Energy Hub
NZTTP Programme

ENERGY HUBS

FILL THE BACKBONE

Net Zero Technology Transition Programme

Net Zero Technology Centre
Technology Driving Transition

Foreword

The European hydrogen market is expanding rapidly, and the time for Scotland to act is now. By swiftly scaling up hydrogen production and leveraging its renewable energy resources, Scotland can secure its place as a leading producer and exporter of hydrogen and its derivatives.

The work NZTC has undertaken is turning this vision into an actionable plan. The Energy Hubs Project delves into Scotland's potential to evolve into a notable producer of hydrogen, emphasising the strategic moves required to meet Europe's increasing demand and capitalise on this growing market.

The first phase of the project has demonstrated that multi-gigawatt scale hydrogen production at dedicated Energy Hubs in Scotland is feasible and reveals the actions needed to deliver this bold ambition. However, unlocking the full potential of green hydrogen production in Scotland will require significant investment, technological innovation, and infrastructure development. The challenges are considerable, but the rewards are even greater.

The second Phase of the project is already underway and focuses on filling the Hydrogen Backbone Link pipeline from Scotland to Europe.

This project has, and will continue to be, critical to forming the foundation that will help industry, government, and investors navigate the complexities of scaling up green hydrogen production and exporting.

Scotland is on the cusp of an exciting transition towards hydrogen and its derivatives being a key player in the future energy mix. The findings from this project will illuminate the path it must take to realise this opportunity.

Myrtle Dawes CEO, Net Zero Technology Centre (NZTC)

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1.0

Executive Summary

The emerging hydrogen market in Europe presents a huge export opportunity for Scotland. To capitalise on this opportunity, Scotland must harness its vast renewable energy resource and scale up hydrogen production in time to meet this growing demand. If Scotland can accomplish this, then it has the potential to become a leading producer and exporter of hydrogen and its derivatives.

Key to establishing a thriving hydrogen economy in Scotland is the development of Energy Hubs. An Energy Hub is a specific geographic location which will host all facilities necessary for the large-scale production of hydrogen and hydrogen derivatives such as e-fuels. The Energy Hubs project[1] is dedicated to advancing the Energy Hub concept by addressing the fundamental questions that emerge when considering how to establish large-scale hydrogen production in Scotland. It focuses on how to optimise the efficiency and economic viability of Scottish Energy hubs, including the opportunities offered by alternative fuels, CO_2 imports and by-products.

Leveraging Scotland's Resources – Going Beyond Current Targets

Energy system modelling performed as part of the project revealed 35 GW of electrolyser capacity could be installed across four Scottish Energy Hubs in 2045. This is a 10 GW uplift above the Scottish Government's target of 25 GW of renewable and low-carbon hydrogen production capacity by the year 2045.

A substantial scale up in hydrogen production is needed to deliver Scotland's Green Export Ambition

Hydrogen and e-fuels are anticipated to be pivotal in decarbonising sectors which cannot be easily electrified. The national and global markets for e-fuels derived from hydrogen are projected to grow significantly, and present additional export opportunities for Scottish hydrogen and e-fuels.

Exporting hydrogen from Scotland to Europe via pipeline is feasible both technically and economically at a 0.9 Mtpa scale. This was demonstrated through the Hydrogen Backbone Link Project, another project within NZTC's NZTTP.

However, producing enough hydrogen to fill the backbone will require several, large-capacity Energy Hubs, each capable of producing hydrogen on a multi-gigawatt level. Integrating several of these large-scale hubs together as a "Super Hub" will optimise their combined performance.

Innovation in Floating Offshore wind will help to unlock Scotland's hydrogen potential

The likely power supply for a multi-gigawatt scale hydrogen or e-fuel Energy Hub is floating wind. The cost of electricity from floating wind will have a significant impact on the commercial viability of the hydrogen produced in Energy Hubs.

Economic modelling indicated that a 10 GW scale Energy Hub producing green hydrogen from floating offshore wind could produce hydrogen for £3.90/kg. The total CAPEX for a development (including both the wind farm and the hydrogen production facilities) was estimated to be £30.2 billion and would produce over 0.9 Mtpa of green hydrogen.

This modelling used forecasted costs for the late 2030s and anticipates that the cost of electricity from floating wind will decrease over time as the technology develops. This pace of innovation must be accelerated if Scottish hydrogen is to be cost competitive with other globally sourced hydrogen.

Scotland's proximity to the European market and the Hydrogen backbone link project will enable low transportation costs, but if production costs are too high then this strategic benefit will be negated.

Patient capital investing to accelerate innovation in key technologies such as floating offshore wind is essential to drive down the cost of green hydrogen production.

To enable Scotland to leverage its vast renewable resource and fully capitalise on future export opportunities, action is required across four key areas:

- Development of the Super Hub concept to maximise the overall performance of Energy Hubs. The Super Hub concept is being explored in more detail in Phase 2 of the Energy Hubs Project, which will conclude in November 2025.
- Investment and Government support to accelerate the development of key technologies:
  - In particular, investment targeted at floating offshore wind is needed to ensure the competitiveness of Scottish green hydrogen. This includes the development of next-generation technologies and manufacturing processes.
  - Innovations in electrolyser technologies are also needed to improve the efficiency of hydrogen production and reduce system costs.
- Development of high efficiency energy storage facilities with GWh capacities.
- System integration: Optimising the integration of energy vectors (including thermal) within Energy Hubs, along with exploring further opportunities in alternative fuels and by-products is needed to ensure the efficiency and economic viability of Energy Hubs. This is being explored in more detail in Phase 2 of the Energy Hubs Project.

[1] The Energy Hubs Project is one of seven projects being delivered through NZTC's Net Zero Technology Transition Programme (NZTTP), which was awarded £15.8 million from the Scottish Government's Energy Transition Fund.

2.0

At a Glance

THE OPPORTUNITY:

- The developing global hydrogen market presents a huge export opportunity for Scotland. Scotland, with its vast renewable resources, could be a leading producer and exporter of hydrogen and its derivatives to emerging markets in Europe.
- The Hydrogen Backbone Link project has shown that exporting hydrogen from Scotland to Europe via pipeline is feasible at a 0.9 million tonnes per annum (Mtpa) scale.
- To fill the backbone, around 900,000 tonnes of hydrogen must be produced each year. Several multi-gigawatt scale Energy Hubs will be needed to produce hydrogen at this scale. Large-scale Energy Hubs will enable Scotland to leverage its vast renewable resources and become a major exporter of zero carbon chemical energy. Modelling confirmed that 35 GW of electrolyser capacity could be installed at Scottish Energy Hubs by the year 2045.
- The export opportunities unlocked by Energy Hubs will support further offshore wind developments, with hydrogen and its derivatives providing a route to market for the electricity generated by offshore wind.
- Hydrogen and e-fuels are anticipated to be pivotal in decarbonising sectors which cannot be easily electrified. The national and global markets for e-fuels derived from hydrogen are projected to grow significantly, and present additional opportunities for Scottish hydrogen: e-fuels provide an additional revenue steam and e-fuel synthesis will also utilise power and hydrogen system excesses, enabling higher capacity factors for wind farms and electrolysers.

ENERGY HUB REALISATION:

- Integrating several large-scale Energy Hubs together as a "Super Hub" will optimise their combined performance.
- Floating wind is crucial for large-scale hydrogen production and advancements in this field will enhance the competitiveness of Scottish green hydrogen. Investment and Government support is recommended to accelerate the development of this technology.
- Innovations in electrolyser technology will improve the efficiency of hydrogen production and reduce the cost of production. Financial support to accelerate the development of electrolyser technologies is recommended.
- High efficiency energy storage facilities with gigawatt hour (GWh) capacities are needed to compensate for renewable energy intermittency.
- Effective system integration is crucial for enhancing the efficiency and economic viability of Energy Hubs. The integration of energy vectors (including thermal) within Energy Hubs should be optimised. Further opportunities in alternative fuels and by products should be explored.
- To avoid wind generation curtailment, microgrids (where generation and consumption are co-located) may be required at locations where the National Grid transmission system is insufficient.
- Smaller-scale projects need to be developed to gain experience and establish a supply chain capable of supporting a large-scale project.

3.0

A Project Portfolio
Accelerating the Transition

In 2021, the NZTC was awarded £16.7 million of public funding from the Scottish Government's Energy Transition Fund to support a programme of seven strategic energy transition projects.

Energy Hub	**Energy Hub**	Identifying key opportunities and technologies to deliver the nations future low carbon energy requirements
Hydrogen Backbone Link	**Hydrogen Backbone Link**	Scotland in a leading role for the development of pan-European hydrogen infrastructure
Alternative Fuel Gas Turbines	**Alternative Fuel Gas Turbines**	Accelerating the development of gas turbines capable of running on clean fuels
Advancing Remote Operations	**Advancing Remote Operations**	Remote operations to create safer, more efficient and lower carbon operations
Data for Net Zero	**Data For Net Zero**	Developing analytics to unlock energy transition action and deliver the world's first smart energy basin
OLTER	**Offshore Low Touch Energy Robotics & Autonomous Systems**	Enabling next generation robotics and autonomous systems for the offshore energy sector
Offshore Energy Digital Architecture	**Offshore Energy Digital Architecture**	Implementing a sector-wide data and infrastructure strategy to enable digitisation

The Energy Hub project has been allocated a total of £4 million, which includes Scottish government and industry contributions. The project is funded over a three-year period and will conclude in November 2025.

The Energy Hub project is evaluating the potential of utilising Scotland's offshore wind resource to produce GW-scale low carbon hydrogen to supply the demand required by the proposed 0.9 Mtpa Hydrogen Backbone Link (HBL). The HBL project, within the same programme as the Energy Hubs project, focuses on the infrastructure required to export Scottish hydrogen via pipeline.

Phase 1 of the project has attracted a strong, active consortium of industry partners who have match funded and contributed to the individual work scopes, ensuring it is industry-led and aligned to drive results and outcomes.

4.0

Scotland's Hydrogen Production Potential

Scotland's abundant renewable energy resource has the potential to produce both electricity and hydrogen on a scale that far exceeds domestic demands. Developing a hydrogen economy is a core part of the Net Zero Strategy of both the UK and Scottish governments.

Hydrogen energy systems are complex networks of components, combining generation technologies, hydrogen production, transportation of energy or energy carriers, energy storage, waste storage and chemical processing.

Green hydrogen is set to play a key role as a fuel of the future in the UK and globally. Hydrogen can be classified as green if its production uses electricity from zero carbon or renewable sources to split purified water into hydrogen and oxygen during the process of electrolysis.

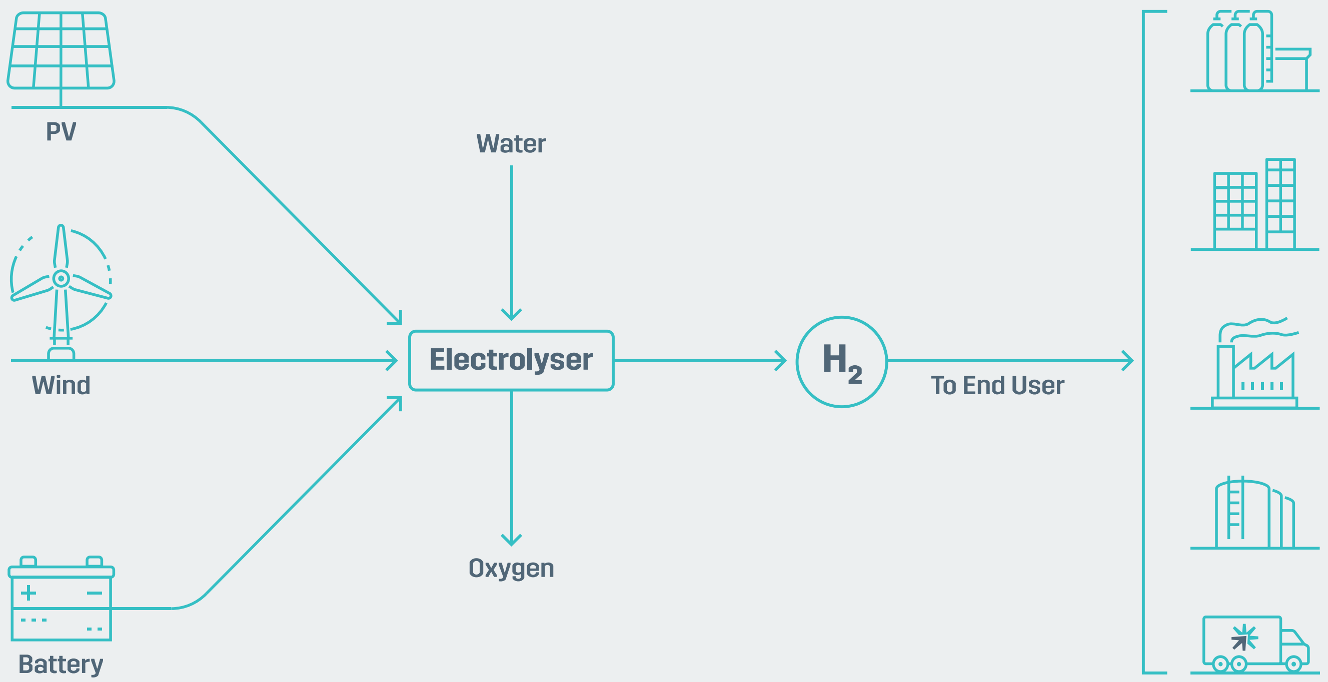
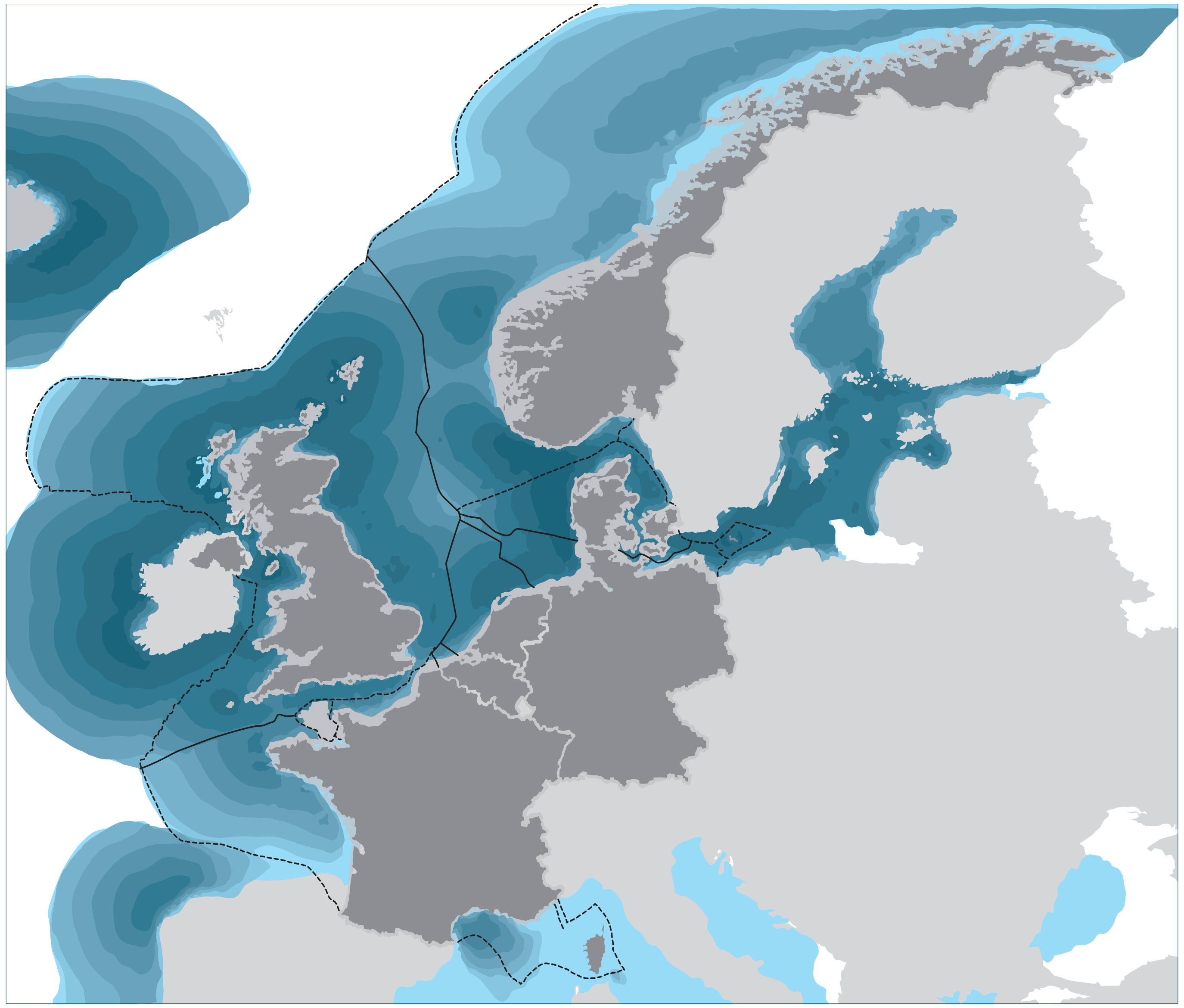


Figure 1: Process flow – green hydrogen production [1]

There is significant opportunity to produce green hydrogen across the North Sea region as it is rich in renewable resources (primarily wind), that can be used to power electrolysis. If Scotland can leverage these resources, it could become a leading producer and exporter of hydrogen and its derivatives.



Hydrogen Production Costs (EUR/kgH2)

<= 2.6 | 2.6 - 2.8 | 2.8 - 3.0 | 3.0 - 3.2 | 3.2 - 3.4 | 3.4 - 3.6 | 3.6 - 3.8 | 3.8 - 4.0 | > 4.0

Figure 2: Hydrogen production cost from Offshore Wind adapted from IEA Accelerated 2030 scenario [2]

5.0

Energy Hub Economics

Green hydrogen is a rapidly expanding sector, with no large-scale production facilities currently in operation globally. The anticipated surge in demand, combined with limited supply in the near to mid-term presents huge opportunities for Scotland if it can scale up production in time. Key technologies to enable low cost floating offshore wind must be accelerated to unlock these opportunities.

Global hydrogen demand is expected to increase by 14% between 2023 and 2030 (from 86 Mtpa to 98 Mtpa) with most of the increase expected to be from low carbon demand sectors (see Figure 3). Looking beyond 2030, the demand is modelled to increase by 270% by 2050 (264 Mtpa) [3] [4].

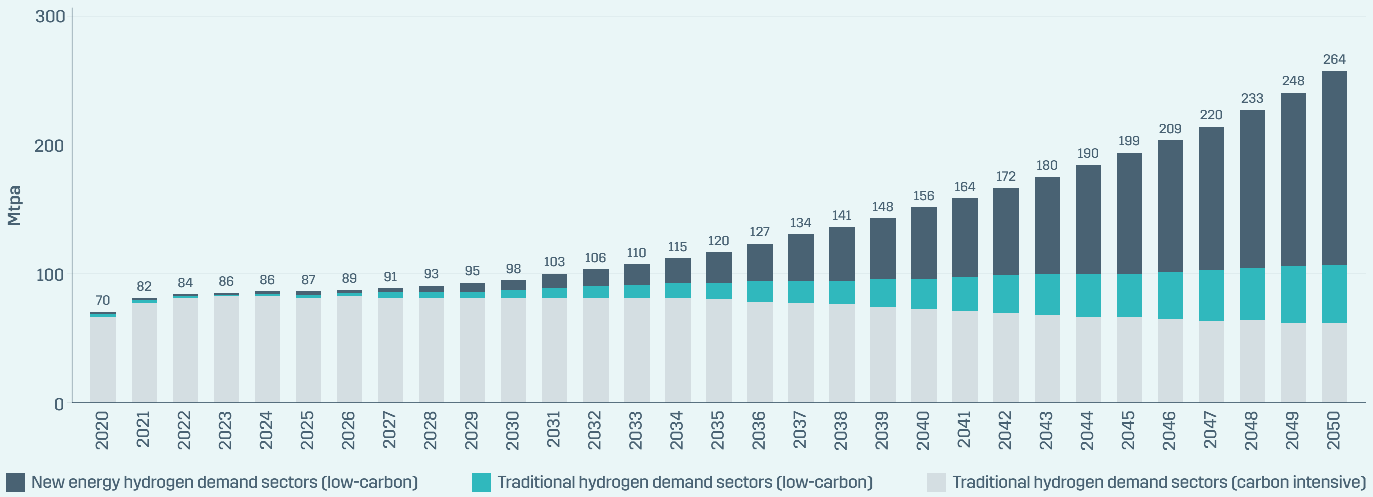


Figure 3: Global hydrogen demand 2020 to 2050 [4]

European hydrogen demand is expected to increase between 2023 (8 Mtpa) and 2030 (9 Mtpa) (see Figure 4).

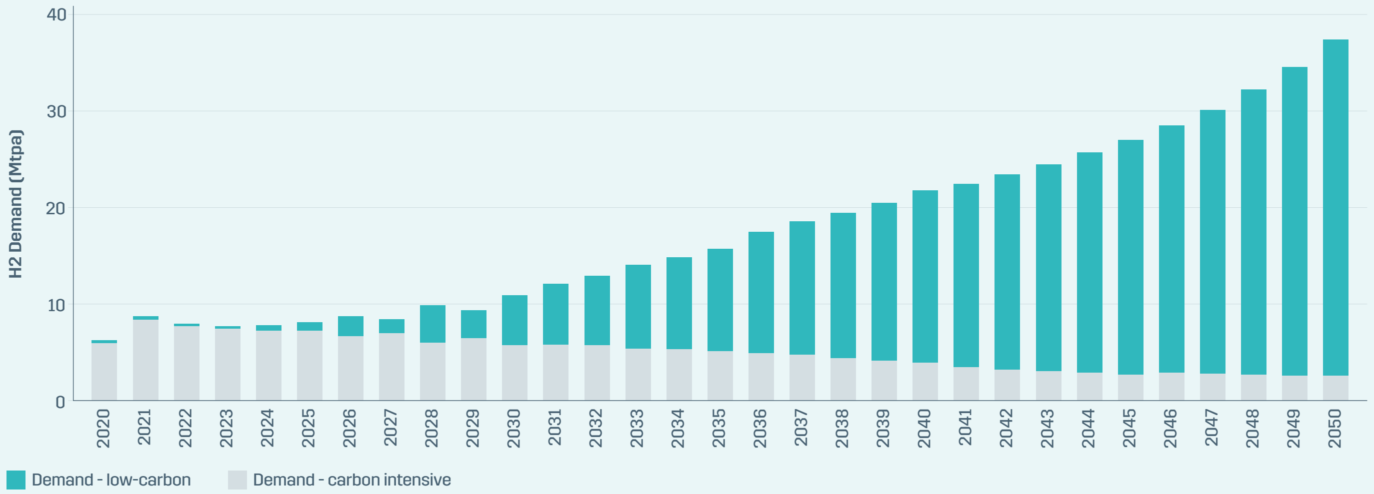


Figure 4: European Hydrogen Demand between 2020 to 2050 [4]

The current Wood Mackenzie Strategic Planning Outlook (SPO) forecast indicates a scenario where European low carbon hydrogen supply fails to meet demand with a deficit of 1.6 Mtpa in 2030 rising to ~6 Mtpa in 2050 [4] .

This presents an opportunity for a green hydrogen hub coming online in the late 2030s to meet some of this demand. The Hydrogen Backbone Link Project demonstrated that exporting hydrogen from Scotland to Europe via pipeline was feasible both technically and economically at a 0.9 Mtpa scale. This pipeline would directly link Scottish hydrogen with European markets.

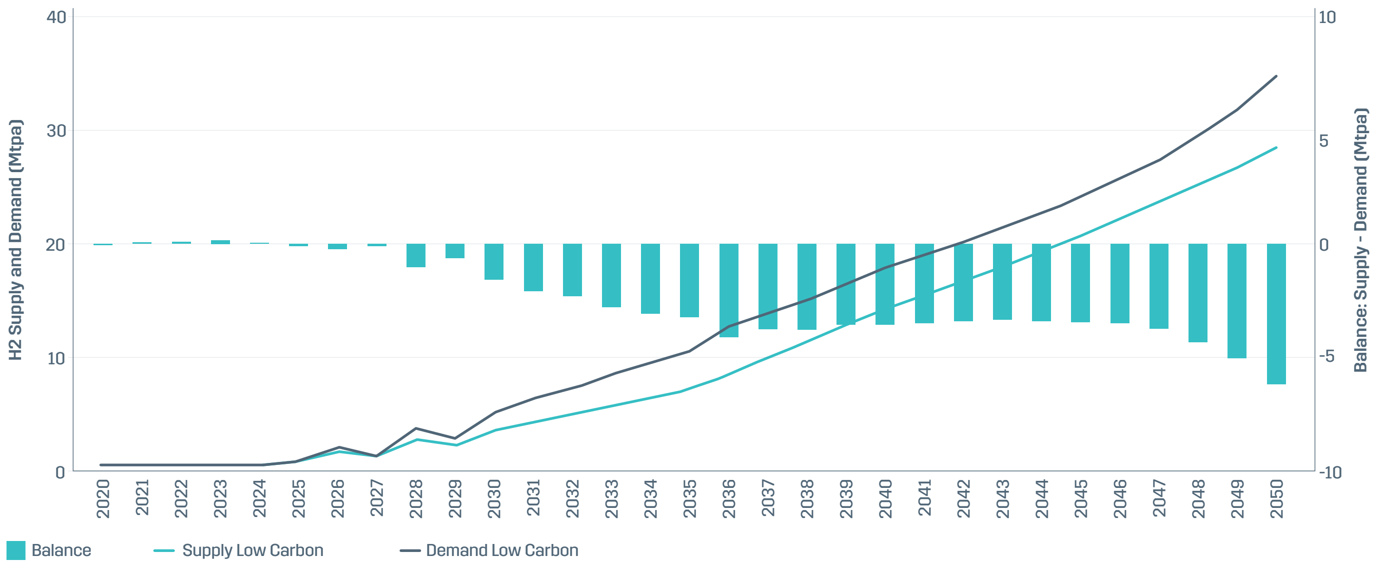


Figure 5: European low carbon hydrogen supply vs demand [4]

Fixed vs Floating Wind

Floating wind is key for powering multi-GW scale hydrogen production [5]. Given the water depth constraints for fixed wind and the rising electricity demand of the UK economy, floating wind is the most likely power source for a multi-GW scale hub.

Floating turbines are an emerging technology with new turbines and updates to ancillary infrastructure expected in the coming decades. Currently the levelised cost of energy (LCOE) for floating offshore wind in the United Kingdom Continental Shelf (UKCS) is estimated to exceed $100/MWh [3], but this is projected to decrease in the coming years as deployment increases, capital costs fall, innovation continues, and operational experience grows.

Hydrogen production volumes depend on the source of the power, whether from a fixed or floating wind development. Floating wind has a higher load factor and can therefore produce more hydrogen. A 10 GW development supplied by floating wind is estimated to produce up to 0.98 Mtpa of hydrogen, 9% more than a fixed wind development of the same scale which produces up to 0.90 Mtpa.

Energy Hub Economics

Economic modelling showed that for a 200 MW green hydrogen development powered by fixed wind, the levelised cost of hydrogen is £3.88/kg. For hydrogen production powered by floating wind, this rises to £4.14/kg. However, scaling up production to fill the 0.9 Mtpa Hydrogen Backbone necessitates production facilities much larger than 200 MW. When the modelling was scaled up to a 10 GW hydrogen production facility powered by floating wind, the levelised cost of hydrogen production fell to £3.90/kg.

The total CAPEX for a development of this scale is estimated to be £30.2 billion and would produce up to 0.98 Mtpa of green hydrogen.

When scaling up the model, it was assumed that the size of the floating wind farm and hydrogen production system would be optimised to find the sweet spot where maximum production is achieved for the lowest cost of production. The construction time and unit CAPEX costs are also adjusted to reflect the larger size of the 10 GW floating wind powered hydrogen production plant.

This modelling used forecasted costs for the late 2030s and anticipates that the cost of electricity from floating wind will decrease over time as the technology develops. The LCOE in the model was set at $60/MWh for floating wind. A lower levelised cost of hydrogen can be achieved if this pace of innovation is accelerated.

Case	Fixed Wind (£/Kg)	Floating Wind (£/Kg)
2 year build	3.88	4.14
2 year build and 20% CAPEX reduction	3.52	3.82
4 year build	4.00	4.25
4 year build and 20% CAPEX reduction	3.62	**3.90**

Table 1: LCOH for 10 GW Energy Hub development in the late 2030s [3]

Case	Fixed Wind (£Bn)	Floating Wind (£Bn)
10 GW Offshore Wind Farm Capex	19.0	21.1
10 GW Hydrogen Production Plant Capex	9.1	9.1
10 GW Total Investment Cost	28.1	**30.2**

Table 2: CAPEX for 10 GW Energy Hub development in the late 2030s [3]

A key finding was that by the late 2030s the gap between the cost of fixed and floating wind-powered hydrogen production could well be within touching distance, assuming the market and technology factors for these types of developments can be fully realised.

Next Steps

- **To ensure the competitiveness of Scottish green hydrogen, investment and government support targeted at floating wind is crucial. This support should focus on accelerating the development of next-generation technologies and establishing manufacturing processes.**
- **The technical elements of floating offshore wind are established at small scale, deploying a pilot project in Scotland at an increased scale would be recommended to provide assurance to prospective investors [5].**
- **Innovation in electrolyser technologies is also needed to improve the efficiency of hydrogen production and reduce system costs.**
- **Enabling electrolyser and floating offshore wind technologies to be scaled up to the required level requires increased investment both now and in the future [5].**
- **Significant efforts are required to make a large-scale project a reality. In the meantime, smaller-scale projects need to be developed to gain experience and establish a supply chain capable of supporting a large-scale project.**

6.0

Energy Hubs

An Energy Hub is a specific geographic location which will host all facilities necessary for the large-scale production of hydrogen and hydrogen derivatives such as e-fuels.

6.1 Energy Resource

Several possible Energy Hub locations exist across Scotland, each with a different mix of energy vectors available. To estimate the resource available, the project assessed the current installed, future planned, and potential renewable energy at five hubs across Scotland.

A preliminary screening was performed to select five Energy Hubs for further detailed study (Figure 6). A detailed analysis of the current, future planned, and potential renewable generation capacity for the five selected hubs was then carried out, to determine the amount and mix of renewable capacity at each hub. The total annual energy that may be generated across these locations was then calculated.

At each location, only energy vectors with a minimum generation capacity of 50 MW were included for analysis. Solar photovoltaic (PV) was initially considered as an energy vector. However, as the major single source of this vector is the accumulation of individual domestic installations, it was discounted from the study.

The study results summarising the generation capacity that may be available for each Energy Hub location are depicted in Figure 7. "Installed" indicates current installed energy resources, "future" indicates planned / in development resources, and "potential" indicates a reasonable estimate of the resources that could be exploited in the future. It should be noted that some offshore wind resources may be accessed by more than one Energy Hub (Aberdeen & NE, Dundee, Fife). Therefore, the combined generation capacity across these three hubs will be less than the total of the three individual hubs depicted in Figure 7.

Figure 6: Five Energy Hub locations selected for detailed analysis (based on map in Scottish Government Hydrogen Action Plan [6]) [7]

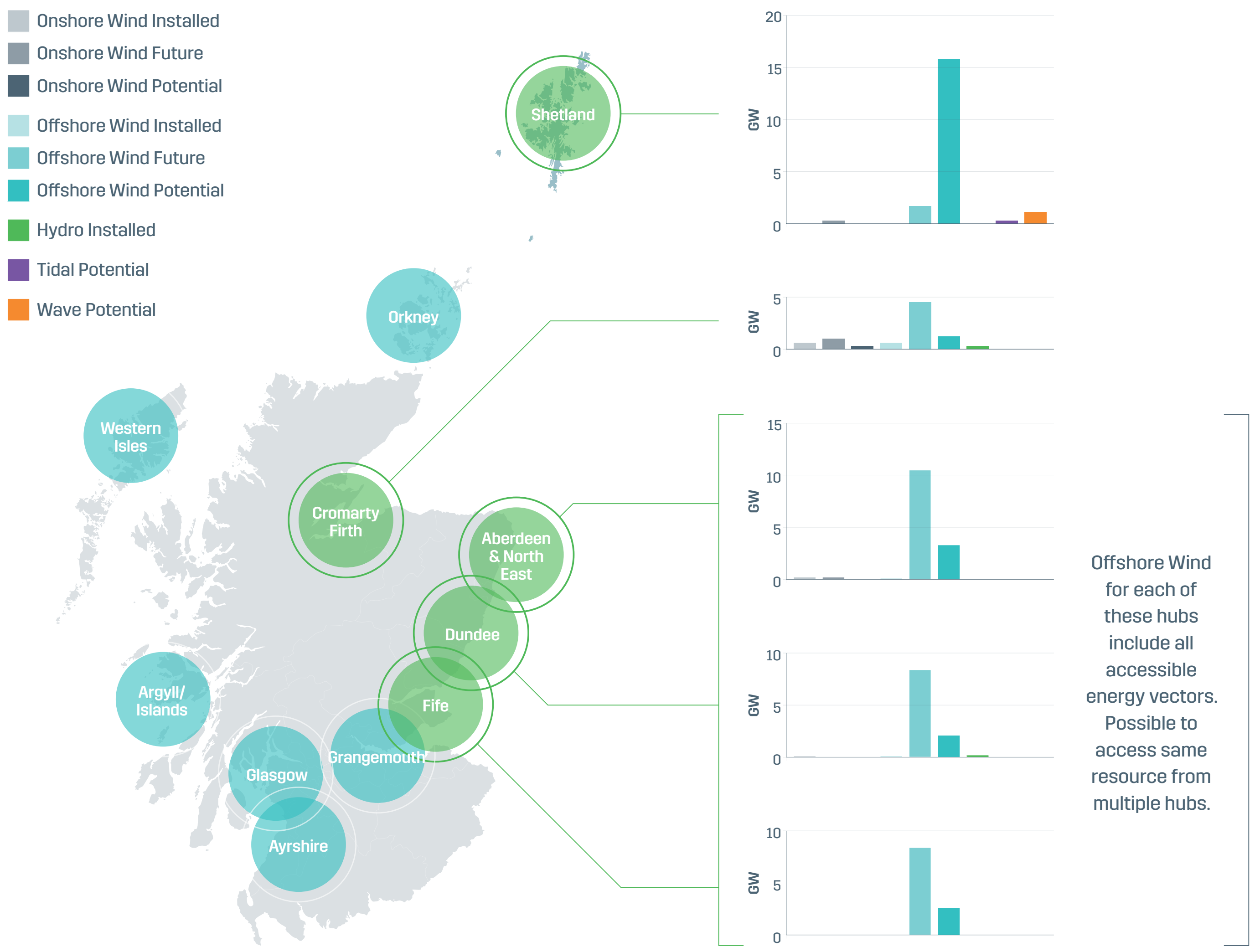


Figure 7: Generation capacity for each Energy Hub [7]

As shown in Figure 7, Aberdeen and the North East, Cromarty Firth, and Dundee each have some installed offshore wind capacity but these will quickly be surpassed by future (larger) offshore wind developments currently in construction or planning.

Shetland has the largest estimated potential offshore wind capacity, at circa 16 GW. Cromarty Firth has the largest capacity for onshore wind (installed, future planned and potential). Shetland is the only hub that has the potential for wave and tidal energy development.

The total energy potential available for all the energy vectors under consideration was estimated and compared with the current demand for electrical energy.

Historically, annual electrical demand in Scotland is between 30 TWh and 35 TWh [8]. As a snapshot, annual demand at the end of 2019 was 28.8 TWh [9]. Utilising data on installed renewable generation capacity in Scotland in 2022, it was estimated that installed renewable energy vectors generate approximately 33 TWh per annum in Scotland, as shown in Table 3.

Energy Vector	Installed Capacity (GW)	Generation Capacity (GW)
Onshore Wind	8.7	2.4
Offshore Wind	1.9	0.8
Hydro	1.8	0.6
Wave/Tidal	Negligible	Negligible
Total		3.8
Equivalent total annual generation in TWh		33.3 TWh

Table 3: Installed and generation capacity all Scotland Q1 2022 (Table uses installed capacity from BEIS ET 6.1 [10] adjusted with capacity factors)

With current installed capacity, on an annualised basis, the demand and the generation from renewables are close to parity. It is the case, however, that at any one time there may be a deficit in generation for the demand or an excess of generation resulting in power export or curtailment, due to the intermittency of renewable energy vectors.

With Scottish electricity demand being met predominantly by currently installed renewable capacity, this means that there is an opportunity to use future (planned and potential) renewable capacity for alternative purposes, such as hydrogen generation.

The analysis established the future (planned and potential) generation capacity for each energy vector at each of the five hubs. To avoid double counting, energy resources within a given area were uniquely allocated to individual hub locations.

The results indicate that if all the future planned generation capacity for the areas covered by the five energy hubs is realised, then this could mean an annual surplus of 160 TWh. Realising renewable energy from sources classed as "potential" would add a further 150 TWh to the total. This incremental annual capacity is shown in Figure 8.

Energy Generation Capacity for five Energy Hubs

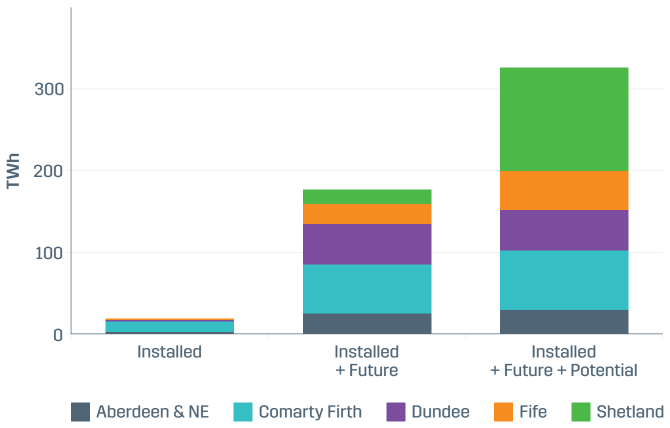


Figure 8: Incremental annual energy generation capacity for five Energy Hub locations [7]

The Scottish Government's Hydrogen Action Plan identified targets for renewable and low carbon hydrogen production capacity of 5 GW by 2030 and 25 GW by 2045 [6]. These targets represent an annual energy requirement of 43.8 TWh and 219 TWh respectively [6].

The former target could possibly be met by the future planned capacity of one Energy Hub (e.g. Aberdeen & North East or Cromarty Firth hubs). However, to achieve the latter target, it would require either all the future planned capacity of the selected five Energy Hubs plus additional hubs, or realisation of the full potential capacity at the five hubs.

Of the conclusions that can be drawn as a result of the study, the most significant is that the range of energy vectors analysed at five possible Energy Hub locations have the potential to deliver significant surplus energy beyond demand. This surplus energy could then be used for different purposes, including hydrogen production.

The results of the detailed analysis revealed that, to achieve a full understanding of the future and potential energy capacity, required a level of analysis that had not been present in the preliminary screening. To address this concern, it was recommended that further analysis is conducted on additional hub locations.

6.2 Location Assessment

6.2.1 Onshore Energy Hubs

The locations shortlisted within the resource assessment study namely Shetland, Orkney, Cromarty, Aberdeen & North East, Dundee, Fife, Grangemouth, Glasgow and Ayrshire, were used as a starting point to further assess the optimal location for an Energy Hub across Scotland.

This assessment was preceded by a market study of green and blue hydrogen, and of carbon capture, usage and storage (CCUS) technology which could be applied within an Energy Hub. This considered existing and future technologies for varying modes of producing green and blue hydrogen, the various means of capturing carbon, a review of e-fuels, and a review of hydrogen storage.

Each location was scored against a set of criteria:

- **Renewable electricity resource (green hydrogen only)**
- **CO_2 resource (CCUS)**
- **CO_2 storage (CCUS and blue hydrogen)**
- **Natural gas supply (blue hydrogen only)**
- **Land availability**
- **Local activity**
- **Local planning attitude/environment**
- **Skilled labour**
- **Export**
- **Connections**

Locations with high renewable power availability, strong export capability, and significant local hydrogen activity scored most favourably for green hydrogen. The four top performing locations for green hydrogen were The Cromarty Firth, Orkney, Aberdeen and the North East and Shetland.

Access to significantly greater renewable power than competing locations positions Cromarty at the top of the pile, whilst Orkney ranks above Aberdeen and the North East and Shetland due primarily to existing export infrastructure at Flotta, and significant ongoing local hydrogen activity respectively [11].

CCUS locations were assessed and shortlisted based on the presence of significant CO_2 point emitters, existing oil and gas processing infrastructure, and accessible CO_2 storage. The four highest ranking locations in the CCUS assessment were Shetland, Aberdeen and the North East, Grangemouth and Fife [11].

Next Steps

Further analysis is now needed to determine the suitability of shortlisted locations for the development of the Energy Hubs including:

- **Market assessments for shortlisted locations, which identify, qualify, and quantify all aspects of the green hydrogen value chain.**
- **Identification of single sites for development of an Energy hub within the confines of the locations shortlisted in this assessment.**
- **Cost models for green hydrogen production.**
- **CAPEX and OPEX assessments for green hydrogen production, incorporating location specific elements.**
- **Location specific stakeholder engagement.**
- **Assessment of development potential of planned renewable capacity.**

CASE STUDY
ABERDEEN & NORTH EAST

Aberdeen & North East was selected as a location for further in-depth analysis given its ability to accommodate the integration of all elements of the hydrogen value chain.

Within the context of Aberdeen & North East, the proposed Energy Hub would take the form of hydrogen production, consumption and storage, and CCUS capabilities. These would be distributed across Aberdeen City and the wider Aberdeenshire region, taking advantage of a number of inherent characteristics offered by the region's location including:

- **A combined renewable power availability of up to 4.6 GW from wind both onshore and offshore.**
- **The potential to generate high volumes of hydrogen and e-fuels from this wind resource.**
- **Potentially achieving between 17% and 65% of Scotland's national hydrogen demand by 2050.**
- **Potentially achieving between 0.75% and 0.44% of global e-methanol and renewable ammonia demand respectively within the same timeframe.**

Announcements on electrical transmission network upgrades give further confidence in the region's ability to accommodate large quantities of renewable power, however greater detail is required on connecting offshore wind to the network.

Aberdeen & North East - Energy Summary

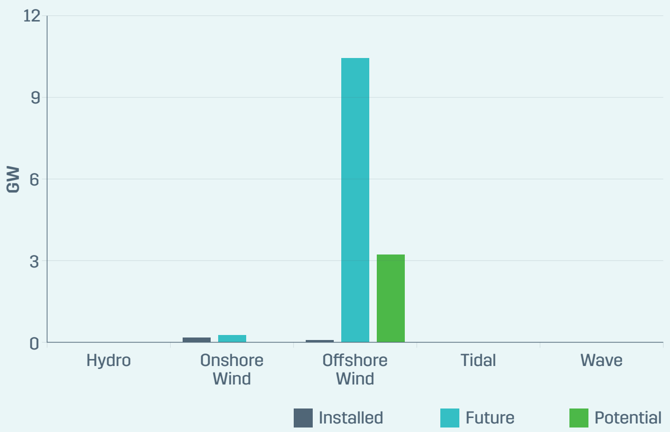


Figure 9: Aberdeen & North East future (planned) and potential wind resource [7]

Realisation of the region's potential with respect to hydrogen and e-fuel production relies on the driving force of strong domestic and international export capability. This could be facilitated by existing pipeline infrastructure from St Fergus, and novel infrastructure developed through schemes such as Project Union[2] which could enable large-scale export of hydrogen to demand centres in the south.

The same pipeline infrastructure could develop a further revenue stream for the region through import of CO_2 to St Fergus for storage in unused reservoirs in the North Sea. The proposed routing of the Hydrogen Backbone link Project includes a link to St Fergus.

In addition, the newly developed Aberdeen South Harbour has the ability to drive large-scale marine export to UK and European neighbours.

The region's supply chain is composed of numerous engineering and technology firms with existing or readily transferrable capability within all aspects of the post-production hydrogen value chain. The region's current deficit in electrolysis manufacturing capability is equally felt on a national basis. The deficit could be addressed through collaboration of existing skills and technology between existing supply chain firms within the North East.

As part of this case study cost estimates for the development of green hydrogen production and international export at scale from Aberdeen & North East were prepared, comparing the key hydrogen vectors of compressed hydrogen and liquid hydrogen. Four scenarios were prepared to evaluate the vectors, analysing the electricity cost of both vectors for grid connection through use of a Power Purchase Agreement (PPA) and considering electricity produced from a wind farm ("behind the meter").

The cost estimates were based on the export to Germany of 50 tonnes per day (TPD) of green hydrogen and ranged from CAPEX of £225 million for grid connected gaseous hydrogen production and export through to CAPEX of £1.01 billion for behind the meter liquid hydrogen production and export [12].

[2] Project Union is a project led by National Gas Transmission which seeks to deliver c.2000 km UK hydrogen backbone through the phased repurposing of existing assets and development of new pipelines. The intended Project Union pipeline route will facilitate the export of hydrogen via pipeline to key industrial centres in the central belt, as well as throughout the rest of the UK.

6.2.2 Offshore Energy Hubs

The North Sea region is rich in renewable energy potential, with Scotland alone having a significant capacity for offshore wind energy generation. The Scottish Government has set targets for 11 GW of offshore wind and 20 GW of onshore wind to be installed by 2030 [13].

However, much of this potential is located in challenging environments far from shore, and restrictions on electron transfer limit the benefits of the wind availability. To address these challenges in production, an Offshore Energy Hub (OEH) could be a viable solution.

A stepwise approach was taken to select suitable areas across technical, physical and environmental constraints. High-level assessments were made for other potential OEHs that are being considered in Europe, including the implications of exporting hydrogen from the OEH system into something like the Hydrogen Backbone, potential off-takers for hydrogen in the North Sea and a safety review considering implications on design, risk and consequences when producing hydrogen offshore.

In addition, a review to determine which technologies would be most suited to offshore deployment was also completed.

Three locations across the North, Central and Southern North Sea were subsequently identified as suitable for an OEH.

Each was characterised by optimal technical features, minimal interaction with physical and environmental constraints in the region, a relatively low Levelised Cost of Energy (LCOE) value, and a high potential for cluster formation.

Each is also in relatively close proximity to export options and ports – to support both installation and operations and maintenance (O&M) activities.

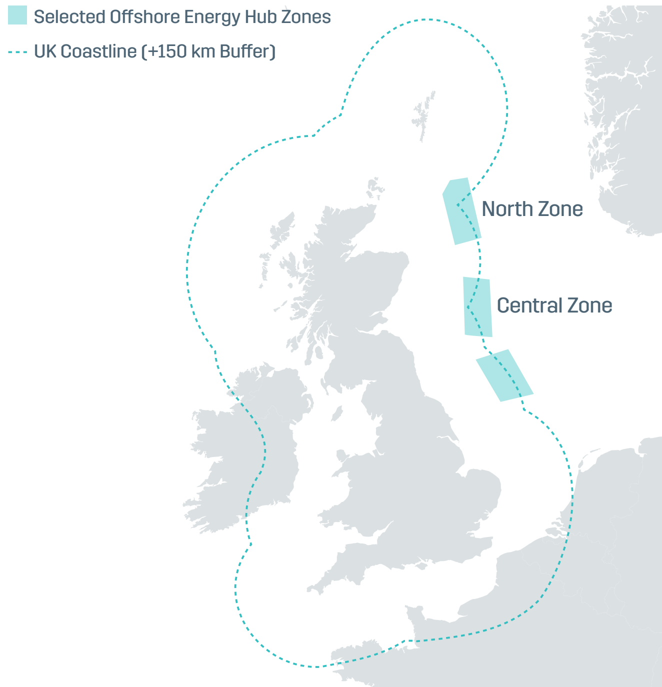


Figure 10: OEH locations [40]

To help determine the critical inputs and variables that can make an OEH a more effective investment, an LCOH analysis was completed. This calculated the levelised cost of hydrogen (LCOH) for two reference cases: an onshore and an offshore green hydrogen development. The key inputs were changed and outputs compared to identify any major benefits for the offshore scenario. From the reference cases, it was clear that the CAPEX and OPEX associated with offshore production are greater than onshore. The estimated LCOH for the offshore reference case was £2.4/kg more than the LCOH for the onshore reference case. This difference is relatively low, considering the technical challenges associated with an offshore facility.

The main scenario where an OEH may be an effective investment is when there is a wind farm that needs to be dedicated to a hydrogen production facility (i.e. is not also connected to grid). This keeps the LCOE high and minimises the difference in LCOH between an onshore and offshore case. In addition, the location would have to be desirable in order to minimise the non-processing CAPEX associated with an offshore facility.

6.3 Energy Hub Modelling

In a 2045 net zero society, energy demands will be different, and electrification will increase demand for low carbon/ renewable electricity. Hydrogen will substitute natural gas in many processes. The National Grid's 'Future Energy Scenario' report envisions the UK requiring 792 TWh of electricity and 263 TWh of hydrogen annually in 2050 [14]. Scotland is assumed to account for 13% of the UK demand in 2050 for both electricity and hydrogen.

An integrated energy system model was created by SLB to find the optimal wind to green hydrogen hub development for 2045 [15]. The model remit was to "produce the lowest cost system whilst meeting 100% of domestic demand for both electricity and hydrogen". Essentially, the model explored what a decarbonised energy system looks like for Scotland in 2045, including how much energy remains for export.

Two models were constructed to produce e-fuels, hydrogen and electricity, with the model outputting a range of performance metrics. A number of technical assumptions were made on wind turbine capacity, electrolysers and e-fuel production. The model also considered OPEX for hydrogen tank storage, lithium-ion batteries and hydroelectric potential storage.

Three ways to move energy were considered: electricity through offshore, onshore and import/export cables; gaseous hydrogen through pipelines; and e-methanol via tanker ships. Subsea high voltage direct current (HVDC) cables were assumed to connect offshore wind farms to the shore.

2019 weather data was used to simulate hourly, daily and seasonal changes in wind strength at all locations where renewable generation is installed. Offshore wind generation was combined with production from onshore wind and pumped hydropower at the scale proposed for 2045. Power curves, efficiencies and performance data for generating components provide the energy flux to the model. The model could export energy as electricity, as gaseous hydrogen via the Hydrogen Backbone Link pipeline (HBL), or as e-fuel via tanker ship.

However, energy supplementation from electricity imports was required during periods of high demand or low wind. The amount of energy exported was consistent across all models, with an average of 1.4 to 1.8 GW per hour of electricity and 15 to 19.3 tonnes per hour of hydrogen exported to England.

In addition, the capacity of the Hydrogen Backbone sometimes constrained production and export from Scotland's wind-to-hydrogen system.

Key Findings from the Energy System Model

- To fully realise the potential of Scotland's renewable energy infrastructure, the National Grid transmission system would need a significant upgrade to avoid network congestion in areas where wind generation from multiple windfarms converge. In particular, the main transmission pathways between offshore generation sites and hydrogen hubs would need to be of sufficient capacity. Wind generation curtailment would occur if the grid cannot accommodate the electricity.
- With an insufficient electrical transmission grid, a mosaic of energy microgrids where generation and consumption are collocated may be more pragmatic.
- E-fuels provide an additional export revenue steam and e-fuel synthesis will also utilise power and hydrogen system excesses, enabling higher capacity factors for wind farms and electrolysers.
- The scale-up of hydrogen capacity could be more ambitious than the Scottish Government's aim of 25 GW of "low carbon" capacity by 2045.
- Scotland has an abundant renewable resource; it is the prediction and control of infrastructure and system costs that dictates the economic viability of any wind to hydrogen system.
- Electrolyser efficiency has a large effect on LCOH and is therefore an important topic for future research and development.
- The CAPEX and OPEX of offshore windfarms have a large effect on LCOH.

Next Steps

- **Individual hydrogen hub locations have been modelled at a gross scale. However, the models do not consider the circular economy. Oxygen from electrolysis and brines from desalination may have potential markets and may provide additional revenue. Modelling of individual hub projects is an essential step prior to their development to prove their economic case.**
- **Superhub modelling: The optimum way of integrating individual Energy Hubs into a "Super Hub" must be determined.**
- **The National Grid is capacity constrained, which would impact the probability of realising full system potential. Collaboration with National Grid to produce a 2045 model scenario which includes future grid constraints would allow the identification of energy bottlenecks and areas for microgrid development.**
- **The efficiency of electrolysers has a significant impact on reducing system costs. Research and development in nascent electrolyser technology (low TRL) and existing technology (high TRL) could help deliver large gains in overall system value.**

7.0

E -Fuels and Decarbonisation

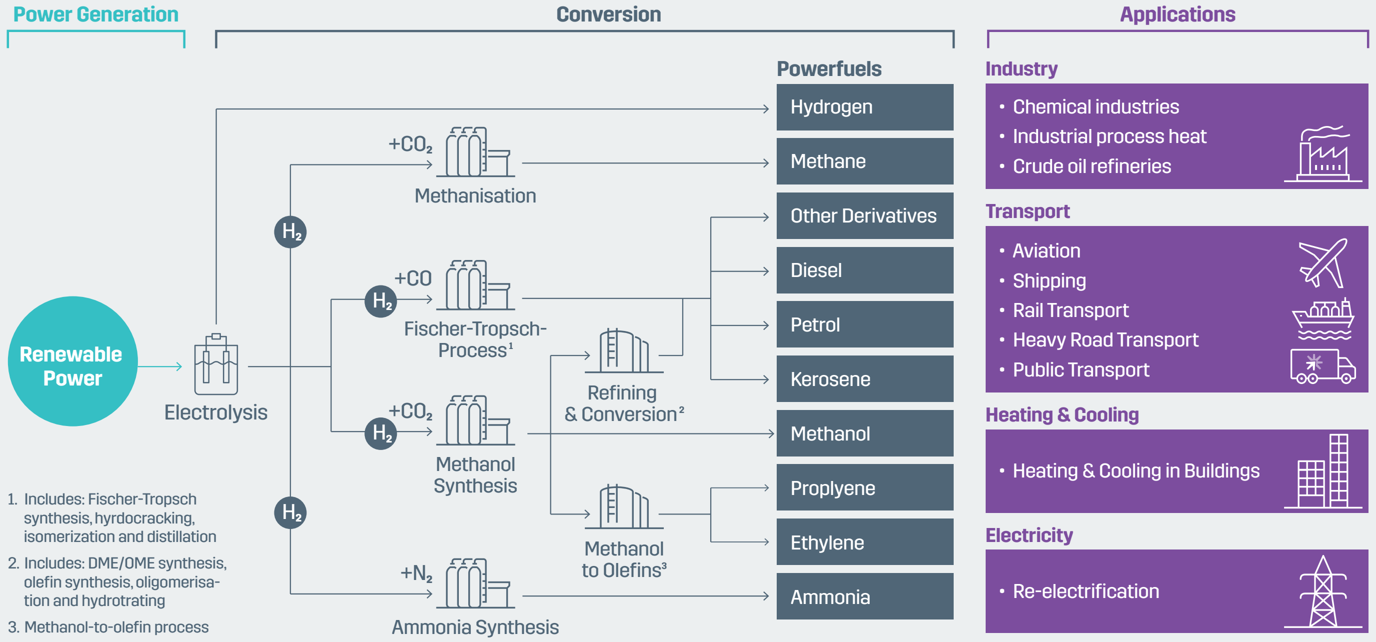
To date, most of Scotland's emissions reductions have come from decarbonisation of electricity generation. Solutions for so-called 'hard to decarbonise' sectors – such as offshore oil and gas production; the shipping industry; aviation; heavy goods transport on land; heating; agriculture; and many industrial sectors – will require a much broader range of technologies and energy systems solutions.

In this respect, e-fuels and hydrogen are likely to play an important role in decarbonising those sectors which cannot be easily electrified. Incorporating E-fuel production within Energy Hubs could present additional revenue streams and help maximise utilisation.

7.1 E-fuels: Feedstock and Production

E-fuels are a type of alternative fuel (see Table 4) produced by the combination of simple molecules such as hydrogen, carbon dioxide, carbon monoxide or nitrogen. The hydrocarbon produced may be a simple molecule such as e-methane, or a more complex hydrocarbon such as e-diesel. This results in a fuel which may be low carbon or even carbon neutral.

The main feedstocks for most synthetic fuels are hydrogen, carbon monoxide or carbon dioxide. Nitrogen and hydrogen are feedstocks for ammonia.



1. Includes: Fischer-Tropsch synthesis, hyrdocracking, isomerization and distillation
2. Includes: DME/OME synthesis, olefin synthesis, oligomerisation and hydrotrating
3. Methanol-to-olefin process

Figure 11: Production pathways to E-fuels [16] [17]

E-methane (CH4)	Green methane production is largely dependent on biological sources as a feedstock, producing biomethane. Synthetic methane production relies on hydrogen and carbon dioxide as feedstock using catalytic methanation. Biomethane production in Scotland from distilling, brewing and agriculture is already successfully operating through anaerobic digestion plants and has potential to increase. Production of e-methane in Scotland has not yet been reported.
E-propylene and ethylene	Green synthesis of olefins (including ethylene and propylene) from bio raw sources (bioMPG) is still under development. Green synthetic propylene and ethylene may be produced using e-methanol as a feedstock. No facilities are planned to be built in Scotland.
Synthetic natural gas or e-gas	Synthetic natural gas encompasses many natural gas derivatives using hydrocarbons from either fossil sources including gas, petroleum, coal, or synthesised using carbon dioxide, monoxide, and hydrogen with renewable energy. No commercial e-gas production derived from the renewable process is present in Scotland yet.
E-methanol (MeOH)	E-methanol is produced by a single-step reaction of hydrogen and carbon dioxide. To produce 'green' (i.e. carbon-neutral) e-methanol, hydrogen and captured carbon must be used. Green e-methanol produced from renewable sources is of high interest to several industries including the transport and chemistry industries. E-methanol is viewed as an energy transition e-fuel and energy carrier. E-methanol may be used as a final product for internal combustion engine vehicles and as feedstock for producing other e-fuels. A green methanol plant for the shipping industry, located at the Nigg Oil Terminal on the Cromarty Firth, was under development in 2021 following an agreement with the port operator, Global Energy Group.
Synthetic gasoline or e-gasoline and e-petrol	E-gasoline production involves methanol-to-gasoline synthesis and requires methanol, hydrogen and carbon dioxide as feedstocks. E-petrol covers production of blends using renewable energy sources and capture of carbon dioxide emitted during the process, categorised as a climate-neutral fuel. However, difficulties are observed with the lack of commercial production and ensuring e-petrol production has been performed using renewable sources. Evidence has been published regarding potential harmful to health pollution from e-petrol combustion at end-user engines.
Synthetic paraffinic kerosene (SPK) or e-kerosene and e-diesel	E-kerosene is produced from green hydrogen and captured carbon dioxide using a synthesis process plus further refining. SPK is a sustainable aviation fuel that can be produced with water and carbon dioxide source, renewable electricity with a power-to-liquid approach, and the Fischer-Tropsch synthesis or conversion process through a methanol route called 'middle distillates'. Production of sustainable aviation fuels including SPK is currently studied in a facility in St Fergus with the potential to be operational by 2026. No current e-diesel facilities have been reported in Scotland.
E-ammonia (NH3)	Ammonia is synthesised from hydrogen and nitrogen. Most of the world's ammonia is made using the Haber-Bosch process. For ammonia produced from natural gas to be low carbon ammonia, the ammonia production plant should be combined with carbon capture and storage. Green ammonia is produced from green hydrogen and nitrogen. Green hydrogen has shown potential to be used as an energy storage alternative to hydrogen in a liquid form avoiding complex and costly cooling systems. Liquid ammonia has a long history of large-scale industrial production and has a high hydrogen content. However, ammonia as gas or liquid presents a high level of toxicity when concentrated with corrosive effects. The first commercial production of green ammonia is planned in Orkney as part of an extension of the Hammars Hill Wind Farm.

Table 4: E-fuels: Alternatives and production readiness

7.2 Decarbonising Oil and Gas Offshore Production

In 2021, UK offshore oil and gas production facilities produced approximately 11.44 million tonnes of carbon dioxide equivalent (MtCO²e) of greenhouse gas emissions [18].

Historically, the majority of installation emissions (over 60%) have been from turbines and 6% have been from engines [19]. Finding alternatives to the fuel gas and diesel that currently fuel these turbines and engines is therefore a vital part of reducing the emissions from offshore installations.

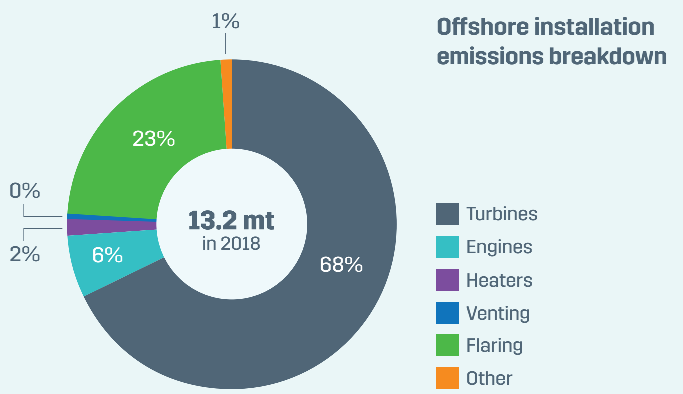


Figure 12: Offshore installation emissions breakdown, OEUK 2019 Emissions Report [19]

Replacing fuel gas (turbine supplied demand)

The demand for fuel gas on offshore installations can be split into three main categories:

- **Power generation:** Gas turbines driving alternators to generate electric power.
- **Mechanical drive:** Gas turbines directly driving rotating equipment such as compressors or large pumps.
- **Heat demand:** Heat recovery from the exhausts of gas turbines is used to supply process heating demands. Heat energy obtained in this way does not require additional combustion of fuel and effectively increases the overall energy efficiency of the combustion equipment.

Each of these categories has a different likelihood of being electrified, and of the three, power generation is the most likely target for electrification. However, achieving 100% electrification of an offshore asset is very difficult if it is not grid connected, due to the intermittent nature of offshore wind generation.

Replacing fuel gas with 'drop-in' e-fuels (e-methanol, ammonia or e-kerosene) could eliminate or greatly reduce many of the challenges associated with offshore electrification.

Replacing Diesel (Engine Supplied Demand)

E-fuels may also be used to meet the power demand currently fulfilled by diesel. Diesel engines are typically used on offshore production facilities as supplementary or back-up power generation, for emergency generation and for fire pump drives.

Diesel engines (or engines using marine heavy fuel oil) are also commonly used on floating production, storage and offloading (FPSO) facilities and floating storage and offloading (FSO) facilities to power marine systems including thrusters used to maintain position or heading.

Diesel may also be used as a fuel during post-cessation of production 'lighthouse' operations (usage in this scenario is low but can continue for a number of years until the facility is fully decommissioned).

E-fuels Replacement Options

Three e-fuels were considered for the offshore oil and gas production industry in the UK: ammonia, e-kerosene and e-methanol. E-kerosene and e-methanol will be significantly easier to adopt than ammonia. Ammonia is more difficult to store and transport, presents new toxicity hazards, and would need development of entirely new transport infrastructure.

E-kerosene and e-methanol require modifications and new large-scale storage offshore. Preference is likely to be driven by cost and availability. In the case of e-kerosene the ability to use bio-derived diesel equivalent fuels in the short to medium term with a later switch to e-kerosene (or similar) once costs are lower and supply is established could be attractive.

This would require fuel standards between biofuel and e-fuel versions to be reasonably well aligned to minimised later cost. Similarly, bio-methanol could be used in the short to medium term while e-methanol production capacity establishes.

Market Projections and Supply Chain Scenarios

The total fuel gas supplied demand suitable for replacing with e-fuels was estimated for 2030, 2035 and 2040. The total diesel supplied demand suitable for replacing with e-fuels was also estimated for 2030, 2035 and 2040. These estimates were then converted into the required volumes and masses of e-methanol, ammonia and e-kerosene.

Combining the results of these two assessments produced an estimate of the maximum e-fuel demand across the UKCS, as shown in Table 5. The maximum annual energy demand (in TWh/yr) that may be met by e-fuels assumes an uptime of 95% – i.e., the total power demand is present 95% of the year. The efficiency of combustion equipment is assumed to be 30%.

	2030	2035	2040
Power Supplied - MW	953	407	363
Total Demand (TWh/yr)	7.93	3.39	3.02
Fuel Energy Demand (TWh/yr)	26.4	11.3	10.1
Methanol - Mt/yr	4.8	2.0	1.8
Methanol - Mm³/yr	6.0	2.6	2.3
Ammonia - Mt/yr	4.2	1.8	1.6
Ammonia - Mm³/yr	5.8	2.5	2.2
Kerosene - Mt/yr	2.2	0.9	0.8
Kerosene - Mm³/yr	2.7	1.2	1.0

Table 5: E-fuel mass and volume demand estimate – replacing fuel gas and diesel on UKCS installations [20]

Table 5 shows a maximum forecast, which is based on the assumption that in cases where both e-fuels and electrification are suitable options for decarbonisation, e-fuels will be chosen. Market analysis revealed that there is potentially a large e-fuel market in supplying offshore oil and gas production facilities, and that there will be several installations with a long remaining operating life for which full electrification will not be a feasible solution. Even considering a part of the diesel market only, this market could support commercial scale e-fuel production.

A supply chain assessment modelled three 2030 energy demand scenarios for each e-fuel: An 800 MW ceiling scenario; a 400 MW scenario, and a 125 MW scenario.

The 800 MW ceiling scenario represents a 2030 estimate of the replacement of the fuel gas demand that is unlikely to be electrified. Alternatively, it represents replacement of approximately 80% of the total fuel gas and diesel demand in 2030. The 400 MW scenario represents 50% of the 800 MW ceiling scenario. The 125 MW demand scenario is intended to represent uptake being primarily as a diesel replacement and represents 100% of the diesel demand in 2030.

For each scenario the needs for feedstock, the renewable electricity to supply that feedstock, the site area, and the water supply were assessed. The assessment showed that a large deployment of renewable power and large-scale CO_2 capture is required even to meet the needs of one or two large production facilities.

A large-scale Scotwind site (say 2 GW) could provide enough power to create e-methanol or e-kerosene to supply approximately 125 MW of power demand. There is almost no e-methanol or e-kerosene available today.

Next Steps

The market analysis for e-fuels in the oil and gas sector has considered offshore production facilities only. As part of the next phase analysis, it is recommended to widen market analysis to consider hard to electrify onshore fuel users further downstream in the value chain. For example, oil export terminals with large pumps for loading oil to tankers, or gas-powered compression stations on the onshore gas transmission network.

Establishing fuel supply, and a clear roadmap to supply, is the largest challenge and the most needed action to enable installation operators to plan for a change to e-Fuels.

7.3 Decarbonising the Shipping/Maritime Sectors

The transport sector accounts for the largest proportion of UK carbon emissions (26% of greenhouse gas emissions in 2021). Within this figure, domestic shipping accounted for 5.3 million tonnes of carbon dioxide equivalent ($MtCO_2e$), and international shipping accounted for 6.2 $MtCO_2e$ in 2021 [21].

The Zero Emission Shipping Goal is an ambition set by the International Maritime Organisation (IMO) to reach net-zero Greenhouse gas (GHG) emissions from international shipping by or around 2050 [22].

The UK Government states that to achieve net zero by 2050, approximately 13% of emissions reduction in shipping would be delivered through efficiency and electrification, with the remaining emissions saving (87%) delivered through the development of zero-carbon fuels [23].

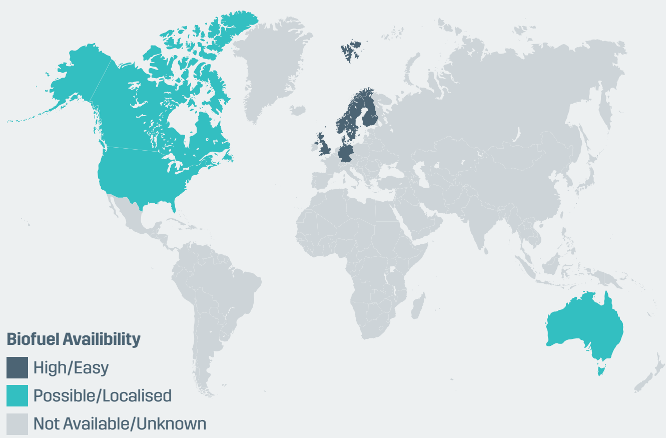


Figure 14: Worldwide availability of biofuels [24]

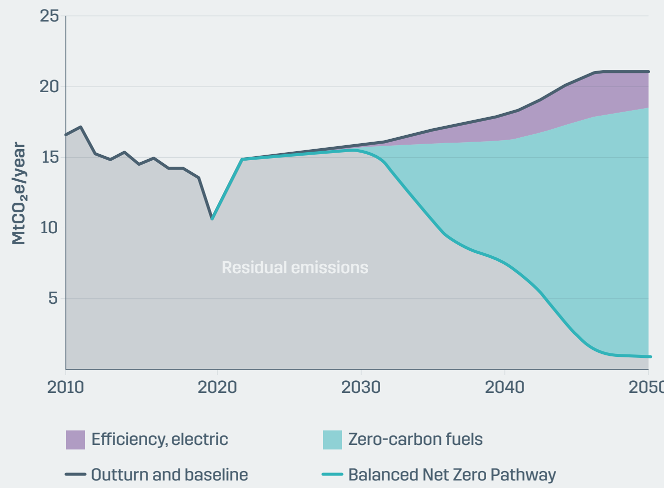


Figure 13: Sixth Carbon Budget projections for net zero pathway for the shipping sector [23]

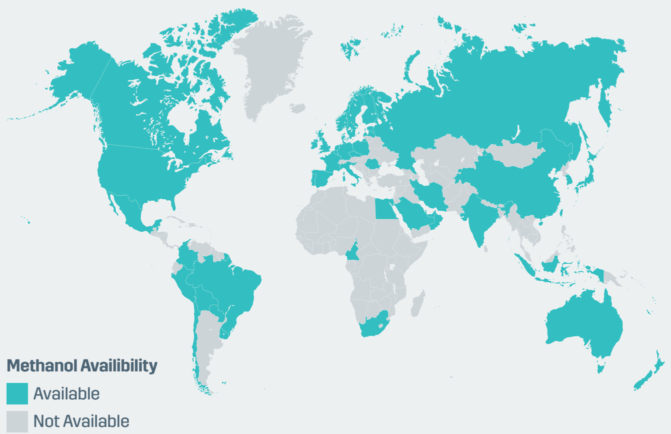


Figure 15: Worldwide availability of methanol [24]

E-Fuel Replacement Options

There is a plethora of alternative fuels being discussed and proposed for use in transition to the Zero Emission Shipping Goal. Unfortunately, only a handful of those are suitable for offshore vessels with deployment of many still in design stage, availability of many greatly limited, and those fuels where production has been scaled up are attractive to other markets.

The alternative fuels to be considered for shipping in the near term are paraffinic, co-processed marine gas oil (MGO) and fatty acid methyl esters (FAME). E-methanol is be expected to be the next long-term transitional fuel for offshore vessels.

Barriers to uptake

There are several barriers to the uptake of biofuels in the maritime sector:

- **Biofuel availability for the maritime industry is limited, with the main North Sea bunkering options in the Amsterdam-Rotterdam-Antwerp region (ARA) and Norway. UK delivery is possible but logistically challenging.**
- **Maritime sector is missing legislation defining biofuel certification, usage and bunkering.**
- **Despite biofuels suitability, combustion of biofuels above 30% requires Flag State dispensation.**
- **Price is considerably higher than fossil Distillate Marine Fuel (DMA) Marine Gas Oil (MGO), and the lack of any incentive schemes (apart from the Netherlands) is limiting usage of biofuels for powering offshore vessels.**

Next Steps

The most likely alternative fuels for the Maritime Sector will be FAME and Methanol.

CASE STUDY
SUBSEA7 FLEET REVIEW AND READINESS

In January 2022, Subsea7 began a paraffinic biofuel trial on the Seven Oceanic. 791 cubic metres (cbm) of MD1-30% Hydrotreated Vegetable Oil (HVO) was bunkered, and ongoing engine performance and condition checks were undertaken [25]. Subsea7 propose to carry out a FAME biofuel trial on a vessel in the fleet, utilising FAME up to 30%. The trial will be conducted in a similar manner to the paraffinic trial.

Half of the Subsea7 fleet is ready for operation on either 30% paraffinic fuels or 30% FAME. Operations on blends above 30% paraffinic or FAME require Flag State exemptions and emissions measurements.

CASE STUDY
PORT OF ABERDEEN SHORE POWER

The Aberdeen South Harbour aims to become one of the first ports in the UK to provide shore power to every berth, without restrictions on the type of vessels. Currently, vessels run onboard diesel engines to power amenities such as lighting, air-conditioning and lifting equipment while at berth. Shore power would allow vessels to turn off engines and plug into onshore power sources when berthed. This will contribute towards decarbonising the shipping sector and will improve local air quality.

The Port of Aberdeen has recently completed the first phase of the South Harbour Development, accounting for 80% of the total berthing capacity at South Harbour which will total ~1.5 km on completion. Port of Aberdeen, in line with national legal requirements on net zero targets, has announced an ambitious plan to be net zero across all three scopes by 2040.

Buro Happold conducted a feasibility study for the implementation of a shore power system at the Aberdeen South Harbour. South Harbour will accommodate a diverse array of vessels including offshore support vessels (OSVs), dive support vessels (DSVs), construction support vessels (CSVs), cruise ships, cargo vessels and jack-up rigs. A flexible shore power strategy that caters for different vessel types at different berths is therefore required.

The success of the shore power project depends on formal commitments from vessel operators, securing grant funding, finding cost-competitive delivery partners and infrastructure suppliers, procuring an affordable electricity purchase price, and considering future marine fuel oil prices and carbon taxation.

Given the high demands of vessels and the level of flexibility required by Port of Aberdeen, the case study proposed a complex electrical network to support the shore power system (see Figure 16). The case study estimated the CAPEX investment (worst case) for the scheme to be £28 million. This could be lowered with grant funding and/or distribution network operator (DNO) absorption of elements of grid upgrade costs.

Over the 40-year modelled lifetime of the scheme, 4660,000 tCO_2e could be saved compared to a marine gas oil counterfactual for the low call duration/low uptake scenario. Up to 830,000 tCO_2e could be saved for the high call duration/high uptake scenario. However, challenges remain, such as grid availability, operator commitment, and the significant capital investment required.

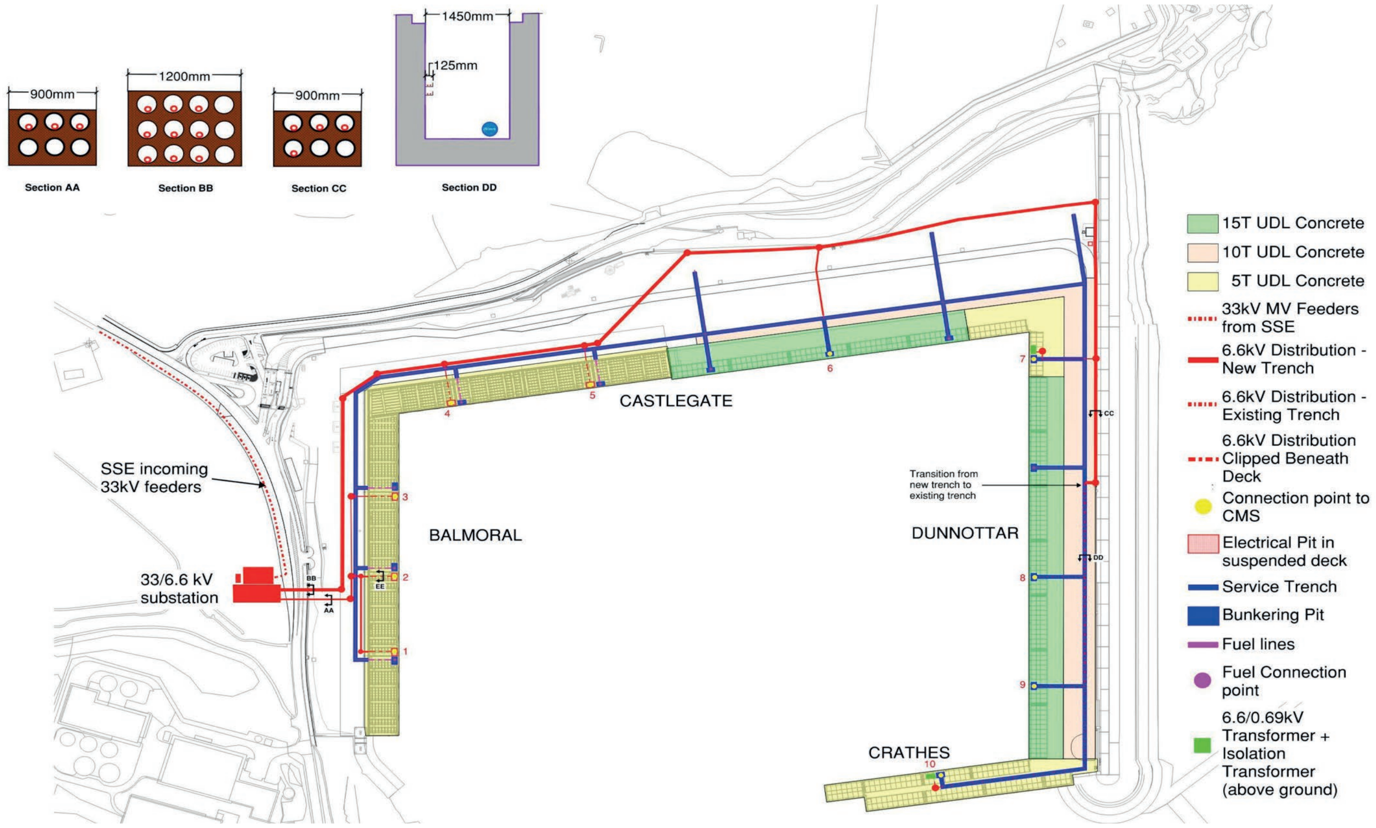


Figure 16: Proposed infrastructure layout at South Harbour [21]

Next Steps

Further refining the project through a detailed study, engaging with stakeholders, and investigating the need for low voltage connections with other vessel operators.

7.4 Decarbonising Onshore Sectors

The main sectors reviewed were aviation; land transport (with a particular focus on heavy goods); heating (residential/domestic); agriculture; and industrial.

The three sectors where fuel usage has the most impact on greenhouse gas emissions are aviation, heavy goods land transport, and the heating and industrial sectors. These three sectors were analysed and contrasted in a detailed assessment of the market opportunity for e-hydrogen and drop-in e-fuels.

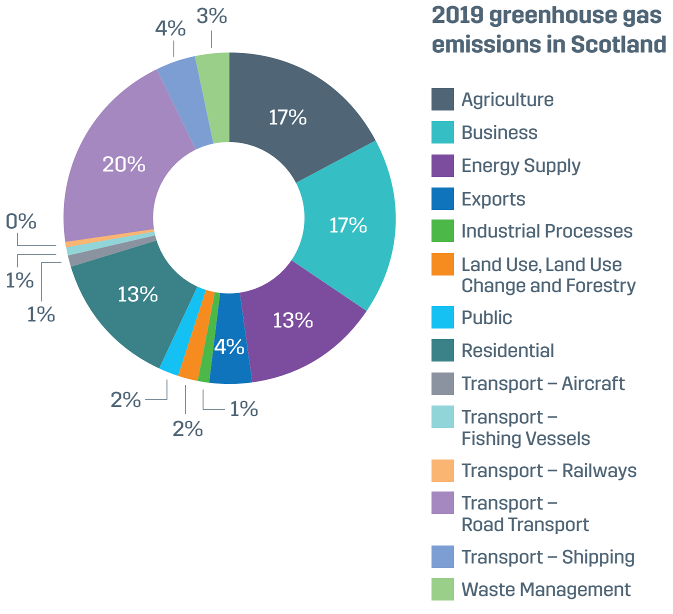
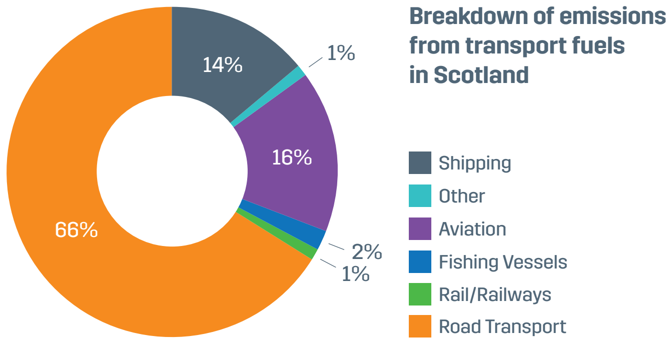


Figure 17: 2019 greenhouse gas emissions in Scotland (as CO_2e, [26])

7.4.1 Aviation

As shown in Figure 18, aviation represented 16% of Scottish transport emissions in 2019. Options to decarbonise the aviation sector are challenging but are required to meet any of the government set targets. In addition, many EU nations have set relevant e-fuel targets in aviation which has placed the aviation sector as a leading target together with maritime transport.



Note: Other includes – Inland goods, motorboats/workboats, personal watercraft, sailing boats with auxiliary engines.

Figure 18: Breakdown of emissions from transport fuels in Scotland, 2019 [27])

The fuel replacement options in aviation may include electrification, e-kerosene, e-methanol, hydrogen, ammonia, synthetic fuel and other Sustainable Aviation Fuels (SAF). Policy and strategies around aviation have highlighted the priority of transitioning to electric aircraft, hydrogen-based aircraft and potential use of e-kerosene as a drop-in fuel.

For e-kerosene production, a move towards synthetic fuel production in Scotland could utilise existing skills in crude oil refining, as well as maintain the use of distribution assets such as pipelines.

7.4.2 Land Transport

As shown in Figure 18, land-based transport represents the majority of Scottish transport emissions. It is a diverse sector, with a range of vehicle types and scales, from personal cars and motorcycles, to articulated trucks and trains. Given the significant infrastructure, cost, and energy challenges that arise from the transition to e-fuels, the industry will need to maximise any leverage it can to reach its targets.

Within land transport, while only representing 2% of registered vehicles and 8% of major road traffic in 2019, buses and heavy goods vehicles (i.e. large vehicles) were responsible for up to 24% of the total greenhouse gas emissions from road transport in the same year. The main fuel used in heavy transport is diesel.

Along with targets to displace some freight tonnage to more carbon efficient modes of transportation (trains and boats), there is a need to transition to zero-carbon emissions vehicles. The main fuel replacement option at a national level is hydrogen which offers significant advantages over electric vehicles (EVs) in heavy fleet vehicles such as buses, heavy goods vehicles (HGVs), non-electrified trains and ferries.

Use of hydrogen vehicles in these favourable modes could be encouraged in the short to medium term to drive demand certainty, and to ensure rapid decarbonisation. Switching public sector transport and back to base fleet vehicles to hydrogen could create the certainty of demand that stimulates investment in hydrogen production. Heavy goods transport is a market that will need to be developed. The supply chain for heavy goods vehicles and large public transport vehicles (buses and coaches) can be pooled with infrastructure necessary for decarbonisation of other road transport – and links with the heating and industrial efforts.

7.4.3 Heating (Residential/Domestic)

This sector has high energy demands but also a real opportunity to decarbonise. Scotland's 2.5 million occupied homes account for around 13% of the nation's total greenhouse gas emissions. As presented in Figure 19, the majority of homes in Scotland (81%) rely on grid gas for their heating fuel, with some 278,000 households (around 11%) heated by renewable or low carbon sources [28].

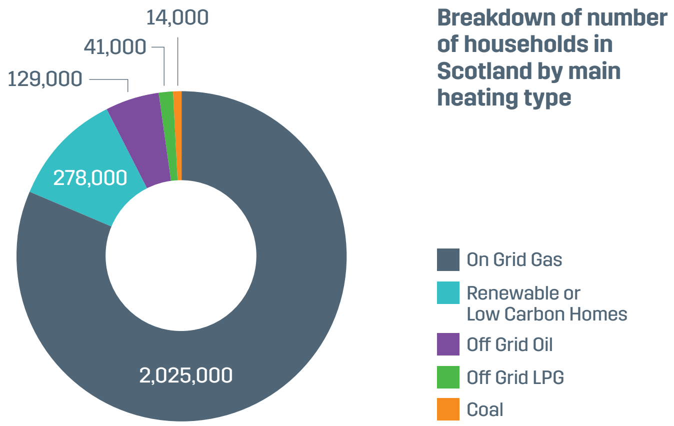


Figure 19: Breakdown of number of households in Scotland by main heating type [16] [28]

Approximately 7% of houses are off the gas grid so currently utilise heating oil, liquefied petroleum gas (LPG) or coal. Although the energy efficiency of Scotland's homes is improving, around 55% of properties are still rated below the recommended minimum energy performance certificate (EPC) rating of 'C'. Furthermore, some 42% of non-domestic buildings are on EPC band G, and around 50% use fuel for heating, ventilation and air conditioning.

In order to meet Scotland's interim climate targets and ensure long-term delivery of Scotland's net zero objectives by 2030, the vast majority of the off-gas homes that currently use high emissions oil, LPG, and solid fuels, as well as at least one million homes currently using mains gas, must convert to zero emissions heating. By 2030, there will also be a need to convert the equivalent of 50,000 of Scotland's non-domestic properties to zero emissions heating [29].

Decarbonising Scotland's domestic heat demand is undoubtedly very challenging. This is reflected in the differing views as to which method would be the most cost effective and practical way of doing so.

However, electrification of heating does provide a credible alternative to carbon-based fuels [30] and the flexibility and storage potential offered by hydrogen could also be key in addressing inter-seasonal heating demand.

The existing gas distribution network could be repurposed to hydrogen, potentially easing the transition from natural gas. However, the evidence base must be developed to support longer term decisions on the future for hydrogen in the gas network. If the indicators are positive, the use of hydrogen in domestic, commercial and industrial space heating could play an important role in unlocking hydrogen production.

7.4.4 Agriculture

Some 80% of Scotland's land mass is under agricultural production, making the industry the single biggest user of the landscape [31]. Agriculture is also one of the largest emitting sectors in terms of CO_2 equivalent. However, as presented in Figure 20 only 10% of emissions from agriculture in Scotland is attributable to fuel combustion.

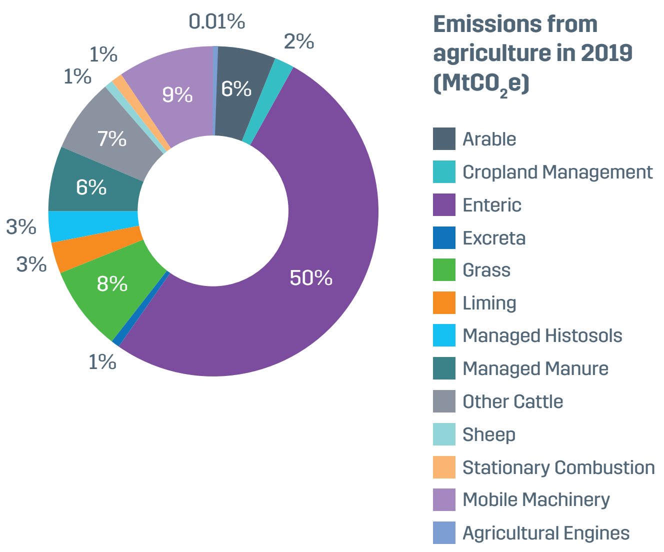


Figure 20: Emissions from agriculture in 2019 ($MtCO_2e$) [27]

The total emissions of the agriculture sector are high but are mainly from land use and livestock. Fuel consumption represents less than 10% of the overall sector emissions. Therefore, there is little impact available from transitioning to e-fuels.

The main fuel used in agriculture activity is red diesel. The diversity of rural small to large agriculture holdings presents a challenge when a new fuel may be introduced to replace current supply to their operations.

There are no export opportunities envisaged for agriculture e-fuel transition. Therefore, despite the high emissions from the agricultural sector, the sector was not selected for more detailed market analysis.

7.4.5 Scottish Industrial Sectors

The industries in scope can be categorised into eight energy-intensive sectors in Scotland: chemicals; oil and gas; food and drink; cement; paper and pulp; glass; metals; and other energy-intensive industries (EIIs).

Emissions are highly concentrated within a handful of sites and sectors: 75% of all emissions from the industries in scope occur within the seven highest-emitting sites which themselves are found in just three sectors (chemicals, oil and gas, and cement) [32]. Natural gas combustion is the biggest source of emissions, followed by the use of internal fuels within the oil and gas and petrochemical industries. Heating processes are the leading driver for industrial emissions, accounting for 74% of emissions.

Hydrogen is considered the main fuel replacement option in these energy-intensive sectors. Hydrogen is already a feedstock for a number of industrial processes in the chemical and petrochemical industry (production of ammonia, methanol, and high value chemicals) and in refining fossil-based fuels.

There are sectors already using fossil-derived hydrogen today in large quantities, usually producing on-site. Additionally, the steel industry is expected to be a significant future user of green hydrogen as the direct reduction of iron ore by hydrogen is seen as the only viable way to reduce greenhouse gas emissions and replace the current coal-based blast furnaces. Moreover, hydrogen can be utilised for generating process heat.

It is anticipated that both blue and green hydrogen could be used in industry. Current natural gas power generation could be replaced by hydrogen generation to support peak electrical demand, though this is likely to play a more modest role given the number of renewables in Scotland [30].

7.4.6 Strategic Market Assessment

Three sectors were analysed in detail to establish the short to medium term markets for e-fuel and hydrogen. For the purpose of the analysis, the industrial sector was considered a part of the heating sector, in particular, in the non-domestic segment. Therefore, the market assessment for the volumes to market focused on a comprehensive review of aviation, heavy goods land transport, and heating.

Aviation

Market	The UK is behind the EU in e-fuel target definition for aviation. In the absence of specific prospective market data, a reasonable proxy for the future market size is country population. Therefore, the UK market share was assumed to be equal to the ratio between the UK population and the sum of Europe and North America population. These represent a reasonable market. In addition, many EU nations have set relevant e-fuel targets in aviation which has put the aviation sector in the leading scene together with maritime transport.
Technology adaptation at end user	The aviation roadmap sets a maximum of 50% blend e-fuel in current engines.
Export potential	Export market targets: the Netherlands have a blending obligation for aviation (14% in 2030; 100% in 2050); Germany has 2% in aviation in 2030 to be considered; Spain has set a target to support power to liquid e-fuels production and use in aviation; the EU has set this as a long-term option for ships and planes; and Norway mentions aviation.
Opportunity link to other national industry	E-methanol links to maritime industry. E-kerosene links to off-grid heating.
E-fuel market pressure	Sustainable aviation roadmap identifies a wide market assessment for other biofuels that are set to be interesting as well. However, e-kerosene and e-methanol are both mentioned in different national and EU documents as relevant e-fuels for the sector.

Table 6: Features of the Aviation sector as a market for e-fuels [16]

Heavy Goods Land Transport

Market	Considering energy demand, HGV and bus transport account for 8.4 TWh. Considering a blending of hydrogen up to 30% under an Internal Combustion Engine (ICE) scenario, there would be an immediate 2.5 TWh demand for hydrogen in heavy goods. As fleets age, there is an opportunity to replace with bespoke fuel cell systems that run 100% on hydrogen via fuel cell technology. The EU Commission has set the decarbonisation of engines in land transport as a target for 2035 but fails to address fuel decarbonisation. This market statement sets a vision, reaching its maximum by 2035, then probably decreasing as full decarbonisation of transport should be a priority for car manufacturers, with battery powered electric engine or fuel cell powered ones.
Technology adaptation at end user	Up to 30% blend of hydrogen only requires the installation of a hydrogen injector in diesel internal combustion engines. In theory, this blending would reduce carbon-based emissions. Exact estimates of the impact of blending on emissions depend on load cycles and the application.
Export potential	The same hybrid technology with dual injection of hydrogen and diesel can be used in export markets, providing an avenue for fast widespread adoption of hydrogen usage in heavy duty transportation.
Opportunity link to other national industry	Heavy goods transport is a market that will need to be developed. The supply chain for heavy goods vehicles and large public transport vehicles (buses and coaches) can be pooled with infrastructure necessary for decarbonisation of other road transport. It links with the heating and industrial efforts above.
E-fuel market pressure	It is important to account for any negative community vision of e-fuels. At the same time the latest targets from the EU state that cars and heavy land transport will need to use decarbonised fuels, but not engines until 2035. Considering this, hydrogen would be the obvious alternative.

Table 7: Features of the Heavy Goods Land Transport sector as a market for e-fuels [16]

Heating

Market	Overall gas network demand is 29.3 TWh, from which 5.9 TWh would represent a present market for hydrogen. The top three local authorities for gas usage are Glasgow City, City of Edinburgh, and Fife, all of which are relatively near to the Grangemouth industrial cordon. Grangemouth is 46 km from Glasgow, 41 km from Edinburgh and 63 km from Fife. The estimated energy demand from Grangemouth (Dunbar, Alloa and Fife included) is 6.2 TWh. A portion of this energy demand will undertake an electrification process while the rest is forecasted to be replaced with green hydrogen. The distribution between electrification and hydrogen is still uncertain at this stage.
Technology adaptation at end user	The UK has set a 20% blend target based on: • Earlier studies (e.g. HSE Research Report RR1047, 2015), indicate that the addition of up to 20% hydrogen by volume is unlikely to present significant changes to any risks already associated with natural gas delivery. • 20% is the level at which it is expected that gas customers' supply and usage will not be affected by the change in gas composition. • Gas appliances manufactured after 1996 have been designed to operate with a hydrogen mix up to 23%.
Export potential	Hydrogen is the main energy carrier in the EU market. Hydrogen is clearly recognised as an essential element of a decarbonised energy system. While national strategies obviously differ in detail, reflecting individual country interests and industrial strengths, there is a clear, strong, and lasting international momentum behind the universal recognition that hydrogen is an essential and indispensable element of a decarbonised energy system [33].
Opportunity link to other national industry	E-kerosene in off-grid heating may benefit from aviation production as a side market for both. Hydrogen mix is set as a near future target. Supply chain should be easier. Requires some end user technology adaptation. The natural gas replacement with hydrogen links the heating and industry requirements. The 100% of urban heating and the 56% of industrial fuel use both require replacement of natural gas. There exists a geographical concentration of higher demand within an area of 100 km radius. • Urban heating: the top three local authorities for gas usage are Glasgow City, City of Edinburgh and Fife, at 46 km, 41 km and 63 km distance respectively from Grangemouth only. • Industrial decarbonisation: heavy industrial carbon is 75% concentrated in Grangemouth. Both heating and industrial decarbonisation share distribution infrastructure, and therefore they will share the strategy of injection technology and supply chain adaptation.
E-fuel market pressure	Electrification is aligned to the hydrogen economy efforts where electrification and heating are complementary.

Table 8: Features of the Heating and Industrial sectors as a market for e-fuels [16]

Next Steps

The development of the hub model in more detail may be required if decarbonisation is to be maximised. The hybrid model (geographically distributed rather than centralised) allows the current energy constraints placed on developers by the grid to be better utilised producing low-cost alternative fuels for redistribution and export. In addition, this could allow the further development of alternative fuels to suit sector requirements (e.g. airport distribution) and local feed stock availability.

Fuel replacement in aviation may be electrification, e-kerosene, e-methanol, hydrogen, ammonia, synthetic fuel and other sustainable aviation fuels.

Hydrogen is an alternative to EVs in heavy fleet vehicles such as buses, heavy goods vehicles, trains and ferries.

The flexibility and storage potential offered by hydrogen could also be key to addressing inter-seasonal heating demand. The existing gas distribution network could be repurposed to hydrogen, potentially easing the transition from natural gas. However, the evidence base must be developed to support longer term decisions on the future for hydrogen in the gas network.

If the indicators are positive, the use of hydrogen in domestic, commercial and industrial space heating could play an important role in unlocking hydrogen production.

Build upon current work on e-fuels in this Phase to understand the international export market demand of each e-fuel product option. Performing an assessment study to determine which e-fuel product would be the most viable for production in, and export from, Scotland. Markets and technologies are developing and remaining up to date with industry advancements is crucial. [5].

8.0

Energy Storage

The energy storage system (or systems) that will be best suited for an individual Energy Hub will be dependent on the site. Factors such as location, size, current infrastructure, energy demand, current energy supply and import/export routes should all be considered. There is no 'one size fits all' but there is a wide variety of energy storage solutions that could be deployed.

8.1 Storage Options

Hydrogen storage, combined with a second form of energy storage (most likely battery storage technology) to support a blackstart (to restart the system in the event that power is lost), would provide a robust overall energy storage system. Key considerations include:

- **Hydrogen provides the highest energy density per unit volume, although the production of hydrogen requires significant energy and the energy loss in producing hydrogen is greater than any of the other storage options considered.**
- **Energy stored as hydrogen provides flexibility in how the energy is used, exported as a fluid or converted to electricity.**
- **Thermal storage options also provide flexibility on how the stored energy is used, as heat or conversion to electricity.**
- **The generation of hydrogen can produce heat as a by-product which could be recovered using a thermal storage system.**
- **Battery storage is a mature system and provides the best all round storage solution, although large-scale battery systems may be required to provide the facility for a blackstart.**
- **Mechanical storage options require specific natural conditions and have a large infrastructure footprint. They do, however, provide large quantities of energy storage.**

8.2 Hydrogen Storage

A comparison of the storage options available for hydrogen has shown that the most appropriate storage option will be dependent on:

a) whether energy generation is required directly from storage, or the energy source will be exported

b) the location and infrastructure at the storage site.

The final choice for hydrogen storage will be influenced by the end user and their energy demands and requirement on a case-by-case basis. Key considerations include:

- **Liquid hydrogen is a poor option for storing or transporting hydrogen.**
- **If there is a continuous supply of hydrogen and a pipeline infrastructure available, gaseous hydrogen is a good option.**
- **Gaseous hydrogen, e-methanol and ammonia can be used as fuels for electricity generation or power and SAF can be used primarily for power.**
- **If there is no pipeline available for export, e-methanol, ammonia, liquid organic hydrogen carrier (LOHC) and SAF can be stored in large storage tanks and transported by ship.**
- **Metal hydrides and metal-organic frameworks (MOFs) provide a solution for smaller volume storage although commercially these systems are not currently available.**

CASE STUDY
SULLOM VOE [34]

For energy storage at Sullom Voe, Shetland, the best options are hydrogen and methanol with hydrogen stored in re-purposed hydrocarbon pipelines and methanol stored in above ground storage tanks as both these fluids can be used directly in a gas turbine.

However, both fluids are corrosive, and the infrastructure would need to be assessed for compatibility with the fluid. If the current infrastructure cannot be re-purposed, compressed air and molten salt should be considered as alternative energy sources.

In either case, a battery system should be installed to provide an energy source to support a blackstart. For export, the best options are methanol and LOHC.

While methanol is potentially corrosive, LOHC is compatible with petrochemical storage tanks and likely to be compatible with other infrastructure and transport options.

CASE STUDY
MONTROSE/DUNDEE [34]

There is not currently a practical solution for energy storage that would provide all the power to supply Dundee in the event that there was no power from wind energy. Thermal storage systems could provide power storage to supply supplementary power at times of peak demand.

While hydrogen provides a good medium for energy storage, there is no current power generation plant located local to Dundee that could be re-purposed to a hydrogen-based fuel. The most practical option is to import power, such as by connection from the national electricity grid, which would provide power from a diverse range of sources. To attain overall net zero, at times of surplus renewable energy, the export of energy can be offset against the import of energy when there is a dearth of local supply.

For export, the best option from those considered is ammonia. Ammonia production, however, requires process equipment and a supply of nitrogen although systems for both of these are known and functioning technologies. Ammonia is corrosive and requires specialist storage tanks. The next alternative option is to export hydrogen as a gas through a purpose-built pipeline.

8.3 Power System Analysis

A battery energy storage system (BESS)-based power solution for the Energy Hub concept was studied. It presents a system-level power analysis strategy to predict the long-term power performance of the integrated system, including wind turbines, BESS, and loads.

A Simulink model was developed for future digital twin-based power analysis investigations and to demonstrate the analysis process (see case study).

The analysis assumed that renewable energy was generated by a single wind turbine. The generated alternating current undergoes voltage transformation to a lower level before being converted to direct current.

The power flow is controlled by surface and subsea intelligent energy management systems (IEMS), which consider factors such as wind power generation status, BESS status, and load requirements.

These load requirements include power conditioning, wind turbine operations, power-to-X processes, recharging of autonomous vehicles or drones, and charging of crew transfer vessels (CTVs) or service operation vessels (SOVs) at the infield.

CASE STUDY
SIMULINK-BASED POWER ANALYSIS MODEL

Seven case studies were undertaken using the Simulink-based power analysis model to predict the long-term power performance of an integrated wind turbine-BESS loads system. The case study covers a period of 10 years using wind speed data collected from Cromarty Firth, Scotland.

The wind turbine considered in the study is an IEA 15 MW offshore wind turbine, and the chargers used are Sinexcel PWS1-250K-EX. The BESS considered in the study is the Verlume Halo system. Halo is a scalable, modular battery-based energy storage system [35].

The analysis and discussions focus on the Halo's reactions to wind speed, turbine power generation, and load requirements, demonstrating its typical reactions and long-term power performance.

Potential improvements for the analysis strategy and models are also suggested for future work, including considering wind farm layout and wake effects, updating efficiencies of charge and discharge operations, linking temperature impacts to real-time estimations, and developing a more user-friendly interface.

	Time length in consideration		
Performance statistics	3 month	1 year	10 year
Times to start charge	17	101	1240
Duration of charge (hr)	33	215	2,529
Times to start discharge	31	169	1,922
Duration of discharge (hr)	247	1,588	17,328
Times to start standby mode	15	67	695
Duration in standby mode (hr)	1,881	6,781	66,490
Times of being unavailable due to energy shortage	0	14	113
Duration of being unavailable due to energy shortage (hr)	0	177	1,254
Overall cycle count	5.6	34.2	360.5

Table 9: The Halo's power performance statistics in different time lengths (1 MWh capacity) Data from Verlume, 2023 [36]

KEY FINDINGS

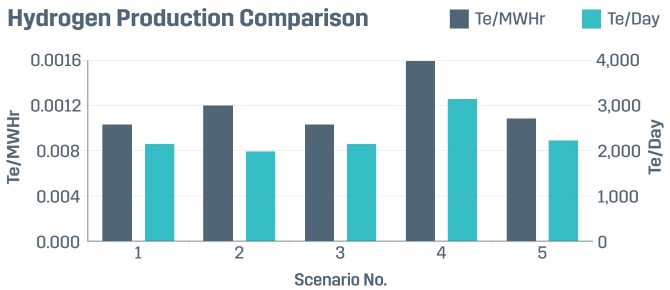
- **With an appropriately sized BESS, the wind turbine can operate without external power supply for an extended period, regardless of wind conditions.**
- **The integration of wind turbine and BESS systems, even without external power sources, can provide stable power delivery by effectively managing the BESS's charge and discharge operations.**
- **The proposed power analysis strategy and Simulink-based model are suitable for conducting high-level power analysis in a 'Generation-Storage-Loads' framework.**
- **The Simulink-based power analysis model serves as a digital twin platform and offers opportunities for future system updates in later design stages.**

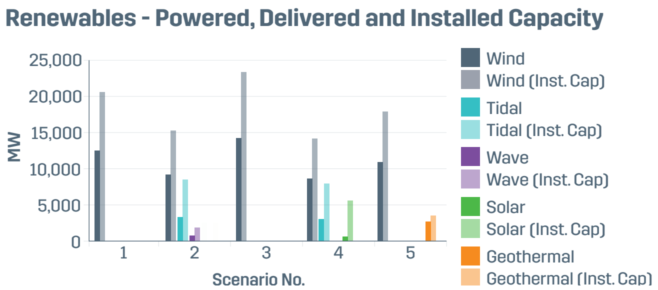
8.4 Microgrids

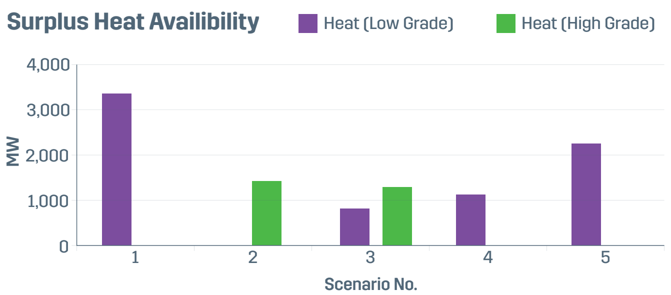
Additional investigations considered how a hydrogen hub could operate as a microgrid to identify the optimum microgrid architecture for maximum hydrogen efficiency without the need to connect to the grid.

Five microgrid scenarios were selected for further development, each containing a different combination of the main variables. In defining the scenarios, a key aim was to ensure a broad range of energy sources, energy storage solutions, and electrolyser technologies were covered, with several scenarios including more than one renewable energy source and/or electrolyser type. Refer to Table 10 on the opposite page for the key features of each scenario.

The study focused on 10 GW production and was location agnostic. Each microgrid is made up of a combination of renewable energy sources, electrical transmission and distribution networks, energy storage facilities, hydrogen generation (electrolysis) plant and auxiliaries, and symbiotic interfaces.







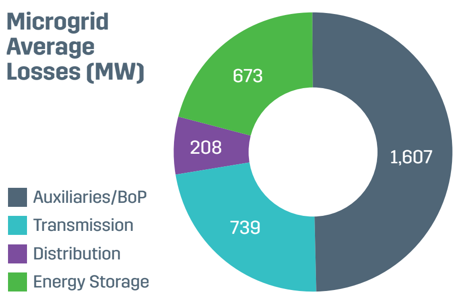


Figure 21: Key results for the five scenarios [37]

	1	2	3	4	5
Renewables	Offshore Wind	Offshore Wind + Tidal + Wave	Offshore Wind	Offshore Wind + Tidal + Solar	Offshore Wind + Geothermal
Transmission	HVDC	HVDC	HVAC	HVDC + HVAC	HVDC
Energy Storage	Pumped Hydro	Hydrogen	CAES	BESS	Sand Battery
Electrolyser(s)	PEM	SOE	SOE + PEM	AEM + CFEC	PEM + sHYp

Table 10: Five scenarios for maximising microgrid efficiency [37]

Key findings (Scenario specific)

Based on the five scenarios assessed, it was identified that for a 10 GW hydrogen energy hub:

- **Scenario 4 was found to be the most efficient in terms of hydrogen production per unit of electrical input energy, with hydrogen efficiency of 0.01596 tonnes/MWhr. Scenario 4 was a microgrid with a mix of renewable sources, a combination of CFEC and AEM electrolysers, HVDC transmission, and battery energy storage system (BESS).**
- **Hydrogen production rates ranged from 2,215 (Scenario 2) to 3,525 tonnes/day (scenario 4).**
- **Microgrid total power demand to deliver this ranges from 12.3 GW to 14.3 GW, requiring an installed renewable capacity of 20.6 GW to 27.6 GW.**
- **Balance of plant/auxiliary systems (pumps, water treatment, H_2 export compression etc.) make up the largest proportion of system 'losses', ranging from 43% to 67%.**
- **Available waste heat ranges from 1.1G W to 3.3 GW. Electrolyser efficiency has the greatest effect on heat availability. The electrolyser type used in scenario 1 is 100% PEM (typical efficiency of 65%), which leads to 3,400 MW of waste heat, the largest quantity of all scenarios considered. Given the expected capacity of heat consumers, it will be challenging to make use of low-grade waste heat on this scale.**
- **By-products from the microgrid will be oxygen and a concentrated brine stream. At >1,000 tonnes/hr, oxygen is generated in very large quantities for all scenarios. Scenarios that didn't include a salt production plant, to use the brine productively as part of the microgrid, would generate a concentrated brine stream exceeding 400 m^3/hr.**

As the study has been location agnostic, and availability of renewable energy and energy storage opportunities will vary in different locations, interpretation of the study results will be necessary in applying them to a specific geographical area.

General Conclusions

Renewables

- **Offshore wind is anticipated to be the dominant energy source for any 10 GW hydrogen microgrid.**
- **To increase electrolyser uptime combining this with other reliable/predictable sources such as tidal or geothermal is advantageous.**
- **Given that the microgrid total power demand exceeds 10 GW, sources with higher capacity factors are favoured, to prevent the required installed capacities becoming infeasible (given the scale that sources such as wave and tidal are at presently).**

Transmission and Distribution

- **The capacity of the transmission system will need to be significantly greater than 10 GW to allow for periods of over generation and to overcome system losses.**
- **High Voltage Direct Current (HVDC) was confirmed to be more efficient than High Voltage Alternating Current (HVAC) for transporting large capacities of electrical energy over long distances and has a lower LCOE. Therefore, HVDC is expected to be the primary microgrid transmission technology used (as offshore wind more than 80 km from shore will be the dominant renewables source).**
- **For energy generated closer to the microgrid location HVAC becomes viable and is especially efficient when combined with Medium Voltage Alternating Current (MVAC) microgrid distribution.**

CASE STUDY
SYMBIOTIC INDUSTRIES

As part of any microgrid design, as a means of utilising the concentrate brine waste stream (as an alternative to its treatment for disposal), a salt production plant should be considered.

Use of high-grade thermal energy from an SOE for amine regeneration in a carbon capture and storage (CCS) unit has been identified as a potential use. Co-location with a power station would enable thermal energy to be supplied to the microgrid during startup. Other potential symbiotic uses of high-grade heat from an SOE include generation of steam, either for heating of industrial processes or for generation of electrical power via steam turbine generators.

In addition to internal microgrid use of thermal energy to supply de-salination and water treatment facilities, consumers of low-grade thermal energy (from the other electrolyser technologies) include industries such as pharmaceuticals or food and drink production, and the heating of buildings and warehouses. Captured substation waste heat has been identified as a good source of low-grade thermal energy for supply of district heating networks.

The large volume of oxygen generated (>1000 tonnes/hr) will likely exceed demand, however it could be dried, purified and bottled for sale to external users. Pharmaceuticals and food & drink production facilities could be integrated into a microgrid as potential consumers of low-grade heat, high purity oxygen and surplus electrical power.

With ambition for 10 GW of hydrogen production capacity, the scale of facilities and associated energy inputs and outputs, far exceeds the size of existing facilities. This presents challenges associated with scaling up electrolyser and energy storage capacities, but also opportunity to positively influence the development of technologies that offer the best potential to form part of an efficient microgrid.

General Conclusions (Continued)

Electrolysis

- **Selection of electrolysis technology was found to have the greatest effect on overall microgrid efficiency.**
- **Emerging electrolyser technologies including Capillary Fed Electrolysis Cell (CFEC) and Seawater Hydrogen Production (sHYp) have high theoretical/test bench efficiencies however are yet to be proven at scale or in industrial applications.**
- **Of the established technologies, Solid Oxide Electrolysis (SOE) at TRL7 was found to have the highest efficiency at 75% to 85%; however, a high-capacity source of high-grade heat would be required for an SOE facility, constraining the locations where this facility could operate.**

Energy Storage

- **Energy storage for a 10 GW facility poses a significant challenge. Uninterrupted operation of the hydrogen production facility during periods of renewable energy intermittency has several benefits (maximises hydrogen production rate, avoids curtailment, extends electrolyser life), but is dependent on energy storage capacity.**
- **None of the storage mediums considered currently have capacities approaching 10 GWh (to support full load for one hour).**
- **The subject of energy storage capacity would benefit from further assessment (including cost benefit analysis) to determine the sensitivity of hydrogen production rates (and electrolyser life) to varying levels of energy storage capacity.**

Further investigation

- Comparison of hydrogen production rates, based on varying generation/storage capacities, with demand levels from the 0.9 Mtpa Hydrogen Backbone Link (HBL).
- Determine the microgrid generation/storage capacity required to maintain continuous supply to an HBL above its minimum demand level during periods of low renewable input power and assess any cost benefit in having capacity greater than this.
- Establish likely salt demand, should a salt production plant form part of the microgrid. Assess economic feasibility, i.e. compare cost of microgrid salt production to other sources.
- Use findings from this study to evaluate specific potential microgrid locations, considering their associated renewable and energy storage characteristics.

9.0

Conclusions

Phase 1 of the Energy Hubs project confirmed that Scotland could become a major exporter of zero carbon hydrogen and its derivatives.

Small scale hydrogen production has, in some instances, already been approved at FID. However, to meet UK and Scottish Government targets and successfully ‘Fill the Backbone’, large-scale hydrogen production is required: to meet the demands of the hydrogen backbone link, Energy Hubs will need to produce approximately 900,000 tonnes of hydrogen per year.

Modelling confirmed there are sufficient domestic renewable energy resources to over-supply Scotland with both electricity and hydrogen and showed that 35 GW of electrolyser capacity could be installed at Energy Hubs – surpassing the Scottish Government's target of 25 GW of renewable and low-carbon hydrogen production capacity by the year 2045.

Economic modelling indicated that a 10 GW scale energy hub producing green hydrogen from floating offshore wind could produce hydrogen for less than £4/kg in the late 2030s. The actual cost will be heavily dependent on how far the cost of electricity from floating wind falls, therefore developments in floating offshore wind are key to the commercial viability of Scottish Hydrogen production.

Location assessments identified Cromarty, Shetland, Aberdeen & North East, and Orkney to be optimal locations for green hydrogen production.

Hydrogen and e-fuels are anticipated to be pivotal in decarbonising sectors which cannot be easily electrified. The national and global markets for e-fuels derived from hydrogen are projected to grow significantly, and present additional opportunities for Scottish Energy Hubs.

Energy storage for a 10 GW facility poses a significant challenge. For Scotland to be able to meet its own domestic hydrogen demand, sufficient hydrogen storage for lulls in production associated with low wind conditions is needed. The subject of energy storage capacity would benefit from further assessment (including cost benefit analysis) to determine the sensitivity of hydrogen production rates (and electrolyser life) to varying levels of energy storage capacity.

To avoid wind generation curtailment, microgrids (where generation and consumption are collocated) may be required at locations where the National Grid transmission system is insufficient. Integrating several large-scale hubs together as a “Super Hub” will optimise their combined performance.

Phase 2 of the Energy Hubs project will conclude in November 2025. Phase 2 will continue to focus on how to achieve large-scale hydrogen production at Energy hubs and will develop the Super Hub concept further. This phase will look further into system integration and how to optimise symbiotic processes – for example how to integrate thermal energy within Energy Hubs and how alternative fuels and by products (e.g. brines) may be leveraged to maximise the efficiency and economic viability of energy hubs. Phase 2 will also support the development of crucial technologies. This includes providing direct financial support to accelerate innovative electrolyser technologies.

9.0

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