Net Zero Technology Centre

Technology Driving Transition

Closing the Gap

Technology for a Net Zero North Sea

Full Report

September 2020

Acknowledgements

The team that researched and prepared this report was led by Malcolm Forbes-Cable and included Amy Bowe, David Linden and Kristina Beadle from **Wood Mackenzie**, and Samhitha Udupa, Arnold Bos, Oscar Gámez and Başak Çınlar from **Lux Research.**

In-house sector experts:
Wood Mackenzie: Peter Martin, Benjamin Gallagher, Søren Lassen, Shimeng Yang, Dan Eager, Shashi Barla, Shane Murphy, Sandra Smith.
Lux Research: Arij van Berkel, Michael Holman, Holly Havel.

The project team were supported and advised by the Net Zero Technology Centre team:
Led by Martyn Tulloch with the support of Jason Paterson, Hayleigh Pearson, Emma Swiergon, Dr Vinay Mulgundmath, Neil Wilkinson and Caragh McWhirr.

Industry experts interviewed for the report:
Myrtle Dawes **(Net Zero Technology Centre),** Luca Corradi **(Net Zero Technology Centre),** Gillian White **(Net Zero Technology Centre),** Graeme Rogerson **(Net Zero Technology Centre),** Stuart Young **(ABB),** Roy Stenhouse **(Aker Solutions),** Kjartan Pedersen **(Aker Solutions),** Sam Coupland **(BP),** James Lawson **(Chrysaor),** Robert Barrie **(Chrysaor),** Graeme Wilson **(Chrysaor)** Stuart Duncanson **(Doosan Babcock),** Stephen Cunniffe **(Doosan Babcock),** Professor Stuart Haszeldine **(Edinburgh University),** Professor Mercedes Maroto-Valer **(Heriot-Watt University),** Chris Ayers **(OPEX Group),** Martin McCormack **(Opportunity Northeast),** Andy Rodden **(Opportunity Northeast),** Ralph Torr **(ORE Catapult),** Hugh Riddell **(ORE Catapult),** Steve Murphy **(Pale Blue Dot Energy),** Nigel Holmes **(Scottish Hydrogen and Fuel Cell Association),** Robert Cullen **(Shell),** Matthew Knight **(Siemens),** Robert Stephen **(Siemens),** Katie Abbott **(Total),** Tara Schmidt **(Wood),** Martyn Link **(Wood),** Keith Anderson **(Wood),** Alan Mortimer **(Wood).**

Production and design team:
Wood Mackenzie: Craig Unsworth, Ross Pollock, Steve Robertson-Pool, Pari Karani, Katrina Melvin, Susan McGurk.

The Net Zero Technology Centre would like to thank the Scottish Government and Chrysaor for contributing to this study as core funding partners.

Net Zero Technology Centre
Technology Driving Transition

Wood Mackenzie
A Verisk Business

Lux Research

Scottish Government
Riaghaltas na h-Alba
gov.scot

CHRYSAOR

Foreword

Solutions that deliver incremental improvements are always valuable, but with less than 30 years left to achieve our net zero goals, it is critical we focus on the big priorities – and move fast. So, this study focused on identifying the technologies that would really move the dial to create a net zero North Sea.

In recent months, much has been written about the need to accelerate the transition to a lower carbon and ultimately net zero energy system. Big companies have pivoted their strategies, regulators have set out their visions of the future and governments have provided targeted support. Now we need to make it happen and technology is critical.

At the Net Zero Technology Centre, our mission is to develop and deploy technologies that enable a net zero energy system, investing alongside companies, governments and innovators. We're focused on supporting the oil and gas sector as it transitions to a net zero future, recognising how critical its expertise is for the net zero energy system, and working with a range of other sectors from renewables and marine to defence and aerospace.

We try to be holistic in our approach, creating alliances and partnerships to tackle big technology challenges. This study provides valuable insights to help identify the key innovation gaps, shape our roadmap and projects and direct our future investment. There are several clear areas that need to be unlocked.

We need to invest in technologies that reduce oil and gas operational emissions. Creating offshore power grids and infrastructure to electrify platforms is critical – both power from shore and from offshore wind. At the same time, new solutions are required to prevent routine venting and flaring, and significantly reduce methane leaks.

With the rapid growth of fixed-bottom offshore wind power, the UK has become world-leader in offshore power production, but we have not capitalised on the investment in job creation or manufacturing capability. To become the leader in floating offshore wind technology we must seize the opportunity to build design, manufacturing and installation capability, to standardise turbine design, invest in a next generation of transmission infrastructure and pioneer new energy storage solutions.

There's a lot of talk about the UK becoming a hydrogen economy but progress has been painfully slow. We need to accelerate new technologies that effectively halve the cost of hydrogen – solutions to separate hydrogen from carbon dioxide for blue hydrogen and saltwater electrolysis for green hydrogen generation offshore alongside wind farms.

For carbon capture, utilisation and storage, the real challenge is the lack of a feasible commercial model. However, technology can help with the economics. We need to tackle the technology risks, innovate to cut the costs of existing technology and look for new incremental solutions to increase the pace of deployment.

Reimagining the North Sea as an integrated energy system is essential for the UK and Scotland to achieve their net zero ambitions. But we need to invest now to close the gap on the key technologies needed to make this ambition a reality. We need to partner cross sector and share our skills and capabilities for the greater good of the UK.

With decades of energy expertise this country has a huge opportunity to become a leading manufacturer, designer, installer and operator of next generation energy systems. This is where governments and industry should focus investment at pace in the coming years.

Colette Cohen OBE
CEO, Net Zero Technology Centre

Executive Summary

The unique attributes of the UK Continental Shelf (UKCS) and the UK's advanced energy sector give the region a head start in developing net zero industries. Investing in low carbon technologies and establishing an integrated energy system will be pivotal to achieving the legally binding net zero 2050 target for the UKCS and the wider economy.

As the UKCS transitions, oil and gas will naturally deplete, but this will be more than offset by growth in offshore renewables, hydrogen and carbon capture, utilisation and storage (CCUS). This could more than double the economic impact of the UKCS, contributing £2.5 trillion to the UK economy and creating over 200,000 new jobs.

Creating an integrated energy system on the UKCS requires investment of £430 billion, with £270 billion expected to be spent in the UK. Over the next 15 years, the investment profile is dominated by oil and gas and offshore wind, each requiring £75 billion in capital investment, around half of which is expected to be spent in the UK.

As climate change policy progresses not only in the UK, but also in Europe and further afield, there will be an increasing number of opportunities for the UK to export low carbon technologies, products and expertise, emulating the success of the oil and gas sector. To realise this opportunity we need to invest with pace.

Key findings

More investment is needed in oil and gas emissions reduction technology

Additional investment is required to make oil and gas operations more efficient and reduce emissions. The key innovation gaps are in platform electrification, methane leak detection and prevention, flaring mitigation and advanced subsea developments.

Offshore wind will make a massive contribution, but technology innovation is still required

While fixed wind is expected to play a crucial role in meeting the country's net zero targets, significant opportunity remains to innovate across many areas including developing larger blades and taller towers, automated inspection technology and innovative recycling and decommissioning options.

UK must tackle innovation gaps to become a global leader in floating offshore wind

The UK can become a global leader in floating offshore wind but critical innovation gaps such as robust dynamic cabling and mooring systems must be addressed to unlock this potential. Optimising and standardising floating wind foundation designs with a specific focus on UKCS meteorological and bathymetric conditions will be crucial if the full potential of the basin's offshore wind resource is to be harnessed.

Blue hydrogen can play a key role, especially if existing technology can be enhanced

Blue hydrogen needs improved yield and enhanced CO_2 capture efficiency to make it commercially viable, with opportunities to innovate in both hydrogen membranes and CO_2 sorbents. Alternatively, novel hydrogen concepts such as plasma-based processes may offer disruptive solutions.

Technological innovation will be critical to reduce the cost of green hydrogen generation

Developing cost-effective saltwater electrolysis technology is essential to unlocking the potential of green hydrogen. Producing durable electrolyser catalysts materials and creating combined subsea electrolysis and compression systems are areas of particular promise.

Hydrogen transportation and storage offer opportunities to leverage oil and gas knowledge

Repurposing the existing offshore pipeline network to convey hydrogen offers opportunities to develop innovative pipeline re-lining techniques and leak detection devices, while underground storage in either salt caverns or depleted hydrocarbon fields requires research across many areas, including reservoir rock reactivity and modelling hydrogen migration through water-filled porous media.

Hydrogen fuel cells could be used to provide low carbon power to offshore assets

Fuel cells could help to power field production operations if provided with a sufficient fuel supply or a connection to nearby hydrogen pipelines. To make this efficient, fuel cell catalyst materials need to be made more durable and less costly and fuel cell manufacturing techniques need to be optimised.

Significantly reducing the cost of carbon capture technology will drive growth and scale

Reducing the cost and improving the efficiency of carbon capture technologies, from the solvents and sorbents to membranes and conversion solutions, will improve feasibility and could also lead to more scalable, accessible direct capture technology.

CO_2 storage requires innovation across many fronts

To fully realise the CO_2 storage potential of the UKCS, technological innovation is needed to better model and understand CO_2 behaviour after injection. Developing compact CO_2 processing plants and subsea separation and injection equipment offers opportunities to drive down costs, while the disruptive potential of numerous carbon utilisation technologies should not be overlooked.

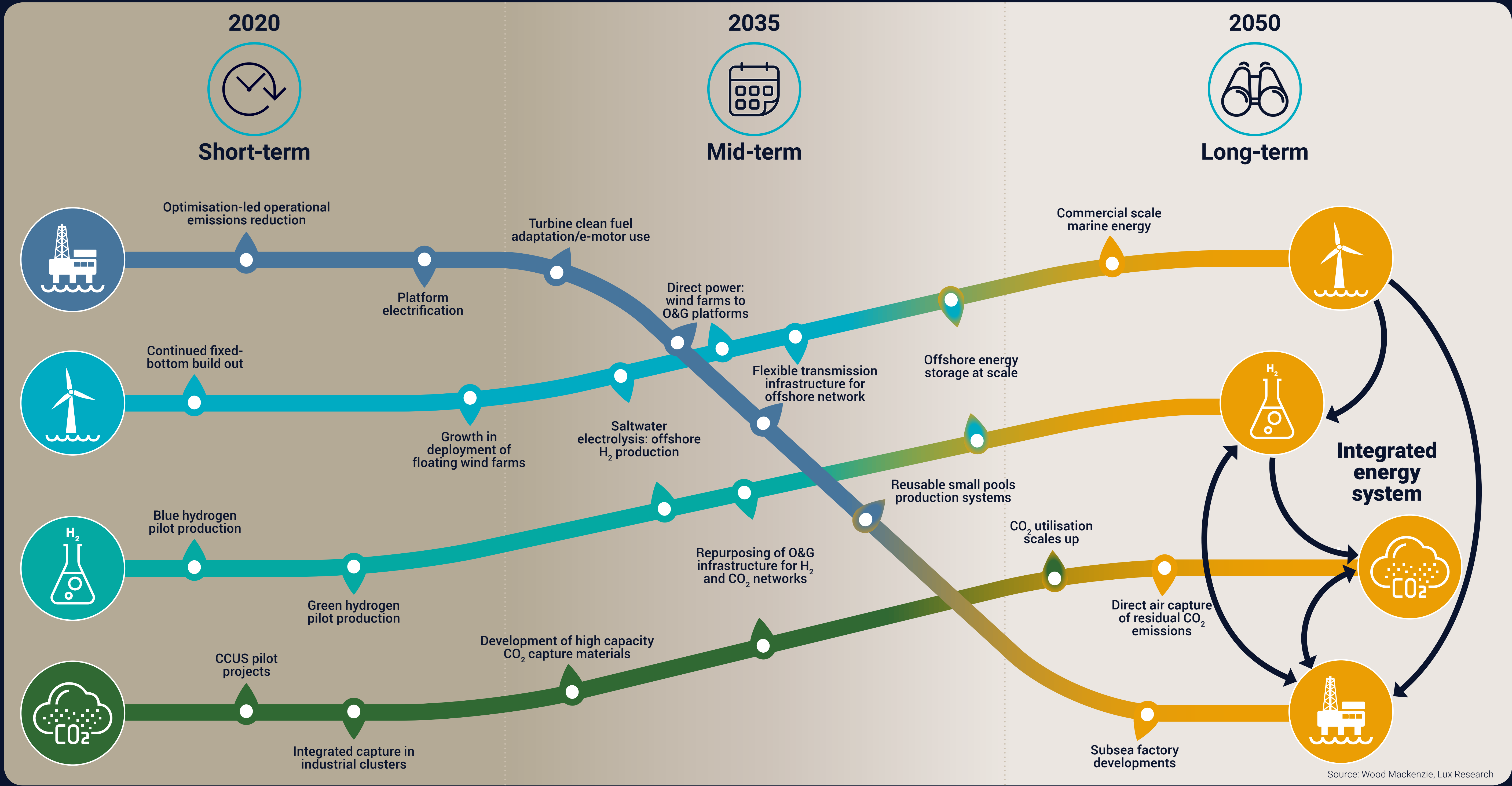
Other renewable energy technologies could have a role to play on the UKCS

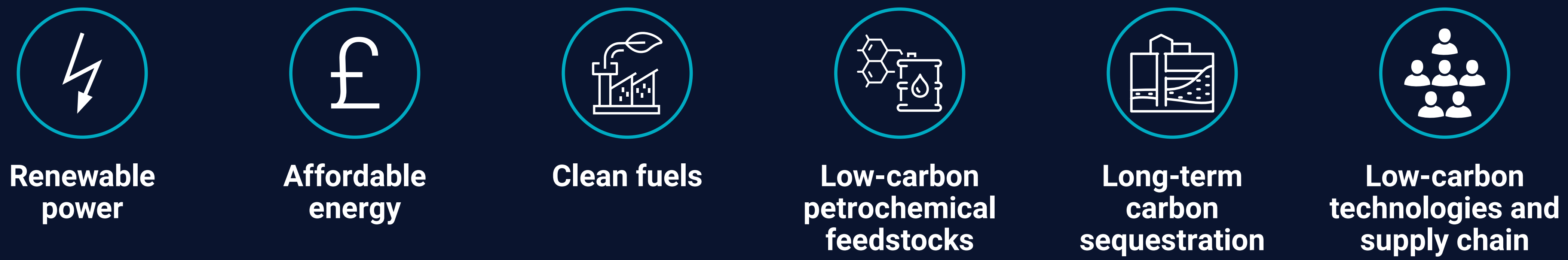
Technological innovation is essential if the abundant wave and tidal resource available across the UKCS is to be harnessed. In marine energy, innovation is required to develop economically feasible power take off technologies and foundations and support systems; in floating solar, enhancing existing systems to cope with harsh UKCS conditions could add another option in the UKCS renewable energy portfolio.

Understanding and managing interdependencies is critical to creating a net zero UKCS

Delivery of an integrated UKCS energy system has many critical interdependencies, and a clear and cohesive strategy is needed to ensure that technological innovation, regulation and policy are aligned and harmonised. Additionally, digital technologies need to be leveraged across the oil and gas, renewables, hydrogen and CCUS sectors in order to create an efficient and coordinated integrated energy system on the UKCS.

UKCS technologies: roadmap to achieving a net zero integrated energy system





Requirements and benefits of achieving an integrated net zero UKCS

Oil and gas

- **Platform electrification, methane leakage detection and flaring mitigation** will be key for emissions reduction.
- **£80 billion of capital investment*** will be spent in the UK between 2020-2050 to ensure production targets are met and offshore emissions are reduced.
- The offshore oil and gas industry could have a **total economic impact of £900 billion** on the UK economy between 2020 and 2050.

Offshore Renewables

- **Abundant wind potential and significant development momentum** means offshore wind is on track to meet the CCC's target.
- Achieving the 75 GW 2050 target will result in **£60 billion of capex*** being invested in UK industries such as construction.
- By 2050, the offshore renewables industry could support **150,000 jobs** and have generated an **economic impact of £600 billion.**

Hydrogen

- Challenges around **hydrogen transport and storage** need to be overcome to allow a hydrogen economy to develop.
- **Over £70 billion of UK based capital investment*** is required to meet the CCC's target of 270 TWh of hydrogen demand in 2050.
- Development of a hydrogen economy could support more than **100,000 jobs** in 2050 and have a total **economic impact of £800 billion** between now and 2050.

CCUS

- The biggest barrier to CCUS development is the **lack of feasible business model.**
- **Upwards of £60 billion of UK capital investment*** is needed to meet the CCC's 176 $MtCO_2$/yr CO_2 capture and storage target.
- The CCUS industry could generate **a total economic impact of £200 billion** between 2020 and 2050 and create **15,000 new jobs.**

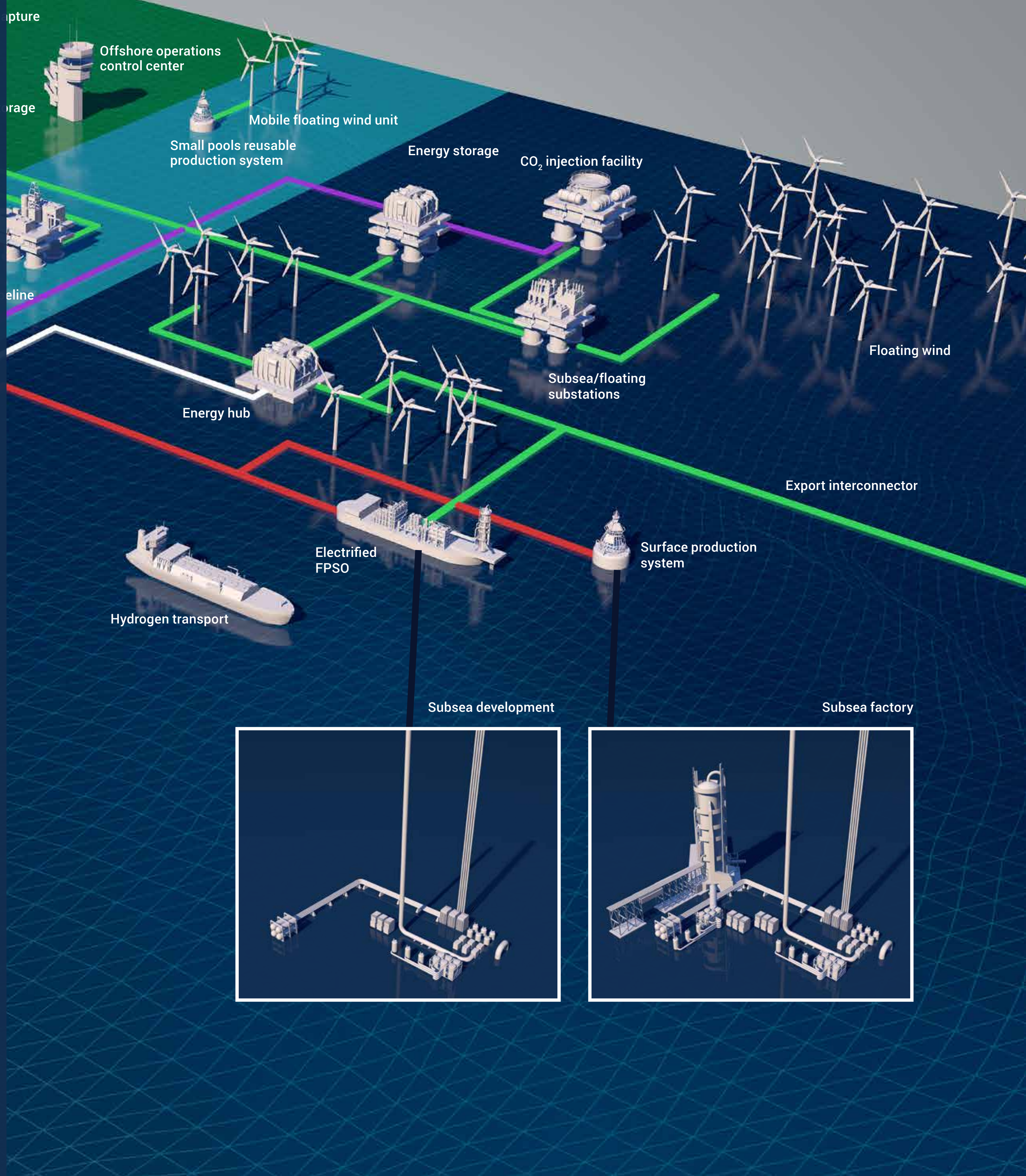
Economic Impact

- **Over 200,000 new jobs** could be created across the UK through the growth of offshore renewables, hydrogen and CCUS.
- **Over £430 billion** of capex is required between 2020 and 2050 to meet the CCC and OGUK targets, the UK content of this is expected to be around **£270 billion.**
- An integrated UKCS energy system could generate **£36 billion per year in revenue by 2050** through the domestic sale of products and services.

*UK content of capital investment. For full capex see section 6.1.

UKCS integrated energy vision **2050**

Schematic view of what an integrated UKCS energy system could look like in 2050



Technology Challenges

Short-term challenges

Offshore power grid management

Integrating offshore wind developments with existing and planned offshore oil and gas operational power demand via interconnected infrastructure could enable the critical electri cation of oil and gas installations, while at the same time facilitating stable low-carbon electricity supply to the National Grid. Power grid costs can be shared between oil and gas, wind farm, energy storage and transmission operators. However, to unlock this prize, technological innovation is required at both system and individual technology level.

CCUS

While coordinate nancial and policy support will be necessary to create favourable conditions to kick-start the CCUS industry, reducing the cost of carbon capture, transportation and storage technology will be essential to ensuring that the costs of implementing CCUS are minimised. Today's high capex costs associated with the development of CO_2 capture, transportation and storage infrastructure offer many opportunities for both evolutionary and disruptive innovation.

Hydrogen innovation

For hydrogen to play a key role in reaching net zero targets, a hydrogen supply chain needs to be in development before 2035. This requires a concerted and coordinated effort to develop economically viable solutions across the end-to-end hydrogen economy – from production, though transport and storage, to end use. The opportunity to develop blue and green hydrogen production technologies, alongside novel transportation and storage solutions, offers an unparalleled opportunity for the supply chain to seize a position at the vanguard of this nascent international market.

In order to stimulate demand, there is a need for clear incentives for low-carbon hydrogen in order to develop suf cient demand in onshore industries, including transportation, domestic or industrial heating, or even hydrogen or CO_2 derived materials, chemicals and fuels.

Long-term challenges

Digitalisation

A reliable and connected data infrastructure, combined with widespread use of data analytics and control, will be essential for the ef cient delivery of low carbon energy from the UKCS. Digital technologies will initially promote operational and energy ef ciency. As an integrated energy system develops, unmanned and autonomous digital facilities within each industry will need to be connected. This requires ensuring data interoperability across the different components in the energy system and strong communication infrastructure. Maintaining the highest possible level of cyber security between assets and operations centres onshore will remain critical tasks in any digital system.

Energy hubs

Energy hubs which combine operation, production, storage and transport of the four energy industries key to the UKCS' future will be the cornerstones of an integrated energy system. In order for these hubs to be deployed optimally, innovation is required across all four sectors, for example eliminating methane leaks, reducing the cost o oating wind foundations, optimising blue hydrogen production and better understanding CO_2 reservoir behaviour. All infrastructure developed for and around such energy hubs will also need to consider end-of-life, with designs that allow for easy decommissioning or repurposing.

Storage and transport

Energy storage and transport will be crucial to safeguarding the UK's energy supply. Developing the technology to reliably identify and deliver suitable geological options for long and medium term energy storage will be critical to ensuring that system costs are minimised. Repurposing the existing offshore infrastructure, and constructing new purpose-built infrastructure, will require innovation in materials, equipment, installation methods and renovation techniques.

Contents

1

Introduction

2

Sizing up the UKCS on the Road to Net Zero

3

Closing the Gap to 2050 Technologies

4

Integrated Energy System Roadmap

5

Benefits to the UK: Economic impact of achieving net zero targets

6

Unlocking the Potential

7

1

Introduction

1.1: Project Vision

The Project Vision was created at the start of the work through a cross-sector workshop with more than 30 industry representatives. Its purpose is to provide context to what net zero UKCS means, highlighting the most important characteristics. This statement gave the project team a shared understanding of what a net zero UKCS means beyond the balance of emissions.

To develop the UKCS into a net zero integrated energy system that will sustain the offshore sector's critical role in the nation's economy, energy infrastructure and secure supply of affordable energy.

The UKCS will play a pivotal role in meeting the national net zero target delivering sustainable energy and leading the way on carbon sequestration.

This transition will harness the unique qualities of the UKCS. That is, world-class oil and gas and renewables sectors, with abundant natural resources, connected to substantial domestic and international markets. Integral to achieving the net zero target, will be the development of new businesses that supply skills, services and technologies to the UK and global energy markets. The energy industry will work collaboratively with other UKCS stakeholders to ensure the sustainable use of offshore resources while reaching the net zero target.

1.2: Introduction to Closing the Gap — Technology for a Net Zero North Sea report

In May 2019 the Committee on Climate Change (CCC) recommended that the UK should legislate as soon as possible to reach net zero greenhouse gas emissions. As a result, the Climate Change Act 2008 was amended in June 2019, committing the UK to reducing carbon emissions by at least 100% of 1990 levels (net zeroby 2050 and to work to reduce global emissions. In doing so, the UK became the rst major economy to pass a net zero emissions law. Soon after, in September 2019, the Scottish parliament passed the Climate Change Act which commits Scotland to achieving net zero emissions by 2045. In June 2020 the UK's offshore oil and gas industry then committed to cutting operational emissions 50% by 2030, 90% by 2040 and to achieve net zero production by 2050.

These new targets require a radical change to the way we produce and consume energy and resources. Technology will enable this transition by reducing emissions from current operations and providing new sources of clean energy.

For decades the offshore oil and gas sector has been at the heart of the UK economy and while this will continue to be the case, the types of activities and their operations in the UK will need to be transformed. UKCS has long been synonymous with oil and gas, but in the coming years and decades, it will become just one part of a diverse mix of renewable energy, clean fuels and carbon storage.

The Net Zero Technology Centre leads research into technology development on the UKCS. In 2019, in partnership with industry, it created the Net Zero Solution Centre to accelerate the development and deployment of technologies to decarbonise offshore operations. In support of Roadmap 2035, it aims to develop the UKCS into the first net zero oil and gas basin globally. This initiative has been a springboard for cross-sector engagement between the oil and gas, renewables, hydrogen and CCUS sectors, among others. While these sectors have predominantly operated in isolation to date, far more joined-up working will be needed to meet the UK's net zero commitments. This will require integrated thinking.

To support the progression of an integrated energy vision for the UKCS – a vision dependent on technology development – the Net Zero Technology Centre identified the need for a review and analysis of the technologies that will be required to realise a net zero future. This Closing the Gap — Technology for a Net Zero North Sea study addresses that need. It is a cross-sector analysis highlighting the technologies that will be instrumental in achieving a net zero UKCS. The focus is on technologies that can contribute the most to achieving this goal in the key offshore sectors – oil and gas, renewables, hydrogen and CCUS – and the innovation gaps that will need to be closed.

Part one of the study (Sizing up the UKCS on the road to net zero) establishes the current position in each sector. From there, we have developed a technology roadmap (Closing the Gap to 2050 Technologies) that prioritises and assesses each technology's potential contribution and the extent of the innovation gaps that need to be closed. Using the CCC's 2050 targets and the industry's Roadmap 2035 as a guide, our report identi es and assesses the key technologies that can play a role in achieving the UK's net zero targets and because our report takes a 30-year view across the energy system, there are a large number of options to consider.

Th nal part of the study evaluates the economic impact for each sector (Bene ts to the UK: Economic Impact of the Roadmap) and how this will evolve over the next 30 years, highlighting the investment that will be required and the job creation potential of each technology. While the net zero target is the key driver of this analysis, the economic bene t of developing these low-carbon sectors, both in terms of domestic economic impact and export potential, is a primary consideration.

2

Sizing up the UKCS on the Road to Net Zero

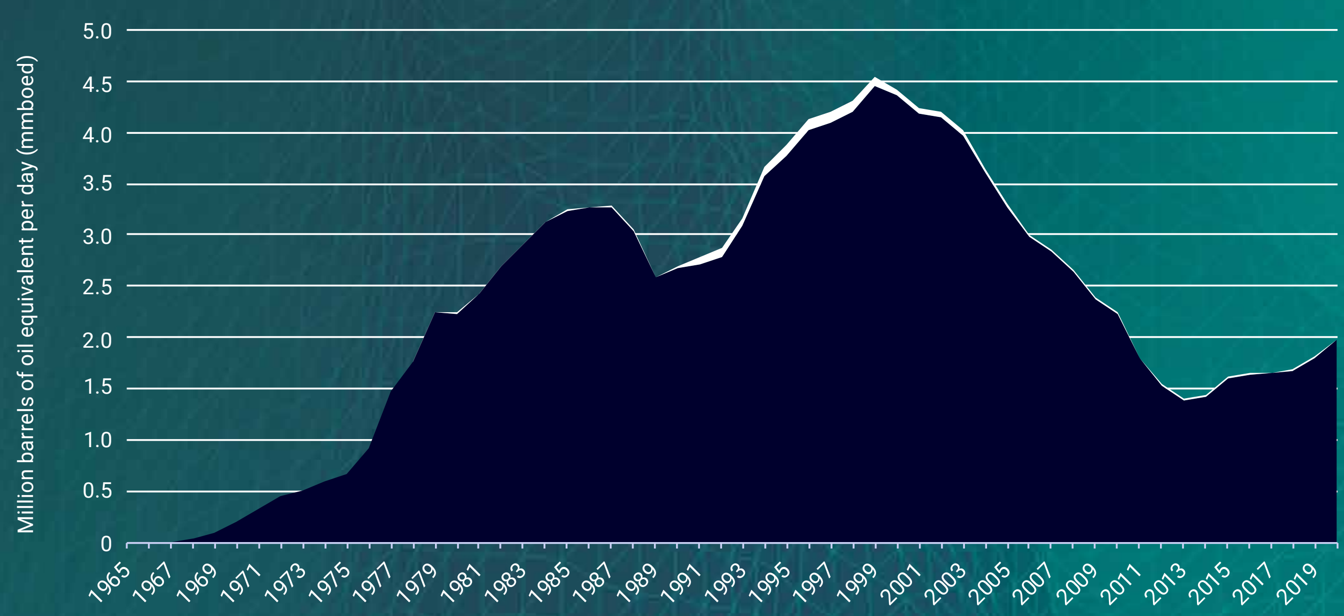
2.1: Introduction to the UKCS

History of UKCS

The UK Continental Shelf (UKCS) is the area of water that the UK has mineral rights to and includes parts of the North Sea, Irish Sea, Celtic Sea, English Channel and Atlantic Ocean. The UKCS has contributed substantially to the UK's energy industry and economy since the early 1960s, primarily through oil and gas production.

The exploitation of the UKCS drove the development of the UK's oil and gas industry and in the process made a vital contribution to the global offshore industry. Oil and gas exploration started on the UKCS in the early 1960s, with th rst offshore well drilled in 1964 an rst discovery made in 1965[1]. Hydrocarbon production started in 1967 and peake rst in the mid 1980s, reaching 3.3 million barrels of oil equivalent per day (mmboed), and then again in the late 1990s when production reached 4.5 mmboed[1]. Since 1999, oil and gas production from the UKCS has been declining, reaching a low of 1.4 mmboed in 2013[1]. A renewed focus on exploration and maximising economic recovery has reversed this decline with production increasing year-on-year since since 2014 to present. (se gure 2.1).

Figure 2.1: UK oil and gas production (1965-2020)

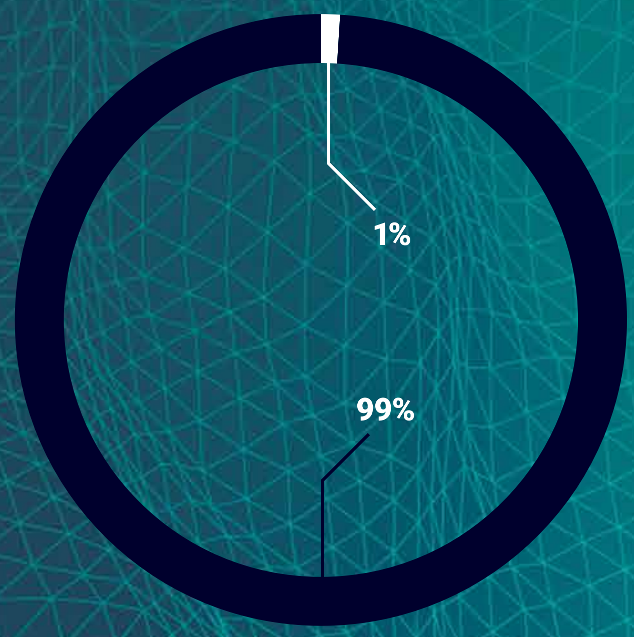


Source: Wood Mackenzie

Establishing the UKCS oil and gas industry in the 1960s and 1970s required new standards for offshore operations: developments in a harsh marine environment and in such water depths had not been attempted before.

The West Sol eld in the Southern Gas Basin produced the UKCS rst gas in 1967, whilst the discovery of the Arbroat eld in 1969 represented the rst domestic oil production. Soon after, the Forties eld was discovered, establishing the UKCS as a global player in the oil and gas industry. Developing elds in extreme offshore conditions fostered innovation, and created new technologies which have been exported the world over. The 'North Sea Standard' became a global operations benchmark and made the UKCS a centre of excellence. Looking to a net zero future, this rich heritage of engineering leadership and innovation provides a strong foundation for developing renewable technologies, carbon sequestration and an integrated offshore energy network.

Figure 2.2:
UK offshore vs onshore historic oil and gas production



Source: Wood Mackenzie

UK offshore wind capacity

Recently the UKCS' potential for offshore wind generation has started to be realised. In 2003, operations began at the UK' rst commercial offshore wind farm: the 60MW North Hoyle farm located off the coast of Liverpool. By 2005, the UKCS' wind capacity had reached 0.2GW and grew another 1GW over the nex ve years to 1.2GW (se gure 2.3).

From 2010 onwards, technological developments, newly enacted climate policy and subsidies accelerated offshore wind expansion. The UK held it rst offshore wind capacity auction in 2014, and in 2015 the UK's installed capacity reached 5.1 GW. In 2017, Equinor began operations at the world's rst commercia oating wind farm: the 30MW Hywind Scotland project, located 15 miles off Peterhead in Scotland. As of the end of 2019, the UK is still the only country in the world to host an operationa oating wind farm and is currently the world leader in offshore wind, with more installed capacity than any other country.

> This rich heritage of engineering leadership and innovation provides a strong foundation for **developing renewable technologies, carbon sequestration** and an **integrated offshore energy network.**

Economic bene s of UKCS

The UKCS provides signi cant socio-economic bene t to the UK, contributing tax revenues and jobs, as well as helping to meet the country's energy demand.

Oil and gas production from the UKCS contributes 1.2% to the UK's GDP[2], having previously reached a high of 2.5% of GDP in 2008[3].

Since 1970, the oil and gas industry has contributed over £350 billion in government tax revenue[2]. Oil and gas tax revenue peaked in 2008 when it reached more than £12.5 billion[4], ~3% of total government tax revenue in that year[5]. Since then, tax revenue from oil and gas has been falling and during the oil price crash of 2014 to 2016 reached zero[3]. In the 2017 to 201 scal year, UKCS oil and gas companies paid £1.2 billion in tax revenue[6,7], less than 1% of total government taxes[5]. Offshore wind has been supported by the UK government through subsidies. However, as the costs of offshore wind development continue to decline, and market structures evolve, the subsidies paid out by the government for new projects is reducing[8].

The UK oil and gas supply chain exports approximately £12 billion of goods and services each year[2]. Exports of wind energy products and services are currently estimated to be worth £525 million per year[9].

In total, energy related activities on the UKCS accounted for approximately 1% of all UK jobs in 2018[11]. The UK oil and gas industry employed 259,900 people — through direct (30,000), indirect (116,000) and induced (113,000) employment[10]. That number has fallen from a high of 463,900 in 2014[10] (1.5% of the total UK workforce). 7,200 people were directly employed in the offshore wind sector[12], approximately 0.02% of the UK's total workforce[13,14,15], and an estimated 700 people worked in the marine energy (tidal and wave power) sector in 2018[16].

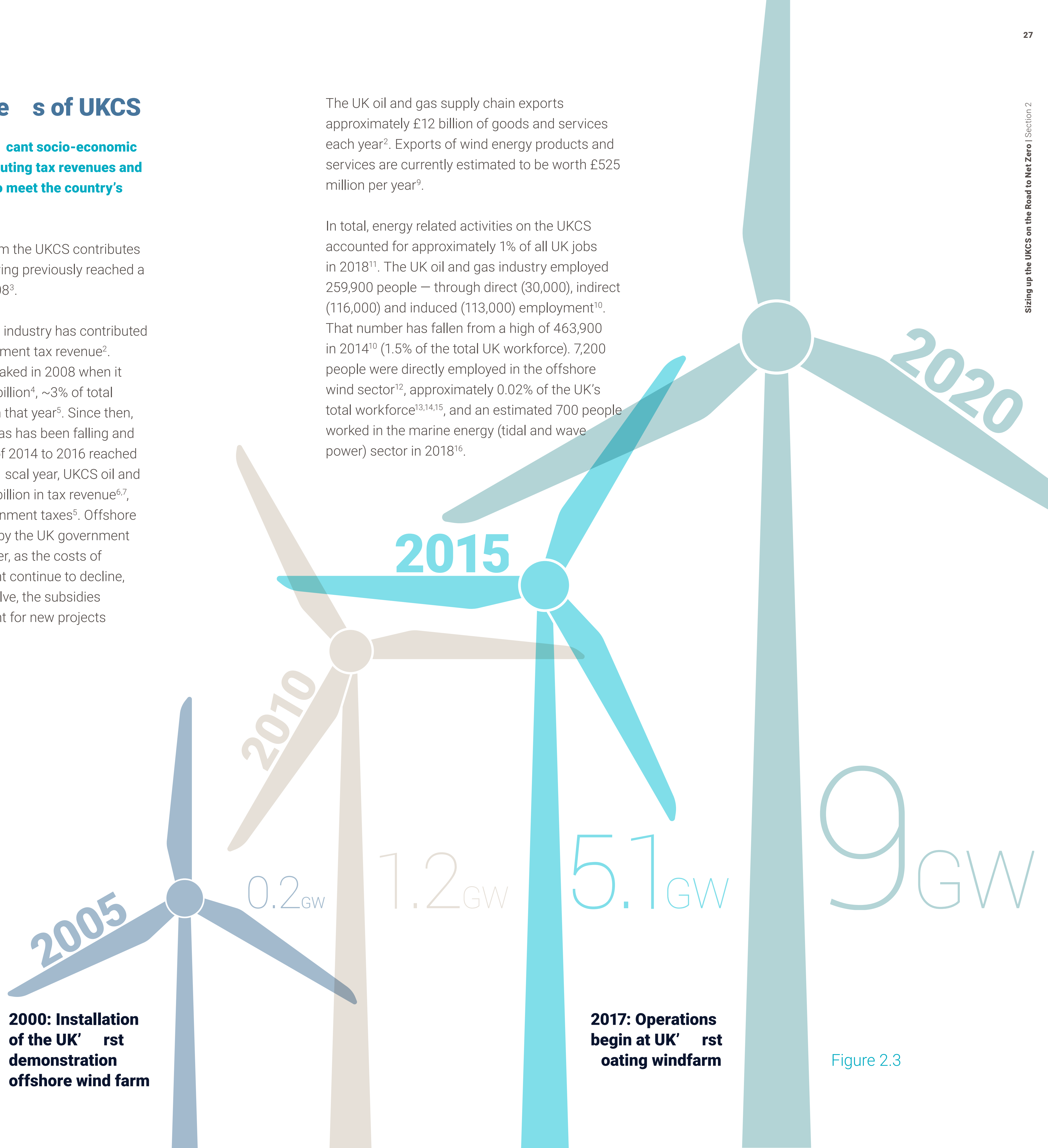


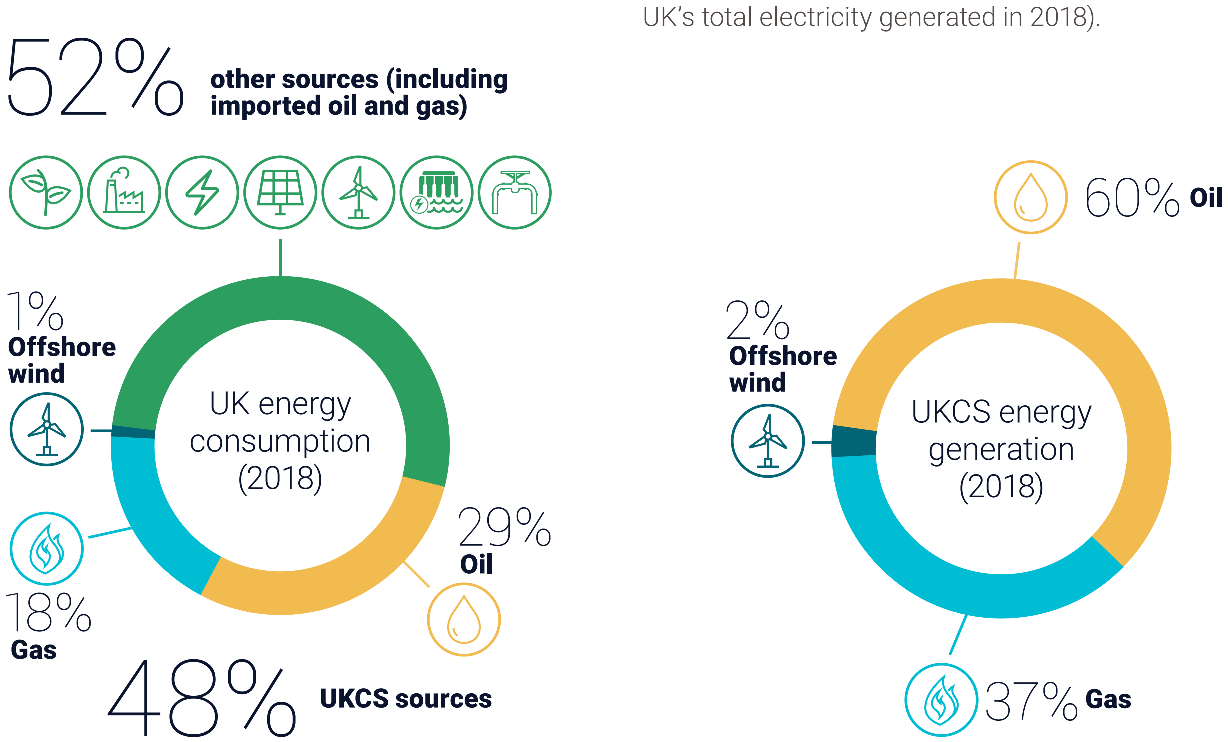
Figure 2.3

Energy bene f UKCS

Resources from the UKCS provide for just under half of the UK's energy, this is primarily from oil and gas which currently meets over 45% of the UK's total energy demand[2] (se gure 2.4).

Renewable energy sources (solar and wind, but excluding hydro) account for approximately 4% of the UK's primary energy demand, with offshore wind meeting just over 1% of the country's energy usage[17,18]. Wind and solar's share of electricity is higher, currently generatin fth of the UK's supply; again, offshore wind accounts for just under half of this power generation (8% of the UK's total electricity generated in 2018).

Figure 2.4



Source: Wood Mackenzie

Source: Wood Mackenzie

N.B Energy mix: sources of all energy usage, includes electricity generation, transport, residential, commercial and agriculture (RCA), industry and losses. Power mix: sources of electricity generation.

Box 2.1: Greenhouse gas emissions categories

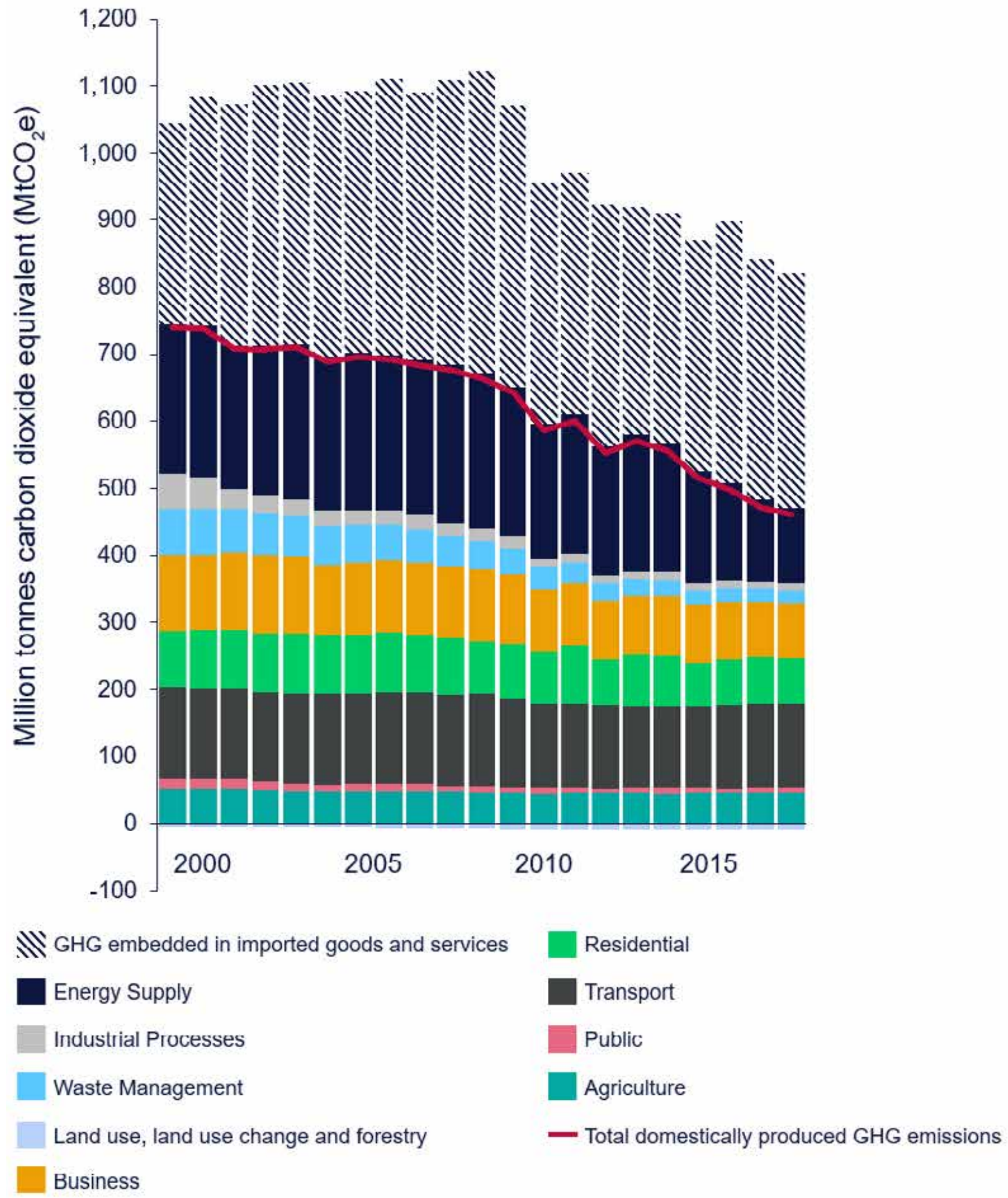
Scope 1	Scope 2	Scope 3
All Direct Emissions from the activities of an organisation or under their control	Indirect Emissions from electricity purchased and used by the organisation	All Other Indirect Emissions from activities of the organisation, occurring from sources that they do not own or control, i.e. end use of products

Carbon emissions from UKCS

In 2018 the UK produced 451 million tonnes CO_2 equivalent ($MtCO_2e$) of greenhouse gas emissions. Oil and gas produced from the UKCS contributes signi cantly to these emissions[19,20].

Direct emissions (scope 1) from oil and gas activity on the UKCS amounted to 14.6 $MtCO_2e$, approximately 3% of total emissions. The generation of energy (mostly from fossil fuels) produced 23% of emissions, and the transport industry (mostly through the use of oil-based products) accounted for a further 28% (se gure 2.5)[19]. As UKCS production meets more than three quarters of the UK's oil demand and half of the UK's gas demand, scope 3 emissions associated with resources from the UKCS make up a large proportion of the UK's total GHG emissions. Additionally, hydrocarbons that are imported to meet the remainder of gas and oil demand also contribute to embedded GHG emissions.

Figure 2.5: UK GHG emissions (1997-2017)



Source: UK government

UKCS stakeholder groups

Outside of the energy industry there are a number of other stakeholders who have significant economic, logistic and ecological interests on the UKCS. These include commercial shippers, the fishing and aquaculture industries, oceanographic and hydrography researchers, the Royal Navy, and communication companies[21].

Historically the energy industry and other stakeholders have worked together on the UKCS. For example, the Fisheries Legacy Trust Company (FLTC) manages interactions between the offshore oil and gas industry and fishing industries, and all offshore oil and gas operators must have a Fisheries Liaison Officer to collaborate with the government and fishing organisations on relevant issues[22].

As the energy mix of the UKCS develops and offshore infrastructure evolves, continued close cooperation between stakeholders will be important to ensure all interests are considered.

Additionally, established UKCS stakeholders will need to diversify from traditional activities and work together to tackle the climate change policies relevant to reaching net zero. For example, the Oil and Gas Climate Initiative (OGCI) is planning to spend more than £750 million on implementing and scaling low carbon solutions in oil and gas, industrial and commercial transportation[23]. BP and Shell are also part of a new hydrogen taskforce which aims to plan how the UK can effectively capitalise on hydrogen opportunities[24]. Several other UKCS stakeholders have grouped together to form cross-sector alliances and academic research groups to investigate how the different industries can work together to develop the utilisation of the UKCS. These groups are summarised in the table below:

Table 2.1: Some of the UKCS low-carbon groups

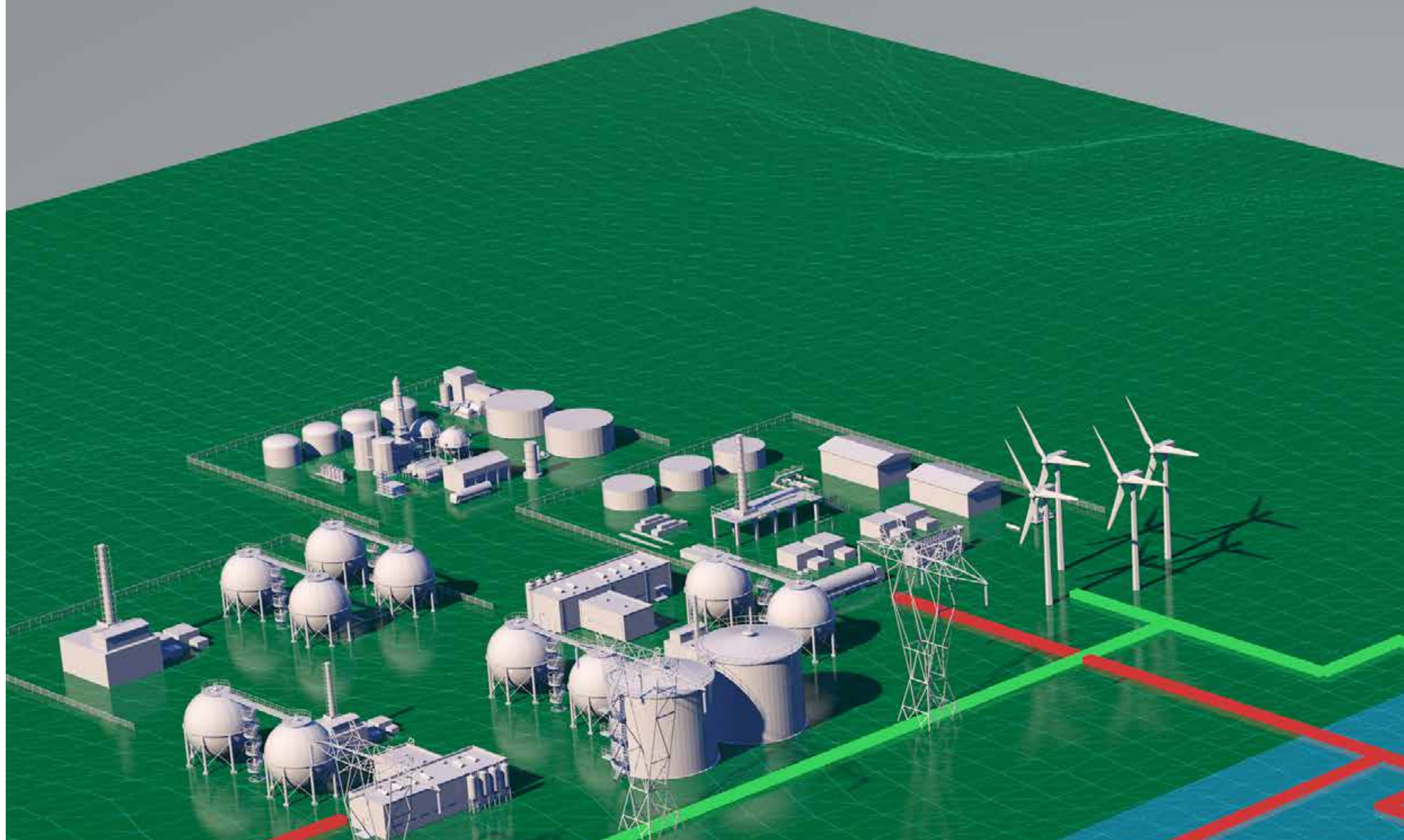
Group	Stakeholders	Description
NECCUS (North East CCUS)	Industry (i.e. Shell, Total, Chrysaor, Pale Blue Dot, Ineos), academia (i.e. University of Aberdeen, University of Edinburgh, University of Strathclyde, Heriot Watt University, NGOs (i.e. Scottish Government and Crown Estates Scotland) and other orgnaistaions (i.e. Net Zero Technology Centre, SHFCA, Opportunity North East)	Industry-led alliance drawn from industry, academia, membership organisations and private sector bodies to promote CCUS in Scotland
Hydrogen Taskforce	BP, Shell, BNP Paribas, Arup, ITM Power, Arval, Cadent, Storengy, DBD and Baxi	Political alliance that promotes hydrogen as an alternative fuel and provides government with suggested hydrogen related aims
Industrial Decarbonisation Research and Innovation Centre (IDRIC)	Industrial Strategy, Engineering and Physical Sciences Research Council	Aims to accelerate the cost-effective decarbonisation of industry by developing and deploying low-carbon technologies
CCUS Cost Challenge Taskforce	Industry (i.e. Shell, BP, Equinor, Cadent Gas, BHP, Summit Power, Siemens, Pale Blue Dot etc.), academia (Cambridge university, Imperial College London etc.), NGOs (Crown Estate, Crown Estate Scotland) and international organisations	Aims to inform and propose a strategic plan for supporting the development of CCUS in the UK

2.2: UKCS Resource Base

The UKCS has a large, unique resource base ranging from natural processes, such as wind and wave, to natural materials, such as gas and oil.

As the exploitation of these resources progresses, policies develop and demand changes, new uses for the UKCS are being considered. For example, the huge volumes of depleted hydrocarbon reservoirs that initially provided oil and gas are now being considered as storage sites for captured CO_2.

Further to this, natural gas that has been historically used in its original form is now being considered as a source for hydrogen production. Other natural processes are also being investigated for their renewable power generation potential. Although the UKCS' potential is currently exploited through standalone activities (see figure 2.6 which represents the current configuration of UKCS operations), the development of a connected energy system which unlocks the different resources' potential will be key to realising the UKCS' net zero future.



UKCS current reality **2020**

Schematic view of the current set-up of UKCS energy system with stand-alone oil and gas and offshore wind

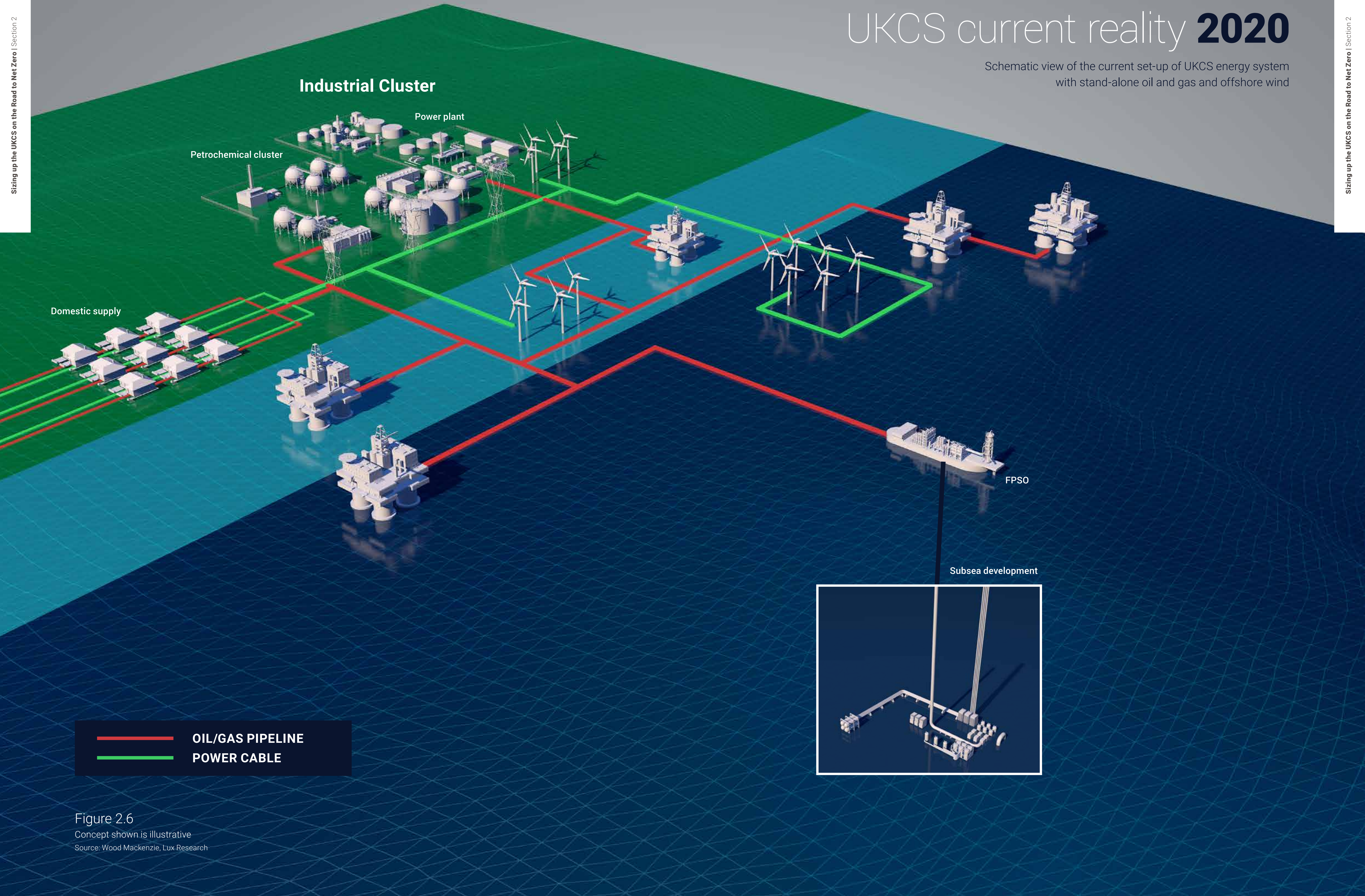


Figure 2.6
Concept shown is illustrative
Source: Wood Mackenzie, Lux Research

Sizing up the UKCS on the Road to Net Zero | Section 2

OIL & GAS

Scale of resource

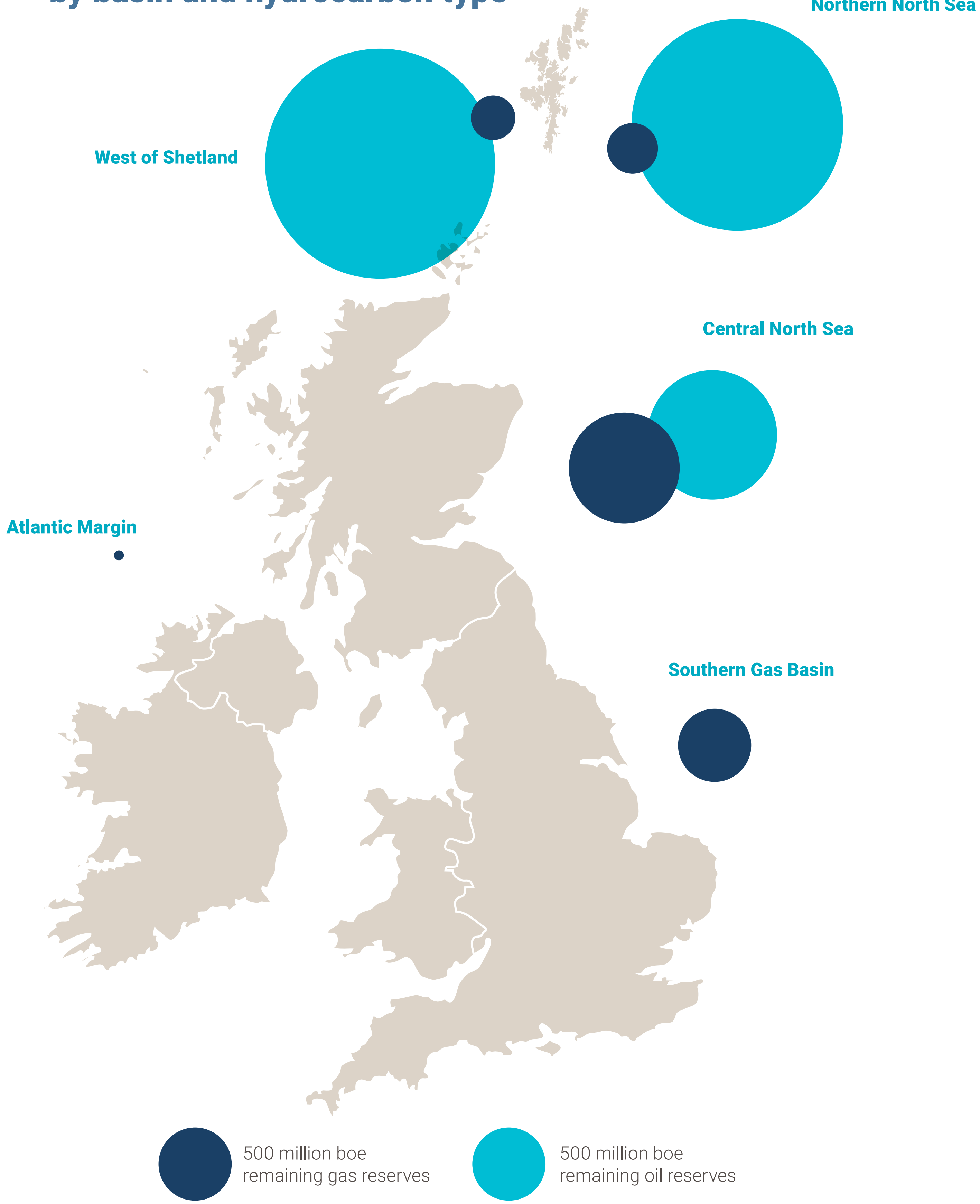
The UKCS contains several prolific petroleum basins which can be broadly divided into five main areas: Central North Sea, Northern North Sea, Southern Gas Basin, West of Shetland and Atlantic Margin.

Over the past 50 years the Southern Gas Basin has been a prolific gas producer and the Central and Northern North Sea basins have been key to producing both oil and gas.

More than 45,000 million barrels of oil equivalent (mmboe) of oil and gas has been produced to date and Wood Mackenzie estimates there is 6,800 mmboe of reserves remaining (under current cost and pricing assumptions)[1]. Total production from the UKCS was 1.7 mmboed in 2018[6], with liquids production averaging just over 1 mmboed and gas production around 3,600 million cubic feet per day[1]. The West of Shetland is the UKCS' key growth region and has a total remaining reserves base of 2,000 mmboe of oil and gas (see figure 2.7), with large development projects at Clair, Rosebank and Cambo accounting for 1,400 mmboe of these reserves[1].

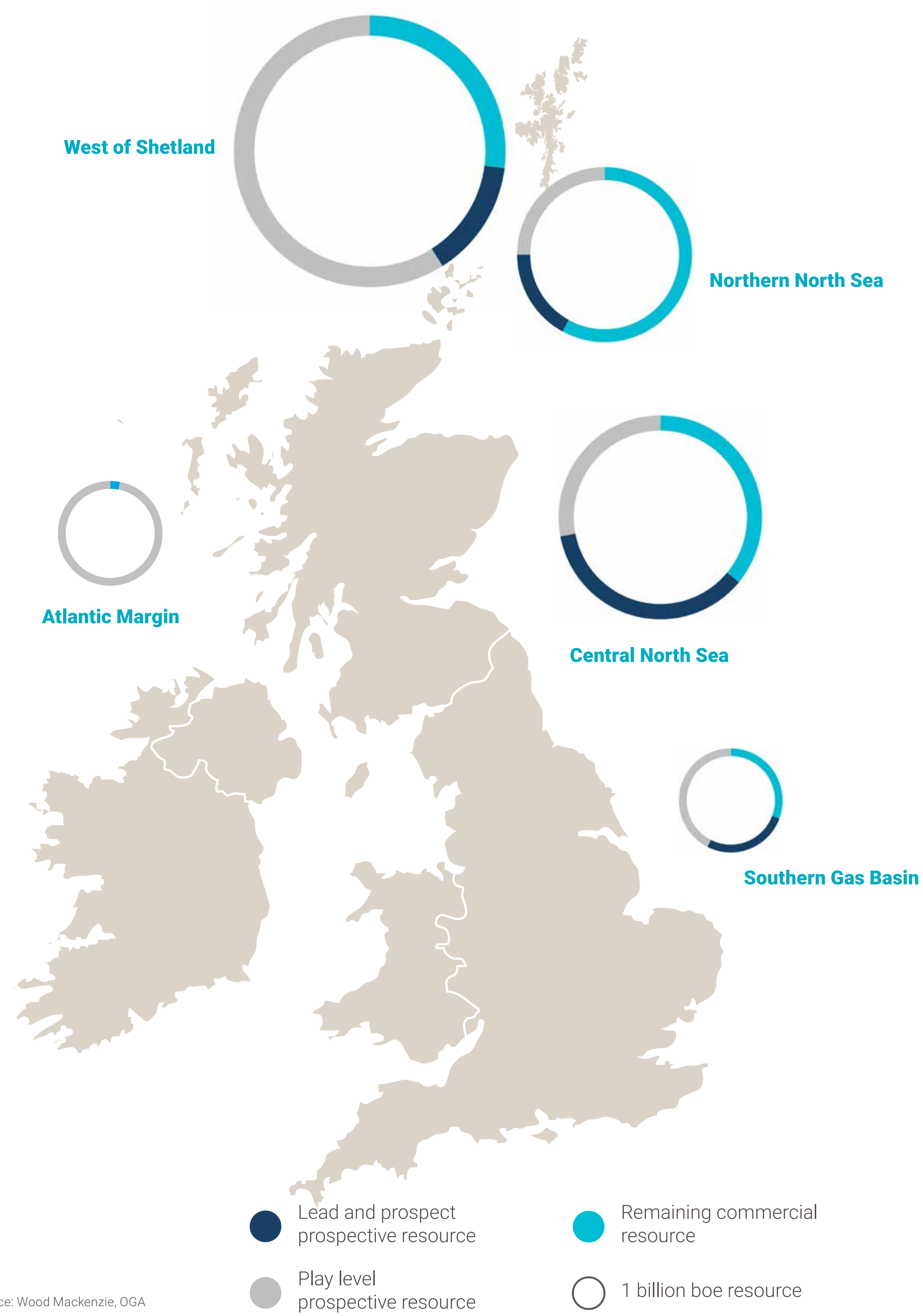
More than **45 billion boe** of oil and gas has been produced to date and Wood Mackenzie estimates there is **6.8 billion boe**[1] of reserves remaining

Figure 2.7: **UKCS remaining reserves by basin and hydrocarbon type**



Source: Wood Mackenzie

Figure 2.8: **UKCS remaining reserves and prospective resource**



Source: Wood Mackenzie, OGA

Regulation

An independent review of the UKCS oil and gas industry was published in 2014 and informed the UK government Energy Act 2016, which created the Oil and Gas Authority (OGA). The OGA was charged with effective stewardship and regulation of the UKCS, which includes responsibility for licensing.

The OGA holds regular licensing rounds covering areas in both the mature UKCS basins and exploration opportunities in frontier basins.

In May 2020 the OGA published a consultation on an update of its core aims to include a requirement for the oil and gas industry to help achieve the UK net zero target by 2050[403].

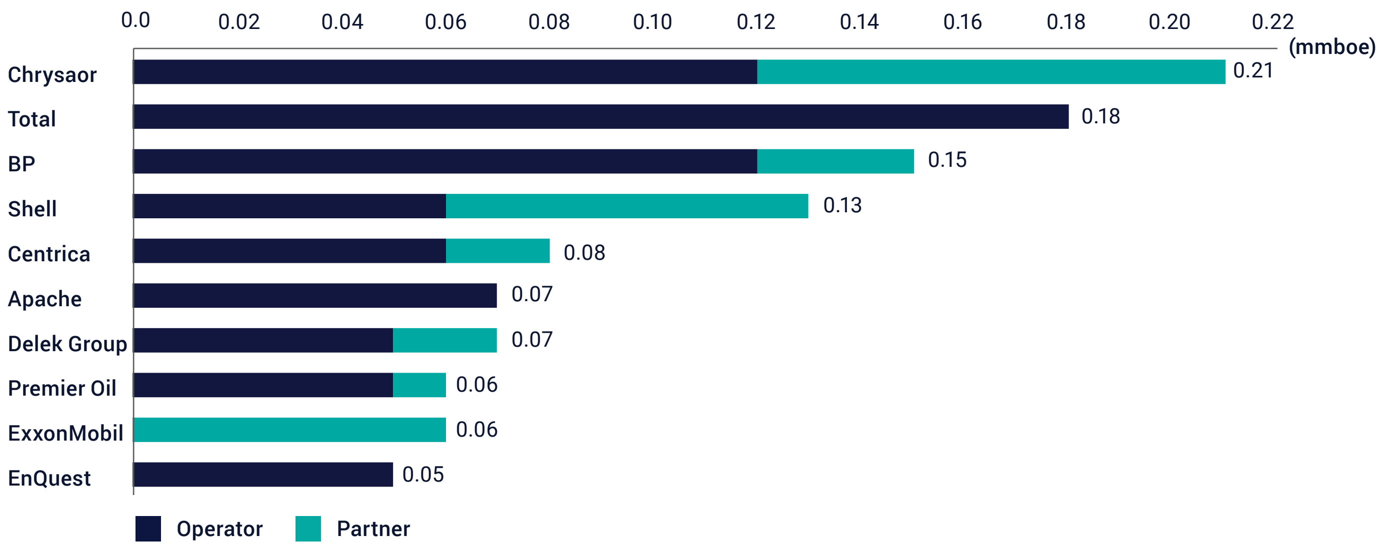
Corporate landscape

Major oil companies, including BP and Shell, have historically dominated oil and gas activity on the UKCS. As the industry has matured, the corporate landscape has become increasingly fragmented, with more than 100 companies now holding acreage on the UKCS.

Collectively, the Majors still hold 20% of the total licensed acreage and more than 40% of remaining reserves[1]. However, for th rst time since UK production began, a non-Major oil company is now the top producer. Chrysaor's acquisition of ConocoPhillips' UK business, coupled with asset divestments by Total, puts the private equity-backed player at the top of the production charts for 2019 (se gure 2.9).

Shell is set to be the largest investor on the UKCS in 2020 as a result of ongoing development at the Penguin eld and i ll drilling at Clair Ridge and Schiehallion. In 2019, Total and BP were the two largest investors in the UK, driven by development activity in the central North Sea in the case of the former, and exploration West of Shetland in the case of the latter. Chrysaor, Equinor and Apache are also major investors, focusing on development activity in the North Sea[1].

Figure 2.9: Top oil and gas producers in the UK (net entitlement production - 2020)



Source: Wood Mackenzie

> "...the Majors still hold **20% of the total licensed acreage** and more than **40% of remaining reserves**."

Current issues facing sector

Balancing efforts to sustain oil and gas production with growing pressure to reduce carbon emissions has become a key focus for the industry. Additionally, decarbonising hydrocarbon products to support a net zero economy and sustainable fuel demand is becoming increasingly important.

Direct emissions from offshore oil and gas activities account for approximately 3% of the UK GHG emissions and three quarters of these offshore emissions are due to power generation on platforms. The remaining emissions are a result of fugitives aring and leakages.

In 2019, OGUK – the industry body for the UK offshore oil and gas industry - publised its "Roadmap 2035; a Path to Net Zero" report which outlines how the industry will balance energy security, economic and emissions objectives over the next 15 years. The Roadmap sets speci c targets for the industry to reach[2]:

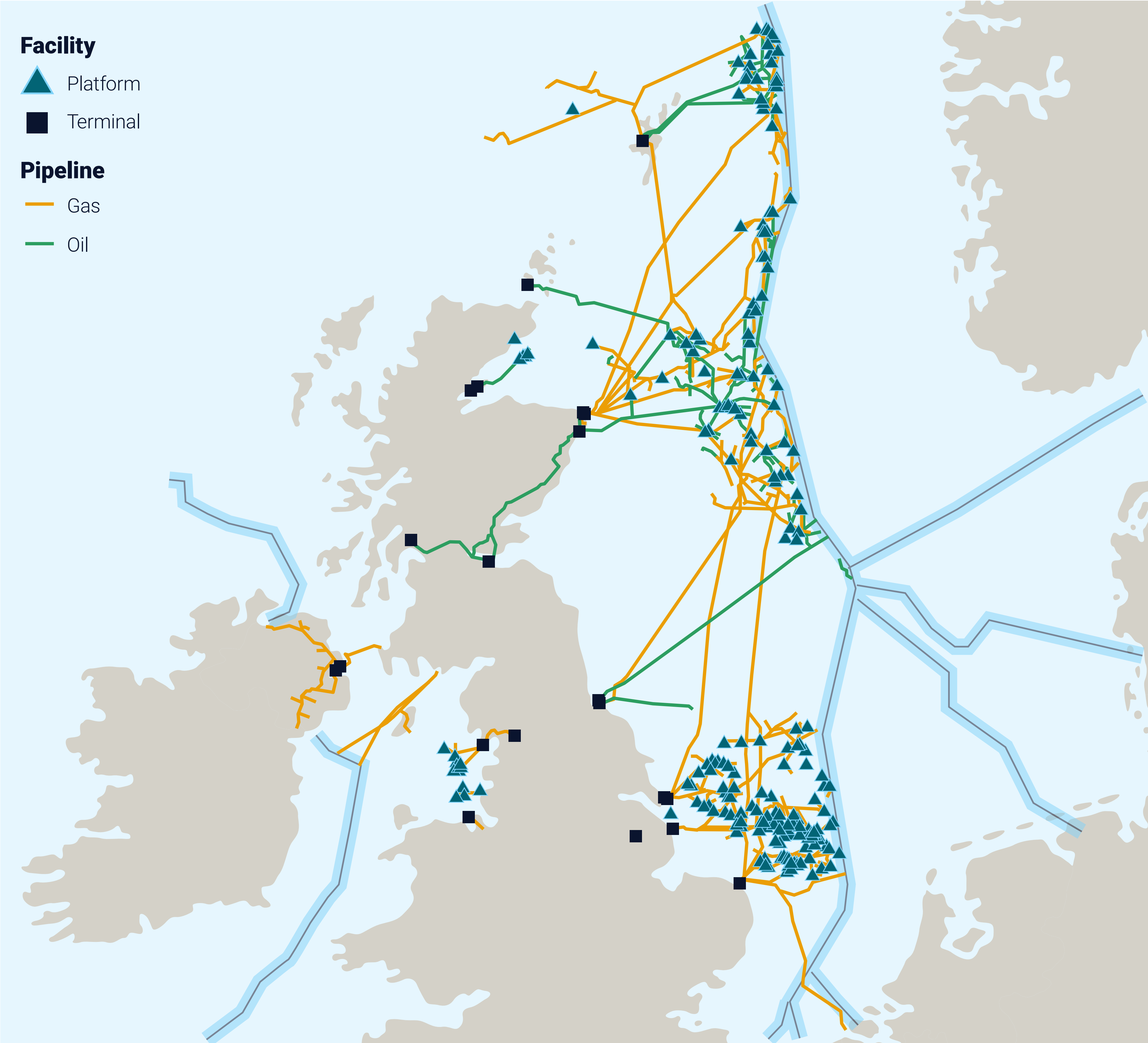
- **Become a net zero GHG emissions basin by 2050**
- **Meet at least 50% of UK oil and gas demand from domestic production — thereby minimising higher carbon intensity imports**
- **Grow and diversify energy supply chain export revenues to £20 billion per year (from the £12 billion currently)**
- **Secure at least 130,000 direct and indirect jobs**
- **Create over £10 billion in economic value through technology and innovation**

The UKCS is a mature hydrocarbon region. In an attempt to offset production decline, a 'Maximising Economic Recovery' (MER) strategy was recommended as part of a 2014 industry review[1]. The OGA subsequently implemented changes in the licensing regime to encourage new exploration, administered two government-funded seismic campaigns and continues to thoroughly review requests to cease production at olde elds. More recently, the OGA has been developing initiatives to reduce the carbon footprint of offshore operations and to support carbon capture and storage and hydrogen, thus contributing to the UK's net zero target[403]. The OGA's UKCS Energy Integration[407] report, published in August 2020, in collaboration with Ofgem, The Crown Estate and the Department for Business, Energy and Industrial Strategy (BEIS), highlights how the integration of offshore energy systems, including oil and gas, renewables, hydrogen and carbon capture and storage, could contribute to deliver approximately 30% of the UK's total carbon reduction requirements needed to meet the 2050 net zero target.

A more immediate issue for the oil and gas sector to address is the decommissioning of ceased elds, removal of infrastructure and abandonment of wells. Over the next 15 years this is estimated to cost around £50 billion (2019 terms)[1].

Existing infrastructure

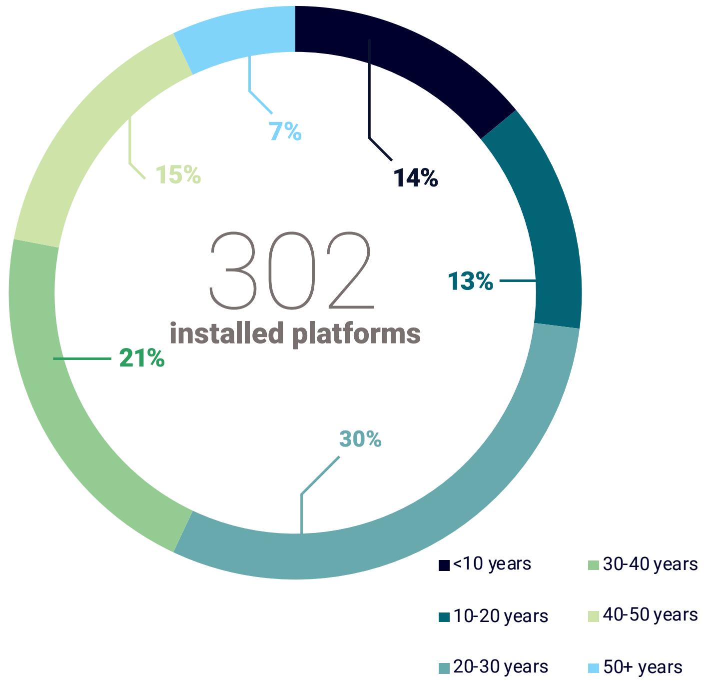
Figure 2.10 - UK offshore oil and gas infrastructure



Source: Wood Mackenzie

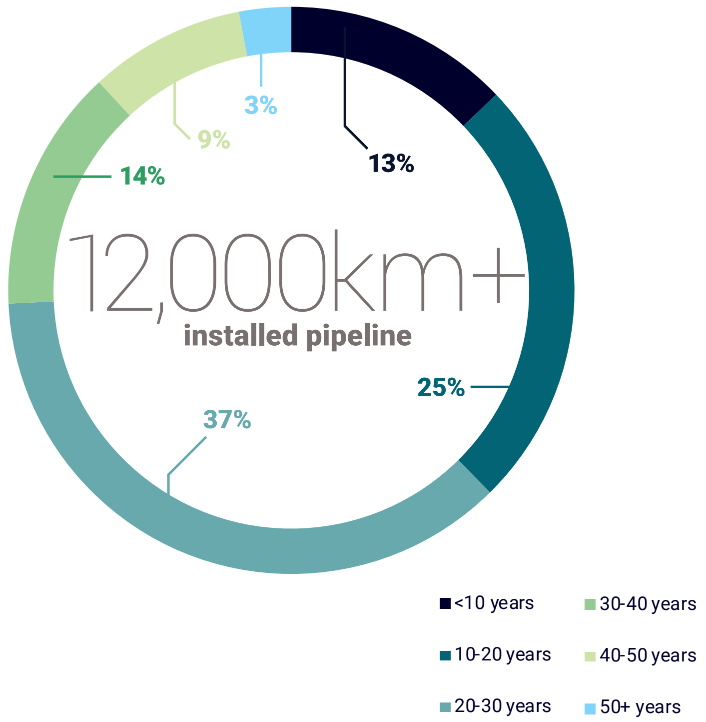
After more than 50 years of oil and gas production, the UKCS has a substantial amount of infrastructure in place: more than 300 platforms[25] and 12,000 km of pipelines[26]. However, much of the infrastructure is ageing; more than 40% of existing platforms[25] and a quarter of existing pipelines[26] were installed more than 30 years ago.

Figure 2.11: Installed platform age



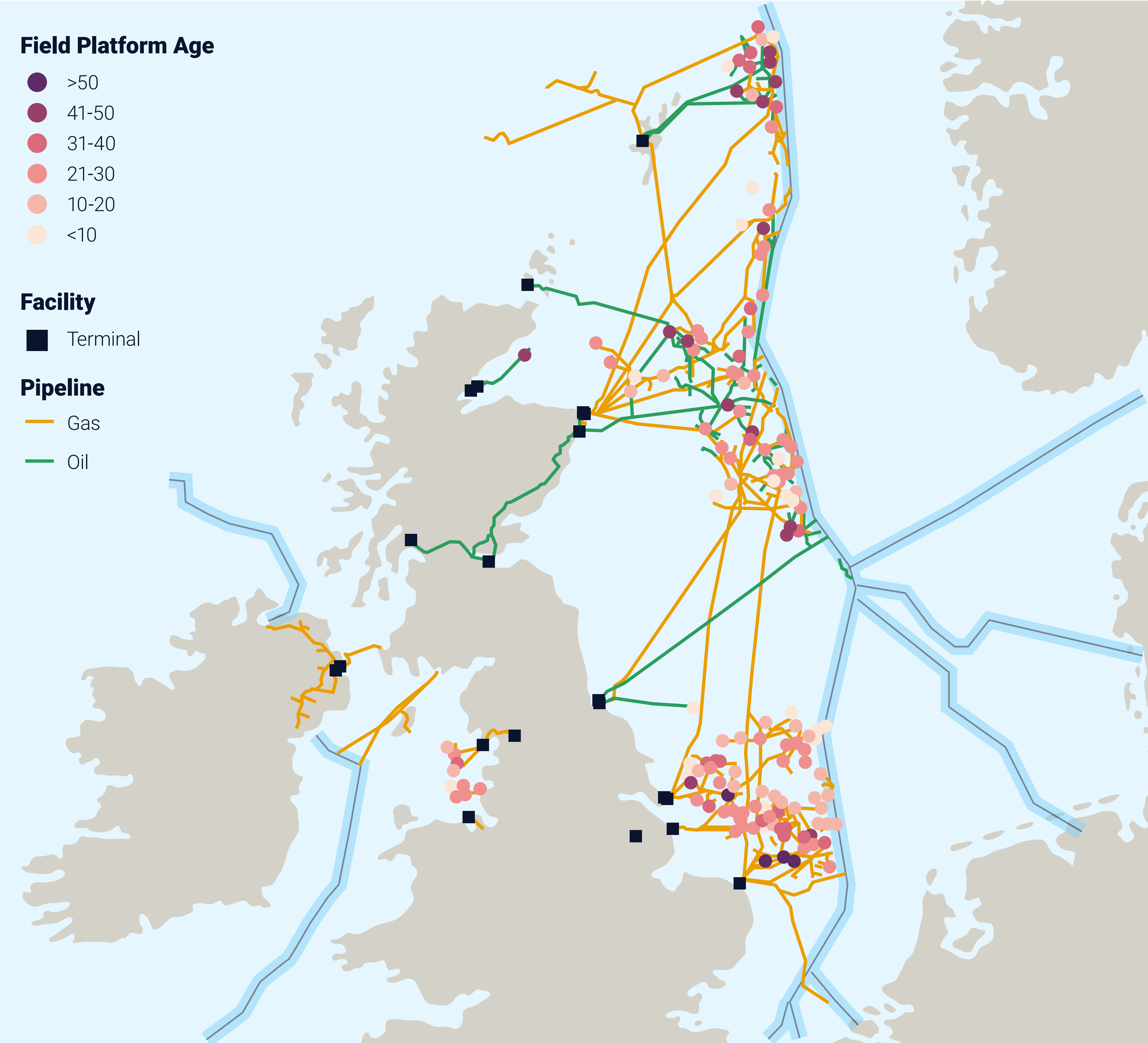
Source: Wood Mackenzie

Installed pipeline age



Source: Wood Mackenzie

Figure 2.12: Field platform age at U elds



Source: Wood Mackenzie

A elds reach the end of their lives and are decommissioned, operators need to plan for removal of platforms and associated infrastructure (subsea structures and pipelines). This decommissioning activity is ongoing across the UKCS with a particular focus on the most mature areas like the Southern Gas Basin. It is planned that over a third of existing platforms will cease operating within the nex ve years, and a further third will cease operating before 2030[25].

How many oil and gas platforms can be repurposed for other uses is unclear, as in most cases they are old and integrity issues mean maintenance costs are high. Additionally, the repurposing of oil and gas wells for long-term CO_2 injection is still uncertain as they were designed and located for different objectives.[27].

Current uncertainty about the future of the concrete gravity-based structures and whether they will be left in place or removed makes them potential hubs for alternative projects such as carbon storage, substations for electrical networks or for locating electrolysers. The extensive oil and gas pipeline infrastructure across the UKCS could be used for a CO_2 or hydrogen network, although once again, integrity issues will be a serious consideration due to the age of the networks.

> “The extensive oil and gas pipeline infrastructure across the UKCS could be used for a CO_2 or hydrogen network, although **integrity issues will be a serious consideration due to the age of the infrastructure.**”

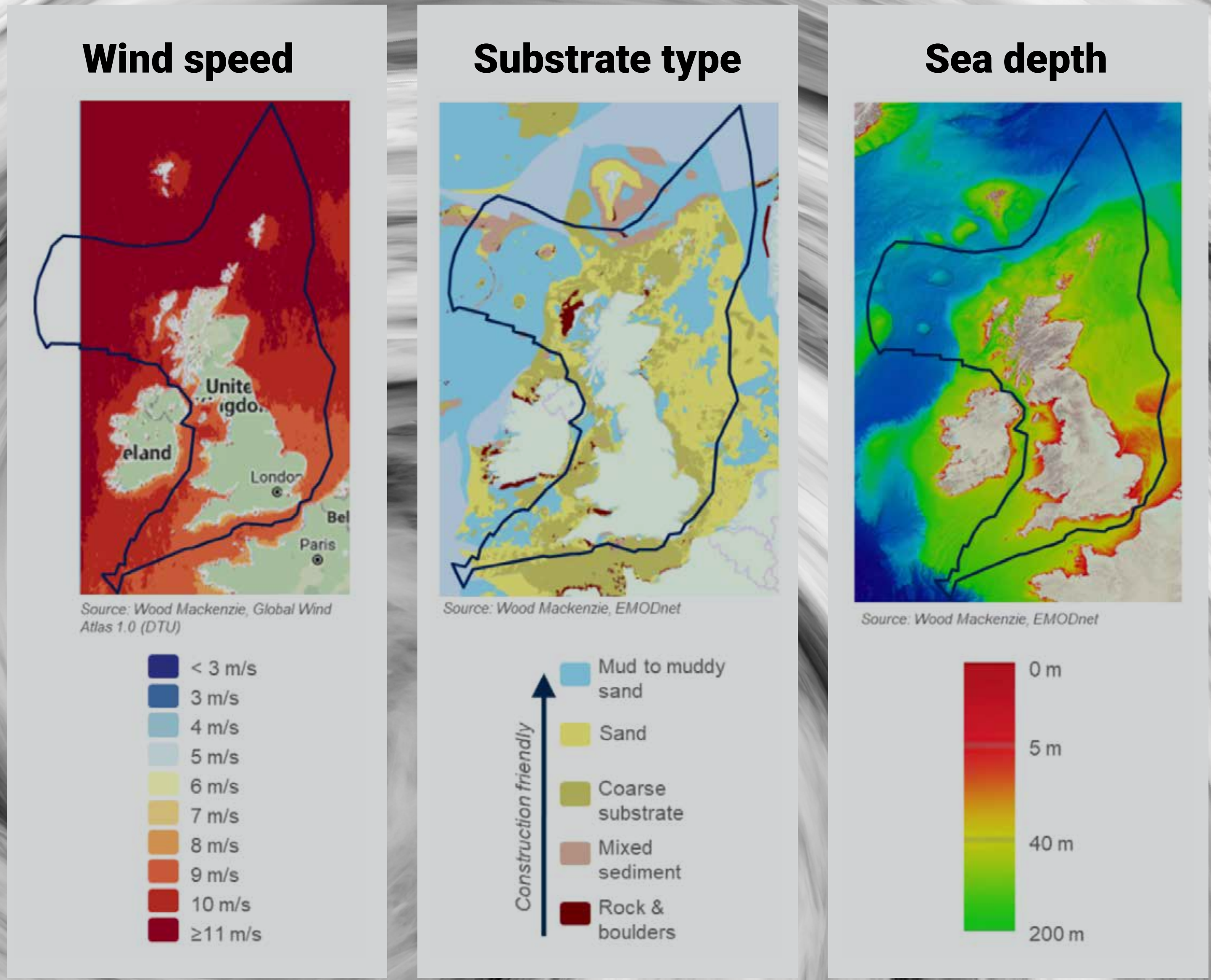
WIND

UK — a world leader in offshore wind

The strong wind speeds, shallow water depths and appropriate seabed substrate (se gure 2.13), alongside early adoption, technology evolution and clear political will, have resulted in the UK becoming the world leader in offshore wind, with more installed capacity than any other country[28].

The deeper water depths of parts of the North Sea are ideal fo oating wind, where botto xed wind turbines are not viable. Estimates show that over half of the North Sea is suitable for deploying oating wind power[29].

Figure 2.13: UKCS physical conditions relevant for offshore wind developments



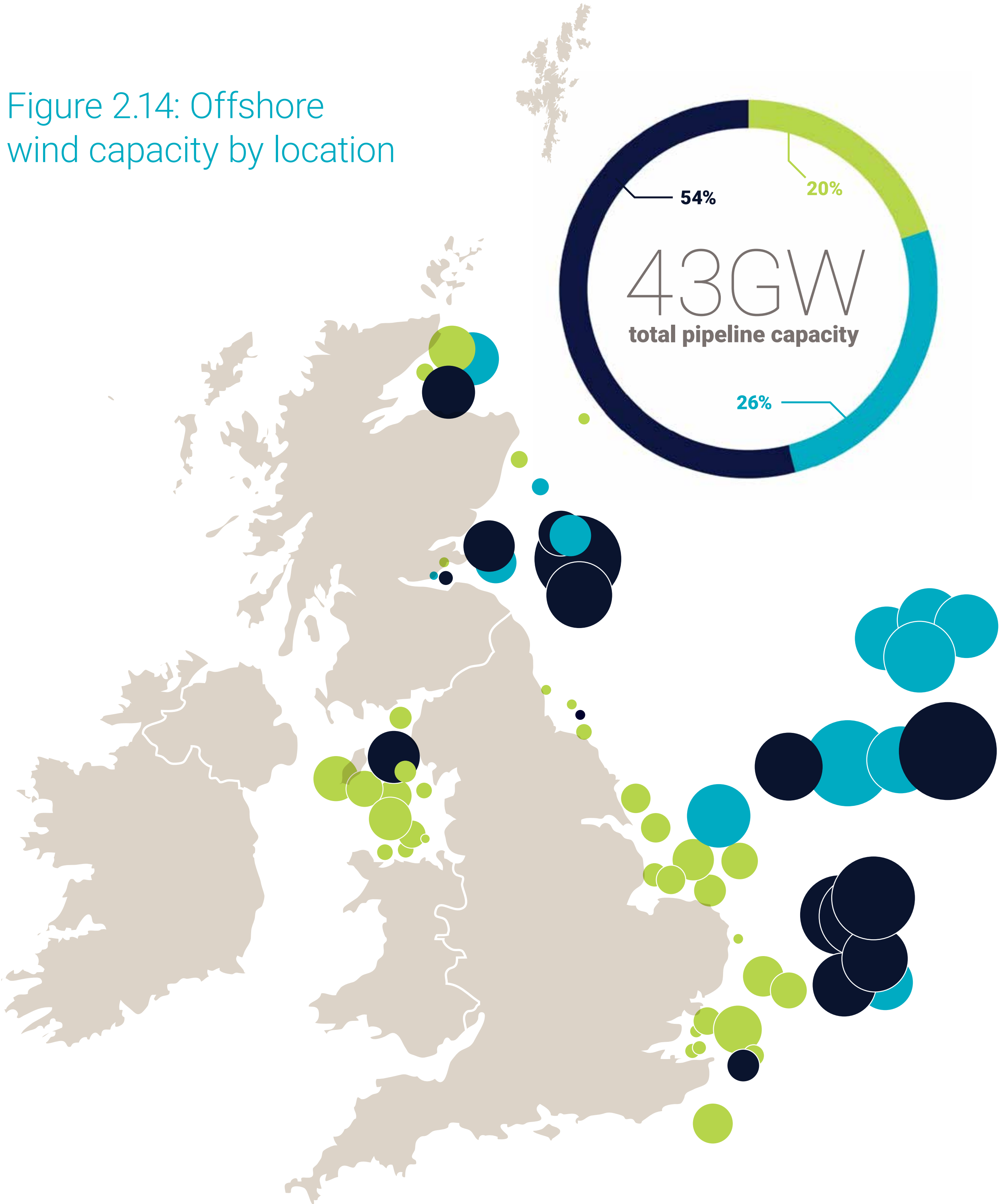
At the end of 2019 the UKCS had an installed capacity of 8.6GW[30] across more than 35 operational offshore wind projects. In 2020, offshore wind is expected to generate 10% of the UK's electricity[28].

In total 20 projects are currently planned or under construction on the UKCS and will contribute an additional 19GW of capacity over the next 10 years[30,31]. A further 16GW of capacity is in the planning stage but is yet to receive a permit[30]. The Government aims to reach 40GW of offshore wind capacity by 2030[32] and looks on target to do so with the 34GW of capacity in the active pipeline (se gure 2.14)[30].

The key drivers of growing offshore wind capacity are continued cost reduction and government policy which is aiming to increase renewables' share of the UK's energy mix[30].

In the longer term, the potential for operators to sell electricity at higher prices directly to the market - rather than agreeing strike prices with the government - and technological developments such as increasing project size, will be the primary drivers of capacity growth.

Figure 2.14: Offshore wind capacity by location



1GW **Project Size**

Operational*

Secured pipeline**

Early stage pipeline***

Source: Wood Mackenzie

*Note: *'Operational' refers to capacity which is fully grid-connected (including decommissioned capacity).*
***'Secured pipeline' refers to capacity which has been awarded a support scheme but is still not operational.*
****'Early stage' refers to capacity which has not secured a support scheme.*

Figure 2.15: Upcoming UK offshore wind leasing rounds

Draft Plan Options (DPO) for ScotWind | 10 GW+ offshore capacity expected to be awarded

DPO – no ornithological constraints

DPO subject to the need for further regional level survey and assessment

Likely that no license or consent can be awarded without further evidence

DPO subject to high levels of ornithological constraint

Likely that no license or consent can be awarded

Crown Estate leasing round 4 bidding areas | 7 GW - 8.5 GW new seabed rights

Dogger Bank

South East

Eastern
- Southern North Sea region
- The Wash region
- East Anglia region

Northern Wales & Irish Sea
- North Wales region
- Irish Sea region
- North part of the Anglesey region

Source: Wood Mackenzie, Scottish Government, The Crown Estate Information Memorandum - Introducing Offshore Wind Leasing Round 4

Regulation

The Crown Estate holds all rights to the seabed around England, Wales and Northern Ireland and is responsible for awarding developers the rights to install offshore technology[33]. The Crown Estate Scotland is responsible for awarding and managing leases in the Scottish section of the UKCS[34].

The Offshore Wind Leasing Round 4 was launched at the end of 2019 and offers more than 7GW of seabed rights in waters around England and Wales (se gure 2.14)[30,35]. Seabed in Scotland is being leased through the 2020 ScotWind leasing round which was launched in June 2020 and offers up to 10GW of capacity across a variety of locations in Scotland (se gure 2.15)[36]. A portion of this capacity i oating wind.

Since 2014, the UK government, on behalf of the Crown Estate, has also held three Contracts for Difference (CfD) Allocation Rounds (AR) as a means to support new offshore wind capacity. During these rounds, more than 9.8 GW of capacity support has been awarded[8].

In 2019, the UK government and offshore wind sector released the Offshore Wind Sector Deal which outlines how the Government and sector will work together to continue to support offshore wind growth. The deal outlines that the sector should aim to increase UK content to 60% by 2030, the number of UK jobs in offshore wind to 27,000 and exports from £0.5 billion currently to £2.6 billion by 2030[12]. To achieve that, the sector will invest up to £250 million to develop the UK supply chain and establish the Offshore Wind Growth Partnership (OWGP) to support productivity and increase competitiveness[12].

> “The Offshore Wind Sector Deal builds on the United Kingdom’s global leadership in offshore wind, **maximising the advantages for UK industry from the global shift to clean growth.**”

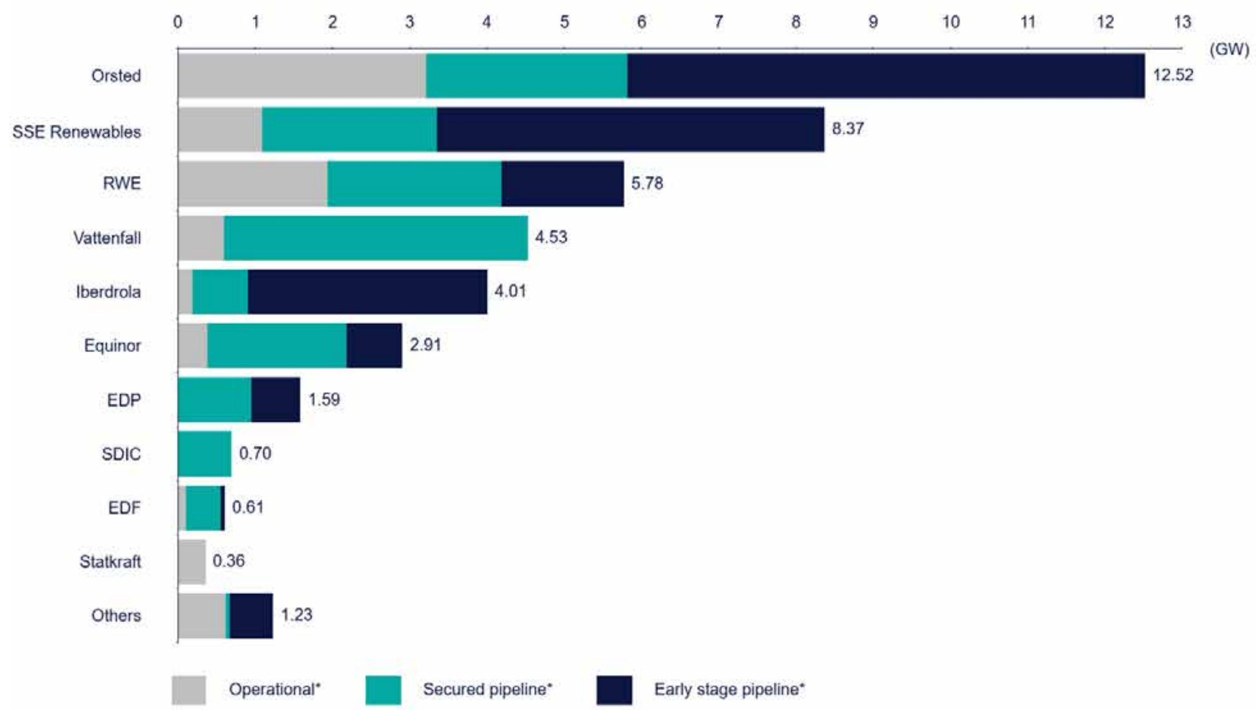
Corporate landscape

The UK market has attracted large foreign suppliers and 32% of the major suppliers are now based in the UK. However, 68% of the offshore wind supply chain is sourced from non-UK base rms [37].

SSE is one of the most active onshore and offshore wind developers and operators in the UK and is one of the few developers based in the UK[14].

As of the end of 2019, the Danish company Ørsted had the largest UK offshore wind portfolio (se gure 2.16)[14]. Other companies with large UK offshore wind portfolios include RWE, Vattenfall, Iberdrola and Equinor[38]. In the latest Contract for Difference (CfD) Auction Round 3 (AR3) support auctions, SSE took 41% of awarded capacity, Equinor 33% and Innogy 26%[8]. Other major energy players are showing an interest in the UK’s offshore wind sector, such as Total who in March 2020 acquired a stake in a U oating project.

Figure 2.16: Top offshore wind developers in UK by portfolio status - 2019



Source: Wood Mackenzie

Current issues facing sector

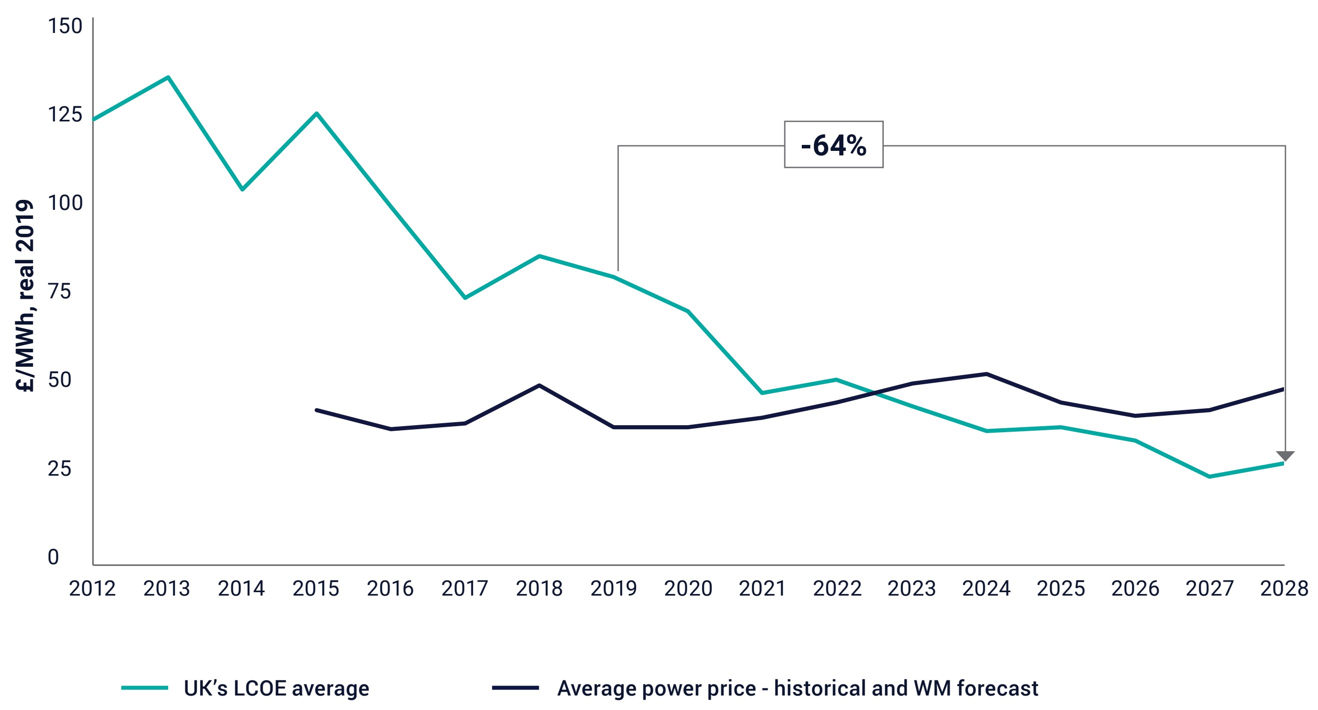
Key barriers to offshore wind growth are uncertainty around power prices, competition from alternative fuels and worsening area characteristics as all the 'best' wind areas are licensed[30] and projects are forced to locate in more technically challenging areas further from shore[39].

Cost reductions

The UK's offshore wind levelised cost of energy (LCOE) has nearly halved since 2012 and is expected to drop by a further 64% by 2028, from ~£100/MWh in 2019 to just under ~£40/MWh (se gure 2.17)[39].

As projects are pushed to locate in less attractive and more complex areas (they are already being deployed over 100km from the shore and in water depths of more than 50 metres[12]) they will have higher capital costs (capex). However, the average offshore wind LCOE in the UK will continue to decline, as technology improves, more innovative ways of working become standard, projects bene t from economies of scale and synergies and demand outlook steadies.

Figure 2.17: UK offshore wind levelised cost of electricity (LCOE)



Source: Wood Mackenzie

> The **world's rst ating offshore windfarm** was installed 15 miles off Scotland's northeast coast in 2017.

In the UK's latest wind capacity support auction, AR3, the awarded strike prices ranged between £44.95/MWh and £47.18/MWh (indexed to 2019 prices). This was 35% lower than that in AR2 and close to the average wholesale electricity price of around £45/MWh in 2019[8]. The low strike prices indicate that the cost of offshore wind is comparable to other traditional power generation options and a competitive electricity option.

New technology

The UKCS' higher mean wind speeds and less extreme weather conditions compared to many developing wind markets mean that it can offer attractive opportunities for the adoption of the latest offshore wind turbine technologies.

The Hornsea Project One is planned to start operations this year and will overtake the 659MW Walney Extension in the Irish Sea, as the largest offshore wind farm in the world[40]. The farm is located off the coast of Hull and will have a total capacity of 1.2GW from 174 turbines, each 190 metres tall and spread across an area 407km^2 in size[41]. Both Walney Extension and Hornsea Project One are operated by Ørsted.

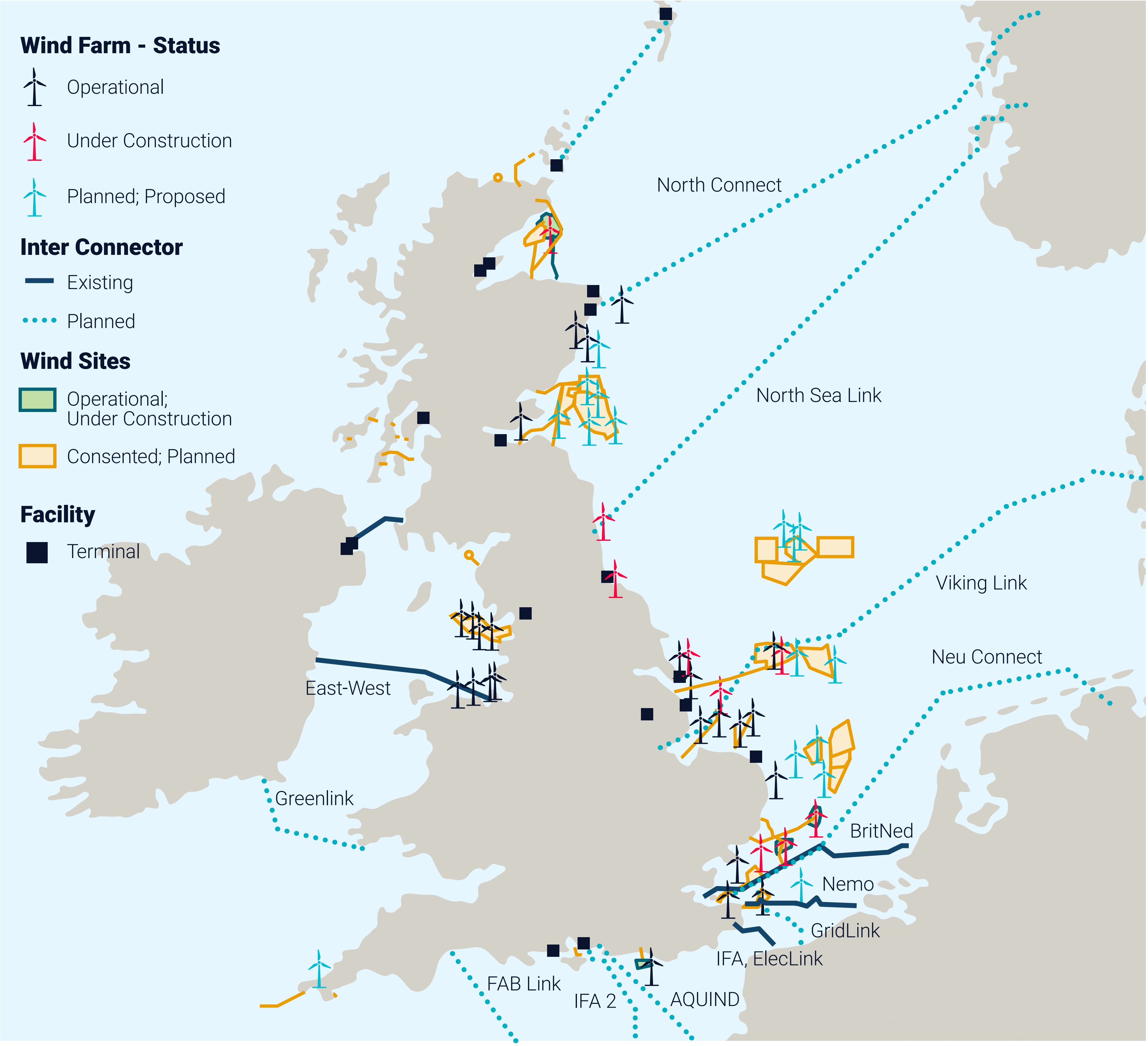
Transmitting power to the UK market is becoming increasingly complex as wind farms are located further offshore. The Dogger Bank project, in the Southern Gas basin, will utilise high voltage direct current (HVDC), which is expected to mitigate energy transmission losses and could also lower transmission asset construction costs[39].

As the bulk of easy to access, shallow water wind locations are already licensed, the industry is starting to investigat oating offshore wind's potential. The world' rs oating offshore wind farm was installed 15 miles off Peterhead in Aberdeenshire by Equinor in 2017. The 30MW Hywind Scotland project is currently the only existing project of its kind[29], yet more than 7 oating wind concepts are being considered worldwide and more than 350MW o oating wind demonstrators are set to be grid connected in the nex ve years. Of these, 22% are in the UK[41].

Floating wind has advantages ove xed-bottom wind: it is less intrusive for the seabed, the location can be mor exible and there is greater potential for standardisation and mass production. However, policy-makers need to develop a clear route to market for th oating wind industry to take off at commercial scale. So far, the commercialisation o oating wind has been hampered by misalignment between developers and governments. Developers argue that capacity is needed to reduce the cost o oating wind, and governments counter that cost declines are needed to allocate generation capacity t oating wind.

Existing infrastructure

Figure 2.18: Existing and planned UK offshore windfarms and electricity interconnectors



Source: Wood Mackenzie

As the bulk of easy to access, shallow water wind locations are already licensed, the industry is starting to investigate **floating offshore wind's potential.**

Other renewables

Floating photovoltaics (PV) solar (high wave offshore solar)

The UK has an installed PV solar capacity of more than 12,000MW direct current (MWdc)[42] – 0.1% of which (11MWdc) in floating PV solar[43]. Growth is expected to be slow as the economic case is not as clear as it is for wind[43].

Offshore PV solar is expected to grow especially slowly due to the technical challenges associated with these projects and limited government support. To date, almost all floating PV solar projects have been deployed on lakes, reservoirs fish farms, and other places where there are calm water conditions.

If floating PV solar were to be installed offshore, salt would erode components and rougher water conditions would create extra wear and tear. Both of those factors would add to project complexity and increase capital costs[44]. Nevertheless, there are several global projects going ahead with high-wave offshore solar plans.

The company Oceans of Energy claims to have developed the first offshore floating solar farm in the Dutch sector of the North Sea that has the ability to withstand waves up to 13 metres high and a capacity that will be expanded to 50 kW this year[45]. A Belgian consortium (led by Environmental and Marine Engineering (DEME), and including Dredging, Tractebel, Jan De Nul Group, Soltech and Ghent University) recently announced plans to invest £1.75 million in a "high-wave" offshore PV farm in the Belgian section of the North Sea[46]. These developments, if proven successful, could translate to further growth in floating PV solar on the UKCS.

> The main barrier to marine energy develop-ment is **a lack of 'route to market'.**

Marine energy

Marine energy is electricity generated from the movement of water in oceans, rivers and seas. In 2018 the UK produced 8GWh of electricity from marine energy, less than 0.003% of the total electricity generated in that year[47]; however, it is estimated that the UK has a technical marine energy resource of 16,000 GWh per year[48].

Marine energy can be split into two main technology sectors: wave and tidal. Tidal energy uses the power of tides to generate electricity and is usually found in estuaries or streams, whereas wave energy utilises waves to generate electricity. It is estimated that the UK has between 25 and 30 GW of tidal energy resource, primarily within estuaries, such as the Severn Estuary, or in the north west of the UK[48]. UK wave energy is estimated to have a potential resource capacity of up to 20GW[48].

Tidal energy technology has now been operated under test and at-sea conditions and can be employed with a good degree of confidence[49]. Wave technology is still at a development stage and several different concepts are being progressed; however, there is still no agreement on its optimal design[49]. A total of 23 wave energy technology developers and 22 tidal device developers were active in the UK in 2018[49]. As of 2018, installed tidal capacity in the UK was 10MW and capacity from wave projects - either operational or under development - was 137MW[49]. The levelised cost of energy (LCOE) for tidal and wave projects is estimated to be around £300/MWh based on recent projects/prototypes[49].

The main barrier to marine energy development is a lack of route to market within existing government frameworks and no allocation of generation capacity. To achieve a route to market marine energy would have to prove it meets the government's "triple test": cost reduction, UK economic benefit and carbon reduction. Currently the technology is proving too costly; however, a study by ORE Catapult estimates that the LCOE associated with tidal power could reduce to £80/MWh as the scale of installed capacity increases[49].

Hydrogen

The main uses of hydrogen in the UK today are in fertiliser production and oil refining to produce low sulphur petrol[51]. However, hydrogen can be used as an alternative to natural gas in the heating, industry, transport, chemicals and power sectors; traditionally very high emission intensive industries[52].

There is a strong case for hydrogen as an alternative to natural gas in the energy system as it is:

- Abundant (hydrogen is the most abundant element on earth)
- Clean (hydrogen produces no emissions at the point of use)
- Produces an abundance of energy (hydrogen has one of the highest energy densities by mass of any fuel)
- Can be stored and transported efficiently (hydrogen can be stored and transported in a variety of forms)

There are four processes for producing hydrogen, all with differing deployment levels and variable associated GHG emissions (see Box 2.1). Currently, over 95% of hydrogen is produced from fossil fuels[53], which accounts for the use of 6% of global natural gas and 2% of global coal . These processes result in the production of approximately 2% of total global emissions (as of 2017)[54]. Green and blue hydrogen are produced by lower emission processes. The development of technology associated with green and blue hydrogen production is therefore required to make hydrogen an effective low-carbon alternative in both existing operations and new uses. The abundance of natural gas production and growing renewable electricity production on the UKCS make it a key area for the development of both blue and green hydrogen production.

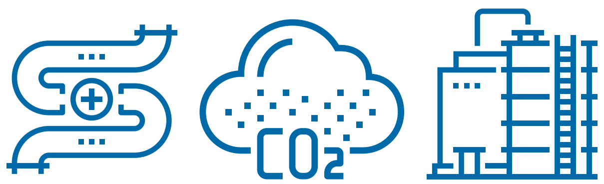
Box 2.2: Hydrogen formation processes

Grey hydrogen

- Produced via thermochemical conversion of natural gas
- Main processes are steam methane reformation (SMR), partial oxidation (POX) or autothermal reforming (ATR)
- Natural gas is the source of ~71% of global hydrogen production[54]
- Process is associated with high emissions

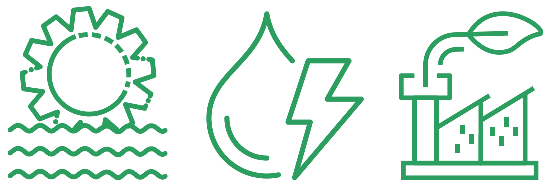
Brown hydrogen

- Produced from the gasification of coal and lignite
- Is widely used, especially in China and Australia, but is less common method of production than SMR[55]
- Coal is the source of ~27% of global hydrogen production[54]
- Process is associated with high emissions



Blue hydrogen

- Produced via SMR, ATR or POX paired with carbon capture, utilisation and storage (CCUS)
- Process is associated with low emissions
- As of the start of 2020 there were two operational blue hydrogen plants; Air Products SMR in Port Arthur, Texas and Quest in Alberta, Canada



Green hydrogen

- Produced from water electrolysis powered by renewable electricity
- Accounts for 1% of hydrogen production[54]
- Currently very expensive to produce
- Process is associated with low emissions

Hydrogen has been identified as key in helping the UK reach its emission reduction targets

Over 50 million tonnes (Mt) of hydrogen is produced globally per year[56]. Only 0.74Mt of this is produced in the UK, mostly at the Esso Fawley refinery near Southampton,[5] but there are more than 10 small scale hydrogen projects across the UK. The majority of the 27 Terawatt-hour (TWh) of hydrogen energy currently produced in the UK is for non-energy uses and is produced using Steam Methane Reforming (SMR), i.e. grey hydrogen[52]. A very small portion of UK hydrogen is produced via electrolysis and is primarily used in the transport sector[58].

Hydrogen has been identified as key in helping the UK reach its emission reduction targets and several new low-carbon hydrogen projects have received funding both from the government and private companies. In February 2020 five projects received funding from the Department for Business, Energy & Industrial Strategy as part of the Hydrogen Supply Competition Phase 2;

- ***Dolphyn - £3.12 million - led by Environmental Resources Management Limited (ERM) - aims to develop a prototype floating wind turbine that also has systems for water intake, desalination and the conversion of water into hydrogen via proton exchange membrane technology[59] (green hydrogen)***
- ***HyNet - £7.48 million – led by Progressive Energy Ltd – aims to develop a clean hydrogen production facility with carbon capture and storage, as part of the HyNet Cluster (blue hydrogen)***
- ***Gigastack - £7. 5 million - led by ITM Power Trading Ltd – aims to produce zero-carbon hydrogen through a gigawatt scale polymer electrolyte membrane (PEM) that uses electricity from the Hornsea Two offshore wind farm[60] (green hydrogen)***
- ***Acorn Hydrogen Project - £2.7 million – led by Pale Blue Dot Energy – aims to develop an advanced reformation process using North Sea Gas while capturing and sequestering the associated CO_2 emissions (blue hydrogen)***
- ***HyPER - £7.44 million – led by Cranfield University – aims to develop low carbon bulk hydrogen supply through pilot scale demonstration of the sorption enhanced steam reforming process (blue hydrogen)***

Development of a hydrogen network and low-carbon industrial clusters will be imperative to the large scale hydrogen deployment needed to achieve the net zero targets. In 2019, Drax group, National Grid Ventures and Equinor announced plans to explore the feasibility of constructing a blue hydrogen production facility with carbon capture and storage in Humberside – the UK's highest emissions industrial cluster (se gure 2.22) - with the aim of starting development of a zero carbon cluster by the middle of the decade[61].

The Zero Carbon Humber project aims to capture CO_2 from the new hydrogen facility, existing power station and other industrial activities in the Humber area before being transported via pipelines and stored in subsurface reservoirs or aquifers in the Southern North Sea[61].

The project involves a range of energy companies that each have a unique role to play: Drax through continuing development of alternative fueled power generation, National Grid through the development of a regional CO_2 pipeline network, and Equinor through utilising its UKCS subsurface knowledge to effectively store captured CO_2.

Figure 2.21 provides details of other hydrogen projects including: Hydrogen Offshore Production (HOP) on Orkney; Project Acorn at St Fergus; HyNet Northwest on Merseyside; and H2H Saltend on Humberside.

Carbon capture, utilisation and storage

Carbon capture, utilisation and storage involves capturing CO_2 (either directly from emitting sources or from the atmosphere) and permanently storing it, usually in underground sites such as saline aquifers or depleted oil and gas reservoirs, or using it in another process.

CCUS can be used to reduce emissions at a variety of industrial facilities, including power generation, natural gas processing, petroleum re ning, cement production, hydrogen reforming and chemical production[62]. Depending on the application, CCUS can reduce carbon emissions from industrial processes by 90%[62]. The huge volume of both aquifers and depleted oil and gas reservoirs on the UKCS make it a prime candidate for storing CO_2.

Globally, there are more than 60 operational CCS projects of varying capture capacity (se gure 2.19). Of these, the Drax bioenergy plant is currently the only operational carbon capture project in the UK[62] . The largest carbon capture trial in the UK took place at the Ferrybridge Power Station in West Yorkshire between 2011 and 2013 where 100 tonnes of CO_2 was captured per day. Since 2009, 12 other CCS projects associated with coal power plants in the UK have been put on hold or cancelled[62].

Five of the 32 global CCS project currently under development or construction are in the UK (se gure 2.21)[62]. Three of these projects are investigating the potential to capture CO_2 at natural gas power plants and the other two projects are investigating capturing CO_2 from gas processing and/or hydrogen production projects[62].

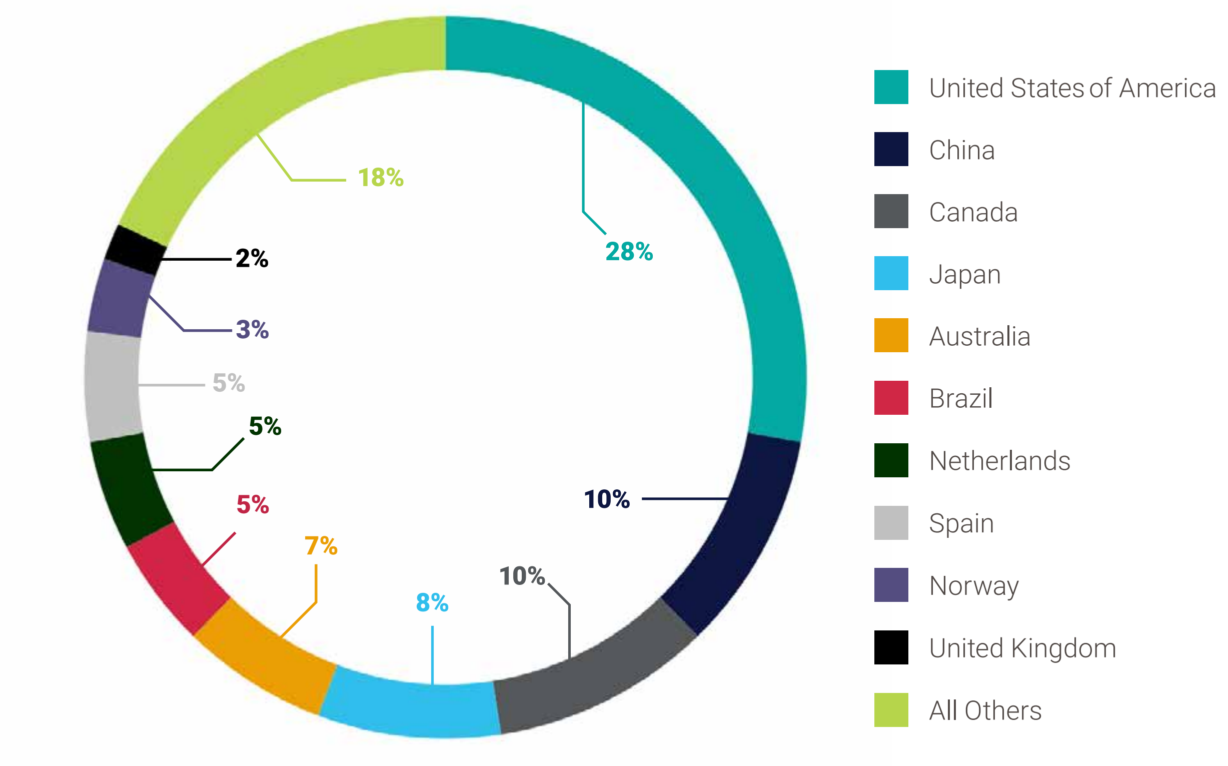
Global installed CCS capacity was estimated at 41.9 million metric tons per year ($MtCO_2$/yr) in 2019 (equal to 1.1% of global emissions in 2019[62]); the UK has a current capacity of less than 0.5 $MtCO_2$/yr [62]. Based on currently announced projects, global CCS capacity will reach 85.3 $MtCO_2$/yr by 2030. More than four times this capacity (461 $MtCO_2$/yr) is required by 2030 to keep pace with a 2-degree warming trajectory[62].

The UK government has established the CCUS Infrastructure Fund which dedicates £800 million to the development of CCUS projects in at least two sites, one to be operational by the mid 2020s and one by 2030[63]. The sites earmarked for the CCUS projects include industrial clusters such as St Fergus in Scotland and Teesside, Humberside and Merseyside in England (se gure 2.22).

The economics of CCUS projects are still borderline due to high capital costs and long lead times[64] which have resulted in many planned projects being put on hold or terminated. This has been the case for post-combustion CCUS schemes at coal- red power plants, as well as cement and steel manufacturing. With regards to the latter, the applications have so far been only proven in theory. Signi cant policy incentives such as carbon taxes and the development of CCUS clusters are likely needed to help CCUS be competitive. On a cost of CO_2 avoided (the carbon price needed to make a project economic) most applications of CCUS need a minimum carbon price of £75/tonne, approximately three times that of the current European traded carbon price (as of the start of 2020)[65].

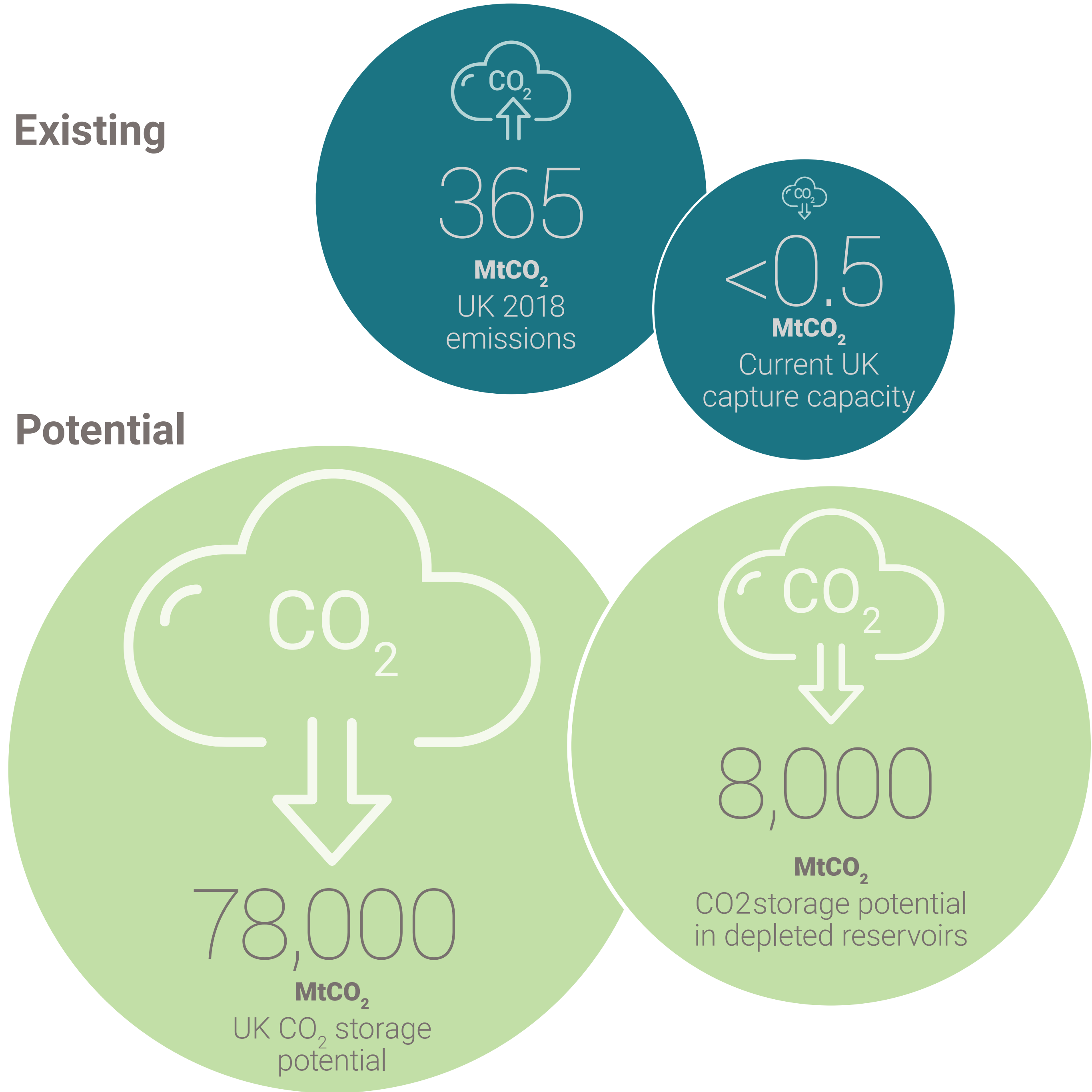
Utilising existing infrastructure and knowledge on the UKCS could be key in reducing CCUS costs[66]. The large number of depleted reservoirs on the UKCS make ideal candidates for storing CO_2 as they have the required porosity for storage, thorough subsurface information and, in most cases, infrastructure already in place that could be used for CO_2 transport and storage activities. However, there are uncertainties around the long term integrity of depleted reservoirs and monitoring for leakage could add signi cant complication and cost to projects. According to the Global CCS Institute, there is an estimated 78,000 $MtCO_2$ storage potential in the UK, 8,000 $MtCO_2$ of which is in depleted oil and ga elds.[27]

Figure 2.19: Global operational CCS plants (by number)



Source: Wood Mackenzie

Figure 2.20: UK capture and storage potential



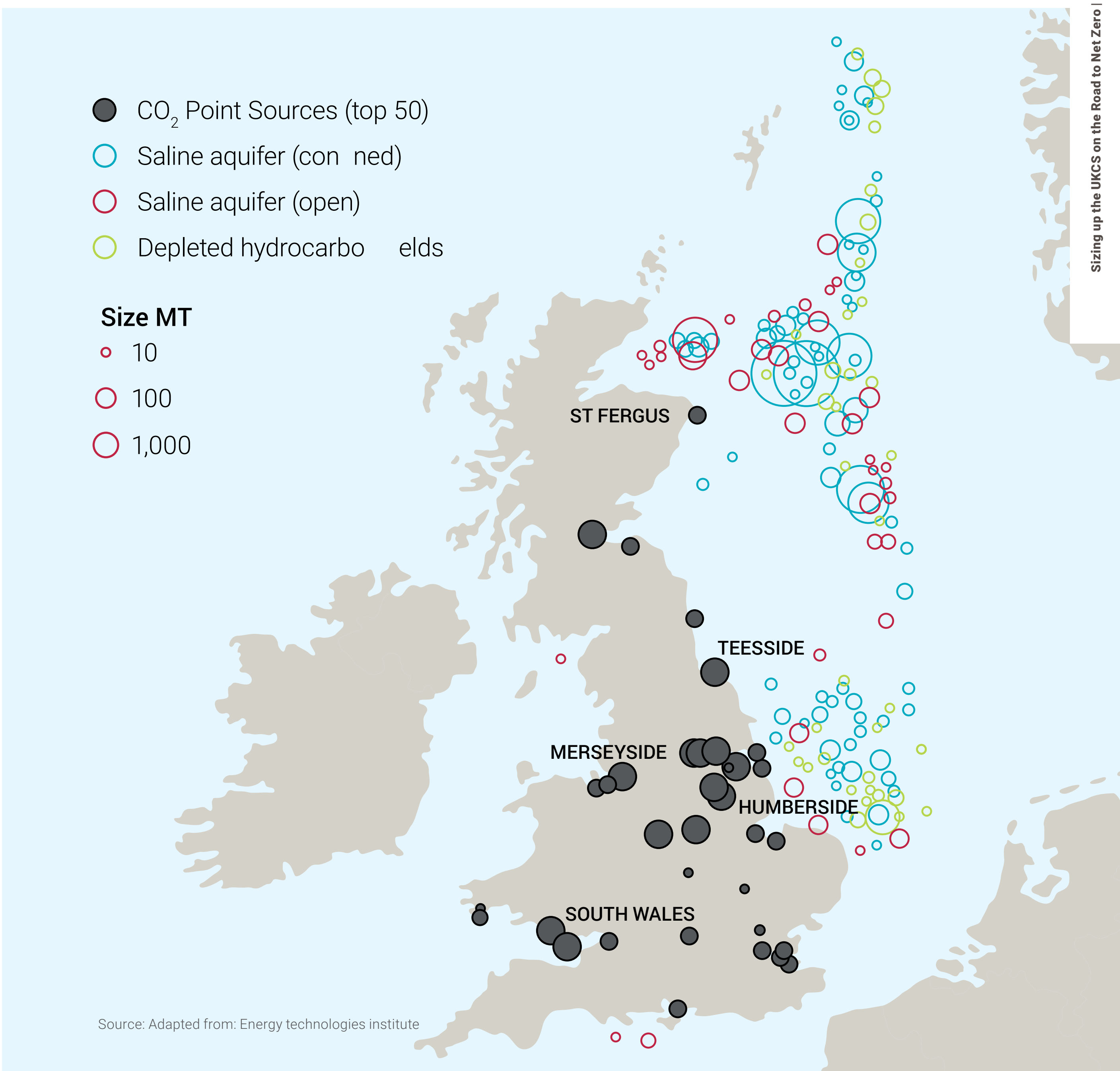
A study conducted by The Energy Technologies Institute in 2016 identi ed over 20 oil and ga elds suitable for CO_2 storage and high-grade ve for in-depth analysis[27]. Thes elds were selected based on substantial subsurface data already available, meaning there is high co dence that CO_2 could be stored at commercial rates. A potential development plan was produced for each of these sites demonstrating how delivering between 3 and 10 $MtCO_2$/yr storage capacity over a minimum 15-year period could be implemented cost effectively.

Although all the sites have existing infrastructure (platforms, wells and pipelines), the study recommended new infrastructure be installed as existing infrastructure was designed and installed for alternative purposes and so is not t for purpose for CCS[27].

Figure 2.21: UK CCUS and low carbon hydrogen projects

No	Project Name	Stakeholders	Aim	Progress	Type
1	**Hydrogen Offshore Production (HOP)**	Aquatera, Doosan, Cranfield University, EMEC Hydrogen, NOV, Net Zero Technology Centre	Repurpose offshore infrastructure for hydrogen production and establish a test centre for hydrogen technology acceleration	Funding awarded by BEIS, feasibility study completed	
2	**Project Acorn — CCS and Hydrogen**	Pale Blue Dot, Shell, Total, Chrysaor, Macquarie Group	Utilise existing infrastructure for transportation and then storage of CO_2 in reservoir quality rocks (i.e. the Captain Sandstone) in the North Sea. The project then aims to reform North Sea gas to make hydrogen and store associated emissions using the Acorn CSS project	Funding awarded by BEIS, FEED study in progress, aiming for FID in 2021	
3	**The Caledonia Clean Energy Project**	Summit Power	Capture CO_2 from natural gas- red plant and store in depleted oil and ga elds in North Sea	Feasibility study completed	
4	**Net Zero Teesside**	BP, Eni, Equinor, Shell and Total	Decarbonise a cluster of carbon-intensive businesses through CCUS	Feasibility study in progress	
5	**HyNet Northwest**	Jaguar, Land Rover, Essar, Unilever, Inovyn, Encirc, Cargill, CPW, Novelis, Prinovis, Pilkinton, CF, Ibstock Brick, Essar, Solvay, North west Hydrogen Alliance	Develop blue hydrogen production and industrial fuel switching alongside CCS	Funding awarded by BEIS, FEED study in progress	
6	**Drax power station**	Drax group, National Grid Ventures, Equinor	Develop scalable bioenergy power production with CCUS	Pilot project in progress	
7	**H2H Saltend**	Equinor	Develop blue hydrogen production with carbon capture and storage in the Southern North Sea (i.e. the Endurance aquifer). Enable CO_2 capture and fuel switching across the Humber industrial cluster	FEED study in progress with FID planned for 2023	
8	**Gigastack**	Ørsted, ITM Power and Element Energy	Develop green hydrogen production using offshore wind power (from Hornsea 2 windfarm)	Funding awarded by BEIS, feasibility study in progress	
9	**Project Dolphyn**	ERM	Develop green hydrogen production using oating offshore wind power	Funding awarded by BEIS, FEED study in progress	

Figure 2.22: UKCS storage potential and highly emissive industrial clusters



Source: Adapted from: Energy technologies institute

A 2018 UK government funded study recommended the development of CCUS 'cluster' areas where CCUS could be developed in proximity to highly emissive activities such as ga red power generation or blue hydrogen production. Th ve areas identi ed were; Teesside, Humberside, Merseyside, St Fergus Scotland and South Wales, all of which have existing industrial activity or potential for hydrogen developments (se gure 2.22). Blue hydrogen projects make up over 20% of the CCUS development pipeline due to the push for hydrogen through national hydrogen roadmaps and emissions reduction targets, and include projects in Humberside and Merseyside[62].

Overall energy mix

The UK's energy market has been transitioning to a lower carbon mix. Coal is being switched out for gas and there have been major investments in offshore wind and solar PV. In 2018, oil was still the primary fuel used for energy and its main use was in the transport sector, which accounted for over 70% of total oil demand.

Gas was the second most used fuel in the UK in 2018 and was the leading fuel for electricity generation, producing 40% of output. Gas demand has increased over the pas ve years as coal has been phased out. Coal is expected to disappear completely from the energy mix by 2024, resulting in gas and renewables' share of power generation increasing (se gure 2.25). Nuclear will also account for a decreasing proportion of the energy mix as old reactors are decommissioned. Renewables are expected to see the greatest growth, especially offshore wind and solar, which are forecast to make up 50% of the power mix by 2030. Power production from other solid fuels, in the form of renewable bioenergy, is also expected to grow.

Figure 2.23: UK gas production and demand (1965-2018)

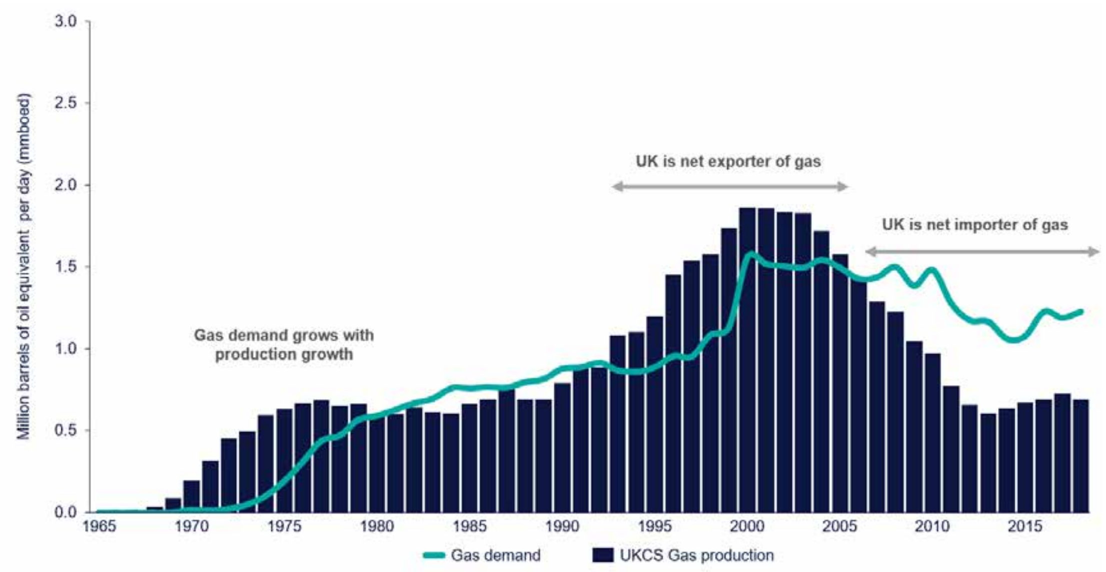
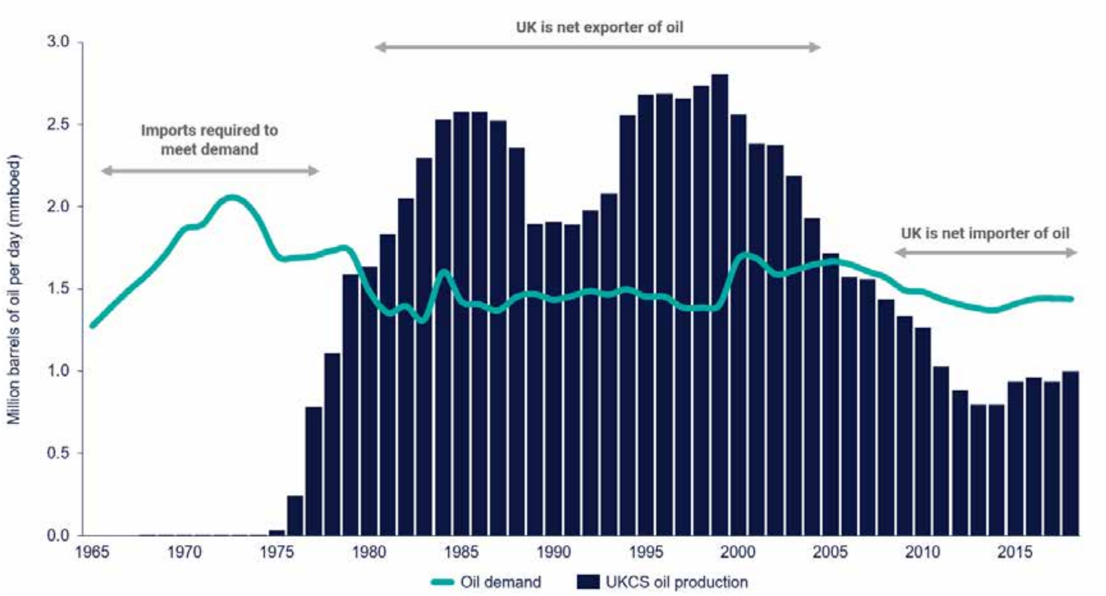


Figure 2.24: UK oil production and demand (1965-2018)

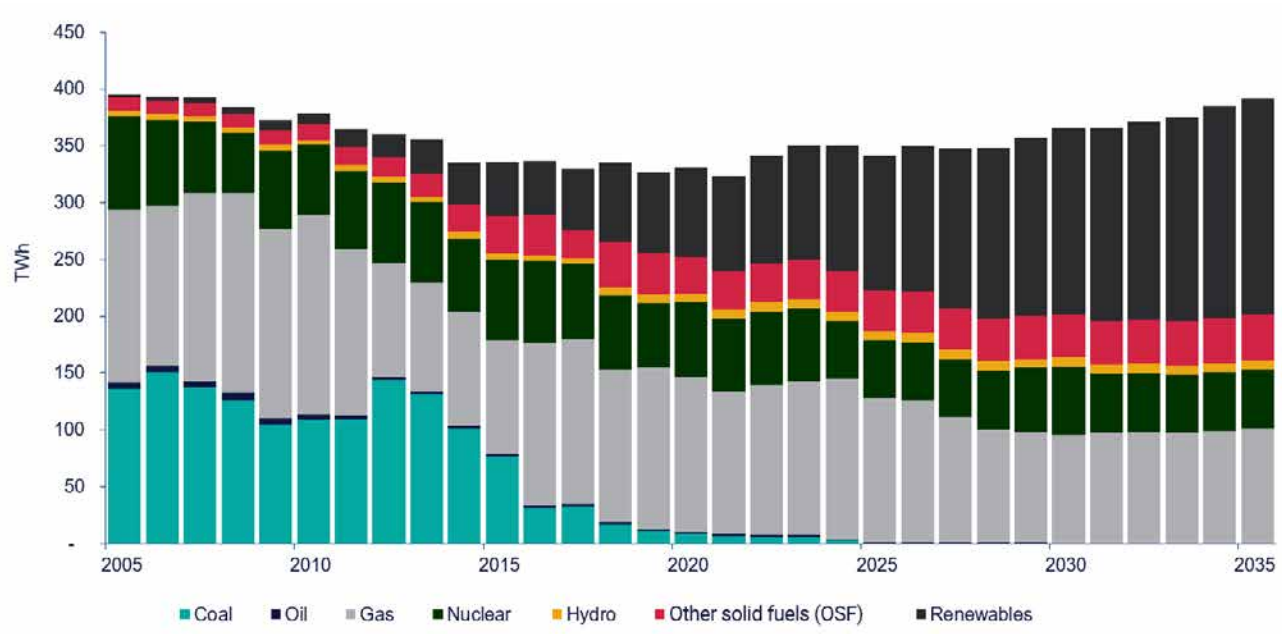


Source: Wood Mackenzie, IEA

In 2018, gas accounted for 36% of the UK's total primary energy demand, and oil 39%[17]. Most of the gas produced on the UKCS is delivered to the UK onshore network, the National Transmission System, and consumed domestically. When demand is low, or due to the location of certai elds, some gas is exported through interconnectors to the European market. The majority of gas is used for power generation and in the residential/commercial sector[17]. In 2019, over 40% of the UK's electricity was produced using gas[17]. Increasing renewable generation and warmer temperatures have driven gas demand down over recent years - natural gas demand fell 4.6% between 2016 and 2017[2]. Approximately 50% of the UK's gas demand is met by gas from the UKCS[17].

Transport makes up over 70% of the UK's oil demand. The UK has been a net importer of oil since 2010, and output from the UKCS meets 76% of the UK's oil demand[17].

Figure 2.25: UK power mix- historical and forecast



Source: Wood Mackenzie, IEA

In 2010 offshore wind generated less than 1% of the UK's electricity; by 2018 this had increased to 8%[13]. Offshore wind is expected to make up an increasing share of the UK's energy mix as coal- red power plants are phased out. It is assumed new offshore wind investments will be prioritized in policy over onshore wind and solar PV as the latter two energies transition towards more market-based forms of support, i.e. power purchase agreements (PPAs) between electricity generators and electricity providers.

In 2018, renewables (hydro, wind, solar and other solid fuels) accounted for 11% of total energy consumption and 35% of total UK electricity generation. Renewable generation capacity reached 44.3GW in 2018[67]. Electricity generation from offshore wind increased by 29% to 27TWh in 2018[18]. Other installed renewable capacity reached 34GW in 2018, 38% of which was solar capacity and 62% onshore wind capacity.

In total, resource from the UKCS (offshore wind, oil and gas) generated just under half of the UK's total energy demand and approximately a third of the UK's electricity in 2018[17,18].

> Resource from the UKCS (offshore wind, oil and gas) **generated just under half of the UK's total energy demand**

Imports

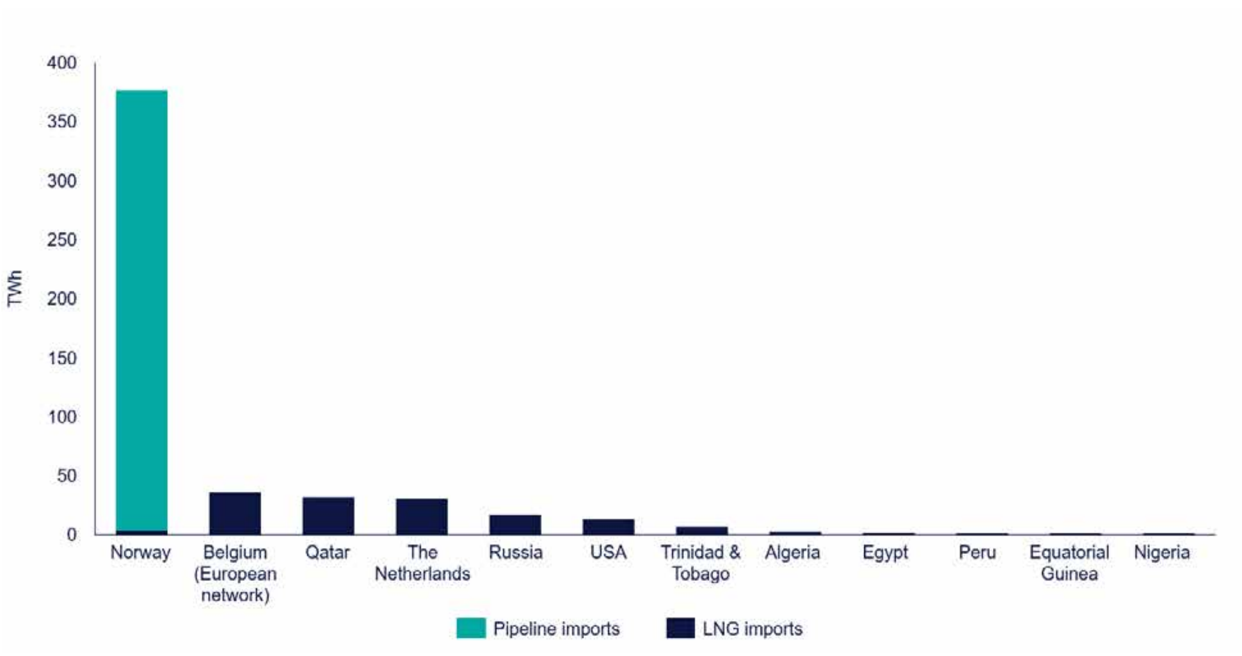
In 2018, the UK was a net importer of all main fuel types, importing 38% of its total energy supply[20]. The UK imports approximately 50% of its gas supply[20], the majority being pipeline imports and remainder from liqui ed natural gas (LNG)[2].

LNG imports are used as a swing fuel when either demand increases or indigenous production falls. The majority of LNG imports come from Qatar (41% in 2018), but other primary LNG sources include Russia and the US (providing 21% and 17% of the UK's LNG imports in 2018 respectively)[68]. The carbon intensity of gas imported as LNG is signi cantly higher than the intensity of domestically produced gas. Although emissions associated with LNG imports are not directly attributable to the UK's net zero target, they are accounted for as part of embedded GHG emissions from imported products and services. As domestic gas production declines and LNG imports increase, the overall carbon intensity of gas used in the UK will go up. Norway is the key source of oil and gas imports to the UK, accounting for 85% of piped gas imports, while other piped gas is imported from the Netherlands and the European network via Belgium (se gure 2.26)[67].

The UK imports more oil than it produces, however it also exports a large proportion of oil (se gure 2.27). This is due to the differing qualities of oil produced on the UKCS and elsewhere in the world, and the type of feedstock required by domestic re neries. In 2018, the UK produced enough oil to meet 73% of its total oil demand.[17]

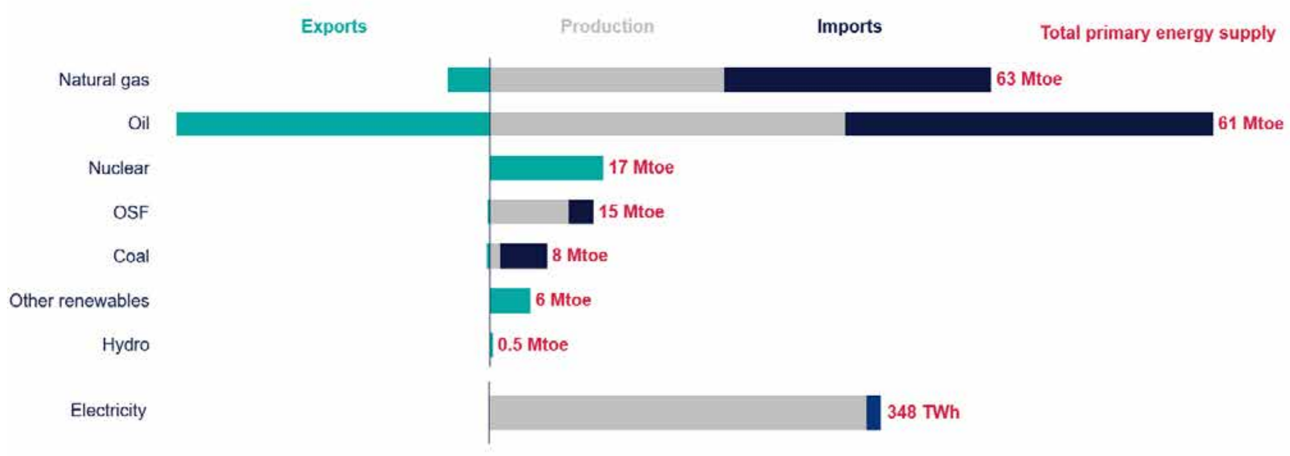
In 2018 the UK generated 335 TWh of electricity and imported 4% - 13 TWh - of the total electricity consumed[17]. The UK currently imports electricity from Ireland, the Netherlands, Belgium and France via interconnectors running across the UKCS. There are plans to expand the UK's interconnector network with new links to Norway, Denmark, France and Ireland, which are expected to become operational by 2022.

Figure 2.26: UK gas imports - 2018



Source: UK government, Wood Mackenzie

Figure 2.27: UK import reliance - 2018



Source: IEA, Wood Mackenzie

2.3: Policy, regulation & commitments

Global policy

The UK rati ed the Paris Agreement in 2016. The Paris Agreement aims to keep the rise in average global temperature to well below 2 degrees Celsius and ideally to limit warming to 1.5 degrees Celsius, compared to pre-industrial levels.

The Paris Agreement obligates signatories to aim for the 'highest possible ambition' with regards to climate change.

In line with the Paris Agreement, the European Commission (EC) announced its aim to become th rst carbon neutral continent by 2050. In 2018, the EU released its "Clean Planet for all" strategic framework which outlines a "direction of travel" for future EU climate and energy policies[69]. The European Parliament has since endorsed the carbon neutrality aim and the EC plans to propose that the 2050 target is codi ed, as part of the European Green Deal (the EU's new growth strategy which aims to cut emissions whilst boosting jobs and economies[70]).

UK policy

The UK was th rst major country to commit to legally binding emission reduction targets with the introduction of the Climate Change Act of 2008.

The act provides legally binding targets to reduce UK emissions; the initial target was an 80% reduction compared to 1990 levels by 2050, however this has since been revised to a 100% reduction in emissions by 2050. This requires the government to set binding 5-yearly carbon budgets. The UK is currently in the third budget period (2018-22). By 2032, the UK should have reduced emissions by 57% compared to 1990 levels. These targets can be adjusted according to factors such as technological progress and economic predicament.

The National Renewable Energy Action Plan (NREAP) was legislated via the Climate Change Act of 2008 and sets out renewable energy targets for 2020 as part of the UK's contribution to EU energy targets. Under those targets, renewables should account for 15% of overall energy demand, 30% of electricity, 12% of heat and 10% of transport by 2020. Currently, the electricity target has been reached; however, the targets for heat and transport look unlikely to be met.

Each renewable source - onshore wind, offshore wind, solar and others - has individual targets.

Sizing up the UKCS on the Road to Net Zero | Section 2

Paris Agreement

Keep the rise in average global temperatures to below 2 degrees Celsius.

Obligates signatories to aim for the 'highest possible ambition' with regards to climate change.

UK Climate Change Act 2008

Established the Commitee on Climate Change which recommends carbon reduction.

Requires the government to set binding 5-yearly carbon budgets.

The UK is currently in the third budget period (2018-2022), which aims for a 37% emissions reduction by 2020.

In 2018 had achieved a 43% reduction compared to 1990 levels.

The UK government has committed by law to reduce net GHG emmissions by 100% of 1990 levels, i.e. net zero, by 2050.

The National Renewable Energy Action Plan (NREAP) (as part of EU energy targets) targets that renewables account for 15% of overall energy demand by 2020:

30%	12%	10%
of electricity	of heat	of transport

Sector speci argets for the proportion of energy that should be met by renewable power

Committee on Climate Change

As part of the UK's commitment to the Paris Agreement, the Committee on Climate Change (CCC), the UK's independent climate advisory body, recommended a new target of bringing all greenhouse gas emissions in the UK to net zero by 2050. The Net Zero Emissions 2050 policy was implemented in June 2019.

The CCC further recommended Scotland target net zero emissions by 2045. Scotland previously had a target to reduce emissions of all greenhouse gases by at least 80% by 2050 relative to 1990 as part of the Climate Change (Scotland) Act (2009); however, a new Climate Change bill, which sets a legally binding net zero target of 2045, was passed by the Scottish Government in September 2019. The bill further sets an interim target of a 75% reduction by 2030, compared with 1990 levels.

To reach the UK's net zero target emissions, the CCC is proposing an approach that combines;

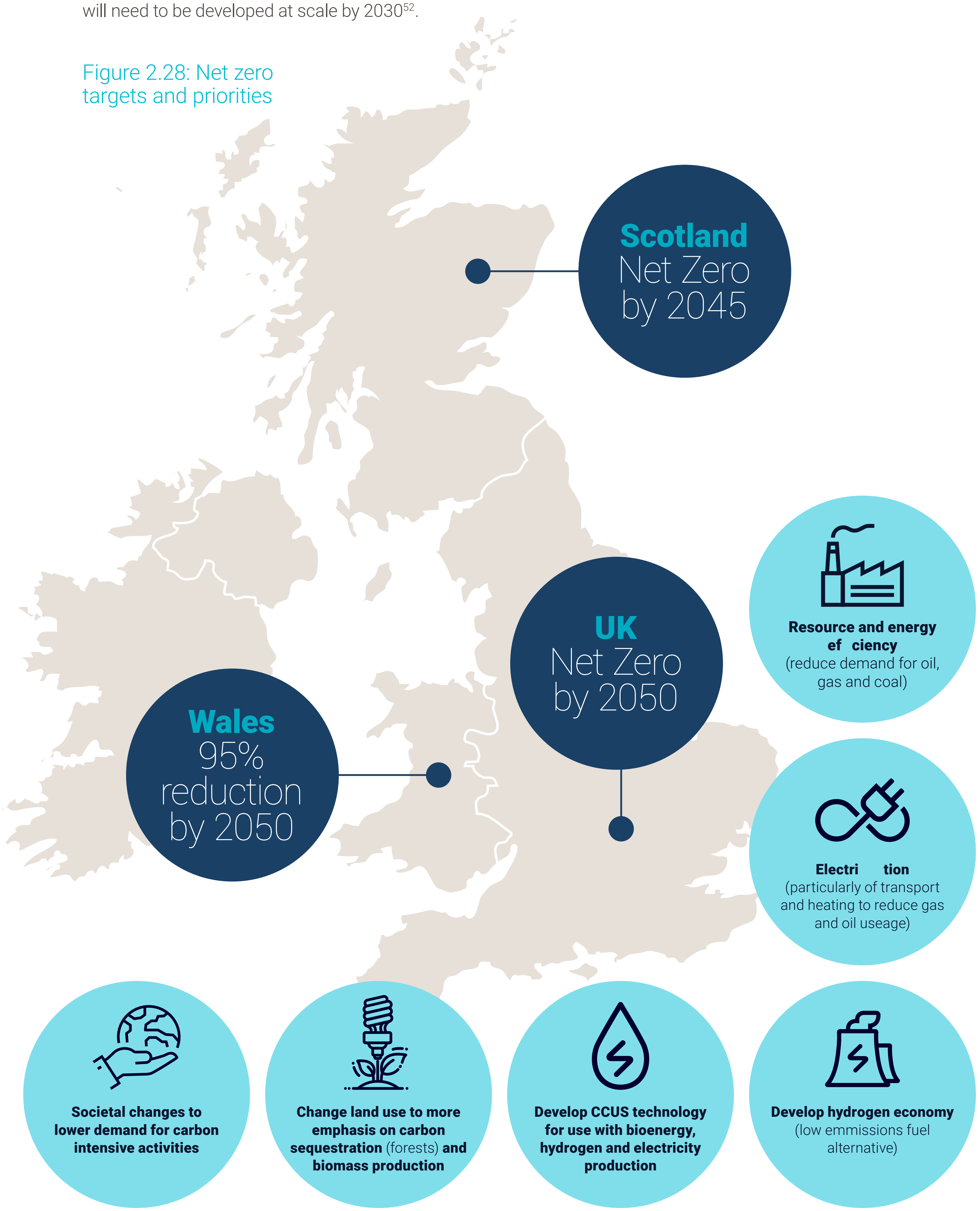
- **reduced energy demand through better energy ef ciency and increased electri cation**
- **increased energy production from renewable sources**
- **a switch to a hydrogen economy**
- **increased carbon sequestration through afforestation and carbon capture, utilisation and storage (CCUS)**

Major technological advances will be required to implement these plans at scale and economically, especially hydrogen production and CCUS. Additionally, to achieve the net zero target, signi cant growth of renewable capacity is required; for example, installed offshore wind capacity will need to reach 75GW by 2050.

The CCC recommends that hydrogen use increase from current levels of 27TWh today to 270TWh in 2050: a 900% increase and equivalent to over 80% of the UK's 2018 electricity usage[17,39]. To reach this target, production from reformers (i.e. SMRs and ATRs) will need to increase to a capacity of 29GW and production from electrolysis to 6-17 GW by 2050. Development of a hydrogen gas grid or alternative transportation infrastructure and carbon capture and storage infrastructure will also be required[39].

To reach net zero by 2050, UK wide carbon capture and storage capacity needs to reach 176MtCO_2; 46Mt for GHGs associated with hydrogen production, 57Mt for power generation, 35 Mt for bio-energy with carbon capture and storage (BECCS), 24Mt for industry and 9MT for biofuel production[52]. To achieve these levels, CCUS transportation and storage infrastructure will need to be developed at scale by 2030[52].

Figure 2.28: Net zero targets and priorities



Roadmap 2035

The UK's oil and gas industry has expertise and infrastructure key to enabling the UK to reach its net zero target. The industry therefore responded to the government's net zero policy by developing the "Roadmap to 2035: A blueprint for net zero". This was followed on in June 2020 with "The Pathway to Net Zero: Production Emissions Targets" which details targets to reduce emissions from upstream operations by 50% by 2030, 90% by 2040 and to reach net zero emissions by 2050[115].

Developed by OGUK the roadmap outlines how the UK oil and gas industry will aim to reduce emissions associated with production activity and help develop new low-carbon technology, while also continuing to maximise production and provide significant indigenous supply to meet the country's energy demands. The industry aims to reduce the level of offshore emissions from the 14.6 million tonnes CO_2e produced in 2018 to half this in 2030 and net zero by 2050[115]. The emissions reduction will be measured at a basin-wide level, and not on an individual operator or asset basis, and three primary methods to reduce emissions have been identified: operational improvement, reduce flaring and venting and step-change action[115]. As well as emission reduction targets, the industry has set production targets, with UK oil and gas producers to aim to produce over 1 million barrels of oil and gas per day, over half of the UK's oil and gas demand, in 2035 and extend production on the UKCS out to 2050 and beyond[71]. Based on current production forecast, UKCS production will be a third less than this target[2].

The OGUK, through the Roadmap 2035, also highlighted how the oil and gas industry will help the UK reach its net zero target[72];

- **Better control of hydrocarbon consumption and emissions through reduced reliance on international petroleum imports and maintenance of indigenous production by attracting international investment, continued exploration and maximum recovery of existing resource**
- **Reduce emissions from production operations; primarily through electrification of platforms, the development of energy hubs and reducing flaring**
- **Support the development of emissions mitigation technologies, mainly CCUS and hydrogen fuel by utilising existing knowledge, skills and infrastructure within the oil and gas industry**
- **Invest in the expansion of low-carbon business and technologies, such as offshore wind, wave and tidal power, again using existing infrastructure, skills and knowledge within the industry**

Figure 2.29: Industry specific Targets and commitments

UK government and offshore wind sector: offshore wind sector deal

- Increase UK content to 60% by 2030
- Increase UK jobs in offshore wind to 27,000
- Increase exports to £2.6 billion by 2030
- 30GW of capacity by 2030*

*Target increased to 40GW by 2030 in November 2019

UK oil and gas industry Roadmap 2035

- Become a net zero GHG emissions basin by 2050
- Secure at least 130,000 direct and indirect jobs
- Grow and diversify energy supply chain export revenues to £20 billion per year
- Keep production output above 1 million boe per day and meet at least 50% of UK's oil and gas demand.

UK government CCUS deployment pathway: an action plan

- Have the option to deploy CCUS at scale in the 2030s, subject to costs coming down sufficiently
- Address policy barriers and set out policy options
- Work with other governments to identify and address barriers to cross border transport of CO_2
- Deliver £4 million innovation programmes focussed on CCUS

Hydrogen Taskforce: The role of hydrogen in delivering Net Zero

- Develop hydrogen strategy within UK government
- Government to commit to spending £1 billion on production, storage and distribution projects
- Enable hydrogen blending into the UK Gas Grid and take the next steps towards 100% hydrogen heating
- Collaboration to establish 100 hydrogen refuelling stations (HRS) by 2025

The Net Zero Technology Centre's Net Zero Solution Centre

To support the Roadmap 2035, the Net Zero Technology Centre established a Net Zero Solution Centre in 2019.

The centre aims to investigate and implement technologies that will both reduce emissions from offshore oil and gas activities and develop new technologies that will offset emissions. A key aim of the centre is to utilise existing oil and gas infrastructure, supply chains and skills to develop new integrated energy hubs that can help meet the UK's energy needs while also reducing emissions produced. The centre is supported by member companies including BP, Shell, Total, Wood, Chrysaor, CNOOC and is backed by the Scottish Government.

3

Closing the Gap to 2050

Technologies

3.1: Introduction and approach to the technology roadmap

The UKCS' role is going to be central to the UK achieving its net zero target. The UKCS is going to deliver renewable power on a scale not seen before, produce low emissions oil and gas for industry, produce clean fuels for the economy, as well as provide a source for long term carbon storage. In essence the UKCS will go beyond net zero. This will require transformational changes to the energy mix and step-change improvements in efficiencies and environmental footprints of incumbent industries, and, most importantly, integration of energy systems that are either nascent or siloed today. Achieving these goals in the next three decades will require significant research, development and scale-up efforts, with an emphasis on the key technology challenges and innovation gaps that are hampering commercial realisation. This section will explore these challenges and innovation gaps to build a net zero technology roadmap for the UKCS.

Oil and gas operators on the UKCS are already taking steps to reduce carbon emissions by improving operational efficiency, deploying lower-carbon technologies to power operations and developing next-generation tools to unlock features such as automation and predictive maintenance. These developments are, in turn, the result of increasing efforts by oil and gas operators to analyse and understand data collected through the myriad of instruments and sensors across their operations. These actions will continue to decarbonise the region while maximising its economic recovery.

However, there is an opportunity for the UKCS to not only decarbonise its operations, but also to support the UK in achieving net zero GHG emissions by 2050 (and by 2045 in Scotland). This will require significant efforts and coordination across multiple industries – incumbent and emerging, including offshore oil and gas, wind, onshore power generation, hydrogen, and many others. To decarbonise its own operations while expanding its role as the UK's main resource base, the UKCS will need carbon storage infrastructure and increased low-carbon energy in the form of renewable electricity and hydrogen for its platforms. Many of the technologies needed are available but are often developed in industrial silos and significant innovation gaps must be addressed.

The purpose of the Technology Roadmap is to identify the most critical low-carbon technologies and the challenges that need to be overcome. Technologies will be considered as technology "families" - groups of technologies that serve a similar function - and the analysis will focus on families that:

1. **Support the decarbonisation of the UKCS itself;**
2. **Support decarbonisation of the UK as a whole;**
3. **Require outsized innovation and funding support to address technology challenges and bridge innovation gaps.**

Net Zero Technology Roadmap approach

To identify the technologies that address these objectives, the study began with an exhaustive taxonomy of energy technologies that exist or could exist on the UKCS, compiled with inputs from technology experts on the UKCS. These included:

Oil and gas
(drone sensors to re-usable subsea systems)

Renewables
(offshor xed-bottom and oating wind to wave and tidal energy)

Hydrogen
(production, transportation, storage)

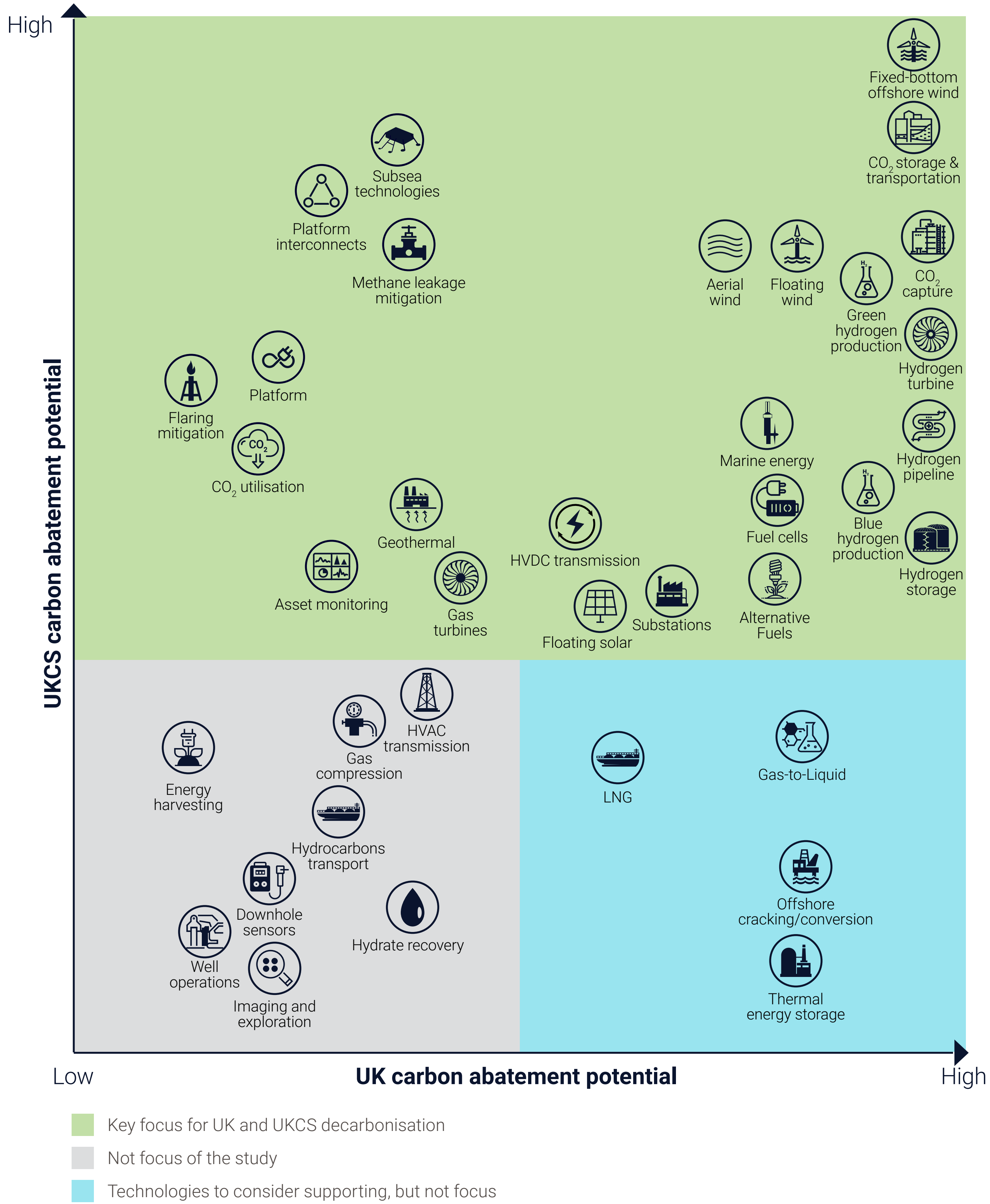
CCUS
(capture membranes, calcium looping, amine scrubbers, CO_2 enhanced oil recovery)

Digitalisation
(digital twins, simulation tools, arti cial intelligence)

The technology families wer rst prioritised based on their decarbonisation potential for the UKCS and for the UK as a whole (se gure 3.1). Those families with the greatest decarbonisation potential were selected for further analysis (see green section of gure 3.1).

With extensive inputs from key industry stakeholders, the priority technology families were systematically evaluated against two mutually exclusive sets of metrics: these considered the technology perspective (challenges, maturity, innovation momentum, commercial scaleability on the UKCS) and the ecosystem perspective (market demand nancing, dependencies and other barriers to commercialisation). The roadmap explores the key technology challenges and innovation gaps, identi es how the various technologies interlink across the wider energy ecosystem and outlines a path to advance these technologies towards a net zero energy system by 2050.

Figure 3.1: Technology families with greatest decarbonisation potential



Source: Lux Research

3.2: OIL & GAS

Emission reduction technologies

As the energy transition progresses, hydrocarbons will still play a key role in the economy. Oil and gas operations will continue to provide secure energy sources and valuable feedstocks to produce chemicals and materials. The growing demand for hydrocarbons is palpable: according to the International Energy Agency (IEA), natural gas accounted for almost one-third of the total energy demand growth over the past decade[73].

The production and transformation of energy and fuels represents a significant proportion of energy demand and emissions in the UK (see Section 2 – Carbon emissions from UKCS. However, as the offshore industry has been focusing on increasing productivity and uptime, it has also worked to upgrade and optimise operations, which in turn, has resulted in a 15% reduction in carbon intensity since 2013[74]. For instance, operators have started implementing technologies such as digital twins, predictive analytics and digital optimisation, which help to operate equipment such as pumps, compressors and turbines at optimum efficiency. These technologies, driven by operators and technology developers, will continue to incrementally improve efficiencies and emissions.

The Net Zero Technology Centre is currently developing an Offshore Emissions Reduction Solutions report, due for publication in 4Q 2020. The report will provide details on a range of crucial short, medium and long-term quantified measures that UKCS oil and gas operators can implement to reduce the carbon intensity of their offshore assets. This report will importantly reflect the knowledge and practices of the operators and supply chain who are driving the energy transition on the UKCS.

The OGA's UKCS Energy Integration[407] report, highlights the importance of energy integration for the oil and gas sector in reducing production emissions, as well as accelerating the progress of CCS and hydrogen in support of net zero.

The implementation of more revolutionary solutions has, however, been hampered by the overall maturity of the basin and limited availability of capital due to low oil prices. In this section, we will explore the decarbonisation solutions that require more support from industry – those that might have been set aside because of high technology hurdles, or those that need more government support and inter-industry collaboration. These can broadly be categorised as: platform electrification, mitigation of flaring and methane leaks and subsea systems.

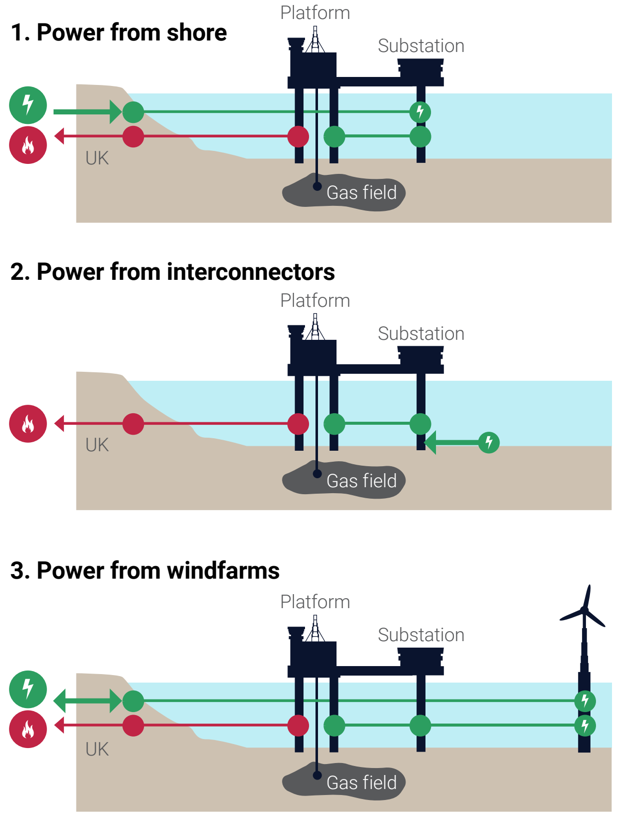
Platform electrification

Today, 74% of CO_2 emissions offshore come from combustion equipment that either provides electrical power to platforms or drives mechanical loads such as compressors[75]. Electrification of offshore oil and gas installations can significantly reduce emissions in two main forms – first, by supplying low carbon electricity from renewables to existing electrical loads; secondly, by potentially replacing open cycle gas turbines that drive mechanical loads with electric motors.

Current status

Power demand from UKCS platforms is approximately 24 TWh/year. This represents over 8% of total UK power demand and accounts for over 10% of total power plant emissions[76]. Due to platforms' remote locations, this demand is usually met by gas turbines – using wellhead gas – and diesel generators. However, open cycle gas turbines are inefficient (typically in the 28% to 38% range, depending on the load, with lower efficiencies often observed on platforms in the UKCS[77]) and result in high CO_2 emissions. A platform with an output capacity of 100MW would emit over 620,000 tonnes of CO_2 per year.[78].

Figure 3.2:
Platform electrification scenarios



Source: Adapted from OGA image

Platform electrification can be either full or partial. Full platform electrification replaces gas turbines and diesel generators with electricity from onshore generation or from offshore wind farms. This also requires heat generation and high-power mechanically-driven equipment like gas compressors to be replaced to run on electricity, which leads to high capital costs, as well as to footprint and weight challenges. Partially electrifying is a nearer-term alternative, where gas turbines continue to cover high-power mechanical loads, while remaining processes use electricity. Though partial electrification can already reduce CO_2 emissions by a third[79], using alternative fuels like hydrogen or ammonia in gas turbines can further amplify carbon savings while overcoming space and weight constraints on offshore platforms where full electrification is not feasible. (see section 3.4 - Hydrogen technologies).

Technology challenges

The business case for platform electrification depends on platform conditions and location, as well as timing of cessation of production. Connecting onshore power to offshore platforms involves a significant investment, as platforms on the UKCS are often more than 200km from shore. To justify infrastructure outlay, new platforms are generally more suitable for electrification, though factors such as the overall power consumption, types of loads and platform size will have an impact on the decision to electrify. For existing facilities, electrification will only be viable if the savings in operating costs - resulting from increased uptime and reduced maintenance costs - compensate for the high cable and platform conversion investments as well as the lost earnings from production downtime – in the case of full electrification – while transitioning to an electrified platform. Electrifying a cluster of fields helps to share these capital costs.

A study by the Norwegian University of Science and Technology estimated the capital expenses to fully electrify the Utsira area in the Norwegian continental shelf – consisting of the Edvard Grieg, Johan Sverdrup, Ivar Aasen and Gina Krog fields – were approximately £1,150 million[80]. The study assumes the use of onshore power, meeting heat demand with electric heaters and an AC transmission system. A partial electrification project relying on gas turbines for high-power equipment such as compressors as well as using waste heat to supply heat demands could have capital expenses of nearly £750 million[80]. Though cost reductions in subsea cabling, power electronics, and compressors using electric drives are needed to speed up the adoption, platform electrification was shown in the same study to reduce operational costs by nearly 45% at periods of high energy demand[80].

Power transmission

Subsea cabling costs are high and range from £1 million per km to £2 million per km, depending on the voltage rating and the level of inclusion of electrical equipment such as power converters.[81]. Electrification projects will therefore benefit from developments that lower the costs of subsea cabling while ensuring that these are robust enough to withstand harsh conditions on the seabed[82]. Platform electrification stands to benefit from developments in the offshore wind energy sector, which maintains a sharp focus on reducing cabling costs.

Electrification costs also depend on the type of power transmission system used. Platforms connected to onshore power in the Norwegian North Sea demonstrate feasibility for both high voltage AC and DC transmission[83]. DC transmission will be a more cost-effective solution for distances higher than 100km due to lower line losses than AC systems[84,85]. However, converting onshore AC power to DC power for transmission and back to AC power for usage can cost approximately £0.2/W depending on voltage and power rating, which can add up to a capital cost of £100 million for two 250 MW conversion stages[86,87]. Furthermore, the power electronics equipment necessary to convert onshore frequency of 50Hz to the operating frequency of 60Hz in the North Sea basin creates further challenges with respect to the available space on platforms.

An additional consideration for projects with power from shore – either through wind farms or direct connection to an onshore grid – is the potential strain that electri ed platforms can put on onshore power grids. This can result in the need for grid upgrades, leading to additional costs for platform operators.

Space constraints also play an important role. A study in the Netherlands assessed the electri cation potential of three platforms (K5, K14 and P15) and found that the required deck space varied from four to seven 40-foot containers depending on power demand[88]. With space at a premium offshore, power electronics need to reduce converter footprint - including that of associated cooling systems - while maintaining the high conversion ef ciency of larger equipment. These developments can enable broader uptake of platform electri cation. In this regard, companies such as QL Tech have started to develop concepts of converter stations that are 10 times smaller than existing systems. Similarly, the development of subsea substations represents another technology alternative tackling the issue of limited space on offshore platforms.

Electri tion of equipment

Gas compressor systems dominate platform energy consumption[89]. In the UKCS, a third of the gas turbines in operation drive mechanical compressors[90]. Although installing electric motors in place of ga red turbines can result in operational ef ciencies and lower maintenance costs, the capital costs, weight and size of high-power electric motors are signi cantly higher than those of gas turbines[91]. This can limit the potential for electri cation to lower power systems (below 15 MW[92]). Replacing natural gas with low-carbon fuels like hydrogen or ammonia can provide a decarbonisation pathway for platforms where switching from mechanically driven compressors is not feasible (see section 3.4 - Hydrogen technologies).

Emerging solutions for electri cation of platforms

There are four options to reduce capital expenses associated with platform electri cation from onshore power (see table 3.1).

Supplying the high power demand of platforms solely through wind power will require energy storage capacity to be installed either at the platform or nearby o xed o oating platforms. Alternatively, backup gas turbines or diesel generators would be needed to continue to supply power during times of low wind. This could also have an impact on how much electricity could be used, as speci c equipment such as compressors require a constant and reliable power source. However, the use of this hybrid solution using both wind power and gas- red generators will be restricted to facilities where electric motors already drive the main loads in platforms. Finally, the use of wind power will also require the implementation of load management controls to ensure reliable operations.

Electrifying platforms usin oating wind turbines that can be relocated on-demand will require technology to be developed that will allo oating structures to be quickly disconnected and re-connected. Further development of dynamic cabling technology is needed to lower costs while ensuring that fatigue-prone components, like the external sheath, can withstand the high loads of waves, ocean currents and th oating structures for longer times[94]. Likewise, cost reductions in the manufacture o oating structures, which can potentially be achieved through economies of scale, can contribute to the deployment o oating wind-powered platforms.

Table 3.1: Options to electrify platforms

	Solution	Bene t	Challenges
Option 1	Use existing subsea interconnectors	Reduced capital expenses as shorter subsea cables are needed.	Lack of infrastructure in most key producing areas in the North Sea. Link connections to existing subsea interconnectors have not been deployed[93]. High cost of switch gear and substations. Regulated energy markets.
Option 2	Offshore wind turbines: these can share the same transmission infrastructure that connects wind farms to shore.	Platforms could bene t from wind power in periods of high wind while relying on onshore power generation or their own gas turbines in periods of low wind.	Creates the risk of adding load to a potentially strained onshore grid in periods of low wind.
Option 3	Connecting multiple platforms to dedicated offshore wind farms in a microgrid co guration.	Companies could potentially share capex and opex for power distribution infrastructure, while reaping electri cation bene ts.	Dedicated backup generation or energy storage is required.
Option 4	Mobile power generation units such a oating wind turbines.	Mobile generation can help electrify smal elds on a temporary basis before being re-located to other platforms.	High capex o oating generation units (see section 3.3 - Renewable energy technologies). Local, or mobile, energy storage capacity necessary as back-up power.

Table 3.2: Technology challenges of platform electr cation

PLATFORM ELECTRIFICATION	INNOVATION GAP
Subsea cables and HV substations: high capital costs of strong and reliable (static and dynamic) installations	
Temporary electrification solutions: high capital costs and footprint to electrify ageing platforms and smal elds	
Disconnection & reconnection: lack of fast connection solutions that enable on-demand electri cation of oating structures	

 Critical gap, unlikely to be resolved without strong effort

 Needs additional effort

 On track to be resolved

Accelerators, enablers, and interdependent technologies

There are several system-level interdependencies of electrifying platforms. Four stand out:

1. **Offshore wind:** using wind farms currently connected to onshore grids to power platform operations can avoid production curtailment in periods of high wind.
2. **Hydrogen production:** electri cation could potentially enable the re-use of old platforms as hydrogen hubs, where electricity is used to power electrolysers for hydrogen production and subsequent storage and transportation. This model would only be applicable to the few platforms with optimal locations; i.e. those in the vicinity to shore, other platforms or wind farms (see section 3.4 - Hydrogen technologies).
3. **Subsea production:** for subsea systems to realise their full decarbonisation potential, electri cation of subsea equipment with low-carbon electricity is critical.
4. **Energy storage:** Energy storage can further aid in the decarbonisation of platform operations in the context of electri cation. While widespread deployment of batteries is a challenge due to space and weight constrains, batteries have the potential to replace generators operating as spinning reserves. In this case, batteries can supply electricity to the platform while back up generators are brought online.

Several electri cation initiatives are already underway or in the planning phase (see table 3.3), highlighting the feasibility of electri cation from onshore power. However, advancing electri cation projects relying on offshore wind power will require careful coordination between stakeholders. Industry players who are collaborating to establish offshore grids should consider offshore wind capacity coming online, oil and gas production forecasts, power needs for offshore assets and the possible repurposing of old platforms for other applications such as hydrogen production and CCUS.

Table 3.3: Electr cation projects to date and planned

								Cluster development			
Operator	**Equinor**	**Equinor**	**Neptune Energy**	**Equinor**	**Equinor**	**Aker BP**	**Equinor**	**Total**	**Shell**	**BP**	**BP**
Offshore eld name	Johan Sverdrup (Phase 1)	Martin Linge	Q13A-A*	Goliat	Johan Sverdrup (Phase 2)	Valhall	Troll B and C[97]	Elgin-Franklin[98]	Shearwater[98]	ETAP[98]	Clair[99]
Country	Norway	Norway	Netherlands	Norway	Norway	Norway	Norway	UK	UK	UK	UK
Basin	Northern North Sea	Northern North Sea	Southern North Sea	Barents Sea	Northern North Sea	Central Graben	Northern North Sea	Central North Sea	Central North Sea	Central North Sea	West Shetland
Planned date	**2019**	**2018**	**2018**	**2016**	**2022**	**2011**	**-**	**2023**	**2023**	**2023**	**-**
Power transmission system	DC	AC	AC	AC	DC	DC	-	-	-	-	-
Cable length	200km	162km	14km	106km	N/A	292km	<100km	>200km	>200km	>200km	>75km
CO_2 reduction (MT/year)	620,000MT	200,000 MT[12]	16,500 MT	80,000 MT[95]	N/A	300,000 MT[96]	-	-	-	-	-

* PosHydon project testing the concept of an integrated energy system

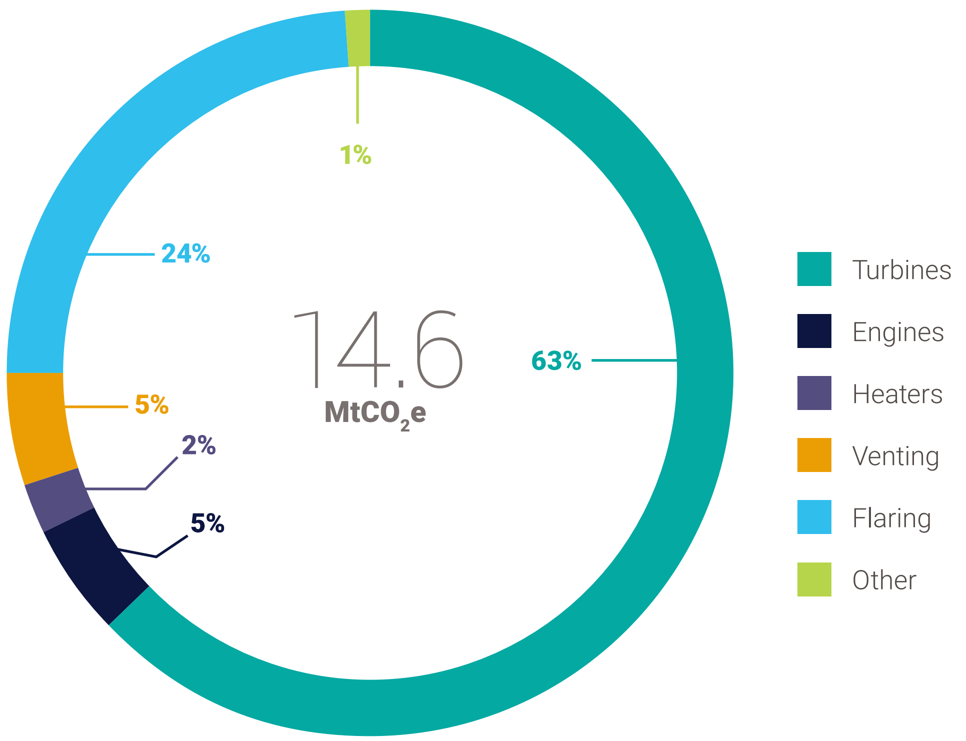
Flaring and venting mitigation

Flaring and venting are two ways operators dispose of associated natural gas, typically for operational, safety, or economic reasons. Venting is often the result of an emergency pressure release whil aring is a carbon-intensive combustion of principally methane and is the most economical way for operators to dispose of low-value associated natural gas.

Current status

According to the IEA, approximately 4,950 billion cubic feet (bcf) of gas i ared each year around the globe[100]. The OGUK "Environment Report 2019" stated that over 49 bcf of gas wer ared on the UKCS in 2018, a 6% decrease on 2017. On the other hand, 3,900 million cubic feet (mmcf) of gas were vented in the same year, a 53% increase from 2017[101]. In total aring and venting accounted for approximately 29% of the UK's upstream production CO_2 equivalent (CO_2e) emissions[4]. Mitigating routin aring and venting of natural gas, as well as limiting methane emissions from incomplete combustion i ares and gas turbines could contribute signi cantly towards reducing emissions.

Figure 3.3: Upstream greenhouse gases emission sources



Source: OGUK

Technology challenges

There are several sources o ares and vents including: base loa ares, which result from the gas used for safe and ef cient operation of the process facility an are system aring from operational or mode changes, which includes aring from the start-up and planned shut down of equipment during production ares from emergency shut down or process trip of equipment; and unignited vents, which includes inert gases and hydrocarbon gases that may be discharged to an atmospheric vent from e.g. oil storage tanks[108]. The production of associated natural gas in oil production operations also results i aring and venting. It is estimated that ~3% of associated gas produced i ared and vented[109].

Associated gas is highly variable i ow and composition, making any kind of technology-driven mitigation very challenging. Despite this, platforms in Norway have achieved zero routin aring - with policy playing a crucial by ensuring that the eld developments were designed to prevent routine aring.

Norway introduced a total ban on non-emergency aring in the Norwegian continental shelf in 1971, requiring oil and gas producers to present gas utilisation plans before developin elds, while mandating thorough monitoring and reporting systems. Later, the country introduced a carbon tax and trading scheme, calculated based on the ared and vented volumes and reaching a rate of £95 per 1,000 cubic metres[102]. These policies prompted companies to plan pipeline networks to transport associated gas. For example, the Drauge eld re-injected associated gas into a nearby aquifer for three years while a gas export pipeline became operational; such planning was crucial for eld development to obtain regulatory approval[103].

Associated gas re-injection has become commonplace in Norwegia elds. Common re-injection methods include water-associated gas (WAG) and miscible injection that are used for enhanced oil recovery (EOR). However, the effectiveness of associated gas re-injection as a sole strategy to avoi aring is limited due to factors such as high energy requirements for re-injection, high reservoir pressure, different permeability in the reservoir, risk of hydrate formation[104] and the need for more capital equipment to be added to a platform. Furthermore, the availability of natural gas re-injection equipment on a platform does not guarantee a reduction i aring. In fact, a study by the University of Edinburgh found that platforms on the UKC tted with re-injection systems saw no signi cant reduction o aring rates compared to platforms with no re-injection infrastructure[105]. New platforms on the UKCS already avoi aring for gas disposal. For more matur elds, using waste gas to generate electricity could help to mitigate aring.

Accelerators and enablers

As part of the World Bank's Global Gas Flaring Reduction Partnership, companies and governments are targeting the eradication of routin aring, when it is economically viable, in existin elds by 2030[110]. In the "Roadmap 2035" report, OGUK already states the industry's commitment to supporting the initiative[111].

Nonetheless, Norway's progress highlights that policy changes – and not technology – are the main driver to reduce or eliminat aring. Installing high precision systems to measur aring and venting emissions is a ke rst step towards reducing such activities. Similarly, setting industry-wide mandatory targets to reduc aring and venting, as well as accompanying measures to ensure compliance, are key to adoption.

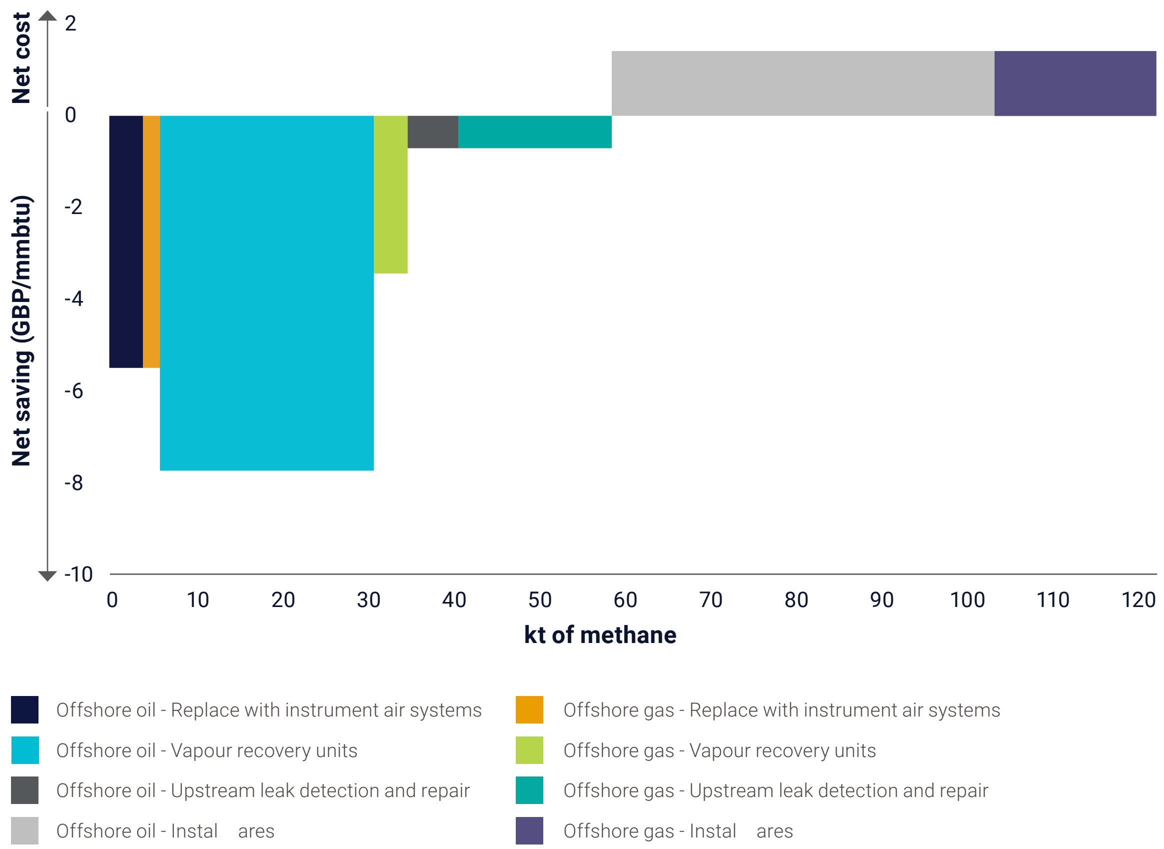
Methane leak mitigation

Methane is estimated to have a global warming potential 28 times higher than CO_2 over 100 years. Oil and natural gas operations alone accounted for approximately 82 million tonnes of methane emissions in 2019[112]. Key sources of methane emissions include leaks from pipelines, compressor stations, storage tanks, and natural gas processing plants and leaks at metering and regulating stations[76].

Current status

The IEA estimates that methane emissions from oil and gas production and processing in the UK reached approximately 334,000 tonnes in 2019, with offshore operations being responsible for nearly 129,000 tonnes[114]. Measures for methane emissions abatement are well-known, and include the installation of vapour recovery units as well as the replacement of compressor seals. However, fugitive emissions - or leaks - are an important fraction of the methane emissions on the UKCS. The IEA estimates that methane leaks accounted for nearly 29,000 tons, or 0.7 $MtCO_2e$/yr; yet, a recent study from Princeton University suggests that fugitive emissions could be double the IEA estimate[113]. A key measure to tackle these emissions involves the implementation of leak detection and repair programmes.

Figure 3.4: Methane abatement costs



Source: IEA

Leak detection and repair programmes are common practice among operators. While some detection methods rely on human operation, which results in longer detection times, new internal and external systems have emerged to quickly and accurately detect leaks of different sizes in different environments. Internal sensors are installed across pipelines or pipeline terminals to monitor parameters such as pressure, temperature flow rate and sonic velocity inside equipment and pipelines[116,117]. This data helps determine flow conditions and potential losses. External systems measure physical properties around equipment and can more rapidly detect and locate smaller leaks than internal systems. This includes sensors for capacitance, temperature differentials, acoustics and optical signatures. External sensing can be integrated in remotely operated vehicles (ROVs), or autonomous underwater vehicles (AUVs) to detect leaks subsea. Conversely, unmanned aerial vehicles (UAVs) can be mounted with sensors to detect leaks from topside equipment.

Technology challenges

Offshore leak detection faces many challenges because of harsh environmental conditions, which lead to poor system accuracy. For example, internal systems can detect large leaks, but have limited ability to detect small, chronic leaks. Dynamic modelling is a promising way to detect leaks in both surface and subsea pipelines. It continuously measures the discrepancy between measured data and simulated values based on statistical and fluid flow models. Implementation has been limited because of the high computational demands[118].

In the case of external systems, restrictions include their limited sensing range, difficulty in quantifying the size of leaks, vulnerability to ocean currents and susceptibility to false alarms[119]. A promising external system that can potentially enable real-time monitoring is fibre optic leak detection. The technology has the potential to detect and locate small leaks accurately by measuring changes in temperature along pipelines and capturing the acoustic signature of leakage fluids. Currently, the technology remains at an early development stage for offshore environments due to high installation costs and costly peripheral equipment[120].

Operations and maintenance service providers need to integrate sensors in ROVs, AUVs and UAVs. The technology itself could be restricted by bad weather conditions and the travel range of these vehicles is restricted by the limited energy densities of the batteries powering them.

Table 3.4: Technology challenges of methane leak detection

METHANE LEAK DETECTION	INNOVATION GAP
Resilience: sensors that withstand harsh environmental conditions	
Sensor flexibility: accurate detection of all types of leaks	
Sensor range: sufficient coverage per sensor to minimise number required	

Critical gap, unlikely to be resolved without strong effort
Needs additional effort
On track to be resolved

Subsea technologies

Current status

Subsea technology has been a key focus for operators on the UKCS and wider North Sea since the 1960s. The basin has been a global leader in innovation, with more than 250 subsea systems deployed to date[121]. Subsea production has the potential to be more energy ef cient than conventional upstream facilities on platforms o oating production, storage and of oading (FPSO) units[122], partly due to the electri cation of power-consuming components like compressors. Ultimately, subsea factories are th nal frontier of subsea technology development. This concept involves a standalone subsea production system on the seabed conducting operations like single- and multi-phase boosting, gas compression, gas-to-liquid and liquid-to-liquid separation, as well as water re-injection. Subsea factories thus have a high decarbonisation potential[123].

Subsea factories could transform traditional offshore spend by eliminating large offshore platforms altogether, replacing them with simpler oating structures limited to atmospheric pressure operations like oil-gas separation. Aker Solutions, Atkins Global and Crondall Energy are examples of companies developing such reusable production buoys[124,125,126]. Given the maturity of the UKCS, the potential to eliminate topside platforms is largely limited to new developments. However, subsea factories can also enable the development of over 300 small pools on the UKCS through subsea tie- backs of these margina elds to existing platforms – or t oating hubs - in the future. The use of subsea equipment for small elds opens the door to the re-use of equipment once a reservoir has been depleted, as individual equipment can be removed from the seabed, refurbished as necessary and placed on a new eld[127,128]. Nevertheless, the re-use of equipment not speci cally designed for a reservoir could result in reduced operational ef ciency, and so how this impacts emissions will need to be taken account of.

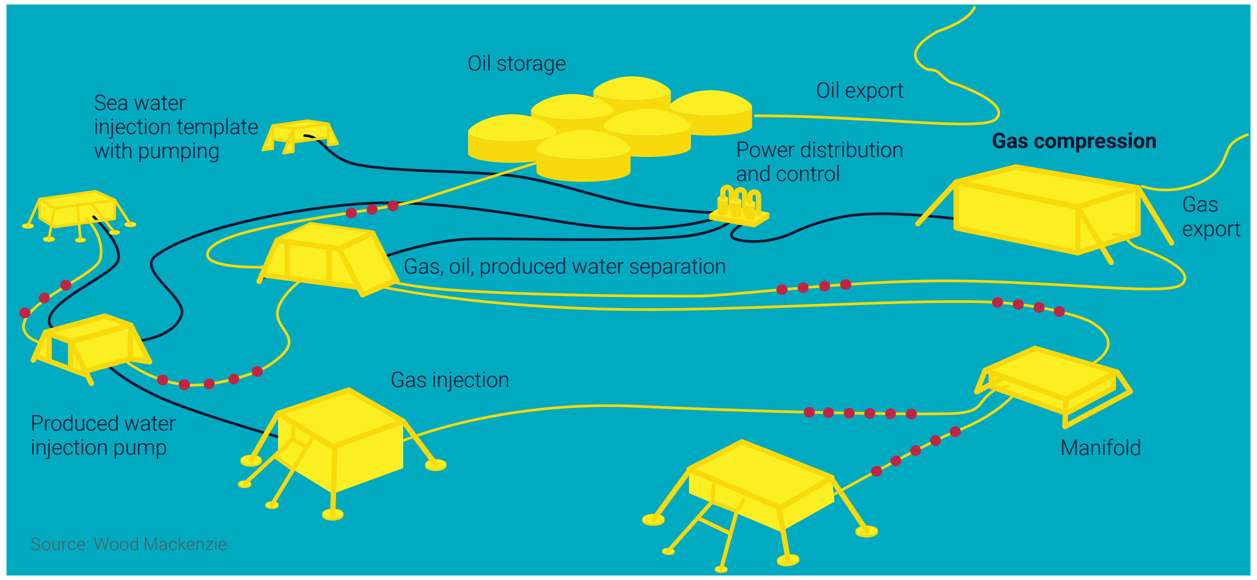
Individual subsea technologies that improve the ef ciency of oil and gas production processes – ranging from subsea wellheads to boosting and injection systems – have already been deployed globally, with companies such as TechnipFMC, Aker Solutions and OneSubsea standing out as key developers. However, subsea compression and power distribution are two key technologies under development that can unlock greater decarbonisation potential on the UKCS:

- Subsea compressors are more energy ef cient than their platform counterparts. On the seabed the back pressure is lower than on the platform and so the same production rates can be sustained but using less power. Aker Solutions recently showed that the overall energy consumption of a subsea compression system can be up to 38% lower than topside compression over the lifecycle of the system[129]. An additional advantage of subsea compression is its potential to extend plateau production of a well due to a lower pressure drop in pipelines downstream. Fields with a projected decline in reservoir pressures could thus bene t from subsea compression[57].

- Subsea substations are key to supplying power to factories on the seabed without relying on increased riser capacity while alleviating the need for topside space[130]. These will enable subsea networking and integration of oil and gas with renewables, either off- or onshore.

- Though technologies such as subsea pumping or subsea oil storage are also of high relevance to move topside operations to the seabed and so help to unlock marginal oi elds in an economic manner, the impact of these technologies on decarbonisation is lower than that of subsea compression or distribution systems.

Figure 3.5: Multiple technologies can combine for subsea operations



Technology challenges

Subsea compression has long been a development target in the industry. It wa rst deployed in 2015 at Equinor's Åsgar eld in the Norwegian continental shelf, using technology developed by Aker Solutions and MAN. Later, companies such as Shell and Chevron started to implement the technology at the Ormen-Lang eld in the Norwegian continental shelf and Jansz-Io eld in Australia, respectively[131]. Currently, the technology relies on encasing compressors with their high- speed drives in hermetically sealed, pressurised containers[132] - which makes it an expensive solution. However, Aker Solutions and MAN continue to optimise the technology, claiming that capital expenses and installation costs could eventually be 50% of what they are today[133].

Subsea substations are currently under development, with no systems deployed commercially. A key challenge is the design of electronics with materials resistant to pressurised environments.

Cooling systems that can guarantee the thermal performance of the electronics is another important challenge[134]. However, Siemens and ABB recently completed testing their respective pressure- compensated subsea distribution systems that incorporate transformers, variable speed drives and switchgears, as well as power electronics[135]. Both systems are expected to require signi cant capital expenditure, although ABB claims that its technology can offer capex savings of more than £400 million if eight loads – such as compressors or pumps – are networked through a single cable[136].

The UKCS has a unique opportunity to leverage subsea equipment to tap underexploited small pools and unlock low-carbon production of precious, but otherwise expensive, resources. The rst goal is to build reusable subsea equipment with easy disassembly and re-assembly – an important target for the dozens of developers already working on subsea systems[137]. In addition, designing subsea equipment that ties together oating hubs with oil processing units will help to make the idea of subsea tie-backs of small pools a reality. Designing equipment for integration with technologies such as offshore wind farms, subsea electrolysers and fuel cells (see section 3.4 - Hydrogen technologies) will also be of paramount importance to improve the decarbonisation potential of the UKCS.

Subsea compression and distribution technologies (among others) still need to demonstrate their long-term reliability and achieve signi cant cost reductions. However, there are no obvious technology gaps in the long term to get to a "subsea future". Operators like Equinor, BP, Total and Shell and technology developers like Aker Solutions, Man, TechnipFMC, OneSubsea, ABB and Siemens are already driving this development across the globe. These ongoing collaborations are likely to result in more robust designs that could be commercial in the mid-term.

Table 3.5: Technology challenges of subsea technologies

SUBSEA TECHNOLOGIES	INNOVATION GAP
Subsea equipment: high capital costs and installation costs	
Resilient materials: electronics that operate under high pressure conditions while maintaining thermal performance	
End-of-life design: subsea equipment that can be re-used and integrated with renewables	

 Critical gap, unlikely to be resolved without strong effort  Needs additional effort  On track to be resolved

Technology accelerators and enablers

One of the main reasons for high costs in subsea installations is due to operators working with suppliers to produce tailormade solutions on a project-by-project basis. The industry is currently exploring standardisation, which will help reduce capex and project development time. DNV-GL is currently managing several joint industry projects to standardise different elements of subsea systems, such as subsea welding, testing of forgings and specifications for subsea pumping systems to boost operations[138]. Similar initiatives will be needed to deploy reusable equipment for marginal fields on the UKCS.

Oil and gas ecosystem and path to 2050

In the near-term, the decarbonisation of the industry will continue to rely on the implementation of technologies to improve the operational and energy efficiency of the UKCS. Digital technologies will play a key role as enablers of such efficiency improvements. The widespread rollout of new technologies will require sustained development efforts, industry collaborations and policy support. Yet, technologies such as platform electrification and subsea production systems can have an impact beyond CO_2 emissions reduction by helping unlock the remaining reserves on the UKCS.

Initial UKCS electrification projects will rely on onshore power and partial electrification will be an attractive lower-capital option for existing platforms on the UKCS. Using onshore power for existing early life or new developments will be key for oil and gas companies and suppliers to better understand the infrastructure and equipment changes required for electrification. However, the implementation of any electrification project will continue to depend on the location, productivity and age of a platform, despite the potential for lower lifetime operational expenses and CO_2 emissions[80]. Similarly, electrification with power from shore will be dependent on low-cost electricity from renewables. Multi-variable scenario-based models to clearly visualise potential returns on investment of electrification projects will be important decision support tools. Wider deployment of electrified platforms with onshore power will be contingent on reducing capital costs of AC and DC subsea cabling and high-voltage substations and on reducing their footprint. A key consideration is that for the UKCS, deployment of electrification projects will only occur in the mid term as supply chains are not assembled, the legal framework to implement electrification projects is not developed on the UKCS, and the installation of electrification infrastructure can take up to seven years for full electrification projects.

In the mid-to-long term, offshore wind developments should have unlocked th rst few offshore energy hubs, enabling electri cation of nearby platforms far from shore – where installing subsea cables becomes economically unfeasible – and offer additional exibility and risk mitigation to the energy system. Development of lower cost and reliable dynamic interconnects, as well as rapid disconnection and reconnection technology, can eventually enable oating wind farms to electrify platforms on demand. These developments will also bene t the development of subsea factories, which rely on electri cation to realise their decarbonisation potential. To enable these developments, regional stakeholders will need to address regulatory barriers around ownership and operation of integrated energy systems.

To mitigate methane emissions, near-term actions include the reduction of venting and methane leaks through the replacement of seal systems and equipment prone to leaks, including pumps, valves, storage tanks and compressors. More frequent inspection programmes using available leak detection technologies such as infrared or ultrasonic systems can help prioritise which equipment to retro t. After 2030, broad-scale continuous monitoring equipment and sensors will be required to quickly address leaks, while avoiding recurrence of leaks at the same locations. Industry will need robust integrated sensing systems that are able to continuously monitor equipment for leaks of all sizes with high spatial accuracy and a suf ciently long range to limit the number of units needed for overall systems-level capex reduction. For places where sensor coverage is poor, the industry will need to deploy UAV, AUV and ROV technologies to pinpoint the location of leaks and repair them. While technology has a role to play, strong regulatory frameworks, compliance protocols and industry commitment are crucial to promote methane leak an aring mitigation. Building more comprehensive emissions tracking is a key step towards the quanti cation of methane emissions and ef cacy of leakage detection and mitigation technologies. While near-term alternatives such as gas re-injection and microturbines exist, the high variability of associated gas and reservoir conditions will limit the impact of these technologies, especially in ageing platforms.

> “In the mid-to-long term, **offshore wind developments will unlock energy hubs,** enabling electri cation of nearby platforms far from shore”

Leading operators like BP, Equinor, Shell and Total are already investing in developing subsea technologies. As developments continue to bring down costs, the UKCS can take a lead on the integration of subsea technology with unmanne oating topside systems. This will not only help in achieving decarbonisation objectives, but also create opportunities to economically recover hydrocarbons from small pools with reusable equipment that can connect to suc oating structures. In order to achieve this, the industry will need to establish standard testing protocols to optimise the certi cation and deployment of subsea equipment that can be easily connected to energy generation assets and even to othe oating production hubs. Towards 2050, subsea systems can then become the preferred option for new discoveries because of their ability to avoid the installation of costly topside infrastructure. Finally, as the industry’s understanding of subsea operations deepens, hydrogen production, storage and usage operations can also start moving to the seabed to enable further integration of the oil and gas sector with other low-carbon sectors.

Speculative technologies for oil and gas

Downhole hydrogen production[139]

- Generate and separate pure hydrogen via in situ autothermal reforming of either crude oil or natural gas, or both, in depleted oil eld reservoirs.
- Produce hydrogen via existing oil and gas wells while leaving all hydrocarbons in the subsurface. The process only generates clean water and energy as by-products and therefore there are limited emissions associated with the process.

Figure 3.6

Oil and gas technology roadmap

2020 — Short-term

- **Temporary electrification solutions:** high capital costs and footprint to electrify ageing platforms and small fields
- **Subsea cables and HV substations:** high capital costs of strong and reliable (static and dynamic) installations
- **Resilience:** sensors that withstand harsh environmental conditions
- **Sensor flexibility:** accurate detection of all types of leaks
- **Sensor range:** sufficient coverage per sensor to minimise amount required
- **Subsea equipment:** high capital costs and installation costs
- **Resilient materials:** electronics that operate under high pressure conditions while maintaining thermal performance
- **End-of-life design:** subsea equipment that can be re-used and integrated with renewables

2035 — Mid-term

- **Disconnection & reconnection:** lack of fast connection solutions that enable on-demand electrification of floating structures

2050 — Long-term

Parking lot

"incremental gain" tech challenges that will get resolved with or without dedicated effort

- Natural gas re-injection

Ecosystem

- Multi-variable scenario-based models to clearly visualise potential ROIs of electrification projects will be important decision support tools
- Standardisation of subsea equipment to reduce capital costs and project development time
- Development of clear tracking and reporting systems for flaring and venting emissions
- Establishment of strong regulatory frameworks, compliance protocols, and industry commitment to promote methane leak mitigation and flaring mitigation

Ecosystem

- Standardisation of subsea equipment to enable re-use in multiple fields
- Addressing regulatory barriers around ownership and operation of integrated energy systems

Ecosystem

- Oil and gas systems fully integrated with offshore renewable power system
- Subsea factories with significantly reduced surface footprint
- Unmanned re-usable production systems for small pools deployment

Critical path
Platform electrification
Methane leak detection
Subsea technologies
Flaring mitigation

Source: Wood Mackenzie, Lux Research

3.3:

RENEWABLES

Renewable energy sources will play a key role in reducing emissions in the UK and are critical components of the CCC's Further Ambition scenario. Offshore wind is the biggest contributor with a pipeline of 43 GW and around another 20 GW in upcoming lease zones[140].

To achieve the CCC's vision, a fully integrated renewable energy ecosystem, which includes the necessary transmission and storage infrastructure, is crucial. This ecosystem can unlock the potential of industry electrification and green hydrogen to further lower the carbon intensity of the UK's energy and power mix.

Fixed-bottom offshore wind

Current status

The UKCS currently has around 35% of the global installed offshore wind capacity and 45% of Europe's, almost exclusively fro xed-bottom turbines[141]. Larger blades, turbines and hub heights have increased power ratings and capacity factors which, along with improvements in cable power ratings, installation experience and the development of a local supply chain, have dramatically reduced in cost.

The clustering and extension of existing projects on the UKCS allows operators to share resources and assets which helps to make upgrades cost-effective. At the same time, offshore wind technology continues to evolve, with key developments including:

Table 3.6: Key developments in wind

Larger blades, taller towers and bigger turbines to increase capacity factor.

Most of the UK's future installed capacity will b xed-bottom turbines. To maximise potential, blades are getting longer, and hub heights are increasing. With a rated capacity of 12 MW and 63% capacity factor in North Sea wind conditions[142], GE's Haliade-X is currently the largest wind turbine on the market, with

107 m blades and a 260 m high tower[143]

Currently being tested in the UK[144], GE plans to produce th rst commercial units by mid-2021.

Airborne systems to increase altitudes.

Higher altitudes have higher wind speeds; airborne energy systems (AES) use a tethered kite or a drone y at heights of 150 m to 300 m and can reach capacity factors of up to 70% using less material than turbines. AES is less mature than conventional wind power and improvements i xed an oating turbines have been limiting the role it can play. After Google shelved the Makani project in February 2020[149], developers are cautiously progressing by testing prototypes. One prominent example is Ampyx Power's plans to launch a

150 kW prototype together with RWE

Floating foundations to operate in deeper water.

About 80% of the UKCS' offshore wind resource potential is at depths greater than 60 metres, wher xed-bottom systems are no longer practical[145]. Floating foundations can be used at any depth and unlik xed-bottom, do not require bespoke foundation design for each location[146], making standardised assembly possible to signi cantly cut costs. The larges oating wind project operating today is Equinor's 30 MW Hywind Scotland project, however several projects are set to surpass this size, such as the 50 MW Kincardine wind farm - scheduled to be completed in 2020 - and Equinor's 88 MW Hywind Tampen[147] which will also be used to electrify offshore oil and gas platforms.

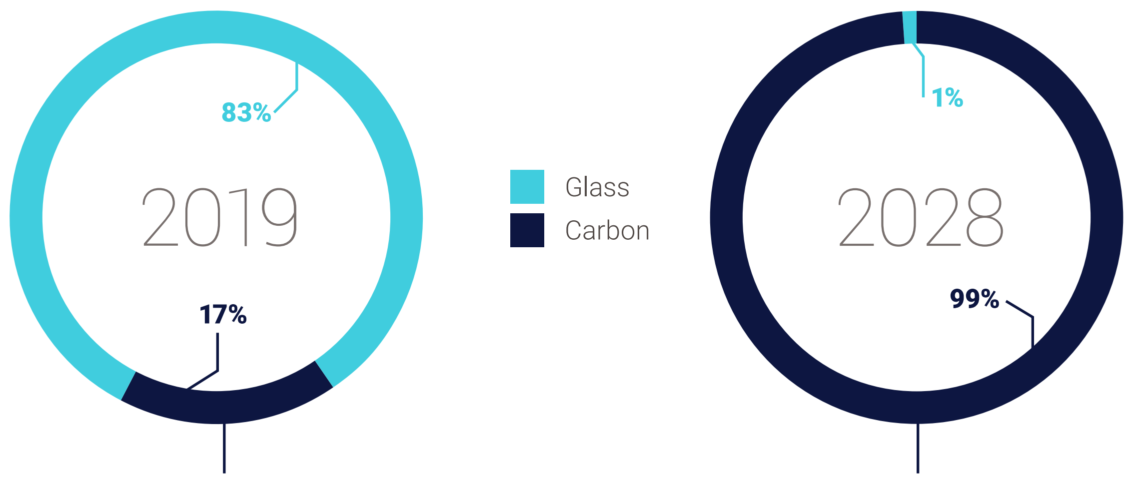
10 GW of floating offshore wind capacity installed on the UKCS by 2050[148]

Technology challenges & accelerators and enablers

System sizes: Larger blades and taller towers can increase wind turbine capacity and economic feasibility, while new materials allow for lighter and longer blades (se gure 3.7). Material choice is increasingly shifting from glass- to carbon- bre composites. For example, Saertex's[150] carbo bre-reinforced spar caps reinforce blades lengthwise[151,152].

Figure 3.7: Trends in designing wind turbine blades

Turbine material trend

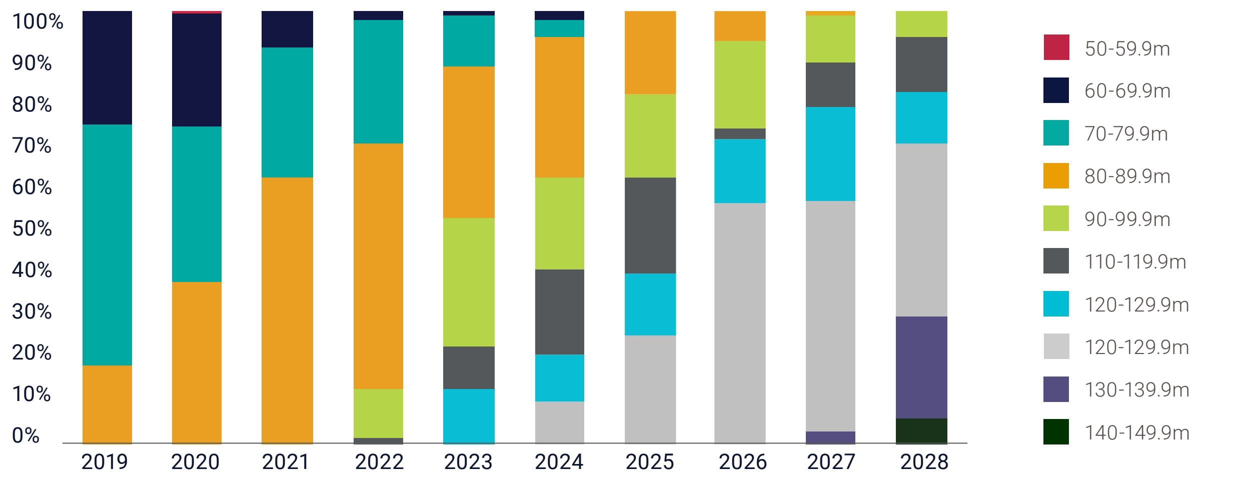


All the offshore turbine blades installed in 2019 are glass bre except for MHI Vestas' 80m blades on the V164.

- However, the learnings from the V164 are being leveraged on V174 blades
- A focus on minimising loads and using aerodynamically enhanced aerofoils results in only a marginal increase in blade weight from 34 tons to 35 tons

- Turbine OEMs shifting to carbo bre blades; notably SGRE is shifting resins on its SG 193-DD for th rst time to use carbon.
- Chinese OEMs are also seeking slender carbon blades for lower wind offshore conditions in China

Blade length trend



Source: Wood Mackenzie

Offshore wind turbines are subject to a host of complex forces. That makes designing ever larger, yet durable and reliable systems an even greater challenge. Foundations need to better stand up to long term hydrodynamic loads and designs require novel nacelles and larger rotors. The models that can predict the load distribution and failure modes are valuable tools to develop more reliable designs[153].

Large turbines have additional operation and maintenance costs. To bring these down, several developers are working on novel coatings to prevent and delay blade erosion, magnetic gearing, technologies to make part replacement easier, and acoustic emission monitoring to safeguard structural integrity. Unmanned aerial vehicles, for example those produced by ZX Lidars[154], can be used for blade inspection and predictive maintenance to further reduce maintenance costs and extend wind turbine lifetimes.

Decommissioning: At the end of service life, decommissioning and restoration activities require the removal of all physical material and equipment. The concrete foundations used to anchor the wind turbines are dif cult to fully remove. Also, dust and toxic gases may be released during the removal of the rotor blades. Given the massive size and inconvenient shapes of these components, they need to be cut or demolished before transportation. Most of the turbines are recycled or sold to wind farms in Asia or Africa, but recycling the blades presents technical challenges due to the use of composites, coatings, and other blended materials[155] , with most ending up in land lls.

Cabling: Due to power losses, crushing failures, and connection degradation and dynamic loading issues, cabling is a major cost item. However, opportunities exist for designing overlapping solutions with oil and gas operations as explained in Section 3.3 - transmission, connection to the grid and to the platform. Alternatively, developments i oating and subsea substation design could pave the way for removing dynamic export cables connecting the substations to shore.

Closing the Gap to 2050 Technologies | Section 3

Table 3.7: Technology challenges o xed-bottom wind turbines

FIXED-BOTTOM WIND TURBINES	INNOVATION GAP
Larger blades: advanced carbo bre-based composites enabling easier to recycle, yet longer blades, and thus larger capacities	
Wind turbine decommissioning: removal, transportation, and recycling of older turbines, including recycling of blades	
Taller towers: novel designs and materials to increase the hub height	
Increased rotor diameters and nacelle designs: to enable larger turbines	
Blade leading-edge erosion: novel materials and coatings to prevent erosion and maintain smoothness for high ef ciency	
Magnetic gearing: remove mechanical gears to reduce lubrication and risks of having to replace multi-ton gearboxes vi oating cranes if these fail under high-stress wind conditions.	
Acoustic emission condition monitoring: maintenance control of the structural integrity	
Automated inspection: unmanned aerial vehicles for inspecting blades	
Unmanned installation: remote onshore control of transporting and installing wind turbines	

Critical gap, unlikely to be resolved without strong effort | Needs additional effort | On track to be resolved

Floating offshore wind

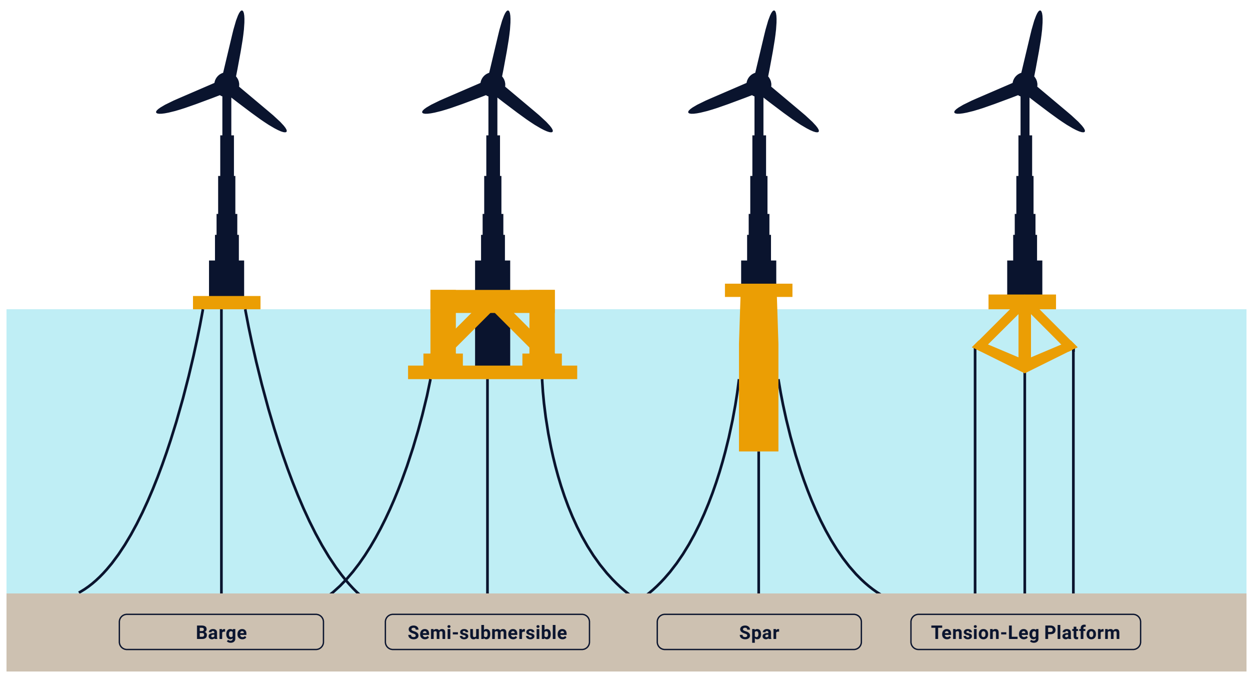
Floating foundations: Displacements from waves, currents and strong winds present additional challenges for oating foundation designs, reducing performance and accelerating ageing. The main challenge is combining foundation stability with acceptable motion while keeping costs low[156].

To keep foundations as stable as possible, there are numerous design variations for the four main types of wind installation: barge, spar, tension leg platform (TLP) and semi-submersible (a merger of spar and barge) (se gure 3.8). Design standardisation allows for production volumes to ramp up quickly using existing supply chains and manufacturing facilities. Floating turbines can be assembled onshore and towed to thei nal location at considerably lower cost.

Cabling is another important challenge. Conventional submarine cables secure the foundation to the seabed, ye oating components that are attached to the cables also move synchronously with th oating turbine. Exposure to the continuous bending and twisting forces from waves, currents and th oater increases the likelihood of mechanical damage. Dynamic cables with superior strength should be used so that cables can match the turbine's service life[158]. Also, as capacity grows and the wind turbines share transmission systems, quick disconnects/reconnects are important to maintain uptime for the remaining turbines of the system when servicing one.

Floating an xed-bottom installations can bene t from additional advances. Automated solutions for inspection and even installations will be increasingly important as wind installations move further offshore.

Figure 3.8: Floating offshore designs



Source: Wood Mackenzie

Table 3.8: Technology challenges o ating wind turbines

FLOATING WIND TURBINES	INNOVATION GAP
Standardisation of floating foundations: to enable mass-production	
Mooring designs: to enable stability against harsh weather and sea conditions	
Dynamic cabling: to withstand change of forces on the cables due to moving foundation	
Shared challenges with fixed-bottom wind: blade leading-edge erosion, magnetic gearing, acoustic emission condition monitoring, automated inspection shared b xed-bottom structures	

Airborne wind

Airborne energy systems: Airborne energy systems have the potential to produce a lower LCOE[159] due to requiring less material, meaning capital costs are lower, and the ability to produce more energy than wind turbines. However, there are a number of issues with AES, including: low capacity factors, shorter lifespans, less reliability and impractical design[160]. If these signi cant challenges are overcome, AES could be deployed on the UKCS over the next three decades.

Table 3.9: Technology challenges of AES

AIRBORNE ENERGY SYSTEMS (AES)	INNOVATION GAP
Energy generation mechanism: feasible, ef cient harvesting of wind energy	
Kite and drone design: ef cient, reliable, and durable designs with a possibility to standardise	
Tethering systems: durable tethers	
Motion control algorithms: machine learning fo ight path optimisation	

Critical gap, unlikely to be resolved without strong effort

Needs additional effort

On track to be resolved

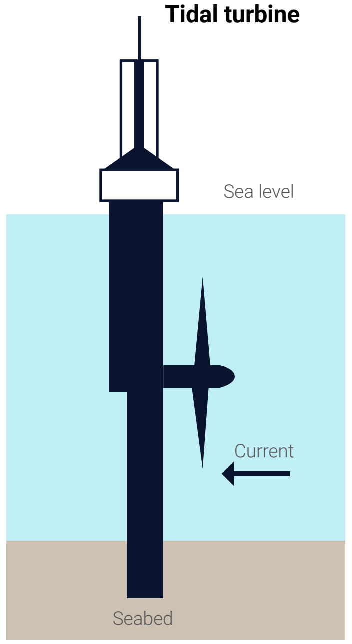
Other renewables

Marine energy

Current status

Tidal and wave energy are the are two most common forms of marine energy. The UKCS has the potential to be a hotspot for marine energy due to predictable wave patterns. Moreover, marine energy could be coupled with wind to balance power output. For example, novel engineering approaches like "Wind for Water injection (WINWIN) from DNV GL[161] could help build momentum for bot oating wind and tidal development at scale by improving operating and power output ef ciencies. However, installations to date have seen limited success and a wide variety of designs are still in development and testing (se gure 3.9). Startups like Ocean Power Technologies and Carnegie Clean Energy have made slow progress, while others like Pelamis have gone bankrupt[162]. The European Marine Energy Centre, based on the Orkney Islands[163], has been at the centre of major developments. The most advanced project is Simec Atlantis Energy's MeyGen pilot in the Orkney waters[164], which exported 13.8 GWh of electricity to the grid in 2019[165] and has plans for two more turbines and an improved grid connection in 2020[166,167].

Figure 3.9: Tidal systems[168]



Source: Wood Mackenzie

Technology challenges, accelerators & enablers

Marine energy's high upfront costs, suboptimal durability in subsea environments and maintenance challenges hamper economic feasibility. The costs and performance of basic components need to be addressed including:

1. the structure and moving components that capture energy;
2. the mooring to keep these systems in place;
3. the power take-off systems converting movement to electricity, and;
4. control systems to safeguard and optimise performance under various operating conditions.

Floating foundations for tidal systems, such as the barge-mounted models from companies like Magallanes Renovables[169] and Orbital Marine Power[170], aim to ease manufacturing, installation and maintenance by removing any construction on the se oor. The sector has not yet reached consensus on a winning design for wave systems – although there are a wide range of options that harness wave power under different conditions and in different places.

Other major barriers to development are site selection and equipment maintenance. Improved data on wave and tidal potential around the UK is needed to improve location selection[171]. Additionally, solutions such as high durability antifouling coatings[172,173,174] or approaches to automatically remove fouling[175], are needed to improve equipment maintenance.

Closing the Gap to 2050 Technologies | Section 3

Table 3.10: Technology challenges of marine energy

MARINE ENERGY	INNOVATION GAP
Power take off: economically feasible energy harvesting mechanism of tidal or wave	
Fouling: antifouling coatings for durability	
Stable foundation and support systems: durable position maintenance in harsh environmental conditions	
Exploration of marine potential: systematic data collection and analysis of the total and feasible potential	

Floating solar

This involves placing solar PV panels o oating supports. Challenges wit oating solar include electrical safety and mooring issues[176] in harsh sea conditions and limited irradiation potential of the UKCS, while other, more attractive renewable energies are easily available. For those reasons oating solar is unlikely to contribute signi cantly to the UKCS' renewable energy generation targets. However, speculative offshore renewables such a oating solar could offer additiona exibility to the future grid and to mitigate the risks associated with relying only on hydrocarbons and wind.

Table 3.11: Technology challenges o ating solar

FLOATING SOLAR	INNOVATION GAP
Wave tolerance: improving the current 1m-2m wave tolerance to withstand UKCS conditions	
Waterclogging: pumping mechanisms to keep the system a oat	
Clouding: coatings or automated cleaning against precipitation on the panels decreasing ef ciency	
Durable photovoltaic panels in seawater conditions: resistance to fouling and saltwater spray	

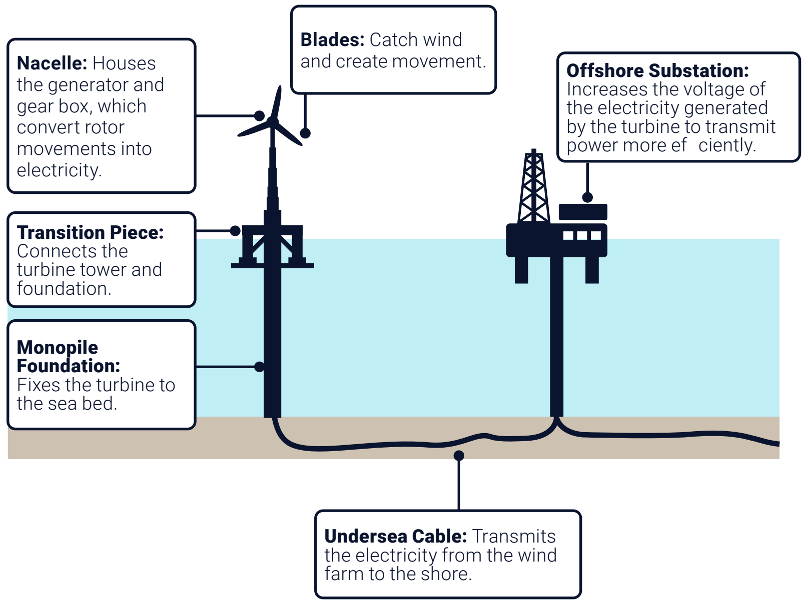
Critical gap, unlikely to be resolved without strong effort   Needs additional effort   On track to be resolved

Transmission, connection to the grid and to the platform

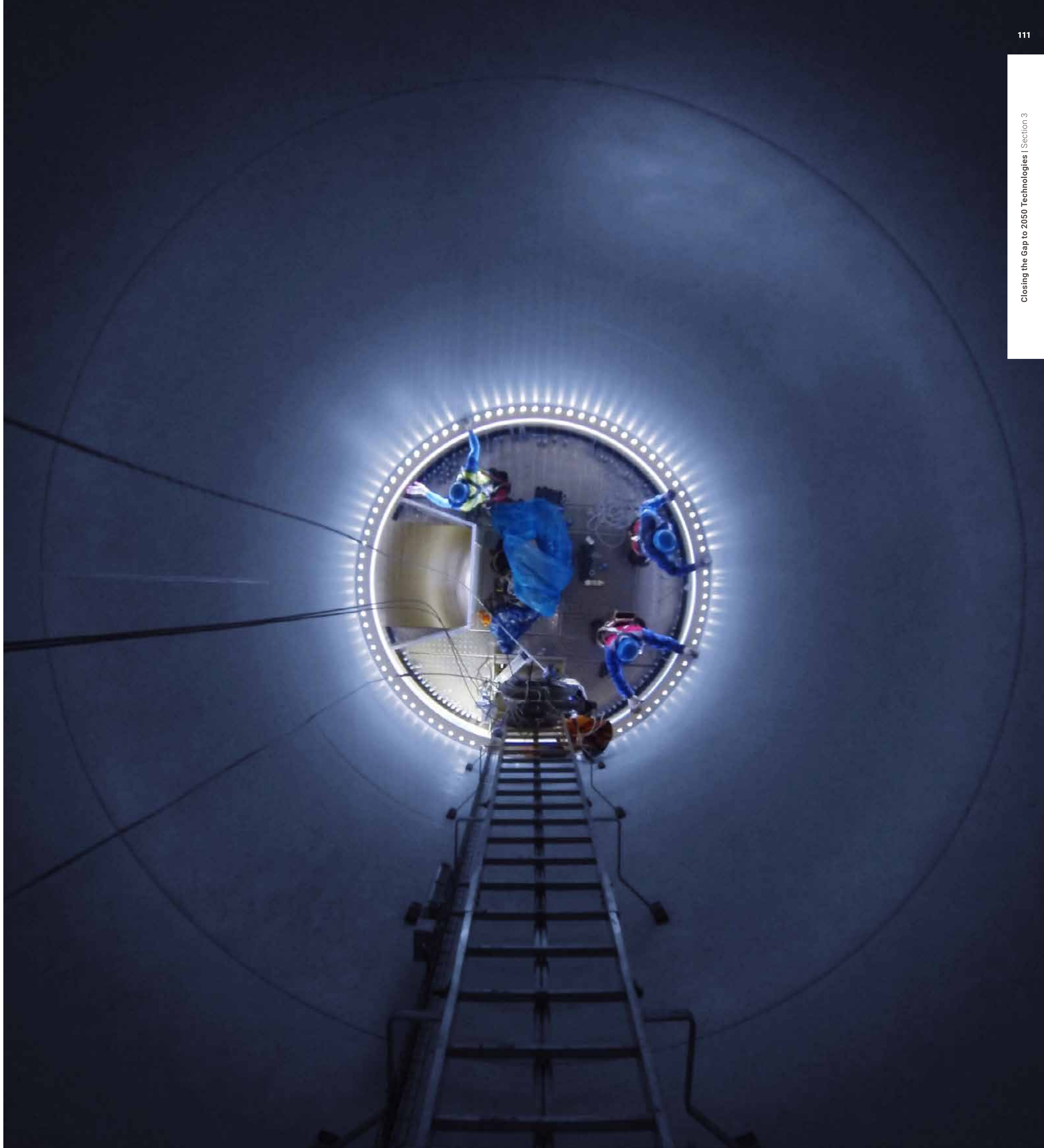
Current status

Today most offshore wind farms are relatively close to shore (<50 km) and are connected to the grid by an AC cable. Offshore substations balance the load[177.] (se gure 3.10). Installations further from shore require other technologies. Germany's latest offshore connection (Borwin 3) at ~160 km from shore uses high voltage direct current (HVDC) converter platforms and cables[178].

Figure 3.10: Connecting to the grid[179]



Source: Adapted from EnBW



Technology challenges, accelerators & enablers

Offshore transmission systems typically face harsh environmental conditions: mechanical loading due to marine currents and the movement of waves, temperature extremes, excessive humidity and salt pollution. Mature cabling technologies for interconnectors between substations and shore connections can manage these conditions. However, lighter and more durable materials make signi cant improvements.

For instance, cables with cross-linked polyethylene (XLPE) insulation are light and allow ships to transport longer sections of it. That means fewer cable joints are required, which decreases installation costs[180]. Improved insulation can also reduce transmission losses and allow for smaller cable sizes. Furthermore, opportunities for co-development and implementation exist with the oil and gas sector given the initiatives for platform electri cation.

Floating substations can also reduce costs and bring exibility to offshore power systems, though they require extra cabling due to their mooring systems (se gure 3.11). Subsea stations that integrate multiple elements such as electricity transmission, platform electri cation and energy storage could enable shared capex between multiple stakeholders. Siemens and ABB[181] are exploring a distributed asset setup like this (se gure 3.12).

Subsea power stations:

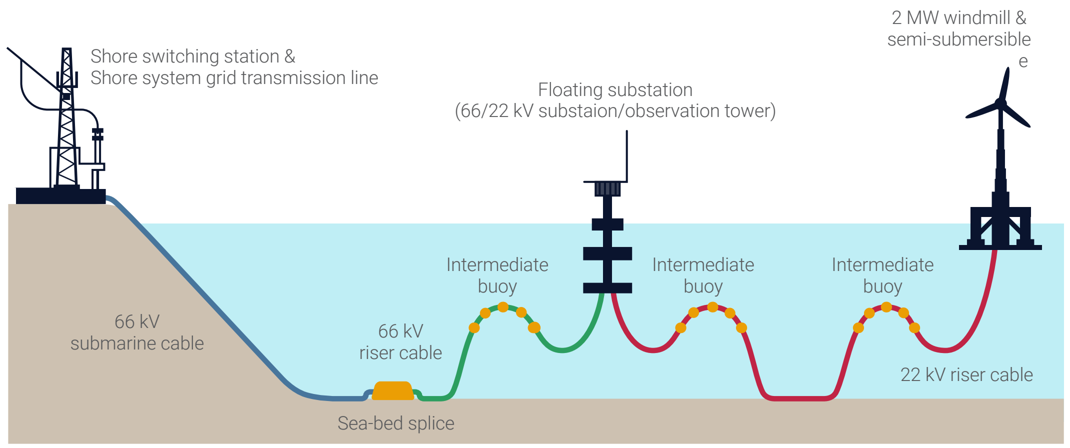
In 2019, **ABB** announced the world' rst subsea power distribution and conversion system after completion of a 3,000 hour shallow water test together with **Equinor, Total and Chevron[182]. Siemens** is also at th nal stages of commercialising its unit after testing in shallow Norwegian waters in November 2018[183]. As the concept of subsea factories develops in the offshore sector, subsea power stations will be vital in supplying the required electricity.

Table 3.12: Technology challenges of transmission systems

TRANSMISSION SYSTEMS	INNOVATION GAP
Light, durable coatings: to cut transportation and installation costs	
Cable inner design: placement of cable elements for electrical stability and improved transmission speed	
Floating substations mooring: to resolve issues around cabling and stability to reduce costs	

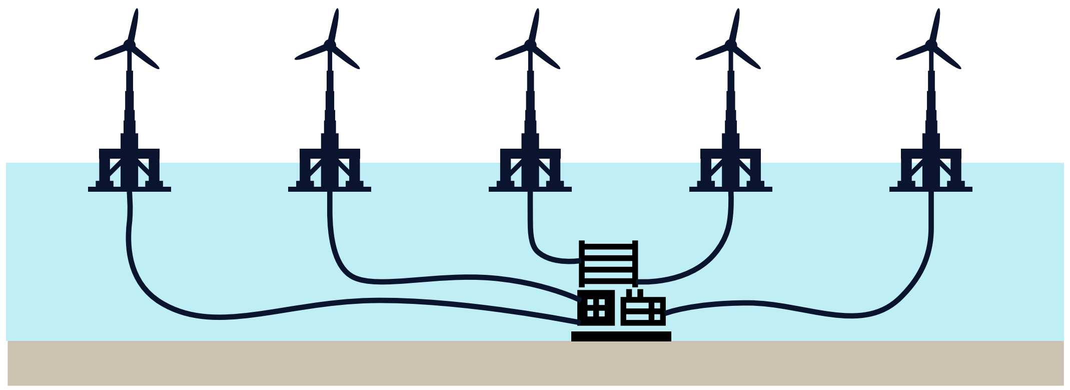
Critical gap, unlikely to be resolved without strong effort — Needs additional effort — On track to be resolved

Figure 3.11: Floating substations[184]



Source: Adapted from Viscas

Figure 3.12: Subsea substation concept



Source: Adapted from Riveramm

Geothermal

For many years, geothermal energy on the UKCS has been discussed as another potential renewable resource, especially for baseload electricity supply. Historically, offshore exploitation of geothermal resources has been considered economically unfeasible, but recent advances in offshore technologies like drilling and power generation, rising interest in repurposing ageing infrastructure, and the increasing urgency of decarbonisation have revived interest in the idea[186]. The concept has yet to be proven offshore, and geothermal leaders like Iceland are only beginning to explore the resource potential in 2020[187]. Lengthy development timelines, high capital costs, unclear ownership structures, and uncertainties around the technologies result in slow momentum for offshore geothermal on the UKCS. With ample availability of more accessible renewable resources, geothermal will likely be at most a minor contributor to the 2050 energy mix.

Energy storage

Current status

The intermittent and variable nature of renewables means that the gap between power supply and demand needs to be bridged. Currently, renewable energy generation does not yet exceed demand at any instant[188]. As offshore renewable capacity grows and becomes a larger component of the UK baseload power supply, it will be increasingly challenging to fully utilise generation capacity and maintain enough reserves for peak demand without suf cient syste exibility. Energy storage capacity and other mechanisms will be key to reducing the costs of integrating variable renewable energy.

Syste exibility can currently be managed in several ways: gas peaker plants, pumped-hydro, demand-response programmes and interconnectors all provide options. As renewables penetration increases, energy storage will be required to manage both short- and long- term needs. Battery systems can store power for seconds to hours for continuous, stable power supply and also improve grid stability. Deployment of grid storage solutions is at an early stage. Nearly 1 GW of battery devices are currently used across the UK[189]. Seasonal storage is not yet possible using batteries and other solutions, such as long-term hydrogen storage, will need to be developed instead.

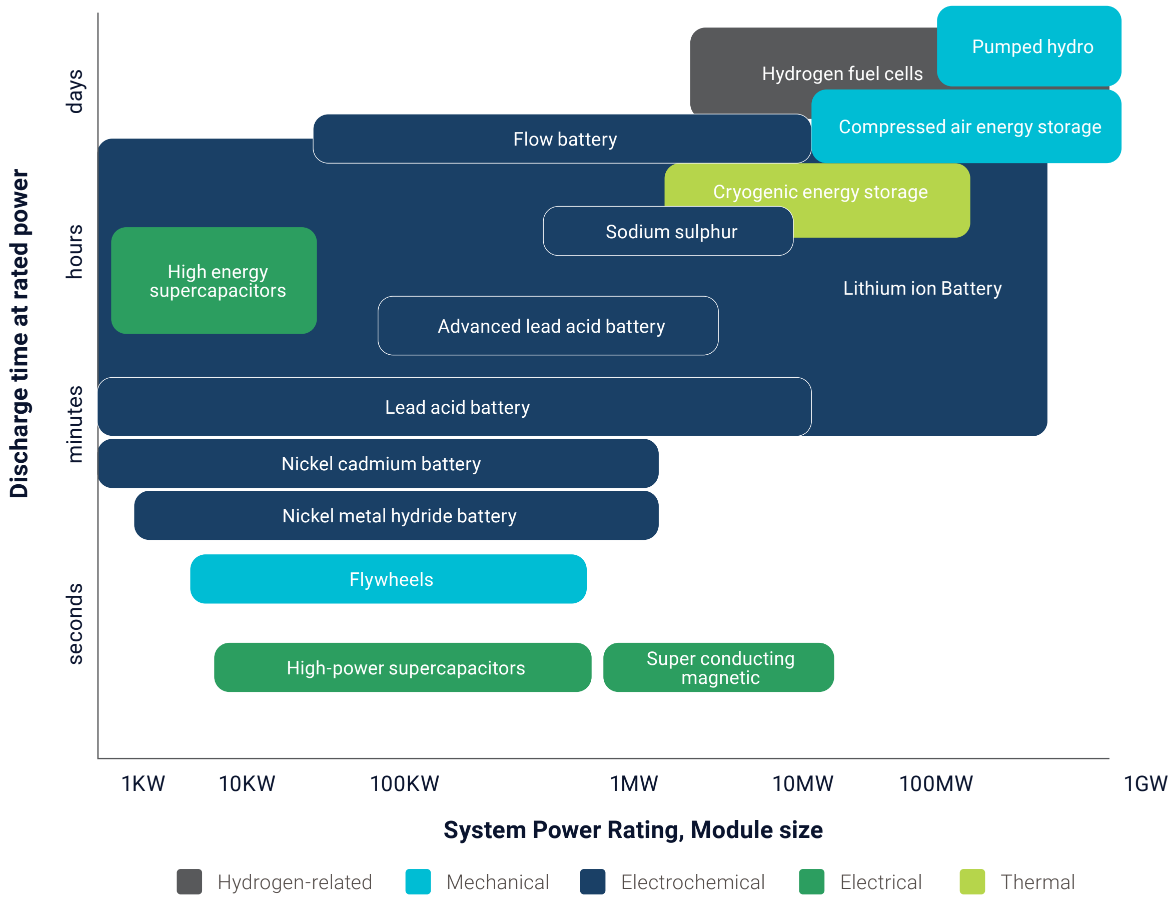
Technology challenges, accelerators & enablers

Wind power's variability means that there is a need for 10 MW-100 MW batteries with shorter discharge durations (seconds to minutes) and energy storage in the minutes to hours (MWh to GWh) range to counter cannibalisation of power prices, the depressive in uence on the wholesale electricity price at times of high renewable output[190] (se gure 3.13). Producers are addressing technology challenges, by commercialising new electrode materials, improving battery cell packaging and including battery management systems to improve capacity, safety and cycle life.

Buoyed by the uptick in electric vehicles, lithium ion (li-ion) batteries have reduced in price and manufacturing has scaled up, making these the preferred energy storage option. Li-ion batteries primarily differ by cathode chemistry: each has its own bene ts and drawbacks. The long lifespan, high safety and relatively low price point of lithium iron phosphate (LFP) make it an attractive option. However, improvements in the nickel manganese cobalt oxide (NMC) li-ion batteries and scale up in production has suf ciently lowered its costs. NMC batteries are a viable and more energy dense option for electric vehicles. Besides li-ion, ow batteries such as vanadium redox or zinc bromine are increasingly used in large power storage applications.

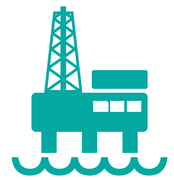
An important use case for batteries offshore is reducing the need for spinning reserves, i.e. keeping multiple gas turbines running for redundancy. 30 minutes on battery power is enough to start a backup gas turbine, thus avoiding the substantial emissions from spinning reserves. In addition, energy storage is vital onshore to ensure power coming from the UKCS can be reliably integrated with the national grid. For example, the Batwind project, announced by Equinor and Masdar, connects the 30 MW Hywind farm to an onshore battery storage farm. Offshore storage will eventually be required as the offshore grid develops. It will be more economical to have storage closer to generation and offshore consumption to minimize the losses through cabling mentioned in Section 3.3 - Fixed-bottom offshore wind. Offshore storage demand could potentially be met through hydrogen. The development of seasonal storage options for offshore renewables is likely to rely on large-scale onshore storage options - such as the recent liquid air battery pilot in Manchester[405] - and on development of power conversion and storage technologies like green hydrogen (as discussed in the hydrogen section).

Figure 3.13: Energy storage technologies: discharge time vs power rating



Source: Fluenceenergy.com

Box 3.1: Use cases for energy storage offshore



Electri cation of oil and gas platforms:

- **Transocean's Spitsbergen semi-submersible** has a hybrid energy storage solution, developed in partnership with **Aspin Kemp and Associates,** which captures waste energy during normal rig operations and uses it to power the rig's thrusters[192].
- **Siemens BlueVault li-ion battery system** will b rst deployed on Northern Drilling's West Mira drilling rig in the North Sea as part of a hybrid diesel-electric power plant[193]. It has four converter-battery systems for a maximum of 6 MW output during peak load times or as backup. It will reduce CO_2 emissions by 12%[194].

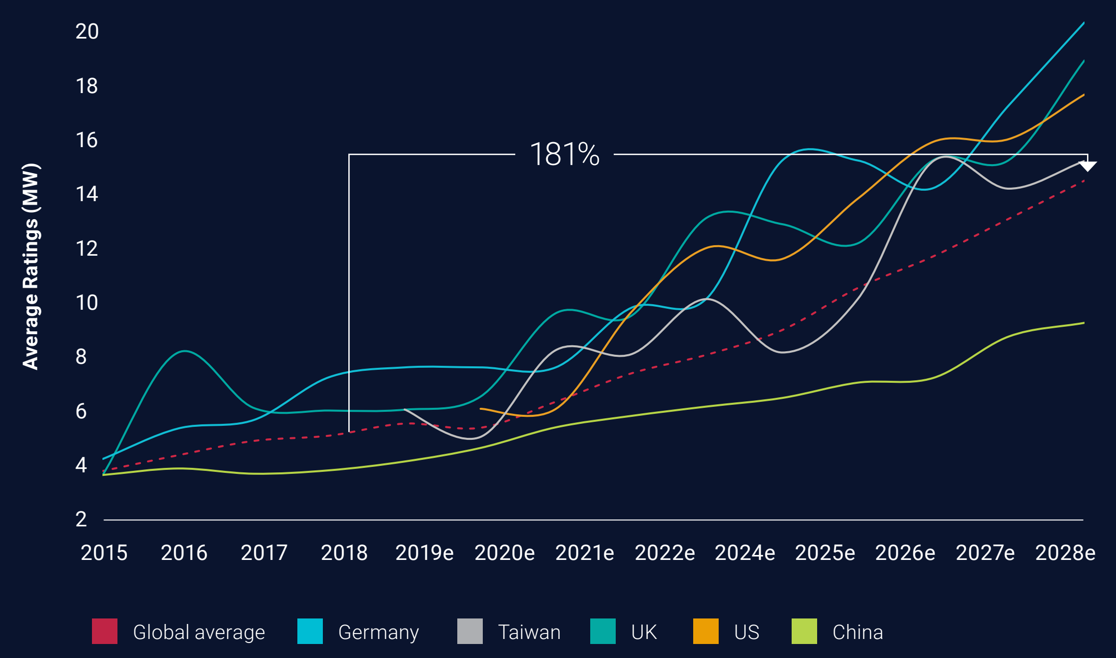
Renewable energy ecosystem and path to 2050

Each of the offshore renewable power systems will have their own ecosystem and will progress at a different pace over the next 30 years.

Fixed-bottom wind will remain the dominant option, with growth largely coming from incremental improvements such as further blade length increases[195]. Average turbines are around 9 MW today and expected to increase to between 12 and 15 MW by 2030 and over 20 MW by 2050[20] (see figure 3.14).

Floating wind can expand the UKCS' potential for energy generation. It would tap into stronger winds in areas with depths or seafloor compositions that are unsuited for bottom-fixed wind. It could also provide flexibility, as turbines could potentially be relocated. Further commercialisation of floating windfarms could result in a ~60% decline in LCOE by 2040, which would make the cost comparable to fixed-bottom wind turbines[20]. Government funded collaborations include the EU's Corewind project[196], which targets cost reductions for mooring systems, cabling and foundation stability, for example. Still, further cost reductions will require significant investments and policy backing. Areas that need improvement are support vessels and infrastructure - large port areas for production lines, component set down and wet storage of assembled units[197,7].

Figure 3.14: Forecasted growth in turbine ratings



Source: Wood Mackenzie

The levelised cost of electricity (LCOE) of airborne wind systems is currently multiple times higher than that of bottom fixed wind. Some optimistic scenarios expect steep cost declines from improvements to the technology, such as lower material use. With those improvements, commercialisation could be expected around 2035. However, AES would first need to overcome considerable technology challenges, such as durability, to match the lifetime of existing wind turbines[198,20]. It's an unlikely choice for the UKCS in the near- and mid-terms.

Marine energy, given its high predictability, could provide stable baseload power. However, funding is limited, and the technology is not yet practical or economical. Its potential by 2050 also remains uncertain. If ongoing pilots like Meygen and CapeSharp Tidal provide promising results, that could merit further government funding.

By 2050, offshore wind farms and other renewable technologies will be increasingly further away from shore. More HVDC cables and more offshore substations will be needed to bring costs down. A 2016 National Renewable Energy Laboratory (NREL)[199] study found that when transmitting electricity at high voltages over 220 kV, HVDC cables are most cost effective for transmission distances over 110 km. Most projects operating or planned for the next decade are closer to shore and would use HVAC. An HVDC network would mostly benefit interconnectors for international energy trade. After 2030, as floating wind farms become more common, HVDC cables will become more important to effectively integrate different systems.

As the offshore renewable energy ecosystem grows, several other challenges need to be addressed:

Grid integration and offshore storage: Renewables will be a large component of a net zero UKCS, eventually supplying power to the UK and to the UKCS itself. Wind's intermittent nature will make it highly challenging to maintain power reliability and quality while it feeds into both the complex offshore grid and the UK's already strained transmission and distribution grid. Therefore, analytics that predict generation and energy storage capacity onshore and ultimately offshore will be critical. Adding storage capacity requires a business model built on a suitable regulatory framework and commercial infrastructure. Adding storage to a grid is complex from an ownership and operational perspective, as the assets both generate and consume, or store, power. In the mid to long term, these complications could be exacerbated as the offshore portion of the grid expands and international connections and energy hubs become more common. When that happens, offshore storage will be required closer to points of use. Flexibility around operational regulations will be critical to securing maximum economic value from the integrated energy system.

Resolving policy and ownership issues: A hub-spoke setup is one of several connection options. This model can connect multiple generation assets to shared central substations and transmission cables to meet demand from various sources: the UK, electrified platforms or interconnectors. The setup has value for governments and energy operators alike but raises issues of ownership and maintenance as the assets are shared. While there is no one size fits all solution to managing offshore assets, transmission system operators are in a position to improve coordination and standardisation of projects. As the energy ecosystem integrates and becomes more complex, system operators need to collectively determine and adopt best practice.

Optimisation of operations and maintenance: Offshore wind farm operations and maintenance are becoming more industrialised as providers consolidate, which has increased scale as services are bundled together. Further improvements in operations and maintenance will help decrease costs and improve reliability and output.

Life extension and decommissioning: Many of the turbines currently operating or installed in the next few years will require life extension or decommissioning by 2050. The impact of this must be analysed now. Studies need to weigh up whether and how to remove substructures in the seabed. They should consider bene ts such as economic value of recovered materials against costs, including damage to marine life that will be caused by recovery operations. The lifetime of the turbine has already increased from 20 years to almost 30 years. That will continue to improve as technology evolves. How often turbines are decommissioned will change as their lifespans increase, while development o oating wind will reduce much of the decommissioning efforts related to turbine removal.

The development of grid management systems and onshore energy storage will need to keep pace with growing offshore energy capacity and intensifying decarbonisation efforts to prevent bottlenecking power delivery. In the long term, robust power management systems will become a crucial component to regulate the offshore grid. The emergence of energy hubs that connect multiple assets such as wind farms, oil and gas platforms, interconnectors and hydrogen production and storage will make that especially important. The UKCS' role in energy supply and international trade will continue to grow for the UK as systems like this are set up.

Speculative technologies for renewable energy

Offshore compressed air storage

- Uses offshore pressure vessels to compress air: startup company FLASC's hydraulic solution displaces a column of seawater with air[200]. Startup Hydrostor compresses air in underwater balloons[201].
- Can provide energy storage for small clusters or single turbines to level out power generation and transmission peaks and reduce cable costs.

Offshore pumped hydro energy storage

- Fraunhofer's StEnSEA project (Stored Energy in the Sea lls or drains subsea concrete spheres with seawater to store energy.
- The project identi ed potential sites with a cumulative storage capacity of around 817 terawatt-hours[202].

Self-assembling large-scale offshore wind turbines

- The EU ELISA project demonstrated a 5 M xed-bottom turbine, constructed as base, tower and turbine modules at an inshore wet yard. Tugboats tow the modules to the offshore location, where the base is ballasted and conventional heavy-lift jacks raise the telescoping tower section-by-section.
- There is only a handful of offshore heavy-lift cranes globally that can construct large turbines. Self-assembly avoids the necessity and high costs of these cranes[203].

Figure 3.15

Renewable technology roadmap

2020 — Short-term

Floating foundations becoming commercial

Automated inspection of blades with unmanned aerial vehicles

Wind turbine decommissioning

Transmission systems HVDC cables connectin oating wind farms to the shore

2035 — Mid-term

Unmanned installation: remote onshore control of transporting and installing wind turbines

Successful AES pilots opening the path for utility scale implementation

Marine energy

Hub-spoke models connecting wind farms to each other and to oil and gas platforms

Micro grids with offshore energy storage

2050 — Long-term

AES at utility scale

Parking lot

"incremental gain" tech challenges that will get resolved with or without dedicated effort

Larger turbines with xed-bottom structures

HVDC cable design with novel coatings

Advanced battery chemistries for long-duration large-capacity stationary storage

Ecosystem (2020)

- Fixed-bottom wind dominate the renewable offshore energy scene, growing in capacity due to larger blades, taller towers, and bigger turbines.
- Onshore energy storage capacity grows to integrate growing UKCS generation capacity into the national grid.
- Automated inspection and maintenance with aerial drones emerge to reduce operating costs.
- Commercial scal oating wind farms start to emerge, with optionally HVDC-transmission systems to connect these to shore or with electri ed platforms.

Ecosystem (2035)

- As dominance o xed-bottom wind continues an oating wind grows, demonstration projects for aerial energy systems (AES) join the scenery.
- Early commercial-scale installations of marine energy can start to emerge.
- Increasing the number of energy generation assets offshore enables the development of offshore micro grids or energy hubs, which can be linked to energy storage and electri ed platforms. Shorter wind farm development timelines are needed to align with oil and gas platform electri cation timelines.

Ecosystem (2050)

- Provided pilots are successful, AES technology can be coupled to existing wind farms to increase capacity factors, while wind farm foundations provide opportunities to couple marine energy systems
- The offshore energy grid increases in complexity, with multi-directional powe ow in a transmission network connecting platforms, energy hubs, storage assets, and interconnects, creating an interconnected system enablin exible energy management and exchange.

Critical path

Wind

Other renewables (marine)

Transmission systems

Energy storage

Source: Wood Mackenzie, Lux Research

3.4: HYDROGEN

Over the last 20 years, hydrogen has been hailed on various occasions as the next big thing in the energy industry. But now, the hype has been backed by investment. Large government initiatives and sizeable investments from major corporates have created new momentum for hydrogen and it looks set to play a more prominent role in the future energy mix[204].

Table 3.13: Reasons for hydrogen

The IEA believes there are four reasons why hydrogen is more likely to succeed this time[205]

1	It's one of the few options for hard-to-abate sectors, like **high-temperature industrial heat**
2	It contributes to policy objectives beyond renewable energy, like **energy security, clean air,** and **economic development**
3	It can be a **long-duration energy storage medium,** critical to maintain the rapid growth of renewable electricity generation
4	Legislative experience bringing other **clean energy technologies,** such as wind and solar, to scale can aid in successful commercialisation

Source: IEA

Box 3.2: Key projects for low-carbon hydrogen production

H_2

Key projects for low-carbon hydrogen production:

- **BP** is partnered with **Nouryon** and **Port of Rotterdam** to study the feasibility of a 250 MW electrolyser supplying BP's re nery[206]
- **Neptune Energy** and its partners PosHYdon[234] project explores electrolysis on an offshore platform off the Dutch coast.
- **Shell** is studying the feasibility of linking 3 GW to 4 GW of offshore wind to electrolysers in the north of the Netherlands[207].
- **Japan** is piloting hydrogen supply chain projects, shipping blue hydrogen from **Brunei** using liquid organic hydrogen carriers and from **Australia** using a dedicated liquid hydrogen transport ship[208,209].

> **The UKCS can play a central role** in supporting a future hydrogen economy

Hydrogen is also being promoted as key to the UK's future energy system. As noted in Section 2 - Sizing up the UKCS on the Road to Net Zero - of this report, by 2050 the CCC forecasts that the UK's annual demand for hydrogen will be 270 TWh, to be used for industrial and domestic heating, energy storage, fuel and chemical feedstock[210].

The UKCS can play a central role in supporting a future hydrogen economy. Besides decarbonising some of its own operations through the use of hydrogen, the UKCS has natural gas resources and vital CO_2 storage capacity for blue hydrogen, strong offshore wind build-out to produce low-cost electricity in the longer term for green hydrogen, and possibilities for large capacity hydrogen storage. Hydrogen technologies also follow the traditional up-, mid- and downstream oil and gas value chain – production (as blue or green hydrogen), storage and transportation and hydrogen use – making the oil and gas industry a natural partner in building a future hydrogen economy.

Hydrogen production

Blue hydrogen

Producing energy or chemicals from hydrogen generates no direct carbon emissions, but hydrogen's carbon neutrality depends entirely on how it is produced. Methane reforming is the primary hydrogen production process, mostly commonly steam methane reforming (SMR). The process involves the mixing of methane - usually from natural gas - with steam over a catalyst at temperatures of 800°C – 900°C which produces synthesis gas (syngas), a mix of hydrogen and carbon monoxide[211]. A water-gas shift reactor can convert the carbon monoxide, plus water, to more hydrogen, plus CO_2. This process produces so-called grey hydrogen. It emits around 8 kg – 10 kg CO_2 for each kg of hydrogen and costs approximately £1.40/kg of hydrogen depending on the local gas prices. Using carbon capture technology in this process yields blue hydrogen and adds around £0.9/kg to the costs[212,213,214,215,216].

Current status

Less than 1% of global hydrogen production is currently blue[7]. Blue hydrogen is not fully carbon-neutral: CO_2 capture ef ciencies[217] reach 85% – 95% at best, and current CC agship projects are closer to 30%[13]. However, it does not require new technology inventions, as blue hydrogen can combine existing methane reforming processes with CO_2 capture equipment, which is well understood. Current blue hydrogen projects under development are typically linked to existing infrastructure in coastal petrochemical clusters, where they can bene t from natural gas supply as well as CO_2 storage options offshore.

H_2

Key projects for blue hydrogen production:

- Examples of blue hydrogen projects under development are the **UK's Acorn** and **HyNet projects**[218] and the **Dutch H-Vision Initiative** and **Hydrogen to Magnum (H2M)** projects[13].

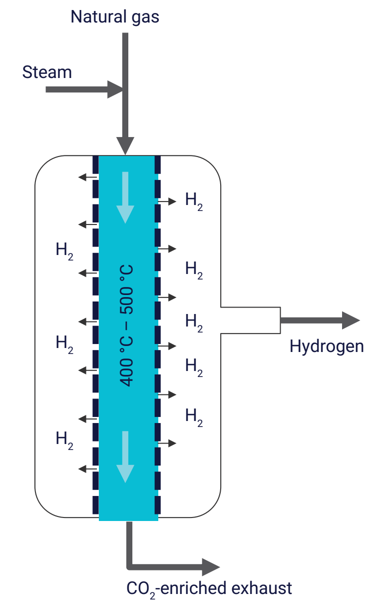
Technology challenges

Like most thermochemical processes, both methane reforming and CCUS are more economical at large scales. High construction costs and space constraints make these technologies a poo t for offshore operations, so nearly all projects are onshore. However, several organisations[10,219,220] are developing methods to increase the ef ciency of reforming and CO_2 capture and decrease system footprints so that these technologies can be considered for use offshore.

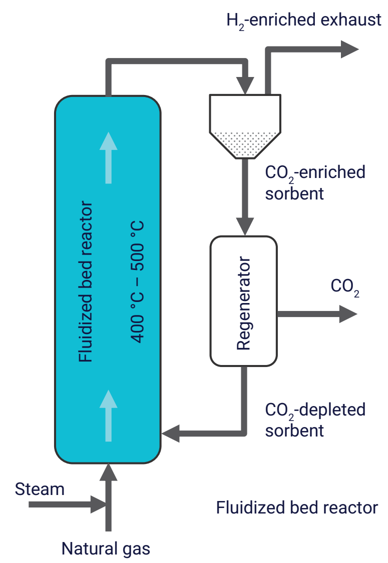
Incremental improvements to SMR units have been in development[221,8] for well over a decade and are readily available[20,222] These incremental innovations can bene t both grey hydrogen production process as well as blue hydrogen. These improvements include better heat transfer and recovery and a reduction in the amount of catalyst materials needed[23].

Alternative reforming technologies for blue hydrogen production can increase hydrogen yields and CO_2 capture ratios while reducing the system footprint, making them relevant for the UKCS. Beyond novel concepts involving the use of sorbents or membranes to increase hydrogen yields, alternatives to SMR are increasing in relevance too. Though autothermal reforming (ATR) has been commercial for decades in applications such as ammonia or methanol synthesis, it is now seeing renewed industry interest. ATR uses oxygen and steam in a single exothermic reaction with methane to form syngas. Compared to SMR it results in a higher concentration and purer form of CO_2, reducing capital costs and allowing increased ef ciency of the carbon capture equipment. Other reforming technologies being researched include plasma-based processes that yield hydrogen and carbon black. Despite the lower footprint of plasma reformers, and no catalyst requirements, chemical selectivity and energy requirement remain a challenge for these technologies[223].

Table 3.14: Novel blue hydrogen concepts

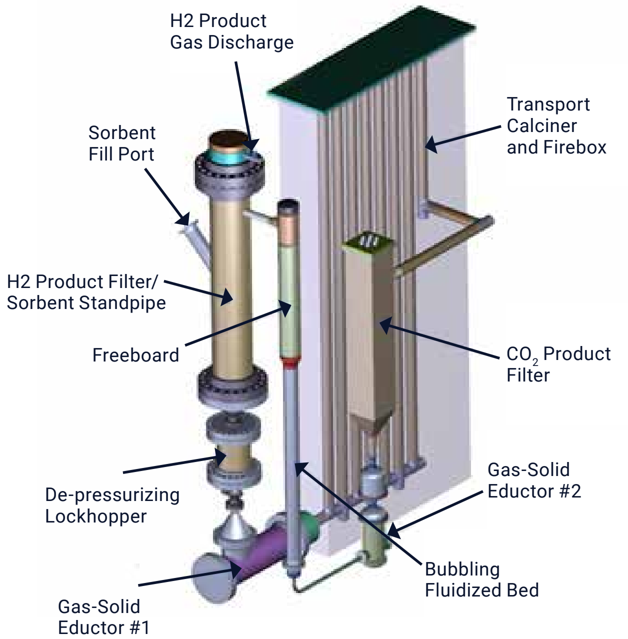


- Membrane removes hydrogen from reforming reaction, shifting reaction balance to higher hydrogen yields at lower temperatures
- CO_2 is concentrated in exhaust as high as 90%, facilitating downstream CO_2 capture
- Key challenge: thinnest possible, yet durable membrane to increase ef ciency[10,224]



- Calcium oxide or other CO_2 sorbent removes CO_2 from reaction, shifting balance to higher hydrogen content in exhaust (>90%) at lower temperatures
- Sorbents are separated from gas stream to de- sorb CO_2. While an energy-intensive process, the released CO_2 is suited for storage without further puri cation[225]

Figure 3.16: Schematic of the sorbent-enhanced reformer to be used in the HyPER project



Source: HyPER project

Green hydrogen

Green hydrogen is produced using one of several types of electrolysers[227,228]. The process uses renewable electricity to split water molecules into hydrogen and oxygen.

Current electrolysis methods are just under 70% ef cient. Green hydrogen economics are almost exclusively determined by a system's power prices, load factor and capital costs[7]. It is possible to place electrolysers onshore and offshore. Though offshore adds the challenge of space constraints and operational costs, it also provides a path to market for excess wind power that would otherwise be curtailed.

Table 3.15: Main hydrogen electrolyser types

	Alkaline (AE)	Proton exchange membrane (PEM)	Solid oxide electrolysis cell (SOEC)
Benefits	• Lower costs – cheaper catalyst metals • Long performance history	• Rapid response time, better suited to pair with intermittent energy sources • Operates at high current density and wide load range	• Operates at very high temperature (>700 °C) and ef ciency
Drawbacks	• Liquid electrolyte is hazardous, corrosive, and susceptible to leakage • Requires several minutes to ramp up and down	• Higher capex • Reliance on rare or costly electrocatalyst materials	• Moderate time to ramp up or down • Not suited for intermittent use because of need for high heat • Unproven in commercial use

Table 3.16: Offshore green hydrogen concepts

CONCEPT	DESCRIPTION
1	**The Dutch PosHYdon[234]** project aims to install a containerised desalination and electrolyser system on the **Neptune's Q13a-A platform** and power it with offshore wind.
2	**Ørsted** and **ITM Power** are exploring a novel concept, placing the electrolyser in or near a wind turbine tower with a direct DC cable connection to minimise power losses. A central substation platform then supplies a network of such electrolysers with desalinated water and powe ow control via umbilicals, while housing the compressor station to pump produced hydrogen into a transmission pipeline .

H_2

Electrolyser system examples:

- In 2018, **ThyssenKrupp[229]** piloted a commercial scale system with a very high ef ciency of 82%, which it accomplished by virtually eliminating the gap between the electrodes and membrane in a so called zero-gap con guration alkaline electrolyser.
- Electrolyser footprint is a crucial constraint for offshore green hydrogen production on the UKCS. For instance, **ITM Power's 2 MW** (800 kg hydrogen per day) electrolyser system and auxiliary system ts in two 40-foot ISO containers[230], minus desalination. Such sizes allow an offshore platform to produce 3 tonnes to 15 tonnes green hydrogen per day, depending on platform size[231]. Based on current infrastructure and proposed systems that repurpose decommissioned platforms, commercial offshore hydrogen production makes the most sense linked with far from shore wind farms, where high costs and energy losses of power cables favour use of a hydrogen pipeline network to demand centres in the UK or UKCS[232,233].

Current status

A recent study[7] found the UK has strong prospects for low cost green hydrogen because of its wind power potential. Globally, several onshore electrolyser projects linked to offshore wind farms have been announced. In industrial settings, electrolyser technology is approaching maximum ef ciency, but design improvements can still achieve incremental ef ciency gains.

As they are able to maintain high ef ciency even while power inpu uctuates, PEM electrolysers are a more attractive option to be used with large scale renewable power from the UKCS. They can ramp up and down within seconds; a typical alkaline electrolyser needs minutes. They can also exceed their maximum capacity up to 200% for a few minutes while still running ef ciently at lower capacity, maximise the usage o uctuating renewable electricity[13].

Electrolyser projects onshore are most economical for electricity that is produced near to shore. Offshore electrolysis is in its infancy and would require desalination systems, but the technology could be used on repurposed or new platforms, in wind turbine foundations and subsea locations. Producing hydrogen offshore has the bene t of making more ef cient use of electricity that is already produced offshore and could provide an accessible and low-carbon alternative fuel to be used on oil and gas platforms.

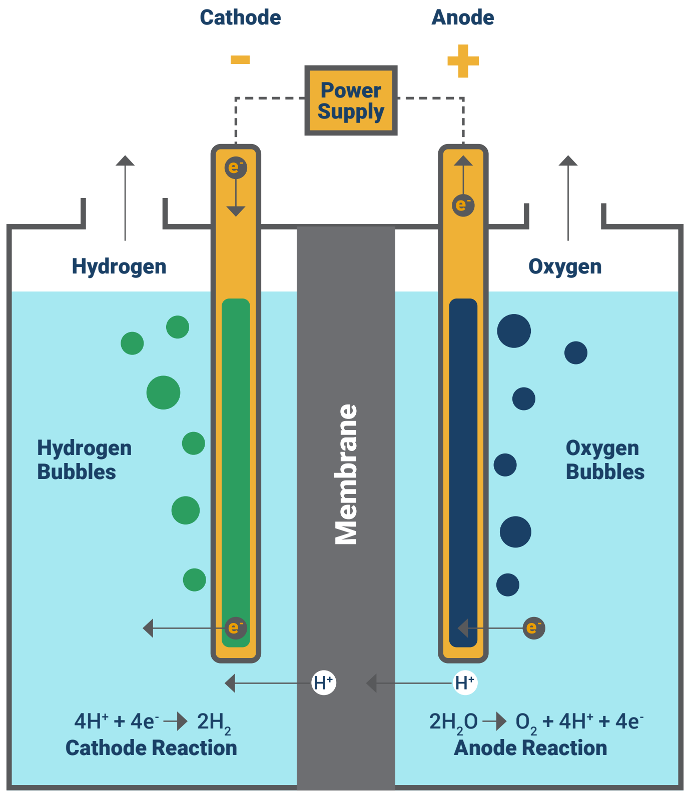
Technology challenges

The high capital cost of electrolysers - currently between £640 and £720/kW - is a major obstacle. The cost can be offset by making optimal use of lower power prices through operational improvements, consistent power supply, and use of digital grid control software. Costs are high because electrolyser stack assembly is a largely manual process done in small factories. Scale-up[236] and automation methods such as roll-to-roll manufacturing could reduce costs by 30% or more by 2030[237].Making these improvements is a major focus for leading producers like ITM Power, NEL, or Siemens. These advances could reduce capex to between £160 and £240/kW after 2040[238], though some Chinese manufacturers claim it is possible to achieve those costs now. The solar PV and battery industries have demonstrated that this can be done: costs for both have plummeted rapidly with massive scale-up of production.

Cheaper electrode catalysts provide another opportunity to reduce costs. PEM electrolysers today use expensive but higher-performing platinum and iridium, but advances in achieving similar performance with lower-cost catalyst materials could reduce capital costs by 5% – 10%.

Using seawater for hydrogen production could become vital to hydrogen economies around the world. A 200 MW ATR can consume up to 30-40 m^3/hr of water, a volume that would be dif cult to source in nations where fresh water is scarce. However, offshore electrolysis has unique challenges as salts can cause corrosion and form chlorine and other toxic gases during the process[239,240]. PEM electrolysers typically require water treatment systems even with drinking-grade water supply; seawater would need membrane desalination technology[241], which would signi cantly increase costs.

Figure 3.17: Electrolysis process



Source: Wood Mackenzie

Table 3.17: Technology challenges of hydrogen production

BLUE HYDROGEN	INNOVATION GAP
High-efficiency reformers: minimal footprint, ef cient reformers with carbon capture for blue hydrogen	
Hydrogen membranes: thin, high- ux, durable membrane to separate blue hydrogen in reformer	
CO_2 sorbents: high-capacity sorbents that are more durable at high temperatures, have the lowest possible energy requirements for ef cient regeneration and release CO_2 in blue hydrogen production	

GREEN HYDROGEN	INNOVATION GAP
Electrolyser manufacturing: economies of scale and production automation in factories	
Electrolyser catalyst: low-cost, high current density, and durable catalyst materials	
Saltwater electrolysis: cost-effective integrated desalination or direct seawater electrolysis to prevent corrosion or formation of chlorine gas in seawater electrolysis	
Subsea electrolysers: systems suited for autonomous exible hydrogen production and pipeline compression on the sea oor	

 Critical gap, unlikely to be resolved without strong effort  Needs additional effort  On track to be resolved

H_2

Technology developments for offshore electrolysis:

- Saltwater desalination for green hydrogen costs is one of the key aspects being explored in the **UK's Project Dolphyn**[242] for large-scale offshore hydrogen production. As an alternative to desalination, a few groups, including the **University of Leiden**[45], **Technical University of Berlin**[243]and **Stanford University**[44], are working on specialised catalysts that allow safe direct seawater electrolysis. As early stage research, these catalysts still need large improvements in lifetime, efficiency and costs before they can compete with desalination-coupled PEM electrolysers. The company **sHYp,** recently selected as part of the **Cohort 3** of the **Net Zero Technology Centre's TechX** accelerator programme, is also working on producing green hydrogen from seawater without the need for desalination[244].
- Since space is scarce offshore, participants in the **U.S. DOE H2@Scale program** are developing subsea electrolyser systems that can be placed below floating wind farms, linked to power supply and a hydrogen export pipeline. While that will require further development of subsea desalination and compact electrolyser systems, the added benefit is that the water pressure can help produce hydrogen at high pressure for pipeline transport, without the need for mechanical compression.

Hydrogen storage and transport

While hydrogen storage and transport has little direct carbon abatement potential, it is a crucial enabler for the hydrogen economy. The UKCS has an important potential role to provide storage capacity for blue or green hydrogen. In addition, the build-out of the necessary storage and transport infrastructure also bene ts development of offshore green hydrogen production, which will require pipelines or shipping routes to bring hydrogen produced far from shore to demand centres[247].

Hydrogen has the highest energy content per kilogram of any fuel yet as the lightest element in the universe, its volumetric energy density is very low: moving any meaningful amount of energy requires large volumes. This low volumetric density makes it impractical to compress and then to store or ship potentially hundreds of tonnes of hydrogen daily from the UKCS to the mainland without extensive multi-stage compression or another conversion to a denser form.

There are broadly four technology options to improve hydrogen transport economics and one large-volume storage option:

Table 3.18: Hydrogen transport and storage options

	Storage & Transport
1	**Compress the hydrogen** up to 50 bar – 100 bar and transport by pipeline
2	**Combustible carrier molecule:** Convert the hydrogen to another energetic carrier molecule, such as ammonia, which can be directly combusted, or cracked to release the hydrogen again
3	**Non-combustible carrier:** Combine hydrogen with a reversible carrier molecule (liquid organic hydrogen carrier, LOHC). The hydrogen is released at the destination and the depleted carrier is reused
4	**Liquify the hydrogen** at –253 °C and store in well-insulated cryogenic tanks
	Storage only
5	**Store very large volumes of hydrogen** under mild pressures in underground reservoirs, connected to a pipeline or a transport terminal

Figure 3.18: Compressed hydrogen volumetric density

5 kg hydrogen compressed to **700 bar, 500 km** range

800 kg hydrogen compressed to **250 bar**

While different technologies have their own bene ts and drawbacks, each approach adds between £1.6 to £4.8/kg to the hydrogen cost[248], depending on distance and local energy costs. Upfront investments that can exceed £80 million per plant are required. Each approach can suffer conversion losses ranging from 10% to 45%[43] of the energy contained in the hydrogen.

Pipelines

Current status

For pipeline transport, blending hydrogen with natural gas is currently possible[7] to about 20% volume without considerable equipment modi cations. The HyDeploy[249] and H21 North projects in the north of England[247] are trialling blended gas for domestic or industrial heating. However, as hydrogen demand grows, pure hydrogen supply chains will also become necessary. Dedicated hydrogen pipelines have been used onshore for decades. The HOP project[229], coordinated by the the Net Zero Technology Centre, found in its preliminary results that 30% of the UKCS' oil and gas pipeline infrastructure could potentially be used for hydrogen services (subject to further assessment), which could potentially offer considerable savings over new construction. Pipelines have the added benefit of line packing, offering hydrogen storage buffer capacity by modulating the pipeline pressures.

Technology challenges

A key technical challenge in pipeline repurposing is that hydrogen under pressure can diffuse into the pipeline materials, and make higher tensile strength steel brittle, or affect gaskets or soft seal materials, increasing the risk of leaks or bursts. Any repurposing requires careful evaluation of the pipeline materials and the condition of valves and other points where hydrogen could leak. For incompatible pipelines, it may be possible to install polymer liners, but this is technically challenging to do, even on land[38]. Furthermore, the lack of an odorant that can mix with hydrogen to make leaks easy to detect creates a safety risk.

Carrier molecules

Current status

Carrier molecules chemically bond to hydrogen, forming a liquid that can provide a high volumetric energy density while being easier to handle than gaseous hydrogen. Common options are reacting hydrogen with nitrogen to form ammonia or bonding it with organic molecules that can later release it again, dubbed liquid organic hydrogen carriers (LOHCs).

Japan has a strong focus on a hydrogen economy and is running a number of international hydrogen supply chain pilots using carrier molecules. Chiyoda, together with consortium partners, has started shipping hydrogen from Brunei[5] to Japan using liquid organic hydrogen carriers[250]. Hydrogen infrastructure developer H2U will use ammonia to export hydrogen from South Australia's Port Lincoln to Japan, as part of Japan's Green Ammonia Consortium[251]. In the UK, Siemens and partners have constructed a green ammonia demonstrator to store hydrogen from an electrolyser powered by wind energy[252].

Technology challenges

For both LOHCs and ammonia, energy conversion losses and transportation costs are comparable to liquid hydrogen, yet the technologies themselves face very different challenges.

H_2

Hydrogen carrier pilot projects:

- Ammonia is produced with the Haber-Bosch process, reacting nitrogen and hydrogen over a catalyst at elevated pressures and temperatures around 500°C. Pure anhydrous ammonia has nearly twice the energy density of liquid hydrogen, and while corrosive and toxic if released, it can be transported at mild pressure and moderate temperatures(<20 bar, -10 to -15°C). It can be burned in internal combustion engines or turbines, or used in specialised fuel cells. The **Equinor supply vessel Viking Energy** will be retrofitted with a 2 MW direct ammonia fuel cell fo rst pilot by 2024[253]. Ammonia cracking to release hydrogen is less mature and requires improved catalysts to increase the energy efficiency at lower temperatures.
- LOHC are often derivatives of toluene, such as the methyl cyclohexane that is being used by **Chiyoda.** They are liquid and largely harmless at room temperature, making it possible to use existing bulk liquid tanks and ships. They release significant heat during hydrogenation, which is lost without waste heat recovery systems. In turn, they require sustained heating at temperatures of between 200°C and 350°C over one to two hours to release most of the hydrogen at destination. Some LOHCs require purification of the hydrogen to remove trace carrier molecules as well as hydrogenation byproducts such as CO_2, CO, methane, and heavier cyclic hydrocarbons[254].

Closing the Gap to 2050 Technologies | Section 3

Liquid hydrogen

Current status

Hydrogen turns to liquid below –253 °C, making liquefaction an inherently energy-demanding process, but its high volumetric energy density means a standard shipping container can hold approximately 3,500 kg[255]. Hydrogen liquefaction is a well-established process in the industrial gas industry, but existing plants range from 5 to 35 tonnes of hydrogen per day, an order of magnitude smaller than what would be needed for large scale use of hydrogen energy[256]. The energy consumption of liquefaction processes is equivalent to 30 to 40% of the energy content of the hydrogen[257], though better energy efficiency is possible[258] at larger plants by minimising heat loss[259]. Liquid hydrogen can be used directly by fuel cells after it is warmed up to become a gas.

Liquid hydrogen supply chains:

- **Kawasaki Heavy Industries** has built a specialised ship to transport 1,250 m^3 liquid hydrogen from Australia to Japan[6], which was launched in December 2019 and will start trials in late 2020[260]. Similarly, in late 2019, **BKK, Equinor, Air Liquide and partners** received PILOT-E support to develop a liquid hydrogen supply chain for maritime applications in Norway[261].

Technology challenges

While it's possible to have small-scale liquefaction plants for the use of hydrogen offshore[262,263], they will be less efficient than large-scale onshore ones. Shipping and storage require specialised cryogenically insulated storage tanks to minimise boil-off, which otherwise claims between 1% and 5% of the hydrogen over a few days. However, tankers and ships could capture boil-off and use it as fuel, while systems such as Linde's LOPEX[73] re-liquefier can turn 80% of the boil-off to liquid hydrogen again.

Underground and subsea storage

Current status

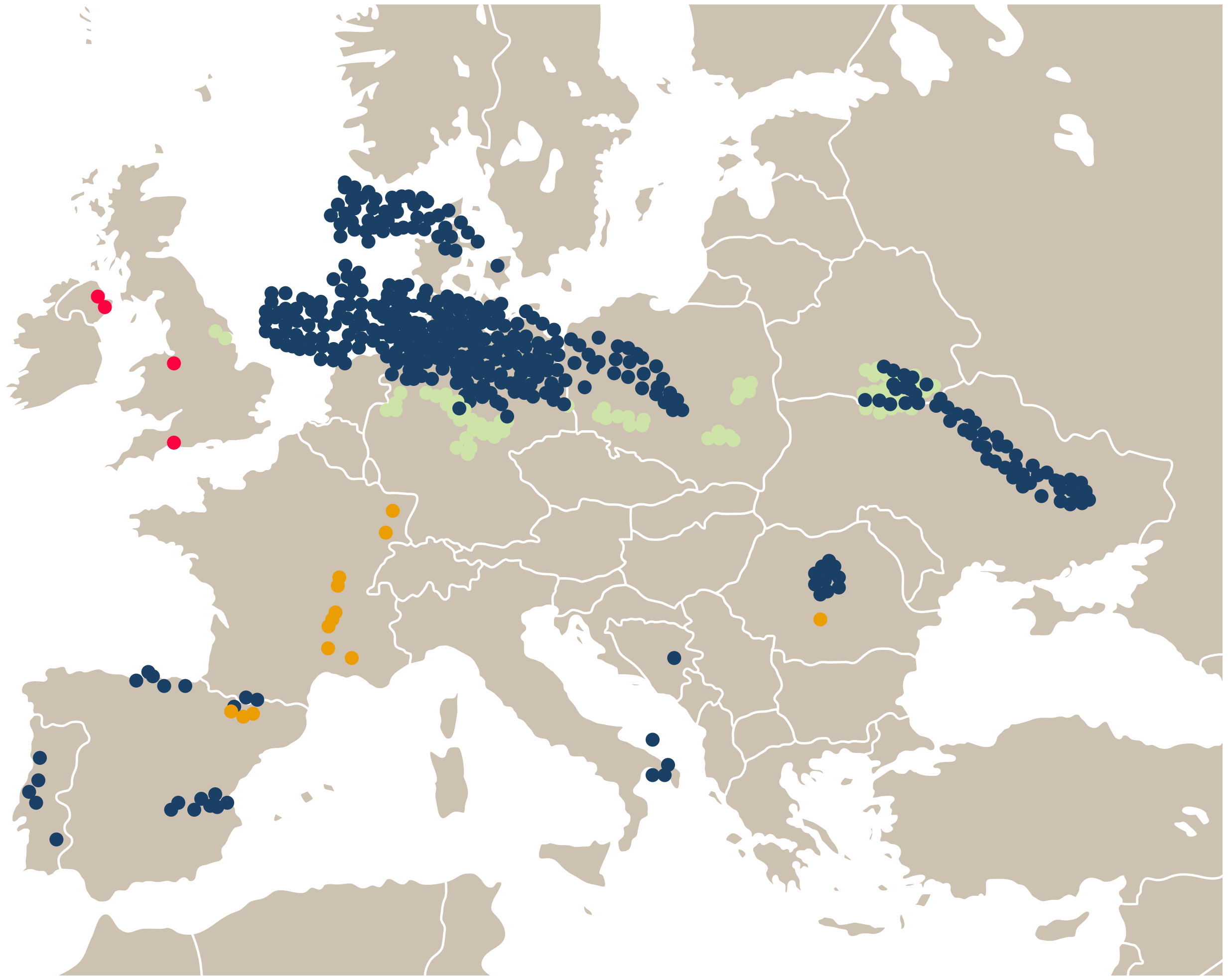
Underground reservoirs can store vast quantities of hydrogen in either salt caverns or depleted natural gas reservoirs. The technology to construct salt cavern for hydrogen storage is not widely used but it is relatively mature. Salt domes above and below the cavern provide a good seal. Two large hydrogen storage caverns have been in operation near Houston, U.S[264] for years and three small caverns have been in use up until recently near Teesside in the UK[265].

Subsea hydrogen production and storage addresses the lack of space in topside platforms while enabling offshore operations. Currently, the DeepPurple project lead by TechnipFMC is the main project developing subsea hydrogen storage. While subsea storage presents materials challenges to the storage tanks related to the harsh environmental conditions, the technology to store hydrogen either in liquid or gaseous form remains unchanged.

Technology challenges

Offshore salt caverns have not yet been used for hydrogen storage, though the central North Sea basin does offer multiple potential salt cavern locations[266]. However, it is still unclear if depleted gas reservoirs are suitable, as hydrogen may escape through low porosity rock that is otherwise impermeable to natural gas. Also the hydrogen can react with the remaining hydrocarbons or sulphur compounds[267], contaminating the hydrogen supply. The HyStorPor project conducted by the University of Edinburgh is currently studying the hydrogen reactivity with the rocks into which it is injected, the effectiveness of hydrogen migration through water-filled porous media, as well as the amount of hydrogen that can be recovered from the rocks[268].

Figure 3.19: Offshore salt structures offer the UK possible salt cavern development options not found onshore



- Salt Structure - potential salt cavern option
- Cenozoic Age (Paleogene) bedded salt deposit
- Mesozoic Age bedded salt deposit
- Paleozoic Age bedded salt deposit

Source: Adapted from: Caglayan et al. (2019)

Closing the Gap to 2050 Technologies | Section 3

Table 3.19: Technology challenges of hydrogen storage and transportation

HYDROGEN STORAGE AND TRANSPORTATION	INNOVATION GAP
Pipeline repurposing guidance: clear understanding of hydrogen's impact on durability of repurposable UKCS pipelines	
Pipeline re-lining: methods to refurbish or coat interior of pipelines to make them suited for hydrogen transport	
Hydrogen leak detection: Odorant or other means to quickly detect potentially dangerous hydrogen leaks without sensors	
Small-scale hydrogen liquefaction: small, modular, energy-ef cient hydrogen liquefaction systems	
Minimal boil-off storage: minimising or recovering boil-off losses from liquid hydrogen storage systems	
Small-scale Haber-Bosch: scale-down of thermochemical ammonia production process without diminished ef ciency	
Ammonia cracking: energy-ef cient ammonia cracking catalyst to obtain high-purity hydrogen at lower temperatures	
LOHC catalysts: catalysts for low-temperature, fast, and complete dehydrogenation of liquid organic hydrogen carriers	
Underground storage: comparison of hydrogen contamination risk in salt cavern vs. depleted oil / ga eld storage	

Critical gap, unlikely to be resolved without strong effort · Needs additional effort · On track to be resolved

Hydrogen use on the UKCS

While the key demand drivers for the hydrogen economy are onshore[9], there is also potential for hydrogen to help decarbonise oil and gas operations offshore using gas turbines or fuel cells. Fuel cell systems can be used for backup power, reducing emissions from gas turbines used as spinning reserves. A more challenging step would involve switching the primary fuel on the UKCS at the platforms from wellhead gas to low-carbon hydrogen. The platform would then depend on an external fuel supply, either via a hydrogen pipeline or storage that is either on deck or in barges. That would be most useful for platforms that can't be reached economically by a direct power cable connection but can have a reliable hydrogen supply with ample redundancy.

Hydrogen turbines

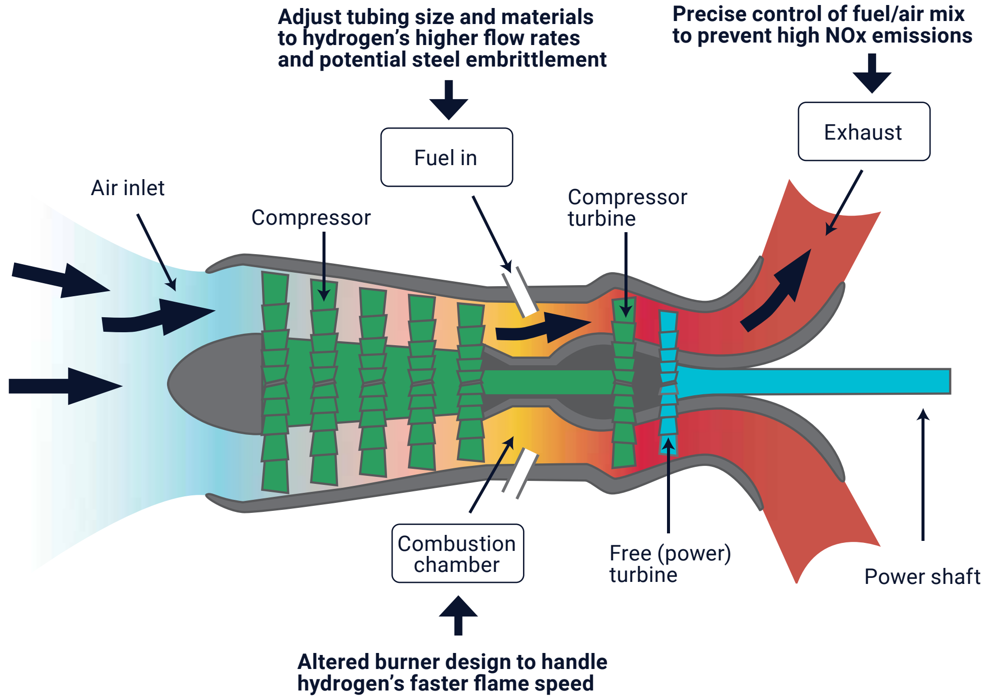
Current status

Currently, platforms on the UKCS use wellhead gas in open cycle gas turbines[269] to either generate power or mechanically drive compressors, using fuels like diesel as backup in case production is interrupted. These turbines are the biggest energy consumer on the UKCS. Many turbines can already run on hydrogen blends of between 5% and 95% hydrogen[268]. All major turbine producers, including Ansaldo[271], GE[82], MHPS[272] and Siemens[273] are developing turbines that are capable of running on 100% hydrogen, including duel-fuel designs[81] that can use multiple fuels. Hydrogen's hi ammability can even increase combustion ef ciency.

Technology challenges

Hydrogen's low volumetric density and potential embrittlement of some metals mean that changes to ducting, seals, and valves are required, as well as possible retro ts for turbine blades so that they can withstand highe ame temperatures[86,274]. Changes in burner design may also be needed to avoid risks of damage because of hydrogen' ammability an ame speed[275,276] and its tendency to form nitrous oxide (NOx) at higher temperatures[86].

Figure 3.20: Required mod cations for hydrogen-fuelled turbines



Even a relatively small 11 MW turbine that is running on pure hydrogen uses 1.1 tonnes of hydrogen per hour[277], or one shipping container full of 500 bar compressed hydrogen every four to five hours. As a result, on the UKCS, hydrogen turbines would remain limited to use cases that require very high- power outputs, such as gas-to-wire applications that are linked to underground hydrogen storage or a hydrogen pipeline network.

Turbines fuelled by an ammonia-hydrogen blend are another alternative, as a blend of around 70% ammonia and 30% hydrogen approximates the combustion characteristics of natural gas[278,279]. The footprint and weight per kg of hydrogen of ammonia storage tanks are 10-fold lower than cryogenic hydrogen storage[280], and ammonia blends also help to reduce turbine NOx emissions[281]. The key challenge is to demonstrate the technical and economic feasibility of using short platform shutdown periods to make the necessary modifications to older turbines. Setting up ammonia barge supply lines and demonstrating the feasibility and, given ammonia's toxicity, safety of this solution are two additional challenges.

Hydrogen fuel cells

Current status

Avoiding a gas turbine altogether translates to fewer personnel, auxiliary facilities and reinforcement structures as well as improved safety[282]. When direct electrification is not possible, a hydrogen fuel cell power system can be an alternative. Fuel cells can have between 60% and 70% electrical efficiency, twice that of an open cycle gas turbine, are substantially less complex and operate reliably when combined with a battery system for peak power supply, without risks like flame-out[283]. Fuel cells have been backed by major governments like Japan, South Korea, the USA and Germany, developed by specialists like Plug Power, FuelCell Energy, Bloom Energy and Ballard Power Systems, and backed by the automotive sector and other major industries. In the U.K., Aberdeen City Council has the largest hydrogen powered bus fleet across Europe with 25 vehicles, with cities such as London and Birmingham planning to follow suit[284]. However, high capital costs have prevented widespread adoption in mainstream uses such as transportation and baseload power[285]. Fuel cells can also find application in the maritime sector, opening up the prospect of decarbonising the oil and gas supply chain. Currently, initiatives such as the HySeas project are testing the implementation of fuel cells in ferries, which can serve as a stepping-stone for the deployment of fuel cells in cargo ships[286].

Technology challenges

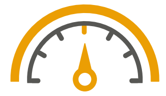
Manufacturing automation and expensive catalyst materials are the main technology challenges for fuel cells. Like electrolysers, more output requires a larger electrode surface area, which limits the cost benefits of scaling up to larger devices. In the UKCS, fuel cells can be particularly attractive for smaller power loads, especially for applications where batteries are not the best solution[38] – like subsea systems[288]. Fuel cells could also help to power floating small field production operations if equipped with sufficient fuel supply or a connection to nearby hydrogen pipelines.

Promoting hydrogen demand:

- A consortium led by **TechnipFMC**[287] has started a study to grow hydrogen demand offshore, combining electrolysers powered by offshore wind with subsea storage and fuel cells to supply power to offshore platforms.
- Governments can also support demand by deploying hydrogen vehicles in public transport or other public services, such as the hydrogen buses serving the London area, or **Alstom's** pilot for a hydrogen-fuelled train[289]. Another option is to subsidise the use of blue or green hydrogen in domestic and industrial heating, or as feedstock for the refining and chemical industry.

Table 3.20: Technology challenges of hydrogen use

HYDROGEN TURBINES	INNOVATION GAP
Hydrogen-combustors: burners and auxiliary systems to retrofit turbines to run on pure hydrogen	
Ammonia-blend turbines: modify existing UKCS gas turbines to run on partially cracked ammonia, with safe ammonia storage on e.g. barges	

FUEL CELLS	INNOVATION GAP
Fuel cell manufacturing: economies of scale and production automation in factories to reduce capital costs	
Fuel cells catalyst: low-cost, high current density, and durable catalyst materials	

 Critical gap, unlikely to be resolved without strong effort  Needs additional effort  On track to be resolved

Technology accelerators, enablers and dependent technologies

Unlike hydrocarbons and renewable power, the use of hydrogen is still very small onshore and absent on the UKCS. The collaborative efforts needed to create this supply chain will be enormous. Three critical factors can enable the UKCS' potential as a hydrogen supply and use hub.

1. The development of CO_2 storage capacity will allow blue hydrogen production capacity onshore to grow to form a foundation for a renewable hydrogen ecosystem.
2. Cost-competitive production of green hydrogen, onshore or offshore, will require continued expansion and cost reductions of offshore renewable power.
3. Multi-billion pound investments will be needed to create supply chains for a hydrogen economy that are largely non-existent today.

The UK and regional governments can follow Japan's example to promote hydrogen demand by supporting various demonstration projects. That would help to reduce uncertainty for companies and justify the large investments needed that are needed to create a low carbon, and eventually renewable, hydrogen supply chain.

Hydrogen ecosystem and path to 2050

An importan rst step for a hydrogen ecosystem centred on the UKCS will be detailed studies on the potential for savings from repurposing existing pipelines and platforms, and on hydrogen's potential to decarbonise older assets. Decommissioning decisions can then be based on the assets' utility for the full future energy system, not only hydrocarbon production[290].

Production

Blue hydrogen production can form the foundations: it can be built with well-understood technologies at competitive cost of £2.3/kg of hydrogen[43], in part because the UKCS can provide critical CO_2 and hydrogen storage capacity. In contrast, costs of green hydrogen are between £3.2 and £4 per kg[291], growing to as much as £5.6 to £6.4 per kg with desalination and electrolysis offshore[38]. As a result, blue hydrogen can be deployed earlier and faster in the UK. That will help to accelerate the development of critical hydrogen storage and transport technologies and build use case and demand for a UK hydrogen economy. Over time, natural gas prices and carbon taxes will tend to raise blue hydrogen costs, while green hydrogen costs will continue to fall as offshore renewable electricity costs drop and ef ciencies help to improve larger-scale electrolysis projects. Th rst commercial deployments for green hydrogen may appear around 2030 and hydrogen production growth may tip in favour of green hydrogen around 2040[47].

Storage and transport

In a hydrogen economy, local conditions and policies will determine which value chain is best suited, and each option will have a commercial niche. Japan, with limited domestic energy resources, is setting up large-scale, long-distance pilot projects[292] to supply hydrogen from Brunei or Australia. The opportunity for the UK lies in the strong potential for UKCS' offshore wind build-out, CCUS capability and existing pipeline infrastructure. All of these should be leveraged to build a hydrogen economy. While the UK is exploring the potential to repurpose UKCS pipeline infrastructure for hydrogen transport, it is not yet emphasising alternative transportation methods. Those alternative methods could position it as a strong player in an intercontinental supply chain for hydrogen as a traded energy commodity.

Table 3.21: Hydrogen transportation technologies

	Ammonia	LOHC	Liquid hydrogen
Benefits	• Taps into existing supply chain • Can be used as shipping fuel or combusted as ammonia-hydrogen blend in gas turbines with potentially minimal burner modi cations • Approx. twice the energy density of other carriers in anhydrous form	• Can be stored and transported in existing liquid bulk assets • Safe to handle at room temperature	• Can remain liquid from production through to onboard tanks in commercial vehicles • Easy to pressurise for compressed hydrogen tanks in passenger vehicles[294]
Drawbacks	• Anhydrous ammonia is corrosive and forms lethal gas clouds if released[293] • Hydrogen cracking is immature and trace ammonia can damage hydrogen fuel cells, thus needing extensive puri cation or direct ammonia fuel cells	• Requires large conversion plants at supply and demand locations • Dehydrogenation step is energy and time consuming • Depleted carrier must be shipped back to hydrogen production site	• Hydrogen lost from boil-off is not consumed for several days • Requires specialised, highly insulated tanks for storage and shipping

Supply chain

By careful integration of widespread blue and green hydrogen production with underground storage potential, newly built or repurposed pipeline infrastructure and hydrogen shipping using ammonia, LOHCs, or liquid hydrogen, the UKCS will have an important role in enabling hydrogen use on the UK mainland and potentially other nations. Importantly, as offshore wind capacity grows, the role of hydrogen pipelines will grow as well; per unit of energy, a mile of (hydrogen) pipeline can be an order of magnitude cheaper than a power cable, making hydrogen a potentially more economic option to transport power from far from shore wind farms[295].

From 2040 onwards, as green hydrogen builds on current pilots and learnings from rapid growth in onshore commercial electrolysis, commercial offshore green hydrogen projects that will have started to appear around 2030 can become cost-competitive with blue hydrogen. By 2050, blue hydrogen may still have double the production capacity of green hydrogen on the UKCS, but as reformer systems and ga elds near their end-of-life, these will increasingly be replaced by electrolysers towards a more renewable based energy system.

Speculative technologies for hydrogen

Photosynthetic hydrogen: direct solar water splitting

- Uses a nanostructured surface under sunlight to directly break down fresh or saltwater into hydrogen and oxygen.
- Can become a more efficient direct path to hydrogen instead of using renewable power and electrolysers.

Small-scale LOHC

- Chinese LOHC developer Hynertech aims to deploy small-scale catalytic units to dehydrogenate LOHC onboard fuel cell buses equipped with a two-tank system for loaded and depleted LOHC.
- While efficiency will be substantially lower than a large-volume dehydrogenation plant, onboard systems allow buses to run on hydrogen fuel that is safe and stable at room temperature in a standard liquid fuel tank.

Adsorption-based hydrogen storage

- Uses high-surface area materials, such as metal-organic-frameworks (MOF’s), to adsorb and release hydrogen from solid materials under controlled temperatures and pressure.
- Solid storage can have a volumetric energy density exceeding that of anhydrous ammonia, if it can overcome challenges with hydrogen losses, needs for extreme temperatures and pressures, high costs that increase in step with storage capacity, and high mass.

Closing the Gap to 2050 Technologies | Section 3

Figure 3.21

Hydrogen technology roadmap

2020
Short-term

Hydrogen membranes: thin, high- ux, and durable membrane to separate hydrogen in reformer

CO_2 sorbents: high-capacity sorbents that are durable at high temperatures, with minimal energy requirements for regeneration and CO_2 release

Saltwater electrolysis: cost-effective integrated desalination or direct seawater electrolysis to prevent corrosion or formation of chlorine gas in seawater electrolysis

Pipeline repurposing guidance: clear understanding of hydrogen's impact on durability of repurposable UKCS pipelines

Pipeline re-lining: methods to refurbish or coat interior of pipelines to make them suited for hydrogen transport

Ammonia cracking: energy-ef cient ammonia cracking catalyst to obtain high-purity hydrogen at lower temperatures

LOHC catalysts: catalysts for low-temperature, fast, and complete dehydrogenation of liquid organic hydrogen carriers

Ammonia-blend turbines: modify existing UKCS gas turbines to run on partially cracked ammonia, with safe ammonia storage on e.g. barges

Fuel cell manufacturing: economies of scale and production automation in factories to reduce capital costs

2035
Mid-term

Hydrogen membranes: thin, high- ux, and durable membrane to separate hydrogen in reformer

Hydrogen leak detection: Odorant or other means to quickly detect potentially dangerous hydrogen leaks without sensors

Small-scale liquefaction: small, modular, energy-ef cient hydrogen liquefaction systems

Underground storage: comparison of hydrogen contamination risk in salt cavern vs. depleted oil / ga eld storage

2050
Long-term

Subsea electrolysers: systems suited for autonomous, exible hydrogen production and pipeline compression on the sea oor

Fuel cells catalyst: low-cost, high current density, durable catalyst materials

Parking lot

"incremental gain" tech challenges that will get resolved with or without dedicated effort

- Small-scale reformers
- Electrolyser manufacturing
- Small-scale Haber-Bosch
- Minimal boil-off storage
- Hydrogen-combustors

Ecosystem (2020)

- Wide-scale adoption of hydrogen requires supply chains for large volumes. With no single clear winning technology, pilots using different options help identify economics and potential to repurpose existing UKCS assets.
- Low-carbon blue hydrogen is the lower-cost option in the near-term, but requires available carbon storage capacity to be achievable.

Ecosystem (2035)

- Besides hydrogen demand onshore, the UKCS could potentially use hydrogen, likely in the form of ammonia, for fuel switching of non-electri ed platforms.
- With growing onshore demand, hydrogen storage will become critical, and together with potential far-from shore wind farms with electrolysers, can support the creation of a hydrogen pipeline infrastructure on the UKCS.

Ecosystem (2050)

- When wind farms develop further from shore, hydrogen can become an energy commodity produced both offshore and onshore in the UK, allowing the UK to potentially export energy in the form of hydrogen carriers or by pipeline.
- With growing hydrogen demand, blue hydrogen production will increasingly be decommissioned in favour of green hydrogen production.

Legend:
- Critical path
- Blue hydrogen
- Green hydrogen
- Hydrogen storage/transport
- Hydrogen turbines
- Fuel cells

Source: Wood Mackenzie, Lux Research

3.5: CCUS

The CCC anticipates carbon capture, utilisation and storage to be critical technologies to decarbonise not only the UKCS, but also the UK overall. The UK's ability to store CO_2 in depleted oil and ga elds or saline aquifers, as well using detailed subsurface knowledge or leverage existing infrastructure, such as legacy pipelines or inactive platforms, is central to the UK's decarbonisation.

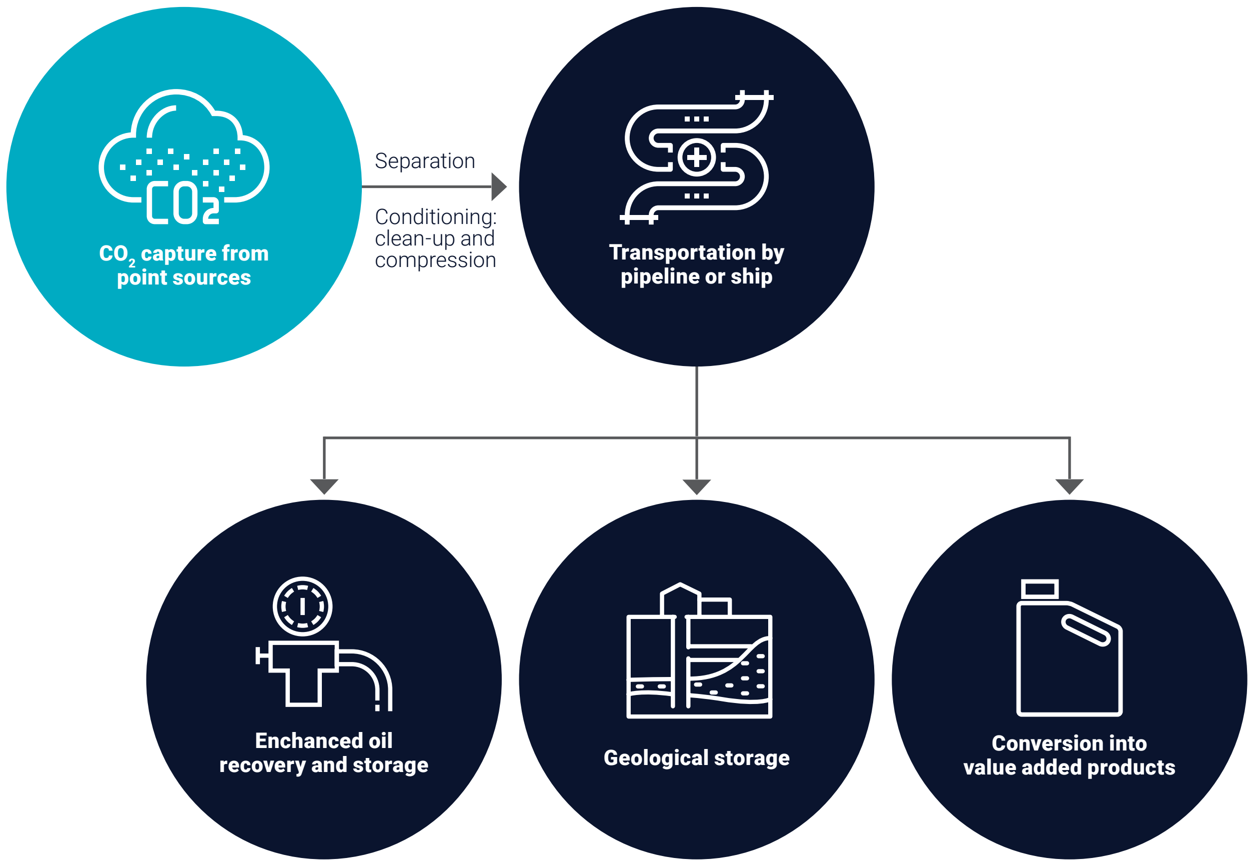
CCUS has the potential to prevent millions of tonnes of anthropogenic CO_2 from entering and remaining in the atmosphere and could play two pivotal roles in the future of energy in the UK, through:

- direct abatement of onshore and offshore CO_2 via sequestration;
- indirect enablement of the integrated energy system, starting with blue hydrogen

Value chain overview

Multiple technologies must come together to effectively capture and store CO_2. Figure 3.22 illustrates a generalised CCUS value chain: CO_2 is first captured and separated at point sources like large power plants, blue hydrogen facilities or natural gas processing plants[296], or potentially offshore platforms. Once captured, the CO_2 must be cleaned, compressed and then transported by pipeline or ship to storage sites, such as depleted hydrocarbon fields and saline aquifers, used for enhanced oil recovery (EOR), or converted into other products using chemical processes. The following sections will look at the technologies involved at each stage of the CCUS chain to identify key bottlenecks to achieving large scale deployment.

Figure 3.22: CCUS value chain



Source: Wood Mackenzie, Lux Research

CO_2 capture

Many first generation CO_2 capture or separation technologies have been deployed commercially for decades. These are limited to applications that either have a direct use for captured CO_2, such as beverages, EOR, or pharmaceuticals, or applications in which product standards require separation of CO_2 from the end product (most of this CO_2 is vented since there is no incentive to store it), such as natural gas processing or hydrogen-rich syngas production that makes ammonia. Because of their large footprint, high capital costs, environmental logistics associated with solvent disposal and several other challenges, CO_2 capture technologies have primarily been focused onshore. Likewise, the bulk of future CO_2 capture in the UK is most likely to occur at onshore industrial hubs: Teesside, the Humber or St. Fergus. Currently, only a handful of small-scale CO_2 capture projects are located offshore and this is unlikely to change in the long-term.

Table 3.22: CO_2 capture processes

PROCESS	DESCRIPTION
Pre-combustion capture	Solid or liquid fuels are first reformed or gasified, yielding a combination of hydrogen and CO_2. The CO_2 is then separated, and the hydrogen can be used as a fuel.
Oxy-combustion capture	Solid or liquid fuel is combusted using a pure oxygen stream instead of air, yielding a near-pure stream of CO_2 and water which can easily be separated.
Post-combustion capture	CO_2 is separated from exhaust gases after combustion has occurred. This is the most common process used in large power plants and industrial facilities.

Table: 3.23: Improvement potential of capture technologies[305]

	Solvent	Solid sorbent	Calcium looping	Chemical looping	Polymeric membrane
Capex	Medium	Medium	Medium	High	Medium
Opex	Medium	High	High	High	High
Depletion of capture material	Medium	Medium	High	Medium	Medium
Toxicity of capture material	Medium	High	High	Medium	High
Retro t potential	High	High	High	Low	Medium

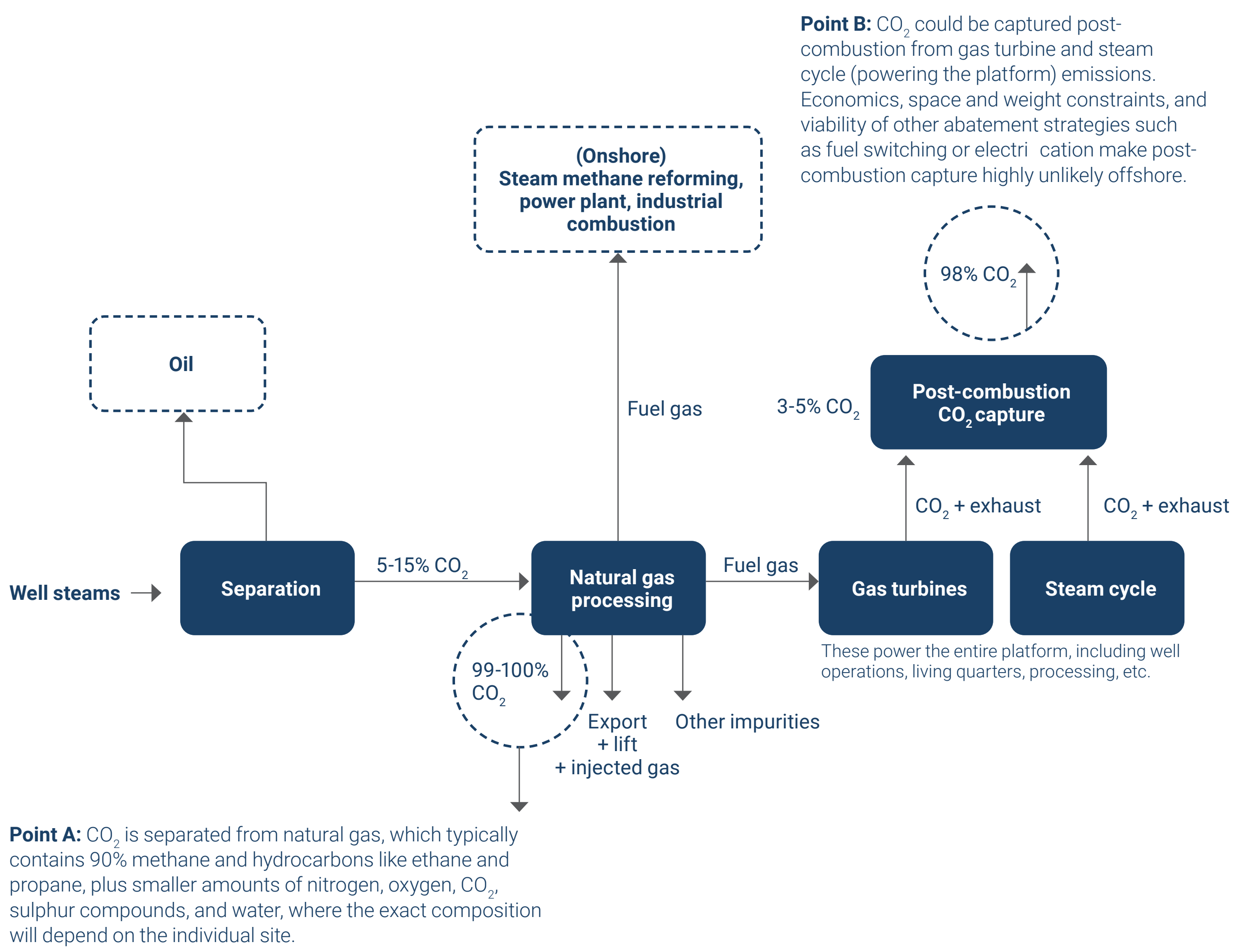
Mid-term improvement potential over 1st generation technology

Low Medium High

Many technologies can be used to separate CO_2 from gas streams. First generation capture technologies are primarily chemical amine solvents[297] that selectively absorb CO_2 from gas streams in a packed bed absorber and release it when heated in a stripper. The solvent is thus regenerated and pumped back to the absorber for cyclic use. Depending on the intended use, the pure CO_2 gas is either vented, or moves to a compressor to be prepared for transportation, utilisation or storage.

Other next generation technologies for separation include selectively permeable membranes, solid sorbents, cryogenic separation (using cooling and condensation to separate CO_2) and calcium and/or chemical looping (reversible binding of CO_2 to calcium or a metal oxide, respectively).

Figure 3.23: Options for CO_2 capture offshore



Source: Adapted from: Nguyen, T., Tock, L., Breuhaus, P., Maréchal, F. and Elmegaard, B.(2016).

To date, the majority of research, development and funding has been focused on CO_2 capture at highly emissive onshore industrial sites, such as large power plants and more recently, heavy industrial emitters such as steel and cement factories[298]. The UKCS currently produces more CO_2 emissions than any of the UK's industrial clusters (Humberside produces 12.4 $MtCO_2e$/yr and is the highest emissions cluster). Commercial factors make capturing CO_2 offshore challenging, nevertheless there are two points on the UKCS where either CO_2 separation or capture could be considered: natural gas processing and post-combustion CO_2 capture (se gure 3.23). Post-combustion capture on the UKCS will be particularly challenging because of the low CO_2 concentrations in gas turbin ue streams, typically 3% to 6%.

A third major source of offshore CO_2 i aring, but CO_2 capture is not a feasible abatement strategy. That has been addressed in the Oil and Gas section of this report.

Natural gas processing

Current status

Extraction of natural gas produces a mixture of hydrocarbons, CO_2, water, N_2, H_2S and other gases. Wellhead gas with higher impurities must be processed. In the UK, offshore platforms and onshore hubs such as Teesside and St. Fergus vent captured CO_2 into the atmosphere.

Although CO_2 capture technology associated with offshore natural gas processing is not widely deployed, it is used a elds with high CO_2 content. There are no examples of this in the UK because of lower CO_2 concentrations and a lack of economic incentives. Equinor operates two such projects in the Norwegian Continental Shelf:

- The Sleipner Field produces natural gas with 9% CO_2. Combined with a carbon tax introduced in the 1990s, the economics of offshore separation and storage became attractive enough to build thi rst-of-a-kind project. Natural gas is processed directly on the platform and CO_2 is injected into an aquifer. The Sleipner T project has been operational since 1996 and is a demonstration of how effective the technology can be, storing 1 $MtCO_2$/y[300].
- The Snøhvi eld produces natural gas through a subsea operation with between 5% and 6% CO_2 content. Wellhead gas is tied back to an onshore LNG plant at Hammerfest, where CO_2 is separated and injected into a formation below the reservoir, storing 0.65 $MtCO_2$/yr[301].

All of the early commercial demonstrations of CCS in natural gas processing, including the Snøhvit and Sleipner projects, us rst generation amine solvent technology[302].

> For the foreseeable future, **mitigation of platform emissions through fuel switching to hydrogen or through electri tion** is a more likely carbon abatement strategy on the UKCS

Closing the Gap to 2050 Technologies | Section 3

Post-combustion capture from natural gas turbines

Current status

Post-combustion CO_2 capture is the most established capture technology. However, efforts for deployment are focused onshore, where implementation is operationally easier and much larger quantities of CO_2 can be captured. Offshore gas turbines produce low concentrations of CO_2, typically between 3% and 5%, yet large pre-treatment units would be required. Space constraints on platforms make deployment of the technology logistically and economically unfeasible offshore.

Centralised offshore capture concepts have thus been proposed, in which emissions from multiple nearby platforms are collected and processed on a centra xed o oating platform. Such a system would circumvent space constraints and bene t from economies of scale for carbon capture. This concept, which has been proven in front-end engineering studies, needs to be further explored for large-scale feasibility. For the foreseeable future, mitigation of platform emissions through fuel switching to hydrogen or through electri cation is a more likely carbon abatement strategy on the UKCS.

Technology challenges

The most obvious challenges with offshore capture technologies are high capital costs and space constraints. All cases described above would require buildout of an adjunct platform to host equipment, which is simply not economically viable without hefty carbon prices, especially for ageing platforms[303].

Onshore and offshore, several factors affect the economics of CO_2 capture. First, the lower the concentration of CO_2 in the gas stream, the higher the capture surface area, capital cost, and energy required for separation. Second, dirtier post-combustion gas streams, such as those found in power plants[304], require expensive pre-treatment process units like blowers, pumps and compressors t lter out impurities and maximise ef ciency of the CO_2 capture technology, which also drives up capital and energy costs[305]. Finally, operating costs are also affected by inherent limitations of the capture materials. For example rst generation amine solvents require roughly 2.5 GJ/tonne CO_2[320] for solvent regeneration, which if very good heat integration opportunities are not available, can lead to around 30% energy penalty in power stations, or around £45 to £55 per tonne CO_2[306]. In post combustion capture, amines can be quickly depleted in the presence of contaminants[305]. Economic constraints stemming from these technology challenges result in average post-combustion CO_2 capture rates in the 60% range, though up to 95% is technically possible.

Emerging capture technologies (second and third generation) mitigate some of these challenges in specific industrial applications[307]. Polymeric membranes work by pushing high pressure gas mixtures across highly structured membranes that selectively filter CO_2 and N_2[308]. Solid sorbent processes selectively adsorb CO_2 without forming chemical bonds, preventing environmental issues with liquid solvent disposal and lowering energy requirements for sorbent regeneration. Looping technologies can deliver pure oxygen streams to combustion chambers, while decreasing the energy requirements to regenerate CO_2 carriers. Other innovations combine novel CO_2 capture materials with engineering to for flexible, hybrid solutions. In the long term, technologies such as direct air capture could also be deployed onshore as a complement to onshore or offshore bolt-on capture solutions, compensating for residual CO_2 that is uneconomical to capture directly from plant emissions.

Compact carbon capture:

- Compact Carbon is developing a containerised, modular lightweight spinning CO_2 capture system that uses G-forces to distribute any CO_2 solvent throughout the stack. The company claims that it is solvent-flexible, can process CO_2 concentrations between 4% and 50% and delivers fully compressed CO_2 ready for transport or storage[11].
- **Aker Solutions** has developed Just Catch, a modular, containerised CO_2 capture solution with a capture capacity of 0.1 $MtCO_2$/year. The solution claims to have easy plug-and-play installation, a minimal 18m x 25m footprint, remote controlled operation and low cost. In addition to several demonstrations, the solution has been deployed at Twence's waste to energy plant in the Netherlands, due to be in operation in 2021[309].

Table 3.24: Technology challenges of CO_2 capture

CO_2 CAPTURE	INNOVATION GAP
Capture materials (sorbents, solvents, membranes, others): high-capacity CO_2 capture materials with minimal energy requirements for regeneration, low toxicity, and long lifetime	
High capex: configurations and engineering solutions that minimise capex required for CO_2 capture, particularly in large-scale post-combustion capture	
Flexible and retrofit-friendly capture: engineering solutions that allow bolt-on CO_2 capture to side-step requirements for large footprint permanent structures	
Subsea separation: capture technologies that function subsea to unlock cheaper offshore CO_2 separation closer to point of storage	
Direct air capture: technologies to decouple CO_2 capture from point sources, which can unlock flexibilities in a facility's approach to full carbon abatement	

 Critical gap, unlikely to be resolved without strong effort  Needs additional effort  On track to be resolved

CO_2 transport

Achieving the CCC's Further Ambition scenario will require significant buildout of CO_2 pipelines, or repurposing existing pipelines, to transport CO_2 from source to storage sites. Depending on the distance, captured CO_2 can be transported via pipelines or storage tankers on ships. There are ongoing studies on the potential to reuse existing oil and gas infrastructure to transport CO_2, rather than having to build new pipelines, considered feasible at distances greater than 350 km[320], in order to save on capital costs.

Pipelines

Globally, there are over 8,000 km of CO_2 pipelines in operation; most of these are in mainland US and were built in the 1980s and 90s to transport naturally sourced CO_2 for enhanced oil recovery (EOR)[310,311]. In the North Sea, there are only two CO_2 pipelines in operation, both in Norway. These are used to connect Equinor's two CO_2 storage sites in Sleipner and Snøhvit.

Current status

CCS projects on the UKCS have proposed repurposing existing gas pipelines for CO_2 transport as a way to build out a CCS value chain more quickly and at lower cost. Retrofit costs will ultimately depend on the current state of legacy pipelines. Differences between natural gas pipelines and CO_2 pipelines are minimal and centre on the level of controls required to maintain safety and asset integrity over time – especially in the case of anthropogenic CO_2[312,313]. CO_2 is usually condensed and transported at super critical conditions (between 12°C to 44°C and 85 bar to 150 bar[314]). Even small variations in temperature and pressure can significantly alter flow rates and overall pipeline safety, meaning that CO_2 pipelines often require more meters, pumps and controls to maintain conditions. Additionally, anthropogenic CO_2 is more likely to contain contaminants and trace amounts of water and oxygen, which could form corrosive acids over time[312]. This would need to be controlled with corrosion-resistant pipeline materials or through additional purification measures at loading.

Offshore CO_2 pipelines will most likely comprise of carbon steel or stainless steel alloys with polypropylene coatings. Thicker pipelines will use concrete coatings. Onshore CO_2 pipelines are fitted with metering devices that ensure safe transport conditions and detect cracks, in which are common in high pressure systems. As anthropogenic CO_2 is more likely to contain corrosive contaminants, these measures will be even more important to protect asset integrity over time[315,316]. Multiple industry-led studies, including CO2PIPETRANS, continue to study the effects of different CO_2 compositions flow rates and external conditions on pipeline performance and integrity[317,324].

The first project that will truly explore the viability of repurposing infrastructure is the Acorn project, a CCS initiative to collect industrial CO_2 – initially from the St. Fergus terminal in Scotland – and store it about 100 km offshore. This project, currently in Phase 1, is looking to avoid the traditionally high capex usually associated with new pipeline and platform construction by repurposing the ageing Atlantic, Goldeneye or Miller Gas pipelines that are suspended and close to decommissioning[318]. Preliminary results from a 2018 ACT Acorn Feasibility Study[319] indicate that repurposing ageing pipelines could cost about 75% less than building something new; however, more recent assessments[320] revealed that required asset integrity inspections and rectifying pipeline corrosion could increase the overall capex up to four-fold.

Technology challenges

CO_2 transportation is technologically well-understood; cost is the main deterrent. However, there are still technology challenges related to retrofits, long-term integrity and monitoring, which could be solved through oil and gas industry know-how.

Table 3.25: Technology challenges of CO_2 transportation

CO_2 TRANSPORTATION	INNOVATION GAP
Corrosion: characterisation and coatings & materials solutions to prevent corrosion from contaminants present in anthropogenic CO_2	
Crack propagation: predictive maintenance solutions to prevent crack propagation and ensure pipeline integrity	
Pressure control: low-cost control valves to maintain consistent pressure, especially in longer pipelines	
Retrofitability of ageing gas pipelines: clear understanding of cost and methodology to retrofit legacy gas pipelines	

Critical gap, unlikely to be resolved without strong effort   Needs additional effort   On track to be resolved

Shipping

Shipping CO_2 for commercial use, such as in the food and beverage industry, has been in operation for almost 30 years. However, those operations are on a 1,000 tonne CO_2 scale, which is at least two orders of magnitude smaller than what industrial CCUS would demand[321]. Full scale CO_2 tankers are very similar to commercial, semi-refrigerated LNG tankers, but any larger capacity ships would require significant redesign to accommodate the harsh conditions of the North Sea[321].

Shipping CO_2 in tankers could serve as a near- to mid- term solution to help demonstrate multiple CO_2 storage sites in the <1 $MtCO_2$/yr scale without the enormous capital outlay that is required to build pipeline infrastructure each time. To date, that has been a major deterrent in the scale-up of CCUS technologies[321]. More importantly flexibility afforded by shipping could also help to open UK storage sites to other European countries, which could be a linchpin to establishing international demand for this unique and vast resource on the UKCS.

CO_2 transport ships will likely need to be built for purpose at roughly 0.05 $MtCO_2$ to 0.1 $MtCO_2$ capacities[322] - although companies like Yara International and Anthony Veder do have dual-purpose LNG/CO_2 ships[321,322,323]. Despite industry hesitancy on whether flexible containers are viable and the lack of regulatory frameworks, shipping does not present any major technology hurdles. On the contrary, it provides a viable option for longer distance and lower volume CO_2 transport[324].

Aker Solutions is working with Equinor, Shell and Total on the Northern Lights CCS project. Industrial CO_2 that has been captured onshore or imported to Øygarden in Western Norway, temporarily stored, before being injected about 2.8 km beneath the seabed in the Johansen and Cook aquifer. As of early March 2020, Equinor drilled and temporarily sealed a wildcat well to characterise this formation's viability for large scale CO_2 storage. Initial results were all positive and the final investment decision for the project was made by the industrial partners in May 2020[325].

CO_2 storage

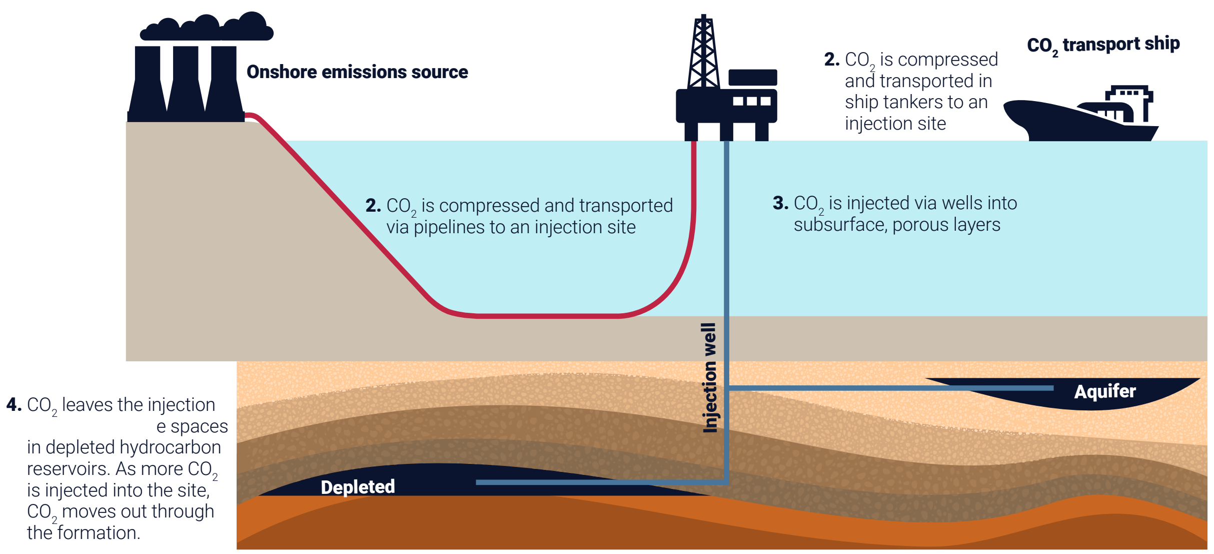
Post capture and transportation, CO_2 can be stored in one of the UKCS' many oil and gas reservoirs or saline aquifers under the seabed. Several storage sites have been nominated as high-priority storage clusters because of their known physical geological attributes.

Current status

Oil and gas operators on the UKCS have been collecting subsurface data for decades, providing a solid foundation for characterising potential storage in saline aquifers or depleted oil and ga elds.

Researchers are still debating whether aquifers or deplete elds are better suited for long-term storage but agree that removing residual oil and gas from elds improves outcomes[326]. Ideal aquifer formations have salinity in excess of 10,000 ppm[327]and are highly permeable (to prevent build-up of pressure leading to potential leakages or man-made seismic events) with strong caprock seals (se gure 3.24). Operators have also deployed secondary trapping mechanisms, such as dissolving CO_2 into aqueous por uid, using capillary forces to trap residual gas and purposeful mineralisation via CO_2 reacting with por uid and rock[328] to further lock in CO_2. While many smal eld trials and front end engineering design (FEED) activities have been completed on the UKCS, there are no CO_2 storage projects that utilise geological storage sites currently in operation.

Figure 3.24: CO_2 storage sites and trapping mechanisms



Source: Adapted from: Energy Technology Institute

Technology challenges

Despite familiarity and availability of geospatial data that characterises UKCS basins, many technology and knowledge gaps exist. These gaps include problems with data availability, interoperability of different data sets and the ability to model the behaviour of CO_2 over time.

- **Robust multi-variable CO_2 modelling:** Many valuable tools exist today, but there is signi cant room for improvement. The industry needs standard methods to model CO_2 migration and interactions[329] in different rock structures and potential cracking and chemical reactions through the different stages of storage (including pre-injection, operational lifetime and after sealing the injection site)[330]. This is particularly critical around existing wells, which could present a higher risk of leakage.
- **Site selection and injection strategy:** Since disparate data sets are very dif cult to compare, like-for-like comparison of key metrics during site selection becomes challenging[331]. Different storage sites also require different injection strategies to optimise storage ef ciency. That means that additional research and development combined with data on hydrocarbon behaviour prior to extraction is needed[332].
- **Phase management of CO_2:** CO_2 behaves very differently in its different phases, which can signi cantly affect trapping mechanisms post-injection. This phenomenon needs to be carefully studied across the different rock formations present on the UKCS, particularly in highly depleted ga elds[332].
- **Low cost long-term monitoring:** While there is some cross-project learning, the industry lacks a standard set of tools and guidelines to establish safe long-term monitoring of storage sites[330,331].

Table 3.26: Technology challenges of CO_2 storage

CO_2 STORAGE	INNOVATION GAP
Modelling, site selection, injection strategy: more robust modelling and data interoperability to improve understanding of CO_2 behaviour in informing site selection and injection strategy	
Geological behaviour of CO_2: improved characterisation of in situ CO_2 behaviour in different injection sites	
Site monitoring: standardised, low-cost long-term monitoring of CO_2 post-injection	

Critical gap, unlikely to be resolved without strong effort · Needs additional effort · On track to be resolved

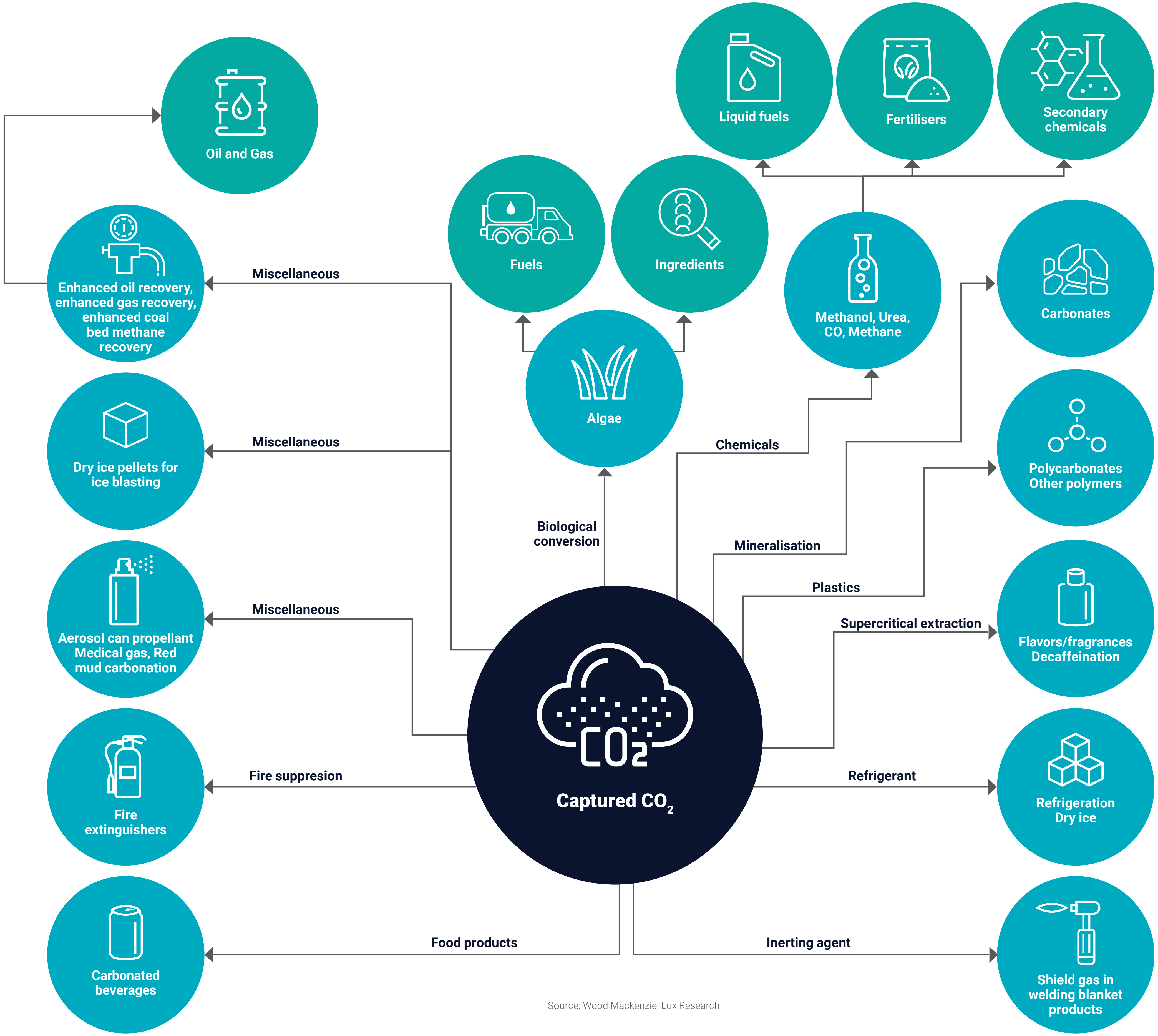
CO_2 utilisation

Onshore utilisation

Carbon utilisation is an emerging group of technologies that convert or directly use captured CO_2 to create value. The main uses of captured CO_2 are onshore and include conversion into energy or fuel, microbial fermentation for chemicals and food ingredients and catalytic conversion for chemicals and materials[333]. CO_2 is a chemically stable molecule and so novel chemical, or catalytic conversions tend to be energy intensive and are largely in the development stage. Nevertheless, uptick in downstream demand from environmentally conscious consumers is driving extensive start-up and corporate activity, as well as sizeable investments from ventures, corporations and governments[333].

Utilisation has an important role to play in creating market demand for CO_2 as a feedstock. For example, stricter emissions regulations in the marine sector are driving ship operators to explore lower carbon fuels such as methanol, which can be directly produced from CO_2. However, this demand will never be suf cient to abate a meaningful portion of the CO_2 that is emitted on the UKCS and the UK. Finding new markets in the petrochemical or food industries can help to create new revenue streams for CCUS. However, geological storage will likely be the most scaleable CCUS option.

Figure 3.25: CO_2 utilisation pathways



Source: Wood Mackenzie, Lux Research

Offshore utilisation

Current status

Globally, enhanced oil recovery (EOR) is the primary use of CO_2 offshore. EOR involves injecting combinations of pressurised fluids and gases into rock formations, pushing out oil that would otherwise be trapped in rock pores. In CO_2 EOR, injected CO_2 becomes permanently trapped and the remaining CO_2 solvent is recovered, along with residual oil, brine and other fluids and reinjected; eventually, all injected CO_2 remains stored underground[334,339]. EOR is already used in the UKCS but relies purely on readily available materials (water, associated gas and polymers)[335,336] instead of captured CO_2. Despite a stated target[337] to implement EOR, uptake has been slow because of higher fixed platform, pipeline and operating costs that contribute to higher breakevens. A 2018 review estimated that a Brent price of between £66 and £76/bbl would be required for CO_2 EOR projects to be viable[338].

More than 260 million tonnes of CO_2 have been sequestered globally through EOR activity – the majority through onshore EOR in the US[339]. Despite its success onshore and potentially favourable geological advantages offshore[340,340], in situ offshore conditions (such as high temperature and reservoir heterogeneity) combined with the lack of an attractive CO_2 scheme make the economics unfavourable on the UKCS[336,341].

While there have been at least six small scale pilots (Vietnam, Gulf of Mexico), there is only one offshore CO_2 EOR project in operation: the ultra-deepwater Lula field in Brazil[342]. This field produces associated gas containing roughly 11% CO_2. A strategic decision to avoid venting CO_2 and enhance oil recovery led operators to design a system that is flexible enough to inject enriched CO_2 or associated gas[343]. Producing roughly 800,000 boe per day this project is the most productive ultra-deepwater field in the world and is expected to ramp up to around 1 million boe per day at peak production[344].

Table 3.27: Technology challenges of CO_2 utilisation

CO_2 UTILISATION	INNOVATION GAP
Compact CO_2 processing equipment: low-cost, compact processing equipment to enable offshore CO_2 handling for EOR	
Subsea separation and CO_2 injection: (see CO_2 capture and Oil and Gas sections)	
High efficiency CO_2 conversion: low-cost CO_2 utilisation pathways to value-added products	

 Critical gap, unlikely to be resolved without strong effort  Needs additional effort  On track to be resolved

Technology challenges

Most onshore CO_2 utilisation pathways need significant development before large, commercial scale deployment can take place. For CO_2 EOR[345], the UKCS struggles with several practical, macroeconomic and policy challenges that are preventing adoption. In addition to the innovation gaps related to CO_2 storage, key technology challenges include:

- **Equipment:** space and weight restrictions on existing offshore platforms limit viability of large footprint CO_2 equipment like compressors and recycling units. A large centralised CO_2 processing unit, as described in the CO_2 Capture section, could circumvent several challenges in individual platform injection, including lower flow quantity, variable flow, and physical constraints. This concept needs to be further explored for economic and logistical feasibility.
- **Subsea technologies:** while all of the components for gas processing are already commercially available, adapting these to subsea conditions could be critical to bringing down system cost.

Technology accelerators, enablers, and dependent technologies

Unlike hydrocarbons or renewables, the CCUS value chain is still in its infancy in the UK. Regulation, consumer lobbying and operational realities are driving many industries to demand and improve capture technologies onshore, which will primarily be realised in petrochemical clusters that are located near to the UKCS.

While CO_2 utilisation is also being driven by downstream demand for sustainability in industries like cement, steel and marine, the development of transportation and storage infrastructure for CO_2 will require significant government funding and industry collaboration for a successful rollout.

The UKCS' vast storage potential is an important resource in decarbonising not only the UK but also its European neighbours; harnessing the European CCUS market will help build and establish the UK's position as a global authority on CCUS.

Most importantly, establishing the CCUS value chain will be critical to unlocking low-carbon energy sources such as (blue) hydrogen, whose prospects rely on the viability of onshore CO_2 capture and storage on the UKCS.

CCUS ecosystem and path to 2050

Near-term

The 2018 UK government's "Delivering Clean Growth: CCUS Cost Challenge Taskforce Report" recommended that the UK have at least two CCUS clusters operational in the 2020s, anchored by catalyst projects that would enable 'learning by doing' – a common theme among CCUS developers around the world. While the UK has no operational CCUS projects as yet, the CCC's Further Ambition scenario cites a 2050 capacity storage goal of 176 $MtCO_2$/y. Despite the thirty-year runway, initial projects take up to eight years each[305] before they can begin injection: site selection, completion of FEED stages, securing funding, ironing out complex ownership and building the required infrastructure. Many of the knowledge gaps discussed here can only b lled through experience.

The March 2020 budget announcement pledges £800 million to develop two CCS projects by 2030, which will help move CCS down the cost curve and establish much-needed transportation infrastructure through two key CO_2 pipelines. Construction of these pipelines will demonstrate the value of retro tting the UKCS' existing infrastructure and create incentive for more members of neighbouring industrial clusters to consider implementing CO_2 capture technologies. The UK will also need a strong pipeline of at least two more projects between now and 2035[339]. Building these catalyst projects will also unlock a path to infrastructure buildout through pipelines. Shipping can help to expand project footprints beyond initial pipeline connections. Meanwhile, technical feasibility and cost of repurposing other ageing pipelines and platforms should be thoroughly investigated in the near term before UKCS decommissioning activities accelerate.

Mid-term

Technologies that are in their infancy today (subsea gas separation and compression, third generation capture technologies, CO_2-to-chemicals and blue hydrogen) will need to be entering CCUS pilots. By 2035, onshore CO_2 capture costs will need to reduce by an additional 10 to 15%, buoyed by the construction of at least one additional CO_2 pipeline and from the lessons learnt from two fully built CCUS clusters. While subsea gas processing and capture technologies (for example, enabled by membranes for compact systems) will be cheap enough to integrate into strategically located and newly built platforms, the majority of captured CO_2 will still come from onshore capture projects in major industrial clusters such as St. Fergus and Teesside. The buildout of a CO_2 shipping infrastructure should also open storage sites to international players, enabling more rapid expansion and opening new revenue streams to the UKCS. Finally, CO_2 utilisation, through conversion into valuable chemical intermediates like methanol, will further spur industrial interest in adoption of capture technologies.

Long-term

From 2040 and beyond, CCUS will need to grow into a functional, scaleable industry, building on the learnings and risk mitigation from th rst clusters that would have been established in the 2030s. Demand for blue hydrogen will continue, but onshore industry emissions will need to claim much of the CO_2 capacity connecting to at least four operational storage clusters. To achieve net zero carbon by 2050, all new production platforms will need to be using hydrogen or be fully electri ed. Demand for CO_2 (mostly through strategic carbon pricing set by the UK government) will need to have changed CCUS into a standalone industry.

Reducing costs and improving the CO_2 capture efficiency will improve CCUS feasibility. To realise the full storage potential of the UKCS better modelling of CO_2 subsurface behaviour will be required. In parallel, for CCUS to succeed, firm government support is necessary. When first-of-a-kind project costs can exceed £800 million[339] investors need a robust business case and this will require coordinated financial and policy support. With 62 operational CCUS projects around the world and none yet in the UK, rapid progress is required to meet national net zero commitments.

Speculative technologies for CCUS

CO_2 electrolysis

- Decomposition of CO_2 into chemicals using electricity, under development by Siemens, Su re, and others.
- On-site production of higher-value chemicals for easier transport. When coupled with water electrolysis, it can lead to the production of syngas for downstream processing.

Electrochemical direct air CO_2 capture

- Electrochemical plates react with CO_2 in the air, capturing it. The reverse reaction delivers power and ejects a pure stream of CO_2.
- Capture of CO_2 even at different concentrations, including 400 parts per million found in the atmosphere.

Allam Cycle power generation

- Oxy-fuel combustion of natural gas with a mixture of oxygen and recuperated supercritical CO_2. This is fed through the turbine, after which water is condensed and separated out.
- CO_2 and heat are recuperated after the turbine and fed back into the process. Excess CO_2 from the process is high purity and so directly suited for storage or utilisation.

Figure 3.26

CCUS technology roadmap

2020
Short-term

2035
Mid-term

2050
Long-term

Capture materials (sorbents, solvents, membranes, others): high-capacity CO_2 capture materials with minimal energy requirements for regeneration, low toxicity, and long lifetime ⚠

Flexible and retro t-friendly capture: engineering solutions that allow bolt-on CO_2 capture to side-step requirements for large footprint permanent structures

Subsea separation: capture technologies that function subsea that can unlock cheaper offshore CO_2 separation closer to point of storage

Geological behaviour of CO_2: improved characterisation of in situ CO_2 behaviour in different injection sites

Compact CO_2 processing equipment: low-cost, compact processing equipment to enable offshore CO_2 handling for EOR

High ef ciency CO_2 conversion: low-cost CO_2 utilisation pathways to value-added products ⚠

Direct air capture: technologies to decouple CO_2 capture from point sources, which can unloc exibilities in a facility's approach to full carbon abatement

Ecosystem

- Capture development continues to be driven by industrial demand from high emitters like cement or fertilizer production.
- Pipeline development contingent on successful pilots, where business models and ownership are established. These pilots can unlock blue hydrogen as they're scaled up from initial injection sites.

Ecosystem

- Successful pilots in near-term lead to CCUS cost reductions through ef ciencies and learnings from experience.
- Demand for CO_2 storage needs to be built in the mid-term, and is directly linked to successful implementation of a clear and consistent CO_2 policy in the UK.
- Meanwhile, storage demand from neighbouring countries can also increase the UK's economic recovery of the UKCS, through shipping or transcontinental CO_2 pipelines.

Ecosystem

- Despite development of highly ef cient solutions, onshore capture hits price ceilings, where capturing residual point CO_2 emissions no longer makes economical sense. In the long-term, direct air capture could be a viable supplement for operators to address residual CO_2 emissions to achieve net zero economically.
- Progress in CO_2 utilisation technologies could also provide exible outlets for petrochemical cluster emissions, while creating value-added products.

Parking lot

"incremental gain" tech challenges that will get resolved with or without dedicated effort

- High capture capex
- Pipeline corrosion & crack propagation
- Pipeline pressure control
- Retro tability of ageing gas pipelines
- Modelling, site selection, injection strategy
- Site monitoring

⚠ Critical path
- Capture
- Transportation
- Storage
- Utlisation

Source: Wood Mackenzie, Lux Research

3.6: DIGITALISATION

Over the last decade, digital technologies and the industrial internet of things (IIOT) have allowed oil and gas operations to run faster and more ef ciently, reducing costs by up to 30% and completing projects up to 25% faster[346]. The role of digitalisation will continue to grow on the UKCS. It will become a central enabler for renewables and hydrogen technologies to be integrated with the UKCS energy system, and will allow the oil and gas sector to decarbonise further, electrify and move more operations subsea.

Ecosystem and path to 2050

The role of digitalisation in an integrated energy system

Creating an integrated energy system on the UKCS will require digital technologies to be developed and used in parallel across the oil and gas, hydrogen, CCUS and renewables sectors. A system that coordinates the operations of these four sectors as a single unit will become crucial.

Overall, digital technologies will deliver six key bene ts to the different steps in the value chain of the integrated energy systems (se gure 3.27).

Appraisal and development

Digitalisation will help in the planning stages of any project. For the construction of new power generation capacity, digital systems already help to map resources and determine the best sites, depending on wind availability or wave potential. The use of big data and forecasting algorithms to model and evaluate possible future scenarios can further help during the integration phase of renewables, hydrogen and CCUS projects. Such scenario modelling systems will serve, for instance, as tools to assess the likelihood and extent of potential future stressors on the new offshore energy system. This information will help to plan energy back-up infrastructure or connections to onshore generation and storage capacity without incurring excessive costs.

Figure 3.27: Digitalisation across the energy value chain

Operation and production

With the widespread availability of sensors across platforms and power generation equipment, technologies such as digital twins will further enable the visualisation of all relevant parts in the integrated energy system. They will ease the management of assets off-platform, such as subsea production systems, offshore substations and different types of generation assets. In the wind energy industry, services based on digital twins are now common for operations. These service build on existing control tools used for wind turbines[347]. In this way, in-field performance of turbines is compared to the digital twins to identify faulty components, improve operational parameters and apply predictive maintenance. Such visualisation and simulation tools can also provide oil and gas operators, engineering, procurement and construction companies (EPCs), service companies and stakeholders in the power sector with an environment that allows them to work together to streamline projects, design equipment in synchrony and form best practices[348].

Digitalisation will be important in enabling the UKCS to reach its net zero target through modeling and validating of the potential outcomes of low-carbon technology implementation. Understanding how any solution might impact capex and opex in the long term, i.e. through changing fuel and energy usage and CO_2 tax implications, will be imperative before new technologies are deployed.

Digitalisation can help optimise continuous processes to maximise operational efficiency. In this way, sensor data and machine learning algorithms determine the optimal setpoints to maximise well production, for example in artificial lift applications[349]. Control algorithms will also help to ensure that electrolysers for hydrogen production operate at maximum efficiency[350].

Digital systems enable automated operations in platforms, reducing personnel requirements. Similarly, equipment inspections can be scheduled automatically and carried out by unmanned vehicles that capture images of infrastructure and automatically identify physical anomalies. This has the potential to not only reduce maintenance costs, but also improve safety in offshore operations[351].

Integrated energy system

As electricity from renewables starts to power oil and gas operations, energy management systems will play a prominent role in meeting power demand by coordinating power supply from different renewables' sources, energy storage systems, or even onshore power capacity. Digital systems can plan the flow of energy from different resources by taking into account weather forecasts, market conditions and future energy demand either onshore or offshore. The distribution of hydrogen for offshore use via fuel cells or for onshore processing will also be based on these demand forecasts.

Standardisation on data handling, storage, sharing, and security

Most companies on the UKCS are using digital technology, but this lacks standardisation. For instance, most sensor data is not compatible across software platforms. This issue will be exacerbated as data points from equipment including wind turbines, energy storage, CO_2 storage monitoring and subsea equipment come online. For digital technologies to reach their full potential, oil and gas companies need to create a digital ecosystem that supports the integration of software data across all operations by 2030. Furthermore, consortia standardising data from renewables, hydrogen, CO_2 and oil and gas industries will be critical as the UK transitions to an integrated energy system. Naturally, data sharing presents considerable security risks, not only to the operators but to the energy security of the UK – so cybersecurity needs to be high on the agenda every step of the way[356].

Table 3.28: Case Studies

Digital Twins	Safety assurance	Smart contracts
A digital twin is a virtual replica of a piece of equipment that operators can use to test new software or other modifications, or feed with real-time data from connected sensors, to predict failures and optimise performance[352]. For instance, Norske Shell doubled the lifetime of ageing topside and subsea assets while reaching a 99% uptime with high levels of safety and energy efficiency[353]. Digital twins already help wind farm operators to optimise maintenance strategies, improve turbine reliability and availability and increase annual energy production[354].	Digital technologies can improve safety by better informing workers, or by removing human risk altogether with autonomous operations. Since 2017, Innogy has been deploying drones to carry out inspections at the Nordsee Ost wind farm off the German coast. Drones avoid the need for industrial climbers to carry out inspections, while reducing the downtime of wind turbines as less time is required to complete an inspection. Remote inspection and maintenance will continue to improve as companies develop their analytics and imaging systems to improve fault identification.	Digital tools can enable new business models like smart contracts with performance-based rewards. Aker BP and Framo have signed a deal in which Framo uses sensor data from seawater pumps to predict performance and ensure uptime and is paid based on uptime delivered[355].

Implications for industry

By 2030, predictive maintenance and automated operations should be common business practices, minimising risk of failures and disruptions, while maximising reliability and efficiency. That will bring major changes to the business models of companies operating on the UKCS. EPC companies will need to dedicate fewer resources to the upfront design stages of projects but will be able to offer monitoring and optimisation services through a facility's lifetime[357]. Service contracts will evolve from fixed price models to outcome-based business models, which in turn will incentivise further investment in digital and automation technologies.

Beyond 2040, digital technologies will increasingly move UKCS operations to shore-side support, maximising the level of unmanned, autonomous and subsea development. That will have two important consequences for the sector. First, it facilitates more complex operations in harsh locations, through reliable automated or semi-automated remote operations. More importantly, it will have far-reaching consequences for employees– data science skills will become crucial, requiring multi-disciplinary teams with new talent. Recruiting a new generation of workers with digital expertise needs to begin in the near term, so that these new crucial skillsets can play a part in the decarbonisation of the UKCS and UK energy system.

4

Integrated Energy Sytem Roadmap

Integrated Energy System Roadmap | Section 4

4.1: Changing UKCS landscape

As the UKCS' energy system grows in diversity and energy output, it will be made up of an increasingly complex mix of technologies that support the UK's decarbonisation. On the path to 2050, the landscape will evolve from today's siloed industries operating side-by-side, to an integrated energy system: one offshore industry where operations are interlinked, enabled by digital solutions.

Operational upgrades are already underway in the offshore oil and gas sector and, combined with the increasing presence of offshore wind, is leading to near-term progress in decarbonisation. As the UKCS evolves towards 2035, the renewable power grid will gradually integrate with the offshore oil and gas sector to electrify platforms (B i gure 4.3), while continuing to supply the UK mainland with power. It will also aid in the development of a hydrogen economy, through both green hydrogen (A i gure 4.3) and, as CO_2 storage emerges, blue hydrogen (C i gure 4.3). Multiple CCUS and hydrogen pilots and demonstrations will be critical to establishing technology and business cases for these foundational decarbonising technologies as stepping stones towards a net zero UKCS in 2050.

Closer to 2050, operations will need to increasingly interlink and the lines between the offshore industries will blur with more CO_2 storage and hydrogen (D i gure 4.3) being added to the mix.

The UKCS will need to evolve into an integrated energy ecosystem comprising a multitude of technologies, where complex operations across sectors are managed though widespread digitalisation and automation. The OGA's UKCS Energy Integration report[407] highlights the potential bene ts of integration of offshore energy systems including improved economics of energy production and cutting greenhouse gas emissions. Figure 4.1 shows the current UKCS energy system an gures 4.2 and 4.3 represent a view of how an integrated UKCS energy system could look in 2035 and 2050 respectively.

UKCS current reality **2020**

Schematic view of the current set-up of UKCS energy system with stand-alone oil and gas and offshore wind.

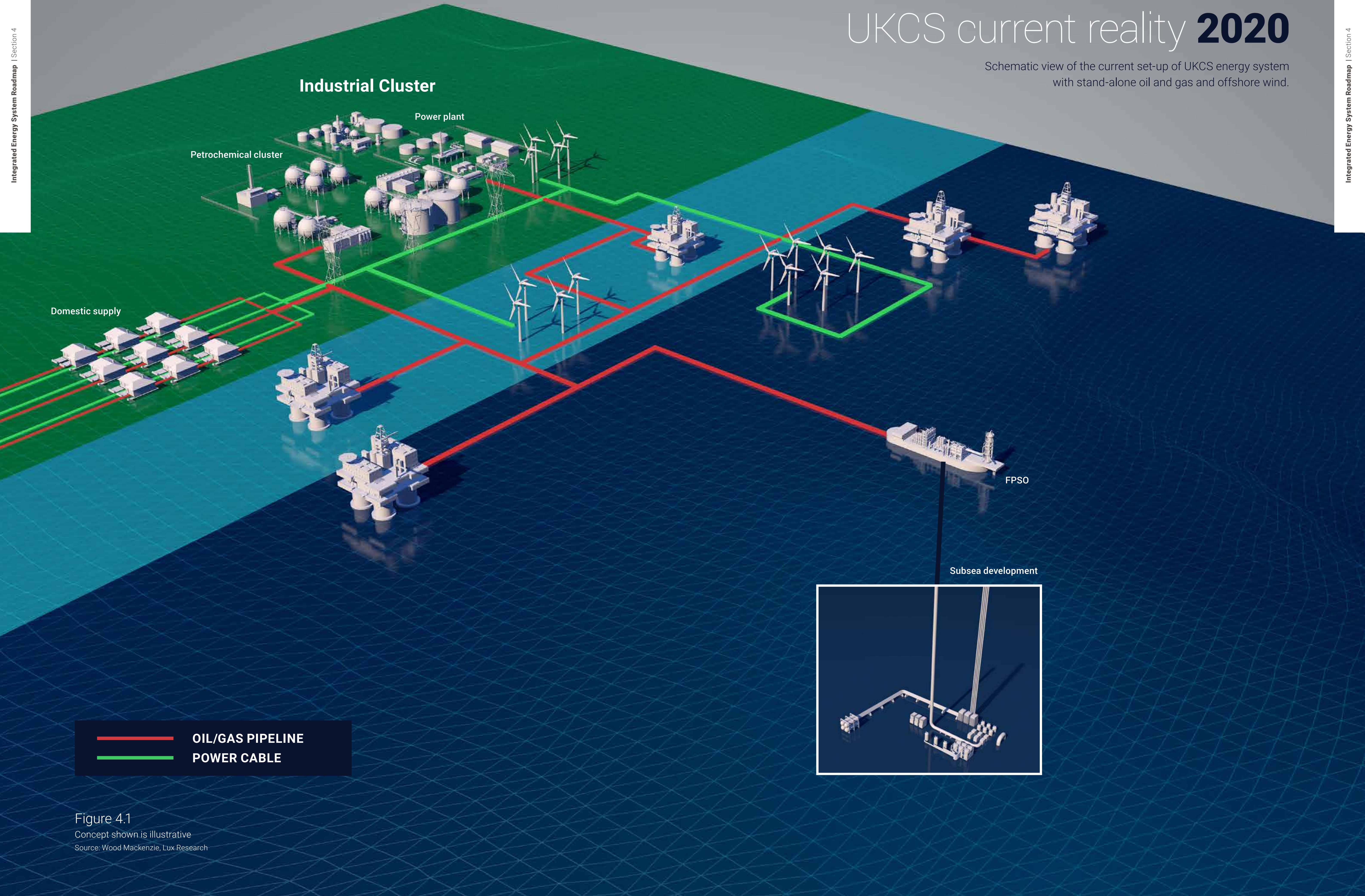


Figure 4.1
Concept shown is illustrative
Source: Wood Mackenzie, Lux Research

Integrated Energy System Roadmap | Section 4

UKCS integrated energy vision **2035**

Schematic view of how the UKCS could develop into an integrated energy system. In 2035 there needs to be increased integration and repurposing of offshore energy infrastructure, i.e. offshore wind powering oil and gas production and oil and gas platforms being used for CO_2 injection.

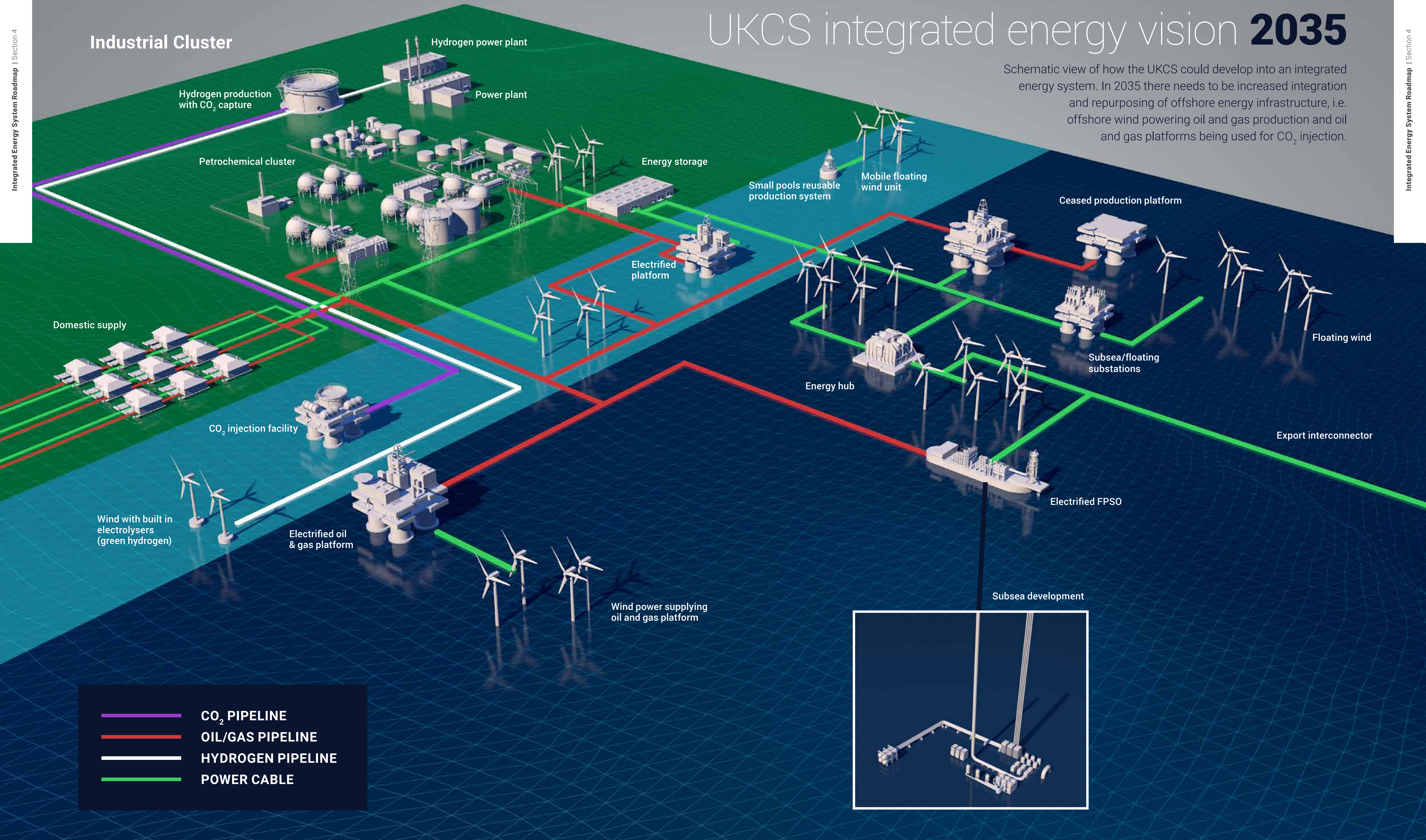


Figure 4.2

Concept shown is illustrative

Source: Wood Mackenzie, Lux Research

UKCS integrated energy vision **2050**

Schematic view of how the UKCS could develop into an integrated energy system. In 2050 the UKCS needs to have developed into a fully integrated system of oil and gas and hydrogen production powered by renewable energy, as well facilities for large scale CO_2 transport and storage. Offshore energy hubs and energy storage facilities will need to be developed to ensure the system i exible and runs ef ciently.

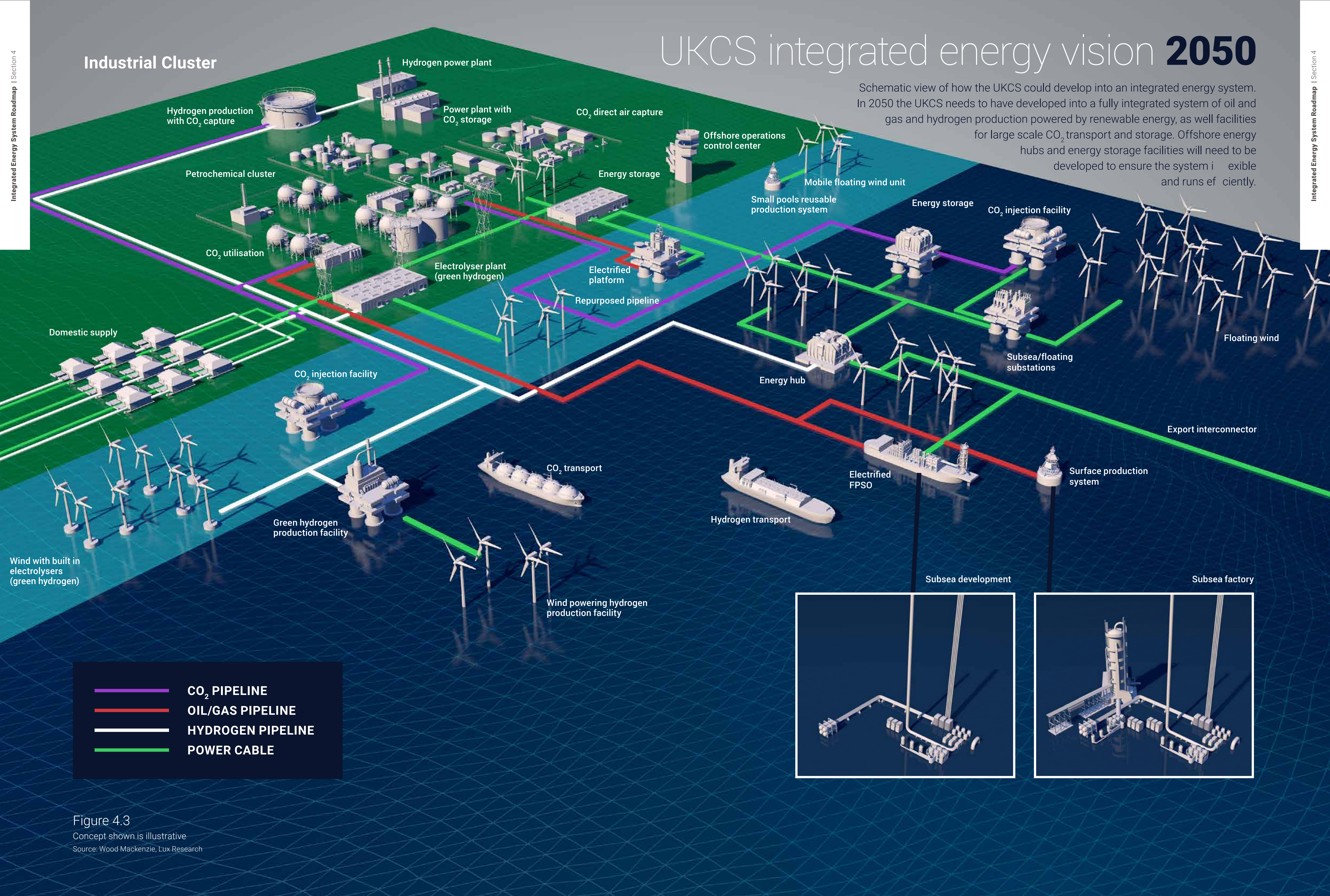


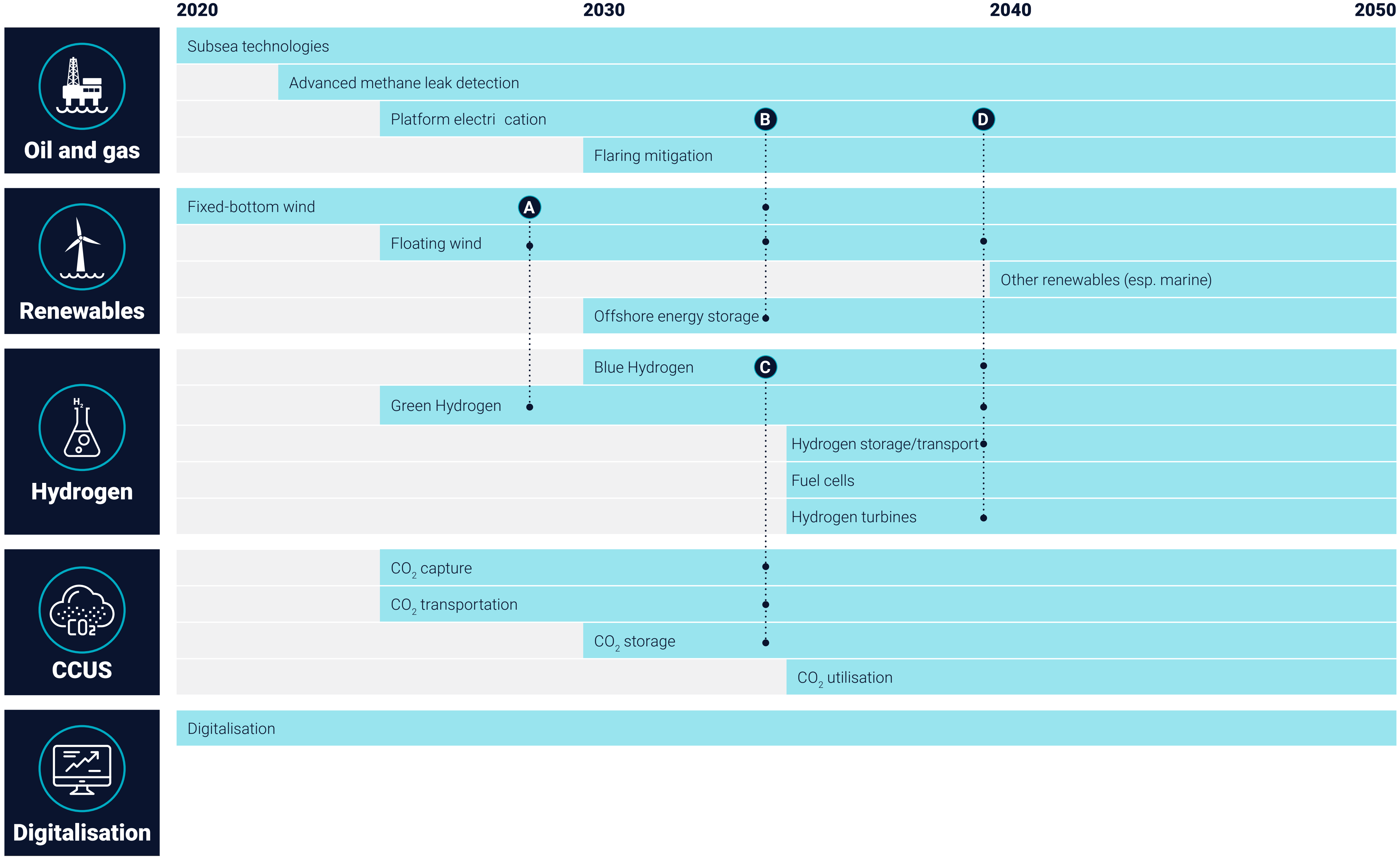
Figure 4.3
Concept shown is illustrative
Source: Wood Mackenzie, Lux Research

4.2: Development of an integrated energy system

Integration of the UKCS energy system creates interdependencies, where commercial progress of one energy system impacts that of another. This calls for integration to be considered during technology development, rather than linking disparate technologies developed in isolation, as has been the approach to date. It is critical to consider the technology roadmap for an integrated system and identify the key milestones and interdependencies.

Figure 4.4 illustrates the overall UKCS Integrated Energy System Roadmap, highlighting the critical cross-industry dependencies to build an integrated energy system:

Figure 4.4: UKCS Integrated Energy System Roadmap



Source: Wood Mackenzie, Lux Research

A Multiple large-scale onshore electrolyser projects are already in development, some depending on power from offshore wind farms to make green hydrogen. Eventually, scale-up of green hydrogen will lower electrolyser capex through large-scale manufacturing. As industrial demand for low-carbon hydrogen continues to build a sustainable hydrogen market, falling costs and growing capacity of offshore wind power will drive green hydrogen scale-up and commercialisation – a more expensive, but available, alternative to blue hydrogen in the short term.

B Platform electri cation will add considerable complexity to the offshore power grid. Ultimately, connecting a platform will require balancing power generation from offshore renewables against demand from other offshore assets, the onshore UK grid and international demand via interconnectors. Since this grid is in its infancy today, developers have the opportunity to design fo exibility, relying on features like bi-directional powe ow, power quality management and energy storage in the form of batteries and hydrogen storage. Th exibilities will help prevent future grid congestion issues of the kind that plague the onshore power grid today.

C While existing steam reforming and carbon capture technologies can already produce partially decarbonised hydrogen, commercial scale-up of blue hydroge rmly depends on scale-up of CO_2 pipelines and storage in large-volume reservoirs.

D A developing hydrogen value chain on the UKCS bene ts more than decarbonisation onshore. It creates opportunities to transport energy as hydrogen from far-from-shore wind farms via pipelines and store large volumes in reservoirs. Additionally, it can bene t further decarbonisation of the oil and gas sector as an alternative to platform electri cation, especially for ageing assets where electri cation is technically or economically not viable.

As the role of the UKCS evolves, several technologies will need to be developed in tandem and existing industries will begin to integrate with new industries to create a new landscape.

4.3: Meeting the CCC targets

In this section we have used the CCC's Further Ambition scenario to get an appreciation of the required scale and pace of deployment of the technologies identified in the Closing the Gap to 2050 Technologies section of this report. The scenario focuses on achieving a high level of electrification, advancement of CCUS and deployment of hydrogen infrastructure in the UK. The CCC analysis concluded that the targets outlined in figure 4.5 would need to be reached by 2050 to achieve UK wide net zero emissions. Each of these targets was assessed by the CCC to identify the level of the feasibility.

Although the CCC provides no specific targets for oil and gas production, it does highlight the need for a reduction in methane venting and leakage. Oil and gas will continue to play a role in meeting the UK's energy demand and so we have used the UK oil and gas industry's Roadmap 2035 to forecast future production as this takes into account the CCC's net zero target (see figure 4.6 - oil and gas production).

For the purposes of this report, and in assessing the role of the UKCS' contribution to achieving the 2050 targets, the 2020 to 2050 forecasts of oil and gas production, offshore wind power generation, hydrogen production (assumed to equal hydrogen use) and CCUS capacity were evaluated. Our assessment combined:

- **The CCC's targets and notes on target 'feasibility'**
- **This report's technology roadmap, including technology readiness, limitations/challenges**
- **The existing/planned project pipeline**
- **Other industry targets that aim to align with the CCC targets (i.e. the Roadmap 2035)**

The resulting forecasts show figure 4.6 represent one pathway of how the 2050 targets could be achieved and what this would mean for the deployment of the different technologies. More work is being done by the Net Zero Technology Centre and Offshore Renewable Energy Catapult (ORE catapult) to understand how different pathways could evolve. The Integrated Energy Vision report will be published in 4Q 2020. As recognised throughout this report, government policy, technology innovations and investment in new infrastructure will be required to support the scale and pace of technology deployment.

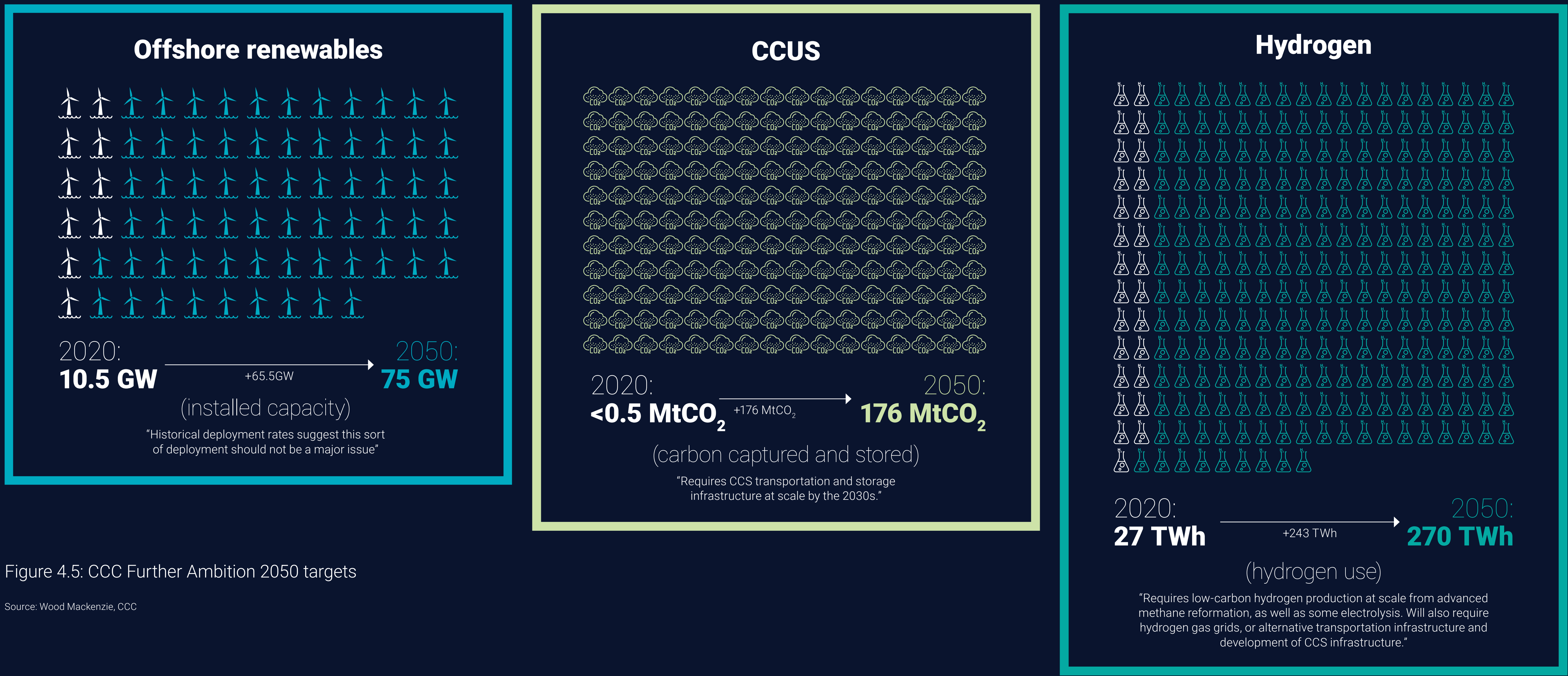


Figure 4.5: CCC Further Ambition 2050 targets

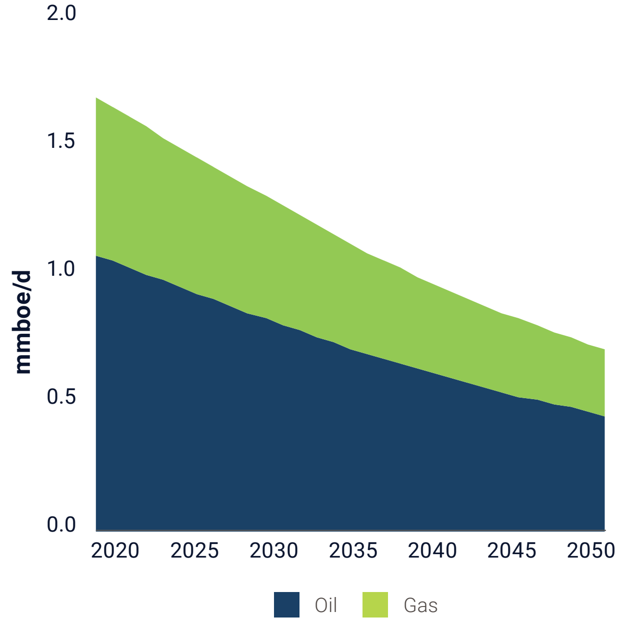
Source: Wood Mackenzie, CCC

Figure 4.6: Pathway to Further Ambition 2050 targets

Oil and gas production

Production from the UKCS is declining but will still help to meet the UK's energy and petrochemical needs. New technology deployment will still be required to ensure ef ciency and low carbon operations

- The forecast is based on the OGUK Roadmap 2035 oil and gas production forecast
- This forecasts production out to 2035 and assumes the UK will produce 1 mmboe/d of oil and gas in 2035
- 2035-2050 production has been extrapolated based on the 2020-2035 trend
- The production has been split into oil and gas production using the OGA oil and gas production split out to 2024
- This assumes 57% of production is oil, 36% is gas and 6% is NGLs

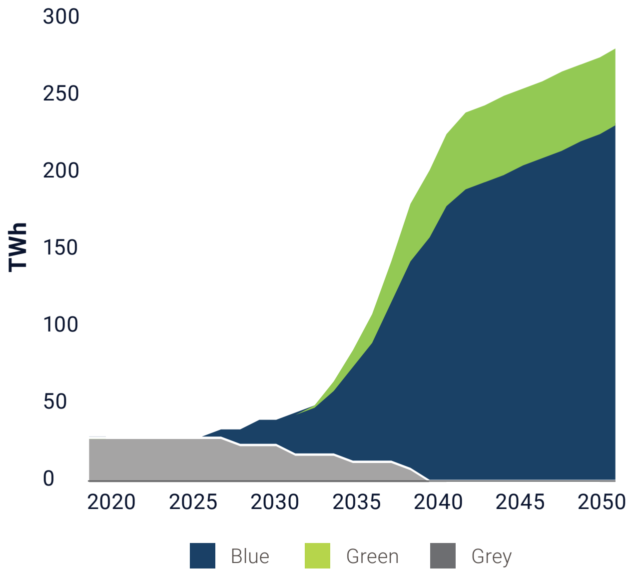


Source: Wood Mackenzie, OGUK

Hydrogen production

Blue hydrogen creates the foundation for the low-carbon hydrogen industry. The steep rise in capacity growth will require a similar ramp up in CO_2 capture and storage capacity

- The CCC 2050 hydrogen target is made up of 225 TWh from blue hydrogen and 44 TWh from green hydrogen
- 30-60 SMR plants would be needed to achieve the blue hydrogen target: this equates to an average plant size of 5 TWh
- We assume blue hydrogen will be develope rst, both as new builds and as conversion of grey hydrogen facilities as CCUS develops
- Capture rates at blue hydrogen projects are expected to be ~50% in the short term and reach upwards of 90% after 2035
- Green hydrogen deployment is assumed to be gradual as new turbines are built; the Dolphyn project model[240] was used as an analogue for future green hydrogen projects

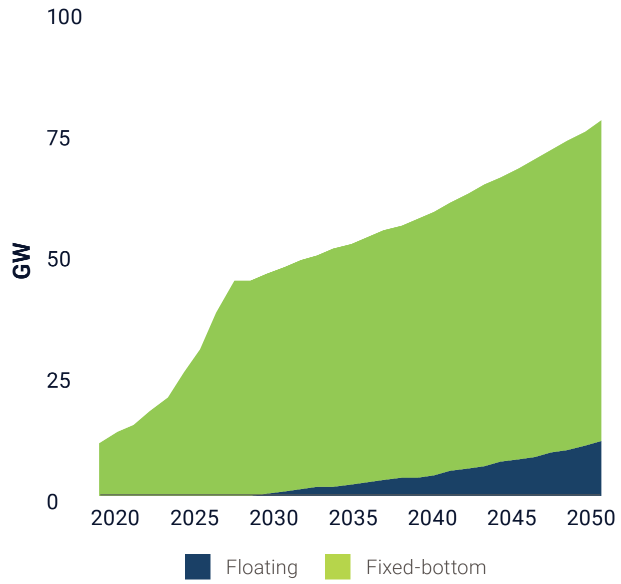


Source: Wood Mackenzie, CCC

Offshore renewable capacity

There is a strong pipeline of offshore wind projects over the next decade. After 203 xed-bottom deployment will grown steadiliy whil oating wind growth picks up

- The forecast is based on Wood Mackenzie's assumptions o xed-bottom an oating capacity deployment
- Most of futur xed-bottom capacity is expected to be in England, Wales and Northern Irish waters whereas the majority o oating wind capacity is expected to be in Scottish waters
- It includes known capacity deployment awarded through previous auction rounds
- It also accounts for announced capacity to be awarded in planned auction rounds
- Th xed-bottom v oating split is based on capacity announcements as part of future auction rounds

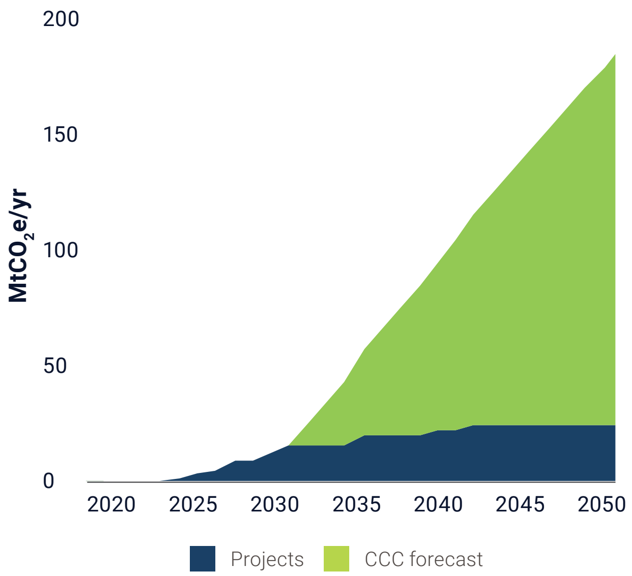


Source: Wood Mackenzie, CCC

CCUS capacity

Investment in capture, transport and storage infrastructure is needed now to ensure blue hydrogen production can ramp up. A steep increase in capacity is needed to reach the CCC target

- The forecast includes existing CCUS projects and their expected capacities, such as the Acorn project, Net Zero Teesside and H2H Saltend project
- We assume these projects are operational by 2030, as per the CCC's recommendation
- Other CCUS projects are expected to be developed at industrials hubs such as the wider Humberside area, Merseyside and South Wales but the storage potential of these projects is unknown and so they are included in the unknown category
- Capture and storage capacity is assumed to grow in line with blue hydrogen production



Source: Wood Mackenzie, CCC

5

Benefits to the UK: Economic impact of achieving net zero targets

5.1: Introduction to input-output analysis

Meeting the CCC's Further Ambition target through the scaling up of net zero technologies on the UKCS - identified in this report's Closing the Gap to 2050 Technologies section - creates a significant economic opportunity for the UK. An input-output analysis was conducted to measure the impact these technology sectors (oil and gas, offshore renewables, hydrogen and CCUS) and their related industries could have on the UK economy out to 2050.

Further details regarding the methodology and assumptions are included in the appendix.

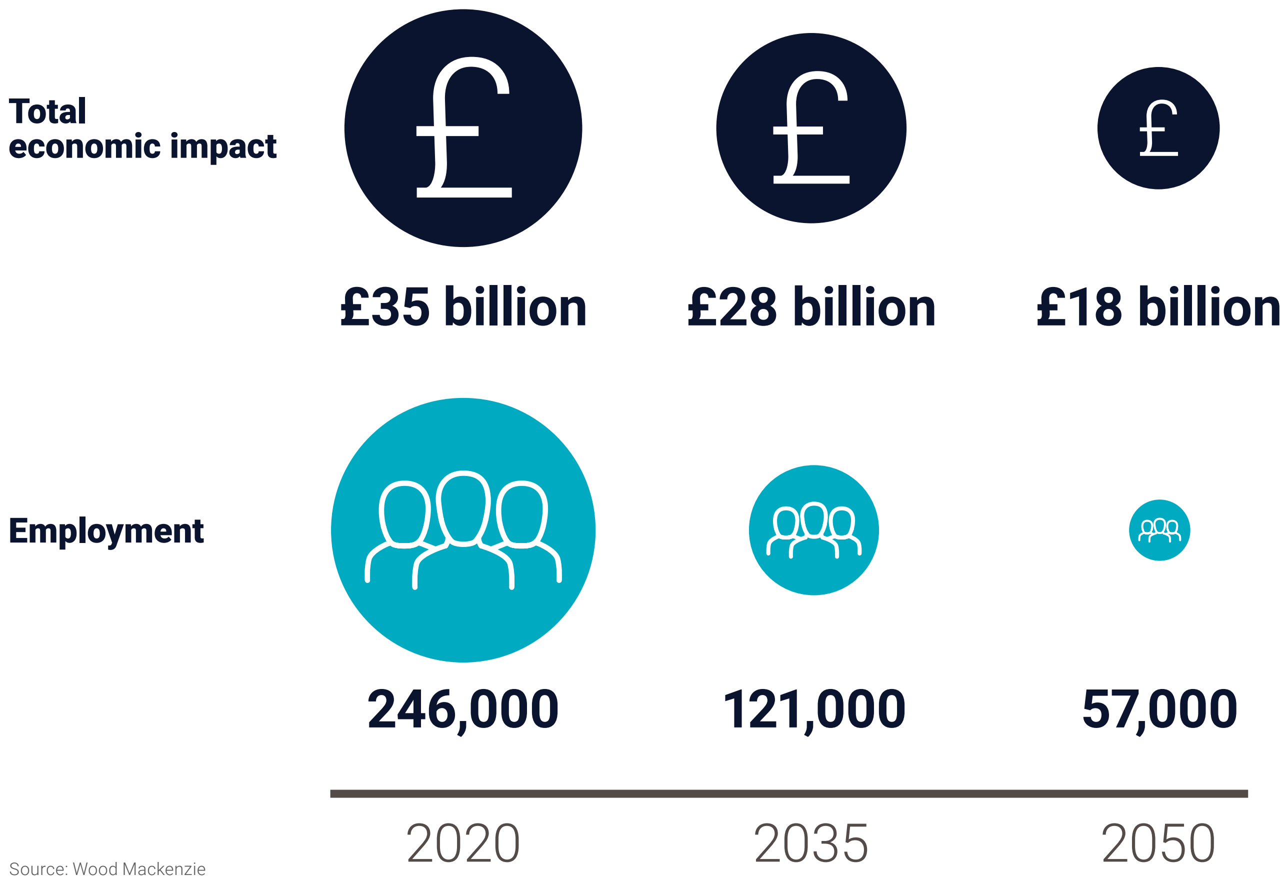
5.2: Sector outlook

Oil and gas

Hydrocarbon production from the UKCS peaked in 1999, however the oil and gas industry will continue to play a major role in the UK economy over the next 30 years. The industry could have a total economic impact of £900 billion from direct, indirect and induced effects on the economy between now and 2050.

Figure 5.1: Direct, indirect and induced impact of the oil and gas industry (in specific years)

Oil and gas industry total 2020-2050 economic impact: **£900 billion**



Source: Wood Mackenzie

Box 5.1: Examples of offshore decarbonisation technology costs and potential benefits

- Electrifying a cluster of fields with a **200MW power demand** would cost in the region of **£1.1 billion.** Although unlikely to offset the upfront capex, increased revenue from gas previously used for powering a platform is one of benefits of platform electrification: approximately 1m^3 of additional sales gas becomes available per 2.3kg of CO_2 saved[204].
- Installing methane leak detection and repair (LDAR) would cost between **£120,000** and **£200,000** in upfront capex and a further **£70,000** to **£90,000** per site per year but could save up to **£4 million** in tax if methane emissions were included under carbon tax rules. Methane emissions at UK fields can be as high as 10,000 tonnes per year[359] and could be taxed at up to £448 per tonne (28 times the current CO_2 tax rate due to methane's higher global warming potential)[360] under the European emissions trading system (ETS).

Although the majority of future investment will be traditional capex at greenfield and brownfield developments, investment in carbon reduction technologies will be significant in order to meet net zero targets. Capex related to decarbonisation technologies can be high, but that needs to be balanced against the long term opex reductions from improved efficiency, increased uptime and lower carbon tax payments. Investment choices to reduce the carbon intensity of production will ultimately depend on factors such as:

- Regulatory and fiscal considerations
- Development maturity
- Remaining life of onstream fields
- Platform system designs

Employment levels within the oil and gas industry are expected to fall as production declines and facilities cease operations, naturally reducing capacity. Technological advances in digitalisation and subsea operations will also mean that fewer personnel will be required offshore. As that happens, there is potential for people to transition to other industries in the energy value chain such as renewables, hydrogen and CCUS. A range of transferrable skills and knowledge – particularly in geosciences, engineering and energy systems –as well as the crossover locations of energy and industrial hubs, will facilitate this.

Risks and uncertainties

Current OGUK forecasts production from existin elds of 271 mmboe in 2035, equivalent to approximately 30% of total demand. Roadmap 2035[361] targets the UKCS meeting 50% of UK oil and gas demand which will therefore require continued exploration and development activity.

Additionally, for exploration and production to align with a net zero UKCS, the industry will need to invest in retro tting and designing new low-carbon operations. Traditional capital investment will also need to support new and existing developments. Low oil prices and volatile market conditions and budgetary constraints could slow investment in emissions abatement. However, investor pressure and the regulatory environment could help to counteract this and sustain a focus on emissions reductions.

The high costs associated with certain technologies and the often complex ownership structures of oil and gas assets mean that concerted industry effort is required to ensure deployment of new technologies that will help the UKCS play a role in meeting net zero targets. This is especially true for major projects such as platform electri cation, where the cost could be spread through a consortium approach with shared infrastructure and development costs.

Upside potential

The UK oil and gas industry exports approximately £12 billion of goods and services annually and aims to increase this to £20 billion as part of the Roadmap 2035[361]. Investing locally in the innovation and manufacturing of decarbonising technologies now would give the U rst-mover advantage: as other oil and gas basins around the world start to decarbonise, that could boost the industry's export value.

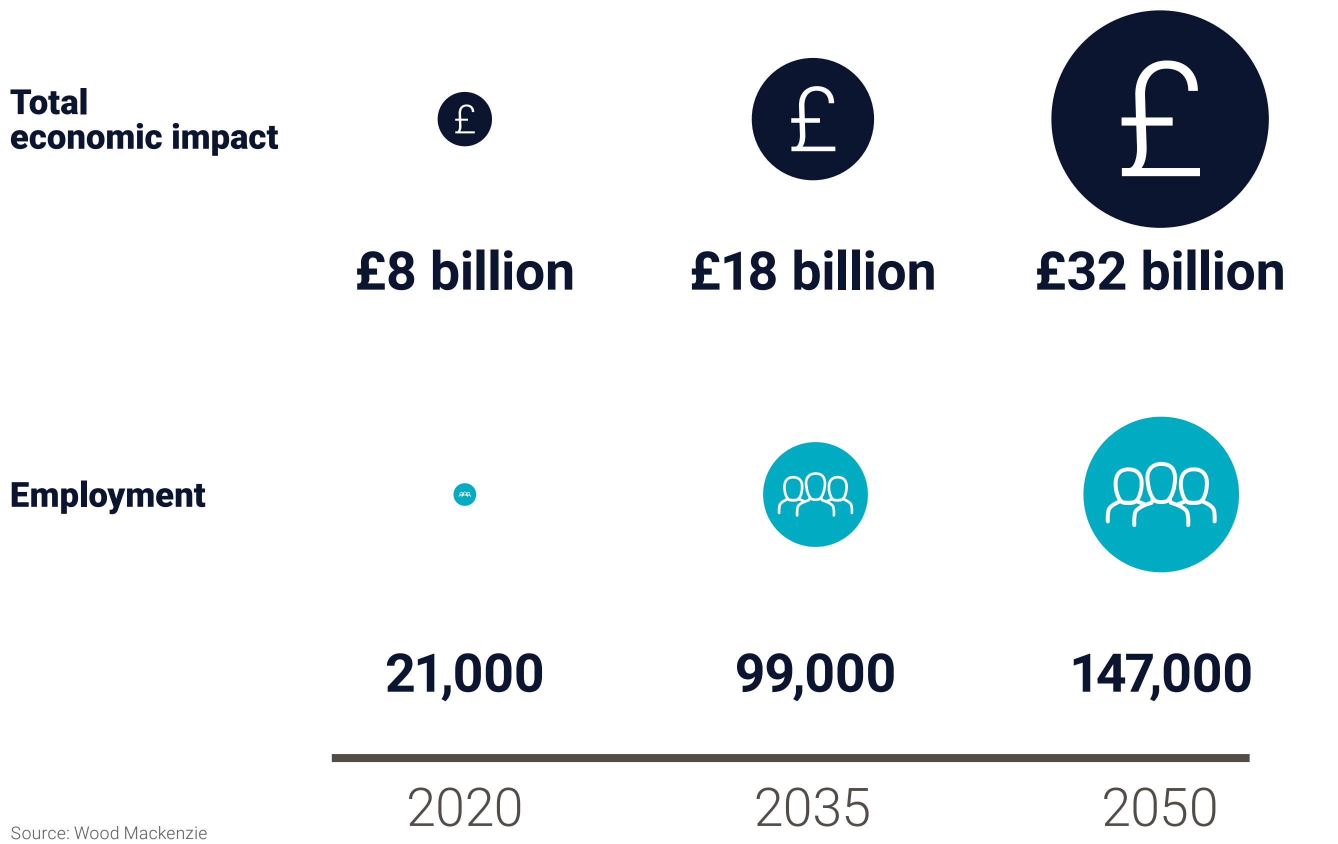
Offshore renewables

Offshore wind will be the biggest economic contributor to the offshore renewable industry, with a potential economic impact of £600 billion between now and 2050. The offshore wind industry's contribution to the UK economy is however subject to investment in new wind farms. Progress in the next decade will be driven by the build out of capacity that has been awarded in recent auctions. We assume a steady investment pro le beyond that to re ect the necessary capacity additions that will be needed to reach the CCC's 75GW offshore wind target. Investment will also be driven by continued unit (per MW) cost reductions for bot xed an oating wind as power ratings (power produced per turbine) and capacity factors increase. Floating an xed-bottom costs are expected to reduce by up to 60% and 70% respectively by 2050 (se gure 5.3), and units costs fo oating wind will get close to those o xed-bottom by the 2040s[362]. Overall oating wind is expected to make up a small proportion of installed capacity and total spend.

The economic impact of the offshore wind industry is also in uenced by the level of UK content within offshore wind projects. The offshore wind sector currently has an average UK content of 50%[12]. The Offshore Wind Sector Deal[12] aims to increase this to 60% by 2030 and we expect this to continue to increase out to 2050, especially if a loca oating wind supply chain is developed.

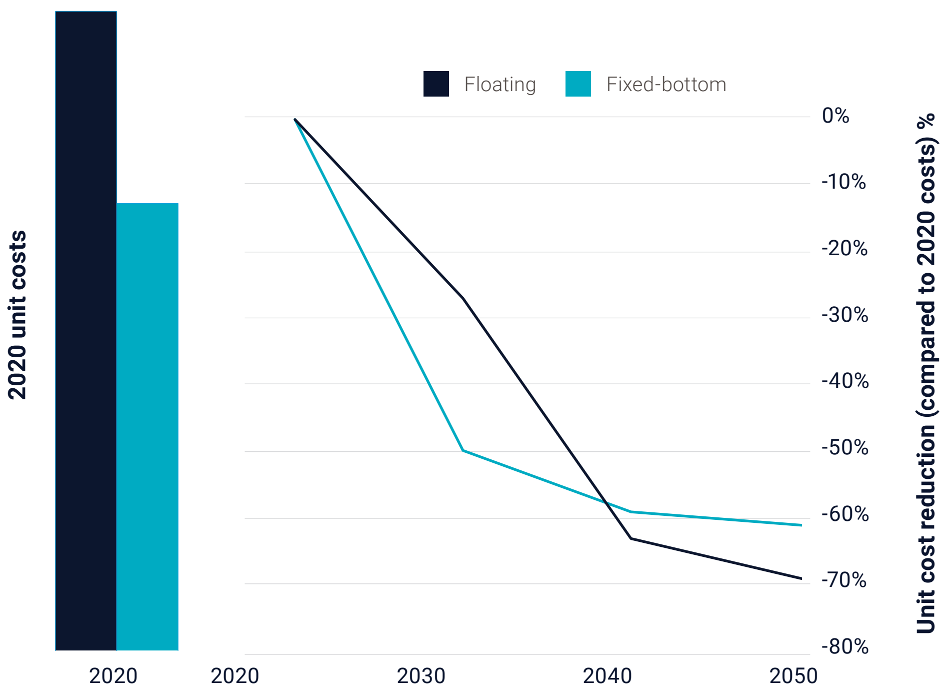
Figure 5.2: Direct, indirect and induced impact of the offshore renewables industry (in spec c years)

Offshore renewables industry total 2020-2050 economic impact: **£600 billion**



Source: Wood Mackenzie

Figure 5.3: Fixed bottom an   ating wind unit cost reductions (compared to 2020 costs)



Source: Wood Mackenzie

The pro tability of the offshore wind sector is highly dependent on the capture price achieved through the sale of wind power. The capture price is dependent on the future power mix: the level and price of gas generated power and the growth of hydrogen produced power are important. Any pricing agreements made with the government during auctions rounds will ultimately dictate the price achieved by wind developers.

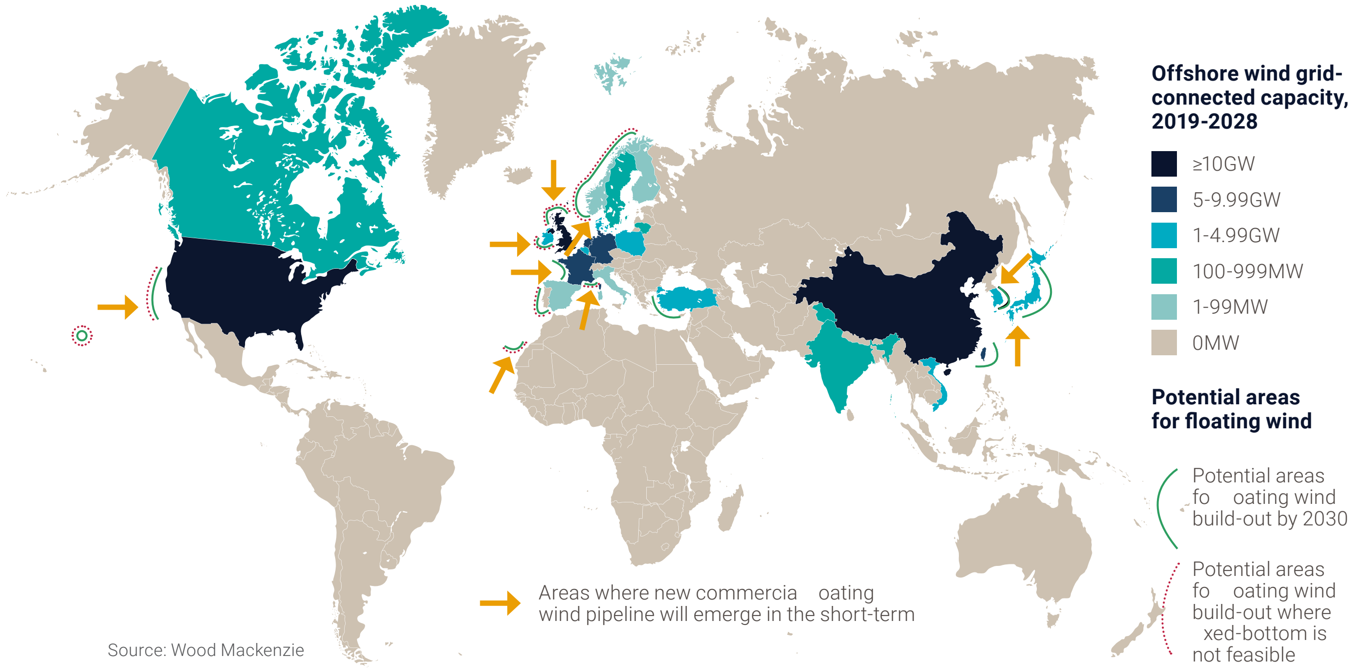
The offshore renewable industry has the potential to support nearly 150,000 (direct, indirect and induced) jobs by 2050, and will overtake the oil and gas sector as the largest UKCS employer in the late 2030s. While the offshore renewable industry is relatively 'employee light' as day-to-day operations are not labour intensive, increased renewable power is expected to create tens of thousands of new indirect jobs. Employment will be created in the electricity industry, in manufacturing during project development and construction, and through the growth of local supply chains. Even though the UK has the largest deployed offshore wind capacity in the world and several domestic manufacturing facilities[363], a large proportion of renewable technology is still imported. The Offshore Wind Sector Deal aims to generate more economic bene t by reducing the reliance on imports, increasing UK content to 60% by 2030, and creating more than 25,000 direct jobs by 2030[364]. Alongside capacity build out, the development of the domestic supply chain will be the main driver of increased employment in offshore wind and related industries.

Risks and uncertainties

Although the offshore wind project pipeline is relatively secure to 2030, the timing and scale of buildout is still uncertain after that. New auctions will need to be held in addition to those already planned and market conditions will need to remain favourable for bid rates to remain as high as they have been in past auction rounds.

Government subsidies may still be required to ensure future projects go ahead, especially in the case o   oating wind projects. Although some developers are considering the merchant route to market – the sale of electricity directly to distributors at a spot price - the feasibility of that business model for offshore wind is still risky. The level of future government subsidies is therefore a key uncertainty.

Figure 5.4: Global offshore wind 2028 forecast and potentia   oating wind sites



Source: Wood Mackenzie

The proportion o   xed-bottom an   oating capacity is also uncertain as the development o   oating projects will be driven by unit cost reductions. The commercialisation o   oating wind needs capacity growth to drive cost reduction, however scale, cost reduction and a local supply chain are needed for governments to allocate capacity t   oating wind.

Upside potential

The demand for renewable energy across Europe is increasing as new policies, such as the European Green Deal, are developed, and as the green hydrogen economy grows. The offshore wind sector accounted for £0.5 billion of exports in 2018[365] with the UK exporting renewable (onshore and offshore wind and marine energy) products and services to 40 countries[366]. Additionally, the UK can directly export renewable power to mainland Europe via interconnectors to France, the Netherlands and to Belgium (se   gure 2.18). Plans to build new interconnectors to Norway, Denmark, Germany and France will increase the amount of renewable power the UK can export and the growth of domestic supply chains will allow more UK products and services to be exported globally.

The UK is currently in the unique position of having the only operationa   oating wind farm in the world, however it does not have a well-developed   oating wind supply base. Developin   oating wind expertise and supply chains locally could allow the UK to become a key exporter of these technologies and knowledge. The technical deployment potential o   oating wind is virtually unlimited: moving quickly in this space could allow the UK to become the go-to fo   oating wind developers and manufacturers and to serve a global market[367]. This could signi cantly bene t the UK economy, creating jobs, skills and expertise and technology that can be exported.

Although wind has the biggest potential in the UK's offshore renewables sector, the growth of other technologies including wave and tidal have economic potential but not on the same trajectory as wind. These technologies are not as scalable or as mature as wind, but they are continuing to develop and will support employment and supply chains in coastal areas. The levelised cost of electricity for tidal energy is currently around £300/MWh. This could reduce by 70% to £90/MWh if capacity were to increase to 1GW[368].

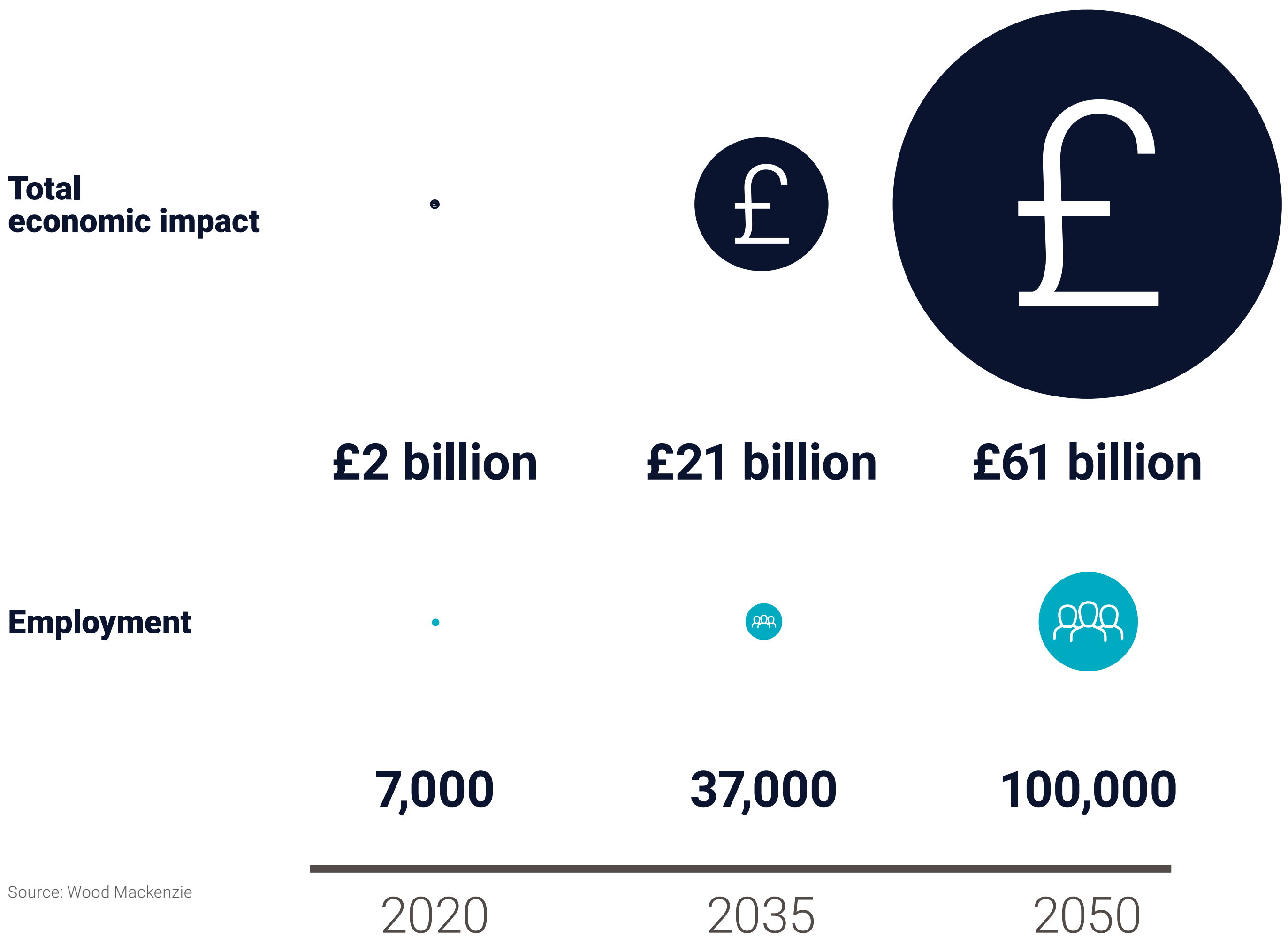
Hydrogen

The growth in demand for hydrogen over the next 30 years will be driven by its use as a low carbon alternative in heavy transport and a wide range of hard-to-abate sectors such as heating and heavy industry. Employment is expected to increase in line with revenue[369] and the projected growth of the blue and green hydrogen industries could create over 90,000 new jobs within research and development, manufacturing, installation and operations. However, the economic impact potential from the development of blue and green hydrogen industries extends beyond employment: its widespread potential use, the need to develop new infrastructure and its interdependence with other related industries, will all add up. One of the main contributing factors to the large economic impact that could be generated by the hydrogen industry are the high operating costs associated with the purchase of feedstock – gas in the case of blue hydrogen and electricity and water for green hydrogen – as well as having to pay for CO_2 storage and transport (in the case of blue hydrogen). While those are added expenses for hydrogen producers, the gas, electricity and renewables and CCUS industries will gain revenue, with a positive economic impact across the UK economy.

The level of investment associated with hydrogen production is driven by production method. The main capital investment for blue hydrogen relates to the installation of CO_2 capture equipment, and the operating costs are mainly related to transporting and storing captured CO_2 and the feedstock cost of the natural gas (see Closing the Gap to 2050 Technologies – Hydrogen for more details). Associated operating costs are expected to increase in the long term as carbon taxes and the price of natural gas increase.

Figure 5.5: Direct, indirect and induced impact of the hydrogen industry (in spec c years)

Hydrogen industry total 2020-2050 economic impact: **£800 billion**



Source: Wood Mackenzie

Green hydrogen's primary opex are feedstock costs for water supply and electricity. As the amount of available renewable energy increases, we expect the electricity costs to decrease. Electrolyser capex costs for green hydrogen production are high as most parts of the electrolyser are made manually. Manufacturing automation will be a key cost-reduction driver.

Both green and blue hydrogen will need to be transported to demand centres– industrial hubs or hydrogen networks –and adequately stored. Domestic gas grids will also need to be adapted or developed to allow hydrogen to be mixed with, or replace, natural gas for domestic use. The infrastructure and facility development that is required will have a further economic impact.

Risks and uncertainties

Demand for hydrogen in the UK is currently very limited. The CCC recommends developing a hydrogen economy in which hydrogen is used in home heating, transport, industry and energy generation; however, developing the supply and demand to scale and in unison will require careful planning and coordinated investment. Several projects, such as Hynet NorthWest, are already investigating the development of hydrogen economies at a regional scale. These projects are still in the feasibility stage and need further funding and approval. Without a major growth in hydrogen demand across the economy, neither the scale of hydrogen production, nor the economic impact of it as modelled in this study, will materialise.

Both blue and green hydrogen are not currently cost competitive when compared to grey hydrogen and other forms of energy[370]. For production to ramp up, costs need to come down. Either government support or a suitable carbon price are likely to be needed to develop and scale hydrogen technologies. Additionally, increased offshore wind capacity, developed at a decreasing cost, would improve the economics of green hydrogen.
The development of blue hydrogen is dependent on the construction of carbon capture, transportation and use or storage infrastructure that will allow the CO_2 created during the production process to be abated. If the CCUS industry were to develop more slowly than forecast, this would jeopardise the growth in blue hydrogen production that is required to meet the CCC's targets.

If hydrogen is cheaper to import than to produce domestically, the industry's development could have fewer bene ts for the UK economy and employment than what we have modelled in this study. Other countries such as Australia are already utilising their sizeable renewables potential to develop green hydrogen production and if it or other regions with low cost renewable energy, can supply hydrogen at a lower cost than the domestic market, that will clearly impact the scale of the local industry and supply chain.

Upside potential

If large scale competitive hydrogen production succeeds, then the UK could become a net exporter of blue and green hydrogen to other countries. This could be either in the form of hydrogen or converted and shipped as ammonia, methanol or similar chemicals. Global and regional demand for hydrogen products is set to grow. Within the EU, the hydrogen roadmap outlines the signi cant potential for the hydrogen economy, suggesting that investments of over €52 billion by 2030[371] will be made in the industry. The UK could also become a centre for international industries looking to decarbonise, such as the shipping sector, through offshore fuelling hubs.

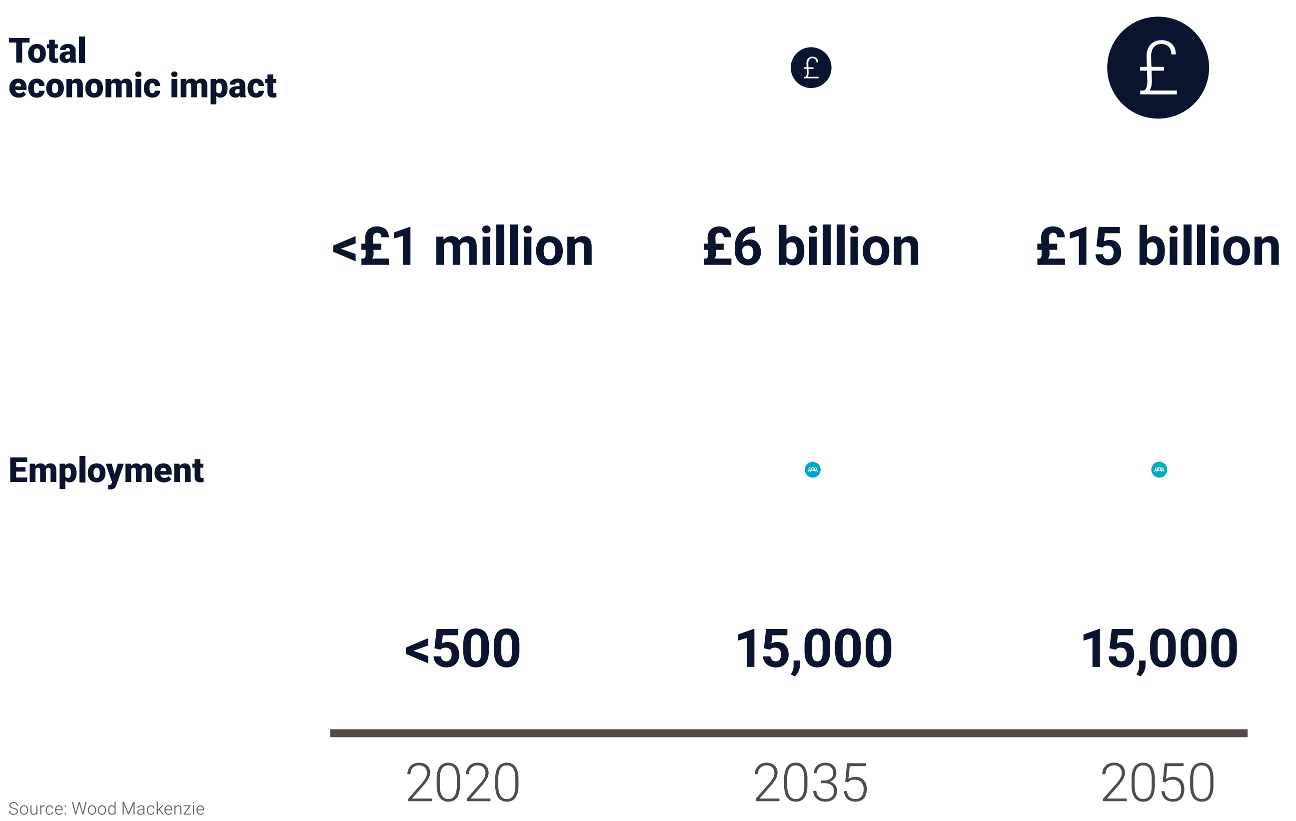
There are already more than 100 companies and over 35 academic and contract research groups in the UK[372] that have been internationally recognised for their development and research on hydrogen production, supply and storage. If the UK continues to develop its domestic hydrogen base and expertise, it has the opportunity to become a centre of excellence for hydrogen production, and a chance to export knowledge, skills and innovative technologies globally.

CCUS

CCUS remains a nascent industry in the UK. It will require signi cant capital investment in a relatively short period to develop the necessary capture, transport and storage infrastructure to meet the CCC target. The highest capital costs are associated with the capture technology which will need to be installed at all large- scale emission sites. Capture costs make up the largest proportion of CCUS capex. Currently, capture costs are around £100 per tonne of CO_2 captured however these costs are expected to signi cantly reduce by 2050 to less than £50 per tonne of CO_2. The costs associated with CO_2 transportation will vary depending on distance, location (onshore vs offshore) and if a pipeline is a newbuild or has been retro tted. To reduce costs, we assume the majority of carbon will be captured at industrial sites and transported to offshore storage sites in regional proximity.

Figure 5.6: Direct, indirect and induced impact of the CCUS industry (in spec c years)

CCUS industry total 2020-2050 economic impact: **£200 billion**



Source: Wood Mackenzie

Table 5.1: Potential government policies for incentivising CCUS growth

Governments provide tax credits for every tonne of CO_2 stored.
For example, the 45Q tax credit scheme in the US allows industrial manufacturers to earn up to \$50 per tonne of CO_2 that is permanently stored and up to \$35 per tonne CO_2 that is used for EOR[375].

A tax credit is available for capturing emissions.
For example, California's Low Carbon Fuel Standard CCS protocol allows CCS projects to be used to offset emissions associated with the production of transport fuels and therefore earn credits which can be worth up to US\$190 per tonne of CO_2 captured[376].

Governments introduce policy that requires fossil fuel suppliers to offset a proportion of the scope 3 emissions associated with the end use of their products.
For example, "a carbon take-back scheme" was proposed by UK academics in 2015[406] and would oblige fossil fuel producers to prove they have stored, or paid a third party to store, a certain proportion of CO_2 emissions associated with the end use of their carbon related products. The proportion of emissions that need to be offset would increase, eventually reaching 100%.

A carbon tax is introduced that makes it more cost effective for CO_2 producers to invest in capture, transport and storage equipment than pay the tax.

Governments introduce CfD agreements which guarantee thermal power or industrial players that install carbon capture technology a **guaranteed price for, respectively, electricity sales or carbon abated.** These companies then pay carbon transport and storage operators a regulated fee for transporting and permanently sequestering the carbon.

By 2050, the CCUS industry could create up to 15,000 new jobs (direct, indirect and induced). Most of these jobs are expected to be created during the manufacturing and construction phase of projects. Once a CCUS project is in operation, it is expected to be relatively 'labour light'[373].

A viable business model for the CCUS industry is still unclear as there is currently limited economic incentive to store CO_2. For example, the current European Emission Trading System (ETS) carbon price is insuf cient to support the case for CCUS investment[374]. Government intervention is required to kick start the CCUS industry and there are multiple options for doing so, as outlined in table 5.1.

For the purposes of this report, we assume CO_2 producers will invest in CO_2 capture technologies and then pay a fee to have CO_2 transported and stored by a specialist CCS operator.

Risks and uncertainties

The high upfront capital costs and the lack of a clear business model mean that the CCUS industry needs more support if it is to develop. Several CCUS projects received UK government funding in the early 2010s but the projects did not progress past pilot stages after the funding was stopped. New CCUS projects, such as Acorn and Teesside, are currently progressing through the concept phase and in the 2020 budget, the government announced £800 million of funding for CCUS projects.

The blue hydrogen industry is one of the key cornerstones for CCUS development. If the blue hydrogen industry does not scale as expected, then it will remove a key driver to develop CCUS.

Current CCUS projects are planning to take advantage of carbon sources and underground sinks that are geographically close together to reduce transport costs. However, this will not be the case for all CO_2 emissions; cost effective storage or utilisation methods will be needed for highly emissive industrial sites that are not near storage sites.

Upside potential

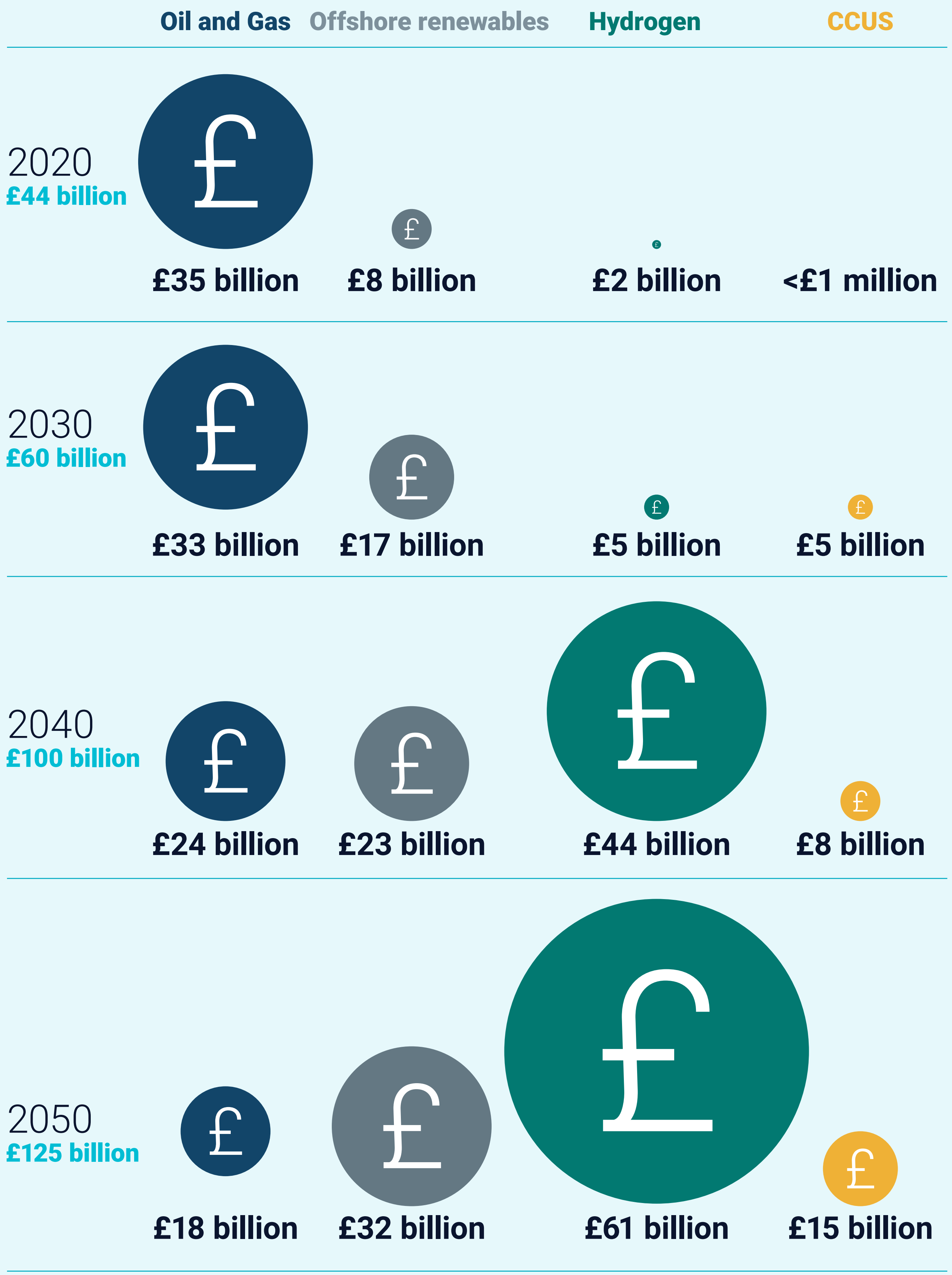
The CCC estimates that the global CCUS industry could be worth around £100 billion by 2050[377]. The UK's storage potential is enough to sequester nearly 200 years of CO_2 emissions[378] – based on the UK's current emission rate – and is therefore in a position to set itself up as a CO_2 hub, storing CO_2 from other countries at a fee. Carbon offsetting is growing as a way for companies to achieve net zero targets and it is estimated that, in 2018, 100 Mt CO_2 was traded, creating a global market worth nearly US$300 million[379]. If the UK CCUS industry develops ahead of other countries, it could be in a prime position to take advantage of the global carbon offset demand.

As well as storing CO_2, the UK could build on its utilisation industries. Developing a use for captured CO_2 not only has a direct economic benefit through the sale of the new product, but could also lead to the development of another new export industry.

Over 200 CCUS academics are working across numerous UK institutes to develop world-class CCUS research[380]. Building on this existing research and innovation positions the UK to become a world leader in CCUS, exporting knowledge and technologies to further benefit the UK's economy.

Total economic impact

Figure 5.7: Total economic impact in specific years (based on direct, indirect and induced effects)



Source: Wood Mackenzie

5.3: UK impact summary

Investing in low-carbon technologies and establishing an integrated energy network will be pivotal to achieving the net zero 2050 target for both the UKCS and the wider economy. As this analysis demonstrates, the natural decline of the oil and gas sector will be more than offset by the growth in renewables, hydrogen and CCUS. This transition will drive signi cant economic growth through the expansion of the energy sector and development of an integrated energy network across the UKCS. The direct, indirect and induced effects of this could have a total economic impact of £2.5 trillion on the UK economy between now and 2050, as well as create over 200,000 new jobs. Employment across the oil and gas, offshore renewables, hydrogen and CCUS industry would add up to more than 300,000 in 2050.

There is also huge export potential for the low-carbon industries, particularly within Europe. The European Commission's "A Clean Planet for all" strategy[381] highlights the importance of innovative technologies in renewable energy, CCUS, energy storage and substitute products in energy intensive industries in meeting the European Green Deal's net zero GHG emissions by the 2050 target[382]. Over €10 billion - money raised through the sale of EU ETS allowances - is to be invested in innovative technologies by 2030, demonstrating the EU's commitment to these low carbon technology industries. Th rst of the annual funding opportunities launched in July 2020 and will make £1 billion available to large-scale renewable, blue/green hydrogen, energy storage and CCUS projects.

These commitments indicate the potential scale of the market in Europe and associated export opportunities for the renewables, hydrogen and CCUS industries. Using the ratio of the current oil and gas export value and total domestic economic impact as a proxy, the export potential across the offshore renewables, hydrogen and CCUS industries could be worth £36 billion – on top of the domestic economic impact – in 2050. Export of renewable energy, hydrogen and CCUS products and expertise could outstrip that of oil and gas as European policy encourages the growth of these industries and interconnectedness between countries (see table 5.2).

Table 5.2: European opportunities

Renewables	**The EU aims to increase renewable's share of total energy consumption to 32% by 2030[383].** Although it has been suggested more renewable power (primarily solar) could be imported to Europe from North Africa[384], logistically this is likely to only serve southern European countries. That leaves an opportunity for the UK to export renewable power to northern European states using both existing and planned interconnectors. To meet the EU hydrogen production targets, more than 30,000 TWh of renewable electricity would be required[385] – more than all the electricity that is currently produced globally[386] . That has the potential to be signi cant new demand sector that UK offshore renewable power could supply.
Hydrogen	**Under the "Hydrogen Roadmap Europe", Hydrogen could meet 24% of total energy demand in 2050, equivalent to ~2,250 TWh of energy.** That would create an estimated €130 billion industry in Europe by 2030, reaching €820 billion by 2050[387]. Many European countries have already set up national hydrogen policies. For example, the Portuguese government is targeting a €7 billion investment in green hydrogen projects by 2030, underpinning its goal to reach carbon neutrality by 2050[388].
CCUS	The European Commission considers CCUS as the only option to reduce large scale emissions from industrial processes and its role is acknowledged in the 2030 climate and energy policy framework[389]. **CCUS projects that link energy systems of different EU countries – projects of common interest (PCIs) – are being encouraged through favourable funding opportunities and reduced regulatory barriers[390].** The latest list of PCIs, released in 2019, include ve cross-border carbon dioxide network projects. The UK based Acorn project was one of these, as was the Norwegian Northern Lights project, which aims to create a CO_2 cross-border transport connection project: CO_2 would be captured from several countries including the UK and shipped to a storage site on the Norwegian continental shelf[391].

Capital investment

To achieve the targets set out in the Integrated Energy System Roadmap – meeting the CCC Targets section of this report, a total of £270 billion of capex will need to be invested in UK industries between 2020 and 2050. Over the next 15 years, direct investment will be particularly important to ensure that the CCUS and low-carbon hydrogen industries take off. The UK government has allocated funding to initiatives in these industries including £800 million to CCUS and £28 million to low-carbon hydrogen projects[392], although a further £3.5 billion will be required over the next 10 years. Early and committed investment is one of the most signi cant risks in reaching the CCC's targets. Both hydrogen and CCUS will see most capital investment from 2035 onwards, each requiring between £70 and £100 billion of total capex to reach their respective 2050 targets. If UK industries move early, they could ensure they capture well over half of this investment.

Over the next 15 years, the offshore wind and oil and gas industries will each require £75 billion in capital investment to reach their respective targets. Approximately half of this is expected to be spent in the UK due to the current local content levels in each industry. Growing the local supply chains will ensure a greater proportion of future capex is captured by UK industries. It is assumed the hydrogen and CCUS industries will develop strong local supply chains and so a larger proportion of capex spend will feed into the UK economy.

Capital investment

Figure 5.8: Forecast capital investment (UK content) for spec c years

	Oil and Gas	Offshore renewables	Hydrogen	CCUS
2020 £8 billion	£5 billion	£3 billion	<£1 billion	<£1 billion
2030 £5 billion	£3 billion	£1 billion	<£1 billion	£1 billion
2040 £10 billion	£2 billion	£2 billion	£4 billion	£3 billion
2050 £11 billion	£2 billion	<£1 billion	£4 billion	£5 billion

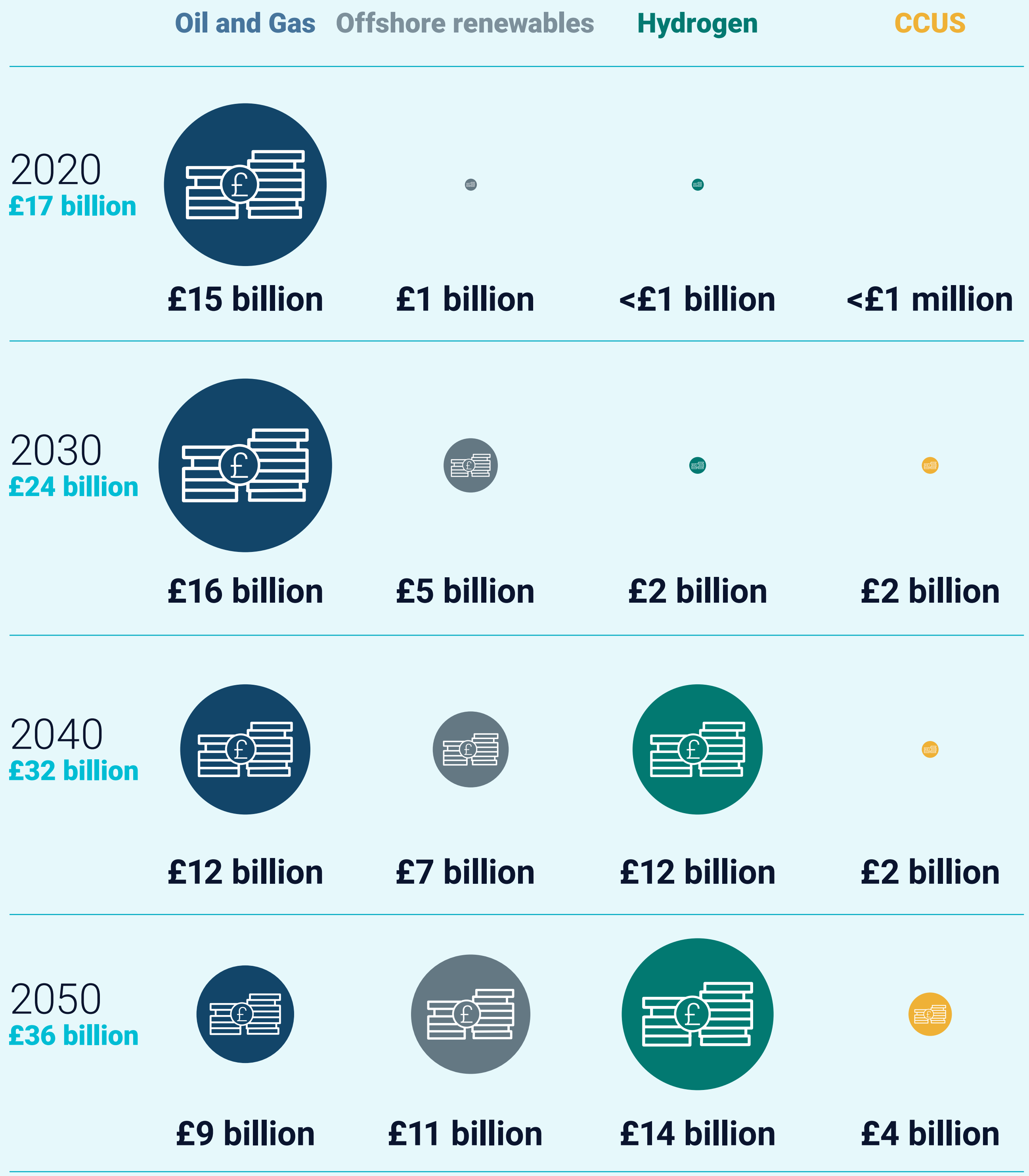
Source: Wood Mackenzie

Revenue

The investment in net zero technologies and an integrated energy system has the potential to generate £36 billion in revenue in 2050 through the domestic sale of products and services – more than double the total revenue generated across these industries today. The development of a low-carbon hydrogen industry and an increase in offshore renewable power generation will be the main drivers of this growth. Nevertheless, a wide range of stakeholders will need to manage the interdependencies across all four low-carbon industries that will be created by the integrated nature of the energy system. Most importantly, government funding and policy and regulatory changes will be required.

Revenue

Figure 5.9: Forecast revenue in spec c years



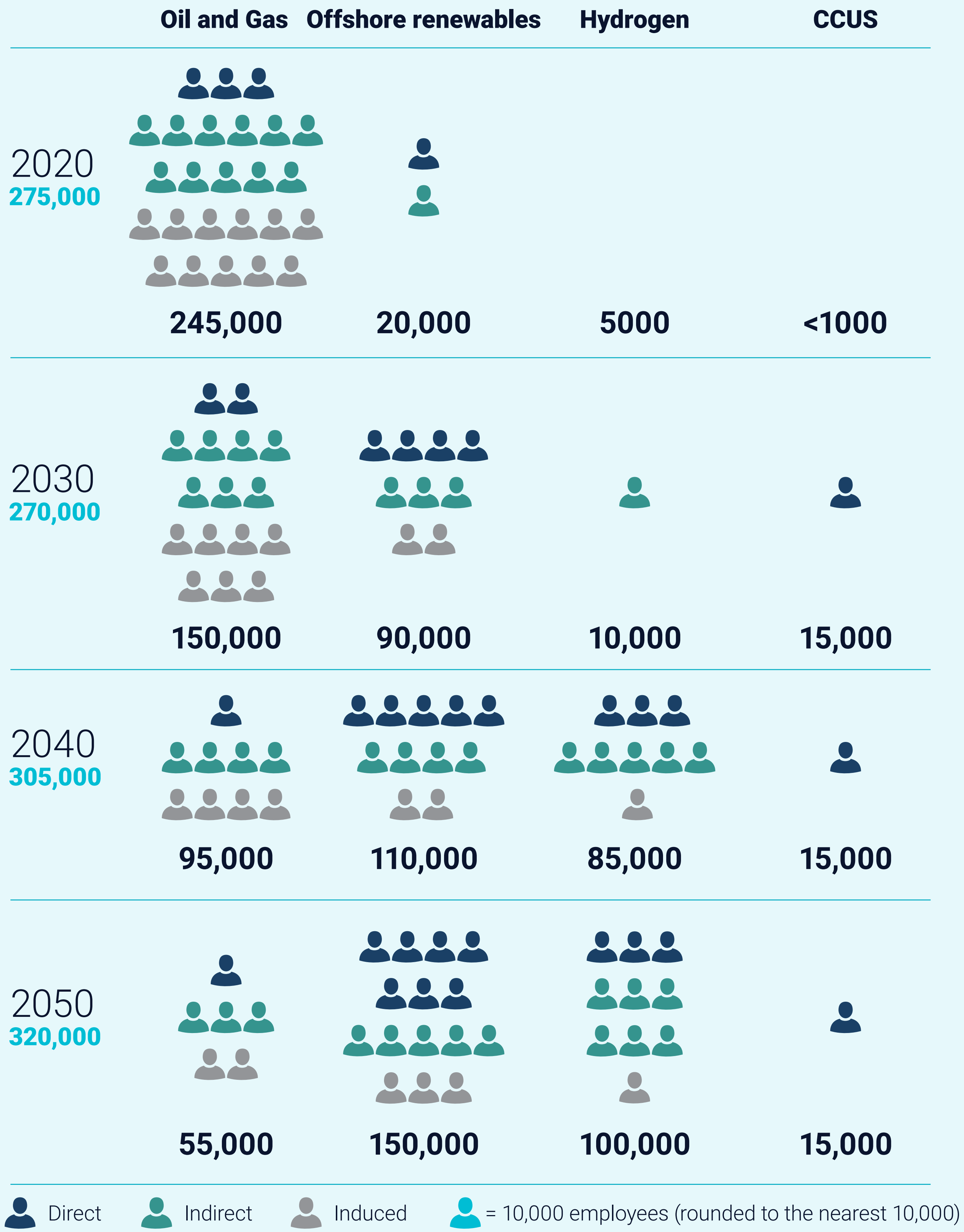
Source: Wood Mackenzie

Employment

As well as economic impact, over 200,000 new direct, indirect and induced jobs could be created across the UK through the growth of offshore renewables, hydrogen and CCUS. That will more than offset the decline in employment in the oil and gas industry as there will be more than 300,000 jobs across all these sectors by 2050. These new jobs are likely to be created in industrial areas, where traditional industries are in decline, and in North Sea coastal cities, where oil and gas industries make up a large part of the economy. Global export of products and services creates a portion of direct and indirect employment in the oil and gas industry, whereas the employment forecasts shown here for the offshore renewables, hydrogen and CCUS industries only re ect domestic production and consumption. If these industries were to realise the potential export opportunities, as we saw evolve in the oil and gas sector, this could further increase direct and indirect employment numbers.

Employment

Figure 5.10: Forecast direct, indirect and induced employment in spec c years



Source: Wood Mackenzie

6

Unlocking the Potential

Unlocking the Potential | Section 6

6.1: Technology gap priorities for unlocking the UKCS' potential

	Current level of development versus CCC 2050 targets	Key technologies, timelines and system dependencies (2020 – 2030 – 2040 – 2050)	Innovation gap priorities	Potential economic impact: Total capex required between 2020 and 2050**	Potential economic impact: Total domestic economic impact between 2020 and 2050	Potential economic impact: UK employment in 2050 (direct, indorect and induced)
Oil and gas	CAGR: -3% **1.6 mmboed ▶ 0.7 mmboed** Oil and gas production*	Subsea technologies Advanced methane leak detection Platform electri cation (B) (D) Flaring mitigation	**Short term:** build out of electri cation infrastructure (subsea cables and HV substations) **Short term:** retro t gas turbines to run on ammonia-hydrogen blend where possible **Short-mid term:** design of subsea equipment that can be re-used and integrated with renewables	**£123bn**	**£0.9tr**	**57,000**
Renewables	CAGR: 7% **10.5 GW ▶ 75 GW** Installed offshore wind capacity	Bottom- xed wind (A) Floating wind Other renewables (e.g. marine) Offshore energy storage	**Short term:** build out of transmission systems, i.e. HVDC cables connecting oating wind farms to the shore **Short term:** standardisation o oating foundation designs **Mid-long term:** improve ef ciency of nascent technologies (AES and marine energy)	**£100bn**	**£0.6tr**	**147,000**
Hydrogen	CAGR: 8% **27 TWh ▶ 270 TWh** Total hydrogen production	Blue Hydrogen (C) Green Hydrogen Hydrogen storage/transport Fuel cells Hydrogen turbines	**Short term:** development of integrated desalination and electrolysis units to couple with offshore wind turbines **Short term:** improve yield and CO_2 capture ef ciency of blue hydrogen reactors **Mid-long term:** development of hydrogen pipeline (develop repurposing practises) and storage facilities (i.e. underground storage)	**£120bn**	**£0.8tr**	**100,000**
CCUS	CAGR: 55% **<0.5 $MtCO_2e/yr$ ▶ 176 $MtCO_2e/yr$** CO_2 capture and storage potential	CO_2 capture CO_2 transportation CO_2 storage CO_2 utilisation	**Short term:** improve ef ciency of capture technologies (i.e. solvents, sorbents, membranes etc.) **Mid-long term:** improve ef ciency of CO_2 conversion processes **Long term:** scale-up and deployment of direct air capture	**£90bn**	**£0.2tr**	**15,000**

UKCS integrated energy system interdependencies

- (A) Green hydrogen
- (B) Platform electri cation
- (C) Blue hydrogen
- (D) Hydrogen value chain

*Based on Roadmap 2035 extrapolated to 2050

**Total capex required, i.e. includes UK content capex and capex spent internationally

Source: Wood Mackenzie, Lux Research

6.2: Technology Challenges

Short-term challenges

Offshore power grid management

Integrating offshore wind developments with existing and planned offshore oil and gas operational power demand via interconnected infrastructure could enable the critical electri cation of oil and gas installations, while at the same time facilitating stable low-carbon electricity supply to the National Grid. Power grid costs can be shared between oil and gas, wind farm, energy storage and transmission operators. However, to unlock this prize, technological innovation is required at both system and individual technology level.

CCUS

While coordinate nancial and policy support will be necessary to create favourable conditions to kick-start the CCUS industry, reducing the cost of carbon capture, transportation and storage technology will be essential to ensuring that the costs of implementing CCUS are minimised. Today's high capex costs associated with the development of CO_2 capture, transportation and storage infrastructure offer many opportunities for both evolutionary and disruptive innovation.

Hydrogen innovation

For hydrogen to play a key role in reaching net zero targets, a hydrogen supply chain needs to be in development before 2035. This requires a concerted and coordinated effort to develop economically viable solutions across the end-to-end hydrogen economy – from production, though transport and storage, to end use. The opportunity to develop blue and green hydrogen production technologies, alongside novel transportation and storage solutions, offers an unparalleled opportunity for the supply chain to seize a position at the vanguard of this nascent international market.

In order to stimulate demand, there is a need for clear incentives for low-carbon hydrogen in order to develop suf cient demand in onshore industries, including transportation, domestic or industrial heating, or even hydrogen or CO_2 derived materials, chemicals and fuels.

Long-term challenges

Digitalisation

A reliable and connected data infrastructure, combined with widespread use of data analytics and control, will be essential for the ef cient delivery of low carbon energy from the UKCS. Digital technologies will initially promote operational and energy ef ciency. As an integrated energy system develops, unmanned and autonomous digital facilities within each industry will need to be connected. This requires ensuring data interoperability across the different components in the energy system and strong communication infrastructure. Maintaining the highest possible level of cyber security between assets and operations centres onshore will remain critical tasks in any digital system.

Energy hubs

Energy hubs which combine operation, production, storage and transport of the four energy industries key to the UKCS' future will be the cornerstones of an integrated energy system. In order for these hubs to be deployed optimally, innovation is required across all four sectors, for example eliminating methane leaks, reducing the cost o oating wind foundations, optimising blue hydrogen production and better understanding CO_2 reservoir behaviour. All infrastructure developed for and around such energy hubs will also need to consider end-of-life, with designs that allow for easy decommissioning or repurposing.

Storage and transport

Energy storage and transport will be crucial to safeguarding the UK's energy supply. Developing the technology to reliably identify and deliver suitable geological options for long and medium term energy storage will be critical to ensuring that system costs are minimised. Repurposing the existing offshore infrastructure, and constructing new purpose-built infrastructure, will require innovation in materials, equipment, installation methods and renovation techniques.

7.1: Appendix

Wind costs and prices

Levelized cost of energy (LCOE)	The price per MWh a generator must earn to cover its full life capital and operating costs; the higher the capital and operating costs of a project, the higher the LCOE (£ or $ per MWh)
Strike price	An agreed price per MWh paid to a wind generator for delivery of electricity. Wind generators bid a strike price to win capacity contracts with the government; if the actual received for electricity is lower than the strike price the government will pay a 'top-up' to the generator: if the actual price is higher than the strike price, the generator pays the 'extra' to the government (£ or $ per MWh)
Capture price	Refers to the actual price (£ per MWh) a renewables project is likely to receive through the sale of electricity. It is determined by market factors, i.e. the amount of energy entering the system at the time of sale, and the profile of energy output, i.e. when the energy is produced and the electricity demand/price at that time.

Input-output methodology

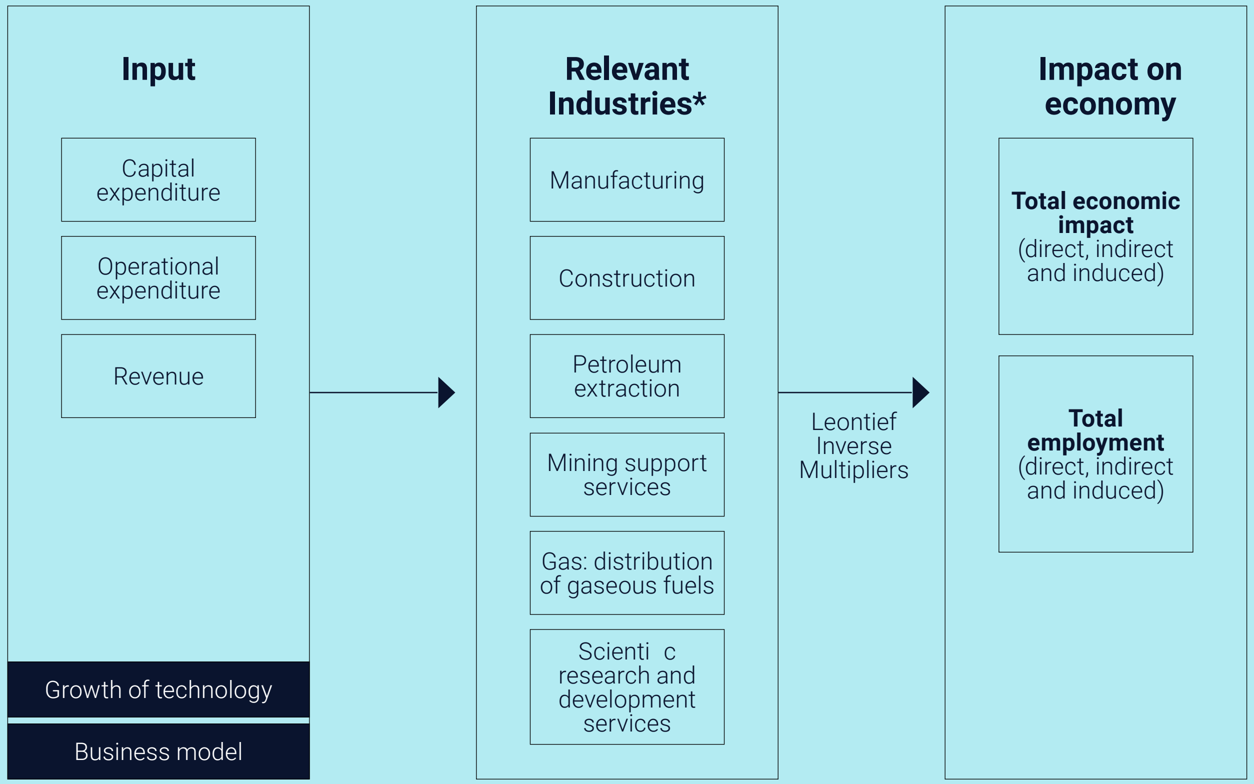
For each of the technology sectors, relevant inputs - in the form of expenditure and top line revenue - were defined and assigned to the related industries they impact. The overall impact on the UK economy was then calculated using a relevant economic impact multiplier (a Leontief Inverse Multiplier). The impact across the economy will vary for each industry due to the different interdependencies between sectors, i.e. for every £1 million inputted into the extraction of crude petroleum and natural gas industry, there is a total economic impact of £1.7 million through direct, indirect and induced impacts on the economy.

The input-output analysis was based on the 2015 detailed UK input-output analytical table,[393] which is consistent with the 2018 editions of the United Kingdom National Accounts Blue Book and United Kingdom Balance of Payments Pink Book. The multipliers from the 2015 input-output table have been modified to show potential change over time and to include type II impacts (induced effects). The compound annual growth rate from 1995-2015 was calculated from previous input-output tables and used to extrapolate future Leontief Inverse multipliers. The additional type II multipliers that measure the induced impact on the economy have been calculated using data released by the Scottish government[394] , as the Scottish economy was considered a good analogue for the UK as a whole.

Technology industry inputs are determined by how capital and operating expenditure (capex and opex) is spent, the revenue that is generated through sales of products and services (i.e. the business model), as well as the capacity and growth outlook from the integrated energy system roadmap (which combines the technology roadmap and a pathway to meeting the CCC Further Ambition targets). The impact on the economy is assessed as the direct, indirect and induced economic impact and employment created.

We note that there is much uncertainty in the scale and pace of our outlook, as well as the business model of choice for each technology family – as a result we have highlighted some of the risks and uncertainties.

Figure 7.1: Representation of input-output model



* Example of relevant industries

Input-output model: economic assumptions

Model input	Description	Reference
Oil and gas revenue	Assumes revenue from the sale of oil and gas. Production forecast is an extrapolation of the OGUK "Roadmap 2035" report extrapolated to 2050. The Wood Mackenzie Q2 2020 oil price assumption has been used which assumes a long-term Brent price of US$50/bbl in 2020 real terms.	Production forecast: OGUK[395] Oil/gas price: Wood Mackenzie
Oil and gas expenditure	Assumes spend from this industry in the form of capital and operating expenditure. Forecast is based on the OGA 2020-2024 spend extrapolated to 2050 based on production forecast.	Expenditure forecast: OGA[396]
Offshore wind revenue	Assumes revenue from the sale of electricity produced from offshore wind. Electricity (capture) price is based on Wood Mackenzie research.	Capture price forecast: Wood Mackenzie
Offshore wind expenditure	Assumes spend from this industry in form of capital and operating expenditure. This is speci c to turbine type (xed bottom v oating) and is based on Wood Mackenzie's forecast of offshore wind capacity growth and cost reductions.	Expenditure forecast: Wood Mackenzie
Hydrogen revenue	Assumes revenue from the sale of hydrogen. Price is modelled as £/kg and varies depending on production method. The price of blue hydrogen is assumed to fall from £1.93/kg in 2020 to £1.67/kg in 2050. The price of green hydrogen is assumed to fall from £4.78/kg in 2020 to £1.67/kg in 2050.	Hydrogen price forecast: Lux Research and Wood Mackenzie
Hydrogen expenditure	Assumes spend from this industry in the form of capital and operating expenditure. Blue and green hydrogen capital and operating costs were collated in the preparatory work to prepare the Closing the Gap to 2050 Technologies section of this report. We assume up to 7,660km of hydrogen pipelines could be developed, equivalent to the current length of the NTS[397].	Expenditure forecast: Lux Research and Wood Mackenzie
CCUS revenue	Assumes revenue from the use of transport and storage facilities as a £/per tonne CO_2 stored cost. Assumes drop in storage and transport fee from £150/tCO_2 in 2020 to £20/tCO_2 in 2030.	Transport and storage fee forecast: Lux Research and Wood Mackenzie
CCUS expenditure	Assumes spend from this industry in form of capital and operating expenditure. CCUS costs were collated during the Closing the Gap to 2050 Technologies section of this report.	Expenditure forecast: Lux Research and wood Mackenzie

Input-output model: employment assumptions

Model input	Description	Reference
Oil and gas labour intensity, indirect and induced employment multipliers	Employment/production used to calculate direct, indirect and induced employment forecasts. Based on 2018 data.	Employment and production data: OGUK[398]
Offshore wind labour intensity	Employment/capacity used to calculate direct employment forecast. Based on 2018 data.	Direct employment data: Of ce for National Statistics (ONS)[399] Capacity data: Wood Mackenzie
Offshore wind indirect employment multiplier	Multiplier applied to direct employment to calculate indirect (type I) employment.	Indirect employment data: ORE catapult and Crown Estate Scotland study[400]
Offshore wind induced employment multiplier	Multiplier applied to direct employment to calculate induced (type II) employment.	Multiplier: Scottish government[394]
Hydrogen labour intensity	Employment/revenue used to calculate direct employment forecast.	Labour intensity estimate: UK HFCA[369] Production forecast: Integrated Energy System Roadmap - Meeting the CCC Targets section
CCUS labour intensity	Employment/storage capacity used to calculate direct employment forecast.	Direct job estimate: Teesside Net Zero[401] Capture and storage capacity forecast: Integrated Energy System Roadmap - Meeting the CCC Targets section
Hydrogen/CCUS indirect employment multiplier	Multiplier applied to direct employment to calculate indirect (type I) employment. Gas industry used as an analogue for hydrogen. Mining support services industry used as an analogue for CCUS industry.	Indirect employment multipliers: Of ce for National Statistics (ONS)[402]
Hydrogen/CCUS induced employment multiplier	Multiplier applied to direct employment to calculate induced (type II) employment. Gas industry used as an analogue for hydrogen. Mining support services industry used as an analogue for CCUS industry.	Induced employment multipliers: Scottish government[394]

References

1 Wood Mackenzie. (2019). United Kingdom upstream summary

2 Oil & Gas UK. (2019). Economic Outlook 2019. [online] Available at: <https://oilandgasuk.cld.bz/Economic-Report-2019> [Accessed 10 February 2020]

3 Hough, D., (2017). UK offshore oil and gas industry. [online] Available at: <https://www.parliament.uk/commons-library> [Accessed 10 February 2020]

4 Hinson, S., Rhodes, C., Dempsey, N., Sutherland, N., Pratt, A., (2018). Uk oil and gas industry. [Online]. Available at: <https://researchbrie ngs.parliament.uk/ResearchBrie ng/Summary/CDP-2018-0088#fullreport> [Accessed 13 February 2020]

5 Statista.com. (2019). United Kingdom (UK) total HMRC tax receipts fro scal year 2000/01 t scal year 2018/19 [Online]. Statista. Available at: <https://www.statista.com/statistics/284298/total-united-kingdom-hmrc-tax-receipts/> [Accessed 17 February 2020]

6 Oil & Gas UK. (2019). Business Outlook 2019. [online] Available at: <https://oilandgasuk.cld.bz/Business-Outlook-2019> [Accessed 10 February 2020]

7 UK Government. (2019). [Online]. Available at: <https://www.gov.uk/government/statistics/government-revenues-from-uk-oil-and-gas-production--2> [Accessed 17 February 2020]

8 Wood Mackenzie. (2019). UK CfD allocation round 3 awards 5.5GW of offshore wind – UK government could receive £2.4 billion from these projects

9 Of ce for National Statistics. (2018). Low carbon and renewable energy economy, UK:2018. [online] Available at: <https://www.ons.gov.uk/economy/environmentalaccounts/bulletins/ nalestimates/2018#turnover-and-employment> [Accessed 17 February 2020]

10 Oil & Gas UK. (2019). Workforce Outlook 2019. [online] Available at: <https://oilandgasuk.cld.bz/Workforce-Report-2019> [Accessed 10 February 2020]

11 Ons.gov.uk. (2019). UK employment data [Online]. Of ce for National Statistics. Available at: <https://www.ons.gov.uk/employmentandlabourmarket/peopleinwork/employmentandemployeetypes/bulletins/employmentintheuk/september2019> [Accessed 13 February 2020]

12 UK Government. (2020). Offshore wind Sector Deal. [online]. Available at: <https://www.gov.uk/government/publications/offshore-wind-sector-deal/offshore-wind-sector-deal> [Accessed 13 February 2020]

13 Offshore Renewable Energy Catapult. (2019). UK Offshore Wind: Realising the Sector Deal Opportunity. [Online]. Available at: <https://ore.catapult.org.uk/analysisinsight/realising-the-sector-deal-opportunity/> [Accessed 10 February 2020]

14 Whitmarch, M., Canning, C., Ellson, T., Sinclair, V., Thorogood, M., (2019). The UK Offshore Wind Industry: Supply Chain Review [Online]. Available at: <https://www.renewableuk.com/news/436350/The-UK-Offshore-Wind-Industry-Supply-Chain-Review.htm> [Accessed 12 February 2020].

15 Energy & Utility Skills. (2018). Skills and Labour Requirements of the UK Offshore Wind Industry [Online]. Available at: <https://aurawindenergy.com/uploads/publications/Aura-EU-Skills-UK-Offshore-Wind-Skills-Study-Full-Report-October-2018.pdf> [Accessed 13 February 2020]

16 Statista.com. (2019). Employment in the renewable energy sector in the United Kingdom (UK) 2018, by technology [Online]. Statista. Available at: <https://www.statista.com/statistics/690043/renewable-energy-employment-uk/> [Accessed 13 February 2020].

17 Wood Mackenzie. (2020). Energy Market Service: UK data

18 Wood Mackenzie. (2020). Power & Renewables: UK offshore wind data

19 Department for Business, Energy and Industrial Strategy. (2020). Final UK greenhouse gas emissions national statistics [Online]. Available at: <https://data.gov.uk/dataset/9568363e-57e5-4c33-9e00-31dc528fcc5a/ nal-uk-greenhouse-gas-emissions-national-statistics> [Accessed 13 February 2020]

20 International Energy Agency. (2020). Data and Statistics: data tables [Online]. Available at: <https://www.iea.org/data-and-statistics/data-tables?country=UK&energy=Balances&year=2018> [Accessed 13 February 2020].

21 Maritimefoundation.uk (2018) Editorial: How do we value the oceans? [Online]. Maritime Foundation. Available at:<https://www.maritimefoundation.uk/publications/maritime-2018/ocean-values/> [Accessed 18 February 2020].

22 Oil & Gas UK. (2020). Fisheries [Online]. Available at: <https://oilandgasuk.co.uk/ sheries/> [Accessed 18 February 2020].

23 Oil and Gas Climate Initiative. (2020). [Online]. Available at: <https://oilandgasclimateinitiative.com/climate-investments/> [Accessed 03 March 2020].

24 Renews.biz (2020) Taskforce targets hydrogen growth in the UK homes [Online]. ReNews. Available at: <https://renews.biz/58903/taskforce-targets-hydrogen-growth-in-the-uk/> [Accessed 03 March 2020].

25 Wood Mackenzie. (2020). Upstream Supply Chain – Platform database

26 Wood Mackenzie. (2020). Upstream Supply Chain – Pipeline database

27 Energy technologies institute. (2016). Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource [Online]. Available at: <https://s3-eu-west-1.amazonaws.com/assets.eti.co.uk/legacyUploads/2016/04/D16-10113ETIS-WP6-Report-Publishable-Summary.pdf> [Accessed 18 February 2020].

28 Renewable UK. (2020). Wind Energy [Online]. Available at: <https://www.renewableuk.com/page/WindEnergy> [Accessed 10 February 2020].

29 Equinor.com. (2020). The market outlook fo oating offshore wind [Online]. Equinor. Available at: <https://www.equinor.com/en/what-we-do/ oating-wind/the-market-outlook.html> [Accessed 10 February 2020].

30 Wood Mackenzie. (2019). Europe offshore wind power outlook 2019

31 Wood Mackenzie. (2019). Potential impact of hard Brexit on the UK offshore wind industry

32 Committee on Climate Change. (2019). Net Zero – The UK's contribution to stopping global warming [Online]. Available at: <https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/> [Accessed 10 February 2020].

33 The Crown Estate. (2020). On the seabed and coast [Online]. Available at: <https://www.thecrownestate.co.uk/en-gb/what-we-do/on-the-seabed/> [Accessed 13 February 2020].

34 The Crown Estate. (2020). Offshore wind [Online]. Available at: <https://www.crownestatescotland.com/what-we-do/marine/asset/offshore-wind> [Accessed 13 February 2020].

35 Oil & Gas Authority. (2018). Carbon Capture Storage Licence Awarded [Online]. Available at: <https://www.ogauthority.co.uk/news-publications/news/2018/carbon-capture-storage-licence-awarded/> [Accessed 18 February 2020].

36 Crown Estate Scotland. (2019). ScotWind Leasing, Seabed leasing for new offshore wind farms zero [Online]. Available at: <https://www.crownestatescotland.com/maps-and-publications/download/346> [Accessed 26 March 2020].

37 Wood Mackenzie. (2019). Potential impact of hard Brexit on the UK's offshore wind industry

38 The Crown Estate. (2018). Offshore wind operational report. [Online]. Available at: <https://www.thecrownestate.co.uk/media/2950/offshore-wind-operational-report-2018.pdf> [Accessed 12 February 2020].

39 Wood Mackenzie. (2019). Globa xed-bottom offshore wind LCOE

40 The Crown Estate. (2019). The Crown Estate showcases another record-breaking year for UK offshore wind, with the launch of its 2018 Offshore Wind Operational Report [Online]. Available at: <https://www.thecrownestate.co.uk/en-gb/media-and-insights/news/2019-the-crown-estate-showcases-another-record-breaking-year-for-uk-offshore-wind-with-the-launch-of-its-2018-offshore-wind-operational-report/> [Accessed 12 February 2020].

41 Wood Mackenzie. (2019). The Momentum of Floating Wind and its Outlook Implications

42 Wood Mackenzie. (2020). Power & Renewables - Global Utility-Scale Solar PV Project Database

43 Wood Mackenzie. (2019). Floating solar landscape 2019

44 Wood Mackenzie solar expert

45 Oceansofenergy.blue. (2019). A world' rst: offshor oating solar farm installed at the Dutch North Sea [Online]. Oceans of Energy. Available at: <https://oceansofenergy.blue/2019/12/11/a-worlds- rst-offshore- oating-solar-farm-installed-at-the-dutch-north-sea/> [Accessed 12 February 2020].

46 Rechargenews.com. (2019). World' rst 'high-wave oating PV array to be built off Belgium [Online]. Recharge. Available at: <https://www.rechargenews.com/transition/world-s- rst-high-wave- oating-pv-array-to-be-built-off-belgium/2-1-641095> [Accessed 12 February 2020].

47 International Energy Agency. (2020). Data and Statistics [Online]. Available at: <https://www.iea.org/data-and-statistics?country=UK&fuel=Renewables%20and%20waste&indicator=%20Renewable%20share%20(modern%20renewables)%20in%20 nal%20energy%20consumption%20(SDG%207.2)%20> [Accessed 10 February 2020].

48 UK Government. (2013). Wave and tidal energy: part of the UK's energy mix [Online]. Available at: <https://www.gov.uk/guidance/wave-and-tidal-energy-part-of-the-uks-energy-mix> [Accessed 18 February 2020].

49 Offshore Renewable Energy Catapult. (2018). Tidal stream and wave energy cost reduction and industrial bene t [Online]. Available at: <https://www.marineenergywales.co.uk/wp-content/uploads/2018/05/ORE-Catapult-Tidal-Stream-and-Wave-Energy-Cost-Reduction-and-Ind-Ben t-FINAL-v03.02.pdf> [Accessed 10 February 2020].

50 Offshore Renewable Energy Catapult. (2019). Annual Report 18/19 [Online]. Available at: <https://ore.catapult.org.uk/reports-and-resources/reports-publications/ore-catapult-reports/> [Accessed 10 February 2020].

51 Energy Research Partnership. (2016). Potential Role of Hydrogen in the UK Energy System [Online]. Available at: <http://erpuk.org/wp-content/uploads/2017/01/ERP-hydrogen-report-oct-2016.pdf> [Accessed 20 February 2020].

52 Committee on Climate Change. (2019). Net Zero – Technical Report [Online]. Available at: <https://www.theccc.org.uk/publication/net-zero-technical-report/> [Accessed 10 February 2020].

53 IRENA. (2019). Hydrogen: A renewable energy perspective [Online]. Available at: <https://www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective> [Accessed 1 April 2020].

54 Wood Mackenzie. (2019). Green hydrogen production: Landscape, projects and costs

55 IRENA. (2018). Hydrogen from Renewable Power, technology outlook for the energy transition [Online]. Available at: <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf> [Accessed 1 April 2020].

56 UK Hydrogen and Fuel Cell Association. (2020). Hydrogen [Online]. Available at: <http://www.ukhfca.co.uk/the-industry/hydrogen/> [Accessed 10 February 2020].

57 Newscientist.com. (2020). UK could use hydrogen instead of natural gas – if it can make enough [Online]. New Scientist. Available at: <https://www.newscientist.com/article/2206546-uk-could-use-hydrogen-instead-of-natural-gas-if-it-can-make-enough/> [Accessed 10 February 2020].

58 Department for Business, Energy & Industrial Strategy. (2019). Business Models for Carbon Capture, Usage and Storage; A consultation seeking views on potential business models for carbon capture, usage and storage Zero [Online]. Available at: <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/ le/819648/ccus-business-models-consultation.pdf> [Accessed 17 March 2020].

59 Rechargenews.com. (2019). Floating wind-to-hydrogen plan to heat millions of UK homes [Online]. Recharge. Available at: <https://www.rechargenews.com/wind/ oating-wind-to-hydrogen-plan-to-heat-millions-of-uk-homes/2-1-670960> [Accessed 03 March 2020].

60 Itm-power.com. (2019). Gigastack Feasibility Study with Ørsted [Online]. ITM Power. Available at: <https://www.itm-power.com/item/58-project-to-demonstrate-delivery-of-bulk-low-cost-and-zero-carbon-hydrogen-through-gigawatt-scale-pem-electrolysis-manufactured-in-the-uk> [Accessed 18 February 2020].

61 Drax.com. (2019). Leading energy companies announce new zero-carbon UK partnership [Online]. Drax. Available from <https://www.drax.com/press_release/energy-companies-announce-new-zero-carbon-uk-partnership-ccus-hydrogen-beccs-humber-equinor-national-grid/> [Accessed 10 February 2020].

62 Wood Mackenzie. (2020). Carbon capture and storage

63 Edie.net. (2020). Clean transport, CCS and biodiversity championed in Budget 2020 homes [Online]. Edie. Available at: <https://www.edie.net/news/11/Clean-transport--CCS-and-biodiversity-championed-in-Budget-2020/> [Accessed 12 March 2020].

64 CCUS Cost Challenge Taskforce. (2018). Delivering clean growth: CCUS Cost Challenge Taskforce report System [Online]. Available at: <https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report> [Accessed 20 February 2020].

65 Wood Mackenzie. (2020). Future energy – carbon capture and storage

66 Carbon Capture & Storage Association. (2020). CCS projects and proposals [Online]. CCSa Available at: <http://www.ccsassociation.org/why-ccs/ccs-projects/current-projects/> [Accessed 10 February 2020].

67 Department for Business, Energy & Industrial Strategy. (2019) Digest of UK Energy Statistics 2019 [Online]. Available at: <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/ le/820277/DUKES_2019_Press_Notice_GOV.UK.pdf> [Accessed 10 February 2020].

68 Department for Business, Energy & Industrial Strategy. (2019). Natural gas imports and exports [Online]. Available at: <https://www.gov.uk/government/statistics/natural-gas-chapter-4-digest-of-united-kingdom-energy-statistics-dukes> [Accessed 18 February 2020].

69 European Commission. (2019) A European strategic long term vision for a prosperous, modern, competitive and climate neutral economy. [online] Available at: <https://ec.europa.eu/energy/sites/ener/ les/documents/2_dgclima_rungemetzger.pdf> [Accessed 18 February 2020]

70 European Commission. (2019). What is the European Green Deal [Online]. Available at: <https://ec.europa.eu/commission/presscorner/detail/en/fs_19_6714> [Accessed 18 February 2020].

71 Oil & Gas UK. (2019). Roadmap 2035: A blueprint for net-zero [Online]. Available at: <https://www.energyvision2035.com/roadmap-2035/helping-meet-uk-energy-needs> [Accessed 26 March 2020].

72 Oil & Gas UK. (2019). Energy Transition Outlook 2019. [online]. Available at: <https://oilandgasuk.co.uk/wp-content/uploads/2019/12/OGUK-Energy-Transition-Outlook-2019.pdf> [Accessed 10 February 2020]

73 IEA.org. (2020). Fuels and technologies: gas. [online] IEA. Available at: <https://www.iea.org/fuels-and-technologies/gas> [Accessed 4 May 2020].

74 netzerotc.com. (2018). Application of data analytics technologies to improve asset operations and maintenance. [online] Net Zero Technology Centre. Available at: <https://www.netzerotc.com/media/2380/digital-landscaping-study-of-the-oil-and-gas-sector-application-of-data-analytics-technologies-to-improve-asset-operations-and-maintenance.pdf> [Accessed 4 May 2020].

75 Oilandgasuk.co.uk. (2019). Environment report 2019. [online] OGUK. Available at: <https://oilandgasuk.cld.bz/Environment-Report-2019> [Accessed 4 May 2020].

76 Ogauthority.co.uk. (2019). UKSC energy integration interim ndings. [online] O&G Authority. Available at: <https://www.ogauthority.co.uk/media/6257/ukcs-energy-integration-interim- ndings.pdf> [Accessed 4 May 2020].

77 Sintef.no. (2013). Offshore energy ef ciency technologies. [online] Sintef. Available at: <https://www.sintef.no/globalassets/project/effort/effort-presentation-at-the-otc-conference-houston-may-6-2013.pdf> [Accessed 4 May 2020].

78 Equinor (2020). A breakthrough in emissions reductions. [online] Equinor. Available at <https://www.equinor.com/en/what-we-do/johan-sverdrup/climate.html> [Accessed 29 June 2020].

79 Rystadenergy.com. (2017). Electrifying the Barents Sea. [online] Rystad Energy. Available at: <https://www.rystadenergy.com/newsevents/news/press-releases/electrifying-the-barents-sea/> [Accessed 4 May 2020].

80 Riboldi, L., Voller, S., Korpas, M.and Nord, L. O. (2019). An Integrated Assessment of the Environmental and Economic Impact of Offshore Oil Platform Electri cation. Energies, 12(11), p. 2114.

81 Nieradzinska, K., MacIver, C., Gill, S., Agnew, G. A., Anaya-Lara, O.and Bell, K. R. W. (2016). Optioneering analysis for connecting Dogger Bank offshore wind farms to the GB electricity network. Renewable Energy, 91, p. 120-129.

82 Windpowermonthly.com. (2019). How can innovation in submarine cabling reduce costs for offshore wind?. [online] Wind Power Monthly. Available at: <https://www.windpowermonthly.com/article/1664467/innovation-submarine-cabling-reduce-costs-offshore-wind> [Accessed 28 April 2020].

83 Oedigital.com (2020). Tapping Shore Power for Offshore Oil and Gas Facilities. [online] Offshore Engineer. Available at: <https://www.oedigital.com/news/475350-tapping-shore-power-for-offshore-oil-and-gas-facilities> [Accessed 27 April 2020].

84 Xiang, X., Merlin, M. M. C., and Green, T. C. (2016). Cost analysis and comparison of HVAC, LFAC and HVDC for offshore wind power connection. IET International Conference on AC and DC Power Transmission 2016, Beijing, p. 1-6.

85 Abb.com. (2020). HVDC: economic and environmental advantages. [online] ABB. Available at: <https://new.abb.com/systems/hvdc/why-hvdc/economic-and-environmental-advantages> [Accessed 28 April 2020].

86 Abb.com. (2019). Johan Sverdrup. [online] ABB. Available at: <https://new.abb.com/oil-and-gas/case-studies/offshore/johan-sverdrup> [Accessed 28 April 2020].

87 Hartel, P., Vrana, T. K., Hennig, T., von Bonin, M., Wiggelinkhuizen, E., and Nieuwenhout, F. (2017). Review of investment model cost parameters for VSC HVDC transmission infrastructure. Electric Power Systems Research, 151, p. 419-431.

88 Northseaenergy.eu. (2019). Synthesis paper. [online] North Sea Energy. Available at: <https://www.north-sea-energy.eu/documents/NSE2%20%20Deliverable%20Synthesis%20paper.pdf> [Accessed 4 May 2020].

89 Kivi.nl. (2019). An outlook on the integration of North Sea energy systems. [online] KIVI. Available at: <https://www.kivi.nl/uploads/media/5d00e297ec523/20190605%20KIVI-O&G%20-%20An%20outlook%20on%20the%20integration%20of%20North%20Sea%20energy%20systems%2005.06.209.pdf> [Accessed 28 April 2020].

90 Oilandgasuk.co.uk. (2015). Offshore Gas Turbines and Dry Low NOx Burners - An analysis of the Performance Improvements (PI) Limited Database. [online] Oil & Gas UK. Available at: <https://oilandgasuk.co.uk/wp-content/uploads/2015/05/producys-cayrgory.pdf> [Accessed 28 April 2020].

91 Epa.gov. (2011). Electric compressors PRO Fact Sheet. [online] EPA. Available at: <https://www.epa.gov/sites/production/ les/2016-06/documents/installelectriccompressors.pdf> [Accessed 28 April 2020].

92 Chrysaor, (2020). 'Primary Research'.

93 Windpowermonthly.com (2017). Boundary Pushers: The offshore meshed grid challenge. [online] Wind Power Monthly. Available at: <https://www.windpowermonthly.com/article/1446911/boundary-pushers-offshore-meshed-grid-challenge> [Accessed 28 April 2020].

94 TNO.nl. (2011). WP 3: technologies state of the art, Task 3: grid integration aspects. [online] ORECCA. Available at: <https://publications.tno.nl/publication/34629094/b7N68c/e11014.pdf> [Accessed 28 April 2020].

95 Offshoreenergy.biz. (2019). Golia eld support vessel completes rst stage of hybrid power conversion. [online] Offshore Energy. Available at: <https://www.offshore-energy.biz/goliat- eld-support-vessel-completes- rst-stage-of-hybrid-power-conversion/> [Accessed 28 April 2020].

96 Abb.com. (2017). Valhalla power from shore afte ve years of operation. [online] ABB. Available at: <https://library.e.abb.com/public/b1dfd6e22ebc402fb11e86726619aece/VALHALL%20HVDC%20Power%20From%20Shore%205%20years%20experience%20,%20EUR17_35.pdf> [Accessed 28 April 2020].

97 Offshoremag.com. (2020). Equinor launches emissions offensive. [online] Offshore Magazine. Available at: <https://www.offshore-mag.com/regional-reports/article/14168426/equinor-launches-emissions-offensive> [Accessed 28 April 2020].

98 Energyvoice.com. (2019). BP boss con rms green power plans for North Sea platforms. [online] Energy Voice. Available at: <https://www.energyvoice.com/oilandgas/north-sea/213349/bp-boss-con rms-green-power-plans-for-north-sea-platforms/> [Accessed 28 April 2020].

99 Upstreamonline.com. (2019). BP eyeing low carbon power for Clair South. [online] Upstream Online. Available at: <https://www.upstreamonline.com/low-carbon/bp-eyeing-low-carbon-power-for-clair-south/2-1-718140> [Accessed 28 April 2020].

100 IEA.org. (2019). Tracking fuel supply. [online] IEA. Available at: <https://www.iea.org/reports/tracking-fuel-supply-2019/ aring-emissions> [Accessed 2 May 2020].

101 Oilandgasuk.co.uk. (2019). Economic report 2019. [online] OGUK. Available at: <https://oilandgasuk.co.uk/wp-content/uploads/2019/09/Economic-Report-2019-OGUK.pdf> [Accessed 4 May 2020].

102 Egyptoil-gas.com. (2016). Norwegion Lesson in Gas Flare Elimination. [online] Egypt Oil and Gas. Available at: <https://egyptoil-gas.com/features/norwegian-lesson-in-gas- are-elimination/> [Accessed 2 May 2020].

103 Draugen.industriminne.no. (2018). Draugen ga aring or reinjection. [online] Draugen Field. Available at: <https://draugen.industriminne.no/en/2018/04/27/draugen-gas- aring-or-reinjection/> [Accessed 3 May 2020].

104 Gbadamosi, A. O., Kiwalabye, J., Junin, R., and Augustine, A. (2018). A review of gas enhanced oil recovery schemes used in the North Sea. Journal of Petroleum Exploration and Production Technology, 8, p. 1373–1387.

105 Sccs.org.uk. (2014). A Review of Flaring and Venting at UK Offshore Oil elds. [online] SCCS. Available at: <http://www.sccs.org.uk/images/expertise/reports/co2-eor-jip/SCCS-CO2-EOR-JIP-WP11-Flaring-Venting.pdf> [Accessed 2 May 2020].

106 Bsee.gov. (2017). Venting and Flaring Research Study Report. [online] BSEE. Available at: <https://www.bsee.gov/sites/bsee.gov/ les/5007aa.pdf#page=176&zoom=100,45,104> [Accessed 1 May 2020].

107 Schmidt, D., and Oster, B. (2007). Low-BTU Field Gas Application to Microturbines. [online] University of North Dakota. doi: 10.2172/986862.

108 ogauthority.co.uk (2016). Flaring and Venting During the Production Phase. Available at: <https://www.ogauthority.co.uk/media/2467/ aring-and-venting-during-the-production-phase-1016.pdf> [Accessed 29 June 2020]

109 SCCS.org.uk (2014) A Review of Flaring and Venting at UK Offshore Oil elds. Available at: <http://www.sccs.org.uk/images/expertise/reports/co2-eor-jip/SCCS-CO2-EOR-JIP-WP11-Flaring-Venting.pdf> [Accessed 29 June 2020]

110 Worldbank.org. (2020). Zero Routine Flaring by 2030. [online] World Bank. Available at: <https://www.worldbank.org/en/programs/zero-routine- aring-by-2030> [Accessed 2 May 2020].

111 Offshore-Technology.com. (2020). OGUK sets out plans to decarbonise the UK oil and gas industry. [online] OT. Available at: < https://www.offshore-technology.com/news/oguk-sets-out-plans-to-decarbonise-the-uk-oil-and-gas-industry/> [Accessed 8 May 2020]

112 IEA.org. (2020). Methane tracker. [online] IEA. Available at: <https://www.iea.org/reports/methane-tracker-2020/methane-from-oil-gas> [Accessed 2 May 2020].

113 Princeton.edu. (2019). Offshore oil and gas rigs leak more greenhouse gas than expected. [online] Princeton University. Available at: <https://www.princeton.edu/news/2019/08/15/offshore-oil-and-gas-rigs-leak-more-greenhouse-gas-expected> [Accessed May 1 2020].

114 IEA.org (2020). Methane Tracker 2020: Interactive Country and Regional Estimates. IEA. Available at: <https://www.iea.org/reports/methane-tracker/country-and-regional-estimates> [Accessed 29 May 2020].

115 Oil & Gas UK. (2020). Pathway to a Net-Zero Basin: Production Emissions Targets. [online]. Available athttps://oilandgasuk.co.uk/wp-content/uploads/2020/06/OGUK-Production-Emissions-Targets-Report-2020.pdf [Accessed 22 June 2020].

116 Offshore Engineer. (2013). Offshore pipeline leak detection for Arctic application. [online] OE. Available at: <http://9f50f0311489b2d45830-9c9791daf6b214d0c0094462a66ea80c.r0.cf3.rackcdn.com/offshore-pipeline-detection.pdf> [Accessed 1 May 2020].

117 Eagle.org. (2019). Subsea inspection, maintenance and repair advisory. [online] ABS. Available at: <https://ww2.eagle.org/content/dam/eagle/advisories-and-debriefs/ssimr-advisory-19016.pdf> [Accessed 2 May 2020].

118 Adegboye, M. A., Fung, W., and Karnik, A. (2019). Recent Advances in Pipeline Monitoring and Oil Leakage Detection Technologies: Principles and Approaches. Sensors, 19, p. 2548.

119 Shama, A., Bady, A., El-Shaib, M. N., and Kotb, M. A. (2017). Review of leakage detection methods for subsea pipeline. 17th International Congress of the International Maritime Association of the Mediterranean (IMAM 2017), Lisbon.

120 Aogexpo.com.au. (2015). Real-time Subsea Pipeline Leak Monitoring using Fiber Optic Sensing Technology. [online] INTECSEA. Available at: <https://aogexpo.com.au/wp-content/uploads/2015/03/Real-time-Subsea-Pipeline-Leak-Monitoring-using-Fiber-Optic-Sensing-Technology.pdf> [Accessed 1 May 2020].

121 Ogauthority.co.uk. (2016). UKCS Exploration & Appraisal Status. [online] O&G Authority. Available at: <https://www.ogauthority.co.uk/media/3163/oga-gunther-newcombe-keynote-presentation-prospex-december-2016-public.pdf> [Accessed 4 May 2020].

122 Ramberg, R. M., Davies, S. R., Rognoe, H., and Oekland, O. (2013). Steps to the Subsea Factory. Offshore Technology Conference 2013, Rio de Janeiro.

123 Lux Research, (2017). Advancements at the Seabed – The Future of Subsea Production in the Low Oil Price Era.

124 Lux Research, (2018). Net Zero Technology Centre and Total partner with Crondall Energy for reusable production buoys for the North Sea.

125 Atkinsglobal.com. (2020). DDPSO - expanding th exibility of FPSOs. [online] Atkins Global. Available at: <https://www.atkinsglobal.com/en-gb/projects/ddpso> [Accessed 1 May 2020].

126 Akersolutions.com. (2020). Floater Designs. [online] Aker Solutions. Available at: <https://www.akersolutions.com/what-we-do/products-and-services/ oater-designs/> [Accessed 28 April 2020].

127 Chrysaor, (2020). 'Primary Research.

128 Offshore-technology.com. (2008). Decommissioning the North Sea. [online] Offshore Technology. Available at: <https://www.offshore-technology.com/features/feature2069/> [Accessed 3 May 2020].

129 Akersolutions.com. (2019). Subsea Compression & Processing: Reducing the Industry's Carbon Footprint. [online] Aker Solutions. Available at: <https://www.norwep.com/content/download/40666/297970/version/1/ le/Drew+Sage%2C+Technical+Director+Front+End+%E2%80%93+Australia%2C+Aker+Solutions.pdf> [Accessed 28 April 2020].

130 Marinetechnologynews.com. (2018). Powering the Sea oor: Put a Plug in It. [online] Marine Technology News. Available at: <https://www.marinetechnologynews.com/news/powering-sea oor-socket-561313> [Accessed 1 May 2020].

131 Marinetechnologynews.com. (2019). Chevron to Use Subsea Compression at Jansz-Io. [online] Marine Technology News. Available at: <https://www.marinetechnologynews.com/news/chevron-subsea-compression-jansz-586913> [Accessed 1 May 2020].

132 Turbomachinerymag.com. (2011). The hermetically sealed compressor for offshore and subsea. [online] Turbo Machinery Mag. Available at: <https://www.turbomachinerymag.com/the-hermetically-sealed-compressor-for-offshore-and-subsea/> [Accessed 28 April 2020].

133 Oedigital.com (2020). Aker, MAN shrink subsea compression size, costs. [online] Offshore Engineer. Available at: <https://www.oedigital.com/news/448183-aker-man-shrink-subsea-compression-size-costs> [Accessed 4 May 2020].

134 ABB.com. (2017). Subsea variable speed drive successfully tested under water. [online] ABB. Available at: <https://new.abb.com/news/detail/2811/subsea-variable-speed-drive-successfully-tested-under-water> [Accessed 4 May 2020].

135 Dredgingandports.com. (2019). Subsea power grids underg nal testing. [online] Dredging and Port Construction. Available at: <https://dredgingandports.com/news/2019/subsea-power-grids-undergo- nal-testing/> [Accessed 5 May 2020].

136 Forbes.com. (2019). . [online] ABB Strikes 'Holy Grail' Of Subsea Power Systems For Offshore Energy Rigs. Available at: <https://www.forbes.com/sites/gauravsharma/2019/11/20/abb-strikes-holy-grail-of-subsea-power-systems-for-offshore-energy-rigs/#7c385a487a82> [Accessed 27 April 2020].

137 Gep.com. (2019). The Circular Economy: An Innovative Path to Sustainability in Oil and Gas. [online] GEP. Available at: <https://www.gep.com/mind/blog/the-circular-economy-an-innovative-path-to-sustainability-in-oil-and-gas> [Accessed 5 May 2020].

138 Offshore-mag.com. (2020). Subsea standardization initiatives aim to remove uncertainty, improve quality. [online] publisher. Available at: <https://www.offshore-mag.com/subsea/article/14172696/subsea-standardization-initiatives-aim-to-remove-uncertainty-improve-quality> [Accessed 3 May 2020].

139 Proton.energy. (2019). Protein Technologies. [online]. Available at: < http://proton.energy/> [Accessed May 8 2020}

140 Wood Mackenzie, (2020). Gauging the unsubsidized offshore wind potential in the UK, April 2020.

141 Wood Mackenzie, (2020). Global offshore wind power project database, Q1 2020.

142 Lux Research, (2019). General Electric and Vattenfall join forces on 12 MW Haliade-X offshore turbine.

143 Cleantechnica.com. (2019). GE Renewable Energy Unveils 12 Megawatt Haliade-X Offshore Wind Nacelle. [online] Clean Technica. Available at: <https://cleantechnica.com/2019/07/23/ge-renewable-energy-unveils-12-megawatt-haliade-x-offshore-wind-nacelle/> [Accessed 1 May 2020].

144 Genewsroom.com. (2019). World's biggest offshore wind turbine heading to the UK for testing. [online] GE. Available at: <https://www.genewsroom.com/press-releases/worlds-biggest-offshore-wind-turbine-heading-uk-testing> [Accessed 29 April 2020].

145 Windeurope.org. (2018). Floating offshore wind energy: a policy blueprint for Europe. [online] Wind Europe. Available at: <https://windeurope.org/wp-content/uploads/ les/policy/position-papers/Floating-offshore-wind-energy-a-policy-blueprint-for-Europe.pdf> [Accessed 30 April 2020].

146 Konstantinidis, E. I., and Botsaris, P. (2016). Wind turbines: current status, obstacles, trends and technologies. IOP Conference Series Materials Science and Engineering, 161.

147 Greentechmedia.com. (2020). UK Considers Support Measures to Fire Up Floating Offshore Wind Market. [online] GTM. Available at: <https://www.greentechmedia.com/articles/read/more-momentum-for- oating-wind> [Accessed 1 May 2020].

148 Cleantechnica.com. (2018). UK Floating Wind Could Support 17,000 Jobs & Generate £33.6 Billion In Value By 2050. [online] Clean Technica. Available at: <https://cleantechnica.com/2018/10/30/uk- oating-wind-could-support-17000-jobs-generate-33-6-billion-in-value-by-2050/> [Accessed 1 May 2020].

149 Techcrunch.com. (2020). Alphabet takes the wind out of its Makani energy kites. [online] Tech Crunch. Available at: <https://techcrunch.com/2020/02/18/alphabet-takes-the-wind-out-of-its-makani-energy-kites/> [Accessed 29 April 2020].

150 Compositesworld.com. (2019). SAERTEX provides material for 87.5-meter carbo ber spar cap. [online] Composites World. Available at: <https://www.compositesworld.com/news/saertex-provides-material-for-875-meter-carbon- ber-spar-cap> [Accessed 30 April 2020].

151 Compositesworld.com. (2019). Wind blade spar caps: Pultruded to perfection? [online] Composites World. Available at: <https://www.compositesworld.com/articles/wind-blade-spar-caps-pultruded-to-perfection> [Accessed 30 April 2020].

152 Lux Research, (2019). Saertex demonstrates record-length carbon ber composite spar cap for wind turbine blades at 87.5 meters.

153 Salic, T., Charpentier, J. F., Benbouzid, M., and Boulluec M. L. (2019). Control Strategies for Floating Offshore Wind Turbine: Challenges and Trends. Electronics, [online]. Available at: <https://www.mdpi.com/2079-9292/8/10/1185/pdf> [Accessed 30 April 2020].

154 Zxlidars.com. (2020). The home of remote sensor performance veri cations. [online]. ZX Lidars. Available at: <https://www.zxlidars.com/wind-measurement-services-lidar/remote-sensing-device-lidar-test-site/> [Accessed 3 May 2020].

155 Institute for Energy Research (2020). The Cost of Decommissioning Wind Turbines is Huge. [Online]. Available at https://www.instituteforenergyresearch.org/renewable/wind/the-cost-of-decommissioning-wind-turbines-is-huge/ [Accessed 26 May 2020].

156 Butter eld, S., Musial, W., Jonkman, J.and Sclavounos, P. (2005). Engineering challenges fo oating offshore wind turbines. [online] NREL Conference September 2007, Copenhagen. Available at: <https://www.nrel.gov/docs/fy07osti/38776.pdf> [Accessed 3 May 2020].

157 Windeurope.org (2018). Floating Offshore Wind Energy, a policy blueprint for Europe. [pdf]. Wind Europe Available at <https://windeurope.org/wp-content/uploads/ les/policy/position-papers/Floating-offshore-wind-energy-a-policy-blueprint-for-Europe.pdf/> [Accessed 26 May 2020].

158 Taninoki, R, Abe, K., Sukegawa, T., Azuma, D., and Nishikawa, M. (2017). Dynamic Cable System for Floating Offshore Wind Power Generation. SEI Technical Review, 84.

159 Irena.org. (2019). Future of Wind: Deployment, investment, technology, grid integration and socio-economic aspects. [online] IRENA. Available at: <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Oct/IRENA_Future_of_wind_2019.pdf> [Accessed 3 May 2020].

160 Physicsworld.com. (2019). The promise and challenges of airborne wind energy. [online] Physics World. Available at: <https://physicsworld.com/a/the-promise-and-challenges-of-airborne-wind-energy/> [Accessed 4 May 2020].

161 DNVGL.com (2020). WIN WIN - Wind-powered water injection. [online]. Available at <https://www.dnvgl.com/energy/feature-articles/win-win-wind-powered-water-injection.html>. [Accessed 26 May 2020].

162 Bbc.com. (2014). Wave powe rm Pelamis calls in administrators. [online] BBC. Available at: <https://www.bbc.com/news/uk-scotland-scotland-business-30151276> [Accessed 5 May 2020].

163 Emec.org.uk. (2015). Pathway to commercialisation: an EMEC guide to research, development, and testing of marine energy technology. [online] EMEC. Available at: <http://www.emec.org.uk/?wpfb_dl=188 > [Accessed 4 May 2020].

164	Simecatlantis.com. (2020). Meygen. [online] SIMEC Atlantis Energy. Available at: <https://simecatlantis.com/projects/meygen/> [Accessed 4 May 2020].
165	Cnbc.com. (2020). A tidal project in Scottish waters just generated enough electricity to power nearly 4,000 homes. [online] CNBC. Available at: <https://www.cnbc.com/2020/01/27/tidal-project-generates-electricity-to-power-nearly-4000-homes.html> [Accessed 5 May 2020].
166	Nbcnews.com. (2020). Tidal energy pioneers see vast potential in ocean currents' ebb an ow. [online] NBN News. Available at: <https://www.nbcnews.com/mach/science/tidal-energy-pioneers-see-vast-potential-ocean-currents-ebb- ow-ncna981341> [Accessed 5 May 2020].
167	Cleantechnica.com. (2020). MeyGen Tidal Power Facility Exported 13.8 GWh Of Electricity To The UK Grid In 2019. [online] Clean Technica. Available at: <https://cleantechnica.com/2020/01/29/meygen-tidal-power-facility-exported-13-8-gwh-of-electricity-to-the-uk-grid-in-2019/> [Accessed 5 May 2020].
168	Deepresource.wordpress.com. (2012). Tidal Energy Animation. [Blog] DeepResource. Available at: <https://deepresource.wordpress.com/2012/04/20/tidal-energy-animation/> [Accessed 3 May 2020].
169	Emec.org.uk. (2020). Magallanes Renovables. [online] EMEC. Available at: <http://www.emec.org.uk/about-us/our-tidal-clients/magallanes-renovables/> [Accessed 1 May 2020].
170	Orbitalmarine.com. (2020). Orbital O2 2MW. [online] Orbital. Available at: <https://orbitalmarine.com/technology-development/catching-the-tide/orbital-o2> [Accessed 1 May 2020].
171	Lux Research, (2019). Innovations in Wave and Tidal Energy.
172	hal.archives-ouvertes.fr. (2015). Marine Renewable Energy Converters and Biofouling: A Review on Impacts and Prevention. [online] HAL. Available at: <https://hal.archives-ouvertes.fr/hal-01199624/document> [Accessed 4 May 2020].
173	Marineenergy.biz. (2018). CTC presents new protective coating for marine renewables. [online] Marine Energy. Available at: <https://marineenergy.biz/2018/02/01/ctc-presents-new-protective-coating-for-marine-renewables/> [Accessed 4 May 2020].
174	Phys.org. (2016). Long-lasting coatings for offshore renewable energy. [online] Phys.org. Available at: <https://phys.org/news/2016-02-long-lasting-coatings-offshore-renewable-energy.html> [Accessed 3 May 2020].
175	Marinenergy.biz. (2019). RoBFMS Project to Deploy Marine Energy Anti-Fouling System at Orkney Test Site. [online] Marine Energy. Available at: <https://marineenergy.biz/2019/09/13/robfms-project-to-deploy-marine-energy-anti-fouling-system-at-orkney-test-site/> [Accessed 28 April 2020].
176	Greentechmedia.com. (2019). Floating Solar Gets Ready for the High Seas. [online] GTM. Available at: <https://www.greentechmedia.com/articles/read/ oating-solar-gears-up-for-the-high-seas> [Accessed 28 April 2020].
177	Ogauthority.co.uk. (2018). Gas-to-Wire: UK SNS & EIS. [online] UK Oil & Gas Authority. Available at: <https://www.ogauthority.co.uk/media/5049/oil-gas-gas-to-wire.pdf> [Accessed 29 April 2020].
178	Northseawindpowerhub.eu. (2019). Cost Evaluation of North Sea Offshore Wind Post 2030. [online] TNO. Available at: < https://northseawindpowerhub.eu/wp-content/uploads/2019/02/112522-19-001.830-rapd-report-Cost-Evaluation-of-North-Sea-Offshore-Wind....pdf > [Accessed 27 April 2020].
179	Enbw.com.tw. (2019). Insight into an Offshore Wind Farm: Turbines – Powering Offshore Wind Farms. [online] EnBW. Available at: <https://www.enbw.com.tw/en/blog_content.aspx?serno=45&not=1585606713994> [Accessed 29 April 2020].
180	New.abb.com. (2018). HVDC technology for offshore wind is maturing. [online] ABB. Available at: <https://new.abb.com/news/detail/8270/hvdc-technology-for-offshore-wind-is-maturing> [Accessed 29 April 2020].
181	New.abb.com. (2020). Subsea Power Substation. [online] ABB. Available at: <https://new.abb.com/oil-and-gas/sectors/offshore-oil-and-gas/subsea/subsea-power/subsea-power-substation> [Accessed 29 April 2020].
182	Rigzone.com. (2019). New Subsea Era Could Begin with Power Tech. [online] Rigzone. Available at: <https://www.rigzone.com/news/new_subsea_era_could_begin_with_power_tech-03-dec-2019-160472-article/> [Accessed 4 May 2020].
183	Transformer-technology. (2019). ABB and Siemens test world's rst subsea substations for underwater factories. [online] Transformer Technology. Available at: <https://transformer-technology.com/news/us-news/431-subsea-power-grids-for-underwater-factories-receive- nishing-touches-transformer-technology.html> [Accessed 3 May 2020].
184	Viscas.com. (2013). Fukushima Floating Offshore Wind Farm Demonstration Project. [online] VISCAS. Available at: <http://www.viscas.com/english/e_news2013.10.html> [Accessed 3 May 2020].
185	Rivieramm.com. (2019). Aker Solutions oating wind doesn't need demos. [online] Riviera. Available at: <https://www.rivieramm.com/news-content-hub/news-content-hub/aker-solutions- oating-wind-doesnsquot-need-demos-56863> [Accessed 28 April 2020].
186	Drax.com. (2018). Electric Insights: April to June 2018. [online] Drax. Available at: <https://www.drax.com/wp-content/uploads/2018/08/180809_Drax_Q2_Report.pdf> [Accessed 3 May 2020].
187	Based on WoodMacKenzie Energy Storage data for cumulative end of 2019, comprising 880MW front-of-the-meter, grid connected energy storage, 50MW non-residential (C&I), 40MW residential.
188	Cornwallinsight.com. (2018). Wholesale Power Price Cannibalisation. [online] Available at: <https://www.cornwall-insight.com/insight-papers/wholesale-power-price-cannibalisation> [Accessed 25 May 2020]
189	Fluenceenergy.com (2019), Energy Storage MythBusters. [online] Fluence Energy. Available at < https://blog. uenceenergy.com/energy-storage-technologies-mythbusters> [Accessed 7 May 2020]
190	Maritime-executive.com. (2020). Expected to Transform the Offshore Supply Chain. [online] The Maritime Executive. Available at: <https://www.maritime-executive.com/article/2020-expected-to-transform-the-offshore-supply-chain> [Accessed 26 April 2020].
191	Offshore-energy.biz. (2018). 'West Mira' to become world' rst hybrid offshore rig. [online] Offshore Energy. Available at: <https://www.offshore-energy.biz/west-mira-to-become-worlds- rst-hybrid-offshore-rig/> [Accessed 29 April 2020].
192	Lux Research, (2018). Siemens supplie rst battery solution for offshore drilling rigs.
193	Cdn.ymaws.com. (2019). The UK Offshore Wind Industry: Supply chain review January 2019. [online] Offshore Wind Industry Council. Available at: <https://cdn.ymaws.com/www.renewableuk.com/resource/resmgr/publications/supply_chain_review_31.01.20.pdf> [Accessed 5 May 2020].
194	Cordis.europa.eu. (2020). Cost reduction and increase performance o oating wind technology. [online] CORDIS EU Commission. Available at: <https://cordis.europa.eu/project/id/815083> [Accessed 5 May 2020].
195	Analysis.newenergyupdate.com. (2018). GE launches 5.3 MW onshore wind turbine; Floating wind study calls for 'urgent' port spending. [online] New Energy Update. Available at: <http://analysis.newenergyupdate.com/wind-energy-update/ge-launches-53-mw-onshore-wind-turbine- oating-wind-study-calls-urgent-port > [Accessed 5 May 2020].
196	Ore.catapult.org.uk. (2019). An introduction to airborne wind. [online] Catapult. Available at: <https://ore.catapult.org.uk/analysisinsight/an-introduction-to-airborne-wind/> [Accessed 6 May 2020].
197	Nrel.gov. (2016). A Spatial-Economic CostReduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015–2030. [online] NREL. Available at: <https://www.nrel.gov/docs/fy16osti/66579.pdf> [Accessed 5 May 2020].
198	Lux Research, (2016). Batteries included in world' rst offshore oating wind farm.
199	Offshorenergystorage.com. (2020). FLASC Working Principle. [online] Offshore Energy Storage. Available at: <https://www.offshoreenergystorage.com/> [Accessed 25 April 2020].
200	Greentechmedia.com. (2016). Fraunhofer races hydrostor for underwater storage. [online] GTM. Available at: <https://www.greentechmedia.com/articles/read/fraunhofer-races-hydrostor-for-underwater-storage> [Accessed 30 April 2020].
201	EU Cordis (2017). Introducing the self-installing offshore wind turbine. Available at: <https://cordis.europa.eu/article/id/120526-introducing-the-sel nstalling-offshore-wind-turbine/> [Accessed May 8 2020].
202	Hydrogencouncil.com. (2020). Path to hydrogen competitiveness: a cost perspective. [online] Hydrogen Council. Available at: <https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf> [Accessed 5 May 2020].
203	IEA.org. (2019). The Future of Hydrogen. [online] IEA. Available at: <https://www.iea.org/reports/the-future-of-hydrogen> [Accessed 1 May 2020].
204	Nuoryon.com. (2019). BP, Nouryon and Port of Rotterdam partner on green hydrogen study. [online] Nuoryon. Available at: <https://www.nouryon.com/news-and-events/news-overview/2019/bp-nouryon-and-port-of-rotterdam-partner-on-green-hydrogen-study/> [Accessed 27 April 2020].
205	Greentechmedia.com. (2020). Shell Exploring World's Largest Green Hydrogen Project. [online] Green Tech Media. Available at: <https://www.greentechmedia.com/articles/read/shell-exploring-worlds-largest-green-hydrogen-project> [Accessed 1 May 2020].
206	Thestar.com. (2020). Brunei ships 4.7 tonnes of hydrogen to Japan. [online] The Star. Available at: <https://www.thestar.com.my/news/regional/2020/02/21/brunei-ships-47-tonnes-of-hydrogen-to-japan> [Accessed 1 May 2020].
207	Ft.com (2019). Japan launche rst liquid hydrogen carrier ship. [online]. Financial Times. Available at <https://www.ft.com/content/8ae16d5e-1bd4-11ea-97df-cc63de1d73f4/> [Accessed May 27 2020].
208	CCC (2019). Net Zero The UK's contribution to stopping global warming [online]. CCC. Available at: <https://www.theccc.org.uk/wp-content/uploads/2019/05/Net-Zero-The-UKs-contribution-to-stopping-global-warming.pdf>
209	Afdc.energy.gov. (2001). Review of small stationary reformers for hydrogen production. [online] IEA. Available at: <https://afdc.energy.gov/ les/pdfs/31948.pdf> [Accessed 2 May 2020].
210	Woodmac.com. (2019). Green hydrogen production: Landscape, projects and costs. [online] Wood Mackenzie. Available at: <https://www.woodmac.com/our-expertise/focus/transition/green-hydrogen-production-2019/> [Accessed 3 May 2020].
211	Franchi, C., Capocelli, M., Falco, M. D., Piemonte, V., and Barba, D. (2020). Hydrogen Production via Steam Reforming: A Critical Analysis of MR and RMM Technologies. Membranes, 10(1), p.10.
212	Sun, P., and Elgowainy, A. (2019). Updates of Hydrogen Production from SMR Process in GREET 2019. [online] Argonne National Laboratory. Available at: <https://greet.es.anl.gov/publication-smr_h2_2019> [Accessed 27 April 2020].
213	IEA.org. (2019). The clean hydrogen future has already begun. [online] IEA. Available at: <https://www.iea.org/commentaries/the-clean-hydrogen-future-has-already-begun> [Accessed 26 April 2020].
214	Irena.org. (2020). Hydrogen from Renewable Power. [online] IRENA. Available at: <https://www.irena.org/energytransition/Power-Sector-Transformation/Hydrogen-from-Renewable-Power> [Accessed 25 April 2020].
215	Tno.nl. (2020). Ten things you need to know about hydrogen. [online] TNO. Available at: <https://www.tno.nl/en/focus-areas/energy-transition/roadmaps/towards-co2-neutral-fuels-and-feedstock/hydrogen-for-a-sustainable-energy-supply/ten-things-you-need-to-know-about-hydrogen/> [Accessed 28 April 2020].
216	Ofgem.gov.uk. (2019). UKCS energy integration interi ndings. [online] UK Oil & Gas Authority. Available at: <https://www.ofgem.gov.uk/system/ les/docs/2019/12/ukcs_energy_integration-_interim_ ndings.pdf> [Accessed 28 April 2020].
217	Hygear.com. (2020). Hy Gen: on-site hydrogen generation. [online] Hy Gear. Available at: <https://hygear.com/technologies/hy-gen/> [Accessed 1 May 2020].
218	Cordis.europa.eu. (2019). Biogas membrane reformer for decentrallzed hydrogen production. [online] CORDIS EU Comission. Available at: <https://cordis.europa.eu/project/id/671459> [Accessed 2 May 2020].
219.	Ieahydrogen.org. (2011). IEA-HIA Task 23 Small-scale Reformers for On-site Hydrogen Supply. [online] iea Energy Technology Network. Available at: <http://ieahydrogen.org/pdfs/Task23_Final-Report_ISBN.aspx> [Accessed 3 May 2020].
220	Chemengonline.com. (2015). Modular hydrogen production technology uses modi ed SMR process. [online] Chemical Engineering. Available at: <https://www.chemengonline.com/modular-hydrogen-production-technology-uses-modi ed-smr-process/> [Accessed 28 April 2020].
221	Taratova,E., et al. (2019). Plasma for environmental issues:From hydrogen production to 2D materials assenbly. [online] Technical University of Lisbon. Available at: < https://www.researchgate.net/publication/266799291_Plasmas_for_environmental_issues_From_hydrogen_production_to_2D_materials_assembly> [Accessed 26 May 2020].
222	Sintef.no. (2019). Hydrogen Production using Membrane-Assisted Autothermal Reforming Integrated with Chemical Looping Air Separation. [online] SINTEF. Available at: <https://www.sintef.no/globalassets/project/tccs-10/dokumenter/d2/tccs2019.pptx.pdf> [Accessed 1 May 2020].
223	Gti.energy. (2020). Low-carbon hydrogen – international project examines new technology. [online] GTI Energy. Available at: <https://www.gti.energy/low-carbon-hydrogen-international-project-examines-new-technology/> [Accessed 3 May 2020].
224	Greencarcongress.com. (2020). HyPER project using sorbent-enhanced steam reforming for low-carbon production of H2 from natural gas. [online] Green Car Congress. Available at: <https://www.greencarcongress.com/2020/02/20200219-hyper.html> [Accessed 28 April 2020].
225	Lux Research, (2020). Water Electrolysis Tech Page.
226	Irena.org. (2018). Hydrogen from renewable power: Technology outlook for the energy transition. [online] IRENA. Available at: <https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power> [Accessed 29 April 2020].
227	Lux Research, (2018). Thyssenkrupp makes a splash in water electrolysis by launching a highly ef cient alkaline electrolyzer.
228	ITM-power.com. (2020). HGas3SP. [online] ITM Power. Available at: <https://www.itm-power.com/hgas3se> [Accessed 1 May 2020].
229	netzerotc.com. (2019). Phase 1 Project Report: Delivery of an offshore hydrogen supply programme via industrial trials at the Flotta Terminal. [online] publisher. Available at: <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/ le/866379/Phase_1_-_OGTC_-_Hydrogen_Offshore_Production.pdf> [Accessed 30 April 2020].
230	Babarit A, et al., Techno-economic feasibility o eets of far offshore hydrogen-producing wind energy converters, International Journal of Hydrogen Energy (2018), https://doi.org/10.1016/j.ijhydene.2018.02.144
231	TNO, North Sea Energy Offshore System Integration (2018). Towards sustainable energy production on the North Sea - Green hydrogen production and CO2 storage: onshore or offshore? [Online]. Available at <https://energeia-binary-external-prod.imgix.net/2lakN2oy4sQF2hn1EzqXJ3LvK80.pdf?dl=North+Sea+Energy+I+-+Towards+sustainable+energy+production+on+the+North+Sea+-+Green+hydrogen+production+and+CO2+storage%3A+onshore+or+offshore%3F.pdf>. [Accessed 27 May 2020].
232	Ogauthority.co.uk. (2019). PosHYden Pilot: offshore green hydrogen. [online] Neptune Energy. Available at: <https://www.ogauthority.co.uk/media/6220/ogauthoritysharepointcom-ssl-davwwwroot-sites-ecm-tbw3-documents- les-exchange-malcolm-workshop-slides-301019-neptune.pdf> [Accessed 29 April 2020].
233	Offshorewind.biz. (2020). Ørsted and ITM Power Explore Different Approach to Integrating Offshore Wind and Hydrogen. [online] Offshore Wind. Available at: <https://www.offshorewind.biz/2020/04/13/orsted-and-itm-power-explore-different-approach-to-integrating-offshore-wind-and-hydrogen/> [Accessed 30 April 2020].
234	LinkedIn.com. (2019). Competition for World's Largest Capacity Electrolyzer Factory. [online] NEL, ITM Power. Available at: <https://www.linkedin.com/pulse/competition-worlds-largest-capacity-electrolyzer-factory-patch/> [Accessed 28 April 2020].
235	Nrel.gov. (2019). Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolyzers. [online] NREL. Available at: <https://www.nrel.gov/docs/fy19osti/72740.pdf> [Accessed 29 April 2020].
236	Irena.org. (2019). Hydrogen: A renewable energy perspective. [online] IRENA. Available at: <https://www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective> [Accessed 30 April 2020].
237	News.standford.edu. (2019). Stanford researchers create hydrogen fuel from seawater. [online] Stanford University. Available at: <https://news.stanford.edu/2019/03/18/new-way-generate-hydrogen-fuel-seawater/> [Accessed 29 April 2020].
238	Phys.org. (2018). A step closer to sustainable energy from seawater. [online] Phys.org. Available at: <https://phys.org/news/2018-06-closer-sustainable-energy-seawater.html> [Accessed 30 April 2020].
239	Parker.com. (2017). Desalination System Provides Ultra-Pure Water for Offshore Oil and Gas Rigs. [online] Parker. Available at: <http://blog.parker.com/desalination-system-provides-ultra-pure-water-for-offshore-oil-and-gas-rigs> [Accessed 30 April 2020].
240	Gov.uk. (2019). Dolphyn Hydrogen. [online] Department for Business, Energy and Industrial Strategy. Available at: <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/ le/866375/Phase_1_-_ERM_-_Dolphyn.pdf> [Accessed 30 April 2020].
241	Technischechemie.tu-berlin.de. (2019). Direct Electrolytic Splitting of Seawater: Opportunities and Challenges. [online] ACS Energy Letters. Available at: <https://www.technischechemie.tu-berlin.de/ eadmin/fg109/2019_ACS_Lett_S%C3%B6ren_Direct_Electrolytic_Splitting_of_Seawater.pdf> [Accessed 30 April 2020].
242	Net Zero Technology Centre (2020). Mission sustainability: four more cleantech start-ups join award-winning technology accelerator. Available at <https://www.netzerotc.com/newsroom/news/2020/mission-sustainability-four-more-cleantech-start-ups-join-award-winning-technology-accelerator/> [Accessed 26 May 2020}
243	Gtah2.com. (2019). Scalable Subsea Electrolysis Arrays for Offshore Wind Energy Hydrogen Production. [online] GTA Inc. Available at: <https://s23.a2zinc.net/clients/awea/owp2019/Custom/Handout/Speaker11671_Session5138_1.pdf> [Accessed 30 April 2020].

244 Ieee.org. (2018). Subsea Electrolyzers for Hydrogen and Oxygen Production. [online] IEEE. Available at: <https://site.ieee.org/tnc/event/subsea-electrolyzers-for-hydrogen-and-oxygen-production/> [Accessed 1 May 2020].

245 Lux Research, (2020). Evolution of Energy Networks: Decarbonizing the Global Energy Trade.

246 Lux Research, (2020). 'Primary Research'.

247 Northerngasnetworks.co.uk. (2018). Hydrogen to heat homes: £14.9m for UK' rst trials on public gas network. [online] Northern Gas Networks. Available at: <https://www.northerngasnetworks.co.uk/2018/11/29/hydrogen-to-heat-homes-14-9m-for-uks- rst-trials-on-public-gas-network/> [Accessed 3 May 2020].

248 Chiyodacorp.com. (2020). SPERA Hydrogen: Chiyoda's Hydrogen Supply Business. [online] Chiyoda. Available at: <https://www.chiyodacorp.com/en/service/spera-hydrogen/> [Accessed 3 May 2020].

249 Greenammonia.org. (2020). Green Ammonia Consortium. [online] GAC. Available at: <https://greenammonia.org/index_eng.html> [Accessed 3 May 2020].

250 Lux Research, (2018). Siemens aims to demonstrate ammonia for energy storage applications.

251 Equinor.com. (2020). The world' rst carbon-free ammonia-fuelled supply vessel on the drawing board. [online] Equinor. Available at: <https://www.equinor.com/en/news/2020-01-23-viking-energy.html> [Accessed 4 May 2020].

252 Modisha, P. , Ouma, C., Garidzirai, R., Wasserscheid, P., and Bessarabov, D.. (2019) The Prospect of Hydrogen Storage Using Liquid Organic Hydrogen Carriers. [online] Energy & fuels. DOI: 10.1021/acs.energyfuels.9b00296

253 Hydrogeneurope.eu. (2020). Hydrogen transport & distribution. [online] Hydrogen Europe. Available at: <https://hydrogeneurope.eu/hydrogen-transport-distribution> [Accessed 30 April 2020].

254 Hydrogeneurope.eu. (2020). Liquefaction systems. [online] Hydrogen Europe. Available at: <https://hydrogeneurope.eu/liquefaction-systems> [Accessed 28 April 2020].

255 Irena.org. (2019). Hydrogen: a renewable perspective. [online] IRENA. Available at: <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf> [Accessed 28 April 2020].

256 Yin, L., and Ju, Y. (2019). Review on the design and optimization of hydrogen liquefaction processes. [online] Frontiers in Energy, doi: 10.1007/s11708-019-0657-4.

257 Cardella, U., Decker, L., and Klein, H. (2017). Economically viable large-scale hydrogen liquefaction. IOP Conference Series: Materials Science and Engineering, 171.

258 Global.kawasaki. (2019). World's First Lique ed Hydrogen Carrier SUISO FRONTIER Launches Building an International Hydrogen Energy Supply Chain Aimed at Carbon-free Society. [online] Kawasaki. Available at: <https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487> [Accessed 27 April 2020].

259 Norled.no. (2019). Partners receive PILOT-E support to develop liquid hydrogen supply chain for maritime applications in Norway. [online] NORLED. Available at: <https://www.norled.no/en/news/partners-receive-pilot-e-support-to-develop-liquid-hydrogen-supply-chain-for-maritime-applications-in-norway/> [Accessed 28 April 2020].

260 Garceau, N. M., Baik, J. H., Chang, M. L., Kim, S. Y., Oh, I., and Karng, S. W. (2015). Development of a small-scale hydrogenliquefaction system. International Journal of Hydrogen Energy, 40(35), p. 11872-11878.

261 Bmvi.de. (2007). CEP Progress Report 2002-2007. [online] CEP. Available at: <https://www.bmvi.de/SharedDocs/EN/Documents/VerkehrUndMobilitaet/cep-progress-report-2002-2007.pdf?__blob=publicationFile> [Accessed 1 May 2020].

262 Crotogino, F., Donadei, S., Bunger, U., and Landinger, H. (2010). Large-Scale Hydrogen Underground Storage for Securing Future Energy Supplies. 18th World Hydrogen Energy Conference 2010 (WHEC 2010), Julich.

263 Energy.ox.ac.uk. (2019). Hydrogen for energy storage. [online] UCL Institute for Sustainable Resources. Available at: <https://www.energy.ox.ac.uk/wordpress/wp-content/uploads/2019/10/Paul-Dodds-Hydrogen-for-energy-storage.pdf> [Accessed 3 May 2020].

264 Caglayan, D., Weber, N., Heinrichs, H. U., Linßen, J., Robinius, M., Kukla, P. A., and Stolten, D. (2019). Technical Potential of Salt Caverns for Hydrogen Storage in Europe. International Journal of Hydrogen Energy, doi: 10.1016/j.ijhydene.2019.12.161.

265 Amid, A., and Mignard, D. (2016). Seasonal storage of hydrogen in a depleted natural gas reservoir. International Journal of Hydrogen Energy, 41(12), doi: 10.1016/j.ijhydene.2016.02.036.

266 HyStorPor (2020). Project focus and outcomes. [online] The University of Edinburgh. Available at: < https://blogs.ed.ac.uk/hystorpor/project-focus-outcomes/>. [Accessed 28 April 2020]

267 Oilandgasuk.co.uk. (2015). Offshore Gas Turbines and Dry Low NOx Burners: an analysis of the Performance Improvements (PI) Limited Database. [online] Oil & Gas UK. Available at: <https://oilandgasuk.co.uk/wp-content/uploads/2015/05/producys-cayrgory.pdf> [Accessed 28 April 2020].

268 Ge.com. (2020). Hydrogen fueled gas turbines. [online] GE. Available at: <https://www.ge.com/power/gas/fuel-capability/hydrogen-fueled-gas-turbines> [Accessed 26 April 2020].

269 Ansaldoenergia.com. (2020). High hydrogen gas turbine retro t to eliminate carbon emissions. [online] Ansaldo Energia. Available at: <https://www.ansaldoenergia.com/Pages/High-Hydrogen-Gas-Turbine-Retro t-to-Eliminate-Carbon-Emissions.aspx> [Accessed 28 April 2020].

270 Rechargenews.com. (2020). World- rst green hydrogen and storage plan to help turn Los Angeles 100%-renewable. [online] Recharge. Available at: <https://www.rechargenews.com/transition/world- rst-green-hydrogen-and-storage-plan-to-help-turn-los-angeles-100-renewable/2-1-771614> [Accessed 5 May 2020].

271 New.siemens.com. (2020). This Swedish scientist works towards ful lling Siemens' 2030 hydrogen pledge. [online] Siemens. Available at: <https://new.siemens.com/global/en/company/stories/energy/hydrogen-capable-gas-turbine.html> [Accessed 4 May 2020].

272 Insideclimatenews.org. (2008). Technology roadmap: carbon capture and storage. [online] IEA. Available at: <https://insideclimatenews.org/sites/default/ les/IEA-CCS%20Roadmap.pdf> [Accessed 3 May 2020].

273 Hydrogeneurope.eu. (2020). Liquefaction systems. [online] Hydrogen Europe. Available at: <https://hydrogeneurope.eu/liquefaction-systems> [Accessed 28 April 2020].

274 Inoue, K., Domen, S., Miyamoto, K., Tamura, I., Kawakami, T., and Tanimura, S. (2018). Development of Hydrogen and Natural Gas Co- ring Gas Turbine. [online] Mitsubishi Heavy Industries Technical Review, 55(2). Available at: <http://www.mhi.co.jp/technology/review/pdf/e552/e552160.pdf> [Accessed 3 MAy 2020].

275 Ge.com. (2019). Power to gas: Hydrogen for power generation. [online] GE. Available at: <https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel- exibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf> [Accessed 4 May 2020].

276 Windpowermonthly.com. (2020). Siemens launches ammonia storage demo. [online] Wind Power Monthly. Available at: <https://www.windpowermonthly.com/article/1486298/siemens-launches-ammonia-storage-demo> [Accessed 5 May 2020].

277 Valera-Medina, A., Gutesa, M., Xiao, H., Pugh, D., Giles, A., Goktepe, B., Marsh, R., Bowen, P. (2019). Premixed ammonia/hydrogen swirl combustion under rich fuel conditions for gas turbines operation [online]. Available at: <https://www.sciencedirect.com/science/article/abs/pii/S0360319919305907> [Accessed 4 May 2020].

278 Siemens, (2020). 'Friday Thoughts' [PowerPoint presentation], March 6, 2020, Aberdeen.

279 Valera-Medina, A., Gutesa, M., Xiao, H., Pugh, D., Giles, A., Goktepe, B., Marsh, R., and Bowen P. (2019). Premixed ammonia/hydrogen swirl combustion under rich fuel conditions for gas turbines operation. International Journal of Hydrogen Energy, 44(16), p. 8615-8626.

280 Tno.nl. (2016). Strategies towards an ef cient future North Sea energy infrastructure. [online] TNO. Available at: <https://www.tno.nl/media/9413/sensei_strategies_towards_an_ef cient_future_north_sea_energy_infrastructure.pdf> [Accessed 5 May 2020].

281 Prototech.no. (2020). Fuel Cell Power Systems. [online] Prototech. Available at: <https://www.prototech.no/applications/power-systems-fuel-cells/> [Accessed 4 May 2020].

282 The Press and Journal. Worl rst for Aberdeen as city orders 15 double decker hydrogen buses. [online] The Press and Journal. Available at <https://www.pressandjournal.co.uk/fp/news/aberdeen/1799344/world- rst-for-aberdeen-as-city-orders-15-double-decker-hydrogen-buses/> [Accessed 26 May 2020]

283 Lux Research, (2020). Fuel Cells Technology Page.

284 Hyseas (2020). Hyseas III. The Project. [online] Hyseas. Available at < https://www.hyseas3.eu/> [Accessed 26 May 2020]

285 Rivieramm.com. (2019). Hydrogen experts join offshore wind 'electrolysis in the turbine' study. [online] Riviera. Available at: <https://www.rivieramm.com/news-content-hub/news-content-hub/hydrogen-experts-join-offshore-wind-electrolysis-in-the-turbine-study-55446> [Accessed 3 May 2020].

286 Teledynees. (2020). Subsea Supercharger. [online] Teledyne. Available at: <http://www.teledynees.com/our-products/fuel-cell-products/subsea-supercharger> [Accessed 1 May 2020].

287 Cnbc.com. (2020). UK government announces millions in funding for 'low carbon' hydrogen production. [online] CNBC. Available at: <https://www.cnbc.com/2020/02/18/uk-government-announces-funding-for-low-carbon-hydrogen-production.html> [Accessed 27 April 2020].

288 Oedigital.com. (2019). A Blue/Green Energy Revolution. [online] Offshore Engineer. Available at: <https://www.oedigital.com/news/473907-a-blue-green-energy-revolution> [Accessed 28 April 2020].

289 Energyvoice.com. (2019). Offshore hydrogen production: Am I missing something? [online] Energy Voice. Available at: <https://www.energyvoice.com/opinion/213562/offshore-hydrogen-production-am-i-missing-something/> [Accessed 27 April 2020].

290 Ammoniaenergy.org. (2018). Ammonia Positioned for Key Role in Japan's New Hydrogen Strategy. [online] Ammonia Energy Assocation. Available at: <https://www.ammoniaenergy.org/articles/ammonia-positioned-for-key-role-in-japans-new-hydrogen-strategy/> [Accessed 29 April 2020].

291 US National Research Council. (2008). Ammonia Acute Exposure Guideline Levels, Acute Exposure Guideline Levels for Selected Airborne Chemicals: Volume 6, [online]. Available at: <https://www.ncbi.nlm.nih.gov/books/NBK207883/> [Accessed 30 April 2020].

292 Linde-engineering.com. (2019). Hydrogen fuelling station with cryo pump technology. [online] Linde Engineering. Available at: <https://www.linde-engineering.com/en/images/DS_Cryo%20Pump_tcm19-523716.pdf> [Accessed 4 May 2020].

293 Tudelft.nl. (2018). Hydrogen: key to the energy transition. [online] TU Delft. Available at: <https://d1rkab7tlqy5f1.cloudfront.net/Websections/Powerweb/Lunch%20Lectures/Presentation%20Ad%20van%20Wijk%20Hydrogen%20key%20to%20the%20energy%20transition%20Powerweb%2014-6-2018.pdf> [Accessed 5 May 2020].

294 Globalccsinstitute.com. (2013). IEA 2013 CCS Roadmap. [online] Global CSS Institute. Available at: <https://www.globalccsinstitute.com/archive/hub/publications/109576/iea-2013-ccs-roadmap.pdf> [Accessed 2 April 2020].

295 Rochelle, G. T. (2009). Amine Scrubbing for CO2 Capture. Science, 325(5948), 1652–1654.

296 Lux Research, (2020). CO2 Capture Tech Page.

297 Nguyen, T., Tock, L., Breuhaus, P., Maréchal, F. and Elmegaard, B.(2016). CO2-mitigation options for the offshore oil and gas sector. Applied Energy, 161, p. 673-694.

298 Equinor.com (2020). Here's how your CO2 emissions can be stored under the ocean. [online] Equinor. Available at: <https://www.equinor.com/en/magazine/carbon-capture-and-storage.html> [Accessed 15 April 2020].

299 Equinor.com (2020). Drilling for replenishment of Snøhvit gas. [online] Equinor. Available at: <https://www.equinor.com/en/news/drilling-replenishment-snohvit.html> [Accessed 25 April 2020].

300 Rufford, T., Smart, S., Watson, G., Graham, B., Boxall, J., Diniz da Costa, J. and May, E., (2012). The removal of CO2 and N2 from natural gas: A review of conventional and emerging process technologies. Journal of Petroleum Science and Engineering, [online] 94-95, p. 123-154. Available at: <https://www.sciencedirect.com/science/article/abs/pii/S0920410512001581> [Accessed 18 March 2020].

301 Lux Research carbon capture expert

302 IEA (2011). Technology roadmap - carbon capture and storage in industrial applications. [online] IEA. Available at: <https://www.iea.org/reports/technology-roadmap-carbon-capture-and-storage-in-industrial-applications> [Accessed 4 March 2020].

303 Zero Emissions Platform (2017). Future CCS Technologies Report. [online] ZEP. Available at: <https://zeroemissionsplatform.eu/wp-content/uploads/ZEP-Future-CCS-Technologies-report-12-January-20171.pdf> [Accessed 5 March 2020].

304 Khraisheh, M., Almomani, F. & Walker, G. (2020). Solid Sorbents as a Retro t Technology for CO2 Removal from Natural Gas Under High Pressure and Temperature Conditions. Sci Rep 10, p. 269.

305 Fosbøl, P., Gaspar, J., Ehlers, S., Kather, A., Briot, P., Nienoord, M., Khakharia, P., Le Moullec, Y., Berglihn, O. and Kvamsdal, H. (2014). Benchmarking and Comparing First and Second Generation Post Combustion CO2 Capture Technologies. Energy Procedia, 63, p. 27-44.

306 Han, Y. and Ho, W. (2018). Recent advances in polymeric membranes for CO2 capture. Chinese Journal of Chemical Engineering, 26(11), p. 2238-2254.

307 Thechemicalengineer.com (2019). Aker Solutions to provide carbon capture technology to waste-to-energy plant (2019). [online] The Chemical Engineer. Available at: <https://www.thechemicalengineer.com/news/aker-solutions-to-provide-carbon-capture-technology-to-waste-to-energy-plant/> [Accessed 26 April 2020].

308 Peletiri, S., Rahmanian, N. and Mujtaba, I. (2018). CO2 Pipeline Design: A Review. Energies, 11(9), p.2184.

309 Global CCS Institute and IEAGHG. (2014). CO2 Pipeline Infrastructure January 2014. [online] Global CSS Institute and IEAGHG. Available at: <https://ieaghg.org/docs/General_Docs/Reports/2013-18.pdf> [Accessed 4 April 2020].

310 Barber, L., Liu, M., Spence, W., Hunen, K., and Lewis, J. (2020). ISO/TC 265 - Carbon Dioxide Capture, Transportation, And Geological Storage. [online] ISO. Available at: <https://www.iso.org/committee/648607.html> [Accessed 5 April 2020].

311 Zhang, Y., Wang, D., Yang, J., Adu, E., Shen, Q., Tian, L., Wu, L., and Shi, B. (2017). Correlative comparison of gas CO2 pipeline transportation and natural gas pipeline transportation. Modelling, Measurement and Control, 86, p. 63-75.

312 Serpa, J., Morbee, J. and Tzimas, E. (2011). Technical And Economic Characteristics Of A CO2 Transmission Pipeline Infrastructure. [online] EU JRC. Available at: <http://publications.europa.eu/resource/cellar/4ab1c4e2-398e-426c-b06f-1175d3c5a403.0001.02/DOC_1> [Accessed 24 March 2020].

313 Oosterkamp, A. and Ramsen, J. (2008). State-of-the-Art Overview of CO2 Pipeline Transport with Relevance to Offshore Pipelines. [online] PolyTec Norway University. Available at: <https://www.researchgate.net/publication/228688545_State-of-the-Art_Overview_of_CO_2_Pipeline_Transport_with_Relevance_to_Offshore_Pipelines> [Accessed 4 May 2020].

314 Wetenhall, B. Race, J. M., Downie, M. J. (2014). The Effect of CO2 Purity on the Development of Pipeline Networks for Carbon Capture and Storage Schemes. International Journal of Greenhouse Gas Control, [online] 30, p. 197–211. Available at: <https://www.sciencedirect.com/science/article/pii/S1750583614002771> [Accessed 4 May 2020].

315 DNVGL.com. (2020). CO2 Pipetrans. [online] DNV GL. Available at: <https://www.dnvgl.com/oilgas/joint-industry-projects/ongoing-jips/co2pipetrans.html> [Accessed 5 April 2020].

316 Acorn.com. (2018). The Acorn Options. [online] ACORN. Available at: <https://www.actacorn.eu/about-act-acorn/acorn-options> [Accessed 5 April 2020].

317 Acorn.com. (2018). D11 Infrastructure Reuse. [online] ACORN. Available at: <https://actacorn.eu/sites/default/ les/ACT%20Acorn%20Infrastructure%20Re-use%20Report%201.0.pdf> [Accessed 2 April 2020].

318 Net Zero Technology Centre Net Zero Taskforce member on ACORN steering committee

319 Element Energy. (2018). Shipping CO2 – UK Cost Estimation Study November 2018. [online] Element Energy. Available at: <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/ le/761762/BEIS_Shipping_CO2.pdf> [Accessed March 15, 2020].

320 Neele, F., de Kler, R., Nienoord, M., Brownsort, P., Koornneef, J., Belfroid, S., Peters, L., van Wijhe, A. and Loeve, D. (2017). CO2 Transport by Ship: The Way Forward in Europe. Energy Procedia, 114, p. 6824-6834.

321 SCCS. (2018). Ship transport of CO2 for Enhanced Oil Recovery – Literature Survey. [online] SCCS. Available at: <http://www.sccs.org.uk/images/expertise/reports/co2-eor-jip/SCCS-CO2-EOR-JIP-WP15-Shipping.pdf> [Accessed 5 April 2020].

322 Zero Emissions Platform. (2010). The Costs of CO2 Transport Post-demonstration CCS in the EU. [online] ZEP. Available at: <https://www.globalccsinstitute.com/archive/hub/publications/119811/costs-co2-transport-post-demonstration-ccs-eu.pdf> [Accessed 1 April 2020].

323 Northernlightsccs.com. (2020). Northern Lights Project. [online] Northern Lights SCCS. Available at: <https://northernlightsccs.eu/en/timeline> [Accessed 1 April 2020].

324 Raza, A., Gholami, R., Rezaee, R., Bing, C., Nagarajan, R. and Hamid, M. (2018). CO2 storage in depleted gas reservoirs: A study on the effect of residual gas saturation. Petroleum, 4(1), p. 95-107.

325 Wen, G. and Benson, S. (2019). CO2 plume migration and dissolution in layered reservoirs. International Journal of Greenhouse Gas Control, 87, p. 66-79.

326 Zhang, S., and DePaolo, D. J. (2017). Rates of CO2 mineralization in geological carbon storage. Acc. Chem. Res., 50, p. 2075–2084.

327 Jenkins, C. R., Cook, P. J., Ennis-King, J., Undershultz, J., Boreham, C., Dance, T., et al. (2012). Safe storage and effective monitoring of CO2 in depleted ga elds. Proc. Natl. Acad. Sci. U.S.A., 109(35–41).

328 Energy.gov. (2017). Accelerating the clean Energy Revolution. [online] US Department of Energy and Kingdom of Saudi Arabia Ministry of Energy, Industry, & Mineral Resources. Available at: <https://www.energy.gov/sites/prod/ les/2018/05/f51/Accelerating%20Breakthrough%20Innovation%20in%20Carbon%20Capture%2C%20Utilization%2C%20and%20Storage%20_0.pdf> [Accessed 6 April 2020].

329 Aminu, M., Nabavi, S., Rochelle, C. and Manovic, V. (2017). A review of developments in carbon dioxide storage. Applied Energy, 208, p. 1389-1419.

330 Palebluedot.com. (2018). Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource. [online] Pale Blue Dot. Available at: <https://s3-eu-west-1.amazonaws.com/assets.eti.co.uk/legacyUploads/2016/04/D16-10113ETIS-WP6-Report-Publishable-Summary.pdf> [Accessed 27 April 2020].

331 Lux Research, (2019). CO_2 Capture and Conversion: Innovative technology developers in the emerging CO_2 capture and conversion space.

332 Lux Research, (2020). Enhanced Oil Recovery Tech Page.

333 Awan, A., Teigland, R., and Kleppe, J. (2008). A Survey of North Sea Enhanced-Oil-Recovery Projects Initiated During the Years 1975 to 2005. SPE Reservoir Evaluation & Engineering, 11, p. 497-512.

334 Offshoremag.com. (2020). BP Employs Lessons Learned For North Sea EOR Projects. [online] Offshore. Available at: <https://www.offshore-mag.com/production/article/16758510/bp-employs-lessons-learned-for-north-sea-eor-projects> [Accessed 4 May 2020].

335 Oil and Gas Authority UK. (2016). Enhanced Oil Recovery (EOR) Delivery Programme. [online]. Available at: <https://www.ogauthority.co.uk/media/3092/eor_delivery_programme.pdf> [Accessed 15 March 2020].

336 Offshoremag. (2020). Technical, Economic Constraints Hinder Widespread UK Offshore EOR Retro ts. [online] Offshore. Available at: <https://www.offshore-mag.com/ eld-development/article/16762087/technical-economic-constraints-hinder-widespread-uk-offshore-eor-retro ts> [Accessed 4 May 2020].

337 Global CCS Institute. (2019). Global status of CCS 2019 Targeting climate change. [online] Global CSS Institute. Available at: <https://www.globalccsinstitute.com/wp-content/uploads/2019/12/GCC_GLOBAL_STATUS_REPORT_2019.pdf> [Accessed 2 April 2020].

338 Ghanbari, S., Mackay, E. J., and Pickup, G. E. (2016). Comparison of CO2-EOR Performance between Offshore and Onshore Environments. Offshore Technology Conference Asia. doi:10.4043/26590-ms. Available at: <https://www.onepetro.org/conference-paper/OTC-26590-MS> [Accessed 4 May 2020]

339 Vox.com. (2020). Could Squeezing More Oil Out of the Ground Help Fight Climate Change? [online] Vox. Available at: <https://www.vox.com/energy-and-environment/2019/10/2/20838646/climate-change-carbon-capture-enhanced-oil-recovery-eor> [Accessed 4 May 2020].

340 Eide, L., Batum, M., Dixon, T., Elamin, Z., Graue, A., Hagen, S., Hovorka, S., Nazarian, B., Nøkleby, P., Olsen, G., Ringrose, P. and Vieira, R. (2019). Enabling Large-Scale Carbon Capture, Utilisation, and Storage (CCUS) Using Offshore Carbon Dioxide (CO2) Infrastructure Developments – A Review. Energies, 12(10), p.1945.

341 World Petroleum Council Comité Español. (2017). Offshore CO2 enhanced oil recovery with CCS programs. [online] Club Español de La Energie. Available at: <http://www.enerclub.es/ le/39igbUIX1QN-8qvaUlEaug> [Accessed 14 March 2020].

342 Rosa, M. B., Cavalcante, J. S. de A., Miyakawa, T. M., & Freitas, L. C. S. de. (2018). The Giant Lula Field: World's Largest Oil Production in Ultra-Deep Water Under a Fast-Track Development. Offshore Technology Conference. doi:10.4043/29043-MS

343 NordiCCS CO2. (2013). CO2 from Natural Gas Sweetening to KickStart EOR in the North Sea. [online] NordiCCS. Available at: <https://www.sintef.no/globalassets/sintef-energi/nordiccs/d1.1.1402-co2-form-natural-gas-sweetening-to-kick-start-eor-in-the-north-sea_web.pdf> [Accessed 20 March 2020].

344 Offshoremag.com. (2019). Digitalization provides opportunities and challenges. [online] Offshore. Available at: <https://www.offshore-mag.com/production/article/16763950/digitalization-provides-opportunities-and-challenges> [Accessed 2 May 2020].

345 Lux Research, (2018). The Digital Transformation of Power.

346 Lux Research, (2019). Key takeaways from PowerGen Asia 2019.

347 Lux Research, (2019). The Digital Transformation of Oil and Gas.

348 Sintef.no. (2020). Dynamic control of an electrolyser for voltage quality enhancement. [online] Sintef. Available at: <https://www.sintef.no/globalassets/project/nexpel/pdf/ipst11_id50_chiesa.pdf> [Accessed 2 May 2020].

349 Lux Research, (2018). Digitalization of Solar and Wind.

350 Offshoreenergy.biz. (2020). Digitalization Provides Opportunities and Challenges. [Online]. Available at< https://www.offshore-mag.com/production/article/16763950/digitalization-provides-opportunities-and-challenges>. [Accessed 2 May 2020].

351 ABB.com. (2020). Next Level oil, gas and chemicals Harnessing the power of digitalization to thrive in the 'new normal' of low oil prices. [online] ABB. Available at: <https://search.abb.com/library/Download.aspx?DocumentID=9AKK107045A4259&LanguageCode=en&DocumentPartId=&Action=Launch> [Accessed 3 May 2020].

352 SWZMaritime.nl. (2020). Digital Twinning of Floating Offshore Wind TurbineIln Harsh Weather. [online] SWZ Maritime. Available at: <https://www.swzmaritime.nl/news/2019/09/24/digital-twinning-of- oating-offshore-wind-turbine-in-harsh-weather/?gdpr=deny> [Accessed 3 May 2020].

353 Framo.com. (2020). Aker BP Signs "Data Liberation Contract" With Framo. [online] Framo. Available at: https://www.framo.com/news/aker-bp-signs-data-liberation-contract/ [Accessed 3 May 2020].

354 Offshoreenergy.biz. (2020). Subsea Digitisation - Offshore Energy. [online] Available at: <https://www.offshore-energy.biz/subsea-digitisation/> [Accessed 3 May 2020].

355 Energyvoice.com. (2020). The Era of Oil and Gas Digitalisation is Upon Us - Woodmac - News for The Oil And Gas Sector. [online] Energy Voice. Available at: <https://www.energyvoice.com/opinion/202177/the-era-of-oil-and-gas-digitalisation-is-upon-us-woodmac/> [Accessed 3 May 2020].

356 Equinor.com. (2020). Digitalisation in our DNA. [online] Equinor. Available at: <https://www.equinor.com/en/how-and-why/digitalisation-in-our-dna.html> [Accessed 3 May 2020].

357 Equinor.com. (2017). Norway' rst platform to be remotely-operated from land. [online] Equinor. Available at: <https://www.equinor.com/en/news/09nov2017-valemon-remote.html> [Accessed 3 May 2020].

358 Offshoreenergy.biz. (2020). Production from Equinor's First Unmanned Wellhead Platform To Start In September - Offshore Energy. [online] Offshore Energy. Available at: <https://www.offshore-energy.biz/production-from-equinors- rst-unmanned-wellhead-platform-to-start-in-september/> [Accessed 3 May 2020].

359 Wood Mackenzie, (2020). Emissions Benchmarking Tool

360 UK Government. (2019) Technical note - Carbon Emissions Tax. [online]. Available at: <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/ le/828824/Carbon_Emissions_Tax_-_Technical_Note__1_.pdf> [Accessed 13 May 2020]

361 Oilandgasuk.co.uk. (2020). Economic Contributor. [online]. OGUK. Available at: <https://oilandgasuk.co.uk/economic-contribution/> [Accessed 13 May 2020]

362 Wood Mackenzie (2019). The Momentum of Floating Wind and its outlook Implications.

363 Offshore Renewable Energy Catapult (2018). An innovator's guide to the offshore wind market. [online]. Available at: <https://ore.catapult.org.uk/app/uploads/2018/10/OREC01_7468-SME-Report-2-Offshore-Wind-Market-SP.pdf> [Accessed 13 May 2020]

364 UK Government (2020). Offshore wind Sector Deal. [online]. Available at: <https://www.gov.uk/government/publications/offshore-wind-sector-deal/offshore-wind-sector-deal> [Accessed 14 May 2020]

365 Ons.gov.uk. (2018). Low carbon and renewables energy economy, UK:2018. [online] Of ce for National Statistics Available at: <https://www.ons.gov.uk/economy/environmentalaccounts/bulletins/ nalestimates/2018#exports-and-imports> [Accessed 14 May 2020]

366 RenewableUK.com (2019) Export Nation: UK Wind, Wave and Tidal Exports 2019 [online] Renewable UK Available at: <https://www.renewableuk.com/store/ViewProduct.aspx?ID=15152706> [Accessed 12 May 2020]

367 Wood Mackenzie (2019). The Momentum of Floating Wind and its outlook Implications.

368 Offshore Renewable Energy Catapult (2018). New report shows tidal stream and wave energy can pass UK government's 'triple test' for emerging technology support [online] Available at: <https://ore.catapult.org.uk/press-releases/new-report-shows-tidal-stream-and-wave-energy-can-pass-uk-governments-triple-test-for-emerging-technology-support/> [Accessed 5 May 2020]

369 Uk Hydrogen and Fuel Cell Industry. (2012). Hydrogen and fuel cell industry: on track to deliver over 2,200 new jobs to the UK by 2020. [online] Available at: <http://www.ukhfca.co.uk/wp-content/uploads/Hydrogen-and-fuel-cell-industry.pdf> [Accessed 11 May 2020]

370 World Energy Council. (2018). Hydrogen-Industry as Catalyst. [online] Available at: <http://www.wereldenergieraad.nl/wp-content/uploads/2019/02/190207-WEC-brochure-2019-A4.pdf> [Accessed 11 May 2020]

371 Hydrogen Europe, 2018

372 Ukhfca.co.uk. (2020). The Industry. [online] UK Hydrogen and Fuel Cell Association. Available at: <http://www.ukhfca.co.uk/the-industry/> [Accessed 11 May 2020]

373 Global CCS Institute. (2020). The value of Carbon capture and storage (CCS). [online] Available at: <https://www.globalccsinstitute.com/wp-content/uploads/2020/05/Thought-Leadership-The-Value-of-CCS-2.pdf> [Accessed 11 May 2020]

374 Europa.eu. (2019). The potential for CCS and CCU in Europe. [online] IOGP. Available at: <https://ec.europa.eu/info/sites/info/ les/iogp_-_report_-_ccs_ccu.pdf> [Accessed 11 May 2020]

375 Cen.acs.org. (2020). 45Q, the tax credit that's luring US companies to capture CO2. [online] Chemical & Engineering News. Available at: <https://cen.acs.org/environment/greenhouse-gases/45Q-tax-credit-s-luring/98/i8> [Accessed 14 May 2020]

376 Global CCS Institute. (2019). The LCFS and CCS protocol: an overview for policymakers and project developers. [online] Available at: <https://www.globalccsinstitute.com/wp-content/uploads/2019/05/LCFS-and-CCS-Protocol_digital_version.pdf> [Accessed 11 May 2020]

377 Committee on Climate Change. (2019). Net Zero – Technical Report [Online]. Available at: <https://www.theccc.org.uk/publication/net-zero-technical-report/> [Accessed 21 April 2020]

378 Eti.co.uk. (2020). Strategic UK CCS Storage Appraisal. [online] Energy technolgies institute. Avaiable at: <https://www.eti.co.uk/programmes/carbon-capture-storage/strategic-uk-ccs-storage-appraisal> [Accessed 11 May 2020]

379 Vox.com. (2020). Can you really negate your carbon emissions? Carbon offsets, explained. [online] Vox. Available at: <https://www.vox.com/2020/2/27/20994118/carbon-offset-climate-change-net-zero-neutral-emissions> [Accessed 11 May 2020]

380 UKCCS Research Centre. (2020). [online] Available at: <https://ukccsrc.ac.uk/> [Accessed 11 May 2020]

381 European Comission. (2019) A European strategic long term vision for a prosperous, modern, competitive and climate neutral economy. [online] Available at: <https://ec.europa.eu/energy/sites/ener/ les/documents/2_dgclima_rungemetzger.pdf> [Accessed 21 May 2020]

382 Europa.eu. (2019). A European Green Deal. [online] European Commission. Available at: <https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en> [Accessed 21 May 2020]

383 Europa.eu. (2020). [online] Available at: <https://ec.europa.eu/eurostat/cache/infographs/energy/bloc-4c.html> [Accessed 21 May 2020]

384 Worldbank.org. (2016). Renewable energy export-import: a win-win for the EU and North Africa. [online] World Bank blogs. Available at: <https://blogs.worldbank.org/energy/renewable-energy-export-import-win-win-eu-and-north-africa> [Accessed 21 May 2020]

385 Euractiv.com. (2020). Global hopes for hydrogen economy revived amid EU push. [online] Euractiv. Available at: <https://www.euractiv.com/section/energy-environment/news/global-hopes-for-hydrogen-economy-revived-amid-eu-push/> [Accessed 21 May 2020]

386 Enerdata.net. (2018). Electricity domestic consumption. [online] Enerdata. Available at: <https://yearbook.enerdata.net/electricity/electricity-domestic-consumption-data.html> [Accessed 21 May 2020]

387 Fuel Cells and Hydrogen 2 Joint Undertaking. (2019). Hydrogen Roadmap Europe. A sustainable pathway for the European energy transition. [online] Available at: <https://www.fch.europa.eu/sites/default/ les/Hydrogen%20Roadmap%20Europe_Report.pdf> [Accessed 22 May 2020]

388 Econews.pt. (2020). Government approves hydrogen strategy, €7B investments. [online] Eco. Available at: <https://econews.pt/2020/05/22/government-approves-hydrogen-strategy-e7b-investments/> [Accessed 21 May 2020]

389 Europa.eu. (2020). Carbon Capture and Geologial Storage. [online] European Comission. Available at: <https://ec.europa.eu/clima/policies/innovation-fund/ccs_en> [Accessed 21 May 2020]

390 Ccsassociation.org. (2020). CCS in Europe. [online] Carbon Capture & Storage Association. Available at: <http://www.ccsassociation.org/new-about-ccs/proven-technology/> [Accessed 11 May 2020]

391 Eur-lex.europa.eu. (2019). Commission Delegated Regulation (EU) 2020/389. [online] European Commiossion. Available at: <https://eur-lex.europa.eu/legal-content/en/ALL/?uri=CELEX:32020R0389> [Accessed 11 May 2020]

392 Gov.uk. (2020). £90 million UK drive to reduce carbon emissions. [online] UK Government. Available at: <https://www.gov.uk/government/news/90-million-uk-drive-to-reduce-carbon-emissions> [Accessed 11 May 2020]

393 Ons.gov.uk. (2020). UK input-output analytical tables. [online] Of ce for National Statistics. Available at: <https://www.ons.gov.uk/economy/nationalaccounts/supplyandusetables/datasets/ukinputoutputanalyticaltablesdetailed> [Accessed 11 May 2020]

394 Gov.scot. (2019). Supply, Use and Input-Output Tables, 1998-2016. [online] Scottish Government. Available at: <https://www.gov.scot/publications/supply-use-input-output-tables-multipliers-scotland/> [Accessed 21 April 2020]

395 Oilandgasuk.co.uk. (2020) Roadmap 2035: A blueprint for net-zero. [online] OGUK. Available at: <https://oilandgasuk.co.uk/roadmap-2035/> [Accessed 21 April 2020]

396 Oil & Gas Authority. (2019). Projections of UK Oil and Gas Production and Expenditure. [online] Available at: <https://www.ogauthority.co.uk/media/5382/oga_projections-of-uk-oil-and-gas-production-and-expenditure.pdf> [Accessed 21 April 2020]

397 Nationalgrid.com. (2020). About us. [online] National Grid UK. Available at: <https://www.nationalgridgas.com/about-us> [Accessed 21 April 2020]

398 OGUK. (2019) Workforce Report 2019. [online] Available at: <https://oilandgasuk.cld.bz/Workforce-Report-2019> [Accessed 21 April 2020]

399 Of ce for National Statistics. (2018). Low carbon and renewable energy economy, UK:2018. [online] Available at: <https://www.ons.gov.uk/economy/environmentalaccounts/bulletins/ nalestimates/2018#turnover-and-employment> [Accessed 21 April 2020]

400 Crown Estate Scotland, Offshore Renewable Energy Catapult. (2018). Macroeconomic bene ts o oating offshore wind in the UK. [online] Available at: <https://www.crownestatescotland.com/maps-and-publications/download/219> [Accessed 21 April 2020]

401 Netzeroteesside.com. (2020). The UK' rst decarbonised industrial cluster. [online] Net Zero Teesside. Available at: <https://www.netzeroteesside.com/> [Accessed 21 April 2020]

402 Of ce for National Statistics. (2019). Type I UK employment multipliers and effects, reference year 2015. [online] Available at: <https://www.ons.gov.uk/economy/nationalaccounts/supplyandusetables/adhocs/009746typeiukemploymentmultipliersandeffectsreferenceyear2015> [Accessed 21 April 2020]

403 Oil and Gas UK. (2020). Pathway to a Net-Zero Basin: Production Emissions Targets. [online] Available at: <https://oilandgasuk.co.uk/product/production-emissions-targets-report/> [Accessed 23 June 2020]

404 Wood Mackenzie. (2020). Decarbonising Norway's upstream industry - is it pro table?

405 Gov.uk (2020). Greater Manchester to house to world's largest liquid air battery. [Online]. Available at: <https://www.gov.uk/government/news/greater-manchester-to-house-to-worlds-largest-liquid-air-battery> [Accessed on 18 June 2020].

406 Oxfordmartin.ox.ac.uk. (2016). CO2 capture may be our only option for stabilising temperatures - we need t nd out the costs, fast. [online]. Available at: <https://www.oxfordmartin.ox.ac.uk/blog/co2-capture-may-be-our-only-option-for-stabilising-temperatures-we-need-to- nd-out-the-costs-fast/> [Accessed 4 June 2020]

407 The Oil & Gas Authority. (2020). UKCS Energy Integration. [online]. Available at:<https://www.ogauthority.co.uk/news-publications/publications/2020/ukcs-energy-integration- nal-report/> [Accessed 20 August 2020].

References | February 2020

Wood Mackenzie™, a Verisk business, is a trusted intelligence provider, empowering decision-makers with unique insight on the world's natural resources. We are a leading research and consultancy business for the global energy, power and renewables, subsurface, chemicals, and metals and mining industries. For more information visit: **woodmac.com**

Europe +44 131 243 4400
Americas +1 713 470 1600
Asia P +65 6518 0800
Email contactus@woodmac.com
Website www.woodmac.com