RAF134/2223
Energy Innovation Needs Assessment: Hydrogen

June 2025

Authors

The 2025 Energy Innovation Needs Assessment: Hydrogen was commissioned by DESNZ and delivered by a consortium led by the Carbon Trust, including Mott MacDonald, UCL and Pengwern Associates.

Carbon Trust was the lead technical author for the hydrogen technology theme report.

Views expressed in this report are those of the author and not necessarily those of the UK Government.

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Abbreviations

Abbreviation	Description
ASU	Air separation unit
ATR	Autothermal reforming
CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CCUS	Carbon capture, utilisation and storage
CO2	Carbon dioxide
DESNZ	Department for Energy Security and Net Zero
DGFS	Depleted gas field storage
EINA	Energy innovation needs assessment
FC	Fuel Cells
GHG	Greenhouse gas
GHR	Gas heat reformer
H2	Hydrogen
HAR	Hydrogen Allocation Round
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
NH_3	Ammonia
OCGT	Open cycle gas turbine
OPEX	Operational expenditure
PEM	Proton exchange membrane
SMR	Steam methane reforming
SOEC	Solid oxide electrolysers
T&S	Transport and storage

Key Findings

The Energy Innovation Needs Assessments (EINAs) have been developed and updated to identify key innovation needs across the UK's energy system, to provide an evidence base for the prioritisation of investment and support for clean energy innovation. This report summarises the analysis and findings from the EINAs across the hydrogen technology theme, focusing on autothermal and steam methane reforming, electrolysis, hydrogen transport, hydrogen turbines and depleted gas field storage technologies.

Clean hydrogen could play a significant role in the UK's low carbon energy system, providing long duration energy storage and supporting the decarbonisation of hard-to-abate industries and of hard to electrify transport sectors (heavy duty on and off-road vehicles, aviation, maritime and production of e-fuels).

Energy system modelling to assess the potential impact of innovation in key net zero technologies was conducted using UK TIMES. Technologies were assessed at three levels of innovation (low, medium and high) and across three hypothetical illustrative scenarios: Minimally Constrained, High Hydrogen and High Diversification.[1] The key results from EINAs system modelling suggests that:

- The hydrogen technologies examined by the EINAs play a varying role in supporting net zero by 2050 across the scenarios leading to their innovation having a mixed impact. There is relatively large variation in their deployment across scenarios which is often impacted by scenario design constraints.
- Autothermal reforming (ATR) deployment, resulting in the cheapest form of hydrogen production modelled, hits deployment limits in all but the High Diversification scenario. In the latter scenario, higher reliance on domestic energy production stops nearly all ATR production due to the model's limits on methane imports. Cumulative cost savings due to innovation in autothermal reforming is relatively low compared to innovation in electrolysers, reaching £6.6 billion in 2050 in the High Hydrogen scenario. With more relaxed constraints it could have a larger role in the energy system resulting in significantly higher potential cost saving, however uncertainty on potential level of upstream fugitive emissions from methane imports limits certainty on decarbonisation impacts.
- High potential savings could be realised through innovation in electrolysers and H2 turbines, particularly in the High Diversification and High Hydrogen scenarios, but their deployment is reduced by BECCS and DACCS innovation. High levels of innovation in electrolysers in the High Diversification scenario creates a potential saving of £23.6

[1] These scenarios do not represent government policy but were selected due to their differing constraints which provide a diverse set of outputs and insights. More information on the scenarios can be found in the system benefits from innovation in hydrogen section of this report and in the EINAs Methodology report.

billion by 2050, whilst high levels of innovation in H2 turbines provides a potential £5.6 billion in the High Hydrogen scenario.

- Innovation in hydrogen production technologies, such as BECCS-H2 and electrolysis, drives an increase in the capacity of hydrogen transmission and storage and associated potential cost savings through innovation in those scenarios.

The analysis is independent and was developed before the latest DESNZ Hydrogen Strategy. Therefore, illustrative scenarios and overall results, as across other EINA reports, do not represent government policy but rather are an analytical exercise.

Table 1 below summarises the key innovation opportunities across the technology areas assessed on the basis of potential cost and barrier reduction impacts. Further detail on these, including innovations with lower expected impacts, are provided in the 'Tables of innovation needs' section of the report.

Table 1: Innovation needs for the EINAs hydrogen technologies

Innovation area	Description
Autothermal reforming with CCS	Small-Scale Modular Reformers combining combustion, heat recovery and reaction and could be advantageous for offshore, remote or small-scale methanol plant applications. For both ATR and SMR, innovation is needed to integrate with CCS at scale. New Water-Gas Shift Technologies, particularly reverse WGS (RWGS), are emerging for a range of applications including the production of sustainable aviation fuel.
Electrolysis	Effective integration with renewable electricity sources. Improved electrode design and materials for low temperature electrolysers to reduce dependence on precious metals. Modularising components to adapt for various power requirements. High Temperature Electrolysers–Enhancing durability of materials to achieve mechanical, thermal and chemical stability while reducing costs. Increasing the density of stacks to reduce need for mechanical compression.
Hydrogen storage and transport	Improved efficiency in ammonia production, improving transport viability and use for shipping. Improved efficiency, cost, scalability and operational flexibility in gas separation technologies to enable de-blending hydrogen into existing infrastructure. New network design for re-purposing key gas network sections to high pressure transmission pipelines.
Hydrogen OCGTs and CCGTs	Improved safety measures for flammable hydrogen gas, including the gas turbine enclosure and ventilation system design. Demonstration of 100% hydrogen gas turbines use over long periods of time.

If hydrogen technologies are to be implemented at scale to support the net zero scenarios, numerous barriers such as skilled workforce training, supply chain development and enabling infrastructure need to be overcome. Additionally, supportive policies which offer clarity and certainty into the long-term will be critical to help the hydrogen sector develop. Three of the primary market barriers to scale up and deployment of hydrogen technologies include:

- **Business model:** Clean hydrogen is currently more expensive than incumbent alternatives, this is likely to continue – particularly as renewable energy currently accounts for 70% of the cost of green hydrogen production. There is also uncertainty around how the enabling infrastructure will be funded. Enablers such as the Hydrogen Storage and Transport Business Models are expected to bring more certainty in this area.
- **Enabling infrastructure:** Hydrogen transport and storage infrastructure will be essential, but existing capacity is limited. Large scale storage assets have long lead times, and pipelines can take up to 6-12 months of pre-construction and 3 years for construction or repurposing. For hydrogen produced via electrolysis, manufacturing capacity will need to be scaled up.
- **Regulatory environment:** New regulatory frameworks will be needed for depleted gas field storage, and existing regulation for salt caverns will need to adapt to account for faster rates of cycling, and to support both regulated and private assets. For hydrogen transmission, more work needs to be done around purity, pipe specification and safety to achieve a sufficient regulatory framework. The existing regulatory frameworks, unless adapted, can cause delays in deployment, which may stall the development of hydrogen production and transport and storage infrastructure in the coming years. Multiple consultations have been launched as of 2025, with further clarity expected from an updated UK Hydrogen Strategy.

The business opportunity analysis based on the illustrative system modelling scenarios suggest the following potential impacts:

- Depending on the scenario, GVA associated with the technologies studied in this report reaches between £1.3 and £2.8bn by 2050 at a medium innovation level.
- Over 47% and 123% more GVA in the hydrogen sector supported by 2050 in the High Hydrogen scenario compared to the High Diversification and Minimally Constrained scenarios, respectively. This is because of this scenario's higher rates of ATR, transmission/transport and turbine deployment.
- The importance of each technology differs between scenarios. For High Diversification, electrolysis is the largest contributor to GVA in 2050, contributing around 70% of the total. For the High Hydrogen scenario, the GVA contribution is split relatively evenly between hydrogen to power (27% of total GVA), electrolysis (31% of total GVA) and autothermal reforming (34% of total GVA). The Minimally Constrained scenario is dominated by the two hydrogen production technologies which, in combination account for 84% of total GVA in 2050.

- Supported total employment (direct and indirect jobs) by the technologies studied reaches between 24,000 and 54,000 jobs by 2050, depending on scenario.
- In the relevant scenarios, hydrogen storage could support an additional 1,800 and 2,400 jobs to the sectoral total by 2050.
- The domestic market is estimated to support the majority of jobs in hydrogen goods and services with 81-90% of jobs supported by domestic deployment in 2035 rising to 95-98% in 2050. The size of the export market is based on Ricardo analysis estimating a constant export market share between 2035 and 2050, contributing approximately 1,200-1,400 jobs across the period.
- As the sector matures and the ratio of new capacity to existing capacity falls, a shift from GVA and jobs being driven by construction activity to being driven by operations and maintenance.
- High skilled science, research and engineering, technology professional occupations, as well as director/managerial jobs are the predominant employment profiles.

Introduction

The Energy Innovation Needs Assessments

Achieving the UK's ambitious clean power by 2030 mission and 2050 Net Zero target requires the accelerated scale up and deployment of innovative clean energy technologies. The UK Government has a central role to play in supporting the research, development and deployment of these innovations to achieve global and national climate objectives. The decisions made now on the prioritisation and investment in crucial clean energy technologies will be pivotal to enable progress in the coming years and decades.

The Energy Innovation Needs Assessments (EINAs) have been developed and updated to identify key innovation needs across the UK's energy system, to provide an evidence base for the prioritisation of investment and support for clean energy innovation. The 2025 publications reflect an update on the 2019 exercise, accounting for the significant changes and progress both in the clean energy sector and wider economy. To complement and build on the UK's Net Zero Research and Innovation Framework, the updated EINAs will inform key decisions on clean energy innovation funding through a structured evidence base that quantifies and assesses the role and scale of opportunities. The evidence enables comparison across technologies and takes account of wider factors that may impact deployment and scale up. The methodology followed is detailed in the EINAs technical report and is summarised below.

The EINAs technologies were decided through a prioritisation exercise, taking into account insights from key sector experts and prioritising against key DESNZ criteria. An initial longlist of 190 technologies for analysis was put together based on:

- Previously published global and national scenarios (including the 2019 EINAs)
- DESNZ priorities
- Insights from DESNZ engagement activities
- Input from technical experts

This longlist was then assessed and prioritised to inform a shortlist of EINAs technologies, which were then taken forward for analysis including:

- An assessment of each technology's innovation needs, costs and barriers to deployment.
- Modelling, using the UK TIMES and HighRES models, to assess the impact of different levels innovation in these technologies on the UK's energy system in hypothetical Net Zero scenarios, including on system cost, capacity and energy security.
- Business opportunity analysis, including Gross Value Added (GVA) and employment, of the deployment of the technologies across scenarios and innovation levels.

This report summarises the findings across the hydrogen technology theme.

The 2025 EINAs publications have been commissioned by DESNZ and produced by a consortium led by the Carbon Trust, including Mott MacDonald, UCL and Pengwern Associates. Carbon Trust was the lead technical author for the hydrogen technology theme report.

Scope and Limitations of the EINAs:

The EINAs project is a research exercise to evaluate the potential impact of technological innovations on the UK energy system and Net Zero targets, and help inform decisions on clean energy innovation.

A number of technologies were included as part of the prioritisation but were not included in the systems modelling due to limitations of the models used for the EINAs, data availability and resource constraints. The three hypothetical scenarios developed to represent potential routes to Net Zero were selected due to their differing constraints which provide a more diverse set of outputs and insights.

The technologies and scenarios selected do not represent UK Government policy.

The hydrogen technology theme

Hydrogen is expected to play a key part in the UK's clean energy transition due to its versatility across a range of low carbon applications. Low carbon hydrogen is produced using methods including steam methane reformation with Carbon Capture and Storage (CCS), and electrolysis. Low carbon hydrogen can be used to decarbonise hard-to-abate sectors including industry through direct use as a fuel and a feedstock, or through providing industrial-grade heat, fuel for transport, flexible low carbon power generation and long duration energy storage. There are opportunities for innovation across the hydrogen value chain to facilitate the scaling of these opportunities.

A shortlisting and prioritisation exercise was conducted to determine the hydrogen technologies to be modelled and studied in this update of the EINAs. This followed a framework which considered the following factors important to DESNZ:

- **Known net zero priority:** Technologies where there is a clear government direction or expert consensus on Net Zero relevance.
- **Energy security:** Technologies necessary for UK energy system resilience and to protect against grid and import shocks.
- **UK relevance:** Technologies suitable for UK specific circumstances, and where the UK is likely to have an impact.
- **Technology Readiness Level (TRL) relevance:** Technologies close to commercialisation or likely to be commercially viable by 2040.

The hydrogen technologies included as part of the EINAs are detailed in Table 2. The selection or exclusion of technologies does not reflect government policy but rather is an outcome of the EINA criteria outlined above and the overall research process.

Table 2: EINAs technologies assessed as part of the hydrogen technology theme

Technology	Description
Electrolysis	An electrolyser uses electricity to split water into hydrogen and oxygen. The oxygen can then be used as a by-product, or released into the atmosphere, and the hydrogen is compressed and utilised or stored until required. Electrolysis powered with renewable electricity is used to produce green hydrogen. There are four mainstream electrolyser technologies, each offering distinct advantages and facing specific challenges. Proton Exchange Membrane (PEM), Alkaline and Solid Oxide Electrolysers (SOEC) are the most commercially developed technologies. Anion Exchange Membrane (AEM) is a less mature technology that can be retrofitted into some designs of alkaline electrolysers. This report focuses on PEM, alkaline and SOEC electrolysers. **Alkaline** is the oldest and most mature technology (TRL 9[2]) for hydrogen production, operating at efficiencies between 62% - 82%. They are well understood, relatively low cost and can operate at scale, with installations currently in operation with up to 400 MW capacity.[2] **Proton Exchange Membrane (PEM)** electrolysers are commercially available (TRL 9[2]) and operate at scale, with existing installations with up to 50MW capacity.[2] The current project pipeline suggests a global capacity of 230GW by 2030.[2] PEM offer high efficiencies (67% - 82%)[3], produce high purity hydrogen at a high pressure, can operate at higher current densities and are capable of quick start up and dynamic operation.[4] However, PEM includes higher costs due to expensive catalysts and membrane materials. PEM are a less mature technology than alkaline electrolysers and face challenges to scale including membrane durability and manufacturing capacity.

[2] IEA (2024) Global Hydrogen Review
[3] Wolf, S. E. (2023) Solid oxide electrolysis cells – current material development and industrial application
[4] IEA (2024) Global Hydrogen Review

Technology	Description
	Solid Oxide Electrolysers (SOEC) can provide highly efficient electrolysis at high temperatures, from around 85% to over 100% when integrating waste heat.[5] SOEC technology has recently reached TRL 9 at 100 MW. Manufacturing techniques are reducing cost and increasing scale, and materials advancements are enhancing durability with improved coatings, electrode materials and thermal management design.
Hydrogen storage – depleted gas field storage (DGFS) and medium salt caverns	The UK's hydrogen sector will depend on the ability to utilise large scale storage. Underground storage can be achieved via a number of geological routes (salt caverns, lined rock caverns, aquifers, and depleted oil and gas reservoirs). Underground salt caverns are a proven method of storing hydrogen, offering inter-year storage, although technical uncertainties remain.[6] While lined rock and salt caverns will be important to support onshore hydrogen storage, repurposing depleted gas fields could be a cost-effective option for large-scale offshore storage, although significant uncertainty remains.[7, 8] It is also possible to store hydrogen in saline aquifers offshore which provide much larger storage capacity, but these are geologically less well understood and significant technical and commercial barriers remain.[9] For this EINAs assessment, DGFS is included in the systems modelling analysis. Medium salt cavern storage, while prioritised for qualitative analysis, was excluded from the UK TIMES modelling due to limitations of the systems modelling. For the purposes of the business opportunities analysis, data from highRES modelling on salt cavern storage was used to provide a high-level analysis on the business opportunities of hydrogen storage.
Reforming processes with Carbon Capture and Storage (CCS)	CCS variants of both autothermal reforming (ATR) and steam methane reforming (SMR) are being developed at pace by industry in response to commercial pressures. This includes technologies and products aimed at retrofitting CCS into SMR

[5] Hjalmarsson, P. et al, (2024) Technology update of Ceres electrolysis program
[6] Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report
[7] Lysyy, M. et al. (2021) Seasonal hydrogen storage in a depleted oil and gas field
[8] Hydrogen UK (2022) Hydrogen Storage: Delivering on the UK's Energy Needs
[9] Hydrogen UK (2022) Hydrogen Storage: Delivering on the UK's Energy Needs

Technology	Description
	plants. There may be a need for limited additional innovation beyond that already being undertaken by industry.
Hydrogen turbine (OCGT and CCGT)	Hydrogen gas can be used to generate electricity using gas turbines. An open cycle gas turbine (OCGT) compresses air, then burns it with gaseous fuel and expands the resulting gas through a turbine to extract energy in the form of electricity. A combined cycle gas turbine (CCGT) starts with an OCGT and adds a “bottoming cycle” that uses the exhaust heat from the gas turbine to make steam that expands through another turbine to generate additional electricity. This additional cycle makes CCGTs more expensive to build, but also more efficient at converting the energy content of the gas to electricity. This means that CCGTs have lower operating costs and greenhouse gas (GHG) emissions per megawatt-hour (MWh) of electricity produced. However, CCGTs have longer start-up times than OCGTs, so OCGTSs are optimal for fast-response power. Gas turbine technologies are commercially available and represent mature technologies in current natural gas operations. However, there are number of features of hydrogen gas which have implications for turbine design and safety mechanisms, including flammability, increased likelihood of leakage, risk of embrittlement, increased production of water vapour during combustion, and high flame temperatures which impact Nox reduction techniques. At the time of writing, continuous 100% hydrogen use in large-framed gas turbines for prolonged periods of time has not yet been demonstrated. OCGT operates at a peak efficiency below 45% and CCGT typically can achieve 55%, although OCGT will struggle to achieve this rate if operating using hydrogen as a fuel. Gas turbine efficiency is very sensitive to ambient temperature and humidity and manufacturer’s claimed headline efficiencies of 60% are only possible under ideal conditions.
Hydrogen transmission and transport	Hydrogen can be transported using distribution and transmission pipelines. The estimated levelised costs for large scale hydrogen

Technology	Description
	transport via pipelines is considered economically attractive and a cost-effective option.[10] In addition to purpose-built hydrogen pipelines, there is potential to repurpose existing natural gas infrastructure. Currently, hydrogen can be blended into the natural gas network at a maximum ratio of 1:4 with natural gas, but beyond this the existing infrastructure will require upgrades.[11] Much of the existing gas network is being upgraded to plastic piping, which is resistant to hydrogen embrittlement, enhancing the possibility of integrating hydrogen into the existing network. Furthermore, there are numerous projects underway across the existing networks to prove the viability of transporting hydrogen via pipelines to industrial clusters across the UK.[12] However, technical challenges including prevention and monitoring of leakages, and hydrogen contamination, remain barriers.[13] Where transport by pipeline is impractical, tube trailers (lorries which carry compressed hydrogen) can be used, for example where small volumes of hydrogen are needed, or for temporary construction sites.[14] Hydrogen can be transported as a liquid using trucks or trailers, with energy required for cooling, and losses through boil-off. Availability of liquifiers is also a consideration for the storage and transportation of liquid hydrogen. For longer distances, large amounts of hydrogen can be shipped as ammonia via rail freight.

Additional hydrogen technologies which were considered as part of the initial EINAs longlist but deprioritised for analysis are outlined in Table 3.

[10] Dinh, Q. V., et al. (2024) Levelised cost of transmission comparison for green hydrogen and ammonia in new-build offshore energy infrastructure: Pipelines, tankers, and HVDC
[11] The Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report
[12] HyNet North West (Accessed: 2025) HyNet
[13] The Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report
[14] Department for Energy Security and Net Zero (2023) Hydrogen Transport and Storage Networks Pathway

Table 3: Hydrogen technologies deprioritised at shortlisting stage

Technology	Reason for exclusion
Hydrogen production from waste	Hydrogen production from waste is anticipated to be a relatively small source of potential low carbon hydrogen relative to hydrogen produced using electrolysis or autothermal reforming.
Hydrogen production – AEM	AEM is at an earlier TRL stage than the three electrolysis technologies considered in the EINAs analysis and was excluded from the modelling due to a lack of reliable, up-to-date data.
Hydrogen storage – lined rock caverns	Lined rock caverns are capital intense and tend to have smaller storage capacity than other geological storage options (salt caverns and depleted gas field storage) and are therefore difficult to justify in locations where these alternatives exist. However, LRCs are less geographically restricted and may be well placed in areas where salt caverns and DGFS are not an option. LRCs are likely to be a more niche solution for hydrogen storage and have therefore been deprioritised.
Chemical hydrogen storage	While offering increased energy density for storage, and offering the potential for fewer safety concerns relative to compressed storage, chemical storage options must be integrated with large scale heat transfer and will need to compete with more mature compression technologies. Given the UK's advantages in geological storage, chemical storage is deprioritised for this assessment.
Hydrogen conversion to / from ammonia/methanol	The conversion of hydrogen to ammonia and methanol is a very mature and well-established technology. While conversion from ammonia and methanol to hydrogen is less mature, innovation in this area is likely only to be relevant if the UK imports large quantities of green ammonia/methanol from abroad. Innovation in this area is unlikely to be a priority for the UK, and other nations are more interested in developing these technologies due to their demand for imported hydrogen. An overview of ammonia production from hydrogen as well as recent technological advances is provided in the Disruptive technologies section of this report.

e-Fuels (other than ammonia and methanol)	Despite the high efficiency of modern processes converting power to synthetic natural gas, fugitive emissions will limit application of this in the UK to a small number of hard-to-decarbonise industrial processes. E-versions of other synthetic fuels use half the carbon used by more conventional gasification and pyrolysis routes and enable additional usage of otherwise curtailed renewable energy. Given the UK's strengths in advanced electrolysis, and the UK's strong links to the aviation industry, there is likely to be continued advancement of innovation in this area. However, this has been deprioritised for the EINAs due limited information for modelling purposes as well as focusing effort on production, transportation and storage.

Technologies which were excluded from the systems modelling due to methodological challenges relating to data availability and UK TIMES capabilities include: shallow salt cavern storage and deep salt cavern storage. Additionally, hydrogen technologies with primary application in the transport sector have been excluded for in-depth analysis, as the transport sector was out of scope for the EINAs.

Hydrogen in the UK energy system

The UK is well positioned to capitalise on the emerging hydrogen market. Low carbon hydrogen has the potential to provide low carbon power generation and can be used to produce electricity when renewables struggle to meet electricity demand, such as when there is limited wind and sun. Clean hydrogen also has the potential to play a role as a low carbon fuel, supporting the decarbonisation of hard-to-abate industries including industry (such as chemicals and steel), and heavy transport. The UK's geography, geology, and a strong pipeline of hydrogen projects means that there is a significant opportunity to produce, store and use hydrogen cost-effectively.

Transitioning to and scaling up clean hydrogen production methods, using autothermal reforming (ATR) or steam methane reforming (SMR) with CCUS (blue hydrogen) or renewable-powered electrolysis (green hydrogen) can support the transition of these industries to low carbon fuels, and provide low carbon, high temperature heat for large industrial clusters. Clean hydrogen could also provide GWh or TWh long-term energy storage which, when combined with hydrogen turbine technology, could provide demand-matching low carbon electricity generation to help balance seasonally variable renewables or years with adverse weather. The transportation sector can also benefit, as green hydrogen, green ammonia, e-methanol and e-SAF are low carbon alternative fuels for heavy transport, rail, maritime and aviation. There are expected to be e-methanol projects exceeding 15 million tonnes of annual production capacity globally by 2030, according to the IEA's Global Hydrogen Review.[15]

Clean hydrogen production does not yet exist at scale in the UK, but initiatives such as the Hydrogen Allocation Rounds (HAR 1 & 2) aim to increase the volume of clean hydrogen produced.[16] Alongside supporting policies, such as the Hydrogen Production Business Model, the Low Carbon Hydrogen Standard and the Hydrogen Transport and Storage Business Models, this will help to unlock private sector investment needed to accelerate the UK's hydrogen activity. The UK government is also developing a Hydrogen to Power business model, following consultation, to de-risk investment and bring forward capacity.[17] Recent government assessment suggests that hydrogen to power can be economic at lower load factors (below 30%), enabling it to be cost effective where flexible load factors are expected to fall as renewable generation increases.[18]

Infrastructure, and particularly the distribution and storage of hydrogen, will be a core part of the growth of the hydrogen sector. Building hydrogen transmission pipelines, as well as utilising and adapting the UK's existing gas transmission pipelines will be essential for hydrogen distribution going forward. This will not only enable the rapid distribution of hydrogen to off takers but can also repurpose otherwise redundant assets while alleviating the costs of building hydrogen pipeline infrastructure.

By utilising UK renewables to produce green hydrogen which can be used as a fuel or feedstock to displace natural gas, as well as providing long-term energy storage, clean hydrogen could play an important role in supporting the UK's energy security and decarbonisation.

[15] IEA (2024) Global Hydrogen Review
[16] UK Government (2024) Hydrogen Allocation Rounds
[17] UK Government (2024) Clean Power 2030: Action Plan: A new era of clean electricity
[18] UK Government (2024) Clean Power 2030: Action Plan: A new era of clean electricity

Hydrogen: Innovation opportunities

Overview of technologies

Autothermal reforming (ATR) and steam methane reforming (SMR)

Hydrogen can be produced from natural gas using autothermal reforming and steam methane reforming (SMR) processes. SMR is the most established method of producing hydrogen from natural gas and currently accounts for 50% of the global hydrogen supply. In the SMR process, natural gas reacts with high-temperature steam (700-1000°C) over a catalyst in a highly endothermic reaction, producing hydrogen and carbon monoxide. The carbon monoxide is then combined with water to generate hydrogen and carbon dioxide. The endothermic reaction requires heat, which is generally supplied through burning natural gas, generating carbon dioxide emissions. The application of CCS to SMR can reduce the emissions from this process and would enable the production of low carbon blue hydrogen. In this process, carbon needs to be captured from both the natural gas combustion, and from the syngas produced through the reaction process.

The ATR process reacts pure oxygen with natural gas and steam to produce a syngas product of H_2 and CO_2. In contrast to the SMR process, which uses combustion of natural gas to supply heat, the ATR process partially oxidises the natural gas feedstock to generate heat for the endothermic reaction between the remaining natural gas and steam. The air separation unit to produce oxygen for this process is extremely energy intensive, but the CO_2 stream is more concentrated and therefore easier to capture from the ATR process, relative to the SMR process.

ATR or SMR processes with CCS can be used to produce blue, low carbon hydrogen. When assessing the full effective efficiency of both processes, including power requirements (i.e. to power the air separation unit for ATR), there is less than 0.5% difference in efficiency, with the ATR process being more expensive with higher electricity prices more representative of those in the UK. [19] Additionally, the ATR process has been assessed to carry a higher through life carbon footprint when both types of plant are built from scratch. The carbon intensity and cost of the processes will depend on electricity costs and supply of renewable energy. SMR technology improvements, including oxygen enhanced combustion, have the potential to enable increased retention of plant hardware when existing SMR plants are converted to carbon capture.

The production of blue hydrogen could be a bridging technology to scale the production of clean hydrogen, reducing costs through economies of scale. According to the recent Carbon Budget 7 publication by the Climate Change Committee, the application of low-carbon

[19] U.S. Office of Scientific and Technical Information (2022) Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies

hydrogen in industry is likely to be focused on areas such as ceramics and chemicals, as high temperature process heat may be provided more readily and efficiently through electrification.[20]

Costs and components

This section summarises the key components and estimated cost elements for the production of hydrogen from natural gas, using ATR with CCS. Figures in this section are drawn from the 2025 NESO scenario analysis.[21] These cost ranges indicate one potential scenario for build times of ATR – CCS plants between 2025 and 2050, with the LCOH in this scenario ranging from 73 - 99 £/MWh.

- CAPEX: 17% – 33%. This will include the reformer unit, steam turbine, balance of plant, and the technological components of the plant.
- Fixed OPEX: 5.5% - 8.9%. The fixed OPEX will be a constant maintenance cost independent from the utilisation of the plant and includes ongoing maintenance.
- Variable OPEX: 0.9% - 1.4%. This will vary depending on the utilisation of the plant and includes operating costs.
- Electricity cost: 6.3% - 8.4%. This will include the electricity used to power the air separation unit to produce the oxygen to oxidise the natural gas feedstock.
- Fuel cost: 34% - 46%. This will include the natural gas used as feedstock.
- CO_2 transport and storage cost: 15% - 21%.
- Emissions cost (cost of CO_2 emissions not captured): 1.2% - 1.8%.

Blue hydrogen's dependence on natural gas exposes the LCOH production to international gas prices and supply.[22] Furthermore, the cost of blue hydrogen will depend on the scale up and performance of CCS technology.

Electrolysis

Electrolysis uses electricity to split water into hydrogen and oxygen. Using renewable electricity, electrolysis is a means to produce low carbon hydrogen. Three electrolysis technologies are considered for this analysis:

- Proton exchange membrane (PEM) electrolysis: this technology has the ability to ramp up and down quickly. In addition, it is possible to generate compressed hydrogen directly in the PEM electrolyser, thereby reducing the additional pressurisation cost for hydrogen storage. However, platinum-group electrocatalyst is expensive and suffers from poor stability, and degradation of the polymer limits the lifetime of the stack. Iridium is particularly problematic and is unlikely to be able to reach terawatt-hour scale. This is

[20] Climate Change Committee (2025) The Seventh Carbon Budget
[21] NESO (2025) Levelised cost of blue hydrogen modelling
[22] The Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report

being addressed by PEM electrolyser manufacturers who are reducing the need for precious metals in their products[23].

- Alkaline (ALK) electrolysis: Alkaline water electrolysis is a key technology for large-scale hydrogen production powered by renewable energy. While photovoltaic panels can be directly coupled to alkaline water electrolysers, wind turbines require suitable converters with additional losses. By combining alkaline water electrolysis with hydrogen storage tanks and fuel cells, power grid stabilisation can be performed. Alkaline electrolysis is a mature, reliable and well-established technology.[24] Their relatively simple design mean they are more robust and less prone to malfunctions. Additionally, they do not utilise precious group metal catalysts which are required for PEM electrolysers. However, alkaline electrolysers can be less efficient than PEM electrolysers and can be slower to ramp up or down. They may therefore be better suited to constant operation. The durability of alkaline electrolysers is also limited by degradation of the electrode.
- Solid oxide electrolysis cells (SOECs) can be highly efficient in the electrolysis of water (and/or carbon dioxide) to produce hydrogen gas (and/or carbon monoxide). SOECs have the potential to achieve the highest electricity-to-hydrogen conversion efficiency among all electrolyser types, from around 85% to over 100% when integrating waste heat. There is less experience operating SOECs, and the process requires very high temperatures (600-900ºC)[25]. However, efficiencies of SOECs can be high when integrated into, for example existing chemical industry plants, utilising waste heat from downstream chemical processes.[26] SOECs can be unsuitable for dynamic operation, so high efficiencies are only available in specific application, with progress required to improve material and electrode durability.[27]

Components and Costs

This section summarises the key components and estimated cost elements for electrolyser technologies. Figures in this section are drawn from the Oxford Institute for Energy Studies 2022 electrolyser cost assessment[28], Renewable UK's 2025 analysis[29] and the Green hydrogen in Scotland report.[30]

CAPEX accounts for around 21% of the LCOH from electrolysis:[31]

- **Stacks:** Comprised of cells units, porous transport layers, bipolar plates, end plates, and various smaller parts, these represent the main cost driver of the electrolyser technologies currently on the market (alkaline and PEM systems) and constitute

[23] FCW (2024) ITM Power Announces Breakthrough in Iridium Reduction
[24] Kumar, S. S., and Lim, H. (2022) An overview of water electrolysis technologies for green hydrogen production
[25] Wolf, S. E., et al. (2023) Solid oxide electrolysis cells – current material development and industrial application
[26] Wolf, S. E., et al. (2023) Solid oxide electrolysis cells – current material development and industrial application
[27] Solid oxide electrolysis cells – current material development and industrial application
[28] The Oxford Institute for Energy Studies (2022) Oxford Institute for Energy Studies 2022 electrolyser cost assessment
[29] Renewable UK (2025) Renewable UK's 2025 analysis
[30] Scottish Futures Trust (2024) Green hydrogen in Scotland
[31] Scottish Futures Trust (2024) Green hydrogen in Scotland

between 40-60% of the total electrolyser cost. They account for around half of alkaline electrolyser cost and about 60% of the costs of PEM systems. This difference is attributed primarily to the use of platinum-group metals, which make PEM electrolysers more expensive.

- **Power electronics**: The application of solid-state electronics to the control and conversion of electric power.
- **Gas conditioning:** Includes the mechanical compression of gas to a defined storage pressure, and gas drying to purify the raw hydrogen. It constitutes around 15% of costs for alkaline and AEM systems, 10% for PEM and 6% in solid oxide. However, due to the dramatic cost difference in favour of the commercialised alkaline and PEM electrolysers, gas conditioning in solid oxide and AEM systems is generally of similar or higher expense in absolute terms.
- **Balance of plant:** This includes heat recovery and heat rejection equipment, process material transport systems (such as pumps, valves and piping), control systems, safety systems, waste systems, equipment for maintenance and repair, heating, cooling, ventilation and air conditioning, power supply and distribution, and others. In alkaline and PEM electrolysers this accounts for between 15-20%, and double this for solid oxide electrolysers.
- **Grid connection costs (3% of LCOH):** There is a cost associated with connecting electrolysers to the electricity network.

OPEX:[32]

- **Wholesale electricity costs (37%):** The cost associated with producing the electrical energy used to create the hydrogen.
- **Electricity system costs (29%):** These include the cost of the electricity network, keeping the electricity system in balance. These costs are recovered through regulated charges including network charges and policy levies.
- **Fixed OPEX (7%):** Ongoing operational costs that don’t depend on utilisation. For example, general maintenance costs.
- **Variable OPEX (2%):** Operational expenditure which depends on the level of utilisation of the electrolysers. This includes the cost of replacing the stack.

Key drivers of cost reduction for electrolysis include the cost of electricity and the cost of electrolysers, as well as technical aspects including energy consumption per unit of production, stack lifetime, stack size, load range, and start-up time. Adapting stack design to facilitate large-scale manufacturing will contribute to economies of scale and reduce manufacturing costs. The falling cost of electricity with increased renewable energy is expected to reduce the LCOH from electricity.[33]

[32] Scottish Futures Trust (2024) Green hydrogen in Scotland
[33] The Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report

Hydrogen Fuel Cells

Currently, the primary method of generating electricity from hydrogen is through the hydrogen fuel cell. Hydrogen fuel cells use oxygen with pure hydrogen to produce electricity, with water and heat as byproducts. They operate in reverse to electrolysis. A fuel cell consists of an anode, cathode and an electrolyte.

The fuel cell technology categories used for power generation are the same as those used with hydrogen electrolysers. The most common technologies for industrial and transport applications include Proton Exchange Membranes (PEMFC) fuel cells, Alkaline Fuel Cells, and Solid Oxide Fuel Cells (SOFC). Hydrogen is introduced through the anode, where it reacts. There, they combine with oxygen and electrons to form water. Hydrogen and oxygen from air react inside the fuel cell but the chemistry is through an electrochemical path so that electrical work is delivered instead of combustion heat. The various types of fuel cells do this in different ways; however, they all have an electrolyte that is simply a material that only allows one species through and then only as an ion. In PEM fuel cells this species is hydrogen ions, commonly referred to as protons. In alkali this is hydroxide (OH-) ions and in SOFCs the ionic species are oxide, O2-. [34]

In one of the electrodes, the ionic species reacts and completes the combustion-like process. The specific electrode where this occurs depends on the fuel cell type. Fuel cells that operate at low temperature, namely alkali and PEM, require catalysts to operate, and these are predominantly precious metal based for PEMS. The alkali fuel cells use less expensive catalysts that usually contain little or no precious metals. However, catalyst loading has been dramatically reduced in the last few years and no longer dominates the cost of low temperature fuel cells and has never been a significant component of SOFC cost.

PEM

PEM fuel cells use a permeable polymer membrane for its electrolyte and a precious metal, typically platinum, for its catalyst. The operating temperature of PEM fuel cells is far lower than other types of fuel cell, operating around 80°C. PEMFCs operate at around 40-45% efficiency and are capable of handling large and sudden shifts in power output.

Solid Oxide

SOFCs are the highest temperature fuel cells, operating at 600-850°C. SOFCs use a thin layer of ceramic as an electrolyte, which at high temperatures allows for the conductivity of oxygen ions. The catalyst at the electrodes for solid oxide fuel cells are lower cost materials such as nickel. SOFCs have achieved electrical efficiencies of 60%. Historically SOFCs were sometimes used for combined heat and power but with improvements in efficiency this application is no longer being addressed by mainstream developers. SOFCs do not require

[34] Jamal, T. (2023) Fuelling the future: An in-depth review of recent trends, challenges and opportunities of hydrogen fuel cell for a sustainable hydrogen economy

components for water management or cooling other than a simple blower to supply air, similar to that used by all fuel cells. Contrary to prevailing views, SOFC can offer fast load response when operating at full temperature but require some time to warm up initially.[35] However, unlike PEMs they can sit in a standby mode with very low energy usage. SOFCs operate at higher efficiencies when operated on natural gas or ammonia fuel and are less competitive for stationary grid connected power when operated with hydrogen.

Alkaline

Alkaline fuel cells use potassium hydroxide as the electrolyte and have the ability of using a diverse array of non-precious metals as a catalyst at the anode and cathode. Alkaline fuel cells have had applications proven over several decades and across multiple industries, such as in the US space programme to produce electricity and water aboard spacecrafts.[36] Typical operating temperatures of historical alkaline based hydrogen fuel cells were between 150°C – 200°C. Alkaline fuel cells are no longer being manufactured although membrane based alkaline fuel cells are still in development and less advanced than alkaline membrane electrolysers. Both these typically operate below 100°C.

Hydrogen transportation

The emerging hydrogen sector will require supporting infrastructure in hydrogen transportation, either through new or purposed pipelines, or transport by road, rail or ship.[37] Pipelines are used to transport natural gas or other gases from one location to another and are an essential part of the UK's existing energy infrastructure. Networks are formed of transmission lines and distribution networks. Transmission lines move large quantities of gas longer distances and connect production fields to distribution centres, industrial facilities and export terminals. Distribution networks then transport the gas to smaller customers and businesses. Some existing natural gas pipelines, depending on the type of steel, may be suitable for hydrogen transportation once technical feasibility considerations have been addressed. For transmission pipelines, the higher pressures often result in higher tensile strength materials being used which are more susceptible to embrittlement. There has been a significant amount of work on the suitability of hydrogen for use with plastic piping systems. Whilst polyethylene materials are the first consideration due to their extensive use in gas networks, PVC pipes have also been assessed.[38]

There is currently limited hydrogen transportation infrastructure in the UK. However, there are opportunities for converting parts of the existing natural gas pipeline network to transport hydrogen, enabling access to energy for off-takers including heavy industry. New build

[35] Office of Scientific and Technical Information (2019) LGFCS Prototype System Testing
[36] University of Strathclyde (Accessed: 2025) Hydrogen Economy - Fuel Cell Types
[37] Department for Business, Energy and Industrial Strategy (2022) Hydrogen infrastructure requirements up to 2035
[38] Jansma, S. et al. (2022) PVC Pipes Readiness for the Hydrogen Economy

pipelines for hydrogen will be essential if natural gas is still being used, for example for heating, in the transition, and if new pipeline routes are needed between new generation, storage and end-use locations. Integrated transportation and storage infrastructure will play a central role in the UK's hydrogen sector, providing access to multiple supply points and balancing differences in supply and demand of energy.[39] The NESO Strategic Spatial Energy Plan (SSEP) will map and assess potential locations, quantities and types of electricity and hydrogen generation and storage infrastructure over time.[40]

Ammonia cracking enables hydrogen to be manufactured at or near the point of use, avoiding the challenges of shipping hydrogen over long distances and delays waiting for grid connections. However, this can be an energy inefficient process, and the hydrogen produced is low pressure, requiring additional energy for compression.

Components and costs

The costs of hydrogen transportation pipelines will depend on the pipeline length and the optimisation between pipeline dimensions, pressure drop and compression cost.[41] Costs breakdowns in this section are based on this 2019 Hydrogen in the electricity value chain assessment and refer to both onshore and offshore pipelines.

CAPEX: The pipeline CAPEX accounts for the largest proportion of the total levelised cost and varies significantly according to the length of the pipeline. For 50km pipelines, pipeline CAPEX accounts for around 40% of the total cost. Offshore pipelines require lay barges which contribute additional CAPEX. The compressor CAPEX accounts for around 12% and CAPEX construction around 42% of the total levelised cost.

OPEX accounts for around 4% of the levelised cost of transporting hydrogen through pipelines, split between compressor electricity and non-fuel O&M. Decommissioning accounts for around 2% of the cost.

Hydrogen turbines (CCGT and OCGT)

Clean hydrogen can be used as a low carbon fuel for gas-powered electricity generation. An open cycle gas turbine (OCGT) compresses air, then burns it with gaseous fuel and expands the resulting gas through a turbine to extract energy in the form of electricity. A combined cycle gas turbine (CCGT) starts with an OCGT and adds a "bottoming cycle" that uses the exhaust heat from the gas turbine to make steam that expands through another turbine to generate additional electricity. This additional cycle makes CCGTs more expensive to build, but also more efficient at converting the energy content of the gas to electricity. This leads to CCGT's lower operating costs and GHG emissions per megawatt-hour (MWh) of electricity produced.

[39] Department for Energy Security and Net Zero (2023) Hydrogen Transport and Storage Networks Pathway
[40] NESO (Accessed: 2025) Strategic Spatial Energy Planning (SSEP)
[41] van Gerwen, R., et al. (2019) Hydrogen in the electricity value chain

Gas turbine technologies operating on natural gas are commercially available and represent mature technologies. By substituting fossil-derived natural gas with an energy carrier such as hydrogen, this technology could continue to be an attractive low-carbon alternative to balance power generation in future energy systems.

Recent projects have tested the viability of this process, and gas turbine manufacturers aim to provide modern gas turbines operating 100% hydrogen by 2030.[42] At the end of 2023, the Korean company Hanwha demonstrated 100% hydrogen firing in an 80 MW gas turbine, with nitrogen oxide emissions at less than 9ppm without any specific flue gas treatment, an impressive reduction in NOx. In France, Siemen's HYFLEXPOWER project demonstrated the successful conversion of an existing gas-fired power turbine to operate using renewable hydrogen.[43] Further research and demonstration work is required to test large framed gas turbine performance over long periods of time (e.g. several months) when running on 100% hydrogen to ensure component durability to issues such as hydrogen embrittlement.

Components and costs

The cost breakdown of the LCOE for CCGTs and OCGTs will depend on the methods used to produce hydrogen, transport and store hydrogen, as well as the connection to and role of the generation in the electricity system. Based on gas turbine costs and ammonia use in large-scale power plants, the cost components are estimated to be focused around:[44]

- CAPEX, including planning and permitting, land, site preparation and pipelines, turbines equipment (blades, components, turbines assembly, instrumentation and other equipment), buildings, transformer, along with construction and commissioning costs, hydrogen storage, and transmission and integration with the grid.
- The largest cost component is likely to be the fuel cost, estimated to be at around 70% of LCOE, based on ammonia plant costs forecasts.[45]
- There may be additional non-fuel O&M costs due to the increased temperature and increased water vapour of the combustion gases.

Depleted gas field storage and salt cavern storage

Hydrogen storage has a key role to play in providing long-duration, large-scale storage, enabling the UK to fully utilise renewables by storing energy when production is high, and demand is low, reducing curtailment costs, and balancing intraday and inter-seasonal fluctuations in energy demand and supply. Storage of hydrogen can also support its deployment in industry, power and transport. There are a range of options for hydrogen

[42] IEA (2024) Global Hydrogen Review
[43] Siemens Energy (2023) HYFLEXPOWER consortium successfully operates a gas turbine with 100 percent renewable hydrogen, a world first
[44] Cesaro, Z. et al. (2021) Ammonia to power: Forecasting the levelized cost of electricity from green ammonia in large-scale power plants
[45] Cesaro, Z. et al. (2021) Ammonia to power: Forecasting the levelized cost of electricity from green ammonia in large-scale power plants

storage, including depleted gas field storage, salt caverns, lined rock caverns and chemical storage.

Depleted oil or gas fields, either newly depleted, or repurposed from natural gas storage, are a potential form of hydrogen storage in the UK. Depleted gas and oil fields are underground formations of porous permeable rock from which the hydrocarbons (oil or gas) have been removed.[46] The use of depleted oil and gas fields for hydrogen storage is at an earlier stage of technology readiness than salt caverns, but it is a well-established technology for storing large volumes of natural gas in the UK and worldwide.[47] Depleted gas field storage (DGFS) could be repurposed from existing natural gas storage, or could be converted from depleted gas reservoirs. However, DGFS is geographically constrained due to the location of geological formations and past oil and gas exploration. Furthermore, not all depleted gas fields will have the geological properties required to contain hydrogen without it leaking.[48]

DGFS requires a cushion gas, so the total working volume of gas is likely to be between 50% and 60% of the overall cavern volume. Given that large volumes are required, the choice of cushion gas will depend on the costs, and the availability and purity requirements of extracted hydrogen. There may be competition for sites which have potential for storing carbon (CCS), although optimal sites for carbon and hydrogen storage may differ.[49]

The purity of hydrogen is a further constraint. In a depleted gas field, stored hydrogen will likely mix with pre-existing natural gas, meaning extracted hydrogen will need to be used as a mixed gas, or purified to produce pure hydrogen. Current evidence indicates that cycle rates will be limited because the porous rock structure limits the injection and withdrawal rates that are possible. DGFS would therefore be more suited to long-term seasonal storage. Site screening and characterisation for all types of geological storage is required to de-risk the possibility of geochemical or microbial reactions. This will also be crucial to develop performance and operational strategies, reduce uncertainties on mixing, diffusion and retrieval of hydrogen, understand the hydrogen suitability of well components and construction and how to monitor and mitigate the risk of leakage.[50]

Components and costs

The cost of compressing hydrogen gas for storage underground are lower than for storage in a tank, as the compression requirements are reduced, and longer cycles of retrieval mean that fewer instances of compression are necessary. The geology of the site will also drive differences in the extent to which hydrogen will need to be compressed, and the flow rate will vary depending on the size and depth of the cavern.

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46 Department for Energy Security and Net Zero (2023) Hydrogen Transport and Storage Cost Report
47 Department for Energy Security and Net Zero (2023) Hydrogen Transport and Storage Cost Report
48 Department for Energy Security and Net Zero (2023) Hydrogen Transport and Storage Cost Report
49 Department for Energy Security and Net Zero (2023) Hydrogen Transport and Storage Cost Report
50 Hydrogen TCP (2025) Task 42 Final Report: Building confidence in underground hydrogen storage

There is limited data available on the cost elements for DGFS of hydrogen. The CAPEX for DGFS will include site preparation, pipelines, compressor, cushion gas (depending which type of cushion gas is used which affects purification at the post extraction phase) and the well.[51]

The OPEX will be dominated by the underlying costs of the electricity or gas used to power compression. There will also be maintenance costs associated with the compressor, but this will be a small fraction of the overall operating costs.

[51] Chen, F., et al. (2023) Capacity assessment and cost analysis of geologic storage of hydrogen: A case study in Intermountain-West Region USA

Tables of innovation needs

This table details key components and areas of technology innovation required to reduce cost and accelerate the deployment of the hydrogen technologies assessed in this report. This includes electrolysers (PEM, Alkaline, SOEC), ATR, SMR, hydrogen transport and storage, and use of clean hydrogen in gas turbines for electricity generation. This section draws from the previous EINAs research with updated assessments to reflect progression in innovation areas. The table details the direct technology impacts of innovations, as well as the other EINAs priority technologies that could benefit from innovation in these areas. Each innovation is assessed according to its likely impact on cost reduction and deployment for the relevant technology, with a qualitative assessed 1(very low) – 5 (very high) impact rating. Column descriptors within the table are defined as following:

- Technology: technologies where the innovation is applicable.
- Other impacts: other technology families that are indirectly impacted by this innovation.
- Cost reduction: how the innovation opportunity can reduce the overall costs of the technology, rated from 1 (low) to 5 (high).
- Barrier reduction: how the innovation opportunity can contribute to reducing barriers to deployment, rated from 1 (low) to 5 (high).
- Time frame: period over which the innovation could feasibly start to be adopted and have material implications for the UK energy system and Net Zero

Table 4: Innovation needs for autothermal reforming

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
Integrating ATR and SMR with CCS at scale is crucial for producing low-carbon hydrogen whilst capturing the CO2.	ATR SMR	CCS	4 - Production of blue hydrogen through reforming with CCS becomes economically attractive at large scale.	3 - Accelerate the production, transportation, utilisation and storage of blue hydrogen.	2030
Alternative Reforming Technologies - Metal Oxide Reforming, Calcium Looping Route: Alternative reforming technologies may offer potential benefits over traditional steam methane reforming (SMR), particularly in terms of energy efficiency and carbon capture, however this is yet to be proven.	ATR SMR	CCS	2 - Alternative reforming technologies are currently at lower TRLs. Metal oxide – 4-6 and methane pyrolysis 3-4. The route produces only hydrogen and solid carbon from methane, avoiding the problem of CO2 capture and storage but wasting a large amount of the energy in the natural gas	2 – Limited potential to drive down costs for CCS projects and need significant time to de-risk and scale up as these are not modular.	2035

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
New Water-Gas Shift Technologies, particularly reverse WGS (RWGS), are emerging for a range of applications including the production of sustainable aviation fuel.	Low Temperature Catalysts + advanced reactor concepts	CCS SMR	4 - Within these thermochemical methods, the WGSR may play a role in the prospective hydrogen sector and CO_2 reduction arising from the fact that hydrogen production and CO_2 enrichment can be simultaneously accomplished from this chemical reaction.	3 – Achieves higher concentration of hydrogen thereby lowering the costs/energy associated with clean up processes.	2035
Small-Scale Modular Reformers combine three process steps: combustion, heat recovery and reaction and could be advantageous for offshore, remote or small-scale methanol plant applications.	Reformer		4 - Could accelerate the deployment and scale up of new SMR process technology. Modularisation widens the options for other improvements across some of the technologies above.	4 – Modularisation enables scale up to very large scale with less commercial risk	2030

Table 5: Innovation needs for electrolysis

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
Improved electrode design and materials for low temperature electrolysers to reduce dependence on	Low Temperature Electrolysers	Wind, Solar, Hydro Developers	4 – Reduces carbon footprint and cost-effective growth to larger scale production. Precious metal	4 - Stimulates large scale production of green hydrogen, lowering the	2030

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
precious metals such as platinum and iridium. OEMs continue to strive to enhance electrolyser stack designs and reduce the use of precious metals without compromising the electrolyser's performance.		Energy Storage Networks	reduction avoids contention for critical resources at large scale. Improved durability of electrodes reduces replacement cycles, reducing cost.	longer-term risks on materials.	
Improve Membrane Materials for Low Temperature Electrolysers. This involves developing materials with higher ionic conductivity and better durability whilst maintaining thermal and mechanical stability.	Low Temperature Electrolysers	Wind, Solar, Hydro Developers Energy Storage Networks	3 – Lowers cost through reducing power requirements. Improves operating costs through lengthening stack replacement life.	3 – Reduces investment risk.	2030
High Temperature Electrolysers– Enhancing durability of materials to achieve mechanical, thermal and chemical stability while reducing costs. Achieving long-term stability and durability at high temperatures requires continued addressing material degradation challenges, including mechanical, thermal and chemical	High Temperature Electrolysers	Wind, Solar, Hydro Developers Energy Storage Networks	4 – Improves operating costs through lengthening stack replacement life. Removes competition for precious metals.	4 – Improves performance of the technology, enabling greater deployment and reducing investment risk.	2030

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
issues, whilst optimising electrode materials and electrolyte properties including developing materials with superior corrosion resistance, thermal compatibility and high catalytic activity. This is linked to a need for improved, innovative engineering of stacks and scalable subsystems.					
Increasing the development of modular components for electrolysers is crucial for scaling up hydrogen production and lowering costs. Combining individual modules, electrolysers can be adapted for various power requirements, from small scale to large-scale gigawatt plants, making them more adaptable and cost-effective.	High Temperature Electrolysers Fuel Cells	Wind, Solar, Hydro Developers Energy Storage Networks	4 - Reduce the overall cost of manufacture by increasing volumes and leveraging high volume manufacturing.	4 – Improves investment risk by allowing scalable deployment	2030
Integration of all electrolysers with renewable energy sources is crucial in the production of green hydrogen utilising renewable resources such as solar, wind and hydro.	High & Low Temperature Electrolysers	Wind, Solar, Hydro Developers Energy Storage	5 - Expands availability of cost-effective renewable resources (hydrogen cheaper to transport offshore than power)	5 – Enables the UK to access extensive exportable renewable resources	2030

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
Increasing Density of Stacks leads to higher energy and power output within the same physical space and enables colocation of renewable power production with synthesis of green fuels and chemicals. Increased density is key to cost effective operation of electrolysis at pressure, reducing the need for less efficient mechanical compression.	High & Low Temperature Electrolysers Fuel Cells	Wind, Solar, Hydro Developers Energy Storage	4 – Lowers footprint for installations, mobile and stationary, bringing overall power density to historical expectations. Size impacts cost both directly and indirectly.	3 – Enables the technology to be more locatable in urban, rural and offshore environments	2030
Optimised System Integration enables the combining of different systems and subsystems into a cohesive single system thereby improving efficiency and streamlining processes.	High and Low Temperature Electrolysers	Wind, Solar, Hydro Developers Energy Storage Networks	4 – For low temperature electrolysers, this lowers cost of downstream equipment. For high temperature electrolysers, this enables use of waste process heat to lower hydrogen production costs and improve efficiencies from 85%-100%.	4 – Improves use of renewable resources.	2030

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
Utilisation of impure water feedstocks, such as seawater and wastewater for hydrogen production through electrolysis is a growing area of research and development. This could reduce the capital costs for purification processes and protect drinking water resources.	Low and High Temperature Electrolysers	Offshore Wind	3 – Removes need for costly desalination of seawater and purification processes. This could lower the cost of inputs and enhance circularity.	3 – This could facilitate deployment of hydrogen production in offshore locations.	2035
E-fuels, or synthetic fuels, are produced by combining captured carbon dioxide (CO2) with green hydrogen. The hydrogen and CO2 then go through a synthesis process such as Fischer-Tropsch to create liquid hydrocarbons, such as e-gasoline, e-diesel and e-kerosene. The Fischer-Tropsch process is discussed further in the EINAs Carbon Management report.	Fuel Production Carbon Recycling High and Low Temperature Electrolysers	Decarbonisation of transportation (particularly heavy-duty transport, maritime and aviation)	5 – Significantly simplifies production processes, eliminating capital investment. The integrated processes are up to 3 times more efficient than separate chained processes.	5 – Enables transitional decarbonisation arrangements particularly within the maritime and aviation sectors where battery energy storage is ineffective with a significant carbon footprint and drain on mineral resources.	2030

Table 6: Innovation needs for hydrogen transport, storage and use in electricity generation

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
Ammonia - Hydrogen Transport Technologies. Ammonia is a promising hydrogen carrier, facilitating efficient transport of hydrogen particularly over long distances. At its destination, ammonia can be "cracked" back into hydrogen and nitrogen, with the hydrogen then available for use. This method leverages existing ammonia infrastructure, making it a viable solution for large-scale hydrogen transportation.	Hydrogen Storage Ammonia Cracking Ammonia Synthesis	Enables transport of large-scale hydrogen before hydrogen infrastructure is available	5 - Enables access to large scale renewables resources in the North Sea and globally levelising costs.	4 - Accelerates the deployment of long range zero emission vehicles (heavy duty trucks, trains, maritime)	2030
De-blending Hydrogen into Existing Natural Gas Pipelines De-blending hydrogen from blended hydrogen and natural gas mixtures in existing gas pipelines enables the separation of the hydrogen for specific applications whilst utilising the gas infrastructure to distribute the hydrogen to offtakers such as industry.	Transmission and Distribution Network	R&D, Natural Gas, Hydrogen	5 – Critical to ensuring grid resources can be scaled to levels required. Also avoids the need for vastly greater electrical network upgrading or the cost of investing in new infrastructure.	4 - The ability to utilise current infrastructure would enable substantial volumes of hydrogen to be transported to offtakers. It also enables the scaling up of hydrogen deployment to reach government targets of 10 GW of clean hydrogen by 2030.	2030

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
New Network Design – Hydrogen/Natural Gas Pipelines involves repurposing existing natural gas pipelines for hydrogen transport and extending the network by creating new pipelines specifically for hydrogen, thereby creating a more robust and efficient hydrogen network. This method aims to reduce costs and leverage existing infrastructure whilst enabling wider hydrogen adoption.	Pipelines, Valves, Compression, On-line Repair and Modification Technologies. Full Range of Materials	Industrial process decarbonisation	5 – Critical to convert natural gas network to partial or 100% hydrogen network to avoid the need for further 3-5 x expansion capacity of the electrical network.[52]	5 – Enables planning for optimal energy movement using combined gas and electrical network resources. Enables much wider utility of wind and tidal stream resources around the UK and potential export.	2030
New build turbines and conversion of OCGTs and CCGTs: Improved safety measures for flammable hydrogen gas, including the gas turbine enclosure and ventilation system design The unusual behaviour of hydrogen in combustion necessitates significant changes in gas turbines, covering the compressor as well as the combustor. Compressor discharge temperature must be reduced to avoid	Gas Turbines	Large scale power generation and energy storage. Reduces pressure to add diesel and gas engine farms to balance grid.	4 – Improved safety minimises failures and optimises performance, reducing costs of operation.	4 – Facilitates the safe deployment of hydrogen gas in existing and new build turbines.	2030

[52] HyNet (Accessed: 2025) HyNet North West

Innovation opportunity	Technology	Other impacts	Cost reduction	Barrier reduction	Time frame
autoignition while combustors require complete redesign to accommodate the exceptionally fast flame speed of hydrogen. Enclosure ventilation improvement is essential to prevent the accumulation of flammable hydrogen concentrations. There are techniques such as dilution ventilation that can ensure adequate air changes per hour, as an example. Gas turbine enclosures should be designed with materials compatible with hydrogen. Safety systems like gas detection and fire suppression should be configured to account for hydrogen's unique properties.					

System benefits from innovation in hydrogen

System modelling to assess the potential impact of innovation in key net zero technologies was conducted using UK TIMES, an energy system model of the UK that was developed by UCL and the UK Department of Business, Energy and Industrial Strategy (now the Department for Energy Security and Net Zero or DESNZ). For each of the selected technologies, three levels of innovation were developed representing a low, medium and high innovation case for the technology. The low innovation level represents a business-as-usual case where innovation follows recent trends or is generally limited, whilst the high innovation case represents significant innovation in the technology to decrease costs and improve efficiencies.

The low, medium and high innovation cases were each run against three different hypothetical scenarios which were developed by DESNZ to represent potential routes to net zero for the UK, namely Minimally Constrained, High Hydrogen and High Diversification. They do not represent government policy or forecasts but were selected due to their differing constraints which provide a diverse set of outputs and insights on innovation impacts. A summary of each is presented below, a more in depth description can be found in the methodological report.

- **Minimally Constrained**: Designed to show the largest potential impacts from innovation investments by minimising the number of constraints on the energy system. UK Government data assumptions are used across the scenario.
- **High Hydrogen**: Based on the Minimally Constrained scenario, with a range of constraints added to force hydrogen use across the economy. These constraints are based on estimates of H2 demand ranges in the DESNZ Hydrogen transport and storage networks pathway policy paper published in 2023, and provisional figures from DESNZ sector teams that are set to be refined further for CB7. A maximum hydrogen consumption in each sector and a minimum overall level of consumption is applied in each year from 2035 to 2050. It is important to note that this scenario was developed prior to updates to the UK Hydrogen Strategy.
- **High Diversification**: Based on the Minimally Constrained scenario, this scenario aims to be more energy secure through two means, 1) limiting imports of key commodities to reduce UK reliance on overseas resources, and 2) diversifying resource and technology use across the economy to limit the impacts of any supply interruptions, price rises or technology failures.

The results presented below demonstrate the potential impact of innovation for a specific technology on achieving net zero within the confines of the scenario. In each model run for a specific technology, all other technologies are held at their low innovation case so that the impact on the UK energy system of that technology can be isolated. Changing the costs and performance of technologies through innovation can have both direct and indirect consequences:

- Direct consequences are a reduction in cost or an improvement in the quality of the energy service supplied by the technology. Only cost reductions are examined in the UK TIMES energy system model.
- Indirect consequences are changes to the wider system caused by a relative change of cost of a technology relative to other technologies. If the deployment of a technology increases due to a lower cost and the deployment of alternative technologies reduces then a cost reduction will be realised. This cost reduction will be lower than the direct cost reduction that would have occurred if the new technology had already been used at lower innovation levels. More profound changes could also occur across the energy system, for example changes in total electricity consumption or in the relative rate of decarbonisation between sectors of the economy.

We have not considered rebound effects where lower costs of energy due to innovation investments lead to higher energy service consumption. An elastic demand version of UK TIMES could be used to explore potential rebound effects of innovation investments.

The below analysis refers to only to the hydrogen technologies presented in this report. It should be noted that given these results are an output of the system modelling and the three hypothetical scenarios developed for the EINAs that they do not reflect UK government deployment targets and ambitions.

Autothermal reforming

The installed capacity of autothermal reforming reaches 16GW by 2050 in the High Hydrogen scenario compared to 10GW in the Minimally Constrained scenario. There is zero installed capacity of autothermal reforming in the High Diversification scenario, due to import constraints built into this scenario meant to replicate lower import dependency, which reduce the model's ability to use imported methane in the UK energy system. As the model prioritises methane for other use cases based on cost-optimisation and availability of alternatives, no methane is left for use in autothermal reforming.

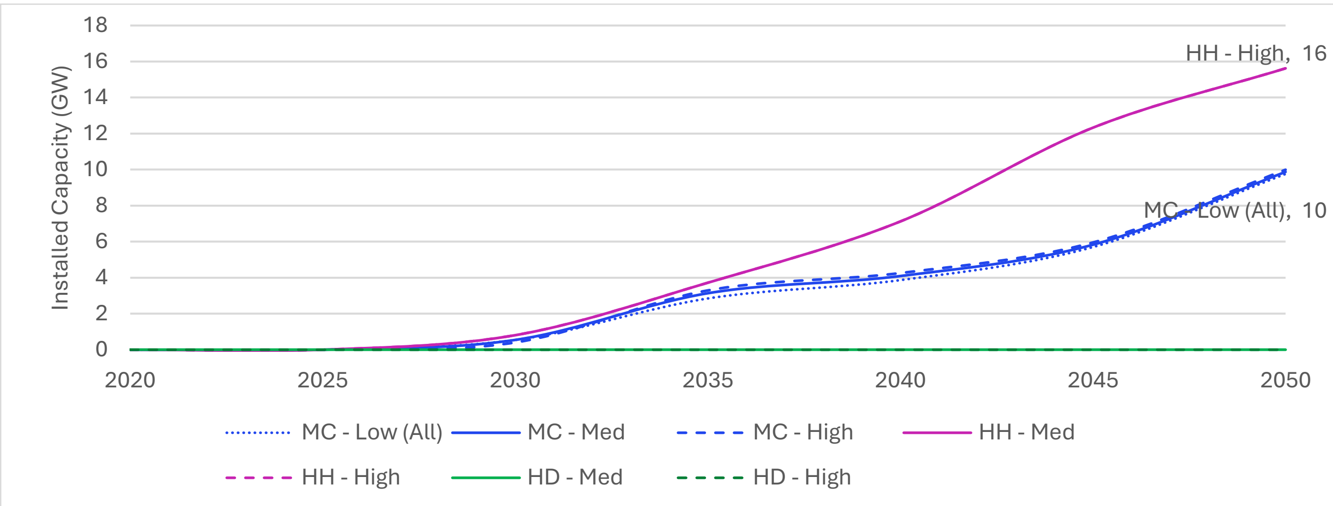

Figure 1: Installed capacity (GW) of autothermal reforming by innovation level and scenario

There is very limited variation in gas reforming with CCS, or blue hydrogen production, based on innovation level used. Scenario assumptions in this case are the key determinants of blue hydrogen usage variation. Installed blue hydrogen capacity the same in High Hydrogen and Minimally Constrained up to 2035, diverging thereafter as shown in Figure 1 above. Labels within figures are defined as innovated technology - Innovation level for given technology (e.g. DACCS-High).

Generation of blue hydrogen varies significantly across the Minimally Constrained scenario dependent on the level of innovation across technologies. The lowest level of blue hydrogen generation is observed when all EINA technologies are at high innovation levels (bottom grey line in Figure 2). Due to modelling constraints on blue hydrogen (there is a maximum proportion of hydrogen production that can be produced by blue hydrogen in all scenarios due to uncertainty on the impact of methane supply chain emissions), these system-wide implications should be interpreted with care as blue hydrogen could otherwise have a much greater role in the energy system. In the High Hydrogen scenario in particular, blue hydrogen production hits the maximum production constraint across all innovation levels.

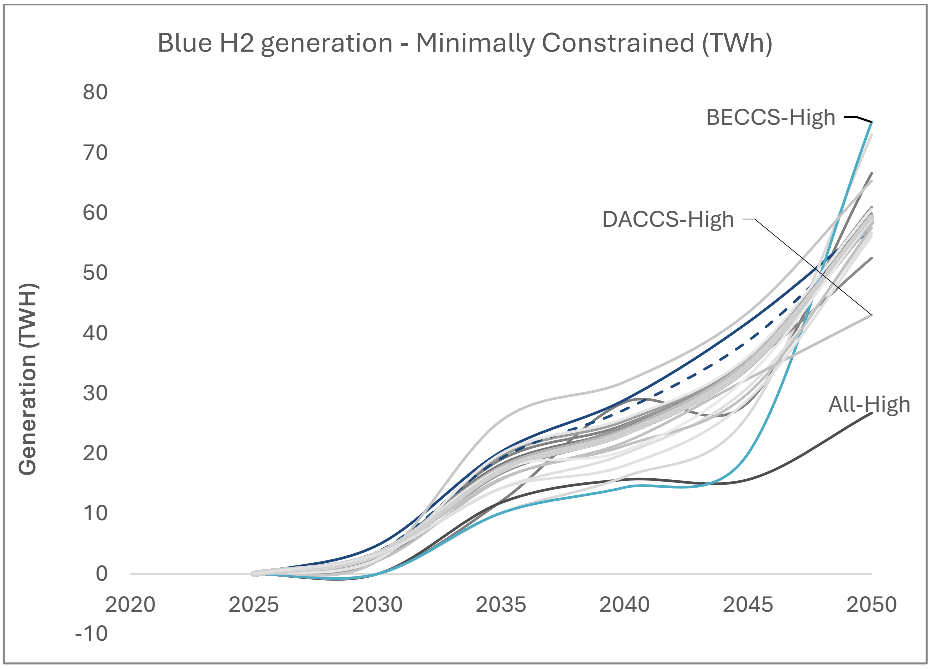

Figure 2: Blue H2 generation (TWh) over time across different innovation runs (low, medium and high levels for each technology) in the Minimally Constrained scenario.

Cumulative cost savings due to innovation in autothermal reforming is relatively low compared to innovation in electrolysers, reaching £6.6 billion in 2050 in the High Hydrogen scenario. However, as mentioned above, this is limited by the constraints put on blue hydrogen in the scenario and so could be significantly higher if it was deployed to a greater extent and without significant supply chain emissions (e.g. fugitive methane emissions).

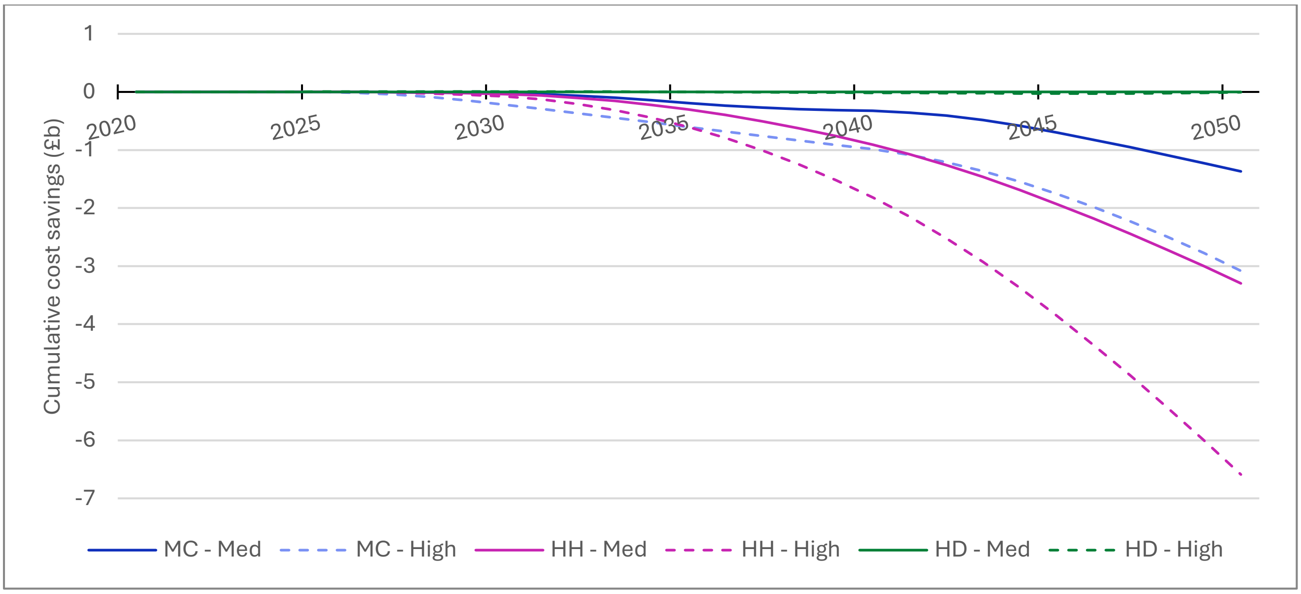

Figure 3: Cumulative cost savings (in real 2022 £) to 2050 for differing levels of innovation in autothermal reforming, compared to base all low innovation case

Electrolysis

PEM electrolysers form the vast majority of electrolyser deployment across all 3 scenarios. Solid oxide electrolysers are not deployed in any scenario whilst alkaline electrolysers are only deployed to a limited extent in the High Diversification scenario from 2045 as the model prioritises PEM electrolyser deployment as it optimises around costs. The installed capacity of electrolysers is not sensitive to the innovation level of the technology but does vary significantly across scenarios. Installed capacity of electrolysers in 2050 reaches 36GW in the High Diversification scenario, compared to 23GW in the High Hydrogen scenario and maximum of 13GW in the Minimally Constrained scenario. Elevated deployment in High Diversification is driven by both lowered energy imports causing the energy system to be more reliant on domestic electricity generation (and therefore limited blue hydrogen) and electricity generation diversity constraints leading to higher hydrogen use for power generation at low-capacity factors.

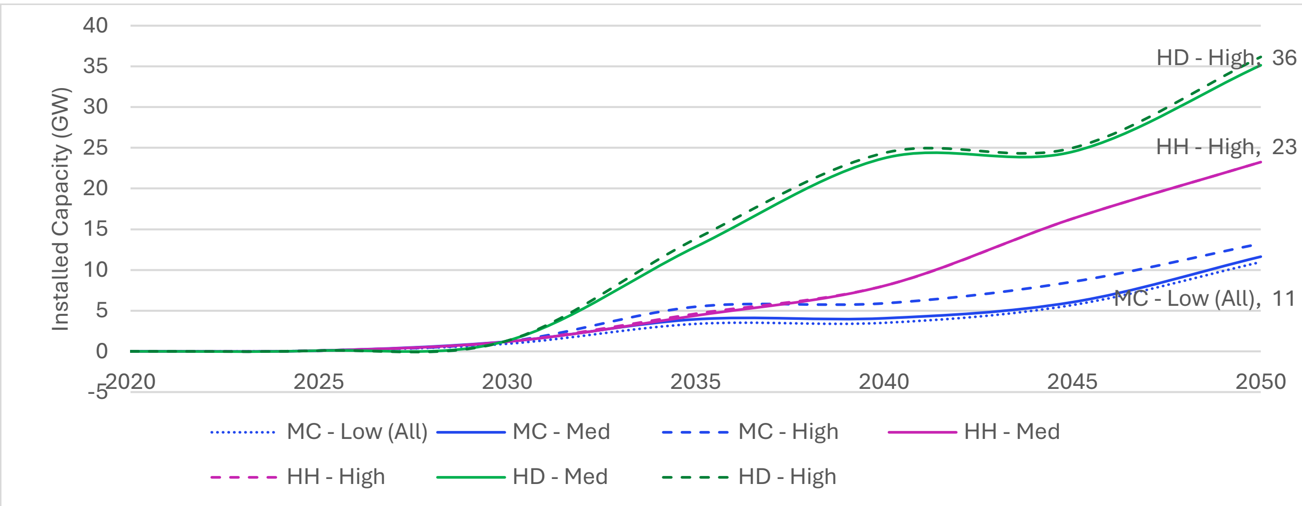

Figure 4: Installed capacity (GW) of electrolysers by innovation level and scenario

Electrolyser deployment is sensitive to innovation in other technologies. Innovation in offshore wind accelerates electrolyser deployment between 2035 and 2045 significantly. This is potentially due to the reduction in the cost of electricity from offshore wind leading to more grid electricity and so surplus ("curtailed") electricity available for PEM. Since electrolysers tend to have offshore wind in their supply chain, innovation in technologies which address emissions and lower overall electricity generation requirements – BECCS and DACCS – causes lower electrolyser deployment. The high innovation run for BECCS almost halves the need for electrolysis by 2050 for Minimally Constrained as it removes the limit on BECCS-hydrogen, lowering the competitiveness of electrolytic hydrogen while the total demand for hydrogen remains consistent. The lowest level of generation (bottom grey line in figure 5) occurred when all EINA technologies were at high innovation levels.

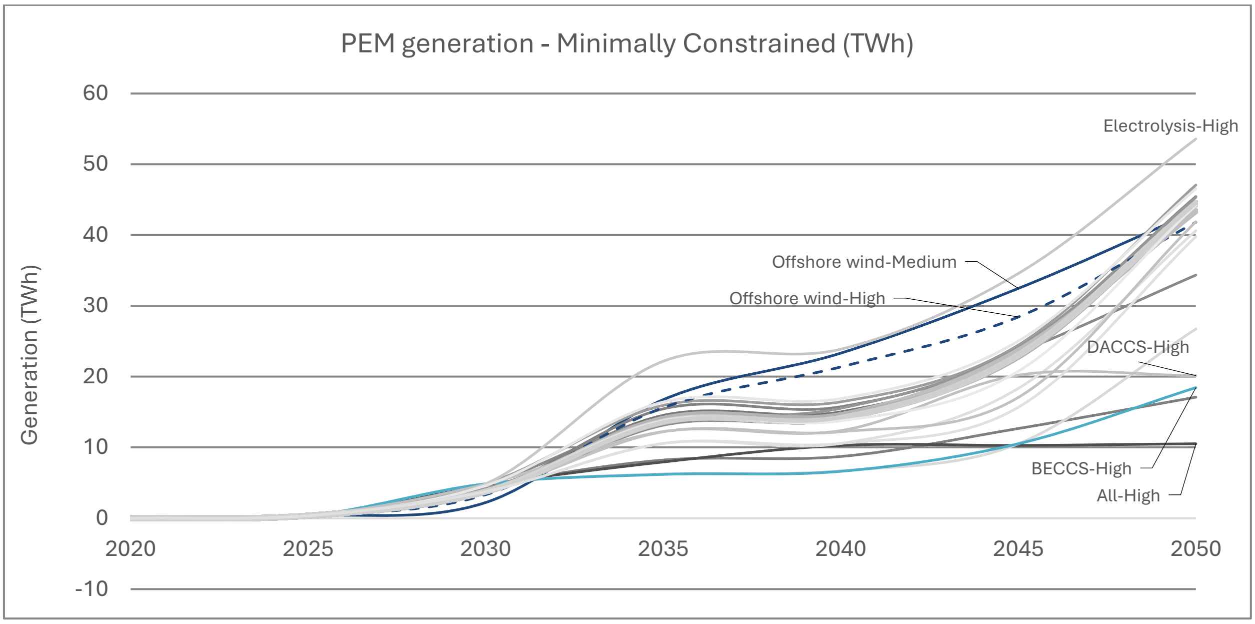

Figure 5: PEM generation (TWh) over time across different innovation runs (low, medium and high levels for each technology) in the Minimally Constrained scenario

Innovation in electrolysers has the potential to significantly reduce system cost compared to the low innovation scenario, particularly in the High Diversification scenario where it is deployed to a greater extent to meet diversification and lowered energy import dependency. Total undiscounted system cost savings for high innovation in the High Diversification scenario is £23.6 billion by 2050 compared to the low innovation scenario, and £6.1 billion and £10.6 billion respectively in Minimally Constrained and High Hydrogen (Figure 6).

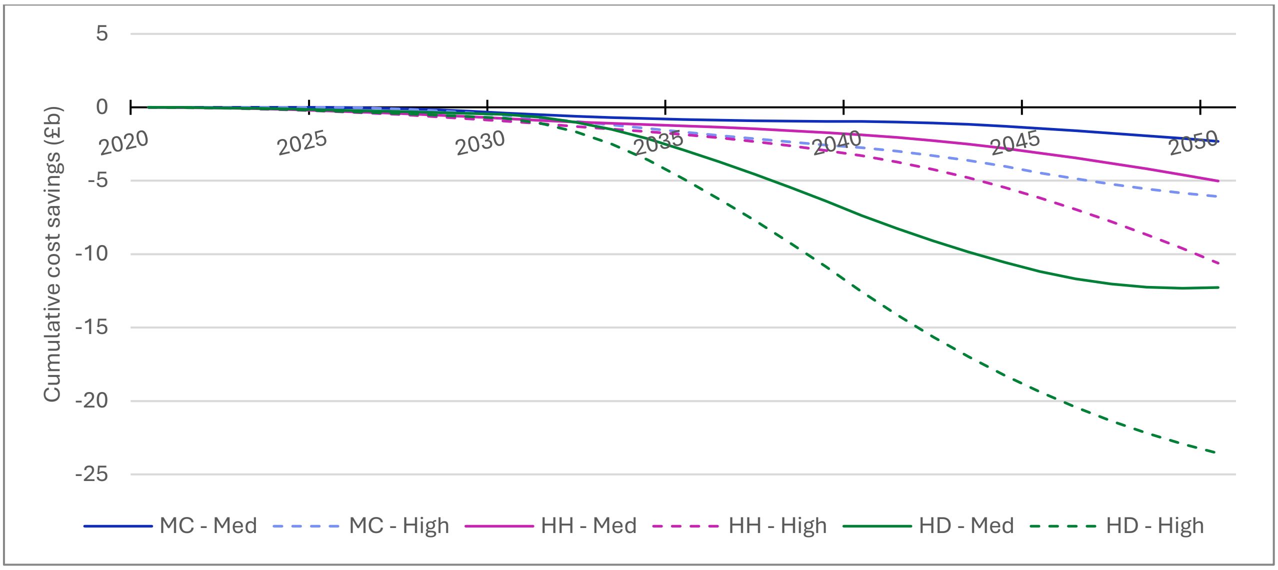

Figure 6: Cumulative cost savings (in real 2022 £) to 2050 for differing levels of innovation in electrolysis, compared to base all low innovation case

As it can be seen in Figure 7, a high level of innovation in electrolysis drives an increase in the generation from offshore wind in 2050 in Minimally Constrained as the demand for clean power is higher. There is also an increase in the autothermal reforming generation. This extra hydrogen generation drives the need for additional transportation of hydrogen. The impact on all other technologies is minimal.

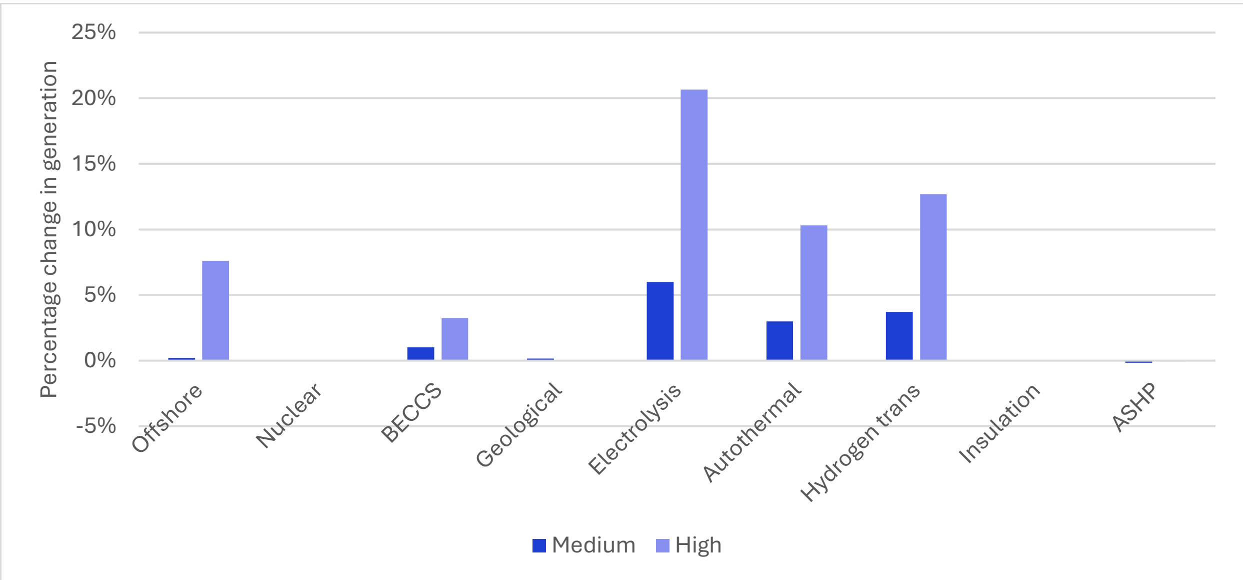

Figure 7: Impact of innovation in electrolysis on generation of other technologies in 2050 compared to low innovation level run for Minimally Constrained

Note – tidal, depleted gas field storage, gas-CCS, H2 turbines, and GSHP have all been excluded as their generation is either zero or too limited to provide meaningful comparison. Additionally, short and medium storage system modelling is performed using the HighRES model and so are also excluded.

Hydrogen transmission and transport

Innovation in hydrogen transmission and distribution increases their total capacity by marginal levels within scenarios. In the High Hydrogen scenario, installed capacity reaches 47GW in 2050 compared to 30GW in the Minimally Constrained and High Diversification scenarios.

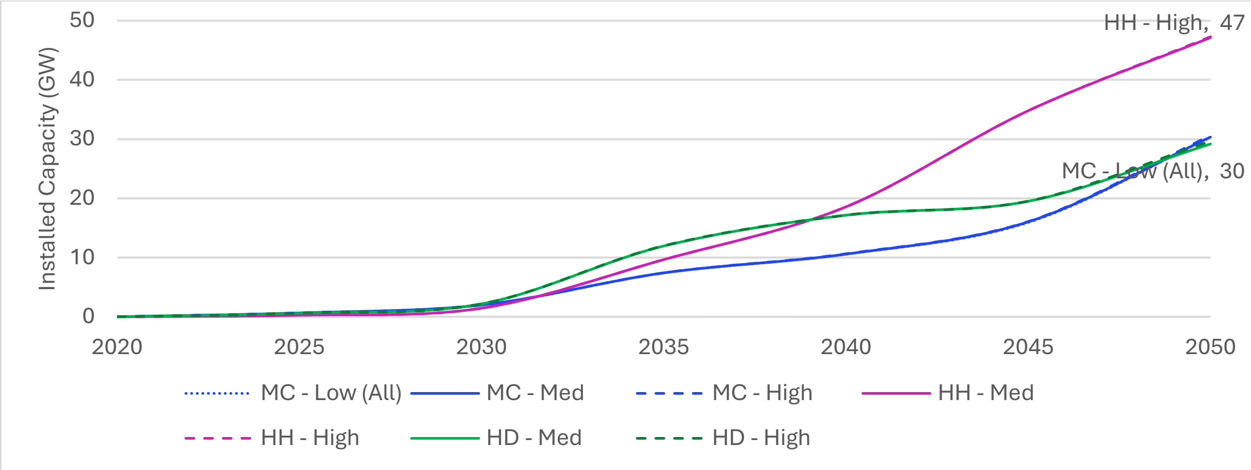

Figure 8: Installed capacity (GW) of hydrogen transmission by innovation level and scenario

Innovation in hydrogen production technologies, such as BECCS-H2 and electrolysis, drives an increase in the capacity of hydrogen transmission and distribution. This can be seen in the below chart where the high innovation level runs for BECCS-H2 (BECCS-High) and PEM electrolysers (Electrolysis-High) show a significantly higher hydrogen transmission capacity in the Minimally Constrained scenario compared to other innovation cases. More generally, the level of hydrogen transmission is an indicator of the system's balance between hydrogen generation and other technologies. For example, innovation in DACCS reduces the required capacity for hydrogen transmission and distribution because higher levels of offsets become available, which decrease the demand for low-carbon hydrogen.

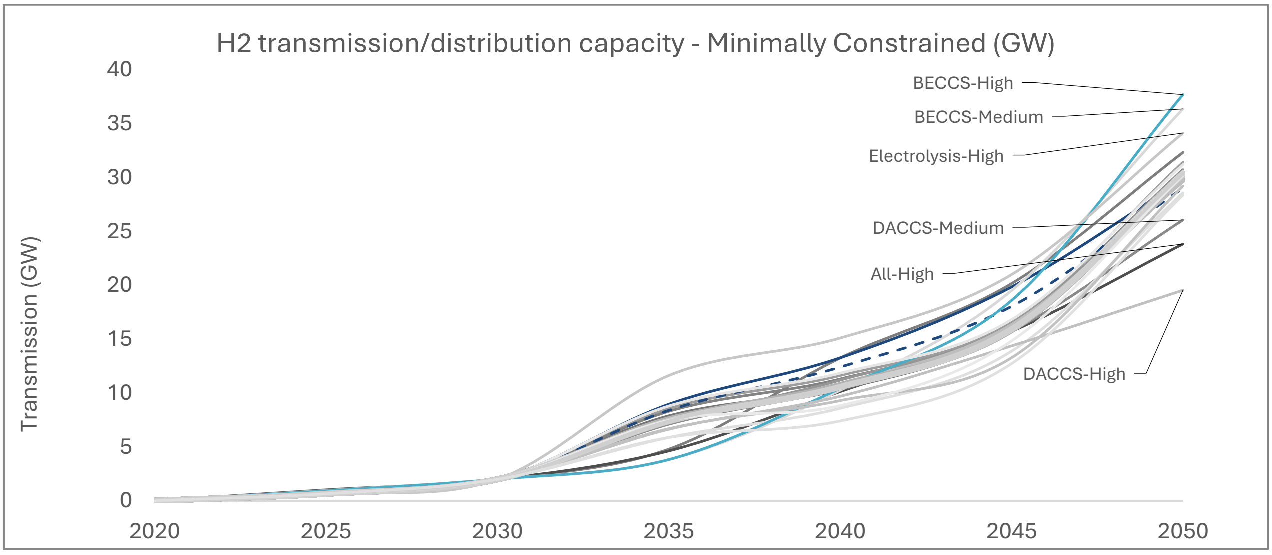

Figure 9: H2 transmission / distribution capacity (GW) over time across different innovation runs (low, medium and high levels for each technology) in the Minimally Constrained scenario

Cumulative cost savings through innovation in hydrogen transmission are relatively low compared to other hydrogen technologies, reaching £1.2bn in the high innovation High Hydrogen scenario. However, as mentioned above, due to the dependency of hydrogen transmission on the deployment of hydrogen generation technologies, higher cost savings would be realised in cases where hydrogen generation is higher through innovation in hydrogen transmission.

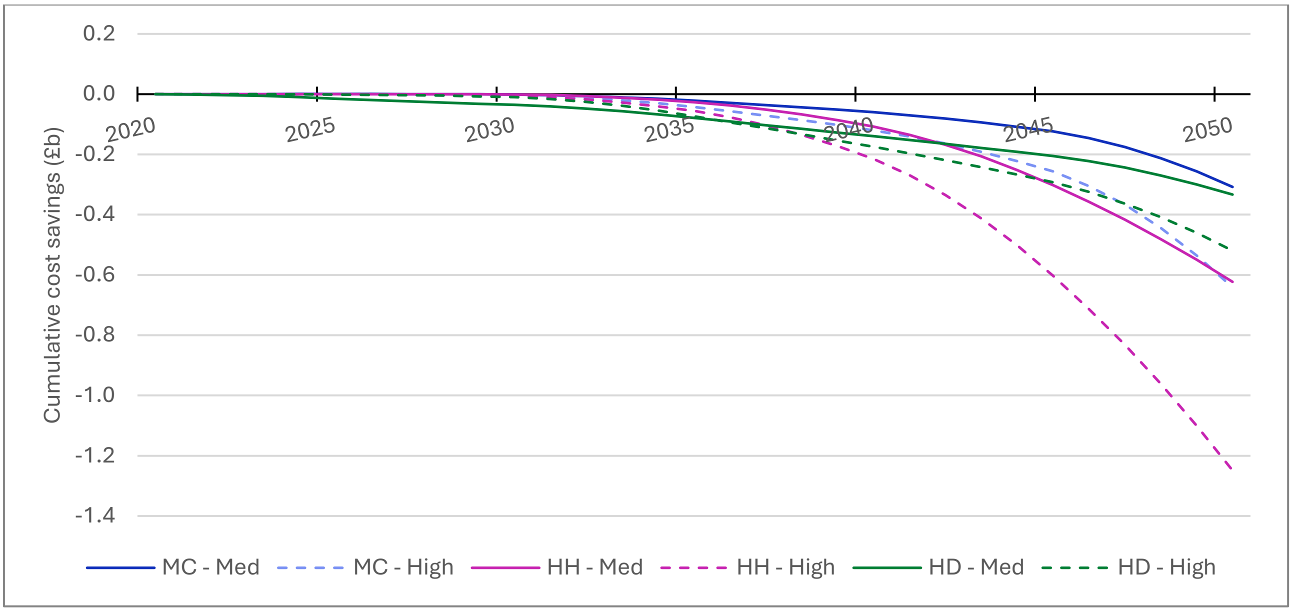

Figure 10: Cumulative cost savings (in real 2022 £) to 2050 for differing levels of innovation in hydrogen transmission and transport, compared to base all low innovation case

H2 Turbines (OCGT and CCGT)

Hydrogen turbines are not used in Minimally Constrained but are deployed in High Hydrogen and High Diversification. This is due to the constraint on minimum amounts of hydrogen in the High Hydrogen scenario and the constraint requiring diversification in High Diversification. Their output is similar in High Hydrogen across all innovation runs. In High Diversification, hydrogen turbine generation is reduced by negative emissions technologies (e.g., BECCS and DACCS) as highlighted by the lagging lines in the High Diversification generation chart in Figure 11. Additionally, their deployment slightly decreases from 11 TWh to 10 TWh in 2050 in the High Diversification run with high innovation in tidal stream.

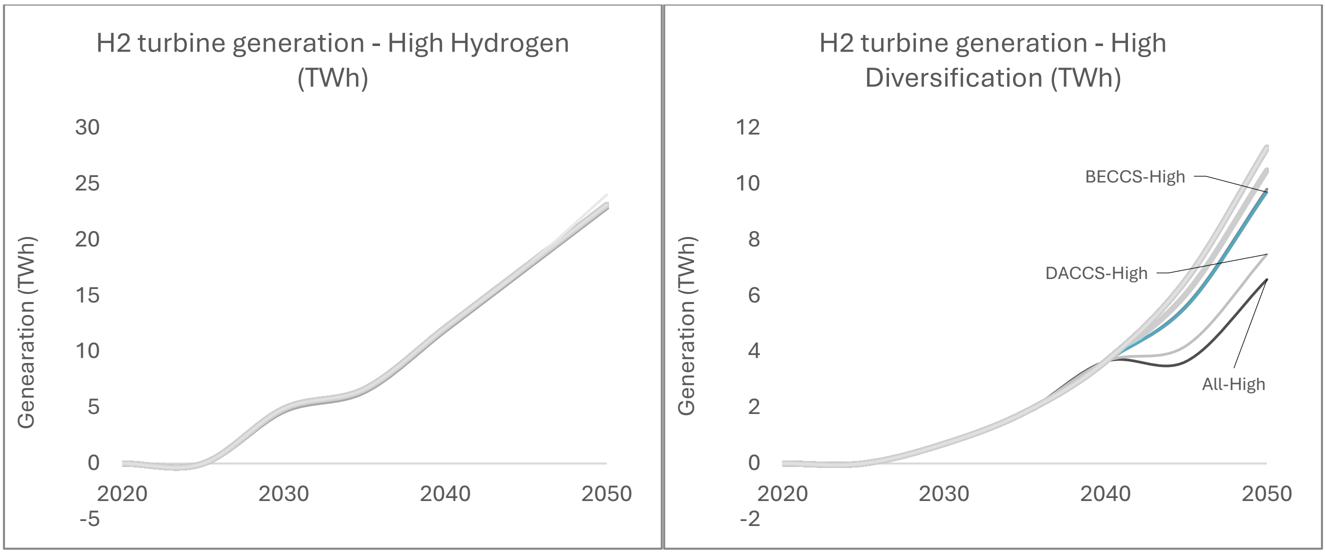

Figure 11: H2 turbine generation (TWh) over time across different innovation runs (low, medium and high levels for each technology) in the High Hydrogen and High Diversification scenarios

The installed capacity of hydrogen turbines is not impacted by their innovation level, rather only the scenario they are based on. Installed capacity is 55GW in 2050 in the High Hydrogen scenario compared to 32GW in the High Diversification scenario.

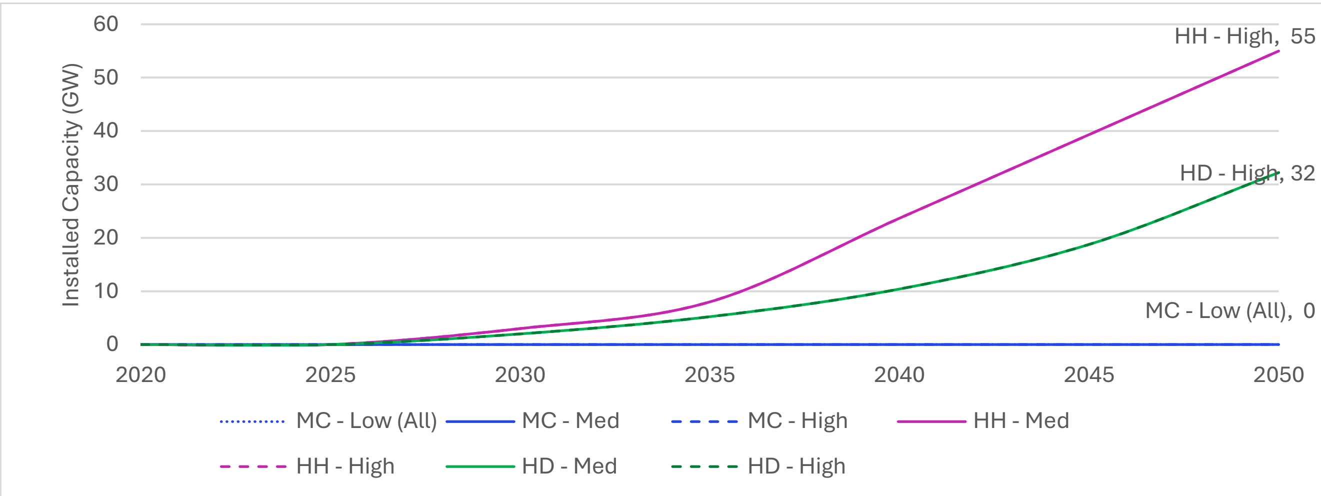

Figure 12: Installed capacity (GW) of H2 turbines by innovation level and scenario

Cumulative cost savings in the High Hydrogen scenario through high levels innovation in the technology reaches £5.6 billion compared to £2 billion in the medium innovation level. Cost saving in the High Diversification scenario through innovation are more modest with cost savings of £1.3 billion in the medium innovation run compared to £2 billion in the high innovation run.

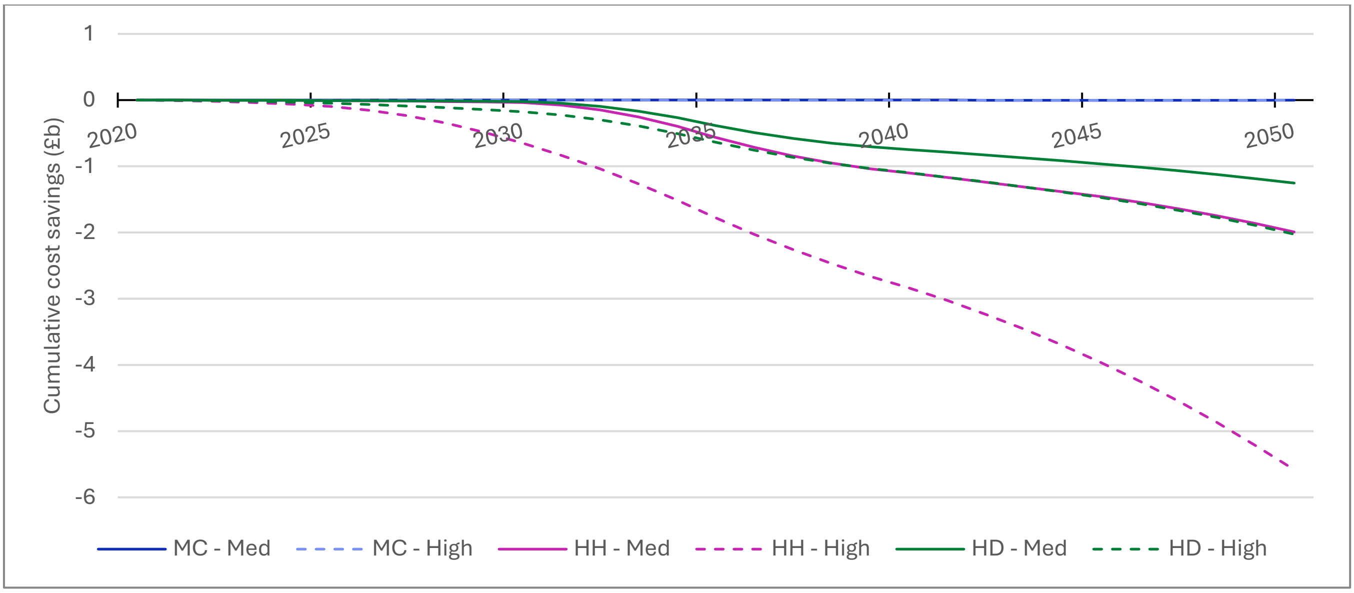

Figure 13: Cumulative cost savings (in real 2022 £) to 2050 for differing levels of innovation in hydrogen turbines, compared to base all low innovation case

Depleted gas field storage

Innovation runs for depleted gas field storage result in very limited deployment across all scenarios. Depleted gas field storage is not deployed by the model in the Minimally Constrained and High Hydrogen scenarios and only deployed to a very limited extent in the High Diversification scenario. Other types of hydrogen storage were not modelled for this research, as detailed in in the introduction section.

Disruptive technologies

This section highlights key findings from DESNZ research into emerging and disruptive technologies additional to the primary EINAs assessment. The purpose of the disruptive technologies research is to:

- Provide insight on emerging technologies outside of the core EINAs scope and explore the potential impacts of deployment on the future energy system; and
- Provide options for further exploration as a supplementary evidence base to inform prioritisation of future government support for clean energy innovation.

The selection of emerging technologies and summarised insights presented was informed by independent qualitative sub-sector analyses and targeted engagement with stakeholders in the academic community, industry, and government.

The technologies highlighted in this section serve as illustrative examples drawn from a long-list of emerging or alternative approaches with the potential to contribute to net zero if successfully deployed at scale.

This section provides an overview of the key findings into novel fuel production and storage methods, including novel hydrogen production and ammonia production.

Table 7: Disruptive technologies: Novel hydrogen production

Overview: Novel hydrogen production	
Description of the technology	Water splitting hydrogen production approaches, such as electrolysis, split water molecules into their hydrogen and oxygen components, to produce hydrogen gas. • Thermolysis is the splitting of water under high temperature, e.g. from a nuclear power heat source or concentrated solar using a catalyst. • Photolysis approaches use photoelectrochemical (PEC) cells immersed in water, to produce hydrogen using solar energy.
Impact on the energy system	Alternative hydrogen production methods can offer carbon negative hydrogen and contribute to a future resilient and secure supply of hydrogen that is not dependent on access/supply of natural gas.
Timescale	Thermolysis and photolysis technologies are estimated to be at TRL 1-4. The earliest they are estimated to reach TRL 9 is 2040.
Key developers	The 2022 HyTN project funded by the National Nuclear Laboratory assessed the development progress of thermochemical hydrogen production from nuclear heat. This report highlights the fact that there is expected to be a

Overview: Novel hydrogen production	
	long lead time for commercial deployment given the combination of technical challenges for deployment and the need to reduce costs to make the process economically attractive. • Photolysis using photoelectrochemical (PEC) cells remains at an early stage of development, as highlighted in a recent review. Whilst the process is proven at lab scale, there are a variety of challenges to overcome before larger scale demonstration can be considered, such as identifying the most effective materials & catalysts, and improving efficiencies and rates of reaction.

Table 8: Disruptive technologies: Ammonia production

Overview: Ammonia production	
Description of the technology	Ammonia is currently produced via the Haber Bosch process, which requires a source of hydrogen. At present, this is typically supplied via reforming of natural gas without CCS (i.e. “grey” hydrogen). The source of hydrogen for the Haber Bosch process could be replaced with any of the alternative/novel hydrogen production methods discussed previously in this report, including retrofitting CCS to existing “grey” hydrogen production. • Beyond this, there are alternative novel approaches to ammonia production, which include: • Electrochemical ammonia production, for synthesising ammonia directly from steam or water and nitrogen. • Non-thermal Plasma (NTP) synthesis for ammonia production, for synthesising ammonia using a low temperature and atmospheric pressure plasma together with a catalyst. • Nitrogenase motivated peptide-functionalised catalyst for ammonia production, the use of an engineered enzyme within an electrochemical system for higher ammonia production efficiencies.
Impact on the energy system	Novel ammonia production processes may offer potential benefits over the conventional Haber Bosch process in the future but are currently all at lab scale. Replacing hydrogen supply in conventional Haber Bosch process is likely to be the best option over the short to medium term.
Timescale	These ammonia production methods are estimated to be at TRL 1-5, reaching TRL 9 between 2035 – 2040 at the earliest.

Market innovation barrier and enabler deep dives

As part of the EINAs project, a simplified barriers and enablers assessment was carried out across the prioritised technologies to understand the factors which should be considered for each technology in addition to technology innovation. This included qualitative analysis across eight variables, as detailed below, which includes a low/medium/high rating for each element to indicate the relevance and risk of each barrier to the deployment and scale up of the technology. The eight variables assessed were:

- **Enabling infrastructure:** There is limited existing infrastructure for producing, distributing or using clean hydrogen. Scaling up production capacity of clean hydrogen will be essential to enabling the growth of the sector and catalyse deployment of the necessary enabling infrastructure.
- **Regulatory environment:** Supportive policies which offer clarity and certainty into the long term will be critical to help the hydrogen sector develop. Conversely, delays, uncertainties or regulations which are not fit for purpose will hinder investment and delay deployment and scale up.
- **Stakeholder acceptance:** Stakeholder acceptance was not identified as a significant barrier to deployment and scale up of the UK's hydrogen sector. Willingness to pay for hydrogen technologies at current costs is low, but there is recognition of the role that hydrogen can play in the transition to net zero.
- **Availability of funding and investment:** Currently, low carbon hydrogen production methods are expensive, as are storage and transport. There is uncertainty around how transportation infrastructure will be funded, although this should be provided through upcoming Hydrogen Transport and Storage business models. The Hydrogen Production Business Model alongside other public support mechanisms such as the National Wealth Fund (NWF)[53] are seeking to provide long-term revenue and funding certainty to firms.
- **Business model viability:** The economics of clean hydrogen production, transport and storage are challenging. The cost of green hydrogen is expected to reduce with increasing renewable energy generation. The Clean Power 2030 Action Plan outlines plans to develop a Hydrogen to Power business model to de-risk investment and bring forward capacity, while the upcoming Hydrogen Transport and Storage Business Models are aimed at incentivising hydrogen infrastructure investment.
- **Resource availability:** For storage and transport, the UK has advantageous geological resources and an existing natural gas pipeline network. The materials needed for new hydrogen transmission pipelines do not currently represent a challenge, although

[53] Department for Energy Security and Net Zero (2025) Hydrogen update to the market: July 2025

material required for balance of plant for hydrogen storage technologies may require metal types that are a limited resource.

- **Supply chain:** There is not yet a sufficient supply chain in place to enable the deployment required to achieve government and industry targets. There are a number of hydrogen-specific and more general components with supply chain gaps and long lead times at scale, including: electrolyser stacks, compressors, high voltage transformers, reformer packages, large storage vessels, metering equipment and industrial equipment such as boilers and burners. GB Energy's recently announced Clean Energy Supply Chain fund could be an option to support companies who have significant potential to grow supply chains needed for hydrogen.[54]
- **Skills and training:** While existing technical experience in the oil and gas sector could be transferrable to some hydrogen infrastructure technologies, the lack of a skilled workforce in construction and technical roles has already been identified as a key challenge to hydrogen project development. There are significant challenges in addressing this gap, including uncertainty around the future pipeline and therefore workforce demand.

This section summarises and expands on key barriers and enablers from this list which have been assessed as most impactful for the hydrogen technologies: business model viability, enabling infrastructure, regulatory environment, supply chains and skills.

Deep dive 1: Business model

Hydrogen production

Hydrogen produced using ATR + CCS is inherently more expensive than grey hydrogen (without CCS) or natural gas due to the additional processes required. However, whilst blue hydrogen costs are linked to natural gas prices, which can fluctuate, in addition to electricity prices for the air separation unit, blue hydrogen will still likely be cheaper than green hydrogen for most of the 2020s.

The economics of green hydrogen production are and will be challenging for the near term, with 70% of its production costs coming from renewable electricity. Green hydrogen is therefore expensive and not cost competitive with grey hydrogen or natural gas in key industrial sectors without government support. Attracting investment will require greater certainty over costs, as well as supportive policy frameworks to provide clear signals of a secure and growing industry.

New market mechanisms may therefore be needed to overcome challenges in bringing the future hydrogen sector to fruition. For instance, green hydrogen will, by definition, be closely coupled to the electricity markets, the renewable energy contribution to the grid and access to

[54] UK Government (2025) Industrial Strategy: Clean Energy Industries Sector Plan

suitable power generation options. Existing challenges facing renewable energy, e.g. the marginal cost pricing system in which the most expensive energy source drawn upon to produce electricity (often gas) sets the wholesale price of electricity – will in turn influence green hydrogen production costs under current market arrangements.[55]

As of early 2025, the Hydrogen Production Business Model (HPBM) is the main UK government initiative designed to enable and accelerate the commercial production of low carbon hydrogen by providing long-term revenue certainty. HPBM support is being allocated through the Hydrogen Allocation Rounds (HARs) and the Carbon Capture, Usage and Storage (CCUS) Cluster Sequencing programme (with initial projects also eligible to receive grant funding through the Net Zero Hydrogen Fund).

Successful first Hydrogen Allocation Round (HAR1) projects are expected to access over £2 billion over 15 years in revenue support from the HPBM and over £90 million in capital expenditure support via the Net Zero Hydrogen Fund. Through the CCUS programme, there are currently three projects in negotiations: HPP1 a priority project and HPP2 a standby project in the Hynet cluster in Northwest England and H2Teeeside project in the East Coast Cluster in Teesside.

Hydrogen storage

Market mechanisms may be needed to support Long Duration Energy Storage (LDES), to incentivise large-scale hydrogen storage development as well as cost-effective operation over long timescales. This could take the form of centrally driven coordination of investment plans, cooperation of members of power pools, or establishment of a central buyer with responsibility by purchasing power from generators and selling it to consumers.[56] Hydrogen UK recommends that a long-term regulated business model for large-scale storage should be designed no later than 2025.[57] At the time of writing a revenue cap and floor awarded through subsidy competition is suggested as most appropriate by DESNZ, with further updates expected on exact details.

The UK government has confirmed their intent to support LDES which potentially could unlock investment opportunities that is vital for renewable energy storage technologies and strengthen the UK's energy security. Increasing long duration storage capacity could lead to billions of pounds in system savings, helping to reduce consumer's bills.

Hydrogen transmission

There is uncertainty around how hydrogen transmission networks might be funded (private vs regulated), combined with uncertainty on when transmission pipelines will be needed to connect large clusters. Both hydrogen storage and transmission infrastructure are expected to receive incentives for investment through the Hydrogen Transport and Storage Business

[55] Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report
[56] Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report
[57] Hydrogen UK (2023) Hydrogen UK Supply Chains Report

Models, as noted in the July 2025 Hydrogen Update to Market publication by the UK government. The intention to develop the transport business model as a Regulated Asset Base (RAB) alongside a government support mechanism has removed some of the uncertainty around the potential shape of the market.

Deep dive 2: Enabling infrastructure

Hydrogen transport and storage (T&S) infrastructure will underpin the UK hydrogen sector.[58] While conversion of current natural gas assets for distribution of hydrogen is proposed, none of this infrastructure is used to move or store hydrogen today, and significant amounts of new infrastructure will need to be developed, even with significant repurposing of existing pipelines. Large scale storage assets, such as DGFS and salt caverns, have long lead times, with conversion of existing geological storage facilities for hydrogen taking around 3-5 years, and new build storage taking 5-10 years to construct.[59] Likewise, pipelines can take an estimated 6 - 12 months of pre-construction and around 3 years for construction or repurposing.[60] These timelines could also be impacted by supply chain limitations on, for example, compressors.

Developing, demonstrating and upscaling T&S systems that are safe, can minimise losses, and reduce costs for hydrogen compression and purification will be essential. The existing gas network can provide an opportunity for hydrogen transport and possible storage through line packing. The risks around leaks, embrittlement and contamination are being addressed through R&D across the transmission and distribution networks. More research is needed on how best to bulk store hydrogen in built-up areas such as urban areas or ports, depending on the spatiality of the hydrogen system and end-uses. Interactions between hydrogen and materials used to store and transport it need to be fully understood across the energy system to reduce the risk of environmental or safety impacts. The first SSEP will be a GB-wide plan that will map potential locations, quantities and types of electricity and hydrogen generation and storage infrastructure over time.[61]

Government support mechanisms such as the Net Zero Hydrogen Fund (a £240m capital fund to support early projects), Hydrogen Allocation Rounds (HAR 1 & 2, and upcoming HAR 3 and 4) are recent examples aimed at incentivising the development of the hydrogen industry. In the 2025 Spending Review, the Government confirmed over £500m support for hydrogen infrastructure, which will enable the development of the first regional hydrogen transport and storage network. Hydrogen Transport and Storage Business Models are also being developed to incentive investment in both hydrogen transport infrastructure and geological hydrogen storage, with the first allocation rounds expected to open in the first half of 2026.[62]

[58] Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report
[59] Department for Energy Security and Net Zero (2023) Hydrogen Transport and Storage Networks Pathway
[60] Department for Energy Security and Net Zero (2023) Hydrogen Transport and Storage Networks Pathway
[61] NESO (Accessed: 2025) Strategic Spatial Energy Planning (SSEP)
[62] Department for Energy Security and Net Zero (2025) Hydrogen update to the market: July 2025

For **autothermal reforming**, methane infrastructure is very well-developed, but distribution of hydrogen to end-users will effectively need to be developed from scratch, as will the supporting CCUS infrastructure. While main feedstock infrastructure (i.e. natural gas) is very well developed, the means of distribution and potential off takers for the hydrogen produced are not likely to be in place until at least the late 2020s.

Electrolysis will face key issues in scaling up production capacity of systems and in securing connections to an already constrained transmission and/or distribution grids. Electrolyser manufacturers are rapidly scaling up their production both in the UK and abroad, though operational manufacturing capacity is likely to lag demand for some years. Additionally, while the UK electricity network infrastructure is well-developed and receiving high levels of investment, connection times are long and the scale of potential electrical demand from electrolysers is high enough to warrant major expansion in the rate of renewables deployment. There will be a significant need for coordination between production, network and storage projects and actors to ensure a cohesive and aligned pathway to scaling up the UK's hydrogen sector. [63]

Deep dive 3: Regulatory environment

The UK's hydrogen sector will be influenced by the political and regulatory environment.[64] Consistent and supportive policies which offer long-term certainty will be critical to help the hydrogen sector develop. [65] Conversely, delays, regulatory uncertainties or frameworks which are not fit for purpose could hinder investment and risk the a country's ability to compete in the global hydrogen market.

The regulatory framework for the hydrogen sector will need further amendments. For example, a 2023 DESNZ consultation response[66] highlighted that under the Gas Act 1986, hydrogen is classified as a "gas", meaning that existing regulations that apply to the transportation, shipping, supply and storage of natural gas may also apply to hydrogen. However, these provisions may not be well-suited to the emergence of hydrogen transport and/or storage infrastructure, due to differences in the technology and scale.[71] Consequently, DESNZ recently held a consultation on regulatory frameworks[72] seeking views on the economic regulatory framework for 100% hydrogen pipeline networks, established under the Gas Act 1986. This consultation sets out proposed changes to this regulatory framework to best suit the needs of hydrogen networks; the government response is expected be published in due course.

The UK government has taken steps to strengthen the regulatory framework for the hydrogen industry. For instance, following consultation, in September 2023 DESNZ made regulations to

[63] Hydrogen UK (2023) Hydrogen UK Supply Chains Report
[64] The Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report
[65] IEA (2024) Global Hydrogen Review
[66] Department for Energy Security and Net Zero (2023) Hydrogen transport and storage infrastructure: minded to positions

extend the relevant oil and gas responsibilities for the Offshore Petroleum Regulator for Environment and Decommissioning and the North Sea Transition Authority to also cover offshore hydrogen pipelines and storage infrastructure. Regulatory bodies such as the BSI and the HSE are engaged in developing standards across the hydrogen sector[67]. Further work between the UK Government, regulators, and devolved administrations is in progress to ensure that non-economic regulatory frameworks are fit-for-purpose.

Regulatory needs vary at each stage of the hydrogen value chain:

- **Production**: Sufficient assurance on emissions from CCS enabled technologies such as ATRs is required to ensure projects are consistent with Net Zero targets and any support mechanism requiring verification of hydrogen emissions. Uncertainties relating to CCS capture rates and upstream methane emissions accounting could therefore pose compliance risks.
- **Storage:** there are established regulations for operating salt caverns used for storage by industry (to date supporting grey hydrogen storage). However, salt caverns in the future will need to be operated in more complex circumstances (high and faster rates of cycling), to support the energy networks (regulated assets) for grid balancing and seasonal storage, as well as specific chemical plants (private assets), requiring further regulatory development. New regulatory frameworks would be needed for depleted gas field storage which have not been used for hydrogen storage to date and present several technical challenges for utilisation. A revenue cap and floor mechanism has been recommended by government[68], providing further certainty on regulatory direction.
- **Transport:** National Gas Transmission and other gas distributors are pushing to better define regulations, for instance on gas blend definitions and risk assessment requirements, and more work needs to be done to set standards on purity, pipe specification and safety before the regulatory environment is sufficiently in place.[69] International transport and trade will similarly require clear standards and agreements with destination or source countries.
- **Usage**: Whilst existing regulations for the use of hydrogen in industry are mature, new regulations would be needed for non-industrial applications. For instance, additional regulation and standards to ensure that the technology operates safely and to the quality required. Developing regulation and standards around hydrogen use in non-industrial settings (e.g. small-scale storage, maritime and aviation usage), and for innovative electrolyser technologies, should be a priority.
- **Compliance**: The necessary infrastructure, personnel and skills for regulators, accreditation and quality assurance will need to be established to ensure compliance and build confidence on different hydrogen supply chain elements and ensure ease of integration in the UK energy system.

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[67] BSI (2025) PAS 4445:2025 | 31 Mar 2025 | BSI Knowledge
[68] Department for Energy Security and Net Zero (2025)
[69] National Gas Transmission (2025) Hydrogen Acceptability Summary Report.pdf

- **Planning:** The UK has robust land use regulation which has often meant that planning takes long periods of time and can be slow and prone to delays. This risks disincentivising or delaying project development. Such delays may stall the development of hydrogen production, transport and storage infrastructure in the coming years and may lead to sub-optimal location of infrastructure. Delays may also render some projects unviable as continued technological innovation can lead to a need to re-engineer delayed projects. The Planning and Infrastructure Bill is aiming to ensure that key clean energy projects are built as quickly as possible, however, detailed implications for hydrogen infrastructure are not known at the time of writing.

Deep dive 4: Supply chain

Given that the hydrogen sector is still nascent in the UK, there is not yet a sufficiently established cohesive supply chain to enable the deployment required to achieve government and industry targets, and it is challenging to define the future hydrogen supply chain needs.[70] There are a number of hydrogen-specific and more general components with supply chain gaps and long lead times at scale, including: electrolyser stacks, compressors, high voltage transformers, reformer packages, large storage vessels, metering equipment and industrial equipment such as boilers and burners.[70, 71] For items such as compressors, high voltage transformers and storage vessels, the increase in demand across different applications is creating a backlog.[71] For more hydrogen-specific elements, such as reformer packages and electrolysers, lead times are being influenced by difficulties in manufacturers scaling up and large orders booking out capacity well in advance.[71]

Hydrogen UK also notes concerns around concentrated supply chains, particularly in areas such as reformer packages, air separation units and gas turbines, where the industry is reliant on a handful of suppliers.[71] The hydrogen sector also faces competition from other sectors who draw on similar supply chains, including SAF, CCUS, chemicals and renewables. Delayed build out by these suppliers will have significant implications for meeting the hydrogen ambitions of government and industry.[71]

However, these supply chain challenges and gaps present significant opportunities for the UK to build on existing capabilities and create economic value and jobs through the development of a domestic hydrogen supply chain. The UK has significant existing strengths, including availability of large-scale hydrogen storage capacity, a broad range of suppliers, internationally recognised UK capability in electrolysis technologies, and government and industry commitment to expanding the hydrogen sector.[70] A 2022 assessment identified key economic opportunities for the UK in electrolysis package manufacture, high pressure hydrogen compressor package manufacture for cavern storage, green hydrogen manufacture, including electrical equipment and materials manufacture, and civil and structural materials for cavern

[70] Department for Business, Energy and Industrial Strategy (2022) Supply Chains to Support a Hydrogen Economy
[71] Hydrogen UK (2023) Anchoring UK hydrogen supply chains: setting out an industry vision

storage.[70] Strong leadership and clear pathways will support certainty and confidence in the hydrogen sector, help overcome key supply chain challenges, and realise significant economic and Net Zero opportunities in the application of clean hydrogen. Some recent public support measures directly target supply chain development: The recent £1bn Clean Energy Supply Chain fund includes hydrogen among seven sectors targeted for investment, while the July Hydrogen Update to Market noted that an expansion to the Contracts for Difference Clean Industry Bonus is being considered to target hydrogen supply chains.

Deep dive 5: Skills and training

The development of a skilled workforce is critical to the advancement of hydrogen technologies, underpinning R&D, product development, manufacture, safe operation, testing, and eventual decommissioning. The lack of a skilled workforce in construction and technical roles has already been identified as a key challenge to hydrogen project development, and persisting shortages will hold back research and the development of the hydrogen sector.[72] There are significant challenges in addressing this gap, as identified by the Hydrogen Skills Alliance (HSA)[73], including uncertainty around workforce demand, sector and technology awareness and attractiveness, lack of diversity within the industry, unknown supply chain skills requirements given the nascent technology, lack of regulator capacity and expertise, and lack of capacity in the provider networks.

However, the UK has historically strong expertise in the oil and gas sector, as well as engineering, procurement, and construction (EPC) businesses, which may prove highly transferable to the hydrogen sector. As with many engineering industries, the current hydrogen industry has an aging workforce and faces competition for new talent from many other new and developing industries. The expansion of the hydrogen sector is expected to create significant employment opportunities, but uncertainty remains, and there needs to be a matching of upskilling opportunities with workforce demand. Further regulatory clarity will help inform the future skills needed to grow and operate hydrogen technologies but bridging the existing skills gap already requires targeted educational and training programs.[74] Collaboration between industry and academia can enable reskilling and upskilling both for industrial and academic workforces, to cover both short-term market-ready technologies and to develop emerging long-term technologies.[74] Further and continuous assessments of the future hydrogen workforce requirements can address these gaps and support the development of a highly skilled workforce for the scale-up of the UK's hydrogen sector.

[72] Hydrogen UK (2023) Anchoring UK hydrogen supply chains: setting out an industry vision
[73] Hydrogen Skills Alliance (2024) Driving Development of Hydrogen Skills in the UK
[74] The Royal Society (2024) Towards a green hydrogen roadmap for the UK | A summary report

Business opportunities in Hydrogen technologies

Introduction

The purpose of this section is to explore the potential scale of business opportunities for the UK associated with the national and global development of the hydrogen technologies examined as part of the EINAs (as elsewhere in this report defined as electrolysis, autothermal reforming, hydrogen storage (DGFS & salt caverns), hydrogen transmission and transport and hydrogen turbine (OCGT & CCGT). Innovation will be a key driver in supporting the growth of this sector in the UK and realising these business opportunities, and therefore an important element to capture as part of this innovation assessment.

The section summarises the key findings from the development of a series of 'economic calculators'. These calculators integrate projections of domestic deployment of the five technologies, derived from scenario-based systems modelling (see system benefits from innovation in hydrogen section), with assessments of the UK's potential market share in overseas markets, informed by global modelling and literature reviews. They combine this understanding of potential deployment with assumptions around the cost structure and employment intensity of the different activities required for the manufacturing, deployment, operation and decommissioning of each technology to generate an understanding of the potential business opportunities in terms of:

- **Gross Value Added (GVA)** – a measure of the value generated by the production of goods and services. GVA can be thought of as broadly equivalent to the contribution of that sector/activity to Gross Domestic Product.
- **Employment** – Employment is measured in terms of jobs and includes both direct employment – the jobs associated with the construction, operation and decommissioning of the assets – and indirect employment – the jobs associated with the production of the goods and services needed by the workers with direct jobs i.e. jobs associated with the supply chain needed to construct, operate and decommission the assets.

All results are illustrative of potential business opportunities of technological innovation. They are generated using a particular set of technologies, hypothetical deployment scenarios, modelling outputs and other assumptions to help inform UK Government decision making**.**

The modelling outputs on which the results are based include modelled expectations for deployment in both 2020 and 2025. While efforts have been taken to calibrate these modelled outcomes with existing deployment data, some inconsistencies will remain. Looking forward, results do not reflect UK government targets/ambitions regarding neither deployment of these technologies nor the business opportunities that might be realised. **It is important to note that**

this analysis is independent of the latest UK Government Hydrogen Strategy and was commissioned two years prior.

It is also important to stress that the results are specific to the particular technologies of focus for the report, rather than the GVA and employment for the wider sector within which these technologies may often be categorised. As such, care should be taken when comparing the figures presented below with estimations which cover the entire hydrogen sector, and use different scenarios and models.

All monetary values in this section refer to 2022 GBP unless otherwise specified. The methodologies for the calculators, along with key caveats and assumptions, is available in the EINAs Technical Methodology report.

Hydrogen market landscape

UK market position

As discussed earlier in this report, the UK has a significant opportunity to produce, store and use hydrogen cost-effectively. Clean hydrogen production does not yet exist at scale in the UK, but a number of government initiatives aim to increase the volume of clean hydrogen produced. There is a growing pipeline of over 250 projects across a range of low carbon hydrogen pathways, with the first Electrolytic Allocation Round offering contracts totalling 125 MW of capacity across 11 projects.[75]

The UK doesn't have a natural cost advantage for the production of green hydrogen with sunnier regions such as the Middle East, South America and Australia and windier regions such as Northern China benefiting from greater renewable energy potential.[76] Despite this, the substantial trade costs associated with the conversion to ammonia, transport and reconversion to hydrogen, are expected to offset higher production costs, particularly in the nearer term, creating an opportunity for domestic producers to be competitive in the domestic market. Blue hydrogen producers face a similar situation with cheaper production possible elsewhere, particularly in the Middle East but the same trade hurdles exist. By contrast, the UK benefits from a strong enabling environment for hydrogen transport and storage, with a large number of suitable storage sites and existing technical expertise in the oil and gas sector. This can support UK-based companies in both domestic and export markets.

Global hydrogen market

There is expected to be a rapidly growing global market for hydrogen production, storage and transport technologies.

- **Electrolysis** – DNV (2022) forecasts that the global deployment of electrolyser capacity could grow to 3,075 GW by 2050 in a scenario where hydrogen accounts for 5% of total

[75] DESNZ (2024) Hydrogen net zero investment roadmap: leading the way to net zero
[76] IEA (2024) Global Hydrogen Review

energy demand in 2050, the same percentage predicted in IEA (2023)'s Net Zero 2050 scenario.[77]

- **Autothermal reforming (AR) –** DNV (2023) forecasts that hydrogen production through fossil fuels + CCS will reach 123 MT of H2 by 2050 in a Net Zero scenario. DNV (2022) forecasts that, in 2050, approximately 86% of hydrogen production through fossil fuels + CCS will be methane reforming which equates to 105 MT of H2.

- **Hydrogen storage (DGFS & Salt caverns) –** IEA (2023) forecasts that, by 2050, 1,200 TWh of underground hydrogen storage capacity will be required under a Net Zero 2050 scenario.[78] Hydrogen UK (2022) estimates that, of the theoretical underground hydrogen storage capacity in the UK, approximately 85% is in the form of salt caverns and depleted gas fields.[79] In absence of better data, it is assumed that this distribution can also be applied to global underground hydrogen storage. The result is an estimate of 1,016 TWh of DGFS and salt cavern capacity globally by 2050.

- **Hydrogen transmission and transport –** It was not possible to identify reliable forecasts of the global market for hydrogen transmission and transport and so the export market for this technology is not included in the analysis.

- **Hydrogen turbines (OCGT & CCGT) –** IEA (2023) forecasts that the global deployment of hydrogen and ammonia turbine capacity could grow to 427 GW by 2050 in a Net Zero 2050 scenario.[80]

Building on this discussion, the quantitative analysis below assumes that the UK can service the majority of its domestic market in these technologies, while also accessing a small share of the global market. The analysis is based on previous modelling conducted by Ricardo for DESNZ using GEM-E3 modelling and Hydrogen UK's UK Hydrogen Supply Chain Strategic Assessment.[81] Ricardo estimate that the UK captures approximately 43% of the domestic market associated with hydrogen production, storage and transport technologies in 2025, rising to 87% by 2050. They estimate a current global market share of just 0.2% and forecast this could decline to 0.1% by 2050. All operations and maintenance activities are assumed to be undertaken by domestic firms.

The sector level estimates for the UK's share of its domestic market are combined with Hydrogen UK's assessment of the likelihood that the UK will be able to attract manufacturing activity for different hydrogen technologies.[82] For technologies where Hydrogen UK evaluate that it is less likely that the UK will be able to develop a significant manufacturing base, the

[77] DNV (2022) Hydrogen Forecast to 2050
[78] IEA (2023) Net Zero Roadmap: A Global pathway to keep the 1.5ºC goal in reach
[79] Hydrogen UK (2022) Hydrogen Storage: Delivering on the UK's energy needs
[80] IEA (2023) Net Zero Roadmap: A Global pathway to keep the 1.5ºC goal in reach
[81] Ricardo (2025) Research to quantify the economic opportunities for the UK as a result of the global energy transition
[82] The Ricardo estimates of domestic market share were adjusted for this analysis as they were deemed to be unrealistically optimistic by sectoral experts and were not fully consistent with the Hydrogen UK hydrogen value chain assessment. The Hydrogen UK assessment found that, in many areas of the hydrogen value chain, the UK had limited manufacturing capacity either in place or in the pipeline and faced significant cost competition from abroad.

Ricardo estimates are discounted significantly whereas, for technologies where Hydrogen UK determine that the picture is more optimistic, the Ricardo estimates are discounted less significantly or not at all. The result of these adjustments are estimates for UK firms' market share of the domestic hydrogen value chain which range between 43% to 64% in 2025 and grow to between 52% to 80% by 2050 depending on the technology.

Hydrogen business opportunity analysis

Comparisons made in this section at the sectoral level only include four of the five hydrogen technologies: electrolysis, autothermal reforming, hydrogen transmission/transportation and hydrogen turbines (OCGT & CCGT). The business opportunities analysis of hydrogen storage (DGFS & salt caverns) is discussed separately in a sub-section at the end of the business opportunities section. The rationale for this approach is that the highRES energy systems modelling for salt cavern hydrogen storage — which, together with depleted gas field storage (DGFS), forms the hydrogen storage technology grouping — was only conducted for the Minimally Constrained and High Diversification scenarios. Consequently, including this technology in aggregated comparisons between scenarios would reduce the value of such comparisons, as it would introduce inconsistencies between the two scenarios where salt caverns are modelled and the High Hydrogen scenario, where it is not.

Gross Value Added (GVA)

All GVA and Jobs analysis has been produced on the basis of technologies assessed in the scope of the EINAs. Jobs and GVA estimates presented reflect only these technologies and should not be interpreted as whole sector jobs and GVA estimates.

The economic calculators suggest that, assuming a 'medium' level of innovation, GVA in the hydrogen sector will grow strongly across all modelled scenarios. Figure 14 shows that GVA in real terms grows to between £1.26 and £2.81bn in 2050. As expected, the High Hydrogen scenario demonstrates a substantially higher level of GVA compared to the other scenarios by 2050 as a result of the increased domestic deployment of autothermal reforming, hydrogen transmission/transport and hydrogen turbines anticipated in this scenario. By 2050, there is 47% more GVA in the High Hydrogen scenario than the High Diversification scenario and 123% more GVA than in the Minimally Constrained scenario. The High Diversification scenario keeps pace with the High Hydrogen scenario until 2040 as a result of a large early build up of electrolysis deployment in this scenario relative to the other two scenarios.

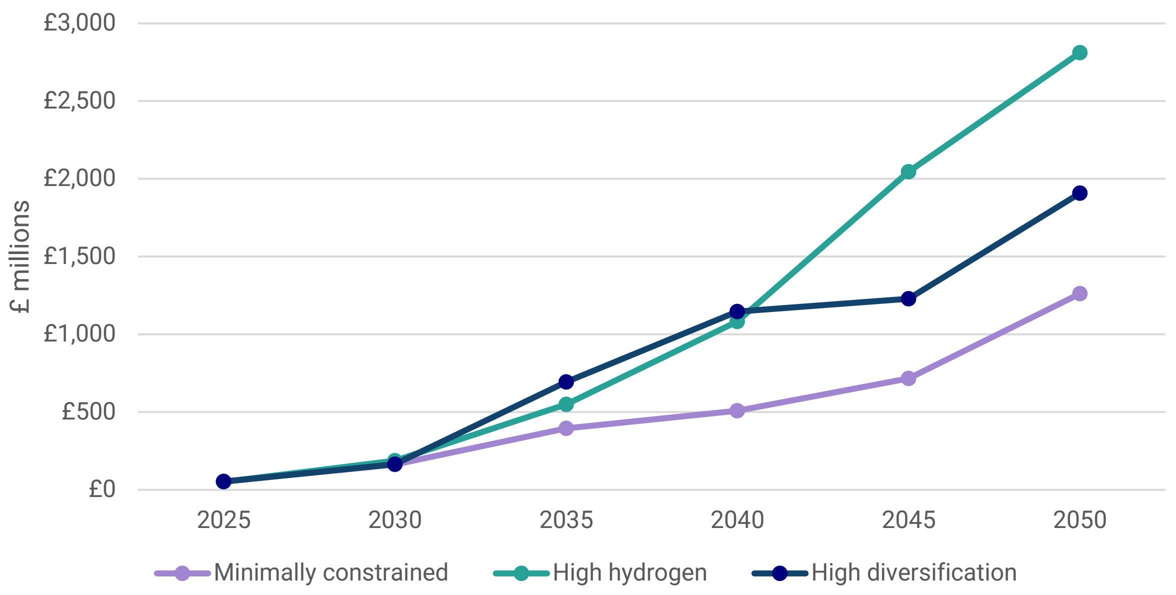

Figure 14: GVA by scenario for electrolysis, autothermal reforming, hydrogen transmission/transportation and hydrogen turbines (OCGT & CCGT)

Note: The figure reports outputs associated with a medium level of innovation.

As is shown in Figure 15, GVA in the sector is projected to become almost exclusively dependent on the domestic market after 2030 as a result of the anticipated difficulties that UK-based firms will have in accessing export markets. The domestic market could generate between £0.3 and £0.6 billion in GVA in 2035 (82-90% of the total, depending on the scenario), potentially rising to between £1.2 and £2.8 billion (95-98% of the total, depending on the scenario) by 2050. Exports are expected to be relatively stable between 2035 and 2050, generating around £0.1 billion in GVA per year as the global market grows but the UK's share of export markets is expected to decline. Electrolysis represents the most promising export opportunity, contributing 85% of export driven GVA by 2050. The rate of domestic capacity additions is generally increasing over the time period in the scenarios modelled, driving increased economic activity.

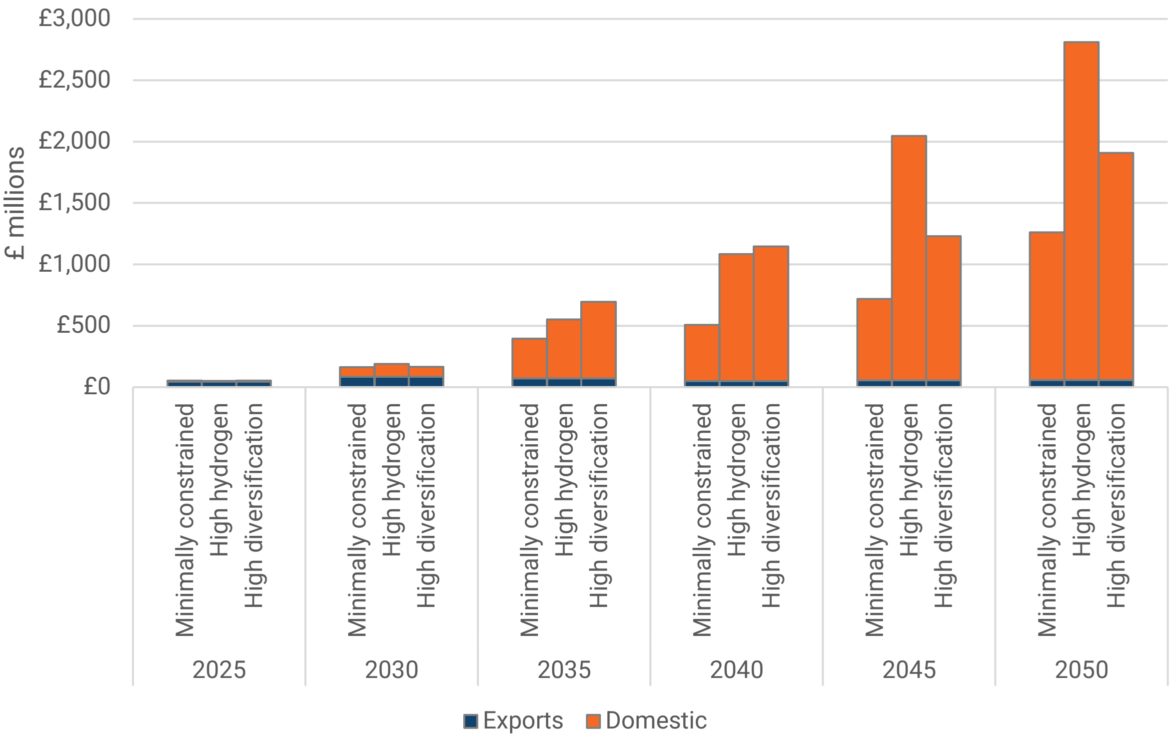

Figure 15: GVA by scenario by market for electrolysis, autothermal reforming, hydrogen transmission/transportation and hydrogen turbines (OCGT & CCGT)

Note: The figure reports outputs associated with a medium level of innovation.

Figure 16 shows that for all modelled scenarios, there is relatively small difference in GVA between the different innovation levels until 2035 but that this variation grows slightly between 2035 and 2050. In 2035, GVA varies by between 9% and 28% when comparing the innovation level where GVA is highest to that where it is the lowest. This range grows to between 21% and 34% by 2050.

In all modelled scenarios, the low innovation level is linked with the highest level of GVA from 2035 onwards. The reason for the counterintuitive result is due to the relationship between costs and economic activity. All else being equal, goods and services that have higher costs, provided they continue to be purchased, are associated with the ascribed value of those goods and services being higher i.e. that the activity leading to those goods and services makes a higher GVA contribution. The lower costs in the medium and high innovation levels compared to the low innovation level do not lead to a sufficiently large increase in deployment to offset this effect. In the modelled scenarios, UK TIMES only uses hydrogen up to the level necessary to meet energy needs that are not met through electrification or other alternatives, and in the case of the High Hydrogen scenario up to the demand constraint that is set in the model. With little to no sensitivity to cost differences within the modelled innovation levels, hydrogen production/use remains the same at different price points, leading to a higher GVA at higher prices (i.e. low innovation).

The potential impact that higher or lower costs may have on the output, and hence GVA contribution, of other sectors in the economy is not captured in this analysis.

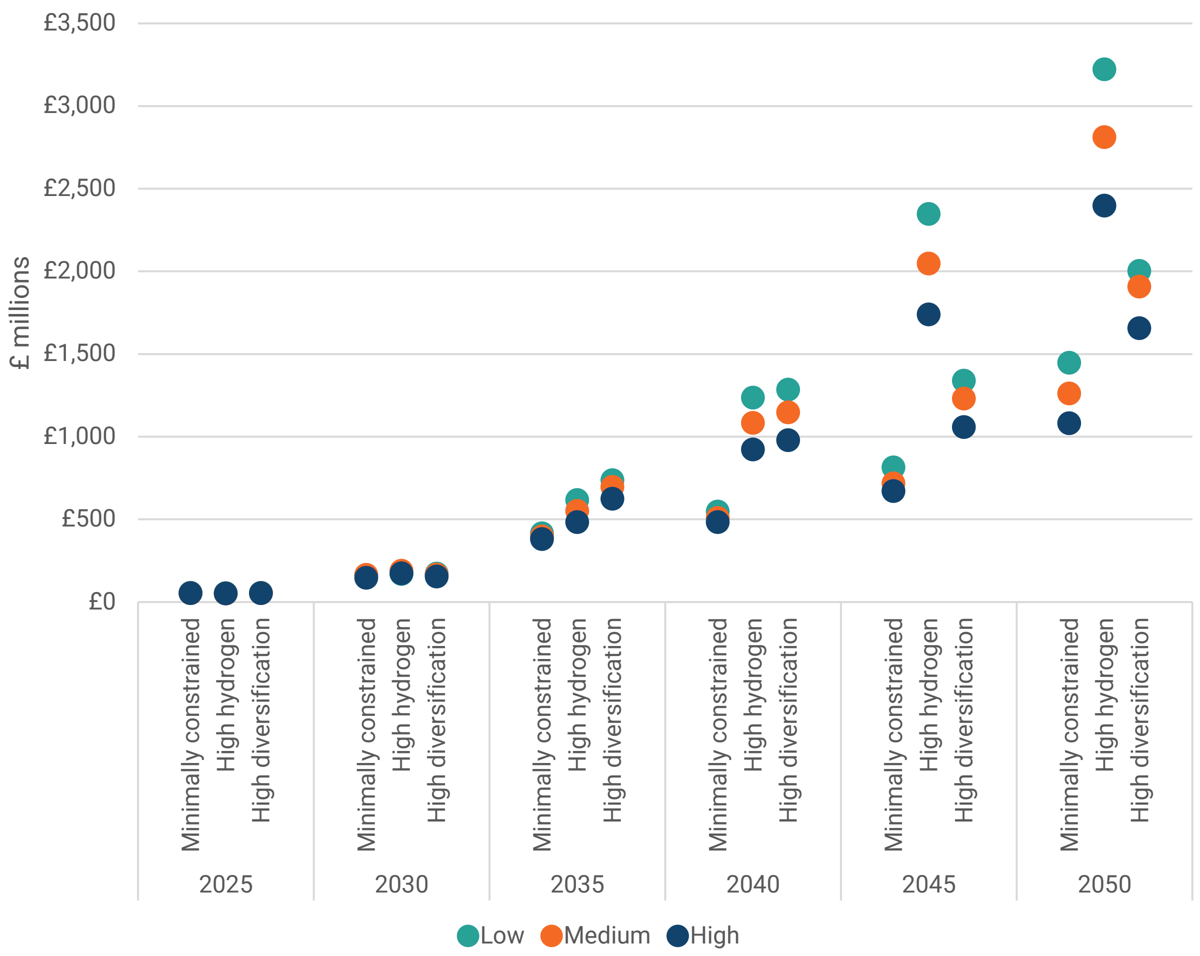

Figure 16: GVA by scenario for low, medium and high innovation levels for electrolysis, autothermal reforming, hydrogen transmission/transportation and hydrogen turbines (OCGT & CCGT)

Figure 17 shows that for each modelled scenario, for the 'medium' innovation level, different technologies make the greatest contribution to GVA, but, within each scenario, the relative importance of each technology is consistent over time. For the Minimally Constrained scenario, the two hydrogen production technologies combine to contribute around 91% of GVA in both 2040 and 2050 with almost all of the remaining 9% accounted for by hydrogen transmission/transport. Hydrogen turbine deployment is negligible in this scenario. In the High Hydrogen scenario, the distribution of GVA between hydrogen production and hydrogen transmission/transport technologies is largely consistent with that in the Minimally Constrained scenario however, there is also a large contribution of GVA from hydrogen turbines which is not evident in Minimally Constrained scenario (~20% of total GVA). The High Diversification scenario differs again. In this scenario, there is almost no GVA contribution from autothermal reforming, given the lower energy import dependency of this scenario, with electrolysis making a much more significant contribution.

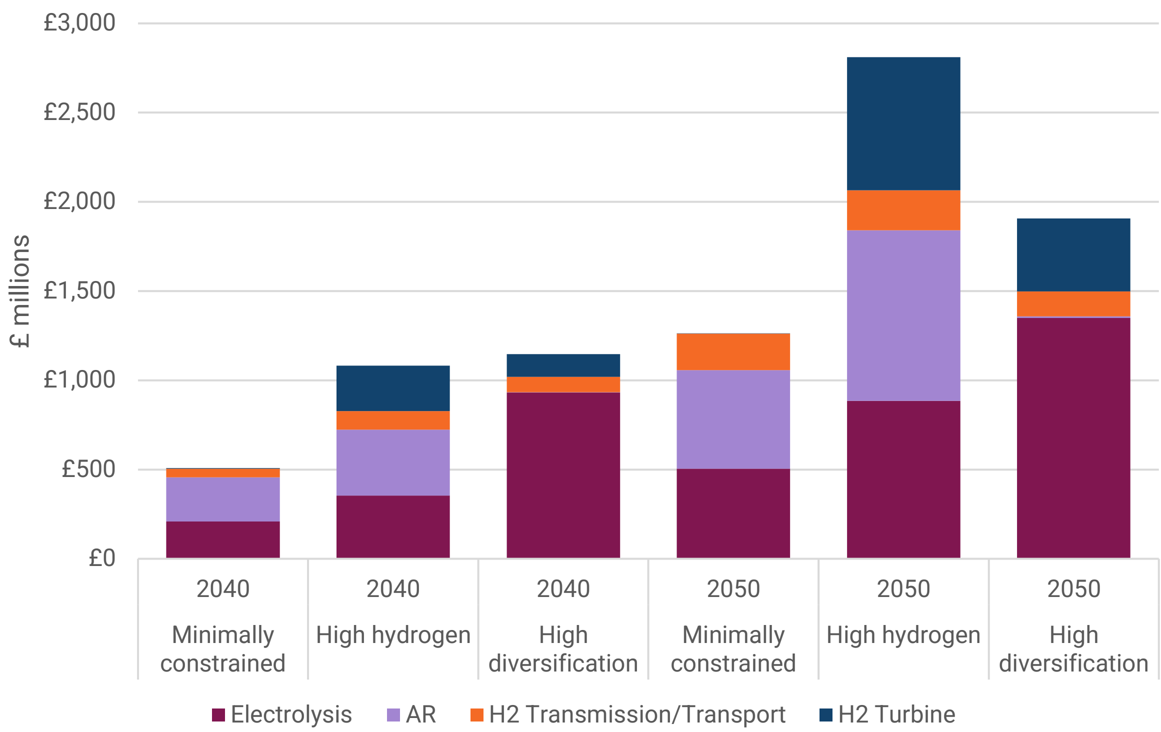

Figure 17: GVA by scenario by technology for electrolysis, autothermal reforming, hydrogen transmission/transportation and hydrogen turbines (OCGT & CCGT)

Note: The figure reports outputs associated with a medium level of innovation.

Direct and indirect jobs

Supported employment (direct and indirect jobs[83]) follows the rapid growth in GVA. Across the scenarios, supported employment rises to between 24,000 and 54,000 jobs in 2050. 55% of these jobs are direct jobs in early years, rising to approximately 60% by 2050, as industry activity shifts from construction to operation and maintenance (see also Figure 18 below), the latter having supply chain activities which, for these technologies, are less employment intensive. The ratio of direct to indirect jobs is consistent between scenarios. In line with the GVA results, the variation in the expected number of supported jobs between scenarios grows over time. By 2050, there are over 40% more total jobs supported in the High Hydrogen scenario than in the High Diversification scenario and 128% more total jobs supported than in the Minimally Constrained scenario; this amounts to 16,000 and 31,000 extra jobs respectively.

[83] A direct job is employment associated with the stated activity. An indirect job is a job that exists to produce the goods and services needed by the workers with direct jobs i.e. those jobs associated with supply chain activities. The estimate of indirect jobs is based on the application of Type 1 multipliers to the different cost categories (activities) within the sector.

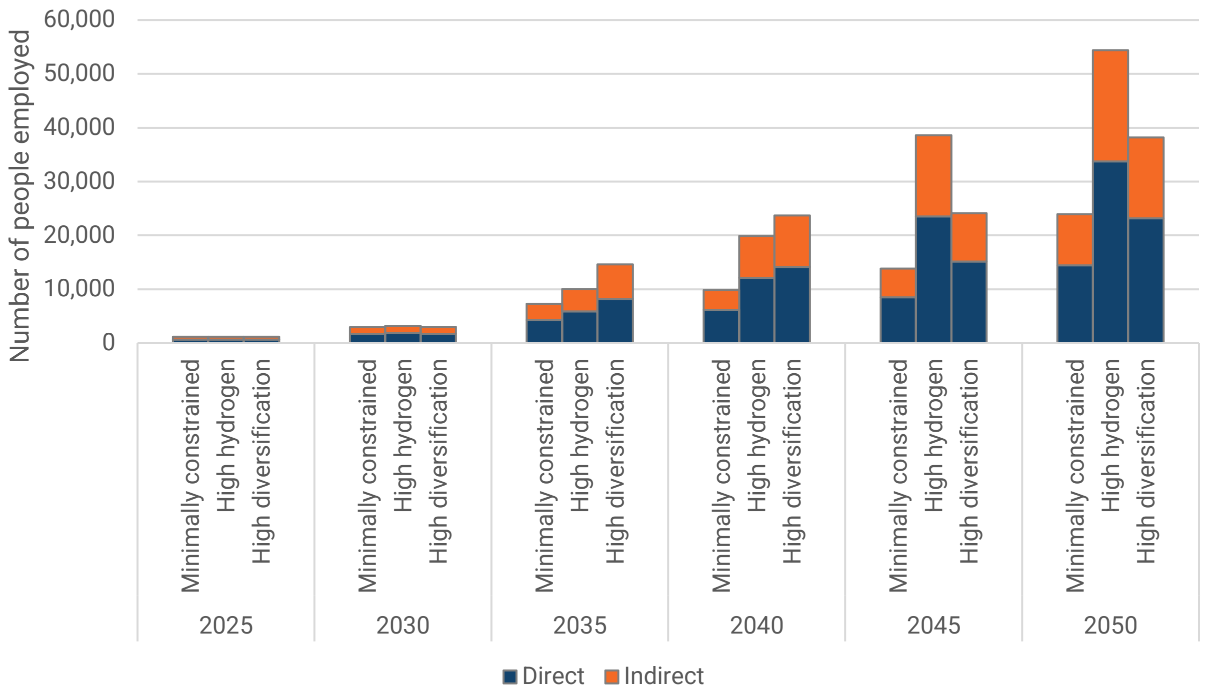

Figure 18: Total jobs supported by scenario by direct vs indirect for electrolysis, autothermal reforming, hydrogen transmission/transportation and hydrogen turbines (OCGT & CCGT)

Note: The figure reports outputs associated with a medium level of innovation.

Figure 19 and Figure 20 show the breakdown of employment by domestic/export market and across different cost categories i.e. construction, operation & maintenance and decommissioning, respectively.

As is the case for GVA, employment in the sector is projected to become increasingly reliant on the domestic market. The domestic market could support between approximately 6,000 and 13,000 jobs in 2035 (81-90% of the total, depending on the scenario), potentially rising to between 23,000 and 53,000 by 2050 (95-98% of the total, depending on the scenario). The drivers of these trends are the same as those for GVA, a growing global market of which the UK is assumed to capture a diminishing share and a rapidly growing domestic market of which UK firms are expected to capture an increasing share.

Supported jobs by cost category follow the expected trend with jobs supported by construction activity being relatively more important in early years but jobs supported by operation and maintenance (O&M) activity becoming much more important by 2050 (between 55% and 76% of the total). There is no decommissioning activity during this period as no assets are expected to reach the end of their useful life before 2050. The variation between the scenarios is driven by the deployment patterns. In the High Hydrogen scenario, there is a quicker build-up of assets than in the other two scenarios, meaning that OPEX jobs become more important more quickly in that scenario.

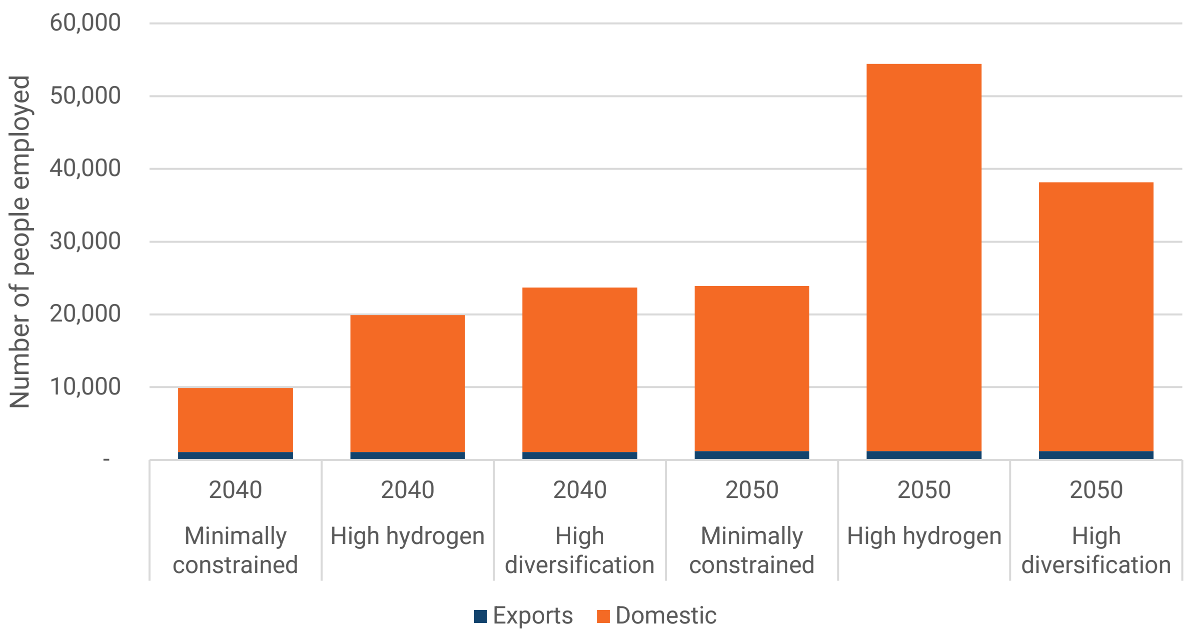

Figure 19: Total jobs supported (direct + indirect) by scenario by market for electrolysis, autothermal reforming, hydrogen transmission/transportation and hydrogen turbines (OCGT & CCGT)

Note: The figure reports outputs associated with a medium level of innovation.

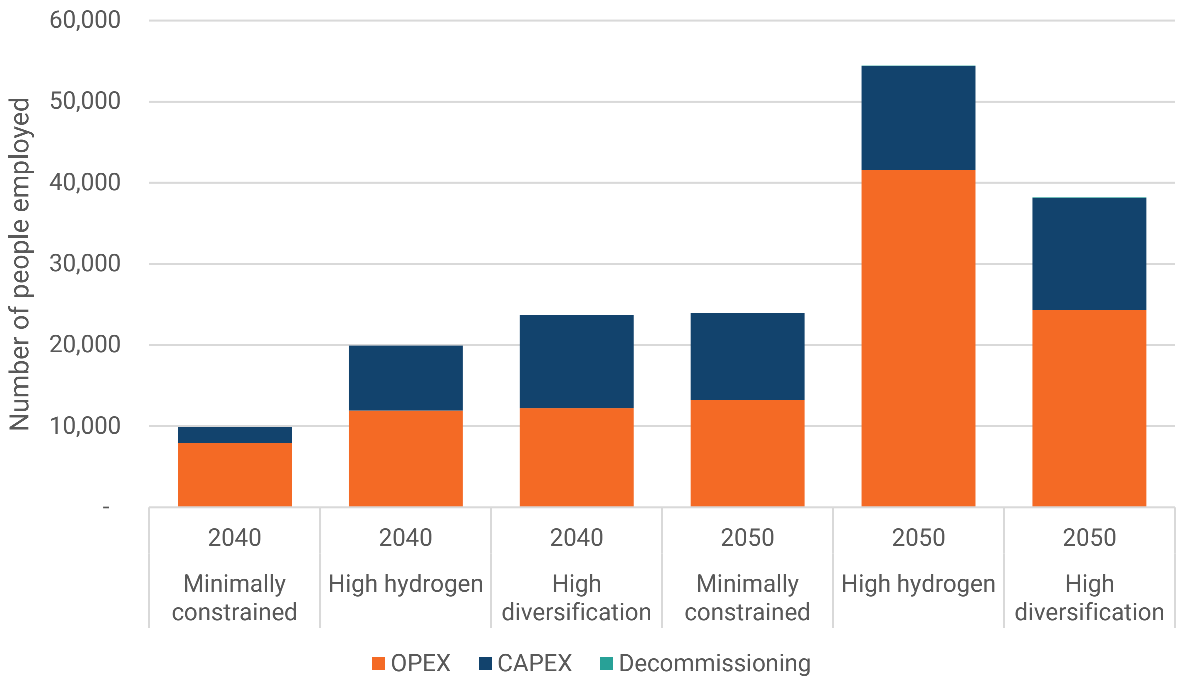

Figure 20: Total jobs supported (direct + indirect) by scenario by cost category

Note: The figure reports outputs associated with a medium level of innovation.

Finally, Figure 21 shows that, in all modelled scenarios, most of the direct jobs supported by the sector in 2050 are expected to be in high-skilled professional occupations. The occupations that account for the largest number of jobs supported are professionals in science, research, engineering and technology (between 4,400 and 12,000 direct jobs, 31-36% of the total), followed by other professional occupations (between 2,300 and 5,300 direct jobs, 16-18% of the total) and managers, directors and senior officials (between 2,200 and 4,600 direct jobs, 14-15% of the total). The sector is also expected to support around 1,500 – 3,100 jobs in skilled trade jobs by this date.[84]

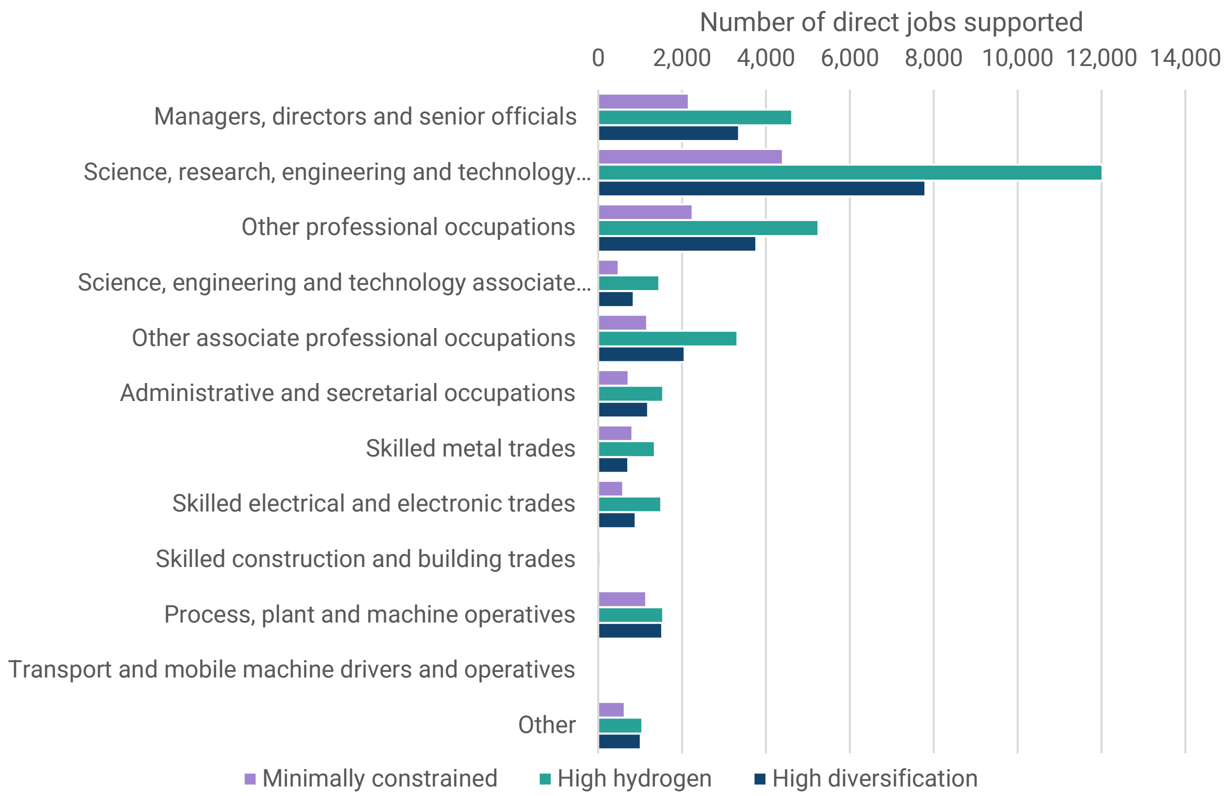

Figure 21: Direct jobs supported by scenario by occupation type in 2050 for electrolysis, autothermal reforming, hydrogen transmission/transportation and hydrogen turbines (OCGT & CCGT)

Note: The figure reports outputs associated with a medium level of innovation. For the purposes of this analysis, the 412 4-digit SOC codes have been aggregated to 15 SOC groupings. See the EINAs Technical Methodology report for more details on this aggregation. In Figure 21 the heading 'other' covers the following 4 SOC groupings: elementary occupations, other skilled trade occupations, sales and customer service occupations and caring, leisure and other service occupations.

[84] Note that the zero jobs reported for transport and mobile machine drivers and operatives and skilled construction and building trades is the result of data gaps in the ONS data on the distribution of jobs by SOC code for each SIC code. The true value is unlikely to be zero but, in cases where the numbers are small, the ONS determines that the value for a particular SOC code by SIC code combination is too small to be reliable and so it is excluded. This is the case for a number of the SIC codes assigned to components of the offshore renewable technologies. To account for this missing data, the calculators assign a zero when really it will be a small non-zero figure. More generally, the analysis assumes that the same pattern of occupations associated with the construction, operation and maintenance of these technologies persists in the future.

Hydrogen storage (DGFS & salt caverns)

The UK TIMES analysis was supplemented by the HighRES model to better understand implications from long term hydrogen storage. As is displayed in Figure 22, long term hydrogen storage could make a GVA contribution to the UK economy of between £90 and £150 million by 2050 depending on the scenario and level of innovation. Hydrogen storage's estimated GVA contribution would equate to an additional 5-7% in sectoral GVA in both the Minimally Constrained and High Diversification scenarios. This uplift is consistent across the different innovation levels. In both scenarios modelled, there is rapid growth in the technology's GVA contribution from a very low base with an estimated CAGR of 16-24% between 2025 and 2050.

As is the case for the other hydrogen technologies, the low innovation level is associated with the highest level of GVA.

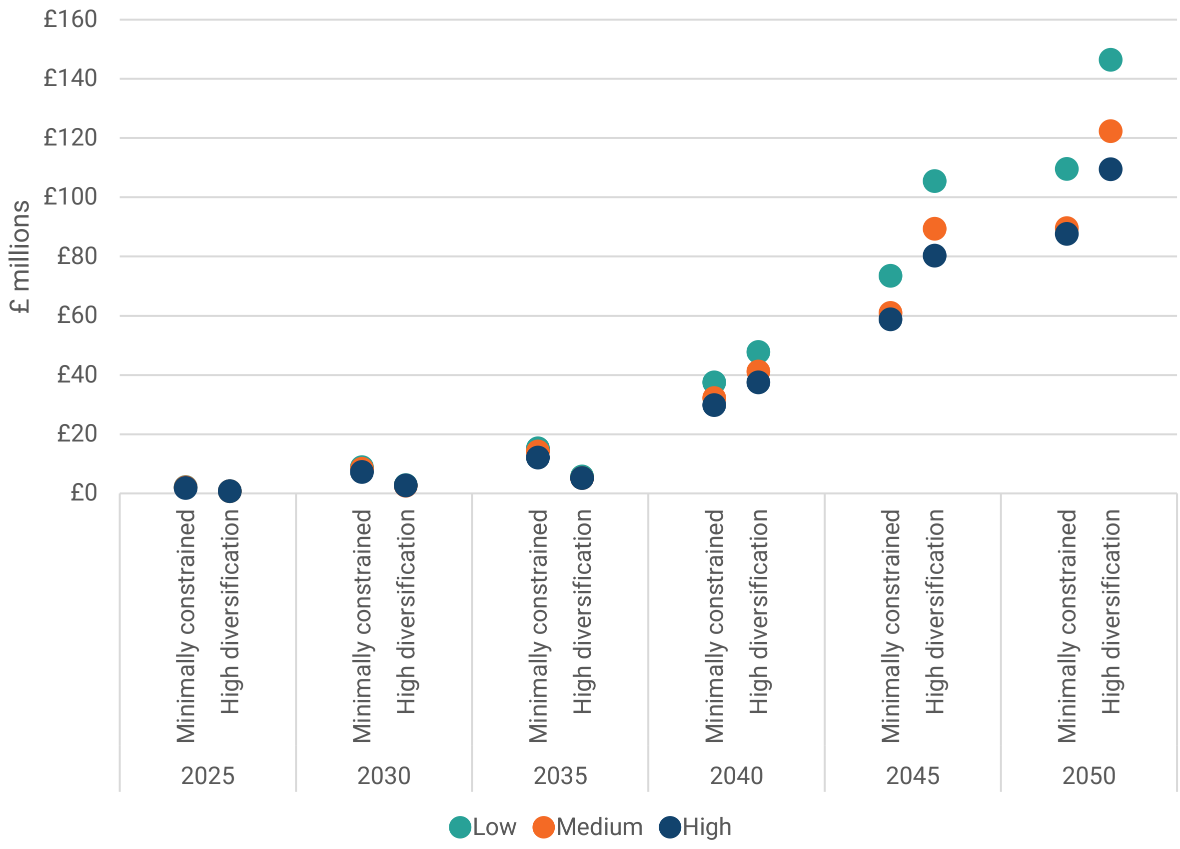

Figure 22: GVA by scenario by innovation level for hydrogen storage technologies

The growth in jobs follows the same trajectory as GVA. As set out in Figure 23, Jobs supported grow to between 1,800 and 2,400 by 2050. The domestic market supports almost all of the jobs. There are expected to be just a handful of jobs supported by export activity across the period. This low level of export-driven employment results from assumptions that the global market for underground hydrogen storage will not be as large as other segments of the hydrogen sector by 2050 and that the UK will face challenges in capturing a large segment of international hydrogen value chains.

The ratio of direct to indirect jobs and the shift from jobs supported by CAPEX activities to jobs supported by OPEX activities later in the period follow the same pattern expected for the other hydrogen technologies examined. Likewise, hydrogen storage largely supports high skilled science, research, engineering and technology occupations.

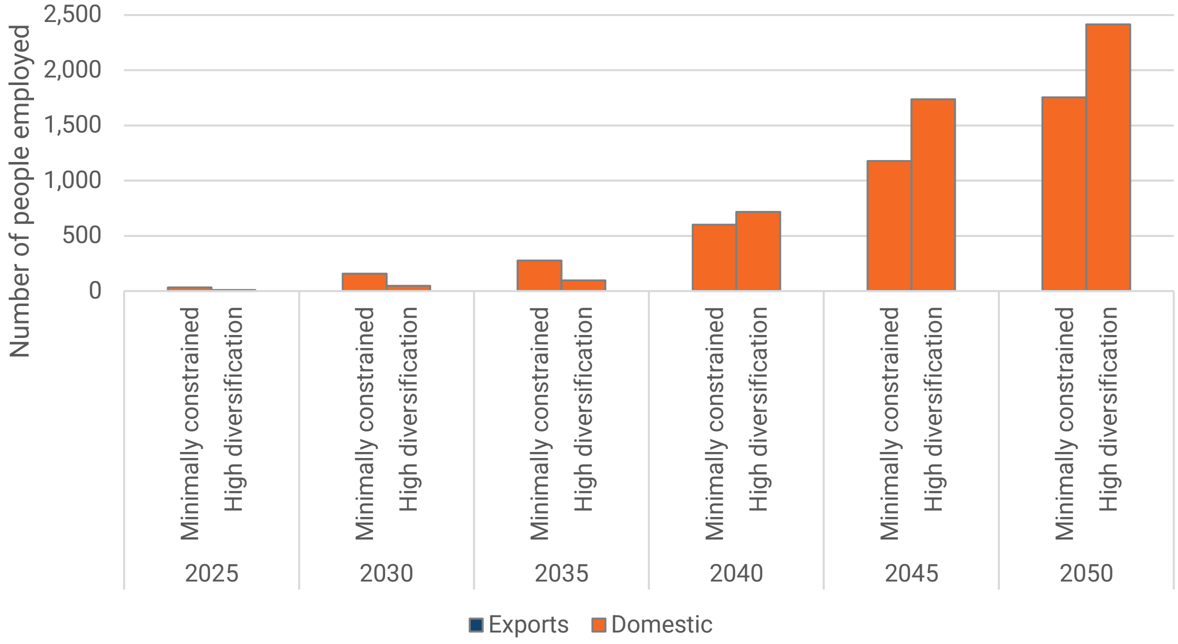

Figure 23: Total jobs supported (direct + indirect) by scenario by market for hydrogen storage technologies

Note: The figure reports outputs associated with a medium level of innovation.[85]

[85] The international hydrogen transmission/transport market was not modelled and so it is unclear how this might compare to exports associated with the other hydrogen technologies.

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