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Delivering a rapid, orderly and just energy transition for the **UK Continental Shelf**

Contents

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Executive summary

The UK Continental Shelf (UKCS) is an oil and gas basin in decline. Reserves are depleting, and since production peaked in in 1999 at 4.5 million barrels of oil equivalent per day, output has fallen dramatically to 1.4 million barrels per day in 2023 - a 69% decrease[1].

All long-term scenarios are scenarios of further decline: in a "maximum" scenario with ongoing licensing and development, the North Sea Transition Authority expect combined oil and gas production to decline at ~7% annually until 2050. A "no new fields" scenario accelerates this to ~9% per year[2].

Various factors could even further accelerate the decline, including a significant slowdown of investment into the basin, market volatility, policy changes, or network effects in the interconnected UKCS infrastructure. Under these circumstances, the annual decline rate could potentially accelerate to up to 20%.[3]

At the same time, limiting global temperature rises in line with the Paris Agreement will require a radical break from the current global emissions trajectory. At current global annual emissions, we risk depleting the total remaining carbon budget of ~200 Gt by 2030[4].

In 2023, the International Energy Agency (IEA) stated that its 1.5ºC aligned net-zero scenario requires "no new conventional long lead time oil and gas projects are approved for development after 2023… this, in turn, means that there is no need to explore for new oil and gas fields from now on."[5]

At COP28 in Dubai in 2023, countries, including the UK, agreed to contribute to global efforts to "transition away from fossil fuels in energy systems, in a just, orderly and equitable manner, accelerating action in this critical decade, to achieve net zero by 2050 in keeping with the science"[6]

As the phase-down of the UKCS continues and potentially accelerates, the UK faces crucial decisions on managing the basin. The decline in UKCS oil and gas production has implications for jobs, tax revenues, and energy affordability and supply security.

While oil and gas production are decreasing, clean energy solutions offer a significant opportunity for a successful UKCS transition. The UK boasts one of the world's richest offshore renewable energy resources, with substantial offshore wind potential and extensive geological pore space for CO_2 storage, and potentially hydrogen in the future.

This study aims to explore managing the UKCS decline within the context of the UK's energy transition. Fully realizing the benefits of this transition and ensuring energy and job security requires comprehensive and integrated planning. Such planning should address the decline in oil and gas production, the scale-up of clean energy solutions, the repurposing and decommissioning of obsolete assets, and the decarbonization of UK homes and industry.

If managed well, the transition of the UKCS could become an international template for successfully transitioning oil and gas fields. It could demonstrate how oil and gas producers can move beyond fossil fuels and develop future clean-energy industries, maximizing the transition's benefits in terms of jobs, investment, and fiscal contribution.

For example, the UKCS is home to hundreds of oil and gas platforms and fields, thousands of wells, and tens of thousands of kilometres of pipelines that will become disused in the next two to three decades[7]. While limited in scale, there is an opportunity to repurpose some of these assets for the clean energy system (where assets include the fields, wells, pipelines, platforms and associated infrastructure).

The most promising repurposing opportunity lies in the geological storage of CO_2 in depleted oil and gas fields, utilising associated infrastructure. An initial assessment has identified 21 out of 798 oil and gas fields with high potential for CO_2 storage, representing approximately 30% of the total field CO_2 storage capacity. However, it's important to note that only a subset of these fields is likely to be repurposed in practice, resulting in an even smaller number of repurposed associated platforms.

All infrastructure that is not repurposed will need to be decommissioned. This undertaking represents a significant task, the North Sea Transition Authority estimates it will cost approximately £40 billion, with His Majesty's Revenue and Customs estimating associated taxpayer costs of around £21.8 billion over the next four decades[8]. Careful planning and coordination between industry stakeholders and regulators will be crucial to manage costs effectively, prevent operator defaults, and maximise the UK's share of the growing UK and global decommissioning market.

The 2013 Wood Review suggested that, as infrastructure becomes disused, the interconnectedness of UKCS assets could become a risk and lead to network – or domino – effects, where the shutdown of one asset impacts others up- or downstream.

Through interviews within and outside the oil and gas industry, we identify four distinct, but interrelated and potentially reinforcing, drivers of the 'network effect': platforms and other infrastructure are typically physically, technically, commercially, and financially interdependent. Initial case-study outcomes suggest that the size of these types of effects could be limited, but a comprehensive network map is needed to properly assess and quantify potential network risks.

While oil and gas production phasedown is inevitable, UKCS energy jobs do not need to decline. In fact, the transition presents an opportunity for job growth if managed strategically. Current estimates show approximately 210,000 jobs in the UKCS energy system, encompassing direct and indirect employment in oil and gas production, decommissioning, offshore wind, and CCS[9]. If the UK successfully meets its renewable energy targets (including both offshore wind and CCS scale up) and develops a robust decommissioning industry, total UKCS energy system jobs could potentially increase to around 250,000 by 2030[10].

Notably, over 80% of these jobs would require skills similar to those in the oil and gas sector, facilitating a potentially smooth transition for the workforce[11]. However, the job outlook is not without risks. In a scenario where oil and gas phasedown accelerates and offshore wind installation falls short of targets, total jobs could decline to approximately 190,000 by 2030[12]. This underscores the critical importance of meeting clean energy goals and developing new industries to maintain and grow employment in the regions linked to the UKCS.

The expansion of renewable energy and parallel decarbonisation of buildings, transport and industry is critical for UK energy security, especially as domestic oil and gas production declines. Modelling based on the Balanced Net Zero (BNZ) pathway laid out by the UK's Climate Change Committee (CCC) in their 6th Carbon Budget suggests that if the UK meets its clean energy targets, energy security could remain stable until 2030 despite decreasing UKCS oil and gas production, with 2030 primary energy imports projected at 700-1000 TWh (compared to ~800 TWh today)[13]. By 2050, the UK aims for significant energy import independence through large-scale domestic renewable generation and increased energy efficiency, potentially reducing energy imports from ~40% to 20-30% of consumption[14].

Notably, the diminishing impact of UKCS is evident, as a 'maximum' oil and gas scenario in 2030 would only increase domestically produced energy by 4 percentage points compared to a 'no new fields scenario'[15]. This underscores the crucial role of renewable transition in ensuring long-term energy security, reducing exposure to volatile international fossil fuel markets, supporting the UK's net-zero ambitions, and creating potential jobs in the clean energy sector.

The CCC's net-zero scenarios requires a sector-by-sector transition away from fossil fuel energy sources. Reducing gas consumption in line with the BNZ pathway requires implementing low-carbon district heating for 1.5 million homes and installing heat pumps for 2.8 million homes by 2030, jointly totalling ~14% of UK homes[16]. In line with the same scenario, gas demand for manufacturing and construction needs to fall by 40% by 2030[17].

The Office for Budget Responsibility (OBR) estimates cumulative tax revenue from UK oil and gas production over the 2023-29 period to be approximately £22 billion. High-level modelling adapted from the OBR projections of the pre-2024-election fiscal regime suggest that whether maximum production is realised, or no new fields are developed will likely not materially change this revenue[18], underscoring the diminishing economic returns from the North Sea basin. While the OBR has not published an updated forecast post-election, the new government's tax changes have been relatively modest. The Energy Profits Levy (EPL) was increased, raising total marginal taxation from 75% to 78%, and the EPL's 29% investment allowance was removed.

However, other investment allowances were maintained, suggesting that the overall fiscal impact on the sector remains largely unchanged. This stability in projected tax revenue, despite varying production scenarios, highlights the need for the UK to diversify its energy portfolio and revenue streams, particularly through the development of renewable energy sources and associated industries.

While a significant task, the UKCS transition is possible and could be a success story and template for the rest of the world. The clean energy scale-up is a key lever to mitigate the impact of oil and gas production phasedown to society: it provides jobs for similar skill sets as currently employed in the oil and gas sector, and it provides domestic energy production to boost security of supply.

We have set out seven ways in which government, regulators and the energy industry could facilitate a rapid, orderly, and just transition for the UKCS:

1. **Enhance data collection and monitoring**: Improve continuous or regular asset-, network- and system-level data assessment to inform decision-making and track transition progress.
2. **Clarify the UK's energy vision**: Provide a clear roadmap that narrows the vision for the UK's future energy system (e.g. the role of green and blue hydrogen, or the role for Carbon Capture and Storage) to bolster private sector investment in renewable energy, direct grid improvements and guide the UKCS transition effectively.
3. **Clarify the UK's parallel sector transition strategy**: Provide the parallel roadmap for the decarbonisation of UK buildings, industry and transport to ensure that domestic

reliance on - in particular - gas is rapidly reduced, supporting energy resilience as UKCS production continues to decline.

4. **Prioritise renewable energy scale-up**: Focus on renewable energy build-out, including offshore wind and CCUS, as the primary driver of job creation and energy security throughout the transition period.
5. **Proactively manage the phasedown**: Utilise government tools such as licences, consents, investment allowances, fiscal policies, and expanded decommissioning planning mandates to guide the process.
6. **Develop granular, localised asset strategies**: Implement targeted approaches to minimise network contagion risks, maximise repurposing opportunities, and accelerate decommissioning where appropriate.
7. **Foster integrated decision-making**: Explore options ranging from enhanced inter-agency coordination to establishing a single regulatory body to oversee the transition holistically.

As one of the first major oil and gas producers to enter a phase of decline, the UK's approach to managing the transition of the UK Continental Shelf (UKCS) has the potential to serve as a valuable blueprint for other countries facing similar challenges. If the UK was to develop and implement a comprehensive UKCS transition plan that includes a range of strategies - such as rapidly scaling up renewable energy, strategic (but limited) repurposing of existing infrastructure for carbon capture and storage, and actively managing the socioeconomic impacts of the oil and gas industry decline – it could serve as a significant global example of successful transition. However, it's crucial to recognise that the UK's experience cannot be universally applied. Countries with greater economic and fiscal dependence on oil and gas revenues, limited renewable energy potential, or more extensive and interconnected oil and gas infrastructures will likely encounter additional hurdles in their transition.

Factors such as geological conditions, regulatory frameworks, and the availability of alternative economic opportunities will also shape each nation's unique path towards decarbonization. Nevertheless, if the UK can demonstrate a proactive, positive approach to balancing impacts on jobs, energy security, economic interests, and climate goals during this transition period this can offer valuable insights for policymakers and industry leaders worldwide as they navigate their own energy transitions.

Introduction

The UK Continental Shelf (UKCS) is an oil and gas basin in decline. Reserves are depleting, and since production peaked in in 1999 at 4.5 million barrels of oil equivalent per day, output has fallen dramatically to 1.4 million barrels per day in 2023 - a 69% decrease[19]. All long-term scenarios are scenarios of further decline. As the phase down of the UKCS continues and potentially accelerates, the UK faces an important set of decisions over how to manage the basin.

The UKCS has been the subject of much discussion in recent years: The North Sea Transition deal was signed between Government and offshore oil and gas industry in 2021; proposed changes in the licencing policy, tax rates, and investment allowances were debated during the July 2024 General Election; and the seventh Carbon Budget expected in early 2025 will potentially set out new projections for the UK to reach Net Zero, including for oil and gas demand.

Additionally, all oil and gas basins, including the UKCS, are part of the debate on keeping global temperature rise to below 1.5°C. In 2023, the International Energy Agency (IEA) stated that its 1.5°C aligned net-zero scenario requires "no new conventional long lead time oil and gas projects are approved for development after 2023… this, in turn, means that there is no need to explore for new oil and gas fields from now on."[20]

At COP28 in Dubai in 2023, countries, including the UK, agreed to contribute to global efforts to "transition away from fossil fuels in energy systems, in a just, orderly and equitable manner, accelerating action in this critical decade, to achieve net zero by 2050 in keeping with the science"[21]. In June 2024 the UK Supreme Court ruled that emissions from burning the fossil fuels produced by new projects (i.e., scope 3 emissions) should be considered in decisions to grant permits. This has left the legal status of consents issued prior to the court's decision unclear, with judicial reviews ongoing regarding the decisions to grant consents to the Jackdaw and Rosebank fields[22].

The decline of UKCS oil and gas production has implications for jobs, tax revenues, and energy affordability and supply security, and optimal adjustment of the UK economy, capabilities, and energy mix requires time – new sectors need to scale, skills need to be instructed, homes and industry need to be electrified, and alternative energy generation as well as appropriate grid connections, energy storage facilities and power transmission lines must be deployed. But done well, the managed transition of the UKCS could become the international template for successfully transitioning oil and gas fields. It could demonstrate how oil and gas producers can move beyond fossil fuels and develop the future clean-energy industries, maximising the transition's jobs, investment and fiscal contribution.

While the UK is making significant progress in transitioning towards a net-zero energy system, notably through decarbonisation of the power sector and electrification of road transport, oil and gas still comprised 71%[23] of the UK's primary energy consumption in 2023, and there is no clear plan in place for transitioning away from oil and gas production.

This study aims to explore managing the UKCS decline in the context of the UK's energy transition. The scope of this study encompasses the entire UKCS energy system, including upstream oil and gas production, offshore clean energy production and transportation, and offshore storage solutions. The study does not include a view on onshore energy, mid- and downstream oil and gas use or non-energy related areas of the economy. While just transition elements are considered, we didn't start from the aim of describing a just transition plan or a place-based strategy. Three central themes in this study, explored through the framework presented in figure 1, are:

- What are current transition dynamics? This includes (drivers of) the speed of decline of UCKS oil and gas production, as well as speed of the clean energy scale-up.
- How can existing offshore oil and gas assets be best managed throughout the transition? This includes the potential for repurposing assets for the clean energy scale-up, managing infrastructure interdependencies, and ensuring the large decommissioning task ahead is optimally managed.
- How can outcomes for society be optimised throughout the transition? This includes the transition for current oil and gas workers and their communities, affordable energy security, limiting/managing the fiscal impact, and maximising global climate action leadership.

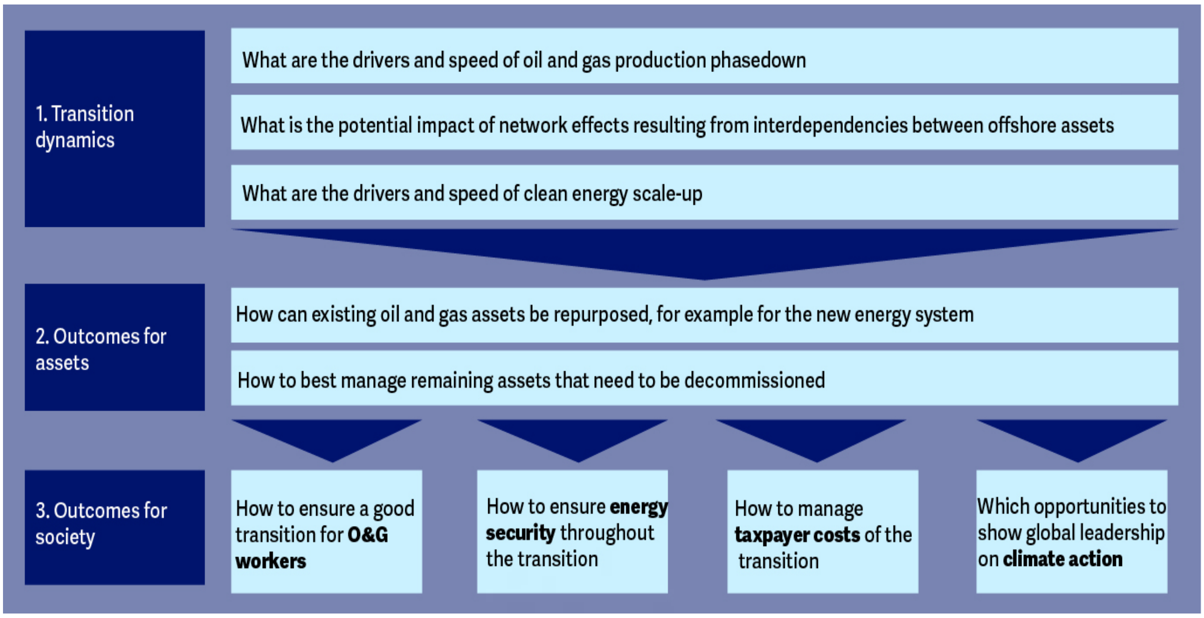


Figure 1: Framework for the fact base for the UKCS transition

This study starts from the UK Climate Change Committee's (CCC) Balanced Net Zero pathway, which provides a roadmap for a successful UK's clean energy transition. The CCC's 6th carbon budget included five core scenarios: Headwinds, Tailwinds, Balanced Net Zero, Widespread Engagement, and Widespread Innovation[24].

While there are several commonalities across scenarios, such as a drop in overall primary energy demand, an increase in renewable energy generation, and a decline in primary fossil fuel consumption, there are also significant areas of difference (see figure 2 below). These include the extent of diet changes, wholesale electricity costs, the role of low-carbon hydrogen (for industrial decarbonisation, power generation, and energy storage), and the balance of low-carbon hydrogen production between green and blue production routes[25]. The aspects of the clean energy scale up most relevant to the UKCS are offshore wind and CO_2 storage, based on current Technology Readiness Levels and the projects pipeline[26]. The CCC scenarios detail projections for the evolution of UK energy consumption by source (including overall consumption of oil and gas) and of power generation from renewables, but do not prescribe pathways for UK oil and gas production.

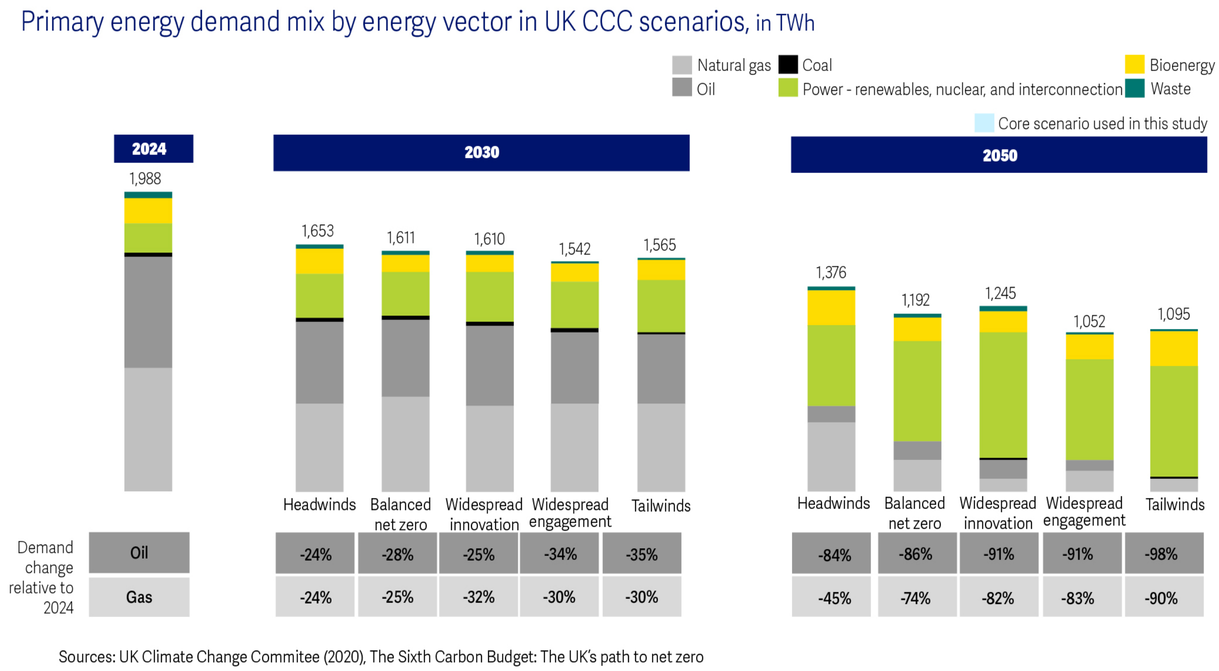


Figure 2: Primary energy demand breakdown across CCC scenarios

This report addresses in turn:

1. The dynamics of the UKCS transition that is ongoing: The historical decline of oil and gas production and future scenarios, including drivers of different possible trajectories. It explores the possibility of network effects (also sometimes referred to as domino effects) and their potential impact on accelerating the oil and gas phase-down.
2. The future of existing oil and gas infrastructure on the UKCS, including platforms, pipelines, (depleted) fields, wells, and other infrastructure: It explores the potential for repurposing oil and gas assets for clean energy sector, as well as critical enablers of an orderly decommissioning.
3. Outcomes of the UKCS transition for UK society: This includes the expected and possible effects on number and quality of UKCS energy system jobs, the impact on energy security, costs to the taxpayer as well as oil and gas related tax income, and finally the opportunity for the UK to show climate leadership.
4. Key insights and implications for policy makers, regulators and industry and for other oil and gas production basins around the world.

This report includes two annexes, the 1st providing more detail on the comparison between the UKCS and oil and gas production in other countries, and the 2nd providing deeper technical insight into the methodologies and sources used.

1 Transition dynamics

1.1 UKCS oil and gas reserves, resources, and production

The UKCS is a basin in decline, and annual oil and gas production has declined relatively steadily from ~250 Mtoe in 2000 to ~70 mtoe in 2023 (i.e., from 4.5 mn to 1.4 mn boe per day), see figure 3[27]

. This section looks in more detail into pathways for future UK production.

The upper bound of future oil and gas production is determined by remaining reserves and resources in the basin. An estimated ~3,000 Mtoe of reserves and medium-to-high likelihood resources currently remains in the UKCS (~20 billion boe). For context, cumulative historical UKCS production is ~6,500 Mtoe (~45 billion boe), and UK oil and gas consumption in 2023 was ~130 Mtoe[28]. Reserves and resources are classed into the following categories:

- 1P (proven) reserves: virtually certain to be technically and commercially producible, i.e. have a better than 90% chance of being produced
- 2P (probable) reserves: estimated to have a better than 50% chance of being technically and commercially producible
- 3P (possible) reserves: estimated to have a significant – more than 10% but less than 50% – chance of being technically and commercially producible
- 1C resources: virtually certain to be technically producible, i.e. have a better than 90% chance of being producible, but are not (yet) commercially viable.
- 2C resources: estimated to have a better than 50% chance of being technically producible but are not (yet) commercially viable[29].

The estimate of ~3,000Mtoe of reserves and medium-to-high likelihood resources is based on 1P, 2P and 3P reserves, and 1C and 2C contingent resources; 3C resources were not included (these are currently estimated to have more than

10% but lower than 50% chance of being technically producible and are, as such, highly speculative).

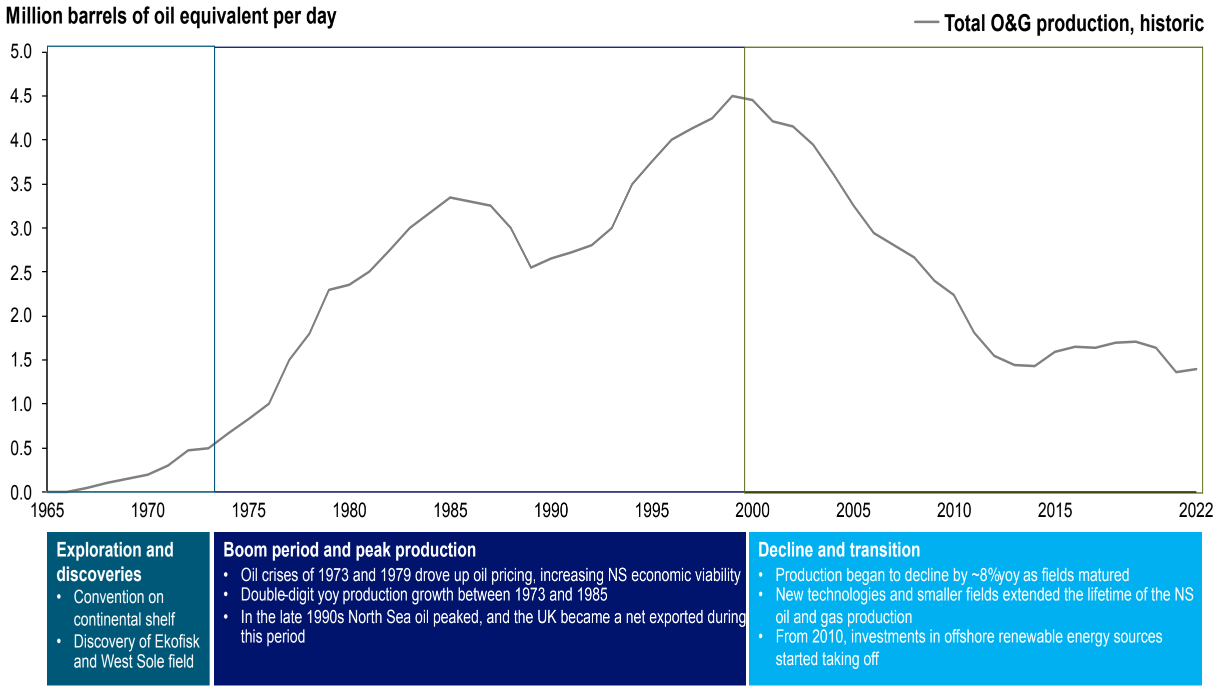
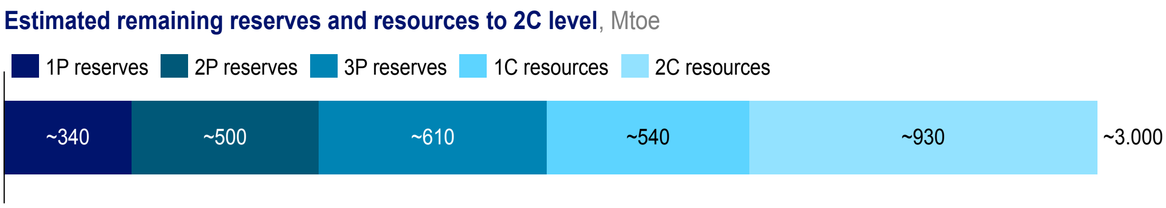


Figure 3 Historical oil and gas production on the UKCS



Notes: Conversion factor of 1 bcm – 1 Mtoe used based on historical production data
Sources: NSTA *(2022) UK Oil and Gas Reserves and Resources*

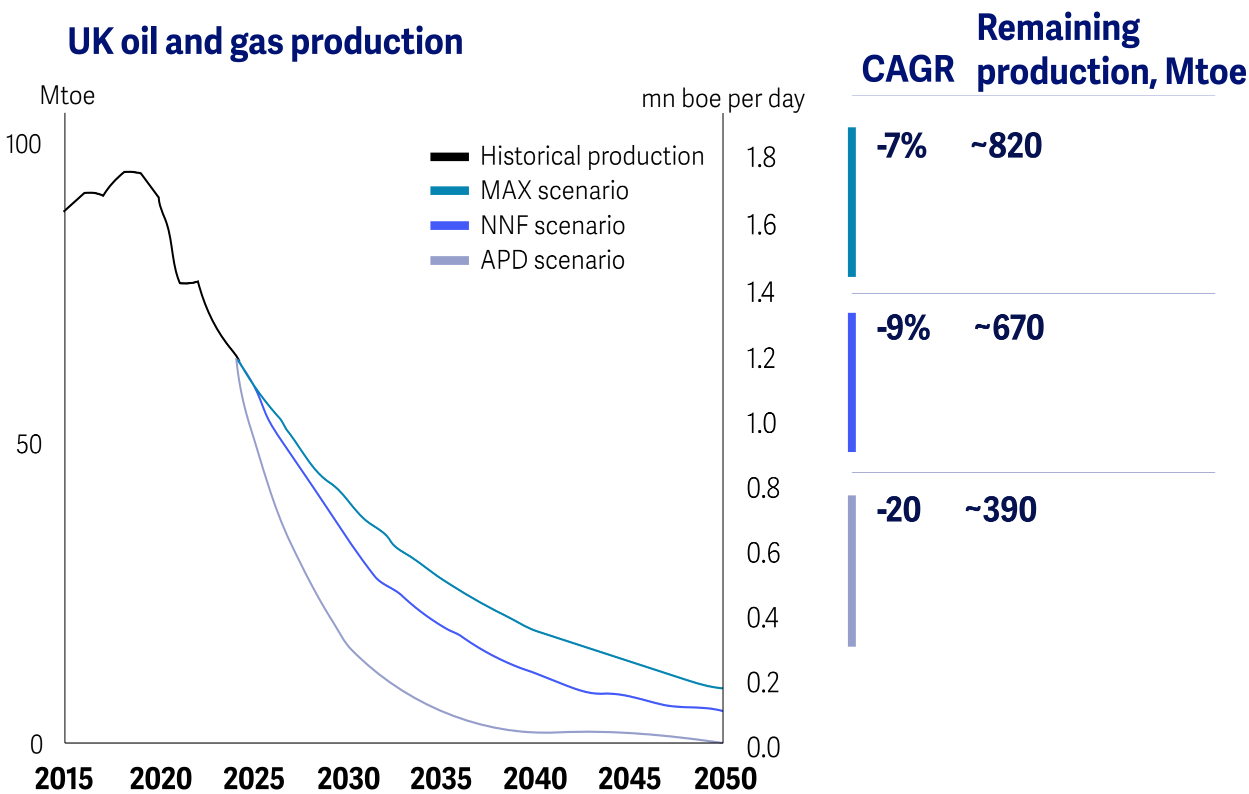
Figure 4: Remaining reserves and resources in the UKCS across different categorisation

Oil and gas reserves and resources can have several legal statuses, ranging from fields in unlicenced blocks which would require a new Seaward Production Licence followed by consents for all activities required for production, to actively producing fields, to fields that have ceased production and for which the licence has ended. Box 1 (page 18) provides a more detailed overview of licences and consents on the UKCS.

Leveraging NSTA insights and analytics, we derive three illustrative pathways for oil and gas phasedown, each within the boundaries of available reserves and resources. These are shown in figure 5.

- **"Maximum" (MAX) scenario (from NSTA projections**[30]): This is the upper boundary of what's possible and would only be achieved if future licensing rounds take place and new consents are issued, market dynamics do not deteriorate, and maximum economic recovery is pursued. The estimated maximum total oil and gas production until 2050 is ~820 Mtoe (~5.6 billion boe)[31 32], implying a year-on-year production decline of ~7% from today onwards (compared to an average decline of 5.8% per annum in the last 5 years). Note that this maximum possible extraction is significantly lower than the total of 1P,2P,3P,1C,2C reserves and resources, as a large share of those are expected to not be present, or not technically or commercially recoverable.
- **"No new fields" (NNF) scenario (from NSTA projections**[33]): No new licence rounds are held and no development of current undeveloped discoveries[34], and major incremental projects in existing fields receive consents. Oil and gas production until 2050 would be ~670 Mtoe (~4.6 billion boe), with an annual decline rate of ~9%. Note this includes the Jackdaw and Rosebank fields.
- **"Accelerated phasedown" (APD) scenario (calculated for this report**): We estimated the lower bound of oil and gas production (in the absence of extreme global events or a complete ban on oil and gas production) until 2050 to be ~390 Mtoe (~2.7 billion boe), associated with a ~20% annual decline rate. In this scenario, fields which have received development consents do not start producing, and there are no consents for major incremental projects in existing fields. There is also a significant slowdown of business-as-usual investment in existing fields. If this scenario is realised, ~80Mtoe of the ~420Mtoe reserves which are currently commercial will not be produced[35]. Two distinct but interrelated accelerators could push production down from the ~670 Mtoe NNF scenario towards the ~390 Mtoe APD scenario:
    - » One accelerator could be **a significant decline in business-as-usual investment**. If regular investments into new wells, enhanced oil recovery, or injection are no longer undertaken, the rate of decline of the basin roughly doubles relative to a situation in which regular business-as-usual investments continue to be made[36]. This implies a year-on-year decline rate of ~20% for the UKCS basin. Causes of such decline in investment could be a significant fall in global oil and gas prices, increased market uncertainty, or changes in the fiscal regime (e.g. a significant reduction in investment allowances, combined with high tax rates).

» A second accelerator could be **network effects** where infrastructure shutdowns have knock-on effects on other infrastructure, to the extent that they have not yet been considered in the current Cessation of Production (CoP) planning. There is a detailed assessment of network effects in the next section (1.2).



Notes: Based on applying 20% CAGR from 2024 to 2050. This is based on approximately doubling the rate of decline (9%) under the NSTA no new fields scenario
Sources: NSTA: Systemiq analysis

Figure 5 Oil and gas production scenarios

BOX 1

LICENCES AND CONSENTS IN THE UKCS

The first step for production in the UKCS is to secure a licence from the NSTA - licences are awarded for blocks or part blocks of the UKCS and grant the licence holder exclusivity to explore for and produce petroleum within the licence area. The typical licence is a Seaward Production Licence. These are divided into Terms - Initial Term (exploration phase), Second Term (appraisal phase) and Third Term (production phase. Note a licence does not grant consent for any physical activity, and additional consents from the NSTA are required for drilling new wells, seismic acquisition, and developing pipelines, infrastructure and facilities to produce hydrocarbons.

A particular oil or gas field can have one of six statuses:

1. **The field is in a block which does not have a licence.** Developing this field would require a new Seaward Production Licence, followed by consents for all activities required for production.
2. **The field is in a block which has a Seward Production Licence, but no consents have been issued.** Consents to locate and drill wells and/or development consents to install production facilities are required before production can start. Note that Carbon Brief analysis (published in August 2024) found that 13 fields were in this category (e.g., Cambo, Avalon), with potential total production over the field lifetimes of 858m boe. If this production occurred, they estimated that burning the resulting fuel would result in 350 $MtCO_2e$ emissions[37].
3. **The field is in a block with a Seward Production Licence and has received development consent but has not started production.** These have been given the permissions for their Field Development Plans but are yet to complete installation. There are 9 fields which have received development consent since 2019 but not yet started producing, including Jackdaw and Rosebank[38]. According to the Rystad Energy's baseline forecast, total cumulative oil and gas production from these fields between 2024 and 2045 will be ~420mboe (Jackdaw and Rosebank contribute ~340mboe of this). Total production from all fields is forecast at ~6,130mboe, hence production from the consented but not yet producing fields makes up 7% of the forecast total[39].
4. **The field has the required licence and consents and is currently producing.** Production from this field has all the consents it requires, but drilling new wells or developing new infrastructure will require additional consents. The vast majority of the ~450-500 Mtoe commercial reserves falls inside this category.
5. **The field has ceased production with no further production planned and is progressing to decommissioning.** The Seaward Production Licence remains active until decommissioning activities have been completed and infrastructure removed or repurposed[40].
6. **The field has ceased production, decommissioning activity has been completed and the licence is ended.**

1.2 Network effects and their impacts on the phasedown

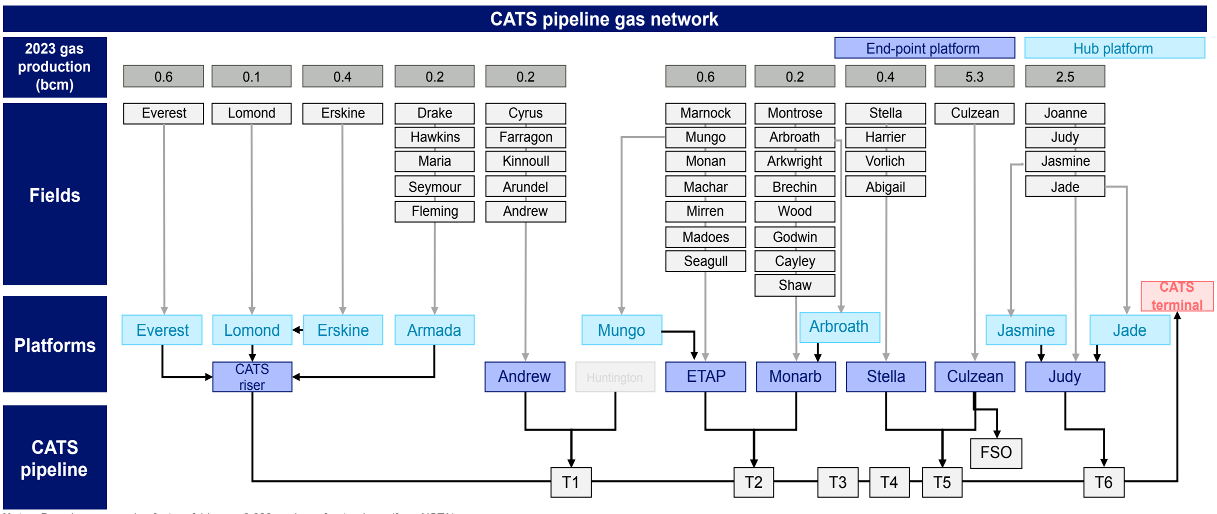
The UKCS is a highly interconnected basin built opportunistically and incrementally, and without its the phasedown in mind. As the basin's production declines over the next decades, interdependencies between installations and infrastructure may lead to network effects – where the closure of one asset impacts the continued existence of others[41]. In this section we explore whether it is likely that large-scale disruptions or domino effects will occur.

There is currently no comprehensive definition of the network effect, nor a publicly available quantification of its potential impacts. Additionally, while companies report on their individual networks and the NSTA has a view at the hub-level, a comprehensive and up-to-date system-level view of UKCS interconnectedness which enables identification of linkages and possible domino effects in the basin, is not available. As such, productive engagement between industry and government bodies to understand and potentially mitigate network effects remains difficult. In this section we aim to shed light on the concept of network effects.

Through extensive interviews within and outside the oil and gas industry, we identify four distinct, but interrelated and reinforcing, drivers of the 'network effect': platforms and other infrastructure are typically physically, technically, commercially, and financially interdependent. To better understand the scale of these network effects, we developed a case study on the Central Area Transmission System (CATS) gas-condensate network in the Central North Sea, the largest single gas network on the UKCS[42].

These four 'network effects' could play out as follows[43]:

- First, **physical transport dependencies**, which occur when platforms depend on other platforms for the physical transportation of hydrocarbons to shore. Some platforms process hydrocarbons from their 'own' associated fields and tiebacks, but instead of transporting directly to shore, they transport the fluids to the next platform. The next platform also processes its own hydrocarbons. It transports those, combined with fluids from the previous platform, onwards again until the final hub platform transports the combined fluids to shore. As many platforms produce multiple streams (e.g. oil, condensate, and gas), they are connected to several networks in an interdependent way. If hub platforms were to cease operation, the route to shore for dependent platforms becomes obstructed. This would leave dependent platforms with four options: reroute their volumes via new pipelines (but it is unlikely that the investment required would be commercially attractive in a declining basin), use offshore loading (requires significant retrofit, also unlikely to be commercially attractive), increase unit payments for transport to keep the hub in operations longer, or cease production. Our case study of the CATS gas network, illustrated in figure 5 below, found that 8 out of 15 operational platforms, representing 3.4 out of 10.7 bcm of gas produced by fields in the CATS network fields in 2023 (i.e., ~30% of volumes), do not have their own feed-in into the CATS pipeline, and depend on other platforms for transportation of hydrocarbons to shore. It is important to note that, aside from physical dependency onto the CATS gas network, all platforms that export to CATS also export to separate oil pipelines and as such also depend on the oil pipeline being available.



Notes: Based on conversion factor of 1 bcm = 6.089 mn boe of natural gas (from NSTA)
Sources: NSTA; Rystad Energy's UCube; Systemiq analysis

Figure 6: CATS network overview

- Second, **technical blending dependencies** occur when the composition of the hydrocarbon blend flowing through pipelines changes significantly due to changes in the upstream field composition. If the blend changes beyond a tipping point on technical characteristics such as viscosity, wetness, or the presence of chemicals, pipelines and terminals might no longer be able to process the fluids. It is typically possible – at higher cost – to increase processing efforts to adjust hydrocarbon blend or adjust technical blend requirements of the infrastructure. Nevertheless, the NSTA expects the risk from this dependency will could likely increase as the portfolio of fields connected to a particular system reduces.
- Third, **commercial transport and processing dependencies**. Operating costs for an offshore installation are more or less fixed, so an individual platform's economics depend highly on volumes[44]. When upstream volumes decline,

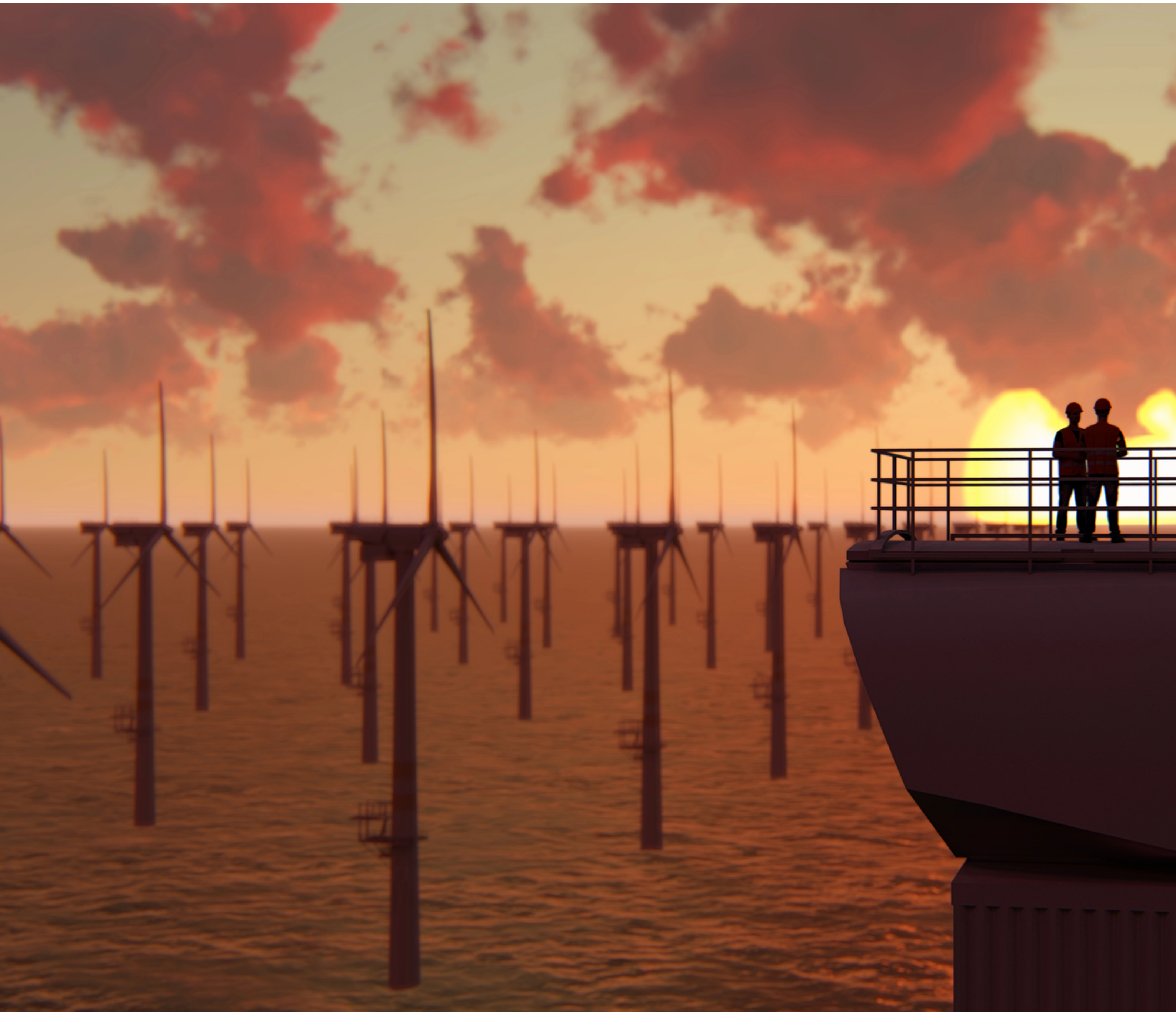
the unit costs of processing and transportation of hydrocarbons increase. Transportation costs are typically low at ~3% of total barrel costs (including tax). As such, an operator can absorb a steep decline in transportation volumes. However, processing costs are ~35% of total costs, which means that a steep processing volume reduction leads rapidly to a loss-making platform. In a younger basin with regular licensing rounds, these economics can be continuously improved using tiebacks to increase volumes, but in the mature UKCS, this is unlikely to be practically and legally feasible. Therefore, the commercial processing dependency is very likely to occur throughout the basin, leading to early shut-down of some platforms. However, by definition, the issue arises when volumes are too low for commercial operations, and to large extent this effect is expected to be accounted for in the current Cessation of Production planning. As such, the volumes at risk are likely to be relatively low.

- Finally, **financial joint venture dependencies**. UKCS assets are often owned by a joint venture of several upstream oil and gas players. If the balance sheets of some of these players are pressured, this impacts liabilities and risks for their joint venture partners. As such, financial distress and defaults could cause a domino effect of financial distress in the basin. This study has not assessed financial dependency risks.

The vast majority of UKCS oil and gas production is estimated to be transported via offshore pipelines, and as such is part of an infrastructure network and subject to the above dependencies. However, several oil fields, especially in deeper waters, are not connected to transportation pipelines. Instead, the oil is recovered to shore using floating production and storage offloading units (FSPO's) and tankers. Those fields would not – or to lesser extent – be subject to the above dependencies. There is no public information on the share of total oil volumes that is transported using tankers.

Our initial review suggests that while some network effects are likely to materialise throughout the phasedown, the most significant are likely to be physical transport and commercial processing dependencies[45]. Although the interconnectedness of UKCS assets could theoretically lead to network effects or domino effects, initial case-study outcomes (i.e. the share of "dependent" volumes) and the nature of the network effect, which comes into effect only when volumes are low, suggest that the size of these effects could be limited and the risk of large-scale disruption might be overstated. However, while this study has described and provided an initial high-level assessment of risk for three out of four dependencies, it was not comprehensive. The true size, likelihood and interrelatedness of each of these risks remains unclear. Consequently, it is uncertain to what extent these network effects could accelerate the phase down of oil and production. Additionally, we have not investigated the dependence of offshore assets on onshore processing and transport facilities.

To properly assess and quantify potential network risks, a comprehensive network map is needed. Enhanced visibility and mitigation plans for these risks would benefit from more systematic collation and assessment of data on UKCS oil and gas networks and the interconnections between different assets. Developing a UKCS-wide network model, for example compiled by the NSTA, would be instrumental in this effort. By creating and monitoring such a 'network map', the risks of disruptive events could be better identified and mitigated, informing and shaping discussions between industry and government.



2

Outcomes for infrastructure and assets

The UKCS is home to a vast network of oil and gas infrastructure and installations, of which the majority are still operational. As the UKCS basin is highly mature and in decline, most existing infrastructure and installations will become disused in the next two decades. The rate at which these assets will cease production in the following years is unprecedented in the UK and warrants a coordinated and systematic approach to their post-Cessation of Production (CoP) treatment.

When an asset ceases operation, it can take one of two routes: Either the asset is repurposed, for example for the clean energy system, or the asset is decommissioned. This section explores these two options in turn.

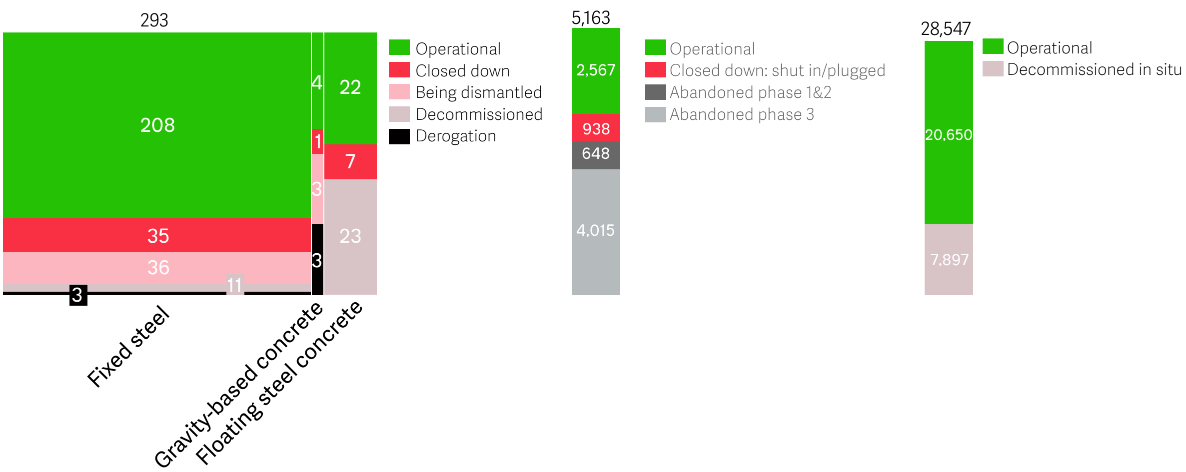


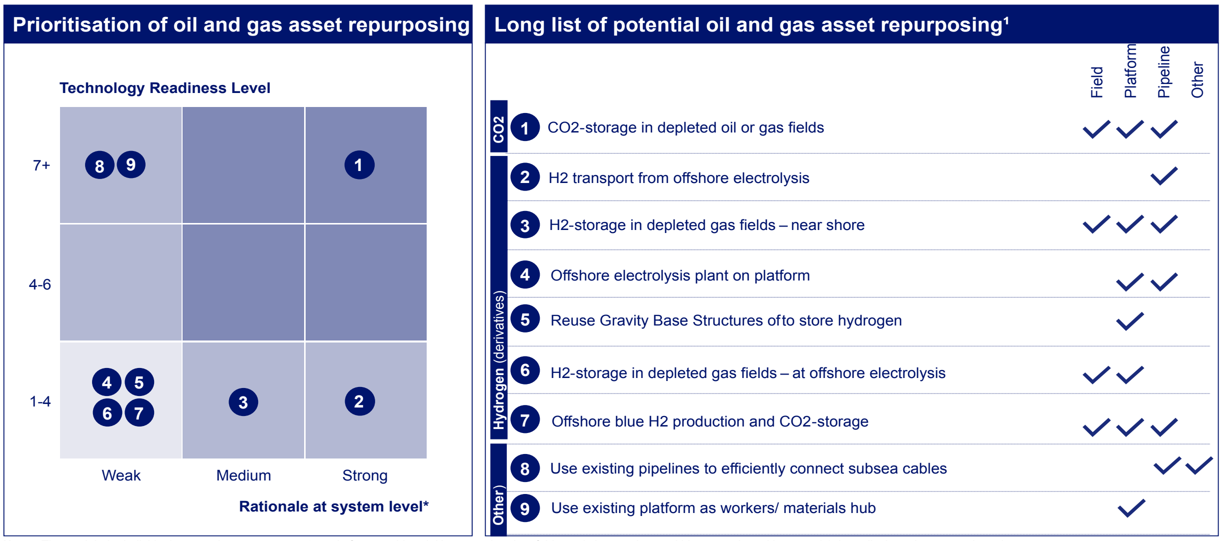
Figure 7: UKCS oil and gas assets

2.1 Repurposing, or 'recommissioning', existing oil and gas assets

In theory, many opportunities exist for repurposing existing disused oil and gas assets, i.e. pipelines, wells, fields, and platforms, to use in the clean energy economy (see figure 7 for the long list of potential repurposing use cases).

However, to understand the scale of repurposing which might occur it is critical to assess these potentials against a range of criteria: the practical feasibility of repurposing, the potential size of the new use case, and economic viability of the conversion (especially compared to green field development). Considering these factors, only three opportunities have a medium to strong (economic) rationale and potential to scale based on today's outlook:

- **CO_2 storage**, where depleted fields are used as storage reservoirs. This technology is mature, and several UK-based projects are already in the pipeline, though only one has taken Final Investment Decision as of December 2024. There could be potential for pipelines, platforms, and wells associated with these fields to be used for associated CO_2 storage operations.
- **Hydrogen storage**, where depleted fields are used as storage reservoirs, and again, the potential for associated pipelines, platforms, and wells to be used in operations. This technology has a Technology Readiness Level below 4. H_2 storage in depleted fields has several technical challenges that have not yet been overcome. There are no current projects in the UK or anywhere else in the world, but the technology could mature in the coming years, and front-end engineering and design (FEED) studies are currently being undertaken to redevelop Centrica's Rough gas storage field for H_2 hydrogen storage .
- **Hydrogen transportation through existing offshore pipelines**, for which the offshore case seems to be most prominent in the case of offshore electrolysis. Transporting pure hydrogen through existing gas pipelines is not a mature technology and is not done at-scale anywhere in the world. However, pilots are underway, including National Gas' FutureGrid programme – which is testing H_2 blends up to 100% at a purpose-built facility in Spadeadam, Cumbria.



Notes: There might be individual cases where use cases 49 are in fact considered. However, the aim of this study is to understand bgger trends and impacts. | 1. Long list based on expert interview.
Source: Expert interviews

Figure 8: Prioritisation of repurposing use cases[48]

Below we summarise, for each of the three priority use cases, the capacity required, the capacity available, site selection criteria, ability to repurpose infrastructure and implications for likely level of repurposing of disused oil and gas assets.

Repurposing use case 1: CO_2 storage

The opportunities for CO_2 storage in depleted fields are quite certain, and several projects are already at advanced planning stages or have taken Final Investment Decision. However, relative to the breadth of infrastructure available, the opportunity to repurpose infrastructure for CO_2 storage will be very limited.

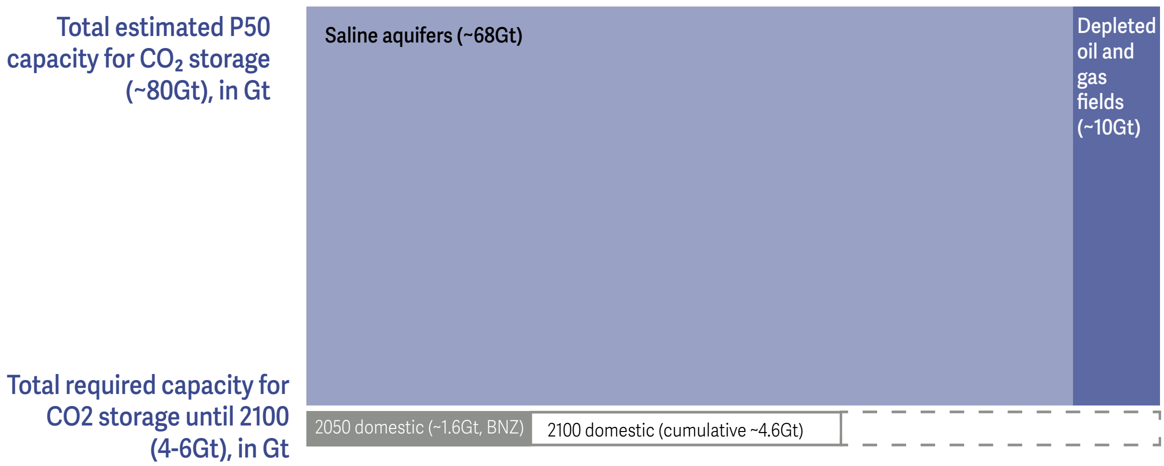
Demand for CO_2 storage capacity: The CCC estimated required CO_2 storage capacity for UK domestic CO_2 capture needs ranges between 1.1-2.3 Gt cumulative by 2050[49]. Capture beyond 2050 is difficult to predict, but an initial estimate suggests the maximum additional demand for storage capacity to be ~4 Gt. Thus, the demand for CO_2 storage would be ~1.1-2.3Gt cumulatively by 2050 and could be ~4-6Gt cumulatively between today and 2100[50]. Beyond domestic needs, the UK is well placed to import CO_2 captured in neighbouring countries in the future given its abundant storage availability.

The CCC does not take a view on potential UK imports of CO_2 for storage. The

Carbon Capture and Storage Association's (CCSA) CCUS Delivery Plan 2035 lays out three scenarios for the development of the UK's market. In their 'Global Leadership Scenario', the "UK, as a first mover, is a major sink for European emitters", and by 2050 a cumulative ~0.5 Gt of CO_2 is imported and stored in the UK[51]. Experts from The British Geological Survey (BGS) indicated in an interview they also see a high potential for the UK to store imported CO_2.

Availability of CO_2 storage capacity: The estimated available CO_2 storage capacity on the UKCS exceeds any estimate for storage demand. The total estimated capacity by the BGS CO_2 Storage Appraisal Project, at the P50 confidence level[52], is ~80 Gt, split between saline aquifers (~70 Gt) and depleted oil and gas fields (~10 Gt)[53]. Though this theoretical capacity is large, there is significant uncertainty over the economic, technical, and regulatory viability, and a large proportion may not be practically suitable for CO_2 storage. Attaining definitive numbers on total suitable capacity requires rigorous on-site technical appraisal of each individual reservoir.

Though there are distinct pros and cons for aquifers and depleted fields, there is no definitive preference for either of the two options. An important benefit of repurposing a depleted field versus a saline aquifer is that the reservoir is already well-known and understood, which can reduce development planning and appraisal. On the other hand, saline aquifers tend to have higher integrity and no risk of faulty wells. Current planned projects show a balance between saline aquifers and depleted gas fields. Aquifer-based projects include the Northern Endurance Partnership (which has taken their Final Investment Decision (FID)), Acorn, and Poseidon, and depleted field-based projects include HyNet North-West, Viking, Bacton Thames Net Zero, Medway Hub, Orion, Morecambe Net Zero, and Enquest (none of which have yet taken FID).



Notes: Storage capacities are P50 theoretical estimates for storaget capacity and requirements are for the UK only. Box sizes are proportional to total estimated storage capacity, taking into account pressure and temperature, and thus not volumes. Required CO2 storage includes CSS, BECCS, and DAC. Note that though theoretcially available, technical, regulatory, commercial, and economic factors limit actual potential. | 1. CCC Balanced Net Zero Scenario

Figure 9: Demand for and supply of CO_2 storage capacity in the UK North Sea

An initial desktop review of asset-level suitability of depleted fields based on a large set of defined criteria (such as porosity, permeability, geospatial characteristics, and others[54]) finds that 21 fields are highly suitable with a total capacity of ~3Gt, and 118 fields have medium suitability with a total capacity of ~6Gt[55]. The remaining fields are likely unsuitable, often because storage capacity is too low (so the investment case is not justified) and sometimes because technical requirements are unmet. Aquifers were not included in the review, but as explained above, these are likely to comprise the majority of future CO_2 storage capacity in the UK.

The geospatial distribution of suitable depleted fields is quite balanced, as mapped in figure 9 below. It is expected that every Carbon Capture hub on the UK will be able to find suitable storage capacity in the vicinity. However, it is worth noting:

- The Southern North Sea has a particularly attractive geology for CO_2 storage with multiple sizable and suitable fields located near shore and relatively close to each other.
- Most fields in the Central North Sea are relatively small and are not suitable for CO_2 storage. Under these circumstances several alternatives could be considered: taking a clustered approach where multiple smaller depleted oil and gas fields comprise are developed together to form one CO_2 storage project (the Acorn project is taking this approach), storage further offshore, or using aquifers rather than depleted oil and gas fields.

Where depleted oil and gas fields are suitable and attractive to repurpose for CO_2 storage, the use of the field itself and the associated infrastructure (platforms, pipelines, wells) must be considered separately:

Repurposing a depleted field. The reservoir (depleted field or aquifer) is the decision driver when selecting a site for CO_2 storage. The economic and technical feasibility of CO_2 storage is determined by the reservoir and well-related metrics, and less so by the availability of other existing infrastructure. Where depleted fields are suitable and attractive to repurpose for CO_2 storage, their wells must be plugged and abandoned to a high standard. This comes at increased costs, potentially up to 35% higher than standard plugging and abandonment, so suitability of a field must be understood before decommissioning is carried out[56]. An unanticipated acceleration of phase-down of the basin could jeopardise the ability to appraise and plan for repurposing. However, if the wells are decommissioned appropriately and repurposing planned accordingly, the field can be left for several years before storing CO_2, and no strict temporal matching between CoP and repurposing is required. To minimise costs, higher standard plugging and abandonment is only likely to be carried out for fields likely to be used for carbon storage.

Repurposing associated infrastructure. Whether infrastructure at the field can be repurposed is of lower priority than field suitability: it has no impact on technical feasibility of using a field for CO_2 storage and has a limited impact on economics. It is theoretically possible to repurpose pipelines, wells, risers, and platforms for CO_2 storage operations with some general refurbishment and replacement of some equipment such as vents and compressors. However, in practice, several of the first planned projects in the North Sea have opted for greenfield. Reasons to develop greenfield infrastructure and installations include more cost-effective or higher quality meeting of technical requirements, risk management, the desire to optimally position the injection wells, and a meagre economic benefit of repurposing versus greenfield (especially on the project's total costs). If infrastructure is to be repurposed, CoP and repurposing of installations and infrastructure would ideally happen concurrently, and certainly within 1-2 years – implying that close temporal matching between the two is necessary.

The alternative would be to hibernate assets for a period, to allow repurposing later. However, any form of hibernation requires explicit approval from the regulator, and operators prefer decommissioning over hibernating assets due to costs and balance sheet risks. As such, decommissioning usually occurs soon after CoP, and once the asset is decommissioned (even if decommissioned in situ), it will no longer be suitable for repurposing.

Finally, the overall number of UK CCS projects will not be large. The CCC estimates an annual CO_2 injection requirement to increase to up to ~100Mtpa in the next decades. The average size of UK projects announced to date is 5-10 Mtpa injection rate, and below 5Mtpa is considered noneconomical. As such, the total number of projects is likely to be between 15-20 (compared to hundreds of fields and platforms).

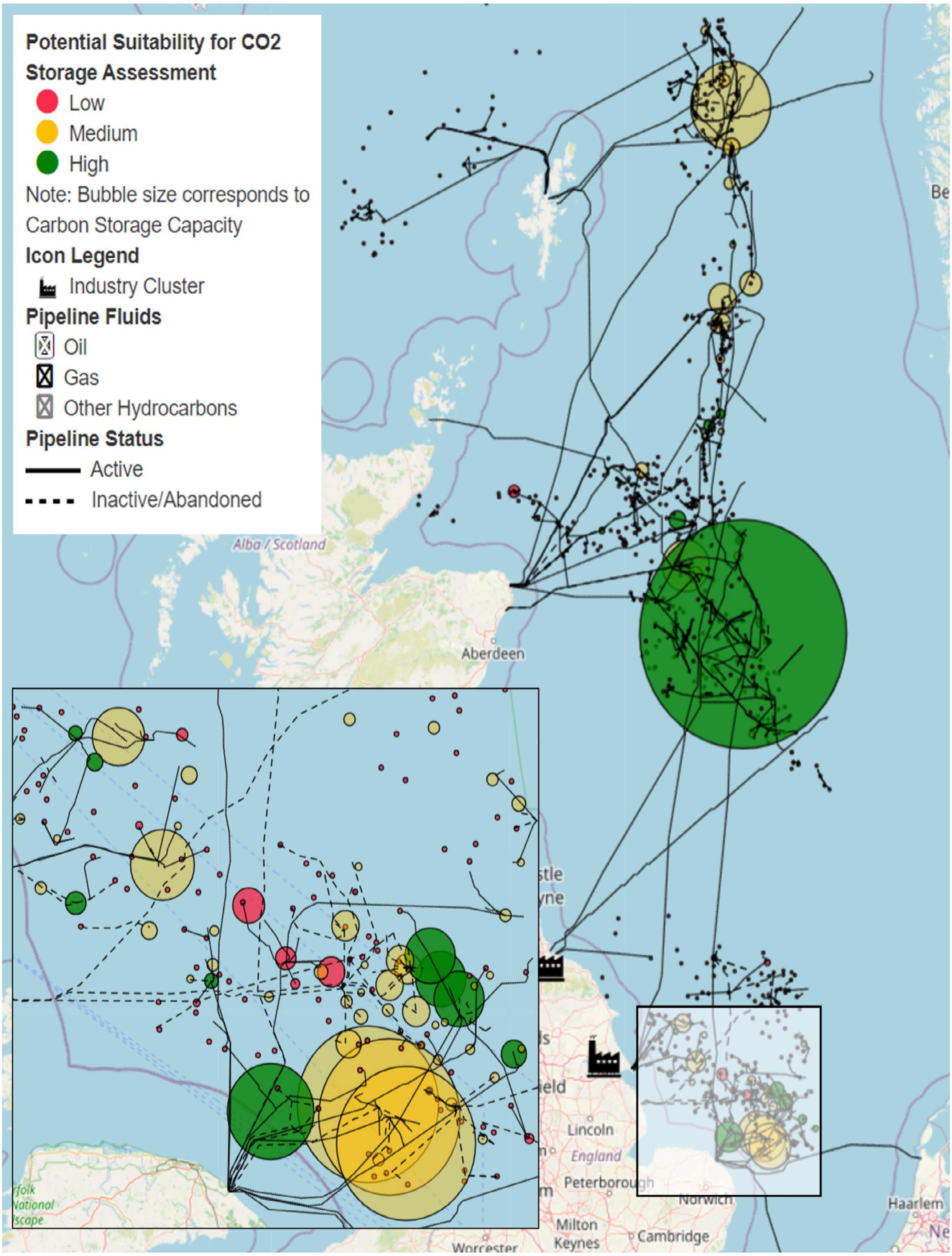


Figure 10: Field-level CO_2 storage suitability screening

Repurposing use case 2: Hydrogen storage

The opportunities for H_2 storage in depleted fields are highly uncertain, and there is relatively low expected total demand for large-scale offshore geological H_2 storage. As such, H_2 storage in depleted fields and unlikely to scale significantly.

Demand for H_2 storage capacity: The estimated 2050 and beyond requirement for UK domestic H_2 storage varies between 17 and 150TWh and is highly dependent on assumptions about the uptake of hydrogen use for power-to-gas-to-power to balance a variable renewable dominated power system (versus natural gas plus CCS) and hydrogen use in building heating (versus electrification)[57 58].

H_2 storage is fundamentally different from CO_2 storage, in the sense that while CO_2 is stored to lock it away forever, hydrogen is stored to recover it again later. This has two implications: First, H_2 storage does not cumulate the way that CO_2 storage does, and second, injection and extraction cycle length matters, ranging from intra-day to seasonal or even longer cycles. These cycling rates in turn dictate suitable storage type, ranging from smaller storage tanks for intraday cycling to large geological reservoirs for long-term storage. Using depleted fields for H_2 storage would only make sense for long-term storage and/ or seasonal cycling, which presents a subset of the 17-150 TWh demand range.

Availability of H_2 storage capacity: There is an estimated 18,000 TWh of geological hydrogen storage capacity available in the UK and the UKCS, of which 9,000 in salt caverns, ~7,000 in depleted fields, and ~2,000 in saline aquifers[59].
At present, salt caverns are clearly the most suitable geological reservoir for H_2 storage in the UK: they are abundantly available in strategic onshore locations, costs of storage are low due to low cushion gas requirements, and the technology is proven at Technology Readiness Level 9[60]. In fact, hydrogen has been stored in salt caverns across the world since the 1970s. Depleted fields and aquifers on the other hand are at Technology Readiness Level 2-3. Several technological challenges must be overcome before H_2 storage in depleted fields is ready for commercial deployment. There are no planned projects for H_2 storage in depleted fields anywhere in the world, but some research and testing is underway.

Repurposing a depleted field: Our initial estimate (based on a range of criteria such as well delivery rate, cushion gas to working gas ratio, porosity, permeability, and geospatial characteristics) suggests that a small number of fields in the UKCS would be highly suitable for H_2 storage, with a combined capacity of ~130TWh[61]. If and when the technology to store hydrogen in depleted fields matures, there could be a rationale for storing strategic H_2 reserves in those reservoirs.

Repurposing associated infrastructure and installations: It is unclear whether there is any economic benefit is repurposing existing assets, versus developing new. The hydrogen molecule differs in size and properties from the CO_2 molecule. As such, integrity requirements and technical specifications for infrastructure to process and transport hydrogen are more stringent than those for methane or CO_2. Though some oil and gas assets can in theory be repurposed, this requires significant retrofit and refurbishment, especially when valves, compressors, and other handling equipment is needed.

Repurposing use case 3: Hydrogen transport from offshore electrolysis

The opportunities for H_2 transport through disused gas pipelines are highly uncertain. While technical feasibility is expected in the next years, demand for offshore transport of hydrogen remains unclear and highly dependent on offshore electrolysis business cases.

Demand for offshore hydrogen transport: As wind parks are constructed further offshore towards 2040/50 (especially once floating wind is deployed), a business case for offshore electrolysis may emerge. While building an electrolysis plant onshore costs less than offshore (no need for an offshore platform/ island, no need for a desalination plant, and lower maintenance cost), offshore pipelines are comparatively cheaper than offshore power cables[62]. Experts expect that offshore electrolysis becomes economically viable beyond 100-150km from shore as the cost-benefit of pipelines over cables exceeds the cost-benefit of onshore electrolysis versus offshore. The scale at which offshore electrolysis will materialise is, however, highly uncertain.

Repurposing oil and gas infrastructure: While commercial-scale electrolysers are too large and heavy to be housed even on the largest platforms in the North Sea, existing gas pipelines could potentially be used to transport hydrogen from the electrolysis plant back to shore. Transportation of pure hydrogen through existing gas pipelines is not yet technologically mature, but experts expect that this will become feasible in the next years and decades and testing is currently underway.

For example, National Grid has created FutureGrid high pressure test facility to assess the effects of hydrogen on pipes and assets[63]. If hydrogen transport using offshore existing pipelines does reach technical maturity, we estimate that at least 8 pipelines are potentially suitable based on several criteria desk research, including the Knarr, Goldeneye, and Sean to Bacton pipelines[64].

In conclusion, while repurposing of assets is possible today for CO_2 storage, and potentially in the future also for several hydrogen use cases, the scale of repurposing will be limited compared to the amount of existing infrastructure available. As such, most assets will need to be decommissioned.

2.2 Decommissioning oil and gas assets

Only a small number of total UKCS installations and infrastructures will likely be repurposed for the clean energy scale-up. As per the United Nations Convention of the Sea[65] and the 1998 UK Petroleum Act[66], all infrastructure and installations that are not repurposed must be decommissioned after Cessation of Production. This section explores these costs and some key considerations for UKCS stakeholders in relation to decommissioning.

In the case of platforms and other sub-sea installations, decommissioning means complete cleaning and removal from the marine environment. In some instances, derogation is granted, for example, if concrete substructures are too heavy to remove at acceptable risk. Total costs of decommissioning UKCS oil and gas infrastructure are estimated to be ~£40 billion[67]. Total costs of platform removal are estimated at £14-16Bn, and an additional £1-2 billion for other subsea installations. Wells must be plugged at several intervals in the well, and all structures above the seabed must be removed. The total costs of decommissioning wells are estimated at £16-20 billion. Finally, pipelines must be cleaned and disconnected and are typically decommissioned in situ. In some cases, they are buried, and in most cases, seawater is let in to let the pipelines degrade. Total costs of pipeline decommissioning are £1-2 billion[68].

Managing decommissioning carefully is critical to minimise taxpayer costs. While decommissioning costs are borne by the asset owner, part of the costs are passed onto the tax-payer through the fiscal regime. Operators can carry back decommissioning costs against previous profits, resulting in tax rebates. Additionally, operators can deduct decommissioning costs from their taxable profits, reducing in year tax income to the Exchequer. His Majesty's Revenue and Customs estimates that the net result of both effects yield estimated costs to Treasury of £21.8 billion over the next four decades, with the largest share of costs landing in the next two decades.[69,70]

However, total decommissioning costs are not fixed. They can increase or decrease depending on the rigor of decommissioning planning, phased use of supply chains, and cost optimisation. In fact, industry's ability to coordinate activity, share knowledge and produce robust plans helped lower the decommissioning cost estimate by £15 billion between 2017 and 2022[71]. One good example is the NSTA coordinated wells-decommissioning campaigns, where one ship is commissioned to decommission wells from fields owned by several operators, capturing economies of scale and supply-chain efficiencies. Disorderly decommissioning or delays to decommissioning will lead to higher costs, which also results in higher costs incurred by the treasury.

Another area for attention is the risk of operator defaults or operators retracting from the basin while decommissioning liabilities are still outstanding. Under section 29 and section 34 of the Petroleum act[72], in the case of an operator default, the state can pass on the decommissioning liability to previous owners of the asset. However, if no previous owner is able to decommission the liability is passed onto the state. 20-40% of fields on the UKCS are not and have not been owned by a large operator in the past, and thus, the state is more exposed to default risk for this subset of assets[73]. NSTA and OPRED have a more detailed view of operator default risk, but this information is, as of today, not public.

Decommissioning can be an economic opportunity for the UK. The ~£40 billion decommissioning expenditure, of which the vast majority will be spent between today and 2040, is also a major economic opportunity. As part of the North Sea Transition Deal the industry has agreed a target of 50% UK content over the lifecycle of decommissioning projects, including capital investment[74].

Under current Supply Chain Action Plans (which operators must submit to demonstrate actions to meet this target), UK suppliers will secure 70% of work[75]. This growth in employment offers a critical buffer for communities impacted by the decline of traditional oil and gas roles, as many decommissioning jobs require similar skills and expertise. Capturing this opportunity, however, will require investment in UK skills and supply chain capacity, as well as careful coordination and planning to maximize utilization of local supply chains. Whilst detailed data was not available, evidence from interviews during this study found that that most large UKCS decommissioning projects to date had been done by crews and workers from abroad. There are also only 4 scrapyards in the UK with the capability to recycle platforms[76].

In addition to employment opportunities, decommissioning is a highly technical field, demanding innovative approaches and specialised knowledge. As one of the first major offshore basins to enter large-scale decommissioning, the UK has the chance to position itself as a global leader. By mastering decommissioning techniques domestically, the UK could export its expertise and services to other basins worldwide, transforming a domestic necessity into an international economic and strategic advantage.

In conclusion, there are several reasons why it would be sensible to develop a more coordinated approach to the decommissioning effort. While the NSTA and OPRED already coordinate decommissioning to the extent that their mandate allows, further efforts to set Cessation of Production dates further in advance, phase CoP dates smoothly, streamline the supply chain, and coordinate joint decommissioning efforts could further improve outcomes for society.

Outcomes for society

As the UKCS transitions away from oil and gas production, many stakeholders have concerns. There are currently an estimated 120,000 people directly and indirectly employed in the offshore oil and gas sector who are uncertain about their opportunities outside the sector, roughly 40% of domestic gas consumption is supplied by the UKCS, and the government collects annual tax revenues (including the post-COVID windfall tax) from UKCS oil and gas production between £3.8-5.2 billion.

As such, it is critical that the societal risks in terms of jobs, tax revenues, and energy security are mitigated through proactive management. On the other hand, given that the UKCS is already in decline, and will continue its decline in all scenarios, demonstrating how this decline can be managed via an orderly, rapid and just UKCS transition offers a significant opportunity for the UK to demonstrate global climate leadership. Two important levers are the clean energy scale up to provide alternatives to fossil fuel consumption, and the decarbonization of industry and homes to allow end-users to switch to these clean energy sources. If the UK can succeed in both challenges (in line with the UK CCC Balanced Net Zero pathway), manage the decline in oil and gas production in an orderly and planned way, and develop expertise in offshore clean energy activity, total UKCS energy jobs as well as energy security could increase. Given that the UKCS basin is in decline tax revenues will also inevitability decline.

In this chapter we explore the UKCS transition outcomes for jobs, energy security, tax revenues, and the UK's global climate leadership. The MAX, NNF, and APD oil and gas production scenarios (explained earlier in the study, see figure 4) as well as clean energy targets and pipeline (see box 2) were used to underpin the analysis.

BOX 2

STATE OF THE UK'S CLEAN ENERGY SCALE-UP

Offshore wind

- Current offshore wind capacity on the UKCS is 15 GW (as of December 2023). Following the Contract for Difference (CfD) Allocation Round 6, completed in September 2024, there is a pipeline of ~31 GW, of which ~8 GW is under construction. The remaining projects are divided into secured CfD (~9 GW), consented but not yet secured CfD (~5 GW), and consent application submitted but not yet approved (~8 GW).

- If the current pipeline of secured CfD, consented, and consent submitted projects come online by 2030 this would lead to 46 GW deployed by 2030 (corresponds to "current pipeline" scenarios in figure 10). This is just short of the 50 GW 2030 target (corresponds to "targets are met" scenarios in figure 10) and the 48 GW capacity requirement based on CCC offshore wind power generation trajectory in the Balanced Net Zero scenario[84].

- Delivering the entire 31GW pipeline and/ or 35GW additional target to reach targets in the next 5 years will be a difficult task given long lead times for wind and grid-related development[85]. Recent policy developments have recognised these challenges and started to set out elements of a delivery plan. For example, the new Mission Control for Clean Power 2030 will work with energy companies, Ofgem, the National Grid and new National Energy System Operator (NESO) to deliver a clean power system by 2030. The Clean Power Action Plan published by NESO in 2024 includes plans to change the connections queue and expand the CfD system[86].

CO_2 storage

- CO_2 storage in the UK is not yet operational, and as such annual storage today is zero. The government target for 2030 is 20-30 $MtCO_2$ storage per annum, which is slightly higher than the CCC outlook on required annual CCS (22 $MtCO_2$ per annum) in the Balanced Net Zero scenario from the CCC. The pipeline of planned projects is quite thick, at a total of 64 $MtCO_2$p.a. of storage by 2030[87] and 49 MtCO2p.a. of capture by 2030, but experts expect that up to 50% of these projects will never reach CO_2 injection, due to challenges related to economics and technical feasibility of developing and scaling new CCS projects[88].

- Only one UK CCS project (Hynet) has taken Final Investment Decision in December 2024, following confirmation that a total of ~£20 billion would be invested by the government in CCS projects over project lifetimes[89]. Whilst the government announcement aimed to provide confidence to developers and clarity to stakeholders in the energy system, some uncertainty remains. Five of the eight track-1 CCS projects are still awaiting decisions on government funding[90].
.
- The NSTA has awarded 27 carbon storage licences for depleted oil and gas fields and saline aquifers to date[91].

  If all these became operational, they could store up to 30 $MtCO_2$p.a by 2030, but this is highly unlikely, given the uncertainty around technical feasibility for carbon storage (discussed above). Greater investment in pre-licence appraisal is required to fast-track storage development, as it can take up to 10 years between an exploration licence being issued and a field being ready for injection and securing the associated carbon storage permit.

3.1 Outcomes for oil and gas workers and their communities

In this section we evaluate the overall employment impacts on the UKCS energy system of the transition, under different scenarios. When describing the number of jobs in the industry, one of three definitions is typically used:

- Direct jobs, defined as "employment in companies that provide specialist goods and services with a focus on oil and gas projects". Both Offshore Energy UK (OEUK)[77] and the UK Office for National Statistics (ONS) estimated in 2022 that there are ~30k jobs in this category.
- Direct and indirect jobs, which in addition to direct jobs includes "employment in the wider supply chain whose roles are supported by oil and gas activity". OEUK, the Energy Skills Intelligence Hub (ESIH), and Robert Gordon University (RGU) estimated that there are ~120k jobs in this category.
- Direct, indirect and induced jobs, which in addition to direct and indirect jobs includes "employment created by the additional personal spending (e.g., eating at a restaurant) by both direct and indirect workers". OEUK estimated that there are ~200k jobs in this category.[78]

This study examines both direct and indirect jobs, as focusing solely on direct jobs is widely regarded as too narrow and not representative of actual employment in the sector. At the same time, including induced jobs is often seen as overly speculative and less reliable. This study has leveraged data and insights from the Energy Skills Intelligence Hub database. This database provides bottom-up, detailed job forecasts vetted by experts and tested against other forecasts. To our knowledge, this is the most comprehensive and detailed jobs database currently for UK Energy jobs. Important to note, however, is that underlying assumptions are only qualitatively available publicly.

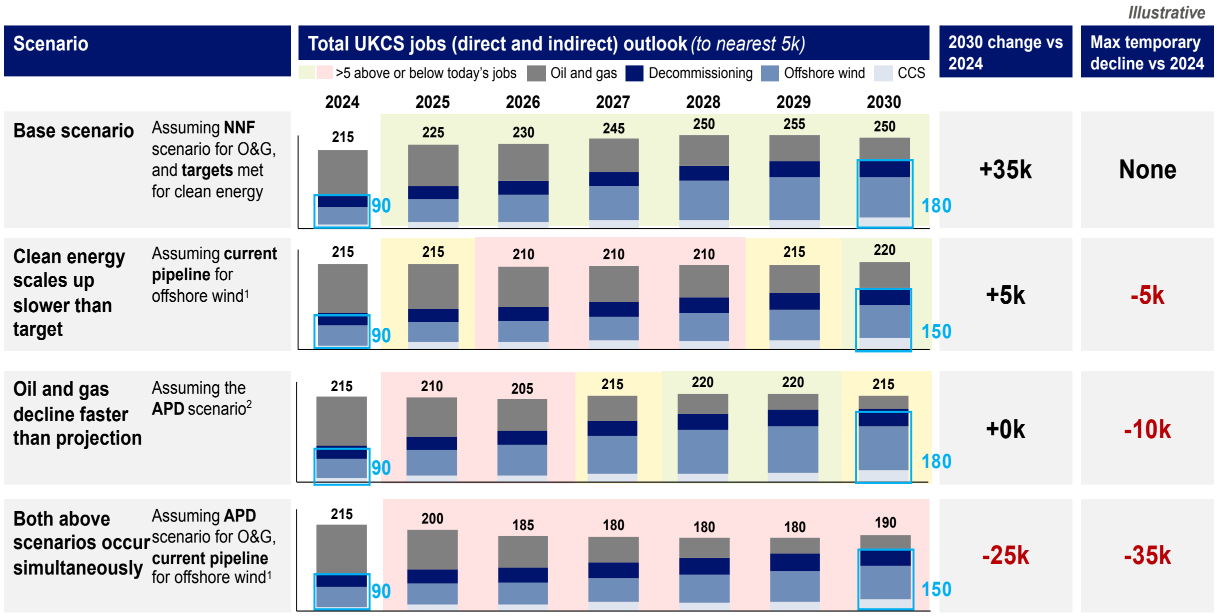
Employment trends and opportunities throughout the UKCS transition

Regardless of policy direction, employment in oil and gas exploration and production is set to decline over the coming decades, approaching near-zero levels by 2050 or earlier[79]. Even under a maximum oil and gas production scenario, annual output in 2030 is projected to be approximately 45% lower than in 2024, inevitably leading to job losses.

A 2020 Greenpeace survey of around 1,400 UK offshore oil and gas workers suggests that over 80% would consider employment outside the sector, with offshore wind, decommissioning, and carbon capture and storage (CCS) emerging as preferred alternatives[80].

The cumulative jobs in the UKCS energy sector will depend on the pace of the oil and gas sector decline as well as the pace of the clean energy scale-up. Figure 10 shows the outcomes of a scenario analysis, comparing on the one hand the speed of oil and gas sector decline, with NNF being the slow decline scenario and APD the faster decline scenario, and on the other hand the pace of the clean energy scale-up with government targets being the fast scenario, and realization of current pipeline only the slower scenario.

In summary, if government targets for offshore wind and CCS are met, employment in non-oil and gas sectors on the UK Continental Shelf (UKCS) could double in the next 5–10 years, increasing from ~90k to ~180k jobs (figure 10), serving as a significant jobs growth engine and hedge against oil and gas jobs decline. However, if oil and gas sector declines at accelerated pace and the clean energy scale-up does not accelerate, net jobs are likely to go down.



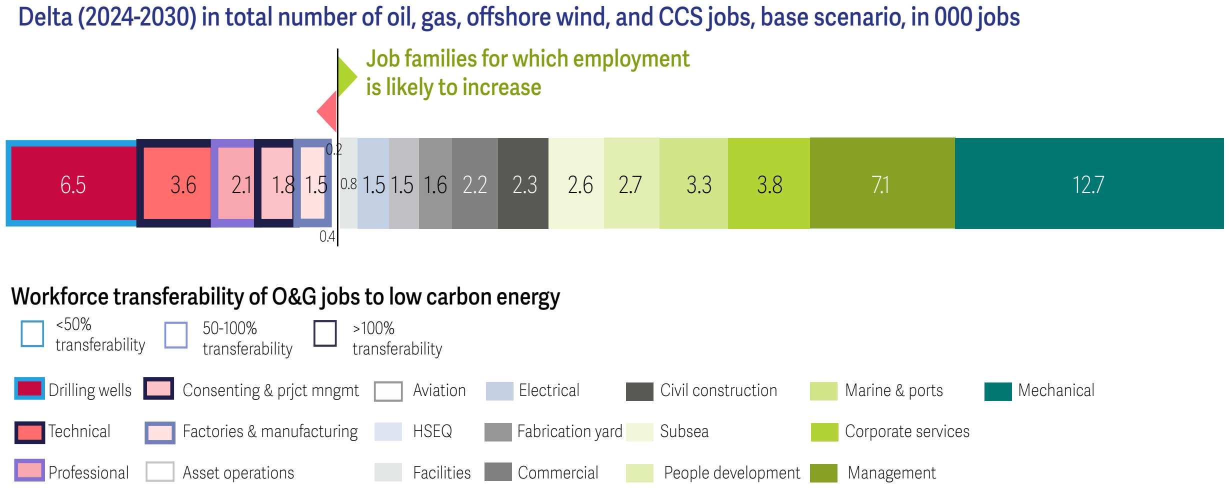
Notes: 1. Offshore wind pipeline from BNEF database. Assume same jobs intensity per GW as RGU 2021 Workforce Transferability study2. Oil and gas jobs intensity figure from ESIH 2024 jobs projection applied to 'accelerated phase down' production scenario. Decommissioning jobs assumed the same – more decommissioning takes place, but assumed UK supply chains cannot absorb the increase as additional decommissioning is disorderly and less well-planned
Sources: Energy Skills Intelligence Hub (ESIH); *UK Offshore Energy Workforce Transferability Review*, Robert Gordon University Energy Transition Institute, May 2021; Nes Fircroft, *UKCS Decommissioning Cost and Performance Report 2023*, NSTA, 2023; Systemiq analysis

Figure 11: UKCS energy jobs to 2030

Ensuring a smooth transition for workers

Across the 19 identified job families spanning offshore wind, CCS, decommissioning, and oil and gas production, demand is expected to rise in 13 categories (figure 11). Mechanical roles, for instance, are forecast to grow by ~13k while management and corporate services are projected to add ~11k jobs. Conversely, five job families are expected to see a decline, including drilling and wells capabilities, which could lose around 6,500 jobs by 2030[81].

Additionally, thousands of positions in professional oil and gas services and related manufacturing will require reskilling to enable a smooth transition into emerging industries.



Notes: 1. Based on mapping job family categories in RGU study to categories in ESIH database. Note this is RGU central scenario - 40GW offshore wind, 20MtCO2, CCS, 5GW H20, 0.7mn boe/d O&G by 2030, 30-40% UK offshore energy Capex executed by UK supply chain by 2030 (consistent with ESIH base scenario).
Sources: Energy Skills Intelligence Hub; Robert Gordon University Energy Transition Institute (Sept 2023) Powering up the Workforce: the future of the UK offshore energy workforce

Figure 12: Job-family level growth and transferability of skills

A good transition for oil and gas workers will require not only maintaining or increasing job numbers but also safeguarding job quality. Anecdotal evidence suggests that oil and gas roles tend to offer higher salaries than those in the renewable energy sector. A European-level study[82], indicates a salary differential of approximately 10–20%, but UK-specific numbers are not publicly available. Should the gap exist in the UK too, factors such as the reduced need for overnight offshore stays and reduced on-the-job risks may partially explain the differential. Further, anecdotal insights from stakeholder interviews point to concerns regarding job security in the renewable sector, where – in the deployment phase – roles are frequently subcontracted, often without fixed contracts and / or with lower levels of union membership advocating for workers in the renewables sector. These issues require deeper investigation to inform policies that mitigate potential disparities and ensure equitable outcomes for transitioning workers.

While most regions are expected to benefit from UKCS related job growth, modelling from the Energy Skills Intelligence Hub suggests that there could be small number of specific regions or towns where the net jobs impact turns out negative[83]. Special attention to such regions would be warranted, to manage potential adverse impacts.

By addressing these challenges, the UK can support its workforce through a fair and sustainable transition, maximizing opportunities in the renewable energy sector while minimizing economic and social disruptions (refer to Chapter 4 for more detail).

3.2 Outcomes for energy security

While the relationship between domestic fossil fuel production and energy security is complex, the phasedown of UKCS production carries significant implications for the UK's reliance on energy sources from abroad, and its exposure to volatile fossil fuel prices, which are determined by global events (e.g. Russia's invasion of Ukraine in 2023).

The focus of this section is on how the phase down of UK oil and gas production may impact UK energy security. Note, is does not explore overall energy affordability in depth beyond the impact of fossil fuel price volatility. Therefore, it does not go into the policy mechanisms which might be required to support energy affordability in a clean energy system (e.g. reforms to power market design, etc).

Energy production, imports, and dependence trends

Today, gas production from the UK Continental Shelf (UKCS) meets approximately 40% of the UK's domestic natural gas demand, while oil production satisfies around 60% of domestic petroleum demand. However, this presents a simplified view of energy dependence, as the UK operates within a highly interconnected global energy system.

The global oil market exhibits a very high level of interconnectedness. Around 75% of crude oil produced in the UKCS is exported for refining abroad (see figure 12 below), meaning that domestic production has minimal influence on the UK's gross imports of crude and refined oil products[92].

The relationship between energy security and domestic oil production is indirect, and decline of domestic oil production does not significantly alter UK energy security.

For natural gas the situation is different: most UK-produced gas is consumed domestically. In 2023, the UK imported ~500 TWh of natural gas and exported ~175 TWh[93].

Export is mainly driven by seasonal demand variation and low gas storage capacity in the UK: during the summer months, liquefied natural gas (LNG) is imported and transported via pipeline to Europe, whereas in winter, significantly lower volumes are re-imported[94]. The most important import partners for the UK are Norway (at ~58% of total gas imports in 2024), the USA (~26%), and Qatar (~6%). Other import partners include Peru, Angola, Algeria, and other, which each make up less than 5% of total UK gas imports[95]. The UK has direct gas pipeline connections with Norway, the Netherlands, Belgium, and Ireland, allowing for gas trade to occur via pipeline. From other countries, the UK imports LNG.

Given the international dynamics already at play regarding UK domestic oil production, the remainder of this chapter focuses on gas.

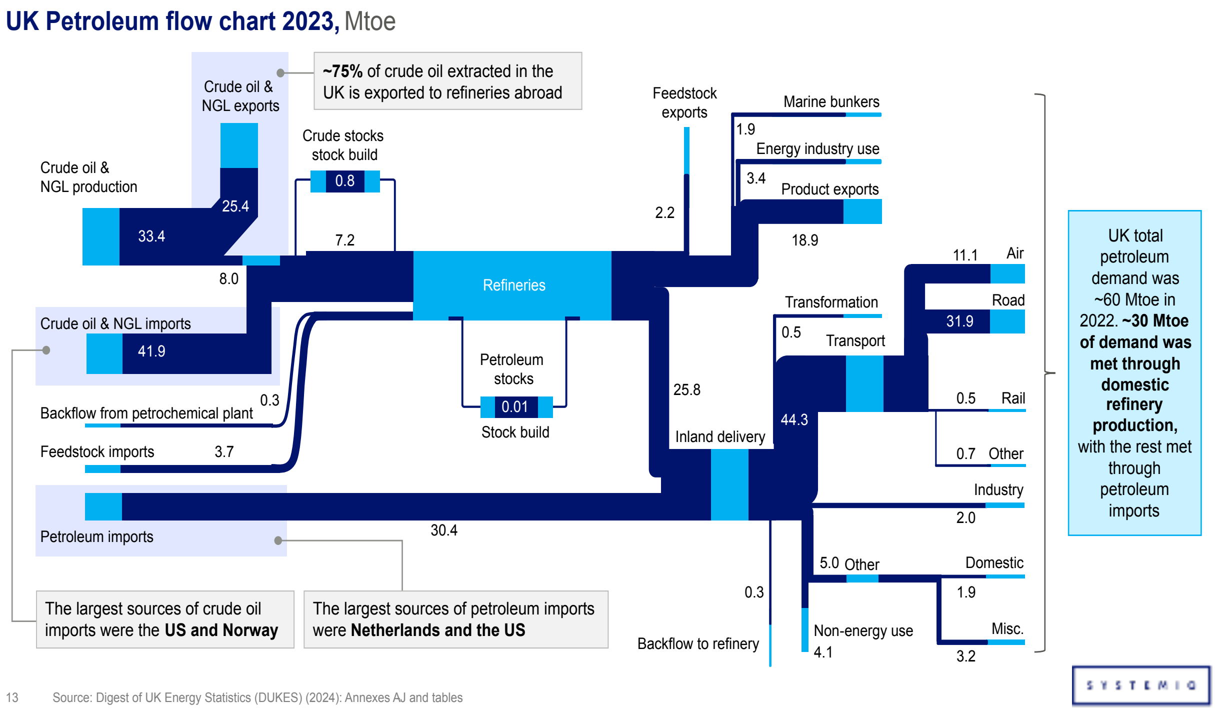
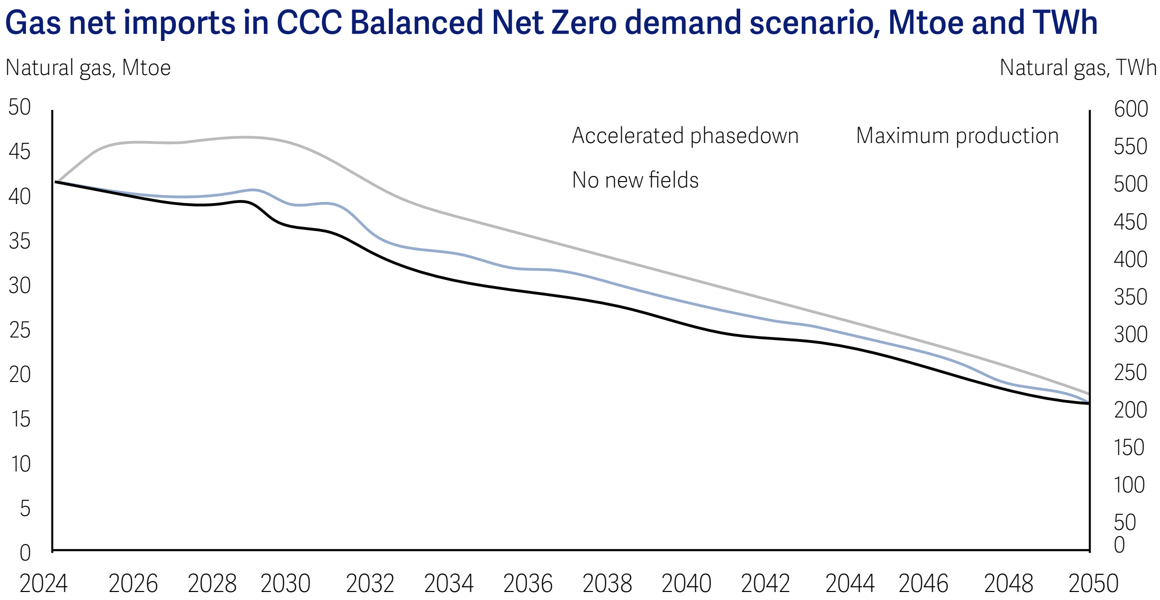


Figure 13: UK petroleum flows

Impact of gas production phasedown on UK energy security

If the UK aligns with a net zero trajectory and can progressively shift away from gas use in residential buildings, commercial buildings, and industry, the future contribution of domestic gas production to energy security will be limited. The CCC's BNZ pathway has domestic gas demand declining from 836TWh today to 631TWh by 2030, via electrification and increase energy efficiency[96].

Against this BNZ trajectory, across the three UKCS production scenarios in this study, UKCS production would meet 30% of domestic gas demand in 2030 in the MAX scenario and only 15% in ADP. This represents a decline from the ~40% of consumption domestic production provides today, although the decline is relatively modest in the case of the MAX and NNFs scenarios. It is also worth noting that as both consumption and production levels are falling simultaneously, across scenarios absolute gas imports remain broadly consistent at ~39-46 Mtoe (~40 bcm), or ~450 TWh, similar to today's levels[97]. Beyond 2030, if the CCC's BNZ is realised, even with declining production, absolute gas imports will decline (and oil imports, although this is not the focus of the analysis here) (see figure 13) as a result of the accelerated shift in the UK's energy mix away from oil and gas consumption, and towards renewables based electrification, bioenergy, and hydrogen.



Note: Oil and gas production data converted to TWh using 0.074 Mtoe per TWh for oil and 0.087 Mtoe per TWh for gas (based on historical data).
Sources: Systemiq analysis of UK CCC and NTSA

Figure 14: Projected UK gas imports[98]

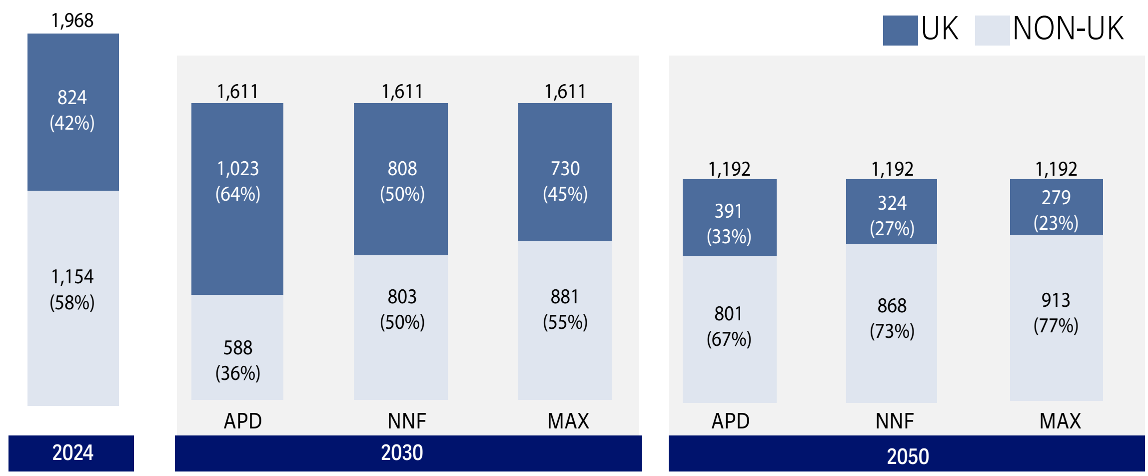
The UK's overall energy security position must take all energy imports into account. Looking beyond oil and gas, the increasingly electrified UK economy laid out in the BNZ pathway would also see potential for power, hydrogen and biomass imports. However, a clean energy economy is expected to rely more strongly on domestic production, e.g. of the ~360TWh of power demand in 2030, the CCC expects ~240 TWh to be produced from domestic wind and solar[99].

Across the three UK oil and gas production scenarios analysed here, energy import dependence is expected to be similar in 2030 relative to today in the MAX and NNF (~50-55% domestic production overall) and decrease to 36% in the ADP accelerated decline scenario – an increase of 14% vs. NNF (see figure 14). By 2050 the impact of different UKCS oil and gas scenarios on energy import dependence is marginal, as oil and gas demand should be very low. Across scenarios, energy import independence would be significantly strengthened, as the build out of domestic clean energy production, shift towards clean energy sources in buildings, industry and transport, and improvements in energy efficiency reduce reliance on foreign energy sources.

As discussed above with respect to oil, it is worth noting that these shares represent net imports, and therefore include a point of view on UK energy exports. Further, as the UK shifts to an electrified economy powered by variable renewable power generation, predominantly wind, balancing the power system will become an increasingly important challenge[100].

Today balancing needs are meet by a combination of gas based electricity generation (from both domestic and imported gas sources), and regional power interconnectors to local power markets, including from Norway, France and Denmark[101]. As wind generation increases, and domestic gas production phases down, new forms of energy storage (e.g. via batteries, heat sources, or for longer storage durations via green hydrogen) and regional power interconnection will be increasingly critical for UK energy security.

Primary net energy demand mix by source in UK CCC Balanced Net Zero Scenario, TWh



Notes: Domestic coal production based on Our World in Data, assumed 0 in 2030 and 2050. Assume waste is sourced 100% locally. Interconnectors included in power analysis. UK proportion taken from CCC forecasts. Oil and gas production data converted to TWh using 0.074 Mtoe per TWh for oil and 0.087 Mtoe per TWh for gas (based on historical data).
Sources: UK Climate Chaneg Committee (2020), The Sixth Carbon Budget: The UK's path to Net Zero; Systemiq analysis

Figure 15: UK versus non-UK production of domestic energy demand

The importance of decarbonising UK homes and industry

To ensure that the expected decline in UK gas production does not compromise energy security, it is crucial for the UK to urgently decarbonize homes and industries, both of which are still heavily reliant on natural gas. While there are several policies in place, there is space for further integrated planning and policy to transition these sectors away from gas consumption in alignment with the CCC's net zero pathways, which require significant reductions in gas use by 2030. Without a clear and actionable strategy, the increasing need for imports would pose a risk to energy security, potentially leaving the UK dependent on emissions-intensive LNG imports. For instance, the CCC's BNZ pathway necessitates low-carbon district heating for 1.5 million homes and heat pumps for 2.8 million homes by 2030. While the UK government set the ambition to install 600,000 heat pumps per year by 2028[102], only around 40,000 heat pumps were installed in 2023[103 104].

Emissions intensity of imported gas

The source of gas imports has significant implications for emissions intensity (see figure 15). Norway is one of the cleanest gas producers globally. Pipeline gas from Norway has a Scope 1 and 2 emissions intensity of approximately 8 kg CO_2/boe, compared to 21 kg CO_2/boe for gas from the UKCS[105 106]. Imported LNG is particularly emissions-intensive, with scope 1 and 2 emissions ranging between 70–80 kg CO_2/boe[107],

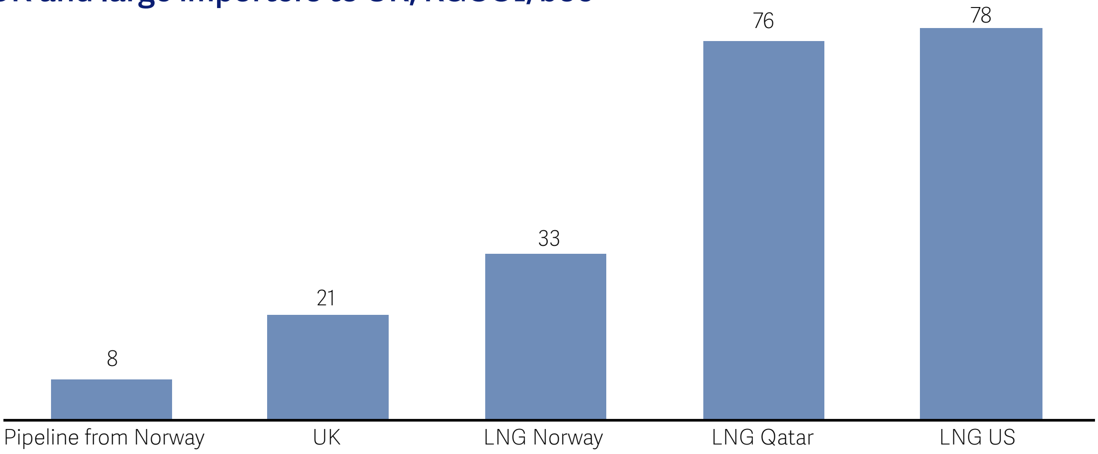
once emissions from extraction, liquefaction and transportation are considered. Additionally, many LNG sources have significant problems with methane leakage, and as such some estimates find LNG is "dirtier than coal"[108]. Currently there is no capacity to increase pipeline imports from Norway beyond today's levels[109], and piped gas import from the European continent is similarly challenged. This suggests that additional gas import requirements would be met by higher emissions LNG gas imports.

In a world where the UK aims to meet CCC carbon budget targets and deliver its decarbonisation pathways, it is important that emissions intensity plays a role in shaping both the UK's import and domestic production strategy. However, these considerations should be kept in context:

- First, it is important to remember that scope 1 and 2 emissions from production are small relative to overall emissions from oil and gas. Total oil and gas upstream emissions were 12.9 $MtCO_2e$ in 2023, which is ~3% of total UK emissions[110].

- Second, as explained above, if the UK takes the necessary actions to align with a net zero trajectory and reduces its reliance on gas combustion, absolute gas imports will steadily decline despite the expected decline in domestic gas production – thus additional imports would not be necessary.

2022 carbon footprint of gas (production, processing and transportation) for UK and large importers to UK, KGCO₂/boe



Sources: NSTA, Natural gas carbon footprint analysis

Figure 16: Emissions intensity of natural gas from different sources

Emissions intensity of blue hydrogen

A related area of consideration is the production and use low-carbon blue hydrogen within the UK as a clean fuel. For blue hydrogen to meet the UK's low-carbon classification, emissions intensity must not exceed ~2.4 kg CO_2 per kg H_2. Intensity is heavily influenced by emissions intensity of the natural gas feedstock. Currently, imported LNG far exceeds this requirement, while domestically produced natural gas remains near the threshold. As a result, the UK's ability to produce low-carbon blue hydrogen relies on continuing to access lower-emissions pipeline gas from Norway or reducing the emissions intensity of UKCS production through proactive emissions abatement and electrification of platforms[111].

However, it is important not to overstate the role of blue hydrogen in the UK's transition to Net Zero. The CCC expect clean hydrogen to meet from 10-20%[112] of the UK's final energy demand by mid-century. But recent cost trends suggest clean electrification might play a relatively larger role, taking share from hydrogen-based routes. Also, while in the short term blue hydrogen projects are scaling faster than green projects[113], longer term there are indications that green hydrogen could be the preferable, lower cost clean hydrogen production route. Green hydrogen avoids residual CO_2 and CH_4 from gas extraction and less than 100% CCS capture rates. It can also provide a potential use for excess clean renewable power generated in a variable renewable dominated system, and thus it is expected to become lower cost than blue hydrogen over the coming decades[114].

The CCC's central BNZ expects ~220 TWh of clean hydrogen to be used in the UK by 2050, and of this ~32% is from domestically produced blue sources, equivalent to ~70TWh per year[115]. However, significant uncertainty remains regarding hydrogen's future role, with modelling based on UK CCC scenarios putting 2050 blue hydrogen demand between 16-189 TWh per year. These levels are also dependant on successfully scaling carbon capture and storage projects and related infrastructure to enable natural gas reformation with CCS at scale, which as discussed above is yet uncertain.

3.3 Outcomes for tax revenues

In the years leading up to the Russian invasion of Ukraine, annual tax revenues from UK oil and gas production ranged between approximately £900 million and £1.5 billion, with the exception of the COVID-19 period (2020–2021), when revenues fell to just £311 million[116].

In response to surging global oil and gas prices, the Energy Profits Levy (EPL) was introduced in 2022, significantly boosting revenues. As a result, annual tax revenues are projected to reach £3.8–5.2 billion between 2023 and 2025[117].

However, as oil and gas production declines toward 2030, revenues are expected to decrease substantially. Under the pre-election fiscal regime and a ceteris paribus assessment based on the Office of Budgetary Responsibility's Economic and Fiscal outlook of March 2024, annual tax revenues are estimated to fall to £1.3–2.9 billion, depending on whether production follows the APD or MAX scenario[118].

Post-election fiscal changes are not incorporated into these estimates. However, civil service modelling pre-election concluded the Labour party's proposed policy changes could generate an additional £3.4 billion cumulatively by 2030[119].

This tax revenue analysis is high-level and does not include detailed consideration of possible changes in investment and investor confidence under different policy outlooks. Nonetheless, it gives an indicative view that regardless of production scenario, it is likely that UKCS oil and gas will not be a source of major tax revenue in the future.

Beyond tax revenues, UK taxpayers will also face significant costs associated with decommissioning oil and gas infrastructure. As explained above, total decommissioning liabilities for HM Treasury are estimated at £21.8 billion, primarily via tax rebates due to decommissioning activities and reduction in taxable profits[120]. The majority of this cost will materialise over the next two decades and can be reduced via advanced asset level decommissioning planning and increased cross-operator coordination of activities. Further potential risks, such as operator defaults, could exacerbate these costs, placing additional financial pressure on the taxpayer (see discussion in section 2.2).

3.4 Opportunity for climate leadership

To stay within global carbon budgets phasing out all unabated fossil fuel consumption and significant phasing down global fossil fuel production is urgently needed[121]. If the UK was to take a lead in phasing out oil and gas production it would demonstrate the UK's commitment to a 1.5ºC aligned pathway and enhance its credibility and leadership in climate negotiations going forward. There is also an opportunity for UK leadership in this space to deepen the UK's exportable expertise in fossil basin transition. UK companies can develop the technical solutions, and workers the skills, required to rapidly scale activities like oil and gas decommissioning, CCS, and H_2 storage. Exporting this know-how and experience offers an opportunity for the UK to enhance its global climate leadership.

There are several active discussions about the climate impact of UKCS oil and gas production phase-down, and the question of climate leadership and responsibility. Below, we address two.

Allocating remaining production across different producing countries

Climate change is by its nature a collective challenge impacting all countries across the world. At the global level, it is possible to analyse global carbon budgets, and global fossil fuels reserves, and understand the pathways required to keep the world on a 1.5C pathway. The IPCC AR6 process analysed many global pathways, and the IEA's landmark 2021 Net-Zero report outlined a specific 1.5C aligned energy transition pathway for the first time. Globally the IEA estimates that only ~68,000Mtoe oil and ~50,000Mtoe gas can be extracted and consumed to keep within 1.5C global carbon budgets[122].

Yet moving from global totals to country specific allocations and pathways presents significant additional challenges. Looking at the UKCS oil & gas production pathways discussed in this study and comparing them to the global annual production decline rate that is required in the IEA global net zero scenario (NZE):

- A simple comparison shows that UKCS production in the MAX, NNF and ADP scenarios is projected to decline more rapidly than the IEA NZE global pathways. Global oil production declines ~4% year-on-year to 2050 in IEA NZE and gas production ~2.5%. This compares to a ~6.5/8% decline rate in oil production in MAX/NNF, and a ~9/12% decline in gas production in MAX/NNF.

- A more nuanced comparison moves from global averages to those for regional geographic blocks. The IEA's NZE projects European total annual oil and gas production must decline at ~8% p.a., closer to the UK scenarios discussed in this study.

An alternative approach is to consider a 'fair allocation' of remaining global oil and gas extraction between countries. However, there are different perspectives on how this should be done. The IEA's 2023 report The Oil and Gas Industry in Net Zero Transitions notes several rationales proposed to allocate remaining production: some producers emphasise low production costs or emission intensity, others energy security considerations, economic development considerations, or fairness related to historical emissions[124]. There is no consensus on which allocation principle should be used, or any mechanism to apply any allocation in practice.

However, it is useful to understand how the UK stands against the different allocation criteria proposed to determine where remaining oil & gas production should take place (see annex for further discussion):

- **Prioritising lowest cost producers**: UK per-barrel costs are 30-60% higher than European producers such as Norway and 3-8 times higher than Middle Eastern producers[125].

- **Prioritising lowest emissions intensity producers**: UK production carbon intensity is slightly above the global average and exceeds Norway's emission intensity 2-3-fold[126].

- **A 'fair share' allocation allowing countries with lower national income a greater share of remaining production**: The UK is among the higher-income oil and gas producing countries, with the 8th higher GDP per capita of producing countries[127].

- **A 'fair share' allocation allowing countries with lower historical GHG emissions a greater share of remaining production**: The UK ranks 2nd place globally at ~1.1 ktCO_2 per capita, when considering historic emissions per capita (based on today's population)[128].

- **A 'fair share' allocation allowing countries with higher economic dependence on oil and gas a greater share of remaining production**: The UK economy has limited dependence, at only 1% of tax revenues and 0.4% of GDP, compared to some countries at 40-80% and 20-60% respectively, primarily in the Middle East and Africa.

Some studies have attempted to quantify these types of country allocations. For example, Welsby et al.'s study finds that for a 50% chance to keep global warming below 1.5ºC, European countries can produce only 28% of oil reserves, and 57% of gas reserves, where reserves refer to fields in production or scheduled to be developed[130]. To illustrate, directly translated to the UK, this would mean producing no more than ~130Mt of oil and gas in the future, which is lower than the scenarios used in this study[131].

UKCS transition impact on emission intensity of consumed gas

While Scope 1 and 2 emissions accounted for only 12.9Mt of CO_2e in 2023[132] , versus an estimated 200-250Mt of CO_2e in scope 3 emissions associated with oil and gas produced in the UK, emission intensity of gas is not a trivial topic. Some imported gas has a higher emissions intensity than domestically produced gas. As discussed in section 3.3, imported LNG has an emissions intensity of approximately 70-80 $kgCO_2$/boe, compared to around 22 $kgCO_2$/boe for domestically produced gas[133]. However, the UK's largest trading partner, Norway, has a lower pipeline gas emissions intensity of about 8 $kgCO_2$/boe.

Currently, the total weighted average emissions intensity of imports is around 38 $kgCO_2$/boe[134], which is higher than that of domestically produced gas. This suggests that, if not accompanied with transitioning buildings, power, and industry away from gas, the decline of gas production in the short term could lead to an increase in domestic emissions intensity if it is not possible to increase supply from low emissions intensity sources.

In the context of the UKCS decline, the emissions intensity of imports underscores the importance of transitioning the UK economy away from gas as a core pillar of the UK's energy transition. Additionally, it highlights the need for an import strategy that targets low emissions intensity sources, such as reducing reliance on LNG where possible.

Implications for the UK and abroad

A rapid, orderly, and just transition is a balancing act between delivering the oil and gas phasedown and absorbing its impact on society. While a rapid phasedown is warranted from a climate perspective, optimal adjustment of the UK economy, capabilities, and energy mix requires time – new sectors need to scale, new skills need to be taught, homes and industry need to be electrified, and alternative energy generation as well as appropriate grid connections and energy storage facilities must be deployed. Any increase in oil and gas phasedown speed would thus need to be matched by increased ambition and action on clean energy scale-up and associated capabilities.

We have set out seven ways in which government, regulators and the energy industry could facilitate a rapid, orderly, and just transition for the UKCS:

1. **Enhance data collection and monitoring**: Currently, there is a gap in the systematic tracking of asset-, network- and system-level data, including repurposing suitability. An orderly phasedown of oil and gas infrastructure – particularly in the context of no new licences - requires access to the right data to quantify and monitor risks and to proactively manage points of system failure as well as allow for early engagement on potential repurposing opportunities. For example, without clear data fields may be disregarded as potential options for CO2 storage in the future due to uncertainty over well plugging practices and thus risks to storage containment. Improvement in records could also enhance risk assessment at manageable cost. The mandate to maintain improved asset-level and network data and the capability to collect it should be put in place rapidly, and where appropriate this data should be made available to the public.

2. **Clarify the UK's energy vision**: The UK CCC scenarios outline various pathways to achieve net zero and successfully deliver the UK's energy transition. However, there are significant differences between the future energy mix described, particularly in the role of gas, CCS, and blue versus green hydrogen. Narrowing down and specifying the target energy system transition trajectory is crucial to identify the critical actions required to deliver the future energy mix, bolster private sector investment in clean energy projects and facilitate the UKCS transition.

3. **Clarify the UK's parallel section transition strategy**: Provide the parallel roadmap for the decarbonisation of UK buildings, industry and transport to ensure that domestic reliance on, in particular, gas is rapidly reduced. This will include accelerating the deployment of energy efficiency measures, electrification, grid, and low-carbon heating solutions in homes to meet the 5.5 million decarbonised homes target for the UKCCC balanced net zero pathway, as well as the decarbonization of industry. Reducing domestic reliance on gas is critical to ensure energy resilience as the UKCS production phases down.

4. **Prioritise renewable energy scale-up**: To ensure a just and orderly transition from the oil and gas sector, particularly for workers and energy security, clean energy targets must be met. Incentives and long-term policy clarity must be available to investors to incentivise them to contribute more to a well-designed UK clean energy economy. If we can ensure renewable energy jobs are available in the right locations, workers can transition to new sectors where their skills are transferable or once they have received retraining where needed. This includes well-designed and sufficient auction rounds, incentives to build out the UK supply chain (e.g. the Clean Industry Bonus[135]), and actions to address supply chain bottlenecks, to scale offshore wind. It also includes a fast roll-out of support for track-1 and track-2 CCS projects and further CO_2 storage licence, given that 5-10 years of appraisal are required before permits can be issued to begin CO_2 injection.

5. **Proactively manage the phase-down**: To steer the speed of the phasedown, the Government should consider utilizing the suite of tools at its disposal. This includes strategically limiting licences and consents, offering limited and targeted investment allowances and adjusting the tax regime. Additionally, the government should explore expanding the mandate to impose narrower decommissioning windows and more actively coordinate asset-level

decommissioning timelines. These measures could improve supply chain availability, enhance local job creation, reduce costs and, accelerate progress.

6. **Develop granular, localised asset strategies**: Implementing a strategic asset strategy based on transparent criteria could provide greater clarity to industry stakeholders, enable targeted and early engagement on asset repurposing, provide a foundation for the NSTA to mandate CoP dates for non-strategic assets, and enable early view for on risks in the network. 'Strategic' assets might face distinct standards or differentiated options, such as higher well decommissioning standards, rig electrification requirements or support, the opportunity to apply for new consents or CoP phasing. Any such approach must be carefully managed to ensure legal robustness, sufficient capacity to manage, and the avoidance of 'moral hazard' risks.

7. **Foster integrated decision-making**: The UKCS is entering a new phase, where success hinges on transitioning from the old energy system to the new. Achieving greater visibility, coordination and consistency across sectors will be essential. Moving towards more integrated decision-making could enhance planning and coordination. Options to achieve this, ranging from fostering greater coordination between agencies to establishing a single regulator and decision-maker, should be explored. It is crucial to carefully manage any governance changes to mitigate potential risks, such as delays due to organisational restructuring or the loss of specialised expertise.

Implications for international oil and gas production basins

As one of the first major oil and gas producers to enter a phase of decline, the UK's approach to managing the transition of the UK Continental Shelf (UKCS) has the potential to serve as a valuable blueprint for other countries facing similar challenges. The UK must grapple with the hard questions over the coming years: How to physically phasedown a complex and interdependent network without risking disruptions? How to best manage the implications of the transition on energy security and prices? How to mitigate impact on GDP, tax income, and jobs? **How to find alternative opportunities for economic success?**

If the UK was to develop and implement a comprehensive UKCS transition plan that includes a range of strategies, it could serve as a significant global example of successful transition, offering valuable insights for policymakers and industry leaders in other countries navigating their own unique paths to a sustainable energy future. As outlined in this document, this plan must include rapidly scaling up renewable energy, decarbonizing homes and industry, strategic (but limited) repurposing of existing infrastructure for carbon capture and storage, coordinating orderly decommissioning, and actively managing the socioeconomic impacts of industry decline.

While there are many lessons that are likely highly transferable, including the importance of robust data, the need to be granular and localized in asset-planning, the necessity of a sector-by-sector transition strategy, and the importance of fit-for-purpose governance, it is crucial to recognise that the path to phasing down oil and gas production and transiting to alterative clean energy sources looks very different across the world. The UK's experience cannot be universally applied.

Countries with greater economic and fiscal dependence on hydrocarbon revenues, limited renewable energy potential, or more extensive and interconnected oil and gas infrastructures will likely encounter additional hurdles in their transition. Factors such as geological conditions, regulatory frameworks, and the availability of alternative economic opportunities will also shape each nation's unique path towards decarbonization. Below, we highlight five fundamental characteristics of oil & gas basins across the world (for further discussion and exhibits see annex 1):

1. **Current production trajectory**: The UK's oil and gas production has been in decline since ~2000, due to declining reserves and resources in the basin. Many countries are, however, still in a stable or upward oil and gas production trend. Notably, 22 out of the 41 biggest oil and gas producers in 2023 are on a stable or increasing production trend, in some cases increasing very steeply (notably the US and Australia, whose annual oil and gas production roughly doubled between 2010 and 2023)[136]. UK stakeholders have anticipated decline and adjusted accordingly. In other contexts, unexpected production changes could lead to stranded assets or disorderly transitions, highlighting the benefits of early planning in countries with stable or growing oil and gas production.

2. **The importance of oil and gas to the national economy**: Any oil and gas producing country will need to respond to the decline in oil and gas jobs, economic activity, and energy supply as production phases down. The UK is comparatively well-positioned to mitigate that impact due to limited reliance on oil and gas production for GDP, high quality renewable resources, and progress in scaling offshore wind and other renewables. Countries with marginal GDP reliance on oil and gas will experience lower impacts, while those with high renewable energy potential can sooner mitigate the economic impact and retain

energy security. However, countries heavily dependent on oil and gas production (e.g. GDP derived from oil and gas production c.20-50%) face significant challenges and require profound economic transformation. These countries account for approximately 45% of global production, and include countries like Russia, the Gulf states, and several Central Asian nations[137]. Similarly, countries with lower quality renewable resources, or nascent renewable energy deployment face a bigger challenge to mitigate the impact of fossil production phasedown on jobs, energy security, and the economy.

3. **Governance surrounding oil and gas infrastructure**: As production phases down and assets become disused, a robust regulatory regime for decommissioning become critical, along with granular assessment of the potential of repurposing oil and gas infrastructure. While the UK has a relatively strong regulatory regime, many countries lack specific regulations for decommissioning assets, leaving operators subject only to international conventions that lack the necessary specificity. Ambiguity in ultimate liability in the case of defaults could expose governments to significant decommissioning liabilities, especially if operators have few remaining interests in the region. To avoid costs to society and marine ecosystems and maximise opportunities from disused assets (notably decommissioning jobs), strong legal regimes for decommissioning are crucial, ideally incentivising local decommissioning activities.

4. **Opportunities for repurposing assets**: More generally, opportunities to repurpose assets will depend on the specific technical characteristics of the infrastructure and reservoirs available and are bound by the total local requirements for CO_2 storage, and to a lesser extent H_2 storage and offshore hydrogen transportation. In the UK, we have seen that the total available storage capacity for these technologies is much larger than requirements in the next century. While the ratio of available capacity versus required capacity will differ country to country, repurposing of assets could be marginal in most regions.

5. **Location, age, and interconnectedness of installations and infrastructure**: The maturity and estimated size of offshore production networks vary significantly across the world, and each network is unique in terms of asset design and configuration. This variation will impact both the timing and scale of potential decommissioning activities, necessitating detailed asset-level assessment of risk and potential to manage transition costs. For example, the largest offshore oil and gas networks, such as those in the USA's Gulf of Mexico (and the UKCS),

are likely to require significant planning in the short term, while smaller networks in other regions like Australia and China are most likely more straightforward to manage[138].

Additionally, a significant portion of the world's oil and gas production occurs onshore, which allows for easier management of potential network effects but may lead to challenges around local opposition to repurposing. Countries with onshore networks, will have different challenges and opportunities should they wish to developing decommissioning capabilities.

Nevertheless, if the UK can demonstrate a proactive, positive approach to balancing impacts on jobs, energy security, economic interests, and climate goals during this transition period this could offer valuable insights for policymakers and industry leaders worldwide as they navigate their own energy transitions in the coming years.

FEBRUARY 2025

Annexes and bibliography

Annex 1: International comparison of oil and gas production basins

Additional data on the current production trajectories of oil and gas basins

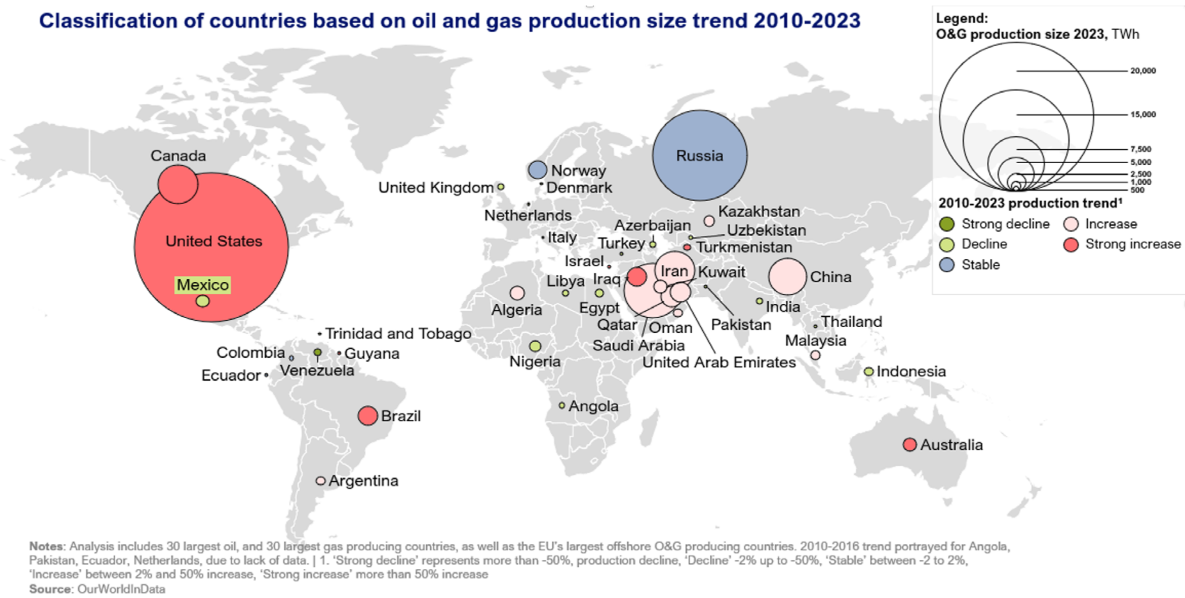


Figure 17: Oil and gas production trend 2010-2023

Additional data on the importance of oil and gas to the national economy.

The role of oil and gas varies significantly among the world's largest oil and gas producing countries, as illustrated by figure 18. The countries analysed can be broadly categorised into three groups based on their reliance on oil and gas rents as a percentage of GDP. Prominent countries with minor GDP reliance on oil and gas contributions (<2%) include China, India, and the USA, while those with moderate reliance (2-10%) include nations such as Ecuador, Nigeria, and Norway . Countries depending heavily on oil and gas production (e.g. the share of GDP derived from oil and gas production among Gulf states varies between 18% and 42%) account for approximately 45% of global production, and include countries like Russia, the Gulf states, and several Central Asian nations. For these countries transitioning away from oil and gas production will necessitate a profound economic transformation, as a substantial portion of their jobs and overall economy are tied to oil and gas production.

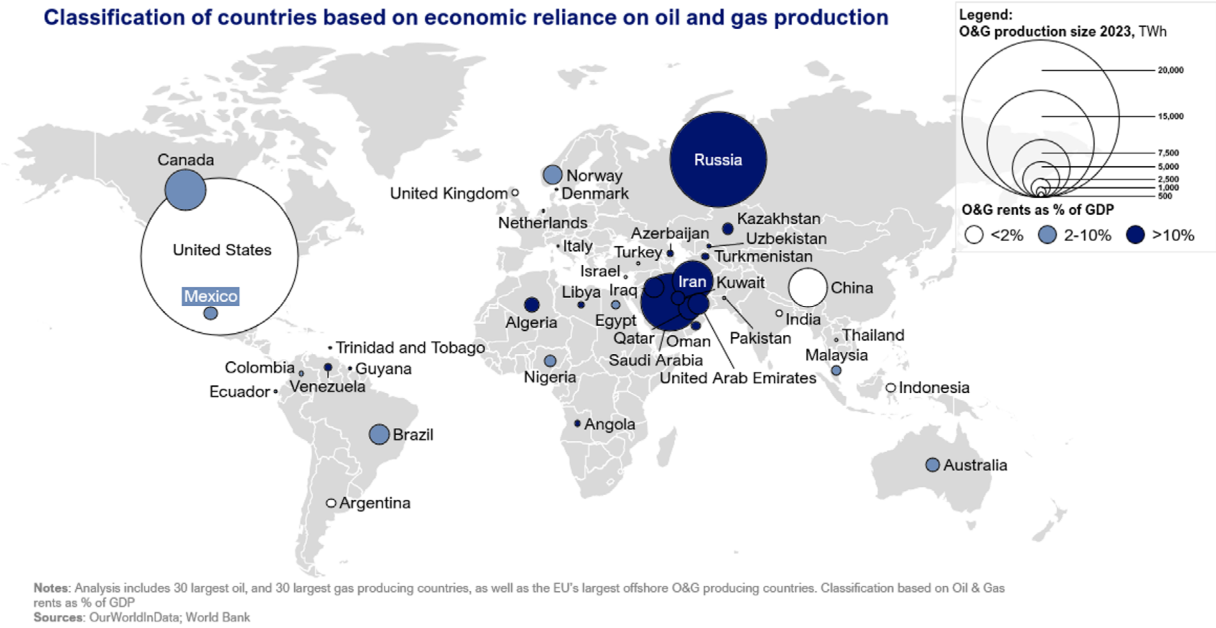


Figure 18: Economic dependence on oil and gas production

Additional data on the location, age, and interconnectedness of installations and infrastructure.

Figure 19 displays the maturity and estimated size of offshore production networks globally, which will impact both the timing and size of the decommissioning challenge ahead.

The largest offshore oil and gas networks account for more than half of the maturest networks (defined here as those with production starting before 1980) and will require most of the decommissioning work in the short term. Here, the decommissioning industries present in the USA's share of the Gulf of Mexico and the UKCS are among the most mature and sizeable respectively, whereas others (e.g. Australia, China) are facing a significant decommissioning ramp-up in the next decade. Other relatively sizeable offshore production centres like Iran, Thailand and Israel, contain less mature offshore production networks and could rather benefit from decommissioning experiences on the long-term.

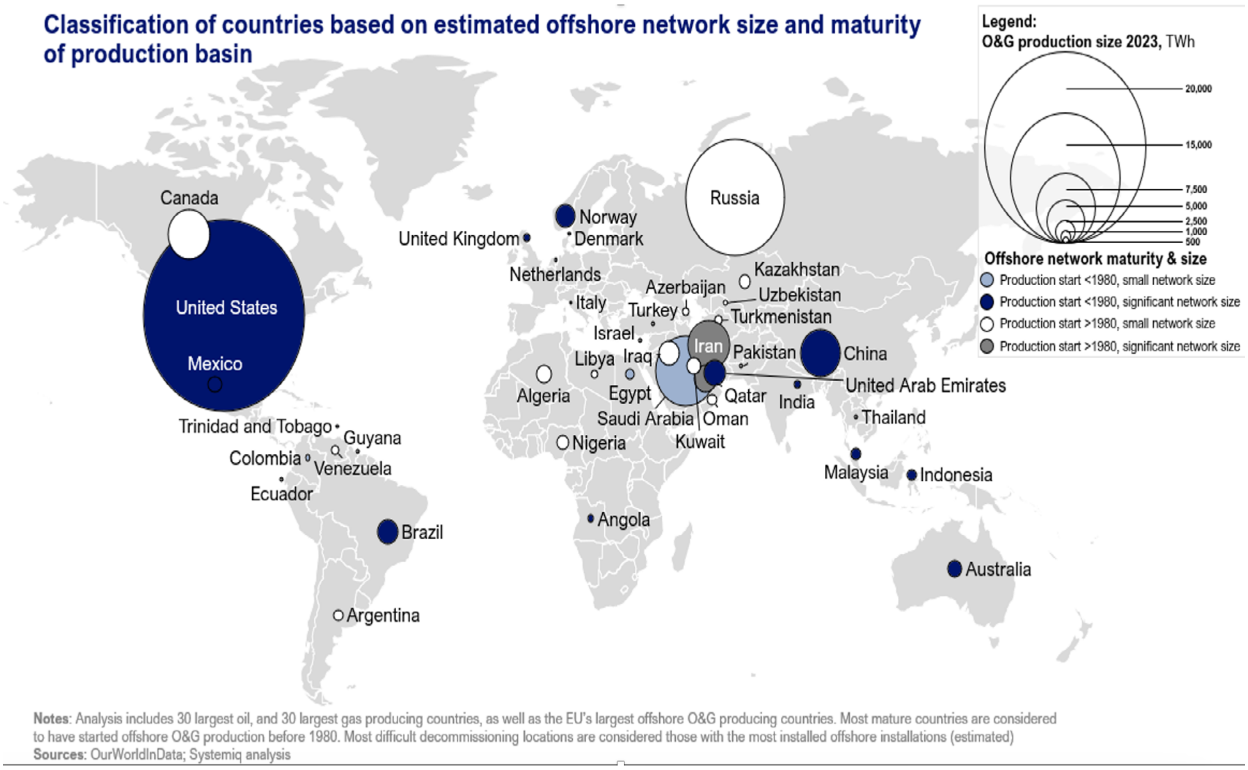


Figure 19: Maturity and difficulty of decommissioning for offshore oil and gas production networks

Below, more detail is provided regarding the methodology and sources underpinning the modelling in this report. We have also outlined limitations and potential extensions to improve the coverage and detail of the calculations. Topics covered include: oil and gas production scenarios, repurposing use-case selection, assessing field-level suitability for CO_2 and H_2 storage, assessing pipeline suitability for H_2 transport, modelling employment impacts, modelling energy security impacts, modelling tax revenue impacts, and potential areas of further analysis.

Oil and gas production scenarios

1. MAX scenario: Projection including development of all commercially viable discovered and undiscovered fields. Future licensing rounds for fields and new consents, based on Maximum Economic Recovery (current NSTA mandate). From NSTA Production and expenditure projections March 2024, previously available at https://www.nstauthority.co.uk/data-and-insights/insights-and-analysis/production-and-expenditure-projections/ (projections were then updated in October 2024).
2. NNF scenario: Projection without development of new fields. No new licence rounds are held and no development of current undeveloped discoveries (this includes fields which have received development consent but not yet started producing, as well as some fields which are licenced but not have not yet received development consent). From NSTA Production and expenditure projections March 2024, previously available at https://www.nstauthority.co.uk/data-and-insights/insights-and-analysis/production-and-expenditure-projections/ (projections were then updated in October 2024).
3. APD scenario: No new licences; no development consents for licenced fields; fields which have received development consents do not start producing, e.g., Jackdaw and Rosebank. No consents for major incremental projects in existing fields and stop or significant slowdown of business-as-usual investment in existing fields (and potential network effects). View based on expert input and desk research is that stopping business-as-usual investment in a context where production is decreasing leads to the decline rate approximately doubling. Given 2020-50 CAGR in NNF is -9%, the APD CAGR is therefore approximated to be -20% from 2024 onwards.

Note that throughout the report we show toe and boe units for oil and gas production. However, as there is no standard conversion factor from toe to boe for oil production (because the composition of oil and the ratio of crude oil : natural gas liquids varies over time) we use an approximate average conversion.

Repurposing use-case selection

Several potential use cases for repurposing oil and gas infrastructure were investigated in this study but were disregarded for having a weak (economic) rationale on the system level
. Below, we elaborate:

- Offshore electrolysis plant on platforms:
    - Commercial electrolysis ranges upwards from ~500MW capacity, which requires space of >800 hectares (excluding desalination plant required offshore). As such, a typical gas or oil platform does not have the space capacity to house electrolysis
    - Building several smaller electrolysis units on several different platforms could be considered, but is expected to be prohibitively costly in terms of maintenance
    - There are several pilot projects with electrolysis on a platform in Europe, but these are all <10MW demonstration size
- Reuse Gravity Base Structures for hydrogen storage
    - There are 12 platforms in the UKNS that have Gravity Base Structures – subsurface oil storage tanks stemming from the age when pipelines were not yet developed
    - There is no view on feasibility of storing H_2 in these structures, but technical and safety issues are likely prohibitive
    - There is no clear rationale for storing hydrogen far offshore when there is significant onshore/ close to shore, proven storage capacity available
    - Note that, at SoS agreement GBS is typically decommissioned in situ, so repurposing could in theory occur at a later stage
- Store hydrogen in depleted fields at the offshore electrolysis site
    - HSSE standards do now allow for storage of any kind (CO_2, hydrogen, other) within the navigational safety zones for helicopters of an offshore windfarm and/ or electrolysis plant
    - There is no clear rationale for storing hydrogen at the site of electrolysis, versus closer to shore
- Offshore blue hydrogen production and CO_2-injection
    - No clear rationale, as onshore blue hydrogen production is lower cost

    - Transporting natural gas from offshore fields to onshore blue hydrogen production facility is does not require any retrofit, while transporting the energy as hydrogen is not proven and will require retrofit
- Use existing pipelines to efficiently connect subsea cables and minimize seabed disturbance
    - There are real advantages to using existing pipeline routes for new development, including minimizing ecosystem disturbance, and reducing permitting effort
    - However, pipelines are often decommissioned in situ (not removed), so there is no rationale to not decommission
- Use platform as hub for workers and materials for offshore wind deployment and maintenance
    - Offshore wind is built using large ships, which houses both the materials and the workers
    - Keeping the topside of a platform compliant and safe is expensive, and currently already accounts for ~10% of total decommissioning costs of the sector. As such, using the platform for a low-value purpose is not economically feasible

CO_2 storage

Demand for storage: Required CO_2 storage capacity for the UK ranges between 1.1-2.3 Gt cumulative by 2050 for domestic capture, based on UK CCC scenarios (lowest CO_2 storage requirement is 'Widespread Engagement', highest is 'Headwinds'). Required capacity range between 2050 and 2100 could not be estimated based on UK CCC scenarios as those scenarios extend until 2050 only. As such, the additional demand was estimated using expert input, assuming some plateauing or decline of annual injection beyond 2050, as more industries will decarbonise their production processes fundamentally. Maximum additional demand before 2100 was estimated at ~4 Gt. CCSA Global Leadership Scenario from CCUS Delivery Plan 2035 is used to estimate CO_2 import potential.

Availability of storage: Based on BGS CO_2 Storage Appraisal Project at P50 confidence level.

Assessing field-level suitability for CO_2 storage:

We went through a multi-stage approach to determining the list of criteria to use – as shown in the exhibit below. The H/M/L threshold values were based on academic literature and expert input.

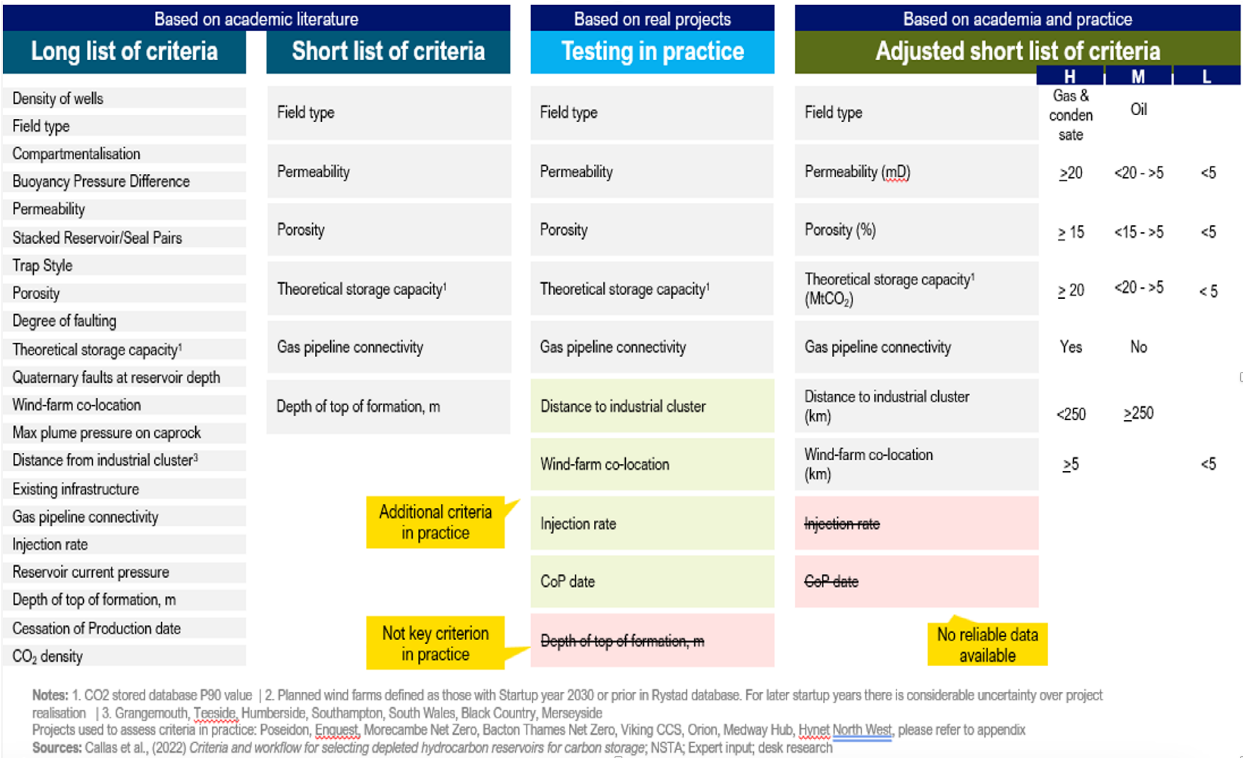
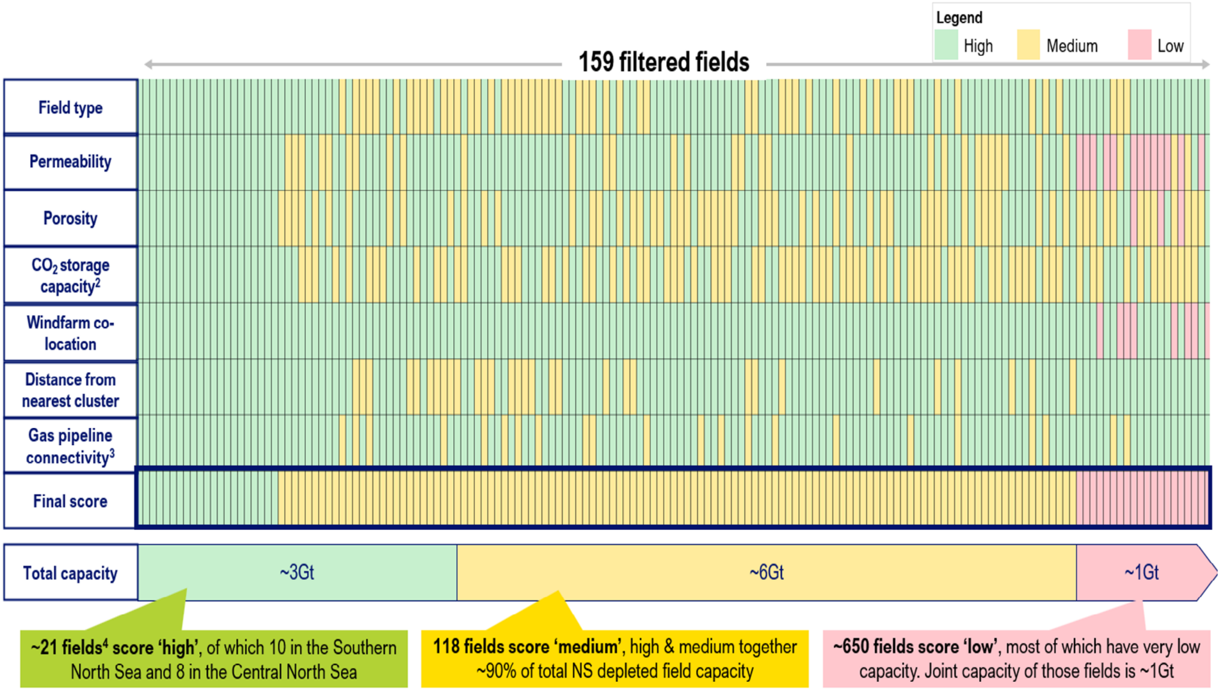


Figure 20

The results of the assessment are show in the exhibit below. These results are filtered for fields with theoretical storage capacity > 5 $MtCO_2$. Note the full set is 798 assets/ fields, based on the Rystad Energy's UCube. Note that this desktop assessment represents an initial assessment only. Not all critical criteria are included in the assessment due to data availability issues, notably the integrity of existing wells. One example of an anomaly from the analysis is the Culzean field, a large gas condensate field that is assessed as highly suitable in our assessment based on existing data but known to be likely unsuitable due to its high temperature high pressure characteristics. Similar anomalies the other way round are possible.

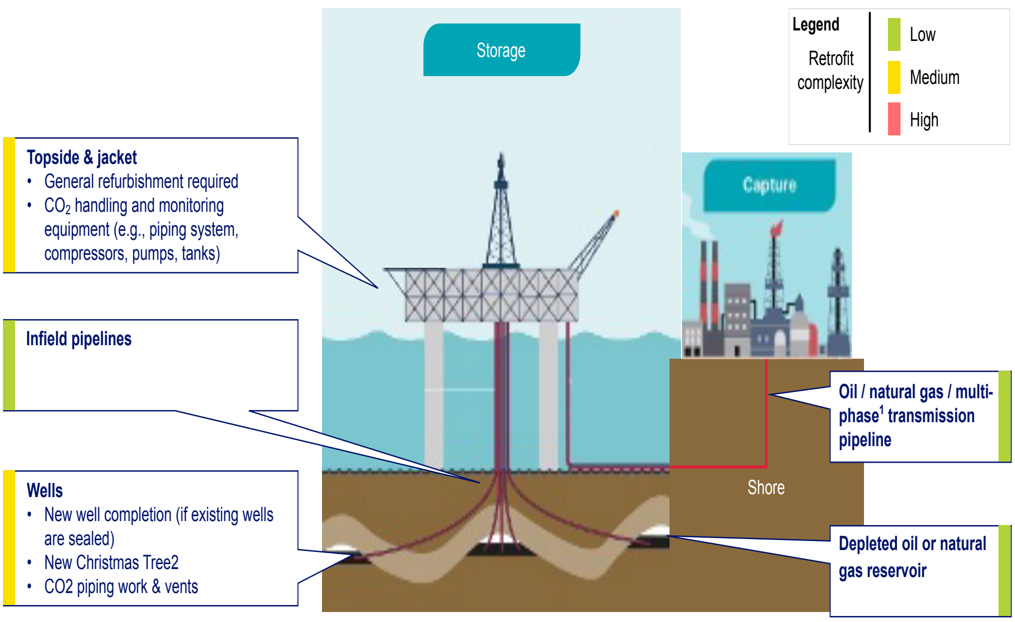


Notes: 1. 639 were filtered out and not displayed here for visibility of this page | 2. Based on CO2 Stored database theoretical P90 storage capacity. | 3. Note assumed 'Yes' for all gas fields, checked for gas/condensate and oil fields.| 4. Amethyst East, Brae East, Brae North, Britannia, Cleeton, Culzean, Fleming, Goldeneye, Hewett, Indefatigable (Perenco part) (West), Indefatigable (Shell part), Indefatigable North, Lancelot, Lomond, Merganser, Morecambe North, Neptune, Orwell, Scoter, Sean, Starling. *Analysis based on Rystad data – splits UKCS into 798 assets/ 'fields' - may differ from other datasets, e.g., Leman gas field divided into Leman East, Leman South, and Leman (Shell part)
Source: Systemiq analysis based on Rystad

Figure 21

Assessing asset suitability for repurposing:

Simplified schematic of offshore O&G infrastructure



Notes: 1. Multi-phase pipelines transport a mixture of both oil and natural from offshore platforms to the coast, which must then be separated. | 2. A "Christmas Tree" is a piece of equipment that sits on top of oil and gas wellheads which controls the flow produced by a well. Note: there is currently no commercial offshore CO_2-EOR.
Sources: Liu & al (2021) *The Progress of Offshore CO2 Capture and Storage;* Concawe (2021) *Re-Stream: Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe;* Shell (2016) *Peterhead CCS Project: FEED summary report for full CCS chain;*Expert interviews.

Figure 22

H_2 storage

Demand for storage: Range based on several studies:

- Scafidi & al. (2021), A quantitative assessment of the hydrogen storage capacity of the UK continental shelf: 150 TWh
- Mouli-Castillo & al. (2021) Mapping geological hydrogen storage capacity and regional heating demands: 77 TWh
- The Royal Society (2023) Large-scale electricity storage: An applied UK case study: 60-10 TWh
- National Grid (2023), Future Energy Scenarios 2023: 11-56 TWh
- Department for Business, Energy & Industrial Strategy (July 2022) Benefits of Long Duration Energy Storage: A report to BEIS: 11-17 TWh

Availability of storage: Salt cavern potential based on Caglayan et al. (2020) Technical potential of salt caverns for hydrogen storage in Europe. Depleted gas field potential based on Scafidi et al. (2021) A qualitative assessment of the hydrogen storage capacity of the UK continental shelf

Assessing field-level suitability for H_2 storage:

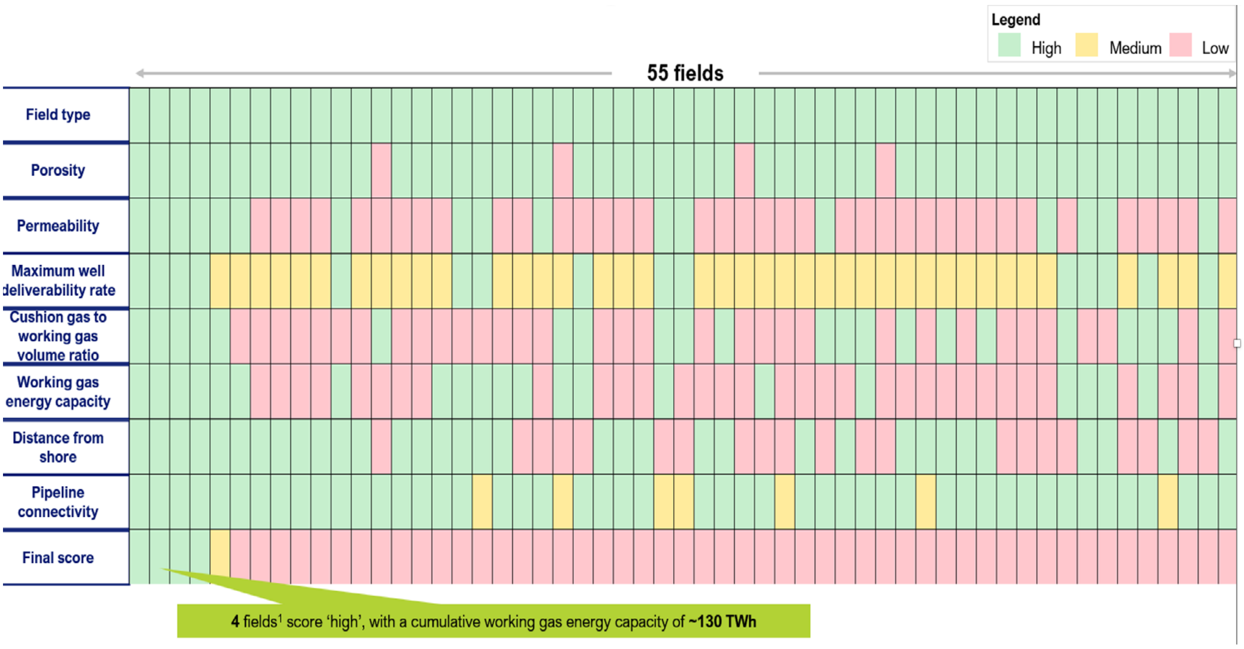
In a similar approach to the analysis for CO_2 storage, a set of criteria was chosen based on academic literature and expert input.

Category	Criteria	Assessment		
		H	M	L
Technical	Field type	← Gas/ Gas-Condensate →		Oil
	Porosity	≥ 10%		<10%
	Permeability	≥ 100mD		<100mD
	Maximum well delivery rate	>100 mn sm^3/d	≤ 100 mn sm^3/d	
	Cushion gas to working gas volume ratio	≤ 10		>10
Geospatial	Working gas energy capacity	10 ≥ TWh		<10 TWh
	Distance from shore	< 100 km		≥100 km
Network	Pipeline connectivity	Connected to operational gas pipeline	Not connected to operational gas pipeline	

Source: Harati et al (2024) Multi-criteria site selection workflow for geological storage of hydrogen in depleted gas fields: A case for the UK

Figure 23

The results of the assessment are shown below. Note that due to data limitations, the assessment was carried out on a subset of 55 fields, based on the Harati et al dataset. They are therefore likely to underestimate the cumulative H_2 storage capacity in the UKCS.



Notes: Hamilton, Hamilton North, Crovette, Tolmount

Source: Systemiq analysis based on Harati et al, (2024) Multi-criteria site selection workflow for geological storage of hydrogen in depleted gas fields: A case for the UK

Figure 24

Assessing pipeline-level suitability for H_2 transport

A set of criteria was chosen based on academic literature and expert input.

Category	Criteria	Assessment H	Assessment M	Assessment L	
Geospatial	Pipeline length	> 100 km		≤100 km	Important for blended[2] and dedicated
	Pipeline near planned offshore wind farm[1]	<20 km	20-50 km	>50 km	
Network	Pipeline direct connection to shore	Yes		No	
	International interconnector	No		Yes	
	2035 anticipated production throughput	*Insufficient data*			Important for dedicated
	Ability to re-route 2035 production to other pipelines	*Insufficient data*			
Technical	Pipeline coating, wall thickness, and max operating pressure	*Insufficient data*			
	Pipeline age	<15 years	15-35 years	>35 years	

Notes: 1. Defined as wind farm with a Startup year post-2030. 2. On demonstration-scale, hydrogen can most likely be blended with natural gas in the pipeline. Commercial-scale however, requires a dedicated pipeline.
Sources: TNO (November 2022) *Offshore hydrogen for unlocking the full energy potential of the North*; Expert input

Figure 25

The results of the assessment are shown below. These results are filtered for gas pipelines of length >100 km.

Pipeline name	Pipeline length, m	Nearest planned offshore wind farm	Connection to shore	International interconnector	Pipeline age, years	Final score
20" GAS GOLDENEYE - ST. FERGUS	101,677	Yes	Yes	No	Data n/a	High
KNARR GAS EXPORT PIPELINE	105,409	Yes	Yes	No	10	High
SEAN P TO BACTON TERMINAL TRUNKLINE	106,336	Yes	Yes	No	Data n/a	High
HFC TO ST. FERGUS SOUTH	173,806	Yes	Yes	No	10	High
30 IN SIRGE GAS EXPORT	233,000	Yes	Yes	No	12	High
20" GAS FULMAR A - ST. FERGUS	289,049	Yes	Yes	No	Data n/a	High
36" GAS BRENT A - ST. FERGUS (FLAGS)	446,894	Yes	Yes	No	Data n/a	High
34 INCH GAS SHEARWATER - BACTON SEAL LINE	474,658	Yes	Yes	No	Data n/a	High
GJOA GAS EXPORT - P261	131,252	Yes	Yes	No	15	Medium
THEDDLETHORPE TO MURDOCH MD	181,327	Yes	Yes	No	31	Medium
BRITANNIA TO ST FERGUS	185,260	Yes	Yes	No	21	Medium
SAGE PIPELINE	323,766	Yes	Yes	No	32	Medium
CATS PIPELINE	404,974	Yes	Yes	No	31	Medium
24 IN ALWYN TO TP01 SUBSEA BYPASS GAS EXPORT	107,000	Yes	Yes	No	36	Low
LOGGS PP TO THEDDLETHORPE GAS LINE	118,997	Yes	Yes	No	37	Low
VIKING AR TO THEDDLETHORPE GAS LINE	136,932	Yes	Yes	No	43	Low
32 IN MCP01 BYPASS BUNDLE TO ST FERGUS GAS PLANT	186,000	Yes	Yes	No	47	Low
BBL BALGZAND TO BACTON	229,280	Yes	Yes	Yes	18	Low
BACTON TO ZEEBRUGE	231,848	Yes	Yes	Yes	Data n/a	Low
LANGELED PIPELINE	543,048	Yes	Yes	Yes	19	Low
LAGGAN-TORMORE 18" FLOWLINE 2	141,785	No	Yes	No	12	Low
LAGGAN-TORMORE 18" FLOWLINE 1	141,973	No	Yes	No	12	Low
20in Gas Trunkline - Schiehallion PLEM to Sullom Voe terminal	188,000	No	Yes	No	23	Low
INTERCONNECTOR 2 SCOTLAND TO IRELAND IC2	192,205	No	Yes	Yes	21	Low
INTERCONNECTOR 1 SCOTLAND TO IRELAND IC1	203,897	No	Yes	Yes	33	Low
EOS	207,990	No	Yes	No	24	Low
HFC TO ST. FERGUS NORTH	130,530	No	No	No	10	Low
32 IN TP01 SUBSEA BYPASS TO MCP01 BYPASS BUNDLE	175,269	No	No	No	47	Low

28 filtered pipelines

8 pipelines score 'high', based on applying the criteria for which data is available

In practice, **pipelines which score highly for H_2 transport repurposing, will also be good candidates for CO2 transport**, and hence may be repurposed for CO2

Figure 26

Modelling jobs impacts

Projections by the Energy Skills Intelligence Hub (ESIH) taken as the starting point for jobs modelling.

- For oil and gas, an intensity of 1,890 jobs per Mtoe of oil and gas production was used, based on ESIH 2024 jobs data and NSTA 2024 production data, and applied to the production scenarios MAX, NNF, and APD.
- For offshore wind, the base case uses the ESIH base case. To estimate the impact of offshore wind deployment being in line with the current pipeline, rather than target, we apply the base case jobs intensity figures from the UK Offshore Energy Workforce Transferability Review study by the Robert Gordon University Energy Transition Institute (May 2021): 2250 jobs per GW offshore wind installed. The offshore wind pipeline is based on Bloomberg New Energy Finance (BNEF) Q2 2024 projections.
- For CCS, the base case uses the ESIH base case, and no sensitivities are applied.
- For decommissioning, the mid-point of the jobs projection from Nes Fircroft is used (19,000), with the assumption that this corresponds to £1

billion decommissioning spend in the UK, based on NSTA data on actual decommissioning spend. Future decommissioning spend per annum is also based on NSTA data (note the NSTA provides forecast decommissioning spend per decade) – the 19,000 jobs per £1 billion decommissioning spend intensity was applied to this trajectory.

More granular job projections are all from the ESI base case. Workforce transferability data is based on the Powering up the Workforce: The future of the UK offshore energy workforce study by the Robert Gordon University Energy Transition Institute (September 2023).

Modelling energy security impacts

This was largely based on the projections in the CCC's 6th carbon budget, which provides energy demand by source (oil, gas, coal, electricity, bioenergy, and waste). UK domestic energy production was based on:

- Oil and gas: MAX/NNF/APD scenarios (NSTA for MAX and NNF, APD calculated for this study)
- Coal: 2024 figure from Our World in Data. Assumed 0 in 2030 and 2050.
- Power generation from renewables and nuclear: from CCC BNZ (note the UK is projected to be a net exporter of power via interconnection in 2030 and 2050)
- Bioenergy: from CCC BNZ (note 2024 and 2030 data not available so the 2018 and 2035 values were used respectively)
- Waste: from CCC BNZ (assumed that waste for energy is 100% sourced domestically).

Non-UK produced energy was calculated as the energy demand less UK-produced energy.

Modelling tax revenue impacts

Tax modelling as based on applying the OBR's March 2024 projection of oil and gas revenues (hence based on the pre-election fiscal regime). The OBR also published the oil and gas production and price assumptions that underlined this modelling. Based on these, we calculated total industry oil revenues and gas revenues in each year 2024-30, and calculated tax revenue as a % of total revenues in each projected year. The average of this was 18%. We applied the same price projections to the MAX/NNF/APD production projections to calculate industry revenues, and multiplied by the 18% average in each year to estimate government revenues.

Climate leadership

The following data was used in the Climate Leadership chapter

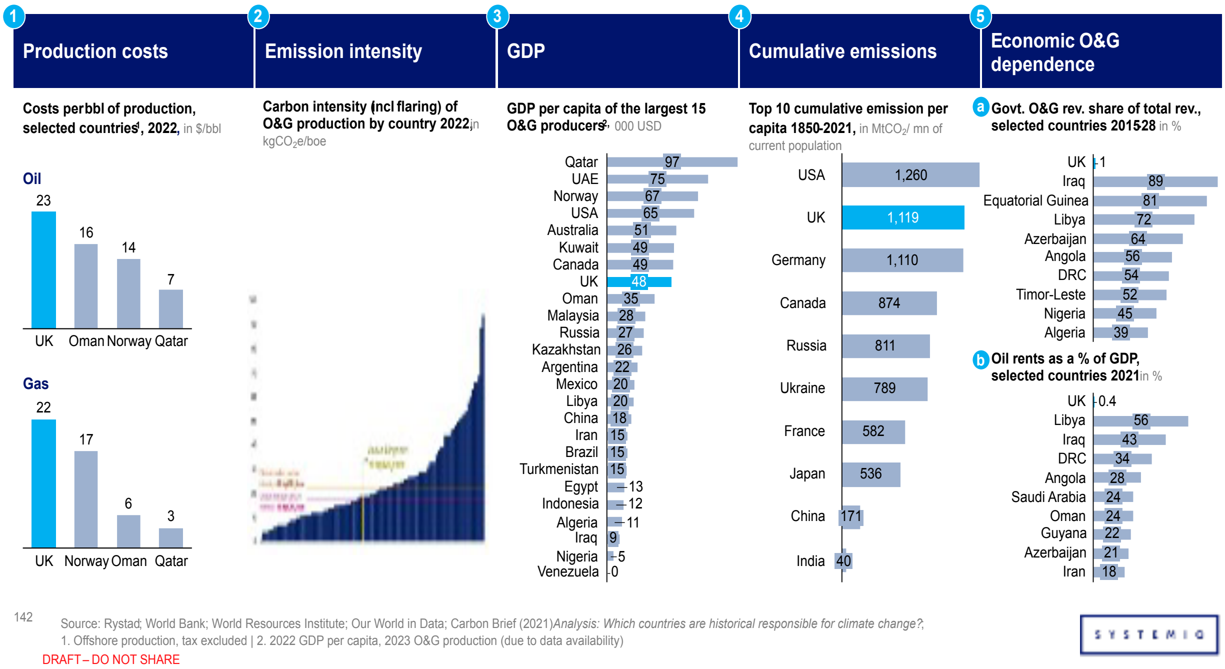


Figure 27

Commentary on methodology

The scope and time available for this initial integrated fact based consolidation necessarily limited the depth of modelling possible across analytical areas. Additional analytical work which would be useful to further refine the analysis include:

- **Oil and gas production scenarios**: Refining and strengthening the APD scenario modelling assumptions. Based on further case study analysis, and more granular data on interconnectedness to complete a more widespread assessment of network effects, a more sophisticated model of an APD scenario could be developed, accounting for different rates of decline across assets and regions and sub-regions of the UKCS.
- **CO_2 storage**: The UK's capacity for CO_2 storage could be understood in more depth through more detailed analysis of the CO2 Stored Project database (e.g., with particular focus on the P90 storage capacity).
- **H_2 storage**: The field-level suitability assessment was only completed for ~50 fields due to data availability. The study could be expanded by collecting the relevant variables for H_2 storage field suitability for a wider range of fields, and

expanding the analysis to those fields.

- **Decommissioning**: The NSTA estimates that 20% of fields have higher risk of decommissioning liabilities passing on to the state due to lack of previous major ownership, but the detail behind this calculation is not public. Reviewing the assumptions behind this calculation would enable a better understanding of this risk. Further, to assess the size of the opportunity for UK supply chains in decommissioning and key barriers to tackle, an in-depth review of Supply Chain Action Plans submitted by operators would be required.
- **Jobs impacts**: With more granular data on the assumptions regarding the pipeline of CCS and offshore wind projects, and the local content assumptions was available from ESIH, this would improve the quality of the employment sensitivity analysis. A more detailed literature review and set of expert interviews would enable a deeper understanding of the skills gaps that need to be addressed for the UK to onshore jobs in decommissioning and clean energy.
- **Tax revenue impacts**: the analysis in this study was based on applying revenue intensity assumptions to a set of production and price assumptions. A more accurate view would be developed through detailed tax policy modelling, as is developed by organisations such as the OBR.

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