January 2023

Hydrogen UK

Recommendations for the Acceleration of Hydrogen Networks

Written By Networks Working Group

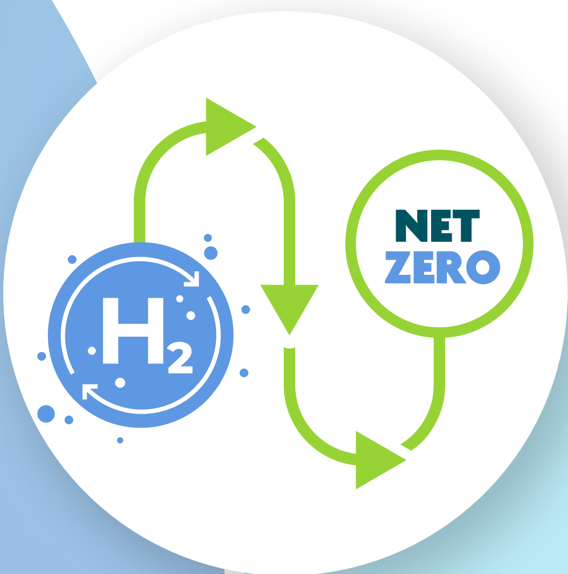
Introduction

Executive Summary

As the need for energy security increases in the UK, so does the requirement for a successful UK hydrogen economy. Large curtailment payments falling into consumer energy bills highlights the need to ease the current constraints on the UK electrical system. Hydrogen networks will enable the growth of all components of the hydrogen value chain and play a crucial role in solving these issues.

Hydrogen networks have a key role to play by:

- **Helping achieve energy security and net zero targets**
- **Supporting a whole systems approach by linking hydrogen production and electricity generation to end users within clusters and beyond**
- **Linking geographically bound assets such as wind farms, gas fields and salt cavern storage**
- **Providing flexibility in a net zero electricity system, when combined with long duration energy storage**
- **Reducing costs by making use of current assets and alleviating the need to invest into decommissioning and electricity grid reinforcement.**



The UK's recent increase in hydrogen production ambition, to 10GW by 2030 as stated in the Energy Security Strategy, demonstrates the significant role hydrogen is expected to play in the future energy mix. Developing 100% hydrogen networks is crucial to not only meeting this aim, but also ensuring the decarbonisation benefit is felt in end use sectors across the country.

To ensure this opportunity is met, Hydrogen UK recommends:

1. **Take interim measures to facilitate design and planning before the design of Transport Business Models**
2. **Design Regulated Asset Base models in both growth and steady state phases**
3. **Create a strategic planning body which facilitates the coordination between networks and storage infrastructure projects**
4. **Political commitment to the development of a national network of 100% hydrogen pipelines**
5. **Determine a national strategy to decarbonise industry.**

The Role of Hydrogen in Net Zero

It is widely accepted that hydrogen will play a vital role in the UK's transition to Net Zero, being included in all major scenarios. Hydrogen has the potential to decarbonise hard-to-abate sectors such as industry, heavy transport, heating and power. In order to realise the decarbonisation potential of hydrogen, domestic hydrogen production will need to increase significantly – the UK Hydrogen Strategy estimates that to meet Net Zero aims by 2050, hydrogen will make up 20-35% of the UK's final energy demand (250-460 TWh a year).

Gas Networks Deliver a Range of Benefits to the Energy System

The key role of gas networks is to move grid scale quantities of energy in a reliable, efficient and cost-effective manner, moving it not only physically over long distances, but also temporally through 'linepack' and connection to storage. Crucially, existing gas networks hold the potential to transport hydrogen, via both the repurposing of current pipelines and the construction of new pipelines.

Hydrogen networks are an important requirement for the successful implementation of a secure and resilient hydrogen economy for the UK and are fundamentally needed to harness the unique potential hydrogen offers in decarbonising hard-to-abate sectors. Such a network will allow the UK to make the most of its natural strengths and connect geographically constrained assets that will be critical in decarbonising the energy system. Hydrogen networks will be instrumental not only in the UK, but also in Ireland and the European network, providing a resilient integrated hydrogen system.

The main benefits that hydrogen networks deliver:

- **Market coupling** - linking geographically diverse supply and demand. For hydrogen this allows production to be located in the most suitable location, such as near wind farms for electrolytic hydrogen and gas fields for CCUS-enabled hydrogen.
- **Energy storage and resilience** - linking end users to large scale storage assets and diverse production methods and suppliers, including import facilities, increases the resilience of the energy system, ensuring sufficient energy is available on demand all year.
- **Flexibility** - in a net zero electricity system, hydrogen networks and seasonal storage provide a means to balance the grid while allowing further deployment of less flexible renewable energy generation assets.
- **Connectivity and efficiency** - shared infrastructure allows for economies of scale to be realised and costs to be more evenly spread.
- **Energy independence** - maximising domestic production of energy coupled with cost-effective transport will reduce reliance on imports, and opens up the potential for exports via hydrogen interconnectors.
- **Customer centric** - allows customers to continue using familiar and effective heating and cooking appliances in the same manner, giving consumers a choice in the energy transition. This will be critical if the option of hydrogen for heat is to be made available widely across the UK.
- **De-risking production** - there is a significant benefit of hydrogen networks in overcoming the 'chicken and egg' problem and de-risking hydrogen production by reducing counterparty risks associated with off-taker outages.
- **Reduced Costs** – repurposing an extensive national grid can reduce or even avoid decommissioning costs and reduce the cost of electricity system upgrades and reinforcements.
- **Whole Systems** – hydrogen networks can deliver significant whole system benefits by linking diverse methods and sites of hydrogen production, electricity generation and other infrastructure (including storage, CO_2 transport and water), to all end users both within clusters and beyond, achieving decarbonisation in the hardest to abate sectors and geographies.

A World-Leading Gas Network

Great Britain is home to a world-leading 284,000 km of gas network infrastructure which currently delivers 900 TWh of energy every year via the transportation of natural gas. This accounts for over 40% of primary energy demand, more than four times the contribution of electricity. Over 85% of homes are connected to the gas grid, relying on it for heating and cooking, with domestic demand amounting to approximately one third of total gas demand. Industry and power generation account for the other two-thirds. Gas networks in Great Britain have a reliability rate of 99.9% with an unplanned interruption to supply once every 140 years on average.

Through the Iron Mains Risk Replacement Programme, gas distribution networks are forecast to have invested £28bn in replacing old iron mains pipelines with new hydrogen-ready ones. As of 2022, nearly 75% of low-pressure gas distribution pipelines are already ‘hydrogen ready’, with the programme set to be completed in 2032.

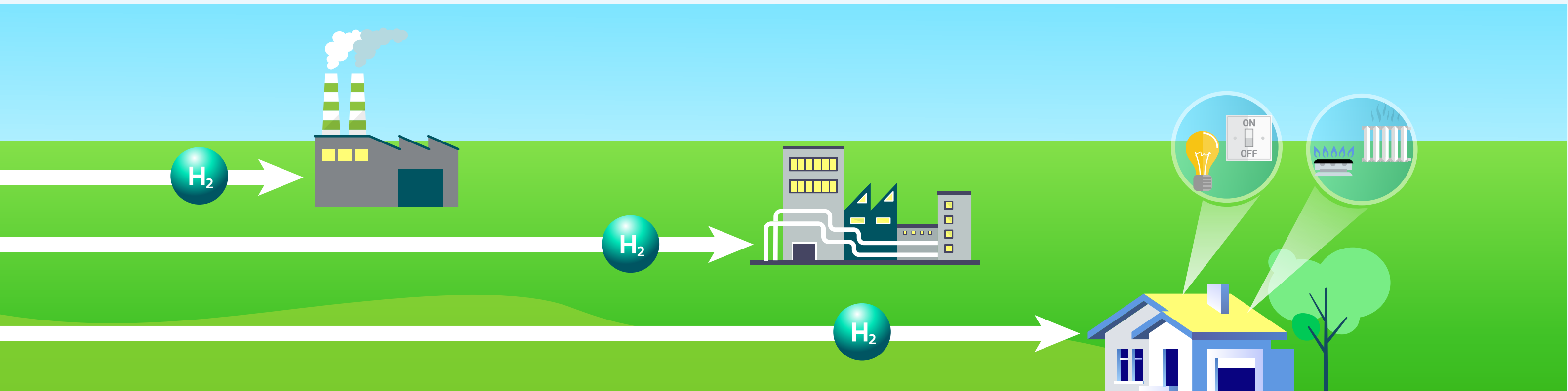
Market Coupling – Efficiently Matching Supply to Demand

A strong case for the implementation of a UK hydrogen network can be made based on the limitations of renewable generation and the distributed national energy demand within the UK. Similar to the UK’s largest geological energy storage locations, areas of rich renewable energy generation are geographically bound, making the task of matching renewable energy generation to distributed locations of high demand particularly challenging. Hydrogen networks offer a solution to this by facilitating the production of hydrogen where it is most economical and transporting the hydrogen in a reliable, safe, low-cost manner.

The most cost-effective strategy is one whereby hydrogen is produced in locations with favourable geographic and economic conditions before being transported to areas of high demand through a hydrogen pipeline. Examples include areas that have access to high wind speeds, offshore gas fields or constrained wind power. Modelling undertaken by Imperial College showed that a more centralised approach to hydrogen production for heat, making use of a national transmission system, would yield investment savings of approximately £5.9 billion per year when compared with the annual system costs of a more distributed approach without a national transmission system.

In the absence of a national hydrogen transmission system, a distributed production approach loses the benefit of diverse inter-regional demand and access to large-scale storage. This will drive the overall capacity requirements for hydrogen production and storage higher.

Whilst long duration energy storage is needed to help balance the electricity grid in conditions of variable seasonal demand, transferring energy from areas of high generation to a disparate demand across the UK is also an essential requirement in reaching national Net Zero aims. **Figure 1**, taken from National Grid’s Future Energy Scenarios, highlights this disparity in electricity generation and demand currently and the projection for 2030. The figure demonstrates how the levels of geographic disparity are likely to increase and therefore the electricity grid, which is already highly constrained, will feel the effects of constraint to an even greater extent.



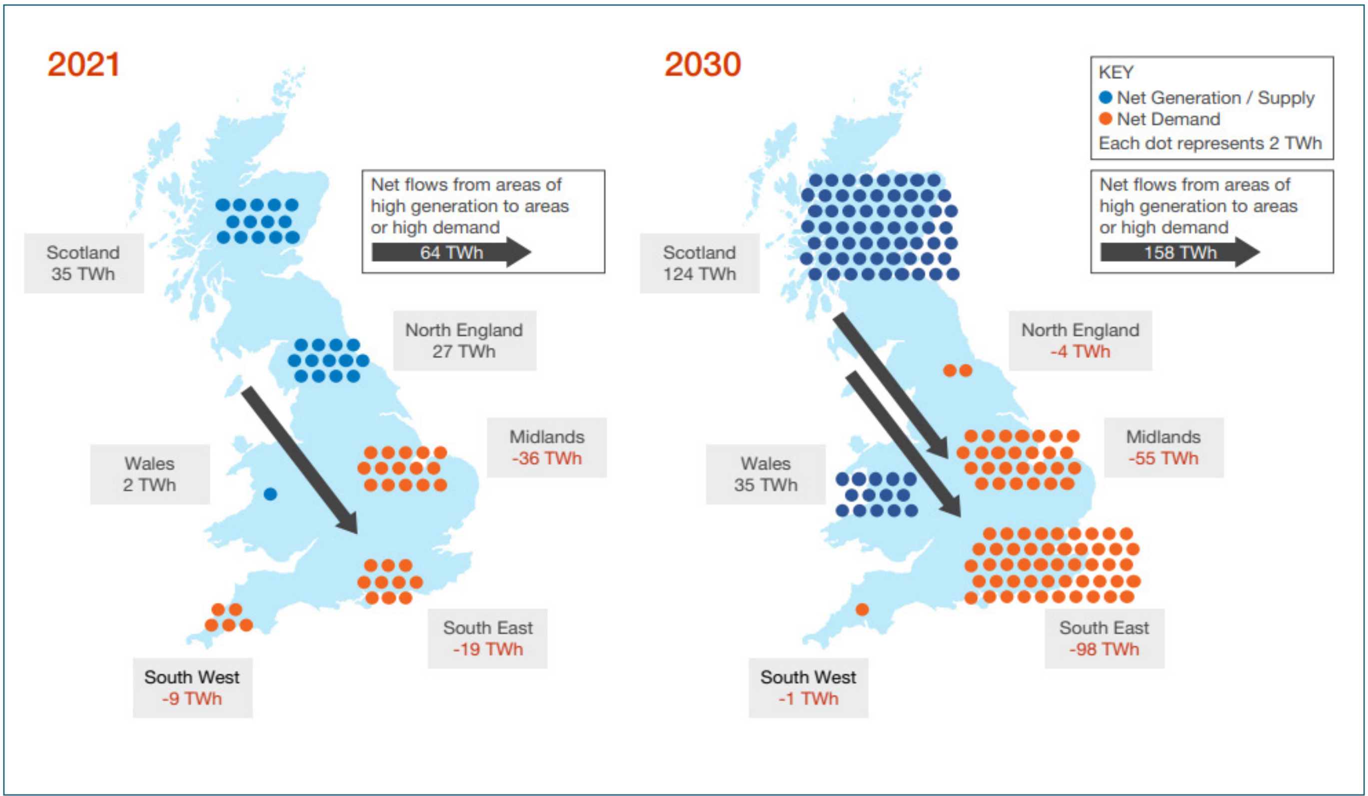


Figure 1: Geographical Disparity between Hydrogen Production and Industrial Emissions

Several studies have indicated the potential cost advantage of moving energy over long distances via hydrogen pipelines compared to cables. Imperial College's 2018 analysis on heat decarbonisations pathways, demonstrated that investment costs for a national hydrogen transmission system is approximately 5.5 times cheaper than the equivalent investment required for onshore electrical transmission system, and 7.1 times cheaper than subsea transmission. This cost differential is also demonstrated in international studies; a US research paper found that transferring energy over long distance via hydrogen pipeline is more than 8 times cheaper than via electrical cable , and analysis from SNAM which found that transporting energy between North Africa and Italy using hydrogen pipelines would cost between £2-£4.1/MWh, approximately 13% and 8% of ultra-high-voltage (UHV) powerline costs and green ammonia production and shipping costs, respectively. Hydrogen UK notes that as the need to transfer energy in the most cost-effective way increases, so too will the need for a detailed comparison of the relative cost of energy transfer specific to UK conditions. Such a comparison should not be limited to direct costs, since other non-economic considerations may result in increased system costs or physical constraints, affecting its viability.

Transporting energy via pipelines can alleviate some of the constraints already being felt in the electricity system. The independent energy body Regen recently wrote a letter to BEIS Secretary of State on behalf of six trade bodies calling for urgent action to address electricity network constraints, highlighting that energy projects are facing delays of up to fifteen years to connect to the network due to constraints at the transmission level. Solar Energy UK, one of the six trade bodies that contributed to Regen's letter, states that more than 40 projects totalling 3.5GW of capacity have been impacted or delayed by grid connection problems. In particular, the B6 boundary between the SP Transmission and National Grid Transmission acts as a significant bottleneck for electricity transmission from Scotland to England. This highlights the scale of both the challenge that the UK faces to achieving a net zero power system by 2035, and of the opportunity for hydrogen networks to alleviate some of those constraints in a reliable and cost-effective way.

Decarbonising Industrial Emissions in Clusters and Beyond

The UK industrial sector account for approximately a quarter of all UK carbon emissions and since more than half of these emissions come from a small number of industrial clusters ,the decarbonisation of these is a priority. Closed system hydrogen networks will aid industrial decarbonisation by transporting hydrogen produced on site to various end users within individual clusters via the repurposing of existing pipelines and creation of new pipelines. Closed networks will provide the framework for hydrogen networks to be scaled regionally and then nationally. Investigations into these closed system networks are being made in the 2020-2025 period with the first cluster aiming to become operational in 2025. The cluster sites will then gain access to a national hydrogen pipeline backbone connecting each cluster to one another as seen in **Figure 2**. This backbone is due to be developed between the mid-2020s to the early 2030s and will increase the systemic resilience of hydrogen supply between clusters.

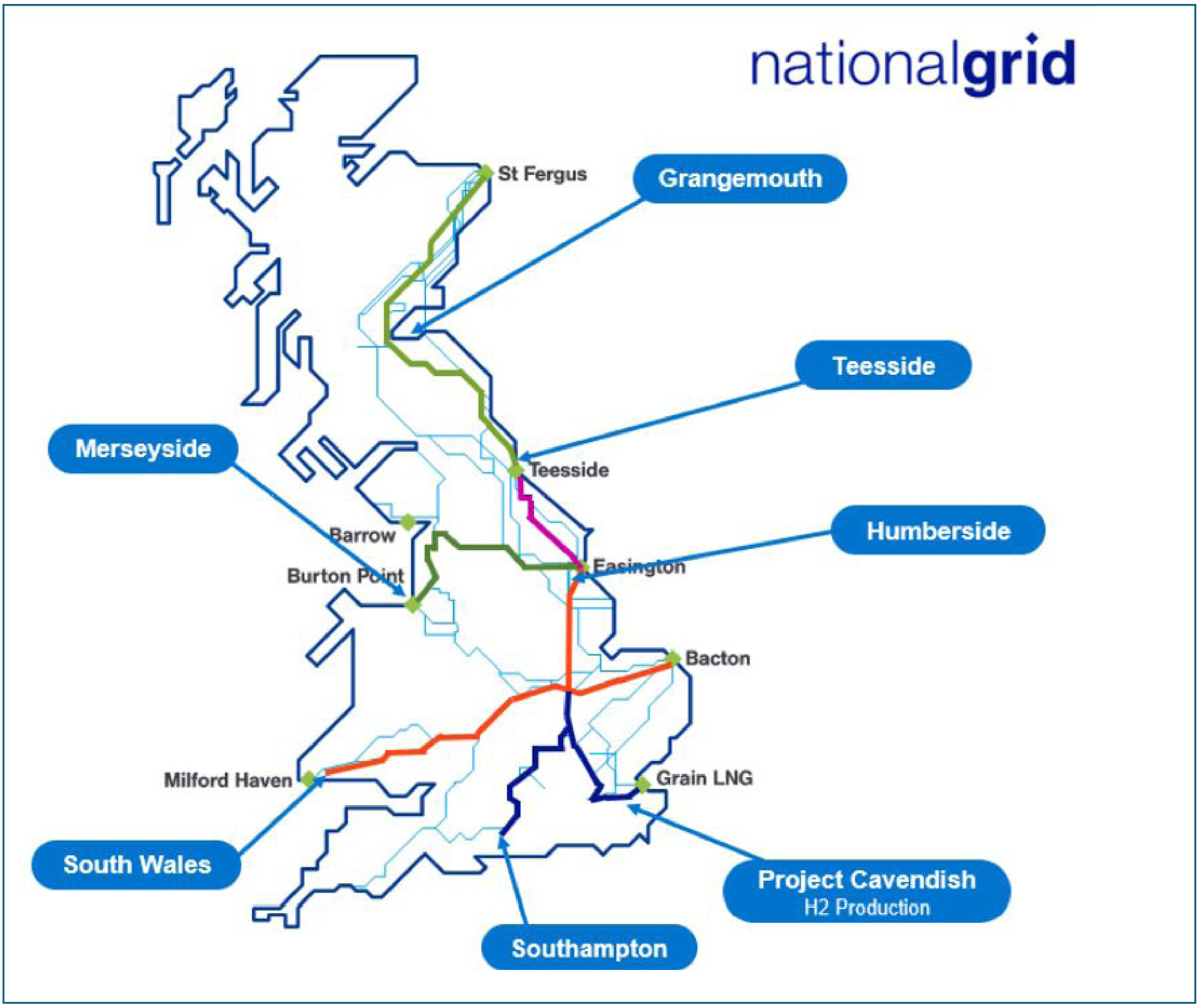


Figure 2: Map showing the Cluster Phase in the UK (BEIS)

Whilst clusters are responsible for more than half of UK industrial emissions, a significant quantity (47%) emanates from dispersed sites that will not be abated when clusters receive hydrogen via pipeline. **Figure 3** shows a spatial view of emissions across the UK compared to both 'blue' (CCUS-enabled) and 'green' (electrolytic) hydrogen production projects.

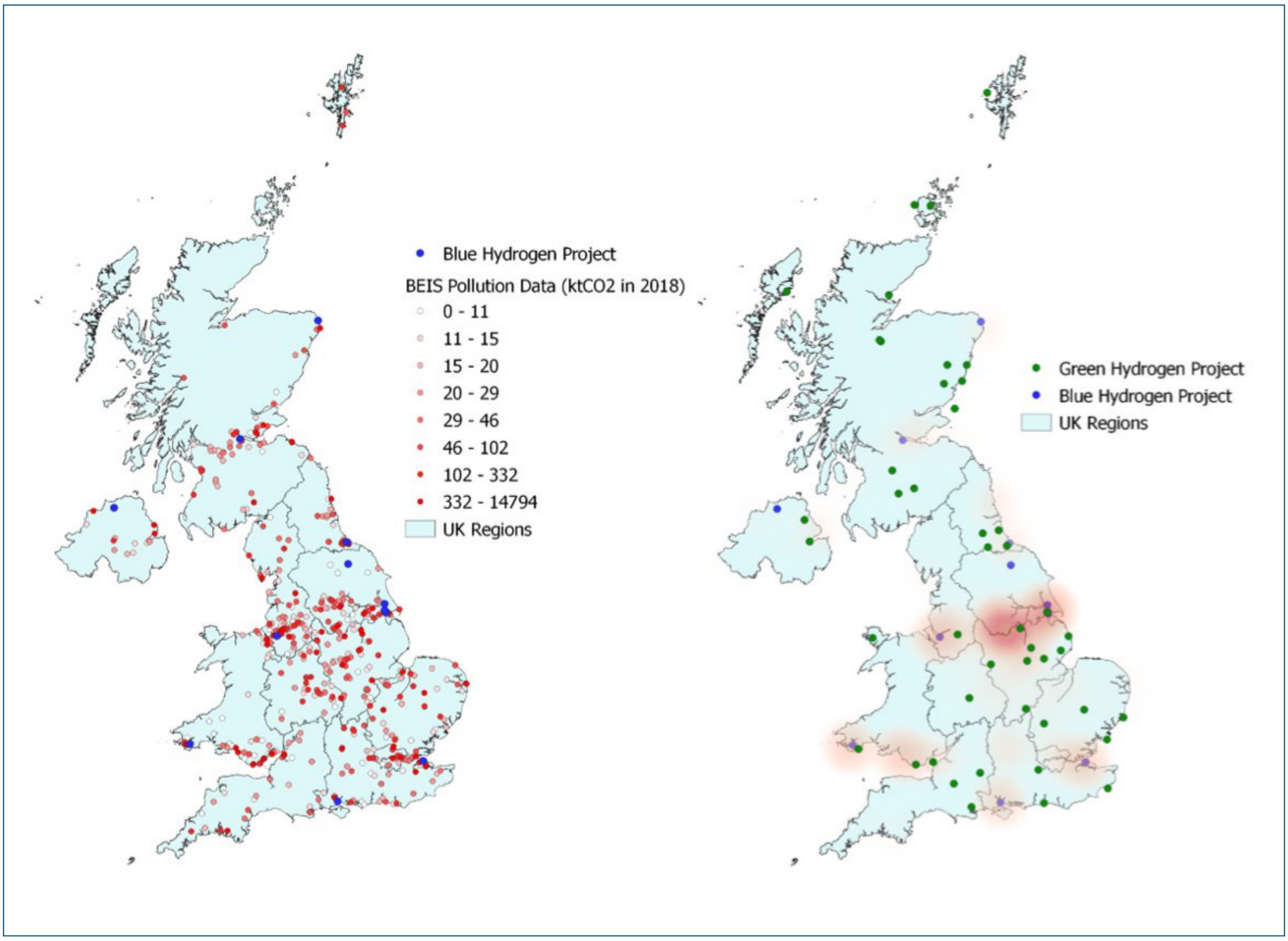


Figure 3: Geographical Disparity between Hydrogen Production and Industrial Emissions

In a similar fashion to both large scale energy storage and renewable generation, the industrial clusters are geographically fixed. Electrolytic projects are more dispersed than large scale CCUS-enabled hydrogen production plants, and electrolytic projects that are operational before 2030 are likely to have their maximum production capacity matched to the demand of their intended end use, making it very unlikely that any excess electrolytic hydrogen will be produced. This is due to the small scale capacity and lack of pipeline network to create a liquid market. Therefore, the decarbonisation effect generated through these dispersed electrolytic projects will only be felt at the point of their intended end use and the benefits in terms of emissions reduction will not extend to nearby industrial emitters.

This therefore means that hydrogen networks are needed to transport hydrogen from locations with excess production within the clusters to industrial emissions points situated outside of cluster zones. In the UK Hydrogen Strategy, BEIS state that by the late 2020s and early 2030s, hydrogen networks may span tens of kilometres of length, supplying end users either within cluster regions or more broadly. BEIS anticipate that by the mid-2030s, the network may span hundreds of kilometres serving multiple end use applications. The ENA's hydrogen network timeline indicates that clusters are likely to be decarbonised via an initial 'backbone' of national pipeline (seen in **Figure 2**), due to become operational in the late 2020s and early 2030s , subject to the government's decision on the future role of hydrogen in domestic heat in 2026. A complete national hydrogen network could be operational 10 years after that.

According to predicted timelines, these areas of decentralised industrial activity will receive hydrogen in this later stage thus meaning their pathway to decarbonisation will lag 5-10 years behind the industrial clusters. In this lag time, huge amounts of carbon dioxide will continue to be pumped into the atmosphere due to the combustion of natural gas and indeed UK manufacturers may be placed at a competitive disadvantage due to a failure to decarbonise their products. It is essential that the UK government find a solution to decarbonising these decentralised areas of industrial activity to ensure this does not happen.

While many industrial operators will not be able to justify the cost of installing their own electrolyser, and in the absence of hydrogen networks, transporting hydrogen via tankers is likely to be required. However tankering is limited in its capacity, adds emissions (where completed using fossil-fuel driven trucks) and studies have shown that pipelines are the more cost effective mode for transporting increasing volumes of hydrogen over longer distances.

The above highlights the reality that when looking to decarbonise industrial emissions, the decarbonisation of industrial clusters is not the complete story. For hydrogen to realise its full potential in reducing industrial emissions, pipelines will be required to extend its reach.

Supporting a Flexible and Resilient Net Zero Power System

The UK has access to a significant amount of shoreline which experiences high wind speeds, hence providing a good environment to deploy offshore wind. The UK's offshore wind market is already one of the largest in the world comprising 10 GW of installed capacity, with a further 5 GW in pre-construction and 11 GW under planning. Recent policy amendments reflect the government's growing commitment to offshore wind; the British Energy Security Strategy published in April 2022 increased the UK's 2050 offshore wind target from 40 GW to 50 GW, and the Scottish Government has set its own target of 20 GW by 2030. Offshore wind is an asset that the UK must fully optimise; we cannot let slip the potential that offshore wind holds in transforming the UK's energy system.

In times of peak generation, the supply exceeds the capacity of the electricity grid to transfer it and thus production must be curtailed. Renewable electricity generation frequently exceeds circuit capacity, forcing producers to switch their facilities off, costing Britain 2.3 TWh in lost generation and £507 million in curtailment payments in 2021.

There is also significant variation in inter-seasonal heat and power demand in the UK. The daily average for domestic gas consumption in the summer is 0.4 TWh, however this increases to 3.5 TWh in winter, demonstrating a significant seasonal fluctuation. Great Britain's electrical demand in January 2022 was 35% higher than for June 2021. These large ramp-ups over winter currently require dispatchable power generation, primarily via natural gas combustion in Combined Cycle Gas Turbines (CCGT). In order to reach a net zero power system, these dispatchable generation assets must be converted to zero or low-carbon technologies, such as hydrogen. The availability of hydrogen networks will enable these assets to reliably access significant volumes of low carbon hydrogen from storage assets which may not be in close proximity.

Hydrogen networks have a vital role to play in creating a flexible and resilient net zero energy system. Excess renewable energy generated from offshore wind that would otherwise be curtailed can be used to produce "green" hydrogen via the process of electrolysis. The hydrogen produced can then be transferred via pipeline networks to long duration energy storage facilities where it can be later used in industry, in the heat sector over the winter months, or in hydrogen power generation processes to balance the grid in times of low renewable electricity generation. Large scale storage technologies including salt caverns and depleted gas or oil reservoirs will be required for these purposes. Hydrogen UK's latest report 'Hydrogen Storage: Delivering on the UK's Energy Needs ' estimated that the UK's 2030 hydrogen storage requirement could reach 3.4 TWh, increasing to 9.8 TWh by 2035. Underground storage technologies are geographically fixed and hence long duration energy storage requires networks to provide a reliable and cost-effective method of transporting hydrogen to and from these storage facilities.

Complementing large-scale storage facilities, hydrogen within the transmission and distribution networks will be critical to balance short-term demand and supply fluctuations. In a practice known as 'linepacking', natural gas stored within the Local and National Transmission System (LTS and NTS) has been largely supporting the flexibility of the UK natural gas supply, with an hourly linepack capacity of 4886 GWh. It is known that due to hydrogen's lower volumetric density compared to natural gas, this linepack capacity would decrease, something that SGN's LTS Futures project is investigating. Assuming highly flexible production, Imperial College modelling found that linepack storage in existing networks can provide up to 90% of hydrogen storage across the year. Although this proportion is expected to be lower due to production constraints and inter-seasonal storage demand, the results of the Imperial College study demonstrate the important role hydrogen networks will play in hydrogen storage and energy system resilience.

Figure 4 shows the predicted annual curtailment of renewables predicted by National Grid's Future Energy Scenarios. The chart shows that between 2035 and 2040, annual curtailment figures range from approximately 30 TWh to 86 TWh across the four different scenarios. The System Transformation scenario peaks at 86 TWh in 2036, which for context is 22% of the total UK electricity demand for that year. Considering a cost of £501 million was incurred due to 2.3 TWh of electricity being curtailed in 2021, the magnitude of future costs from annual curtailment will be significantly greater.

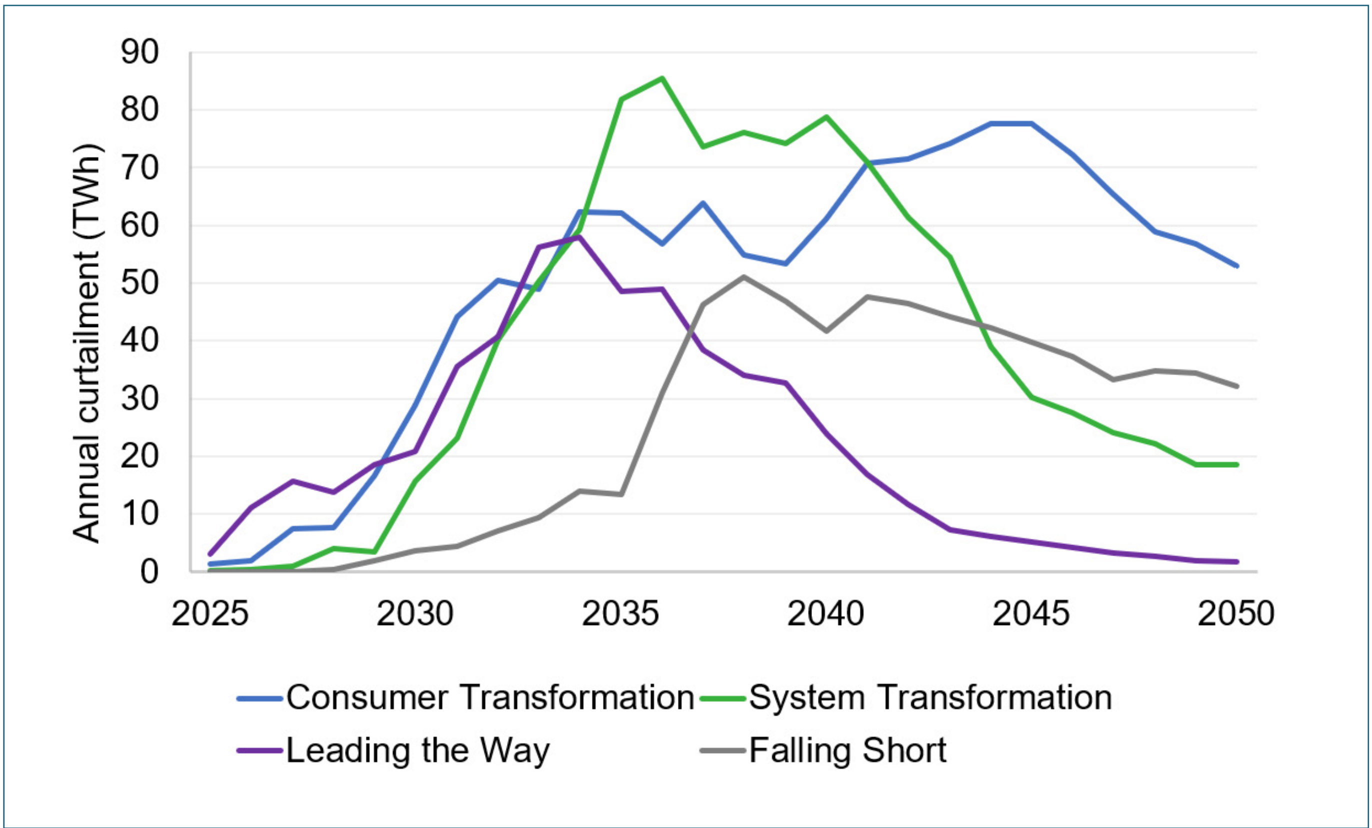


Figure 4: Curtailed Electricity used for Hydrogen Production (CCC 2020)

The Leading the Way scenario demonstrates the quickest return to low curtailment figures out of the four scenarios. The assumptions for this scenario include the quickest deployment of electrolysers, greatest capacity deployment before 2045 and the highest level of interconnector capacity.

This demonstrates that the challenge of curtailment, and the associated total curtailment costs assuming these payments remain, will only increase over the coming decades, and also that rapid deployment of electrolytic hydrogen production could be a solution to combat this. Importantly, this solution relies on the successful implementation of hydrogen networks to transfer hydrogen between production locations and long duration energy storage facilities. From here, hydrogen may be transported to sources of demand, including power generation, providing the flexibility needed by the future net zero energy system.

This is further shown in the Committee of Climate Change's (CCC) Sixth Budget in which the future amount of curtailed electricity used to produce electrolytic hydrogen is predicted, as shown in **Figure 5**. Here it can be seen that the increase in production from curtailed electricity massively increases over the next decade. Whether this hydrogen is used for long duration energy storage or to help transport energy through a constrained grid, hydrogen networks are a crucial requirement.

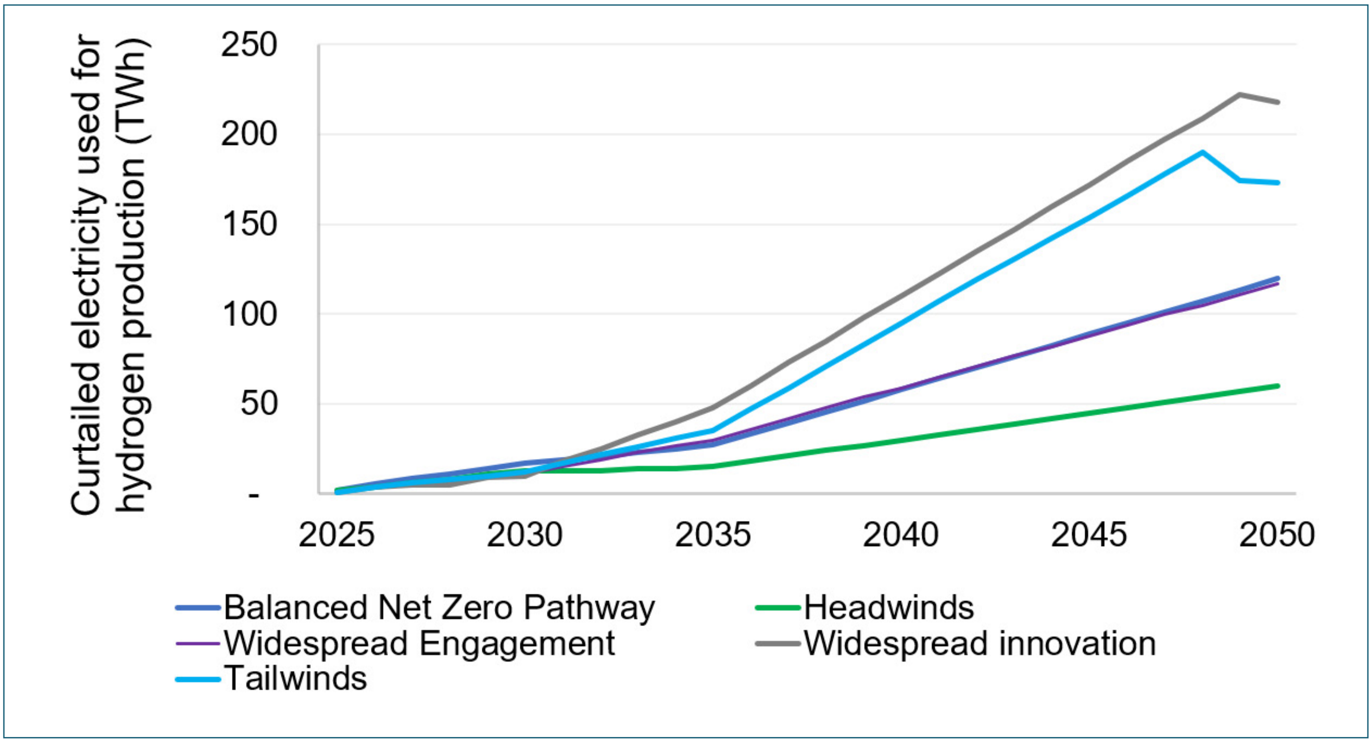


Figure 5: Curtailed Electricity used for Hydrogen Production (CCC 2020)

Hydrogen networks allow the UK to make use of its natural assets. These include large scale storage technologies and optimum locations for both electrolytic and CCUS-enabled hydrogen production. Through this, hydrogen networks can help enable the decarbonisation of industrial clusters, emissions outside of clusters, help balance the electricity grid in times of low renewable generation and help transport energy around the nation from areas of high generation to those with high demand.

Offshore hydrogen networks provide further optionality to support the deployment of innovative technologies, including the combination of electrolysers and offshore wind turbines. Several developers are looking to deploy this combination of technologies in UK waters including the ERM Dolphyn concept, led by ERM and funded through BEIS' Net Zero Innovation Portfolio Low Carbon Hydrogen Supply 2 Competition. The Dolphyn concept would be a first of its kind project with an electrolyser co-located with a wind turbine installed on a floating sub-structure producing hydrogen from seawater. Technoeconomic modelling in the concept select phase showed that producing the hydrogen offshore and transporting it onshore via a subsea hydrogen pipeline would result in a lower unit cost of hydrogen than transporting the electricity via cables and producing the hydrogen onshore.

As noted previously there has been increased ambition for offshore wind capacity to help meet net zero while delivering energy security. However, there are already considerable constraints on electricity grid connections, and this is particularly true for offshore generation assets. Networks of offshore hydrogen pipelines, connected to hydrogen production facilities located in deep waters where abundant renewable electricity is available, could play a vital role in alleviating some of this pressure.

Network Strategy Development

Implementing a transformation of the National Transmission System is a task that cannot be physically delivered in a single step. The integration, constructing and development of infrastructure is a task that requires gradual transformation combined with strategic planning for the energy transition. The premise of an overarching strategy for the implementation of hydrogen networks can be seen in **Figure 6.**

Figure 6: Network Development Scenarios

Small Clusters Scenario: Pipelines will be developed within and around dedicated industrial clusters. The repurposing of decommissioned pipelines and new build pipelines will allow hydrogen to be transported from production to end use within the cluster site. New pipelines will likely be used initially to avoid compromising the resilience and functionality of the existing natural gas system. These projects will take place in 'closed' systems. Examples of this are the Regional Hydrogen Energy Hubs proposed in the Scottish Hydrogen Action Plan and the HyNet North West low carbon cluster where construction of the HyNet Pipeline is due to start in 2025, enabling the distribution of hydrogen from production to end use.

Initial Backbone Scenario: Pipelines will connect industrial clusters via a national pipeline 'backbone'. Hydrogen will be transported between these sites to increase system resilience and allow for future scale up of national hydrogen networks. National Grid's Project Union will deliver a hydrogen transmission system through a phased repurposing and newbuild of transmission pipelines helping to develop this backbone of pipeline. The ten phases (Union 1-10) aim to become operational from approximately 2026-2033.

Hydrogen Scenario: Also referred to as 'plug and play', an integrated whole system will be developed on a national scale and offtakers will be able to access hydrogen supply via pipeline across the country.

The time periods associated with the scenarios in **Figure 6** are aligned with Ofgem's RIIO timelines, which set price controls for the gas and electricity network companies of Great Britain to balance the relationship between investment in the network, company returns and the amount that they charge for operating their respective networks.

Progress to Date

A variety of projects have been undertaken in the UK to develop greater understanding of how to best achieve a national hydrogen network. Projects have assessed different points of the overarching strategy as outlined below.

FutureGrid

FutureGrid is a project run by National Grid looking to gain understanding into how the gas network needs to be developed and operated to allow for a full-scale conversion of the National Transmission System (NTS) to transport hydrogen. FutureGrid is an example a of a one-to-one demonstrator project where DNV, the main delivery partner, have built a closed system test facility. The facility is connected to the H21 distribution facility creating a representative UK hydrogen testing and training facility. FutureGrid is testing four concentrations of hydrogen, 2%, 5%, 20% and 100%, and is focusing on the viability of transporting these blends through decommissioned assets (at DNV Spadeadam) to demonstrate that the NTS can transport hydrogen. The 5% blend testing has been included as a test blend level based on proposals in a recent EC policy paper which suggests the acceptance of 5% hydrogen as a first step for European transmission networks transiting to hydrogen. Furthermore, the UK wants to ensure the continuation of seamless gas trading with the European market. FutureGrid is examining material considerations, safety developments, flow characteristics, compression and network management. Currently the NTS carries three quarters of the UK's energy through 7660 km high pressure pipelines and comprises £6.3 billion of existing assets. The findings from FutureGrid will feed into Project Union in developing a national backbone of hydrogen pipelines throughout the country linking industrial cluster sites.

Figure 7: FutureGrid Phase 1 Facility Jan 2023

Project Union

Project Union furthers the research by FutureGrid by aiming to connect hydrogen production, storage and demand through repurposing existing pipelines within the UK. The project will deliver a hydrogen transmission backbone for the UK through repurposing approximately 2000 km of pipeline, equal to 25% of the UK's existing natural gas transmission pipelines. Repurposing assets as opposed to building new pipelines is up to five times more cost effective and limits impacts on the surrounding environment8. Project Union will link key hydrogen production and use centres offering the potential for future expansion to connect beyond this initial backbone demonstrating an example of a one-to-few project. The project is due to be completed in the early 2030s and will directly support c.£300 million annual GVA and 3,100 jobs at peak construction.

H21

H21 is a collection of projects undertaken by the UK's leading gas network operators to determine whether repurposing the current gas network to transport hydrogen is a viable and safe option. H21's goal is to make use of the extensively linked gas network within the UK through repurposing pipeline instead of building new networks. The H21 programme is funded by Ofgem and led by Northern Gas Networks in partnership with Cadent Gas, Wales and West Utilities, SGN, National Grid, Leeds Beckett University, DNV and the Health and Safety Executive Science and Research Centre. Thus H21 encompasses the lower pressure tiers of the UK gas distribution operators, harnessing the entire pool of network expertise and ensuring work is not duplicated in the future. Since its commencement, 13 projects have been completed under H21 with 4 projects underway at the time of this report (Oct, 2022). H21's first project, Leeds City Gate, launched in 2016 and through a feasibility study, showed that conversion of the UK gas network to 100% hydrogen was technically possible and could be delivered at an acceptable cost. The project included storage for interseasonal demand (as well as intraday). H21 has laid out plans to repurpose the gas grid to transport hydrogen in all major cities within the UK, starting with Leeds and ending in London in the mid-2040s.

H100 Fife

SGN are leading on developing the UK's first hydrogen network used to heat residential homes with 100% hydrogen in Fife, Scotland. The project based in Buckhaven and Denbeath will go live in 2024 and operate until March 2027. The network will be formed through the construction of new build distribution pipeline and heat approximately 300 residential homes using new hydrogen appliances that are fitted and maintained for free. The network, which will pass 1000 homes, will be laid in parallel to the existing natural gas network using the same polyethylene material commonly used by gas distribution networks today. Due to the new build network being laid parallel to the existing network, the project will not derogate from GS(M)R allowing customers the ability to refuse to partake in the project and enabling customer choice. Other components used in the network include pressure reduction, flow metering and hydrogen quality and odorization. Bespoke billing arrangements supported by commodity balancing will also form part of the network.

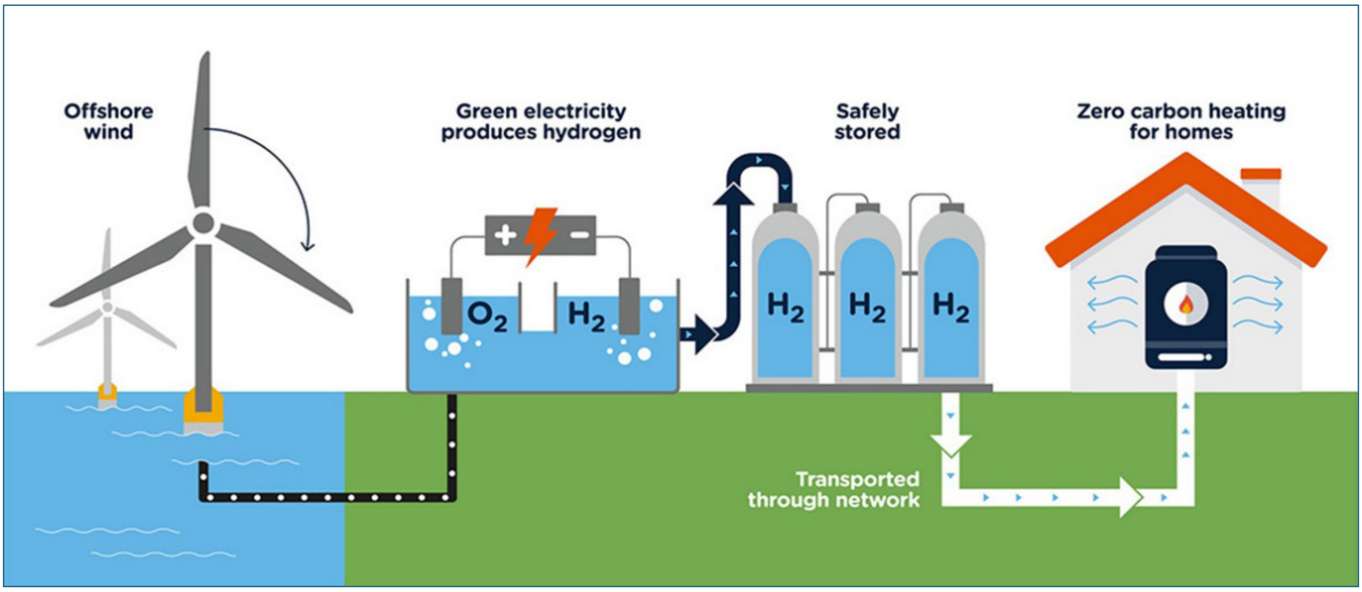


Figure 8: SGN's H100 Fife Project

Figure 8 shows how H100 plans to produce and transport electrolytic hydrogen to the participants homes. A 5MW alkaline electrolyser will produce the hydrogen used in the trial and will be stored in six purpose-built tanks operating at 30bar. The electrolyser will be powered by a 7MW offshore wind turbine, meaning the hydrogen used will be carbon free. During the operational phase of the project, H100 Fife will save over 2650 tonnes of carbon dioxide which is equivalent to half the homes participating taking a car off the road. H100 Fife is part of Gas Goes Green with ENA, National Grid, Cadent, NGN, and Wales and West Utilities all partnering with the project.

LTS Futures

SGN, supported by INEOS, are delivering the LTS Futures Project which will research, develop and test the compatibility of transporting hydrogen through the Local Transmission System (LTS). Evidence will be gathered not only on hydrogen in LTS pipelines, but also in associated plant and ancillary fittings. A further aim of the project is to investigate how linepacking with hydrogen performs in comparison with natural gas. In April 2022, LTS Futures secured funding of £29.9 million through Ofgem. The 30km of repurposed pipeline in Grangemouth, Scotland, has been chosen because it is statistically representative of the greater LTS system and thus will help develop plans for the future repurposing of the LTS in Great Britain. **Figure 9** shows the whereabouts of the trial location. The first of its kind demonstration project is due to go live in 2024.

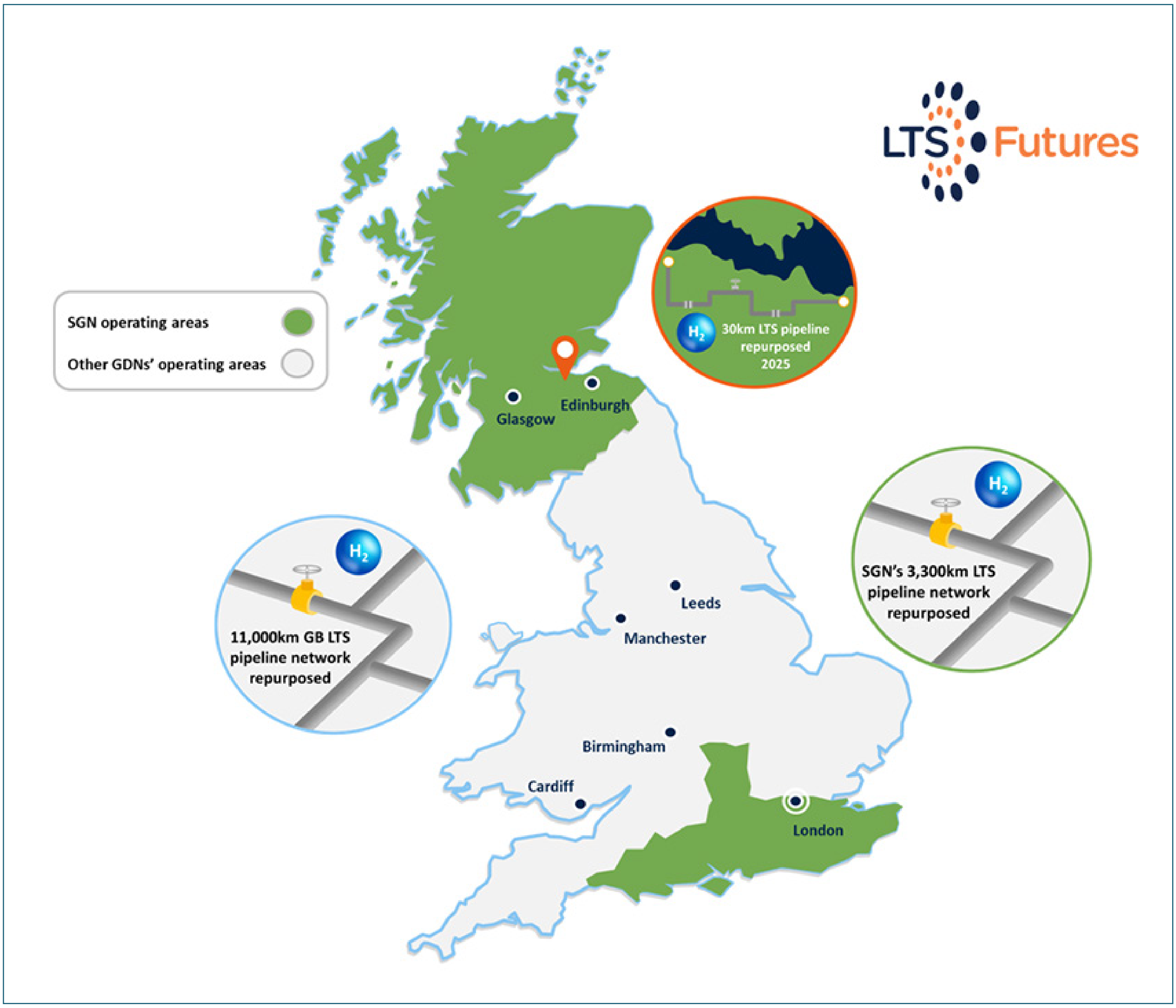


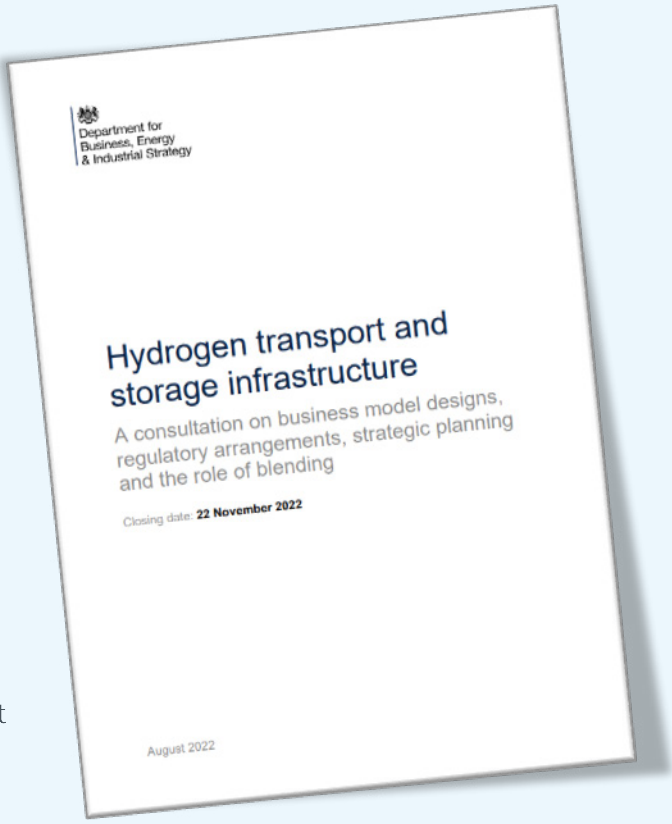
Figure 9: SGN's LTS Futures Project

Transport and Storage Business Models Consultation

With large-scale networks and storage infrastructure being key enablers of hydrogen production investments, the Government's decision to increase their strategic ambition to achieve 10 GW production capacity by 2030, from the previous 5GW ambition, made it critical that infrastructure projects reach final investment decision as soon as possible.

However, considerable market barriers, such as lengthy development lead times, high capital costs and uncertain returns mean that such infrastructure projects are unlikely to materialise in time. In addition to growth state obstacles, hydrogen networks are also expected to become a natural monopoly in a later stage of market evolution similar to current natural gas networks, and therefore the fairness of future transmission and distribution costs must be considered and regulated.

To overcome these market barriers and improve investment certainty and financing, the Government is designing a hydrogen-specific policy framework by 2025. In August 2022, an open consultation was released to seek opinions on the most suitable transport and storage business models. BEIS also gathered views on the future regulatory framework, implications for hydrogen blending with natural gas and the nature of a future strategic planning body which is considered critical for the coordinated development of network and storage projects. Although the early launch of the consultation was a critical step for the hydrogen economy and welcomed by industry, it is important to emphasize the urgent need of a business model and further government signals and interim measures before 2025. Given the long lead times, interim measures, such as CAPEX and DEVEX support and a short-term business model will be crucial to meet the Government's hydrogen production and emission targets by 2030.



Case Study – Blending

Blending hydrogen into the National Transmission System at a low percentage will displace natural gas thereby reducing carbon emissions. Any end user of natural gas (power generation, industry, heat) could benefit from these carbon savings. The HyDeploy project aimed to demonstrate whether a hydrogen blend of 20% volume could be safely used in existing distribution pipelines and domestic and commercial appliances. The initial trial took place at Keele University ending in March 2021. The second trial took place in Winlaton and supplied 668 houses with a 20% by volume hydrogen blend for 10 months. HyDeploy showed that a 20% blend could be used in existing gas distribution pipelines and appliances with little disruption.

The HyDeploy report notes that "Both the 10 Point Plan and Energy White Paper specifically identify the need to unlock hydrogen blending by 2023. HyDeploy (including HyDeploy 2) is the only major technical programme within the UK driving the deployment of hydrogen blends within the gas distribution system, therefore the successful outcome of the broader HyDeploy programme is now crucial to facilitating the delivery of HMG hydrogen policy objectives."

The carbon savings from blending hydrogen into national pipelines are significant. Analysis by the Energy Networks Association (ENA) shows that a 20% blend of hydrogen (by volume) into the Gas Distribution Networks (GDN) could annually heat the equivalent of around 3 million homes with hydrogen and save around 6 million tonnes of carbon dioxide per year. This comes from a maximum possible blending capacity of 35 TWh/year within the GDNs. There is an approximate total blending capacity of 60 TWh/year if the National Transmission System is also included. The effect from this would be equivalent to heating around 5 million homes with hydrogen and reducing carbon dioxide emissions by 10 million tonnes. These figures show the maximum benefit blending could offer when modelled with the assumption of a 20% hydrogen blend (by volume) *.

It is more likely that blending will not be utilised to its maximum potential, especially in the early years, and will instead be used as an offtake of last resort to reduce demand risk for producers. Examples of this include when an offtaker has planned/unplanned maintenance and can no longer accept hydrogen from a producer. Another example is if the hydrogen production is online before an off-taker can accept the hydrogen – this could be caused by delays in switching equipment for instance. In these scenarios hydrogen can continue being produced and blended into the gas network, which acts as a buffer mechanism. This also allows for hydrogen production to come online early and reduces the investment risk surrounding hydrogen production should producers be unable to secure an early offtaker. Furthermore, blending as an offtake of last resort is particularly important as it will significantly increase investability and reduce costs for early production projects before large scale storage comes online. Interest in blending at a lower percentage than 20% has increased recently, with National Grid including a trial blend of 5% in the FutureGrid project in their 2022 project progress report. Blending should not, in any way, reduce the need or urgency of 100% hydrogen networks.

Strategic Planning for Hydrogen Networks

Roadmaps for UK hydrogen network rollout plans are largely high level and qualitive. Whilst they provide a good overview of what the coming decades could look like in terms of pilot projects, approximate cluster plans and a suggestion of when the UK will have a fully connected grid system, it leaves ambiguity regarding whether critical activities, including the current plans for governmental support, are commencing early enough.

The UK government has said that hydrogen transport and business models will be designed for 2025, but has also commented on the lengthy development lead times, high capital costs and uncertain financial investment associated with hydrogen network infrastructure. Not only does this show that infrastructure is unlikely to materialise without these business models, but it raises the question as to whether 2025 is early enough for this support to become available sufficiently soon for it to meet its 2030 target for hydrogen production of 10 GW.

The ENA, in its response to the August 2022 BEIS Hydrogen Transport & Storage Consultation, noted that final investment decisions must be made in the next 12 to 18 months, and cannot wait for a business model design decision in 2025. To discern whether the transport and storage business models are being released too late, a detailed roadmap is needed to compare lead times of hydrogen network projects against expected completion dates. Currently this level of granularity for a 100% network plan does not exist in the public domain.

Figure 10 shows an indicative timeline of activities required for a 100% hydrogen network based largely on combining publicly available sources from ENA , Project Union and RIIO regulatory timelines. The timeline is indicative, with clear links and dependencies not identified, highlighting the importance of a more detailed strategic network plan to identify the critical path. The danger of not identifying whether governmental support is needed prior to 2025 is the knock-on effect it has on the overall network roll-out. As development of a 100% hydrogen network in the UK is likely to occur in sequential, iterative phases, delays to initial stages can significantly impact the later stages of the deployment programme. For context, DNV estimate periods of three to four years for pipeline routing, design, planning applications and consents and ordering pipe stock , clearly demonstrating that there will be significant lead time between project investment decisions and operation. A unified roadmap is needed, detailing lead times for projects involving transmission and distribution, with differentiating lead times associated with the repurposing of pipelines compared to new build, alongside production projects.

Careful strategic planning is needed to successfully implement hydrogen networks within the UK and a detailed roadmap is required within this to determine critical paths for network deployment. Hydrogen UK will work with its members, Government and the wider industry to develop this vital evidence in order to better inform decision timelines and improve the likelihood that the UK will hit its hydrogen production and net zero targets.

The risk of delaying the development of hydrogen networks, and falling behind developments in other regions such as the EU Backbone, is stunted deployment of hydrogen production and end use technologies. This would result in a significant lost opportunity for the UK in terms of the economic growth and stable jobs that would be delivered by a thriving hydrogen economy. Networks enable economies of scale which fosters confidence in investors to support the creation of domestic supply chains.

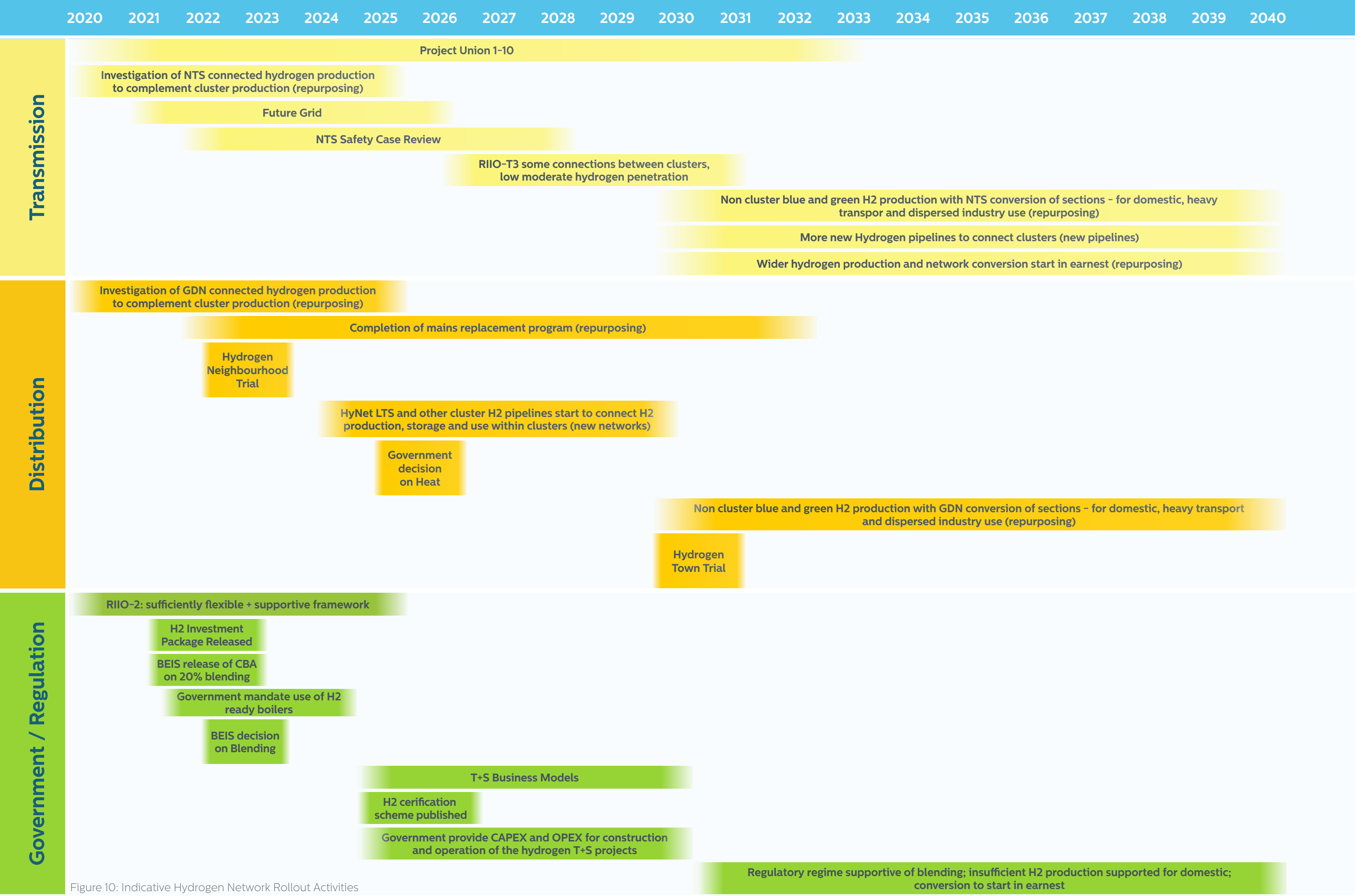


Figure 10: Indicative Hydrogen Network Rollout Activities

Recommendations

1. Design Regulated Asset Base models for both growth and steady state phases

To ensure compatibility and smooth transition between growth and steady state phases, Hydrogen UK favours a Regulated Asset Base (RAB) business model approach in both the infancy and the steady periods.

RAB is well understood by industry, given the wide range of large-scale projects it has been used for in the UK and the rest of Europe.

- Gas network investments have worked generally well, maintaining low transmission and distribution costs for consumers throughout the years.
- As opposed to contractual models, RAB can mitigate both price and volume risks, accelerating hydrogen production and transport investments.
- Moreover, when the market matures and natural monopoly materialises, little change needs to be made to the existing business models.

However, RAB would have to be supplemented with an additional external funding mechanism due to the insufficient demand in the growth period. This is not only to reduce volume risks but also to protect the low number of initial consumers from bearing disproportionately high costs in the infancy period. External funding mechanism options include:

- **Capacity Payments.**
  - Under this mechanism, a certain volume of network capacity which could not be sold, would be reserved by the Government, decreasing the amount of costs the developer could recover from one user.
- **Gradually increasing allowed return on investment.**
  - Under this mechanism, the developer could only recover lower revenue in the growth phase to protect the small consumer base from excessive network charges. The allowed return, however, would gradually increase with growing consumer base, incentivising the developer to expand its network capacity.
- **Combination of the two above.**

Additionally, co-investments by Government might be needed when projects of strategic importance are identified. The market framework should be designed in a manner that encourages offtakes in areas like transport and industry to adopt hydrogen as opposed to alternative high-carbon fuels. To achieve this, the post-distribution cost of hydrogen should be the same or near to that of natural gas, in line with the Hydrogen Business Models. External government support, as described, should therefore be sufficient to account for the small initial consumer base whilst incentivising the potentially costly process of switching to hydrogen as a fuel source.

2. Take interim measures to facilitate design and planning before the design of Transport Business Models

It is increasingly urgent that hydrogen network projects reach final investment decision and get online in the early 2030s. To ensure that the UK is to meet its 2050 emission targets, it is imperative that large-scale network investments begin prior to the design of business models in 2025.

Suitable interim measures include but are not limited to:

- **Actions that financially incentivise early deployment:**
  - DEVEX and CAPEX support for the early development activity for strategic hydrogen transport | and storage projects
  - Temporarily extending the existing natural gas RAB to hydrogen or introducing a short-term business model until 2025
- **Actions that improve investment certainty:**
  - A strategy for the phase out of grey hydrogen production
  - Continued commitment to setting the UK ETS cap in line with Net Zero
  - Defining the role of hydrogen in the power sector
  - Strategy for hydrogen distribution for transport with associated incentives for vehicle purchase and deployment
  - Accelerating the hydrogen for heat decision and mandating hydrogen ready domestic boilers from 2026
  - Increasing the number of hydrogen heating trials in order to successfully demonstrate hydrogen heating in practice across a spectrum of users
  - Increasing the number of locations taking part in the hydrogen town pilot and accelerate the timeline

3. Create a strategic planning body which facilitates the coordination between networks and storage infrastructure projects

Hydrogen UK believes that, at least in the growth stage when market signals are not sufficient in driving the efficient rollout of transport infrastructure, some form of strategic planning is required. In the Transport and Storage Business Models Consultation, BEIS were correct to identify the market barriers, and these may be more difficult to overcome without the influence of a strategic planner. With the significant lead times of infrastructure projects, a purely market-led approach may have insufficient steer to deliver an efficient hydrogen network. Where possible, cohesion between the strategic planning approach for transport and storage should be maintained.

The remit and resources of the planned future system operator should also ensure that it is adequately equipped to make decisions in relation to the use of hydrogen on an equal basis with electricity.

4. Political commitment to the development of a national network of 100% hydrogen pipelines

A nationwide network of 100% hydrogen pipelines linking industrial clusters, with options to connect distributed industrial users, should be supported by Government(s) to enable conversion work to commence in 2026. Government should also implement measures to speed up delivery of major energy infrastructure through fast-track consents. An updated National Policy Statements for the energy sector should be published in early 2023.

5. Determine a National Strategy to decarbonise Industry

Many in industry see 2050 as a long-stop date for decarbonisation, whereas, in reality the bulk of decarbonisation from industry needs to happen sooner. A national strategy is key to decarbonising decentralised industrial sites in a similar timescale to industrial clusters. Without such a plan, a significant portion of industrial emissions may not be decarbonised for an additional decade. A clear plan to phase out grey hydrogen is also needed.

Additional Recommendations for Blending

1. BEIS should provide clarity around the future of blending within the UK, especially to hydrogen producers in industrial clusters (including any attached conditions)
2. Further assessments need to be taken into connection applications with impact assessments that reflect billing, network blends, settlement etc.

References

[1] BEIS (2021), UK Hydrogen Strategy, pp. 12 Available **here**

[2] ENA (2021), What you need to know about Britain's Hydrogen Network Plan, Available **here**

[3] ENA (2021), Britain's Hydrogen Network Plan, pp. 22 Available **here**

[4] BEIS (2021), Digest of UK Energy Statistics - Annual data for UK, 2021, Available **here**

[5] ENA (2019), ENA welcomes new focus on Net Zero, Available **here**

[6] Imperial College (2018), Analysis of Alternative UK Heat Decarbonisation Pathways pp.69 Available **here**

[7] Imperial College (2018), Analysis of Alternative UK Heat Decarbonisation Pathways pp. 68 Available **here**

[8] National Grid ESO (2022), Future Energy Scenarios, pp. 160, Available **here**

[9] Imperial College (2018), Analysis of Alternative UK heat Decarbonisation Pathways, Available **here**

[10] DeSantis D, James, B.D, Houchins C, Saur G, Lyubovsky M (2021), Cost of Long Distance Energy Transmission by Different Carriers, Available **here**

[11] Hydrogen Europe (2022) Clean Hydrogen Monitor, pp. 92. Available **here**

[12] Regen (2021), Industry calls for urgent action to address electricity network constraints, Available **here**

[13] IET (2023), Renewables Industry calls for grid investment as delays threaten net zero, Available **here**

[14] National Grid ESO (2023), Scottish boundaries, Available **here**

[15] Rattle I, Owen A (2022), UKERC – The role of local action in addressing industrial emissions, Available **here**

[16] BEIS (2021), Clean Growth Grand Challenges: Industrial Clusters Mission, pp.2 Available **here**

[17] ENA (2021), Britain's Hydrogen Network Plan, pp. 90 Available **here**

[18] ENA (2021), Britain's Hydrogen Network Plan, pp. 26 Available **here**

[19] BEIS (2022), Hydrogen Transport and Storage Analytical Annex, pp. 11, Available **here**

[20] National Grid (2022), Project Union: Launch Report 2022, pp.6 Available **here**

[21] Rattle I, Owen A (2022), UKERC – The role of local action in addressing industrial emissions, Available **here**

[22] BEIS (2021), UK Hydrogen Strategy, pp. 40 Available **here**

[23] ENA (2021), Britain's Hydrogen Network Plan, pp. 26 Available **here**

[24] Christopher Yang, Joan Ogden, Determining the lowest-cost hydrogen delivery mode, International Journal of Hydrogen Energy, Volume 32, Issue 2, 2007

[25] DIT, Offshore Wind, Available **here**

[26] BEIS (2022), Energy Trends September 2022, pp. 14, Available **here**

[27] LCP (2022), Renewable curtailment and the role of long duration storage, pp. 15, Available **here**

[28] Wilson I.A.G, Rennie A.J.R, Ding Y, Eames P.C, Hall P.J, Kelly N.J (2013), Energy Policy, pp. 302, Available **here**

[29] National Grid ESO (2023), Great Britain's Monthly Electricity Stats, Available **here**

[30] Hydrogen UK (2022), Hydrogen Storage: Delivering on the UK's Energy Needs, Available **here**

[31] UKERC (2019), Flexibility in Great Britain's gas networks: analysis of linepack and linepack flexibility using hourly data, Available **here**

[32] SGN (2022), LTS Futures - Future of Gas, Available **here**

[33] CCC (2018), Hydrogen in a low-carbon economy, pp. 86. Available **here**

[34] National Grid ESO (2022), Future Energy Scenarios, pp.222, Available **here**

[35] National Grid ESO (2022), Future Energy Scenarios, pp.221, Available **here**

[36] CCC (2021), Sixth Carbon Budget – Dataset, Available **here**

[37] Catapult, Frontier Economics (2021), Gas Network Regulation for the Net Zero transition, Available **here**

[38] BEIS, Hydrogen Transport and Storage Infrastructure Consultation, pp. 28 Available **here**

[39] Scottish Government (2022), Hydrogen Action Plan, Available **here**

[40] Cadent, HyNet Hydrogen Pipeline, Available **here**

[41] Catapult, Frontier Economics (2021), Gas Network Regulation for the Net Zero transition, Available **here**

[42] National Grid (2022), Project Union: Launch Report 2022, pp.9 Available **here**

[43] Catapult, Frontier Economics (2021), Gas Network Regulation for the Net Zero transition, Available **here**

[44] Ofgem (2021), Network price controls 2021-2028 (RIIO-2), Available **here**

[45] National Grid (2022), Future Grid: Project Progress Report, Available **here**

[46] National Grid (2022), Future Grid: Project Progress Report, pp. 7, Available **here**

[47] National Grid (2022), Project Union: Launch Report 2022, pp.6 Available **here**

[48] SGN, H100 Fife, Available **here**

[49] SGN, H100 Fife, Available **here**

[50] OFGEM (2020), Network Innovation Competition, pp. 6 Available **here**

[51] OFGEM (2020), Network Innovation Competition, pp. 6 Available **here**

[52] OFGEM (2020), Network Innovation Competition, pp. 6 Available **here**

[53] SGN, H100 Fife, Available **here**

[54] Fuel Cells Bulletin (2021), Nel to Supply 5 MW alkaline electrolyser for H100 Fife Project, Available **here**

[55] SGN, LTS Futures, Available **here**

[56] Ofgem (2022), SGN LTS Futures Project – Decision, Available **here**

[57] SGN, LTS Futures, Available **here**

[58] SGN (2022), SGN to deliver £29.9m national strategic hydrogen transmission and storage project, Available **here**

[59] HyDeploy case study information available **here**

[60] HyDeploy2 (September 2022), Winlaton Trial Report, Available **here**

[61] ENA Hydrogen Blending capacity maps, available **here**

[62] Ofgem (2020), Decision on revised Typical Domestic Consumption Values for gas and electricity and Economy 7 consumption split, Available **here**

[63] National Grid (2022), Future Grid: Project Progress Report, pp. 7, Available **here**

[64] BEIS, Hydrogen Transport and Storage Infrastructure Consultation, pp. 7 Available **here**

[65] ENA (2021) Britain's Hydrogen Network Plan, Available **here**

[66] National Grid (2022), Project Union Launch Report, Available **here**

[67] Ofgem, Network Price Controls, Available **here**

[68] DNV (20210), initial Hydrogen Strategy Report, pp. 92, Available **here**

Hydrogen UK