the sea.
- Requirement of monitoring and assessment of all human activities on the marine environment, to ensure Good Environmental Status is achieved.
- Assessment of impacts from offshore installations to be taken into account in the establishment of environmental targets and related indicators.

Environmental Impact Assessment (EIA) Directive

- Requires assessment of projects that are likely to have a significant effect on the environment before they are approved (including decommissioning). Screening is required all Annex II projects.
- Monitoring post-decommissioning is required, reflecting the severity of the risk.
- Stakeholders have the opportunity to react on any proposed project subject to EIA. Public authority duly considers the results of the consultation.
- License holder is responsible for the decommissioning process, for the preparation of the EIA report and carrying out public consultation. Authorisation of the project is up to the Competent Authority.

Waste Framework Directive (WFD)

- Establishes waste hierarchy and management of waste streams and requires its application.
- All waste management costs are borne by the original or current waste producer.

Environment Liability Directive (ELD)

- Objective is to prevent and remedy environmental damage, following the 'polluter pays' principle.
- Covers elements relevant to the process of decommissioning, but not any long term issues e.g. wells after being P&Aed.
- Operators bear cost of environmental damage.
- ELD requirement to conserve species may be at conflict with Regional Sea requirements removal obligations

Based on the research carried out into the relevant EU instruments, an overview of coverage of different decommissioning aspects is presented in the table below.

Table 6 Overview of coverage of different decommissioning aspects under EU law

Decommissioning Aspect	Coverage under EU Law
Long-term liability	**ELD:** Operators must bear all costs of environmental risks resulting from activities under Annex III.
Financial capacity of operators to cover decommissioning costs	**OSD:** license can only be awarded if the applicant has sufficient financial capacities to cover liabilities arising from decommissioning up to the point of the end of the decommissioning activity offshore.
Monitoring	**EIA Directive:** monitoring of environmental hazards or risks that occur post-decommissioning is required reflecting the severity of the risk. The same applies to (decommissioned) wells; if there is a significant adverse effect on the environment.
Transparency on decommissioning options	**EIA Directive:** the public has the opportunity to express its opinion on any proposed project. Public authority duly considers the results of the consultation.
Environmental Impact Assessment (EIA)	**EIA Directive**: EIA is mandatory for projects where there is a significant effect on the environment (all Annex I projects and Annex II projects for which it is determined that these would have such effects). Whether an EIA is to be undertaken for decommissioning will depend on the scope of the initial project and the works necessary for the decommissioning.
Comparative Assessment (CA)[6]	Not in place.
Re-use/re-purposing	Not in place in relation to decommissioning. **WFD** requires the application of the waste hierarchy.

3.3. National legislation

Appendix B details national legislation and regulation relevant to decommissioning of offshore oil and gas installations in EU Member States, the UK and Norway.

Table 7 below summarises the legislative framework for each country in Europe with a larger oil and gas industry and how eight key decommissioning regulatory factors are covered in the concerned national legislation, including national implementation of the relevant EU legislation.

The overview for the EU-countries with a smaller offshore oil and gas industry in

Table 8, does not provide the same detail as for these countries, provisions regarding re-use, long term operator financial capacity and monitoring requirements are either not in place, or unclear. Implementation of the above mentioned international and regional regulation is less universal in these countries too.

[6] Comparative Assessment (CA) is a method used by the offshore oil and gas industry to examine feasible decommissioning options and identify the optimum option by evaluating against criteria: safety, environmental, socio-economic, technical feasibility and cost. For a further explanation please refer to section D.2.2

Table 7 Regulatory framework in Norway, UK and EU-Member States with large offshore oil and gas industry

Parameter	United Kingdom	Norway	The Netherlands	Denmark	Italy
Primary legislation (EIA covered below)	• Petroleum Act 1998; and • Energy Act 2016.	• Petroleum Act; and • Petroleum Regulation	• Mining Act.	• Subsoil Act; • IMO Resolution A.672; and • OSPAR Decision 98/3.	• The basis is formed by applicable EU law; and • Legislative Decree.
Regulator	• OGA / BEIS-OPRED.	• Ministry of Petroleum and Energy.	• Ministry of Economic Affairs and Climate (MEA).	• Danish Energy Agency under the Ministry of Energy, Utilities and Climate	• Ministry of Economic Development and Environment.
Long Term Liability	• In perpetuity on S.29 (licence) holder (including damage or inconvenience caused either wilfully or inadvertently by abandoned facilities, and conditions extending beyond decommissioning itself); and • Unclear arrangement if licensee defaults.	• Some liability provision in place; and • Unclear arrangement if licensee defaults.	• Not (yet) in place; the Mining Act is undergoing an amendment; and • Liability under private law for damage caused by the outflow of minerals during five years after abandonment.	• Financial liability for licence holders for any damages, losses or injuries caused; and • Unclear arrangement if licensee defaults.	• Not in place.
Operator Financial Capacity for Decommissioning (in all countries financial liability post-decommissioning is unclear)	• OGA collates data; • Security Arrangements; and • Petroleum Tax relief on decom	• Requirement to provide proof of financial security for the fulfilment of decommissioning obligations; and • Insurance requirement, including to cover decommissioning-related damages.	• A licensee can be required to provide proof of financial security to MEA.	• Financial capacity assessed at the application for exploration stage.	• Decommissioning financial guarantee is required (e.g. in a form of an insurance or bank guarantees).
Monitoring	(also considered in Section 4) • Schedule for future monitoring included in the close-out report; and • No formal post P&A survey schedule for abandoned wells	• Operators must conduct a survey of the seabed after decommissioning; and • No monitoring requirements of abandoned installations.	• Full removal of all structures; and • Regular inspection of abandoned pipelines and cables.	• Not in place.	• Mandatory for 6 months after decommissioning.
Transparency on decommissioning options	• Public consultation; • OPRED led; and	• Public consultation; • Relevant reports are made available to the public; and • Parliamentary approval of derogation.	• Not in place; and • Decommissioning projects are evaluated by MEA.	• Not in place in relation to decommissioning options.	• Not in place.

Parameter	United Kingdom	Norway	The Netherlands	Denmark	Italy
	• Relevant reports are made available to the public.				
Environmental Impact Assessment (EIA)	• The proposed decommissioning programme must include an environmental appraisal.	• Mandatory EIA.	• EIA is required only for projects within the territorial sea (not required within the EEZ).	• Based on Decommissioning Plan and decided on case-to-case basis.	• Carried out by the Ministry of Environment, based on information provided by operators.
Comparative Assessment (CA)	• Comparison of potential options in EIA.	• Disposal Plan to include CA of options.	• CA for pipelines only or when installation is not fully removed.	• Not in place.	• Not in place.
Re-use / Re-purposing	• Not addressed in legislation; and • OGA can advise on re-use possibilities	• Not addressed in legislation.	• Tax incentives; and • Evaluation on case-to-case basis.	• Not addressed in legislation.	• Operators can submit a proposal.

Table 8: Regulatory framework in EU-Member States with a smaller offshore oil and gas industry

Parameter	Croatia	Spain	Romania	Germany	Ireland	Greece	Poland
Legislation	• Hydrocarbon Act; and • Follows Barcelona Convention, OSPAR practices.	• Law 34/1998; and • Follows OSPAR Decision 98/3 and Barcelona Convention.	• 256/2018 Offshore Law.	• Federal Mining Act 1980; and • Follows OSPAR Decision 98/3.	• Petroleum Act 1960; and • Follows OSPAR Decision 98/3.	• No specific legislation; and • Follows Barcelona Convention.	• No specific legislation; and • Follows Helsinki Convention.
Regulator	• Hydrocarbons Agency (CRA).	• Ministry of Energy (MoE).	• Competent Authority for Regulating Offshore Petroleum Operations (CAROPO).	• Federal Ministry for Economic Affairs (BMWI); and • Authority for Mining, Energy and Geology (LBEG).	• Commission for Regulation of Utilities (CRU).	• Hellenic Hydrocarbon Resource Management (HHRM).	• Ministry of the Environment (MoE).

3.4. Strengths and weaknesses of the current legal framework

In the following section the strengths and weaknesses of existing relevant legislation are assessed based on its scope and extent of coverage, in other words based on the extent to which major decommissioning aspects are addressed in legislation. Based on the analysis a list of potential areas for improvement will be presented (see section 3.5) that can be addressed by a revised and/or newly introduced EU directive (discussed in the following sections of the report).

The first aspect related to decommissioning and the extent of its coverage under the different legal regimes to be addressed is **long-term liability** for licence holders in the post-decommissioning phase. In Member States and third countries with large offshore oil and gas industries legal provisions addressing this are, to some extent, in place, i.e. in the UK, Norway, Denmark and under development in the Netherlands. Similarly, under EU law, the Environmental Liability Directive, Operators have to bear all costs of environmental risks resulting from activities under Annex III (strict liability). For all other activities, liability is fault-based. However, this only applies to defined entities. The Offshore Safety Directive is focussed on the initial phase of decommissioning an asset[7], up until it is removed (or the major hazards to safety are eliminated, and so does not cover long term liabilities in the post-decommissioning period. In general, national as well as EU and international provisions focus on liability resulting from damage caused; the major legislative shortcoming regarding this aspect is that it is not clear what the arrangements are if the original licence holder ceases to exist.

Secondly, in all Member States and other European countries with large offshore oil and gas industries legal provisions exist that require that operators should have the **financial capacity to cover decommissioning costs**. Similarly, in the EU the Offshore Safety Directive prescribes that a project can only be approved if the relevant authority has compelling evidence that the applicant has sufficient financial capacities to cover liabilities arising from decommissioning up to the point of the end of the decommissioning activity offshore. As such, the requirement for operators to have financial capacity is well established in legislation. However, similarly to the above, financial liability in the post-decommissioning phase is not explicitly addressed in any of the analysed legislation.

Another aspect to consider is **monitoring of decommissioned installations**. In most concerned Member States and non-EU countries the legislation addressing this aspect is not very comprehensive. In some cases (e.g. Italy), monitoring of decommissioned installations is required for 6 months after the decommissioning phases closes while in Denmark or Norway there is no such monitoring requirement in place. The OSD does not address long term monitoring following removal of major hazards. However, under EU legislation (EIA Directive), monitoring of environmental hazards is required depending on the severity of the risk and, although not explicit for oil and gas infrastructure in the post-decommissioning phase, the EIA Directive is applicable in this context. The same approach applies to sealed wells; monitoring is required only if there is a risk of a significant adverse effect on the environment. As such, this decommissioning aspect seems not adequately covered in any of the legislation analysed.

An **Environmental Impact Assessment (EIA)** for decommissioning projects is covered by EU legislation (EIA Directive). EIA is mandatory for projects where there is a significant effect on the environment (all Annex I projects and Annex II projects for which it is determined that these would have such effects).

Comparative Assessment (CA), the method used by the offshore oil and gas industry to examine feasible decommissioning options and identify the optimum option by evaluating against several criteria (safety, environmental, socio-economic, technical feasibility and cost), is not addressed under EU legislation. For a further explanation of CA refer to section D.2.2.

[7] COM (2020) 732 Final – Report from the Commission to the European Parliament, the Council and the European Economic and Social Committee Assessing the Implementation of Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on the Safety of Offshore Oil and Gas Operations and Amending Directive 2004/35/EC/

To some (limited) extent, this decommissioning aspect is addressed in some Member States' national legislation. For example, in the Netherlands a legal provision exists that requires a comparative assessment for pipelines. However, there are no minimum requirements in place at EU level in relation to comparative assessments and as such, Member States are at liberty to establish their national requirements.

None of the analysed national legal frameworks of relevant Member States and third countries do have comprehensive legislation in place in relation to potential **re-purposing of structures identified for decommissioning**. While in some cases this can be done (e.g. in Denmark, the subsea reservoir the Nine West was certified as feasible for the storage of CO2 in November 2020) or tax incentives exist to do so (in the Netherlands), there are no legislative obligations to consider this option. In the EU, the Waste Framework Directive requires the application of the waste hierarchy, however no specific requirements exist in relation to decommissioning of offshore installations.

The next aspect considered is the extent to which adequate **legislation is in place in relation to infrastructures left in situ** (e.g. mattresses, wells and pipelines). In the Netherlands, specific standards on abandonment of wells and removal of pipelines have been introduced. Furthermore, in cases of abandoned pipelines and cables it is required that these are regularly monitored. Similarly, in Denmark there are standards in place for decommissioning of wells and requirement of a CA and case-by-case consideration for pipeline removal / leaving in situ decision. In Italy, closure of wells is regulated by the Presidential Decree of 24 May 1979 no. 886, which mandates the removal below the seabed of the lining column, the intermediate columns and the production column, by cutting and recovery. However, there are currently no standardised rules and/or guidelines at EU level in relation to the part of the offshore installation that is (or can be) left in situ. Even though there is a requirement stemming from international law (OSPAR Convention) that full removal of unused floating and fixed installations (except pipelines) is expected unless a derogation can be granted, issued on a case by case basis. Nevertheless, the OSPAR Convention does not have a comprehensive scope; not all EU Member States with offshore oil and gas industries are subject to its requirement.

The last aspect to consider is **transparency and public participation** on decommissioning options. Such requirement is only in place under national legislation in non-EU Member States with large offshore oil and gas infrastructures (i.e. in UK and Norway). In relevant Member States (i.e. the Netherlands, Denmark and Italy) no such requirement is in place in relation to decommissioning projects. In EU legislation, the requirement for transparency and public participation is closely connected to the requirements of the EIA Directive, which prescribes that the public has the opportunity to express its opinion on any proposed project subject to EIA. Public authority duly considers the results of the consultation. However, whether an EIA is to be undertaken for decommissioning will depend on the scope of the initial project and the works necessary for the decommissioning. Therefore, in some cases where an EIA is not undertaken in relation to the decommissioning phase, it is possible that there is no public participation requirement established by EU legislation.

3.5. Potential areas for improvement of the regulatory framework

The above overview and analysis show that national legislation in some Member States is, in some cases, further developed than applicable EU legislation and national legislation in Member States with a smaller oil and gas industry, and in some cases there is no adequate legislation in place. Therefore, potential areas that could be considered for improvement, for example through an introduction and/or revision of an EU directive (discussed in the following chapters), are:

- EU to encourage **consideration of offshore oil and gas infrastructure re-purposing**;
- Clarity on the **long-term liability for wells and for infrastructure that is left in-situ**. For decommissioned wells, licence holders have to survey the well locations on completion of decommissioning, but there are limited formal requirements on the frequency of post-decommissioning surveys. For jackets and foundations, the number that will be left in the EU is very low. However, there will be several thousand kilometres of pipelines left in-situ in a variety of environments; deep-water, shallow water, estuarine, inter-tidal, areas of dynamic sea-bed, within fishing grounds and in designated environmentally sensitive areas, and both buried (or trenched) and laid on the seabed. A large number of wells have also to be decommissioned and, although each one has a very low possibility of leaking, the total risk of a decommissioned well leaking into the sea in the long-term is higher;
- Establishment of **minimum requirements with regards to monitoring** of decommissioned offshore installations (sealed wells and material left in-situ if any). The OSD requires operators of installations to submit an amended Report of Major Hazards to the competent authority for approval. This must address all aspects of decommissioning, but once decommissioning is complete, the OSD ceases to apply, and there is no provision for long term monitoring or treatment of environmental hazards in the post-decommissioning period;
- Establishment of **minimum requirements in relation to comparative assessments** of decommissioning options;
- Clarity on **derogations for infrastructures to be left in situ**, e.g. by aligning EU requirements to those of the OSPAR Convention to ensure a level playing field across the EU; and
- Establishment of **minimum requirements regarding stakeholder consultation and transparency**.

4. Environmental Impact of offshore oil and gas infrastructure Decommissioning

4.1. Infrastructure left in-situ

Once best endeavours have been made to remove remaining hazardous material, there is still the potential for long-term environmental impact from any infrastructure that is left in-situ, which may include jackets (below a certain depth), GBS and their remaining contents, drill cuttings, pipelines and mattresses. The potential environmental impact of each of these is shown in the table below. For steel structures that are removed, there is also the positive aspect of recycling and related employment. For all infrastructure types, removal can have a local temporary negative environmental impact and potentially remove a local biosystem based around the infrastructure.

Table 9: Long term impact of infrastructure left in-situ

Infrastructure	Quantity in EU	What is left in-situ?	Current Best Practice	Long-term Environmental Impact of leaving in-situ	Other Options
Facility Topsides	Many	Fully removed.	Removal by SLV, HLV, using single lift, reverse installation, modular removal or piece-small removal.	-	Re-use in oil and gas application. Re-purposing for alternative offshore use.
Steel Substructure (non-derogable)			Removal by SLV, HLV, using single lift or reverse installation.		
Floating Structures			Removal on thrusters / by tow.		
Subsea Structures			Removal by SSCV / CSV using reverse installation.		None
Wells	Many	Sealed subsurface wellbore.	Establish barriers at reservoir, zones of flow potential and an environmental cap. Well Decommissioning Guidelines, Issue 6, OGUK.	Potential failure of sealing system and leak of reservoir contents to the environment. Potential for long duration release while well is redrilled and leak location identified and sealed. Magnitude dependent on reservoir re-charge potential.	None
Steel Sub-structure (derogable)	Zero	Upper section is removed leaving lower part of jacket, or footings. Minimum depth of removal is to -55m LAT.	Remove top section to -55m LAT. IMO Guidance on Removal of Offshore Oil and Gas Structures. OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations.	Minimal. Impact on local fishing due to snagging. Exclusion of fishing operations in area surrounding jacket foundations.	Remove to deepest depth possible with available technology. Full removal.
Gravity Based Structures (GBS)	Netherlands (1) Denmark (1)	The whole GBS, which is then monitored.	Leave in situ. OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations.	Minimal, though see below for the GBS contents. Impact on local fishing due to snagging and exclusion of fishing operations in area surrounding jacket foundations.	Full removal of GBS. Removal of GBS legs only.
GBS Cell Contents	As above (contents are mainly ballast).	Hazardous materials are removed but difficult to remove it all.	Clean and flush cells or leave contents in-situ based on findings of a Comparative Assessment.	As the cell degrades it will gradually leak and slowly release contaminants into the sea with an impact on the local area.	Cleaning of GBS and removal of hazardous waste. Full removal of cell (and GBS).

Infrastructure	Quantity in EU	What is left in-situ?	Current Best Practice	Long-term Environmental Impact of leaving in-situ	Other Options
Drill Cuttings	Many	Cuttings left in place unless need to be disturbed to remove the jacket.	Leave in situ unless disturbed to remove jacket based on findings of a Comparative Assessment. OSPAR Recommendation 2006/05.	Potential for oil to seep from the cuttings.	Removal, which may have a greater environmental impact.
Pipelines	Many	Pipeline left in-situ and filled with inhibited water.	Buried and trenched sections left in situ. Exposed sections removed or covered with rock. Small diameter pipe and umbilicals removed based on findings of a Comparative Assessment. Netherlands completed a single CA for all pipelines on DCS to which individual decommissioning projects refer.	Potential for small amounts of oil, or other contaminants to seep into the environment once pipeline degrades, but at a level most likely well below that permitted in produced water in production operations.	
Mattresses	Many	Left in-situ if the pipelines they protect are left.	Buried mattresses are left in situ, exposed mattresses are removed unless it is not safe to do so or required to maintain stability of pipeline left in situ. Generally, based on findings of a Comparative Assessment.	Possible plastic from the material that holds the mats together. Potential snagging risk to fishing nets if exposed.	

Topsides and subsea structures (being relatively small) are not considered here as they are always removed and likewise floating structures as they can be reused (usually after modification). Removal of subsea structures can impact the local environment temporarily with some methods being less intrusive than others.

Note that **all concrete GBSs decommissioned to date have been derogated with some infrastructure left in situ.**

4.2. Wells

To decommission an offshore oil or gas field, all wells are plugged and abandoned (P&A). From the well, materials such as production tubing are returned to shore for waste processing and recycling via established processes. Well P&A isolates the reservoir from the marine environment through the placement of two or more cement barriers in the well bore. In the short to medium term, this can be demonstrated to provide isolation. **However, the long-term integrity (in terms of the 'in perpetuity' requirement) of well P&A barriers is not proven**. Monitoring of the barrier condition in the long term is not realistic with current technology as this would require the intermediate barriers to be breached, and thus failure may only be detected when a release to the marine environment is detected. Intervention to repair a leaking well would be technically challenging, time consuming and expensive.

There is no internationally agreed standard for well P&A. In the North Sea, individual countries have differing standards and, in an effort to align them, the North Sea Offshore Authorities Forum (NSOAF) tried to initiate development of common practices for wells decommissioning.[8] The main findings were "*that the goal setting regulatory requirements are quite similar in each of the NSOAF countries. However, the prescriptive regulatory requirements and related*

[8] Working together to come to a common standard on well decommissioning, State Supervision of Mines, The Netherlands https://irfoffshoresafety.com/wp-content/uploads/2018/10/2018-October-The-Netherlands-NSOAF-initiative-for-a-common-standard-for-well-decommissioning.pdf

National Standards contain significant inconsistencies on the criteria for well decommissioning barriers". It concluded that substantial benefits could be achieved by minimising or preferably eliminating inconsistencies and recommended alignment of P&A guidelines/standards within the NSOAF territory.

4.3. Environmental assessment

Environmental Assessment (EA) is a mature process to assess the environmental impact of a project and, as part of this, in considering whether to leave offshore oil or gas infrastructure in-situ, a comparative assessment (CA) between the full removal option(s) and the leave in situ-option(s) is carried out. The assessment should enable a reasoned judgement on the practicability of each disposal option and that the determination should be supported by suitable data, evidence and arguments.

The assessment should consider the potential impacts of the proposed disposal of the installation on the environment and on other legitimate users of the sea. The assessment shall also consider the practical availability of re-use, recycling and disposal options for the decommissioning of the installation.

4.3.1. Comparative Assessment Process

The comparative assessment (CA) process is applied in decommissioning programmes where infrastructure is proposed to be left in-situ including:

- fixed sub-structures conforming to derogation criteria in OSPAR Decision 98/3; and
- drill cutting piles and pipelines that are candidates for in situ decommissioning as described in national petroleum legislation.

The purpose of the CA is to compare options, examine if there are real differences between them, and identify the 'most preferred' option. The CA should provide evidence and reasoning that demonstrates that leaving in situ is a preferable option to that of complete removal when the; Environment, Safety, Social Impact, Engineering Feasibility, and Economics are considered through a set of "value criteria". The criteria are further divided into sub-criteria that the comparative assessment, or supporting technical assessments, should assess as follows:

Safety	Risk to personnel
	Risk to other users of the sea
	Risk to those on land
Environmental	Marine impacts
	Other environmental compartments (including emissions to the atmosphere)
	Energy / Resource consumption
	Other environmental consequences (including cumulative effects)
Technical	Risk of major project failure
Societal	Fisheries impacts
	Amenities
	Communities
Economic	Cost estimates

The criteria (main criteria and sub-criteria) used in the comparative assessment need to be carefully defined to avoid inconsistency and misunderstanding. The means of assessing each criterion may also be specified, as part of the criterion definition. Defining a good set of criteria is one of the most important steps. The set of criteria should be:

- Complete, non-overlapping and assessable;
- Cover all of the objectives of the stakeholders; all aspects of the options that stakeholders consider important when making the decision;
- Different and independent, to avoid double counting;
- Possible to assess the options against the criteria, using either data or expert judgement; and
- Relative assessments may be possible at the time of the decision, not requiring that an option be implemented before its impact can be assessed.

Three evaluation methods are generally considered.

- Method A - Narrative / Red- Amber- Green Indication;
- Method B - Narrative + Scoring; and
- Method C - Narrative + Scoring + Weighting.

The methods become increasingly more quantitative, but all draw upon some qualitative assessment, or valued judgement, in the decision-making process, particularly when drawing comparisons between evaluation criteria. This could be achieved through use of facilitated workshops.

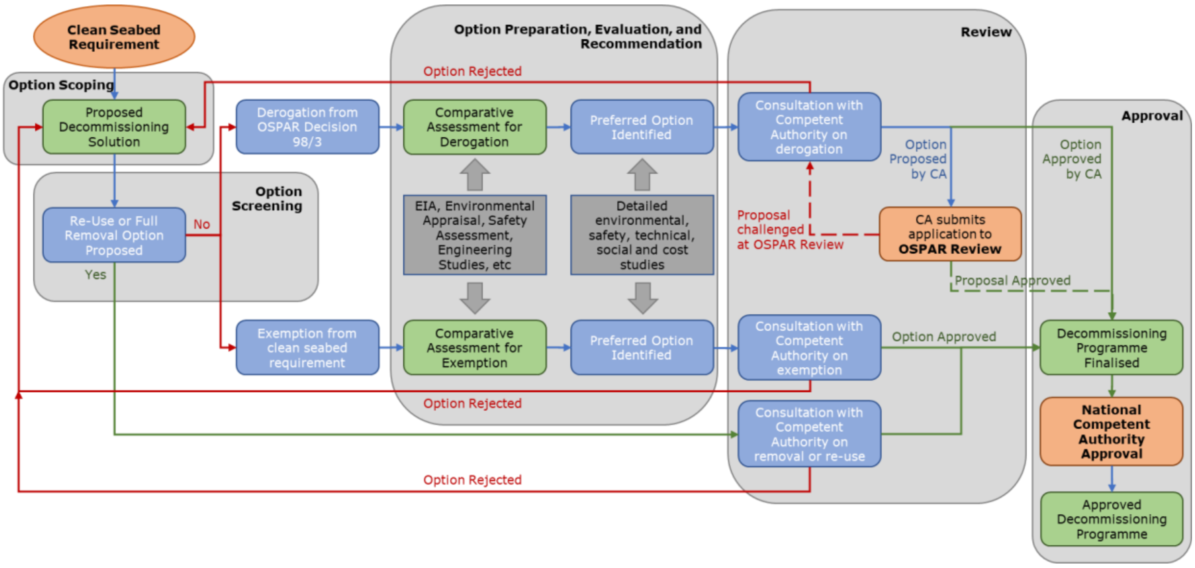
Regardless of the evaluation method adopted, it is unlikely that the CA and the chosen evaluation method will satisfy all stakeholders. Therefore when evaluating options against criteria and sub-criteria it is important that workshop attendees are presented with technical data supported by knowledge of the options and their differentiators, and the evaluation should be performed or supported by technical / subject matter experts who are both familiar with the assets being considered and the decommissioning methods being assessed. Pros and Cons of each method are presented below:

Evaluation Method	Description	Pros	Cons
A: **Narrative / Red-Amber- Green**	Evaluation Method A is a qualitative assessment, utilising broad assumptions regarding comparisons across each decommissioning option, with a focus on key and significant differentiators. The assessment is carried out using supporting evidence, such as comparison of activity type, vessel types and numbers, vessel duration on station, weight of recovered materials across the options. Results are categorised as Red (least preferred), Amber (moderate) and Green (most preferred). It is applied to most pipeline CA and initial assessment of simple installation derogation cases, or where there is a previous project which sets a precedent.	Least amount of effort and preparation Scales and thresholds are described by a narrative only and can be understood by non-engineering stakeholders. Used for simple CA where differentiators between options are clear and trade-offs can be articulated by narrative.	Regarded as too subjective by some stakeholders as all assessments across criteria are based on high level, qualitative assessment. It is difficult to compare across different sub-criteria as scales and thresholds adopted will not be directly comparable across different criteria. Does not suit the application of weighting across criteria. Evaluation results will need to be justified and explained by the narrative.
B: **Narrative + Scoring**	Method B uses a combination of qualitative and quantitative raw data. However, it is still very subjective and a scoring mechanism or scale is developed to enable the differentiators between the options across the criteria to be rationalised and compared. Scores/ numbers are applied instead of the RAG approach of Method A, with a colour coding applied to emphasize key results in the assessment.	Supporting evidence, both qualitative and quantitative, can be referenced from existing studies and decommissioning programmes. The process can rationalise scores across evaluation criteria and produce better definition of differences between options than Method A. May also be used as a pre-screening tool with areas that cannot be differentiated identified for assessment by Method C.	The combination of quantitative and qualitative metrics in the assessment requires more supporting studies to be carried out to define metrics. The use of scores/ numbers can imply a false sense of accuracy, for what still remains a subjective assessment. Scoring basis will still require to be justified and explained by narrative as in evaluation method A.
C: **Narrative + Scoring** **+ Weighting**	Method C combines criteria with qualitative judgement and quantitative data. Scoring of option criteria is applied as in Method B, but introduces weightings to the criteria, to allow an overall score to be derived for each option.	The method makes explicit the assumptions underlying each criteria/sub-criteria and assigns a weight to them. It allows scenario/sensitivity analysis to be performed to test the options selected. Most transparent of the Methods when adequately described.	Significant additional effort required to produce results, weightings and multi-criteria decision analysis models. Judgements and assumptions are explicit and open to potential challenge. May give a false sense of accuracy as still dependent on accuracy of raw data used to inform the process. Weighting basis and scores will still require to be justified and explained by narrative – generally, in greater detail than the Methods A and B.

The CA method and the value criteria are generally developed by the derogation applicant, usually the operator of the oil or gas field, and submitted to the national Competent Authority for review and distribution to other statutory consultees and stakeholders at a national level, such as governmental maritime and marine authorities, environmental and ecological authorities, fisherman's associations, recreational diving associations, and NGOs with and interest in oil and gas exploration, development and decommissioning.

Once approved at national level, the CA informs the Decommissioning Plan and Programme for the field and assets. The derogation application is then issued to the OSPAR Offshore Industry Committee (OIC) with the recommendation for derogation by the Competent Authority of the nation concerned. The OIC can then review the application and recommendation and approve, or challenge the decision and recommend improvements to the application to the national Competent Authority. However, it remains the responsibility of the national Competent Authority to make the final decision and the application.

Figure 1: Comparative Assessment Process Overview



The Comparative Assessment process is divided into scoping, screening, preparation, evaluation, recommendation, review and approval phases.

Scoping

During scoping the full scope and boundaries of the Comparative Assessment are defined; including definition of the assets, the options being assessed and the decision-making process. Only facilities for which derogation is sought are included in the Comparative Assessment process, which may include (parts of) fixed installations, pipelines and, sub-sea infrastructure and equipment.

OSPAR Decision 98/3 requires complete removal of all installations. Therefore, the Comparative Assessment scoping phase considers a range of "complete removal" options, and at least one complete removal option follows the full Comparative Assessment screening and evaluation process.

An initial assessment to identify the criteria and sub-criteria to be adopted in the Comparative Assessment is completed to inform the level and type of supporting studies required. The suitability of these criteria may need to be revisited at later stages of the process as data, information and feedback are collated and evaluated. The five main criteria to be considered are: Safety, Environmental, Socio-Economic, Technical Feasibility and Economics. These may be divided into discrete sub-criteria as required to aid option assessment.

The decision-making process should be established including: the aims of the process, how results will be used, the evaluation method(s) to be adopted, etc. It should be agreed with key stakeholders before moving to the screening phase

Screening

The screening phase reviews and screens out non-viable or marginal options from the Comparative Assessment. Operators may apply their own coarse screening criteria, or adopt a process from best practice guidance, where available. The reasons for removing any options should be documented in a screening report, which provides a list of technically feasible options for more detailed review in the preparation and evaluation phases. For derogation candidates, a full removal option must be considered.

For derogation candidates, the OSPAR framework requires consideration of the following options for all, or part, of the installation: re-use, recycling, final disposal on land, and options for disposal at sea.

Preparation

The preparation phase examines in more detail the decommissioning options from the screening phase. It covers the development of supporting studies or method statements to be used in the evaluation phase. Terms of Reference (ToR) for the Comparative Assessment are developed and include: decommissioning options and methods, the extent of the comparative assessment, the evaluation process, potential criteria and sub-criteria to be used, the stakeholders and their roles, the decision making process, what data is required to allow option evaluation and any supporting studies required to gather data.

Gap analysis, based on the deliverables anticipated and the data available, is completed to identify potential gaps in data and to inform scoping of supporting studies and the evaluation phase of the comparative assessment.

Evaluation

The evaluation phase executes the assessment of different options against the agreed criteria and sub-criteria using a selected evaluation method. The evaluation process may take different forms depending on the complexity of the decommissioning options, stakeholder expectations, project/ company requirements, etc.

There are three suggested evaluation methods:

A. Narrative + ‘Red – Amber - Green’ qualitative assessment;
B. Narrative + qualitative scoring + visualisation; and
C. Narrative + semi-quantitative scoring and weighting.

Evaluation methods A through to C become more complex. Data used to support the evaluation method may be qualitative or quantitative. It may be that the evaluation process requires further data gathering and analysis not envisaged in earlier stages.

Recommendation

The Comparative Assessment report includes discussion on the preferred decommissioning option and, for the principal items in the Comparative Assessment, declare whether a derogation is sought or complete removal is preferred. Any recommendation(s) reported must be clear and unambiguous, with a discussion and evaluation of each option against each criterion and sub-criterion.

The Comparative Assessment does not need to specify the detail of the final removal or recovery method at the completion of the Comparative Assessment process, but the general approach should be defined.

Review and Approval

The proposed recommendations from the Comparative Assessment must be agreed by all stakeholders involved in the process prior to finalisation and publication. This includes any independent experts involved in the review and verification of the selected decommissioning option for any derogation candidates. Regulatory authorities are also consulted and made aware of the preliminary conclusions of the Comparative Assessment so that their response can be evaluated prior to final submission.

Although there is no formal requirement to submit the Comparative Assessment report to the regulator, the details of the decommissioning option proposed must be reported clearly in the final decommissioning programme document.

Early submission of the Comparative Assessment can be used to simplify the explanation and justification in the decommissioning programme documentation and reduce the review and comment cycle when decommissioning programme is submitted.

For derogation candidates, once the decommissioning programme is agreed at national level between the applicant, Competent Authority and other statutory consultees to the derogation process, the programme is submitted by the Competent Authority to the OSPAR Offshore Industry Committee for consideration.

The OSPAR Offshore Industry Committee consider the derogation application and can make suggestions to the Competent Authority to improve the decommissioning proposal so that it aligns more closely with the principles of OSPAR Decision 98/3 and full removal, or approve the application.

Where a derogation application is initially rejected, the Competent Authority may decide to either address the concerns of the OSPAR Offshore Industry Committee through further discussion and assessment with the applicant or, should the Competent Authority consider the concerns to have no merit, approve the derogation application.

4.3.2. Strengths and Weaknesses of Comparative Assessment

The CA process as applied to the evaluation of potential decommissioning options has both strengths and weaknesses. It is recognised as an effective means of identifying data requirements and evaluating potential options for decommissioning and as an aide to the selection of a preferred option. However, shortcomings have been identified with the application of the process:

- A **lack of a common process** for CA across the EU can result in different approaches to evaluation of potential decommissioning options being applied by applicants, a lack of clarity and consistency in approach, and in the interpretation of results, quality of output, option selection and decision making by the applicant and competent authorities reviewing the decommissioning application and comparative assessment;
    - In the Netherlands, the Competent Authority has established multi-stakeholder forums, including oil and gas operators, industry bodies, regulators, government departments and non-governmental organisations. These forums have established the framework for the CA of common infrastructure items (e.g. pipelines) and the development of approved fit-for-purpose decommissioning solutions that the oil and gas industry can refer to and adopt - simplifying the decommissioning programme application and approval process.
- The selection and application of **evaluation criteria and their relative weightings** within the process, have led to observations that elements of bias can be introduced that guide the process toward a preferred option for decommissioning;

  - The licence holders are responsible for the development and consultation on the CA. They are guided by the Competent Authority, industry and regulatory guidance, and their own internal comparative assessment processes and procedures in development of the CA; and
  - Improved communications with a wider group of statutory consultees and their participation in early phase activities, such as scoping and establishing assessment criteria and weightings, and continued discussion may improve the process, though there is always significant room for debate in a qualitative method like a CA. A requirement to include uncertainty in the analysis such that it is shown that the same conclusion would be reached if reasonable changes in the input and method itself would be a more honest approach than considering that a good CA is always going to give them same result. Given that decommissioning is a politicised process, it would be analogous to expecting all good politicians to always give the same opinion as each other.
- **Lack of consultation** at each stage of the CA process;
  - There are statutory consultees that need to be informed and given the opportunity to be involved in the CA;
  - The derogation process is a two-stage process where the applicant first seeks approval from the national competent authority, through the presentation of a decommissioning programme that is fully supported by the CA and EIA;
  - The competent authority then presents the preferred approach to decommissioning and the rationale to the OSPAR Offshore Industry Committee members to seek their input and approval. The CA is not necessarily submitted in this latter process, as it has been accepted by the national Competent Authority, as such the OIC may not be fully informed when evaluating the decommissioning programme if the detail of the CA is not presented, or the OIC has not been involved in earlier stakeholder consultation;
  - Further, an objection by the OIC may be received once a decommissioning decision has been made or after a decommissioning stage has been completed that limits future action on infrastructure subject to the derogation process (such as removal of topsides, prior to submission of the sub-structure decommissioning programme);
  - Should the OIC object to the preferred decommissioning approach there is no dispute settlement mechanism that the OIC, national Competent Authority, or proposer, should follow; and
  - The inclusion of early and frequent consultation with a broader range of consultees and stakeholders, for example having discussion with statutory consultees before key milestones in the development of the Decommissioning Programme, could improve the review process by having those bodies involved in more regular reviews of the proposed decommissioning options and outcomes.
- It is extremely difficult to compare any **long-term impact** of leaving a structure in-situ **against the short-term impact** of its removal and CA conclusions are open to challenge. Furthermore, a specific option favoured by one group of stakeholders (e.g. fishermen) could be considered negatively by another group (e.g. residents living near an onshore dismantling facility).

As an example, the Shell Brent EIA was a very comprehensive environmental assessment, and was peer reviewed, but still contentious. Overall, the CA process involves subjective judgement, and even if the CA is peer reviewed, the outcome may still be challenged by parties that do not support the recommended decommissioning option.

4.4. Environmental monitoring

A post-decommissioning environmental survey may be required, particularly where infrastructure left in-situ needs to be monitored to assess its condition, its colonisation by marine life (including both native and non-native species), or the potential risk to fishing. Operators develop a survey strategy for this infrastructure and also wells, and it may entail multiple surveys, with the first being part of the decommissioning close-out process. The results of post-decommissioning monitoring surveys are submitted to the regulator, who will consider the need for further surveys.

Norway and the Netherlands define monitoring requirements in the short term, 6 and 5 years respectively, while the UK has a goal-setting regime where the licence holders propose a monitoring programme. However, many other countries have not yet developed preferred approaches for post-decommissioning monitoring.

4.5. Potential areas for improvement

Based on this analysis, potential areas to be considered for improvement are:

- **Minimum EU-wide well abandonment requirements;**
- **Minimum requirements for monitoring post decommissioning; and**
- **Changes to Comparative Assessments to improve their public acceptance.**

5. Best Practice in Decommissioning

5.1. Planning for Decommissioning

Cessation of Production occurs when continued production is no longer economically feasible. Planning for decommissioning should occur in advance of this, such that the time to transition from the end of production to the beginning of decommissioning is minimised and the duration of decommissioning is as short as practicable so as to be safe, efficient and environmentally responsible.

In the UK, a 'glidepath' philosophy has been developed by the OGA to assist licence holders in focussing on decommissioning during the late-life operating phase. It includes engaging with regulatory and competent authorities to ensure they have a clear decommissioning strategy three to six years in advance of production ending. Planning for decommissioning during the late-life stage will ensure that licence holders have flexibility to respond to early cessation of production should the need arise and be well placed to execute cost-efficient decommissioning.

5.2. Removal of Structures

It is a requirement of UNCLOS, IMO Guidelines and regional sea conventions, such as OSPAR Decision 98/3 and Barcelona, that oil and gas industry structures are completely removed, unless it is not practicable to do so. However, there are many methods by which this can be achieved, including:

- piece-small removal, where structures are cut into small sections offshore for return to shore for recycling or disposal;
- modular removal, where structures are cut into larger sections, or removed as separate modules, offshore for return to shore for recycling or disposal;
- reverse installation, where structures are removed in the reverse sequence that they were installed in; and
- single-lift, where structures such as topsides and jackets are removed in their entirety in one operation.

In practice a decommissioning operation will likely combine one or more of these methods to complete a removal, for example a bridge, flare structure, drilling facilities, or accommodation module may be removed as part of a modular removal or reverse installation phase, while the removal of the remaining integrated structure may then be achieved by a single lift.

There are no universal decision criteria to select a particular removal method and each installation has its own particular requirements and restrictions that will determine the final method(s) selected. Location constraints (sea conditions, environmental conditions, water depth, etc), structural design, and commercial terms can restrict options available to a licence holder. As examples:

- A larger capacity lift vessel was identified by an operator as a preferred option because the removal operation could be achieved with fewer major lifts and over a wider set of weather and sea states. However, the water depth at the location of the installation was insufficient to allow a larger unit with a deep draft to operate. The removal was then re-designed for a larger number of smaller lifts using a lower capacity lift vessel with a shallower draft; and
- A single lift was identified as the preferred method of removal of an installation topsides. However, structural calculations identified that the integrated cellar deck section could not support a single lift without significant underdeck structural strengthening. The

operator deemed that the risk to personnel executing the strengthening works, using rope access for extended periods in the harsh environment of the splash zone underdeck, was unacceptable and the removal operation was redesigned for modular removal of upper level modules and final removal by reverse installation of the integrated cellar deck.

5.3. Well Decommissioning

There is no internationally agreed legislation with regards to well decommissioning. Well decommissioning follows requirements produced by Member States and oil industry best practice. In many instances, licence holders and drilling contractors associate themselves with internationally recognized organizations, e.g. Norsk Sokkels Konkuranseposisjon (NORSOK) and Oil and Gas UK (OGUK), either partially or fully, when developing policies and procedures for well decommissioning. Industry standards and procedures produced are generally based on lessons learned, incidents and the introduction of new technologies and techniques.

A number of common aspects from Member States requirements are collated here as best practice themes for well decommissioning, as follows:

- A well decommissioning plan shall be submitted to review by a competent authority prior to the well decommissioning activity occurring;
- The well decommissioning shall achieve a permanent seal, such that no fluid flow to or from the well, or from any other zone of flow potential, is possible. As a minimum, permanent barriers shall be placed:
    - as a primary barrier, to isolate a source of inflow, formation with normal pressure or over-pressured/impermeable formation from the surface/seabed;
    - as a secondary barrier to the primary barrier against any source of inflow;
    - to prevent flow between formations; and
    - at the surface as an environmental barrier.
- The barrier shall be a cement or a mechanical/cement combination barrier, or any other verified barrier method that provides equivalent or greater sealing to a cement barrier;
- A surface environmental plug shall be set placed in the top section of the well;
- Independent verification of the permanent barriers through pressure testing;
- Removal of all casings at the seabed surface to a depth that eliminates the risk of snagging on the top of the well to other users of the sea; and
- Sample periodic monitoring of decommissioned wells shall be undertaken at a frequency based on mutual agreement between the licence holder and Member State competent authority.

5.4. Pipeline Decommissioning

There is no agreed best practice on the decommissioning of pipelines. However, a number of state-level regulations drive approaches to decommissioning of pipelines and these have a number of common features:

- Each pipeline shall have a decommissioning plan, considered either on an individual case–by–case basis, as a group of pipelines related to a wider field decommissioning, or as a specific class of pipelines for which a prescribed treatment option is agreed;

- A pipeline has the following disposal options: clean and leave in situ, burial/trenching, rock coverage, or removal. These options are subject to a CA process to determine the most appropriate solution;
- Pipelines need to be cleaned and flushed of hydrocarbon fluids. Cleanliness levels shall be agreed between the licence holder and competent authority and are based on reasonably achievable concentrations in water of target materials; and
- Leave in-situ is generally only refused if the pipeline presents a risk to other users of the sea, or may present a potential hazard to the environment by being left in place.

5.5. Identification and Classification of Decommissioning Costs

As decommissioning of offshore oil and gas structures becomes more common across EU Member States, it is important that the industry, Competent Authorities and other Governmental authorities understand their potential exposures to the costs of decommissioning. The OGUK has developed Guidelines on Decommissioning Cost Estimation that present a Work Breakdown Structure, which:

- provides a framework against which operators can develop comprehensive decommissioning cost estimates with a high degree of consistency;
- delivers a common basis for data assessment for collation and comparison of cross-industry information of decommissioning; and
- acts as a framework for benchmarking.

The framework consists of a series of project cost groupings that cover the potential decommissioning tasks:

1. Project Management

   Decommissioning is a complex engineering project that requires significant planning to be completed successfully, mobilising diverse resources from the licence holders and the specialist decommissioning supply chain. Efficient project management includes the delivery of regulatory submissions and execution of engineering studies required to support the decommissioning plan in the demonstration of best engineering and environmental options. The cost is normally proportional to the complexity of the assets to be decommissioned, however project management cost efficiency can be improved through the development of standardised processes within the operating company that are repeatable across the asset base to be decommissioned.

2. Post-CoP Running Costs

   Post-CoP Running Costs represent the ongoing costs of operating, manning and maintaining the infrastructure following CoP. To minimise costs post-CoP it is important to strive to minimise the duration that the asset is in place. This can be reduced through planning decommissioning in late life, in advance of CoP, and executing those activities that can be completed, or advanced, during the late life period of the asset. These may include early well decommissioning, preparation for removal, removal of redundant structures and equipment, installation of temporary equipment necessary for decommissioning, separation of structural elements, and optimisation of personnel levels. Once these activities are completed, the last activities are removing personnel from the installation and placing it into ‘cold suspension’ where only navigational aid systems are left functioning.

3. Well Decommissioning

   Well decommissioning represents the largest proportion of total decommissioning cost, usually between 40% and 60% of the total cost. Therefore, understanding in detail the well decommissioning requirements is essential to accurately estimate this significant cost element.

The proposed EU Guidance on Well Decommissioning will bring together the information required to accurately characterise the well in a well risk assessment; history, integrity issues, interventions, cement bond log quality, potential leak paths, that are necessary to estimate what effort is required, the number and location of barriers, and what alternative methods of decommissioning may be available, to successfully seal the well. This assessment will provide an indication of the activities and associated time and cost required to execute well decommissioning on a well-by-well basis and allow opportunities for identifying efficiencies in the well decommissioning programme, e.g. in the identification of high risk wells, the preparation of alternative decommissioning strategies, etc.

4. Facilities and Pipelines Permanent Isolation and Cleaning

   Facilities permanent isolation and cleaning generally follows establish operator procedures for shutdown, including depressurisation, drain, purge and vent of process lines and vessels, vessel entry, cleaning of vessels and pipework, isolation of open and closed drains, etc. As such, these operations and their sequence are familiar to operators and the cost element is reasonably well understood.

5. Topsides/Floating Unit Preparation

   Preparation activities are generally proportional to the integrity of the asset to be decommissioned, with those younger or better maintained structures generally requiring less resource allocation to this task. The chosen removal method can also impact the amount of preparation work required, with reverse installation, or modular removal, generally requiring less resource allocation than other methods. A key cost element is the amount of remedial work required below the lowest deck (usually a cellar deck), typically structural strengthening for removal, and separation of connections between the topsides and jacket. These operations generally require the deployment of rope access technicians and are sensitive to delays due to waiting on suitable weather and sea conditions.

6. Topsides/Floating Unit Removal

   Topsides and floating unit removals are particularly sensitive to external market costs, e.g. fluctuations in the availability of vessels and costs of mobilisation, transit, and time on-site performing the removals. Single Lift Vessels and Semi-Submersible Crane Vessels are generally the largest day rate costs for a decommissioning programme, therefore it is important for the operator to mitigate these risks, e.g. through a strategy covering multiple removals within a campaign, or establishing ‘removal windows’ in the decommissioning programme, which allows the removal contractor flexibility in scheduling the removal, and thereby reducing the day-rate cost of the vessel. For complex projects, the ‘removal window’ may be spread over a number of years to provide availability of the structure for the largest number of removal contractors and vessels possible.

7. Sub-structure Removal

   As with topsides removal, substructures are sensitive to external market costs, e.g. fluctuations in the availability of vessels and costs of mobilisation, transit, and time on-site performing the removals. Similar mitigation measures to topsides removal can be applied for sub-structures to reduce costs.

   Sub-structures to be left in-situ need to be appropriately marked to prevent interaction with other users of the sea and there is an ongoing cost for maintaining identification systems post-decommissioning.

8. Topsides and Sub-structure Onshore Disposal

   Disposal of topsides and sub-structures on shore is generally controlled by waste disposal and management regulations. The process follows norms around hazardous facility demolition and is typically accounted for in cost estimates on a cost-per-tonne basis. Contracting for disposal is generally included in the removal contractor scope of work for the removals.

9. Subsea Infrastructure

   Subsea structures such as wellhead protection frames, manifolds, exposed pipeline sections and spool structures are usually removed. Cost reduction opportunities are available to operators through deploying lower cost vessels such as anchor handling vessels and construction support vessels to perform removals of these structures, rather than bundling the removals within the topside/sub-structure removals contract.

10. Site Remediation

    Site remediation removes the final debris associated with oil and gas operations and demonstration that the structures left in-situ are suitably identified to other users of the sea. These operations are generally completed by construction support vessels following completion of the decommissioning activities and removal of assets from site.

11. Post-Decommissioning Monitoring

    As discussed above, allowance must be made for monitoring of the removal site(s) to demonstrate that the local environment has stabilised following the decommissioning project. This cost element only includes activities up to the completion of the decommissioning project close out report and not those long-term monitoring arrangements post-decommissioning.

The framework can be developed in parallel with the planning for decommissioning, with the level of definition improving as the project progresses through the life cycle. It provides the licence holders with current cost estimates for decommissioning and can form part of the licence holder's demonstration to the Competent Authority that there are sufficient financial resources to undertake decommissioning of the asset in question.

The UK guidelines have been adapted for use in other countries such as the Netherlands and as such are considered good practice.

5.5.1. Impact of Decommissioning Cost Estimates

Licence holders are required by financial accounting standards to provide reasonable estimation of asset decommissioning costs. Competent Authorities in countries with mature decommissioning processes are increasingly requiring operators to submit decommissioning cost estimates in order to gather benchmark data on key decommissioning programmes and cost metrics that allow the Competent Authority to set targets or focus on areas for improvement and investment in decommissioning to lower the overall decommissioning cost in the medium to long term.

6. Areas for potential improvement by EU measures

6.1. Methodology

From the preceding analysis of the physical situation and regulatory regime for decommissioning across Europe and consideration of the responses from consulted stakeholders, areas for potential improvement by EU-led or instigated measures have been identified. In addition to those areas, topics 6, 8 and 9 arise primarily from the feedback on the questionnaire with the need for (6) driven by EU Member States with smaller offshore oil and gas assets that would benefit from knowledge transfer and topics 8 and 9 being predominately industry issues.

This section describes potential measures to address the identified regulatory shortcomings and legislative, technical, environmental and economic challenges. For each shortcoming a number of suggested solutions have been identified which are qualitatively compared to the status quo. The areas for potential improvement are:

1. Minimum well abandonment requirements
2. Post-decommissioning long term monitoring of decommissioned oil and gas wells and structures left in-situ
3. Integration of re-use option into decommissioning programmes
4. Changes to Comparative Assessments to improve their public acceptance
5. Common EU Legislation for Removal Requirements for Decommissioned Oil and Gas Structures
6. Decommissioning Knowledge Transfer
7. Cost Provision for Long Term Decommissioning Liabilities
8. Post-decommissioning short term monitoring
9. Collaboration on Decommissioning Activities

Each of these areas is developed in the following tables with potential options for their development and implementation. Each of these options is assessed against criteria for:

Legislation:	how feasible is it that legal instruments can be enacted and enforced at EU level to implement the option?
Technical:	what technical issues surround the implementation of the option?
Environmental:	what benefits or disadvantages would the option entail to the environment?
Cost:	what are the implications of the option on the overall cost of decommissioning?

according to:

Negative for this option	Slightly negative for this option	Positive for this option	Neutral, or minor impact

and a judgement made as to which options are considered the most relevant to take forward to the impact analysis in Section 7. The options that are selected for further analysis are in **bold** text.

In addition to the above, the creation of an EU body to arbitrate between different parties should the result of a decommissioning EIA and CA be disputed has been considered. Such a body exists in the Water Framework Directive for resolving disputed transboundary effects. However, given the small number of platform structures in the EU that might remain in-situ, the difficulty any such body would have in coming to a conclusion and the legal issues associated with said EU body effectively having jurisdiction over a Member State, this is not considered appropriate.

6.2. Shortcomings with remedial options taken forward to impact assessment in Section 7

Topic 1: Minimum well abandonment requirements

Well decommissioning is the process of sealing the well such that the hydrocarbon bearing strata are sealed from other strata and cannot leak into the environment. The effectiveness of this is dependent on the amount and location of cement that is put in the well, and on the technical quality of the sealing. Well decommissioning requirements are currently developed by the oil and gas industry to align with requirements at Member State level within the EU. In the UK, Norway and Netherlands the requirements are mature, while some other Member States have not fully developed their requirements.

At 45 – 60% of total decommissioning project cost, well commissioning makes up the largest cost component. Those countries with mature decommissioning approaches have already achieved significant reduction in the time taken to decommission a well and its subsequent cost and have invested in technology that may provide alternative, affordable and reliable well decommissioning methods.

It would be advantageous for Member States that are beginning decommissioning activities, and with relatively few wells to decommission, to make use of these best practices through common abandonment guidance applied across the EU.

Option	Legislative	Technical	Environmental	Cost
Continue with individual Member State arrangements for well decommissioning (status quo).	Member States beginning to decommission will need to determine their well abandonment standards.	Differing approaches to well abandonment between MSs. EU has no direct impact on content of national standards.	Objective of all P&A methods is to permanently and reliably seal reservoir from external environment and differences have limited impact on environmental risk.	Cost of well abandonment is greater due to adapting to differing well requirements between MSs.
EU develops guidance for common well abandonment requirements.	EU OAG has the mandate to lead the development of an instrument such as a minimum well abandonment requirement.	Harmonisation likely to be readily achievable given broad commonality in well abandonment methods	Common approach provides the same standard of environmental protection across EU seas.	A well abandonment requirement based on industry best practice would result in well P&A cost reduction through the application of a common approach.
EU legislates for a Common Well Decommissioning Standard via a Directive.	Competency for development of well abandonment standard lies within the oil and gas industry. Subject too technical for a Directive. Modifications to the standard to include new technology or approaches would require changes to the Directive.	Technical innovations in well P&A outside the framework of the Directive may not be permitted by Competent Authorities.	Common approach provides the same standard of environmental protection across EU seas.	Common well abandonment standard results in cost reduction.

Explanation

Guidelines on a minimum set of well abandonment requirements would provide a common basis across the EU Member States for the environmentally critical process of sealing a well for geological time. Standards in countries with significant decommissioning experience can be used as a starting point. Binding legislation is not recommended as it is not suited to such a technical subject and could have the effect of stifling innovation, improvement and cost reduction.

Topic 2: Post-decommissioning long term monitoring of decommissioned oil and gas wells and structures left in-situ

Monitoring arrangements defined in the decommissioning plan generally identify the ‘baseline’ environmental data that needs to be gathered before and immediately after decommissioning, but are less well-defined for long term monitoring of wells and legacy structures once a steady-state environmental condition is achieved especially decades after decommissioning has been completed. Although licence holders cannot transfer away liability, the ability of a regulator or Competent Authority to identify the body responsible for any further monitoring on these timescales is uncertain.

In other extraction industries with legacy management issues, such as coal mining, the state has taken on the responsibility of remediating legacy issues, e.g. the management of waste water from mines and spoil tip in the UK is administered by the Coal Authority.

Option	Legislative	Technical	Environmental	Cost
Licence holder retains responsibility for monitoring long term (status quo).	No change to current arrangements.	Once decommissioning project team is disbanded, knowledge retention within the licence holder organisation will be lost. Licence holder may not exist after some time.	Potential damage sustained in period between identification of issue from monitoring and legacy entity engaging resources to remedy it.	Licence holder has to set aside funding for programme of monitoring over many years. Resources may not be available or sufficient to finance long term requirements (e.g. liquidation, bankruptcy).
EU-Member States may – with mutual agreement of the Licensee - take responsibility for long term monitoring of residual oil and gas footprints and infrastructure should it be environmentally and economically advantageous to do so. The MS would determining when proactive monitoring ceases.	Clarifies ownership and future remediation liability. MSs may consider such EU legislation to be inappropriate as it may be thought to impose a responsibility on them.	Coordinated large scale regional surveys by MSs easier to manage than surveys by individual operators. Same parameters used for all assets.	Environmental parameters can be specified for the monitoring plan in a consistent way. Ensures no areas of survey are missed. Ceasing proactive monitoring may be perceived as ending environmental responsibilities.	May be perceived as a cost transfer from the industry to the state for a long time period. Potential to reduce overall post-decommissioning survey cost through recognition of a far future end date for proactive monitoring.
Licence holder takes responsibility for monitoring and decision on when no further proactive monitoring occurs.	Legislating for a license holder to make such a decision may be difficult.	Once decommissioning project team is disbanded, knowledge retention within the licence holder organisation will be lost. Licence holder may not exist after some time.	Ceasing proactive monitoring may be perceived as ending environmental responsibilities.	Licence holder has to set aside funding for programme of monitoring over many years. Resources may not be available or sufficient to finance long term requirements (e.g. liquidation, bankruptcy).

Explanation

Although the transfer of the post decommissioning monitoring responsibility to the concerned Member State could *a priori* be considered inappropriate, it would be a pragmatic and efficient option that would also enhance the quality, reliability and comprehensiveness of the monitoring. Monitoring costs are a comparatively small amount (typically less than 1%) of the total cost of a decommissioning programme, or the cost of potential remediation, which could be recovered from decommissioning tax relief returns, a decommissioning bond, or decommissioning fund. For clarity, remediation costs are not proposed to be transferred to the Member State.

Topic 5: Common EU Legislation for Removal Requirements for Decommissioned Oil and Gas Structures

UNCLOS and IMO conventions require installations to be fully removed to allow safe navigation of shipping and other uses of the sea. Regional Seas Conventions are in place for the North Sea (OSPAR), Mediterranean Sea (Barcelona), Black Sea (Bucharest) and Baltic Sea (Helsinki). OSPAR has decision processes and administrative structures for regulating the offshore oil and gas industry, but, the other regional sea conventions are less well-developed, have not been widely ratified, or do not have specific provisions for removal of oil and gas structures. As such there is no common standard for the removal of oil and gas structures from EU controlled waters.

IMO conventions and OSPAR requirements for removal allow for removal derogation for large steel jackets and concrete gravity base structures if no feasible full removal option exists. In Europe, the majority of such derogable structures are in UK or Norwegian waters. Applying the OSPAR framework across Europe, would mean all steel structures in EU MS waters having to be fully removed.

Option	Legislative	Technical	Environmental	Cost
Maintain decommissioning regulation and management as present with no further EU legislation (status quo).	Differences in approach between MSs depending on individual MS legislative framework. Inconsistent implementation of decommissioning across EU MS controlled waters. Lack of common understanding or approach to decommissioning may result in objections to decommissioning programmes from stakeholders despite approval by Competent Authority of the MS.	No common approach to decommissioning. Many potential technical options available depending on location. Decommissioning Plan may be acceptable to a MS, but not to a Regional Sea authority or common sea stakeholder.	Potential for adverse impact on the environment from non-harmonised approach.	Potential for cost escalation in decommissioning programme due to late amendments to account for expectations from stakeholders outside the original consultation and approval process.
EU legislation for decommissioning equivalent to OSPAR approach.	Such legislation would be technically and legally feasible based on an accepted international framework.	Technical basis already exists in OSPAR, which is also considered to be good practice. OSPAR has known shortcomings in consultation process.	OPSAR currently represents environmental good practice.	May raise cost of decommissioning in EU MSs not currently under OSPAR.
EU legislates at a level beyond current OSPAR requirements requiring removal of all structures unless demonstrated by comparative assessment as not practicable technically or environmentally.	EU legislation harmonised around an internationally accepted decommissioning framework (OSPAR) that addresses observed shortcomings in lack of common treatment of pipelines and wells.	Higher requirements for removal would be technically more challenging, but potentially achievable for all but the most massive GBS structures. Previously decommissioned infrastructure may not be compliant with legislation.	Long term environmental impact eliminated by full removal of structures.	Potentially more costly decommissioning programmes in MSs compared with similar programmes outside EU jurisdiction.

Explanation

The two factors that affect the decision on which option to take forward are: a lack of robust decommissioning regulatory structures in some EU Member States with a smaller oil and gas industry, and; a lack of a cohesive approach to the assessment of structures that may be candidates to be left in situ. It is concluded that harmonising and extending EU regulatory requirements to include all infrastructure proposed to be left in situ allows for a consistent assessment of all offshore oil and gas infrastructure in the EU and this should be at a level similar to OSPAR.

Topic 7: Cost Provision for very Long Term Liability				
The licence holder will generally make some allowance in its decommissioning cost estimate for monitoring and survey activities up to the production of the decommissioning close-out report. Financial arrangements for potential remediation after the decommissioning phase are generally not included within the decommissioning cost estimate. Allowance for a bond or general insurance coverage can be made post-decommissioning by a licence holder. However, there is concern that there is insufficient funding to cover potential remediation requirements should remediation of decommissioned infrastructure be required in the future, with the likely outcome being that Member States would have to intervene and pay to remediate infrastructure.				
Option	**Legislative**	**Technical**	**Environmental**	**Cost**
Continue with current long term liability arrangements that are not consistent or fully defined for multi-decade timespans (status quo).	No EU wide requirements for long term liability coverage. No clear indication of liability should issues arise in the long-term.		Potential delay in remediation of an issue if liability unclear.	Long term liability coverage across the EU is uncertain.
EU Directive to require Member States to ensure licence holders can demonstrate sufficient coverage in decommissioning funds or bonds to pay for both decommissioning costs and potential remediation costs after decommissioning phase.	May be possible to include in EU Offshore Safety Directive, which already covers operational liability. Ownership of liability clarified, but legal entity may cease to exist during or after decommissioning phase.	Licence holder may not retain necessary expertise to efficiently carry-out long-term remediation.	Clarification of funding of future liability issues.	Clear requirement that separate funds for future decommissioning and ongoing liability are held by licence holders.
EU to mandate Member States to set-up a decommissioning fund also covering future liability	Difficult to implement. Potential to be interpreted as the Member State taking responsibility for decommissioning.	MSs may not retain necessary expertise to efficiently plan for long term remediation.	Would guarantee that funds for decommissioning and potential remediation of future liabilities are available.	Very high budget required given the mature nature of most oil and gas fields in the EU.
EU Directive to include provision for allowing a mutual agreement where licence holders' liability for monitoring is transferred to the MS, while the licensee retains responsibility for remediation where necessary.	Clarifies ownership and future remediation liability. MSs may consider such EU legislation to be inappropriate as it would impose responsibility on them.		Clarification of funding of liability issues in the post-decommissioning phase.	Cost would have to be borne by the Member State.
Explanation				
To address this shortcoming, there is no single option that stands out as all of them have advantages, but also significant issues. Therefore, all but one are taken forward to the impact analysis (including the status quo).				

6.3. Shortcomings with remedial options NOT taken forward to impact assessment in Section 7

Topic 8: Post-decommissioning short-term monitoring				
Monitoring arrangements defined in the decommissioning plan generally establish the monitoring requirements that the licence holder considers appropriate. It may be appropriate to alter these arrangements based on the data collected.				
Option	**Legislative**	**Technical**	**Environmental**	**Cost**
Maintain monitoring arrangements as per decommissioning plan (status quo).	No change in legislation.	Less transparent process for change in monitoring arrangements in some MSs.		No opportunity for cost saving if a steady state environmental condition is quickly reached.
EU to mandate Competent Authority to define appropriate rules for short-term monitoring and potential variation in its frequency.	Meets the requirements of Decommissioning Plans within Member State Regulations	Transparent process for change in monitoring frequency.	Potential improvement in short-term monitoring arrangements in some Member States	Likely to be an increase in monitoring and subsequent cost.
EU to produce guidance on changes to the frequency of the post-decommissioning surveys.	May be difficult to integrate EU level requirements into Member State legislation without disruption to existing requirements.	Transparent process for change in monitoring frequency.	As above, but with common standard across the EU.	As above
Explanation				
The short-term monitoring arrangements will vary from location to location and so are best defined by agreement between Licensees and Member State Competent Authorities as part of the activities and circumstances of the individual decommissioning programme. Long-term monitoring aspects are considered under a separate option and the measure relates mainly to a cost saving for the industry, which it could make itself, rather than an improvement in outcome.				

Topic 3: Integration of re-use / re-purposing options into decommissioning programmes

The assessment of possible re-use/re-purposing of structures is not common practice within the EU as potential applications are limited and most oil and gas structures are not suitable for other purposes. Most of the structures in EU Member State waters will be completely removed from their offshore location and returned to land for re-cycling.

In theory, substantial overall cost and environmental benefits could be made from re-purposing existing assets or re-use of redundant equipment. However, Operators of assets at cessation of production are focussed on moving forward with decommissioning and opportunities for re-purposing or re-use of oil and gas infrastructure in other applications may hence not be properly considered. Due to their age and condition many of these structures will not be suitable for re-purposing or re-use and the asset owners are in general not focussed on presenting a compelling case for retaining and maintaining them offshore for a speculative opportunity. Similarly, potential new users may not be interested in legacy issues associated with the structure and prefer a purpose-built structure to one that is a brownfield redevelopment.

Furthermore, there may be a significant time window between cessation of oil and gas operations and another company being ready to re-use the infrastructure. Co-ordination of opportunities for re-purposing/re-use will be required for structures to be identified and retained. If structures are identified as having re-purposing/re-use potential, then a mechanism to transfer the structure from the oil and gas operator to the new-use operator would need to be implemented.

Option	Legislative	Technical	Environmental	Cost
Maintain current arrangements (status quo).	n/a	Full re-evaluation of asset potential for re-purposing/re-use is generally not understood by oil and gas operators.	Lose potential opportunity for cost-effective re-purposing/ re-use of existing structures.	
EU to develop legal provisions in existing or new Directive to mandate Member States to have a national plan for potential re-use of assets.	The quality of such a plan would be difficult to define in legislation and Member States may genuinely find it difficult to produce one.	Oil and Gas Competent Authority and operator may not have cross industry knowledge to determine if asset is suitable for alternative application.	A plan would mean a greater likelihood of re-use.	Cost of maintenance of assets during transition period identified for re-purposing/re-use needs to be established.
EU to develop legal provisions in existing or new Directive to mandate Member States to have a national plan for re-purposing / re-use of assets and a mechanism for temporary ownership of oil and gas structures identified for re-purposing / re-use prior to later transfer to another application.	May be seen as MS intervention in decommissioning oil and gas assets that should be the responsibility of the operator. Mechanism for transfer of assets to the state needs to be developed. May be viewed as operators offloading depreciated assets to the MS.	Arrangements for maintenance of assets and potential decommissioning of structure during transition period to be developed otherwise the asset could deteriorate further during the intermediate period.	Environmental benefit maximised by re-purposing / re-use of structures instead of decommissioning them.	Cost of maintenance during transition period to be borne by concerned Member State. Has the potential to make decommissioning more costly.

Explanation

It is expected that only a small number of installations will be suitable for repurposing to alternative applications and the benefits of additional EU legislation in encouraging re-purposing / re-use of offshore oil and gas infrastructure for such a small population of assets is not expected to be proportionate to the efforts required. However, a principle requiring a Competent Authority to consider repurposing, as an alternative proposal to removal, within any proposed draft text for an EU Directive on Decommissioning, may be appropriate.

<table>
<tr><th colspan="5">Topic 4: Changes to Comparative Assessments to improve their public acceptance</th></tr>
<tr><td colspan="5">There is variability in the approach, scope and content of comparative assessments across Member States, with some CAs being accepted without an assessment of full removal, or assessment of viable options only. There is a perception from external stakeholders that the Comparative Assessment process is not transparent with decisions regarding weightings being poorly described in Decommissioning Plans and allocated to favour options preferred by the licence holder.

There are many items of common infrastructure, e.g. pipelines, or small platforms where the decommissioning options are similar. For such items, a single, general Comparative Assessment may be more appropriate than multiple submissions from individual licence holders. This would allow focus on critical areas of decommissioning. In the Netherlands, common CAs for pipelines and topsides have been developed with agreement from licence holders, authorities, stakeholders and NGOs and operators make reference to these CAs as part of decommissioning programmes.</td></tr>
<tr><th>Option</th><th>Legislative</th><th>Technical</th><th>Environmental</th><th>Cost</th></tr>
<tr><td rowspan="2">Continue with current Comparative Assessment approach (status quo, though with variability between Member States).</td><td>Variability in approach, scope and content leaves CA process open to challenge.</td><td>There is no guidance on weighting between long term and short-term impacts.</td><td rowspan="2">Full treatment of all options not considered. Best environmental solution may not be identified or assessed. A full study of net environmental benefit and disbenefit is not always presented.</td><td rowspan="2">There is no standard cost assessment model or framework.</td></tr>
<tr><td>Current framework may not be the best means to ensure efficient, environmentally responsible decommissioning offshore.</td><td>There is no guidance on how treatment of similar magnitude risk for conflicting assessment criteria should be addressed.</td></tr>
<tr><td>EU develop guidance on an option assessment process for common infrastructure items that only requires specific Comparative Assessment where the actual conditions are not covered in the common Comparative Assessment.</td><td>Difficult to achieve through specific oil and gas guidance as needs to be consistent with other industries.</td><td>Clarity on requirements and approach that will meet legislation for common infrastructure items.</td><td>Assists in identification of best environmental solution.</td><td>Common cost evaluation and assessment methods can be applied across EU Member State controlled waters.</td></tr>
<tr><td>EU to implement a Directive with specific Offshore Oil and Gas Decommissioning Comparative Assessment requirements.</td><td>Difficult to achieve through an oil and gas Directive as needs to be consistent with other industries.</td><td>Clarity on minimum requirements and approach. The requirements must meet the needs of all MS independent of scale and complexity of oil and gas infrastructure.</td><td>Assists in identification of best environmental solution.</td><td>Common cost evaluation and assessment methods can be applied across EU nation state controlled waters.</td></tr>
<tr><th colspan="5">Explanation</th></tr>
<tr><td colspan="5">Comparative Assessments use a common methodology across the EU for all industries. As such, any change would have to be applied to all industries and it would not be appropriate to just provide guidance for Comparative Assessments related to offshore oil and gas decommissioning, without also referring to other concerned industries. Therefore, the considered measure is not taken forward.</td></tr>
</table>

Topic 6: Decommissioning Knowledge Transfer				
The operators and authorities active in larger and more mature basins have developed technical and regulatory approaches for decommissioning that could directly benefit countries with less experience and less oil and gas infrastructure and deliver technically better and more cost-efficient decommissioning.				
Option	**Legislative**	**Technical**	**Environmental**	**Cost**
No change to current arrangements (status quo)	n/a	Lack of common approach to decommissioning across EU Member States.		Potential lack of adoption of good practice might negatively affect quality and drive up cost of decommissioning projects in Member States with limited experience.
EU to review, develop and update decommissioning Best Available Technology (BAT) Guidance.	EU OAG has the mandate to lead the development of an instrument such as a minimum well abandonment requirement.	Promotes a common approach to decommissioning understanding across the EU.	Potential for improved environmental outcome of decommissioning across the EU.	Cost reductions associated with cross industry knowledge transfer.
EU to amend the Offshore Safety Directive to require Member States to maintain an asset database with a full inventory of oil and gas infrastructure, to record potential CoP date estimates from operators, and lessons learned from decommissioning.	Not related to safety, so does not necessarily fit with OSD Large burden placed upon Competent Authorities in Member States with small oil and gas operations.	Learning opportunities and decommissioning data available for planning at Member State level.		Potential cost reductions from Member State data being made available.
Explanation				
Defining decommissioning best practice would give some benefit from standardisation of decommissioning approaches and subsequent reductions in the cost of decommissioning. However, this can be carried out by industry bodies with input from competent authorities as required without legislative intervention. A legal initiative at EU level in this domain is hence not considered appropriate.				

<table>
<tr><th colspan="5">Topic 9: Collaboration on Decommissioning Activities</th></tr>
<tr><td colspan="5">Most Member States contribute to the cost of decommissioning, either through a share in the licence, tax relief on ongoing production, or direct payment for decommissioning. Thus, initiatives that may lead to reduction in cost are also of benefit to Member States. Collaboration between operators, rather than competition for decommissioning resources is seen as a method of reducing the overall cost of decommissioning particularly in major cost areas such as well decommissioning, or infrastructure removal.

Examples of initiatives on collaboration include NexStep in the Netherlands and the UK OGA that have developed initiatives for multi-operator collaboration on decommissioning activities such as subsea and exploration well abandonment campaigns with the aim of reducing overall cost compared with multiple operators pursuing independent programmes.</td></tr>
<tr><th>Option</th><th>Legislative</th><th>Technical</th><th>Environmental</th><th>Cost</th></tr>
<tr><td>No formal incentivisation for cross-operator collaboration (status quo).</td><td>n/a</td><td>n/a</td><td>n/a</td><td>Loss of potential savings from co-ordinated multi licence holder campaigns.</td></tr>
<tr><td rowspan="3">EU could mandate or incentivise Member States to provide or encourage cross operator co-operation using the NexStep or OGA collaboration model.</td><td>Difficult to see how such legislation, that affects private enterprises only, could be enacted.</td><td>Allows co-ordination for large programmes across licence holders by Member State Competent Authority.</td><td rowspan="3">n/a</td><td>Potential considerable savings for application at scale across multiple licence holders vs individual licence holder approaches.</td></tr>
<tr><td>Small number of Member States impacted by improvements to collaboration.</td><td rowspan="2">Uncertainty and delay to individual licence holder decommissioning programmes due to waiting for co-ordinated approach to be formulated.</td><td>Difficulty in allocating ongoing maintenance cost to individual assets whilst co-ordinated decommissioning programme is underway.</td></tr>
<tr><td>Large burden placed on Member States with limited offshore oil and gas infrastructure.</td><td>Difficulty in allocation of savings and costs across licence holders.</td></tr>
<tr><th colspan="5">Explanation</th></tr>
<tr><td colspan="5">Improved collaboration on decommissioning activities can be carried out by the industry with encouragement from Member State authorities (and this is already done in countries that have a sizeable offshore industry) without specific EU legislation. A legal initiative at EU level in this domain is hence not considered appropriate.</td></tr>
</table>

7. Impact Analysis of potential measures

7.1. EU Legislation for decommissioning (Topic 5)

<table>
<tr><th colspan="2">EU Legislation for Decommissioning</th></tr>
<tr><td>Description</td><td>EU legislation to harmonise the principles and procedures to approve decommissioning programmes including the requirement to remove infrastructure from the seabed and derogations from the full removal requirement where there is greater technical, safety or environmental risk created by removal. The legislation would need to meet, or exceed, the equivalent best practice model addressing post-decommissioned structures that is currently in place, which is judged to be OSPAR (and Decision 98/3). The new or revised EU-Directive would also include treatment of pipelines and other oil and gas infrastructure such as mattresses by the same process.</td></tr>
<tr><td>Objectives</td><td>To harmonise across the EU a common set of best-practice principles and practices applied by Competent Authorities in approving decommissioning programmes and in determining what needs to be removed in the decommissioning process.</td></tr>
<tr><td>What / type of instrument?</td><td>Amending the Offshore Safety Directive could be considered, but developing a new Directive that also covers long term liability (see Section 7.3) seems more appropriate, as it would allow the OSD to maintain its focus on safety and operational matters (including the process of decommissioning.</td></tr>
<tr><td>Cost Benefit Analysis</td><td>
<table>
<tr><th>Group</th><th>Country</th><th>Relative Cost</th><th>Relative Benefits</th></tr>
<tr><td>Member States with Mature Decommissioning Framework under OSPAR
(Others for information only)</td><td>Netherlands, Denmark
(UK, Norway)</td><td>Low – these Member States already need to conform to OSPAR and have separate mechanisms for assessment of pipelines.</td><td>Low – the Directive would mirror OSPAR, but include infrastructure, such as pipelines, that are currently not covered by the OSPAR convention.</td></tr>
<tr><td>Member States with OSPAR governance requirements</td><td>Ireland, Germany, Spain (Biscay)</td><td>Low – these Member States already need to conform to OSPAR.</td><td>Low - small number of fields for decommissioning, but new Directive could make compliance with OSPAR principles and approach more straightforward.</td></tr>
<tr><td>Member States outside OSPAR Convention with Mature Decommissioning Framework</td><td>Italy</td><td>Medium – existing decommissioning governance framework would need to be altered to meet requirements of new EU Directive.</td><td>Medium – implementation and development of Barcelona Convention on oil and gas structures not as comprehensive as OSPAR.</td></tr>
<tr><td>Member States outside OSPAR Convention with limited decommissioning experience</td><td>Spain (Med), Croatia, Greece, Romania. Bulgaria, Poland</td><td>High – would need to amend current, limited decommissioning legislative frameworks with the cost being relatively high for size of industry in Spain, Greece, Romania and Poland.</td><td>High - implementation and development of Regional Seas Conventions on oil and gas structures not as comprehensive as OSPAR. Small number of fields to be decommissioned where adoption of best practice would allow efficient knowledge transfer from more mature practices and experience from a larger number of decommissioning projects.</td></tr>
</table>
</td></tr>
<tr><td>Legal feasibility and proportionality</td><td>Development and inclusion of such legal provisions in a Directive is legally feasible. It would overlap with current regulation in OSPAR territories, but, given that the cost impact in these areas is low, it is overall judged to be a proportional approach due to the benefit elsewhere and the overall harmonisation. From the stakeholder feedback and numerous other sources, it is also clear that this is an area of concern to many parties.</td></tr>
</table>

Coherence with other EU policies and legislation	The objective of the Directive would align with the consideration of long-term environmental hazards from offshore oil and gas infrastructure in the Environmental Impact Assessment Directive and Environmental Liabilities Directive. The Directive would not be in conflict with the OSD, as it focusses on the non-OSD aspects of the decommissioning phase of a lifecycle and in the provisions for managing long term environmental hazards in the post-decommissioning period.
Effectiveness	It would be possible for a Directive to establish minimum requirements for decommissioning in a similar framework to that of OSPAR Decision 98/3, which is considered to be good practice. Derogation from the full removal obligation is a critical issue and in OSPAR Decision 98/3, the decision-making process is complex and not accepted by all. However, if the principles of the draft Directive are enacted there would be a common framework of principles across the EU for decommissioning, which is not currently the case. Including pipelines in the remit of the Directive allows major seabed infrastructure to be assessed and evaluated as part of the common assessment framework and would provide more effective control across EU Member States than is currently the case. This would also address the issue of limited scope for assessment infrastructure left in situ in current obligations under regional seas conventions such as OSPAR Decision 98/3.
Administrative burden and efficiency	In terms of efficiency, OSPAR Decision 98/3 already exists so its approach can be readily adapted and adopted via this Directive. The Directive would formalise and facilitate the transfer of learnings and approaches from Member States with mature decommissioning frameworks to those with less mature frameworks. Higher efficiency within the industry and, to some extent, regulators would be achieved from enacting common provisions via a Directive. As outlined in the cost benefit analysis, Member States with mature post-decommissioning frameworks that are aligned to the proposed Directive will experience little impact. Member States not party to OSPAR Decision 98/3 with immature post-decommissioning frameworks, or low levels of decommissioning, will be impacted by the implementation of the new requirements. However, in all cases, the administrative burden would be reasonable as the Directive would be implemented by competent authorities that are already carrying out very similar, or the same, regulatory duties.
Feasibility: political and technical	Technically, creating a Directive is feasible as they would be based on the OSPAR Decision 98/3 approach. Politically, it is likely that this measure would be welcomed by regulators in areas outside of OSPAR with a small offshore industry. It would be unlikely to be welcomed in OSPAR countries with a sizeable industry, although the relative impact would be low. However, this is potentially outweighed by the stakeholder interest in ensuring that EU seabed's are returned to as clean a state as possible.

Conclusion: The effectiveness of the implementation of regional seas conventions varies across Member States. An EU Directive implementing a common approach to approval of decommissioning programmes and consideration of infrastructure left in-situ is a viable option for the EU to pursue to harmonise practices within the EU. A new decommissioning Directive (to also cover **liability – see Section 7.3) is** considered **more appropriate** than modification of the OSD as it **would allow the OSD to maintain its focus on safety and operational matters (including the process of decommissioning**).

Two scenarios have been considered for evaluating the suitability of the considered measure:

1. **where oil and gas production continues to decline in the EU according to projections**; and
2. **where oil and gas demand declines and decommissioning is accelerated due to transition away from oil and gas toward renewable and low-carbon energy sources**.

Experience with the Offshore Safety Directive has demonstrated that such a Directive can be approved and implemented within 2 to 3 years and so in either scenario it could be enacted before the majority of installations in EU Member States enter decommissioning.

7.2. Guidance for common well decommissioning requirements (Topic 1)

<table>
<tr><th colspan="2">Guidance for common well decommissioning requirements</th></tr>
<tr><td>Description</td><td>A set of common, or minimum well decommissioning requirements would provide a common basis across EU Member States for the environmentally critical process of sealing a well for geological time.
Well decommissioning guidance representing good practice exists for the North Sea and the North Sea Offshore Authorities Forum (NSOAF) is developing common decommissioning guidance for use in the North Sea basin based on practices from the UK, Norway and Netherlands. This guidance could be implemented as an EU best practice guidance.</td></tr>
<tr><td>Objectives</td><td>Harmonisation of a set of common well decommissioning requirements to ensure a minimum standard for the sealing of wells.</td></tr>
<tr><td>What / type of instrument?</td><td>Well decommissioning best practice guidance can be developed and owned by the EU OAG, based on a mandate included in the Directive as referred to in Section 7. Including such requirements in a Directive was considered, but not deemed appropriate, as a Directive is not suited to such a technical subject and could stifle innovation, improvement and cost reduction.</td></tr>
<tr><td>Cost benefit Analysis</td><td>
<table>
<tr><th>Group</th><th>Country</th><th>Cost</th><th>Benefits</th></tr>
<tr><td>Member States with Mature Well decommissioning guidance and many wells</td><td>Netherlands, Denmark, Italy
(UK, Norway)</td><td>Low – common guidance likely to be based on the principles from these countries' existing approaches to well decommissioning.</td><td>Low – reflecting the minor changes required for implementation and impact on current practices. Opportunities of scale from common approach.</td></tr>
<tr><td>Member States with limited well decommissioning experience or few wells</td><td>Ireland, Germany, Spain, Croatia, Greece, Romania, Bulgaria, Poland</td><td>Medium – many MSs already informally adopt well decommissioning practices from more mature MSs, but some realignment of practices is anticipated to conform to a common approach.</td><td>High - guidance would provide a common approach for these MSs with a lower cost of development.
Potentially greater benefit outside of OSPAR region where the seas are enclosed and consequences of an oil release could be higher.</td></tr>
</table>
</td></tr>
<tr><td>Legal feasibility and proportionality</td><td>As guidance, it would not be legally enforceable other than through Member State legislative frameworks. Guidance is the most appropriate and proportionate mechanism given the technical nature of the topic and the potential diversity in well design.</td></tr>
<tr><td>Coherence with other EU policies and legislation</td><td>As far as possible, the guidance needs to align with Member State Well Decommissioning requirements and identified best practice from Member States and industry bodies.</td></tr>
<tr><td>Effectiveness</td><td>Alignment around common guidance would allow learnings and practices from Member States with mature well decommissioning frameworks to be adopted by States with less mature frameworks. This harmonisation ensures well decommissioning is carried out to a consistent standard across the EU.</td></tr>
<tr><td>Administrative burden and efficiency</td><td>Being a guideline, its operation is efficient with the administrative burden related only to its creation, which would need to involve a number of parties.
The cost benefit analysis suggests that the benefit is at least as high as the burden for Member States, which indicates that the administrative burden is acceptable and that it is an efficient instrument.</td></tr>
</table>

Feasibility: political and technical	Technically the guidance proposed is feasible as there is already commonality in existing guidance. The guidance would establish the minimum recommended practice; individual Member States or oil and gas operators could decide that a higher decommissioning requirement is needed for individual wells. Politically, it is likely that it would be welcomed by regulators in areas outside of OSPAR with a small industry. It would likely also be welcomed in existing OSPAR countries with a sizeable industry as current differences in requirements have a slight cost impact. Other non-industry stakeholders would likely welcome an EU guideline.
Conclusion: Common well decommissioning guidance based upon current best practices is likely to be accepted by industry stakeholders and Member States, as it would be relatively straightforward to implement due to the broad commonality amongst the various guidance and approaches and provide benefit especially in Member States with limited history of decommissioning, or a small offshore oil and gas industry. Two scenarios have been considered for evaluating the suitability of the development and implementation of common Guidelines: 1. **where oil and gas production continues to decline in the EU and wells continue to be decommissioned according to projections**; and 2. **where well decommissioning is accelerated due to the imposition of a time limitation between cessation of production from the well and its decommissioning**. It is considered that common Guidance can be developed within 2 years and so in either scenario it would be available and implemented before the majority of wells are decommissioned.	

7.3. Long Term Monitoring of Oil and Gas Infrastructure Left in-situ (Topic 2)

<table>
<tr><th colspan="2">Long term monitoring of residual oil and gas footprints and infrastructure are, by mutual agreement, transferred from the Licensee to the Member State, once stable environmental conditions are demonstrated and not less than a number of decades after decommissioning, with the Member State planning and determining when proactive monitoring ceases.</th></tr>
<tr><td>Description</td><td>As part of a decommissioning programme a licence holder determines a monitoring strategy to assess the decommissioning activity’s impact on the surrounding environment until a stable environment post-decommissioning is reached.
Long term monitoring of periodic and reactive survey of residual oil and gas footprints and infrastructure, once stable environmental conditions are demonstrated, could - by mutual agreement between the Member State and Licensee – be transferred from the Licensee to the Member State when it is environmentally and economically advantageous to do so. The Member State would not assume responsibility for remediation of environmental damage, which would remain the responsibility of the Licensee. Should the Member State take responsibility for monitoring then the Member State would determine, in agreement with the Licensee, when pro-active monitoring should cease. This would be based on the long term monitoring and survey results.</td></tr>
<tr><td>Background</td><td>Over decades, decommissioned fields in a Member State’s territorial waters will increase, oil and gas licence holders may no longer be in existence, or ownership and related liability may become difficult to ascertain. This may result in a more comprehensive survey being delivered by a single entity that is more economic and efficient to achieve than from multiple independent sources. Therefore, it may be better other entities to take responsibility for administering long term monitoring, beyond that of the licence holder’s commitment in the decommissioning programme, for the survey of oil and gas infrastructure, plugged and abandoned well stock, and drill cuttings piles. A new or revised EU Directive on Decommissioning referred to in Section 6.1 could include a provision for the potential transfer of long term monitoring should it be environmentally or economically beneficial to do so.</td></tr>
<tr><td>Objectives</td><td>This measure would meet objectives for effective monitoring of long-term environmental risk from oil and gas legacy infrastructure by clarifying responsibilities for survey of legacy infrastructure over many decades.</td></tr>
<tr><td>What / type of instrument?</td><td>Enacted through Member State compliance with a new or revised Directive that would also include the OSPAR requirements (see Section 7).</td></tr>
<tr><td>Cost Benefit Analysis</td><td><table>
<tr><th>Group</th><th>Country</th><th>Relative Cost</th><th>Relative Benefits</th></tr>
<tr><td>Member States with large areas for survey or large inventory of legacy items</td><td>Netherlands, Denmark, Italy, Croatia, Romania
(UK, Norway)</td><td>Medium - Cost to the MS to implement monitoring previously done by Licence Holder. With centralised administration, survey organisation is simplified. Opportunities of scale from common approach to marine survey.</td><td>Medium - Transfer to MSs allows area surveys incorporating many locations. Ensures surveys are continued particularly over many decades, but have a well-defined endpoint.</td></tr>
<tr><td>Member States with smaller area and inventory to survey</td><td>Ireland, Germany, Spain, Greece, Poland</td><td>Medium – Cost to the MS to implement monitoring. Fewer licence holders and smaller survey areas mean benefits of a centralised system are less.</td><td>Medium - Transfer of survey responsibility to MSs ensures surveys are continued – particularly over many decades.</td></tr>
</table>
In all cases, responsibility for remediation of environmental damage remains with the licensee for this option, though this is discussed further in Section 0.</td></tr>
<tr><td>Legal feasibility and proportionality</td><td>The hazards from decommissioned oil and gas infrastructure are limited as hazardous materials are removed during decommissioning ad the well is sealed. However, in the very long term there is the small potential risk of well seal failure. Given the cost benefit analysis above, such legislation may be disproportionate to the benefit gained. Legally, it would transfer the monitoring responsibility to the Member State, while the potential hazard and the cost of its remediation remains with the licence holder.</td></tr>
</table>

<table>
<tr><td>Coherence with other EU policies and legislation</td><td>It would need alignment with Environmental Liability Directive.</td></tr>
<tr><td>Effectiveness</td><td>The change from individual; operator to Member State being responsible for all monitoring after a period of time would make long-term monitoring more effective. A single entity (the Member State) with a single wide area monitoring and survey regime is considered more efficient than a multitude of licence holders conducting individual studies when the risk of any environmental hazard is low.</td></tr>
<tr><td>Administrative burden and efficiency</td><td>In terms of efficiency, large scale surveys covering many licence areas would be an efficient method of gathering macro data on condition, environmental deterioration or potential leaks over many decades and would be most efficiently administered at Member State level.

The administrative burden to set-up such legislation is low, but the burden for the Member State in taking on the monitoring role from licence holders would be disproportionally high if there is a small amount oil and gas infrastructure. Economies of scale from wide area monitoring of multiple fields are only realised when multiple adjacent oil and gas licence areas are included in the monitoring scheme.</td></tr>
<tr><td>Feasibility: political and technical</td><td>The transfer of responsibility for the survey from the licence holder to the Member State on a timescale of decades may prove controversial, as it may be interpreted as the oil and gas industry being discharged from its responsibilities for long term legacy management. However, it is proposed only to transfer the responsibility for survey and the approval to cease proactive monitoring to the Member State – an activity that, over the multi-decade timescale, would be more efficiently and economically managed by a single centrally administrated body rather than by multiple licence holder entities. Responsibility for any remediation would still rest with the licence holder, or its successor entity. Furthermore, with the current practices, part of the cost of the survey by the licence holder may still be borne by the Member State, through operator decommissioning tax recovery mechanisms, therefore it is in the interests of the Member State to ensure that this activity is delivered as efficiently as possible.</td></tr>
<tr><td colspan="2">Conclusion This measure is likely to be controversial as it would be perceived as Member States taking over licence holder responsibilities and decision making on proactive monitoring necessity. However, single wide area surveys will be more efficient and ensure fuller coverage than multiple licence holders' surveys.

Two scenarios have been considered for evaluating the suitability of implementing this measure by a Directive:
1. where oil and gas production continues to decline in the EU and offshore infrastructure continues to be decommissioned according to current projections; and
2. where decommissioning accelerates due to the impact of the energy transition leading to lower demand and decreasing commodity prices making production less economic.

In either scenario the volume of decommissioned infrastructure will increase. As the considered measure would only take effect after a number of decades, it does not need to be in place immediately. However, Member States should be consulted on their arrangements for long term monitoring and how robust and practical current methods for monitoring are when applied to multi-decade timescales. This would allow consideration of any potential necessary measures before their implementation. However, should decommissioning accelerate then action would be needed in the medium term rather than the far future.</td></tr>
</table>

7.4. Cost provision for very long-term liability (Topic 7)

Cost provision for very long-term liability			
Description	Three options are proposed for consideration: 1. Continue with the current long-term liability arrangements in EU Member States. 2. EU Directive to require MSs to ensure licence holders can demonstrate sufficient financial coverage to pay for future remediation. 3. EU Directive to include a mechanism for transfer of monitoring from the licence holder to the Member State by mutual agreement. The responsibility for the cost of remediation remains with the Licence holder.		
Objectives	The primary aim of each option is that if any remediation is required in the future, there is available funding to cover the cost and the financial risk to the Member State is minimised.		
What / type of instrument?	Options 2 and 3 propose an EU Directive for ensuring financial coverage of future potential liabilities.		
Background	Currently, where regulation of long-term liability exists, the licence holder is required to retain adequate financial provisions for the remediation of potential long term environmental impacts extending over a period of decades and the liability for remediating any observed and adverse change remains with the licence holder entity or its successor entities. However, in the long term there is the risk that the licence holder entity ceases to exist and the long-term financial coverage may be insufficient for the potential remediation required.		
	Status Quo (Option 1)	**EU Directive on Funding Arrangement for Future Remediation (Option 2)**	**EU Directive incl. transfer of monitoring to MS by mutual agreement (Option 3)**
Legal feasibility and proportionality	n/a	Process is similar to that currently applied in the OSD for liability until decommissioning is complete, therefore considered to be legally acceptable and proportional.	Given the low risk of long-term monitoring liability, transfer to the Member State may be proportional. The political willingness of transferring the monitoring liability to the state may however be low.
Coherence with other EU policies and legislation	Current arrangement is coherent with other legislation, principally the Environmental Liability Directive and Polluter Pays Principal.	Coherent with other legislation, principally the Environmental Liability Directive and Polluter Pays Principal.	Abatement under the 'Polluter Pays' principle in the Environmental Liability Directive required for the very long duration of potential liability, spanning multiple decades, that are required for decommissioning.
Effectiveness	Challenged by the fact that in the long term the licensee may no longer exist.	Effectiveness challenged by the difficulty in determining the amount of funding that is required.	Could be effective, though it requires the Member State to fund monitoring arrangements. May be more efficient due to single entity co-ordination rather than multiple licence holders.
Administrative burden and efficiency	n/a	Requires significant administration to set-up and operate.	Requires administration from the Member State to determine when the monitoring liability moves to the Member State.
Feasibility: political and technical	Responsibility for any remediation remains with the licence holder, or	Responsibility for any remediation remains with the licence holder, or its successor entity so is feasible in this	The transfer of monitoring responsibility over a multi-decade timescale may prove controversial, as it may be interpreted as

	its successor entity so is feasible in this regard.	regard. Difficult to persuade the industry to hold back more funding for potential remediation and technically difficult if these companies cease to exist.	the oil and gas industry being discharged from its responsibilities for long term legacy management.

Cost Benefit Analysis	**Option**	**Country**	**Relative Cost** (Licence Holder and Member State)	**Relative Benefit**
	1	All	**Medium (LH) /Low (MS)** – continues to follow current principles with licence holders having liability. Typically, multiple licence holders in the licence history could be required to cover the cost of liabilities before the Member State is required to do so.	**Low** – licence holder entity may no longer exist when liability is due. By default, Member State has potentially undefined responsibilities for liabilities as owner of last resort.
	2	All	**High (LH) / Low (MS)** – Potentially licence holders would need to hold even higher levels of financial coverage than in Option 1 to provide acceptable limit of exposure for the Member State.	**Medium** – Member States have fixed the liability coverage under the terms of the licence.
	3	All	**Medium (LH) / Medium (MS)** – in initial decades, the monitoring and remediation responsibilities remain with the licence holder. Post-transfer the responsibility of monitoring is with the MS, while remediation will rest with the licence holder.	**High** – clear responsibility for monitoring and remediation mutually agreed between licence holder and Member State.

Conclusion: Two scenarios have been considered for evaluating the suitability of the status quo (option 1), or implementation of a Directive to clarify responsibilities regarding monitoring and remediation liabilities (options 2 and 3).

1. **where oil and gas production is expected to decline in the EU and offshore decommissioning continues according to the current projections**; and
2. **where decommissioning is accelerated due to the impact of the energy transition leading to decreasing demand and hence low commodity price accelerating production decline.**

Given the issues with the status quo, Options 2 and 3 should be considered and Member States consulted on arrangements for long term liability apportionment and how robust and practical current methods for liability recovery are when applied to multi-decade timescales. However, should decommissioning accelerate, which might be expected taking into account the impact of the Green Deal (scenario 2), then action would be needed in the medium term rather than the far future to secure an arrangement for decommissioning long term liability financing that minimises the risk to the Member States.

8. Conclusions

8.1. Potential improvement measures

Nine shortcomings were identified in the current regulatory framework for decommissioning, with a number of potential measures to resolve each, of which four were considered potentially suitable for intervention at EU level.

1. Apart from OSPAR (and Decision 98/3), regional sea conventions do not contain well-established oil and gas decommissioning requirements. Within the European Union, offshore oil and gas decommissioning requirements are generally established at Member State level, with no common legislative or regulatory framework, or best practice for implementation across EU Member States.

   Potential Measure: EU Legislation for Decommissioning to ensure common practices and approaches to decommissioning are consistent across all EU Member State waters.

2. Due to the potential hazard from wells or infrastructure left in-situ decades into the future, long term proactive monitoring needs to be maintained at a level proportionate to the potential risk. Over decades, the concerned oil and gas licence holders may no longer be in existence, or ownership and related liability may become difficult to ascertain.

   Potential Measure: If environmentally and economically beneficial to do so, a Member State could take responsibility for periodic and reactive survey of residual oil and gas footprints and infrastructure once stable environmental conditions are demonstrated over a long baseline following decommissioning, with the Member State planning and determining when proactive monitoring ceases.

3. Currently, where regulation of long term liability exists, the licence holder is required to retain adequate financial provisions for the remediation of potential long term environmental impacts extending over a period of decades and the liability for remediating any observed and adverse change remains with the licence holder entity or its successor entities. However, in the long term there is the risk that the licence holder entity ceases to exist.

   Potential Measure: Three options are considered to address this issue.

4. The integrity of wells that are decommissioned is not known in the long-term and while there is no reason to expect any loss of integrity, wells are sealed to differing standards in different countries with no EU wide common requirements.

   Potential Measure: Guidance for Minimum Common Well Decommissioning Requirements.

Each of these potential measures were subject to impact analysis and the conclusions are given below.

8.2. EU Legislation for Decommissioning

The Regional Seas Conventions that the EU and its concerned Member States have ratified - the OSPAR (North East Atlantic area), Barcelona (Mediterranean Sea), Bucharest (Black Sea) and Helsinki (Baltic Sea) Conventions – bind EU Member States in these waters to the requirements within the respective Conventions, including provisions for the decommissioning and disposal of oil and gas infrastructure. However, there is a wide disparity in the approaches to offshore decommissioning taken in the respective Conventions with the OSPAR and Barcelona Conventions being more developed than the Helsinki and Bucharest Conventions. This difference is potentially due to the relative numbers of oil and gas installations in each of the Convention areas, with a high proportion of Europe's offshore oil and gas installations in territories of OSPAR Contracting Parties. OSPAR is considered the most developed set of regional arrangements regarding offshore oil and gas decommissioning and an example of international good practice.

The Commission could consider a new or revised EU Directive for decommissioning that harmonises Member State requirements on a common set of minimum requirements for preventing major environmental damage from decommissioned offshore oil and gas infrastructure that continues to present potential for environmental risk and limiting the consequences of such damage. The principles of the Directive would be focussed on this aim by enabling Member States to:

1. require licence holders to ensure that exploration and production oil and gas wells are permanently sealed and that such seals will prevent the flow of fluids from oil and gas reservoirs, and other zones of flow potential, to the marine environment;
2. require licence holders to ensure full removal of disused offshore oil and gas infrastructure and return to land for disposal; and
3. require licence holders to ensure timely decommissioning of disused offshore oil and gas infrastructure.

Experience with the Offshore Safety Directive has demonstrated that such a Directive could be approved and implemented within 2 to 3 years and so it could be enacted before the majority of offshore oil and gas installations in the EU enter decommissioning.

To be effective, legislation should meet, or exceed, the equivalent best practice model addressing post-decommissioned structures that is currently in place, which is judged to be OSPAR (Decision 98/3). The Directive could also include treatment of pipelines and other oil and gas infrastructure such as mattresses that are presently not subject to a convention decision. A draft Directive for consideration is proposed below.

8.2.1. Draft Proposal for a Potential EU Directive on Decommissioning of Offshore Oil and Gas Infrastructure

The following text presents an initial proposal for an EU Directive on Decommissioning of offshore oil and gas infrastructure. Next to the proposed **Scope**, **Principles** and **General requirements**, more detailed provisions regarding the derogation option and consultation procedure are presented in the annexes. The draft **Recital** and **Definitions** are not included in this proposal.

Scope of the proposed EU Directive
This Directive establishes minimum requirements for decommissioning of offshore oil and gas infrastructure in view of preventing major environmental damage from sealed wells and any infrastructure left in-situ.
Principles
1. Member States shall require licence holders to ensure that disused exploration and production oil and gas wells are permanently sealed and that such seals will prevent the flow of fluids from oil and gas reservoirs, and other zones of flow potential, to the marine environment and between each other.

Scope of the proposed EU Directive
2. Member States shall require licence holders to ensure full removal of disused offshore oil and gas infrastructure and return to land for disposal.
3. Member States shall require licence holders to ensure decommissioning of disused offshore oil and gas infrastructure is planned within an appropriate timeframe that, through mechanisms such as structural degradation, does not result in potential increase in risk to the environment or safety of personnel involved in decommissioning.
General Requirements
1. Wells must be permanently sealed by using a method approved by the Member State Competent Authority to prevent:
a. migration of reservoir contents into the wellbore;
b. release of reservoir contents to the environment; and
c. release of reservoir contents into other permeable, or fluid bearing rock strata.
2. Member States shall take adequate measures to ensure full removal of disused offshore installations, well structures, pipelines, drill cutting piles, mattresses, and other subsea oil and gas infrastructure in a timely manner within the sea zones for which they are responsible;
3. Derogations from this general principle of full removal according to paragraph 2 can only be considered for the following categories of disused offshore installations (excluding their topsides) and infrastructure:
a. steel installations weighing more than ten thousand tonnes in air[9];
b. gravity based concrete installations;
c. floating concrete installations; and
d. any other item (such as pipelines, mattresses, subsea infrastructure and drill cuttings piles) for which it has been demonstrated by assessment that leaving it partly or wholly in-situ does not result in an environmental hazard or interference with other legitimate uses of the sea.
4. Derogations from the requirement for complete removal of disused fixed and floating infrastructure as mentioned under paragraph 3, can only be authorised by the Competent Authority of the relevant Member State on the basis of an assessment in accordance with Annex 1 showing that there are compelling reasons why an alternative option is preferable to full removal. In that case, the Competent Authority may grant derogation for:
a. all or part of the footings of a steel installation in a category in paragraph 2, to be left in place;
b. a concrete installation in a category listed in paragraph 3 or constituting a concrete anchor base, to be dumped or left wholly or partly in place;
c. a pipeline and associated mattresses in a category listed in paragraph 3, to be dumped or left wholly or partly in place;
d. drill cutting piles to be left wholly or partly in place; and
e. any other disused offshore infrastructure to be 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.
5. Member States' Competent Authorities can, in their evaluation and decision making regarding possible derogations from full removal, request evaluation of repurposing of offshore gas and oil infrastructure for other uses, e.g. carbon transport and storage;
6. An assessment for decommissioning oil and gas infrastructure may be developed, adopted and applied to assets of similar, or common, features, e.g. pipelines, with agreement of the competent authority of the Member State;

[9] After consultation, the EU Directive could define acceptable weight constraints and date installation criteria

Scope of the proposed EU Directive

7. For those assessment options that result in a leave at sea recommendation, the licensee must ensure that the assessment of the options is verified by an Independent Competent Verifier, approved for that purpose by the Member State Competent Authority;
8. The Member State Competent Authority shall ensure that the licensee has a plan to decommission all infrastructure within a reasonable timeframe in accordance with all other provisions in this Directive. The timeframe should be such that any potential delay does not adversely affect environmental or safety outcomes of the decommissioning;
9. Member States shall ensure that the concerned licensees are and remain financially liable for the prevention and remediation of environmental damage, caused by the decommissioning of their offshore oil and gas infrastructure or from their infrastructure, including wells, left in place following decommissioning. The competent authority shall ensure that the means and provision of coverage for the liability are adequate;
10. Member States may, after a period agreed with the concerned licensees, take responsibility for long term environmental monitoring of infrastructure left in place, if it is from a technical, environmental or economical perspective considered as a beneficial solution in the concerned Member State. In this case, a method for licences to fund the monitoring must exist. Financial liability for remediation of environmental damage resulting from infrastructure left in place shall remain with the concerned licensees;
11. Before a decision is taken to authorise a derogation under paragraph 3, the relevant Member State Competent Authority shall first consult relevant Competent Authorities in other concerned countries with potential exposure to residual hazards associated with the derogation in accordance with Annex 2;
12. Any derogation decision allowing a disused offshore installation or infrastructure to be left wholly or partly in place shall be in accord with the requirements of Annex 3; and
13. Member State Competent Authorities shall establish a record keeping system comprising relevant information on the offshore infrastructures within their jurisdiction including, where relevant, information on their decommissioning and disposal, such as: Decommissioning Plans, Comparative Assessments, and Environmental Impact Assessments, for inclusion in the data store to be maintained by the Competent Authority, which should be accessible to other authorities and stakeholders.

Annex 1: Framework for the Assessment of Proposals for the Leaving at Sea of Disused Offshore Infrastructure

Scope

1. This framework shall apply to the assessment by the relevant competent authority of proposals for the issue of a derogation authorisation under paragraph 3; and
2. The assessment shall consider the potential impacts of the proposed disposal of the installation or infrastructure on the environment and on other legitimate uses of the sea. The assessment shall also consider the technical and economic feasibility of repurpose, reuse, recycling and disposal options for the decommissioning of the infrastructure.

Information Required

3. The assessment of a proposal for disposal at sea of disused offshore infrastructure shall be based on descriptions of:
   a. the characteristics of the installation or infrastructure, including the substances contained within it; if the proposed disposal method includes the removal of hazardous substances, the removal process to be employed, and the results to be achieved, should also be described; the description should indicate the form in which the substances will be present and the extent to which they may escape during, or after, the disposal;
   b. the proposed disposal site: for example, the physical and chemical nature of the sea bed and water column and the biological composition of their associated ecosystems; this information should be included even if the proposal is to leave the installation or infrastructure wholly or partly in place; and

Scope of the proposed EU Directive
c. the proposed method and timing of the disposal.
4. The descriptions of the infrastructure, the proposed site and the proposed disposal method should be sufficient to assess the impacts of the proposed disposal, and how they would compare to the impacts of other options;
Assessment
5. The assessment shall cover not only the proposed disposal, but also the practical availability and potential impacts of other options. The options to be considered shall include:
a. re-purposing of the infrastructure, or part of the infrastructure, for an offshore application other than oil and gas extraction or transportation;
b. re-use of all or part of the infrastructure;
c. recycling of all or part of the infrastructure;
d. final disposal on land of all or part of the infrastructure; and
e. other options for leaving at sea.
6. The information collated in the assessment shall be sufficiently comprehensive to enable a reasoned judgement on the practicability of each of the disposal options, and to allow for an authoritative comparative evaluation. In particular, the assessment shall demonstrate how the requirements of paragraph 3 of the General Principles are met;
7. The assessment of the leave at sea options shall take into account, but need not be restricted to:
a. technical and engineering aspects of the options, including re-purposing, re-use and recycling and the impacts associated with cleaning, or removing chemicals from, the installation while it is offshore;
b. the timing of the decommissioning;
c. safety considerations associated with removal and disposal, taking into account methods for assessing health and safety at work; and
d. impacts on the marine environment, including:
i. exposure of biota to contaminants associated with the installation;
ii. other biological impacts arising from physical effects;
iii. conflicts with the conservation of species, with the protection of their habitats, or with mariculture; and
iv. interference with other legitimate uses of the sea.
e. impacts on other environmental compartments, including emissions to the atmosphere, leaching to groundwater, discharges to surface fresh water and effects on the soil;
f. consumption of natural resources and energy associated with re-use or recycling;
g. other consequences to the physical environment which may be expected to result from the options;
h. impacts on amenities, the activities of communities and on future uses of the environment; and
i. economic aspects.
8. In assessing the energy and raw material consumption, as well as any discharges or emissions to the environmental compartments (air, land or water), from the decommissioning process through to the re-use, recycling or final disposal of the installation, the techniques developed for environmental life cycle assessment may be useful and, if so, should be applied. In doing so, internationally agreed principles for environmental life cycle assessments should be followed;

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9. The assessment shall take into account the inherent uncertainties associated with the analysis and facts of each option, such that the conclusion is not changed by reasonable changes in methodology, inputs, or parameters and demonstrate this. The conclusion shall be based upon conservative assumptions about potential impacts;
10. Cumulative effects from the disposal of installations in the maritime area and existing stresses on the marine environment arising from other human activities shall also be taken into account;
11. The assessment shall also consider what measures might be required to prevent or mitigate adverse consequences of the leaving at sea, and shall indicate the scope and scale of any monitoring that would be required after the leaving at sea; and
12. The assessment shall be sufficient to enable the competent authority of the relevant Member State to draw reasoned conclusions on whether or not to issue authorisation under paragraph 4 and, if such authorisation is thought justified, on what conditions to attach to it. These conclusions shall be recorded in a summary of the assessment which shall also contain a concise summary of the facts which underpin the conclusions, including a description of any significant expected or potential impacts from the disposal at sea of the installation on the marine environment or its uses. The conclusions shall be based on scientific principles and the summary shall enable the conclusions to be linked back to the supporting evidence and arguments. Documentation shall identify the origins of the data used, together with any relevant information on the quality assurance of that data.
Annex 2: Consultation Procedure
1. A Member State Competent Authority which is considering a derogation authorisation under paragraphs 3 and 4 of this Directive shall start a consultation procedure by sending to the affected Competent Authorities a notification containing:
a. an assessment prepared in accordance with Annex 1;
b. an explanation why the relevant Member State Competent Authority considers that the requirements of paragraphs 3 and 4 of the General Requirements may be satisfied; and
c. any further information necessary to enable other concerned Competent Authorities to consider the impacts and practical availability of options for re-use, recycling and disposal.
2. If a Competent Authority wishes to object to, or comment on, the derogation authorisation, it shall inform the Member State Competent Authority that is proposing the derogation authorisation, and shall send a copy of the objection or comment to the other affected Competent Authorities. Any objection shall explain why the Competent Authority which is objecting considers that the case put forward fails to satisfy the requirements of paragraphs 3 and 4 of the General Requirements. That explanation shall be supported by scientific and technical arguments;
3. Competent Authorities shall seek to mutually resolve any comments on or objections to the proposed derogation authorisation. The Member State Competent Authority proposing to issue a derogation authorisation shall inform all the affected Competent Authorities of the outcome of the consultations; and
4. Before making a derogation authorisation according to this Directive, the Member State Competent Authority proposing the derogation shall consider any views expressed by other Competent Authorities in the course of this consultation and provide justification for the acceptance of the proposed derogation.
Annex 3: Derogation Authorisation Conditions and Reports
1. Every derogation authorisation issued in accordance with this Directive shall specify the terms and conditions under which the infrastructure element(s) may be left in place and shall provide a framework for ensuring compliance;
2. In particular, every authorisation shall:
a. specify the procedures to be adopted for the disposal of the infrastructure;

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b. require independent verification that the condition of the infrastructure, before the disposal operation starts is consistent both with the terms of the derogation authorisation and with the information upon which the assessment of the proposed disposal was based;
c. specify any management measures that are required to prevent or mitigate adverse consequences of the decision to leave in situ;
d. require arrangements to be made, in accordance with any relevant international guidance, for indicating the presence of the infrastructure on nautical charts, for advising mariners and appropriate hydrographic services of the change in the status of the infrastructure, for marking the infrastructure with any necessary aids to navigation and fisheries and for the maintenance of any such aids;
e. require arrangements to be made for any necessary monitoring of the condition of the infrastructure, of the outcome of any management measures and of the impact of its disposal on the marine environment and for the publication of the results of such monitoring;
f. specify the responsibility for carrying out any management measures and monitoring activities required and for publishing reports on the results of any such monitoring; and g. specify the owner of the parts of the infrastructure remaining in the maritime area and the person liable for meeting claims for future damage caused by those parts (if different from the owner) and the arrangements under which such claims can be pursued against the person liable.
3. Every assessment under paragraph 7 of the General Principles shall set out:
a. the reasons for the decision to issue an authorisation;
b. the extent to which the views expressed by other Member State Competent Authorities during the consultation process, were accepted by the relevant Member State Competent Authority; and
c. the authorisation issued.
4. Every report shall set out:
a. the steps by which the asset was left in situ;
b. any immediate consequences of leaving in situ which have been observed; and
c. any further information available on how any management measures, monitoring or publication required by the derogation authorisation will be carried out.

8.2.2. Impact of the Draft Proposal for a Potential EU Directive on Decommissioning of Offshore Oil and Gas Infrastructure

All relevant EU Member States have some requirements at national level that govern decommissioning - usually an objective ‘to secure safe abandonment of wells’, and ‘remove or decommission infrastructure’ - as part of the initial Production Licence process established in oil and gas resource exploitation, exploration and production legislative frameworks. However, the scope and detail of works required to constitute successful, compliant decommissioning varies greatly between States.

Much of the legislative requirement for decommissioning is derived from application of international conventions governing activities in the marine environment, which are generally defined geographically by ‘regional seas’ initiatives. Thus, there is already a significant contribution to, and variation in, decommissioning legislation at the international and state levels.

Furthermore, decommissioning programmes are currently underway, or in the final stages of planning, in:

- 'Regional seas' with EU members, such as the North Sea, where external nations (the UK and Norway) have mature decommissioning processes;
- Major EU oil and gas producers, such as the Netherlands and Italy, that are developing and applying State requirements; and
- Minor EU oil and gas producers, such as Germany, Ireland, and Spain, that have either developed their own processes or adopted those processes in place in more mature countries.

Decommissioning is going to increase over the next 10 years, as more infrastructure ceases production in mature areas, with additional EU Member States experiencing decommissioning for first time. Therefore, it is essential that any EU legislative initiatives are both timely in their development and enactment and have the minimum disruption to decommissioning programmes that are being developed, executed or are already completed.

Therefore, it is considered that adopting international best practice across the EU is the most efficient way of standardising decommissioning around an established and mature process.

The proposed EU Directive would provide a set of common principles and requirements for decommissioning across the EU. The Directive is based upon currently recognised international best practice, with additional requirements to close perceived weaknesses in the approach and in the scope of coverage of assets to be considered under the Directive.

For those EU Member States with mature decommissioning processes and within in the North Sea basin, such as the Netherlands, and Denmark, and other countries such as UK and Norway, the impact of the Directive is expected to be minimal, due to the alignment of the proposed Directive to current best practice (OSPAR) that is generally applied in these countries.

However, the proposed scope of the EU Directive would be more comprehensive than OSPAR, as it would require other structures and materials that are planned to be left in situ to be evaluated by the same process to that which fixed structures are currently assessed, bringing consistency in evaluation and decision making processes across all oil and gas infrastructure.

The requirement to include infrastructure in the evaluation process, beyond that mentioned in Decision 98/3, will likely increase the number of evaluations to be reviewed by the Competent Authorities. However, as pipelines and other items such as drill cutting piles and mattresses are already subject to comparative assessment, and submitted as part of a Decommissioning Plan, it is considered that their inclusion in the Directive scope will not greatly increase regulatory compliance requirements for licence holders and in the technical content supplied to the Competent Authority for regulatory review and approval. Therefore, existing guidelines within Member States on the timeframes for regulatory approval can be maintained.

For those EU Member States that are currently decommissioning offshore oil and gas infrastructure, but outside the North Sea area, such as Italy, are not directly aligned to the current best practices that the principles of the proposed Directive would adopt, the impact will be greater as national processes and approaches to decommissioning will need to be evaluated and adapted to ensure that gaps between the national approach and the EU Directive are closed.

For those EU Member States, such as Croatia, Spain, and Romania, with immature decommissioning processes or limited oil and gas infrastructure such as Poland, Germany, Ireland and Greece, the impact will be greatest. However, it should be comparatively simple for these Member States to align their processes with the principles of the Directive. In addition, these Member States will benefit from adoption of the best practice that the principles of the Directive are based upon.

8.3. Responsibility for Long-Term Monitoring of Decommissioned Infrastructure

The proposed draft EU Directive on Decommissioning includes a provision for potential transfer of long term monitoring, by mutual agreement, from the licence holders to the Member State once a steady state environmental condition has been reached and not less than a number of decades after decommissioning.

Such a change is pragmatic, but is likely to be controversial as it may be perceived as the State taking responsibility for the residual infrastructure left in situ. However, as the volume of decommissioned infrastructure under survey will increase with time, single wide area surveys will become more efficient to deliver and ensure fuller and more consistent coverage than those of multiple licence holders.

Also, critically, some licence holders may gradually cease to exist. As this new legal provision would only take effect after a number of decades, and then only by mutual agreement between the licence holder and Member State Competent Authority, it does not need to be in place immediately. This would allow Member States to be consulted and develop their own specific arrangements for long term monitoring, and gather evidence on how robust and practical current methods for monitoring are over multi-decade timescales.

In any event, it is recommended that only long term monitoring is considered for transfer to the Member State. Responsibility for short term monitoring, within the decommissioning programme close out period, remains with the licence holders, in order to establish a post-decommissioning environmental baseline and complete the decommissioning programme requirements.

After this process is complete and subsequent post-programme monitoring identifies that a steady-state in the infrastructure in-situ and surrounding environment is reached, then the process of mutually agreed transfer of monitoring responsibility may occur. The cost of the monitoring programme could be recovered through retention of part of the tax relief allocated to decommissioning, a centrally administered decommissioning fund, or licence holder bond.

Regardless of the selected monitoring regime, the responsibility for remediation of infrastructure, and any environmental damage caused, will remain with the licence holders.

Impact of Long Term Monitoring Transfer

For those European countries with larger offshore oil and gas operations, supported by Competent Authorities with a broad range of capabilities and capacities, the transfer of management of monitoring to the Competent Authority, and merging of multiple licence holder surveys into large area single surveys, will result in cost and resource savings to both parties.

Further, retaining decommissioning fund or tax relief, payable or returnable to licence holders, within the Competent Authority to finance the long term monitoring requirement would decrease the potential risk exposure from long term licence holder default.

For those countries with smaller offshore operations, the benefits of amalgamation would be less or may result in a cost-burden to the Competent Authority, and it may be more appropriate for the individual licence holders to retain the long term monitoring liability.

Thus, the proposed draft EU Directive maintains the liability for monitoring with the licence holders, unless long term monitoring is transferred by mutual agreement between the Competent Authority and licence holder.

Only the monitoring function would be transferred to the Competent Authority. The liability for remediation of infrastructure and restoration of the environment would remain with the licence holder entity and the ‘Polluter Pays Principle’ would be maintained.

8.4. Cost Provision for Very Long-Term Liability for Decommissioned Infrastructure

Currently, where regulation of long term liability exists, the licence holder is required to retain adequate financial provisions for the remediation of potential long term environmental impacts extending over a period of decades and the liability for remediating any observed and adverse change remains with the licence holder entity or its successor entities. However, in the long term there is the risk that the licence holder entity ceases to exist.

Financial arrangements for potential remediation after the decommissioning phase are generally not included within the decommissioning cost estimates. Allowance for a bond or general insurance coverage can be made post-decommissioning by a licence holder. However, there is concern that there would not always be sufficient funding to cover potential remediation requirements in place and available should remediation of decommissioned infrastructure be required in the future, with the likely outcome being that Member States would have to intervene and pay to remediate infrastructure.

Three options were identified for consideration:

- Continue with the current long term liability arrangements in the different EU-Member States;
- EU Directive to require Member States to ensure licence holders can demonstrate sufficient financial coverage to pay for future remediation; and
- EU Directive to include a mechanism for transfer of monitoring from the licence holder to the Member State by mutual agreement. The responsibility for the cost of remediation remains with the Licence holder.

The primary aim of each option is that if any remediation is required in the future, there is available funding to cover the cost and the financial risk to the Member State is minimised. The third option is likely to be controversial as it would be perceived to be the Member State taking over licence holders' responsibilities for monitoring (see Section 8.3 above).

However, it is deemed appropriate to consider options 2 and 3 and to consult with Member States on arrangements for long term liability apportionment and how robust and practical current methods for liability recovery are over multi-decade timescales. However, should decommissioning accelerate, which might be expected taking into account the impact of the Green Deal, then action would be needed in the medium term rather than the far future to secure an arrangement for decommissioning long term liability financing that minimises the risk to Member States.

Impact of Cost Provision for Long Term Liabilities

At present, there is uncertainty with regard to the potential long term liability for the impacts of oil and gas operations on the wider environment. Leaving large steel fixed structure foundations and pipelines in situ, will present a potential risk to other users of the sea until the steel or concrete is degraded by the environment. The release of contents, residual plastics from coatings and hazardous materials from the structures present a risk to the environment. However, the greatest potential long term risk is from barrier failure of decommissioned wells. Such failures are more likely to occur over the long term and any mitigation feature will need to be aligned to this risk profile.

Within the EU Member State waters, there are thousands of wells, both production and exploration, that will require decommissioning. In 'regional seas' that the EU Member State share with other States that number rises to tens of thousands. In addition, there will be many thousands of kilometres of pipelines left in situ and multiple significant structures, both steel and CBS. Any cost mitigation arrangement will need to consider the likelihood of unplanned degradation and failure.

EU Member States with large offshore oil and gas infrastructure are generally more exposed to potential failures, however those nations with operations closer to shore, or in areas used by other users of the sea, e.g. fishing grounds, tourism, may have greater consequences of any failure. Also, those Member States with smaller operations may be more adversely impacted by a failure, due to a lack of adequate resources to respond to a failure.

The proposed draft EU Directive would allow transfer of monitoring to the Competent Authority of a Member State, with the mutual agreement of the licence holder and Competent Authority. The cost would be recovered from tax relief due on decommissioning programmes, decommissioning funds or bonds held by licence holders. The proposed draft EU Directive requires that the responsibility for the cost of remediation remains with the licence holder and aligns to the Offshore Safety Directive that requires licence holders to demonstrate sufficient financial coverage for their operations, in the case of decommissioning this would ensure a licence holder can finance future remediation of wells and structures left in situ. It is recommended that this financial evaluation remains with the Competent Authority on behalf of the Member State.

8.5. Common Well Decommissioning Guidance

There is no internationally agreed legislation with regards to well decommissioning. Well decommissioning follows requirements produced by Member States and/or oil and gas industry best practice. Well decommissioning practices are currently developed by the oil and gas industry to align with requirements at Member State level within the EU; some regimes, such as the UK, Norway and Netherlands, are mature, while some other Member States have not fully developed national requirements. A set of minimum well decommissioning requirements would provide a common basis across EU Member States for the environmentally critical process of sealing a well for geological time.

As such, there are a number of different practices for well decommissioning across Europe, but good practice well decommissioning guidance is present in the North Sea. There have been initiatives to amalgamate current practices amongst industry associations in the North Sea via the North Sea Offshore Authorities Forum (NSOAF) to harmonise Well Decommissioning requirements. The proposed EU guidance could draw upon good practice in the engineering for well decommissioning contained in:

- Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 and OGUK Well Decommissioning Guidelines, Issue 6[10] (UK);
- NOGEPA Standard 45: Well Decommissioning (Netherlands);[11]
- NORSOK Standard D-10 Well Integrity in Drilling and Well Operations, Rev. 4 (Norway); and
- DEA Guidelines for Drilling (Denmark).[12]

This guidance could be implemented as EU best practice guidelines and would cover the decommissioning of the majority of wells in the North Sea (and thus European waters).

Common well decommissioning guidance based upon current best practice approaches is likely to be accepted by industry stakeholders and Member States authorities, as development of a common requirement would be simple to implement due to the broad commonality amongst the various guidance and approaches. It is considered that such Guidelines can be developed within 2 years and so they would be available and implemented before the majority of wells will be decommissioned in the EU.

[10] https://oilandgasuk.co.uk/product/well-decommissioning-guidelines/

[11] Standard 45 – Well Decommissioning/Het buiten gebruikstellen van putten - NOGEPA

[12] A Guide to Hydrocarbon Licences in Denmark, Exploration and Drilling Activities, September 2011 (ens.dk)

The common principles identified are:

1. A well decommissioning plan shall be submitted by the well operator to a competent authority for review prior to the well decommissioning activity occurring;
2. The well decommissioning plan shall include a well risk assessment to identify zones of flow potential, integrity issues with the well design, construction and operation, potential leak paths, and mitigation measures to reduce the risk of failure of the barriers;
3. The well decommissioning shall achieve a permanent seal, such that no fluid flow to or from the well, or from any other zone of flow potential, is possible. As a minimum, permanent barriers shall be placed:
    a. as a primary barrier, to isolate from the surface/seabed:
        i. a source of inflow;
        ii. formations with normal pressure; or
        iii. over-pressured/impermeable formations.
    b. as a secondary barrier to the primary barrier;
    c. to prevent flow between formations; and
    d. as an environmental barrier above the primary and secondary barriers.
4. The barrier shall be a cement or a mechanical/cement combination barrier, or any other verified barrier method that provides equivalent or greater sealing to a cement barrier;
5. Independent verification of the permanent barriers through pressure testing, tagging or a combination of both methods;
6. Removal of all casings at the seabed surface to a depth that eliminates the risk of snagging on the top of the well to other users of the sea; and
7. Sample periodic monitoring of decommissioned wells shall be undertaken at a frequency based on mutual agreement between the licence holder and Member State competent authority.

There are some differences in requirements contained in guidelines, e.g. varying cement heights required in annuli, length of cement barriers required, methods for testing of barriers, and logging requirements to qualify for barrier acceptance. Allowance should be made for Member States to set specific requirements within Member State Guidance supplementing these EU common guidelines, but only where the proposed requirements are demonstrably compliant with and complementary to the requirements in the EU Guidelines.

8.5.1. Impact of Common Well Decommissioning Guidelines

Failure of sealing mechanisms within decommissioned wells presents a significant risk to the environment being exposed to leakage of contents from the reservoir and other fluid bearing rock strata. Releases from wells have the potential to impact environmental receptors at significant distances from the source of the leak, potentially across marine boundaries of states. Therefore, EU guidelines providing a common approach to well decommissioning are considered appropriate.

Well decommissioning guidelines are currently available in several concerned EU Member States, but with varying quality, usually determined by the magnitude of decommissioning and the experience of the industry and Competent Authority in well decommissioning.

The impact of implementing common Well Decommissioning Guidelines across the EU would be minimal in those Member States with mature well decommissioning processes, as the common principles in the Guidelines are derived from the experience obtained from applying those guidelines and processes. Member State Competent Authorities with less experience in managing and approving well decommissioning solutions would benefit from the learnings developed from the more mature Member States approaches to well decommissioning that would be incorporated into the common guidance.

8.6. Timing of the potential measures' implementation: two scenarios

Two scenarios that may affect the timing required for implementation of the potential measures shown in Section 7 for offshore oil and gas decommissioning in the EU are postulated:

- Scenario One: continued demand for oil and gas with a rising commodity price;[13] and
- Scenario Two: energy transition away from oil and gas to non-fossil fuel sources, leading to reduced demand and falling commodity price[14].

Independently from these possible trends in global demand and supply, there are already strong projections for oil and gas production decline in European production basins, irrespective of demand evolution and commodity prices. This is due to the mature status of most of the major fields in production, which are now approaching the end of their economic life. As such there is already a rising trend in the amount of decommissioning required to be completed through the next decade and beyond. Even in the scenario of continued demand for oil and gas and a commercially viable commodity price, the decline in remaining reserves will result in assets entering decommissioning. The decommissioning activity in Europe will hence largely be independent of such upside events.

However, downside events such as postulated in Scenario Two, with a reduced demand and falling commodity price can impact decommissioning. Reduced demand can result in the cessation of production of a field ahead of its anticipated schedule, if that is based on a more optimistic price outlook than can be reasonably achieved in the medium to long term. This is particularly the case of assets in late life, where the exposure to price shocks is increased by the shorter remaining production life.

Similarly, reduced commodity prices result in lower income for the operator, which in turn can impact planned decommissioning spending and lead to capital redeployment to improving efficiency in productive assets or maintaining production at higher levels or refunding shareholders or creditors.

Both these effects can increase the rate of decommissioning, the former through increasing the number of assets entering decommissioning and the latter by delaying or deferring planned decommissioning. The outcome is the same, driving a 'bow-wave' of decommissioning into future years, with year on year demand for decommissioning rising. Ultimately, this will drive up decommissioning costs as more assets require to be decommissioned in a given future time period, and although it may be offset by a lack of outlay in the present, there are concerns about the ability of the industry to fund its commitments in the long term.

Thus, to be effective, EU regulation on decommissioning will need to be implemented over a short timescale in order to deliver meaningful change to both current and planned decommissioning projects and ensure that Member States are protected from potential long term financial risks resulting from having to resource and fund offshore decommissioning to meet International Convention obligations.

Thus, in regard to the potential measures that have been selected for further assessment:

1. EU legislation for decommissioning based on the current OSPAR approach

[13] According to one of the scenarios considered in EIA's Annual Energy Outlook 2021, published in February 2021, world oil demand is seen driving Brent prices to $173/b by 2050, compared to $95/b in the reference scenario.

[14] According to the IEA Roadmap "Net zero by 2050", published in May 2021, gas demand would decline by 55% to 1 750 bcm while oil would decline by 75% to 24 mb/d, from around 90 mb/d in 2020. This reduced demand would lead to falling commodity prices.

Experience with the Offshore Safety Directive has demonstrated that such a Directive can be approved and implemented within 2 to 3 years and so in either scenario it could be enacted before the majority of installations enter decommissioning.

2. Guidance for common well decommissioning requirements

   It is considered that common guidance can be developed within 2 years and so in either scenario it would be available and implemented before the majority of wells are decommissioned.

3. Responsibility for long-term monitoring

   In either scenario the volume of decommissioned infrastructure will increase. As the potential measure would only take effect after a number of decades, it does not need to be in place immediately. However, Member States could in an early stage be consulted on their arrangements for long term monitoring and how robust and practical current methods for monitoring are when applied to multi-decade timescales. This would allow consideration of any potential necessary measures before their implementation. However, should decommissioning accelerate (Scenario Two), then action would be needed in the medium term rather than the far future.

4. Cost provision for very long-term liability

   EU legislation covering very long-term liability could be considered and Member States consulted on arrangements for long term liability apportionment and how robust and practical current methods for liability recovery are when applied to multi-decade timescales. However, in Scenario 2, action would be needed in the medium term rather than the far future to secure an arrangement for decommissioning long term liability financing that minimises the risk to the Member States.

APPENDIX A International and EU legal frameworks for decommissioning

This appendix provides a detailed overview of the legal instruments (listed in Table 10) on an international, regional and EU level relevant to decommissioning of offshore oil and gas infrastructure.

Table 10 - Overview of relevant international, regional and European legal instruments

International instruments
UN Law of the Sea Convention
International Maritime Organisation and its relevant instruments
London Convention
Regional instruments
OSPAR Convention
Barcelona Convention
Bucharest Convention
Helsinki Convention
EU instruments
Offshore Safety Directive
Marine Strategy Framework Directive
Waste Framework Directive
Environmental Liability Directive
Environmental Impact Assessment Directive

A. 1 International legal framework

A.1.1 UN Law of the Sea Convention

The **UN Law of the Sea Convention ('UNCLOS')**[15], adopted in 1982, defines the rights and responsibilities of nations with respect to their use of the world's oceans, establishing guidelines for businesses, the environment, and the management of marine natural resources. All Member (and third) States within the scope of the study, including the European Union, are parties to the Convention.

As per its Article 60 on artificial islands, installations and structures, the UN Law of the Sea Convention allows its Parties to construct and/or to authorise their construction within their exclusive economic zone (EEZ) and its continental shelf.[15] It also governs the management of these structures when they are decommissioned and/or abandoned. As such, States have the obligation to remove installations 'to ensure safety of navigation'. While doing so, they must also have 'due regard to fishing, the protection of the marine environment and the rights and duties of other States' and 'take into account any generally accepted international standards established in this regard by the competent international organization'.[16]

[15] UNCLOS, Art. 60(1), available at https://www.un.org/depts/los/convention_agreements/texts/unclos/unclos_e.pdf
[16] UNCLOS, Art. 60(3)

A.1.2 International Maritime Organisation

The International Maritime Organisation (IMO) is a specialised agency of the United Nations responsible for regulating shipping. IMO's primary purpose is to develop and maintain a comprehensive regulatory framework for shipping and its remit today includes safety, environmental concerns, legal matters, technical co-operation, maritime security and the efficiency of shipping. All EU Member and other States within the scope of the study are members of the organisation. IMO is recognised as a 'competent international organisation' referred to in Articles 60(3) and 208(3) UNCLOS.

While the IMO has prepared more than 50 legal instruments, the one relevant to the topic of this study is the **Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the EEZ**[17], adopted in 1989 and stemming from Article 80 of the UN Law of the Sea Convention. The Guidelines state that abandoned or disused offshore installations or structures on any continental shelf or in any EEZ are required to be removed, except where non-removal or partial removal is consistent with the stated Guidelines and Standards. The Guidelines also state that any decisions for non-removal must be made on a case by case evaluation by the coastal State (with jurisdiction over the installation or structure), taking into account, amongst others, the following:

- Complete removal of all structures in <75 m deep water and <4,000 tonnes in air, excluding deck and superstructure;
- Complete removal of all structures emplaced on the sea-bed after 1/1/1998, in less than 100 m deep water and weighing <4,000 tonnes in air, excluding the deck and superstructure;
- Removal should cause no significant adverse effects on navigation or the marine environment;
- Any structure projecting above the surface of the sea should be adequately maintained to prevent structural failure. In cases of partial removal, an unobstructed water column sufficient to ensure safety of navigation, but not less than 55 m, should be provided above any partially removed installation or structure which does not project above the surface of the sea;
- Where living resources can be enhanced by the placement on the sea-bed of material from removed installations or structures (e.g. to create an artificial reef), such material should be located well away from customary traffic lanes, taking into account relevant standards; and
- Since 1/1/1998, no installation should be installed unless the design and construction is such that entire removal upon abandonment would be feasible.

The possibility of partial removal or abandonment of the structures remains in the following cases:

- When their removal is not feasible from a technical point of view (first generation structures);
- When the removal is excessively costly; or
- When the removal might pose an unacceptable risk for people or for the environment.

[17] See https://cil.nus.edu.sg/wp-content/uploads/formidable/18/1989-Guidelines-and-Standards-for-the-Removal-of-Offshore-Installations-and-Structures-on-the-Continental-Shelf-and-in-the-Exclusive-Economic-Zone.pdf

A.1.3 London Convention

The 1972 Convention on the Prevention of Marine Pollution by the Dumping of Waste and other Matter at Sea ('1972 London Convention') and its 1996 Protocol promote the effective control of all sources of marine pollution and to take all practicable steps to prevent pollution of the sea by dumping of waste and other matter. It is one of the first global conventions to protect the marine environment from human activities and has been in force since 1975. Art 3(1)(a)(ii) of the London Convention, states that the option of deliberately disposing an installation in the sea, where no new use is envisaged, is classified as dumping.

Its 1996 Protocol is more restrictive: application of a "precautionary approach" is included as a general obligation; a "reverse list" approach is adopted, which implies that all dumping is prohibited unless explicitly permitted; incineration of wastes at sea is prohibited; export of wastes for the purpose of dumping or incineration at sea is prohibited.

As per Article 4, there is a general prohibition against dumping of 'wastes or other matter in whatever form or condition except as otherwise specified'. The Convention (in its Annexes) also lists specific types of waste and how they are to be handled:

- Annex I (the "black list") prohibits the dumping of "highly hazardous" substances;
- Annex II (the "grey list") requires the issuance of a "special permit" (defined in Article 3 as a "permission granted specifically on application in advance") for the dumping of the listed substances; and
- Annex III requires a "general permit" (defined in Article 3 as a "permission granted in advance") for the dumping of all other substances.

Under this Convention's framework **Specific Guidelines for assessment of platforms or other man-made structures at sea**[18] have also been introduced. These are intended for use by national authorities responsible for regulating dumping of wastes and embody a mechanism to guide national authorities in evaluating applications for dumping of wastes in a manner consistent with the provisions of the London Protocol and when applicable the London Convention.[19]

A.1.4. Concluding remarks

At the international level, the framework comprising of UNCLOS, the London Dumping Regime, and the IMO Guidelines favours complete removal of obsolete structures but does not prohibit in-situ decommissioning. The term 'decommissioning' is not used in any of the main international legislation; although the need to deal with obsolete offshore platforms and infrastructure is referred to. There is a lack of international law that deals specifically and only with the offshore oil and gas industry, let alone the decommissioning phase. **Enforcement of international (environmental) conventions**, however, remains to be a somewhat problematic topic. With regards to the conventions , these are of binding nature and often include enforcement mechanisms. It however remains at the discretion of sovereign states whether they choose to become a party to (and to ratify) a certain conditions. However, even after a state has ratified, enforcement of international environmental law is generally based on state's compliance, rather than enforcement. Nevertheless, if needed, it is also possible that enforcement procedure on domestic level (before national courts) can be relied upon. The situation, however, is different in relation to the IMO Guidelines. As the name suggests, the Guidelines do not have the status of international law and are therefore not of binding legal nature. Their legal value remains at a level of a recommendation.

[18] See https://cil.nus.edu.sg/wp-content/uploads/2019/02/2000-Specific-Guidelines-for-Assessment-of-Platforms-or-Other-Man-Made-Structures-at-Sea-1.pdf

[19] Based on stakeholder input

As a result of the analysis, a number of **good practices** have been identified across the different international legal instruments:

- The **UN Law of the Sea Convention** has been prepared as a **framework convention**, or, in other words, as a 'living instrument'. This has been done by using so called 'rules of reference' in many of its provisions and referring to 'accepted other international rules and/or standards'.[20] In practice that means that the Convention makes a reference to other accepted international rules (e.g. rules under the International Maritime Organisation), which at the given point in time can be of stricter nature and/or more up to date. States, which are party to UNCLOS, are then expected to follow these other accepted international rules in order to be abiding by the UNCLOS requirements;
- As per Article 208(3) UNCLOS requires State parties to adopt laws, regulations and measures that 'shall be not less effective than international rules, standards and recommended practices and procedures'. In practice this means that this provision of **UNCLOS sets minimum requirements and/or standards** and, hence, ensures that national legislation is not less effective than international rules;[21] and
- The **IMO Guidelines provide recommendations on how to address materials which are not removed**, included within the body of the Guidelines These should be indicated on nautical charts and where necessary properly marked with aids to navigation. Coastal states have a responsibility to ensure that these aids to navigation are maintained and to monitor the condition of any remaining material so as to ensure continued compliance with the Guidelines. The coastal state is required to ensure that the legal title to installations and structures which have not been completely removed is unambiguous, and that the responsibility for maintenance and liability for future damages is clearly established.[22]

[20] Trevisanut, 2020

[21] Trevisanut, 2020, Techera, E. J., & Chandler, J. (2015)

[22] Decommissioning of International Petroleum Facilities Evolving Standards & Key Issues - Tim Martin available at <http://timmartin.ca/wp-content/uploads/2016/02/Decommissioning-of-Int-Petroleum-Facilities-Martin2004.pdf>

A.2 Regional legal framework of regional seas

A.2.1 OSPAR Convention

The **OSPAR Convention** opened for signature in September 1992 and came into force in March 1998, replacing the Oslo and Paris Conventions.[23] It aims to conserve marine ecosystems and safeguard human health in the North East Atlantic by preventing and eliminating pollution, protecting the marine environment from adverse effects of human activities, and contributing to the sustainable use of the seas.[24] The OSPAR Commission implements the Convention and its strategies by adopting decisions – which are legally binding on the Contracting Parties[25] – as well as recommendations and other agreements, all of which set out actions to be undertaken by the Contracting Parties. The Commission's work is structured around six areas, among which the offshore industry. Of particular interest in the context of decommissioning of offshore oil/gas installations are OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations and OSPAR Recommendation 2006/5 on the Management Regime for Offshore Cuttings Piles.

OSPAR Decision 98/3 forbids the dumping and the leaving (wholly or partly) in place of disused offshore installations in the maritime area covered by the Convention. Derogations can be granted by the competent authority of the relevant Contracting Party in specific cases,[26] and each decommissioning option applying for a derogation to Decision 98/3 must be accompanied by a comparative assessment that considers potential impacts on the environment and other legitimate uses of the sea, as well as the practicability of reuse, recycling and disposal options on land for the decommissioning of the installation. Stemming from this assessment, a proposed option is put forward. In addition, a consultation process with the Contracting Parties must take place (as outlined in Annex 3). One gap is that the Decision does not include performance standards nor does it specify the techniques to be applied; little detail accompanies the decision to allow a determination of Best Available Technique (BAT) by operators or competent authorities.[27] Once a permit for a derogation under Decision 98/3 is granted by a Contracting Party to an operator, the Contracting Party must submit a report to the OSPAR Commission which: outlines arrangements to be made for any necessary monitoring, the outcome of management measures and of the impact of disposal on the marine environment, and for the publication of the monitoring results (Annex 4. §2.e); specifies the responsibility for carrying out these activities (Annex 4. §2.f); and specifies the owner of remaining installations and the person liable for meeting claims for future damage caused by those parts as well as the arrangements under which such claims can be pursued against the person liable (Annex 4. §2.g).[28]

OSPAR Recommendation 2006/5 aims to reduce the impacts of pollution by oil and/or other substances from cutting piles to a non-significant level. The regime to manage cutting piles is divided into two stages, with Stage 1 requiring the initial screening of all cutting piles within two years of the Recommendation taking effect (i.e. 30 June 2006), and Stage 2 calling for a BAT and/or Best Environmental Practice (BEP) assessment in the event that oil loss and area of contaminated seabed thresholds set in the recommendation are surpassed. This recommendation was partly driven by concerns that oil and other contaminants could be

[23] OSPAR Commission (n.d.) OSPAR Convention. Available here: https://www.ospar.org/convention

[24] OSPAR Convention Article 2.1(a)

[25] Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, The Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and the United Kingdom, and the European Union

[26] OSPAR Commission (2019) Special Consultative Meeting. Available here: https://www.ospar.org/news/special-consultative-meeting

[27] Amec Foster Wheeler Environment & Infrastructure UK Limited (2015) Best Available techniques guidance document on upstream hydrocarbon exploration and production (Hydrocarbons BREF). Available here : https://ec.europa.eu/environment/integration/energy/pdf/Subgroup%20discussion%20paper.pdf

[28] As per stakeholder feedback (Regulator)

released into the marine environment from the remobilization of cutting piles due to disturbance from decommissioning activities.[29]

There is one option for derogation to these rules stated in **Annex III of the OSPAR Convention** on the Prevention and Elimination of Pollution from Offshore Sources. It notes that, in cases of *force majeure* that threaten the safety of human life or of an offshore installation, dumping can be conducted if it minimises the likelihood of such damage, and that it should be reported to the Commission (Article 6). The Contracting Parties are mandated to work on preventing and eliminating pollution resulting from the abandonment of offshore installations at sea caused by accidents (Article 7).

Effectiveness Evaluation

In 2009, the OSPAR Commission assessed that – generally speaking – the implementation of the Convention and subsequent Decisions and Recommendations by Contracting Parties had significantly improved the overall quality status of the OSPAR maritime area as a whole.[30] Currently, remaining questions of relevance to decommissioning include: whether the current contractual and design considerations regarding decommissioning and recycling or re-use are suitable and sufficient; the impact of partial or complete removal of single or multiple structures on biodiversity compared to leaving in-situ; and how to best monitor and quantify this impact.[31]

There is some degree of evidence available on Recommendation 2006/5. While it is not legally binding, at least Norway, the UK and the Netherlands implemented administrative actions following its publication. For the other Contracting Parties, there is a lack of information on the Recommendation's implementation in practice, and on measures applied by parties. Notably, none of the three Parties that reported on its implementation (i.e. Norway, UK and the Netherlands) found discharge sites exceeding the limits set, meaning that the prohibition of discharge of cuttings with contaminated oil has resulted in significant reduction in pollution and recovery of the seabed. A more recent assessment supports these conclusions, although temporary effects on water and sediment quality may be observed near the site of disturbance during or immediately following that disturbance, with a return of the seabed to its previous status within a few years. However, this same study notes knowledge gaps on impacts of oil and chemical discharges on the marine environment, and on noise impacts on marine animals.[32]

While the assessment of OSPAR's effectiveness is difficult due to knowledge gaps, there is a general consensus that OSPAR's decommissioning provisions have even had an effect beyond its jurisdiction. Most inexperienced countries in decommissioning are learning from experienced ones, notably the UK and Norway. As these two countries have themselves been influenced by the OSPAR Convention and subsequent Decisions, Recommendations and Guidelines, OSPAR has indirectly influenced decommissioning policy in countries beyond its geographic area of application.[33] In addition, OSPAR requirements are recommended by other guidelines with a worldwide scope for application where local regulatory requirements do not exist or are less stringent, for instance in the International Finance Corporation (IFC) Environment, Health and Safety guidelines for Offshore O&G development (2015). Assessment of impacts of offshore oil and gas activities in the North-East Atlantic

[29] OSPAR Commission (2009) Implementation report on Recommendation 2006/5 on a management regime for offshore cutting piles. Available here: https://www.ospar.org/documents?v=7170

[30] OSPAR Commission (2009) Assessment of impacts of offshore oil and gas activities in the North-East Atlantic. Available here: https://www.ospar.org/documents?d=7154

[31] European Marine Board (2017). Decommissioning of offshore man-made installations: Taking an ecosystem approach. EMB Policy Brief No. 3, April 2017. ISSN: 0778-3590 ISBN: 978-94-920433-1-3

[32] OSPAR (2016) Impacts of certain pressures of the offshore oil and gas industry on the marine environment – stocktaking report. Available here: https://www.ospar.org/documents?v=35692

[33] Fam, M. L., Konovessis, D., Ong, L. S., & Tan, H. K. (2018). A review of offshore decommissioning regulations in five countries–Strengths and weaknesses. *Ocean engineering*, *160*, 244-263.

More specifically, Decision 98/3 is recognised as having had a pioneering influence on regulations for the decommissioning of platforms.[34], [35] One NGO which submitted an answer to the stakeholder survey assessed Decision 98/3 as a success for both the marine environment and for material reuse and recycling, but noted that – ultimately – its effectiveness depends on implementation and interpretation by Contracting Parties (NGO stakeholder survey feedback). An example related to the Decision and to the OSPAR Offshore Committee more generally is the Shell Brent Decommissioning Programme/EIA/CA, where the UK and OSPAR took different viewpoints regarding some items left in situ, and most specifically the cell contents.

Linked to the point on uneven implementation, the same NGO noted that the comparative assessment process fails to appropriately compare all options against each other. Indeed, rather than requiring a full treatment of all options, OSPAR only mandates that a process is in place to compare options. In addition, an NGO argued that stakeholders were insufficiently consulted, whereby those with less resources are ignored or their views are not ascribed any weight in the assessment (NGO stakeholder survey feedback). During stakeholder consultations, the a National Authority also noted that the comparative assessment process as laid out in the Decision was insufficient.

Efficiency

OSPAR's Decision 98/3 provisions, which exclude the possibility of re-using parts of offshore installations as Rigs-to-Reefs (RtR) structures (i.e. the conversion of decommissioned oil and gas offshore rigs into artificial reefs), are the subject of a continued debate on their cost-effectiveness. On the one hand, proponents of RtR argue that the financial cost of complete removal is significant, and that these costs are partly borne by taxpayers given that decommissioning costs are in principle deductible from the taxable income.[36,37] In addition, they argue that leaving parts of offshore structures (i.e. in-situ decommissioning) can have environmental benefits, including energy savings and benefits for marine species, which could justify this practice, unless very large societal value is ascribed to clear seabed and trawling access. On the other hand, opponents contest the claim that in-situ decommissioning is less costly, and instead argue that the cost-savings argument favours the oil and gas sector rather than the society and the environment, thus emphasising that oil and gas companies use RtR as a cover to evade disposal rules and removal costs. Moreover, they urge for following the precautionary principle in the face of insufficient evidence, as the debates on whether RtR structures boost biomass production or merely serve as marine life aggregation devices, and on whether the environmental benefits of RtR projects outweigh their negative impacts, are still ongoing.[38]

Relevance

Decision 98/3 requires the OSPAR Commission to review it regularly, in light of experience and technical developments, to consider whether the derogations it contains remain appropriate. This process is based on the presumption that derogation categories may be reduced following technological advancement.[39] The Decision was recently reviewed by the OSPAR Offshore Industry Committee, which agreed that the derogation categories in Annex 1 should remain unchanged, taking into account experience gained in relation to the development and execution of decommissioning programmes as well as feedback received

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[34] OSPAR (2010). Official Statements. Available here: https://www.ospar.org/documents?v=7250

[35] Trevisanut, Seline. "Decommissioning of Offshore Installations: a Fragmented and Ineffective International Regulatory Framework." *The Law of the Seabed*. Brill Nijhoff, 2020. 431-453.

[36] Ounanian, K., van Tatenhove, J. P., & Ramírez-Monsalve, P. (2020). Midnight at the oasis: does restoration change the rigs-to-reefs debate in the North Sea?. *Journal of Environmental Policy & Planning*, *22*(2), 211-225.

[37] Techera, E. J., & Chandler, J. (2015). Offshore installations, decommissioning and artificial reefs: Do current legal frameworks best serve the marine environment?. *Marine Policy*, *59*, 53-60.

[38] Ounanian, K., van Tatenhove, J. P., & Ramírez-Monsalve, P. (2020). Midnight at the oasis: does restoration change the rigs-to-reefs debate in the North Sea?. *Journal of Environmental Policy & Planning*, *22*(2), 211-225.

[39] BEIS (2018) Guidance notes: Decommissioning of Offshore Oil and Gas Installations and Pipelines.

from statutory nature conservation bodies, academic institutions and other independent bodies.[40] Since 2020, the Offshore Industry Committee meetings have a standing agenda item on progress made on decommissioning technology developments that would help reduce the number of derogation categories.[41]

In a 2015 study commissioned by the EC, Recommendation 2006/5 was deemed likely to remain relevant and was viewed as up-to-date in terms of its approach. However, the OSPAR Commission has recognised that Recommendation 2006/5 only looks at the hydrocarbon content of the pile, thus ignoring other contaminants such as heavy metals which are also important in assessing environmental risks. In recent years, work was undertaken to ensure that characterisation of drill cuttings piles is not limited to hydrocarbon content but also includes an assessment of the full range of potential contaminants, thus building on the Recommendation to make the practices more relevant to current needs.[42]

A.2.2. Barcelona Convention

The **Barcelona Convention** was initially adopted in February 1976, and subsequently amended and renamed in June 1995 (entry into force of the amendments in 2004).[43] The first general obligation of the Contracting Parties summarises the aim of the Barcelona Convention as “to prevent, abate, combat and to the fullest possible extent eliminate pollution of the Mediterranean Sea Area and to protect and enhance the marine environment in that Area so as to contribute towards its sustainable development” (Article 4.1). Two out of seven of the Convention’s Protocols – which are all legally binding for its 22 Contracting Parties[44] – are of relevance to offshore decommissioning: the Protocol for the Prevention of Pollution of the Mediterranean Sea by Dumping from Ships and Aircraft (the ‘Dumping Protocol’) and the Protocol for the Protection of the Mediterranean Sea against Pollution resulting from Exploration and Exploitation of the Continental Shelf and the Seabed and its Subsoils (the ‘Offshore Protocol’).

The 1978 **Dumping Protocol** was amended in 1995, and this amendment has not yet entered into force. It prohibits all dumping of waste but lists some exceptions, among which are platforms and other man-made structures at sea. As specified in Article 4.2(d)), this exception only applies if material that could create floating debris or contribute otherwise to pollution of the marine environment has been removed to the maximum extent, and without prejudice to the provisions of the Protocol concerning Pollution Resulting from Exploration and Exploitation of the Continental Shelf, the Seabed and its Subsoil. Moreover, exceptions are granted via special permits from the competent national authorities (Article 5), which should be issued after careful consideration of the factors listed in the Annex (i.e. by looking at characteristics and composition of the matter, characteristics of the dumping site and method of deposit, and other general conditions on possible effects) or on criteria, guidelines and procedures adopted by the Contracting Parties (Article 6). Strict conditions have been set in the **2003 ‘Guidelines for dumping of platforms and other man-made structures at sea’**, which lay out requirements for granting an authorisation for the dumping at sea of offshore installations, including public review and participation in the permit evaluation process, a consultation procedure with the other contracting parties, and monitoring operations for disposal.[45] As these guidelines are not legally binding, there is room for national interpretation.

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[40] OSPAR Commission (2018) Annual Report 2017-2018. Available here: https://www.ospar.org/documents?v=39108

[41] As per stakeholder feedback (Regulator)

[42] OSPAR Commission (2019) Assessment of the disturbance of drill cuttings during decommissioning. Available here: https://www.ospar.org/documents?v=41247

[43] UNEP (n.d.) Barcelona Convention and Protocols. Available here: https://www.unenvironment.org/unepmap/who-we-are/barcelona-convention-and-protocols

44 Albania, Algeria, Bosnia and Herzegovina, Croatia, Cyprus, Egypt, the European Union, France, Greece, Israel, Italy, Lebanon, Libya, Malta, Monaco, Montenegro, Morocco, Slovenia, Spain, Syria, Tunisia, and Turkey.

45 Milieu Ltd (2013) Safety of offshore exploration and exploitation activities in the Mediterranean: creating synergies between the forthcoming EU Regulation and the Protocol to the Barcelona Convention. Available here:

The 1994 Offshore Protocol came into force in 2011. So far, few Contracting Parties have ratified it, but its ratification by the EU means that it has become legally binding on its Member States.[46] [47] The Protocol, however, has been ratified by the EU.[48] As such, the Offshore Protocol is binding on all EU Member States. It aims to "prevent, abate, combat and control pollution in the Protocol Area resulting from all activities, inter alia by ensuring that the best available techniques, environmentally effective and economically appropriate, are used for this purpose" (Article 3.1). Thanks to its measures to reduce pollution from all phases of offshore activities, to address offshore pollution incidents and concerning liability and compensation,[49] the Offshore Protocol is a relatively detailed instrument covering the complete life-cycle of offshore operations.[50] Of relevance to decommissioning, initial applications or renewals of authorization for offshore activities must include plans for the removal of installations (Article 5.1(g)), as well as proof of insurance or other financial security to cover liability (as prescribed in Art.27.2(b)) (Article 5.1(i)). Moreover, the Offshore Protocol stipulates that operators shall be required by competent authorities to remove any abandoned/disused installations (i.e. ascribing responsibility and therefore the costs), taking into account guidelines and standards adopted by the competent international organisation (Article 20.1) and in order to ensure safety but also to account for fishing activities, marine environmental protection, and the rights and duties of other contracting parties. In addition, it obliges coastal states to act if the operator fails to comply (Article 20.XX). Competent authorities can ask operators to either remove pipelines or to clean them (Article 20.2).

The Offshore Protocol is complemented by the **2016 Mediterranean Offshore Action Plan**, which includes an objective on developing and adopting regional offshore standards (objective 7), and notably "common criteria, rules and procedures for the removal of installations and the related financial aspects" (7.h), as well as an objective on developing and adopting regional offshore guidelines (objective 8), including "regional Guidelines on removal of installations and the related financial aspects" (8.d). As the aforementioned 'Guidelines for dumping of platforms and other man-made structures at sea' already exist since 2003, the extent to which this objective in the 2016 Plan is relevant and provides added value is unclear.

In addition, the Barcelona Convention Offshore Oil and Gas Group Sub-Group on Environmental Impact has been working on the development of Common Standards and Guidance on the Disposal of Oil and Oily Mixtures and the Use and Disposal of Drilling Fluids and Cuttings.[51] These are being developed to ensure that the practices of Contracting Parties become harmonised, and therefore that the objectives of the Offshore Protocol are being achieved (i.e. its Article 10 on developing common standards for discharge contents, and methods of use and disposal). The draft guidance also details a procedure to follow prior, during, and after decommissioning activities. Notably: (1) pre-decommission surveys should be used to establish the current condition of the seabed, including mapping and characterisation of cutting piles; (2) the presence of any protected species on installations should be discussed by the Operator and the Competent Authority, and managed in accordance with the Convention on International Trade in Endangered Species of Wild Fauna and Flora (CITES) requirements; and (3) surveys should be undertaken and used to recover

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https://ec.europa.eu/environment/marine/international-cooperation/regional-sea-conventions/barcelona-convention/pdf/Final%20Report%20Offshore%20Safety%20Barcelona%20Protocol%20.pdf

[4646] UNEP (n.d.) Offshore Protocol. Available here: https://www.unenvironment.org/unepmap/who-we-are/contracting-parties/offshore-protocol

[47] [47] The Protocol entered into force in Albania, Croatia, Cyprus, Libya, Morocco, the Syrian Arab Republic, Tunisia, and the European Union.

[48] Council Decision 2010/631/EU

[49] UNEP (n.d.) Barcelona Convention and Protocols. Available at: https://www.unenvironment.org/unepmap/who-we-are/barcelona-convention-and-protocols

[50] Trevisanut, S. (2020). Decommissioning of Offshore Installations: a Fragmented and Ineffective International Regulatory Framework. In *The Law of the Seabed* (pp. 431-453). Brill Nijhoff.

[51] UNEP (2019) Second Meeting of the Barcelona Convention Offshore Oil and Gas Group Sub-Group on Environmental Impact. See: https://wedocs.unep.org/bitstream/handle/20.500.11822/28710/19wg476_04_corr2_eng.pdf

debris, as well as a seabed sampling to monitor levels of certain contaminants after decommissioning has taken place.[52]

Effectiveness Evaluation

There is no study attempting to evaluate the effectiveness of the decommissioning regime outlined in the Barcelona Convention and its Protocols in the literature. However, the low ratification rate of the Dumping Protocol, which has been amended 25 years ago, is an indication of the limited influence of the Barcelona Convention. In addition, notwithstanding this problem, the Barcelona Convention's approach to the handling of residual chemicals has been argued to be much less stringent than other regional Conventions.

A.2.3 Bucharest Convention

The **Bucharest Convention**, signed in April 1992 (entry into force in January 1994), aims to "prevent, reduce and control the pollution in the Black Sea in order to protect and preserve the marine environment and to provide legal framework for co-operation and concerted actions to fulfil this obligation".[53] It obliges its six Contracting Parties[54] to "take all appropriate measures and cooperate in preventing, reducing and controlling pollution caused by dumping in accordance with the Protocol on the Protection of the Black Sea Marine Environment Against Pollution by Dumping which shall form an integral part of this Convention" (Article 10). However, it does not specifically address decommissioning.

The Convention is accompanied by a Protocol on the Protection of the Black Sea Marine Environment against Pollution by Dumping ('**Dumping Protocol**'), which states that the dumping of oil and other hydrocarbons of any origin requires a prior special permit from competent authorities on a case-by-case basis (Article 3). The dumping of all waste and matter not listed in Annex I or II (i.e. most likely including offshore oil and gas installations, although this is not made explicit) requires a prior general permit from competent authorities (Article 4). A permit shall be issued after careful consideration of factors set in annex 3 (i.e. characteristics and composition of the matter and characteristics of dumping site and disposal method) (Article 5), and exceptions to these provisions are identical to Helsinki Convention Article 9 (Article 6). However, the Dumping Protocol does not touch upon decommissioning either. Of relevance to decommissioning activities, the Bucharest Convention's approach to the handling of residual chemicals has been argued to be much less stringent than other regional Conventions.

A.2.4 Helsinki Convention

The **Helsinki Convention**, signed in March 1974 (then amended in 1992 and entered into force in January 2000), was created as an attempt to address the increasing environmental challenges stemming from industrialisation and other human activities with a severe impact on the marine environment. The Convention prohibits its 10 Contracting Parties[55] from dumping (Article 9.1), except in case of danger to human life or if the safety of a vessel/aircraft is threatened by complete destruction or total loss, and if dumping is the only way of adverting the threat and if damage will be less than would otherwise occur (Art.9.4). If dumping is undertaken, it should be reported and dealt with according to provisions laid out in Annex 4 and should be reported to the Helsinki Commission (Art.9.5).

In complement, **Regulation 8 from Annex VI of the Convention mandates** that the governments of the Contracting Parties "ensure that abandoned, disused offshore units and

[52] Regional Marine Pollution Emergency Response Centre for the Mediterranean Sea (2019) Thirteen Meeting of the Regional Marine Pollution Emergency Response Centre for the Mediterranean Sea. Available here: https://www.rempec.org/en/knowledge-centre/online-catalogue/2019/rempec-wg-45-inf-17-rationale-for-the-draft-guidelines-on-the-disposal-of-oil-and-oily-mixtures-and-on-the-use-and-disposal-of-drilling-fluids-and-cuttings-english-only

[53] Black Sea Commission (n.d) Convention. See: http://www.blacksea-commsion.org/_convention.asp

[54] Bulgaria, Georgia, Romania, Russian Federation, Turkey, and Ukraine.

[55] Denmark, Estonia, the European Union, Finland, Germany, Latvia, Lithuania, Poland, Russia and Sweden.

accidentally wrecked offshore units are entirely removed and brought ashore under the responsibility of the owner and that disused drilling wells are plugged." The 2007 HELCOM Baltic Sea Action Plan, which runs until 2021, specifies that operators should apply the "zero-discharge" principle[56] while decommissioning offshore installations. This implies that installations shall be removed, dismantled and subsequently treated in an environmentally friendly manner.[57] As part of this process, an EIA is required and operators must introduce an environmental management system. However, the Plan does not describe techniques nor include specific standards.[58]

A.2.5 Concluding remarks

The OSPAR Convention and the Barcelona Convention approaches to offshore decommissioning are significantly more developed than those of the Helsinki and the Bucharest Conventions, and there is a general consensus that OSPAR is the most developed set of regional arrangements regarding offshore decommissioning.

First, turning to the less-developed regional regimes, one major gap of the Bucharest approach is that neither its Convention nor any of its Protocols even mention the decommissioning of offshore oil and gas platforms. As such, it is up to the Contracting Parties to take all decisions regarding the decommissioning of these structures, with their only obligations related to the dumping of hydrocarbons. No guidance (e.g. Recommendations or guidance documents) has been found either. The Helsinki Convention does address the topic, but provides minimal mandatory requirements on offshore decommissioning, by laying out a clause in case of danger, but leaving all the exception procedures to the discretion of its Contracting Parties. Notably, the complete removal of units and plugging of wells as well as liabilities are laid out in a Recommendation, and are therefore non-binding. Moreover, there are no detailed guidelines on the burden of proof regarding the inevitability of dumping.

Furthermore, regional conventions fall under the scope of international legal framework, with one difference; their applicability is not global but regional. Nevertheless, the **enforcement** procedure of regional conventions remains the same as of international conventions, as discussed above. As such, each individual convention can include its own enforcement mechanism (e.g. under the Barcelona Convention). Where such compliance mechanism is missing (e.g. the London Convention, prior to the Protocol's entry into force[59]), the State's (lack of) compliance with international law can be challenged before national courts.

The following major gaps were identified in the OSPAR and Barcelona regimes:

- Some elements under both Conventions are non-binding. Coupled with the fact that there is no publicly available systematic evaluation of Contracting Parties' implementation of the Conventions and their protocols, means that the extent to which non-binding elements have been implemented remains uncertain. Major non-binding elements under both Conventions include:
    - OSPAR Recommendation 2006/5;
    - Guidelines are being developed under the Barcelona Convention on how to manage and monitor cutting piles, including in relation to decommissioning activities. This is a positive development, but it points to

[56] The "zero-discharge" principle is defined by the Helsinki Convention as "a general approach to ensure the proper treatment of all kinds of offshore platform-generated wastes, including processing and consumption wastes, on land or on the offshore platforms according to Best Available Techniques and Best Environmental Practices and MARPOL 73/78, with the aim of avoiding discharges to the marine environment."

[57] Helsinki Commission (n.d.) Action Plan for the protection of the environment from offshore platforms. Available here: http://archive.iwlearn.net/helcom.fi/BSAP/ActionPlan/otherDocs/en_GB/OffshoreActionPlan/index.html

[58] Amec Foster Wheeler Environment & Infrastructure UK Limited (2015) Best Available techniques guidance document on upstream hydrocarbon exploration and production (Hydrocarbons BREF). Available here : https://ec.europa.eu/environment/integration/energy/pdf/Subgroup%20discussion%20paper.pdf

[59] There are no compliance mechanisms under the London Convention, however, with the entry into force of the London Protocol on 26 March 2006, a set of Compliance Procedures and Mechanisms pursuant to Article 11 of the London Protocol, were adopted in November 2007 and subsequently revised in 2017.

the fact that, so far, the Contracting Parties have had an important leeway in that regard. Additionally, guidelines are non-binding and – as such – leave room for national interpretation or non-compliance;

  - The Barcelona Dumping Protocol has not yet entered into force because few countries have ratified it, meaning that its provisions are not yet binding on the Contracting Parties, and therefore they may not have been incorporated into national legislation; and
  - The Barcelona Offshore Protocol mandates competent authorities to ask operators to remove any abandoned/disused installations, taking into account guidelines and standards adopted by the competent international organisation. The 2003 Guidelines are meant to provide further guidance and include similar procedures as those laid out in OSPAR Decision 98/3; however, as Guidelines are non-binding, in practice Contracting Parties are allowed to set their own criteria for granting exceptions to the Dumping Protocol, if the installations that could create debris or other forms of marine pollution have been removed to the maximum extent.

- OSPAR Decision 98/3 does not include any prescription on the decommissioning of disused pipelines (for a summary of Decision 98/3, see Section 2.2.1); and
- Leaving parts of offshore installations in-situ for biodiversity purposes (RtR) is prohibited under OSPAR, and is not addressed by the Barcelona Convention nor its Protocols.

Some best practices have been identified under OSPAR:

- The fact that the exception system is binding (as opposed to under the Barcelona regime) made it a baseline standard for determining whether a structure can be left in place in the North Sea;
- Decision 98/3 is widely viewed as a pioneering and effective regulation laying out rules regarding the removal of offshore installations. The standard is also deemed to be still relevant to this day, although there are calls to make it more flexible with regards to new scientific evidence on the potential of RtR to bring benefits for the surrounding ecosystem in specific instances;
- OSPAR provides for potentially valuable consultation procedures between neighbouring states (both EU Member States and third parties), including via the mandatory system of consultation under Decision 98/3; and
- Overall, OSPAR streamlines the national approaches of its Contracting Parties with regards to decommissioning, and contributes to ensuring that a coherent approach is followed in its jurisdiction.[60]

[60] As per stakeholder feedback (from authorities)

A.3 European Union legislation

A.3.1 Offshore Safety Directive

The Offshore Safety Directive (2013/30/EU) sets a legal framework for the safe decommissioning of offshore installations with respect to major (safety) hazards and the environmental impact that may follow such an event. It also covers the requirement for an operator to have sufficient funding to carry out decommissioning.

The Directive is implemented across the EU (and the UK, but excluding Norway) and, when assessing whether to grant or to allow the transfer of a license, due account must be taken of the applicant's financial capabilities, including any financial security, to cover the costs that may derive from the offshore oil and gas operations in question, including decommissioning and abandonment costs (Article 4.2). Licenses can be granted by national licensing authorities only if they have compelling evidence that the applicant has or will make adequate provisions to cover for such liabilities (Article 4.3). Member States must also ensure that licensees are financially liable for preventing and remediating any environmental damage caused by offshore operations – including decommissioning (Article 7). However, the Directive does not cover environmental risks following the completion of decommissioning and abandonment, nor environmental hazards that are not a result of a major safety incident. It is important to note, as it means that the Offshore Safety Directive does not cover long term liability following the conclusion of decommissioning.

While the Offshore Safety Directive does not explicitly include a requirement to conduct EIAs, it does specify that the OSD is without prejudice to other Union legislation, including the EIA Directive. Furthermore, it does mandate Member States to ensure that (prospective) licensees elaborate upon risk management, including how the decommissioning of the installation will be undertaken, both during the license application and the pre-decommissioning stages. During the license application stage, prospective licensees must include these plans in the report of major hazards (Annex III, point 3(v)).[61] However, in practice this requirement is not usually implemented. The competent authority will review this report before granting authorization to begin production. Licensees must submit an amended version of that report prior to the dismantling of an installation (Article 11).

A.3.2 Marine Strategy Framework Directive

The Marine Strategy Framework Directive (2008/56/EC) does not specifically address any of the aspects of decommissioning listed below in Table 13 (Effectiveness of EU legal regime in relation to different decommissioning aspects); rather, it mandates Member States to develop and implement marine strategies that protect and restore marine ecosystems, and that prevent and reduce inputs into the marine environment so as to phase out pollution and ultimately prevent risks to marine biodiversity, marine ecosystems, human health or legitimate uses of the sea. Human activities should be managed to ensure that their pressure is compatible with the achievement of good environmental status (Article 1). These requirements set boundaries with regards to offshore decommissioning by requiring that the marine environment is not negatively impacted and – if needed – that additional activities are undertaken to restore that environment to an appropriate state.

Offshore installations were identified as a human activity affecting the environment in Annex III of the Directive, as revised through Directive 2017/845/EU65. The main pressures that oil and gas activities can place on the marine environment are operational and accidental

[61] EC (2020) REPORT FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL AND THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE assessing the implementation of Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on the safety of offshore oil and gas operations and amending Directive 2004/35/EC. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0732&from=EN

discharges of chemicals, crude oil and produced water but also underwater noise, marine litter including micro plastics and the drilling and placement of installations and pipelines on the seabed. If inappropriately managed, these pressures could affect hydrographical conditions, the integrity of the seabed, and contribute to habitat degradation. Risks from decommissioning activities especially concern contamination from leaks from plugged wells and the disintegration of parts of infrastructure left in situ.[62] As such, their effects on the environmental status of waters must be analysed as part of Marine Strategies (Article 8.1(b)), and this assessment must be taken into account in the establishment of environmental targets and related indicators (Article 10.1).

A.3.3 Waste Framework Directive

The Waste Framework Directive (WFD) contains a few provisions relevant to decommissioning of offshore oil and gas installations and waste treatment. These focus on the observance of waste hierarchy, necessity to hold valid waste permits and identification, management and treatment of hazardous waste.

Amongst others, Articles 4 and 13 provide for general requirements on how all waste should be treated. First of all, when decommissioning activities result in disposal or recovery of waste, the waste hierarchy of i) prevention, ii) re-use, iii) recycling, iv) recovery and v) disposal must be observed. Furthermore, Member States are also required to carry out waste management without harming human health and the environment (Article 13). While articles 4 and 13 are considered the core provisions relevant to decommissioning, articles 9, 10 and 11 (on prevention of waste, recovery and re-use and recycling, respectively) should also be considered.

The WFD also prescribes that all costs of waste management must be borne by the original producer or current holder of the waste, in accordance with the polluter pays principle. However, it also leaves it within the discretion of Member States to decide whether (partial share of) the waste management costs are also to be borne by the producer of the product or of the waste (Article 14). That means that, unless Member States decide otherwise, operators are to bear all decommissioning costs. Furthermore, companies who are in charge of disposal of the given waste for others must obtain a permit to do so from a competent authority of the appropriate Member State, in which, at least, the following should specify (WFD, Article 23):

- Type and quantity of waste to be treated;
- Technical, and other requirements, of the concerned site;
- Safety and precautionary measures to be taken;
- Method of the treatment;
- Monitoring of the treatment; and
- Closure and after-care provisions.

As per the last aspect, it should be specified in the permit that Member States competent authorities could require the installations and their site to be monitored after the decommissioning is complete. The WFD, however, provides for an exemption from the permit requirement. Member State authorities may exempt establishments treating waste if they dispose their own non-hazardous waste at the place of production or if they engage in recovery of waste.

Where installations contain hazardous waste (e.g. hazardous oils), Member States are required to ensure that its treatment is carried out in such conditions that are not harmful to the environment and human health. Those in charge of the disposal of hazardous waste have the obligation of record keeping. As per Art. 35 a chronological record should be kept 'of the

[62] EC (2020) SWD(2020) 269 final of 16.11.2020. Available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020SC0269R(01)&from=EN

quantity, nature and origin of the waste, and, where relevant, the destination, frequency of collection, mode of transport and treatment method foreseen in respect of the waste, and shall make that information available, on request, to the competent authorities' (WFD, Article 35(1)). These records should be preserved for a period of 3 years (WFD, Article 35(1)). However, these are often standard systems of waste recording rather than a special system for decommissioning.

A.3.4 Environmental Liability Directive

The focus of the Environmental Liability Directive (ELD) is suggested by its full name its focus is on the prevention and remedying of environmental damage. Its specific purpose is defined directly under Article 1: 'to establish a framework of environmental liability based on the 'polluter-pays' principle, to prevent and remedy environmental damage'.

The scope of activities to which the Directive applies is listed under Annex III of the Directive. Those relevant to decommissioning activities are listed in Table 11 below:

Table 11: Activities relevant to offshore decommissioning within the scope of the ELD

Annex	Activity relevant to decommissioning
III (1)	The operation of installations subject to permit in pursuance of Directive 2010/75/EU on industrial emissions.
III (2)	Waste management operations, including the collection, transport, recovery and disposal of waste and hazardous waste, including the supervision of such operations and after-care of disposal sites, subject to permit or registration in pursuance of Directive 2008/98/EC on waste.
III (7)	Manufacture, use, storage, processing, filling, release into the environment and onsite transport of dangerous substances as defined in Regulation (EC) No 1272/2008 on classification, labelling and packaging of substances and mixtures.
III (8)	Transport by […] sea […] of dangerous goods or polluting goods as defined in Directive 2002/59/EC establishing a Community vessel traffic monitoring and information system.
III (12)	Transboundary shipment of waste within, into or out of the European Union, requiring an authorisation or prohibited in the meaning of Regulation (EC) No 1013/2006 of the European Parliament and of the Council on shipments of waste.

The Directive also distinguishes between two different types of liability; strict liability and fault-based liability. Operators face strict liability for damage resulting from activities listed in Annex III of the Directive (see Table 11 above). This means that faults need not be established for the operator to be held liable for damage to land, water and protected habitats and species. Fault-based liability applies to any other occupational activity. Fault or negligence needs to be established for the operator to be held liable.[63]

A.3.5 Environmental Impact Assessment Directive

The purpose of the Environmental Impact Assessment Directive (EIA Directive) is to ensure that projects that are likely to have a significant effect on the environment are adequately assessed before they are approved.

The EIA Directive defines the term 'project' as 'the execution of construction works or of other installations or schemes' or 'other interventions in the natural surroundings and landscape including those involving the extraction of mineral resources'. Decommissioning activities therefore fall within the scope of the Directive.[64] This was confirmed by the Court of Justice of

[63] See https://ec.europa.eu/environment/legal/liability/pdf/eld_brochure/ELD%20brochure.pdf
[64] EIA Directive, Art. 1(2)(a)

the European Union (CJEU), which stated that 'demolition works come within the scope of the Directive and constitute a project' within its definition.[65]

The Directive differentiates between two types of projects; i) projects that are expected to have a significant effect on the environment, and ii) projects that do not necessarily have a significant effect on the environment. The requirement as to whether an EIA is to be carried out depends on the classification of the project in Annex I or II of the Directive and the type possible impact of the project. Projects with presumed significant effect are listed in Annex 1 of the EIA Directive and shall undergo an EIA (Art 4(1)). For projects listed in Annex II such significant effects cannot be always presumed and the Member States have to provide for a determination of the necessity to undergo an EIA. Such determination can be done on a case by case basis or/and through establishment of criteria or thresholds set by Member States (Art 4(2)). In both cases (case-by-case examination or thresholds/criteria set up), according to criteria set up in Annex III shall be taken into account (Art. 4Art 4(2) and (3)).. However, Art. 2(1) limits this discretion of Member States and requires that projects that are likely to have a 'significant effect on the environment by virtue, inter alia, of their nature, size or location are made subject to a requirement for development consent and an assessment with regard to their effects on the environment'.

The EIA Directive is also relevant to **post-decommissioning monitoring**, where significant adverse effects on the environment occurring post-decommissioning are required to be monitored reflecting the severity of the risk. This requirement is established in Article 8a which stipulates that "the type of parameters to be monitored and the duration of the monitoring shall be proportionate to the nature, location and size of the project and the significance of its effects on the environment".

The Directive is also of relevance in relation to **public engagement**. First of all, as per Art. 6, effective participation of the public (as well as environmental, local and regional authorities) should be ensured; the public should be provided with information early in the environmental decision-making procedures referred to in Article 2. The public shall also be given the opportunity to participate in the environmental decision-making and shall be entitled to express comments and opinions when all options are open.[66] In addition, Art. 11 also establishes access to justice for member of the public, where they can seek a legal review of decisions subject to public participations. Lastly, the preamble of the Directive also makes a reference to the Aarhus Convention, which provides for public participation in decisions on projects listed in Annex I of the EIA Directive and on projects not listed which may still have a significant effect on the environment.[67]

To summarise, offshore decommissioning and dismantlement projects are subject to the terms of the EIA Directive for the decommissioning of structures (as Annex I or II), or their decommissioning of the Wells (Annex II). The Directive also establishes a requirement of public participation before a decision on a project is taken.

A.3.6 Coverage of decommissioning aspects within EU legal instruments

Based on the sections above addressing the EU legal instruments relevant to decommissioning, Table 12 below presents findings regarding their effectiveness (the same decommissioning aspects are used for the analysis of relevant national legislation).

[65] CJEU, Case C-50/09 *European Commission v Ireland.*

[66] EIA Directive, Art. 6

[67] EIA Directive, Preamble

Table 12: Effectiveness of EU legal regime in relation to decommissioning aspects

Decommissioning aspect	Assessment
Long-term liability for environmental risks	Environmental Liability Directive: Operators have to bear all costs of environmental risks resulting from activities under Annex III (strict liability). For all other activities, liability is fault-based. However, this only applies to defined entities.
Financial capacity of operator to cover decommissioning costs (including external costs)	Offshore Safety Directive Article 4.2: This Directive mandates that licenses (or the transfer of licenses) can only be approved if the relevant authority has compelling evidence that the applicant has sufficient financial capacities to cover liabilities arising from decommissioning up to the point of the end of the decommissioning activity offshore. Waste Framework Directive: all waste management costs are to borne by the original or current waste producer.
Monitoring of abandoned installations (including wells)	EIA Directive: monitoring of environmental impacts or risks that occur post-decommissioning is required reflecting the severity of the risk. The same applies to (decommissioned) wells, if there is a significant effect on the environment. Waste Framework Directive: Member States can require the permits for waste treatment to include provisions on after-care.
Transparency & public engagement (including public consultation on decommissioning project)	The EIA Directive requires that members of the public concerned must be given the opportunity to comment on the proposed project before a final decision is taken by the competent authority on a request for development consent. When approving a project, the competent authority is required to take duly into account the results of consultations and to inform the public, notably on the measures envisaged to avoid, reduce or compensate for environmental impacts. The public must be informed of the development decision and can challenge it before the courts. The Offshore Safety Directive: there is a requirement for public participation on the possible effects of planned offshore oil and gas operations on the environment. If public engagement did not take place, it shall be ensured that the public is informed.
Environmental Impact Assessment of decommissioning project	EIA Directive: EIA is mandatory for projects where there is a significant effect on the environment (all Annex I projects and Annex II projects for which it is determined that these would have such effects). Whether an EIA is to be undertaken for decommissioning will depend on the scope of the initial project and the works necessary for the decommissioning.
Comparative assessment of decommissioning options	Not covered by EU legislation.
Potential re-use of structures identified for decommissioning	No specific requirement in relation to decommissioning. Waste Framework Directive requires the waste hierarchy to be applied, which includes re-use and recycling. Member States have the obligation to promote re-use and recycling.

APPENDIX B National legislative frameworks for decommissioning

B.1 The United Kingdom

B.1.1 Legislation

A number of Acts and Regulations regulate offshore decommissioning in the UK, with international law and the OSPAR Convention influencing some of their provisions. The UK's approach is oriented towards "goal-setting", whereby operators must develop their own ways to achieve safety and environmental objectives that are set in law, and must convince the regulator that they are meeting these objectives.

Decommissioning of offshore oil and gas installations and pipelines in the UKCS is primarily controlled through the Petroleum Act 1998 [68] and Energy Act 2016 by the Department of Business, Energy and Industrial Strategy (BEIS). The Oil and Gas Regulator (OGA) is responsible for the economic review of the cessation of production application by the Operator. This has to demonstrate that further economic production is not feasible and that re-use in oil and gas extraction or for other offshore applications is not possible without excessive spend.

Once accepted, the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) is responsible for ensuring that the decommissioning requirements of the Petroleum Act 1998 are complied with. It is ultimately the responsibility of the operator to decommission installations, wells and pipelines at the end of a field's economic life in an effort to return the seabed as close to its original state as possible. It is required by the Petroleum Act 1998 that, as part of this, the operator is required to submit a decommissioning programme to OPRED detailing all items that have been installed or drilled at the location in question and the proposed decommissioning strategy for those installations and wells.

There are two main criteria for the decommissioning of installations in the UKCS:

- Platform's topsides must be returned to shore; and
- Steel platforms with a substructure jacket weight of less than 10,000 tonnes in air must be completely removed for re-use, recycling or final disposal on land.

For large steel and concrete based structures with jackets weighing more than 10,000 tonnes in air, of which there are a significant number in the UKCS, there is a potential opportunity for derogation from OSPAR - leaving the footings of a jacket in-situ, or the entirety of the concrete gravity base structure. A derogation candidate will be assessed by OPRED, and submitted to the OSPAR Offshore Committee by BEIS. This is applied on a case by case basis to determine its suitability for derogation. However, there are several criteria these installations must meet before a derogation case is granted including, the installation must have been installed prior to 9th February 1999 and there must be a clear statement that there are no viable or alternative re-use or disposal options.

Decommissioning obligations for the operator and each licensee of an installation arise when the Secretary of State issues a **section 29 notice** under the Petroleum Act 1998, requiring them to submit a decommissioning programme. In a nutshell, section 29 was created to ensure that those who benefitted from the exploitation or production of hydrocarbons also bear the responsibility for decommissioning, thus protecting taxpayers from bearing the full costs.[69] It is important to note, however, that the UK government still funds between 40 and 75% of a field decommissioning costs, depending on the taxation arrangements on production. Indeed, decommissioning spending is a tax deductible expense which can be recovered by the

[68] UK Public General Acts, Petroleum Act 1998, https://www.legislation.gov.uk/ukpga/1998/17/contents

[69] BEIS (2018) Guidance notes: Decommissioning of Offshore Oil and Gas Installations and Pipelines.

operator from other production tax income due by the operator, or by transfer of monies from the UK Treasury to operators where decommissioning expense exceeds tax income from an operator.

Decommissioning programmes describe what needs to be decommissioned, how it will be decommissioned, and by what timetable. They also describe what activities will be ongoing after decommissioning is complete, such as monitoring, to ensure that any legacy infrastructure remains in its 'as left' state and poses no hazard to other users of the sea. Finally, they lay out the conditions under which the monitoring by the operator will cease. Each decommissioning programme must include an Environmental Impact Assessment (EIA) which compares decommissioning options and presents a management plan for the selected option. This assessment anticipates the environmental impacts of planned decommissioning activities, ensures compliance with environmental law (this requires, for instance, an assessment of cutting piles following OSPAR Recommendation 2006/5), incorporates environmental considerations in project planning and design, ensures best practice, and allows for public participation of stakeholders.[70, 71, 72] When assessing the programme, the BEIS seeks comments from other governmental and non-governmental agencies, departments, organizations, as well as other bodies.[73] Once the programme is approved, the section 29 notice-holders are legally obliged to carry it out on a joint and several liability basis.[74]

The operator is required to submit a close-out report within four months of the completion of offshore decommissioning work, including debris clearance and post-decommissioning surveys. The report should detail important variations from the decommissioning programme, costs, independent verification reports, and the schedule for future monitoring. The operator must monitor the condition of legacy infrastructure left in situ to confirm that it remains in the state in which it was left after decommissioning. The inspection frequency is 'risk-based', meaning that if no major change is noted between surveys, the frequency can be lengthened until a steady-state is achieved. Then, the operator can apply to cease monitoring. There is no long-term obligation concerning abandoned wells, provided that they have been abandoned in accordance with best practice.

To ensure that financial securities exist even prior the cessation of activities, the Act gives the Secretary of State some powers to investigate the license holder’s ability to fund existing or potential decommissioning obligations by granting powers to gather information and to require action (including establishing financial security) to be taken by an operator.[72] The prescriptions on financial security were significantly amended in subsequent Acts, and are discussed in greater detail in the below paragraphs on the Energy Acts.

The licensee remains liable for decommissioning obligations until the section 29 notice has been withdrawn. And instead – or in addition to – serving a section 29 notice on the operator, BEIS may also do so to:

- any person having an ownership interest in the installation/pipeline;
- a parent company or associated companies of a licensee;
- any person intending to carry on specified activities in relation to the installation/pipeline in the future;
- any transferor of an interest in an offshore installation/pipeline in cases when the transferor has failed to obtain the consent of the Secretary of State for that transfer; and

[70] Fam, M. L., Konovessis, D., Ong, L. S., & Tan, H. K. (2018). A review of offshore decommissioning regulations in five countries–Strengths and weaknesses. *Ocean engineering*, *160*, 244-263.

[71] Techera, E. J., & Chandler, J. (2015). Offshore installations, decommissioning and artificial reefs: Do current legal frameworks best serve the marine environment?. *Marine Policy*, *59*, 53-60.

[72] BEIS (2018) Guidance notes: Decommissioning of Offshore Oil and Gas Installations and Pipelines

[73] OECD (2016) An overview on the decommissioning process in the oil & gas sector.

[74] ICGL (2018) The International Comparative Legal Guide to: Oil & Gas Regulations 2018. 13th edition. Available here: https://www.acc.com/sites/default/files/resources/vl/membersonly/Article/1478061_1.pdf

- any licensee and parties to joint operating or similar agreements related to the exploration or extraction licence, even if they have not benefitted from the particular installation (Energy Act 2008).

This wider class of parties is usually contacted if BEIS assesses that the arrangements proposed by the operator and licensees are unsatisfactory. A section 29 notice can also be served to former licensees who were liable at the time the first section 29 was served (Section 34 of the Petroleum Act) as well as to a party which was previously released from its decommissioning obligations i.e. to a party which transferred its assets and which was released from its section 29 obligations by BEIS.[74]

Those who own an installation/pipeline or are section 29 holders will also remain the owners of any residues and remains after decommissioning. This residual liability remains in perpetuity.[75] This means that, in addition to being liable for decommissioning activities, the licensee or owner is liable for damage or inconvenience caused either wilfully or inadvertently by abandoned facilities, unless the Ministry decided otherwise.[76]

Within this framework, the definition of ‘in perpetuity’ is uncertain. Once the entity(ies) with the obligation around the Section 29 duties is (are) dissolved, it is unclear who would be accountable for long term liability issues, particularly in the event that there is no legacy organisation within UK jurisdiction that could be pursued. The UK Oil and Gas Licence holders are migrating away from State and large International Oil Companies (IOCs), which have the legal, financial, business and moral imperative to act to mitigate liabilities, to medium and small cap companies (MSCCs), which almost certainly do not have the resources to fund long term liability issues. By selling assets to MSCCs with decommissioning liabilities specifically included in the sale terms or otherwise strictly limited, the IOCs can seek to avoid long-term liability obligations. The regulator has responded by asking for bonds or insurance coverage from MSCCs as a condition of licence ownership, but these instruments would not cover the full cost of all potential liabilities in perpetuity. Indeed, the terms of the bonds and insurance instruments are generally only valid for the period that the asset is in production and decommissioning, meaning that post decommissioning the bond and insurance coverage lapses in most cases. They have also pursued investors in licences, in accordance with the aforementioned provisions from the Energy Act 2008. A second concern is that, if a section 29 holder cannot meet their decommissioning obligation, there is a domino effect, with the distribution of that holder’s share onto the other licence holders, causing those licence holders to fail in turn. This process can then replicate back up the chain of ownership. Some assets in late life have had multiple owners in the latter years of operation, which rapidly confuses the liability picture.

The Energy Act 2016 established the Oil & Gas Authority (OGA) as an independent Government Company and Regulator in charge of maximising the economic recovery of offshore UK petroleum. The 2016 Act lays out powers and obligations on the OGA as well as on other actors, about consulting the OGA on certain decommissioning matters (e.g. the Secretary of State must consult the OGA before approving a decommissioning plan). As part of its portfolio of responsibilities, the OGA considers and advises the state on alternatives to abandoning or decommissioning installations/pipelines (e.g. reuse), and on how to ensure that the costs of decommissioning for operators are kept to the minimum of what is reasonably practicable in the circumstances e.g. by looking at timing or collaboration. With regards to the oversight of decommissioning projects, the OGA has been granted access to company meetings, the capacity to obtain data, and to impose sanctions. This means that it is able to take action from the early stages to address the ‘what if’ scenarios of the operators not meeting the decommissioning milestones.

[75] Fam, M. L., Konovessis, D., Ong, L. S., & Tan, H. K. (2018). A review of offshore decommissioning regulations in five countries–Strengths and weaknesses. *Ocean engineering*, *160*, 244-263.
[76] Ibid.

In addition to these three main building blocks of the UK offshore decommissioning regime, several other Acts and Regulations lay out requirements which must be followed at various stages of the decommissioning process:

- The **Pipelines Safety Regulation 1996** requires the safe decommissioning of pipelines. It states that decommissioning proposals for pipelines should include a comparative assessment and consultation activities, similarly to that of installations. If the pipelines are to be left in place, their monitoring must also be included in the programme. It is general practice that all seabed-based equipment left in-place is suitably buried or protected;
- The **Offshore Installations (Safety Case) Regulations 2015**, which implement provisions of the Directive 2013/30/EU (the EU Offshore Safety Directive), lays out requirements to submit safety cases for all installations. The dismantling of a fixed installation requires the submission of a specific revision of the safety case to account for the particular hazards and risks involved. There is no direct relevance to the state the seabed is left in (Article 20);
- The **Marine and Coastal Access Act 2009** provides a regulatory framework for an updated marine licensing regime, whereby relevant public authorities must take authorization or enforcement decisions in accordance with marine plans. The marine plans are a means to promote clean, healthy, safe, productive and biologically diverse oceans and seas across the UK.[77] Operators need to obtain a license for all decommissioning activities and for any deposits, removals or seabed disturbance resulting from these activities. Most decommissioning operations will include a range of activities requiring licenses. A similar licensing process is outlined in the Scottish equivalent; the **Marine Scotland Act 2010**;
- The **Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001** implements EC Directive 92/43/EEC 1992 on the Conservation of Natural Habitats and of Wild Fauna and Flora (i.e. Habitats Directive) and EC Directive 2009/147/EC 2009 on the Conservation of Wild Birds (i.e. Wild Birds Directive). It mandates the EIA to be conducted as part of the decommissioning programme to identify any habitats and species relevant to the study area which are protected under the regulations, as well as to demonstrate that the protected sites will not be significantly affected by the activities detailed in the decommissioning programme. However, the regulations do not apply to artificial habitats created by the offshore infrastructure (i.e. RtR), nor do they require to justify the removal of structures colonised by protected or rare species;
- The **Offshore Chemicals Regulation 2002** (as amended in 2011) controls the use and discharge of chemicals during the decommissioning of offshore installations and pipelines, or during well suspension/abandonment activities. A specific permit application must be submitted to BEIS, including a forecast of chemicals use and discharge over a three-year period, details of techniques to prevent or minimize use and discharge and monitor these discharges, and a site-specific risk assessment. The regulation also covers the selection of chemicals, in line with the OSPAR approach;[78]
- The **Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005** implements OSPAR Recommendation 2001/1 for the Management of Produced Water from Offshore Installations.[79] The regulations

[77] BEIS (2018) Guidance note for operators – Offshore Oil & Gas sector: Update on Marine Planning in the UK.

[78] Amec Foster Wheeler Environment & Infrastructure UK Limited (2015) Best Available techniques guidance document on upstream hydrocarbon exploration and production (Hydrocarbons BREF). Available here: https://ec.europa.eu/environment/integration/energy/pdf/Subgroup%20discussion%20paper.pdf

[79] GOV.UK (n.d.) Oil and gas: offshore environmental legislation. Available here: https://www.gov.uk/guidance/oil-and-gas-offshore-environmental-legislation

prohibit the discharge of oil from offshore oil and gas installations into the sea except as stated in the terms and conditions of a permit, and require operators to apply for permits for all planned discharges, including for decommissioning operations;[80]

- The **Offshore Installations and Wells Design & Construction Regulations 1996** oblige operators to ensure that installations are designed and built in a way that they can be decommissioned and dismantled safely, to the extent that it remains reasonably practicable (sections 5.1d and 10). It also requires that wells are designed so that they can be suspended or abandoned safely and that no leaks occur afterwards (section 15);
- The **Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) (Amendment) Regulations 2017** is the latest amendment to the eponym 1999 regulation. Each amendment follows those of EC Directive 85/337/EEC on the Assessment of the Effects of Certain Public and Private Projects on the Environment (as amended by Directives 97/11/EC and 2003/35/EC) (i.e. the EIA Directive).[81] Requirements for IAs to support well abandonment operations or decommissioning programmes are out of the scope of this regulation. Here, references to future well abandonment or to the decommissioning of a proposed pipeline or installation in the EIA are limited to confirming how future decommissioning requirements have influenced the initial design of the project;[81] and
- The **Environment Protection Act 1990** sets out waste management and disposal requirements, including Duty of Care. Duty of care lies with the decommissioning operator throughout the waste life cycle. Notably, Section 34 specifies requirements to prevent: unauthorised or harmful deposit, treatment or disposal of waste; a breach to meet the requirement to have an environmental permit or a breach of a permit condition; and the escape of waste from the waste holder's control. There are also requirements to ensure that any person to whom the waste is transferred has the correct authorization, and to provide accurate descriptions when transfers occur. In Scotland, there is a further duty to take reasonable steps to promote high-quality recycling.[82]

The coverage of the UK legal regime in relation to the main decommissioning aspects is summarised in Table 13.

Table 13: Coverage of the UK legal regime in relation to decommissioning aspects

[80] OGUK (n.d.) Decommissioning – Installations. Available here: https://oilandgasukenvironmentallegislation.co.uk/contents/topic_files/offshore/decommissioning_installations.htm

[81] BEIS (2019) The Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (as amended) – A Guide.

[82] Decom North Sea (2018) Guidelines: Managing offshore decommissioning waste. Available at: https://decomnorthsea.com/uploads/pdfs/training/DECOM-WASTE-DRAFT.pdf

Decommissioning aspect	Assessment
Long-term liability for environmental risks	Owners of installations/pipelines and section 29 holders remain liable for any residues and remains in perpetuity. This liability encompasses damage or inconvenience caused either wilfully or inadvertently by abandoned facilities. In addition, those responsible for carrying out the decommissioning programme will remain responsible for complying with any conditions attached to the approval of this programme that extend beyond the decommissioning itself. However, if the legal entity ceases to exist and if there is no parent company party to UK law, it is unclear who has liability. The OGA monitors and sanctions breaches related to the financial framework and to liabilities.
Financial capacity of operator to cover decommissioning costs (including external costs)	The Secretary of State can investigate a person's ability to fund existing or potential decommissioning obligations by gathering information (the OGA can access company meetings and ask for data) and by requiring actions from operators (including establishing financial security and setting up private funds for decommissioning).
Monitoring of abandoned installations remaining in-situ	The operator must include post-decommissioning surveys as part of the close-out report (maximum four months after the end of decommissioning activities). This report must also include a schedule for future monitoring, with the possibility to increase the time between inspections if the operator can demonstrate that the state of the location has remained consistent over time. However, there is no formal post P&A survey schedule for abandoned wells.
Transparency & public engagement (incl. public consultation on decom project)	Public consultations are mandatory for each decommissioning programme. Moreover, as part of its information management system, the government publishes decommissioning reports and comparative assessments on decommissioning options in free access (including listing of approved plans).
Environmental Impact Assessment of decommissioning project	The proposed decommissioning programme must include an EIA.
Comparative assessment of decommissioning options	The mandatory EIA must include a comparison of different decommissioning options.
Potential re-use of decommissioning structures	Not in place, but the OGA considers and advises the state on reuse possibilities. This gap was flagged by OGUK in the stakeholder survey. Who would maintain a structure if it is identified as a potential re-use candidate by the OGA, rather than by the operator, is unclear.

The UK has a well-developed and detailed regime regulating the safe decommissioning of offshore oil and gas platforms, in comparison to many other European countries, as it has a large number of offshore oil and gas platforms and more experience in overseeing decommissioning. One implication is that there are several UK good practices from which its European counterparts could learn from. These were identified in the literature and by stakeholders and subsequently confirmed by the analysis, or emerged during the analysis itself:

- The establishment of an independent regulator to monitor and sanction breaches related to the financial framework and liability of decommissioning (i.e. the OGA). One important aspect is its capacity to take action early on in the decommissioning process. However, the OGA has a dual role, which also includes maximising economic recovery of oil and gas reserves as a central tenet. This can lead to internal conflict within the OGA when faced with a decommissioning programme for an asset that may, in the opinion of the OGA, have residual value that the licence holder does not value, e.g. a production hub asset that is no longer viable sustaining a route to market for more profitable assets upstream;

- The UK has a well-developed system that seeks to minimise the costs borne by taxpayers for decommissioning. However, the Government still recognises that they are the ultimate owner and there is a risk that they will need to underwrite some costs outside of those they have already accepted, despite the mitigations in place. While the UK economy should be capable to absorb these potential costs, nations with smaller economies and offshore operations may have less capacity to enforce cost recovery or absorb costs;
- In terms of workflow optimization, the OGA's well plugging and abandonment optimising programme as part of the bigger decommissioning workflow is a good example of cost efficient collaborative work;
- The UK information management system, whereby the government makes decommissioning reports and comparative assessments on decommissioning options publicly available (including listing approved plans), in order provide to the industry access to a common working knowledge; and [83]
- The flexible monitoring system, whereby the time between inspections can be increased where the Operator is able to demonstrate that the location has remained consistent over a period of time (Worley stakeholder survey response).

Notwithstanding the well-developed nature of the UK regulatory regime, a few gaps have been identified:

- Liability provisions are unclear if the liable legal entity ceases to exist and if there is no parent company party to UK law;
- There is no formal post P&A survey schedule for abandoned wells;
- There are no formal procedures for the re-use of structures (including maintenance requirements and responsibilities); and
- The potential ecosystem benefits of leaving structures in-situ are not incorporated into the comparative assessment process.

B.1.2 Comparative Assessment

In the UK, the main guideline[84] for this CA approach is provided by OGUK, an industry trade group. The OGUK CA guidelines describe the CA process as the following phases: scoping, screening, preparation, evaluation, recommendation, review and submissions.

1. Scoping

Define the scope and boundaries of the CA, including asset definition, the decommissioning options being assessed, and the decision-making process. Only facilities for which decommissioning options are available, or derogation is sought, should be included in the CA process. So, topsides would not normally be subject to a CA, because removal is the only decommissioning option available.

The OSPAR Decision 98/3 requires complete removal of installations, thus the CA scoping phase should consider a range of feasible removal options, plus a complete removal option.

An initial assessment of the criteria and sub-criteria to be adopted in the CA should be completed to inform the supporting studies required.

2. Screening

The screening phase reviews and screens out non-viable or marginal decommissioning options from the CA. The reasons for removing any decommissioning options should be

[83] Fam, M. L., Konovessis, D., Ong, L. S., & Tan, H. K. (2018). A review of offshore decommissioning regulations in five countries–Strengths and weaknesses. *Ocean engineering*, *160*, 244-263.

[84] OGUK, Guidelines for Comparative Assessment in Decommissioning Programmes, Issue 1, October 2018

documented transparently. The screening report should provide a list of technically feasible options for detailed review.

3. Preparation

The preparation phase examines the feasible decommissioning options in more detail, identifies any necessary supporting studies, develops Terms of Reference for the CA workshop including criteria, sub-criteria and criteria weighting, identifies stakeholders, decision-making process etc. A gap analysis is recommended to be completed to identify gaps in data, to inform scoping of supporting studies.

4. Evaluation

The evaluation phase executes (usually in a workshop) the assessment of different decommissioning options against the agreed criteria/sub-criteria. The evaluation process can take different forms depending on the complexity of the decommissioning options, stakeholder expectations, and project or company requirements.

There are three suggested evaluation methods in the guidelines, as below. Evaluation methods A through to C become more complex, and Method C is likely to be more appropriate for complex derogation cases, such as GBS or large jacket structures, where there are a number of decommissioning options, and the overall best option is not clear-cut.

1. Evaluation Method A: Narrative + ‘Red-Amber- Green’ chart
2. Evaluation Method B: Narrative + Scoring + Visualisation
3. Evaluation Method C: Narrative + Scoring + Weighting.

Method C compares the impact of the options against the criteria in a formal, structured way, in order to assess each option. It allows the options to be compared on a single scale. Trade-offs between sometimes conflicting objectives are made logically and transparently, and the process uses a technique called multi-criteria decision analysis (MCDA). MCDA in CAs has benefits, including transparency and robustness, but if using MCDA there are rules which must be followed (see ‘Improvements’ sub-section below).

5. Recommendations

The CA report should include discussion on the preferred decommissioning option. Recommendations must be clear and transparent, with a discussion and evaluation of each option against criteria.

6. Review & Submission

CA recommendations should be agreed by stakeholders prior to finalisation, including independent experts if involved. Although there is no formal requirement to submit the CA to the regulator, the details of the decommissioning option proposed must be reported clearly in the decommissioning programme. Early submission of the CA may simplify the explanation and justification in the decommissioning programme documentation.

B.1.3 Environmental legislative requirements

Differences between practices in UK and other European countries

Topsides

The environmental requirements for topsides decommissioning in the UK is the same for other countries, requiring all topsides to be removed for re-use, recycling or disposal. The UK adopts a mix of single lift, reverse engineering and module removal for the removal of topsides.

Substructure

The UK is host to a number of jacket structures that are large enough to be derogable both steel jackets >10,000 tonnes and concrete gravity base structures. OSPAR Decision 98/3 recognises that these structures may be very difficult to remove and so, they may be candidates for derogation.

Derogation requires a Comparative Assessment (CA) to be undertaken which provides environmental evidence and reasoning that demonstrates it is the appropriate option. CAs produced for steel structures to date have presented cases for removal to minimum depth (-55m below mean sea level) to depths >80m, where the structural assessment can demonstrate safe removal without structural collapse. This has generally increased with the increase in capability and lift capacity of heavy lift vessels. All concrete gravity base structures decommissioned to date have been the subject of derogation applications with the CA proposing leave in situ.

Subsea structures

Subsea structures are expected to be removed. However, in areas where infrastructure is in close proximity on the seabed, e.g. pipe crossings, tees, or equipment adjacent to live infrastructure, some structures may be left in-situ for an extended period until all hydrocarbon production ceases. This is not significantly different to environmental practices in other countries.

Drill Cuttings

There were no identified differences for the decommissioning of drill cuttings between the UK and other European countries.

Wells

The plugging and abandonment of wells is similar for the UK and other countries. The UK follows the OGUK Well Decommissioning Guidelines[85]. This has a philosophy of 'cap rock restoration' with decommissioning requiring the production formation zones to be isolated from other geological strata and the environment through the placement of barriers in the well bore. A minimum of two barriers must be set in a well, the 'cap rock restoration' barrier to isolate the reservoir and the environmental barrier at the top of the well to isolate the marine environment. Well barriers usually a comprise a steel bridge plug with concrete poured above. Although the UK is currently evaluating other well abandonment methods that aim to restore cap-rock by melting the formation around the wellbore using bismuth and similar thermal technologies.

Pipelines and Mattresses

The practice of decommissioning pipelines in the UK generally involves the removal of all interfield pipelines and umbilicals and leaving the larger diameter pipelines in-situ. In the UK, there is an expectation that pipes will be trenched to 0.6 m to top of pipe (TOP). Although the decommissioning of mattresses is not well understood, it is generally the case that if pipelines are removed, mattresses are removed (if safe to do so) and vice versa.

Environmental Assessment

In the UK, the environmental impact assessment (EIA) must be documented in a comprehensive stand-alone Environmental Appraisal (EA) report, which assesses the potential environmental impacts of the selected decommissioning option and identifies any significant environmental impacts and any mitigation or remedial works which may be required. The draft EA is submitted to the regulator (BEIS OPRED) to support the Decommissioning Programme, and goes out for public consultation before finalising, and is a key document in the decision-making process.

In the UK, there is no statutory requirement to undertake an EIA for proposed decommissioning activities that satisfies EU EIA Directive requirements. For example, there is no expectation to assess all the decommissioning options considered, or to assess the impact of accidental events (e.g. spills from vessels). Under the Petroleum Act 1998 there is a more straightforward

[85] OGUK, Well Decommissioning Guidelines, Issue 6, June 2018

requirement to undertake an assessment of the potential environmental impacts of the proposed decommissioning proposals only (i.e. no need to assess all feasible decommissioning options).

In the UK, there is no statutory requirement to undertake a decommissioning EIA that satisfies EU EIA Directive requirements. Hence there is no expectation to assess all decommissioning options (or to assess the impact of accidental events), but only a more straightforward requirement to undertake an assessment of the potential environmental impacts of the proposed decommissioning option. The UK regulator does demand that a comprehensive and detailed assessment be undertaken, usually resulting in a lengthy report.

In the UK, a Decommissioning Programme must include supporting information detailing the potential environmental impacts of the proposed decommissioning activities.

There is no requirement for the UK to undertake an Environmental Impact Assessment (EIA) that satisfies the EU EIA Directive requirements. Under the Petroleum Act 1998, only the environmental impact of the proposed decommissioning plan needs to be assessed in comparison to assessing all feasible decommissioning as required by the EIA Directive. However, the UK regulator still expects a comprehensive and detailed assessment.

Post decommissioning monitoring

Post decommissioning monitoring in the UK is very similar to that of Norway. In the UK, a monitoring survey is required after decommissioning to identify any debris on the seabed within a 500m radius of any installation, and 50m either side of a pipeline. Any debris is required to be removed and evidenced by a follow up survey, which provides the ‘as-left’ baseline survey for future surveys to be compared against.

Operators are required to develop a survey strategy for post decommissioning of structures left in-situ. This is agreed in consultation with the regulatory bodies. For pipelines, initial follow up surveys are used to gather evidence of interaction between other users of the sea and the structures left in-situ and of natural changes to the marine environment, e.g. sand deposition or scour around structures. Significant changes are expected to be remediated by the operator. Once a ‘steady state’ between the structures and the environment is established then the period between surveys can be extended in agreement with the regulator.

For larger structures, such as GBSs, continuous monitoring is required, e.g. of markings, lighting and notification of the structure to other users of the sea. In addition, periodic surveys of these structures is required to assess their condition and any potential impacts as a result.

B.2 Norway

B.2.1 Legislation

Legal context of decommissioning in Norway

The main legal framework for offshore decommissioning in Norway is the Petroleum Act section 5 and the Petroleum Regulation chapter 6. International obligations under the OSPAR convention and UNCLOS are implemented in Norwegian legislation [86].

A key requirement (Petroleum Act section 5-3, cf. Petroleum Regulation section 43-45) is to prepare a decommissioning plan prior to cessation of production. The decommissioning plan must describe possible future areas of application for a facility and provide the government with a basis for reaching a decision on disposal. It will not be subject to approval, and the operators' proposal on a disposal solution is not binding on the government. Hence, the governmental decision may deviate to the submitted plan. In most cases however the decision is in accordance with the plan.

The decommissioning plan constitutes two parts; a disposal plan and an impact assessment (IA). Submitting an IA is mandatory, except if the Ministry of Petroleum and Energy finds that the proposal is not expected to have significant effects. The disposal plan may be considered similar to that of a Comparative Assessment; evaluating alternative disposal options using a wide range of criteria. A public consultation must take place as part of the decommissioning programme preparation process. The disposal plan is not publicly available in its entirety as it may contain sensitive economic data. The findings on environmental and society-related criteria in the disposal plan are a summary of the publicly available IA. The IA process is further described in the next section.

End-disposal of pipelines and cables are evaluated by the government on a case-by-case basis based on among others the documentation provided by the operator in the Decommissioning plan. This generally follows the disposal principles provided in Report no 47 (1999-2000), Disposal of discarded pipelines and cables on the Norwegian continental shelf, to the Storting (Parliament). The overarching principle is to find the best "socio economic" disposal solution, balancing costs with environmental protection and fishing interests. Generally, pipelines/cables can be left in place if they do not cause significant inconvenience or safety risk to fishing, balanced with the costs of implementing the solution i.e. they can be left in areas with insignificant fishing, or when they are safely trenched/buried and covered. It is a prerequisite that pipelines are cleaned prior to disposal.

Prior to execution of decommissioning activities, a consent needs to be obtained from the Petroleum Safety Authority (PSA), Management Regulation section 25. Similarly, for activities with planned use of chemicals and/or discharges to sea or posing some kind of risk of pollution or environmental impact, a permit is required from the Norwegian Environment Agency (NEA), Pollution Control Act section 11, cf. Pollution Regulation section 22.

Onshore yards dismantling offshore petroleum structures and managing the waste streams need a specific permit for such from NEA under the Pollution Control Act section 11.

Requirements for P&A are given in the Facilities regulations section 48; "When a well is temporarily or permanently abandoned, the barriers shall be designed such that they consider well integrity for the longest period of time the well is expected to be abandoned." The detailed specification for fulfilling safe well barriers requirements are given in NORSOK D-010 chapter 9.

Disposal and liability provisions (sections 5.3 and 5.4 of the Petroleum Act), require the licensee and the owner to ensure that a decision relating to the disposal is carried out (unless decided otherwise by the Ministry). If a license or a participating interest in a license has been

[86] The Norwegian Parliament enforced the OSPAR decision 98/3 through Proposition no. 8 (1998-99).

transferred, the assignor can remain partly liable towards the assignee and towards the State with regards to the costs of carrying out the disposal solution (i.e. a joint liability system is in place). The proportion of this financial obligation depends on the size of the participating interest assigned, and remains limited to the costs related to facilities which existed at the time of the transfer. This liability is usually established by means of a Decommissioning Security Agreement between the transferor and the transferee. (A similar obligation of subsidiary liability for future decommissioning cost is in place since 2016 for transfers of controlling ownership interest in licensees or in companies controlling such Licensee companies.)[87] If the disposal decision is not carried out within the time stipulated, the Ministry can take necessary measures on behalf of the responsible party, and can seize their property (i.e. enforcement of distraint). The Act also states that whoever is under obligation to implement a decision linked to disposal according to section 5-3 is liable for damage or inconvenience caused while implementing those decisions.

While the decommissioning costs are partly refunded by the State, liability costs are not. The regulations on decommissioning costs changed significantly in the 2000s, with the repeal of the Removal Grants Act. Since then, following the **Act on Petroleum Taxes 1975**, decommissioning costs are refunded by the State in accordance with the fields' tax regime, which usually amount to 78 percent (50 percent company tax plus 28 percent petroleum specific tax). On the other hand, according to the Petroleum Activities Act (section 5.3), liability costs are not refunded. Notably, there is no "liability/decommissioning fund" system in Norway; instead, the strict aforementioned responsibilities related to liabilities are detailed in the Petroleum Act.

Finally, the Petroleum Activities Act and associated Regulations also include provisions on financial security and insurance. The Ministry can require a licensee to provide financial security for the fulfilment of its decommissioning obligations (Petroleum Activities Act 1996). This provision aims to ensure that those responsible for decommissioning have the financial strength to cover possible liabilities in the future. In addition, licensees should be insured at all time during petroleum activities, to cover damage to installations, pollution damage and other liability towards third parties, removal of wrecks and clean-up after accidents, and workers' compensation (Regulations to the Petroleum Act 1997).

Implementation of EU Directives in Norway

EU Directives on environment, e.g. waste management and environmental liability, are of relevance to decommissioning of offshore structures.

As a party to the European Economic Area (EEA) agreement,[88] Norway has the duty to implement EU Directives and other legally binding instruments as defined by the agreement, though there is the right of reservation to implementation of some Directives (as was the case for the EU Offshore Safety Directive (2013/30/EU), though a similar system exists in Norway.

Environmental policies in Norway and EU have a common basic principle; making environmental policy an integral part of policies for other areas, with the superior objective of environmental protection, sustainability and improved environmental conditions. Hence, there is a close cooperation with EU on environmental policies and major parts of EU regulations and Directives are implemented in Norway via the EEA agreement. All relevant Directives on climate, waste management, chemical management, environmental liability, etc. are implemented in national legislation. Some environmental Directives not implemented by Norway are related to classic nature conservation areas, e.g. Birds Directive (2009/147/EC) and Habitat Directive (92/43/EEC), these not being part of the EEA agreement.

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[87] ICGL (2020) International Comparative Legal Guides: Oil and Gas Regulation 2020. 15th edition. Available here: https://www.acc.com/sites/default/files/resources/upload/OG20_E-Edition%20Reduced.pdf

[88] The Agreement on the European Economic Area, which entered into force on 1 January 1994, brings together the EU Member States and the three EEA EFTA States — Iceland, Liechtenstein and Norway — in a single market, referred to as the "Internal Market".

The coverage of the Norwegian legal regime in relation to the main decommissioning aspects is summarised in Table 14.

Table 14: Coverage of the Norwegian legal regime in relation to different decommissioning aspects

Decommissioning aspect	Assessment
Long-term liability for environmental risks	Includes some liability provisions, but whomever remains liable if the liable entity cannot fulfil its obligations is unclear.
Financial capacity of operator to cover decommissioning costs (including external costs)	The Petroleum and Energy Ministry can require a licensee to provide financial security for the fulfilment of its decommissioning obligations. In addition, licensees are asked to be insured at all time during petroleum activities, including to cover decommissioning-related damages.
Monitoring of abandoned installations remaining in-situ	Operators must conduct a survey of the seabed after decommissioning; however, there are no specific requirements for the monitoring of abandoned installations. The Climate and Pollution Agency can, in special cases, set additional requirements for monitoring beyond the prevailing guidelines.
Transparency & public engagement (incl. public consultation on decom project)	The proposed decommissioning plan must include a public consultation. While findings on environmental and societal criteria are summarized in the publicly-available IA, the disposal plan is not made fully public as it may contain economic information of sensitive character for later bidding processes.
Environmental Impact Assessment of decommissioning project	Yes, it is mandatory to conduct an IEA as part of the proposed decommissioning plan.
Comparative assessment of decommissioning options	The disposal plan submitted as part of the decommissioning plan must include a comparative assessment of disposal options.
Potential re-use of decommissioning structures	Not in place.

Similarly, to the UK, Norway has a well-developed and comprehensive regulatory regime in place overseeing offshore oil and gas decommissioning, thanks to its more advanced level of experience compared to its European counterparts. This makes the Norwegian system an overall good example to emulate. Nevertheless, the analysis revealed three gaps in the country's approach, which are highly similar to those observed in the UK regime:

- Whomever remains liable if the liable entity cannot fulfil its obligations is unclear;
- There are no specific requirements for the monitoring of abandoned installations;
- The potential re-use of decommissioning structures is not addressed; and
- The potential ecosystem benefits of leaving structures in-situ are not incorporated into the comparative assessment process.

B.2.2 Environmental legislative requirements

Approach to IA and assessment methods

IA forms part of the decommissioning plan in Norway pursuant to sections 5-1 and 5-3 of the Petroleum Act. The formal Norwegian IA process is described in section 45 of the petroleum regulations, which outlines the steps in the process and the overall scope of the assessment (options and issues). At a more detailed level, the IA process for decommissioning in Norway normally follows the same approach used for development projects, as described in the official Guidelines for plan for development and operation of a petroleum deposit (PDO) and plan for installation and operation of facilities for transport and utilisation of petroleum (PIO) [MPE 2018].

A best practice industry guidance document (handbook) was produced in 2001 and last updated in 2020 [89]. It includes specific lessons on issues and impacts from execution and final disposal which are relevant to the IA process. The handbook focuses on two areas:

- The IA process – clarifying alternative decommissioning options (removal and disposal, or leave partly in-situ) for assessment and providing guidance on stakeholder dialogue processes; and
- The contents of the IA report – providing guidance on issues and possible methods of assessment, and sharing knowledge of the various issues and aspects.

Hence, in Norway the IA approach and method has generally been quite uniform over the last two decades, with some minor adjustments as the knowledge base has increased and slightly different issues have arisen.

An impact assessment is required for all decommissioning, however the regulations allow for some exemption if, through documentation and prior application, it can be demonstrated that the impacts from execution of decommissioning and end-disposal on the environment and third parties are negligible – and the decommissioning solution is obvious. Such exemptions have been granted for a few subsea structures only.

All impact assessment reports in Norway are publicly available on the operator's website.

Compared to other countries, in Norway, there is a more pragmatic approach to environmental assessment, and the impact assessment reports are not as comprehensive as elsewhere and are written at a higher level, with focus on the key decision-making factors. In Norway the range of feasible decommissioning options needs to be examined and assessed in the Impact Assessment.

Impact assessment process in Norway

Consideration of the decommissioning plan and making the decommissioning decision is coordinated by the Ministry of Petroleum and Energy (MPE) in cooperation with the Ministry of Labour and Social Affairs, also consulting the Norwegian Petroleum Directorate (NPD) and the Petroleum Safety Authority Norway (PSA). Gassco is involved if the plans cover gas pipelines. The Ministry of Climate and the Environment, the Ministry of Trade, Industry and Fisheries, the Ministry of Transport, and their subordinate agencies and directorates serve as consultative bodies.

Depending on the nature and complexity of the project, the decommissioning approval process and final decision will normally be made by the Norwegian government and in exceptional cases by the Storting (parliament). The established and follow practice for projects subject to an OSPAR derogation process or involving specific issues of principal of a societal nature is to be presented to and approved by the Storting. This means some projects may go through a two-stage process: non-derogation facilities (such as topsides) approved by the government and derogation facilities (such as concrete GBSs) submitted to the Storting for approval. It is emphasised that the government is responsible for considering the decommissioning plan and conducting the decision process, including consultations related to OSPAR and other national governments.

Stakeholder consultation is an important and integral part of an IA, and must be undertaken in accordance with national regulations (described above) for both the programme for the Impact Assessment (PIA) and the IA itself. No fixed consultation period is specified in the regulations, and its duration must be agreed in advance with the MPE. The normal practice is for a

[89] Norskolje & Gass, Handbook in Impact Assessment for Offshore Decommissioning June 2020, (https://www.norskoljeoggass.no/miljo/handboker-og-veiledninger/handbok-i-ku-ved-offshore-avvikling-/)

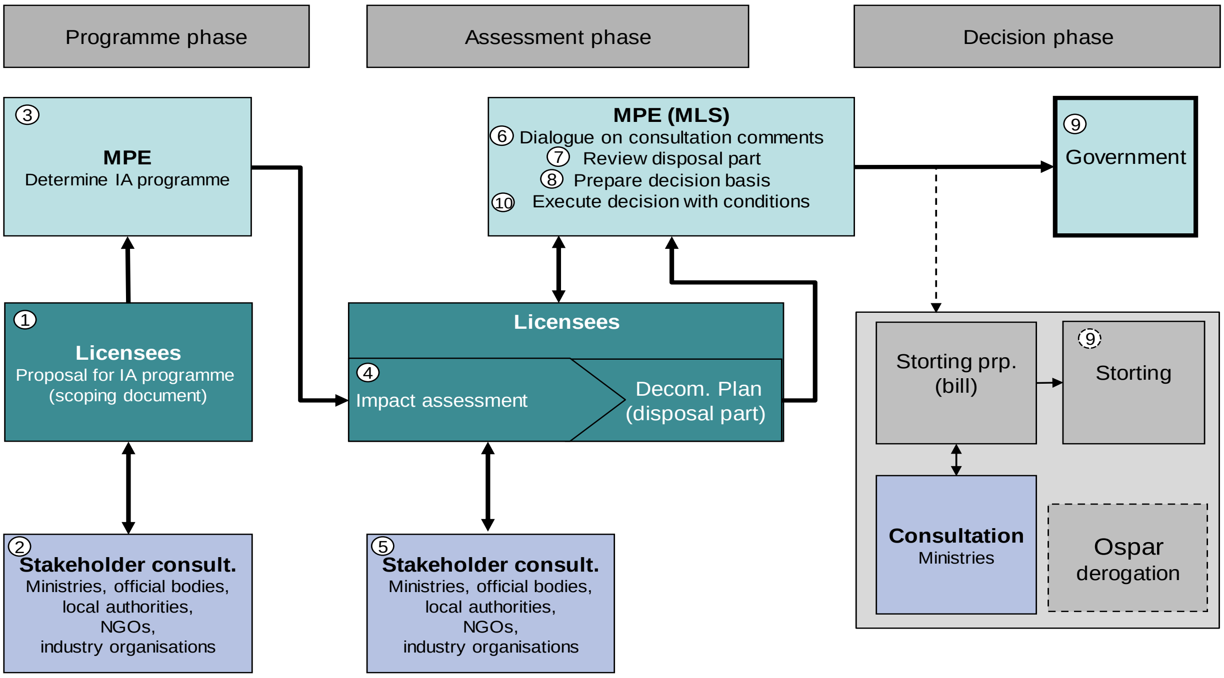
consultation period of at least six weeks and usually 12, as specified in the guidelines for development projects [MPE 2018].

The IA process consists of 3 main steps:

- To develop a draft programme for IA (PIA).[90]
- To perform the actual assessment work
- Authority decision making

The steps in this process are illustrated in Figure 2.

Figure 2: Outline of the steps in Norway's formal IA process until the final official decision. Source: NOROG 2020



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B.3 The Netherlands

B.3.1 Legislation

The principal legal instruments controlling offshore decommissioning in the Netherlands are the international OSPAR Convention, UNCLOS and the Mining Act of the Netherlands (Mijnbouwwet) (2003, as amended). The Mining Act forms the legal basis for exploration and production activities relating to hydrocarbons in the Netherlands (including the Dutch part of the Continental Shelf) and consists of three levels:

- 'Mijnbouwwet' (The Mining Act itself);
- 'Mijnbouwbesluit' (The Mining Decree); and
- 'Mijnbouwregeling' (The Mining Regulations).

The Mining Act prescribes that offshore oil and gas installations that are no longer used must be removed, including scrap and other materials at or immediately near such installations. The Ministry of Economic Affairs and Climate (MEAC) may limit the obligation to a certain depth beneath the water surface, to be determined at its discretion, and may set a time frame within which the obligation must be fulfilled (Article 44). The decommissioning regime with respect to cables and pipelines is slightly different in that the removal obligation does not exist by force of law, but applies if and to the extent that the MEAC has ordered the removal. The obligation rests on the cable or pipeline operator or last known operator (Article 45).

Licenses are issued under the Mining Act and include financial liability for operators. The license will set out means that the holder is obliged to maintain in order to comply with financial obligations that could result from liabilities arising out of the activities to be performed on the basis of the licence (Article 12(2)). More importantly in relation to financial liability arising from exploration under the Mining Act is further addressed in Article 48, according to which the MEAC can stipulate 'that security will have to be provided for the discharge of matters that will become due in the event he takes administrative compulsory legal measures for the enforcement of the obligations under or by virtue of this Mijnbouwwet in respect of the removal or leaving in situ, or the demolition or re-use of cables or pipelines on or in the continental shelf that are no longer used, after removal' (Article 46).

Chapter 5.1.4 and 5.2.4 of the Mining Act establish the requirement for a decommissioning plan to be submitted by the operator of a surface or sub-sea installation or pipeline. A key requirement is this plan must be submitted to the Minister for Economic Affairs within one year of cessation of production of the installation or pipeline. The plan should describe:

- how the decommissioning and removal activities will be achieved and their timetable,;
- what wastes may be present or generated by the decommissioning and demonstrate that safety and environmental risks are prevented or controlled; and
- how the site will be returned to its original condition, or what infrastructure will be left behind

Before a decommissioning plan is executed, Chapter 5.2.3 requires the operator to submit a removal plan to the Ministry for Economic Affairs and Inspector General of Mines for approval. The removal plan describes the removal operation, how and where the installation materials and associated wastes will be treated, processed and disposed of, and a demonstration that the site is free of scrap, waste and other materials.

Chapter 5.3 addresses decommissioning of wells and require that the oil and gas bearing sections are sealed off from formations above.

Chapter 6.4 requires that any pipeline that is decommissioned should be left behind in a clean and safe condition, unless it is removed. The Ministry for Economic Affairs can issue the operator with condition and cleanliness standards that are required to be met by the decommissioning process, establish monitoring provisions following decommissioning to check the condition of any pipeline left in situ, and where necessary require remedial actions to be completed by the operator.

Specifically in relation the environmental impact assessment (EIA), the Mining Act governs the EIA of installations outside of territorial sea and within the EEZ. However, there is no specific obligation for an entirely new EIA to be carried out as a part of the Removal Plan. Instead, attention is paid to the decommissioning phase in the original EIA, giving a rough outline of plans for decommissioning but not providing detail.

Aside from the law, the regulatory regime for decommissioning in the Netherlands also relies on standards such as Standard 45 (Well Abandonment) and standard NEN 3656 (Removal of Pipelines).

Table 15: Regulatory Summary of the Netherlands against decommissioning aspects

Decommissioning aspect	Assessment
Long-term liability for environmental risks	Currently not (yet) in place. An amendment to the Mining Act that could address this topic has been approved and will likely enter into force in July 2021. Furthermore, section 177 subsection 3 of Book 6 of the Dutch Civil Code which stipulates a liability under private law for damage caused by the outflow of minerals during five years after abandonment.
Financial capacity of operator to cover decommissioning costs (including external costs)	The Ministry of Economic Affairs and Climate can stipulate that financial security will have to be provided for costs that are to arise from the removal or leaving in situ, or the demolition or re-use of cables or pipelines on or in the continental shelf that are no longer used, after removal.
Monitoring of abandoned installations	A general rule that installations no longer in use should be removed. Abandoned pipelines and cables, must be inspected periodically (the frequency of inspection varies between 1 to 4 years).
Transparency & public engagement (incl. public consultation on decommissioning project)	Not in place. Decommissioning projects (the Removal Plan) are prepared by operators and evaluated and subsequently approved by the Ministry of Economic Affairs and Climate.
Environmental Impact Assessment of decommissioning project	For projects within the territorial sea, an EIA has to be carried out in order for an offshore project to receive its permit/license. No specific requirements for a second EIA to be carried out in relation to decommissioning. For installations within the EEZ, no EIA is carried out specifically in relation to removal of disused platforms. Decommissioning is roughly addressed in the EIA carried out at the start of the project only. No specific EIA is carried out in relation to removal of pipelines.
Comparative assessment of decommissioning options	Not in place when installation is fully removed, which is the general rule. In place in relation to pipelines only, not in relation to other installations, as there is the general rule in place that unused installations should be removed.
Potential re-use of decommissioning structures	Full removal is required, unless re-use is a foreseeable option. This will be evaluated on a case-to-case basis by operators.

In conclusion, the Dutch Mining Act reflects OSPAR legislation, but also references to general Environmental Impact Assessment (EIA) guidelines set by the EU. In the Netherlands the extraction of oil and gas requires EIA's to be carried out. Together with the input from stakeholders, a number of good practices have been identified within the Dutch national regulatory regime:

- The system of financial security;
- The standards for well abandonment;
- The comparative assessment in relation to pipelines; and
- Industry-led guidance document relevant to decommissioning

Upcoming Legislative Changes

In 2020, the government proposed amendments to the Mining Act to reflect greater understanding of the current costs of decommissioning, estimated at €4.67bn for the offshore assets, and how the market would react to decommissioning. The amendment introduces an obligation for production licensees to enter into a set of agreements on decommissioning obligations that aims to ensure that the operator can charge the costs of decommissioning to all parties in the Joint Operating Agreement. These include:

- A Decommissioning Security Agreement (DSA) that is agreed between the operator and co-licensees. The DSA arranges the timing for and the form of the financial security provided by licensees and is based on a ratio between the expected value of the assets and the remaining reserves and the expected decommissioning costs. The DSA is re-assessed and adjusted annually.
- A Decommissioning Security Monitoring Agreement (DSMA) agreed between the licensees and Energie Beheer Nederland B.V. (EBN), the state-owned company that under Dutch law is non-licensed partner in E&P activities. The DSMA allows EBN to monitor the application of the DSA and to determine whether or not the security is adequate.

The decommissioning security agreements have been developed by NOGEPA, EBN and the Ministry of Economic Affairs and are comparable to security agreements arrangements in the UK between operators and the OPRED.

Investment deductions have also been increased to encourage investment in small fields, and prolong investment in mature assets. This will increase the financial viability of assets at the end of life, but not ultimately alter the cost of decommissioning of the asset.

Finally, the amendment has changed the provision to submit a decommissioning plan for an asset that has reached cessation of production. Currently, the requirement is for a decommissioning plan to be submitted within a year of cessation of production. This has been waived in the event that the licensee proposes alternative use, such as carbon capture and storage or hydrogen production.

B.4 Denmark

B.4.1 Legislation

The Danish Energy Agency (DEA) was established in 1976 and is a part of the Danish Ministry of Energy, Utilities and Climate - the regulatory body behind Denmark's oil and gas production. The regulatory framework for decommissioning is governed by IMO Resolution A.672 and OSPAR decision 98/3 with section 32a of the Subsoil Act outlining the specific guidelines for decommissioning of offshore oil and gas facilities in the Danish sector of the North Sea. Each decommissioning project requires a detailed plan to be submitted to the DEA, where in addition to describing the installations to be removed and the way in which they will be removed, calculated costs are submitted with a description of how and when the funds required for the decommissioning plan will be available.

The decommissioning of production platforms requires the jackets and topsides to be removed and transported onshore for re-use, recycling or disposal. Jackets weighing greater than 10,000 tonnes in air can be considered for derogation by OSPAR. The decommissioning of wells is described in the DEA Guidelines for drilling, which outlines the requirements for the plugging and abandonment of wells. The decommissioning of pipelines will be considered on a case by case basis, using a Comparative Assessment method to determine the suitability of leaving them in-situ. Pipelines must be flushed, plugged and either removed or buried so as not to cause any environmental impact or a danger to passing ship traffic or other users of the sea.

In December 2020 the Government announced that oil and gas production in the Danish North Sea will end by 2050 in an effort to become carbon neutral. Denmark had previously held 7 licencing rounds where operators were invited to tender for exploration and production licences from the Danish Energy Agency, with the upcoming 8th round now cancelled.

With Danish installations in relatively shallow water, the decommissioning of the wells and platforms is expected to be the preferred decommissioning outcome However, the Danish subsea reservoir the Nini West was certified as feasible for the storage of CO_2 in November 2020. This could result in the utilisation of more Danish offshore infrastructure for Carbon Capture Storage (CCS).

The Danish sector follows common practices for decommissioning that have been developed across the North Sea; for example in well decommissioning, comparative assessment of decommissioning options, environmental impact assessment (in accordance with the EIA Directive (2011/92/EU with 2014 amendment) and in the approach to removal of assets in accordance with OSPAR 98/3.

Denmark has officially stated that all offshore constructions must be removed after the facilities have been abandoned. However, some installations may be retained for 'other purposes', such as importing and storing natural gas. The Danish Energy Agency (DEA) can order the removal of all or part of any installation. Danish legislation makes no specific reference to pipeline decommissioning.[91]

The leading legal instrument relevant for decommissioning is the **Subsoil Act**. It regulates the general licensing conditions. It governs preliminary investigations, exploration and production of resources from the Danish subsoil with a focus on hydrocarbons. The purpose of the Danish Subsoil Act is to ensure appropriate use and exploitation of the Danish subsoil, in a manner that is safe and preventative regarding waste.[91]

The crucial provision of the Subsoil Act in relation to decommissioning specifically is Section 32a, which stipulates that applications for a license must be accompanied by a **plan for decommissioning**, which should include, at minimum, the following points:

[91] IGOP, 'Overview of International Offshore Decommissioning Regulations' (2017)

- Calculation of the estimated expenses for implementing the decommissioning plan; and
- Description of how security will be provided for availability of funds necessary for implementing the decommissioning plan.

The decommissioning plan must be approved by the relevant public authority (Ministry for Climate, Energy and Utilities). The public authority also reserves the right to lay down any specific terms and conditions in relation to the decommissioning plan and/or more stringent requirements for the content of the decommissioning plan, such as:

- Assumptions to be used for decommissioning facilities and installations;
- Calculation of expenses (which might also, subject to the decision of the public authority, be required to address the requirement for funds for installations that are permanently abandoned and/or for wells); and
- Requirements on provision of security for the funds necessary for removal (Section 32a).

Furthermore, license holders are **financially liable** for any damages, losses or injuries caused as a result of the license awarded to them (section 35); license holders have a strict liability for all accidents that occur either during decommissioning, or subsequently if any installation is left in situ.

A decision whether a license holder has an obligation to carry out an environmental impact assessment (**EIA**) in relation to the decommissioning project is determined on the basis of the decommissioning plan. Therefore, not all decommissioning projects need an EIA, only the ones where it is determined (by the competent authority; the DEA) that it is required, subject to assessment of the decommissioning plan.[91]

The Subsoil Act also requires for license holder to be **transparent** in relation to their procedures for handling damages caused as a result of their installations (Section 24a (3) and (5)). Furthermore, also in relation to transparency of offshore exploration of hydrocarbons – such exploration can only be initiated once an ‘early and efficient **public participation** with respect to any impact of the planned activities on the environment pursuant relevant EU legislation’ campaign took place. If this campaign does not take place, it is the responsibility of the relevant Danish public authority to ensure such public participation campaign took place (Section 28d (1) and (2)). Lastly, any public or private party has the power to object to decisions made on the basis of the Subsoil Act (Article 37a).

In Denmark, the requirements to decommission relates broadly to all parts of an offshore installations and thus also **pipelines**.

Dismantling must be planned and carried out in such a way that **safety and health** risks and risks of major incidents, including environmental incidents are identified, evaluated and reduced in accordance with the ALARP principle. The operator is in charge of this and sustains the duty to manage the risks through management system controls.

Table 16: Overview of national regulatory framework in Denmark

Decommissioning aspect	Assessment
Long-term liability for environmental risks	License holders are financially liable for any damages, losses or injuries caused as a result of the license awarded to them.
Financial capacity of operator to cover decommissioning costs (including external costs)	This must be addressed in the decommissioning plan submitted prior to the start of exploration of offshore hydrocarbons, subject to the approval of the relevant public authority.
Monitoring of abandoned installations	A uniform regime requiring monitoring is not in place.
Transparency & public engagement (incl. public consultation on decommissioning project)	Not in place in relation specifically to decommissioning. However, public engagement campaigns take place prior to any new offshore projects of hydrocarbon exploration. Furthermore, license holders should be transparent about their procedures for handling damages.
Environmental Impact Assessment of decommissioning project	The decision on whether an EIA is required is made on case-to-case basis, relying upon the submitted decommissioning plan.
Comparative assessment of decommissioning options	Not in place.
Potential re-use of decommissioning structures	Not in place.

The current regulatory regime addresses a number of aspects of the above-mentioned decommissioning aspects. Among identified good practices, the requirement of financial capacity of operators to cover decommissioning costs being addressed in the decommissioning plan can be mentioned.

B.4.2 Environmental legislative requirements

The principal legal instruments controlling offshore decommissioning in Denmark are the international OSPAR Convention, UNCLOS and Section 32a of the Subsoil Act.

In Denmark, a comparative assessment method called Net Environment Benefit Analysis (NEBA) is in general used to assess the benefits versus the disadvantages of various decommissioning options. NEBA is used to compare and rank different alternatives against environmental, socio-economic, cost, safety and technical criteria to identify the preferred option. There appears to be increased emphasis on highlighting the benefits of leaving structures in situ owing to the colonisation of infrastructure over time by marine ecosystems (many offshore structures can function as refuges for fish, and support greater biodiversity).

B.5 Italy

B.5.1 Legislation

The Ministry of Economic Development (MiSE) is the regulatory body for the oil and gas industry in Italy. Prior to decommissioning, the Legislative Decree of the Ministry of Economic Development 15 February 2019 requires operators to provide a detailed work plan and schedule with regards to their intended decommissioning activities. The MiSE issued guidelines on the decommissioning of platforms which clarifies the requirements that must be fulfilled in order to comply with Italian legislation and procedures with regard to decommissioning and for the re-use of offshore E&P facilities. The guidelines refer to EU legislation, UN Conventions, IMO guidelines and the Barcelona Regional Convention, which is the standard Italy adheres to in decommissioning.

Following the Barcelona Convention, platforms and other facilities that are no longer in operation are required to be removed whilst preserving the surrounding environment. Pipelines that are no longer used or abandoned are required to be cleaned and buried or removed so as they do not cause pollution or pose a danger to passing ship traffic and wells requiring plugging and abandonment.

The 2019 Guidelines state that the abandoning of platforms and related infrastructure (i.e. plants connected to the platform and used to allow the production of hydrocarbons and their transport to other plants) is prohibited, except when a reuse proposal has been approved (see below). Prospective operators must provide details on the proposed decommissioning and restoration programme – including necessary actions for the characterization and clean-up of the site – as well as guarantees of their ability to cover expenditure commitments related to these activities when applying for a mining license (i.e. before production begins) (Articles 3 and 4). The operator must also provide economic guarantees that it can cover the costs of a possible accident during the removal activities (Decree 7 December 2016, Article 4). After the expiry of their mining concessions, operators must again provide plans for the removal of installations in a technical report. These plans must be accompanied by a work plan and a time frame of all planned decommissioning activities.[92],[93] The plans must contain the following elements:[94]

- Description of the installations to be dismantled;
- Information relating to the verification of the condition of the installations;
- Detailed engineering:
    - Description of the dismantling option, selected on the base of multi-criteria analysis,
    - Reuse, recycling and waste disposal program and description of the type and categories of waste to be managed during the performance of the operations;
- Characterization of the area affected by the dismantling operations and recovery/remediation project to be agreed with the competent Environmental Protection Agency (ARPA);
- Documentation concerning the cultural heritage, including underwater archaeological one, the landscape of the coastal areas if affected;

[92] IGOP (2017) Overview of International Offshore Decommissioning Regulations. Available here: https://www.extractiveshub.org/servefile/getFile/id/6666

[93] ICGL (2018) The International Comparative Legal Guide to: Oil & Gas Regulations 2018. 13th edition. Available here: https://www.acc.com/sites/default/files/resources/vl/membersonly/Article/1478061_1.pdf

[94] As per stakeholder feedback (Governmental)

- Environmental and post-removal monitoring program.

These elements are sent to the Ministry of Environment, which is in charge of carrying out the EIA.[95] The decision is taken by the relevant National Mining Office for Hydrocarbons and Georesources (UNMIG) Section of the Ministry of Economic Development (MiSE), after consultation with the Harbor Master's Office (Ministerial Decree of 15 February 2019). Subsequently, the relevant UNMIG Section draws up a report on the shutting down of the deposit. The Section also certifies that decommissioning is completed and send a certification to the Ministry for the cancellation of the mineral rights.[96] The Ministry is currently assessing the need to update the guidelines in order to simplify some procedures and accelerate the authorization process, while keeping the current effectiveness standards it has observed. [97]

The closure of wells is regulated by the **Presidential Decree of 24 May 1979 no. 886**, which mandates the removal below the seabed of the lining column, the intermediate columns and the production column, by cutting and recovery (Ministerial Decree of 15 February 2019).

In addition to the decommissioning programme, an amendment to the Report on major risks must be submitted to the Committee for the safety of operations at sea and to the UNMIG Section competent for the territory for evaluation and acceptance prior to both the decommissioning and the reuse activities. The required procedures are laid out in **Legislative Decree no. 145 of 18 August 2015** implementing Directive 2013/30/EU on safety of offshore oil and gas operations and amending Directive 2004/35/EC. The amended report must be submitted at least 90 days before the start of the work and must amend the major risks reports with regards to: the description of environmental limitations, meteorological and seabed as regards the conduction safe operations, and the procedures for identifying risks related to seabed and marine environment hazards such as the presence of pipelines and moorings of adjacent facilities (Article 12; Annex 1). The operator can be fined between 20 000 and 100 000 euros for breaching Article 12.

Other important requirements of Legislative Decree no. 145 relate to general responsibilities and liability. In the event of a serious accident, operators must take all appropriate measures to limit the consequences for human health and the environment. Operations (including decommissioning) must be undertaken on the basis of systematic risk management to limit risks of serious accidents for people, the environment, and offshore facilities to an acceptable level (Article 3). With regards to liability, the operator is financially responsible for the prevention and repair of the environmental damage caused by its offshore oil and gas operations, including decommissioning (Article 7).

Some monitoring activities are required during and after decommissioning activities. Quarterly reports must be sent to the competent UNMIG Section and to the territorially competent Environmental Protection Agency during the execution of the removal works, and a final report must be sent within six months after works are completed. Moreover, at the end of the decommissioning activities, the operator may be required to conduct environmental restoration activities (Ministerial Decree of 15 February 2019). Once licensee monitoring finishes, Authorities competent in alternative reuse will be responsible for supervising safety if the offshore installation is reused, and authorities in charge of the safety of offshore activities will become responsible after complete decommissioning.[97]

As aforementioned, platforms may be reused. To be allowed to do so, interested companies/entities must submit a complete application for the reuse project, with a level of details at least equivalent to a technical-economic feasibility assessment.[97] The application includes a description of planned activities and their impacts (on other uses of the sea, the environment, cultural heritage and landscape, and social/economic effects) and some plans

[95] Italy follows the approach laid out in the EIA Directive and its subsequent amendments. The latest update – Directive 2014/52/EU – was incorporated into Italian legislation via Legislative Decree 16/06/2017 n.104

[96] ICGL (2018) The International Comparative Legal Guide to: Oil & Gas Regulations 2018. 13th edition. Available here: https://www.acc.com/sites/default/files/resources/vl/membersonly/Article/1478061_1.pdf

[97] As per stakeholder feedback (Governmental)

for operations and future decommissioning. Depending on the typology of the project, an EIA may be required. [97, 98] The interested companies/entity must also meet general, technical, economic, financial and organizational capacity prerequisites to prove that they are capable to execute and realize the proposed projects (Ministerial Decree of 15 February 2019). As part of the financial guarantees specifically related to decommissioning, the applicant must provide insurance or bank guarantees for dismantling activities and for environmental recovery interventions. [97] The application must be submitted to several entities: the Ministry of Economic Development (DGSAIE), the Ministry of Economic Development (DGS-UNMIG), the Port Authority, the competent Administration, and if required to the local authorities concerned. Notably, the application can be rejected if some 'acts of dissent' are not overcome. After being granted the authorization for reuse, the operator must also apply for the maritime land concession for the occupation and use of the relevant area. Not all platforms can be reused; the decision is taken by the DGS-UNMIG of the Ministry of Economic Development and is published annually online (Ministerial Decree of 15 February 2019).

Finally, the forthcoming **Plan for the Sustainable Energy Transition of Eligible Areas** (Piano per la Transizione Energetica Sostenibile delle Aree Idonee, or PTSEAI) set to be approved in 2021 will identify onshore and offshore installations with the aim to improve the environmental, social and economic sustainability of hydrocarbon exploration. Within this scope, it will indicate the timing and procedures for the plants to be decommissioned and for the recovery of the related areas.[99]

Table 17: Coverage of the Italian legal regime in relation to different decommissioning aspects

Decommissioning aspect	Assessment
Long-term liability for environmental risks	Not in place. If the offshore installation is reused, authorities competent in alternative reuse will be responsible; after complete decommissioning, authorities in charge of the safety of offshore activities will be responsible.
Financial capacity of operator to cover decom costs (including external costs)	As part of the financial guarantees specifically related to decommissioning, the applicant (for both exploration and reuse projects) must provide insurance or bank guarantees for dismantling activities and for environmental recovery interventions
Monitoring of abandoned installations remaining in-situ	Mandatory monitoring until 6 month after the end of decommissioning activities. An environmental and post-removal monitoring program must be included within the removal and dismantling project.
Transparency & public engagement (incl. public consultation on decom project)	Not in place.
Environmental Impact Assessment of decommissioning project	Operators must submit specific information to the Ministry of Environment, which the latter uses to conduct an EIA prior to decommissioning.
Comparative assessment of decommissioning options	Not in place.
Potential re-use of decommissioning structures	Some platforms are made available for reuse. Interested parties must submit an application, as per the Ministerial Decree of 15 February 2019.

One notable good practice from the country is its detailed provisions for the reuse of structures, which contrasts with the OSPAR approach taken in the North Sea. Some identified gaps are

[98] Manfra, L., Virno Lamberti, C., Ceracchi, S., Giorgi, G., Berto, D., Lipizer, M., ... & Trabucco, B. (2020). Challenges in Harmonized Environmental Impact Assessment (EIA), Monitoring and Decommissioning Procedures of Offshore Platforms in Adriatic-Ionian (ADRION) Region. Water, 12(9), 2460.

[99] As per stakeholder feedback (Governmental)

mentioned in Table 17, notably with regards to provisions for long-term liability for environmental risks, public engagement, and comparative assessments.

B.5.2 Environmental legislative requirements

In Italy, there have been a significant number of platforms entering the decommissioning phase that did not undergo an EIA, as there was no legislative framework requiring this at the time. It has only been in recent years that Italy has adopted national guidelines for the decommissioning of offshore platforms, to ensure the quality and completeness of the assessment of their environmental impact. Additionally, it is notable that of the numerous platforms that have already been decommissioned offshore in Italy, almost half of the steel jacket infrastructure has been left in situ as artificial reefs in a dedicated area of the Adriatic Sea “Paguro”, which is now a Site of Community Importance.

The Italian government supports the comparative assessment method based on Multi-Criteria Analysis (MCA), that is very similar to the OGUK CA guidelines Evaluation Method C (MCDA) described earlier. However, it is unclear if the method been applied to any decommissioned offshore assets in Italy.

B.6 Other concerned EU Member States

B.6.1 Croatia

The Mining Act (Official Gazette 56/13 and 14/14) and Act on Exploration and Exploitation of hydrocarbons (Official Gazette 94/13 and 14/14) provide the legal framework for oil and gas production in Croatia. Under Article 185 of the Act on Exploration and Exploitation of hydrocarbons the licence holders bear full responsibility for decommissioning, from planning to project execution and waste management. Art. 185. describes the process for cessation of production and applying for removal of the infrastructure, while Art. 153 requires the operator to produce a Petroleum Facilities Removal Plan.

Croatia follows the principals and requirements of the Barcelona Accord and OSPAR Convention (although not a signatory to the latter) for decommissioning of oil and gas structures. This requires total removal of all infrastructure, unless there is a strong justification for not doing so. An initial Environmental Impact Assessment (EIA) study is required. This must describe how the impact to the environment from decommissioning operations will be minimised, and include:

- The method of permanent well P&A, for subsurface isolations this follows the emerging practice for well P&A in the UK and North Sea, although the well casing can be cut at seabed level (rather than at a depth below the seabed);
- The total removal of steel topside and jacket structures;
- Transportation of structures to a mainland facility for dismantlement and disposa;
- Pipeline decontamination details – as a minimum the residual hydrocarbon fluid should be removed by flushing, and
- Waste management and arrangement for treatment of wastes produced during decommissioning.

Under this framework, pipeline infrastructure is generally expected to be left in-situ. Currently, the Regulator is evaluating leaving jackets in situ for development as artificial reefs.

There are Croatian licence areas that are jointly produced for both Croatia and Italy, e.g. the Izabella field (or solely produced for Italy). In 2014, Croatia prepared a Production Sharing Agreement which states that operators must follow Croatian legislation for decommissioning. An operator can propose alternative legislation if it is demonstrated that the legislation is of a more rigorous standard than the Croatian equivalent.

Should a production licence be sold, the Act on Exploration and Exploitation of hydrocarbons allows for the full share of decommissioning and associated obligations to be transferred to the new owner. The sale process is subject to review and approval of the new owner by the Government Ministry responsible for oil and gas exploration and production. Under this arrangement, the full decommissioning obligation is transferred ultimately residing with the final licence owners. It is not clear if previous owners can be held liable for a proportion of the cost of decommissioning in the event of a default by the current licence holder. Ultimately, the State will be responsible for the costs of decommissioning in the event of a default by a licence owner.

Table 18 shows whether some of the main topics regarding offshore decommissioning in the national regulatory regime.

Table 18: Coverage of decommissioning topics in the Croatian legislation100

Topic	Croatia (Y/N)
Assets in or approaching Decommissioning	Y
Abandonment in situ	N
Decommissioning guidelines	N
Environmental Impact Assessment for removal	Y
Monitoring during removal	Y
Restoration measures	
Partial removal, alternative use (reuse)	Y
Environmental Impact Assessment for reuse	N

B.6.2 Spain

The fundamental legislation on hydrocarbon exploration and production in Spain is Law 34/1998 and Royal Decree 1716/2004 of 23 July 2004, with the principal decommissioning legislation being OSPAR 98/3 and associated conventions and decommissioning requirements. Spain is also a signatory to the Barcelona Convention, which covers those assets in the Mediterranean.

B.6.3 Romania

Offshore oil and gas production in Romania is governed by four main instruments:

- Law No. 238/2004 (Petroleum Law);
- Law No. 256/2018 (Offshore Law);
- Law No. 165/2016 (Law on the Safety of Offshore Oil Operations);
- Emergency Ordinance No. 68/2007 on environmental liability with regard to the prevention and remedy of environmental damages.

However, a limited reference is made to decommissioning of offshore installations in these instruments. The Petroleum Law establishes the necessity of drafting, by the licence holder, an **abandonment plan** in respect of the physical structures used in the production of petroleum, consisting of complex technical, economic, social and environmental documentation, justifying the closing of the petroleum well and providing for the necessary actions to ensure the financing and effective fulfilment of the measures for cessation of activity. The abandonment plan shall be endorsed by the National Agency for Mineral Resources (ANRM). The production rights may be abandoned only if all the necessary measures to protect the reserves, land and environment are taken. The procedure for the abandonment of a petroleum well is provided in the standard technical instructions regarding the approval of the abandonment of petroleum wells, adopted by the ANRM. The above-mentioned provisions are similar for both oil and natural gas developments.[101]

One topic that is specifically addressed in relation to decommissioning is **liability** arising from it. Broadly speaking, title holders are financially liable until the reparation of all environmental factors that were affected by the petroleum operations is completed. [103] Furthermore, licence holders are financially liable for the prevention and the remediation of environmental damage caused by offshore oil operations carried out by (or on behalf of) the licence holder or the

[100] MDPI, Challenges in Harmonized Environmental Impact Assessment (EIA), Monitoring and Decommissioning Procedures of Offshore Platforms in Adriatic-Ionian (ADRION) Region, July 2020

[101] See https://www.acc.com/sites/default/files/resources/vl/membersonly/Article/1478061_1.pdf

operator.[102] Lastly, in the event of a major accident, operators must take all necessary measures to limit its effects on human health and the environment.[103]

Another decommissioning aspect addressed under Romanian legal system is the requirement to carry out an environmental impact assessment (**EIA**). However, an EIA is only required prior to the start of a exploration project and it is unclear whether the decommissioning phase is considered during this process (as it is, for example, in the Netherlands). According to the methodological norms for the application of the Petroleum Law, exploitation works can only begin after obtaining the environmental agreement and providing the necessary conditions for the capture of petroleum, disposal of waste water and, if necessary, flaring of the associated gas. The EIA report is performed by authorised third parties, natural persons or legal entities that are acting independently of the titleholder of the project. The EIA procedure is led by the central and territorial authorities for environmental protection and is achieved with the participation of other public central or local authorities, organised under the Technical Analysis Committee.[103]

However, for installations of non-productive nature, which the Romanian law defines as 'installation other than an installation used for the exploitation of oil', **a major hazard report** must be prepared prior to the commencement of decommissioning and decommissioning 'shall not commence until after the competent authority has accepted the amended major hazard report for the non-productive fixed installation'.[104]

Lastly, the only other decommissioning aspect somewhat addressed under Romanian legislation is **transparency and public engagement**. However, similarly to the EIA, this aspect is also only addressed prior to the start of a project and not at the decommissioning stage. The public is to be consulted through the means of a public consultation. If that is not the case, the authority authorising the project shall inform the public and consult by other means, where required.[105]

Table 19: Romania – Overview of Regulatory framework

Decommissioning aspect	Assessment
Long-term liability for environmental risks	<u>In place for the entire lifespan of an installation.</u> Concessionaires are financially liable until the restoration of all environmental factors that were affected by the petroleum operations. In addition, the licence holder is financially liable for the prevention and the remediation of environmental damage caused by offshore oil operations carried out by (or on behalf of) the licence holder or the operator.
Financial capacity of operator to cover decom costs (including external costs)	<u>Not in place.</u>
Monitoring of abandoned installations	<u>Not in place.</u>
Transparency & public engagement (incl. public consultation on decommissioning project)	<u>Not specifically in place in relation to decommissioning projects</u>. Public engagement is only considered when a new project is to be initiated. The public is to be consulted through the means of a public consultation. If the public consultation does not take place, the authority authorising the project shall inform the public and consult where required.
Environmental Impact Assessment of decommissioning project	<u>Not specifically in place in relation to decommissioning projects.</u> EIA is only required at the start of the offshore project; it must be carried out prior to the start of offshore oil and/or gas exploitation. There is no evidence suggesting that another Impact Assessment must be carried out in relation to decommissioning of an installation.

[102] Emergency Ordinance No. 68/2007 on environmental liability with regard to the prevention and remedy of environmental damages

[103] See https://uk.practicallaw.thomsonreuters.com/2-566-0966?transitionType=Default&contextData=(sc.Default)&firstPage=true#co_anchor_a986840.

[104] Law No. 165/2016 on the safety of offshore oil operations, Art. 12(5)

[105] Law No. 165/2016 on the safety of offshore oil operations, Art. 5

Decommissioning aspect	Assessment
Comparative assessment of decommissioning options	Not in place.
Potential re-use of decommissioning structures	Not in place.

Additionally, as mentioned by the Romanian Competent Authority in response to the stakeholder questionnaire, there is no specific legislation in Romania covering the decommissioning of pipelines and related equipment as well as of structures below seabed. The same applies to legislation addressing environmental hazards that may arise once the decommissioning phase is completed and/or when wells have been abandoned.

B.6.4 Germany

Germany is a contracting party of the OSPAR convention and therefore, follows OSPAR decision 98/3 on the disposal of disused offshore installations, and the German Federal Mining Act of 1980. A decommissioning plan must be submitted with a description of the inventory to be decommissioned, a method of decommissioning and an Environmental Impact Assessment in accordance with the EIA Directive (2011/92/EU with 2014 amendment). The national legislation (Federal Mining Act) provides for a number of requirements in order a closure plan to be approved:

- Third parties are protected from risk to human health or life caused by operations even after they have been terminated;
- The surface of the area used by the terminated operations is restored; and
- Mining facilities are completely removed from the area of the continental shelf and coastal waters, down to the soil of the seabed.

In addition, according to the Federal Offshore Mining Ordinance, the operator has the obligation to backfill wells that are not or should not be used anymore in a way that they are completely sealed with respect to emissions of liquids and gas. Soil zones that have to be protected and soil horizons with the possibility of adverse effects have to be sealed especially. Additionally, the operator has the obligation to fix these wells in a way, that the seabed is available again as a natural habitat.

According to the German Federal Mining Act (Section 69(2)) monitoring of disused installations can be ended only if ‘it is no longer probable that the operation would pose a danger of death or injury of third parties, or danger to other mining operations and deposits whose protection is in the public interest, or a hazard to the public’.

B.6.5 Ireland

Decommissioning in Ireland is controlled by the Department of the Environment, Climate and Communications (DCENR) under the Petroleum and Other Minerals Act, 1960 and OSPAR decision 98/3. Similarly to UK legislation, operators in Irish waters are required to submit a detailed decommissioning plan which sets out how they plan to remove their facilities, ensuring they create as little impact as possible on the environment. Decommissioning in Ireland requires all wells to be plugged and abandoned and all associated infrastructure within a field being removed. Decommissioning plans are assessed on an individual basis and approved in line with international best practice.

The Irish government has recently agreed the terms for an oil exploration ban that prohibits all future oil exploration. However, it does not extend to gas, which is considered to be a “transition” fuel allowing transition to a lower carbon economy.

Ireland follows common practices for decommissioning in the OSPAR area.

B.6.6 Greece

Oil and gas production in Greece is licenced and regulated through Hellenic Hydrocarbon Resource Management (HHRM). In addition to these roles HHRM is also the oil and gas tax revenue collecting body. There is no specific legislation relating to decommissioning of offshore oil and gas structures, but decommissioning requirements are included in the production licence. It is expected that decommissioning requirements for platforms and pipelines in Greece will conform to the requirements of the Barcelona Accord with regards to structures in the marine environment and will adopt best practices for well decommissioning, Table 20 shows whether some of the main topics regarding offshore decommissioning are covered in the Greek regulatory regime.

Table 20: Coverage of decommissioning topics in the Greek legislation106

Topic	Greece (Y/N)
Assets in or approaching Decommissioning	Y
Abandonment in situ	N
Decommissioning guidelines	N
Environmental Impact Assessment for removal	Y
Monitoring during removal	Y
Restoration measures	Y
Partial removal, alternative use (reuse)	Y
Environmental Impact Assessment for reuse	Y

B.6.7 Poland

Offshore oil and gas decommissioning procedures are laid out in the Geological and Mining Act 2011, which specifies limited mandatory requirements in this respect. The envisaged method of decommissioning does not need to be laid out in the application for a mining concession within the Polish maritime territory (Articles 22.1 and 26.4), and the Act does not mandate the submission of a decommissioning plan to relevant competent authorities. The operator is required to secure or abandon workings, and secure or decommission equipment, installations and facilities, and to specify the methods used to fulfil this obligation (Article 129). After decommissioning, the operator must provide the President of the State Mining Authority with a surveying and geological study (Article 131).

The Act also addresses matters related to financial security and liability. Once granted a mining concession, the operator must set up a decommissioning fund in a separate bank account (Article 128). The transfer of mining concessions can only occur if the entity to which the concession is transferred produces evidence of opening a bank account of a mining plant-decommissioning fund and gathering in said account funds corresponding to the amount of funds gathered by the previous operator (Article 36). In addition, the revocation, expiry or loss of effect of a concession do not preclude an operator from fulfilling its obligations in the scope of decommissioning (Article 39.1).

[106] MDPI, Challenges in Harmonized Environmental Impact Assessment (EIA), Monitoring and Decommissioning Procedures of Offshore Platforms in Adriatic-Ionian (ADRION) Region, July 2020

APPENDIX C Country overviews

This appendix summarises for each concerned country the existing offshore oil and gas installations, the current and planned decommissioning projects and the environmental and monitoring practices. The final section covers emerging trends in decommissioning.

C.1 UK

Offshore oil and gas producers in the UK operate primarily in the North Sea, but also West of Shetland and in the Irish Sea. The North Sea naturally splits into 3 sectors, namely, the Northern North Sea (NNS), the Central North Sea (CNS) and the Southern North Sea (SNS). The number and type of platforms in each of these areas is related to the water depth and differing sea conditions in each area and so:

- The NNS hosts a number of large steel platforms and concrete gravity bases (CGB) in deeper waters (100 – 120m);
- The CNS has more platforms than the NNS of medium size fixed steel installations in medium water depths (50 – 100m) and subsea production systems tied back to floating production, storage and offloading (FPSO) installations in deeper waters; and
- The SNS has the largest number of platforms, the majority of which have a combined jacket and topsides weight of less than 5000 tonnes and in relatively shallow water (20 – 35m).

C.1.1 Installations and Decommissioning

The UK first started producing oil and natural gas from offshore platforms in the North Sea in late 1965. Currently, there are approximately 364 oil and gas fields with approximately 278 production platforms, excluding FPSOs, FSUs, bridge and flare supporting structures etc, all either in production or shut down awaiting decommissioning. In addition to 278 platforms, it is estimated that there is over 10,000 km of offshore pipeline and over 7,800 wells drilled which can be categorised as follows[107]:

- 2128 completed (operating);
- 696 completed (shut in);
- 267 plugged;
- 648 abandoned phase 1 & 2;
- 4015 abandoned phase 3.

The Oil and Gas Authority has defined the different phases of abandonment as:

- Abandoned phase 1 - The reservoir has been permanently isolated. Permanent barrier material is in place to fully isolate all reservoir producing or injecting zone from the wellbore.
- Abandoned phase 2 – All intermediate zones with flow potential have been permanently isolated. Phase 2 is complete when no further permanent barriers are required.

[107] Oil & Gas Authority, Well insight Report 2018, https://www.ogauthority.co.uk/media/5107/oga_wells_insight_report_2018.pdf

- Abandoned phase 3 – Wellhead and conductor has been removed and the well will never be used or re-entered again.

The UK operates several different types of offshore installation, primarily determined on field location within the North Sea and subsequently its water depth and sea conditions and these are fixed steel, floating steel and concrete based structures. The difference in the size and weight of these different types of structure varies greatly with small steel structures having a combined jacket and topsides weight of less than 5,000 tonnes to concrete structures weighing hundreds of thousands of tonnes.

The different types and sizes of installation found throughout the North Sea pose their own set of engineering challenges. The smaller, lighter platforms typically found in the SNS can be removed in a single lift. These small structures can then be transported to shore by vessel for dismantling, cleaning, re-use or disposal. The larger, more complex structures in the NNS pose a far different challenge in terms of size, additional hazardous waste streams and water depth. A summary on the location of UK operated assets either in production or shut down awaiting decommissioning are shown in the table below.

Table 21: UK infrastructure in production or closed down and location

Area	Number of UK Operated Fields	Number of Platforms
North Sea	364	256
West of Shetland	2	4
Irish Sea	10	19

Using available information from OSPAR an overview of UK inventory in the Atlantic and North Sea has been collated and is summarised in the table below.

Table 22: Number of installations in UK waters (status in 2020). Source: OSPAR web pages (2020) [108] and inventory [109] (installations planned/under construction not included)

Type of structure	In operation	Shut down not removed/disposed of	Partly or completely removed or disposed of	Total
Concrete gravity-based structures (including their flare support structures as relevant)	6	3	3	12
Floaters (TLPs, FPSO, FSU, Spar)	35	1	29	65
Fixed steel platforms also counting bridge/flare support structures	242	19	53	314
Well structures, well templates and other subsea installations	407	93	34	534
Other installations (loading buoys, Single anchor leg mooring buoy etc.)	-	-	4	4
Total	**709**	**139**	**100**	**931**

The majority of UK operated oil and gas fields are in the late stages of life, with many platforms approaching Cessation of Production (CoP). Operators in the UK have completed several decommissioning campaigns to date and with declining field reserves, it is expected that a large number of UK operated fields will cease production within the next 10 years, with some platforms operating into the 2040s.

[108] Oil and Gas: Decommissioning of offshore installations and pipelines, 23rd January 2013 https://www.gov.uk/guidance/oil-and-gas-decommissioning-of-offshore-installations-and-pipelines
[109] OSPAR Data & Information Management System, OSPAR Inventory of Offshore Installations, 2017

Table 23 and Table 24 list UK operated concrete gravity base platforms and fixed steel platforms that have either been granted derogation or have derogation applications under consideration . In addition to this, there are approximately 24 known production platforms with substructure weights greater than 10,000 tonnes that may require derogation. These are listed in **Error! Reference source not found.**.

Table 23: Concrete gravity base structures under consideration for derogation or removed [110]

Field	Platform Name	Area	Substructure Weight (Tonnes)	Status
Brent	Brent Bravo	NNS	165,664	Derogation under consideration by OSPAR
	Brent Charlie	NNS	287,542	Derogation under consideration by OSPAR
	Brent Delta	NNS	177,809	Derogation under consideration by OSPAR
Dunlin	Dunlin A	NNS	228,611	Derogation application ongoing
Frigg	Frigg MCP01	NNS	386,000	Derogation complete
	Frigg CDP1	NNS	418,000	Derogation complete
	Frigg TP1	NNS	162,000	Derogation complete

Table 24: Fixed steel structures under consideration for derogation or removed [110]

Field	Platform Name	Area	Substructure Weight (Tonnes)	Status
Brae	Brae Alpha	NNS	20,000	Derogation application underway
Brae	Brae Bravo	NNS	22,000	Derogation application underway
Brent	Brent Alpha	NNS	14,225	Derogation complete
Fulmar	Fulmar Alpha	CNS	12,400	Derogation application underway
Hutton	Hutton NW	NNS	15,587	Derogation complete
Miller	Miller	NNS	18,584	Derogation complete
Murchison	Murchison	NNS	24,640	Derogation complete
Tartan	Tartan A	CNS	14,090	Derogation application underway

Table 25: Concrete gravity base and fixed steel platforms currently in production with potential for derogation [110]

Platform Type	Field	Platform Name	Area	Substructure Weight (Tonnes)
Concrete gravity base	Beryl	Beryl Alpha	NNS	525,837
	Cormorant	Cormorant Alpha	NNS	294,655
	Harding	Harding Platform	NNS	134,300
	Ninian	Ninian Central	NNS	560,000
	Ravenspurn	Ravenspurn CPP	SNS	38,500
Fixed steel	Alba	Alba northern	CNS	14,214
	Alwyn	Alwyn north NAA	NNS	15,900
	Alwyn	Alwyn north NAB	NNS	14,700
	Beryl	Beryl Bravo	NNS	15,332
	Britannia	Britannia Platform	CNS	20,837
	Clair[111]	Clair Ridge DP Platform	WOS	20,000

[110] Oil and Gas: Decommissioning of offshore installations and pipelines, 23rd January 2013 https://www.gov.uk/guidance/oil-and-gas-decommissioning-of-offshore-installations-and-pipelines

[111] Although the Clair and Mariner installations were installed after 9th February 1999 (derogation criteria), it is unknown whether the design of the installations substructures will have taken into account the requirement for full removal at end of life and so derogation may be granted.

Platform Type	Field	Platform Name	Area	Substructure Weight (Tonnes)
	Claymore	Claymore A	CNS	17,000
	Clyde	Clyde	CNS	10,400
	Cormorant	Cormorant north	NNS	20,500
	Forties	Forties FA	CNS	12,310
	Forties	Forties FB	CNS	14,150
	Forties	Forties FC	CNS	14,152
	Forties	Forties FD	CNS	15,550
	Heather	Heather A	NNS	18,700
	Magnus	Magnus A platform	NNS	35,057
	Mariner	Mariner PDQ Platform	NNS	38,000
	Ninian	Ninian north	NNS	15,561
	Piper	Piper B	CNS	22,555
	Saltire	Saltire A	CNS	15,000
	Scott	Scott JD	CNS	16,155
	Tern	Tern	NNS	22,310
	Thistle	Thistle A	NNS	31,500
	Tiffany	Tiffany	NNS	15,505

Decommissioning programmes submitted to OPRED must include dates for decommissioning stages, locations of installations, installations decommissioned, method of decommissioning and close-out reports where available. Decommissioning cannot precede in the UKCS without an approved decommissioned programme.

In addition to requirements regarding the removal of production platforms topsides and jackets, there is OGUK guidance on the decommissioning of wells and pipelines[112]. Each pipeline is assessed individually and must be flushed and either removed or buried if it will not be re-used. The requirements for decommissioning wells are that they must be suspended and abandoned as far as reasonably practicable that there can be no unplanned escape of fluids from the well. This is achieved through isolating areas of flow potential using a permanent barrier such as a good quality cement.

Past Decommissioning

Approximately 10% of UKCS installations have been decommissioned and just over 4000 wells permanently abandoned[113]. The type of installations that have been decommissioned have varied greatly in design and size and so a number of different challenges have already been faced to date.

Current Decommissioning

Draft decommissioning programmes under consideration are publicly available through OPRED[114]. There are currently around 23 installations in the North Sea that have ceased production and are awaiting decommissioning with ~25 currently undergoing decommissioning. The low oil price in 2020 has seen a reduction in decommissioning activity, which is likely to persist until 2023.

[112] OGUK, Well Decommissioning Guidelines, Issue 6, June 2018

[113] Oil & Gas Authority, Well insight Report 2018, https://www.ogauthority.co.uk/media/5107/oga_wells_insight_report_2018.pdf

[114] Oil and Gas: Decommissioning of offshore installations and pipelines, 23rd January 2013 https://www.gov.uk/guidance/oil-and-gas-decommissioning-of-offshore-installations-and-pipelines

Future Decommissioning

Decommissioning for the UK is expected to increase significantly over the next decade with 1,616 wells and 93 installations' topsides expected to be decommissioned and removed by 2029[115].

Re-Use and Re-Purposing

As part of preparing a decommissioning programme, the operator is required to assess the possibilities of re-using component parts of their assets and also the opportunity for re-purposing their infrastructure rather than decommissioning. As part of this, the Oil and Gas Authority (OGA) asks the operator to consider any potential economic development opportunities, such as re-purposing infrastructure for Carbon Capture Utilisation and Storage (CCUS). This would help to reduce the number of installations heading for disposal onshore.

[115] OGUK, Decommissioning Insight, 2020

C.1.2 Completed decommissioning projects

To date, UK operators have completed the decommissioning of approximately 50 production platforms, including fixed and floating types (excluding FPSO's). The majority of these decommissioning projects have been in the North Sea with a couple in the Irish Sea. The heaviest topsides and substructures for fixed and floating structures are listed in Table 26.

Table 26: Largest jacket and topsides weights for decommissioned installations

Type of Installation	Largest Topsides Weight (Tonnes)	Largest Substructure Weight (Tonnes)
Fixed Steel	28,144	27,584
Floating Steel	15,000	51,693

Decommissioning of Shell's Brent Spar platform is probably the most well-known UK decommissioning project. The Brent Spar installation was installed in 1976 and served as a large oil storage facility for the Brent A platform and as a tanker loading facility for the entire Brent field. When production ceased for Brent Spar in 1991, decommissioning studies were carried out by Shell and independent external organisations to assess disposal options. Due to the size of the installation, sinking of the installation in deep water in the Northern Atlantic was the chosen method of disposal and was supported by the UK government. This caused significant public backlash and so Shell later decided that the Brent Spar would be used as part of a quay extension in Mekjarvik, Norway. The project was completed in 1999 and took 330,000 man hours. A build-up of coral on the underside of the buoy meant the project took longer than anticipated and cost approximately £41 million, double the original estimate.

The Maureen A production platform was a floating steel platform which started producing in 1983. The installation consisted of drilling, production, crude oil storage and accommodation facilities and was designed to be re-floated off the seabed so it could be re-used at other locations. Decommissioning began for the Maureen platform in 1993 and was towed to a construction site at Stord Island in Norway where the facility was broken down for scrap.

Several platforms in the SNS have undergone decommissioning, one of the largest decommissioning projects being the Viking B field. The Viking reservoirs began producing in 1972 from two manned multi jacket bridge linked complexes Viking A (Alpha) and B (Bravo). In 1991 the Viking A reservoirs became uneconomical and were decommissioned in 1995. COP applications were submitted in 2016 for the Viking B complex and all associated tiebacks. The decommissioning programme included the removal of a total 8 structures, including 4 production hub platforms and 4 satellite platforms, the largest topsides weighing 3,827 tonnes and all jackets weighing less than 1,000 tonnes. All structures were fully removed to shore where the materials were recycled or disposed of. All pipelines were decommissioned in situ, after being flushed of hydrocarbon to an agreed standard of cleanliness.

There have been some fundamental challenges in the decommissioning of offshore installations in the UKCS. Logistically, decommissioning an offshore installation is a huge challenge with planning and detailed timelines requiring careful consideration. Many platforms in the North Sea are more than 30 years old. During the design phase of these installations minimal consideration was given regarding decommissioning. This makes it difficult for operators to develop a decommissioning programme not knowing the hidden dangers or complications that could occur during removal of these installations.

C.1.3 Decommissioning projects in regulatory planning / in the near future

The majority of fields in the North Sea are mature and approaching the end of their economic life. OGUK have reported[115] that over the next 10 years, approximately 1,616 wells, 660,000 tonnes of topsides and 370,000 tonnes of substructure are to be decommissioned. The majority of the removal weight comes from the decommissioning of platforms in the NNS (40%), followed by 32% in the SNS and 28% in the CNS. Due to the structures in the NNS and CNS being much larger than those in the SNS, it suggests that the number of installations being removed from the SNS is far greater than from the NNS and CNS. The decommissioning of UK infrastructure will be at the forefront of decommissioning, with topsides and substructure decommissioning accounting for 73% and 53% respectively of the total market as shown in Figure 3 and Figure 4.

Figure 3: Topsides decommissioning activity in the North Sea 2020-2029

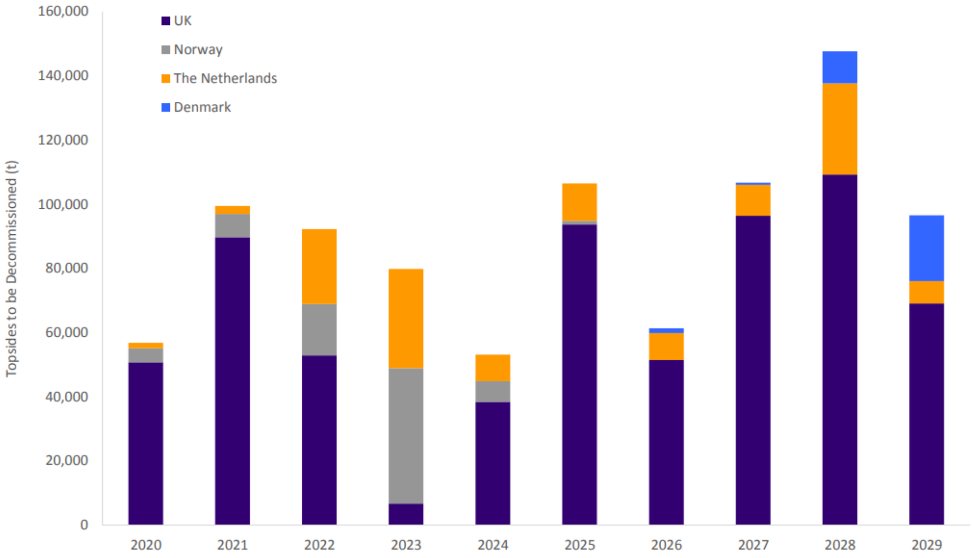
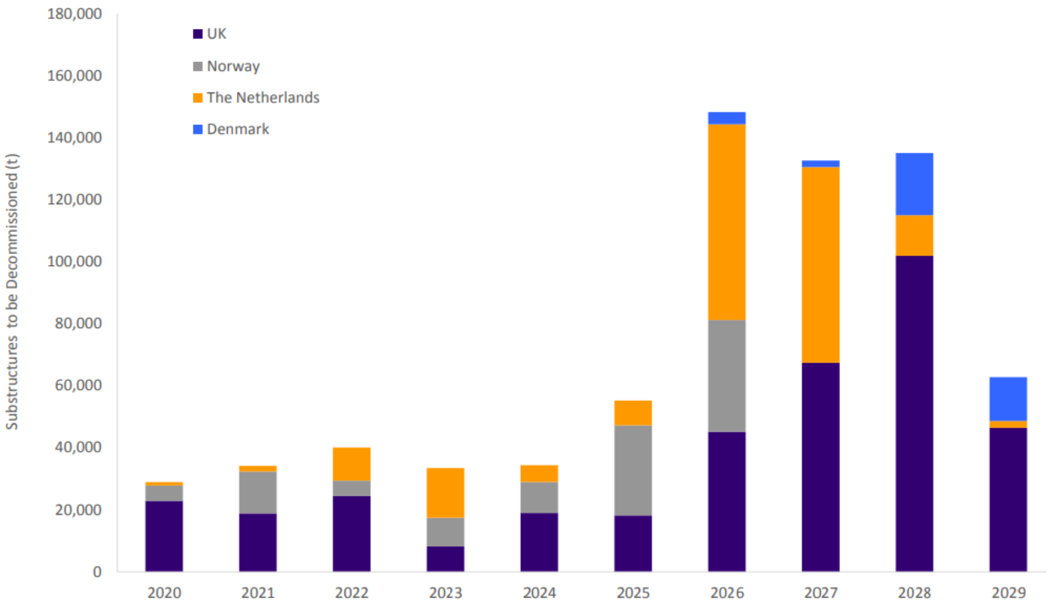


Figure 4: Substructure decommissioning activity in the North Sea 2020-2029



Delays

From the date a platform ceases production to the date decommissioning begins, there is a generally a delay. This delay can happen for a number of reasons, such as the effect of low oil price bringing forward COP dates as fields become uneconomic earlier than anticipated, where no decommissioning programmes have yet been decided. This then requires the operator to produce a programme and present it to the Competent Authority for approval which can take a significant amount of time. Decommissioning programmes can also be delayed if the Competent Authority requests more evidence or rejects an application, which then requires the operator to revisit their plan. This delay between COP and decommissioning can be up to 3 years for a fixed installation and longer for subsea production installations, during which time the installations need to be managed and maintained as if they are still in production.

C.2 Norway

C.2.1 Installations and decommissioning

The first offshore petroleum development on the Norwegian Continental Shelf (NCS) was the Ekofisk field with production starting in 1971. Since then, 114 fields have come on production and the total number of offshore structures is close to 750. Current status is 89 fields in production and 25 fields shut down.

The structures vary significantly both with respect to type and weight, ranging from some tens to above a thousand tons for subsea structures to large concrete gravity-based structures, the largest, Troll A weighs over 1 million tonnes.

Based on information from the Norwegian Petroleum Directorate, an offshore structure inventory overview for NCS in 2020 is presented below.

Table 27: Number of structures on the NCS (status in 2020). Source: NPD web pages (2020). Structures planned/under construction are not included

Type of structure	In operation	Shut down not removed/disposed of	Partly or completely removed or disposed of	Total
Concrete gravity-based structures	10		2	12
Floaters (TLPs, FPSO, FSU, Spar)	23 (26)*		5	31
Steel jackets including bridge/flare support structures	61	8	37	106
Single well subsea structures	165	24	11	200
Multi well templates and other subsea structures	358	5	12	375
Other structures (mono towers, loading buoys, etc.)	9		11	20
Total	629	37	76	744

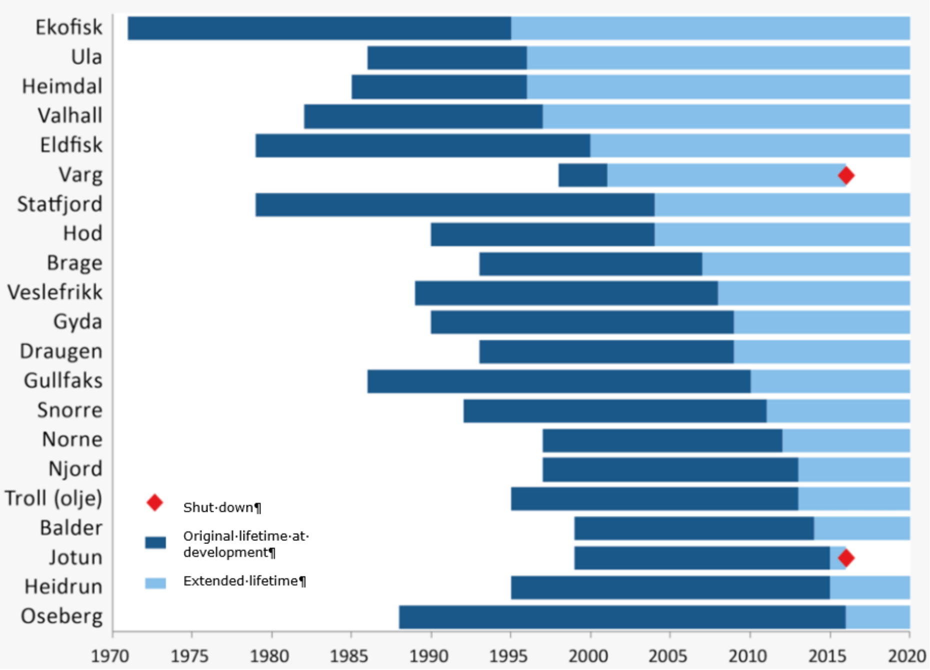
* 3 temporary removed/at yard for upgrade

C.2.1.1 Decommissioning Outlook and trends

The offshore oil and gas sector in Norway, by large, is the most significant industry in terms of value creation (revenue to the State from taxes and ownership), export, employment effects and ripple effects in other industries and the society in general. With a reduction in annual production in recent years, in particular for oil (with the exception of recent production from the Johan Sverdrup field), and a reduced investment forecast, the Norwegian government has implemented tax incentives to accelerate investments in new developments and maintain production over a longer time horizon. Most new development projects represent relatively minor discoveries which are not economically feasible for a stand-alone development. Hence, these developments are being tied-back to existing fields with available processing and export capacities. One consequence of this is that economic lifetime for the host fields are extended, which has already been seen for a decade or two on the NCS, though this extension can also be because of technology/knowledge development.

Such field lifetime extension has impacted on decommissioning on the NCS for decades, generating more value from existing infrastructure. The figure below gives an overview of lifetime extension for some key fields on the NCS compared with planned lifetime when the fields were developed. Some of these fields (e.g. Ekofisk and Valhall) will continue to operate for another 20-30 years, probably longer.

Figure 5: Extended lifetime compared with assumed lifetime at time of development for fields on the NCS. Source: NPD



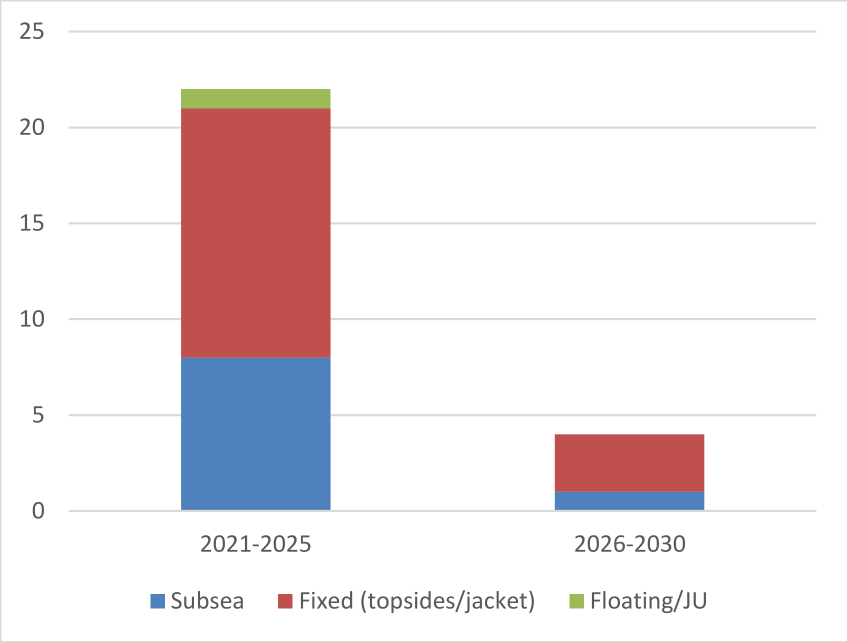
The effect of extended lifetime on decommissioning generally means postponed time of CoP and hence removal. Structures which do not meet the technical and safety requirements for life extension will be decommissioned. The same will apply for many subsea structures as their wells gradually are producing less oil and gas, becoming non-economic.

Another important factor which may influence significantly on both the Norwegian oil and gas production and time for decommissioning is “The green shift”. How will the green policies within EU and individual countries impact on demand for oil and gas, and how will market mechanisms impact the price of oil and gas? The production cost for oil and gas for the different fields on the NCS varies significantly, hence some fields will shut down more quickly if oil and gas prices drop and stabilise at a low level. Other fields will sustain production even at stable oil process at the lower 20’s (USD/bbl).

The NPD database identifies that 36 structures on the NCS currently are shut-down, but not finally disposed of/removed. Of these, 8 are fixed steel structures including flare support/bridge support structures. 5 are subsea multi-well templates and the remaining 24 are single well subsea structures.

Based on a review of shut-down structures and removal contracts awarded, a prognosis indicating time of removal of structures on the NCS this decade is developed (see above). This prognosis is quite approximate for fixed structures however uncertain for subsea structures; 29 subsea structures shut-down as per NPD database, however many of these are part of fields in operation with a long lifetime remaining. Fixed structures for removal within the next 5-6 years are mainly related to the Ekofisk and Valhall fields, Gyda and likely also the Veslefrikk A structure. The two Heimdal platforms are expected to be removed before 2030. The Knarr FPSO will become redundant about year 2025.

Figure 6: Prognosis for removal/end-disposal of offshore petroleum structures on the NCS this decade per structure category

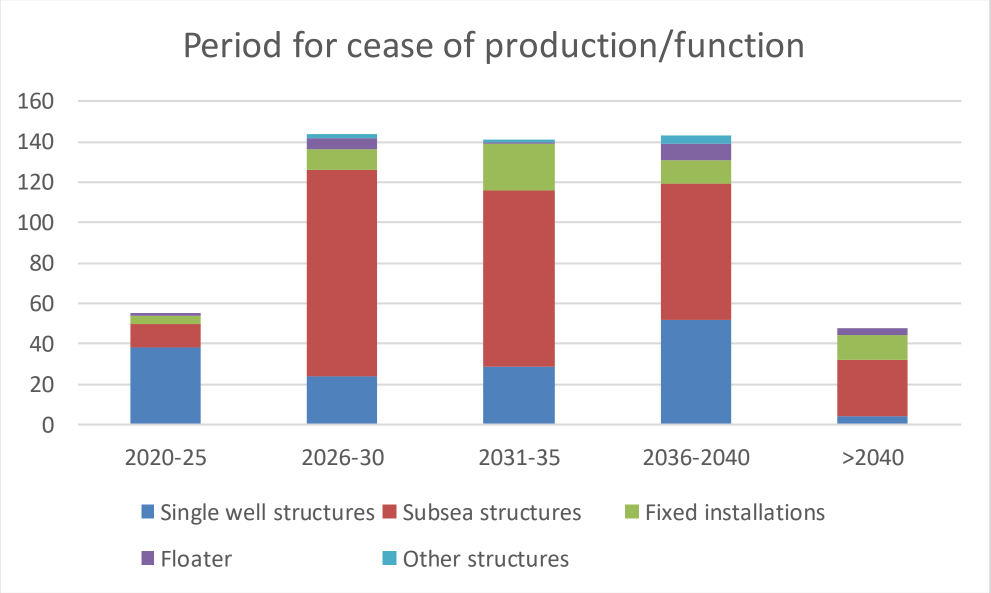


The main reasons for decommissioning a field are either that its production is decreasing, making operating costs too high to sustain further operation, or that technical conditions require shut-down and it is economic to upgrade the structure to continue production. For almost half the fields being decommissioned production has been below expectations, however for most fields more production and a longer lifetime has been achieved prior to decommissioning. In periods with a high oil price, production has been extended even after having a decommissioning plan in place. Some fields have also changed their mode of operation (high pressure to low pressure production) or function (from own production to host for tie-ins or serving as an export hub), with a corresponding longer economic lifetime.

There is no official overview of expected cessation of production for structures on the NCS. The NPD database provides information about year of installation and original design lifetime. However, as most fields and a majority of the structures in reality will have their life extended (see next sub-section), such an overview is not accurate. It indicates that some 50 structures will be redundant the next five years, the majority being subsea structures (including single well structures), but, in practice, the peak of structures becoming redundant and subject for decommissioning should be expected pushed to the late 2030s and the 2040s.

Execution of removal/disposal work normally takes place within a window of 2-5 years after CoP and this timescale is stated in the formal disposal decision (letter from MPE with specific conditions). The wide time window is to increase flexibility and give increased efficiency and potential cost-saving. In most contracts with removal contractors the operating company allows a removal interval to enable for flexibility and efficient utilisation of the removal (heavy lifting) vessels as a cost efficiency measure.

Figure 7: Tentative indication of time period for cease of production/operation for different categories of petroleum structures on the NCS. Data source; NPD database



Well P&A

Current Norwegian plugging and abandonment requirements are prescriptive as to the number and size of permanent well barriers required and the requirements are generally the same for all types of wells. The primary standard for P&A is the NORSOK D010 (Well integrity in drilling and well operations), chapter 9.

To ensure that the effort is directed to an effective decommissioning design, risk-based methods may be applied. By introducing a risk-based approach, tailor-made design solutions may be devised, which better suit the different wells and allow cost-saving benefits to be gained from the least critical wells. One example of such is the DNV GL Recommended Practice for Risk based P&D (RP E-103 (2020)) which has been applied for planning of several P&A campaigns in Norway.

C.2.2 Completed decommissioning projects

Field structures

The first field decommissioning project on the NCS was North East Frigg, followed by Odin (structures from both fields removed in 1996) and later that decade other satellite fields/structures to the Frigg field. Major decommissioning projects on the NCS so far have been the Ekofisk I field (14 structures originally, now plus an additional 2) and the Frigg field (5 structures, of which two were in the UKCS). The first Ekofisk I structures were removed in 2005-2008 (Ekofisk Tank topsides and some minor flare/support structures) followed by 9 fixed steel structures in 2009-2014. Since then, several campaigns have taken place and structures are still being removed from the field; planned for completion of the 16 structures in 2024. Disposal work at the joint UK-NOR Frigg field was executed in the period 2005-2010, including one concrete structure (which remains in situ – see below) and two fixed steel structures on the NCS.

In total 113 structures, or 15% of the overall number of structures on the NCS (742), have been shut down or finally disposed of. Of these, two structures only have been or will be left permanently; the heavy concrete structures Ekofisk 2/4 T (tank with barrier wall, about 1 million tonnes) and the Frigg TCP2 (~250,000 tonnes), in addition to some pipelines (addressed below).

In total 37 fixed structures have been removed and disposed of. Topsides from two concrete gravity-based structures have also been removed and these 39 structures make up the majority of material weight having been removed. The 5 floaters being removed are either re-used or available for re-use. The 34 subsea structures and loading buoys have generally significantly less weight than the fixed structures. With a few exceptions of re-use, these have been brought to shore for dismantling and material recycling. An overview of structures decommissioned per structure category is given in Figure 8.

There are currently five onshore yards licenced for dismantling of offshore petroleum structures in Norway, with some other candidates in the planning phase. The degree of re-use/material recycling from structures being removed is high, normally above 95% for steel substructures and in the range of 90-95% for topsides. The majority of the material is metal and the key metal is steel. Some experience data on material management from decommissioning projects is shown in Figure 9.

Figure 8: Type of structures having been decommissioned, number and percentage. Data source: NPD

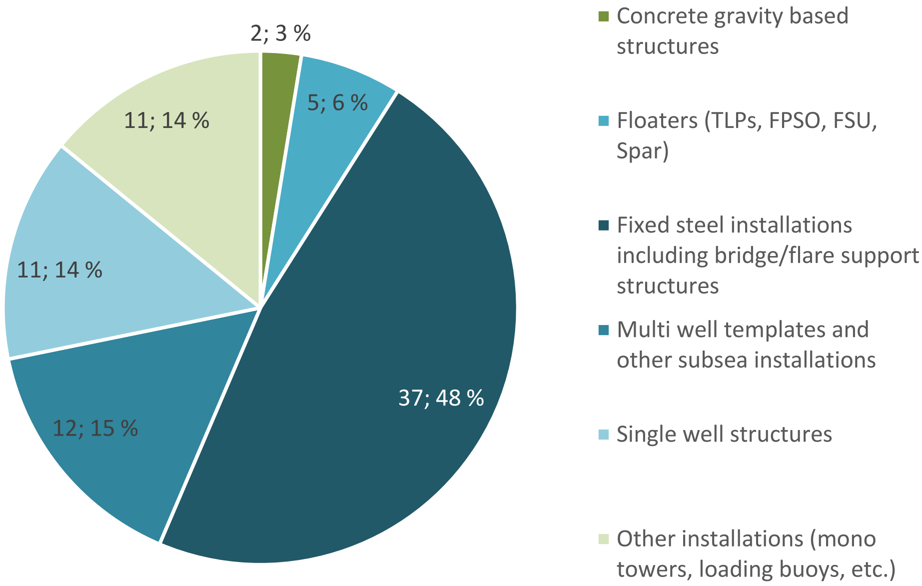
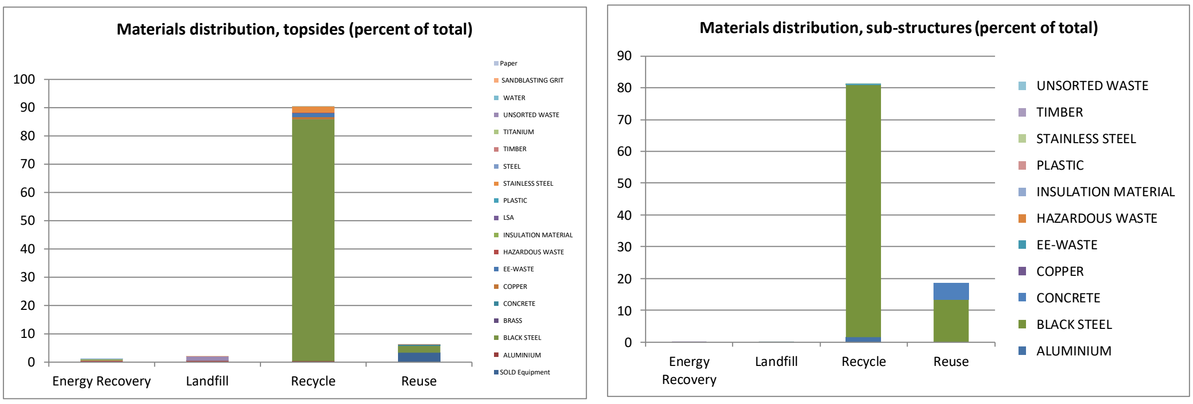


Figure 9: Experience data on material management solution for topsides (left) and steel substructures (right) respectively. Based on 65,000 tonnes of material being managed. Data source: DNV/TOTAL.



Pipelines

Pipelines being decommissioned are generally intra-field lines, some inter-field pipelines and some single field export pipelines (see Table 28). None of the large diameter / long export pipelines have yet been decommissioned. In total there is ~10,200 km of pipelines on the NCS (Source: Norsk Petroleum), not including intra-field pipelines. Of these, ~8,800 km is associated with gas export, the longest >800 km, and diameter ranges between 12-44”. Oil pipelines are generally shorter, with the exception of the Ekofisk-Teesside, Grane-Sture and

Sleipner-Kårstø pipelines – all over 200km long. The diameter for the oil pipelines ranges between 13” and 36”.

Table 28: Pipeline decommissioning experience on the NCS (examples)

Field/pipeline	Description of pipeline as it operated	Disposal solution
Ekofisk I	40 buried pipelines. 4.5" - 34" diameter. 99 % buried, 1% gravel dumped. Burial depth 1-2m.	Leave buried in place.
Valhall- 2/4G	2 x 20" pipeline sections. 1-2m burial depth. 1 minor exposed part (free span).	Exposed part of Valhall pipeline removed. Remaining left in place.
Frigg	15-20 infield pipelines/cables	All pipelines within 500m removed to shore.
Odin	20" D, 26km, exposed on seabed	Burial due to fishing
Frøy	3 pipelines, 1 cable, 32km. 2 pipelines buried, 1 (16") exposed.	Western part of 16" pipeline buried (due to fishing), eastern part left in place. Buried pipelines left in place.
Frostpipe	16"D and 82km long. Exposed.	Trenching in sand eel areas and where technical feasible. Not executed, pending possible reuse.
North East Frigg, East Frigg, Lille Frigg, Mime, Tommeliten Gamma	Various dimensions, all buried and/or gravel dumped.	Left in place

Wells

According to data from the Norwegian Petroleum Directorate (NPD) in the period from 1966 to 2021 a total number of 6931 new wells have been drilled (not counting well bores), of which 5132 are production wells and 1799 are exploration wells.

There is no official overview of permanently plugged wells however it is generally referred to a future plugging scope of 2000-3000 wells over the next few decades. Regulatory requirements are in place for permanent plugging, valid for both exploration wells and production wells. Industry practice follows NORSOK D-010. The NPD forecast in the order of 40-50 wells per year to be permanently plugged in the nearest few years.

C.2.3 Decommissioning projects in regulatory planning

Pipelines subject to decommissioning in the relative near future include:

- Knarr gas export pipeline to FLAGS in the UK;
- Heimdal – Brae (UK) condensate export pipeline;
- Valemon gas export pipeline to Heimdal;
- Veslefrikk oil and gas pipelines to Oseberg and Statpipe;
- Gyda pipelines to Ekofisk and Ula; and
- Subsea tiebacks to UK platforms e.g. Rev, Gaupe and Brynhild.

For pipelines, as for structures, the impact assessments being undertaken as an integral part of the decommissioning plan (see description below) evaluate relevant disposal options and disposal decisions are made by the government, normally with specific conditions and time period for execution of the end-disposal. The governmental decision will, based on the Petroleum Act, formally not have to be aligned with the operators’ proposed plan, however in most cases it will.

C.2.4 Environmental practices

Key IA method applied

There is no mandatory method for decommissioning impact assessment in Norway. However, a generic impact assessment method widely used in various sectors in Norway has been adjusted and adapted for use offshore. This method was described in the first edition of the industry handbook (OLF 2001) and, with a few minor modifications, included in the latest revision (NOROG 2020).

Generally, it considers impacts by looking at two axes; 1) the sensitivity or value of the actual environment potentially affected, and 2) the scale of effect of the actual activities and end-disposal.

- The value or sensitivity of an area or environmental receptor is evaluated on the basis of the information in the environmental baseline. It is either a conservation/ecological value or an economic value.
- The scale of the decommissioning activity's effect on the environment should be based as far as possible on scientific documentation. Several criteria can be used to assess the scale of the effect (depending on the effect under consideration); some examples are given below:

- *Classification of substances.* Formalised criteria for classifying substances as harmful to the environment should be used. Detailed specific criteria for the aquatic environment should be elaborated on the basis of:
    - acute toxicity;
    - biodegradability; and
    - bioaccumulation.
- *Permanence and reversibility.* Defines whether an exposure is temporary or permanent, and should be regarded only as a measure of the temporal status of the effect:
    - no change/not applicable;
    - temporary; and
    - permanent.
- *Cumulative*. This is a measure of whether the effect will have a single direct impact, a cumulative effect over time, or synergies with other impacts:
    - no change/not applicable;
    - non-cumulative single impact; and
    - synergies.
- *Recovery time*. Emissions/discharges and other sources may have many types of ecological effects, at many different levels – such as tissue, organ, individual, population or community. A general scientific view is that effects must be measurable at the population or community level in order to qualify as significant. Furthermore, recovery time is widely applied as a general and overall parameter appropriate for classifying the significance of ecological effects.

Combining the two steps produces a defined "magnitude of the impact", exemplified in Figure 10. The magnitude of the impact can range from "very large negative" to "very large positive". A "moderate negative" or "large negative" impact does not necessarily mean that the impact is considered unacceptable, but that further attention should be given to these issues. A description of the different impact levels is supplied to provide additional context for and understanding of the assessment.

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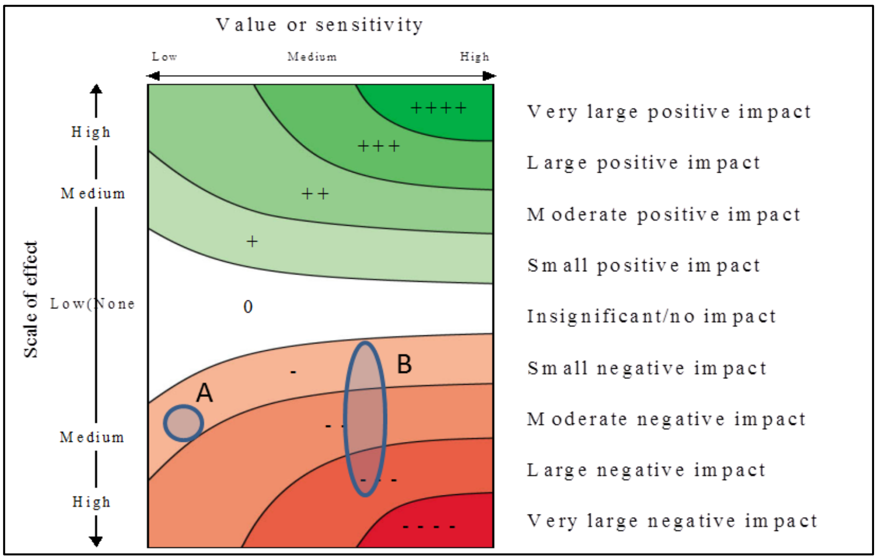
Figure 10: Example of an IA matrix. Source: NOROG 2020

A = low uncertainty. B = high uncertainty about the scale of the effect, low uncertainty about the sensitivity of the receiving environment



Materials and fluids left in the environment

Ideally, no offshore petroleum structure should ultimately be left at sea following decommissioning. The exceptions are those structures/parts of structure falling within the OSPAR Decision 98/3 criteria for such disposal, for which a derogation can be applied (also reflected in Norwegian law) – and pipelines permitted by national authorities to be left in situ/buried.

Some of the gravity based concrete substructures have storage cells for oil and produced water. Before disposal, these storage cells are cleaned. However, these tanks have varying designs, some with challenging access for sampling, cleaning and verification. The strategy for cleaning is presented in the decommissioning plan and impact assessment and the detailed plan for execution of the cleaning activities is subject to specific permitting at a later stage. Demonstration of cleaning forms part of the end-of-disposal notification for fulfilling the completion of the conditions stated in the decommissioning decision.

It is a general requirement that pipelines being disposed of in situ should be cleaned and left without posing a risk to the environment. There is no prescriptive standard level of cleanliness and the degree of cleaning and method to be applied will be evaluated case by case taking into consideration the actual pipeline, type of fluids/residues and the local environmental conditions. The environmental footprint associated with performing cleaning activities will further be balanced with the environmental risk of a certain level of cleanliness (e.g. CO_2 emissions for flushing additional large water volumes to obtain 20 vs. 30 ppm hydrocarbons) – i.e. taking a risk-based approach.

Studies have been undertaken to get an understanding of pipelines degradation processes [Dames & More 1999[116], DNV 1999[117]. Cathodic protection and slow corrosion processes, particularly if the pipeline is buried, will keep the pipelines contained at least for several decades and generally for centuries. Hence, possible minor remnants of hydrocarbons will stay isolated from the external environment and generally the majority will gradually be degraded naturally within a shorter time frame than the actual pipeline material. The pollution risk for cleaned and buried pipelines is hence generally considered low, however subject to case by case evaluations.

Previous studies have further evaluated the possible pollution risk associated with the actual pipeline materials degradation[116]. A few and old pipelines may have impurities of heavy metals

[116] Dames & More, 1998. Long-term degradation of pipelines. Study to the MPE program for disposal of redundant pipelines.

[117] Leaving Ekofisk I-Pipelines in place. Disintegration hypothesis and impact assessment. DNV report 98-4040.

as mercury and cadmium in the cathodic protection. However, due to the low concentrations, slow material degradation processes, burial state/water circulation patterns, the contamination potential is generally considered low.

Key environmental concerns and issues

Stakeholders present their viewpoints and concerns during two formal consultation processes associated with the IA process, and national ministries are involved with the actual decommissioning plan decision. Hence, the decision process opens for broad stakeholder involvement.

Environmental issues related to decommissioning are generally focused in the above-mentioned industry handbook, and it generally has a broad focus, which is narrowed down to fit the actual project scope during the "scoping phase" of the IA. Compared to practice in many other countries, the Norwegian Impact Assessment report should not be very detailed and does not have comprehensive documentation, but is kept on a relatively high level focusing on the key decision making factors. The magnitude of the assessment work should be aligned with the actual scope of decommissioning and disposal. Hence, in Norway the key focus of the impact assessment is on significant impacts.

C.2.5 Environmental monitoring

For petroleum fields in operation, regular environmental monitoring is performed every third year, with the environmental baseline being established prior to initial production drilling (Activities Regulation section 53). This monitoring activity focuses on drilling (regular water column monitoring during the production phase is performed in addition however only for a few fields as representatives for larger regions) and the type and extent of contamination in seabed sediments and associated effects on benthic fauna communities (fixed sampling stations from 250m from the platform, extending to 1-2km distance). Hence, a baseline situation prior to decommissioning exists from the operations phase monitoring.

During decommissioning specific environmental monitoring may be required as part of the activity based environmental permit, e.g. related to particular planned discharges or dredging activities (drill cutting piles, contaminates seabed). This type of environmental monitoring may include water column, biota, seabed sediments as applicable.

Following decommissioning, current requirements (Activities Regulation section 54, specification in NEA guidelines M-408 Guidelines for environmental monitoring of petroleum activities on the Norwegian continental shelf) imply two regular monitoring campaigns with three years interval. To date in Norway there has been no history of needing to monitor beyond this time period. However extra monitoring may be required for future decommissioning of fields with substantial drill cuttings pile and/or GBS structures with oil storage facilities. Further requirements for monitoring will be decided by NEA depending on the results of this monitoring.

Possible monitoring of physical structures being disposed in situ will be required on a case-by-case basis as part of the actual disposal decision with conditions.

C.3 Netherlands

C.3.1 Infrastructure

The Netherlands has produced oil and gas from offshore fields on the Dutch Continental Shelf since the late 1960s. There are currently ~140 installations, 680 wells and 3,000km of offshore pipeline. In addition to the infrastructure currently in production, more than 700 wells have been permanently plugged and abandoned and 30 installations decommissioned. It is projected that, over the next decade, there will be an increase in the rate of offshore fields reaching the end of their economic life, with approximately 120 installations to be decommissioned in the period. Decommissioning of the last producing fields is anticipated in the early 2040s.

The structures are generally of fixed steel construction; conventional 4, 6 and 8 legged structures, either in single platform configuration, or in bridge-linked complexes of multiple platforms that form production hubs. There are also smaller jackets, monopole satellite platforms and sub-sea installations that tie-back to production hubs, with some jack-up production barges. They would all be considered full removal candidates under OSPAR 98/3, due to the materials of construction; typical topside and jacket weights in the range of 500te to 7,500te and 500te to 2,000te respectively, with only a small of production hub structures greater than this range, and water depths that are typically 25m – 50m.

There are two steel gravity base structures (ballasted with cement) and one concrete gravity base structure, which may be challenging to remove due to the sub-structure weights 40,000te to 50,000te. The concrete gravity base may be a derogation candidate under OSPAR 98/3.

Table 29: Installations on the Dutch Continental Shelf (2020)

Type of installation	In operation	Shutdown / partly or completely removed or disposed of	Total
Concrete gravity-base structure	1		1
Steel gravity-base structure	1	1	2
Fixed steel installations	99	30	129
Subsea structures	16		16
Total	**117**	**31**	**148**

The decommissioning of infrastructure and the restoration of the sea-bed in a safe, sustainable and environmentally sound manner is the responsibility of the operator. Prior to decommissioning a work plan must be submitted for approval by the State Supervision of Mines (Staatstoezicht op de Mijnen).

The Dutch government has committed to prioritizing the re-use and re-purposing of offshore infrastructure to facilitate continued production and the energy transition, for example in applications such as CCS or hydrogen production, where practicable. Where re-use or re-purposing is not feasible then there is an expectation that facilities will be decommissioned, removed and recycled at onshore reception facilities in the Netherlands.

There is a strong offshore oil and gas engineering supply chain in the Netherlands with many of the top tier decommissioning and dismantlement organisations located or headquartered in the country.

In the Netherlands OSPAR Decision 98/3 regulates the removal of installations after use and adherence to it is stipulated in the Dutch Mining Decree (article 5.2.3). Thus, the expectation is for complete removal of oil and gas fixed structures.

Decommissioning of pipelines on the Dutch Continental Shelf requires them to be cleaned and flushed with sea water, and buried or otherwise made safe for other users of the sea. A reference comparative assessment has been completed for all pipelines on the Dutch Continental Shelf and operators are expected to develop decommissioning plans that comply with its requirements.

Well decommissioning requirements are established in article 8.5 of the Dutch Mining Regulations. Well P&A requirements for sealing wells require several cement plugs of 100 meters in length placed at intervals corresponding to zones of flow potential in the formation strata that the well is drilled through. The well bore is sealed just below the surface and the steel casings are cut several meters below the seabed.

C.3.2 Completed decommissioning projects

Installations

Since the Dutch Mining Act came into force, all structures have been decommissioned and removed in accordance with the requirements of the act. To date most of the decommissioning activity in the Netherlands has focussed on small satellite structures of simple construction, and sub-sea structures (23), with 8 hub-complex installations removed.

There is no experience in the Dutch sector of derogation application for potentially qualifying structures under OSPAR 98/3. There is an expectation under Dutch requirements of complete removal. It is unclear what will be required for the single concrete gravity base structure that may qualify under OSPAR 98/3.

The lighter weights of the topside and jackets, shallower water depths and more benign environmental conditions and longer lift windows means there are a larger variety of vessels available for decommissioning and dismantlement activities than is typical for harsher, deeper environments in Norway and the UK. The majority of the installations are transported to shore for dismantlement in yards in the Netherlands either on grillage set on transport barges or the deck of the heavy lift vessel, or secured in the hook of the heavy lift vessel.

The Dutch offshore industry has promoted the re-use of petroleum production infrastructure over its dismantlement and recycling onshore. This has led to a number of installation topsides being re-purposed for continued hydrocarbon production offshore rather than constructing new facilities. Increasingly, options are being developed for the re-use of structures in alternative applications such as CCS, wind power substations and hydrogen production. This may delay the return to shore of some infrastructure, but it is recognised that not all infrastructure will be suitable for use in alternative applications and the tonnages of materials for recycling onshore will increase.

Pipelines

Decommissioning expectations are outlined in the general comparative assessment for pipelines in the Dutch continental shelf. To date decommissioning of pipelines has been limited to umbilicals (5) and intra-field (16) and inter-field pipelines (11). Umbilicals are generally removed completely. Intra-field and inter-field pipelines are left in situ, with pipeline ends cut and isolated from the structures. The ends are then weighted down, usually by mattress placement, and the pipeline buried to reduce hazard to other users of the sea.

No large trunklines have been decommissioned to date.

Under the terms of the Mining Act there is a requirement for monitoring of the pipelines by the operator and powers for the regulators to require that remedial works be undertaken to remove or remediate any emerging hazards to other users of the sea, e.g. from scour. If a number of proactive regular surveys of the pipeline do not detect any changes, the monitoring becomes reactive.

Wells

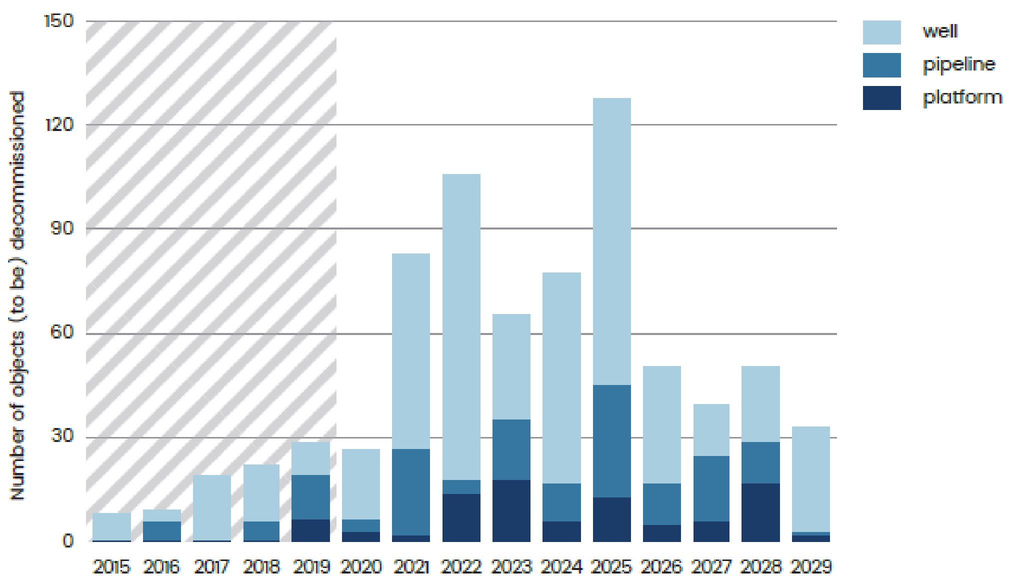
Offshore well decommissioning has been ongoing in the Dutch sector for many years with very few issues encountered with the wells abandoned. Operators had abandoned wells in accordance with NOGEPA Standard 45 on Well Abandonment, which required plugging the well over the reservoir production sections and then further plugs higher in the well. This standard has recently been revised to make the standard more consistent with the OGUK standard. In particular, the standard now encourages cap rock restoration, which contains the reservoir fluid below the cap rock with a cement plug across the cap rock only. This will allow for one plug to isolate the reservoir from the upper well section without further plugs in the reservoir section. Further plugs above the cap rock are then only required in upper zones of flow potential.

C.3.3 Decommissioning projects in regulatory planning / in the near future

The Netherlands has created Nexstep, a collaborative venture between EBN (a state company, involved in all oil and gas operations) and the oil and gas operators in the Netherlands (NOGEPA) with responsibility for co-ordination of re-use and decommissioning initiatives and programmes. The Ministry of Economic Affairs is supporting the program. Nexstep aims to reduce decommissioning costs by 30% through improved collaboration.

Nexstep has produced an estimate of future decommissioning in their 2020 Re-Use and Decommissioning Report[118]. It is estimated that 60% of installations (70) will be decommissioned and removed in the period 2020-2029, with the remaining 40% (47) in the 2030s. This is a significant increase in the rate of decommissioning from current levels, as can be seen from Figure 11 below.

Figure 11: Predicted Levels of Wells, Pipeline and Installation Decommissioning on the DCS in the period 2020-29 [Source Nexstep]



There will be an increase both in the level of P&A activity and the tonnages of materials being returned to shore for re-use and re-cycling.

The estimated increase in the volume of decommissioning may lead to inefficiencies in the delivery of the overall programme. Although, there are a wider variety of suitable units for P&A than in other areas of the North Sea, operators pursuing individual programmes will likely compete for drilling unit and manpower resources, or defer well P&A to later dates. Operators are being encouraged to plan joint multi-operator campaigns on portfolios of wells, which will encourage a steady rate of well P&A rather than the anticipated peaks and troughs of activity through the period, thereby optimising cost of P&A and maximising learning opportunities.

118 Nexstep, Re-use & Decommissioning Report, 2020

C.4 Denmark

C.4.1 Infrastructure

Denmark first started producing oil in 1972 from the Dan field in the North Sea. By 1985 a further 10 fields had been drilled, Denmark then began producing Natural Gas and in 1997 became a net exporter of oil and gas. Since 2004, Danish production has halved. In total, there are 20 fields in the Danish sector of the North Sea. Of these fields, 18 are currently still producing, one is shut in undergoing redevelopment and one is shut down. Key pipelines in the Danish sector of the North Sea can be seen in the appendices.

The Danish sector of the North Sea has a water depth ranging from approximately 37 m to 68 m. This depth of water means that the majority of production platforms are of the fixed steel type, with a couple of floating installations and one concrete structure. There are 63 Danish production platforms, with most, still in operation. However, the majority of the Danish continental shelf is mature and thus, production from the Danish sector has progressively declined with Denmark becoming a net oil importer in 2018.

C.4.2 Completed decommissioning projects

Denmark's Tyra field located in the Danish sector of the North Sea has been at the core of Denmark's energy infrastructure for over 30 years and has produced approximately 90% of the nation's natural gas. The Tyra field consists of 6 platforms in the East Tyra complex and 5 platforms in the Tyra West complex, making the Tyra field Denmark's largest gas field.

Redevelopment of the Tyra field became necessary due to subsidence of the formations below the platforms. Redevelopment of the field began in 2018 and involves removing old facilities, modifying and upgrading the existing ones, and installing new production capacity. During the summer of 2020, the 'Sleipnir' and 'Pioneering Spirit', removed wellhead and riser bases, bridge modules, flare towers, bridges and support braces; ~45,000 tonnes of steel in more than 30 lifts. The existing jackets and wells are to be reused as part of the redevelopment. The integrated accommodation and process platforms formed the second phase of decommissioning, with the 15,500 tonne and 7,800 tonne platforms being removed in single lifts. The decommissioned modules were delivered onshore to Denmark and Holland where more than 95% of the materials will be re-used and recycled[119].

C.4.3 Decommissioning projects in regulatory planning / in the near future

Including the Tyra field redevelopment, there are 19 operating Danish oil and gas fields in the North Sea. The majority of fields in the Danish sector are mature and approaching end of life. In OGUKs Decommissioning Insight 2020 report[119], it is estimated that 92 wells, 32,610 tonnes of topsides and 40,214 tonnes of substructure will be removed over the decade 2021-2030. This estimate came before the Government's decision to set a date of 2050 for the phasing out of oil and gas production and the ban on all new exploration activities, which is likely to accelerate cessation of production and subsequent decommissioning.

The historic production profile for Denmark's oil and gas fields is shown in Figure 12 and Figure 13, with the peak around 2004 and a steady decline since. A more general forecasted production profile for Denmark is shown in Figure 14. In Figure 14, 2024 is highlighted as this is the only year since 2018 where Denmark is expected to be a net oil exporter, after completion of the Tyra field redevelopment.

[119] OGUK, Decommissioning Insight, 2020

Figure 12: Denmark historic oil field production, adapted from[120]

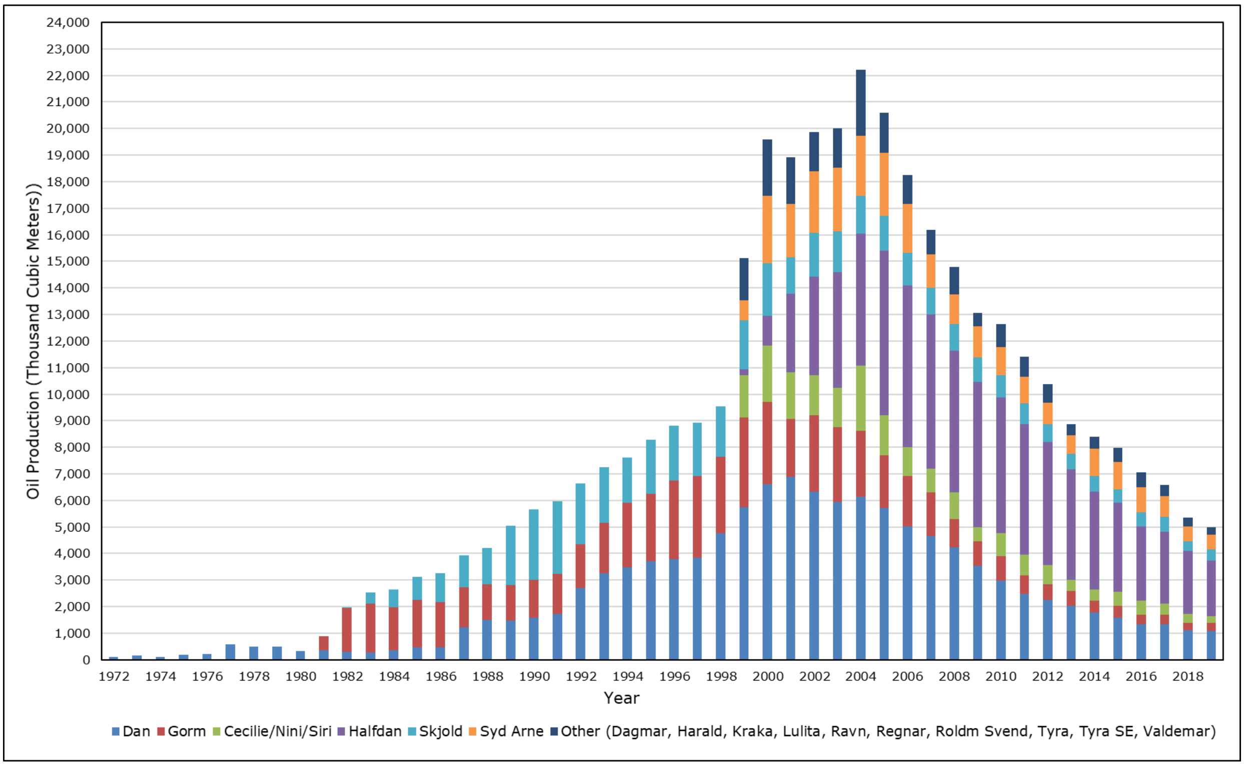
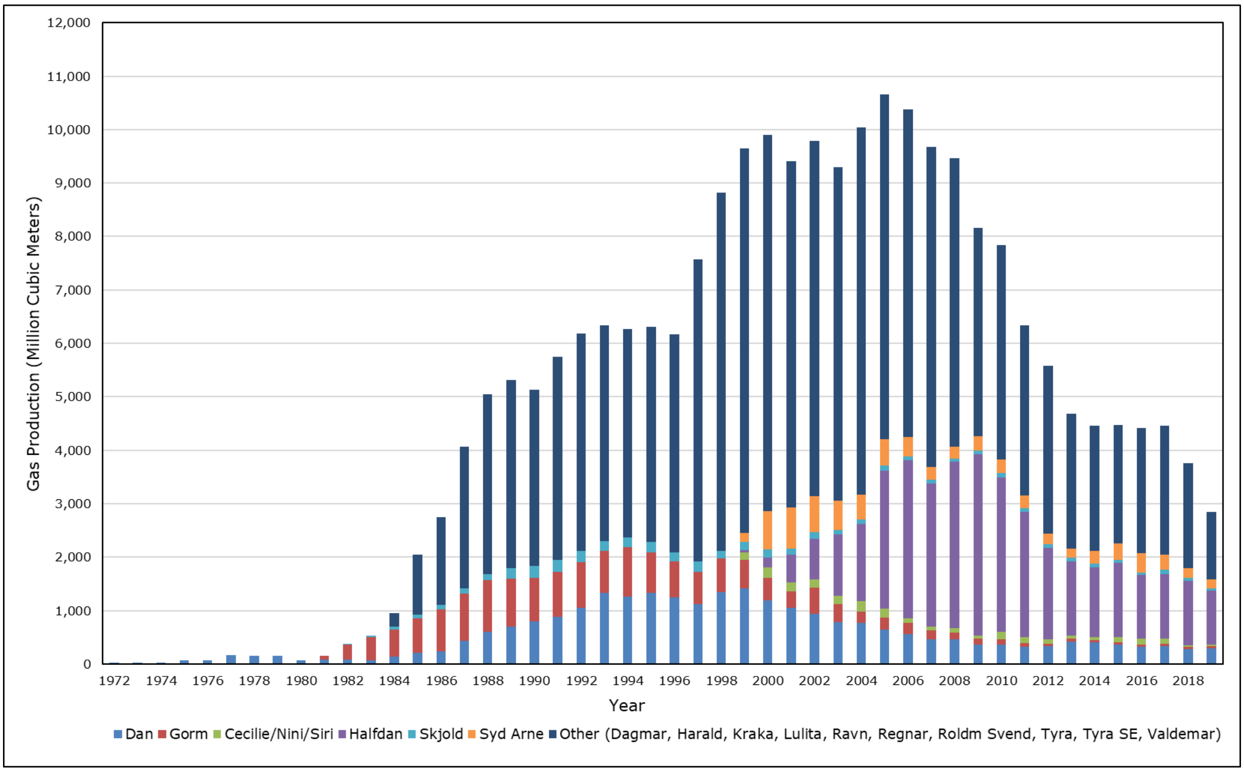
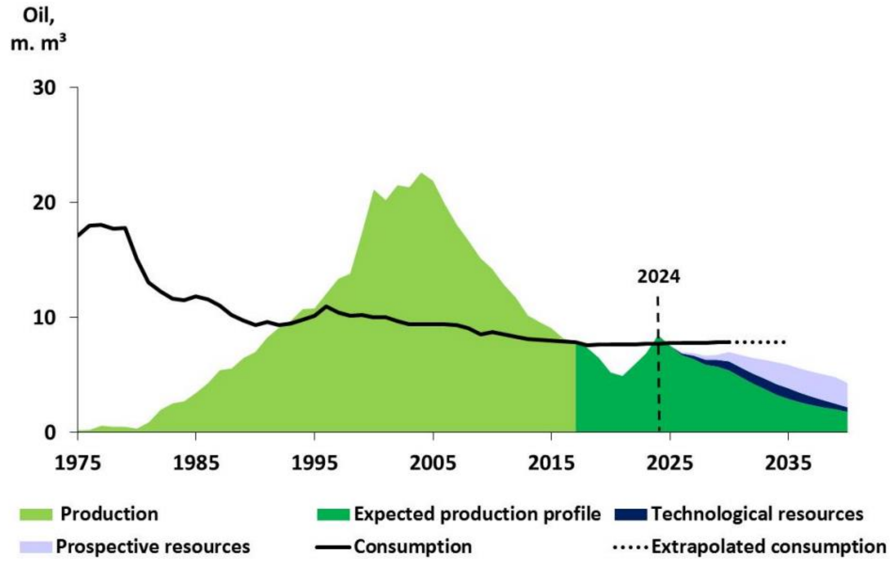


Figure 13: Denmark historic gas field production, adapted from DEA[120]



[120] Danish Energy Agency, Yearly production, injection, flare, fuel and export in SI units Spreadsheet 1972-2019, https://ens.dk/en/our-services/oil-and-gas-related-data/monthly-and-yearly-production

Figure 14: General historic offshore production in Denmark and long term forecast[121]



Expected COP dates are not reported for platforms in the Danish sector of the North Sea. Many factors influence the COP of a platform from reservoir production being less than expected to a low oil price making continued production uneconomic and so these uncertainties make it difficult to pinpoint the CoP date (although the aforementioned Government net-zero emission initiative will likely accelerate decommissioning).

[121] Danish Energy Agency, Resource Assessment and Production Forecasts, August 2018

C.5 Italy

C.5.1 Infrastructure

Italian oil and gas production began in the mid-1960s and activity remained high during the following decades. However, since the mid-2000s there has been a general decline in exploration and production activities.

The bulk of Italian oil and gas production takes place in the Adriatic, off the south coast of the mainland, and south of Sicily. There are approximately 124 production platforms operated by Italian E&P companies throughout Italian waters and in Croatian waters under production sharing agreements, of which approximately 116 are currently in production. There have been approximately 715 wells drilled with just over 260 of them still in production and there is over 1000km of pipeline.

The majority of the offshore infrastructure consists of steel jacket platforms located in relatively shallow water. The number of each type of platform and the maximum water depth is shown below.

Table 30: Number and type of platform in Italian waters and maximum water depth [122]

Type of Platform	Number	Maximum Water Depth
Monotubular	14	42
Bi-tubular	3	36
3 Leg Cluster	7	24
4 Leg Cluster	1	9
3 Leg Lattice Structure	2	78
4 Leg Lattice Structure	47	104
5 Leg Lattice Structure	1	13
6 Leg Lattice Structure	4	38
8 Leg Lattice Structure	34	124
12 Leg Lattice Structure	2	14
20 Leg Lattice Structure	1	10

In addition to the 116 platforms categorised above, approximately 50 have been decommissioned with 23 of the jacket steel infrastructures re-used as an artificial reef in pre-selected areas in the Adriatic Sea, approximately 12 nautical miles offshore the coast [123]. The remaining jackets were transported to shore for recycling and final disposal.

C.5.2 Completed decommissioning projects

There have been approximately 49 decommissioning projects completed in the Italian sector of the Mediterranean Sea, primarily in shallow waters. There is very limited public information available around these decommissioning projects.

Of the 49 Italian operated decommissioned platforms, 23 of the jacket structures were repurposed to form an artificial reef in the Adriatic Sea. The area of this artificial reef was pre-determined and was located approximately 12 nautical miles off the coast of Italy. The purpose was to deliberately place structures on the seabed to attract marine life, improve finishing management and protect against illegal trawling. There have been several studies carried out around artificial reefs and the fishing industry in the Mediterranean Sea[124] and this method of

[122] Ministry of Economic Progress, Marine Platforms Spreadsheet, October 2020, https://unmig.mise.gov.it/index.php/it/dati/ricerca-e-coltivazione-di-idrocarburi/piattaforme-marine

[123] MDPI, Challenges in Harmonized Environmental Impact Assessment (EIA), Monitoring and Decommissioning Procedures of Offshore Platforms in Adriatic-Ionian (ADRION) Region, July 2020

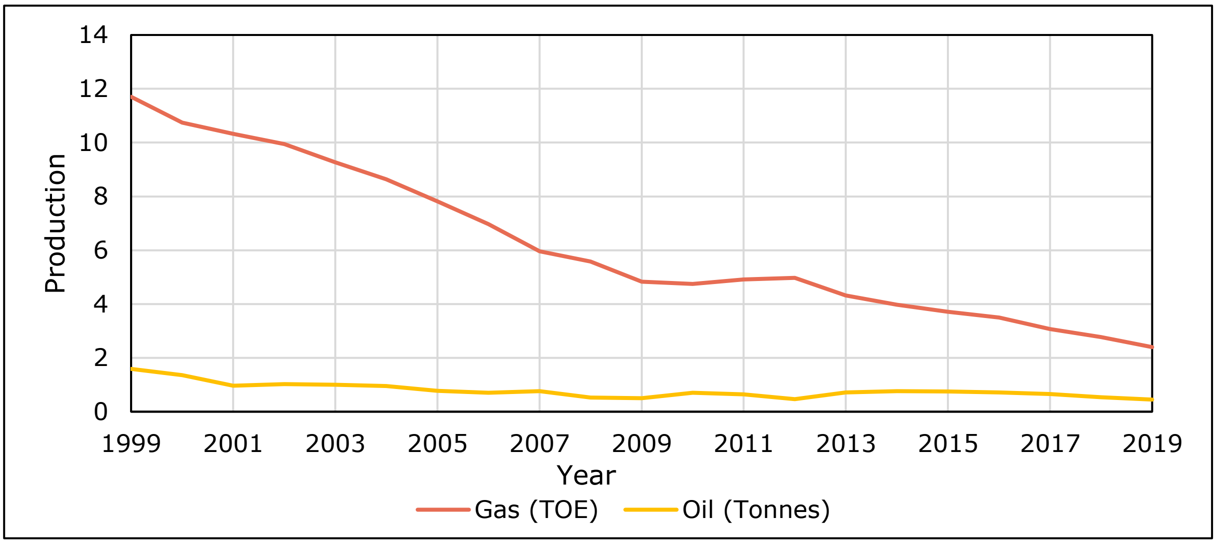
[124] GEAM, Planning for a safe and sustainable decommissioning of offshore hydrocarbon platforms: complexity and decision support systems. Preliminary considerations, December 2017, Pages 101-108

decommissioning is now only considered acceptable if the operator can prove it will result in a net benefit to the environment and that they have exhausted all other possible decommissioning options.

C.5.3 Decommissioning projects in regulatory planning / in the near future

The majority of the oil and gas fields in the Mediterranean were discovered in the 1960s through to the 1980s and therefore, many of these fields are mature and will require decommissioning in the near future. Italy's oil and gas production since 1999 can be seen in Figure 15. There has been a steady decline in production over the past couple of decades. Italy has recently introduced legislation to restrict further exploratory drilling in Italian waters. It is anticipated that these measures will likely bring forward planned Cessation of Production dates for Italian assets.

Figure 15: Italian oil and gas production125



[125] Ministry of Economic Progress, UNMIG Databook 2020, Activity 2019

C.6 Other concerned EU-countries (Croatia, Spain, Romania, Germany, Ireland, Greece and Poland)

C.6.1 Completed decommissioning projects

Croatia

Oil and gas exploration off the coast of Croatia started in the northern Adriatic in 1968. Production in the Croatian part of the Adriatic Sea is currently through 19 gas production platforms and approximately 51 wells[126] with the most recent discovery made in 2008.

There is no history of offshore infrastructure decommissioning in the Croatian sector of the Adriatic Sea. However, in December 2020 an unmanned gas platform, constructed in 2000, the Ivana D platform, located in the Adriatic Sea was structurally impaired during a storm and toppled to the seabed. The cause of this is thought to be due to cracks forming on the piles or the connection to the platform. Although the wells have been isolated sub-surface, they will need to be plugged and abandoned or reconnected to a new production system. Under current Croatian requirements, the remains of the platform will need to be recovered.

Spain

There is little oil and natural gas production in Spain, although there are offshore gas storage facilities in both the Bay of Biscay and Mediterranean. Casablanca is the only offshore production area in Spain. It is in a water depth of 61m in the Mediterranean Sea, has been operating since 1981 and currently produces from 4 active wells. The exploitation licence was extended in 2018, but the assets are expected to enter decommissioning in the near future.

There is little history of offshore decommissioning in the Spanish sector of the Mediterranean. However, the production and gas storage infrastructure is planned to be decommissioned in the near future with the operators currently assessing options for re-use or decommissioning.

Romania

Offshore oil and gas production in Romania is limited to 14 active fields in the Black Sea. There is little history of offshore decommissioning projects in Romania.

Germany

Germany operates only one active offshore oil field in the middle of the Wadden Sea. The Mittelplate field began producing oil in 1987 and is set on a shallow water artificial drilling and production island, 7km offshore, in an environmentally sensitive tidal flat. The installation has 27 production wells and is expected to produce into the 2040s.

There has been a limited number of decommissioning projects completed in the German sector of the North Sea. The Manslagt Z1 gas production platform was a fixed steel production platform that began production in 1993. After 19 years of production the 720 tonne platform was completely removed and taken to shore for dismantlement and recycling. The 6km pipeline was also dismantled.

The second completed project was the Emshorn Z1A platform. Installed in 1981 located 7.5km off the coast at the estuary of the river Ems the Emshorn Z1A platform was located in a water depth of approximately 11m. The platform’s 420 tonne jacket and 150 tonne topsides were removed to shore for dismantlement and recycling.

[126] Croatian Hydrocarbon Agency, Exploration and Production, 2018, https://www.azu.hr/en/exploration-and-production/

Ireland

Ireland began exploration for oil and gas in the 1960s, with the Kinsale Head gas field starting production in 1978. In total, 26 discoveries have been made offshore of Ireland in 5 main basins:

- Celtic Sea;
- Central Irish Sea;
- Rockall;
- Porcupine; and
- Northwest Ireland Offshore.

The majority of Ireland's exploration drilling has taken place in the Celtic Sea, with further exploration around the Porcupine basin.

Decommissioning of Ireland's two offshore installations, located off its South coast, is in progress after cessation of production in July 2020. The 4,700 tonne Kinsale Alpha (KA) and 3,700 tonne Kinsale Bravo (KB) topsides will be removed along with the jackets. They wells will be plugged and abandoned. Associated wellhead structures and manifolds will be removed. Further details are given in Appendix 0.

The only other installation in Ireland is the subsea Corrib development, which is not planned to be decommissioned in the near-term. It is situated off the coast of North-West Ireland.

Greece

There has been little oil and gas exploration in Greece to date, with two producing fields, the Kavana and Prinos fields in the Aegean Sea. No production platforms have been constructed in the Ionian sector. Although there has been very little exploration in the Greek territorial areas of the Mediterranean to date, it is thought that there would be potentially exploitable natural gas reserves.

No decommissioning has been undertaken in the Greek sector of the Mediterranean to date and it is not expected to take place in the near future.

Poland

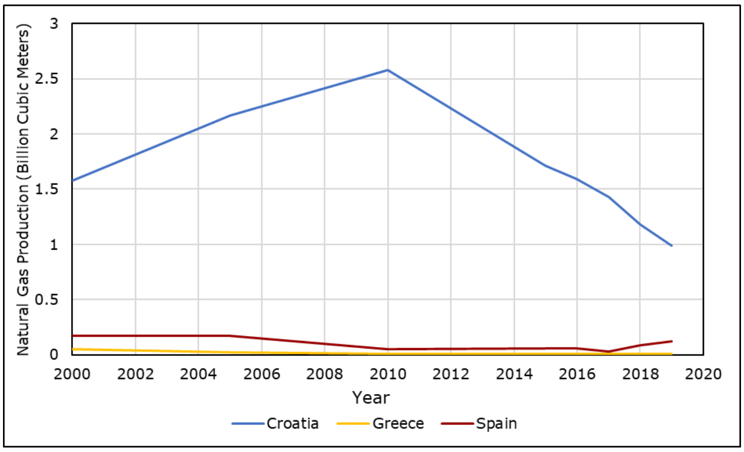
There has been little oil and gas exploration offshore in Poland to date, with one producing field, in the Baltic Sea. There is little history of offshore decommissioning projects in Poland.

C.6.2 Decommissioning projects in regulatory planning / in the near future

Croatia, Spain and Greece

Croatian and Spanish decommissioning, similarly to Italy's, is expected to increase in the near future with declining natural gas production as shown in Figure 16: .

Figure 16: Croatia, Greece and Spain's natural gas production127



Germany

The A6-A production platform is a gas and condensate platform constructed in 2000. The platform is located on the German Continental Shelf in 47.7m deep water and ceased production in mid-2020 after reaching the end of its economic life following 20 years of production. The platform is a 6 legged fixed steel structure with a substructure and topsides weight of 1191 tonnes and 3366 tonnes respectively. A decommissioning plan is not currently available for A6-A, but due to the size of the platform it is likely that both the topsides and jacket can each be removed by single lift using a conventional heavy lift vessel.

With the CoP of the A6-A platform and its decommissioning expected to take place in the near future, the Mittelplate platform is Germany's last producing offshore asset.

[127] NI, World Gas and Renewables Review, Volume 2, 2020

C.7 Emerging Issues and Technology

C.7.1 Removal methods

Some field decommissioning projects on the NCS are beginning to consider "destructive" removal of pipelines. Acknowledging that most retrieved pipelines will not be suitable for re-use, applying methods which do not focus on the quality of the retrieved material is considered cost saving and likely also having a smaller GHG footprint. This may be achieved by employing smaller vessels with modest lifting capacity and using a ROV-assisted tool for subsea cutting.

C.7.2 Emerging issues

Plastics in the environment; this issue has a high general attention, and particularly the widespread discovery of micro plastics in sediments (and biota) has accelerated the focus also on possible sources related to oil & gas activities. Some plastic compounds are integrated in umbilicals and flexible pipelines, of which some are decommissioned in place (trenched or rock covered). This may be subject to a principal focus of future in situ disposal.

APPENDIX D Environmental Impacts of Decommissioning

This part of the report:

- Identifies the main environmental impacts of leaving anything in-situ after decommissioning and the broad way in which oil and gas infrastructure is decommissioned;
- Discusses the methods used to assess environmental impacts, and the methods used to compare impacts of decommissioning alternatives; and
- Identifies shortcomings, emerging themes and possible improvements.

D.1 Principal environmental impacts from decommissioning

Decommissioning offshore oil and gas assets can have both short and long-term impacts on the environment, due to the hydrocarbons and other hazardous substances contained within the facilities, and other issues such as waste generation and energy consumption. Infrastructure left in situ can potentially have long-term impacts on the environment, to fishing and to shipping. For materials brought to shore, dust, odour, waste, noise and traffic impacts are possible during onshore dismantling of decommissioned facilities. Conversely there are positive impacts from recycling steel.

This chapter discusses the principal environmental impacts that can potentially result from decommissioning of offshore oil and gas assets concentrating on the infrastructure that may be left in-situ rather than the process of decommissioning. The chapter is broken down into sub-sections to cover the range of different offshore structures: Topsides, Jackets, GBS, GBS cell contents, Subsea Structures, Drill Cuttings, Wells, Pipelines, Mattresses and Floating Structures.

D.1.1 Topsides

Topsides are required to be removed under OSPAR Decision 98/3 and similar instruments. There are environment benefits from recycled steel and removing hazardous wastes in a controlled manner, but negative impacts are:

- Onshore dismantling - potential dust, noise, visual impact and increased traffic;
- Fuel use during offshore vessel operations and movements & onshore activities and associated atmospheric emissions;
- Hazardous waste generation.

There are no striking differences in decommissioning options or their environmental impact and the options amount to removing the topsides one piece, or removing them by module or piece small.

Although onshore decommissioning of topsides can impact local residents for many months and topside removal can potentially disturb other sensitive receptors such as migratory birds, the potential for impact can be effectively controlled and mitigated, provided operations are permitted and conducted responsibly. No wastes are generated for which the necessary treatment and processing expertise do not exist.

D.1.2 Steel Jacket substructures

There are differences in environmental impact depending on whether the jacket is completely removed to comply with regional sea requirements for a clean seabed or the upper jacket section is partially removed with the jacket footings left *in situ* to meet IMO requirements on providing a safe 55 metre water depth for ship passage. In either case, fuel is used, steel is recycled, employment created and dealing with the large amount of marine growth can be a local, temporary nuisance issue, but the main environmental impact differences between the two approaches are:

- Leaving in-situ
  - Legacy impact of the jacket footings being left in situ may prevent fishermen from trawling over the small area for hundreds of years;
  - Localised marine impacts when footings degrade.

Note that some scientific studies[128] consider leave in situ to be beneficial and supportive of the overall marine ecosystem.

- Removal
  - Drill cuttings may need to be disturbed to assess the sub-structure
  - Seabed excavation to remove jacket legs

There is significantly less impact to the marine environment (in the case of complete jacket removal) if jacket piles are cut internally (as opposed to externally), as the disturbance to drill cuttings and marine sediment is greatly reduced. External cutting requires removal of significant quantities of sand to gain access to the pile below the seabed with concomitant environmental impact whereas internal cuttings access the pile internally from the top and so does not need to disturb sand (other than when the pile is removed). However, there may be technical reasons why internal cutting may not always be possible.

D.1.3 GBS (Gravity Based Structures)

Offshore concrete structures are only located in UK, Norway, the Netherlands and Denmark.

OSPAR Decision 98/3 presumes that structures will be entirely removed, but it also recognises that very large structures such as a GBS may be very difficult to remove, and in these cases, a derogation may potentially be granted. If complete removal involves intolerable environmental/safety risks, it may be ruled out as a feasible decommissioning option. Three main decommissioning options are considered here: full removal, partially remove GBS legs to -55m below sea level, and leaving the whole GBS *in situ*. Any removal creates has the positive impact of creating employment and the negative impact of using fuel and full removal clears the sea-bed, but the negative impacts are:

Complete removal of GBS:

- Significant risk of personnel safety and environmental accidents from complex offshore removal operations;
- Short-term environmental impact of removing the GBS;
- Onshore - potential dust, noise, visual, traffic impacts.

GBS legs are partially removed:

- Legacy impact of leaving GBS partially in situ (though the risk of the legs failing is removed);
- Significant risk of personnel safety and environmental accidents from complex offshore removal operations;

[128] https://s3-eu-west-1.amazonaws.com/static.insitenorthsea.org/files/EcoConnect_final_report_v2.pdf

- Onshore - potential dust, noise and visual impacts and increased traffic.

If the GBS are left completely *in situ*, the main impacts are:

- Legacy impact of leaving GBS in situ for hundreds of years (to ships as the operator may request that the 500m safety zone continue to be maintained to protect fishing vessels, fishermen, marine environment from gradual degradation of the GBS substructures over several hundred years, resulting in a change to the local marine environment);
- They would become more difficult to remove over time as they degrade, if future requirements changed;
- The final collapse of the structures would be uncontrolled and timing uncertain.

D.1.4 GBS Cell Contents

Crude oil, ballast water or produced water from oil and gas production is often stored in dedicated tank cells within the GBS structure, and therefore some residual hydrocarbons, heavy metals or other hazardous material may remain following cessation of production. Attic oil is expected to be recovered and removed from the cell. There are two main decommissioning options possible for the remaining GBS cell contents: removal or leaving in situ.

If the GBS cell contents are removed, it removes hazardous waste from the environment in a controlled manner and creates technology development and employment, but the main negative impacts are:

- Fuel use during both offshore / onshore operations;
- Onshore treatment and disposal of large volumes (>500,000m^3) of hydrocarbon slurry waste (if cell contents are treated onshore and not re-injected into a disposal well offshore); and
- Risk of environmental accident from complex offshore removal activity.

Leaving GBS cell contents *in situ* would have a long-term legacy impact to the marine environment as the concrete cell structures degrade over hundreds of years, gradually releasing hydrocarbons and heavy metals, and would pollute the local marine environment. The exact extent of any pollution depends on the GBS, its contents and the local environment, but an example that the effect is local can be taken from the publicly available Brent Spar EPA[129], in which:

- Modelling results predict the highest impact related to a worst case cell sediment release comes from the hydrocarbons (THC, naphthalene, phenanthrene and benzo[a]pyrene), with predicted impact areas ranging between 0.6-1.7 km^2 and extending to a maximum distance of up to 2 km 10 years after release (without considering biodegradation); and
- Because most of the released sediments exceeding a thickness of 1 cm are predicted only for a very small distance (36 m from release point after 10 years), biodegradation of most of the hydrocarbons released is expected to be relatively quick.

Some stakeholders consider that while derogation of GBS can be understandable based on safety/technical feasibility, cell contents should be removed with no/minimal pollution of the seabed from any installations left in situ, and that the seabed post-decommissioning should support positive long-term marine ecosystem restoration. There are complications in determining how much is acceptable to leave (if any) in a cell, the level of detail to which a cell

[129]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/590278/Brent_Field_Environmental_Statement.pdf

content release should be modelled, and how to deal with uncertainty in the assessment (in some instances, the operator may not know the composition of the cell contents, and although the onus is on the owner to understand its content, sampling the cell contents may be very challenging). These issues would not easily be resolved by legislation above that which already exists and would also apply to only a few structures in the EU and so not shortcoming is identified that can be resolved by legislation.

D.1.5 Subsea Structures

Conventions such as OSPAR Decision 98/3 require the removal of all subsea structures (this includes drilling templates, production manifolds, wellheads to shore for re-use and/or recycling. This could potentially include several hundred tonnes of steel and concrete. If subsea structures are completely removed, the seabed is cleared, but the main negative impacts are:

- Localised impact to marine environment from disturbing seabed sediments (and drill cuttings as applicable) & other natural habitats;

There are different ways to remove structures on the seabed, and removal processes that use 'low-disturbance' type tools and equipment (and avoid the use of water jetting devices) will minimise impacts to the marine environment;

- Some fuel use for removal operations; and
- Risk to offshore personnel from removal operations, e.g. diving.

D.1.6 Drill Cuttings

During the drilling process, small pieces of rock (cuttings) are created which are transported and deposited to the seabed surface with drill fluids. Drill cuttings may contain traces of drilling fluids and hydrocarbons (prior to the early 1990s, Oil Based Mud (OBM) was used).

OSPAR Recommendation 2006/5 seeks to reduce pollution impacts from drill cuttings piles to the marine environment and requires a two-stage assessment. If drill cuttings piles have either an oil loss greater than 10 tpa, or a persistence over the seabed area exceeding 500 km^2yr, they should be subject to a comparative assessment to determine the optimum decommissioning approach.

Typically, most drill cuttings are left in situ, but sometimes disturbance to drill cuttings is required during decommissioning activities because (e.g.) access to jacket footings are required and they are covered by drill cuttings.

So, drill cuttings can be removed and treated/disposed, or they can be left *in situ* and the main difference between these options is short-term (fuel use to remove and marine impact from disturbance of contaminated seabed) versus long-term impact whereby they would eventually degrade and erode over many years, releasing some volume of residual hydrocarbons to the marine environment.

Removing drill cuttings piles by dredging or water jetting would disturb seabed marine sediments over a localised area, and would impact the marine environment in the short-term. Use of 'low-disturbance' type tools and equipment (and avoid the use of water jetting devices) can minimise impacts to the marine environment. There would also be onshore impacts as potentially significant volumes of drill cuttings slurry would be processed and disposed. Any recovered oil could be recycled while remaining solids would likely be landfilled.

D.1.7 Wells

To decommission an asset, all wells are plugged and abandoned (P&A). P&A of wells can involve extensive offshore works over many years, with potentially significant energy use, if there are a lot of wells. Materials such as production tubing are returned to shore for waste processing and recycling via established processes.

The well P&A isolates the reservoir from the marine environment through the placement of two or more barriers in the well bore. In the short to medium term, this can be demonstrated to provide isolation. However, the long-term integrity (in terms of the 'in perpetuity' requirement) of the P&A barrier is not proven. Monitoring of the barrier condition is not possible (without setting monitoring equipment as part of the barrier placement) and failure may only be detected when an emission to the marine environment is detected. Intervention to repair a leaking well will be technically challenging, time consuming and expensive.

With regard to abandonment of offshore wells, there is no internationally agreed standard. In the North Sea, individual countries have differing standards, and in an effort to align national standards, the NSOAF tried to help develop common practices for wells decommissioning[130]. The main findings were "*that the goal setting regulatory requirements are quite similar in each of the NSOAF countries. However, the prescriptive regulatory requirements and related National Standards contain significant inconsistencies on the criteria for well decommissioning barriers*". It concluded that substantial benefits could be achieved by minimising or preferably eliminating inconsistencies and recommended alignment of guidelines/standards within the NSOAF territory on well decommissioning towards a Code of Practice. This would help the long-term integrity of the wells and prevention of leaks.

Also there is increasing focus on post-decommissioning monitoring to check for leaks from abandoned wells. Consistent guidance may be beneficial as practices differ across the EU.

D.1.8 Pipelines

Most countries require a Comparative Assessment of feasible decommissioning options for subsea pipelines, of which there are only two: complete removal or leave the pipelines in place (perhaps with trenching or rock dump). The assessment should consider, for example, the pipeline length, diameter, burial status (e.g. rock dump, trenched, spans), extent of fishing in the area, in determining the most feasible option.

If pipelines are completely removed, steel is recycled, but the main negative impacts are:

- Fuel use during offshore operations;
- Onshore - potential dust, noise, visual, traffic, waste, asbestos coatings;
- Impact to marine environment from removal operations.

Pipelines can be removed by cutting sections of pipe and lifting to the vessels, or by reverse lay using a special vessel. The steel pipes are then brought onshore for recycling and disposal.

If pipelines are left *in situ*, the main negative impacts are:

- Long-term legacy impacts from the degradation of the pipes over time, perhaps over hundreds of years, which would gradually change the local marine environment in the vicinity of the pipeline. As trenched/buried pipelines degrade, any possible residues inside the pipeline will degrade under the seabed sediment and generally should not be exposed to the biotic environment.
- If pipes are rock dumped[131], resources are required to do this and it would also alter the marine environment and would present a potential risk to fish trawling nets which could become snagged on rocks.

Current practices in many countries is to leave many of the larger decommissioned pipelines in situ, once pigged/flushed, if no spans, not interfering with fishing vessels, and demonstrated to be the preferred option. The pipes may need to be trenched, or rock dumped, if left in situ;

[130] 2018-October-The-Netherlands-NSOAF-initiative-for-a-common-standard-for-well-decommissioning.pdf (irfoffshoresafety.com)

[131] Some regulators do not favour rock dumping, as it kills benthic fauna and changes the seabed habitat.

in the UK for example, there is an expectation that pipes will be trenched to 0.6 m to top of pipe.

Flexible flowlines, small diameter pipelines & umbilicals are generally expected to be removed by many EU countries if exposed on the seabed, so would not normally be subject to CA.

D.1.9 Mattresses

Concrete mattresses are sometimes used to protect subsea pipelines and umbilicals. All mattresses should be considered for removal, but if the operator considers removal is not optimal, alternative proposals need to be supported in a CA. In practice, if a pipeline remains in situ, then associated mattresses would also remain.

The main difference between removing mattresses or leaving them in place are short-term versus potential long-term impacts. Removing mattresses would entail some energy use for removal operations, and would have impacts onshore at processing facilities. The marine seabed environment would also be disturbed to some extent as they are removed.

Leaving mattresses *in situ* may have a long-term legacy impact to fishermen. There would be long-term legacy impacts from the degradation of the concrete over time, which would gradually change a very small area of the marine environment in the vicinity. There have been recent studies about whether mattresses could be left *in situ* in locations where local hydrodynamics means they naturally bury over time.

D.1.10 Floating Structures

Floating structures such as FPSO or FSU, will be removed.

D.2 How Environmental Impacts of Decommissioning are Assessed

This section summarises the main features of Environmental Assessment, how it is used to prepare a basis for knowledge-based decision-making, highlights the positives and discusses some shortcomings, and discusses how long term environmental impacts of assets left in situ are addressed.

D.2.1 Environmental Assessment

The EA should be proportional with respect to the proposed decommissioning activities, the potential environmental impacts and the sensitivities of the marine environment in the vicinity of the activities. The EA should also identify and address potential impacts on any Special Areas of Conservation (SAC) or Special Protection Areas (SPA) that could be impacted by the proposed activities, as per EU requirements.

In terms of how to conduct the environment assessment, although they are a mature science having been undertaken for decades, there is no mandatory methodology, and the specific manner in which impacts are assessed depends on company requirements/methodology and the consultancy conducting the EA, who may have their own in-house methodology. However, all EA assess impacts by considering two main elements:

1) the emission (considering different facets of the emission, such as its size, toxicity, biodegradability, bioaccumulation, continuous/temporary); and
2) the sensitivity of the receiving environment (based on information from the environmental baseline). Cumulative impacts also need to be considered.

Aspects considered in the assessment are dependent on the nature of the assets and decommissioning activities, and will be clarified during the EA process, but generally include the following: Energy & emissions , discharges to the marine environment, waste management, underwater noise, impacts on fishing and shipping, impacts on communities (at onshore disposal yard), socioeconomic impacts (e.g. employment), long term legacy impacts (to fisheries, marine environment and to shipping).

There are often some fundamental differences in the environmental impacts of decommissioning options, particularly between:

- Decommissioning options where structures are left in situ (resulting in long-term legacy impacts to marine environment, fishermen and shipping); and
- Decommissioning options to remove structures (resulting in very different short-term negative impacts onshore, to marine environment, and significant energy use; conversely, there are positive impacts such as employment and recycling steel).

An example list of overall impacts is:

- Energy consumption and emissions to the air (short term);
- Planned discharges to the sea or ground (short term);
- Physical impacts (short and long term);
- Waste management and resource utilisation (short term);
- Cultural heritage (e.g. ship wreck) (short term);
- Littering from equipment left in place (long term liabilities);
- Unplanned discharges to the sea (short and long term);

- Impacts on fishing (short and long term);
- Impacts on shipping (short and long term);
- Impacts on local communities (short term);
- Socioeconomic impacts (short term);
- Costs (short term); and
- Other issues (technical risk, safety of personnel, artificial reefs, etc.).

Particular issues being addressed depend on the actual project include drill cutting piles, marine growth on structures, scale with NORM and/or mercury in piping and process equipment, residues in oil storage tanks.

Short and long term are very different types of impacts, and comparing them is not straightforward, and can be challenged. A specific option favoured by one group of stakeholders (e.g. fishermen) could be considered negatively by another (e.g. residents living near onshore dismantling facility). The Shell Brent EIA was a very comprehensive environmental assessment, and was peer reviewed, but still contentious.

D.2.2 Comparative Assessment & similar methods

Comparative Assessment (CA) is a method used by the offshore oil and gas industry to examine feasible decommissioning options and identify the optimum option by evaluating against criteria: safety, environmental, socio-economic, technical feasibility and cost. If derogation options are sought, the CA should provide evidence and reasoning that demonstrates that it is the preferable option. As such, the CA is one of the key processes in making decisions within decommissioning.

Environmental impacts are captured in the CA evaluation, whether they be short-term operational decommissioning impacts of Decommissioning Option A (Removal), or they be long-term legacy impacts to the marine environment from Decommissioning Option B (Leave in situ).

As mentioned previously, there are some fundamental differences in the environmental impacts of decommissioning options, particularly between decommissioning options where structures are left *in situ* (resulting in long-term legacy impacts to marine environment, fishermen and shipping), and decommissioning options to remove structures (resulting in very different short-term negative impacts e.g. onshore, marine impacts, significant energy use). These are very different types of impacts, and comparing them is not straightforward, and can be open to challenge. Improved CA guidance may be beneficial on (e.g.) how to weight ‘in situ’ environmental impacts that are long-term and can last for hundreds of years.

D.2.3 Identified Shortcomings and Potential Improvements

The CA approach is useful and widely applied in Europe and around the world. However, thorough a CA process, it involves subjective judgement, and even if the CA is peer reviewed, the outcome may still be challenged by parties that do not support the recommended decommissioning option.

A possible area for improvement to CA could be on improving transparency, which could potentially be achieved by clearer guidance on selecting criteria and weighting and sub-criteria, particularly for the more complex structures that are eligible for derogation (this topic was discussed at an OSPAR OIC meeting in December 2019). These issues were supported by many stakeholders, some of whom feel that operators can use CA to bias the process and favour the leave in situ option. Without complete transparency of weightings, CA can remain open to criticism that weightings have been biased to lead to a preferred answer. With transparency, although a party might disagree with the recommendation, it would be able to clearly see and understand the reasoning.

D.3 Effectiveness and methods of Environmental Monitoring

D.3.1 Monitoring before and during decommissioning

Operating offshore fields usually have environmental monitoring performed every few years that would typically look at the type and extent of seabed sediment contamination and associated effects on benthic fauna. Stations are typically located from 250m from the platform, extending to 1-2 km distance. Hence, an environmental baseline prior to decommissioning typically exists from the operations phase monitoring.

A gap analysis of existing environmental data can be done to see if additional surveys will be required to support the environmental assessment of decommissioning activities. It may be possible to supplement with use existing regional data.

During decommissioning specific environmental monitoring may be required as per EIA recommendations, to monitor the impact of decommissioning activities, such as dredging, excavation, pipe cutting etc.

D.3.2 Post-decommissioning monitoring

Following decommissioning, the EIA would normally call for a monitoring survey to identify, and recover, any debris on the seabed, e.g. within a 500 m radius of any installation that had a safety zone, or 50 m either side of a pipeline if the operator does not have that data in-house already. Verification that an area is clear of debris that could interfere with future fishing operations may also be required, and this is normally done by relevant fishing body, via a trawl survey.

In addition, a post-decommissioning environmental survey may triggered by the EIA, particularly where there is significant contamination, or where infrastructure decommissioned in situ needs to be monitored to assess its condition, its colonisation or the potential risk to fishing. Operators are required to develop a survey strategy and it may entail multiple surveys, with the first being part of the decommissioning close-out process and further surveys scheduled for some time after the initial survey. The results of post-decommissioning monitoring surveys should be submitted to the regulator, who will take a risk-based approach when determining the requirement for further surveys.

Monitoring requirements in Norway are similar, guidelines imply two regular monitoring campaigns with a three-year interval. Further requirements are decided by the regulator depending on the results. Possible monitoring of physical structures being disposed in situ is required on a case-by-case basis as part of the actual disposal decision with conditions.

D.3.3 Identified Shortcomings and Potential Improvements

Monitoring of the physical structures left in situ offshore is not well established, and is considered on a case-by-case basis. It may be beneficial to specify requirements for long-term environmental monitoring programmes post-decommissioning.

APPENDIX E Decommissioning cost estimates

E.1 Introduction

Much of current oil and gas production in European waters (including UK and Norway) is characterised by post-peak production from mature assets with an increasing number of fields now preparing for, or undergoing, decommissioning.

In the countries with a more mature decommissioning industry, such as the UK, Norway and the Netherlands, projections of decommissioning activity and cost breakdown estimates are being produced to inform decision makers on key aspects of decommissioning, target areas for improvement in project engineering and investment in technologies that could drive reduction in the final costs of decommissioning. This section summarises the methods used to estimate potential decommissioning activity and associated costs in several European countries.

All the estimates and projections are highly sensitive to factors not directly in control of the regulators and operators, such as demand levels and commodity prices for oil and gas, that influence the value of an asset and its economic viability. This can directly impact decision making around cessation of production and the start of decommissioning.

It is projected that the total spending on decommissioning of offshore oil and gas assets in the EU is €4.8bn in the period 2020-2030 sub-divided as: Netherlands €2.6bn, Italy €1.4bn, Denmark €0.4bn, and other Member States €0.4bn. This compares with spending of ca €17bn in the United Kingdom and €9.7bn in Norway over the same period.

E.2 The United Kingdom

In the United Kingdom, cessation of production (CoP) is only granted by the Oil & Gas Authority (OGA) when the licensee has demonstrated that all options for economic extraction of hydrocarbons have been exhausted, and that the asset cannot be converted for alternative uses such as Carbon Capture and Storage (CCS), or hydrogen production. It is generally the operator's estimate of remaining reserves, external demand profiles and commodity prices for oil and gas that have the greatest influence on their estimate of continued viability of a field and associated declaration of CoP.

For assets on the UK continental shelf decommissioning is a tax-deductible expense. The UK government has put in place a legally binding framework - a Decommissioning Relief Deed – with operators, which is set around **£24bn in tax relief for decommissioning expenses up to 2063**. However, this figure has a high degree of uncertainty, as the tax relief estimate is **based on a total spend on decommissioning of £58.3bn**, with a **range between £45bn and £77bn**. So, the figure could easily grow if the cost trends toward the upper figure and the operators claim more in tax relief than anticipated. This figure was estimated against the assets in production in 2017, as more production assets are added (and then decommissioned) this estimate will increase.

The UK operators have traditionally relied upon conventional accounting and cost estimation practices for the estimation of decommissioning costs, such as the production of an Asset Retirement Obligation (ARO) according to the cost estimate classifications by the AACE.

Table 31: AACE Classification of Estimates

Cost Estimate Classification	% Complete Decommissioning Definition	Cost Estimate Technique	Expected Accuracy Range
Class 5: Order of Magnitude	0% to 2%	Stochastic, most parametric, judgement.	L: -20% to -50% H: +30% to+100%
Class 4: Budget	1% to 15%	More parametric, expert opinion, trend.	L: -15% to -30% H: +20% to+50%
Class 3: Preliminary	10% to 40%	More definitive, detailed, unit-cost, activity based, expert opinion.	L: -10% to -20% H: +10% to+30%
Class 2: Intermediate	30% to 70%	More definitive, detailed, unit-cost, activity based, expert opinion.	L: -5% to -15% H: +5% to+20%
Class 1: Definitive	50% to 100%	Deterministic, most definitive, detailed, unit-cost, activity based, expert opinion.	L: -3% to -10% H: +3% to+15%

The OGA expects nearly half of the operator cost estimates to be accurate only within a range of -20% to +100% (Class 5) and another 40% to be accurate within -15% to +50% (Class 4). Much of this uncertainty is carried forward through the decommissioning planning process and is only reduced when major contracts, such as for Well P&A and topsides and substructure removals, are confirmed. The uncertainty over the costs of decommissioning is due to the number and variety of assets to be decommissioned, the condition that these assets are in, the future demand profiles and market hire rates of externally hired equipment, e.g. mobile and platform based drilling units and specialist offshore and heavy lift vessels, that are a critical cost element in decommissioning.

The OGA consults with operators to ensure that the quality and uncertainty in the cost estimates for decommissioning are improved, including requiring an operator to increase the certainty of the cost estimate in a step-wise manner as the decommissioning programme is developed, with estimates required at 6 years and 3 years from decommissioning beginning.

To provide a more accurate figure for the Decommissioning Relief Deeds, and resultant projected cost to the UK Government, the OGA has initiated an annual data gathering programme from operators and licence holders on their estimates for both CoP and the cost of decommissioning assets in their portfolios. It is the responsibility of the operator to ensure that estimates of CoP and decommissioning costs are kept current and in line with accepted practices, latest applicable technology and supply chain and market indices norms, e.g. rig and equipment hire rates, specialist and general vessel charter rates, manpower availability, etc. Should these estimates vary grossly with the emerging industry average, the OGA has powers to direct the field licence holders to revise their estimate or provide justification for the estimate. It also shares metric data with operators to indicate how an individual operator is performing with respect to their peer group.

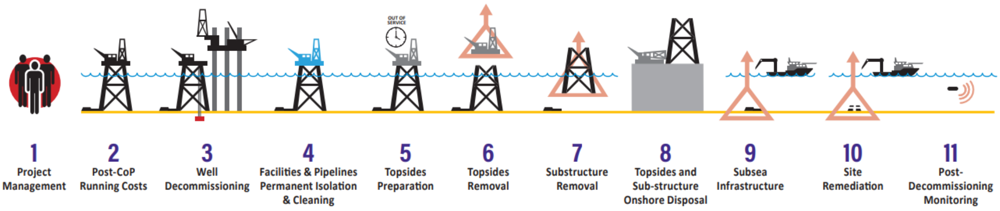
Since the initiation of the annual programme of data gathering, the central cost estimate for decommissioning has dropped from £59bn to £48bn.

Similarly, OGUK has produced a cost estimation method[132] that is widely deployed by UK operators and used in other nations as a basis for cost estimate that can be used for; an estimation of the Asset Retirement Obligation (ARO) during field life, a decommissioning security arrangement when an asset ownership is transferred, planning CoP and the decommissioning cost estimate. The method uses a work breakdown structure (WBS) that assigns decommissioning costs to the eleven common decommissioning activities shown in Figure 17.

[132] UK Public General Acts, Petroleum Act 1998, https://www.legislation.gov.uk/ukpga/1998/17/contents

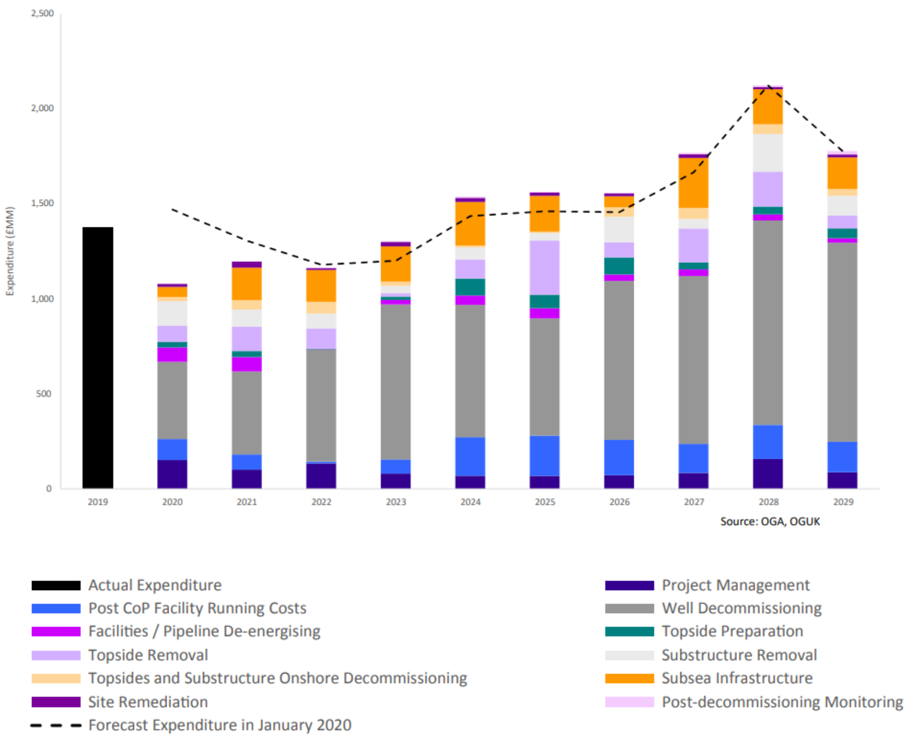
The method has been used to produce a number of cost estimates by UK operators and is aggregated in the OGUK Annual Decommissioning Review[115] to produce data that can be used to project potential decommissioning costs and ranges going forward. The figure shows the forecast expenditure breakdown by the main decommissioning project elements in the UKCS for the decade to 2029.

Figure 17: Projected breakdown of decommissioning costs (£million) in the UKCS. [Decommissioning Insight 2020, OGUK]



	1	2	3	4	5	6	7	8	9	10	11	
Proportion of Overall Ten-Year Expenditure (£MM)	7%	9%	49%	3%	3%	8%	6%	2%	11%	1%	<1%	TOTAL
Northern North Sea & West of Shetland	£389.04	£520.75	£2,940.09	£241.40	£193.39	£703.01	£265.59	£123.96	£519.68	£39.14	£14.35	£5,950.40
Central North Sea	£418.52	£672.60	£3,162.60	£95.90	£183.65	£300.47	£247.17	£147.19	£786.15	£39.49	£19.50	£6,073.25
Southern North Sea & East Irish Sea	£191.15	£176.22	£1,287.77	£87.90	£105.20	£253.84	£417.00	£94.23	£316.61	£94.23	£25.53	£3,049.69
TOTAL	£998.71	£1,369.57	£7,390.46	£425.20	£482.24	£1,257.32	£929.76	£365.38	£1,622.44	£172.86	£59.38	£15,073.34

Figure 18: Decommissioning expenditure estimate 2020-2029 [Decommissioning Insight 2020, OGUK]



It is estimated that the **total cost of decommissioning in the UKCS will be ca £15bn over the next ten years**, of which the Government will release **tax relief of £6.5 to £9bn**. The majority of the spending will be in the Northern North Sea and Central North Sea, both areas spending ca £6bn. The Southern North Sea and East Irish Sea will remove the largest number of structures, and spend ca £3bn.

The largest cost is **well decommissioning** which is estimated at **£7.4bn** in the period. Well decommissioning will average between **120 – 170 wells per year** through the decade, a total of approximately **1,600 wells** (approximately 66% of all North Sea abandonments that will have been completed by then). There is a high degree of confidence in this figure as the majority of the wells have already been identified as P&A candidates or with P&A planning underway. However, there will still remain a much greater number of wells to P&A in the period beyond 2030, which indicates that this rate of decommissioning will need to be sustained or increased up to 2050.

Table 32: Well decommissioning in the UKCS by area and well type [Decommissioning Insight 2020, OGUK]

Well Type	NNS & WoS	CNS	SNS & IS	Total
Platform wells	328	283	371	982 (61%)
Subsea wells	204	303	47	554 (34%)
Suspended exploration and appraisal wells	20	29	31	80 (5%)
Total	552	615	449	1,616

It is estimated that ~660,000 tonnes of topsides and 370,000 tonnes of sub-structure will be decommissioned and returned to shore for recycling and disposal (73% and 53% of North Sea structures by weight). The majority of the tonnage comes from the large Northern North Sea area, but the majority of assets come from the smaller Southern North Sea and East Irish Sea.

Figure 19: Topsides decommissioning activity [Decommissioning Insight 2020, OGUK]

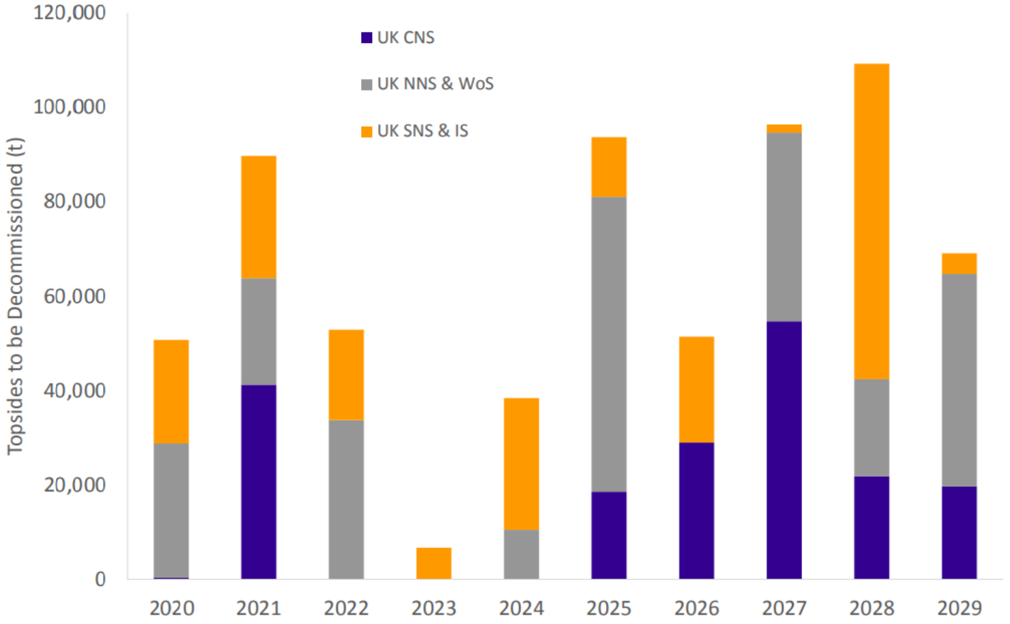


Figure 20: Topsides decommissioning activity [Decommissioning Insight 2020, OGUK]

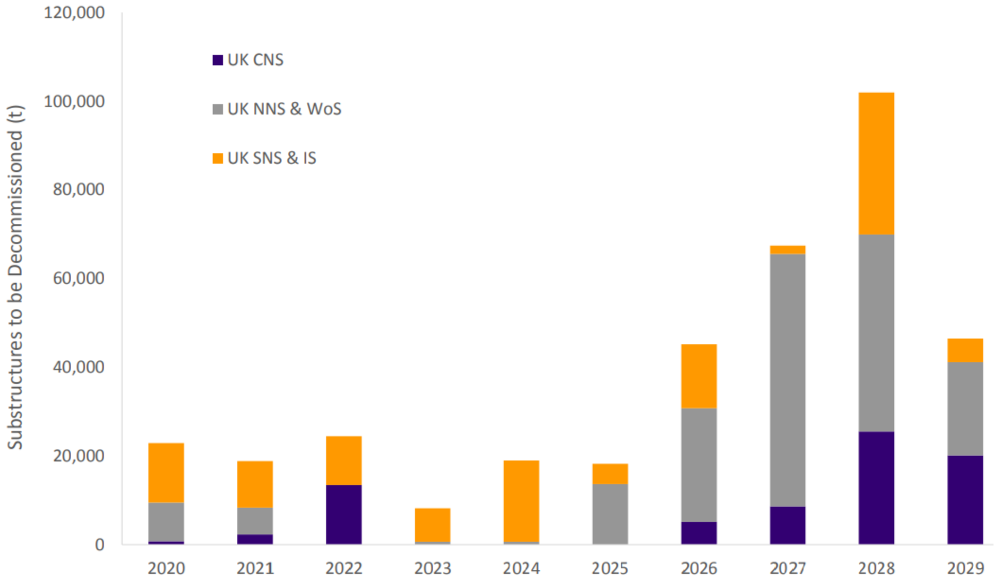


Figure 21: Topsides decommissioning activity [Decommissioning Insight 2020, OGUK]

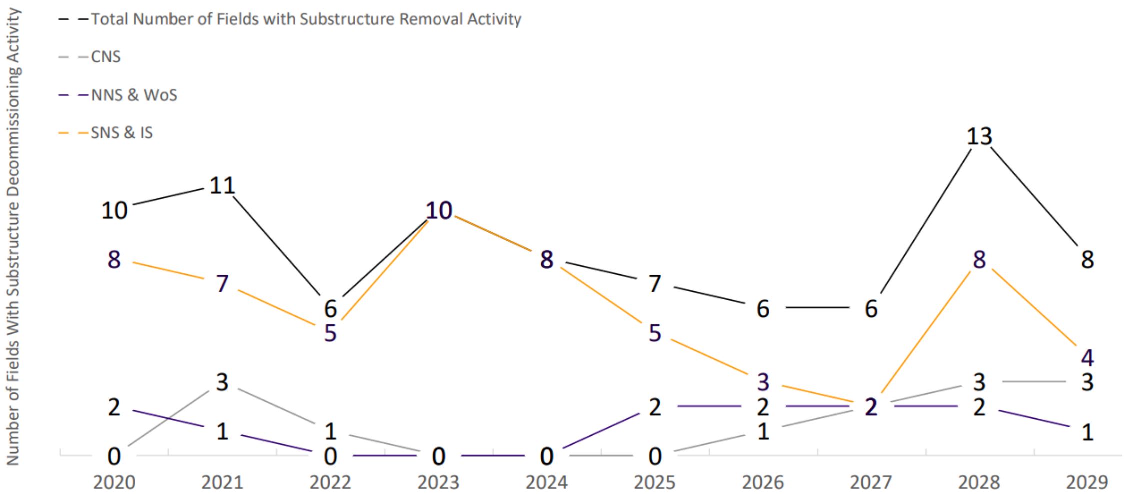
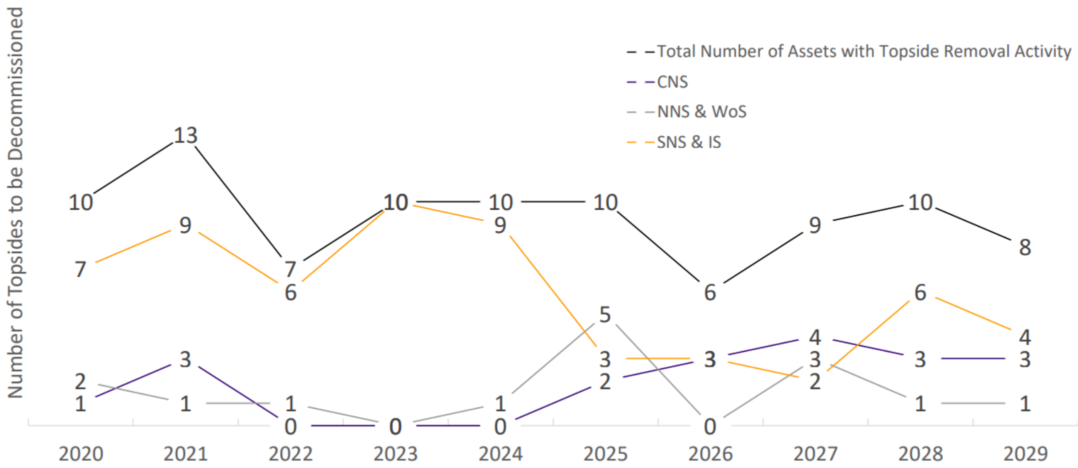


Figure 22: Substructure decommissioning activity [Decommissioning Insight 2020, OGUK]



After the ten years shown, the decommissioning profiles and costs become less certain. However, it is likely that the rate of spend will remain at approximately these levels through the period 2030-40. The 2020 oil price drop has not only brought forward CoP dates for some assets through making them sub-economic to operate, but also reduced investment in decommissioning as oil and gas companies seek to reduce expenditure and focus on maintaining production efficiency. This is leading to a build-up in demand for decommissioning in the medium term that, without co-ordination and management, may see supply chain price escalation and an associated increase in the cost of decommissioning through the 2030s as operators liquidate the excess demand on top of continuing decommissioning of other assets.

OGUK has reported cost forecasts for well decommissioning and topsides and substructure removal for a number of years and has allowed the historical projection of these costs to be tracked. The current median cost estimate for well decommissioning in the various areas of the UKCS are presented below.

Table 33: Comparison of OGUK insight report and OGA 2019 P50 forecasts

Well type	Area	***Decommissioning insight 2019*** **forecast (Median over next 10 years)**	***Decommissioning insight 2020*** **forecast (Median over next 10 years)**	***OGA benchmarking report*** **(P50) 2019 actual performance**
Platform	Northern and Central North Sea	£2.74 million	£3.36 million	£3.7 million
	Southern North Sea and Irish Sea	£2.33 million	£3.04 million	£2.5 million
Subsea	Northern and Central North Sea	£9.01 million	£8.51 million	£7.3 million
	Southern North Sea and Irish Sea	£4.99 million	£6.28 million	£5.4 million

These are illustrated below:

Figure 23: Average forecast well decommissioning costs in the Northern & Central North Sea and West of Shetland

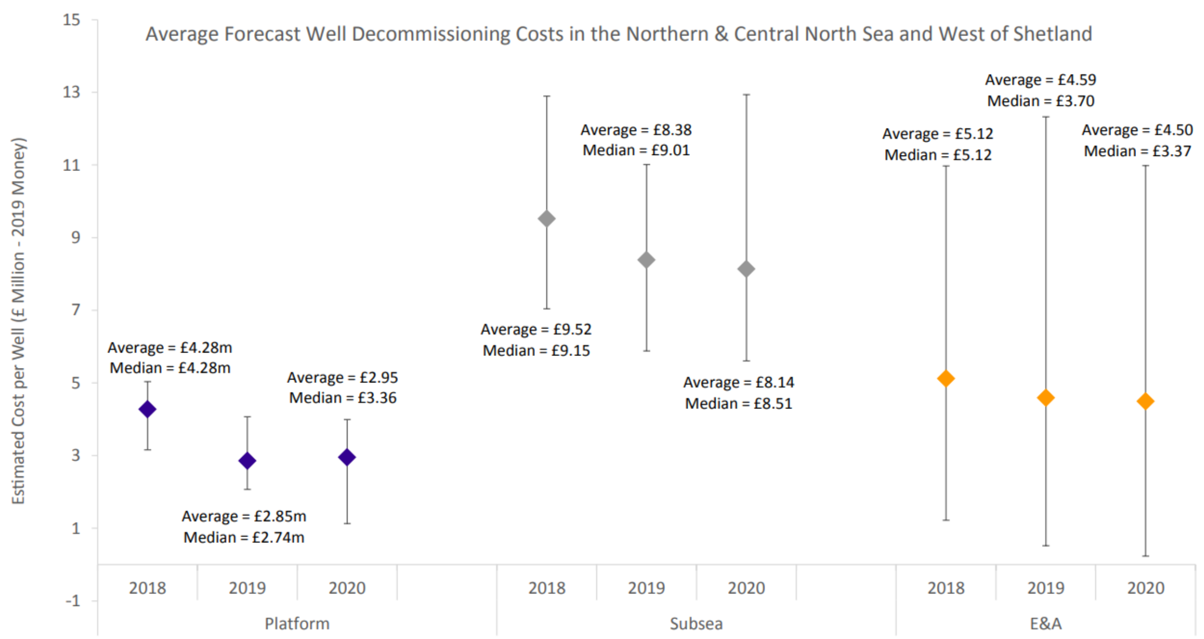


Figure 24: Average forecast well decommissioning costs in the Southern North Sea and Irish Sea

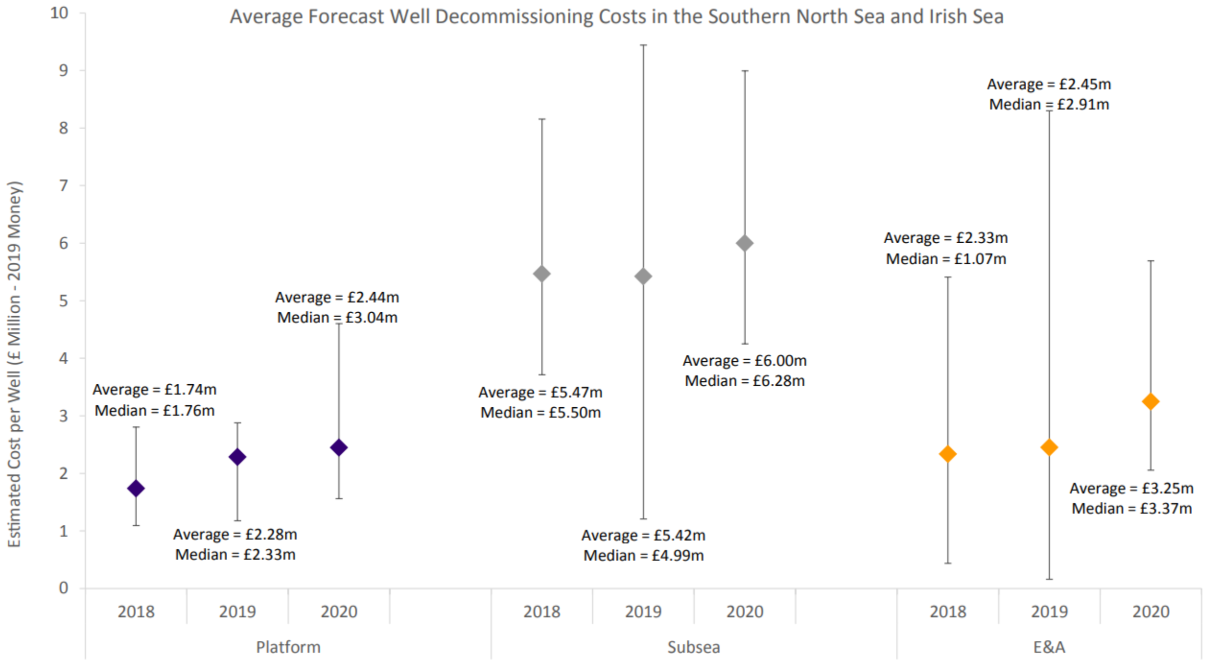


Figure 25: Average forecast topsides and substructure removal costs in the Northern & Central North Sea and West of Shetland

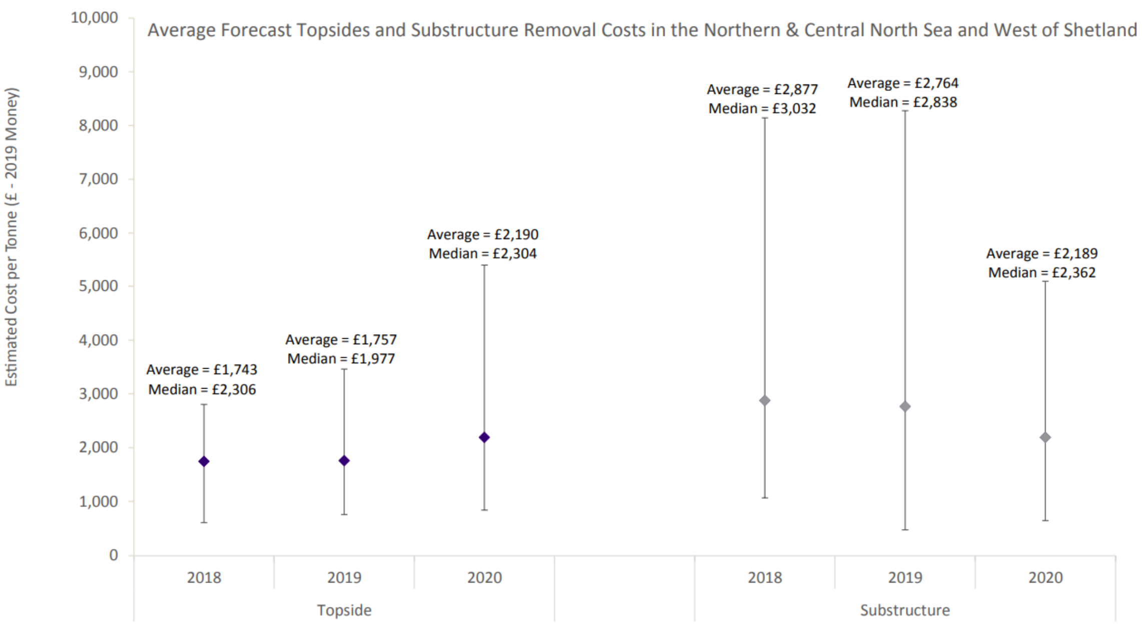
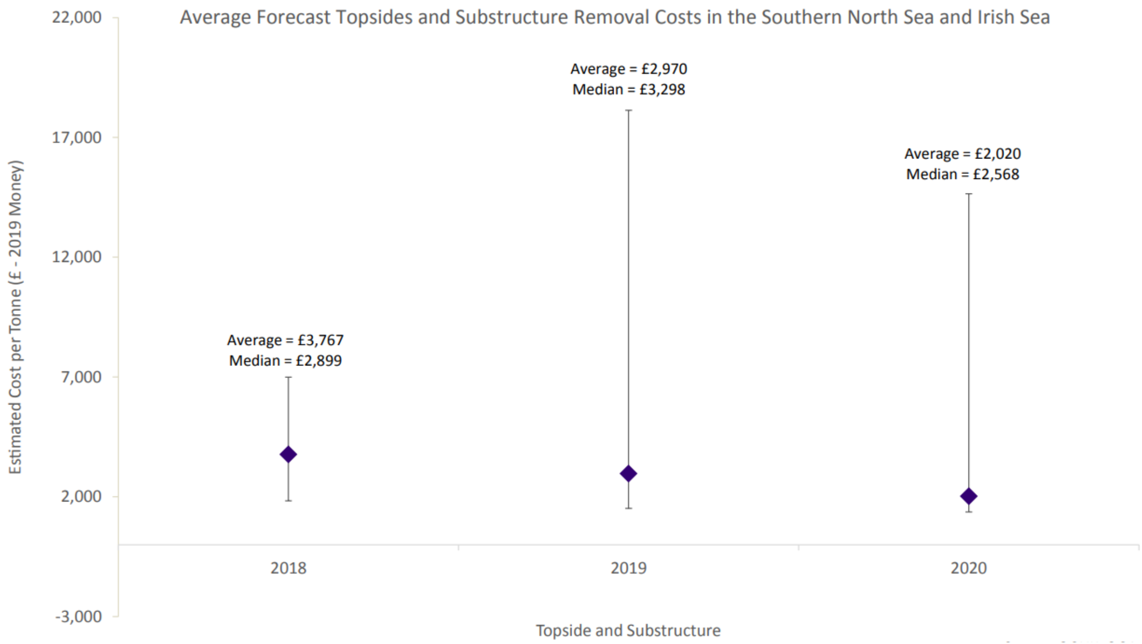


Figure 26: Average forecast topsides and substructure removal costs in the Southern North Sea and Irish Sea



This data provides a useful benchmark for those nations with less well-developed cost data to begin the process of estimating the cost of their own decommissioning portfolio.

Under the Petroleum Act 1998, the state is liable for decommissioning offshore oil and gas assets if oil and gas companies are not able to pay for decommissioning, e.g. due to insolvency. The risk can be partly mitigated because the liability for decommissioning transfers to any remaining current licence holders, and then to the previous owners of the asset. Liability only transfers to the state if the companies cease to exist.

As a consequence, there is a focus on the 20% of offshore assets that never have been owned by larger oil and gas companies, where there is a higher risk of the state paying for decommissioning. In these cases, the OGA has asked operators to set aside monies for decommissioning in the form of a bond or insurance. There is currently ca. £1bn in decommissioning bonds lodged by operators, which is a relatively small sum compared to the risks at stake.

E.3 Norway

Cessation of production, decommissioning and disposal of facilities are regulated by the Petroleum Act and Petroleum Regulations. The decommissioning plan for an asset identifies the preferred decommissioning method and contains a cost estimate for its removal in accordance with the Act and Regulations. The plan must be submitted to the Ministry of Petroleum and Energy (MPE) within two to five years prior to a licence expiring or being relinquished, or when use of a facility ceases.

Approximately, **NOK 100bn (€9.7bn) will be spent in the period 2020 – 2030**. As a number of fields are now in a mature phase and have produced a large proportion of their original reserves this proportion is expected to rise. It is a focus of the decommissioning approval process to identify all potential opportunities for continued use before a final decision on cessation of production.

It is projected that on the NCS in the period 2020-29:

- ca 250 wells will be abandoned (10% of all North Sea abandonments);

- ca 77,500 tonnes of topsides will be returned to shore (10% of all North Sea topsides by weight); and
- ca 108,000 tonnes of substructures will be removed and returned to shore (15% of all North Sea substructures by weight).

Beyond this period, into the mid-2030s and 2040s, well decommissioning and removal tonnages, and associated decommissioning expenditure, are expected to increase as larger fields reach cessation of production and move into their decommissioning phase.

However, it is difficult to estimate exactly when producing fields will shut down. Many facilities continue to produce longer than the original estimate through new tie-ins (satellite fields) and improved recovery initiatives. Similarly, operators have extended commercial life of facilities which are no longer producing from their own deposits by using the facilities as hosts for production from other developments in surrounding areas. A recent review of estimated cessation of production dates for major fields has seen many pushed back by 5 to 10 years by life extension activities.

As a result, the timing and costs related to decommissioning remains uncertain and varies from field to field. A regulatory focus is on ensuring co-operation between licensees, the service and supply industry, and affected interest groups to deliver decommissioning in a more co-ordinated manner than at present, with the anticipation of reduced costs achieved through multi-operator/multi-field decommissioning and removal campaigns.

E.4 EU

E.4.1 The Netherlands

NexStep estimates in its most recent report that 60% of the existing installations will be decommissioned in the period up to 2030, with the remaining 40% decommissioned in the period 2030-2040. However, there is uncertainty in the figures due to recent gas prices trending lower, potentially increasing the rate of decommissioning.

It is projected that in the Dutch Sector there will be a peak in well P&A activity between 2021 and 2025 with installation removals occurring 1-2 years later. In the period 2020-29 it is estimated that:

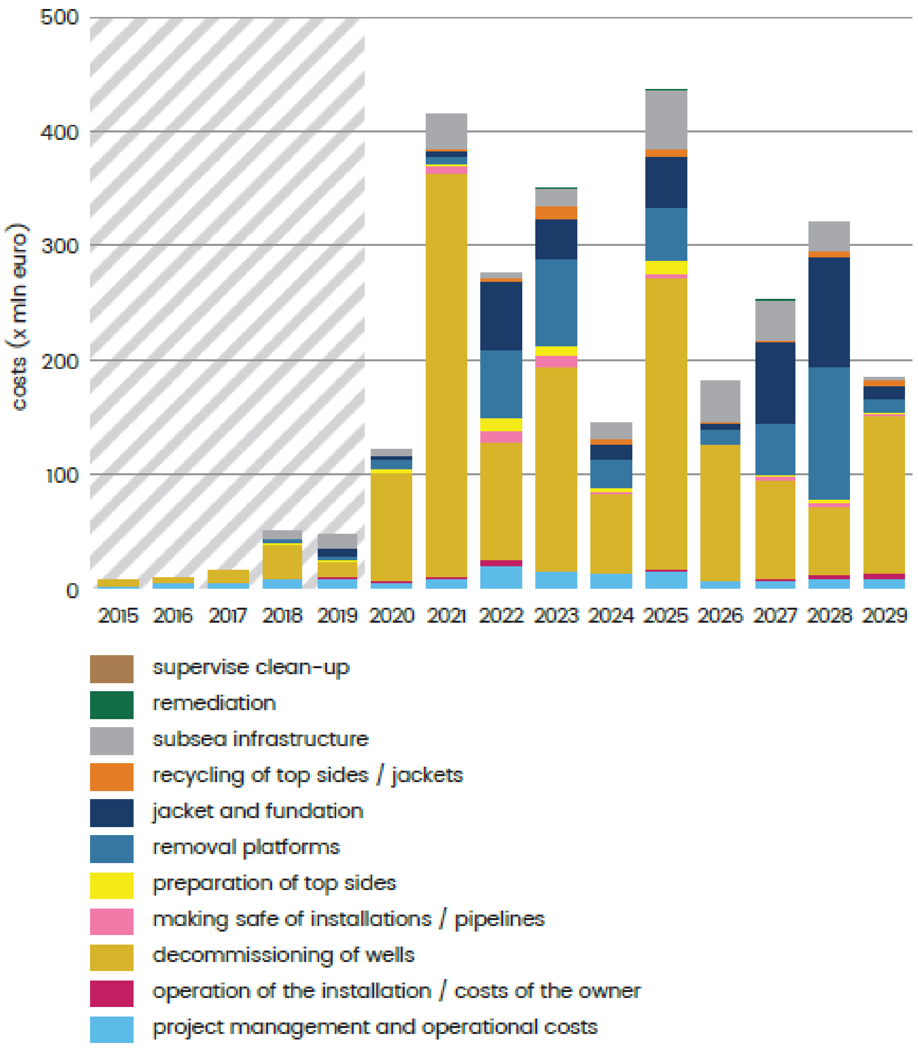
- ca 470 wells will be abandoned (20% of all North Sea abandonments)
- ca 132,000 tonnes of topsides will be returned to shore (15% of all North Sea topsides by weight), and
- ca 184,500 tonnes of substructures will be removed and returned to shore (25% of all North Sea substructures by weight).

The platforms in the Dutch sector are in shallower water and are smaller than those in the UK and Norway Central and Northern North Sea areas. This can be considered advantageous, as there is a larger fleet of drilling rigs and crane vessels that are available for the P&A and removal operations, which can drive competition and lead to cost reductions for these activities on a per well P&A and removal per tonne basis. At water depths of 25m to 50m most of the wells are accessible to jack-up MODU drilling rigs. Most of the lifts over the next decade will be less than 1,000 tons and only eight of the lifts will be over 2,500 tons (of which five are between 4,000 and 7,000 tons that require higher capacity crane vessels).

The **forecast decommissioning cost** for offshore infrastructure in the period 2020-29 **is ca. €2.6bn**. **The Dutch Government will contribute approximately 70% to the costs of decommissioning (€1.8bn)** through the participation of Energie Beheer Nederland (EBN) in field licences where decommissioning is taking place, and from the tax regulations that allow operators production tax relief for decommissioning costs during this period. The total cost of decommissioning all the current offshore installations in the Dutch sector is estimated at **€4.3bn** up to 2040, which represents an annual outlay of ca. **€150mn** for the Government.

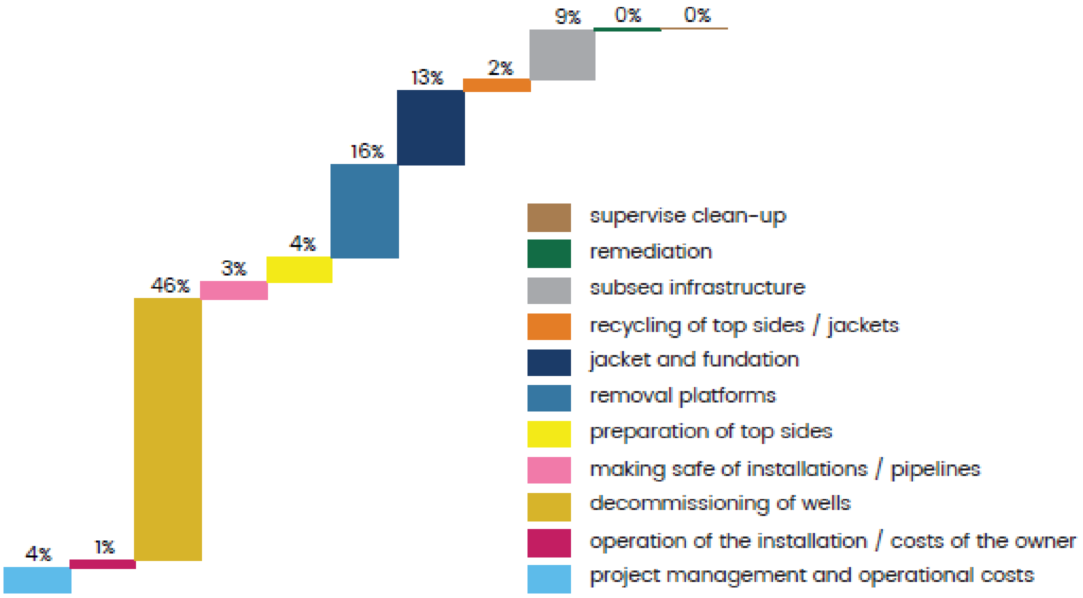
The estimated decommissioning costs in the period 2020-2029 are presented in Figure 27.

Figure 27: Estimate of decommissioning costs in the period 2020-2029 [NextStep, EBN]



The costs are allocated according to the following categories:

Figure 28: Allocation of estimate decommissioning costs in the period 2020-2029 [NextStep, EBN]



This cost allocation is equivalent to:

- €2.6mn per Well abandonment in the period,
- €3,150 per tonne of topsides,
- €1,830 per tonne of substructure.

NexStep has been tasked with achieving a 30% reduction in decommissioning costs and has set up workstreams to investigate where efficiencies may be found in the areas of standardisation of well P&A requirements, co-ordination of well P&A and removal campaigns across operators and supply chain and increasing the re-use of structures either in oil and gas or alternative energy production.

E.4.2 Denmark

Although the Danish Energy Agency regularly produces reports on oil and gas production from Danish installations, there is currently no information available on the cost of decommissioning activities. Oil and Gas Denmark (OGD) has established a decommissioning committee to improve knowledge sharing and co-operation amongst OGD members on decommissioning to drive down the cost of decommissioning. Data gathering from independent sources suggests that in the Danish Sector the following activity is anticipated in the period 2020-29:

- ca 90 wells will be abandoned (4% of all North Sea abandonments)
- ca 32,600 tonnes of topsides will be returned to shore (4% of all North Sea topsides by weight), and
- ca 40,200 tonnes of substructures will be removed and returned to shore (6% of all North Sea substructures by weight).

This would equate to a **total decommissioning spending of ca. DKK 4bn** in the period 2020-29.

E.4.3 Italy

The Italian Ministry for Economic Progress produces an annual report listing the installations for which decommissioning applications have been made. The most recent report identified 5 small near-shore structures in the Adriatic for decommissioning. Out of the 5 identified projects, 4 were proposed as candidates for re-use in alternative energy applications. In addition to those identified in previous years and data source searches, 13 structures have been identified as shut-down and awaiting decommissioning, 9 single well platforms in the Adriatic and 4 subsea well heads (2 in the Adriatic and 2 in the Mediterranean). Current decommissioning activity in Italy, in terms of number and size of the concerned structures, is low.

However, market research estimates indicate that decommissioning activity could cover ca. 75 installations and 380 wells by 2030. This would equate to a **total decommissioning spending of ca. €1.4bn** in the period 2020-29, with most of the expenditure toward the end of the period.

E.4.4 Croatia

The Croatian Hydrocarbon Agency reports that gas is currently recovered from 51 wells, spread over 19 gas production platforms, with one gas compression platform. The estimated total decommissioning spending to remove the assets currently in production is ca. **€0.2bn,** but there are no current plans to decommission any offshore assets in Croatian waters.

E.4.5 Other Areas in EU Waters

There are offshore hydrocarbon production facilities in Romania (14), Spain (10), Bulgaria (6), Ireland (2), Germany (2) and Poland (1). Decommissioning is currently underway or planned in Spain and Ireland. The Bulgarian facilities are shutdown awaiting decommissioning and no decommissioning is planned in Romania, Germany or Poland at this time.

APPENDIX F Questionnaire

To inform the review and obtain opinions on potential legislative changes and what standards decommissioning needs to achieve, a questionnaire was in November 2020 sent out to national and international authorities/regulators, industry associations and NGOs. The responders were:

Country	Category	Responder
International (NE Atlantic)	Regulator	OSPAR
International	NGO	European Association of Fish Producers
International	NGO	European Marine Board
International	NGO	Greenpeace
International	NGO	Surfrider
International	Industry Association	IADC
International	Industry Association	IOGP
Croatia	Government / Regulator	Croatian Hydrocarbon Agency
Cyprus	Regulator	Marine Environment Division (MED) Department of Fisheries & Marine Research (DFMR) Ministry of Agriculture, Rural Development and Environment
Denmark	Government	Danish Energy Agency
Denmark	Industry Association	Oil and Gas Denmark / Danish Shipping
Germany	Government / Regulator	BMWI - representing: Federal Ministry for Economic Affairs and Energy Federal Ministry for the Environment, Nature Conservation and Nuclear Safety German Competent Authorities for Offshore Oil and Gas Activities of the Länder: Authority for Mining, Energy and Geology (LBEG) Mining Authority Stralsund
Greece	Regulator	Hellenic Hydrocarbon Resources management (HHRM)
Italy	Governmental	Ministry of Economic Development
Malta	Governmental / Regulator	MESD Malta
Netherlands	Governmental	State Supervision of Mines (SODM)
Netherlands	Government / Industry Association	NexStep / Netherlands Oil and Gas Exploration and Production Association (NOGEPA)
Romania	Government / Regulator	Autoritatea Competentă de Reglementare a Operaţiunilor Petroliere Offshore la Marea Neagră (ACROPO) - Romania
Sweden	Governmental	Swedish Agency for Marine and Water Management
UK	Regulator	OPRED
UK	O&G Supply Chain	Worley
UK	Governmental	National Decommissioning Centre (NDC) Oil and Gas technology Centre (OGTC)

The summary of the responses is given below highlighting areas where the responses provide suggestions for improvement in the EU legislative framework. Some of these suggestions have been taken into account in further stages of the analysis.

F.1 Current Legislative Framework

Q1: What should the aims of EU decommissioning legislation be with respect to environmental, liability and cost impacts? Are these achieved with current international, EU or national legislation?

Q2: Are there major shortcomings in the current regulatory framework? Please specify your answer per level (national, EU, regional, international regulation). If the EU intended to remove them, is it appropriate to do this in the next 5 years, or in a longer time horizon? Would you consider Guidelines, a Regulation (common application across the EU), or a Directive (where a Nation State defines how the requirements of the directive are achieved in law and the specifics of this) to be the most appropriate EU regulatory instrument to achieve this?

Q3: For equipment that is not covered by OSPAR, or similar decisions, (pipelines and cables, concrete mattresses, structures below the seabed), how is the state that it is left in after decommissioning currently legislated?

Q4: How effective, efficient and relevant is the current regulatory regime for offshore oil and gas decommissioning especially in terms of environmental hazards or risks that may exist once decommissioning has been completed and wells have been abandoned? Please specify your answer per level (national, EU, regional, international regulation)?

The responses to the four legislative questions above can be split into environmental, liability and cost issues and the overall regulatory regime. The safety requirement is already covered by the Offshore Safety Directive, but some responders seemed to consider that this Directive covers the environmental aspects whereas it only covers major environmental incidents following a safety hazard (as occurred at Macondo).

Environment

- **Goals and Standards:** All responders that provided an answer to Q1 (aims of EU decommissioning legislation) agreed that the environment should be protected and many of the responders, both industry and NGOs, noted that the environmental risk could not be reduced to zero. No responder identified a specific environmental standard that would assist in the consideration of how to abandon a well, or whether oil and gas infrastructure could be left on the seabed after decommissioning.
- **Monitoring:** Some responders stated that the issue of long-term monitoring was considered to be poorly defined in the overall legislative framework, though there are goal-setting requirements in those countries with a mature decommissioning history and some specific requirements, such as in the Netherlands licensees are responsible to monitor sites for 5 years after abandonment.
- One responder commented that with decommissioning generally still in its infancy, it was not possible to determine whether the legislation was achieving its environmental aims and this may take another 20 years to determine.
- Q12-14 cover monitoring in more detail.

Liability and Cost

- Some national regulators, or authorities considered that liability was not adequately defined in their nations and EU legislation was a way of doing this. It is noted that Article 4 in the EU Offshore Safety directive on liability does not specifically mention decommissioning in the costs that a licensee needs to be able to pay; its focus is on pollution accidents rather than this final element of operations.

- Where mentioned, responders stated that it should not be the public purse that paid for decommissioning and the "polluter pays" principle was cited[133].

Overall Regulatory Picture

- No responder suggested that the current regime did not work and many responders considered that decommissioning was adequately covered in existing legislation and conventions (e.g. OSPAR, Barcelona).
- National authorities from Italy, Denmark and the Netherlands **strongly** stated that the current regulatory regime in their countries worked well and change was not required. Authorities from Norway and the UK did not reply, but industry bodies that cover operators in these countries replied in the same way.
- Authorities from some countries with a smaller oil and gas industry, or with less experience in decommissioning stated that EU legislation would be beneficial to clarify the responsibilities of all parties (note that, as described in Section 2.3 and mentioned by one responder, the majority of decommissioning in Europe will occur outside the EU i.e. UK and Norway). Elements of this could be achieved by mirroring OSPAR in EU legislation.
- An NGO and one quasi-governmental body cited OSPAR as being (too) restrictive as in some cases the local environment is negatively affected by the removal of oil and gas infrastructure. However, another NGO stated that OSPAR was working well to remove infrastructure from the seabed, also providing jobs, which would help manage the gradual decline of the oil and gas industry in Europe.

F.2 Best Practice

Q5: Which provisions from existing national, regional or international legislation or conventions stand out as good practice, and could be used as a template for either EU-level or national legislation in all concerned EU Member States?

Q6: The EU is considering whether to specify decommissioning best practice to improve decision-making in decommissioning and so reduce its potential financial liability and environmental impact especially in the long-term. How should this be done (e.g. Best Available Techniques Reference (BREF) document)?

Q7: Do higher standards for decommissioning exist elsewhere in the world that would be applicable for the EU?

A number of areas were mentioned as good practice:

- OSPAR (though note the comments above on it being too restrictive and the potential environmental benefits of leaving infrastructure in place);
- The requirement for a public hearing on the environmental impact assessment in Norway;
- The Netherlands decommissioning association (Nexstep) to achieve close cooperation between operators, government and the service industry; and

[133] Governments may have to repay a proportion of production taxation levied on the licence holder(s) to offset decommissioning costs as per the terms of licence agreements. The Netherlands has actively increased the State's share in decommissioning costs from 40% to 70% through EBN (to encourage operators to continue production from assets that would otherwise be uneconomic and to allow evaluation for re-use in alternative energy production, e.g. CCS).

- Of note, the potential for a common well abandonment standard was mentioned by a number of organisations[134]

In regard to the specification of good practice, responders who gave an opinion generally stated that currently available BAT Guidance was sufficient and that the BREF document was the right tool.

No specific higher standards were identified that could be implemented in the EU.

F.3 Potential Changes in EU Legislation

Q8: What environmental criteria should be met on the seabed and for wells once an installation and its wells have been decommissioned?

The environmental criteria identified by the responders was to regain a seabed that was ecologically as healthy as equivalent untarnished seabed. Some responders mentioned the need for a clean seabed, but the criteria as stated leave the possibility of the local environment being improved by, for example, part of a jacket left in-situ. Also, responders stated that the impact of decommissioning itself should be no worse than during production.

Q9: Could you envisage any changes to EU legislation that would positively impact on the cost, effectiveness or environmental impact of decommissioning?

As stated earlier, authorities from countries with a larger oil and gas industry that replied stated that no changes to EU legislation were needed. Beyond this, two suggestions were made in regard to possible legislative improvements: legislation to cover post decommissioning monitoring (see 0) and a change in the tax regime (in the UK at least) to allow for abandonment expenditure to be taken before cessation of production; for example, to abandon a well before CoP is achieved if it is expedient to do so. One country's regulatory body wished to ban various aspects of oil and gas facilities.

Cooperation between different parties (government and industry) was also mentioned as a potential route to cost savings through more efficient decommissioning.

Q10: Should any identified best practice on management of long-term liabilities and condition that the seabed is left-in be promulgated across the EU and how should this be done (noting that Norway and the UK are not in the EU)?

Q11: Who should assume liability for decommissioned assets (mainly wells and OSPAR derogated structures and, to a much lesser extent, pipelines) once licensee monitoring finishes?

One country's regulator recalled [135]: *Carry out further research and an impact assessment for harmonised industry rules regarding liability, financial security, and in a broader context, for the handling of compensation claims.*

In regard to long term liability after licensee monitoring finishes, almost all responders stated that the country should be responsible, though only after rigorous analysis of the decommissioning process by the country's authorities. Long term liability for the remains of sub-structures left in situ on the seabed is almost exclusively an issue for Norway and the UK; both of which are outside of the EU. A UK quasi-governmental body suggested that liability issues were best handled at the national level. A closure fund was suggested for infrastructure left in-situ (or a well).

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[134] 2018-October-The-Netherlands-NSOAF-initiative-for-a-common-standard-for-well-decommissioning.pdf (irfoffshoresafety.com)

[135] Report From The Commission To The European Parliament, The Council And The European Economic And Social Committee assessing the implementation of Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on the safety of offshore oil and gas operations and amending Directive 2004/35/EC

Section 5.15.5.3 of [135] states that:

There is an absolute duty to ensure the well is sealed permanently when abandoned. …Given the potentially vast financial liabilities accruing to parties involved with the abandonment (including potentially the state), further research may provide proposals for best means. This could help ensure that all development wells are permanently sealed from the environment as a consequence of the removal from use of any production installation.

These issues tie in with the suggestion for a common framework to determine what constitutes a sealed well mentioned under question 5-7 and mirrored in 0.

F.4 Monitoring

Q12: Should any long-term environmental hazard from decommissioned assets be periodically reviewed, e.g. for technological improvements or re-evaluation of data, that may mitigate risk? If so, who should be responsible for such reviews?

Q13: Should any requirement for long-term monitoring after decommissioning be included in any forthcoming EU legislation either specifically, or just in terms of overall principles, or should it be solely covered by national legislation?

Q14: Should monitoring requirements once an installation has been decommissioned be specified in legislation? Which ones? Who should pay?

Generally those organisations or countries that do not have a financial stake in oil and gas suggested that monitoring should be regulated at EU level whereas almost all bodies directly associated with the industry (trade associations, regulators) responded that any regulation should be national to take account of the locality of the decommissioned assets. Those outside of the oil and gas industry responded that the industry should pay for monitoring, though there was a recognition that the monitoring responsibility may have to pass over to the state at some point in time. No mechanism was identified that could facilitate to define when and how any transfer of monitoring from industry to the state should take place.

Post-decommissioning monitoring is already required and is dependent on the risk that remains and on the feedback from the monitoring itself. Several responders echoed the requirement to monitor a site after decommissioning, but few identified that a more fundamental review, as suggested by their answer to Q12, should be undertaken. This could be because the environmental hazards of decommissioned oil and gas infrastructure are relatively well-understood.

Four country regulators (three with minimal oil and gas, or no decommissioning experience), a government body and two NGOs considered that long-term monitoring should be standardised to ensure that it occurs and also to ensure efficiency. The counter argument given by some others is that such monitoring needs to be location specific and so is less amenable to EU legislation.

F.5 Environmental Assessment

Q15: Should, and if so how could, acceptance of the outcome of the CA process by all parties be improved?

Q16: What would you consider the best practice methodology for comparison of options? How could CA be improved?

Q17: Are long term potential environmental impacts and the liability associated with them adequately addressed by the CA process?

Q18 Should the EIA include each option within the CA, or just the final option that is chosen? Would the additional time and costs required to carry out an EIA for all feasible

decommissioning options be justified by the number of decommissioning cases where it would make a difference to the outcome?

Q19: Does the current practice for comparative assessment and associated environmental assessment of offshore decommissioning activities provide sufficient assurance that the most appropriate decommissioning option is being deployed?

Q20: Should the Member State requirements for offshore decommissioning environmental impact assessment be maintained, or replaced with an EU requirement (e.g. via an amendment to the EIA Directive)?"

There was general agreement that the comparative assessment (CA) processes applied by operators were robust. However, for complex CAs, NGOs raised concerns over the application of weightings between short term and long term environmental impacts and the influence on the option selection and justification process .

It was acknowledged by nearly all respondents that there is scope for improving the transparency of the comparative assessment process through greater communication and stakeholder engagement in the early stages of the comparative assessment, the improvement of the description of the key criteria and sub-criteria, and in the assigning of weightings to the criteria, potentially including independent verification.

An alternative, net environmental benefit analysis (NEBA) approach was suggested for improving the weighting of in situ option's socio-environmental impacts that are long-term and may last for hundreds of years.

In order to improve understanding of the full decision making process many respondents favoured inclusion in the comparative assessment of justification for those options that were considered and rejected rather than a narrative based on the selected option alone.

For states with limited oil and gas infrastructure, common CAs with general rule sets could be considered, e.g. for pipeline decommissioning, or where the legislative requirement for what the operator has to do is clear.

Stakeholders mentioned the existing Best Available Technique Reference 2019 (Offshore Oil & gas) (REF) as an appropriate instrument to capture updated best practice, and the EU Offshore Oil & Gas Authorities Group (EUOAG) to help ensure harmonisation of best (non-prescriptive) practice across the EU (and build on the decommissioning experience of countries like Norway & UK). However, individual decommissioning options should be considered on a case-by-case basis to cater for differences between regions, and practices from one area should not be templated to other EU areas, as safety measures, environmental controls and social context will vary depending on asset location and design. Any Best Practice specification should not constrain removal techniques.

F.6 Re-Use of facilities

Q21: Could EU legislation on evaluation of re-use potential of decommissioned oil and gas structures be introduced with the aim of increasing the rate of re-use of oil and gas structures?

Q22: Are there any non-technical barriers to re-use that could be removed with a change in legislation?

Q23: Are you aware of any decommissioned structure that was not reused, but could have been economically re-used for an oil and gas, or other application?

The most detailed response in this area came from an oil and gas trade body that pointed out that re-use for carbon storage was at risk due to lack of planning regarding the potential re-use of suitable structures for projects beyond hydrocarbon production, e.g. repurposing for carbon storage, blue & green hydrogen, wind energy parks, etc., and that these possibilities need to be more comprehensively explored. Non-technical barriers that were identified are liability for abandonment should an installation be used for another purpose and treatment of tax for which there are mechanisms for abandonment in place for example in the UK, but not for re-purpose. Therefore, policy and legislation may be required to encourage this transition, with meaningful incentives.

No installations were identified that could have been re-used, but were not.

F.7 Consultation on Decommissioning

Q24: Should the timing of consultation be included in any upcoming EU legislation? Or should consultation arrangements be solely covered by national legislation?

There was a split in the responses to this question that mirrors other questions:

- Industry Bodies and regulators within countries that have already had some decommissioning stated that the consultation process as required by national legislation (note none in the Netherlands) was adequate; and
- NGOs and countries with no decommissioning history stated that the consultation timing (and more in some cases) should be defined in EU legislation.

F.8 Other

Q25: Are there any forthcoming technologies that will have a significant impact on the cost, effectiveness, or environmental implications of decommissioning?

Some new technologies were mentioned by responders: mainly different types of vessel to make removal of platforms and jackets easier, or allowing less to be left in-situ. Use of bentonite and other alternative plugging materials to reduce the costs of P&A of wells, which can account for 50% of decommissioning spend, was identified.

Q26: Please include any other comments or observations on the decommissioning of offshore oil and gas structures that you consider relevant

A small number of additional comments were made:

- Observation that the time gap between cessation of production and potential re-use of the assets for carbon capture/storage may mean that the opportunity for re-use would be lost;
- From an industry body, a strong rebuttal of the need for additional legislation as they felt that current legislation was adequate and that regional requirements differed because of differences in sea conditions making EU-wide harmonised legislation difficult to envisage;
- A marine body suggested that installations should maintain an inventory of hazardous substances; and
- Rigs to Reefs - The issue of leaving some assets in situ (such as the jacket) because they may contribute to the local ecosystem and benefit the marine environment is becoming more prominent, albeit it is contrary to OSPAR principles of complete removal. Some stakeholders considered this topic would benefit being considered in the light of the EU Blue Economy ambitions and the EU Biodiversity Strategy to 2030, to move forward the concept of “rigs to reefs” for suitable facilities, which is practiced in some other parts of the world and has been deployed in Italian waters for 23 jacket structures. Conversely, some stakeholders, particularly NGOs, opposed the rigs to reefs concept.

APPENDIX G Case studies

G.1 Brae Bravo in the UK - a recent OSPAR derogation application

The Brae Bravo platform is located in the North Sea, approximately 270 km off the coast of Aberdeen in a water depth of ~99 m. The platform was installed in 1987 and produced first oil in 1988, producing for 30 years until Cessation of Production (COP) was called in 2018. Since COP, all wells have been plugged and abandoned whereafter, the platform remained in a period of cold suspension while preparations were underway for the removal of the platform's topsides in 2020. Decommissioning of the Brae Area in its entirety is expected to be complete in 2030. Although this is 12 years on from COP of Brae Bravo, this is not unusual for installations of this complexity.

The operator of the Brae Bravo platform submitted a decommissioning programme to the UK government just before COP in 2017. The Brae Bravo installation consists of a 114m tall, eight-legged steel tubular jacket weighing 22,756 tonnes and a 26 module topsides weighing 36,200 tonnes. Due to the weight of the platforms jacket (>10,000 tonnes) and its installation date (before 9th Feb 1999), according to OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations, the sub-structure is a candidate for derogation. The decommissioning plan, therefore, proposed that the bulk of the Brae Bravo steel jacket should be removed to shore, and the jacket footings left in situ.

A number of options were considered for disposal of the Brae Bravo installation, including complete removal of the installation including the footings, partial removal of the jacket down to 84.5 m LAT leaving the footings in place and re-using the infrastructure as a storage hub for CO_2 sequestration. Of these initial options, formal comparative assessments were carried out for full and partial removal as both the fields reservoir and infrastructure were deemed unsuitable for CO_2 storage.

Comparative assessment showed that the complete removal of the installations jacket/substructure by single lift including the footings was not technically feasible. Cutting the foundation piles 3m below the seabed poses a number of technical challenges. To achieve this, extensive excavation would be required to gain access for cutting, which was determined to be unfeasible due to restricted access, requiring divers to carry out part of the scope where access by ROV was not possible. In addition to this, it was evaluated that even if the jacket was severed from the seabed, the sheer weight of the piles, cement and grout on the jacket raises a high probability of collapse during the removal of the jacket to shore. On this basis, removing the jacket in a single lift was deemed not technically possible.

Two options were therefore taken forward for formal comparative assessment. Complete and partial removal by section cut and lift. Additional options such as complete or partial removal by the use of buoyancy tanks, and reverse installation were explored but discounted. Removal using buoyancy tanks involved more steps than the section cut and lift methods and subsequently resulted in additional risks to personnel. Reverse gravity was also deemed not technically achievable as the buoyancy chambers would not be available for recovery as these were intentionally ruptured as part of the piling process during installation.

Of these two options, partial removal by single lift was considered to be the preference because of its feasibility, its reduced risk to personnel involved compared with complete removal, lower emissions associated with partial removal, less disturbance to the marine environment and less disturbance to the seabed. In addition to the platform infrastructure, all wells have been permanently P&Aed to meet OGUK standards. Pipelines have also been flushed and cleaned of any hydrocarbon residuals as required under the Petroleum Act 1998, with approximately 16,600 tonnes of pipeline infrastructure being returned to shore and the remaining 121,000 left in situ. Other subsea infrastructure such as wellheads, manifolds and templates will be removed to shore for reuse, recycling or disposal.

In November 2020, OPRED informed the Operator of their intention to permit that the footings of the 22,756 tonne steel jacket should be left in situ. Decommissioning of the Brae Bravo platform will therefore include, the removal of the topsides to shore for re-use, recycling or final disposal and the steel jacket removed down to the top of the footings, 34m above the seabed, with the upper section of the jacket removed in a single lift. It is understood by the operator that all residual liability for all Brae Bravo plugged and abandoned wells, the section of the jacket left in situ and all buried pipelines is ultimately the operator's responsibility. A post removal survey is planned for 2029. The results of the post decommissioning survey will be reviewed by OPRED and a post monitoring survey regime agreed upon for the continued monitoring of the infrastructure that remains in situ and the surrounding environment.

Alternative Scenario

As with the actual scenario, the alternative scenario would require the full removal of the Brae Bravo topsides. However, rather than partial removal of the sub-structure to -84.5m, the sub-structure would be fully removed.

It is assumed that the top section of the sub-structure would be removed as per the current programme to -84.5m, prior to the final removal of the lower section. The removal of the lower section would necessitate the removal of the drill cuttings pile that is spread around the drill centre. This would either be removed by mass flow excavator, dispersing the contents outside the footprint of the substructure or returning the cuttings to the surface for treatment and disposal on land. It is likely to result in the dispersion of potentially hazardous materials from the drill cuttings into the water column and the spreading of the cuttings onto the surrounding seabed.

It is unlikely that the lower structure would be able to support the additional weight of the piles and cement grouting. Therefore, it would be necessary to make additional vertical cuts to separate the piled legs from the lower sub-structure section. Complex rigging would be required to remove the separated lower section in a controlled manner. Flooded member sections would also make the load potentially unstable during the lift, so the impacted sections would need to have drain holes drilled to allow liquid drainage during the transition out of the water column into the air.

The residual piled leg sections would need to be cut at the seabed and removed. There is no current technology available to cut the legs of such large diameter. So alternative cutting means would need to be developed, or shaped charge explosive cutting used. It is likely that during cutting the leg would need supported, either at the seabed or by rigging supported by a SSCV. To prevent the potential for slippage of the piles in the sleeves, either the piles would need to be pinned in the leg sections, or the leg sections would need to be lowered to the seabed, before re-rigged and lifted in a horizontal position to the surface. Drainage holes would need to be drilled to allow dispersal of liquid in the leg.

The soil surrounding the upper section of the piles in the seabed would need to be excavated to allow the 3m of the top of the piles to be exposed and then cut by external cutting tools a CSV may be sufficient to support this removal operation.

To remove the lower section would require the SSCV to remain on station for the cutting operations to separate the piled legs from the lower jacket structure, the lifting operations of the lower jacket, the cutting of the legs and the removal of the remaining pile sections. It is estimated that an additional allowance of 720 hours of SSCV and ancillary vessel support would be required, at an estimated cost of €25-30mn. Additional costs for design of the removal solution and project management would be estimated at €3-5mn. The site preparation activities are estimated at €7-10mn. A total additional cost of €35-45mn to achieve full removal.

G.2 Frigg in the UK & Norway - a mature left in-situ structure

The Frigg gas field spans the UK and Norwegian sectors of the North Sea requiring collaboration from both the Norwegian and UK governments to determine percentage splits of ownership. In total, the Frigg complex was comprised of 4 gravity based concrete structures with the remaining structures being medium sized fixed steel jackets. All of these installations were located central to the Frigg hub, with the exception of the MCP01 installation situated midway between the Frigg field and St Fergus gas terminal near Aberdeen. A summary of the installations is given in Table 34.

Table 34: Summary of Frigg field platforms and weights

Platform Name	Removal Date	Platform Type	Topsides Weight (tonnes)	Substructure Weight (tonnes)
DP1	-	Fixed Steel	-	7,364
DP2	2007		4,002	11,122
QP	2008		3,063	5,243
TCP2	2007	Concrete Gravity Base	22,900	22,172
TP1	2009		8,021	162,000
CDP1	2009		6,443	418,000
MCP01	2009		13,500	386,000

The Frigg field ceased production in 2004 after producing over 192 billion standard cubic meters of gas. Decommissioning of the field begin in 2005 after well P&A and was the largest decommissioning project executed in the North Sea at that time. The fixed steel structures were removed in their entirety, relatively easily by a single lift for the topsides and jacket of the QP platform but in several lifts for both the DP1 and DP2 platforms. The topsides of the concrete gravity bases were complex removals requiring multiple lifts to remove all modules and modular support frames.

All infield pipelines and cables have been decommissioned and removed to shore, with the larger, disused export pipelines buried and left in-situ. All tanks and pipes within the concrete columns were drained and cleaned to prevent hydrocarbon leakage into the environment and none of the concrete cells surrounding the bases of the concrete structures were ever used for crude oil storage and so these did not require cleaning.

The 8,500 tonne lift of the module support frame from the 3 concrete columns on the TCP2 was the heaviest lift at Frigg before being transported to a disposal yard in Shetland. The external steelwork attached to all of the concrete substructures were considered to be potential obstacles for fishing and trawling and therefore, had to be removed as far as reasonably practicable. Personnel and ROV’s were used to remove as much of the steel as possible, with a small number of items being left in situ, as unrecoverable and considered not to cause any obstruction.

The Ministry of Petroleum and Energy (MPE) in Norway and the Department of Energy and Climate Change (DECC) in the UK issued permits under paragraph 3b of the OSPAR Decision 98/3, in collaboration with the OSPAR Offshore Committee, to leave the concrete structures of the TCP2, TP1, CDP1 and MCP01 in situ. All other platform jackets were removed to shore for disposal as well as all platform topsides and inter-field pipelines and cables.

Decommissioning of the Frigg field saw approximately 73,000 tonnes of material brought to shore for disposal. External steel attached to the concrete substructures was removed as far as possible with several pieces left behind due to difficulties removing. The total cost for the removal of the Norwegian facilities was approximately 3,287 Million NOK with the UK facilities costing just over £207 million. This is an increase on the budget estimate of approximately 6.7% and 20.7% respectively.

Offshore removal of the Frigg fields infrastructure was completed in 2009. Surveys were conducted for the field pre-decommissioning, during decommissioning and post decommissioning. The post decommissioning survey of the Frigg area was conducted in 2010 when it was concluded that there were no major differences to the environment with leaving the concrete substructures in place compared with the 2003 and 2006 surveys. Future monitoring of the concrete structures left in situ is expected to take place when all three Navigation Aids for the concrete structures are inspected. Currently these are inspected every 4 years, however, this may change upon subsequent inspections.

Alternative Scenario

The original Frigg programme proposed full removal of all topsides and fixed steel sub-structures. The only structures left in situ were the concrete gravity base structures TCP2, TP1, CDP1 and MCP01. There are no credible safe and environmentally acceptable alternative removal scenarios for the CGB at this time.

G.3 Windermere in the UK - typical small platform decommissioning

The Windermere field is located in the Southern North Sea (SNS) in approximately 35m of water and is comprised of the Windermere platform, 2 platform wells, gas export pipeline and methanol and corrosion inhibitor umbilical. The platform was installed in 1996 and was a Normally Unmanned Installation (NUI), with a small topside minimum facilities structure, fixed onto a three-legged tripod jacket. The installation began producing in April 1997 and produced for almost 20 years before ceasing production in 2016. The decommissioning plan for the field was submitted to the UK government in 2015 with offshore works starting in 2017, starting with the wells and pipelines.

The Windermere platform being a NUI, was a small installation with a topsides weight of 452 tonnes and a jacket weight of 382 tonnes, typical of the installations found in the SNS. As outlined in OSPAR decision 98/3 an installation the size of Windermere must be completely removed from the seabed to shore, including the jacket. Pipelines were required to be flushed and either removed or buried so as not to pose a danger to other users of the sea in this area and wells must be plugged and abandoned.

There are several options for the decommissioning of offshore pipelines. The comparative assessment for the 6.8 km long pipeline and umbilical at the Windermere field established that both were stable and buried throughout their length and do not have any re-use potential. The majority of the pipeline was proposed to be left in-situ after being cleaned and flushed as this was assessed to have the least impact on the seabed. Two tie in spools on the pipeline were removed with the ends of the pipeline being trenched and buried. The umbilical was also cleaned and flushed and fully left in situ as this was assessed to have the least impact on the environment. For both the pipeline and the umbilical the mattresses and grout bags were removed with the rock dump remaining in situ. In total, approximately 1235 tonnes of infrastructure were removed to shore with approximately 1194 tonnes left in situ – 68% of this coming from the pipeline and umbilical remaining in place.

In 2017 the two gas platform production wells were plugged and abandoned. Oil and Gas UK Guidelines for the Suspension and Abandonment of Wells 2015 provided the basis for the decommissioning of these wells. In total approximately 120 tonnes of well steel were removed to shore including velocity strings and well casings down to 3m below the seabed.

The 452 tonne topsides of the Windermere installation is a 30m x 30m steel structure. Prior to its removal, the topsides of the installation have been flushed of all hydrocarbons and cleaned before being transported to shore. The removal of the platforms topsides will be achieved through a single lift removal by a Heavy Lifting Vessel (HLV) and transported to shore where selected equipment will be re-used or recycled for other purposes. The three-legged tripod jacket will also be removed in a single lift with the piles cut 3m below the seabed before being transported to shore for recycling.

Post decommissioning, a seabed survey will be undertaken and compared to a survey conducted before the decommissioning took place to identify any disturbances on the seabed, particularly around where the wellheads have been plugged and abandoned and where the installation was situated. After the initial survey, estimated to take pace in 2021, a post monitoring survey regime will be determined. The operator of the Windermere installation will remain responsible for the section of pipeline and umbilical left in situ and will therefore, undertake a long term monitoring programme of both to ensure they do not become a hazard.

Alternative Scenario

The original programme proposed full removal of all topsides and fixed steel sub-structures, only the pipeline and umbilicals were to be left in-situ. As the majority of the length was buried, removal would require excavation of the pipeline and umbilical and either side of the pipeline to allow access for a pipeline cutting tool that would cut the pipeline and umbilical into sections for removal, by a Construction Support Vessel. Excavation would result in the dispersion of significant volumes of seabed material into the water column and over the seabed, which would blanket the seabed on either side of the pipeline corridor. Full removal of the pipeline and umbilical from Windermere to the ST-1 platform would require ca 300 lifts, assuming a pipeline length of 7km, cut into 25m sections for removal. Assuming 150 days to fully excavate, cut and remove the pipeline and umbilical has an estimated cost of ca €10-15mn.

G.4 E18-A and Sillimanite - a re-use example in the Netherlands

The Nextstep's Re-use and Decommissioning report[136] outlines the Dutch approach to re-using and recycling offshore infrastructure. The "Road to 30%" roadmap produced by Nextstep aims to reduce offshore decommissioning costs by 30% in addition to ensuring safe, efficient decommissioning with as minimal impact on the environment as possible. One way of achieving this is by utilising already existing offshore infrastructure.

The P14-A platform was a satellite platform located approximately 50km off the coast of Scheveningen in the Netherlands. The platform started producing gas in 1993, producing approximately 3 billion cubic meters of gas until 2006 when COP was introduced due to declining reserves making it uneconomical to continue production.

In 2008 the topsides of the P14-A installation were removed and cleaned in preparation for re-use. The topsides were then moved to approximately 150km northwest of Den Helder where they were re-used on platform E18-A in 2009. The E18-A satellite platform produced natural gas until COP in 2018. The wells were plugged and abandoned in January 2019 with the 1563 tonne topsides given a third life later in the year when they were transported to the new Sillimanite field development to be used ats the topsides for the D12-B platform. The 769 tonne jacket of the E18-A platform was fully removed to shore to be processed for recycling. The re-use of the E18-A topsides for the second time brings the total number of re-used topsides in the Netherlands to 45%.

To find the best option for the development of the Sillimanite field, screening of existing dis-used assets in the Dutch sector of the SNS was undertaken to evaluate their potential for re-use. Table 35 lists the re-use options considered and their associated costs. It can be seen in this table that although re-use of the Q4-B topsides was the least expensive option it was required to be transported on shore for modifications before it could be re-used and so was excluded from further considerations. Re-using the E18-A topsides for the Sillimanite project was considered to be the best option due to accelerated first gas production when re-using infrastructure compared with a new build and was estimated to cost €16.2 Million less than installing a new satellite platform.

Table 35 : Platform re-use options for the Sillimanite development and associated costs.

Options	Costs (Million Euro)
E18-A re-use	30.3
D12-A re-use	32.5
D18-A (ORCA) re-use	36.7
New satellite platform	46.5
New minimum facility platform with helideck	26.1
Q4-B re-use	21.2[137]

Preparation work for re-using the E-18A topsides included flushing and cleaning of the topsides equipment and carrying out maintenance on the sections of the process equipment that would be re-used on the D12-B platform. The total duration of the project took 12 days from start to finish, including removal of the E18-A jacket to shore and conducting a seabed survey.

The potential for the reuse of offshore platform topsides is a definite possibility, particularly for smaller installations where components can be removed in a single lift. Depending on the time delay between COP of platforms and the removal of their components for reuse, additional reengineering and refurbishment could be required but this still comes at less cost than fabricating completely new infrastructure. This method of reuse does not come without its

[136] Nexstep, Re-use & Decommissioning Report, Innovation & Collaboration, 2020

[137] Excluded as required onshore modifications and logistics.

limitations as platforms must be in a relatively suitable condition for re-use and be a match in size for the new installation it is to be repurposed for.

G.5 Q13a-A PosHYdon - a re-use example in the Netherlands

Carbon emissions reductions are currently a focal point for governments across Europe, with many pledging to drastically cut their carbon emissions by 2050, the Netherlands by 95%. These tight targets are putting pressure on the oil and gas industry to diversify into methods of renewable energy and consider the possibilities of utilising existing offshore infrastructure for alternate energy sources. A 95% reduction in emissions would depend greatly on weather dependent energy sources, such as solar and wind energy and so it was proposed that producing green hydrogen on a large scale via shallow water platforms would secure the energy required as well as providing options for large scale energy storage.

The Q13a-A platform is located in the Dutch sector of the North Sea, approximately 13km from Scheveningen in the Netherlands. The platform was installed in 2013 in a water depth of approximately 20m and was a NUI. The platform is a 4 legged fixed steel structure with a jacket and topsides weight of 950 tonnes and 1700 tonnes respectively. In 2019 it was announced that the platform was well suited to become the first fully electrified oil and gas platform in the Dutch North Sea. This PosHYdon project is a two year pilot scheme to integrate offshore wind, offshore gas and green hydrogen produced from seawater. It is an initiative of Nextstep, the Dutch association for decommissioning and reuse and TNO, the Netherlands Organisation for applied scientific research. The shallow water depth that the platform is situated in, and simulated wind data supporting the use of electricity generated from wind farms to power electrolysis on the platform using seawater, made it a good candidate for the pilot project.

Utilising an old disused pipeline, the platform is powered from green electricity provided via a subsea cable from onshore. This means that the platform does not utilise fossil fuels for energy, saving approximately 14,000 tonnes of CO_2 per year. It also means that the platform can be directly powered by offshore wind energy in the future. For the pilot project there will be no direct connection between the wind turbines and the platform.

The hydrogen production facility is very small and sits on the top of the platform. Seawater is pumped into the unit where it is demineralised and fed into an electrolyser. The electrolyser splits the seawater into hydrogen and oxygen, where the oxygen is disposed of and the hydrogen is blended into the gas export line for transportation. Being able to utilise existing offshore infrastructure to convert energy from wind farms to hydrogen offers major advantages and can be extended to wind farms located much further offshore.

The aim of the pilot project is to increase knowledge around the production of green hydrogen on offshore platforms and to obtain valuable insight for successfully integrating offshore energy systems to help support the energy transition. Utilising existing offshore infrastructure would reduce the number of installations requiring decommissioning and provide a purpose for assets that are no longer in use.

G.6 Kinsale Area - Major decommissioning project in Ireland

The Kinsale Area gas fields began producing natural gas in 1978 and are located between 40 and 70km off the Country Cork coast in Ireland. The Kinsale Area, comprising of the Kinsale Head and the Seven Heads gas fields, came to the end of their productive life in 2020. Decommissioning plans for the area were submitted to the Department of the Environment, Climate and Communications (DCENR) in 2018, prior to COP.

The Kinsale Head field was developed with two fixed steel platforms (Kinsale Alpha (KA) and Kinsale Bravo (KB)) and a 24 inch gas export pipeline from KA to shore. Following on from the discovery of the Kinsale Head field, approximately 90 wells have been drilled in the Celtic Sea, however, no other large discoveries have been found. Despite this, a number of small subsea tie-backs to Kinsale Head including the Seven Heads field have been exploited. A summary of the Kinsale Area Fields facilities is given in Table 36.

Table 36: Kinsale Area facilites.

Field	Number of wells	Facilities
Kinsale Head	14	KA & KB platforms with compression facilities on KA
Ballycotton	1	1 Subsea well
Southwest Kinsale	3	3 Subsea wells
Greensand	1	1 Subsea well
Seven Head	5	1 Subsea manifold 5 Subsea wells

Several options were considered for alternative uses of the Kinsale Area facilities, such as Carbon Capture Storage (CCS) or wind farm development, but at the time of COP, these were considered unfeasible. As no alternative uses for the infrastructure were identified, as required by OSPAR decision 98/3 removal of all disused infrastructure must be removed to shore for re-use, recycling or final disposal.

The KA platform consists of an eight legged piled steel jacket and integrated deck module support frame topsides weighing 8,100 and 4,700 tonnes respectively. The KB platform was originally almost identical to the KA platform also having an eight legged piled steel jacket weighing 7,600 and a topsides of 3,700. Both the KA and KB topsides may be removed using a single lift or piece medium method using a heavy lifting vessel. The removal of the platform's jackets is to be scheduled over a number of years, depending on lift vessel availability, cost efficiency and strategy.

All platform and subsea wells will be plugged and abandoned in 2021 using a 'Thru Tubing' technique and all other subsea structures will be removed to shore.

Post decommissioning a seabed survey will be conducted to ensure that no debris remains around the wells and subsea structures. In this instance, residual liability has not been assessed as no non-pipeline facilities associated with the Kinsale Area will be left in situ and no post decommissioning monitoring is proposed for this area.

G.7 Long Term Decommissioning Liability Coverage

Operators' default on decommissioning liability is a major concern for Competent Authorities. While the majority of licence holders respect the requirement to have available sufficient funding to finance decommissioning, there are examples of where licence holders have defaulted on their decommissioning obligations. In such an event and without sufficient financial guarantees, it will be the responsibility of the Member State, as owner of last resort, to manage and finance the decommissioning. This could be a significant commitment for the concerned State.

There are recent examples of decommissioning liability being returned to the State[138][139], which and had to find a means of financing the decommissioning retrospectively.

Case Study 1: Tui Decommissioning (New Zealand)

The operator of the Tui field, Tamarind Taranaki Ltd (TTL), went into receivership and liquidation in December 2019. The parent company also went into administration in March 2020. As part of the TTL liquidation process, the Tui assets were returned to the Crown (the New Zealand Government). The Government has taken responsibility for decommissioning the Tui assets and has provided funding for the decommissioning, estimated at NZ$155m, but now budgeted at NZ$345m.

As a result of this case, the Government is currently amending legislation such that the risk to the taxpayer from decommissioning oil and gas infrastructure is reduced. The amendments impose a statutory obligation on all current and future licence holders to decommission their infrastructure and extends the obligation to former licence holders in the event of an asset transfer. It also allows the regulator to periodically assess the ability of the licence holder to fund their decommissioning obligations and require the licence holder to make provision as appropriate.

Case Study 2: Northern Endeavour & Laminaria and Corallina Decommissioning (Australia)

In 2016, the incumbent operator sold the production rights to the Laminaria and Corallina oil fields and associated production infrastructure (Northern Endeavour FPSO) for a nominal sum to Northern Oil and Gas Australia (NOGA), which included the obligation to decommission the facilities at the end of their productive life. In July 2019, the production facilities were shut-down by the National Offshore Petroleum Safety and Environment Management Authority (NOPSEMA) following a safety incident. In September 2019, NOGA was placed into administration and the control of the production facilities reverted to the Government, who then placed the facilities into 'lighthouse mode', where the facilities are minimally maintained, until a decision to decommission was made. The decommissioning costs for the fields and infrastructure were estimated to be between AUS$200m and AUS$1bn. The previous owner was considered not liable for the cost of decommissioning as the undertaking to decommission was transferred to the new owners as part of the sale. In an attempt to recover the cost of decommissioning the Australian Government has imposed a levy on the whole Australian Oil and Gas Industry, the practicality of which is currently being disputed by other offshore oil and gas producers. Further, the Australian Government had to grant full indemnity to the company contracted to decommission the facilities, including liability for any environmental releases following decommissioning of the wells. All current production licences in Australia are thought to be exposed to similar decommissioning default risks and the current cost of remediation in Australia is estimated to be AUS$66bn over the next 30 years.

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