OIL&GAS UK

DECOMMISSIONING INSIGHT 2016

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1. Foreword

Oil & Gas UK's *Decommissioning Insight 2016* presents a unique forecast of offshore oil and gas infrastructure decommissioning in the UK and Norway over the next ten years. The report gives the most comprehensive picture to date of anticipated activity in these territories, providing asset operators with valuable insights to assist in effective decommissioning planning and pointing the supply chain to where demand for services is likely to lie.

The analysis confirms that, despite low oil prices continuing to challenge the economics of many of the more mature offshore assets, there has not been a rush to decommission. The reality is much more complex, with different market forces influencing decommissioning strategies across the North Sea. While some companies are delaying activity due to cash-flow constraints, others are deferring cessation of production as sustained efforts to improve efficiency result in extended field life. Others are expediting decommissioning as the cost of some decommissioning activities becomes cheaper at lower prices.

Yet it is clear that decommissioning is a growing, if still emerging, market. Last year, £1.1 billion was spent on decommissioning in the UK and £1 billion in Norway, compared with £800 million and £770 million in the same countries in 2014. This trend is expected to continue, as in 2015, decommissioning accounted for 5 per cent of total industry expenditure, up from 2 per cent in 2010. This proportion is likely to exceed 12 per cent in the UK next year. This not only reflects increasing decommissioning activity, but also needs to be set against the wider impact of reducing operating costs and falling capital investment in the lower price environment.

Fifty-two new projects appear for the first time in this year's report, bringing to more than 100 the number of platforms forecast for complete or partial removal from both continental shelves over the next ten years. Over 1,800 wells are expected to be plugged and abandoned and some 7,500 kilometres of pipeline are scheduled for decommissioning. Most of this activity has been long planned.

Overall, decommissioning on the UK Continental Shelf (UKCS) from now until 2025 represents an estimated £17.6 billion opportunity, with over 50 per cent of this market to be found in the central North Sea. This offers considerable scope for companies to develop world-class competencies in decommissioning both for deployment on the UKCS and export overseas. To make the most of this opportunity, the UK's supply chain will need to position itself by offering high quality, cost-efficient goods and services if they are to win business in a fiercely competitive global market.

The offshore oil and gas industry is one of the cornerstones of the UK economy. In 2016, total offshore expenditure is expected to be £19 billion, while the supply chain is forecast to generate revenues of £30 billion. The industry supports around 330,000 highly skilled, well-paid jobs, and provides a secure domestic supply of primary energy. Oil and gas production rose in 2015 for the first time in 15 years, a trend that will continue in 2016.

It is believed that there could be up to 20 billion barrels of oil and gas still to recover. If the UK is to continue to gain the full economic benefit from its oil and gas resource, it is important that the industry works with the Oil and Gas Authority (OGA) and HM Treasury to attract fresh investment, avoid premature decommissioning, retain the critical infrastructure required to access future reserves and ensure decommissioning is carried out in a timely and most cost-effective way.

This work is strengthened by a competitive tax regime designed to promote new investment and government funding for seismic surveys to open up new areas for exploration. Oil & Gas UK is now working with HM Treasury to explore further avenues in its 'Driving Investment' strategy for the sector, including the possibility of transferring tax relief on decommissioning costs on the sale of assets.

In parallel, Oil & Gas UK is working on the MER UK Decommissioning Board with the OGA and the Department for Business, Energy and Industrial Strategy (BEIS) to develop new fit-for-purpose technical, commercial and operational solutions to lower the cost of decommissioning, while maintaining high safety and environmental standards.

The industry fully respects its environmental obligations and is assisting BEIS as it prepares for the forthcoming review of the OSPAR decision 98/3 by the OSPAR Offshore Industry Committee in 2018.

Broad comparisons of the 2016 survey with last year's report suggest that the unit costs of decommissioning are falling, particularly for well plugging and abandonment. This is partly due to a market-driven response to the downturn as associated costs such as rig-rates have fallen, but it may also indicate that the industry's own efficiency improvements and the experiences gained from past decommissioning activity being applied to new projects are beginning to have effect.

This is good news. It will only be through focused and effective collaboration between industry, government and the regulators that the outcomes from decommissioning North Sea assets can be optimised in a mutually beneficial manner.

Michael Tholen,
Upstream Policy Director, Oil & Gas UK

N.B. The collection and analysis of the data by Oil & Gas UK on behalf of the industry has the support of the Norwegian Petroleum Directorate and Norsk Olje & Gass.

2. Executive Summary

Decommissioning Overview

- This report captures data from 186 decommissioning projects[1] across the UK (153) and Norwegian (33) Continental Shelves. Fifty-two of these projects are new to this year's report due to the survey timeframe shifting to 2016 to 2025[2]; some projects being brought forward in response to the low oil price environment; or estimates only now becoming available.

- Seventeen projects have been postponed since last year's survey to outside the timeframe as operators have successfully extended field life.

- Of the 134 existing projects included in both this year's and last year's survey, there have been some movements in the timing of specific decommissioning activities within project scopes. For example, one company might accelerate a well plugging and abandonment (P&A) campaign to take advantage of falling rig rates during the current downturn, while another defers this activity due to cash-flow constraints.

- Looking across the breadth of activity, there is more evidence of projects being brought forward in the central and northern North Sea than in the southern North Sea, Irish Sea and Norwegian Continental Shelf.

- On the UK Continental Shelf (UKCS), 94 per cent of the 153 projects in this region do not yet have firm timings and are still in the early planning stages. This involves outlining the scope of the activities to be undertaken and carrying out feasibility studies that will ultimately be influenced by changing market conditions over time.

- Sustained efficiency improvements and cost reductions could defer cessation of production (CoP) and therefore push back decommissioning in some cases, while the low oil price environment and access to infrastructure issues might expedite it in other cases. For example, over the last 12 months, 33 assets within the timeframe on the UKCS have deferred CoP, 72 have brought forward CoP, while for 135 CoP remains unchanged.

Current Activity

- The decommissioning market is an emerging sector across the UK and Norwegian Continental Shelves.

- Twelve operators carried out decommissioning activity across these regions in 2015.

- In 2015, £1 billion was spent on decommissioning on the Norwegian Continental Shelf and £1.1 billion on the UKCS, compared with £770 million and £800 million[3] in 2014, respectively[4].

- The decommissioning market has expanded from 2 per cent of total industry expenditure in 2010 in both the UK and Norwegian Continental Shelves to 5 per cent of total expenditure in 2015.

- Annual expenditure on decommissioning is expected to reach around £2 billion on the UKCS by 2017 making up 12 per cent of total expenditure, but it is likely to remain close to £1 billion on the Norwegian Continental Shelf and 5 per cent of total expenditure.

[1] Project is defined by the operator and can range from a single well for P&A to multi-platforms.
[2] The 2015 survey covers the timeframe 2015 to 2024 and the 2016 survey covers the timeframe 2016 to 2025.
[3] This survey covers data from end-of-field-life decommissioning projects and does not include expenditure of activity associated with mid-life decommissioning.
[4] Figures for Norway are taken from the Norwegian Petroleum Directorate. See www.npd.no/en

Ten-Year Outlook

- Over the next decade across the UK and Norway:
    - More than 100 platforms are forecast for complete or partial removal.
    - Over 1,800 wells are forecast for P&A.
    - Close to 7,500 kilometres of pipeline are lined up for decommissioning.
- Forecast activity on the UKCS is significantly higher than on the Norwegian Continental Shelf over the next ten years. This reflects the relative maturity of the two regions, with more fields reaching the end of their field life in the UK.
- On the UKCS, £17.6 billion is forecast to be spent on decommissioning between 2016 and 2025.
- This is an increase of £0.7 billion on the 2015 report's ten-year forecast of £16.9 billion, primarily due to 41 new UKCS projects in this year's survey.
- Fifty-three per cent (£9.4 billion) of the forecast expenditure on the UKCS will be concentrated in the central North Sea.
- The Norwegian Petroleum Directorate estimates that annual expenditure on decommissioning will average around £1 billion per year on the Norwegian Continental Shelf until 2020[5], compared with close to £1.7 billion per annum on the UKCS.
- With exception of one well in the Norwegian Sea, all decommissioning activity in Norway over the next decade is planned in the Norwegian North Sea area.
- The largest category of expenditure on the UK and Norwegian Continental Shelves is well P&A at 47 per cent and 56 per cent, respectively.
- Compared with last year's survey, the ten-year outlook for the average unit cost of platform well P&A has fallen by one-third in the southern North Sea and Irish Sea to £2 million, but has remained unchanged across the central North Sea, northern North Sea and west of Shetland at £4.1 million.
- Average subsea exploration and appraisal well P&A unit costs over the next ten years are forecast to fall by over 35 per cent in the southern North Sea and Irish Sea to £5.6 million. The cost per well in the central North Sea, northern North Sea and west of Shetland is also set to be around 20 per cent cheaper at £6.2 million compared with forecasts made last year.
- Subsea development well P&A unit costs over the next decade have fallen by around 20 per cent on average in the southern North Sea and Irish Sea to £7.6 million. The average forecast cost per well in the central North Sea, northern North Sea and west of Shetland has increased by around 3 per cent to £10.2 million.

[5] See Norwegian Petroleum Directorate www.npd.no/en. Total forecast decommissioning expenditure from 2016 to 2025 is not available.

Activity Forecast 2016 to 2025

	Southern North Sea and Irish Sea	Central North Sea	Northern North Sea and West of Shetland	Total UK	Norwegian Continental Shelf	Total – UK and Norway
Number of projects[6]	39	83	31	153	33	186
Number of wells for P&A	396	644	430	1,470	362	1,832
Proportion of wells that are platform wells	80%	37%	73%	60%	85%	64%
Number of platforms for removal	67	16	12	95	14	109
Topside weight to be removed	90,260 tonnes	187,238 tonnes	262,022 tonnes	539,520 tonnes	112,612 tonnes	652,132 tonnes
Substructure weight to be removed	63,745 tonnes	71,056 tonnes	96,737 tonnes	231,538 tonnes	84,734 tonnes	316,272 tonnes
Number of mattresses to be decommissioned	4,526	5,979	1,162	11,667	188	11,855
Subsea infrastructure to be removed	4,268 tonnes	56,714 tonnes	1,697 tonnes	62,679 tonnes	1,745 tonnes	64,424 tonnes
Number of pipelines to be decommissioned	200	484	96	780	67	847
Length of pipelines to be decommissioned	3,426 kilometres	2,666 kilometres	1,038 kilometres	7,130 kilometres	297 kilometres	7,427 kilometres
Total tonnage coming onshore	164,834 tonnes	369,190 tonnes	360,456 tonnes	894,480 tonnes	199,091 tonnes	1,093,571 tonnes

[6] Project is defined by the operator and can range from a single well for P&A to multi-platforms.

Average Forecast Plugging and Abandonment Costs per Well from 2016 to 2025

	Southern North Sea and Irish Sea	Central and Northern North Sea and West of Shetland	UKCS	Norwegian Continental Shelf
Platform well P&A	£2 million	£4.1 million	£3 million	£10 million
Subsea suspended exploration and appraisal well P&A	£5.6 million	£6.2 million	£6.1 million	£16.1 million
Subsea development well P&A	£7.6 million	£10.2 million	£9.6 million	

Average Forecast Cost per Tonne for Removal from 2016 to 2025[7]

	Southern North Sea and Irish Sea	Central and Northern North Sea and West of Shetland
Facilities 'making safe'	£1,200 per tonne	£490 per tonne
Topside removal	£2,600 per tonne	£3,000 per tonne
Substructure removal	£2,600 per tonne	£4,400 per tonne

Some of the average cost forecasts are significantly different to those presented in the 2015 survey. These changes will be discussed in section 7.

[7] Data were unavailable for Norway.

3. Introduction

3.1 Survey Development and Methodology

The *Decommissioning Insight 2016* provides the first joint decommissioning activity forecast for the UK and Norwegian Continental Shelves for the period 2016 to 2025 so that operators and the supply chain have a more comprehensive picture across the North Sea and can effectively plan for decommissioning in the most cost efficient way[8]. The report also provides detailed expenditure forecasts for activity on the UK Continental Shelf (UKCS) and some key expenditure metrics for the Norwegian Continental Shelf. Complete expenditure information was not available for Norway.

The report is compiled through primary data collection from 25 operators on the UKCS and 6 operators on the Norwegian Continental Shelf between June and September 2016. This provides over 95 per cent coverage in both regions. There are more operators on the UKCS with forecast decommissioning activity, reflecting the relative maturity of the two shelves.

The survey was structured around the components of the decommissioning Work Breakdown Structure described in Oil & Gas UK's *Decommissioning Cost Estimation Guidelines*[9]. Following feedback received from the industry and the joint industry-Oil and Gas Authority (OGA) MER UK Decommissioning Board, the report has also been expanded to include additional insight into topside and substructure removal activity on the UKCS, splitting the activity into work already contracted out and work that is still to be contracted.

The information collected is presented in a non-attributable and aggregated format. Analysis has been carried out on a regional basis and split into groups – the central (CNS) and northern North Sea (NNS) and west of Shetland (W o S); the southern North Sea (SNS) and Irish Sea; and the Norwegian Continental Shelf. Almost all of the activity on the Norwegian Continental Shelf is concentrated in the Norwegian North Sea area. Wherever possible, information has been split further into more specific regions. Where particular projects are referred to, this information has been gathered from publicly available data.

3.2 Decommissioning Forecasting

Planning for decommissioning can be a long and challenging process that operators start well before cessation of production (CoP). Over time, the scope of each project is refined as engineering studies and comparative assessments are carried out to determine the optimum approach. Forecasting the precise schedule of decommissioning activity and the associated expenditure at the outset of a project is therefore challenging. There are many uncertainties and factors influencing these, such as the duration of well plugging and abandonment (P&A) or the availability of heavy lift vessels.

Forecasts contained in this report are therefore based on operators' best available estimates at the time of surveying. The majority are not sanctioned decommissioning projects and are subject to change as work scopes are further developed and refined. This is particularly true of activity forecast for the second half of the survey timeframe (2021 to 2025). See section 6 for more on estimate types.

[8] This survey covers data from end-of-field-life decommissioning projects and does not include expenditure of activity associated with mid-life decommissioning.

[9] The *Guideline on Decommissioning Cost Estimation* is available to download at www.oilandgasuk.co.uk/product/op061

4. Decommissioning Expenditure and Activity on the UK Continental Shelf in 2015

Analysis was carried out to assess actual decommissioning activity in 2015 on the UKCS, outlined in Figure 1 below. All of the planned activity was undertaken last year totalling £1.1 billion.

Figure 1: Decommissioning Activity in 2015 on the UK Continental Shelf[10]

Decommissioning Activity	Total
Platform well P&A	50
Subsea well P&A	17
Mattresses decommissioned	575
Subsea infrastructure removed	5,886 tonnes
Pipelines for 'making safe'	357 kilometres
Modules for 'making safe'	13
Modules for topside preparation	34

[10] Complete data were not available for Norway.

5. Decommissioning Activity Forecast – 2016 to 2025

The North Sea decommissioning market does not end at the median line and, as such, forecast activity on both the UK and Norwegian Continental Shelves has been compiled to provide a more complete overview. The following sections focus on specific areas of decommissioning activity. A great opportunity exists for the supply chain offering decommissioning services. However, companies must be able to compete successfully for this work in a global marketplace on quality, efficiency and cost, while maintaining focus on high environmental and safety standards.

In total, this report captures data on 186 decommissioning projects across the UK (153) and Norway (33) Continental Shelves[11]. Fifty-two of these projects are new to this year's report due to the survey timeframe shifting to 2016 to 2025[12]; some projects being brought forward in response to the low oil price environment; or estimates only now becoming available. Seventeen projects have been postponed since last year's survey to outside the timeframe as operators have successfully extended field life.

It should be noted that the peaks of activity over the next decade shown in the following sections are likely to smooth out over the years. This is because decommissioning activities tend to be spread over a number of years, but for the purposes of this survey operators will often select a specific year for particular work to be undertaken.

Over the next decade, forecast activity on the UKCS is significantly higher than on the Norwegian Continental Shelf. This reflects the relative maturity of the two shelves, with more fields reaching the end of their life in the UK.

5.1 Well Plugging and Abandonment

The purpose of well plugging and abandonment (P&A) is to isolate the reservoir fluids within the wellbore and from the surface or seabed. This activity is carried out in accordance with industry guidelines[13] and the Offshore Wells Design and Constructions Regulations 1996[14] on the UKCS, and in accordance with NORSOK D-010 regulations[15] on the Norwegian Continental Shelf. Well P&A can be challenging and may involve intervention in the form of the removal of downhole equipment, such as production tubing and packers, and well-scale decontamination treatment. The process also requires the wellhead and conductor to be removed.

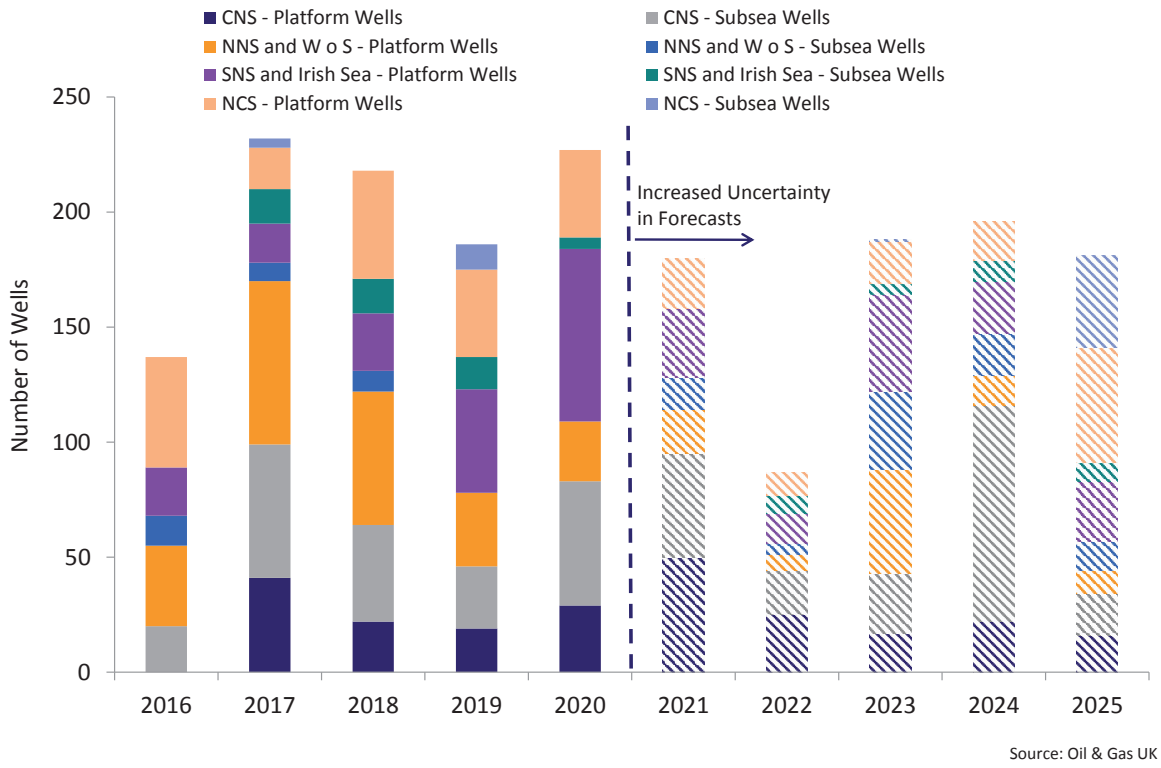
Across the two regions of the North Sea, a total of 1,832 wells are forecast to be plugged and abandoned from 2016 to 2025 (1,470 wells on the UKCS and 362 wells on the Norwegian Continental Shelf). Sixty-four per cent of these (1,180) are platform wells and the remainder are subsea wells, although the proportion varies across each sub-region (see regional breakdown from p14).

Figure 2 opposite shows that there is less variation year-on-year in the combined forecast for the two shelves than in each of the regions considered separately, clearly demonstrating the consistent market opportunity that well P&A in the North Sea represents for the supply chain. In 2016, 137 wells are forecast to be plugged and abandoned, rising to over 230 in 2017. Year-on-year activity will average at around 180 wells per year over the next decade with activity forecast to fall in 2022 before the next wave of projects commences from 2023 onwards.

[11] Project is defined by the operator and can range from a single well for P&A to multi-platforms.
[12] The 2015 survey covers the timeframe 2015 to 2024 and the 2016 survey covers the timeframe 2016 to 2025.
[13] *Guidelines on the Abandonment of Wells* and *Qualification of Materials for Abandonment* are available to download at www.oilandgasuk.co.uk/product/op105 and www.oilandgasuk.co.uk/product/op109
[14] See www.legislation.gov.uk/uksi/1996/913/made
[15] See *NORSOK Standard D-010 Well Integrity in Drilling and Well Operations, (Rev.4 June 2013)* at http://bit.ly/20BWqdD

The region with the highest number of wells of all types forecast for P&A within the survey timeframe is the central North Sea where 35 per cent (644) of the wells are located. The region with the least amount of activity is the Norwegian Continental Shelf where 362 wells are due to be plugged and abandoned of which there is only a single well in the Norwegian Sea.

Figure 2: Combined Well P&A Forecast for the UK and Norwegian Continental Shelves



Source: Oil & Gas UK

There are a variety of factors that affect the timing of well P&A activity, including but not limited to changes to the CoP date, alignment of well activity with other fields, available rig slots and the availability of capital to carry out the work. Where the following forecasts by region indicate high peaks in activity, Oil & Gas UK would expect these to smooth out as operators further develop and define their projects.

Central North Sea

- Of the 644 wells forecast for P&A in this region over the next decade, the number of platforms wells has decreased to 241 from 292 estimated in 2015, while the number of subsea wells has increased by 71 to 403. This leads to an overall increase of 20 wells compared with the 2015 survey. Sixty-three per cent of wells for P&A in this region are subsea, a higher proportion than the 53 per cent forecast in 2015.

- The increase in subsea well activity comes from 21 new projects in this region included in the survey, 19 of which are subsea projects ranging from subsea tie-backs to single suspended exploration and appraisal (E&A) wells as operators take advantage of current low rig rates to carry out this activity during the downturn.

- The net decrease in platform wells is due to activity already completed, combined with field-life extension projects that have postponed decommissioning on some platforms to outside the survey timeframe.

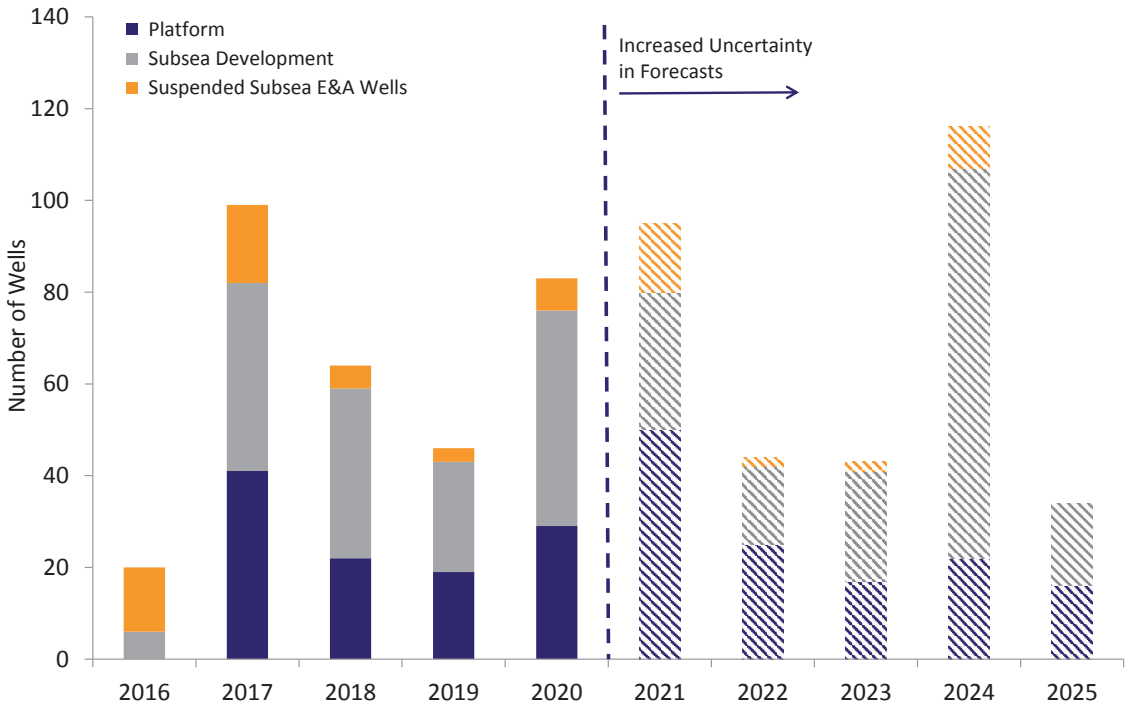
- An additional floating, production, storage and offloading (FPSO) decommissioning project has also been included for the first time, brought forward due to the low oil price.

- Twenty wells are planned for P&A in 2016, rising to an average of 77 wells per year from 2017 to 2021.

- Activity is forecast to peak at 116 wells in 2024 as 16 different projects plan to carry out activity in the same year.

- The scheduling of P&A activity for the majority of projects has changed since the 2015 report as activity has either been brought forward for some projects or postponed for other projects, highlighting how plans can change as project scopes are refined.

Figure 3: Number of Wells Forecast to be Plugged and Abandoned in the Central North Sea



Source: Oil & Gas UK

Northern North Sea and West of Shetland

- The number of wells forecast for P&A over the next ten years in the northern North Sea and west of Shetland has increased to 430 from 326 in the 2015 survey.

- The addition of 81 platform wells and 23 subsea wells is due to two large platform removal projects and a subsea project that now expect to carry out decommissioning earlier due to the challenges of operating in a low oil price environment.

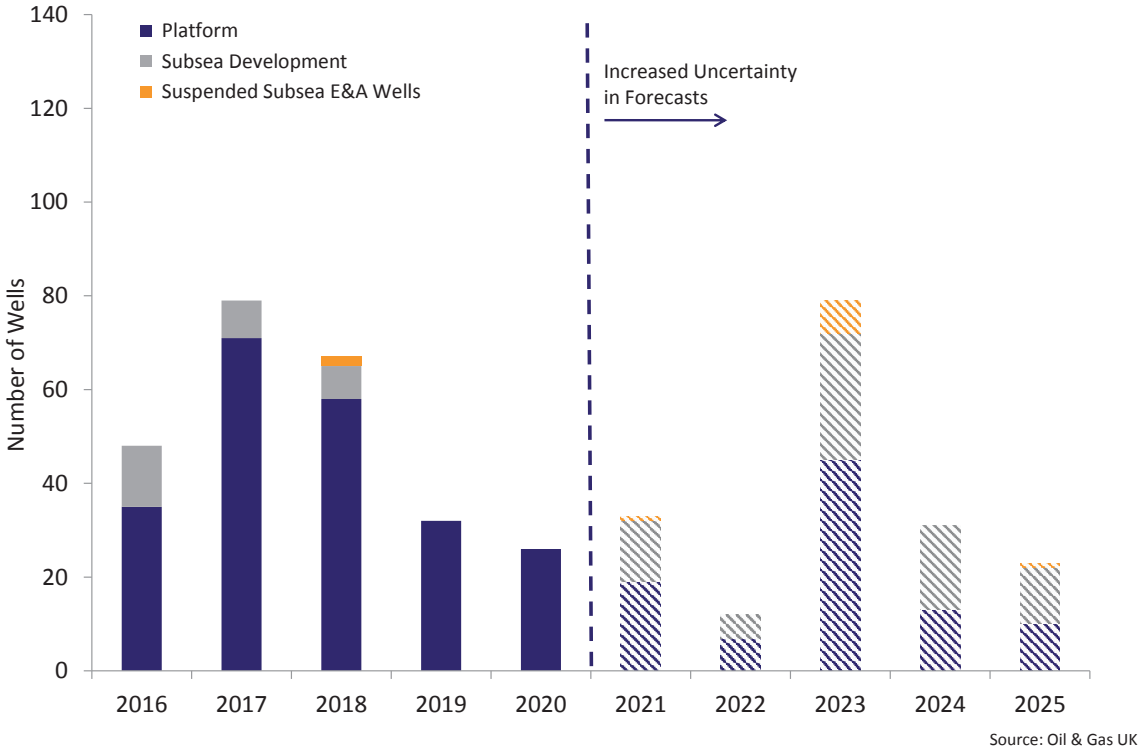
- Seventy-three per cent of wells for P&A in these regions are platform wells.

- Forty-eight wells are forecast to be plugged and abandoned in 2016, with an annual average of 65 wells between 2016 and 2018.

- As several P&A campaigns are likely to start earlier to take advantage of current low rig rates, 80 more wells are expected in the near term (2016 to 2018).

- Activity is forecast to spike at 79 wells in 2023 due to the three new projects in the northern North Sea.

Figure 4: Number of Wells Forecast to be Plugged and Abandoned in the Northern North Sea and West of Shetland



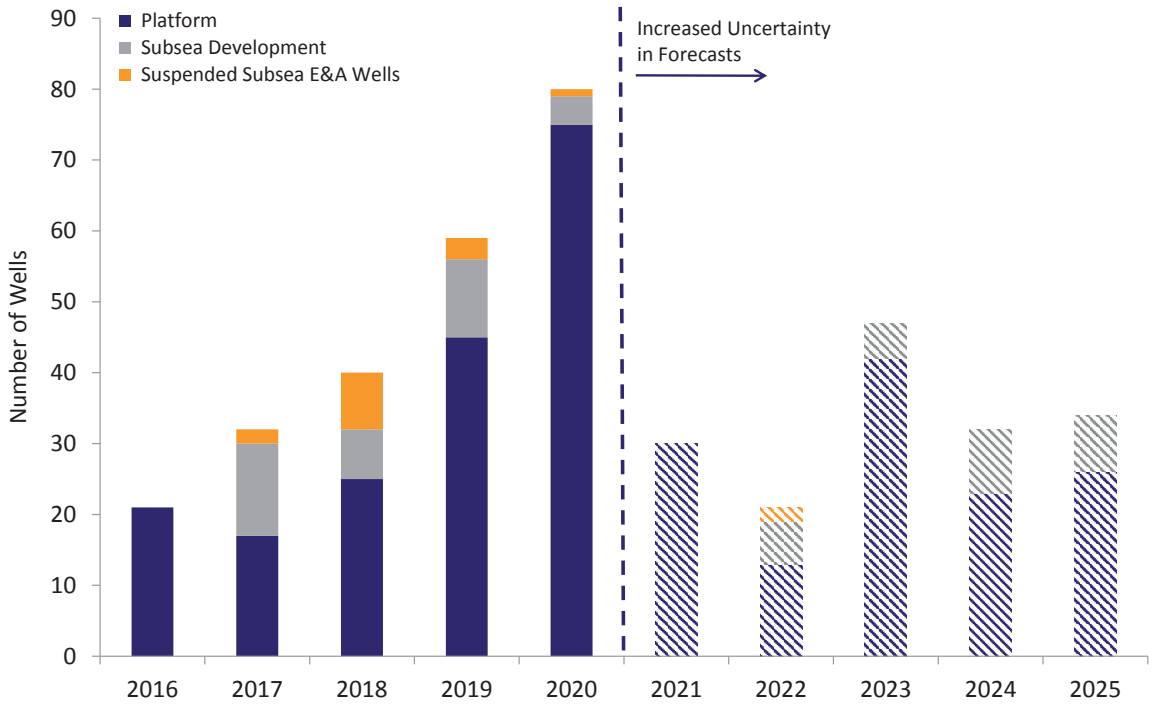
Source: Oil & Gas UK

	Number of Wells 2016 to 2025	Proportion that are Platform Wells
Total	1,074	52%
CNS	644	37%
NNS and W o S	430	73%

Southern North Sea and Irish Sea

- Nearly 400 wells are forecast for P&A in the southern North Sea and Irish Sea over the next decade, an increase of 122 on last year's report due to 17 new projects for which estimates are now available.
- Sixteen of the new projects are platform removals with predominantly platform wells.
- The proportion of platform wells has therefore increased to 80 per cent from 73 per cent in the 2015 report.
- Twenty-one wells are forecast for P&A in 2016, with 40 fewer wells to be plugged and abandoned over 2016 and 2017 as some operators postpone decommissioning expenditure in the current climate to manage cash-flow.
- Activity from new wells will be concentrated towards the end of the survey timeframe.
- The peak year of activity has slipped from 67 wells in 2019 in last year's survey to 80 wells in 2020.

Figure 5: Number of Wells Forecast to be Plugged and Abandoned in the Southern North Sea and Irish Sea



Source: Oil & Gas UK

Number of Wells 2016 to 2025	Proportion that are Platform Wells
396	80%

Norwegian Continental Shelf

- Approximately 800 of the 3,800 wells that will eventually require decommissioning on the Norwegian Continental Shelf have already been plugged and abandoned[16]. Of the remaining 3,000 wells, 12 per cent (362) are forecast to be decommissioned between 2016 and 2025, rising from 284 reported earlier this year due to ten new projects that lie at the end of the survey timeframe.

- Eighty-five per cent of wells for P&A over the next decade are platform wells compared to 95 per cent forecast in the last *Norwegian Decommissioning Insight* as the new projects have a higher proportion of subsea wells.

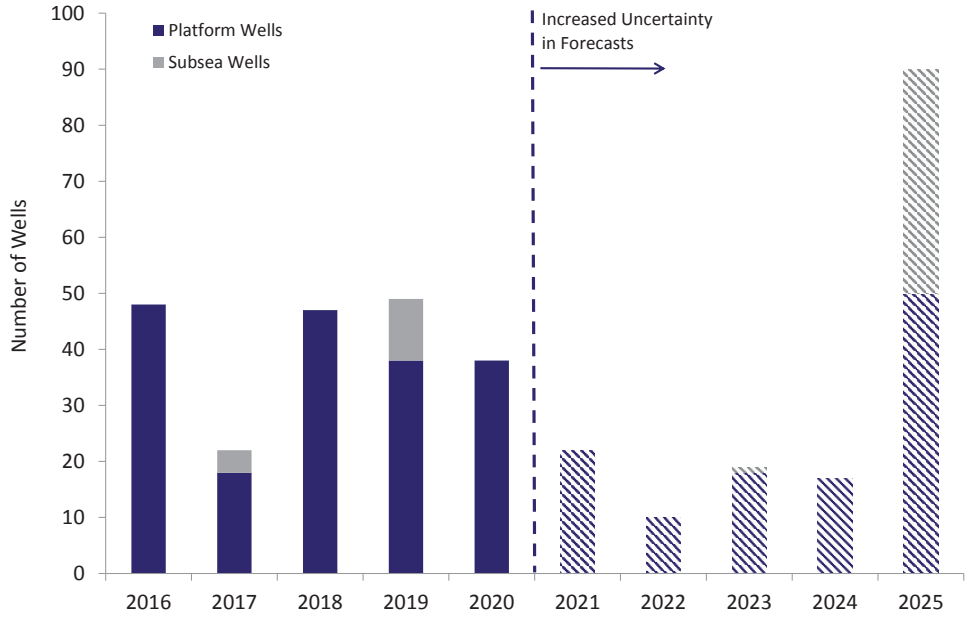
- All of the well P&A activity is concentrated in the Norwegian North Sea region of the basin with the exception of one suspended subsea E&A well in the Norwegian Sea.

- Activity in the near term (2016 to 2020) has increased as the durations of a number of large P&A campaigns have reduced in light of experience gained from previous activity.

- Forty-eight wells are forecast to be plugged and abandoned in 2016, with an average of 41 wells per year from 2016 to 2020.

- Activity is estimated to peak at 90 wells in 2025 due to the new projects included.

Figure 6: Number of Wells Forecast to be Plugged and Abandoned on the Norwegian Continental Shelf



Source: Oil & Gas UK

	Number of Wells 2016 to 2025	Proportion that are Platform Wells
Total	362	85%
Norwegian North Sea	361	85%
Norwegian Sea	1	0%
Barents Sea	No activity	No activity

[16] See *Abandonment of Obsolete Wells and Installation on the Norwegian Continental Shelf; a Study into the Magnitude and Technical and Economic Challenges*, June 2014, University of Stavanger, at http://bit.ly/1m8jpNW

Rig Type

There are a number of methods that can be used for well P&A and the rig type will primarily depend on the well type and water depth. In some instances, the availability of well P&A technologies could remove the requirement for a rig altogether. For example, a low-cost method of well P&A without the requirement of a rig was recently trialled onshore by Centrica in Canada in a collaboration with Interwell P&A, BP, Statoil, and the Norwegian Research Council. The new technology uses a thermite plug to seal off the well by melting both the well components and the rock formation around them to recreate the cap rock. The trial results demonstrated that this technology could potentially reduce well P&A costs in the North Sea by more than 50 per cent.

Platform wells are typically plugged and abandoned in phases. The first phase can be rig-less and uses lower cost methods such as wireline, coil tubing, or a hydraulic workover unit. This is followed by the second and third phases that are more likely to require a rig.

- For platform wells on the central and northern North Sea and west of Shetland, and the Norwegian Continental Shelf, 86 and 68 per cent, respectively, will be plugged and abandoned using an integral rig.

- Modular rigs are also popular for platform well P&A in Norway, although most of the wells using this rig type fall outside the survey timeframe.

- For operators planning to use an integral rig for platform well P&A, the opportunity exists for alternative approaches that preclude the use of the platform's existing drilling derrick, which can prove challenging and expensive to upgrade.

- In the southern North Sea and Irish Sea, the majority (64 per cent) of platform wells will be plugged and abandoned using a standalone jack-up rig.

- Operators are also considering rig-less, lower cost solutions to well P&A. For example, in the southern North Sea and Irish Sea, 30 per cent of platform wells are forecast to use rig-less methods such as coil tubing and wireline.

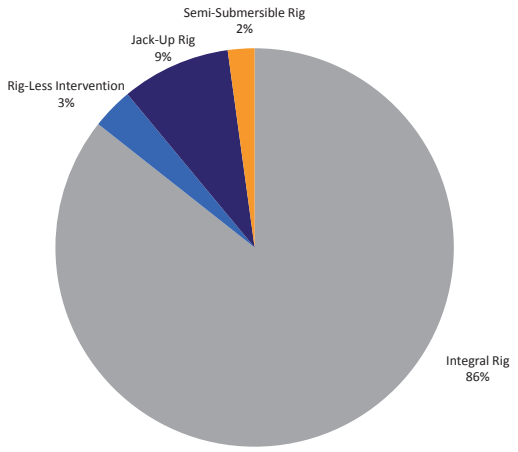
- For subsea wells, a standalone jack-up rig will be used for 98 per cent of wells on the Norwegian Continental Shelf and 70 per cent on the southern North Sea and Irish Sea.

- In the central and northern North Sea and west of Shetland, 63 per cent will use a semi-submersible rig for subsea well P&A due to the greater water depths.

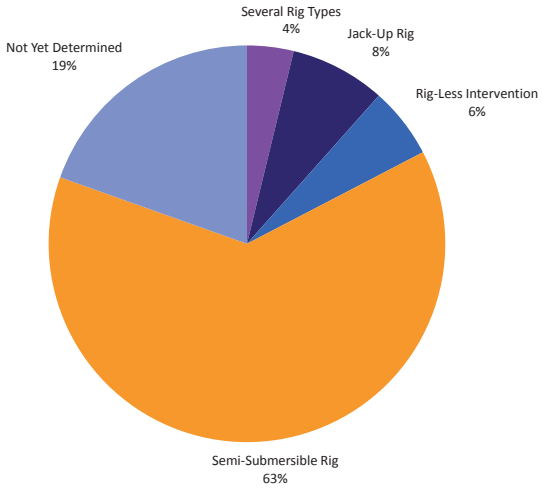
- For a greater proportion of subsea wells, the rig type has not yet been determined as operators consider alternative solutions (25 per cent in the southern North Sea and Irish Sea and 19 per cent in the central and northern North Sea and west of Shetland).

Figure 7: Forecast Rig Type for Well Plugging and Abandonment on the UK and Norwegian Continental Shelves from 2016 to 2025

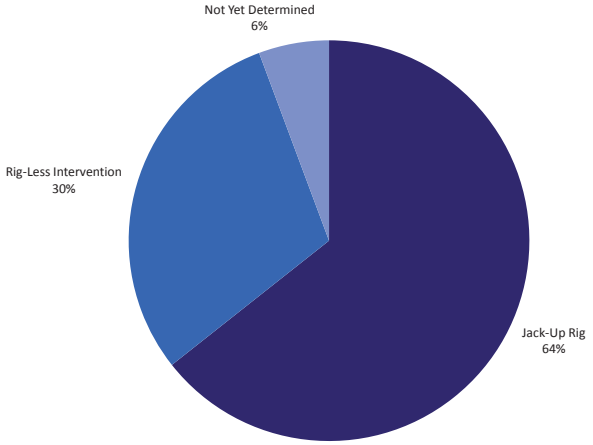
Platform Well P&A – CNS, NNS and W o S



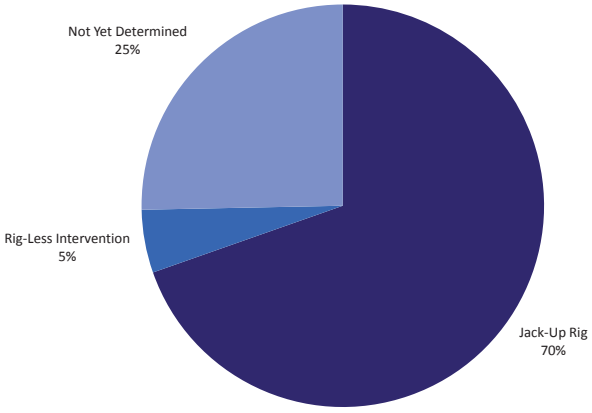
Subsea Well P&A – CNS, NNS and W o S



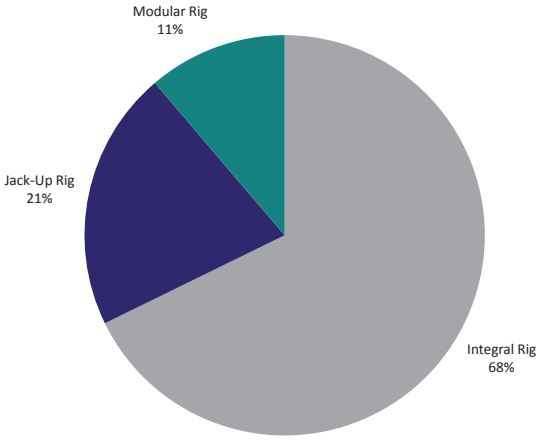
Platform Well P&A – SNS and Irish Sea



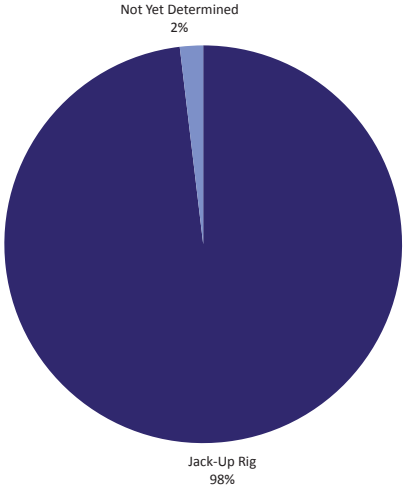
Subsea Well P&A – SNS and Irish Sea



Platform Well P&A – Norwegian Continental Shelf



Subsea Well P&A – Norwegian Continental Shelf



Source: Oil & Gas UK

5.2 Facilities and Pipelines Making Safe and Topside Preparation

For a platform or pipeline to be decommissioned, they must first be hydrocarbon free. This activity is referred to as ‘making safe’ in the Oil & Gas UK Decommissioning Work Breakdown Structure and must be carried out in line with environmental and safety considerations. ‘Making safe’ of facilities includes cleaning, freeing equipment of hydrocarbons, disconnection and physical isolation, and waste management. ‘Making safe’ of pipelines involves depressurising them and removing hydrocarbons. Then the pipelines are cleaned and purged, with the cleaning programme based on the specific needs of the system. This may involve the use of pigs, which are maintenance tools used to clean or inspect the insides of pipelines.

Pipeline ‘making safe’ is sometimes carried out alongside facilities ‘making safe’, particularly in the case of small topside and pipeline tie-backs. In these cases, the same team and some of the same equipment can be used for both activities. ‘Making safe’ can be carried out several years prior to removing a platform or decommissioning a pipeline, leaving them hydrocarbon free until the next phase of decommissioning.

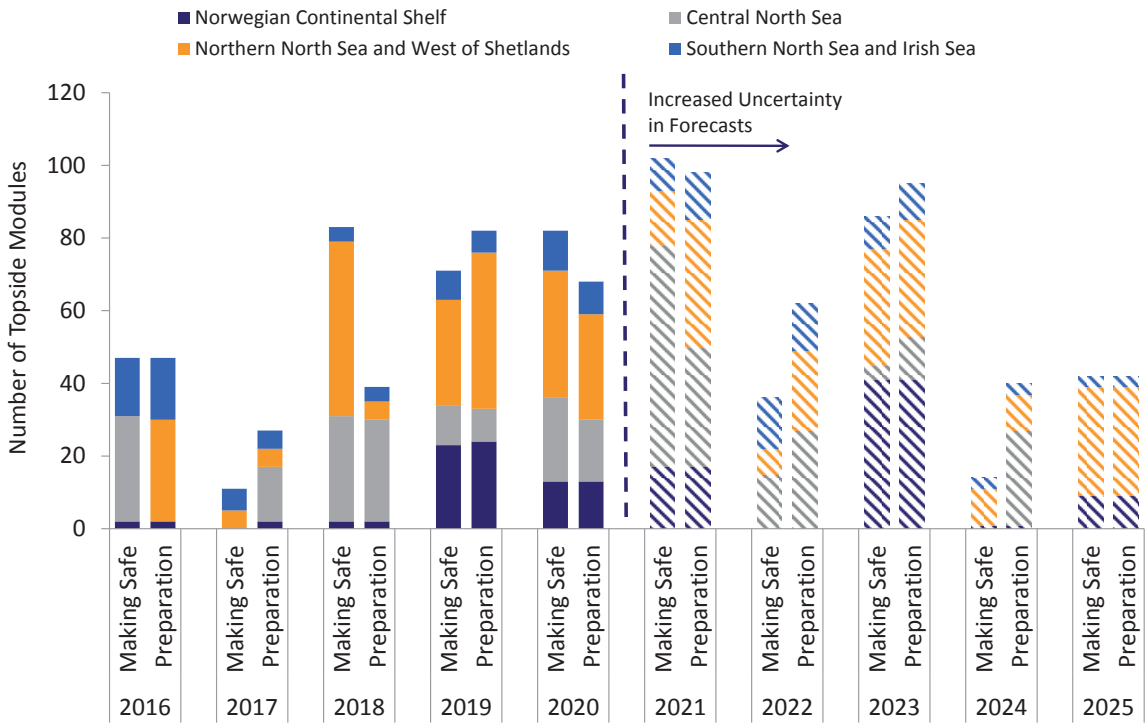
For facilities, the next phase involves separating the topsides and process and utilities modules and carrying out appropriate engineering, such as the installation of lift points to prepare for removal. The topside preparation required will depend on the removal method used.

Over 570 topside modules are forecast for ‘making safe’ on the UK and Norwegian Continental Shelves from 2016 to 2025. The greatest number of modules are located in the northern North Sea and west of Shetland (211) with the least amount in the southern North Sea and Irish Sea (83).

Operators expect 600 topside modules to be prepared for removal. The forecast is slightly higher than that for facilities ‘making safe’ as some projects have already carried out ‘making safe’ activity.

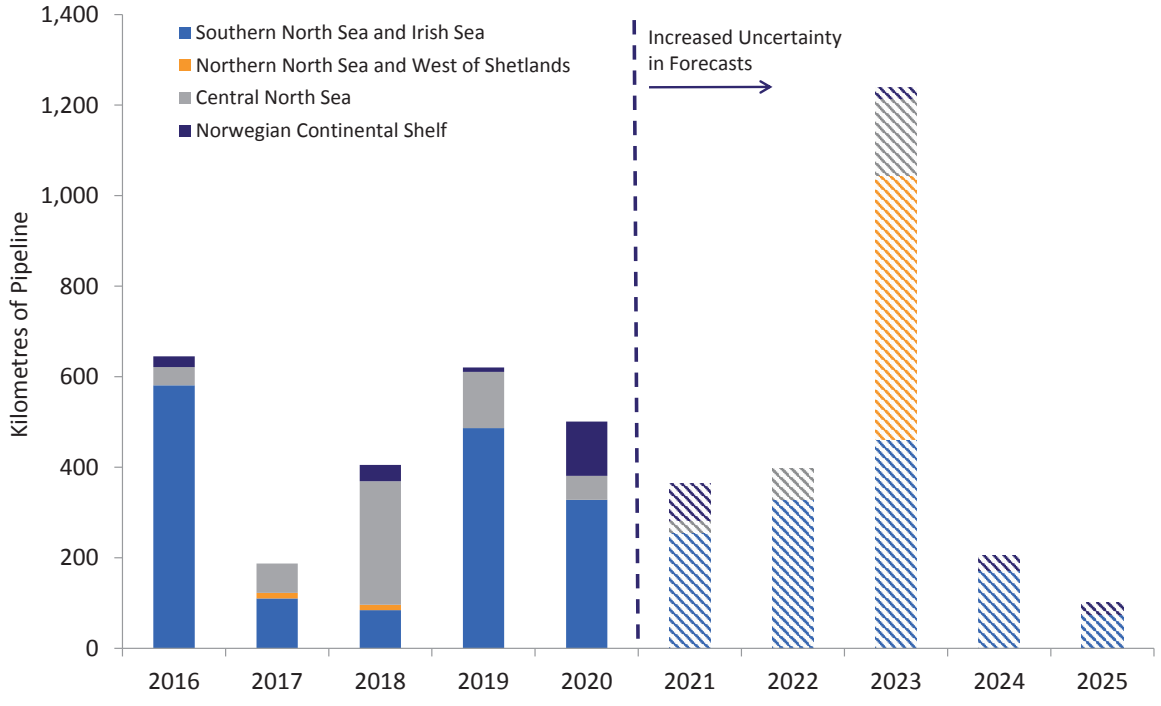
Over the next decade, close to 5,200 kilometres of pipeline are expected to be 'made safe'. Fifty-six per cent of this activity is concentrated in the southern North Sea (2,885 kilometres), while only 7 per cent is forecast on the Norwegian Continental Shelf (354 kilometres).

Figure 8: Combined Facilities 'Making Safe' and Topside Preparation Forecast for the UK and Norwegian Continental Shelves



Source: Oil & Gas UK

Figure 9: Combined Pipelines 'Making Safe' Forecast for the UK and Norwegian Continental Shelves



Source: Oil & Gas UK

Central and Northern North Sea and West of Shetland

- Facilities 'making safe' activities are planned on 26 platforms and 2 FPSOs, equating to 383 topside modules over the next decade.

- The forecast for topside preparation is slightly higher, with 406 modules on 29 platforms and 1 FPSO.

- The overall activity in these regions is higher than that forecast in the 2015 report due to 24 new projects and more detailed schedules for existing projects as their programmes have been developed and refined.

- Four platform removal projects have been postponed to outside the survey timeframe, although this has been offset by two of the new projects that have four large platforms for removal.

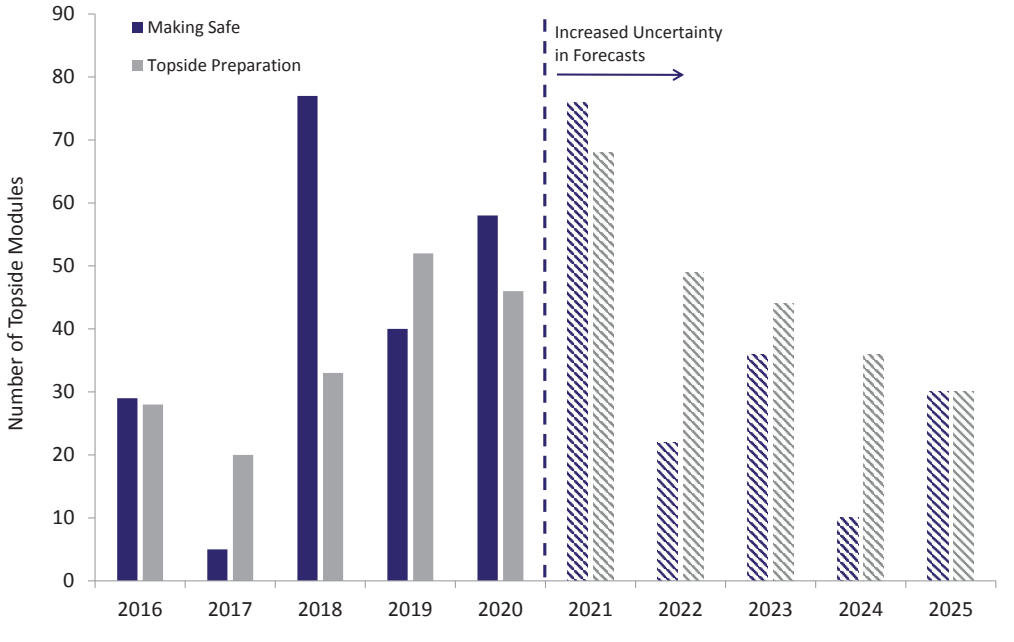
- Close to 30 topside modules are forecast for 'making safe' and topside preparation in 2016, with 'making safe' activity peaking at 77 modules in 2018 and topside preparation peaking at 68 modules in 2021.

- Just under 2,000 kilometres of pipeline are forecast for 'making safe' in these regions over the next decade, with activity varying over the ten-year period, particularly in the second half of the survey timeframe (2021 to 2025).

- Forecast activity is lower than reported in 2015 as some projects with significant levels of activity have been postponed. Although decommissioning on some projects has been brought forward, any associated pipeline activity lies outside the survey timeframe, leading to a net decrease in activity from the 2,350 kilometres forecast in 2015.

- Seven projects currently plan to carry out pipeline 'making safe' in 2023 causing a peak of 753 kilometres. For fields with significant lengths of pipeline to be decommissioned, 'making safe' may be carried out over a number of years.

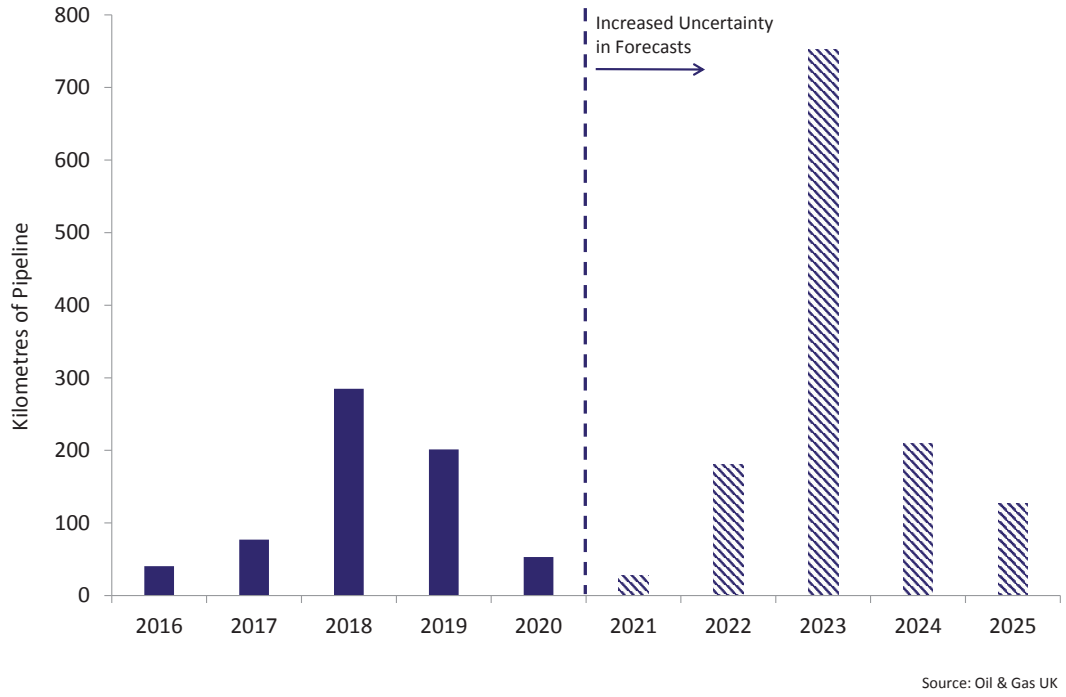
Figure 10: Forecast Number of Topside Modules for 'Making Safe' and Topside Preparation in the Central and Northern North Sea and West of Shetland



Source: Oil & Gas UK

	Number of Modules 2016 to 2025	Number of Platforms 2016 to 2025
Facilities 'making safe'	383	26 platforms 2 FPSOs
Topside preparation	406	29 platforms 1 FPSO

Figure 11: Forecast Length of Pipelines for 'Making Safe' in the Central and Northern North Sea and West of Shetland



Source: Oil & Gas UK

Pipeline 'Making Safe' 2016 to 2025 (Kilometres)
1,954

Southern North Sea and Irish Sea

- Facilities 'making safe' and topside preparation activities are forecast to be carried out on 38 normally unmanned installations (NUIs) and 32 manned platforms in these regions, equating to 83 topside modules from 2016 to 2025.

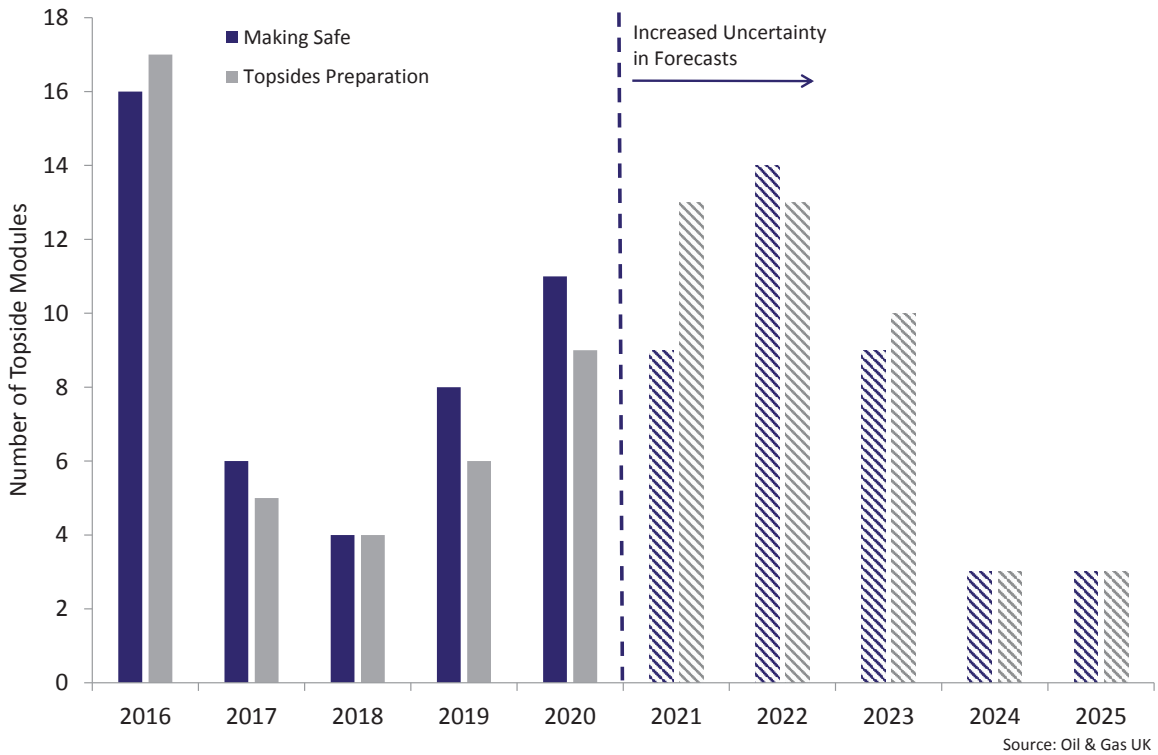
- The overall activity has increased from 65 topside modules forecast a year ago given the 16 new platform removal projects included in the southern North Sea. The additional activity is expected to occur between 2018 and 2025.

- Activity in the near term is consistent with last year's report, indicating that these projects are further along in their planning and the timing is better defined.

- Over the next decade, nearly 2,890 kilometres of pipeline are estimated to be 'made safe' in the southern North Sea and Irish Sea, an increase from the 2,490 kilometres forecast a year ago.

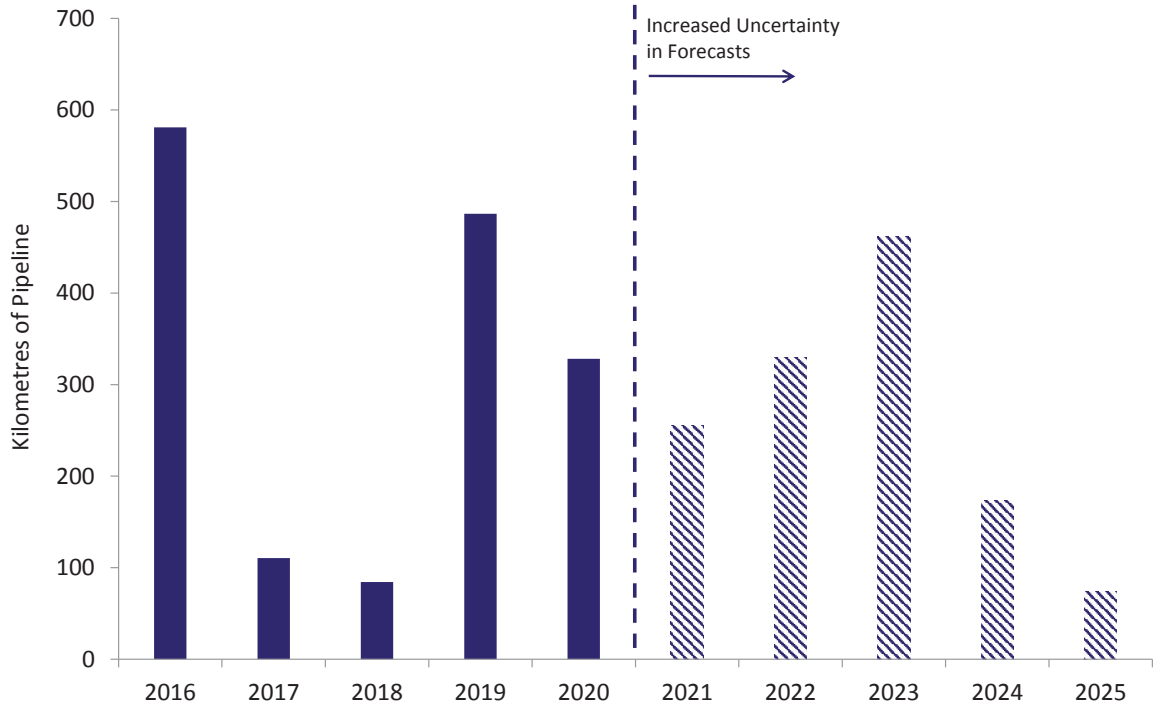
- Activity is forecast to peak at just under 600 kilometres this year, with significant activity between 2019 and 2023 also expected.

Figure 12: Forecast Number of Topside Modules for 'Making Safe' and Topside Preparation in the Southern North Sea and Irish Sea



	Number of Topside Modules 2016 to 2025	Number of Platforms 2016 to 2025
Facilities 'making safe' and topside preparation	83	38 NUIs 32 manned platforms

Figure 13: Forecast Length of Pipelines for 'Making Safe' in the Southern North Sea and Irish Sea



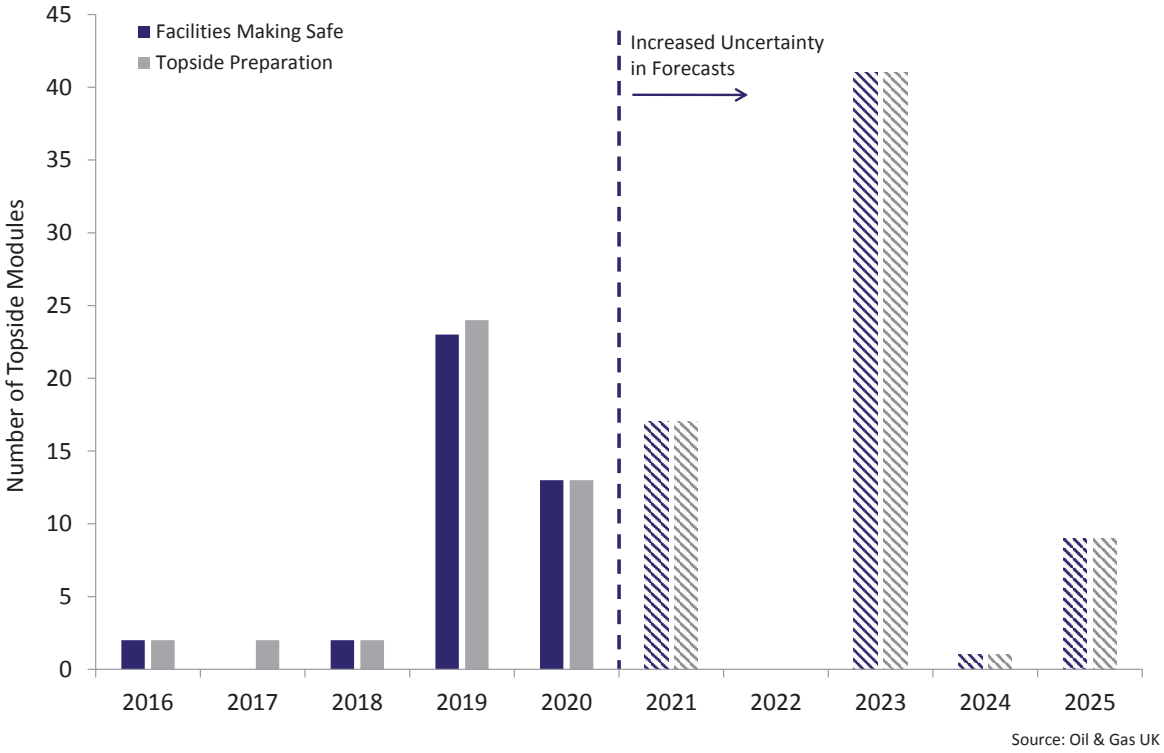
Source: Oil & Gas UK

Pipeline 'Making Safe' 2016 to 2025 (Kilometres)
2,885

Norwegian Continental Shelf

- Operators forecast that 108 topside modules on 13 platforms and 2 FPSOs will be 'made safe' in preparation for removal over the next ten years.
- Topside preparation is slightly higher with a forecast of 111 topside modules on 14 platforms and 2 FPSOs, as 'making safe' work has already been carried out on one platform.
- The bulk of work is planned between 2019 and 2023, peaking at over 40 topside modules in 2023.
- Just over 350 kilometres of pipeline are forecast for 'making safe' on the Norwegian Continental Shelf over the next decade. All of this activity is in the Norwegian North Sea.
- Activity will vary significantly year-on-year, peaking at 120 kilometres in 2020.
- Forecast pipeline 'making safe' activity in the Norwegian North Sea region of the Norwegian Continental Shelf has increased since estimates made last year as ten new projects are captured.
- The bulk of the pipeline decommissioning activity associated with these projects however lies outside the survey timeframe.
- In contrast to the 2015 report, no pipeline decommissioning activity is forecast in the Norwegian Sea due to the deferral of a subsea project.

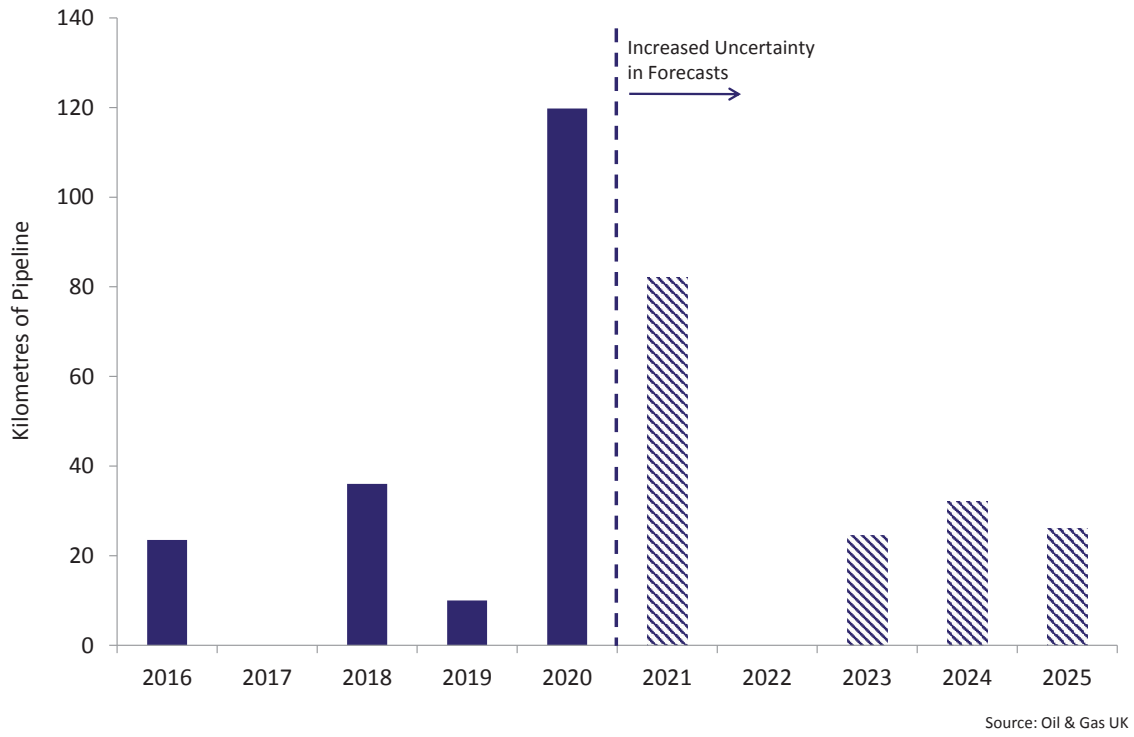
Figure 14: Forecast Number of Topside Modules for 'Making Safe' and Topside Preparation on the Norwegian Continental Shelf



Source: Oil & Gas UK

	Facilities 'Making Safe' 2016 to 2025	Topside Preparation 2016 to 2025
Norwegian North Sea	108 modules on 13 platforms and 2 FPSOs	111 modules on 14 platforms and 2 FPSOs
Norwegian Sea	No activity	No activity
Barents Sea	No activity	No activity

Figure 15: Forecast Length of Pipelines for 'Making Safe' on the Norwegian Continental Shelf



Source: Oil & Gas UK

	Pipeline 'Making Safe' 2016 to 2025 (Kilometres)
Norwegian North Sea	354
Norwegian Sea	No activity
Barents Sea	No activity

5.3 Topside and Substructure Removal

Removal is classified as the removal of topsides, substructures (jackets) and subsea infrastructure. The weights of FPSOs have not been included in this category as they are usually relocated or sold for reuse or recycling.

The ability to cut large and often complex steel sections in an offshore environment is one of the key challenges during this stage of decommissioning. The availability of heavy lift vessels, the development and use of new technology for removing installations, and the capacity of disposal sites will all affect how decommissioning on different projects is implemented. The removal method deployed will depend on the type and weight of the topside and substructure and will be determined through comparative assessment of the available options.

The most common methods for topside removal are piece-small, reverse installation or single-lift.

- The piece-small method involves dismantling the topside and using onshore demolition techniques to produce small, manageable pieces that can be transported onshore.

- For reverse installation, the topside modules are lifted separately onto a transportation barge or the deck of the crane vessel before being taken onshore.

- The single-lift method involves removing the topside in one piece and may involve extra engineering work to reinforce the topside in preparation for removal. As technology moves on to keep up with the decommissioning market, vessels such as the Pioneering Spirit are being designed to lift heavier loads[17].

[17] See www.allseas.com/equipment/pioneering-spirit

For the substructure, the removal method depends on the type, weight and configuration. The substructures to be decommissioned in the southern North Sea and Irish Sea are shallow-water jackets that typically weigh less than 2,000 tonnes and are usually deployed in water depths of 55 metres or less so they may use a single-lift removal method.

For larger substructures (barge-launched and some self-floaters), the jacket may be cut into smaller sections *in situ* and removed in segments. These more complex projects are typically located in the central and northern North Sea and on the Norwegian Continental Shelf. The decommissioning sector continues to innovate in developing existing and new cutting technology to undertake this task.

Operators forecast that over 652,000 tonnes of topsides from 109 platforms are to be removed from the UK and Norwegian Continental Shelves over the next decade.

While the majority of these platforms are located in the southern North Sea and Irish Sea (61 per cent), the area with the greatest amount (40 per cent) to be removed by weight is the northern North Sea at over 262,000 tonnes. This reflects the size of platforms in this region.

Topside removal activity in the near term (2016 to 2020) is lower with between 15,000 and 80,000 tonnes forecast to be removed each year. This rises to 60,000 to 128,000 tonnes per annum from 2021 to 2025.

Considering the forecast for substructure removal, Figure 17 opposite shows that 316,272 tonnes of substructure associated with 100 platforms are forecast to be removed between 2016 and 2025. Just over 30 per cent of this weight comes from the northern North Sea region (96,737 tonnes).

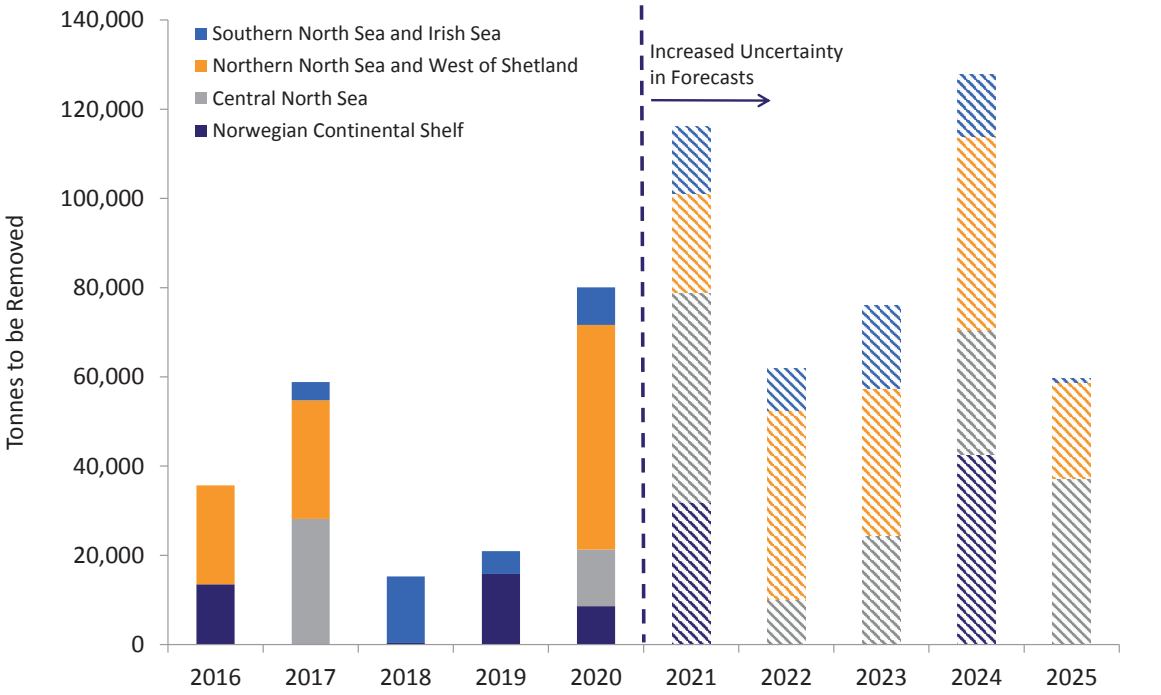
Substructure removal on the UKCS is forecast to begin in 2017, while activity on the Norwegian Continental Shelf is expected to start later in 2019. Again, substructure removal is lower in the near term (2017 to 2020) ramping up to a peak of just under 60,000 tonnes in 2025. Although not captured in the dataset, activity beyond 2025 is likely to remain high as there are a number of projects that have removal activity scheduled for outside the survey timeframe.

Overall, Figures 16 and 17 show that across the UK and Norway there will be decommissioning work available for the supply chain in every year, although no single region anticipates a consistent stream of activity with fluctuations from year to year and area to area. All of the activity on the Norwegian Continental Shelf is concentrated in the Norwegian North Sea region.

A significant amount of work for both topside and substructure removal is yet to be contracted out, as demonstrated in the following sections. This provides a significant opportunity for the supply chain to bid for this work as it becomes available.

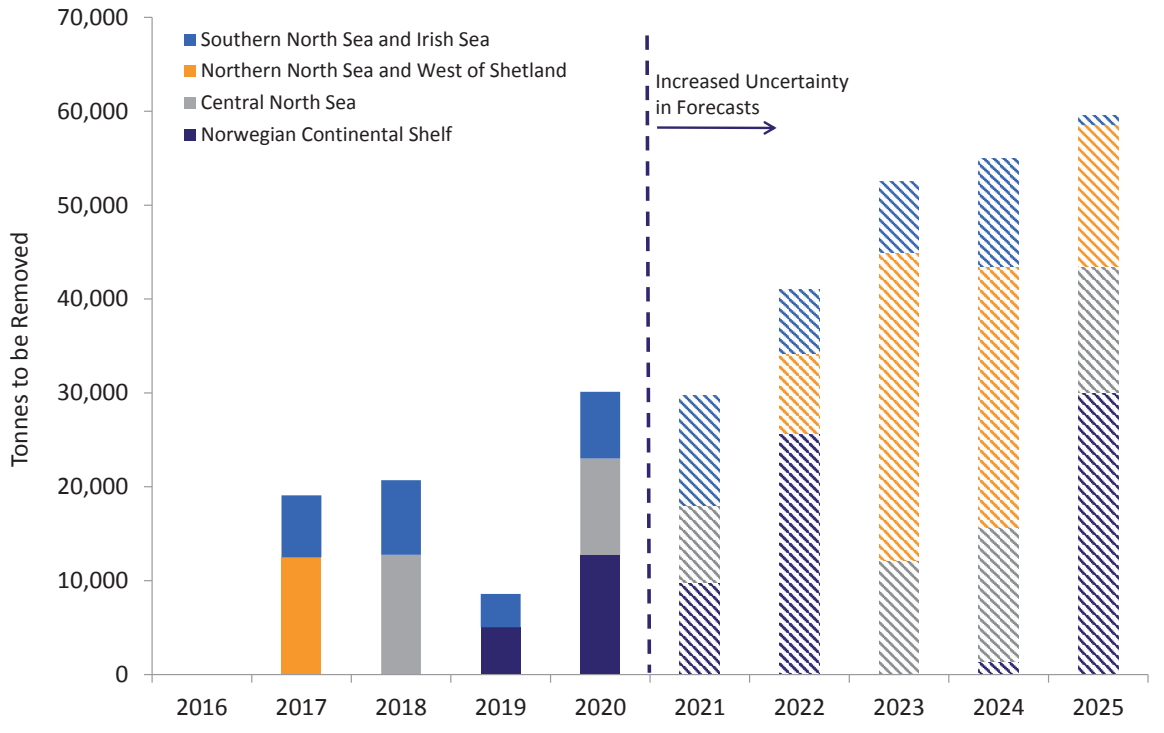
It should be noted that in the survey operators typically indicate a single year for removal activity, but removal contracts commonly include a time window of several years in which the activity must take place.

Figure 16: Combined Topside Removal Forecast for the UK and Norwegian Continental Shelves



Source: Oil & Gas UK

Figure 17: Combined Substructure Removal Forecast for the UK and Norwegian Continental Shelves

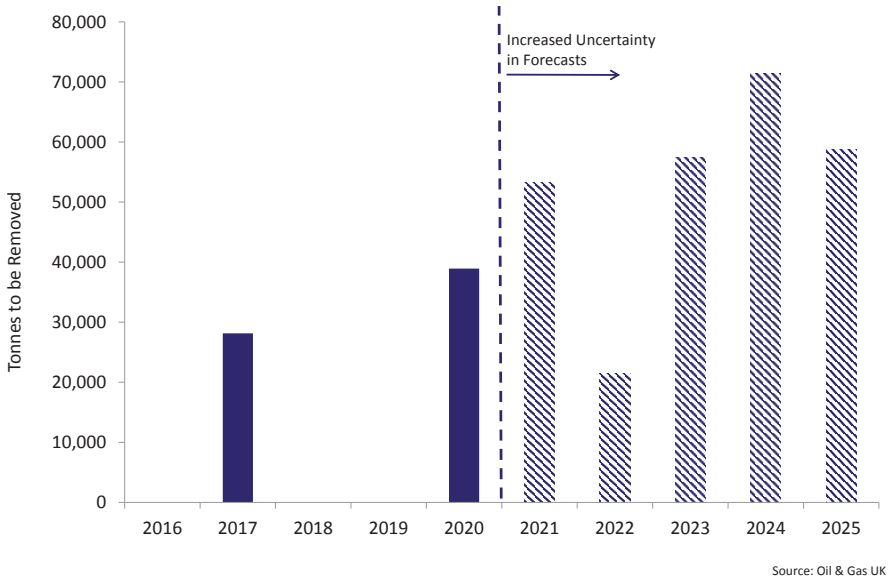


Source: Oil & Gas UK

Central and Northern North Sea and West of Shetland

- Operators forecast the removal of 342 topside modules from 28 platforms from 2016 to 2025, with a total weight of 449,260 tonnes to be removed.
- A number of topside removals are forecast between 2016 and 2017 with no activity between 2018 and 2019. This is similar to the forecast in last year's report due to the small number of large decommissioning projects already under way in the northern North Sea.
- Activity beyond 2019 is higher than last year's forecast due to the inclusion of new projects and more detailed activity schedules.
- From 2020 to 2025, 62,000 tonnes of topsides on average are estimated to be removed per annum.
- Topside removal activity on eighty-two per cent (23) of the platforms has not yet been contracted out.
- Figure 18 opposite shows the tonnage per year of uncontracted topside removals. The topside removals for the Brent and Murchison fields, not shown, have already been contracted to Allseas and a consortium of AF Gruppen and Heerema (the Heerema-AF Consortium), respectively.
- The removal of Brent will be carried out by single-lift using the Pioneering Spirit heavy lift vessel, while the removal method for Murchison involves a combination of reverse installation and piece-small.
- The total forecast for substructure removals in these regions is close to 167,800 tonnes on 21 platforms from 2016 to 2025.
- Activity mirrors the forecast for topside removal, with some planned removals in the near term (2016 to 2020).
- Fifteen of the planned substructure removals are expected to take place between 2023 and 2025.
- Ninety per cent of this activity is yet to be contracted out (19 substructures), shown in Figure 19 opposite.

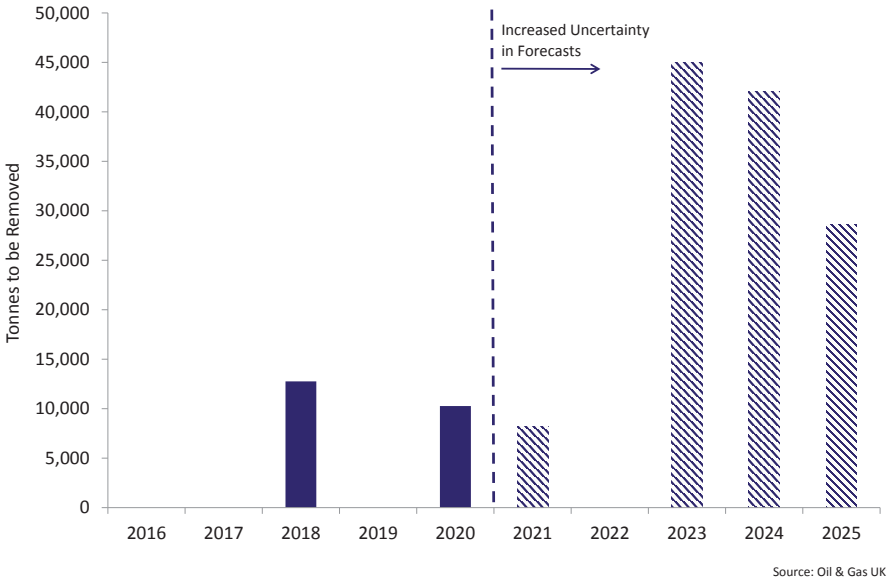
Figure 18: Uncontracted Topside Removal Forecast in the Central and Northern North Sea and West of Shetland 2016 to 2025



Source: Oil & Gas UK

Topside Removal	Weight (Tonnes) 2016 to 2025	Number 2016 to 2025
Total	449,260	342 topside modules on 28 platforms
Contracted activity	119,880	5 platforms
Uncontracted activity	329,380	23 platforms

Figure 19: Uncontracted Substructure Removal Forecast in the Central and Northern North Sea and West of Shetland 2016 to 2025



Source: Oil & Gas UK

Substructure Removal	Weight (Tonnes) 2016 to 2025	Number 2016 to 2025
Total	167,793	21 platforms
Contracted activity	21,000	2 platforms
Uncontracted activity	146,793	19 platforms

Southern North Sea and Irish Sea

- Operators forecast the removal of 83 topside modules on 67 platforms over the next decade, with a total weight of 90,260 tonnes. This is an increase on the 66 modules on 57 platforms in last year's report (78,900 tonnes) due to the new projects.

- Just over 4,000 tonnes of topsides are forecast to be removed in 2017, rising to almost 15,000 tonnes in 2018.

- For three of the projects, although CoP dates have come forward, some decommissioning activity has been deferred as companies want to preserve cash-flow in the current climate.

- Topside removal activity on 85 per cent (57) of platforms has not yet been contracted out, with 18 of these installations set for removal by 2020.

- More operators are looking at decommissioning their assets in batch campaigns compared to last year's forecast. Batching well P&A and topside and substructure removal activity across several assets allows the operator to optimise contracting strategy and the use of vessels, rigs and accommodation. This is now being considered by all operators in the region to carry out decommissioning in a more cost-effective manner.

- Campaigns are not typically cross-operator, however, some operators have carried out feasibility studies looking at the benefits and risks of cross-operator campaigns that could lead to further efficiency gains.

- The estimate for substructure removal in these regions mirrors that of topsides, with 63,745 tonnes of substructure on 67 platforms to be removed over the decade compared with 46,200 tonnes on 57 platforms in last year's report.

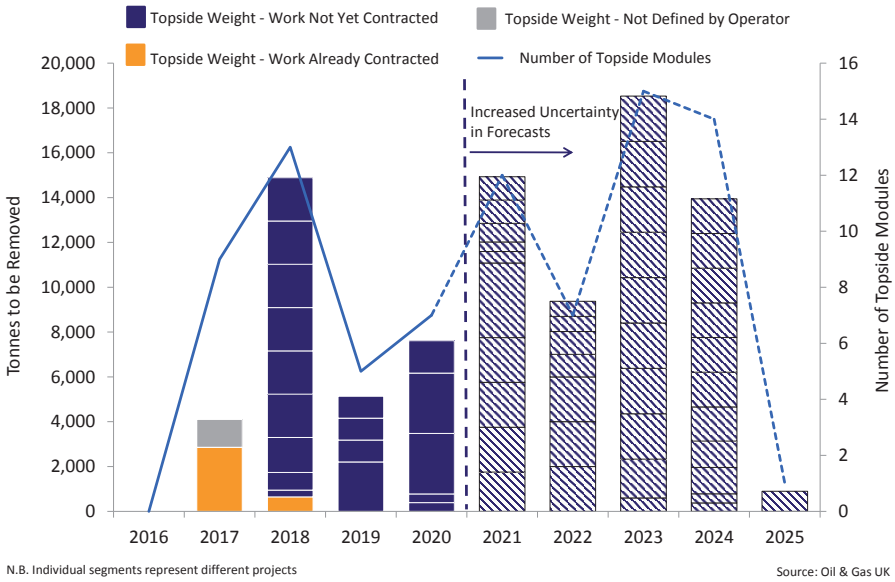
- In 2017, 6,600 tonnes of substructure are forecast to be removed.

- Activity deferral on some projects and spreading of activity on others has caused the peak to shift since a year ago from 2017 to 11,680 tonnes in 2021.

- The inclusion of additional projects in the survey has increased forecast activity for both topside and substructure removal in the second half of the decade (2021 to 2025) compared to last year.

- Again, 85 per cent of the substructure removals (57) planned over the next decade are yet to be contracted out.

Figure 20: Forecast Number of Topside Modules and Topside Weight to be Removed in the Southern North Sea and Irish Sea Split by Work Already Contracted

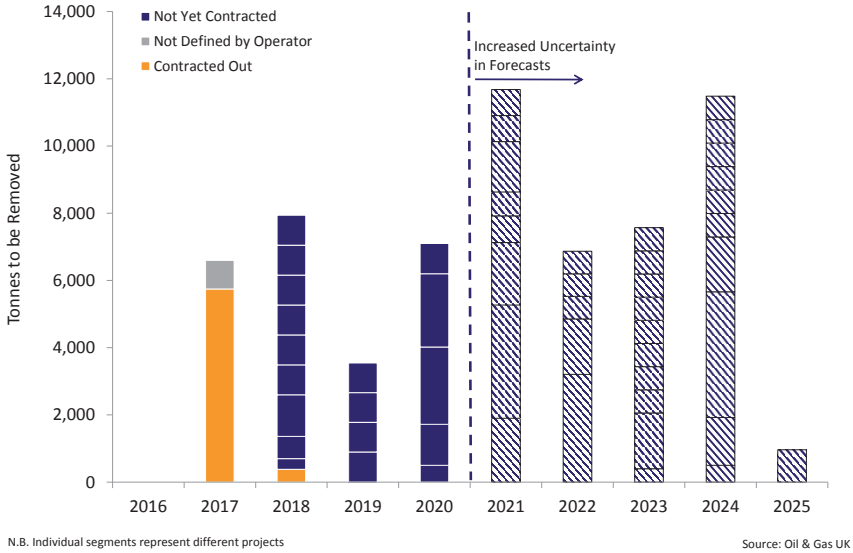


N.B. Individual segments represent different projects

Source: Oil & Gas UK

Topside Removal	Weight (Tonnes) 2016 to 2025	Number 2016 to 2025
Total	90,260	83 modules on 67 platforms
Contracted activity	3,510	9 platforms
Uncontracted activity	85,510	57 platforms
Not defined	1,240	1 platform

Figure 21: Forecast Substructure Weight to be Removed in the Southern North Sea and Irish Sea Split by Work Already Contracted



N.B. Individual segments represent different projects

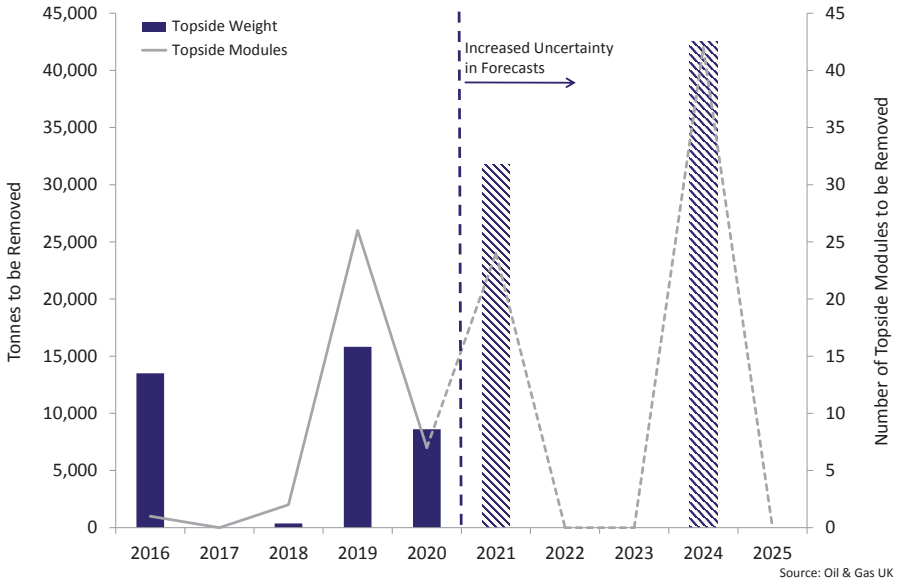
Source: Oil & Gas UK

Substructure Removal	Weight (Tonnes) 2016 to 2025	Number 2016 to 2025
Total	63,745	67 platforms
Contracted activity	6,125	9 platforms
Uncontracted activity	56,770	57 platforms
Not defined	850	1 platform

Norwegian Continental Shelf

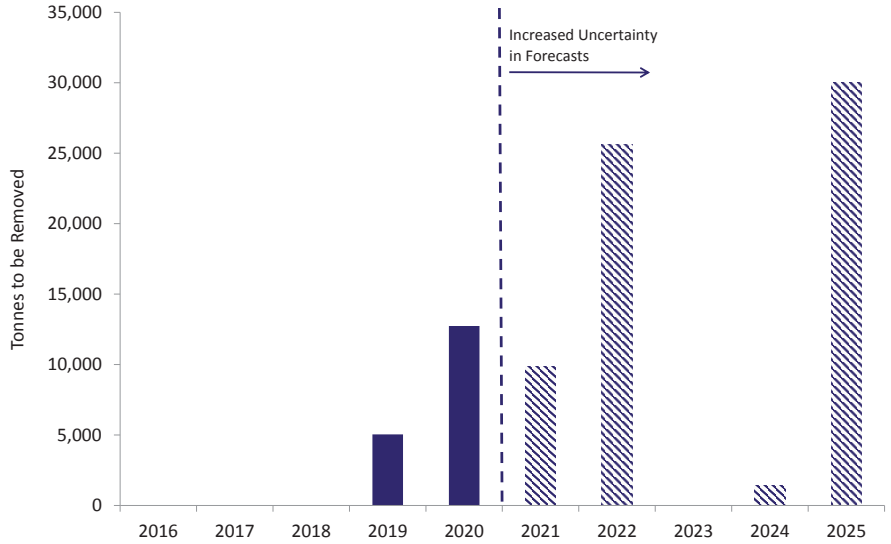
- Operators forecast just over 112,600 tonnes of topsides from 14 platforms will be removed over the next decade, all in the Norwegian North Sea.
- The next removal is scheduled for 2018, following the successful single-lift removal of the 13,500 tonne YME platform in August this year by the Pioneering Spirit heavy lift vessel.
- The bulk of activity over the decade is forecast between 2019 and 2024, peaking at close to 43,000 tonnes in 2024.
- Just over 84,700 tonnes of substructure from 12 platforms will be removed between 2016 and 2025, again all in the Norwegian North Sea.
- Substructure removal is due to begin in 2019, with the majority of activity concentrated between 2019 and 2022, but peaking at 30,000 tonnes in 2025.
- The forecast for substructure removal mirrors the forecast for topside removal, with a time lag of around a year.

Figure 22: Forecast Number of Topside Modules and Topside Weight to be Removed on the Norwegian Continental Shelf



Topside Removal	Weight (Tonnes) 2016 to 2025	Number 2016 to 2025
Norwegian North Sea	112,612	102 modules on 14 platforms
Norwegian Sea	No activity	No activity
Barents Sea	No activity	No activity

Figure 23: Forecast Substructure Weight to be Removed on the Norwegian Continental Shelf



Source: Oil & Gas UK

Substructure Removal	Weight (Tonnes) 2016 to 2025	Number 2016 to 2025
Norwegian North Sea	84,734	12 platforms
Norwegian Sea	No activity	No activity
Barents Sea	No activity	No activity

5.4 Subsea Infrastructure Decommissioning

Mattresses are concrete structures usually used to protect or support subsea pipelines. Mattress decommissioning typically involves recovery from the seabed. This is a diver and vessel-intensive operation, with duration of the work dependent on the mattress age and condition. In some cases where the mattresses are badly degraded, regulatory approval may be sought to decommission mattresses *in situ*.

Other subsea infrastructure includes manifolds, Christmas trees, risers, spools, jumpers, anchors and subsea isolation valves, which are removed as part of the decommissioning programme.

- Just under 12,000 mattresses are forecast to be decommissioned across the UK and Norwegian Continental Shelves from 2016 to 2025.

- Sixty per cent of this activity (see table opposite) is concentrated in the central and northern North Sea and west of Shetland; 38 per cent in the southern North Sea and Irish Sea; and the remaining two per cent on the Norwegian Continental Shelf.

- Just over 64,400 tonnes of other subsea infrastructure will be removed from the UK and Norwegian Continental Shelves from 2016 to 2025, compared with 86,000 tonnes forecast a year ago.

- The decrease in subsea infrastructure removal compared with last year is due to subsea infrastructure removal falling outside the survey timeframe for many of the projects included.

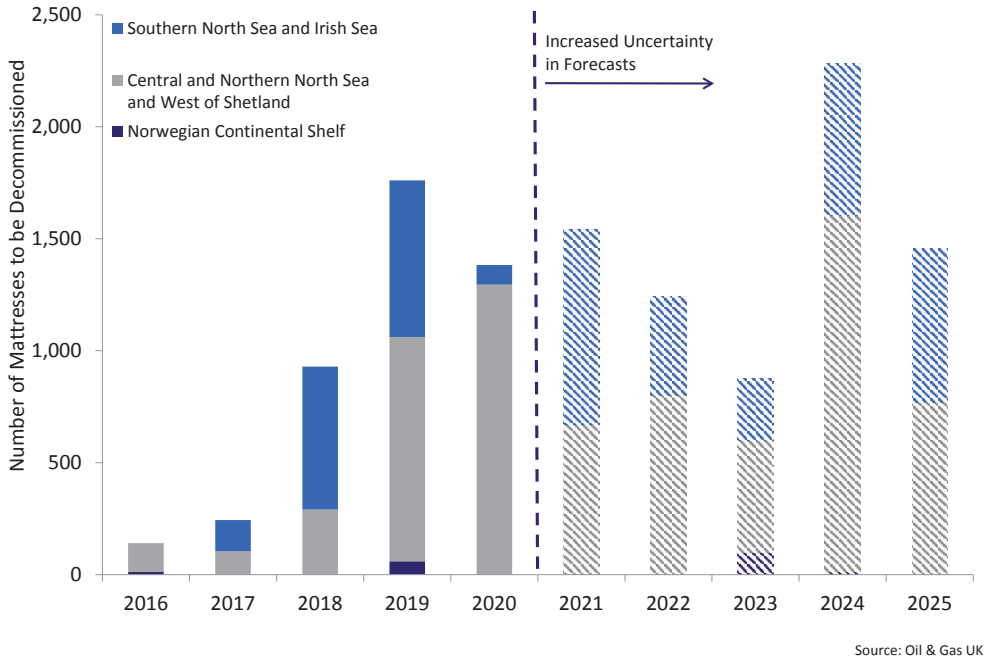
- Ninety-one per cent of this activity is concentrated in the central and northern North Sea and west of Shetland, six per cent is in the southern North Sea and Irish Sea, and three per cent on the Norwegian Continental Shelf.

- All of the mattress and other subsea infrastructure decommissioning activity on the Norwegian Continental Shelf is concentrated in the Norwegian North Sea.

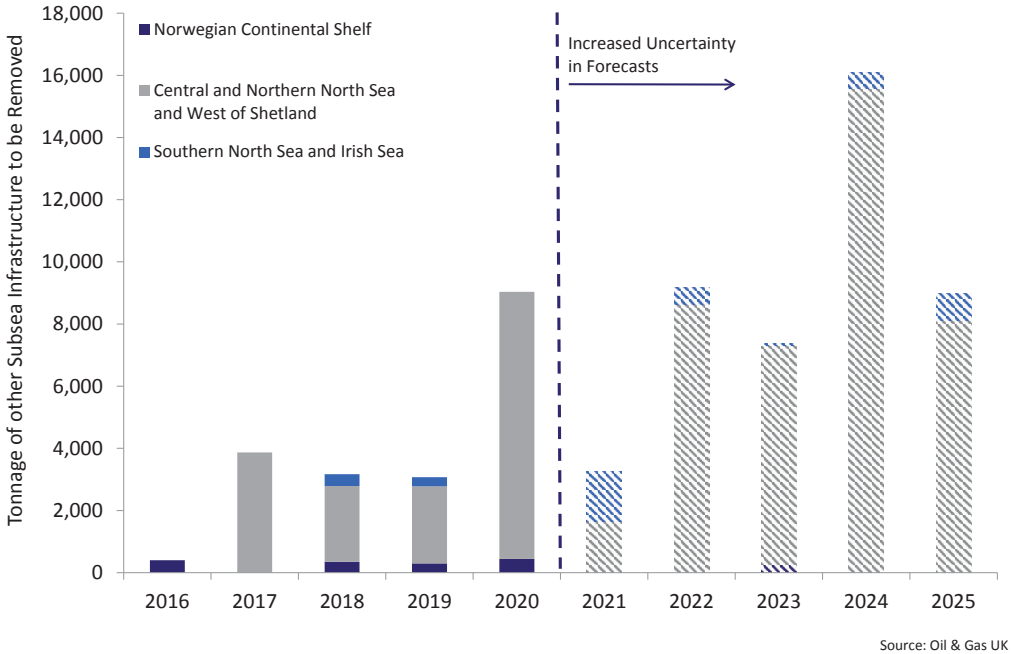
- The large amount of mattress and other subsea infrastructure activity in the central and northern North Sea and west of Shetland is due to the scale and types of projects in these regions. There are 13 fields serviced by FPSOs plus a number of projects with multiple subsea tie-backs.

- The relatively low forecast on the Norwegian Continental Shelf is due to there being fewer decommissioning projects in this region and activity for many projects lies outside the survey timeframe.

Figure 24: Forecast for Mattress and other Subsea Infrastructure Decommissioning on the UK and Norwegian Continental Shelves



Source: Oil & Gas UK



Source: Oil & Gas UK

	Mattresses (Number) 2016 to 2025	Other Subsea Infrastructure (Tonnes) 2016 to 2025
Central North Sea	5,979	56,714
Northern North Sea and West of Shetland	1,162	1,697
Southern North Sea and Irish Sea	4,526	4,268
Norwegian North Sea	188	1,745
Norwegian Sea	No activity	No activity
Barents Sea	No activity	No activity

5.5 Pipeline Decommissioning

The extensive pipeline network in the North Sea measures in excess of 45,000 kilometres in total and is used to deliver hydrocarbons to receiving facilities and end-users across Europe. This transportation network is of vital importance when the economics of field-life extension projects and future development opportunities are being assessed and it is therefore essential that major pipelines are not decommissioned prematurely. On the UKCS, to achieve the objectives of the MER UK (maximising economic recovery from the UKCS) strategy, the deferral of pipeline decommissioning to the end of field life, or for possible reuse, is sometimes carried out under the Interim Pipeline Regime, whereby the regulator – the OGA – may request that the pipeline owner carries out 'making safe' activities and maintains the pipeline for possible future reuse.

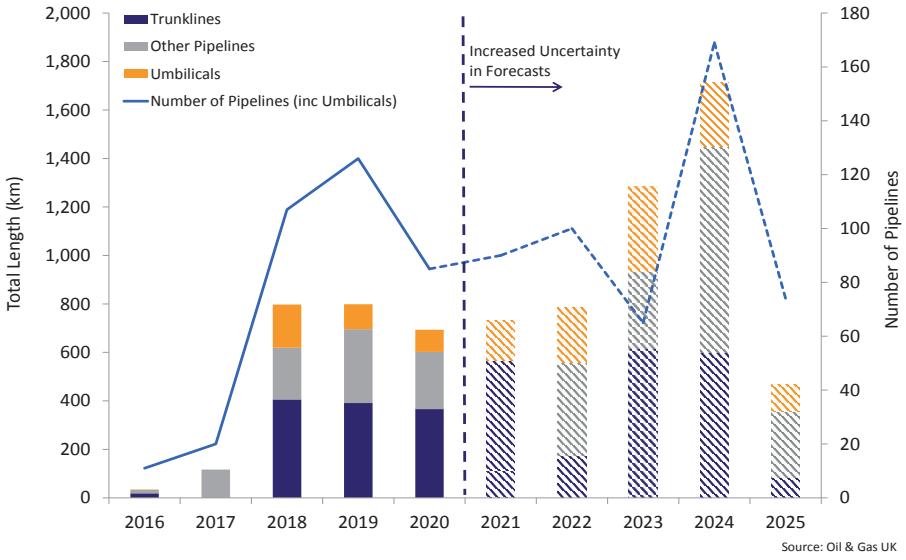
There are rigid pipelines and flexible flowlines in the North Sea. Their diameters can vary between 2 and 44 inches. Options for decommissioning include full removal, decommissioning *in situ*, trenching and burial. The approach adopted will be based on comparative assessments of all the different options and consideration of safety and environmental factors, technical feasibility, other sea users and cost. All decisions are made on a case-by-case basis in consultation with key stakeholders and with regulatory approval.

Operators intend to decommission around 17 per cent of the total pipeline network length from the UK and Norwegian Continental Shelves over the next decade, close to 850 pipelines with a total length of almost 7,500 kilometres.

The central North Sea is the area where the greatest number of pipelines (484) is estimated to be decommissioned, making up 57 per cent of the total. However, in terms of length to be decommissioned, the southern North Sea and Irish Sea will see the greatest proportion at 3,426 kilometres or 46 per cent of the total pipeline length to be decommissioned. On the Norwegian Continental Shelf, all the activity is planned in the Norwegian North Sea.

It should also be noted that many of the larger projects lie towards the end of the survey timeframe and so the associated pipeline decommissioning activity will occur beyond 2025.

Figure 25: Combined Pipeline Decommissioning Forecast for the UK and Norwegian Continental Shelves[18]

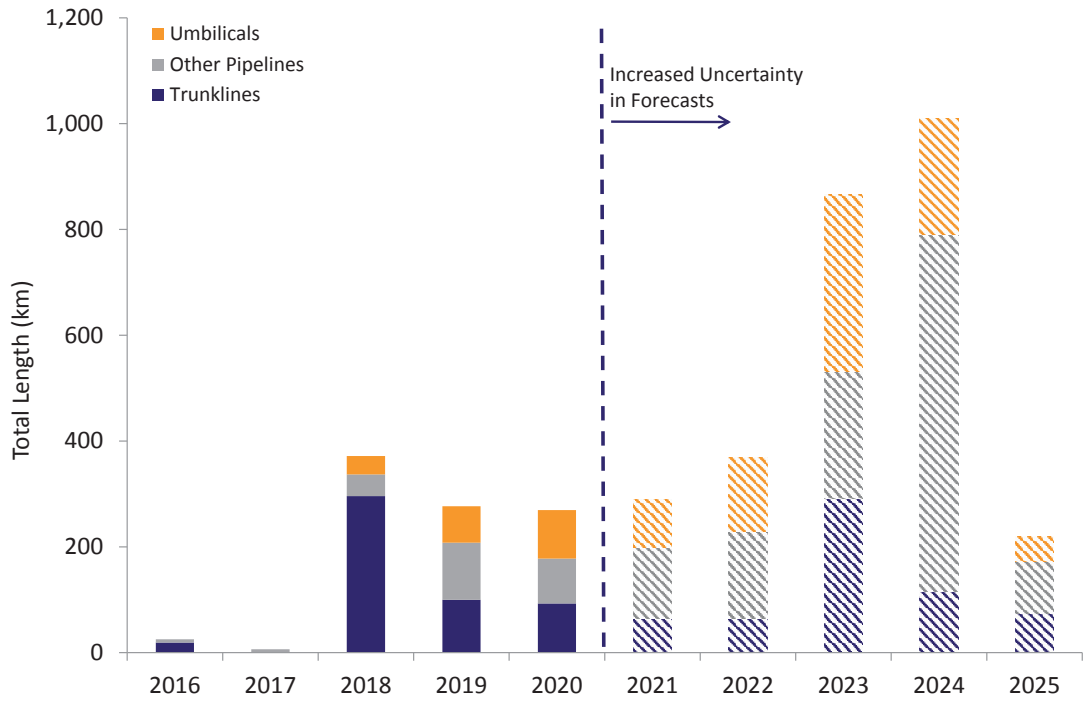


[18] Trunklines are pipelines with a diameter greater than 14 inches and a length in excess of 18 kilometres. Umbilicals are utility support pipelines.

Central and Northern North Sea and West of Shetland

- Operators plan to decommission 580 pipelines with a total length of 3,700 kilometres from these regions over the next decade.
- Around 25 kilometres of pipeline are forecast to be decommissioned in 2016, rising to an average of over 300 kilometres per year between 2018 and 2022.
- Activity is expected to peak at over 1,000 kilometres in 2024.
- The majority of this activity involves inter-field pipelines connecting fields to host facilities, although some import/export lines are included.
- Pipeline decommissioning activity is one of the later activities in a decommissioning project and there is therefore a high degree of uncertainty in the timing.

Figure 26: Forecast of Pipeline Decommissioning Activity in the Central and Northern North Sea and West of Shetland



Source: Oil & Gas UK

	Pipeline Decommissioning 2016 to 2025	Pipeline Decommissioning (Kilometres) 2016 to 2025
Total	580	3,704
Umbilicals	221	1,027
Trunklines	68	1,117
Other pipelines	291	1,560

Southern North Sea and Irish Sea

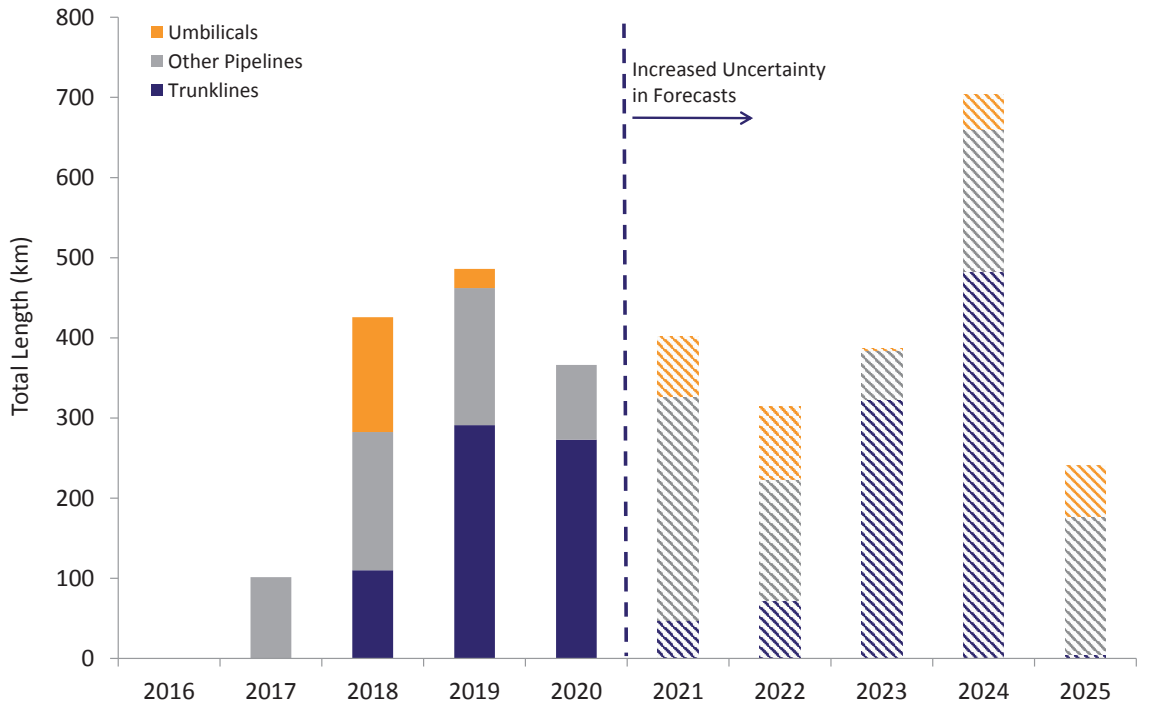
- The overall forecast for pipeline decommissioning in these regions over the next decade at 3,426 kilometres is similar to a year ago, although deferral and spreading of activity has occurred.

- Some 1,600 kilometres of trunkline are forecast to be decommissioned over the next ten years in these regions, with high activity forecast in 2019, 2020, 2023 and 2024.

- Activity is expected to peak at 700 kilometres in 2024, of which just under 500 kilometres is trunkline.

- To achieve MER UK and avoid premature decommissioning, the OGA is in discussion with operators to assess the impact of this decommissioning activity on future production and whether alternative solutions are available.

Figure 27: Forecast of Pipeline Decommissioning Activity in the Southern North Sea and Irish Sea



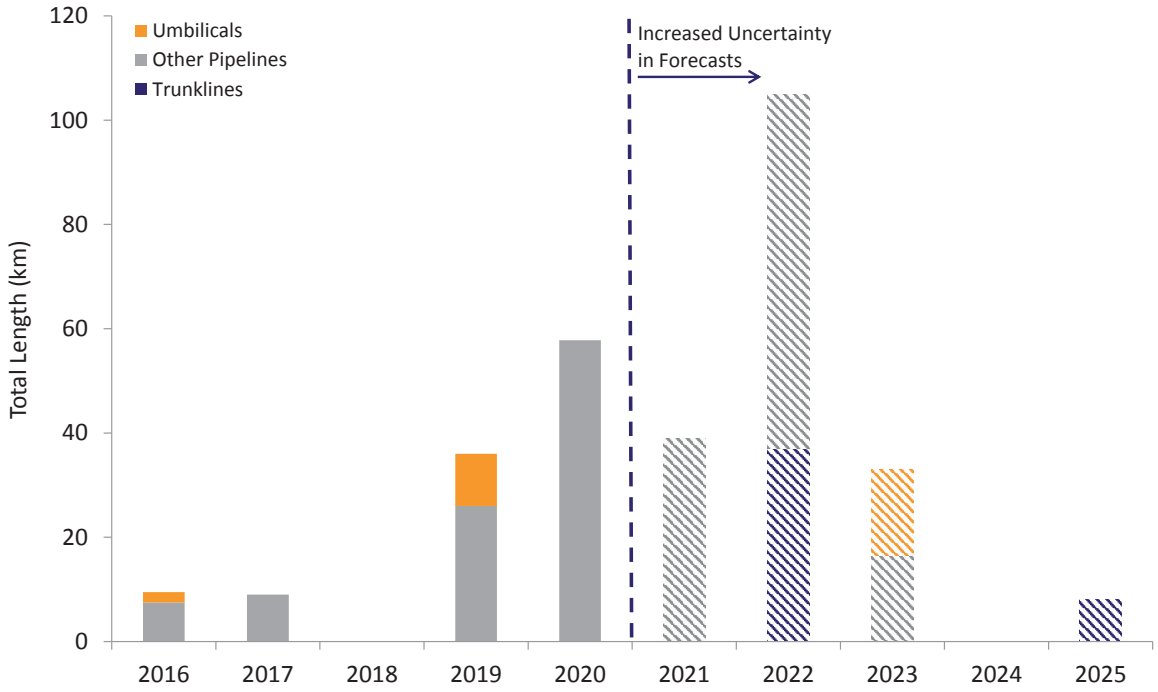
Source: Oil & Gas UK

	Pipeline Decommissioning 2016 to 2025	Pipeline Decommissioning (Kilometres) 2016 to 2025
Total	200	3,426
Umbilicals	46	443
Trunklines	21	1,603
Other pipelines	133	1,380

Norwegian Continental Shelf

- Sixty-seven pipelines with a total length of 297 kilometres will be decommissioned from 2016 to 2025.
- The majority are inter-field connectors that link fields to host facilities.
- Ten kilometres of pipeline are to be decommissioned in 2016, with activity forecast to peak at over 100 kilometres in 2022.
- For many of the projects included in the survey, pipeline decommissioning lies outside the timeframe.

Figure 28: Forecast of Pipeline Decommissioning Activity on the Norwegian Continental Shelf



Source: Oil & Gas UK

		Pipeline Decommissioning 2016 to 2025	Pipeline Decommissioning (Kilometres) 2016 to 2025
Total		67	297
Norwegian North Sea	Umbilicals	5	28
	Trunklines	39	45
	Other pipelines	23	224
Norwegian Sea		No activity	No activity
Barents Sea		No activity	No activity

5.6 Onshore Recycling and Final Disposal

Onshore topside and substructure recycling and disposal includes activities related to the cleaning and handling of hazardous waste, deconstruction, reuse, recycling, disposal and waste management accounting. Operators have a duty to monitor all waste generated offshore and its handling and disposal through an environment management system[19].

Preferred processes to deal with offshore structures that are no longer in use follow the hierarchy of reuse, recycling and onshore disposal. Once the structures are onshore, disassembling and processing takes place on specialist licensed sites.

Reuse is any activity that will lengthen the life cycle of an item, while it is still used for its initial purpose. This is not to be confused with recycling, which is when an item is reprocessed into a new, raw material. Reuse is often more challenging than recycling, however, it is often cost efficient and can help minimise waste disposal. The decision of whether to reuse, recycle or dispose to landfill is driven by various factors, including the amount of maintenance needed, the prevalence of out-dated technology, and the quantity of harmful material on an asset.

Topsides are made from various materials and therefore dismantling and safe waste management is often more difficult than managing substructures that are generally made of steel and can be processed and recycled more readily. Recent decommissioning projects demonstrate high levels of reuse and recycling at 95 per cent of all recovered materials. Hess details a reuse and recycling percentage of 96.9 per cent in the close-out report for the Fife, Fergus, Flora and Angus fields decommissioning programme, with a reuse rate of 48.2 per cent[20].

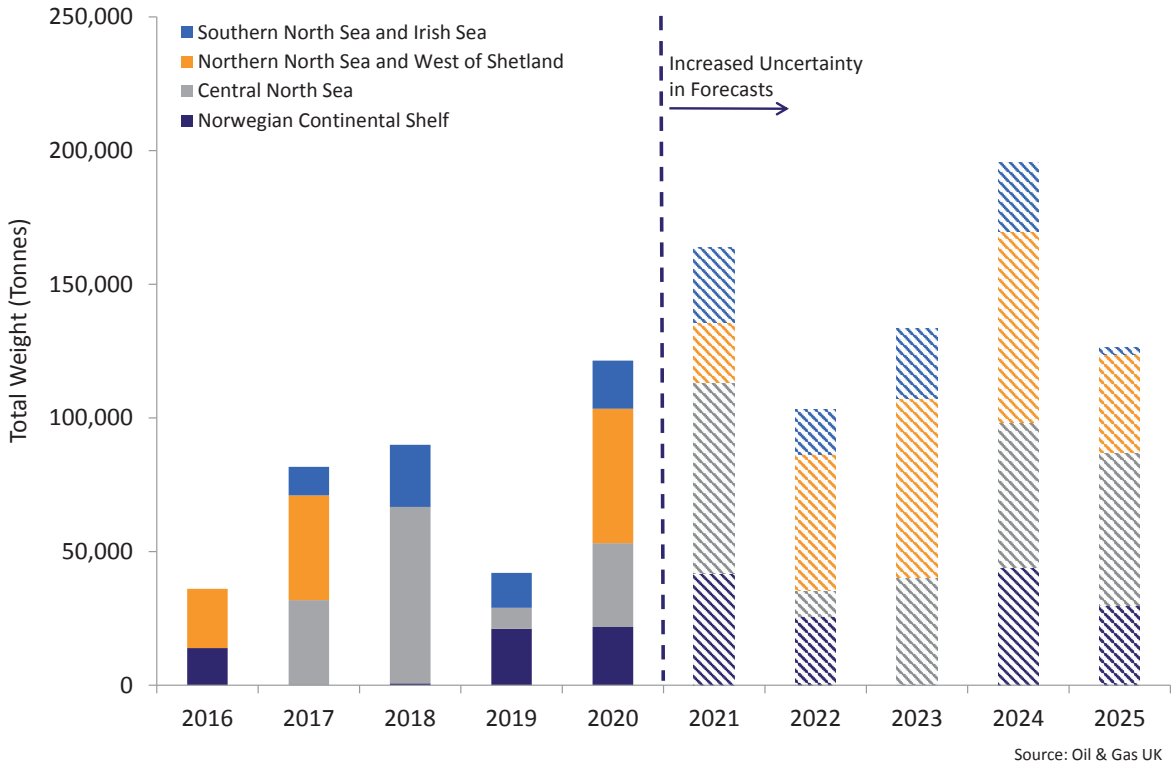
Close to 1.1 million tonnes of infrastructure are expected to be brought onshore for recycling and final disposal from the UK and Norwegian Continental Shelves between 2016 and 2025.

Thirty-four per cent (369,190 tonnes) will come from the central North Sea, 33 per cent (360,456 tonnes) from the northern North Sea and west of Shetland, 18 per cent from the Norwegian Continental Shelf (199,091 tonnes), and 15 per cent from the southern North Sea and Irish Sea (164,834 tonnes).

Over 36,000 tonnes are forecast to come onshore in 2016, with an average yearly weight of 62,400 between 2016 and 2019. Activity is expected to rise as the decade progresses, peaking at just under 200,000 tonnes in 2024.

[19] See Oil & Gas UK's *Environment Report* at www.oilandgasuk.co.uk/environment-report
[20] See http://bit.ly/HessFFF

Figure 29: Combined Forecast of Tonnage Coming Onshore for Recycling and Disposal on the UK and Norwegian Continental Shelves



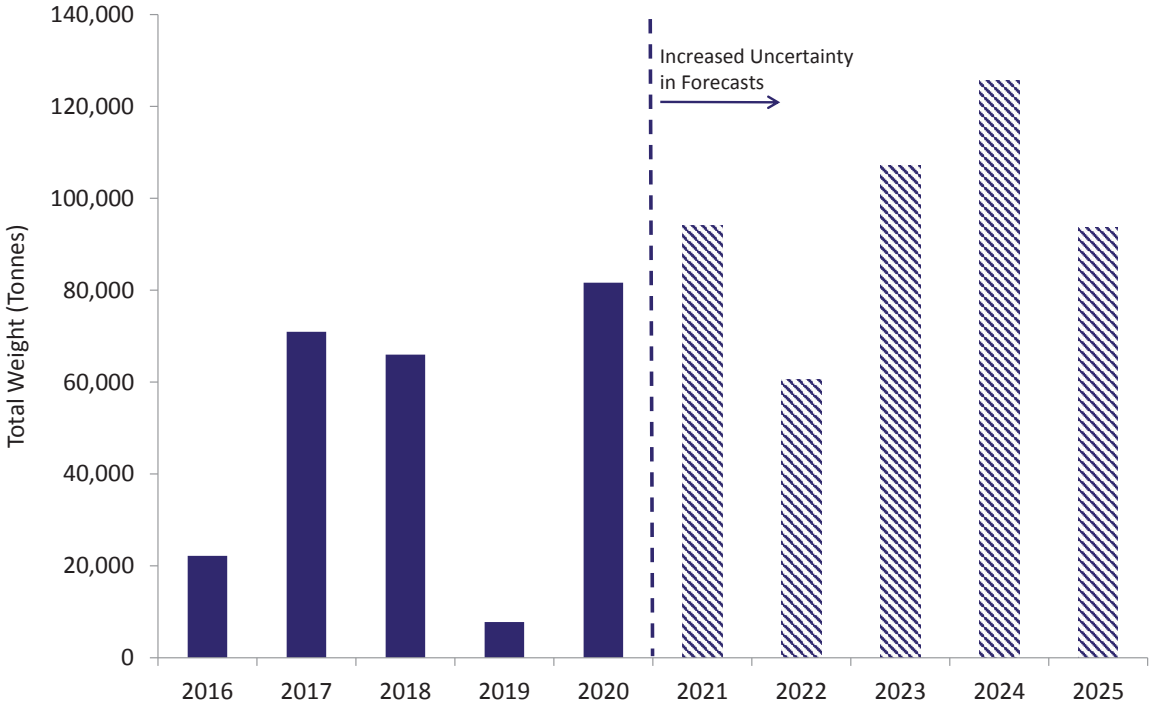
Central and Northern North Sea and West of Shetland

- Operators forecast that close to 729,650 tonnes of offshore infrastructure will come onshore from the regions for recycling and disposal between 2016 and 2025.

- This is an increase of close to 237,400 tonnes on the 2015 report, due to the inclusion of new projects and more detailed forecasts on existing projects.

- The spread of activity across the decade reflects the topside and substructure removal activity – lower in the near-term (from 2016 to 2019) and higher later in the decade, peaking at 125,600 tonnes in 2024.

Figure 30: Forecast of Tonnage Coming Onshore for Recycling and Disposal in the Central and Northern North Sea and West of Shetland



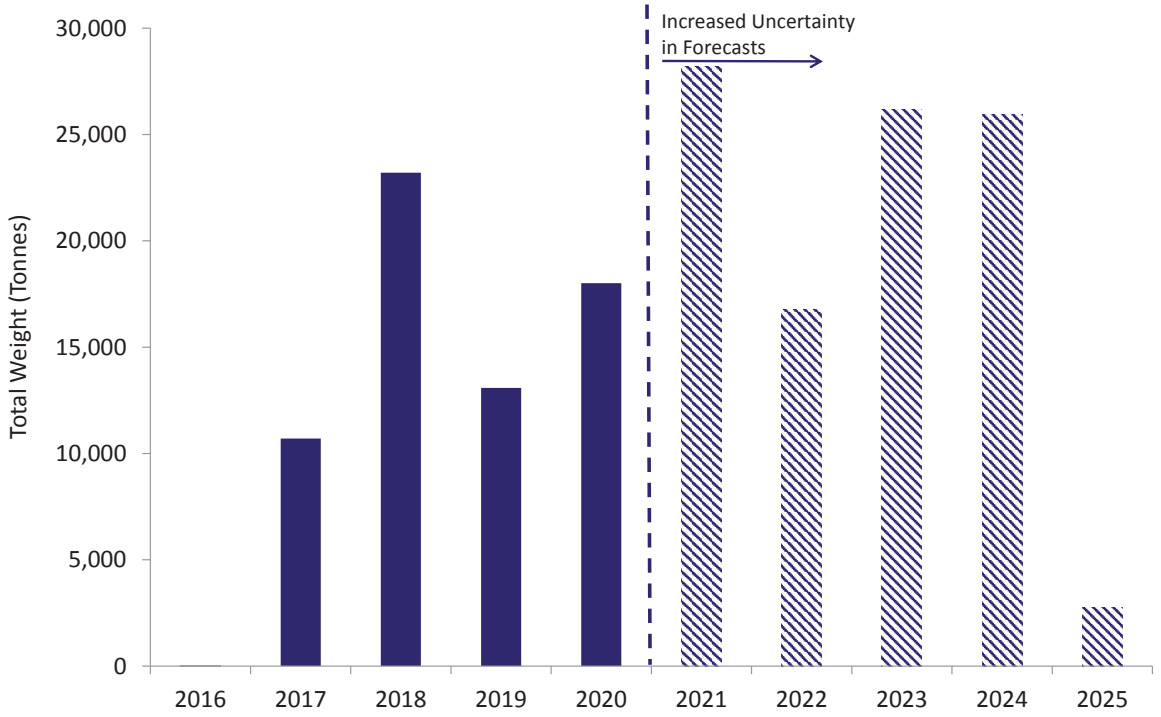
Source: Oil & Gas UK

	Onshore Recycling and Disposal (Tonnes) 2016 to 2025
Central North Sea	369,190
Northern North Sea and West of Shetland	360,456

Southern North Sea and Irish Sea

- Over 164,800 tonnes are to come onshore for recycling and disposal in these regions between 2016 and 2025.
- This is an increase of close to 37,500 tonnes compared to the 2015 report, as new projects are included for the first time.
- The spread of activity again correlates with topside and substructure removal, peaking in 2021 at 28,200 tonnes.

Figure 31: Forecast of Tonnage Coming Onshore for Recycling and Disposal in the Southern North Sea and Irish Sea



Source: Oil & Gas UK

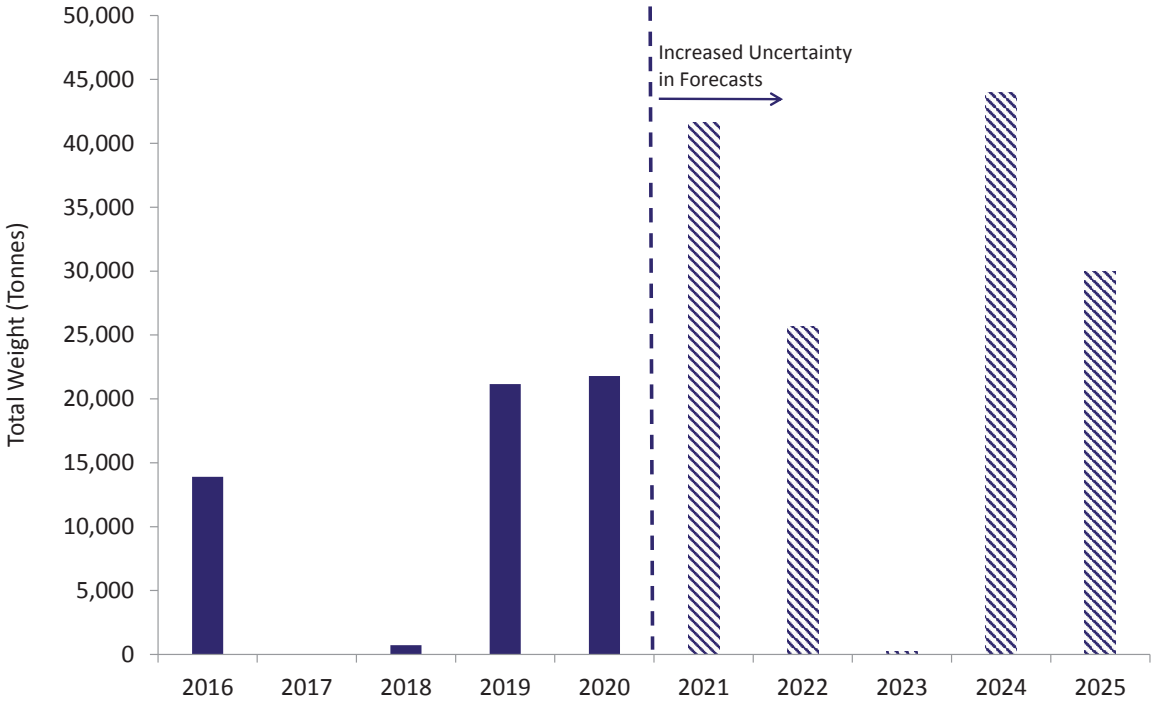
Southern North Sea and Irish Sea Onshore Recycling and Disposal (Tonnes) 2016 to 2025
164,834

Norwegian Continental Shelf

- Close to 199,100 tonnes of offshore infrastructure will be decommissioned and brought onshore from the Norwegian Continental Shelf between 2016 and 2025. Almost all of this activity is in the Norwegian North Sea.

- Activity is forecast to peak in 2024 at 44,000 tonnes.

Figure 32: Forecast of Tonnage Coming Onshore for Recycling and Disposal on the Norwegian Continental Shelf



Source: Oil & Gas UK

Norwegian Continental Shelf Onshore Recycling and Disposal (Tonnes) 2016 to 2025
199,091

5.7 Site Remediation and Monitoring

Site remediation includes cuttings piles management, debris clearance and over-trawl surveys. Over-trawl surveys make sure the seabed is safe for normal fishing activities to resume. Monitoring is the very final stage of decommissioning, where operators must carry out surveys on the site after physical decommissioning has been completed. Details of these programmes are agreed on an individual basis with the Department for Business, Energy and Industrial Strategy.

Activity associated with site remediation and monitoring is not forecast in this report, however, estimated expenditure can be found in section 6.1.

6. Forecast Decommissioning Expenditure – 2016 to 2025

6.1 Forecast Expenditure on the UK Continental Shelf

Forecast decommissioning expenditure on the UKCS between 2016 and 2025 is £17.6 billion, compared with the ten-year forecast of £16.9 billion in the *2015 Decommissioning Insight*[21]. This increase is due to the new projects entering the survey timeframe rather than increased cost estimates from existing projects.

Although decommissioning is still in its infancy on the UKCS, it is a growing area of the business and offers scope for the UK supply chain to diversify and establish a global centre of excellence. Accounting for just 2 per cent of total UKCS expenditure in 2010, the decommissioning market is expected to grow to over 12 per cent of total expenditure by 2017.

Estimate Types

In the survey, UKCS operators were asked to indicate whether the forecasts they were providing for decommissioning expenditure over the next decade were provisioning or project estimates. Provisioning estimates are those developed for Asset Retirement Obligations[22] and are typically calculated prior to carrying out the comparative assessments[23] that determine the decommissioning method to be deployed. Project estimates are those developed during the project delivery process as the decommissioning method is being determined and are therefore typically far more detailed with a higher degree of certainty.

Ninety-six of the 114 projects in the central and northern North Sea and west of Shetland are provisioning estimates. In the southern North Sea and Irish Sea, where decommissioning is likely to occur sooner, only 13 of the 39 projects are provisioning estimates.

Operators were also asked to provide a project cost class estimate using the Association for the Advancement of Cost Engineering (AACE) guidelines[24] (see Appendix for AACE matrix). These classifications seek to define a project and reflect the degree of uncertainty in the estimates.

Overall, 96 per cent of the 153 UKCS projects included in the survey are classified using the AACE Cost Estimation Classification Matrix. It should be noted that a high proportion of projects are classified as Class 4 (39 per cent) or Class 5 (55 per cent), which have project definition levels from 0 to 15 per cent, revealing that 94 per cent of UKCS projects are in the early planning stages of outlining the scope of decommissioning activities and carrying out feasibility studies. This indicates that activity and expenditure forecasts included in this report could change as these projects are refined, particularly for those towards the end of the survey timeframe. Nonetheless, the forecasts provide a good indication of the scale of decommissioning that lies ahead.

[21] The 2015 survey covered the timeframe 2015 to 2024, whereas the 2016 survey covers the period 2016 to 2025.

[22] An Asset Retirement Obligation (ARO) is a liability associated with the eventual retirement of a fixed asset.

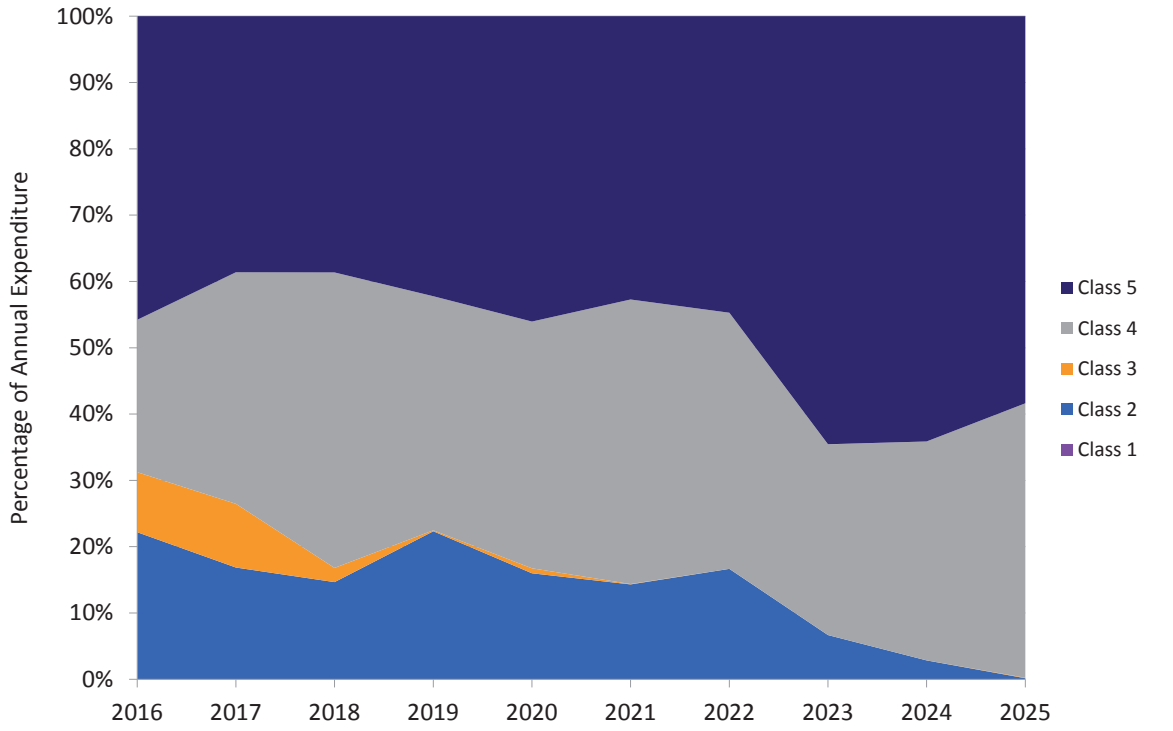
[23] A comparative assessment is used to compare options, examine differences and identify the 'most preferred' option in the development of decommissioning programmes for:
a) All installations for which derogation is sought under OSPAR Decision 98/31
b) All pipelines being decommissioned under the Petroleum Act 1998
c) All drill cuttings piles that are not screened-out at Stage 1 of OSPAR Recommendation 2006/51

[24] Further information on the Association for the Advancement of Cost Engineering (AACE) classification scheme is available at http://web.aacei.org

None of the UKCS projects included in the survey are reported as Class 1. These would have project definition levels of 50 to 100 per cent with many of the activities already in execution. Projects that were classified as Class 1 in the 2015 report have now been completed and no new projects have moved into this category. Only two projects were reported as Class 2, where project definition is between 30 and 70 per cent and is either at the contracting stage or being executed.

Figure 33 shows the percentage of annual expenditure for projects on the UKCS split by AACE classification. Sixty-nine per cent of expenditure in 2016 comes from the large number of Class 4 or 5 projects, each contributing a small amount of expenditure, typically for operator project management or well P&A. Companies often start well P&A while they develop and define the scopes of the other decommissioning activities.

Figure 33: AACE Cost Class Breakdown



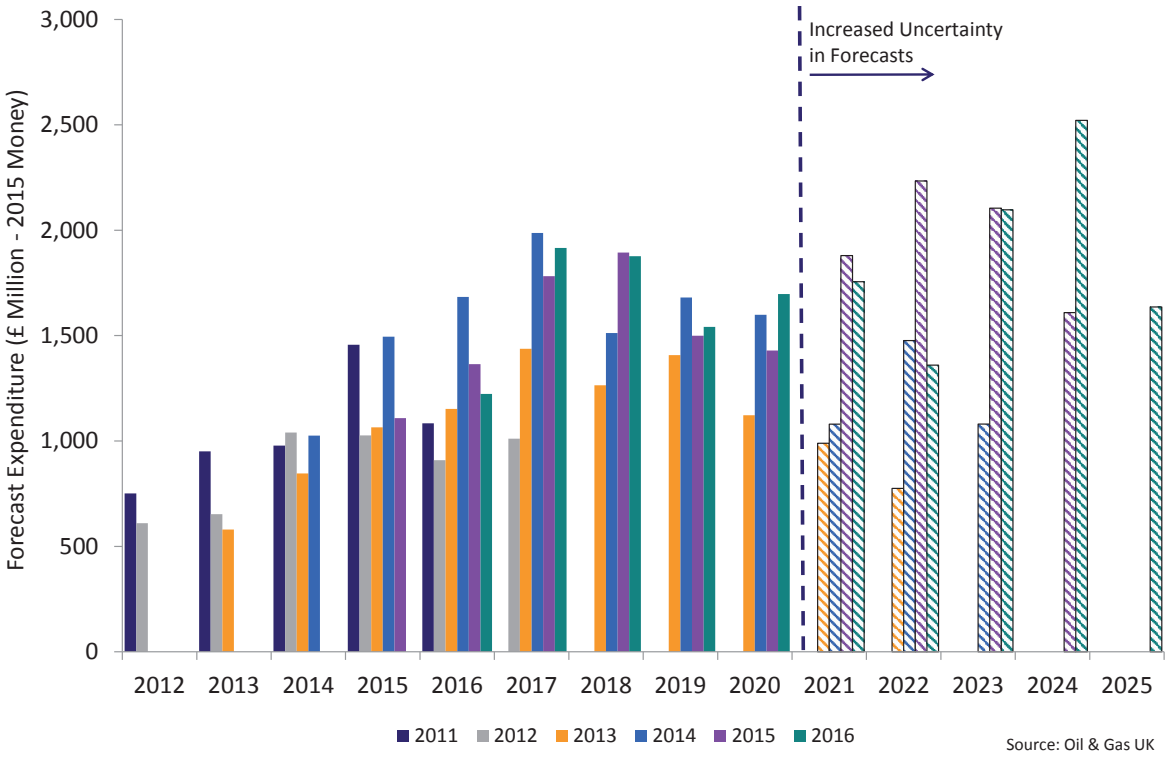
Source: Oil & Gas UK

Historical Comparison of Annual Forecasts

Data for the UKCS from previous *Decommissioning Insight* reports (2011 to 2015) have been used to compare annual forecast expenditure. As illustrated in Figure 34, near-term (2016 to 2019) expenditure forecasts are broadly similar to those in the 2015 report, although a mixture of project deferrals and some projects being brought forward has led to a slight change in the profile. Although expenditure is still expected to rise this year to £1.2 billion, the estimated increase has been revised downwards due to some expenditure slipping over the last 12 months. This means the forecast for 2017 is now almost £2 billion[25].

Over the next ten years, the average annual forecast expenditure is now just under £1.8 billion, an increase on the £1.7 billion reported in 2015. This comes from the inclusion of new projects in the survey, with much of the associated expenditure occurring towards the end of the survey timeframe peaking in 2024.

Figure 34: Comparison of Annual Forecast Decommissioning Expenditure on the UKCS



Regional Breakdown[26]

Looking at the regional breakdown of UKCS decommissioning expenditure from 2016 to 2025, 53 per cent (£9.4 billion) is estimated to be spent in the central North Sea and 30 per cent (£5.3 billion) in the northern North Sea and west of Shetland. The remaining 17 per cent (£3 billion) is allocated to the southern North Sea and Irish Sea, of which over 90 per cent is concentrated in the southern North Sea.

[25] This survey covers data from end-of-field-life decommissioning projects and does not include expenditure or activity associated with mid-life decommissioning.

[26] All forecasts by region and component are rounded and so the sum of them may not come to the total forecast expenditure.

The higher proportion of expenditure in the central and northern North Sea regions reflects the number, size and degree of complexity of projects in these regions. While the number of platforms to be removed is greater in the southern North Sea and Irish Sea, these are typically much smaller installations that are simpler and therefore cheaper to decommission.

Operators start planning for decommissioning far ahead of CoP. The complex decisions on the timing of CoP and the subsequent schedule of decommissioning activity are made by the operator in conversation with industry regulators and take many factors into account, including future recovery potential, tie-back opportunities to existing infrastructure, oil price and the wider business environment.

Analysis has been carried out on the key changes that have taken place on the UKCS since publication of the 2015 report, looking at shifts in both CoP and forecast expenditure. This analysis has been split into two regions – the central and northern North Sea and west of Shetland, and the southern North Sea and Irish Sea.

Central and Northern North Sea and West of Shetland

Seventy-five per cent (114) of the projects on the UKCS are located in these regions. At an individual project level, there have been significant shifts in the anticipated cost and timing of decommissioning projects since forecasts were made a year ago, with the number of projects that have been delayed replaced by those that have accelerated decommissioning.

There has been an increase of £500 million from existing projects that now have a greater proportion of expenditure within the survey timeframe, plus 24 new projects are now expected to be decommissioned earlier bringing a further £1.5 billion of expenditure into the survey timeframe. However, this £2 billion increase has been partially offset by an expected fall in decommissioning costs by £500 million since last year and 14 project deferrals moving an additional £1 billion outside of the survey timeframe. Overall expenditure has increased by a net £500 million to £14.6 billion.

Fourteen projects have been deferred where operators have succeeded in extending field life in line with the statutory obligation to achieve MER UK. These projects range from small subsea tie-backs to larger fields with platforms and multiple subsea tie-backs.

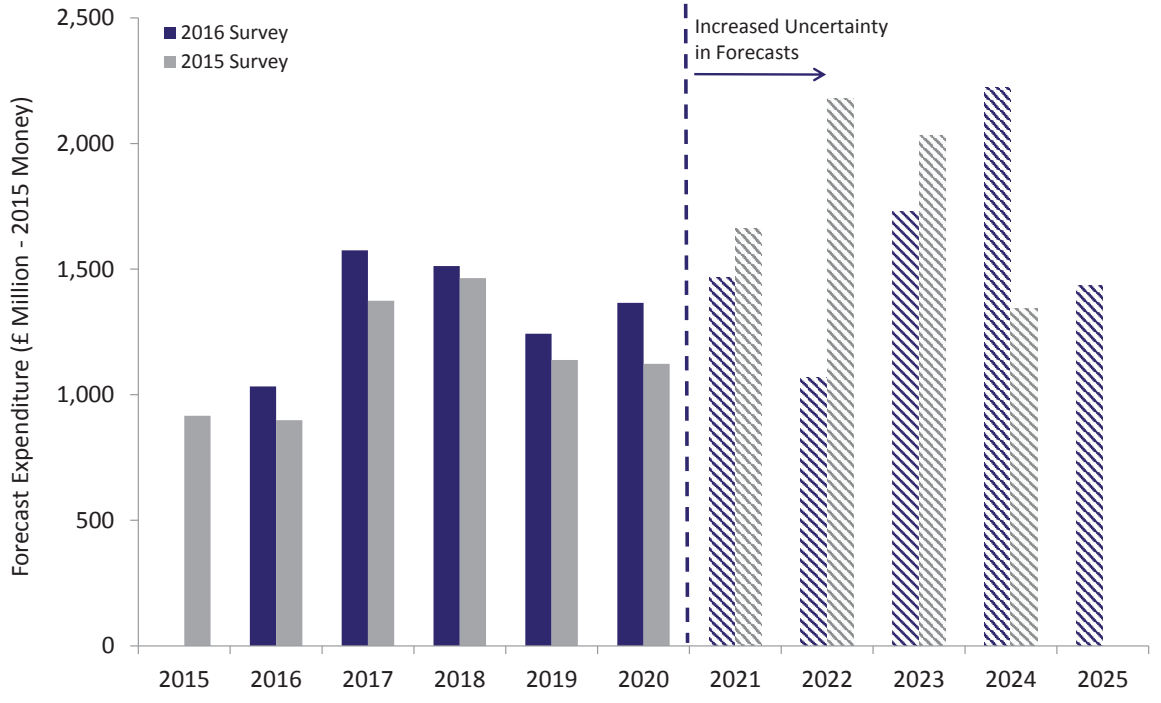
By contrast, 24 new projects are included because CoP and decommissioning dates have moved forward in light of the low oil price environment and a shift in survey timeframe. Many of these are small-scale projects involving single suspended subsea E&A wells or small subsea tie-backs. There are, however, some large new projects involving multiple platform removals.

The associated expenditure has led to an increase in the annual expenditure forecast from 2016 to 2020 in comparison to last year (shown in Figure 35 opposite). By contrast, as several projects have deferred decommissioning activity, the peak year of expenditure has shifted from 2022 to 2024.

For projects included in both this year's and last year's surveys, the majority (87) of assets report no change in planned CoP, while 57 have brought their expected date forward. Operators have cited the low oil price and the knock-on effect of host facilities shutting down earlier than anticipated as the principal reasons for accelerated CoP dates. By contrast, for 19 assets, CoP dates have been postponed due to improved economic outlook or decommissioning being delayed to align with other assets[27].

[27] The number of assets is higher than the number of projects as operators can assign different CoP dates for assets within a project.

Figure 35: Comparison of Forecast Decommissioning Expenditure in the Central and Northern North Sea and West of Shetland



Source: Oil & Gas UK

Southern North Sea and Irish Sea

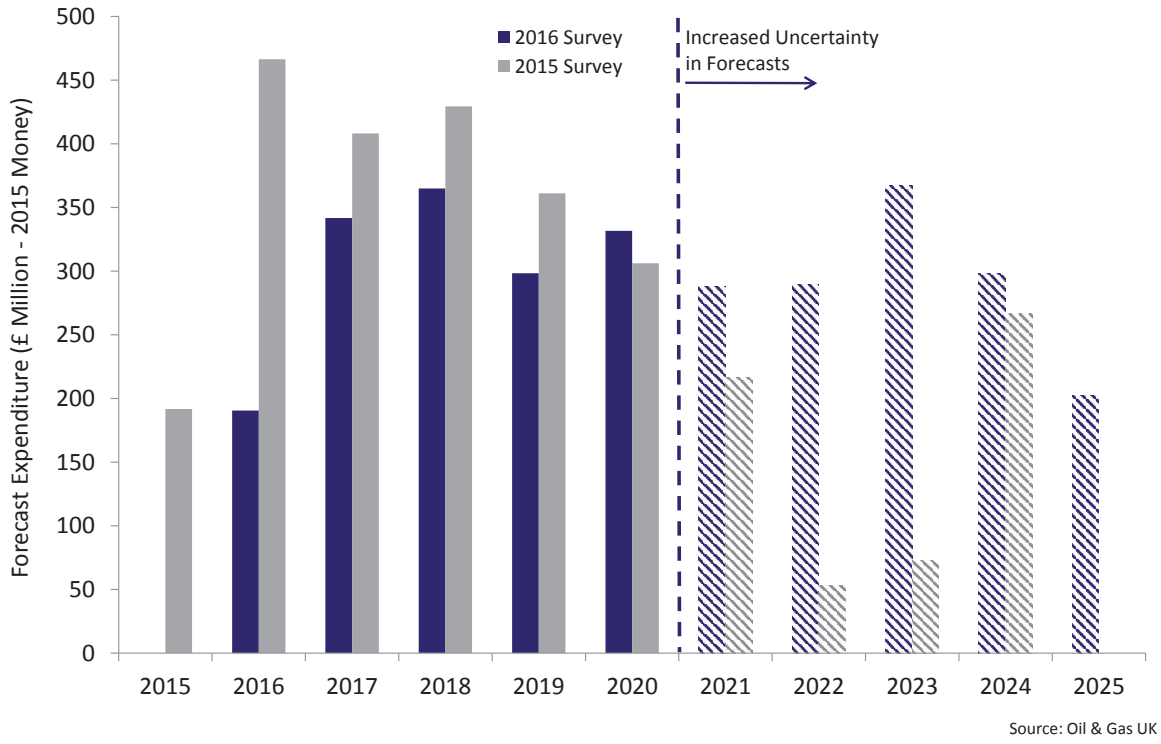
Several changes have taken place in these regions since forecasts were made a year ago. Total forecast expenditure has increased by £200 million to £3 billion over the next decade due to 17 new projects, all of which are platform removal projects with the exception of one subsea tie-back. The net increase in expenditure arising from these new projects totals £550 million, but this has been partially offset by an expected fall in decommissioning costs since last year by a total of £350 million[28]. This reflects lower unit costs for well P&A and for removal costs per tonne as rig and removal vessel rates are deflated amid the global downturn in the industry.

For those projects included in this year's and last year's survey, there has been no change in planned CoP for the majority (48) of assets, although dates have changed for 29 assets, with 15 brought forward and 14 deferred. Increased costs to tie fields back to host facilities, the accelerating CoPs of host facilities and poor results on wells that were drilled to extend field life have all been cited as reasons for earlier CoP.

[28] This conclusion takes into account the difference in survey timeframes.

Overall, Figure 36 shows that near-term expenditure (2016 to 2019) in the southern North Sea and Irish Sea is lower than was forecast a year ago. This can be attributed to the deferral of some activity to preserve cash-flow in the current business climate, larger campaigns spreading their activities across the decade, and lower unit costs for well P&A and removals. The marked increase in forecast expenditure in the latter part of the decade is due to the inclusion of new projects to this year's report.

Figure 36: Comparison of Forecast Decommissioning Expenditure in the Southern North Sea and Irish Sea



Source: Oil & Gas UK

Forecast Expenditure by Decommissioning Component

Decommissioning expenditure is categorised according to the components referenced in the Work Breakdown Structure (see section 3.1 on the survey methodology and the Appendix):

- Operator project management/facility running costs (owners' costs)
- Well P&A
- Removal and other associated activity

The components that incur expenditure are determined by the project size and type. A large and complex decommissioning project, for example, may incur expenditure across all categories. Projects such as these will involve significant overhead costs for project management and operations, as well as requiring substantial engineering expertise, equipment and personnel. In contrast, decommissioning a small subsea tie-back may only involve single well P&A.

Owners' costs are expenses incurred to operate the decommissioning programme post-CoP through to completion. These costs include management of the facility in both the pre-NUI and NUI stages. This covers expenditure associated with logistics, the decommissioning team itself, deck crew, power generation, platform services, integrity management (inspection and maintenance) and specialist services.

As shown in Figure 37 overleaf, owners' costs are forecast to remain relatively stable across the timeframe, with an average annual expenditure of £340 million per year. Expenditure is forecast to increase towards the end of the survey timeframe as activity increases, peaking at £450 million in 2025.

However, owners' costs over the next decade are £300 million less than those outlined in the 2015 report, despite the increase in the level of activity and overall expenditure in this year's survey. This reflects efficiency improvements seen across the industry being projected onto future estimates of facility running costs for decommissioning projects.

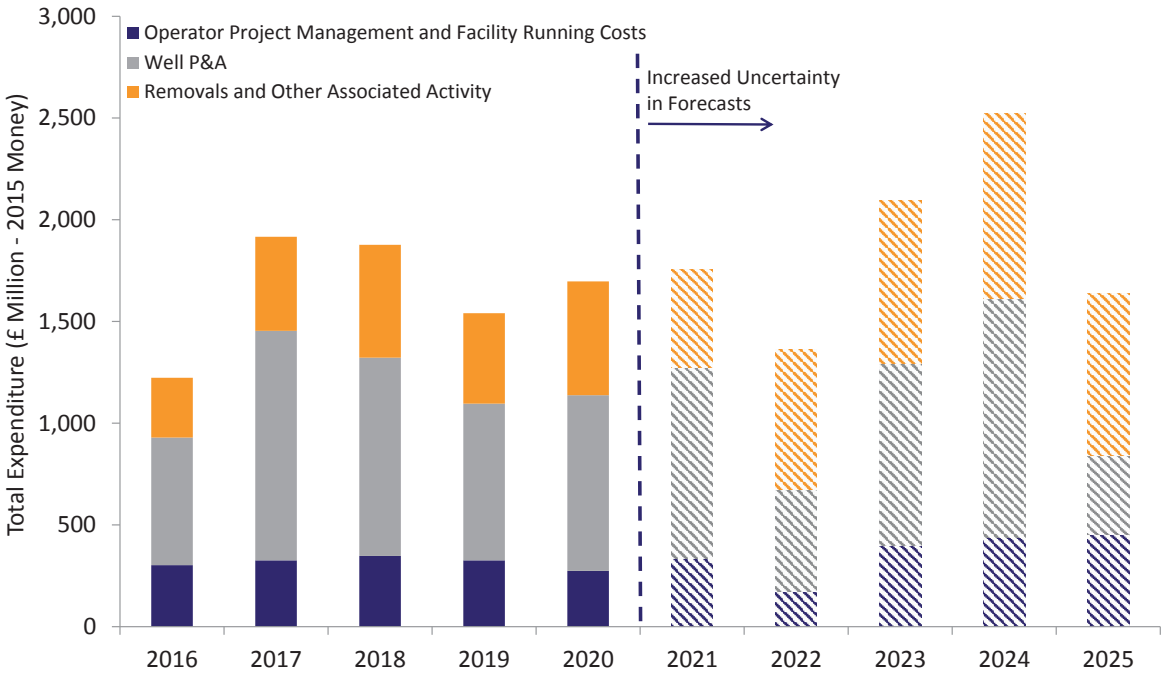
Well P&A costs, meanwhile, include rig upgrades, studies to support wells programmes, project management, operations support, and specialist services such as wireline or conductor recovery. This expenditure is forecast to peak in 2024 at almost £1.2 billion, with an average annual spend of just over £820 million over the next ten years. This compares with an average annual expenditure of £770 million in the 2015 report and £640 million in the 2014 report.

Removal and other associated activity include expenditure on:

- 'Making safe'
- Topsides preparation
- Removal of topsides, substructures and subsea infrastructure
- Pipeline decommissioning
- Transportation and onshore-load in
- Disposal
- Recycling
- Site remediation and monitoring

Expenditure from 2016 to 2025 associated with removal activities is forecast to be lower in the near term, rising year-on-year from just under £300 million in 2016 to a peak of just over £900 million in 2024. Expenditure over the decade has increased by £500 million compared to the 2015 report.

Figure 37: Total Forecast Decommissioning Expenditure on the UKCS by Work Breakdown Structure Category



Source: Oil & Gas UK

	UKCS Expenditure 2016 to 2025
Owners' costs	£3.4 billion
Well P&A	£8.3 billion
Removal	£3.4 billion
Other associated activity	£2.6 billion

In line with previous reports, well P&A remains the largest category of forecast expenditure, accounting for 47 per cent (£8.3 billion) of total forecast expenditure over the next ten years. Owners' costs and expenditure associated with topsides, substructure and subsea infrastructure removal each account for 19 per cent of total forecast expenditure at £3.4 billion each. For subsea projects, well P&A accounts for 65 per cent of the total, compared with 8 per cent for owners' costs (£4 billion total expenditure on subsea projects).

Breaking this down further, of the £8.3 billion expenditure associated with well P&A, 57 per cent (£4.7 billion) is in the central North Sea, an increase from the £4 billion forecast in 2015 due to the additional subsea wells included that are more expensive to plug and abandon.

Ninety-seven per cent (£3.3 billion) of the total owners' costs are concentrated in the central and northern North Sea and west of Shetland. In these areas, platforms are typically manned resulting in much higher facility running costs. Projects are also larger and more complex, with, in turn, higher operator project management costs. The owners' costs account for 31 per cent (£2.5 billion) of expenditure on platform removal projects in these areas compared to four per cent (£118 million) in the southern North Sea and Irish Sea.

Figure 38 overleaf breaks down the total forecast expenditure of £17.6 billion by Work Breakdown Structure component proportion for different project types:

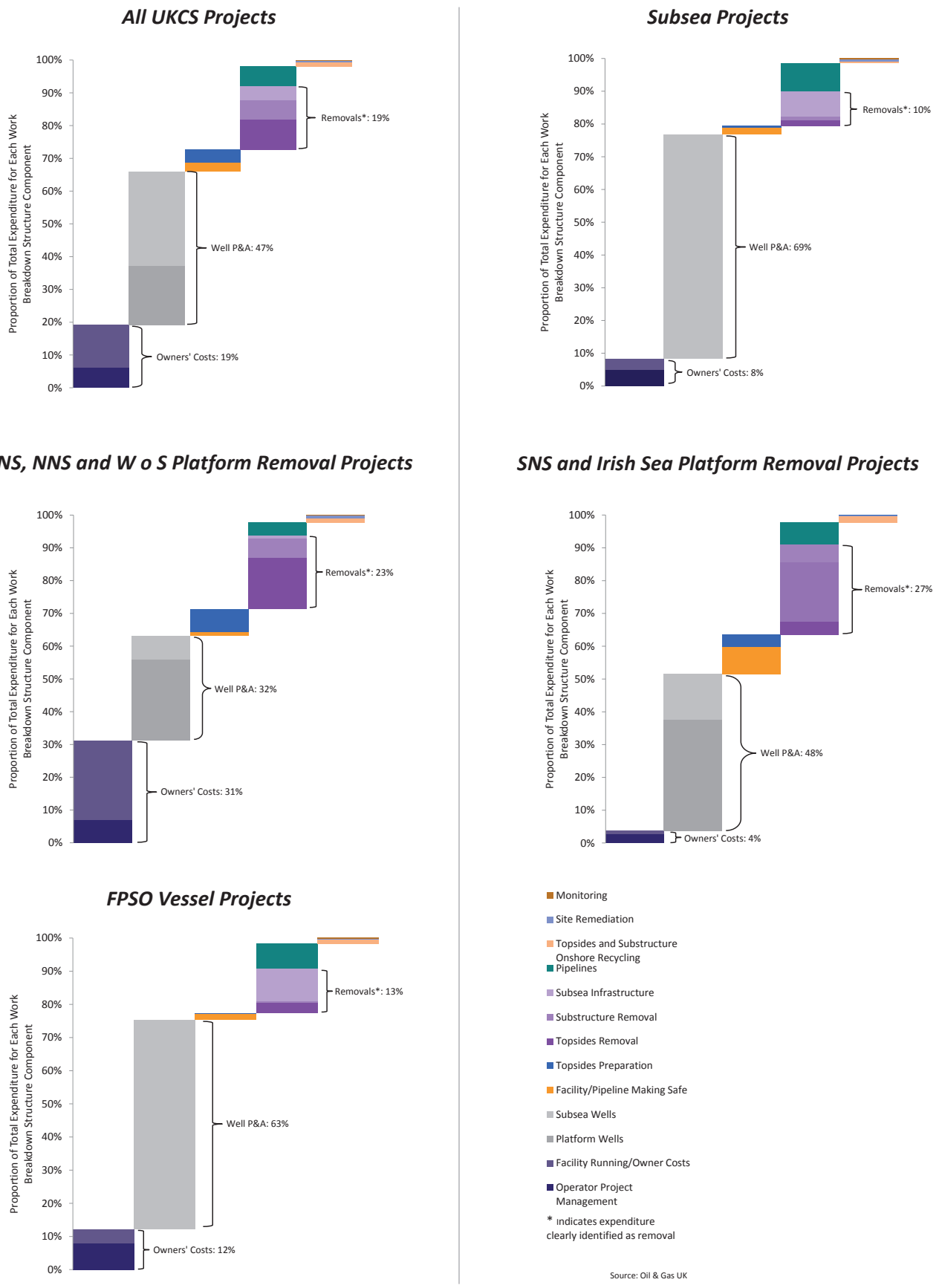
- All UKCS projects
- Subsea projects
- Platform removal projects
- FPSO vessel projects[29]

It is important to note that the graphs only include the breakdown of expenditure that falls within 2016 to 2025. Decommissioning projects can span many years and therefore some expenditure associated with a project may fall outside the survey timeframe.

There are 13 FPSOs forecast to be decommissioned on the UKCS over the next decade, 12 of which are located in the central North Sea. Decommissioning a field serviced by an FPSO primarily involves subsea activity, although some expenditure is also associated with disconnecting the FPSO. Following disconnection, FPSOs are typically relocated or sold for reuse or recycling. These activities are reflected in the breakdown of expenditure seen in Figure 38. The total forecast decommissioning expenditure for fields serviced by an FPSO is £2.6 billion.

[29] Total expenditure for platform removal projects, FPSO projects and subsea projects is £17.3 billion. This does not equal total forecast expenditure because some projects do not fall clearly into one category and therefore have not been used to calculate the Work Breakdown Structure percentage for individual project types.

Figure 38: Total Forecast Decommissioning Expenditure on the UKCS by Work Breakdown Structure Component and Project Type from 2016 to 2025



UKCS	Central and Northern North Sea and West of Shetland	Southern North Sea and Irish Sea	Total
Owners' costs	£3.3 billion	£118 million	£3.4 billion
Well P&A	£4.7 billion (CNS) £2.1 billion (NNS and W o S)	£1.5 billion	£8.3 billion
Facilities 'making safe' and topside preparation	£760 million	£137 million	£897 million
Pipelines 'making safe'	£89 million	£192 million	£281 million
Topside removal	£1.5 billion	£104 million	£1.6 billion
Substructure removal	£544 million	£503 million	£1 billion
Mattress decommissioning and other subsea infrastructure removal	£613 million	£149 million	£762 million
Pipeline decommissioning	£847 million	£193 million	£1 billion
Onshore recycling and disposal	£161 million	£53 million	£214 million
Site remediation	£94 million	£16 million	£110 million
Monitoring	£21 million	£5 million	£26 million

6.2 Key Expenditure Metrics on the Norwegian Continental Shelf

The Norwegian Petroleum Directorate estimates that close to £1 billion will be spent on decommissioning in 2016 on the Norwegian Continental Shelf[30] and that annual expenditure will average at around £1 billion each year until 2020.

A detailed breakdown of forecast expenditure by decommissioning component is not available for the Norwegian Continental Shelf, and operators have instead indicated the proportion of decommissioning expenditure associated with the following four categories for 10 out of 14 removal projects within the survey timeframe.

- Operator project management/facility running costs (owners' costs)
- Well P&A
- Topside removal
- Substructure removal[31]

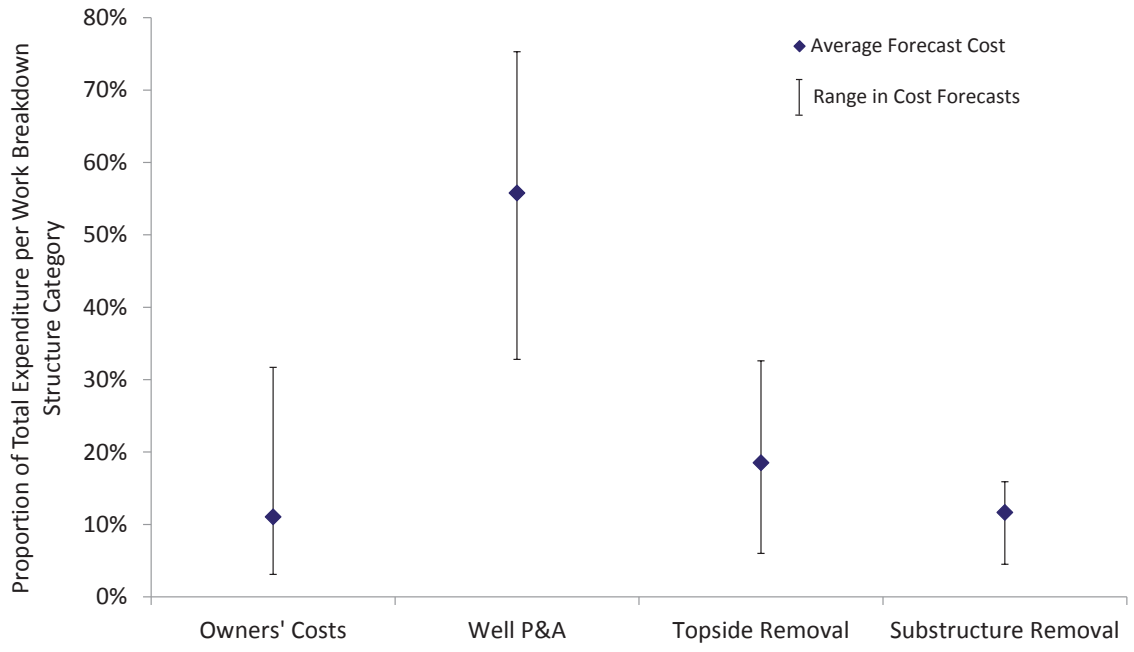
As on the UKCS, the largest category of expenditure is well P&A, which operators estimate to account for, on average, 56 per cent of the total forecast expenditure. Depending on the project, this component ranges from 33 to 75 per cent. Topside and substructure removal together are expected to account for 30 per cent of total expenditure on average, while owners' costs come to 11 per cent.

[30] See Norwegian Petroleum Directorate www.npd.no/en

[31] For some projects, some expenditure is apportioned to other categories of activity in the Work Breakdown Structure, such as pipeline decommissioning, which are not captured here. Total expenditure was not provided.

With the exception of one suspended subsea E&A well in the Norwegian Sea, all of the decommissioning activity over the next decade is located in the Norwegian North Sea region. As illustrated in Figure 39, the proportion of forecast expenditure attributed to each Work Breakdown Structure component varies significantly across the 10 out of 14 platform removal projects that provided data.

Figure 39: Total Forecast Decommissioning Expenditure on the Norwegian Continental Shelf by Work Breakdown Structure Component for Platform Removal Projects



Source: Oil & Gas UK

	Average	Range
Owners' costs	11%	3-32%
Well P&A	56%	33-75%
Topside removal	19%	6-33%
Substructure removal	12%	5-16%

7. Forecast Unit Costs – 2016 to 2025

7.1 Well Plugging and Abandonment

The cost of well P&A depends on a number of factors that differ across the regions of the North Sea. These include water depth, weather, reservoir type, age and, in some cases, measures that may be required to prevent well collapse caused by depressurisation.

The cost estimates included in this report vary significantly in their degree of maturity. While some are informed by previous experience and data from well P&A work that has been carried out, other estimates are at an earlier stage in their development and are inherently more uncertain.

On the UKCS, data from previous *Decommissioning Insight* reports have been used to compare expenditure forecasts for well P&A activity. This analysis shown in Figures 40 and 41 overleaf considers the average and range in well P&A forecasts for each survey year from 2011 to 2016. Platform well P&A is typically cheaper than for both types of subsea wells as it is usually not subject to the same weather constraints or rig requirements and can also be carried out more effectively in batches or campaigns, allowing the operator to share mobilisation costs and other efficiency gains across a number of wells. Furthermore, experienced gained from ongoing platform well P&A has helped to inform future forecasts.

For the first time, operators on the Norwegian Continental Shelf were surveyed on their forecast well P&A costs for projects within the survey timeframe. Figure 42 on p62 shows the average and range in cost forecasts for platform and subsea wells in this region.

Operators have advised that wells at the low end of the cost range are typically simple, rig-less P&As, using wireline, pumping or crane jacks where the reservoir may already have been isolated. Wells at the top end are more complex, rig-based P&As, with challenging access and cementing. They may require retrieval of tubing and casing, milling and cement repairs (see section 5.1 on p18 on rig type for well P&A).

Central and Northern North Sea and West of Shetland

- The average forecast cost for platform well P&A across the decade at £4.1 million per well has not changed since the 2015 report, although the range of estimates has narrowed.

- As 86 per cent of platform wells in these regions are expected to use an integral rig to carry out P&A, the recent reduction in rig rates is unlikely to impact the cost of these wells.

- A wide range in expenditure forecasts for subsea wells in these regions has been reported consistently over the last four survey years, reflecting the variation in the types of wells to be plugged and abandoned.

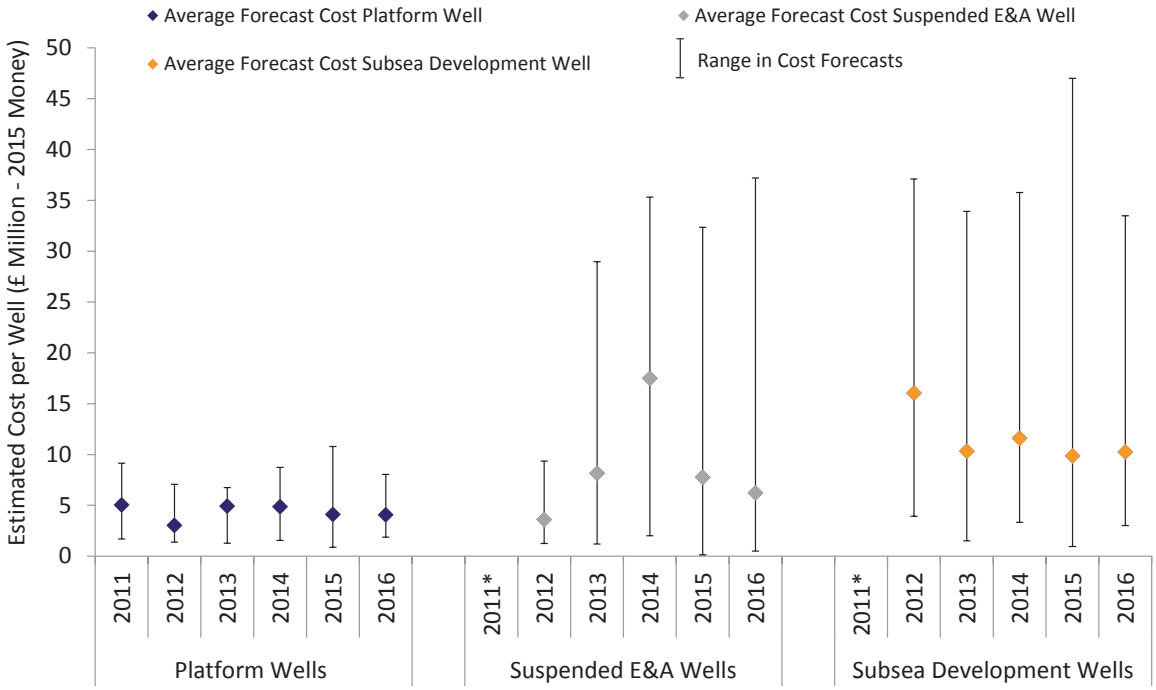
- Average forecast costs for suspended subsea E&A wells have reduced since the 2015 report by an average of £1.6 million per well, although the range in cost forecasts remains wide.

- The same decrease cannot be seen for development wells as the average cost has increased slightly by 3 per cent to £10.2 million per well, while the range in estimates has narrowed.

- Sixty-three per cent of subsea wells in these regions plan to use a semi-submersible rig to carry out P&A. The recent fall in rig rates could explain the fall in forecast unit costs for these wells.

- However, rig rates are only one factor that impacts the cost of well P&A. The number of days to plug and abandon a well is also an important factor, and operators have advised that expected well P&A durations have been revised upwards for some large subsea projects based on data from completed projects and further studies on the condition of the well stock.

Figure 40: Historical Variation in Well Plugging and Abandonment Cost Forecasts in the Central and Northern North Sea and West of Shetland



* Data cannot be split out for subsea E&A and development wells for 2011

Source: Oil & Gas UK

Well P&A	2015 Survey Average	2016 Survey Average
Platform wells	£4.1 million	£4.1 million
Suspended E&A wells	£7.8 million	£6.2 million
Subsea development wells	£9.9 million	£10.2 million

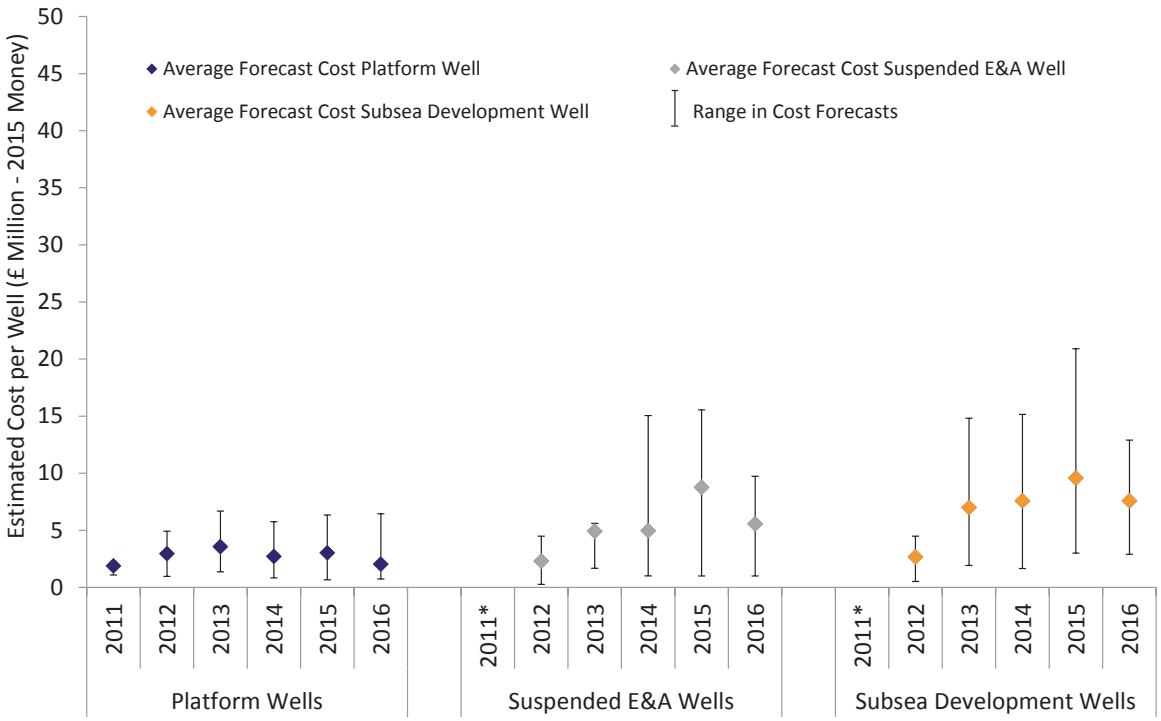
Southern North Sea and Irish Sea

- The average forecast cost per well P&A in these regions has fallen to £2 million per platform well, £5.6 million per suspended E&A well and £7.6 million per subsea development well. The reason for the decrease is two fold: wells included in both survey years are expected to be cheaper to perform than they were a year ago and the new wells included in the survey have cost forecasts at the low end.

- Operators have indicated that reduced well P&A durations and lower rig rates have contributed to the reduction in forecast unit costs. Well P&A durations have reduced over the course of ongoing campaigns, reflected in lower cost estimates for future wells.

- Day-rates for jack-up rigs have fallen by over 40 per cent over the last year – the lower rig rates are likely to be reflected in the cost estimates as 64 per cent of platform wells and 70 per cent of subsea wells in these regions plan to use a jack-up rig for well P&A.

Figure 41: Historical Variation in Well Plugging and Abandonment Cost Forecasts in the Southern North Sea and Irish Sea



* Data cannot be split out for subsea E&A and development wells for 2011

Source: Oil & Gas UK

Well P&A	2015 Survey Average	2016 Survey Average
Platform wells	£3 million	£2 million
Suspended E&A wells	£8.8 million	£5.6 million
Subsea development wells	£9.6 million	£7.6 million

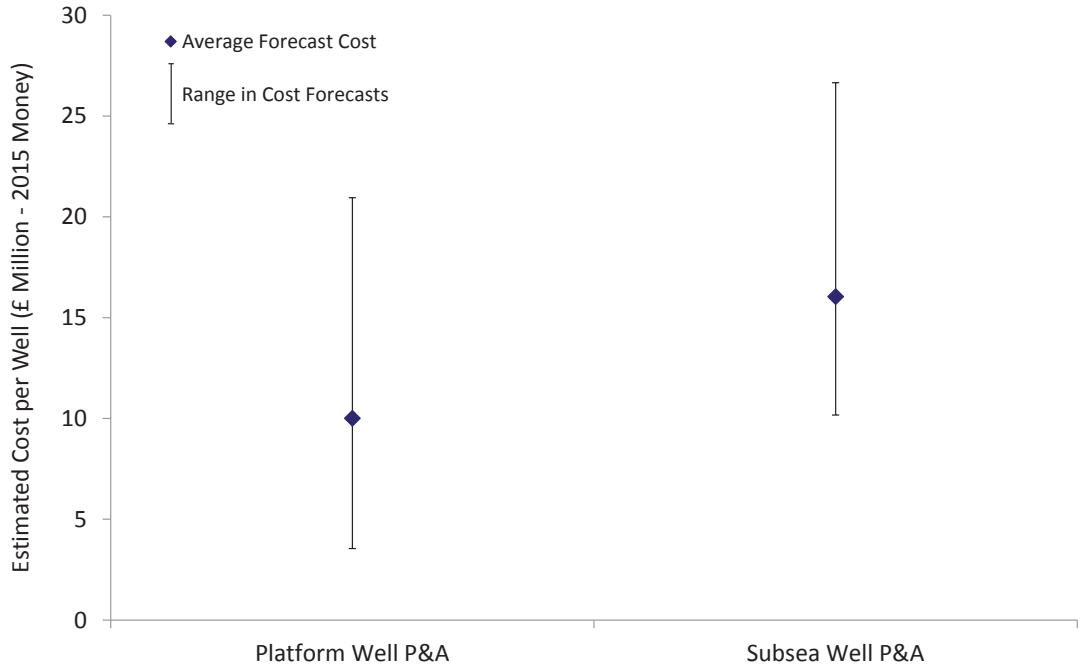
Norwegian Continental Shelf

- The average forecast unit cost for platform and subsea well P&A in Norway is £10 million and £16.1 million, respectively, for the projects included in the survey.

- These cost forecasts are substantially higher than on the UKCS, particularly for platform well P&A.

- The higher cost estimates on the Norwegian Continental Shelf could be due to a number of factors, including different regulatory regimes, higher vessel rates, or the maturity of the estimates. Operators have not indicated the AACE cost classification for estimates on the Norwegian Continental Shelf.

Figure 42: Variation in Well Plugging and Abandonment Cost Forecasts on the Norwegian Continental Shelf



Source: Oil & Gas UK

Well P&A	2016 Survey Average
Platform wells	£10 million
Subsea wells	£16.1 million

7.2 Facilities Making Safe (UK Continental Shelf Only)

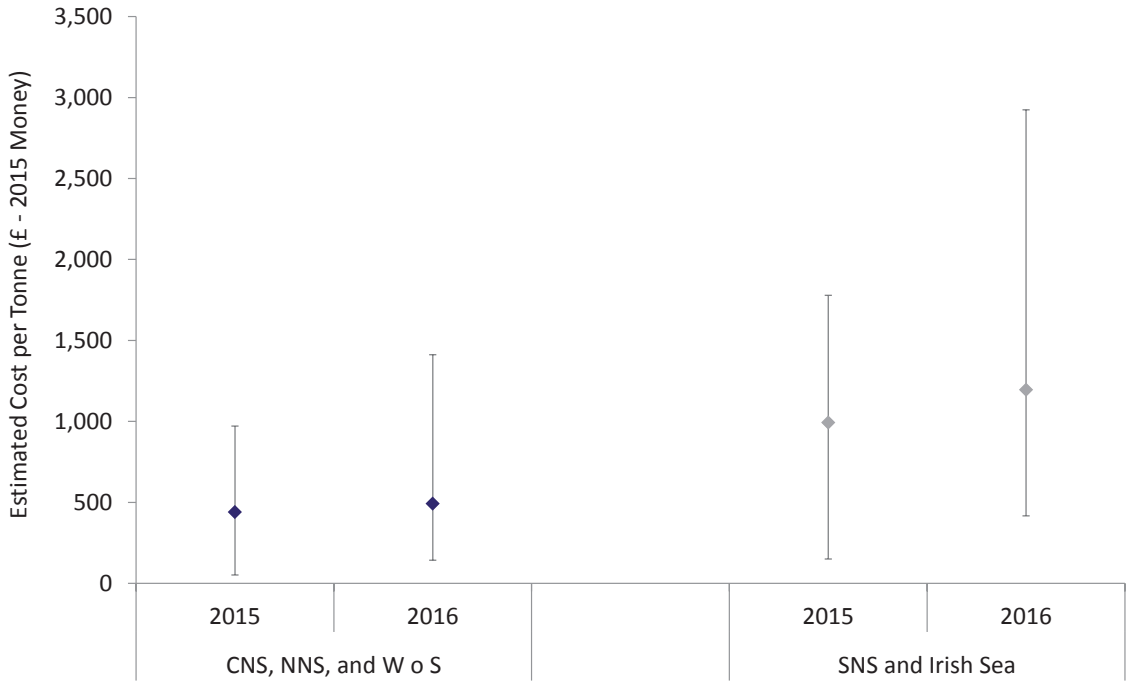
The scope of work associated with 'making safe' is believed to be broadly similar across different platform types. Although activity will typically take longer on larger structures, the fixed costs will be similar, increasing the cost per tonne forecasts for smaller, lighter structures commonly found in the southern North Sea and Irish Sea. Many of the installations in the southern North Sea are smaller NUIs. NUIs require transport by helicopter or an accommodation vessel for a team to carry out 'making safe' activities, adding further cost.

Expenditure at the lower end of the range is in line with those seen in the central and northern North Sea and west of Shetland areas and is likely to be associated with larger, manned platforms.

- The average cost per tonne for 'making safe' is £1,200 in the southern North Sea and Irish Sea compared to just £490 in the central and northern North Sea and west of Shetland.

- The range of cost per tonne forecasts has increased significantly since the 2015 report as new projects fall at the high end of the range.

Figure 43: Historical Variation in the 'Making Safe' Cost per Tonne Forecasts for Topsides on the UKCS



Source: Oil & Gas UK

Facilities 'Making Safe'	2015 Survey Average	2016 Survey Average
Central and Northern North Sea and West of Shetland	£440 per tonne	£490 per tonne
Southern North Sea and Irish Sea	£990 per tonne	£1,200 per tonne

7.3 Topside and Substructure Removal (UK Continental Shelf Only)

The weight of a platform has little effect on some of the expenditure associated with removal, including removal preparation, vessel mobilisation, sea-fastening, transportation and load-in onshore. This can again result in a larger cost per tonne forecast for topside removal for the smallest and lightest structures commonly found in the southern North Sea and Irish Sea. The cost per platform, however, is significantly lower in these regions.

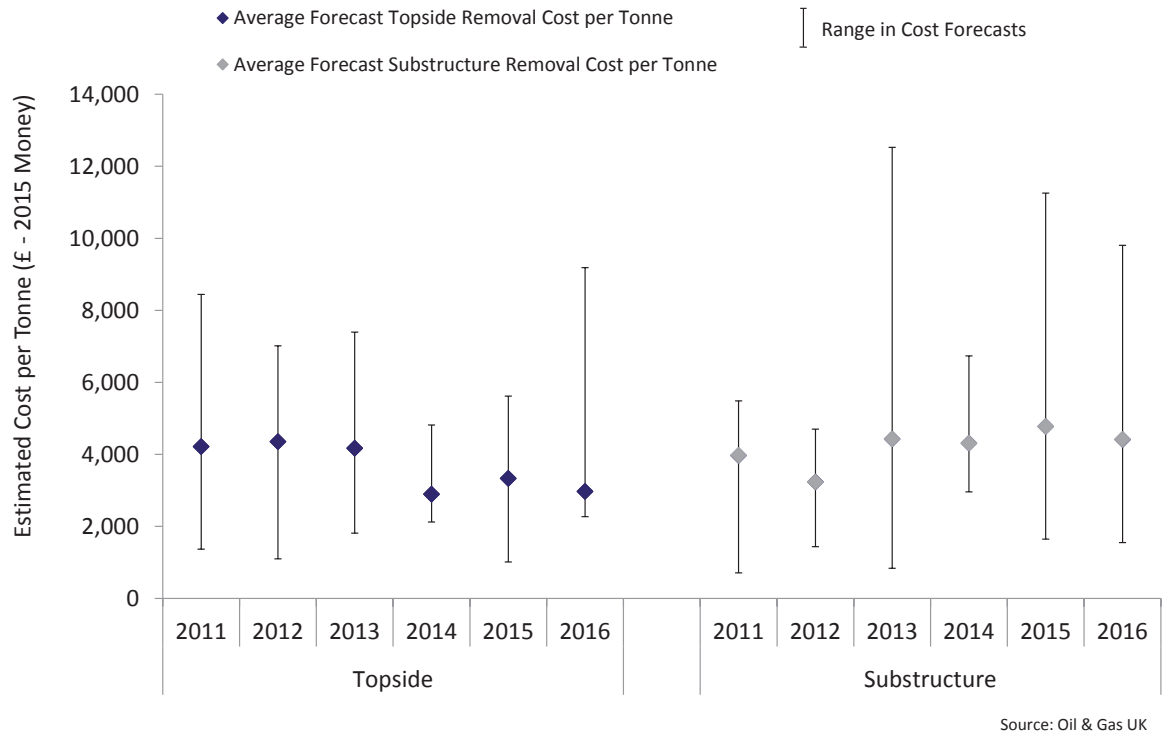
Central and Northern North Sea and West of Shetland

- The average removal cost per tonne forecasts in these regions from 2016 to 2025 has fallen by a smaller amount than in other areas of the UKCS (less than 10 per cent) to £3,000 for topsides and £4,400 for substructures.

- The range in costs per tonne remains high, particularly for substructure removals, due to the variation in substructure types and weights and planned removal methods.

- For the 96 projects classified as provisioning estimates in these regions, the removal method may not yet be determined as operators carry out comparative assessments to determine the best approach. As removal methods become more defined, this can explain the changes in the cost per tonne forecasts from one year to the next.

Figure 44: Historical Variation in the Removal Cost per Tonne Forecasts for Topsides and Substructures in the Central and Northern North Sea and West of Shetland



Source: Oil & Gas UK

Removal Cost per Tonne	2015 Survey Average	2016 Survey Average
Topsides	£3,300 per tonne	£3,000 per tonne
Substructures	£4,800 per tonne	£4,400 per tonne

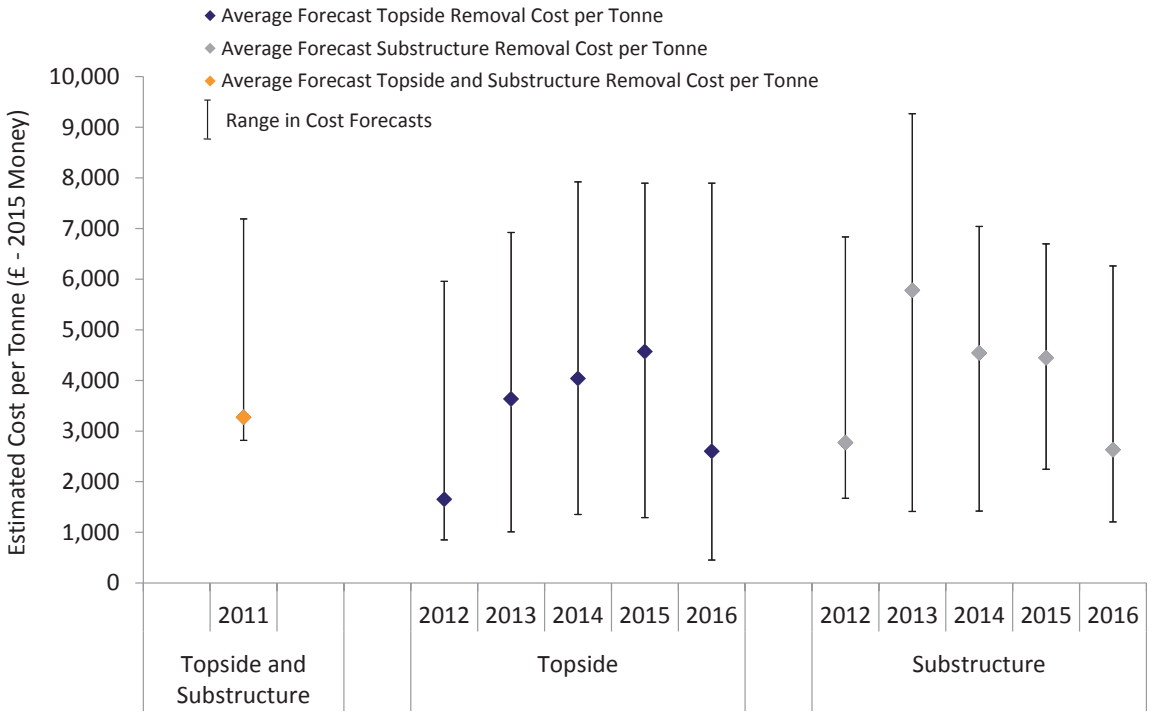
Southern North Sea and Irish Sea

- The average cost per tonne forecasts for both topside and substructure removal have both fallen by over 40 per cent to £2,600 per tonne compared with 2015 forecasts. This is because the new projects fall at the low end of the range and there are lower forecast unit costs for topside and substructure removal reflected in the majority of estimates.

- This could be due to different assumptions about removal vessel day-rates. The supply of removal vessels in these regions is greater than other areas of the UKCS because of the smaller size platforms enabling removal by much smaller barges, driving down vessel rates more than those for large heavy-lift vessels required in the other areas.

- The large range in cost per tonne for both topside and substructure removal seen in the southern North Sea and Irish Sea (see Figure 45 overleaf) is primarily due to varying approaches to platform removals. In these regions, most operators plan to remove multiple platforms in one campaign, allowing mobilisation and other fixed costs to be spread across the structures being removed. Projects at the bottom of the range are typically those included in a batched approach, while those at the top of the range are largely planned as individual removals.

Figure 45: Historical Variation in the Removal Cost per Tonne Forecasts for Topsides and Substructures in the Southern North Sea and Irish Sea



Source: Oil & Gas UK

Removal Cost per Tonne	2015 Survey Average	2016 Survey Average
Topsides	£4,600	£2,600
Substructures	£4,400	£2,600

8. Appendices

A. Work Breakdown Structure and Survey Methodology

Operators were asked to provide expenditure forecasts for the 20 different components of the Work Breakdown Structure outlined in Oil & Gas UK's *Decommissioning Cost Estimation Guidelines*[32]. They were also asked to quantify physical decommissioning activity by components, such as the tonnes of topsides to be removed or the length of pipeline to be 'made safe'.

The *Decommissioning Insight* report has been produced annually since 2011. Although it is possible to compare data across the reports, it is important to note that since 2013 surveys have been modelled on a new Work Breakdown Structure. Historical analysis has therefore only been carried out on comparable categories.

Figure 46: Work Breakdown Structure Categories

Stages - Level 1	
Operator project management	Activities include project management core team, stakeholder engagement, studies to support the decommissioning programme and scope definition/method development, decommissioning programme preparation and decommissioning programme reporting/close-out (admiralty charts, fish safe etc).
Facility running/ owners' costs	Activities include logistics (aviation and marine), operations team, deck crew, power generation, platform services, integrity management (inspection and maintenance) and operations specialist services e.g. waste management.
Well plugging and abandonment	Activities include rig upgrades, studies to support well programmes, well suspension (spread rate/duration), wells project management, operations support, specialist services e.g. wireline, conductor recovery, cleaning and recycling, vessels.
Facilities/pipelines 'making safe'	Activities include operations (drain, flush, purge and vent), physical isolation (de-energise, vent and drain), cleaning, pipeline pigging and waste management.
Topsides preparation	Activities include engineering-up of temporary utilities (power, air and water), module process/utilities separation, dropped object surveys and subsequent remedial actions.
Topsides removal	Activities include removal preparation (reinforcements and structural separation for removal), vessel operations, sea-fastening, transportation and load-in.
Substructure removal	Activities include removal preparation, removal, vessel, sea-fastening, transportation and load-in.
Topsides and substructure onshore recycling	Activities include cleaning and handling hazardous waste, deconstruction, re-use, recycling, disposal and waste management accounting (traceability of all streams).
Subsea infrastructure (pipelines, umbilicals)	Activities include vessel preparation for subsea end-state (remove, trench, rock-dump), sea-fastening and transportation, load-in, subsea project management and waste management accounting (traceability of all streams).
Site remediation	Activities include cuttings pile management, oil field debris clearance (500-metre zone and 200-metre pipeline corridor) and over-trawl surveys.
Monitoring	Activities include navigation aids maintenance and monitoring programme for any facilities that remain.

[32] The *Guideline on Decommissioning Cost Estimation* is available to download at www.oilandgasuk.co.uk/product/op061

B. Association for the Advancement of Cost Engineering Classifications

The five estimate classes in the AACE Cost Estimation Classification Matrix are determined by level of 'project definition' with consideration to a set of secondary characteristics.

	Primary Characteristic	**Secondary Characteristic**		
Estimate Class	Level of Project Definition (expressed as % of complete definition)	End Usage Typical Purpose of Estimate	Methodology Typical Estimating Method	Expected Accuracy Range Typical Variation in Low and High Range
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgement or analogy	L: -20% to -50%H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30%H: +20% to +50%
Class 3	10% to 40%	Budget authorisation or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20%H: +10% to +30%
Class 2	30% to 70%	Control or bid/ tender	Detailed unit costs with forced detailed take off	L: -5% to -15%H: +5% to +20%
Class 1	50% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take off	L: -3% to -10%H: +3% to +15%

9. Glossary

AACE	Association for the Advancement of Cost Engineering
Asset Retirement Obligations	An Asset Retirement Obligation (ARO) is a liability associated with the eventual retirement of a fixed asset. The liability is commonly a legal requirement to return a site to its previous condition.
Barge-launched jacket	Barge-launched jackets weigh between 5,000 and 25,000 tonnes. They are yard fabricated and transported horizontally to the field on a transportation barge, then launched from the barge over rocker beams and upended through controlled flooding. Final positioning may require crane assistance.
Casing	Pipe installed in the wellbore to retain the borehole dimension and seal off hydrocarbon and water-bearing formations. Casing is usually cemented in place to ensure the pipe remains in place. The formation behind the pipe remains intact and flow does not occur in the annulus between the casing and the formations.
Christmas tree	The valves and fittings assembled at the top of a completed well to provide the ability to open and close access to the production tubing and the annuli between the tubing and casing strings and the annuli between casing strings.
CNS	Central North Sea
Coiled tubing	A long continuous length of pipe wound on a spool. The pipe is straightened prior to pushing into a wellbore and rewound to coil the pipe back onto the transport and storage spool.
Comparative assessment	Used to compare options, examine differences and identify the 'most preferred' option in the development of decommissioning programmes for: a) All installations for which derogation is sought under OSPAR Decision 98/31 b) All pipelines being decommissioned under the Petroleum Act 1998 c) All drill cuttings piles that are not screened-out at Stage 1 of OSPAR
CoP	Cessation of Production
Conductor	A large diameter pipe extending upwards from or beneath the seafloor to the top of the well on the platform. The purpose of the conductor is to act as a guide for drilling the well and a protective barrier from the elements for the well casings and tubing during the life of the well.
Drilling derrick	A structure used to support crown blocks and drilling string of a rig.
Decommissioning *in situ*	Leaving infrastructure in place and carrying out appropriate work to ensure that there is minimal risk to other sea users or the marine environment. This could apply to any installed facilities on the seabed, such as pipelines, manifolds, pipeline crossings and the footings of larger jackets.
E&A wells	Exploration and Appraisal Wells
Flexible flowlines	Flexible flowlines usually transport hydrocarbons between subsea infrastructure and the host platform or vessel. They are manufactured from composite layers of steel wire and polymer sheathing that provide protection and flexibility to the flowline.

FPSO	Floating, production, storage and offloading vessel – a floating vessel used by the offshore oil and gas industry for the processing of hydrocarbons, storage of oil and the offloading of the oil either to a tanker or into a pipeline.
Hydraulic workover unit	Remedial work carried out in a well using a mast powered by hydraulic fluid.
Integral rig	Fixed rig installed at the well location, usually self-contained, with steel or concrete legs anchored to the seafloor.
Intervention	Well servicing operations conducted within a completed wellbore to restore or improve production or injection.
Jack-up rig	Self-contained combination drilling rig and barge with legs that can be raised and lowered independently onto the seafloor.
Jumper	A short segment of flexible pipe with a connector half at either end. A jumper is commonly used to connect flowlines and/or subsea facilities together.
Lift-installed jackets	These structures weigh less than 10,000 tonnes and are yard fabricated before being transported horizontally or vertically on a barge to the field. Once at the field, the jacket is lifted from the barge into position using a suitable crane vessel.
Making safe	'Making safe' of facilities includes cleaning, freeing equipment of hydrocarbons, disconnection and physical isolation, and waste management. 'Making safe' of pipelines involves depressurising them and removing any hydrocarbons. Then the pipelines are cleaned and purged, with the cleaning programme based on the specific needs of the system. This may involve the use of pigs, which are maintenance tools used to clean or inspect the insides of pipelines.
Manifold	A manifold in the context of oil and gas production is a pipe to which wells are connected in order to collect, co-mingle and direct fluid flow from more than one well. Such an installation can be on a platform or on the seabed for accumulating several subsea wells. Manifolds can be used for the distribution of fluids for injection into a series of wells.
Mattresses	Mattresses are often used to provide protection, for stabilisation, and as crossover support for pipelines. These comprise flexible blocks linked with rope or wire, or concrete forms or grout bags filled with cement.
MER UK	Maximising Economic Recovery from the UKCS
Milling	A mill or similar downhole tool is used to remove casing in the well where a barrier needs to be installed in case of pressure or potential movement of hydrocarbons behind the casing. The objective is to prevent fluids flowing into another formation or to the surface.
Modular rig	Rig designed in modules that can be lifted onto a platform by crane to be erected on site.
NNS	Northern North Sea
NUI	Normally Unmanned Installation
OGA	Oil and Gas Authority
Over-trawl surveys	Over-trawl surveys make sure the seabed is safe for normal fishing activities to resume.
Pig	A device used to clean pipelines.

Piece-small	The piece-small method involves dismantling the topside and using onshore demolition techniques to produce small, manageable pieces that can be transported onshore.
Production packer	A device installed in a well, used to isolate the annulus and anchor or secure the bottom of the production tubing string.
Project estimate	An approximation of the cost of the total project, developed during project delivery process as the decommissioning method is determined.
Provisioning estimate	Provisioning estimates are those developed for Asset Retirement Obligations and are typically calculated prior to carrying out comparative assessments that determine the decommissioning method to be deployed.
Reverse installation	For reverse installation, the topside modules are lifted separately onto a transportation barge or the deck of the crane vessel before being taken onshore.
Rigid pipelines	Rigid pipelines are manufactured from carbon steel or a high performance steel alloy, with additional coatings providing corrosion protection, stabilisation or, in some cases, insulation. Rigid pipelines transport hydrocarbons between subsea infrastructure and platforms and to shore.
Risers	The portion of a pipeline extending from the seafloor to the surface is termed a riser. The function of a riser is to provide conduit(s) to move produced fluids and/or injection fluids between the seafloor equipment and the production host. Such risers are generally known as production risers in order to distinguish them from other types of risers such as marine drilling risers and completion/workover risers.
Satellite installations	Small, unmanned platforms consisting of minimal facilities (wells, manifolds, and perhaps minimal separation and or testing facilities). These installations are designed to operate in conjunction with a host fixed production platform to provide further processing and onward transportation of fluids.
Sea-fastening	The securing of cargo to a vessel so that movement during transportation does not cause damage.
Self-floaters	These steel jacket structures weigh in excess of 12,000 tonnes and are designed with two large diameter legs for buoyancy during installation. The jacket is fabricated in a construction yard, floated horizontally to the field using the structure's inherent buoyancy, and then upended through controlled flooding. Final positioning may require crane assistance.
Single-lift	The single-lift method involves removing the topside in one piece and may involve extra engineering work to reinforce the topside in preparation for removal.
Semi-submersible rig	Used for deepwater drilling. They have ballasted columns to remain on location by either mooring lines or dynamic positioning systems. Used for exploration and development drilling.
Shallow-water jackets	These structures usually weigh less than 2,000 tonnes and are typically deployed in water depths of 55 metres or less. They include smaller launched and lift-installed jackets, as well as minimum facilities platforms.
SNS	Southern North Sea
Spool	Short segment of rigid pipe with a connector half at either end. A spool is commonly used to connect flowlines and/or subsea facilities together, e.g. a subsea tree to a subsea manifold. On platforms, spools are used to connect pre-installed piping where final connection is performed offshore.

Subsea isolation valves	In relation to wells, these may be referred to as a subsurface safety valve (SSSV). This is a safety device installed in the upper wellbore to provide emergency isolation of the producing fluids in the event of an emergency. Two types of subsea isolation valves are available: surface-controlled and subsurface controlled. In each case, the safety valve system is designed to be fail-safe, so that the wellbore is isolated in the event of any system failure or damage to the surface production-control facilities. In subsea facilities, isolation valves are included in the seabed manifold to isolate wells and piping to protect facilities in the event of an emergency or routine need to prevent fluid flow.
Subsea tie-back	Subsea tie-backs usually connect small reservoir accumulations, developed using subsea trees and manifolds, back to a host platform for onward processing and or transportation.
Trunkline	Trunklines are defined as pipelines with a diameter greater than 14 inches and a length in excess of 18 kilometres.
Tubing	Usually referred to as production (or injection) tubing. This is a pipe inserted in the well to carry and contain the production (or injection) from the reservoir to the surface.
UKCS	UK Continental Shelf
Umbilical	Utility support pipes
Well-scale decontamination	The removal and decontamination of scale build-up that deposits in the tubing of a well during production of reservoir fluids.
Well P&A	Well Plugging and Abandonment
Wellhead	The wellhead is the termination point where the casing strings in the well are supported and provide pressure containment.
Wireline	A form of well intervention that uses an electrical cable to lower tools into the borehole and to transmit data to the surface.
W o S	West of Shetland

OIL&GAS UK

Oil & Gas UK (Aberdeen)
3rd Floor
The Exchange 2
62 Market Street
Aberdeen
AB11 5PJ

Tel: 01224 577 250

Oil & Gas UK (London)
6th Floor East
Portland House
Bressenden Place
London
SW1E 5BH

Tel: 020 7802 2400

www.oilandgasuk.co.uk

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