Oil and Gas Decommissioning

SUBSEA ENGINEERING OPPORTUNITY
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Contents

1. Introduction

This report is part of a series of ten reports considering the opportunities for the Scottish oil and gas (O&G) subsea supply chain in other subsea and related markets. The report is a desk review considering the international activity of each of the sectors including where there is current activity and where there is the potential for activity based on published targets and available resource and opportunity. The report also considers the particular synergies of the given sector and the subsea oil and gas supply chain. These opportunities cover areas where there is a direct cross over and also where there are opportunities for collaboration to provide innovative solutions.

Decommissioning overall

The aim of O&G decommissioning is to seal off a well permanently from any possible escapes of hydrocarbon or water, or cross-flows into other formations, and clearing the seabed and water column from any O&G infrastructure. Decommissioning is a relatively new sector, but is the final stage in the lifecycle of oil and gas (O&G) operations. The programme of activity includes the removal, where applicable, of a fixed platform or floating vessel e.g. FPSOs; any moorings, risers, umbilicals or conductors; subsea infrastructure; the plugging and abandonment (P&A) of subsea wells and subsequent onshore dismantling and disposal. Onshore wells are not being considered as part of this report. There is a significant crossover between the O&G subsea supply chain and O&G decommissioning both in terms of technology requirements, but also in terms of business practices and ‘language’.

Current good practice in the O&G sector is to have a decommissioning plan in place when a well is being drilled. However, this has not always been the case and where no plans were considered during drilling the resulting decommissioning programme is likely to be more complex and include more investigatory activities within the schedule. Companies can often view it as economically beneficial to put off decommissioning as estimating decommissioning costs is difficult (every well is different) and there is no financial return on the expenditure. However, as time passes the installation will degrade; the understanding of the well decreases; and regulations may become more onerous all resulting in increased costs for the decommissioning programme.

Subsea decommissioning

The visible part of decommissioning is the removal of infrastructure and their transport to shore followed by dismantling and recycling, this accounts for approximately 1.2 percent of the spend on decommissioning. However, there is a larger unseen portion that occurs in the subsea environment. All activity that occurs below sea level will be covered in this report – the preparation and removal of infrastructure, particularly in subsea fields, and the plugging and abandonment of subsea wells.

Global activity

O&G decommissioning is a growing area as offshore infrastructure, particularly in the North Sea and the Gulf of Mexico, ages and moves beyond its operational life and fields become uneconomic. Decommissioning in the GOM has so far been predominately in shallow waters, but decommissioning activity is now occurring in deep water as well. Decommissioning of the infrastructure and permanent sealing of associated subsea wells is

the next stage in the O&G lifecycle. Table 1 below gives an overview of decommissioning expenditure globally, highlighting where most of the activity will be in the next 10 years. In the mid-term markets, for example West Africa and Asia Pacific, work is needed on the development of appropriate and efficient regulation and guidelines for decommissioning. These regions can learn from Scotland, particularly for the deeper water fields as well as provide potential collaboration opportunities for deploying Scottish technologies and expertise.

Table 1: O&G hubs with offshore decommissioning expenditure. Source: various

Oil & Gas Hub	**Expenditure to 2025**	**Total Expenditure**
UKCS	£17.1 bn	Targeting £39bn total, without cost reduction mid-point estimate £59.7bn
Norwegian CS	£400-800 million / year	NOK 160 billion (£14.5 billion)
Dutch CS	£650-800 million / year	€3.7bn (£3.2bn)
United States	> £6.3 bn	$39.5 billion (£27.8bn)
Asia Pacific	-	£21 - £42.5 billion Potentially as much as £70 billion without cost reduction

2. Subsector overview

Offshore oil and gas production first began in the 1940s in the Gulf of Mexico[1] and in the 1960s in the North Sea[2] with activity now happening globally and new fields still being discovered and developed.

Oil and gas producing fields employ either fixed or floating structures (e.g. steel jackets, semi-submersibles or spars, amongst others) connected to multiple wells. Subsea wells (those with the wellhead and associated infrastructure on the seabed) were first used in the early 1960s and tend to be used in deep water situations. Many subsea wells can be tied-back to a single fixed or floating platform, or even exporting the oil and gas straight to shore. For example, the Perdido oil field in the Gulf of Mexico has approximately 30 wells from three fields tied-back to a single spar platform and the Orman Lange field in the Norwegian Continental Shelf (NCS) has 50 subsea wells that are grouped at production stations and the gas pumped directly to the shore. The Brent field in the UKCS had four platforms with 154 wells which are currently undergoing decommissioning.

Given the age of oil and gas development globally, particularly in the North Sea, Gulf of Mexico and West Africa, with many fields exceeding 40 years of operation, combined with tightening regulations on offshore structures, decommissioning is a rapidly growing sector. Cessation of production (CoP) mostly occurs at a point where a field becomes uneconomic, such that it costs more to extract the hydrocarbons than they can be sold for. A CoP decision is therefore impacted by oil prices and trends as well as the available hydrocarbons remaining in the reservoir. A CoP decision may also be made where there has been a significant issue, e.g. with the reservoir or infrastructure, that would be uneconomic to rectify based on the likely amount of hydrocarbon that could still be extracted.

The following sub-sections cover the activities associated with decommissioning in a subsea context and the international regulations that cover this area.

2.1. Decommissioning activities

In the UKCS, a decommissioning programme involves a series of activities, based on the Oil & Gas UK Work Breakdown Structure (WBS) which are listed below. The activities highlighted (in bold italics) are those with a significant subsea element that will be considered in this report. These activities are not necessarily linear and overlap across activities is represented in Figure 1 below.

- ***Operator project management***
- Facility running / owner costs
- ***Wells abandonment***
- ***Facilities / Pipelines making safe***
- Topsides preparation
- Topsides removal
- ***Sub-structure removal***

[1] Offshore and Subsea Facilities, PetroWiki, accessed February 2018
[2] Oral History of Lives in the North Sea Oil and Gas Industry, The Project: Brief History of the UK North Sea Oil and Gas Industry, University of Aberdeen, 2006

- Topside and sub-structure onshore recycling
- ***Subsea infrastructure (pipelines, umbilicals, mattresses, christmas trees, etc.)***
- ***Site remediation***
- ***Monitoring***

The chart in Figure 1 shows the stages of work involved in a decommissioning programme as well as key milestones such as CoP, when the asset is hydrocarbon free and when materials are delivered to shore for recycling.

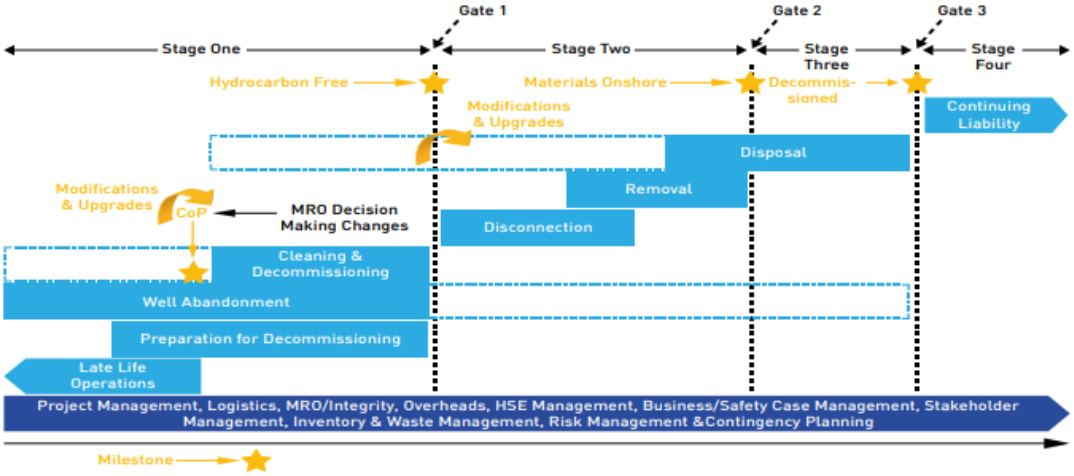

Figure 1: Chart showing the decommissioning stages. Source: Scottish Enterprise Oil and Gas Decommissioning Action Plan.

These activities will be considered in greater detail in Section 3 where the synergies with the subsea oil and gas supply chain will be analysed. As can be seen in Figure 2 well plugging and abandonment (P&A) is the biggest cost in a decommissioning programme, at 49 percent, based on UK figures, and it will therefore be the main focus of this report. The other subsea elements such as the planning and preparation as well as the cleaning, disconnection and removal of subsea infrastructure will also be considered.

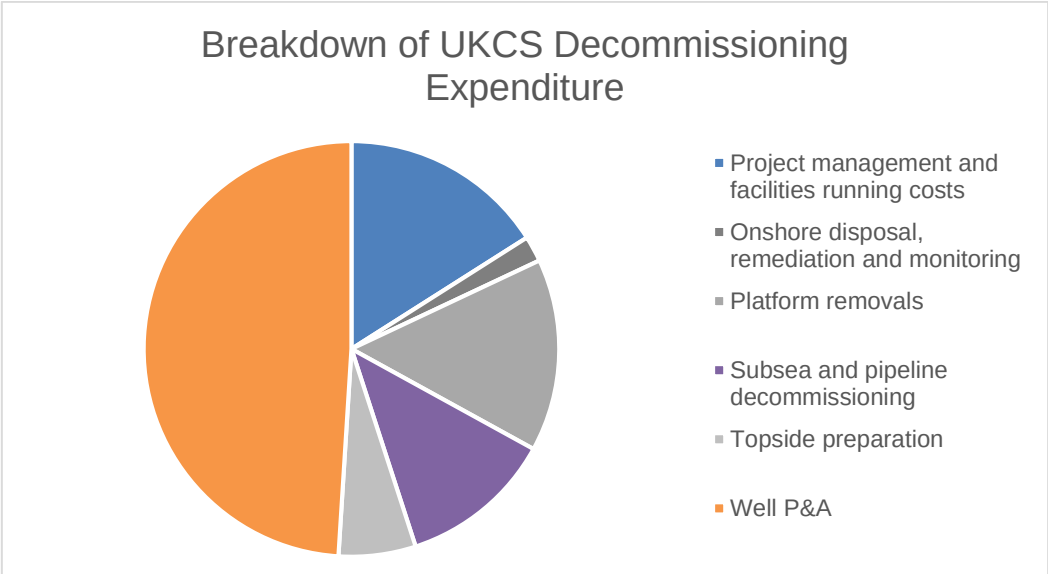

Figure 2: Breakdown of the expenditure on decommissioning by activity. Segments highlighted in colour are subsea or have a subsea element, segments in grey are surface or onshore elements of decommissioning. Source: Oil & Gas UK decommissioning insights 2017

2.2. Well plugging and abandonment

Well plugging and abandonment (P&A) includes, platform wells (those that are operated from a fixed platform); subsea wells (those where the wellhead is on the seabed, and hydrocarbons are removed to a floating vessel, or tied-back to platform infrastructure); and suspended exploration and appraisal (E&A) wells.

The cost of P&A across the three types of well varies, as well as cost variations from water depth, weather, reservoir type, age, condition and complexity of operations.[3] An overview of P&A costs (in 2016 money) in the UK North Sea regions (Table 2) and in the Gulf of Mexico (GOM), USA (Table 3) are below. The UK industry set itself a target to reduce the cost of well P&A by 35% from 2015 levels, these targets are included in Table 2 below.[4]

Table 2: Average and cost range of well P&A in the UKCS, including industry cost reduction target. Source: Oil & Gas UK, Decommissioning Insights 2017; OGA.

Location	Well P&A	2017 average (per well)	2017 range (per well)	35% cost reduction from 2015.
Central and Northern North Sea and West of Shetland	Platform wells	£4.9 million	£0.6 - £14.8 million	£2.6 million
	Subsea wells	£10.1 million	£2.9 – £24.9 million	£6.4 million
	Suspended E&A wells	£6.9 million	£0.6 - £36.8 million	£5.1 million
Southern North Sea and Irish Sea	Platform wells	£2.8 million	£1.3 – £7.6 million	£2.0 million
	Subsea wells	£7.8 million	£3.3 – £11.4 million	£6.2 million
	Suspended E&A wells	£3.4 million	£0.2 – £14.4 million	£5.7 million

Table 3: Cost estimates for the decommissioning of different well types in the GOM, USA. Source: Bureau of Safety and Environmental Enforcement (BSEE)[5]

Type of well	Water depth	Cost estimate by BSEE
Platform well (fixed)	≤ 400 ft (≤122m)	$450,000 (£318,000)
Platform well (fixed) where well has been temporarily abandoned	≤ 400 ft (≤122m)	$150,000 (£106,000)
Platform well (fixed)	>400 ft (>122m)	$565,000 (£399,000) at 401 ft (122m) to $770,000 (£544,000) at 1400 ft (426m)
Platform well (floating)	All	$2,056,000 (£1.5m)
Platform well (floating) where well has been temporarily abandoned	All	$1,325,000 (£936,000)
Subsea well	≤ 400 ft (≤122m)	$2,500,000 (£1.8m)
Subsea well	>400 ft (>122m)	$13,250,000 (£9.4m)

[3] Oil & Gas UK, Decommissioning Insights 2017
[4] Oil & Gas Authority, Decommissioning, Wells, accessed February 2018
[5] Bureau of Safety and Environmental Enforcement, Decommissioning Liability Assessment Workshop, 2016

One of the largest impacts on cost of well P&A is the length of time the campaign takes, due to the day-rates of the vessels and rigs required. An average well P&A in the North Sea will take approximately 45 days, with examples ranging from 21 - 125 days. Understanding the condition of the well, in addition to information on the design of the well, allows work to be planned in advance, rather than time lost through having to tackle situations on an *ad hoc* basis rather than as a programme, during the P&A process.[6] Examples of cost breakdowns from other oil and gas basins, namely the Pacific Outer Continental Shelf (OCS) in the USA, have much lower P&A costs, this can be in part attributed to a difference in classification of tasks within a work breakdown structure, but also, and more significantly, the time taken to perform P&A. Well P&A is calculated as being approximately 18 percent of the cost in the Pacific OCS Region (POCSR), with P&A activities for a well taking 3-5 days, compared to the 45 days seen in the North Sea. The difference in these figures are due to shallower waters, less complex wells and more predictable metocean conditions.[7]

Costs have been coming down in P&A due to learning and new techniques. Further cost reduction can be achieved and Oil & Gas UK have identified the following areas of potential[3]:

- Using a campaign approach. This would involve multiple well P&A's in an area being combined into one campaign to allow the mobilisation costs to be spread across a number of wells. This could also be combined with cross-operator collaboration to increase the number of wells in a single campaign. Part of the campaign should be ensuring that the activity schedule is optimised, e.g. minimising the distance the drilling rig must travel between wells.
- Development of innovative solutions through investment in technology, particular themes being explored through an OGTC call are new barriers including placement and materials, verification of permanent barriers and optimising P&A scope.
- Where possible using rigless methods, or once the topside is removed using a workover rig. Rigless technologies could enable savings of up to 50% on the overall P&A costs.[8]
- Early removal of subsea infrastructure to reduce congestion near the well head.
- Adopting a risk-based approach to allow the scope to be determined based on the risk profile of the well. A risk-based approach can also be used to help encourage the uptake of new technology.
- Assessment of the well condition can be done through using a light well intervention vessel to log well conditions prior to the start of a campaign.

Wells are classified by their condition and therefore the level of intervention required for P&A activities. In the UK, there are guidelines that have categories, with increasing levels of intervention. These are summarized in Table 4 below:

[6] Handel, C., Abandonment of obsolete wells and installations on the Norwegian Continental Shelf, University of Stavanger, 2014.
[7] BSEE, Presentation of the 2015 decommissioning cost estimate for the POCSR platforms, 2015.
[8] BCG, Preparing for the Next Wave of Offshore Decommissioning, 2018

Table 4: Well intervention types. Source: Oil & Gas UK

TYPE 0	No work required, abandonment work has already been completed
TYPE 1	The simplest, likely that these wells only require the removal of the well head. The work is rigless and can be completed with wireline, pumping, crane and jacks. For subsea wells, use of well intervention vessel without a riser.
TYPE 2	Complex rigless abandonment. The activity requires the use of coiled tubing or hydraulic workover unit, wireline, pumping, crane, jacks. Subsea wells will use well intervention vessel with risers.
TYPE 3	Simple rig-based abandonment. These operations require retrieval of tubing and casing using a rig.
TYPE 4	Complex rig-based abandonment – could involve poor access, poor cement that needs repairing, or an unknown suspension status.

2.3. International regulations

Oil & gas offshore installations are subject to international legislation and guidelines, which are often prescriptive about the removal of installations once they are no longer in use. The international laws are in place in order to protect the rights of all sea users including (but not limited to) exploration, extraction, transport and fishing as well as the environment, they include:

- The Geneva Convention on the Continental Shelf (1958), article 5(5) states that '*Any installations which are abandoned or disused must be entirely removed*'. This however is seen to be superseded by UNCLOS[9]
- The 1982 Convention on the Law of the Seas[10] (UNCLOS) states in Article 60(3) that '*Any installations or structures which are abandoned or disused shall be removed to ensure safety of navigation, taking into account any generally accepted international standards established in this regard by the competent international organization*'. The difference between the Geneva Convention and UNCLOS is the lowering of language from *must* to *shall*, along with reference to *generally accepted international standards*, these are the IMO standards described below.[11]
- The 1989 International Maritime Organisation (IMO) Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone ("IMO Guidelines") are based on the principle that all disused installations should be removed, they consider the following points in relation to this:
    - the complete removal of all structures in water less than 100m deep (75m for installations prior to 1998) and weighing less than 4,000 tonnes. However, exemptions can be made for structures where decommissioning would be technically impossible, environmentally damaging, excessively costly or would render the structure inherently unsafe. Exceptions are not upheld where the

[9] Offshore Platforms - Abandonment and Recommissioning: A Review of Current International Law, Baker Botts, 2001.
[10] UN, United Nations Convention on the Law of the Sea
[11] Martin, T., Decommissioning of International Petroleum Facilities Evolving Standards & Key Issues, 2004

structures are located on the approach to ports or for international shipping navigation routes.
    - structures from 01 January 1998 should be designed for complete removal;
    - installations in deeper waters can be partially removed, as long as there is at least 55m of water clearance above the structure.
    - Any remaining installations should be marked on nautical charts and have appropriate navigation aids maintained at the site.
    - The marine environment is included in the IMO Guidelines and in particular the risk of damage through decommissioning activities, e.g. in considering the removal of drill cuttings the decision should reflect "the potential for pollution or contamination of the site by residual products from, or deterioration of, the offshore installation or structure."[11,12]
- 1972 London Convention and the 1996 Protocol to the London Convention, the 'London Dumping Convention' surrounds the rules around dumping at sea. The toppling or disposal of oil and gas structures at sea is covered by this convention. Under the convention it is the relevant coastal state that decides as to whether the 'dumping' is allowed or not.[11]
- The Oslo-Paris Convention (OSPAR), covering the North-East Atlantic including the North Sea. From 1998, OSPAR Decision 98/3 prohibits disused installations being left in place. Derogations can be sought for specific structures such as the footings of large steel structures and concrete gravity based (CGB) structures.[13]
- Pipelines are not explicitly mentioned in the Geneva Convention or UNCLOS, but the IMO guidelines say that the IMO should be made aware of anything that is left on the seabed.
- In Asia, ten countries have come together to form the Asean Council on Petroleum (ASCOPE), whose council is formed by the heads of the state oil companies from the member countries. The Business Development Committee have developed the 'ASCOPE Decommissioning Guideline for Oil and Gas Facilities (ADG)' which are in accordance with international law and national legislation of member countries.[14]
- National guidelines are under development and testing in Africa, four countries so far.[12]

Alongside International regulations on decommissioning many countries, namely the UK, USA, Norway and Denmark have their own national guidelines on decommissioning. In other countries, such as Australia and Canada, guidelines and regulations are state specific and may vary between states/provinces.

2.4. Financing O&G decommissioning

Globally, there are different mechanisms for how decommissioning activities are financed, differences come through how the O&G industry is set up in a particular country, e.g. is there a National Oil Company (NOC) who wholly or partially owns the leases, as well as relevant legislation. In countries with an NOC, investment risks vary depending on the stage of the

[12] Campbell, D., and Twomey, B., Decommissioning of Large Offshore Installations Effect of L&R and Major Risk Identification, Decommissioning & Abandonment Summit, 2017.
[13] Offshore installations, OSPAR website, accessed April 2017, https://www.ospar.org/work-areas/oic/installations
[14] ASCOPE website, accessed April 2018, http://www.ascope.org/Projects/Detail/1061

project, for example during exploration they are with the operator; during production they are shared through a Production Sharing Agreement; and often in the final stages, including decommissioning, liabilities are returned to the NOC. [15]

Decommissioning is often supported by the state through tax breaks for operators which indirectly pays for the decommissioning. Depending on the country, this can be for example in Europe, between 50 and 80 percent of the decommissioning cost. This level of support is a push for ensuring value for money in decommissioning and reducing costs as far as possible as the burden for the cost is largely placed upon the taxpayer. In some countries, e.g. Denmark, the security that is provided as part of the licence conditions also includes covering the decommissioning phase. [16,17]

In the USA, there have been recent changes which are still in discussion, around the provision of additional securities for Outer Continental Shelf (OCS) leases, pipeline rights of way and rights of use and easement. Previously decommissioning was excluded from the additional securities calculation where there was a sufficiently financially secure leasee or co-leasee (whereby they could self-insure), however, the Bureau of Ocean Energy Management (BOEM) now considers that the previous calculations are outdated and insufficient. The new Notice to Leasees and Operators, published by BOEM in 2016, 'NTL No. 2016-N01' now supersedes NTL No. 2008-N07.[18]

[15] World Bank, World Bank Multitaskholder Initiative, Towards Sustainable Decommissioning and Closure of Oil Fields and Mines: A Toolkit to Assist Government Agencies, 2010.
[16] BCG, The North Sea's $100 Billion Decommissioning Challenge, 2017
[17] Getting the Deal Through, Oil Regulation, Denmark, 2018
[18] BOEM, Notice to lessees and operators of federal oil and gas, and sulfur leases, and holders of pipeline right-of-way and right-of-use and easement grants in the outer continental shelf, 2016

3. Subsea engineering synergies

There are defined stages to the decommissioning process, although some of these will run concurrently whilst others will have dependencies. Figure 1 shows an overview of these stages. An outline of each of these stages, as well as the synergies with the subsea oil and gas supply chain is provided in the following sub-sections.

3.1. Operator project management

This phase of decommissioning can start as early as 10-years prior to cessation of production (CoP) with the start of planning for a decommissioning programme. Internationally there will be different regulations as to who is responsible for the drafting, approving and implementation of the plan. In the UK is it drafted by the operator, submitted to the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) and after public consultation is submitted for approval by the Secretary of State. In the USA, a variety of permits are required from the Bureau of Safety and Environmental Enforcement (BSEE), more details given in section 4. Activities in the subsea elements of the decommissioning programme should be considered at least 2-4 years prior to the CoP. This preparatory time is needed not only for the gathering of baseline data, but also for the lead-in time for the heavy equipment and vessels required for decommissioning. The process of this programme preparation will require data from the installation and operational phase of a field such as structural drawings, installation records, process flow diagrams, pipeline maps, etc. as well as any records held on well integrity. [19]

The programme preparation will have to justify the decommissioning activities specified, such as what will be removed, decontaminated, 'reefed' and/or repaired. It is therefore important to know the condition of the wells and infrastructure during the programme preparation period. Gathering of baseline data about the project, includes information such as:

- Environmental surveys
- Technical engineering surveys

There are particular synergies with the oil and gas subsea supply chain in this stage of decommissioning through:

- *Project management*
  The O&G subsea supply chain has plentiful experience of managing complex subsea operations. This is a skill set that will cross over directly with the project management of decommissioning activities. Although a move to decommissioning projects is a change in emphasis in the type of project, many areas such as health and safety practices, offshore operations and personnel management are all common considerations. Experience in O&G projects which will include work practices and shared technical language is a benefit here. Decommissioning has an added push for showing value for money throughout the programme.
- *Environmental services*
  Environmental studies will be used to establish the baseline for the economic and environmental impact assessments. These impact assessments will describe the case for removal (including method) or leaving in-situ (including trenching or rock dumping) of offshore pipelines. These studies have synergies with the early work in O&G exploration where studies are completed to understand the benthic environment.

[19] ICF International, Decommissioning methodology and cost evaluation, prepared for BSEE.

These studies also include metocean studies to establish sea conditions for operations, and geological studies to understand reservoir conditions in the wells to be abandoned.

- *Technical engineering studies*
  These studies are used to determine the structural integrity of the installations that are to be decommissioned to allow a suitable method to be designed for their removal. This will also allow plans to be made to tackle hard to reach parts of the installation that may need cleaning, disconnecting or dismantling as well as making areas safe to work.
  These surveys are a part of all O&G work and therefore have a strong synergy.

3.2. Well plugging and abandonment

As shown in Figure 2 plugging and abandonment (P&A) is almost half (49%) of the expenditure associated with decommissioning in the UKCS. The activities associated with this include[20]:

- *Studies to support well P&A programmes*

Well P&A can only go ahead when the condition and situation of the well are understood. Wells to be abandoned can include E&A wells that have been temporarily abandoned decades previously, or development wells that have been producing and are being shut down. The wells can be decades old with information on the well development missing or incomplete. Studies must therefore be carried out to establish information such as the quality of the annular cement, where the theoretical top of cement is; and the condition of the well casing, etc. these questions can be answered through data collected by wireline tools in the hole coupled with historical data.
New technologies are being developed to improve data gathering including techniques such as x-ray tools and electric lines for testing the integrity of annular cement.
Synergies with the O&G supply chain include companies with capabilities in drilling and particularly around the recording of data associated with drilling new wells including well information (single bore, or side tracks i.e. the completion design); casing placement and annular cement evaluation.

- *Well P&A*

This covers the actual plugging and abandonment of the well. The activities include using a rig, or rigless solutions depending on the complexity of the well, see Table 4; any repair work to the annular cement, which could also include milling and the removal of casing and tubing; the placement of barriers to plug the well; and finally, the verification of these barriers to ensure they are creating a permanent seal.
Many technologies will be used in this, including those with similarities to the drilling process, including those with cementing capabilities, as well as the skills to deal with casings. New technologies are being developed in terms of new barriers, e.g. using resins instead of cement or lasers to melt the casing and rock forming a permanent seal; and new techniques e.g. thermal for cutting casings.

[20] Oil & Gas UK, Guidelines on decommissioning cost estimation, Issue 3, 2013

- *Project management of P&A activities*

There will be synergies between companies that offer project management expertise for subsea projects and the projects for P&A activities. A focus on understanding the subsea environment challenges, dealing with difficult metocean conditions, HSE considerations are all part of subsea projects. The P&A activities have an added emphasis on ensuring that the P&A activities provide a permanent seal to protect the environment as well as having a consideration for value for money of the project.

- *Specialist services, e.g. wireline*

These services include those such as wireline tools which are required as part of the survey and preparation stage as well as the P&A stage of the process. The wireline tools cross over with the subsea supply chain through the capabilities of drilling companies and the wireline tools used during the drilling process.

- *Conductor recovery*

Conductor recovery is an element of the P&A process that can be done with a rig, or in a complex rigless operation. There may be a requirement for milling, cutting and/or lifting as part of these activities.

3.3. Facilities / Pipelines making safe

The purpose of this stage of the decommissioning process is to remove hydrocarbons and other waste from the facilities that are going to be removed. This includes subsea architecture, including the wellbore, as well as pipelines. Such tasks can involve the draining and flushing of the wellbore, lines and manifolds, the pigging of pipelines and the purging and venting of equipment. This process removes e.g. residual hydrocarbons and drilling fluid. This cleaning must be done to a level that any flushed fluids have a hydrocarbon concentration of <30 ppm.
The handling of waste materials such as naturally occurring radioactive material (NORM), contamination from mercury in hydrocarbons[21], and hydrocarbon contaminated waste must be processed and handled appropriately.
These activities have a crossover with the operational life of a field, where pigging programmes will be used to clean and inspect pipelines. Other synergies between these activities and O&G activities could include the treatment of returned drilling fluids and drain water during drilling where techniques such as settling tanks, centrifuges and chemical methods are used.

3.4. Sub-structure removal

The sub-structures of platforms mostly come in the form of steel jackets which are classified as small <10,000 (often significantly less) tonnes or large >10,000 tonnes. Sub-structures can also include concrete gravity based foundations, although these are generally not removed, subject to receiving a derogation, as they are too heavy to be lifted (although they will need to have navigation buoys deployed with them to warn of their presence); and tension-leg platforms, although there are only a few of these in use. Semi-submersible platforms and spar platforms are floated away from their moorings, the remaining mooring

[21] Radford, R., Mercury chemical decontamination in preparation for decommissioning, DecomWorld GOM 2017

lines and anchors will need to be considered as part of the sub-structure removal.

Considering steel jackets, these may be removed or, in some cases, the footings or whole structures left in place. In the case of the latter, sometimes known as ‘rigs to reefs’ the sub-structure is toppled so as to ensure that there is no impedance to vessel movement, etc. the regulations on toppling vary between countries. Where a sub-structure is to be removed the structure may be removed in a single lift, or through dismantling into smaller pieces for multiple lifts. The decision as to which route to take will depend on the weight of the sub-structure to be removed, and the availability of the appropriate class of crane to carry out the lift.

Where the sub-structure is being dismantled divers and/or ROVs will be used for inspection and for carrying out the cutting operations. Preparation work including making the structure safe to work on, including removing other subsea infrastructure to avoid having to operate in congested areas could be carried out. These tasks all have similarities with inspection, repair and maintenance (IRM) techniques where divers and/or ROVs are used for inspection and cutting. Currently cutting tools include diamond wire cutting and high-pressure water jets. Laser cutting is an area of development in subsea engineering. There are also synergies with installation techniques, where companies have expertise in heavy lifting and the associated equipment.

3.5. Subsea infrastructure

These activities involve the decommissioning and/or removal of well heads, pipelines, umbilicals, mattresses, Christmas trees, manifolds, etc. once they have been cleaned and isolated (as per section 3.3).

Flexible pipeline and risers which have previously been attached to floating structures are, once flushed and cleaned, laid onto the seabed before being cut-up and removed. In-field pipelines will also be cleaned, cut and removed. These tasks will involve ROVs and/or divers for the cutting and lifting equipment for the removal. Both tasks have synergies with operational or installation activities.

Subsea infrastructure such as manifolds, blowout preventers and Christmas trees, once cleaned and isolated are cut and removed through lifting, often in a ‘reverse installation’ manner. A drive towards standardization for subsea infrastructure could see an increase in reuse of this equipment rather than recycling. This could increase the emphasis on the removal technique as any procedure would need to minimize damage to the equipment. The disconnection and isolation of these systems would be completed with ROVs and/or divers.

Where items are not removed, such as export pipelines, they are either trenched or rock-piled to bury them, to remove them as an obstruction on the seabed. Such activities involve techniques that are used during pipeline installation.

3.6. Site remediation

Although in a number of cases not all infrastructure will be removed from a decommissioned field, either substructures that have received derogations, pipelines that have been trenched or cuttings piles where it is more environmentally beneficial to leave them in place than to move the pile, the site should be cleared of all other infrastructure and debris. This includes a 500m zone around previous installations, and a 200m corridor for pipelines.

Over-trawl surveys may need to be completed, depending on local regulations, to check that there is nothing that will cause an obstruction to trawling left in place.

3.7. Monitoring

Decommissioned fields will have a monitoring programme for any facilities that remain on the seabed. This will include monitoring for e.g. leaching of hydrocarbons from wells and cutting piles. Surveys carried out at the completion of the decommissioning are compared with the original environmental surveys and a monitoring programme is agreed based on the findings. An example programme would be an initial requirement for two surveys, one within five years of the completion of decommissioning and a second within ten years. The analysis of these results will determine future monitoring requirements. Environmental surveys can be carried out by companies that perform these surveys during the exploration, appraisal and operational activities of oil fields.

Any navigational aides that are deployed to mark the location of installations that have not been removed will need to be maintained. There is a crossover here with companies involved in IRM as well as those providing navigational aids during installation and operational activities.

3.8. Areas for innovation

As a relatively young sector decommissioning is still developing new methods and materials to ensure effective practices as well as value for money. Guidelines are in place for the types of activities that are needed and the quality of the work that is required by the industry. There should however, be a level of risk-based permitting of activities to allow new technologies, techniques and materials to prove themselves in a real-world situation.

Below are areas that the industry has identified as research and development (R&D) challenges for P&A[22,23]:

- Plugging and sealing – ensuring that it is cost effective, the use of novel barrier materials, barrier verification and ensuring the longevity of metal-to-metal seals.
- Cost effective P&A, e.g. exploring rigless options for more complex P&A wells.
- Subsurface cutting, milling and removal – including removal of equipment, debris and collapsed casings and/or screens; entire casing removal; and multiple casing milling
- Monitoring of abandoned wells for leakage/possible leak paths
- Remediation of poor P&A

[22] OTM Consulting, Plugging and Abandonment Collaborative Environment (PACE), Decomworld GOM 2017.
[23] Caulfield, K., Stocking the decommissioning toolkit, A subsea decommissioning joint industry project, Decomworld GOM 2017.

4. Global market with locations of interest

There are over 9,000 offshore platforms in service worldwide[24] from shallow coastal waters at 3m to depths in excess of 3,000m (the current record is 3,400m off the Uruguayan coast)[25] in addition to platforms there are over 72,000 wells in service worldwide[26], all of which will require decommissioning at the end of their economic life. Oil and gas exploration is still happening across the globe and as these assets and wells age they will provide a pipeline of decommissioning opportunities.

Decommissioning in the North Sea alone is expected to cost $150 billion (£106bn); in the Gulf of Mexico approximately $38 billion of decommissioning liabilities is expected (£26.7bn); and in the Asia Pacific region costs are anticipated in the $30-60 billion (£21-42bn). IHS Markit estimate a $13 billion (£9bn) per year spend on decommissioning by 2040, a more than five-fold increase from 2015 levels of $2.4 billion (£1.7bn) meaning a predicted global figure of $210 billion expenditure between 2010 and 2040.[16,27,28]

Table 5 below shows a summary of the decommissioning activity that is expected to occur in the short and medium term, along with estimates of the decommissioning liabilities in the country where available. The following sections provide more information on these decommissioning markets. The report has aimed to include the largest and most near-term markets, but information on all decommissioning markets globally was not available.

Table 5: Summary of decommissioning activity and expenditure estimates for important decommissioning markets worldwide. Source: various

Country	Decom activity	Cost estimates
UK	Period 2017-2025: - 1624 wells to be P&A'd - 98 platforms to be removed.	£1.8-2 bn / year 2017-2022. Overall target £39bn for all current and future installations.
Norway	Period 2017-2025: - 14 platforms and 2 floating structures to be removed, 9 in a multi-platform campaign. - 300 wells to be P&A	£400-800 mn/year in next five years Total cost of NOK 160 billion (£14.5 billion).
Netherlands	Period 2017-2025: - 410 wells to be P&A'd - 17 platforms	£650 – 800 mn/year in next five years. €3.7bn (£3.2bn) for offshore decommissioning
Denmark	Period 2017-2025: - 113 wells to be P&A'd - 17 platforms to be removed	Estimate total cost is £2.8 billion.
Italy	By 2038: - 395 wells to be P&A'd	*Not available*
USA	Upcoming projects include: - 2,000 structures to be removed - 9,000 wells to be P&A'd	$39.5 billion (GOM and POCSR)

[24] Petrowiki, accessed 12 April 2018, http://petrowiki.org/Offshore_and_subsea_facilities
[25] gCaptain, Maersk Drillship Spuds World's Deepest Well, 2016
[26] *This overall wells figure is based on an estimate of approximately 8 wells per platform (calculated from published figures from 7 countries) assumed to be an underestimate as will not include e.g. subsea fields that are exported straight to shore, or E&A wells that have been temporarily suspended.*
[27] World Oil, Over 600 offshore projects to be decommissioned over the next five years, 2016.
[28] SE O&G diversification toolkit, 2017

Brazil	Upcoming activity: - 60 structures to be removed - 165 wells to be P&A's	Rough estimate of US$4.4 billion (£3.2bn) for the imminent decommissioning projects.
Mexico	10 structures to be removed in the period 2013- 2020	*Not available*
Angola	Decommissioning yet to start. 1093 offshore wells, the oldest of which are in shallow waters.	*Not available*
Nigeria	Decommissioning yet to start. Approximately 170 structures in the Niger Delta	*Not available*
Egypt	Egypt has approximately 150 to 200 structures and 700 to 1,000 wells that are expected to become uneconomical in the next 20 years[8]	*Not available*
UAE	The Arabian Gulf stands out as a future hot spot. By 2038, more than 1,000 structures and 3,000 wells in the Gulf will be more than 30 years old.[8]	*Not available*
Indonesia	No decommissioning activity yet, 500 platforms and a share of 15,000 wells are over 30 years old.	*Not available*
China	200 structures and 2,000 wells in - China, are expected to become uneconomical by 2038[8]	*Not available*
Australia	Approximately 50 structures and 700 wells in Australia, are expected to become uneconomical by 2038.[8]	US$21 billion (£15 bn) over the next 50 years.
India	India has approximately 150 to 200 structures and 700 to 1,000 wells that are expected to become uneconomical in the next 20 years[8]	*Not available*

4.1. Europe

The North Sea includes the continental shelves of the UK, Norway, the Netherlands and Denmark. Collectively the North Sea accounts for a significant proportion of global decommissioning spend due to the age of infrastructure, the water depth, weather conditions and types of assets deployed. In the period from 2017 to 2025 it is forecast that over 200 platforms will be partially or completely removed, almost 2,500 wells will be P&A'd and nearly 7,800 km of pipeline will be decommissioned.[3] This represents approximately a quarter of the infrastructure that will need to be removed and wells permanently sealed based on current installation figures (500 fixed platforms, 500 susbea production systems and 10,000 wells).[16]

The combined spend on decommissioning in the North Sea is anticipated to be at least $100 billion (£69.8bn), where although the area does not have the biggest concentration of platforms and wells, the complexity of the operations, metocean conditions and water depth

means that this is almost half the global spend on decommissioning.[29]

In the **UK**, the Oil and Gas Authority (OGA) has estimated the mid-point for the total cost of decommissioning in the UKCS to be £59.7 billion. The estimate ranges from a low (P10) point of £44.5 billion, to a high point (P90) of £82.7 billion. In addition to the figures, based on current (2016) decommissioning cost from 34 operators, the industry has committed to a cost reduction target of 35 percent from the mid-point figure. This means that the industry is aiming for a total decommissioning cost for the UKCS of £39 billion. Achieving this cost reduction will require the adoption of new techniques and technology; industry collaboration, including for example multi-operator P&A campaigns; and new strategies, e.g. contracting strategies.[30] These figures relate to an expected annual expenditure on decommissioning of £1.8-2 billion over the next five years.[3]

Figure 3 below, shows the anticipated breakdown of spend between the UKCS regions. Almost half (£7.9 billion, 46%) of the total figure of £17.1 billion is expected to be spent in the central North Sea where deeper water (ranges from 45 to 143 m) and more complex installations will add to the decommissioning expense. In the southern North Sea, although there are a greater number of installations, the shallower water (18 – 73 m deep) and simpler projects will only account for 19 percent (£3.2 billion) of the spend.[3]

Over the period from 2017-2025, 1624 wells and 98 platforms are expected to be decommissioned with activity starting at approximately 50 wells per year and ramping up towards the end of the period with a planned 153 wells to be P&A'd in 2023.[3]

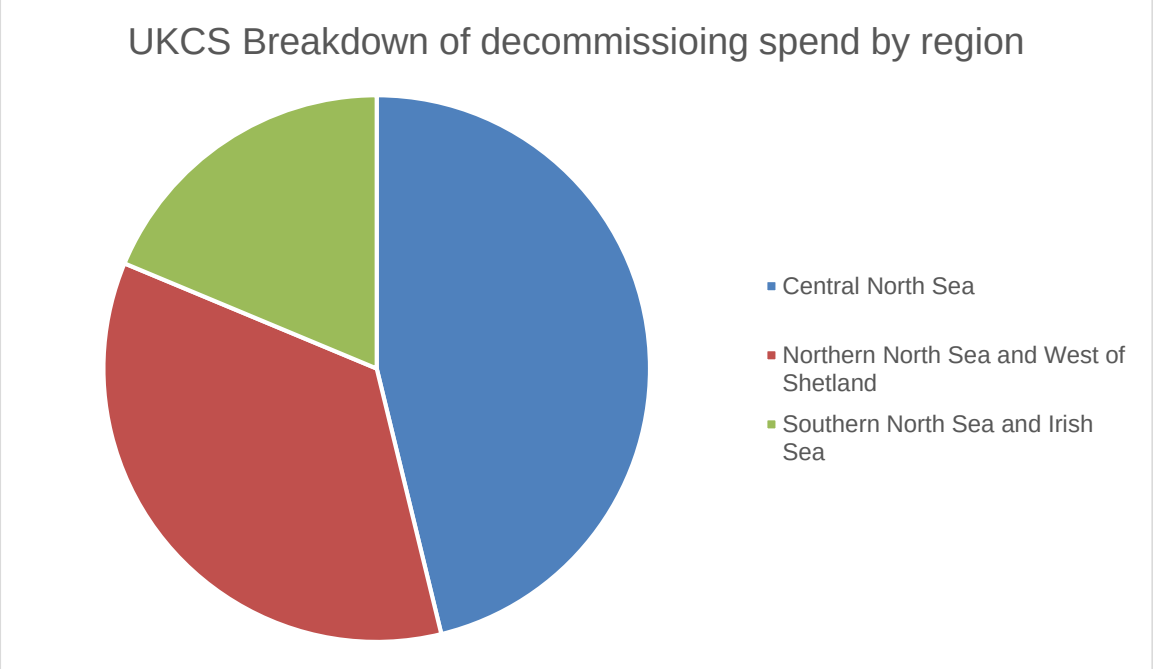

Figure 3: Breakdown of anticipated decommissioning expenditure in the regions of the UKCS between 2017 and 2025. Source: Oil and Gas UK

[29] Worldwide Oil and Gas, Over 600 offshore projects to be decommissioned over the next five years, 2016
[30] Oil and Gas Authority, UKCS Decommissioning Estimate - 2017

Decommissioning in the UK is regulated by the department for Business, Energy and Industrial Strategy (BEIS) and the OGA. Under the Petroleum Act (1998) BEIS is responsible for approving decommissioning programmes, through the Offshore Petroleum Regulator for the Environment and Decommissioning (OPRED). The UK has a strategy for maximising economic recovery (MER UK) from its offshore oil and gas infrastructure on the continental shelf. As part of MER UK, the OGA must be satisfied that a field or project has achieved maximum economic recovery before it is shut down, and the approval is granted for the CoP. The OGA have also published new draft guidelines for the decommissioning of offshore oil and gas installations and pipelines, which after consultation are due to come into use from April 2018.[31]

In **NORWAY** the decommissioning sector is at an earlier stage than that in the UK, although there will eventually be significant activity on the Norwegian Continental Shelf (NCS). There is therefore a potential for learning, expertise and technology to be exported from the Scottish supply chain to the NCS, with the benefit of extensive North Sea knowledge from the UKCS. The Norwegian Petroleum Directorate's estimate for decommissioning on the NCS is around NOK160 billion ($19 billion).[16] The Norwegian decommissioning market is predicted to be between £400-800 million per year over the next five years.[3]

The NCS includes the Norwegian North Sea, the Norwegian Sea and the Barents Sea, with oil and gas activity happening in all areas, although the Barents Sea is less well explored at present. The NCS has had 5306 wells drilled, of which 1469 are exploration wells. Of the remaining 3837 wells, approximately 800 have already been P&A'd. leaving a pipeline of approximately 3000 wells for future P&A campaigns, as well as a pipeline of future wells which could, through some estimates, more than double the number of wells that will require decommissioning to 7000.[32] In the next five years there are plans for the P&A of approximately 300 wells, as well as the removal of 14 platforms, 2 floating structures, 2,555 tonnes of subsea infrastructure and 222 km of pipeline this activity is almost exclusively in the Norwegian North Sea.[3,33]

In Norway cessation plans and decommissioning programmes must be submitted to the Norwegian Petroleum Directorate, part of the Ministry of Petroleum and Energy, for evaluation, two to five years before the expiry of the lease.[34] Well P&A is conducted in line with the regulations NORSOK D-010 which have specific guidelines for well abandonment.[35]

Financing of decommissioning on the NCS is indirectly partially covered by the state through tax deductions, 78 percent of the cost associated with termination and the disposal of facilities are accounted in this way. Where the Norwegian state directly owns a field an even

[31] BEIS, Guidance Notes (Draft), Decommissioning of Offshore Oil and Gas Installations and Pipelines, 2017
[32] Handel, C., Abandonment of obsolete wells and installations on the Norwegian Continental Shelf, University of Stavanger, 2014.
[33] Oil and Gas UK, Norwegian Continental Shelf Decommissioning Report 2016.
[34] Norwegian Petroleum Directorate website, accessed April 2018. http://www.npd.no/en/news/news/2003/the-npds-responsibilities-and-tasks-after-separation-of-the-petroleum-safety-authority-norway--/
[35] NORSOK D-010 Well integrity in drilling and well operations, Rev 4, 2013.

higher percentage of the costs is covered by the state.[36]

According to the **Netherlands**' Energie Beheer Nederland (EBN), the state energy company, the current estimate for decommissioning onshore and offshore infrastructure in the country is €6.7 billion (£5.8 bn), of which 55 percent (€3.7 billion, £3.2 bn) is related to offshore infrastructure. The Dutch state contributes approximately 75 percent of the cost of decommissioning both directly and through EBN.[16,37]

The Netherlands has approximately 3,800 wells, of which 1,400 are offshore, in an industry which began in 1959. It is expected that much of the Dutch oil and gas infrastructure will be uneconomic and therefore ready for decommissioning in the next two decades. So far, 2,000, both onshore and offshore, wells have been P&A'd in the Netherlands. Roughly 150 platforms and 3,500 km of pipeline remain in the Dutch North Sea to be removed.[37] In the period 2017 to 2025 it is anticipated that 410 wells will require P&A, 17 platforms, 1,385 tonnes of subsea infrastructure and 1,827 km of pipeline to be decommissioned, with an annual spend of £650-800 million.[3]

In 2017 EBN published a decommissioning masterplan for the Netherlands which has ten-point plan encompassing near and mid-term objectives. The ten-point plan includes short-term aims around developing effective and efficient regulation; establish a national decommissioning database; ensure learning from projects is captured and establishing a National Platform for decommissioning. The longer-term objectives cover collaboration; standardisation; innovation in technology and approaches; international learning and communication.[37] This presents opportunities for the Scottish O&G supply chain through the sharing of learning, international collaboration and innovative technology and approach solutions.

Decommissioning has yet to commence in **DENMARK** however it is anticipated that there will be 113 wells to P&A in the period 2017-25 along with the removal of 17 platforms, 590 tonnes of subsea infrastructure and 217 km of pipeline.[3] In total Denmark's decommissioning, based on unit costs similar to the UK could be in the region of $4 billion (£2.8bn).[16]

Regulation of decommissioning is covered by the Subsoil Act and Offshore Safety Act as well as the Environmental Protection Act for the Sea (Havmiljøloven) which has prohibited dumping at sea since 1993.[38] Licensees must agree terms of abandonment with the Danish Energy Authority (DEA) prior to submitting the decommissioning programme, such terms include the securities that each party provides for the decommissioning. Licence holders are then responsible for carrying out decommissioning in accordance with the DEA approved decommissioning programme.[17]

In addition to the North Sea, Europe also has other oil reserves including the Italian sector in

[36] Norwegian Petroleum Directorate, Responsible removal of old facilities. Accessed April 2018. http://www.npd.no/en/Topics/Shutdown-and-removal/Temaartikler/Responsible-removal-of-old-facilities/
[37] EBN, Netherlands masterplan for decommissioning and re-use, 2016
[38] Danish Environmental Protection Agency, Offshore Decommissioning.

the Adriatic Sea. **ITALY** is seen as a future decommissioning area of interest with 395 producing offshore wells (1100 including onshore wells) which will start to become uneconomic in the next 20 years.[8,39] The regulatory authority is the General Directorate for Mineral Resources and Energy and is part of the Ministry of Economic Development (DSG-UNMIG). All technical issues on hydrocarbons require the opinion of the Technical Commission for Hydrocarbons.[40]

The licence holder is responsible for decommissioning of any disused installations, including the removal of equipment, such as well infrastructure and pipelines, and the remediation of the area within two years. A decommissioning programme must be prepared by the licensee which sets out the detail of the work to be performed. During the licence application process the applicant must be able to provide a guarantee that the estimated decommissioning cost can be covered, except where the net worth of the company, or a formal guarantee is given by a group of companies having a net worth of over €10 million.[41]

The Scottish supply chain is already active in this sector with Aberdeen-based Zenith Energy completing a P&A job on the Italian Ombrina Mare development well in 2016.[42]

4.2. North and Central America

In the USA, there are over 900,000 active oil and gas wells onshore and offshore.[43] Considering only offshore, there are three main regions for oil and gas production, the Gulf of Mexico (GOM); off the southern Californian coast; and in the Beaufort and Chukchi Seas North of Alaska. The waters include those under state jurisdiction and the Outer Continental

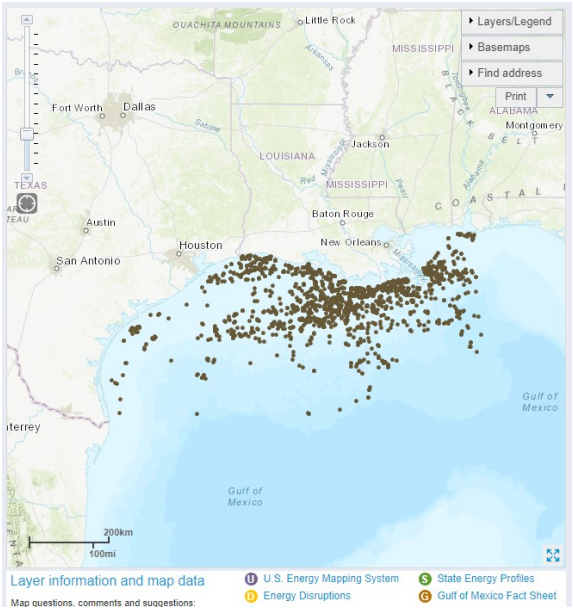

Figure 4: Map of the active oil and gas platforms in the US Federal Waters in the Gulf of Mexico

[39] UNMIG, Frequently Asked Questions - Hydrocarbons exploration and exploitation, accessd February 2018, http://unmig.mise.gov.it/unmig/faq/faq.asp?cat=1
[40] Getting the deal through, Oil regulation: Italy, 2017
[41] The Oil and Gas Law Review Edition 4, Italy, The Law Review, 2016.
[42] Zenith Energy passes first offshore P&A project with flying colors, Offshore Energy Today, 2016.
[43] Meko, T. and Karklis, L., The United States of oil and gas, Washington Post, 2017.

Shelf (OCS).

There are approximately 3,700 active platforms in the OCS, and over 40 percent of these are more than 25 years old. Decommissioning is ongoing in the US and there was an average of 130 platforms removed annually in the last ten years. [44]

Considering specifically the GOM, this is where offshore oil and gas production started and there are now in excess of 5,000 oil and gas installations, many of which are now required to be decommissioned. It is also the biggest decommissioning market in the world, based on number of projects, with over 4,000 platforms decommissioned since the 1980s. The activity that has happened so far has tended to be in shallower waters (<100m) and with smaller steel structures (approx. 600 tonnes). However, future activity will start to happen in deeper waters.[29,45]

Regulations in the USA allow for the disposal of platforms at sea in the Rigs to Reef programme. In 2015 there were 470 platforms that had been converted into artificial reefs. The relevant coastal state and BSEE are responsible for approving a platform to become an artificial reef and conditions about the suitability of the structure for a reef will be taken into consideration as well as local environmental impacts.[46] Even if a platform is to be left in place, any wells associated with the platform must be plugged and abandoned. The regulatory framework for decommissioning is robust with technical standards and financial security requirements. There are ongoing changes to the requirements for security for decommissioning, NTL No 2016-N01, see also section 2.4 for more information. Decommissioning regulation is the responsibility of the US Bureau of Safety and Environmental Enforcement (BSEE). BSEE have the final approval of decommissioning programmes and are responsible for enforcing safety and environmental regulations. This authority is given through the Outer Continental Shelf Lands Act, amongst others.[45,47]

NTL No. 2010-G05, issued by BOEM in 2010, states that all disused wells and platforms, those that have been out of use for five years, including E&A and development wells, must, within three years, be permanently or temporarily plugged and abandoned (in compliance with existing guidance) or zonally isolated. In the last case, within two years the well must be permanently or temporarily P&A'd. For platforms, they must be removed within five years. This notice was issued to minimise the number of idle infrastructure that could cause a safety or environmental concern as well as reducing decommissioning liabilities by decommissioning infrastructure whilst it is still in reasonable condition.[48]

The US Government Accountability Office estimates the decommissioning liabilities in the Gulf at an additional $38 billion (£26.8 bn). Decommissioning activity in the GOM has so far involved more than 1,000 installations being decommissioned between 2010 and 2014 at a

[44] BSEE, Decommissioning, accessed January 2018 https://www.bsee.gov/what-we-do/research/tap-categories/decommissioning
[45] BCG, Decommissioning Hotspots, Successes and challenges in the Gulf of Mexico, 2018.
[46] BSEE, Rigs to Reef, https://www.bsee.gov/what-we-do/environmental-focuses/rigs-to-reefs#2 accessed April 2018.
[47] BSEE, Presentation of the 2015 decommissioning cost estimate for the POCSR platforms, 2015.
[48] BOEM, Notice to lessees and operators of federal oil and gas leases and pipeline right-of-way holders in the outer continental shelf, Gulf of Mexico OCS region, 2010.

cost of $9 billion (£6.3bn).[16] Future decommissioning is expected to include the removal of 2,000 structures and P&A of 9,000 wells. These projects are likely to be in deeper waters (at least 2,000 of these wells in waters >100m) as well as heavier structures (e.g. 11,000 tonnes). These projects will therefore be more complex, and although the GOM is experienced in decommissioning, lessons can be learnt from deep water experience in the North Sea and also the development of new technology. [45]

In addition to the GOM, the Pacific OCS Region (POCSR) has decommissioning liabilities which are estimated to be $1.46 billion (£1bn). There are a significantly smaller number of installations in the POCSR, than in the GOM, with only 11 fields in the POCSR. The platforms were all installed between the 1960s and 1980s, meaning that they will be approaching the decommissioning phase. The platforms are in water depths between 95 ft (30 m) and 1,198 ft (365 m) although mostly in shallow waters. This explains the lower cost estimate than in the GOM region, although the BSEE estimates have increased by over 16 percent from 2010 to 2014 based on assumptions about the decommissioning process.[47]

In **MEXICO** there are 30,000 wells in the National Hydrocarbons Commission (CNH) database, these include onshore and offshore wells, as well as E&A wells. [49] Decommissioning is not yet a significant part of the Mexican oil and gas industry, as many of its 50+ fields are not going to be depleted until after 2022, and there are new fields still being developed. Some decommissioning activity is taking place, with 10 platforms expected to be removed by 2020.[50] Until 2013 all O&G activity in Mexico was through the NOC, PEMEX, but licences can now be awarded to private operators. The relevant authorities for decommissioning in Mexico are CNH, the Energy Ministry (SENER) and ASEA, the regulatory authority of the Environmental Ministry. Financially, a decommissioning trust is set up and managed by the government and the contractor, to provide a guarantee that the decommissioning activities will be carried out by the contractor. [51]

4.3. South America

BRAZIL is seen as the biggest market in South America for decommissioning, with over 50 percent of its installed infrastructure over 25 years old.[29,52] Decommissioning is not progressing as quickly as it could in Brazil as regulation is not efficient, however this is being addressed with the new regulations covering the decommissioning process including fiscal and risk regulations and technical requirements.[8] Early decommissioning projects have largely been in shallow water and simple projects, an example is the Agulha oilfield with 3 platforms that is estimated to have a decommissioning cost of US$220 million (£155 million).[53] Approximately one quarter of Brazil's infrastructure is in deep water, which will increase the cost and complexity of decommissioning projects, there is therefore an export opportunity for learning and expertise from the North Sea in this area.[54]

Studies suggest that 60 structures and 165 wells need to be decommissioned in the coming

[49] https://www.gob.mx/cnh/articulos/centro-nacional-de-informacion-de-hidrocarburos-cnih-64831
[50] Scottish Enterprise, Spends and Trends report 2008-2017, South America
[51] Getting the deal through, Oil regulation: Mexico, 2017
[52] SubseaUK, Decommissioning opportunities in Brazil, 2018
[53] Export.gov, Decommissioning Opportunities in Brazil's Oil and Gas Horizon, 2016
[54] Petrus, Brazil faces decommissioning challenge, 2017

years, with at least 20 of the structures (and their associated subsea infrastructure) being decommissioned by 2020.[53]

Decommissioning in Brazil is regulated by two organisations: the National Agency of Petroleum, Natural Gas and Biofuels (ANP) and the Brazilian Institute of Environment and Renewable Natural Resources.

4.4. Africa

There has yet to be significant decommissioning activity in Africa, and as such regulation and guidance on decommissioning requirements has yet to be fully developed. Regulations so far rely on international legislation (such as that described in section 2.3), national oil and gas laws and Production Sharing Agreements (PSAs). Lessons can therefore be learned from international partners who have a stronger experience in decommissioning.[8] There are over 200 wells in sub-Saharan Africa that were drilled pre-1980, which shows that there will be an imminent focus on decommissioning here.[55] Decommissioning spend in Africa, although it is too early to predict estimated costs, is expected to be driven by Angola and Nigeria.[29]

There has been no significant offshore decommissioning in **NIGERIA**, Africa's biggest oil producer, and also limited regulation developed for decommissioning.[56] The Environmental Guidelines and Standards for the Petroleum Industry in Nigeria (EGASPIN), say that all abandoned installations in less than 100 m of water and with a weight less than 400 tonnes (without the topside) must be entirely removed. EGASPIN, also states that any installation placed on the Nigerian seabed must be designed for total removal at the end of its life.[57] For all oil and gas activity the Department of Petroleum Resources (DPR) is the official regulator. For decommissioning a decommissioning programme must be submitted to the DPR, there are no requirements for decommissioning funds in the legislation, although this can be included in the submitted decommissioning programme.[58]

Nigeria has an NOC, the Nigerian National Petroleum Company (NNPC), who have approximately a 60 percent participating interest in PSAs with international oil companies (IOCs), other NOCs and indigenous oil companies.[58] There are 170 structures[56] in Nigerian waters almost exclusively in the Niger Delta area, although exploration has turned up reserves elsewhere as well. Nigeria has shallow, approximately two-thirds of current production, and deep water, first discovered in the mid-1990s and with some fields in a depth in excess of 2,000 m and an increasing amount of the capex expenditure, with exploration and drilling happening in both. The industry started in the country early in the last century, with significant discoveries being made since the 1960s.[59]

[55] Scottish Enterprise, Spends and Trends Report, Africa 2008-2017.
[56] Financial Nigeria, Prospects of decommissioning oil & gas installations in Nigeria 2018
[57] Stakeholder Democracy Network, White paper on sustainable closure and decommissioning of oil and gas assets in Nigeria, 2015.
[58] Getting the deal through, Oil regulation: Nigeria, 2017
[59] NNPC, Development of Nigeria's Oil Industry

ANGOLA is the second largest oil producer in Africa. There are 1770 wells in Angola of which 1093 are offshore. The wells range in drilling date from 1974 to the present day, although the largest amount of activity has been since the 1990s.[60] Angola is known for it's deep water with fields often in 300 m to 1,200 m and beyond. The oldest wells are in the continental shelf in comparably shallower water, but the overall decommissioning challenge will include these deepwater, subsea wells. No significant decommissioning activity has occurred yet in Angola, there is therefore an opportunity of export of Scottish subsea expertise to help develop this sector. Sonangol, is the Angolan NOC, and partners in all oil and gas projects in the country.

Decommissioning is overseen by the Petroleum Activities Law and Regulations. There is a requirement for the National Concessionaire to provide the Ministry of Petroleum with a decommissioning programme at least one year prior to CoP. Funding of decommissioning comes from a decommissioning fund set up throughout the length of the lease, with fund contributions, which may be tax deductible, allocated based on the rules established in the PSA.[61]

4.5. Asia and Pacific

The Asia Pacific region is a newer region in terms of oil and gas, which means it will be slightly further afield as an opportunity area, however, the long-term forecast suggests a market worth between $30 billion and $60 billion (£21-42 bn).[62] The decommissioning opportunity is approximately 2,600 platforms and 35,000 wells, with up to 600 fields ceasing production in the next decade. [63,64]

The biggest decommissioning challenge facing the region at the moment is a lack of regulation and guidance around the decommissioning process, with limited experience and technical guidance the cost of decommissioning is likely to be much higher than it could be due to inefficiencies. Indonesia, Malaysia and China are the closest to decommissioning, and therefore are the markets most in need of developing appropriate regulations.[63,65] Acknowledging this provides an opportunity for countries further ahead to share their learning and for Asia Pacific to benefit from it as well as providing an international market for technology export. Work has begun with the Asean Council on Petroluem (ASCOPE) publishing their Decommissioning Guidelines. These regional decommissioning guidelines are tailored to the ASCOPE countries whilst abiding by international and national legislation, and have been discussed and approved by the relevant NOCs.[66] 'Rigs to Reef' style

[60] Sonangol, List of wells for consultation or acquisition, 2016. http://www.sonangol.co.ao/Style%20Library/pt-pt/Pdf/dataPackages/Lista_Po%C3%A7os_Aquisi%C3%A7%C3%A3o_Actual06.pdf
[61] Getting the deal through, Oil regulation: Angola, 2017
[62] Scottish Enterprise, Decommissioning report, 2014
[63] Without cost reduction Asia Pacific decommissioning bill could hit US$100Bn, Offshore Support Journal, 2018.
[64] Wood Mackenzie, Decommissioning Asia-Pacific: 600 fields on the front-line, 2016.
[65] Pinsent Masons, Decommissioning in Southeast Asia, 2017
[66] ASCOPE Decommissioning Guideline for Oil and Gas Facilities, 2015

disposal is permitted in Asia, with Malaysia's first structure 'reefed' in 2004. The Baram-8, a three-legged steel jacket that had been storm damaged in 1975 was cut into two sections and transported to it's reefing site 8 nautical miles from its original location and placed on the seabed, along with the conductor, Christmas tree and braces in 2004.[67]

The biggest markets are potentially Malaysia and Indonesia, with spend being driven by shallow-water Australia[29,62]

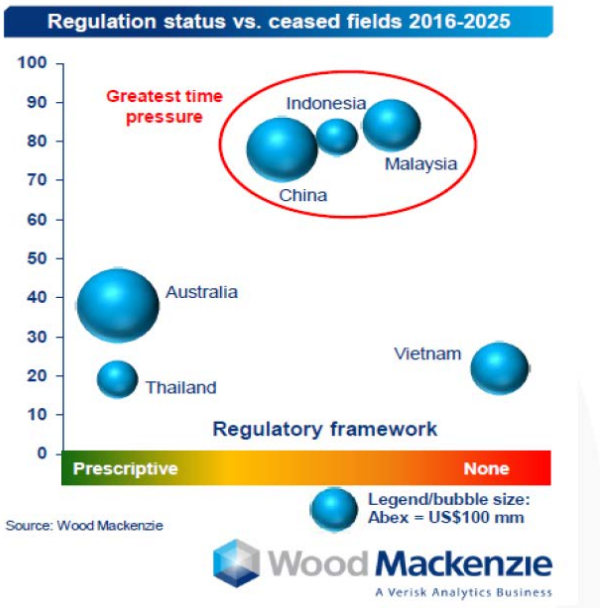

Figure 5: Chart showing situation for countries comparing number of fields that have ceased production versus the development to decommissioning regulation. Source: Wood Mackenzie

AUSTRALIA has different rules for state and territorial waters, those within 3 nautical miles of the coast and the commonwealth waters, beyond this limit. State and territory waters are governed by state regulations and these can differ by state. The Western Australia government issued guidance on decommissioning which applies within its borders. The national government, in 2018, released guidance for commonwealth waters. This guidance promotes the early planning of decommissioning; states that decommissioning is the responsibility of the title holder; works on the baseline of total removal of infrastructure and states that decommissioning must be completed before the title ends.[68,69]

Decommissioning in Australia is estimated to cost US$21 billion (£15 bn) over the next 50 years, due to a lack of decommissioning experience estimated costs are higher than average, and the National Energy Resources Australia benchmarking report put Australia at below the worldwide median when in its analysis of decommissioning. Alongside better regulation and guidance, and the development of new technology the conclusions included learning from other countries that have more experience in decommissioning, such as the

[67] Daud Awang, Oil Rig as Artificial Reef: Example of Baram 8, 2013.
[68] HFW, Developments in Australian offshore decommissioning, 2018
[69] Australian Government, Offshore Petroleum Decommissioning Guideline, 2018

UK.[70,71]

THAILAND is at the start of its decommissioning phase, with some of its infrastructure reaching 40 years of operation. In the Gulf of Thailand, the main oil and gas producing area, 80 of the 450 platforms are at least 20 years old. There are also a number of licences that are due to expire in the period 2021-23. [72] Platforms operated by PTT Exploration and Production Public Co. Ltd. (PTTEP), Thailand's NOC, which account for approximately 60 percent of the infrastructure, have between six and 16 wells associated with each platform, suggesting a total well count of between 2700 and 7200. [73,74]

Regulation for decommissioning in Thailand is based on the national Petroleum Act which highlights that responsibility for decommissioning is on the 'concessionaire(s)' as well as the provision of a security deposit to cover decommissioning. The government is reviewing decommissioning guidance through an initiative known as 'Decommissioning 2.0' which aims to provide a one-stop-shop for licences, etc, where approval would be entirely through the Ministry of Energy's Department of Mineral Fuels (DMF).[8,75] Decommissioning in Thailand is estimated to cost approximately $3 - $5 billion (£2.2 - £3.6 bn). [76] Currently decommissioning should occur when one of the following criteria are met, although exemptions can be made based on other development within the relevant concession block. The criteria include: installations that have not been in use for more than a year; petroleum reserves falling to less than 40 percent; remaining production period will be less than 5 years and concessionaires seeking to decommission their installations.[76]

INDONESIA has over 450 offshore platforms, three-quarters of which are now over 20 years old, and 65 percent are over 30 years old highlighting the potential start of the decommissioning phase of the industry. Infrastructure older than 30 years, includes: 500 platforms, 100,000 km of pipelines and 15,000 onshore and offshore wells. Hindering the development of the decommissioning sector is a lack of clarity about who is responsible for decommissioning activities and liabilities, as until 2008 it was not part of PSAs. Since 2008, the PSA template has included 'abandonment and site restoration' costs, which are held in a fund by SKK Migas. Offshore infrastructure however, is the responsibility of the NOC, Pertamina Energy, and it is therefore likely that decommissioning will fall to them.[8,75,77,78]

MALAYSIA has 349 Platforms, 20 Floating structures, 4,154 wells and 10,105 km of pipeline offshore. Decommissioning however is yet to begin and there are no national guidelines for decommissioning currently. The NOC, Petronas, as the owner of offshore assets is responsible for decommissioning.[79]

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[70] Deloitte, Decommissioning has potential to be Australia's next oil and gas boom, 2017
[71] National Energy Resources Australia, Oil & Gas Industry Competitiveness Assessment Report on the Framework, Baseline Score, Insights and Opportunities, 2016
[72] Barron, M., Reversal of Fortune: Thailand's Oil and Gas Sector, Natural Resource Guidance Council, 2016.
[73] Rigzone, Thailand Looks Ahead: Gears Up for Oil, Gas Decommissioning Work, 2016
[74] Saadawi, H., Offshore Production in the Gulf of Thailand, Society of Petroleum Engineers, 2017
[75] Pinsent Masons, Decommissioning in Southeast Asia, 2017
[76] Rigzone, Thailand Looks Ahead: Gears Up for Oil, Gas Decommissioning Work, 2016
[77] Offshore Technology, Decommissioning Indonesia's oil rigs: a vast but challenging market, 2015.
[78] Gulf Oil and Gas, Indonesia Decommissioning in Oil & Gas Conference 2015, 2015.
[79] Hashim, A., Upstream Decommissioning in Malaysia, LinkedIn, 2016

Appendix: List of Acronyms

BOEM	Bureau of Ocean Energy Management (USA)
CoP	Cessation of Production
E&A	Exploration and Appraisal
EBN	Energie Beheer Nederland (Dutch Energy Authority)
DEA	Danish Energy Agency
FPSO	Floating production, storage and offloading
GOM	Gulf of Mexico
IMO	International Maritime Organisation
IRM	Inspection, repair and maintenance
NCS	Norwegian Continental Shelf
NOC	National Oil Company
O&G	Oil and Gas
OCS	Outer Continental Shelf (USA)
OGA	Oil and Gas Authority (UK)
OPRED	Offshore Petroleum Regulator for the Environment and Decommissioning (UK)
P&A	Plugging and Abandonment
PSA	Production Sharing Agreements also known as Production Sharing Contracts (PSCs)
ROVs	Remotely operated vehicles
UKCS	UK Continental Shelf
UNCLOS	UN Convention on the law of the seas