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UNITED KINGDOM

The H_2 Handbook

Legal, Regulatory, Policy, and Commercial Issues Impacting the Future of Hydrogen

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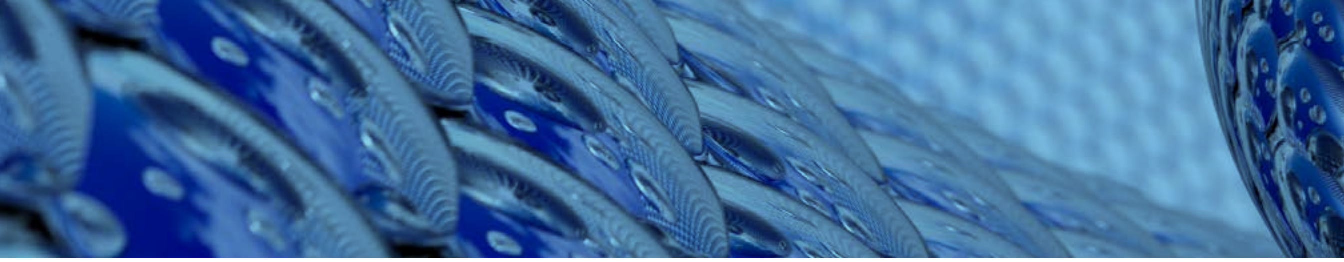

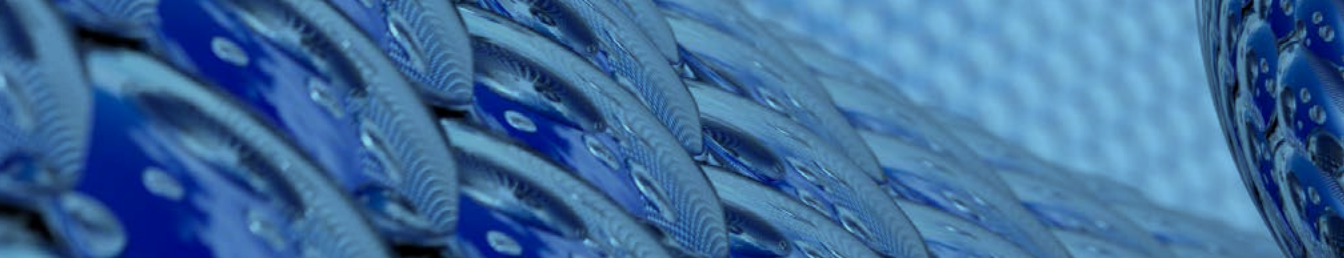

PART I - INTRODUCTION

On 27 June 2019, the United Kingdom became the first major economy to commit by law to reducing its greenhouse gas (GHG) emissions to net zero by 2050. The move to a legally binding net zero target followed the Committee on Climate Change's (CCC) May 2019 report, the UK government's lead scientific advisory on climate change, and the UK decarbonisation agenda, which recommended that the United Kingdom should increase its existing 80 per cent decarbonisation ambition to 100 per cent. The move also reflected growing societal pressure to accelerate the full decarbonisation of the UK economy.

The United Kingdom has been working to reduce its GHG emissions since the United Nations Framework Convention on Climate Change (UNFCCC) Kyoto Protocol in 1997. Since then, the United Kingdom has adopted the Climate Change Act 2008 (which sets decarbonisation targets) and signed up to the 2016 UNFCCC Paris Agreement. Measures put in place by the UK government over the last two decades have achieved significant improvements in the reduction of annual GHG emissions —in fact, the United Kingdom's 2019 annual emissions figures indicate that UK emissions have dropped by 45 per cent compared to 1990 levels.[1] This reduction is primarily the result of measures to decarbonise the power grid by bringing renewable energy sources like wind and solar online and putting measures in place to disincentivise coal-fired power generation.

[1] Department of Business, Energy & Industrial Strategy, 2019 UK greenhouse gas emissions, provisional figures (26 March 2020), page 1, available at https://www.gov.uk/government/statistics/provisional-uk-greenhouse-gas-emissions-national-statistics-2019.

These measures have contributed to emissions reductions in the power sector of 67 per cent from 2008 to 2019.[2] IIn the last two years, clean-power records haven been broken twice in the United Kingdom — in 2019, 37 per cent of power was provided by renewables,[3] increasing to 47 per cent in the first quarter of 2020.[4]

Improvements aside, there is still a way to go to decarbonise the UK economy and achieve net zero. There are a number of paths to this goal, with the two most obvious candidates being the use of renewable electricity and hydrogen. The CCC is not committed exclusively to either and does not propose that an "all or nothing" approach be adopted. Instead, a more nuanced approach is preferred, where renewable electricity and hydrogen are seen as complementary resources with their own strengths and weaknesses.

Renewable electricity can be a very efficient form of energy, as it does not need to go through the various loss-causing step and phase changes that are required in the hydrogen supply chain. However, there are a number of sectors where renewable electricity cannot be used effectively or cost-efficiently, or it simply is not viable as a net zero substitute. Hydrogen is anticipated to be a critical component for achieving the United Kingdom's net zero goals in these areas, which include hard-to-decarbonise sectors such as heavy-duty transport, industry, and shipping.

Scenario modelling by the CCC suggests that as much as 270 Terawatt-hours per year (TWh/y) of hydrogen (comparable to the total UK electricity demand today) could be required to service UK demand by 2050.[5] Other interest groups' modelling has suggested that 2050 demand might even be several multiples of this figure. The United Kingdom currently produces around 27 TWh of grey hydrogen per year,[6] which is used primarily by industrial users and the limited hydrogen refuelling station network that supports early surface transport users. If the modelling forecasts are correct, it is clear that significant investment is going to be required over the coming years on both the supply and demand sides of the equation to adapt the UK economy accordingly.

Hydrogen has long been touted as a future fuel; however, over the years it has had a number of false starts. Several key trends suggest that this time likely will be different, with declining renewables costs, mounting societal pressure to decarbonise, increased investment in and appetite for decarbonised fuels,

[2] Committee on Climate Change, *Reducing UK emissions: Progress Report to Parliament* (June 2020), page 17, available at https://www.theccc.org.uk/publication/reducing-uk-emissions-2020-progress-report-to-parliament/ ("2020 CCC Progress Report").

[3] Department of Business, Energy & Industrial Strategy, *Digest of United Kingdom Energy Statistics 2020* (2020), page 14, available at https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2020.

[4] Department of Business, Energy & Industrial Strategy, *Energy Trends June 2020* (June 2020), page 3, available at https://www.gov.uk/government/statistics/energy-trends-june-2020.

[5] Committee on Climate Change, *Net Zero: Technical report* (May 2019), page 61, available at https://www.theccc.org.uk/publication/net-zero-technical-report/ ("2019 CCC Net Zero Technical Report Report").

[6] Ibid., page 20.

and the significant number of countries pressing ahead with hydrogen strategies and investments, all adding momentum.

The COVID-19 pandemic also may further advance the hydrogen economy. While the pandemic has created many challenges in 2020, it also has brought opportunities. Around the world, including in the United Kingdom, citizens are calling on their governments to put climate change and low-carbon investment at the heart of their coronavirus recovery packages; championing a form of "green recovery." The European Union has included hydrogen as a priority area in its Green Deal and coronavirus recovery fund packages, with announced recovery and green funding in excess of €1 trillion. The UK government has indicated that green efforts will also play a role in the United Kingdom's recovery plans, with further detail expected in late 2020. The benefits of green recovery investment are supported by expert advisory groups as well, including the International Energy Agency and McKinsey & Company, who both argue that carefully designed stimulus packages that invest in low-carbon technologies could generate upwards of six jobs per US$1 million invested.[7] Such packages can also mobilise capital and help countries meet both short-term goals (to restart growth and hiring in their economies) and long-term objectives of achieving net zero emissions.

The European Union recently launched an ambitious hydrogen strategy to increase its green hydrogen capacity by six times existing hydrogen volumes by 2024, and 40 times by 2030. The United Kingdom currently does not have a dedicated hydrogen strategy, and relies instead on a range of local strategies and complementary national strategies (such as the 2017 Clean Grown Strategy), to provide direction. There are increasing calls, both from the CCC and industry, for the United Kingdom to prepare and adopt its own national hydrogen strategy to loudly pronounce its hydrogen ambitions. With the United Kingdom taking the role of president and host at next year's COP26 climate conference, the development and publication of a comprehensive and ambitious national hydrogen strategy ahead of the conference could act as a clear demonstration of the United Kingdom's ongoing role as a climate leader.

This chapter of *The Hydrogen Handbook* covering the United Kingdom is set out in six parts. In **Part II**, we consider the current regulatory landscape for both blue and green hydrogen production projects, as well as the potential for large-scale underground storage in Great Britain. We also consider a range of government supports that could be made available to encourage development of hydrogen supply and demand in the future. In **Part III**, we consider the legal regimes that apply to various forms of hydrogen transport in the United Kingdom, such as truck, rail, and pipeline. **Part IV** considers the

[7] McKinsey & Company, *How a post-pandemic stimulus can both create jobs and help the climate* (May 2020), page 4, available at https://www.mckinsey.com/business-functions/sustainability/our-insights/how-a-post-pandemic-stimulus-can-both-create-jobs-and-help-the-climate; International Energy Agency, Sustainable Recovery (July 2020), page 40, available at https://www.iea.org/reports/sustainable-recovery.

legal issues surrounding a number of hydrogen demand cases, such as natural gas grid injection and use as a surface transport fuel. In **Part V**, we discuss the range of government funding that has been made available to hydrogen projects in the United Kingdom so far, as well as the ongoing or new funding that may be made available for qualifying projects in the future. We conclude in **Part VI** with a discussion of a number of key developments that, depending on their implementation, could have significant impacts on hydrogen in the United Kingdom. A glossary of useful terms and acronyms is included at the end.

Many matters in the energy and climate policy spaces in the United Kingdom are managed by the devolved governments of Wales, Northern Ireland, and Scotland. For the purpose of the UK chapter of *The Hydrogen Handbook*, we will focus primarily on Great Britain, and England in particular.

PART II - PRODUCTION AND STORAGE OF HYDROGEN

The 2019 net zero scenario modelling by the CCC suggested that as much as 270 TWh/y of hydrogen could be required by 2050, an increase of 10 times current production.[8] Scenario modelling by other institutions, such as National Grid and Element Energy, has suggested that as much as 600 TWh/y[9] or even 1000TWh/y[10] of hydrogen could be required by 2050, depending on the role that hydrogen plays compared to other decarbonisation options. Production (or importation) of hydrogen will need to significantly increase in the years ahead if the United Kingdom is to have sufficient hydrogen capacity available to contribute meaningfully to decarbonisation by 2050.

Notwithstanding calls from environmental groups to proceed with green hydrogen only, it is expected that both blue and green hydrogen will play important roles in the United Kingdom over the coming decades. This is driven by a number of factors, including the huge scale of renewable electricity generation capacity and electrolyser capacity that would need to be built to support a 100 per cent green hydrogen scenario and the lead-time required to build such capacity (which could delay decarbonisation efforts in the short to medium term).

Price is also an important factor. The view of many experts is that green hydrogen presently costs too much to enable it to be widely deployed from day one. Driving down its cost will require the scaling-up of electrolysis and significant volumes of green electricity, which will take time. Some commentators consider that significant cost reductions may not be achieved until the 2030s or the 2040s.[11]

[8] *2019 CCC Net Zero Technical Report*, above n 5.

[9] System Transformation scenario, National Grid ESO, *Future Energy Scenarios* (July 2020), available at https://www.nationalgrideso.com/document/173821/download ("FES 2020").

[10] World leading decarbonised economy scenario, Element Energy, *Hydrogen for economic growth* (November 2019), available at http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Study-1-Hydrogen-for-Economic-Growth.pdf.

[11] For example, *see* Wood Mackenzie, *Hydrogen production costs to 2040: Is a tipping point on the horizon?* (August 2020), available at https://www.woodmac.com/our-expertise/focus/transition/hydrogen-production-costs-to-2040-is-a-tipping-point-on-the-horizon/ ("WoodMac Hydrogen Production Costs Report").

In this section we will explore the current state of play for the production of blue and green hydrogen in Great Britain, as well as some options for long-term, large-scale hydrogen storage. We will also consider some of the production supports that might be forthcoming from the UK government, based on the types of incentives that previously have been offered to the renewable electricity and bio-gas sectors, as well as recent soundings from the government in their "business models for CCUS and low carbon hydrogen" consultation process.[12]

I. Blue Hydrogen

A. Application in the United Kingdom

Where natural gas is cheap, gas infrastructure and expertise are readily on-hand, and CO_2 storage is available, blue hydrogen is thought to offer a low-cost source of hydrogen production. The United Kingdom is well-positioned in all of these areas. It is also anticipated that the development of blue hydrogen production over the short to medium term will facilitate building of infrastructure that will be necessary to support a future green hydrogen industry.

The CCC sees blue hydrogen as a key enabler for economywide decarbonisation by 2050. Indeed, the CCC's 2019 net zero scenario modelling suggested that as much as 225 TWh/y of blue hydrogen could be required by 2050, representing over 80 per cent of the anticipated annual hydrogen demand.[13] Scenario modelling by other institutions has suggested that as much as 500 TWh/y[14] or even 1000 TWh/y[15] of blue hydrogen could be required by 2050, depending on the role that hydrogen plays compared to other decarbonisation options.

If hydrogen is to play a substantial long-term role in the United Kingdom, the CCC believes that progress towards blue hydrogen deployment at scale must start immediately,[16] and it has set out the following medium-term milestones to support this transition:[17]

- **Early 2020s:** Trials and pilot projects to establish the practicality of switching to hydrogen across a range of sectors and applications;
- **Mid 2020s:** Demonstration that blue hydrogen can be sufficiently low-carbon to play a significant role in meeting the net zero 2050 target; and

12 Department of Business, Energy & Industrial Strategy, Carbon Capture, *Usage and Storage: A Government Response on potential business models for Carbon Capture, Usage and Storage* (August 2020), available at https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-business-models ("BEIS CCUS Business Models Report").

13 *2019 CCC Net Zero Technical Report Report*, above n 5, page 62.

14 System Transformation scenario, *FES 2020*, above n 9.

15 World-leading decarbonised economy scenario (the study considers that hydrogen demand will be primarily met by blue hydrogen until 2050, with green hydrogen taking an increased role only in the second half of the century), Element Energy, *Hydrogen for economic growth* (November 2019), available at http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Study-1-Hydrogen-for-Economic-Growth.pdf.

16 Committee on Climate Change, *Hydrogen in a low-carbon economy* (November 2018), page 6, available at https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy/ ("2018 CCC Hydrogen Report").

17 *2020 CCC Progress Report*, above n 2, page 58.

- **Second half of 2020s:** Blue hydrogen production at scale, for use initially in applications that would not require major infrastructure changes, such as industrial, power generation, injection into the gas network, and depot-based transport.

1. Natural Gas Infrastructure and CCUS in the United Kingdom

The United Kingdom is the second largest producer of natural gas in Europe, the vast majority of which is located in the UK sector of the North Sea. The United Kingdom also has significant gas infrastructure, including three liquefied natural gas (LNG) import facilities, 10 commercial gas storage facilities, and a significant network of transmission and distribution gas pipelines. This infrastructure could be readily utilised and supplemented to support blue hydrogen production, assisted by a ready supply chain of oil and gas contractors whose knowledge and experience could be redirected to blue hydrogen production and the associated carbon capture, utilisation, and storage (CCUS).

CCUS involves capturing the CO_2 released in the processing or combustion of hydrocarbons so that it is not released into the atmosphere. CCUS can be applied to a range of industries, including a number of hard-to-abate industries such as combined cycle gas turbine (CCGT) power generation, natural gas processing, and cement production. CCUS also can be used to capture CO_2 emissions that are produced during the hydrogen reforming process. It provides a cost-effective means of reducing CO_2 emissions in these industries and, for several sectors, it is the only technology that allows significant CO_2 reductions over a short timescale.

Captured CO_2 can be utilised in a number of ways, including to extend the life of producing fields (by way of injection to enhance oil recovery) and for use as feedstock in algae farming to produce biomass, or it can be sequestered in depleted oil and gas fields. As CCUS is still developing in the United Kingdom, infrastructure to facilitate its transportation will need to be developed (such as a CO_2 pipeline network or dedicated ship capacity), as well as large-scale, proven storage facilities. An important factor for the United Kingdom is that it may be possible to repurpose parts of the existing oil and gas infrastructure (wells, platforms, pipelines) for CCUS once hydrocarbon production ceases, thereby avoiding certain expensive CAPEX (capital expense) investments. The Department for Business, Energy & Industrial Strategy (BEIS) is actively considering this as part of its "Re-use of Oil and Gas Assets for CCUS Projects" consultation process.[18]

Effective CCUS is a critical component of blue hydrogen production. Demonstrating that CCUS works at scale, and can achieve the 95 per cent capture efficiency rates assumed in the CCC's

[18] Department of Business, Energy & Industrial Strategy, *Carbon Capture, Usage and Storage: A Government Response on Re-use of Oil and Gas Assets for Carbon Capture and Storage Projects* (August 2020), available at https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-projects-re-use-of-oil-and-gas-assets.

net zero modelling,[19] will be critical for the United Kingdom's decarbonisation plans. The United Kingdom is thought to be well-suited for the development of large-scale carbon sequestration projects, with depleted fields identified for CO_2 storage in both the North Sea and the Eastern Irish Sea. While there are currently no operational CCUS sites in the United Kingdom, carbon sequestration licences have been granted to several projects and the UK government has committed to establishing at least two UK CCUS clusters in the next decade, including funding supports from a CCUS Infrastructure Fund of at least £800 million.[20] The first of these clusters is aimed to be built by the mid-2020s, and the second by 2030.[21]

2. Important Current Blue Hydrogen / CCUS Projects

a. Acorn Hydrogen Project, Scotland

This project brings together carbon capture and hydrogen generation technologies. Led by Pale Blue Dot Energy, with funding and support from industry partners (Chrysaor, Shell, and Total), the UK and Scottish governments, and the European Union, Acorn CCS obtained the first CO_2 appraisal and storage licence to be awarded by the United Kingdom's Oil and Gas Authority.

The project will form part of developments planned at the St Fergus gas terminal near Peterhead in Scotland, where 35 per cent of all UK natural gas comes ashore. Acorn Hydrogen will produce hydrogen from North Sea gas and store the CO_2 emissions in Acorn CCS infrastructure. The project intends to blend hydrogen (at 2 per cent (vol)) into the National Transmission System and to transition the Aberdeen distribution system to 100 per cent hydrogen.

Front End Engineering Design (FEED) is scheduled to begin early in 2021, construction from 2022, with operations to commence before the end of 2025.

b. Net Zero Teeside

This project is designed to facilitate multiple low-carbon industrial hubs that can capture CO_2 from several industrial sources (including blue hydrogen production) within one region and bring economies of scale by sharing transport and storage infrastructure.

A consortium of BP (as operator), Eni, Equinor, Shell, and Total plan to accelerate the project's development to deliver the United Kingdom's first zero carbon cluster by the mid-2020s.

c. Humber Zero

This is a project to develop a zero-carbon industrial cluster around

[19] *2019 CCC Net Zero Technical Report*, above n 5, page 32.

[20] HM Treasury, *Budget 2020 (Presented to Parliament as a return to an order of the House of Commons)*, section 2.15, available at https://www.gov.uk/government/publications/budget-2020-documents/budget-2020.

[21] Ibid.

Immingham, on the east coast of England. It will integrate established industrial sites including power and petrochemical facilities with CCUS and a hydrogen hub.

In the first phase, CCUS will be installed to capture emissions from two gas-fired power stations and two refineries. In the second phase, a hydrogen hub will be developed to produce blue and green hydrogen to serve a third power station as well as local industry, such as British Steel. The project plans to move to FEED in 2021.

d. HyNet

This project aims to reduce carbon emissions from industry, homes, and transport in the North West of England and to implement a working infrastructure for hydrogen production that can be used as a model for similar projects in the future. A new blue hydrogen production plant will be built at Essar Oil UK's Stanlow refinery in Ellesmere Port and will produce 3TWh/y of hydrogen. Produced hydrogen is intended to be used by local industry, blended into the natural gas grid, and, in time, support a hydrogen transport fuelling network.

Captured CO_2 emissions would be stored in the Liverpool Bay fields, 30km offshore in the shallow waters of the East Irish Sea. Existing pipeline infrastructure for natural gas could be repurposed for CO_2 once the fields are depleted (which is expected to occur within the timescales of the HyNet North West project).

Construction and commencement of initial operations is expected between 2023 and 2026, with expansion works (to extend the project to a wider geographical area and add transport fuelling) envisaged to be delivered between 2027 and 2035.

e. South Wales Industrial Cluster

There is a large manufacturing base in South Wales (specifically around Port Talbot and Swansea), which includes oil, steel, cement, hydrogen, and chemicals industries that are critical to the Welsh economy.

This site has been identified by the UK government as ideal for the development of a CCUS and hydrogen cluster (which could include both blue and green). There are no offshore CO_2 storage sites in the immediate area, and so captured CO_2 will either need to be used as a feedstock by local industry or transported by ship for geological storage.

B. Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom

In this section, we discuss some of the key issues that project proponents will need to consider when developing a large-scale blue hydrogen production facility. These facilities are expected to be large-scale, centralised facilities that take advantage of economies of scale to reduce costs, and that will be located close to industrial end-users (for early offtake) and to CCUS and CO_2 infrastructure (to minimise the need to develop substantial CO_2 transportation systems).

Project developers will need access to the following to develop and operate a blue hydrogen plant:

- Natural gas supply
- Water supply
- CO_2 offtake arrangements
- Environmental and planning approvals

1. Feedstock and By-Products

a. Natural Gas Supply

Hydrogen and CCUS plants located strategically at major ports, terminals, and gas storage facilities would allow gas, whether imported or produced domestically, to be used as feedstock. Gas could be procured under long-term contracts from existing natural gas players, whether from local North Sea production or from gas or LNG imports, and transported to the plant using gas grid infrastructure.

A major consideration for blue hydrogen projects is the risk associated with the price of natural gas. Although oversupply issues caused by the COVID-19 pandemic (among other reasons) have resulted in very low gas prices in Europe and internationally, there are concerns that gas prices (and, by association, blue hydrogen prices) will increase in the decades ahead. Indeed, industry analyst Wood MacKenzie has forecasted that the cost of blue hydrogen could be pushed up by as much as 59 per cent by 2040 as a result of forecast gas price rises and the challenges anticipated in delivering CCUS.[22]

[22] *WoodMac Hydrogen Production Costs Report*, above n 11.

b. Water Supply

The production of blue hydrogen requires large volumes of water for use as steam in the reformation process. In practical terms, this will require a connection to the local water mains supply, which will typically be managed by the local monopoly water company.

Alternatively, if the project is located near the coast, a desalination unit could be installed and seawater could be drawn for consumption. The use of seawater and desalination units is beyond the scope of the UK chapter of *The Hydrogen Handbook*.

c. CO_2 Offtake Arrangements

CCUS is a relatively nascent industry in the United Kingdom. Current projects, such as the Acorn CCUS project and Humber Zero project discussed above, are seeing blue hydrogen developers partnering with oil and gas companies to provide dedicated offshore CO_2 sequestration services for their projects. The hydrogen and CCUS components of these projects will need to be developed in parallel for the blue hydrogen project to succeed. It is possible that we could see the possibility of third-party tie-ins to these CO_2 sequestration services in the future so that further blue hydrogen capacity could be brought online. Currently, it is not clear what the commercial terms of these arrangements are likely to be.

The CCUS landscape is still an evolving space in the United Kingdom. BEIS recently conducted a consultation process on the possible business models that could be adopted at a UK policy level for CCUS.[23] As CCUS can be applied to a variety of industries, current thinking suggests that a diversified set of business models might be required, such as an availability payment plus variable incentive for power station capture activities, a grant plus CO_2 Contract for Difference (CfD) model for industrial facility capture activities, and a long-term regulated asset based (RAB) model for the ownership and operation of CO_2 transportation and storage infrastructure. BEIS has promised an update on the assessment of models by the end of 2020.

2. Environmental and Planning Approvals

There is no dedicated regulatory framework applicable to the development of blue hydrogen projects. However, there are established environmental and planning regimes for the chemical and gas processing industries, as well as for hazardous activities and substances, that will be relevant for blue hydrogen facilities.

a. Planning Approval[24]

Nationally Significant Infrastructure Projects

Since 2008, England has had a dedicated regime to deal with certain nationally significant

23 *BEIS CCUS Business Models Report*, above n 12.

24 Please note points in the **Planning Reforms section (Part VI, Section IV)** that highlight potential significant changes to the planning approval system that may in the future impact on the commentary below.

infrastructure projects (NSIP). Where a development qualifies as an NSIP, it will be reviewed and approved at the national level by the Planning Inspectorate under the Planning Act 2008, rather than at the local level under the Town & Country Planning Act 1990 (TCPA 1990). The Planning Inspectorate is responsible for making recommendations to secretaries of state who decide applications for Development Consent Orders (DCOs) for NSIPs. Blue hydrogen production facilities are not currently included as NSIPs under the Planning Act 2008; however, this may change in the future.[25] An NSIP DCO may be required in any event if new pipelines meeting NSIP thresholds need to be built to support the blue hydrogen facility (such as natural gas supply or CO_2 offtake).

Town & Country Planning Act Approval

Planning approvals for blue hydrogen projects will be managed under the TCPA 1990. High-volume hydrogen production at a centralised site is classified as an industrial activity, and any new development is subject to formal (industrial) land use planning approval and site permitting under the TCPA 1990.

Land use planning approval must be obtained for any site to be used for storage and handling of hydrogen in tanks, cylinders, or composite vessels in order for the site to meet local land use zoning requirements and to ensure the storage and handling complies with safety and hazardous substance requirements. The authority responsible for provision of the land use permission is the Local Planning Authority (LPA). The LPA may also require, as a pre-condition to granting planning approval, entry into a contractual agreement securing delivery of a variety of measures to mitigate the impact of the development. The local authority may involve the Health and Safety Executive (HSE) and the local fire department to provide different perspectives on hydrogen safety aspects.

Under the Town and Country Planning (Environmental Impact Assessment) Regulations 2017, an Environment Impact Assessment (EIA) may be required before a blue hydrogen facility may be developed. The activities that automatically trigger an EIA requirement for a blue hydrogen facility include:

- Industrial-scale manufacturing of basic inorganic chemicals (which would include hydrogen) using chemical conversion processes;[26]
- Storage of chemical products with a capacity of 200,000 tonnes or more;[27] and

[25] The NSIP regime was set up to establish and regulate a nationally uniform framework for certain major infrastructure, such as roads, railways, airports, electricity infrastructure, gas network infrastructure, and water infrastructure. Given the likely need for a coordinated national approach to hydrogen development over the coming decades, and the fact that NSIPs already regulate large energy infrastructure projects that are similar to hydrogen production and transportation projects, expanding the Planning Act 2008 to cover hydrogen would not be an unexpected or surprising step.

[26] *Town and Country Planning (Environmental Impact Assessment) Regulations 2017*, Schedule 1, s 6.

[27] *Town and Country Planning (Environmental Impact Assessment) Regulations 2017*, Schedule 1, s 21.

- Capture of CO_2 streams for the purpose of geological storage or where the total yearly capture is 1.5 million tonnes or more.[28]

There are also other generic discretionary criteria that may trigger the requirement for an EIA, and these will need to be reviewed on a case-by-case, site specific, and industrial process basis.

Additional regulations will apply depending on the quantity of hydrogen storage that will be installed at the production site:

- At more than two tonnes, the Planning (Hazardous Substances) Regulations 2015 (Hazardous Substances Regulations) come into effect; and
- At more than five tonnes, the Control of Major Accident Hazards Regulations 2015 (COMAH) come into effect.

Both COMAH and the Hazardous Substances Regulations ensure that when preparing local plans, LPAs will make a decision to grant planning approval that is in accordance with its local plan (unless there are other material considerations that outweigh it) and having regard for the prevention of major accidents and limiting their consequences. Local authorities must consider the long-term need for appropriate distances between hazardous establishments and environmentally sensitive areas. They also need to consider whether additional measures for existing establishments are required so that risks to people in the area are not increased. When considering development proposals around hazardous installations, the LPA is expected to seek technical advice on the risks presented by major accident hazards.

b. Environmental Permits

A separate environmental permit (EP) also likely will be required for a hydrogen production site depending on the proposed scale and volume of hydrogen production at the site.

For NSIPs, if information about permitting issues is to be given for consideration within the DCO process, the permit application may need to be submitted before the planning application. The Environmental Permitting (England and Wales) Regulations 2016 (EP Regulations 2016) govern permitting in England and Wales. The EP Regulations 2016 have brought together a number of different permitting and licensing regimes with the aim of creating a more coherent, joined up, and user-friendly approach to permitting. One permit can cover a multitude of different activities.

All installations covered by the EP Regulations 2016 (a defined list of industrial facilities, manufacturing sites, or other business premises that produce potentially harmful substances) are required to obtain

28 *Town and Country Planning (Environmental Impact Assessment) Regulations 2017*, Schedule 1, s 23.

a permit from their local authority before they are authorised to operate. The activities that trigger an EP requirement for a blue hydrogen facility include:

- Refining gas (applying where 1,000 tonnes or more of gas is refined in any 12-month period);[29]
- Producing inorganic chemicals, such as hydrogen;[30] and
- Capture of carbon dioxide streams for the purpose of geological storage.[31]

c. Health and Safety Issues

While the regulatory regime relating to health and safety in this context is complex and wide-ranging, the primary piece of legislation is the Health and Safety at Work Act 1974 (HSWA).

Under section 2 of the HSWA, employers have a general duty to ensure as far as reasonably practicable the health, safety, and welfare at work of all employees. This duty extends to matters including arrangements for ensuring the safety and absence of risks to health in connection with the use, handling, storage, and transport of articles and substances.

Under section 3 of the HSWA, it is the duty of every employer to conduct its undertaking in such a way as to ensure, so far as is reasonably practicable, that persons not in its employment who may be affected thereby are not thereby exposed to risks to their health and safety.

As a result of the HSWA obligations, employers that are producing, transporting, or storing hydrogen in a workplace will need to make arrangements (so far as is reasonably practicable) to ensure that any employees engaged in such processes are protected against any risks that may arise. Practically, this could include the provision of necessary protective equipment, training on how to deal with hydrogen or hydrogen escapes, and regular audits to ensure that these measures are sufficient. The workplace should be designed to ensure that the daily tasks conducted by employees dealing with storage can be conducted safely (e.g., floor markings, protective screens, and signs displaying key processes for emergencies). Employers also should consider individuals who are not employees (such as contractors or visitors) but who might come onto the workplace and into contact with hydrogen. Safety measures could include things like providing any necessary protective equipment, and perhaps ensuring that certain areas are not accessible without permission or reserved for employees only.

Employers need to carefully consider their health and safety obligations under a wide number of other

29 *Environmental Permitting (England and Wales) Regulations 2016*, Schedule 1, s 1.2.

30 *Environmental Permitting (England and Wales) Regulations 2016*, Schedule 1, s 4.2.

31 *Environmental Permitting (England and Wales) Regulations 2016*, Schedule 1, s 6.10.

regulations that might relate to their hydrogen activities as well. A non-exhaustive list might include the Management of Health and Safety at Work Regulations 1999, COMAH, the Dangerous Substances and Explosive Atmospheres Regulations 2002, the Pressure Systems Safety Regulations 2000, the Pressure Equipment (Safety) Regulations 2016, and the Equipment and Protective Systems for Use in Potentially Explosive Atmospheres Regulations 2016. Specific advice should be sought on the application of specific regulations to hydrogen activities.

C. Opportunities, Challenges, and Looking Forward

1. Demonstrating and Developing CCUS at Scale

CCUS is a critical component of blue hydrogen production. To date, however, no CCUS projects have yet reached completion in the United Kingdom. According to one report for the BEIS, CCUS technology remains pre-commercial, and there is currently no clear delivery and investment model available in the United Kingdom to incentivise investments in technology improvements and infrastructure. In a similar way that development of the UK wind and solar industries required government and financial support, support may be required to incentivise early CCUS projects and to drive the cost and risk reductions that are required to see it developed at commercial scale. This will then allow CCUS to compete with other decarbonisation options. The UK government's funding announcements and goals to decarbonise industrial clusters, develop CCUS technology, and build CCUS infrastructure over the next decade suggest that this is an area of renewed focus. We anticipate that proponents will be eagerly awaiting the UK government's further announcements in these sectors in future budgets.

2. Government Direction and Support

Significant challenges also remain for the development of the blue hydrogen sector more generally, and the CCC has highlighted a number of obstacles in the further utilisation of hydrogen in the United Kingdom. For example, inconsistent UK government initiatives and lack of incentives were identified as impediments that may make it difficult for private-sector actors to commit to long-term projects.[32] Further, insufficient infrastructure, and failure to adapt existing infrastructure to blue hydrogen production, will make the task of market-creation more difficult. It is hoped that these concerns will be addressed in the near future to avoid limiting the development of hydrogen and CCUS projects and the positive impact such projects can have on the road to net zero.

II. Green Hydrogen

A. Application in the United Kingdom

Green hydrogen is produced using electricity from renewable energy sources to electrolyse water. No emissions are created during its production, making green hydrogen a zero-carbon energy source. However, green hydrogen is currently the most expensive form of hydrogen to produce, costing between three and six times more to produce than grey or blue hydrogen. Notwithstanding current price disparities, the last six months have seen an increasing buzz around green hydrogen. Media mentions are up significantly, numerous international energy companies have announced hydrogen projects and business divisions, and companies such as the United Kingdom's ITM Power and Germany's Thyssenkrupp are rapidly scaling their electrolysers up to gigawatt capacity.

Some energy experts believe that large-scale green hydrogen projects may never be economically viable as a low-cost alternative. Others see green hydrogen as the means to unlocking and commercialising the United Kingdom's "limitless" offshore wind potential, creating an export industry that could match the best years of the North Sea oil and gas industry. A recent report by the Offshore Wind Industry Council and the Offshore Renewable Energy Catapult suggested that a UK green hydrogen industry could be worth as much as £320 billion to the UK economy by 2050, and it could support up to 120,000 new jobs.[33]

With wind energy and electrolyser technology costs falling, the future for green hydrogen is looking promising. Increases in natural gas prices, which are a key ingredient for grey and blue hydrogen, would further narrow this gap and increase green hydrogen's cost-competitiveness. As noted in our discussion in **Key Issues for the Development of Blue Hydrogen Projects**

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32 Committee on Climate Change, *Reducing UK emissions: 2019 Progress Report to Parliament* (July 2019), page 88, available at https://www.theccc.org.uk/publication/reducing-uk-emissions-2019-progress-report-to-parliament/.

33 Offshore Wind Industry Council and Offshore Renewable Energy Catapult, *Offshore Wind and Hydrogen: Solving the Integration Challenge* (July 2020), available at https://ore.catapult.org.uk/press-releases/offshore-wind-green-hydrogen-economic-boom-ore-catapult-owic/.

in the United Kingdom (Part II, Section I.B), Wood MacKenzie forecasts that the cost of blue hydrogen could be pushed up by as much as 59 per cent by 2040 as a result of forecast gas price rises and the challenges anticipated in delivering CCUS. Wood MacKenzie expects that green hydrogen costs will fall by up to 64 per cent during the same period.[34]

As noted in our discussion in **Blue Hydrogen — Application in the United Kingdom (Part II, Section I.A)**, scenario modelling by the CCC has suggested that as much as 270 TWh/y of hydrogen could be required by 2050; however, they anticipate that only 20 per cent (44 TWh/y) will be provided by green hydrogen.[35] Other institutions have considered more bullish scenarios, such as National Grid in its 2020 Future Energy Scenarios report. Based on National Grid's modelling, approximately two-thirds (100 TWh/y) of hydrogen could be green in a "Consumer Transformation" scenario, increasing to 100 per cent (235 TWh/y) if the "Leading the Way" scenario comes to fruition.[36] It is important to note that both the CCC and National Grid reports consider domestic hydrogen production and consumption only, and they do not consider the role that green hydrogen could play as a UK export commodity (and the associated hydrogen production volumes that that would entail).

If green hydrogen is to play a substantial long-term role in the United Kingdom, substantial investment is required now, both to increase electrolyser capacity and bring prices down, as well as to significantly increase the United Kingdom's renewable energy generation capacity.

1. Important Current Green Hydrogen Projects

a. Gigastack, Humber

This project is led by ITM Power, Ørsted, Phillips 66, and Element Energy. The project will use polymer electrolyte membrane (PEM) electrolysers manufactured by ITM Power at their new giga-factory at Bessemer Park, Sheffield.

In the first phase of the project, which completed in 2019, ITM Power developed designs for a low-cost modular 5 MW electrolyser stack and collaborated with Ørsted and Element Energy to identify synergies with offshore wind farms, integration challenges with industrial users, and business models for large-scale electrolysers. The second phase will involve a FEED study on a 100 MW electrolyser system connected to the Ørsted's Hornsea Two offshore wind farm, with the resulting hydrogen supplied to Phillips 66 Limited's Humber Refinery. The project intends to identify a pathway to low-cost renewable hydrogen at gigawatt scale and to act as a blueprint for deploying further large-scale electrolyser projects.

34 *WoodMac Hydrogen Production Costs Report*, above n 11.

35 *2019 CCC Net Zero Technical Report*, above n 5, page 62.

36 *FES 2020*, above n 9.

b. Dolphyn Project, Offshore

"Dolphyn" (Deepwater Offshore Local Production of HYdrogeN) is a concept developed by ERM. The project is being led by ERM and aims to produce green hydrogen from floating offshore wind in deep-water locations.

The project includes a large-scale floating wind turbine (nominally 10 MW) with an integrated desalination unit and electrolyser, all working together to produce green hydrogen that can be piped to shore. Work is currently being undertaken to design a 2 MW prototype system.

c. Orkney Islands, Scotland

A localised hydrogen economy has been set up successfully in the Orkney Islands in North Scotland. The Orkney Islands have plentiful wind and tidal resources and the community's wind turbines were being regularly curtailed to match local power demand and export limits (which could not be improved without expensive upgrades).

The project produces hydrogen from two ITM electrolysers, with the resulting hydrogen then transported around the island network for use in fuel cells and for heat at the harbour, as well as at a vehicle refuelling station. There are plans to convert the ferry to use a hydrogen fuel cell as well.

d. ITM Mobility / Shell Refuelling Collaboration Agreement

The aim of this collaboration is to make hydrogen a convenient and viable fuel choice for passenger cars and commercial vehicles, including heavy goods vehicles (HGVs) and buses. This is achieved by installing ITM electrolysers and dispensing systems at existing Shell service stations.

The collaboration began in 2015 and was recently extended until 2024. So far, hydrogen refuelling facilities have been added to Shell service stations in Cobham, Beaconsfield, Gatwick, and Derby. Further installations are planned, including two London locations.

e. The PosHydon Project, Dutch North Sea

The PosHydon Project was the first offshore green hydrogen project and is located in the Dutch North Sea. Hydrogen is produced from seawater by electrolysis on a disused oil and gas platform, Q13-a. The aim of the pilot project is to gain experience integrating energy systems at sea and the production of hydrogen in an offshore environment.

Although not a UK project, the PosHydon project is an interesting example of how disused oil and gas infrastructure could be repurposed to produce hydrogen offshore, a strategy that could just as readily apply in the UK North Sea.

The project is led by Neptune Energy in collaboration with Nexstep, the Dutch association for decommissioning and reuse, TNO, Gasunie, Eneco, DEME Offshore, NOGAT, and Noordgastransport.

B. Key Issues for the Development of Green Hydrogen Projects in the United Kingdom

In this section, we discuss some of the key issues that proponents will need to consider when developing an onshore green hydrogen production facility.

A different regulatory regime, which is beyond the scope of the UK chapter of *The Hydrogen Handbook,* would likely apply to the development of an offshore green hydrogen production project — for example, where an electrolyser system is co-located as part of the turbine structure, as may be the case in the Dolphyn project, or installed on an offshore platform, as in the PosHydon Project (see **Green Hydrogen - Application in the United Kingdom (Part II, Section II.A**). Use of offshore facilities would likely be managed under the Energy Act 2008 and associated offshore oil and gas legislation. Although hydrogen is not currently included as a regulated "gas" for storage purposes under the Energy Act 2008, this could be changed in the future by an order of the Secretary of State. A grant of rights may also be required from the Crown Estate.

Project developers will need access to the following to develop and operate a green hydrogen facility:

- Electrolyser
- Water supply
- Renewable power supply
- Environmental and planning approvals

1. Electrolyser

The three types of electrolysers are (1) Polymer Electrolyte Membrane (PEM), (2) Alkaline (AEL), and (3) Solid oxide electrolyser cells (SOEC). PEM and AEL are the two main types of commercially available low-temperature electrolysers, and both technologies have the ability to deliver:

- Pressurised hydrogen without a compressor
- On-demand hydrogen
- Pure, dry, and carbon-free hydrogen

It is important to note that AEL has been the main industrial scale electrolysis technology utilised for nearly a decade. For this reason, energy experts view this technology as the most commercially advanced form of electrolysis. AEL has certain advantages over PEM technologies, such as cheaper catalysts, higher durability due to an exchangeable electrolyte, and higher gas purity due to lower gas diffusivity in alkaline electrolyte. PEM electrolysis is currently being utilised in smaller-scale deployment and it is unclear when this will be available at commercial scale.

Although there are significant opportunities in the manufacturing and electrolyser production space, there are only a few manufacturers active and supplying the equipment to projects. In the United Kingdom, ITM Power and Ceres Power are two UK-based companies that are developing electrolysers and hydrogen production. Internationally, other leading manufacturers include Nel ASA and Thyssenkrupp AG. Broadly speaking, these companies design, manufacture, and, in some cases, build and install systems for hydrogen projects. We would expect that each will have their own bespoke terms and conditions, but developers should give thought to how technology risk, system performance risk, intellectual property issues, duration/applicability of any warranties, and the guaranties provided by such manufacturers in respect of such systems are managed/allocated among the parties across all of the relevant contractual agreements.

2. Renewable Power Supply

To achieve green hydrogen production, a critical component is the ability to secure electricity from a renewable energy project. In the United Kingdom, the green electricity supply options for green hydrogen developers are to:

- Receive directly from a renewable energy project and offtake the green electricity produced from the project by way of a direct power purchase agreement (PPA); or

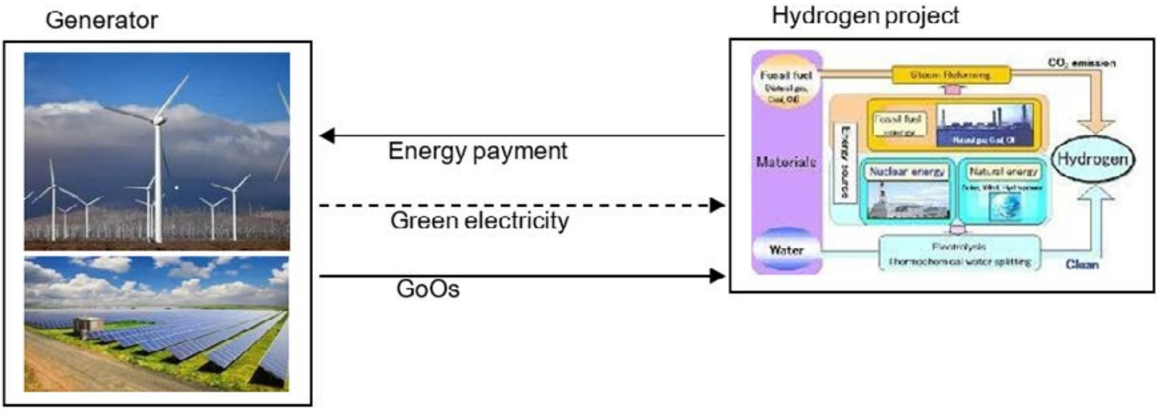
- Receive the supply of green electricity from a renewable energy generator by way of: (1) a physical power purchase agreement, if the generator's plant is on the same distribution network; or (2) a virtual power purchase agreement (VPPA).

a. Direct PPAs

A direct PPA, often referred to as a "private wire PPA," is a direct contractual relationship covering the supply of electricity via a private network connection, between a generator and an offtaker. This involves the generator's solar or wind farm being located at, or near to, the offtaker's project. In the context of supplying energy to a green hydrogen project, there are advantages to implementing a private wire PPA structure — namely, that the generator's project will exclusively supply an agreed volume of renewable electricity to the hydrogen project preferably on a long-term basis. Security of renewable electricity supply on bankable terms for a long period will be essential to enabling green hydrogen projects and therefore these locked-in, exclusive, long-term arrangements are preferential.

That said, it may not always be practically, technically, or financially viable to build a stand-alone green hydrogen project in close proximity to a renewable energy project. It is more likely that renewable energy projects may want to bolt-on a green hydrogen project in close proximity to their wind farm and, in that regard, a private wire PPA structure is an ideal structure. This has been the case for several green hydrogen pilot projects in the United Kingdom and Europe.

Private wire PPA Structure



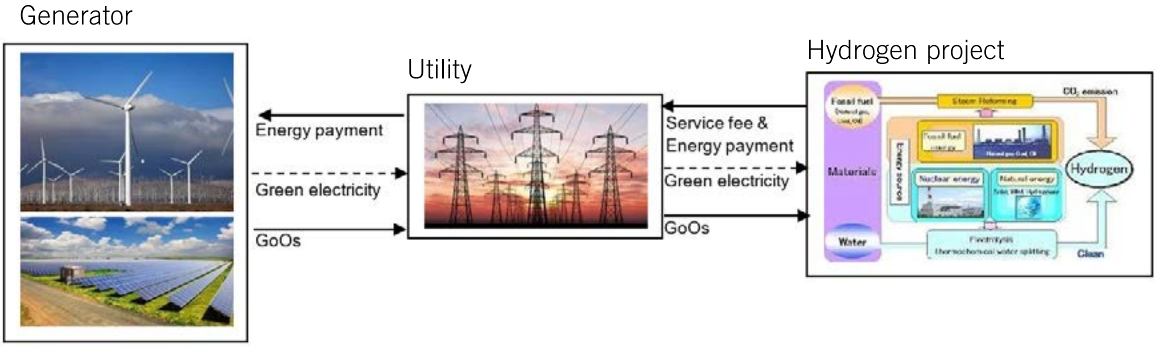
b. Physical PPAs

In the event that the green hydrogen project cannot be directly connected to the generator's renewable energy plant, but the plant is on the same grid network as the hydrogen project, a physical (often referred to as "sleeved") PPA may provide a way in which the parties can buy and sell green electricity from the renewable energy plant. For this structure to be viable, the generator's plant and the hydrogen project must both be connected to the same distribution network. There will be a PPA between the generator and the green hydrogen project and, similar to the private wire PPA structure, the generator agrees to supply an agreed quantity of green electricity from its plant for a fixed price. However, under this approach, the green hydrogen project will appoint a licenced electricity utility company (Utility) as the intermediary between the generator and the project.

In practice, the Utility takes delivery of the green electricity at the generator's plant and sells it on to the project at its point of consumption in consideration for a service fee. In the event that the generator's plant is not producing for whatever reason, the Utility is typically required to cover the plant's supply obligations to meet the hydrogen project's offtake needs and provide the necessary balancing and settlement functions as required by the Balancing and Settlement Code. This arrangement entails a complicated contracting structure involving back-to-back PPAs, on one end between the Utility and generator, and on the other end between the Utility and the project. Ideally, both agreements will be on similar terms to ensure that there is no conflict or additional risk for the parties.

Arguably, this is a costlier and more complicated structure that would theoretically increase the operating costs of the green hydrogen project. However, in the event that it is not feasible to enter into a private wire PPA, but it is possible to construct a green hydrogen project on the same distribution network as a renewable energy project, this physical PPA structure is capable of achieving security of supply from a guaranteed renewable energy source, which is paramount for unlocking green hydrogen.

Physical PPA Structure



c. Virtual Power Purchase Arrangements (VPPAs)

To the extent that it is not possible to construct a green hydrogen project in close proximity to or on the same distribution network as an available renewable energy project, a VPPA is another alternative. A VPPA is a purely financial transaction (rather than a contract for the sale of green electricity), where the green hydrogen project does not take physical delivery of the plant's green electricity. In turn, the project will enter into a power supply agreement with a Utility for the supply of electricity to the project.

Under this approach, the generator enters into a standard PPA with the Utility at the market price. In parallel, the generator and the hydrogen project enter into a separate VPPA incorporating a strike price at which the parties are looking to fix the price of the green electricity. The VPPA then operates as a financial hedge where, depending on the market price at a given time, the generator or the project will pay the other the difference between the market price and the strike price. For example, if the market price is above the strike price, the generator will pay the difference, and if the market price is below the strike price, the hydrogen project will pay the difference. A benefit to the hydrogen project from a "green" perspective is that the strike price paid under the VPPA will factor in the incentives (i.e., a guarantee of origin (GoO)) that the project will be entitled to and confirm that the project has secured electricity from a renewable energy source.[37]

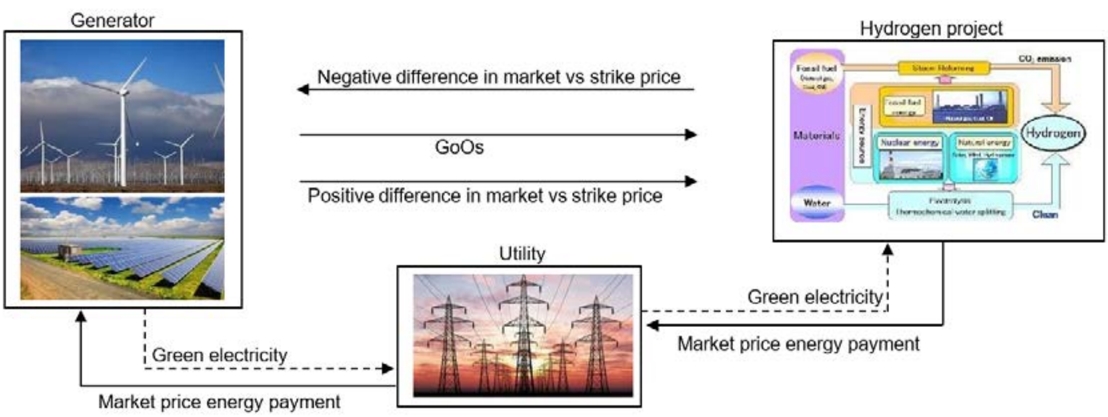
The challenge with a VPPA structure is that the electricity that is physically supplied to the hydrogen project pursuant to the agreement with the Utility may not have actually been produced from a renewable energy source. For example,

[37] Note that, as a purchaser of green electricity, the hydrogen project will be eligible to receive electricity GoOs from all three PPA structures discussed here, whether green electricity is procured under a private-wire, physical, or virtual PPA structure.

notwithstanding that GoOs can be provided to show that renewable energy has been delivered into the electricity grid (e.g., from offshore wind turbines in the Humber), the actual electrons that are delivered to the green hydrogen project (e.g., located on the other side of the United Kingdom in Liverpool) may have been generated by a gas-fired power station. Theoretically, one way to mitigate against that risk is to impose an obligation on the Utility to ensure that supply of electricity to the hydrogen project is from a renewable energy origin. An alternative, which we consider in further detail in **Green Hydrogen - Opportunities, Challenges, and Looking Forward (Section II.C)**, could be to rely on the electricity GoO system.

Although there is some overlap between the three renewable energy-sourcing methods discussed above, fundamentally, the right arrangement for a green

Virtual PPA Structure



hydrogen project will be determined on the dynamics of the project as a whole. For example, it appears that a planned green hydrogen pilot project in Humber, UK, is being developed using estuary-anchored offshore wind, and the Gigastack project is sourcing renewable energy from the Hornsea Two offshore wind farm. It is likely that these will use a private wire PPA structure to facilitate the supply of green electricity to the project. This is an evolving space, and the K&L Gates hydrogen team will continue to monitor how power supply structures are implemented as more green hydrogen projects come to market.

3. Water Supply

The production of green hydrogen requires large volumes of water for use in the electrolysis process. Please refer to our discussion on water supply considerations in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom (Part II, Section I.B)**.

4. Environmental and Planning Approvals

There is no dedicated regulatory framework applicable to the development of green hydrogen, power-to-gas projects. However, as is the case for blue hydrogen projects, there are established environmental and planning regimes for the chemical and gas industries, as well as for hazardous activities and substances, that will be relevant for green hydrogen facilities.

a. Planning Approval[38]

Nationally Significant Infrastructure Projects

As discussed above, England has a dedicated regime to deal with NSIPs. Green hydrogen production facilities are not currently included as NSIPs under the Planning Act 2008; however, this may change in the future. Please refer to the discussion in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom (Part II, Section I.B)** for further information.

Local Planning Approval

Where a green hydrogen facility does not qualify as an NSIP, planning approval from the LPA will be required. At a planning and environmental level, the legislative requirements in connection with the production and storage of hydrogen are considerable. This is to ensure that sites producing and storing dangerous gases are secure and that relevant health, safety, and environmental impacts of the development and its operations are actively considered. Under the Town and Country Planning (Environmental Impact Assessment) Regulations 2017, an EIA may be required before a green hydrogen facility may be developed. The activities that automatically trigger an EIA requirement for a green hydrogen facility include:

- Industrial-scale manufacturing of basic inorganic chemicals (which would include hydrogen) using chemical conversion processes;[39] and
- Storage of chemical products with a capacity of 200,000 tonnes or more.[40]
- There are other generic discretionary criteria that may trigger the requirement for an EIA, and these will need to be reviewed on a case-by-case, site specific, and industrial process basis.

The Hazardous Substances Regulations and COMAH may also be a factor in determining planning applications for storage facilities, in the same way as they may apply to blue hydrogen facilities (which is set out in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom, Part II, Section I.B**).

38 Please note points in the **Planning Reforms section (Part VI, Section IV)** that highlight potential significant changes to the planning approval system that may in the future impact on the commentary below.

39 *Town and Country Planning (Environmental Impact Assessment) Regulations 2017*, Schedule 1, s 6.

40 *Town and Country Planning (Environmental Impact Assessment) Regulations 2017*, Schedule 1, s 21.

b. Environmental Permits

A separate EP for the production of inorganic chemicals (such as hydrogen) will also likely be required for a green hydrogen facility. Further information on the EP regime is available in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom (Part II, Section I.B)**.

c. Health and Safety Issues

Developers and operators of a green hydrogen facility will have to consider a wide range of health and safety issues. Please refer to our discussion in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom (Part II, Section I.B)** for more information.

C. Opportunities, Challenges, and Looking Forward

1. Green Hydrogen from GoO Electricity

Due to the need to purchase electricity from a renewable energy source, the approach taken thus far has been to co-locate hydrogen projects with renewable energy plants, putting pressure to deploy electrolyser systems in specific sites.

Physical PPAs and VPPAs may be a solution to this bottleneck and enable the development of green hydrogen projects in multiple locations, located far away from the renewable energy source itself. This could work by using the electricity GoO system (discussed further in **A Hydrogen GoO, Part VI, Section III**) to "prove" that, at a network level, renewable electricity had been added to the network and that the associated GoO had been "consumed" by the hydrogen producer to produce the green hydrogen.

The UK electricity system is not currently 100 per cent green, having a carbon intensity of 246g/CO_2/kWh in 2018.[41] As a result, some may argue that the only way to truly produce green hydrogen is under a private wire PPA model. However, allowing GoOs to be used to produce green hydrogen could positively impact the renewable energy and hydrogen industries without negatively affecting decarbonisation goals. For example, these could build the investment case for further renewable energy sources to be brought online, and also overcome some of the co-location challenges that hydrogen producers currently face if they wish to produce green hydrogen. Being able to separate the renewable power source from the green hydrogen production system could mean that the generation equipment could be optimally located for generation. Equally, it would allow the production system to be strategically located to best cater to the end-user market and any post-production transportation and distribution. This could have some interesting and positive benefits for the hydrogen economy. For example, a fuel supplier could install electrolysers on its refuelling station forecourts and purchase GoOs from a distant wind farm to produce and sell

[41] *2020 CCC Progress Report*, above n 2, page 78.

certified green hydrogen to end-users throughout the United Kingdom.

For such a structure to be successful, it will be important that the public, industry, and government are in agreement that VPPA structures for green hydrogen production support decarbonisation objectives as a whole. Appropriate design of such a system, together with clear messaging, will therefore be critical to the structure's success.

2. Green Hydrogen from Nuclear Power

Advocates of the hydrogen economy have suggested for decades that nuclear power can play an important role. Proponents of nuclear energy have recently joined in, noting that producing hydrogen may throw a lifeline to today's commercial fleet of nuclear reactors.

Nuclear plants can produce hydrogen by generating both steam and electricity. The high-quality steam produced by nuclear reactors can be electrolysed and split into hydrogen and water. It has been suggested that a single 1,000 MW nuclear reactor has the potential to produce over 200,000 tonnes of hydrogen each year. The United Kingdom currently has just under 9 GW of installed nuclear capacity.

The nuclear industry is in a state of flux in the United Kingdom at present, with concerns over cost-competitiveness of new facilities and how to deal with nuclear waste. In principle, however, nuclear plants could provide a further mechanism for producing low-carbon hydrogen in the United Kingdom.

III. Storage at Scale

A. Application in the United Kingdom

1. The Need for Hydrogen Storage in the United Kingdom

Natural gas demand in the United Kingdom is highly seasonal, particularly in the domestic and commercial market. If hydrogen is to be the successor to natural gas, or at least part of the United Kingdom's future energy network, it follows that this seasonality will affect demand for hydrogen in the same way. Meeting peaks in demand will require the ready availability of hydrogen, and storage in facilities with ready access will be a key strategic part of the transitional strategy.

The United Kingdom typically has met demand for natural gas during high-use periods through a mixture of underground storage, use of gas pipeline "linepack,"[42] as well as by delivery on demand. The CCC has identified a potential "chicken and egg" scenario in the development of the hydrogen network in the United Kingdom, with the demand for storage of hydrogen in some ways dependent on how this barrier is overcome. For example, while the demand for hydrogen in the United Kingdom remains within industrial clusters (discussed more below), and the domestic and commercial demand for hydrogen is nonexistent, the need for large-scale storage infrastructure would seem low. However, as the number and scale of these clusters increases, and

[42] The process of storing gas within gas pipelines, due to the ability to operate them at a range of pressures — i.e., the gas can be stored at maximum pressure in the pipeline, while it is used at minimum operating pressure.

the technology to enable large-scale deployment in the United Kingdom's energy networks is developed, the demand for hydrogen will increase. In such a scenario, storage infrastructure would be expected to play an important role in ensuring that hydrogen supply and demand are efficiently managed.

2. Options for Large-Scale Storage in the United Kingdom

The most oft-touted solution for storing hydrogen in the United Kingdom is in salt caverns, which are particularly numerous in the north of England and in Wales. A number of salt caverns are already used for gas storage, with over 30 in existence across the country. The CCC has recognised that salt caverns are likely to be one of the primary storage solutions for hydrogen to address the seasonality of demand in the domestic and industrial use markets.[43] Effective large-scale storage could also reduce the amount of hydrogen production capacity that needs to be built, as production could be scheduled across the year and channelled to storage during periods of low demand.

However, salt caverns are not without their problems. The composition and structural integrity of the caverns must be adequately assessed and monitored, and daily caps (usually around 10 per cent of the storage capacity) on the amount of hydrogen that can be withdrawn from storage will need to be applied to mitigate against potential collapse, with the remaining percentage retained as cushion gas.[44] This, in turn, can increase the cost of salt cavern storage, as significant resources must be channelled into not only the front-end development of the storage facility but also the maintenance over the cavern's life span.

In areas where salt caverns do not exist, alternative large-scale storage solutions have also been proposed. In Scotland, for example, it has been suggested that depleted oil and gas fields could be used for hydrogen storage — to the extent that they are not already earmarked for CCUS. The cost of developing and maintaining these storage solutions is thought to be far lower than the costs associated with salt caverns. However, there are significant concerns that residual contaminants in these fields may render them unsuitable for hydrogen storage and that higher cushion gas requirements are needed to avoid rock breakage.

In scenarios where a substantial hydrogen pipeline network is developed, either as a stand-alone network or through conversion of the existing natural gas network, the network's ability to linepack hydrogen will add a further large-scale storage solution. As discussed in **Transport by Pipeline (Part III, Section II)**, works are already underway to replace most of the United Kingdom's old iron distribution pipework to new, hydrogen-ready polyethylene

43 Committee on Climate Change, *Hydrogen in a low-carbon economy* (November 2018), page 84, available at https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf.

44 Ibid., page 85.

pipes. The ability to convert the existing gas distribution networks to 100 per cent hydrogen, or to a blend of hydrogen and natural gas, is being carefully considered by a number of projects across the United Kingdom.

B. Regulation of Large-Scale Storage Facilities

In this section, we will consider the regulatory regimes that apply to the development and operation of a large-scale, underground hydrogen storage facility in an onshore salt cavern in England.

A different regulatory regime, which is beyond the scope of the UK chapter of *The Hydrogen Handbook,* would likely apply to the development of an offshore gas storage project. Use of offshore facilities would likely be managed under the Energy Act 2008 and associated offshore oil and gas legislation. Although hydrogen is not currently included as a regulated "gas" for storage purposes under the Energy Act 2008, this could be changed in the future by an order of the Secretary of State. A grant of rights may also be required from the Crown Estate. Where a depleted gas reservoir is being converted into a gas storage facility, it is likely that a petroleum licence would also be required.

Currently, there is no dedicated regime for the development and operation of onshore, salt cavern hydrogen storage facilities. Instead, traditional rules for onshore underground gas storage facilities will apply.

1. Nationally Significant Infrastructure Projects

Since 2008, England has had a dedicated regime to deal with NSIPs. Where a development qualifies as an NSIP, it will be reviewed and approved at the national level by the Planning Inspectorate under the Planning Act 2008, rather than at the local level under the TCPA 1990. The Planning Inspectorate is responsible for making recommendations to secretaries of state who decide applications for DCOs for NSIPs.

Under section 17(4) of the Planning Act 2008, if the working capacity of the underground gas storage facility is expected to be at least 43 million standard cubic metres, or the maximum flow rate of the storage facilities is expected to be at least 4.5 million standard cubic metres per day, the project will qualify as an NSIP. Major onshore hydrogen storage projects that qualify as NSIPs will therefore require a DCO under the Planning Act 2008.

While the overall success rate for DCO projects is high, a number of high-profile DCO refusals relate to CCUS, gas storage, and offshore projects.[45] An indicative timeline for securing a DCO is as follows:

- Pre-application (approximately two years);
- Acceptance and examination (10 to 12 months); and then
- Decision (six months).

[45] For example, a DCO application for the Preesall Saltfield Underground Gas Storage project in Lancashire was refused in April 2013 by the energy secretary against the recommendation of a panel of three commissioners. The panel concluded that the adverse impacts of the proposed development would not outweigh its benefits; however, the energy secretary decided to refuse the application on the basis that a "clear gap" in geological data contained in the application meant that the project had failed to demonstrate the suitability of the geology at the site for salt cavern storage.

In accordance with the Planning Act 2008, a DCO automatically removes the need to obtain several consents that would otherwise be required for development, including planning permission and compulsory purchase orders. The idea of this regime is that it is a quicker process for large-scale development projects to get the necessary planning permission and other related consents that they would require (e.g., an EIA or an application for hazardous substances), rather than having to apply separately for each consent.

2. Local Planning Approval

Where a hydrogen storage facility does not qualify as an NSIP, planning approval from the LPA will be required.

At a planning and environmental level, the legislative requirements in connection with hydrogen storage are considerable. This is to ensure that sites storing dangerous gases are secure and that relevant health, safety, and environmental impacts of the development and its operations are actively considered.

Under the Town and Country Planning (Environmental Impact Assessment) Regulations 2017, an EIA is required before a storage facility for chemical products (which would include hydrogen) with a capacity of 200,000 tonnes or more can be developed.[46]

The Hazardous Substances Regulations and COMAH may also be a factor in determining planning applications for storage facilities, in the same way as they

[46] *Town and Country Planning (Environmental Impact Assessment) Regulations 2017*, Schedule 1, s 21.

may apply to production facilities (which is set out in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom (Part II, Section I.B)**.

3. Environmental Permits

An EP may be required for a hydrogen storage facility. It will depend on whether the proposed facility meets generic discretionary criteria, and these will need to be reviewed on a case-by-case and site-specific basis.

There are other generic discretionary criteria that may trigger the requirement for an EIA, and these will need to be reviewed on a case-by-case, and specific and industrial process basis.

4. Health and Safety Issues

Developing and operating a hydrogen storage facility will mandate consideration of a wide range of health and safety issues. Please refer to our discussion in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom (Part II, Section I.B)** for more information.

5. Gas Act

The *Gas Act 1986* (Gas Act) applies to any gaseous substances that consist wholly or partly of, among other things, methane and hydrogen. The Gas Act will therefore apply to natural gas, hydrogen, and blends of natural gas and hydrogen.

The Gas Act imposes a number of independence rules on the owners of gas storage facilities. Unless a minor facilities exemption has been granted, the owner of a gas storage facility is prohibited from producing gas in certain countries and from engaging in gas shipping or gas supply activities in certain countries.[47] In addition, if an affiliate of the owner engages in any of those activities, the owner must operate the storage facility independently of the affiliate's interests and is required to put a specialised independence programme in place to ensure that they do not discriminate against non-affiliates. The Gas Act does not delineate its regimes by type of gas. Parties who wish to own hydrogen storage facilities in the United Kingdom will therefore need to be mindful of their broader activities, including in natural gas.

A third-party access regime also applies to gas storage facilities under the Gas Act.[48] Unless a third-party access exemption or a minor facilities exemption has been granted, the owner of a gas storage facility is required to publish its main commercial terms for access to storage capacity at least once a year, and must ensure that such conditions do not discriminate against potential applicants. If a third party makes an application for access, then the owner of the facility must negotiate in good faith and endeavour to reach an agreement with the applicant for storage capacity. If the parties are unable to reach agreement, the party seeking access can apply to Ofgem to consider the application.

[47] *Gas Act 1986,* s 8R. Currently any other EEA state (i.e., the EU member states plus Iceland, Liechtenstein, and Norway). However, this will be amended following Brexit so that this restriction only applies to gas production, shipping, and supply activities in the United Kingdom. *See The Electricity and Gas etc. (Amendment etc.) (EU Exit) Regulations 2019.*

[48] *Gas Act 1986*, s 8S.

Ofgem is empowered to give directions to the facility owner to grant access, if this would not prejudice the efficient operation of the facility.

C. Hurdles, Challenges, and Looking Forward

1. Chicken and Egg

There are many solutions to the storage of hydrogen. However, until demand increases, it will be very difficult to establish the right mix of storage solutions to meet demand swings, cost pressures, and technical and regulatory concerns. As mentioned above, an existing challenge is the "chicken and egg" issue: Should supply (including storage) or demand be created first? The CCC is keen to break that deadlock by generating demand for hydrogen through industrial hubs, and developing the technology to build the infrastructure for hydrogen in the United Kingdom at the same time, thereby raising supply and demand simultaneously.

2. Lead Time for Preparing Salt Caverns for Hydrogen

Given the research and development issues with salt caverns — the need to assess compatibility for hydrogen storage, the specific development needs of each site (including staged injections of substantial volumes of cushion gas), and the need to comply with planning and environmental regulations — a cavern may require three to seven years to be ready to operate for withdrawals. If these caverns are to be "online" and ready to provide hydrogen withdrawal services by the 2030s, investment into the development of these caverns needs to start now. If this process is delayed, there is a risk that hydrogen expansion in the future may stall, pending storage availability.

3. Depleted Fields

Depleted fields can only be used for CO_2 or hydrogen. Assuming that the contamination concerns associated with

utilising depleted oil and gas fields for hydrogen storage can be overcome, a further question arises as to whether hydrogen storage is the best use of this space. As discussed in **Blue Hydrogen (Part II, Section I)**, CCUS is expected to play an important role in the United Kingdom's net zero agenda. Of course, if a depleted field is repurposed to store hydrogen, it cannot simultaneously store CO_2. Key policy decisions will need to be taken as to whether (or which) depleted fields should be used for hydrogen storage or for CO_2 sequestration.

IV. Production Supports

At least in the early years, it is anticipated that production supports, or pricing supports that drive production growth, will be required to kick-start the hydrogen economy, to incentivise the scaling up of hydrogen production, and, perhaps most importantly, to help proponents to build bankable business cases.

The United Kingdom has used a range of "push" and "pull" measures to drive investment and incentivise the scaling up of alternative energy sources, such as renewable electricity from wind turbines and biomethane, over the past two decades. "Pull" measures have included financial support mechanisms for generators, such as feed-in tariffs, contracts for difference, and the Renewable Heat Incentive. "Push" measures have included mandatory procurement obligations imposed on market suppliers, such as the Renewables Obligation and the Renewable Transport Fuel Obligation (RTFO).

BEIS recently conducted an industry consultation process on the preferred low-carbon hydrogen business model.[49] A number of business model options are being considered, including CfD, obligation, RAB, direct grant, and an expansion of the RTFO. We consider a number of these in further detail below. BEIS intends to publish an update on their assessment by the end of 2020, consult further on a preferred business model in 2021, and publish a final business model in 2022.

A. Contracts for Difference

CfDs (Contracts for Difference) are the UK government's main contemporary mechanism for supporting low-carbon electricity generation. Under this structure, generators are awarded 15-year CfD contracts through an auction process where they compete against other projects to agree on a "strike price" for all electricity generated. If the wholesale electricity price is less than the agreed strike price, then the generator will receive a top-up payment from the CfD counterparty (a UK government-owned company called the Low Carbon Contracts Company) for its energy. If the market price is higher than the strike price, then the generator is required to pay the excess to the CfD counterparty.

[49] *BEIS CCUS Business Models Report*, above n 12.

The ultimate form of hydrogen CfD is not yet clear, but potential structures could include:

- A mechanism based on a competitively auctioned strike price per kilogram of produced hydrogen;
- Where hydrogen is injected into the natural gas grid, a mechanism that offers a fixed-price CfD against the market price for natural gas; or
- A mechanism based on a competitively auctioned strike price per tonne of CO_2. Under this model, payments would be made to producers when carbon prices are lower than the strike price (which would suggest that carbon-emitting competitor products are not sufficiently penalised to offer a level playing field). If the carbon price moved above the strike price, the producer would pay back the difference. The European Union is considering adopting this type of CfD as part of its Green Deal "Coronavirus Recovery Package." Please refer to the EU chapter of *The Hydrogen Handbook* for more information.

B. Renewable Heat Incentive

The Renewable Heat Incentive (RHI) is a UK government scheme that encourages uptake of renewable heat technologies in domestic and non-domestic households, and supports the injection of biomethane into the natural gas grid.

Accredited biomethane injection facilities receive a long-term tariff (currently 20 years) for the amount of biomethane that they inject into the gas grid. The current scheme is closing on 31 March 2021; however, the UK government is proposing to replace it with a new Green Gas Support Scheme that is envisaged to run from Autumn 2021 to 2025/2026. For longer-term support, the UK government expects to focus on market-based mechanisms for green gas options, such as a model based on CfDs.

The UK government has highlighted the possibility of extending the Green Gas Support Scheme to cover hydrogen.

C. Renewable Transport Fuel Obligation

The Renewable Transport Fuel Obligation (RTFO) is a requirement on large transport fuel suppliers (such as retail fuel suppliers like Shell and BP) to show that a percentage of the fuel they supply comes from renewable and sustainable sources. If the supplier fails to procure enough renewable and sustainable fuel in a year, they are required to pay a buy-out price to cover the shortfall.

The definition of "renewable transport fuel" would allow green hydrogen wholly produced from renewable energy (i.e., by private wire or perhaps sleeved PPA renewable energy supplies — see **Key Issues for the Development of Green Hydrogen Projects in the United Kingdom (Part II, Section II.B)**) to qualify as an acceptable fuel for RTFO purposes; however, blue hydrogen would not currently qualify, as it is produced from a fossil fuel.[50]

[50] *Energy Act 2004.*

In a scenario where hydrogen gains acceptance as a fuel source, whether for light consumer vehicles, heavy goods vehicles, or both, treatment as a RTFO-qualifying fuel could help to drive demand for hydrogen. Extending the scheme to also allow blue hydrogen to qualify (noting that 95 per cent of emissions are targeted to be captured during blue hydrogen production), or to allow hydrogen produced from virtual PPA renewable energy (see **Key Issues for the Development of Green Hydrogen Projects in the United Kingdom (Part II, Section II.B)**), would act as a further production support for the hydrogen industry in the United Kingdom.

PART III - TRANSPORTATION OF HYDROGEN

In circumstances where hydrogen cannot be produced on-site at the point of consumption, or in a scenario where hydrogen production develops in the United Kingdom in a centralised rather than decentralised manner, safe, quick, and cost-effective transport will be of critical importance to end-users and project developers alike.

This section explores the possibility of hydrogen transportation by truck, rail, and pipeline.

At present, hydrogen is primarily transported in the United Kingdom on dedicated, short-distance hydrogen pipelines (for industrial users) or by truck as a liquid or compressed gas. Transportation options likely will expand in the future. Given the similarities between LNG and hydrogen (i.e., they both have a very low density and therefore need to be either pressurised or liquefied to be efficiently transported), transportation methods used in the LNG industry may offer some insights that are worth considering.

LNG is typically transported as a liquid by truck or ship (or in its re-gasified form by gas pipeline). Although transportation by rail is not yet a common form of transport for LNG in the United Kingdom, LNG transport by rail has occurred in Europe and is commonplace in Japan. Transport of LNG by rail is also gaining attention in the United States as well. Given the increased efficiencies of transporting low-density gases as a liquid, and the cost and road congestion benefits that could be achieved by transporting hydrogen on the United Kingdom's significant rail network, it is possible that transport of liquid hydrogen by rail could gain interest in coming years.

One of the key concerns for hydrogen transportation is safety as a result of its chemical and physical properties. These properties can cause embrittlement (structural weakening) of high-strength steels and alloys, may allow for escape from containment, and result in a wide flammability range. Regulation to date is primarily driven by these concerns and reflects the desire to ensure that dangerous goods can be transported safely through Great Britain.

I. Transport by Truck and Rail

A. Liquid or Gas?

Gaseous hydrogen can be transported in pressurised tube trailers or compressed gas cylinders. The largest tank volumes for gaseous hydrogen transport are currently 26 cubic meters. Taking account of the low hydrogen density factor at 500 bar, this results in a load of around 1100kg of hydrogen per lorry. The nature and density of gaseous hydrogen and the equipment needed to transport it (pressurised gas cylinders or tubes bundled together inside a protective frame) means that it is typically transported as a gas in small to medium quantities only.

Over longer distances, it is usually more cost-effective to transport hydrogen in liquid form, since a liquid hydrogen tank can hold substantially more hydrogen than a pressurized gas tank. Liquid hydrogen is loaded into an insulated cryogenic tank for transport. The upper volume of hydrogen that can be transported is currently 3500kg of hydrogen per trailer delivery.

Congestion issues are also important considerations for road transport. A Dutch study undertaken in 2006 estimated the supply requirements for a hydrogen refuelling station supplying an equivalent amount of energy to a typical large petrol station as, on average, two tanker deliveries per day of liquid hydrogen.[51] If the same amount of hydrogen were delivered in gaseous form, it would require, on average, 23 tanker deliveries per day. Figures are not available for the United Kingdom, but the Health and Safety Laboratory's position paper on the hazards of liquid hydrogen hypothesised that similar estimates would apply.[52]

B. Regulatory Framework in Great Britain

1. Dangerous Goods

There are currently no dedicated regulations in Great Britain governing the transport of hydrogen, whether by truck, rail, or otherwise. In the absence of such dedicated regulations, the ordinary rules for the transport of dangerous goods will apply.

Gaseous and liquid hydrogen are classified as flammable gases in UN Class 2.1 and are therefore treated as dangerous goods in the United Kingdom.

Transportation of dangerous goods in Great Britain is regulated through the Carriage of Dangerous Goods and Use of Transportable Pressure Equipment Regulations 2009 (the CDG). The CDG directly incorporates and consolidates a number of international treaties that the United Kingdom is a party to (including

[51] R. Smit and M. Weeda, Energy research Centre of the Netherlands, *Infrastructure considerations for large hydrogen refueling stations* (June 2006), page 5, available at https://www.cder.dz/A2H2/Medias/Download/Proc%20PDF/PARALLEL%20SESSIONS/%5BS11%5D%20Delivery/14-06-06/369.pdf.

[52] Health and Safety Laboratory, *Hazards of liquid hydrogen: Position paper* (2010), available at https://www.hse.gov.uk/research/rrpdf/rr769.pdf.

a UN treaty called the ADR,[53] which regulates the carriage of dangerous goods by road, and an international treaty called COTIF,[54] which regulates the carriage of dangerous goods by rail through the Regulations concerning the International Carriage of Dangerous Goods by Rail (RID)). The CDG applies to both road and rail transport, as well as national and international carriage.

The CDG, ADR, and RID set out the requirements for the classification, packaging, labelling, and certification of dangerous goods. They also include specific vehicle, rail car, and tank requirements, training and safety measures, as well as other operational requirements for the transportation of various dangerous goods.

Trucks and railcars transporting hydrogen must meet the standards for design, construction, and use relating to hazardous cargo and display the correct markings and signs in the correct locations. The truck and trailer or railcar need to be appropriately certified and considered valid for transporting dangerous goods.

The security implications of transporting large volumes of dangerous goods are also relevant, as such shipments could be targeted by individuals with malicious intent. Where more than 3,000 litres of hydrogen is being transported, the carriage will qualify as a "high consequence dangerous good," and heightened security procedures will apply (such as security plans, enhanced operating procedures, background and security checks for staff, and anti-theft measures for vehicles).

2. Special Rules Applicable to Employees Transporting Hydrogen

Drivers who transport hydrogen (including both trucks and trains) are required to have completed specific safety training. Any transport company that employs these drivers is responsible for ensuring that this training is completed and regularly updated. The transport company must also ensure that drivers carry the correct ADR/RID paperwork (as well as a photograph) on every journey, follow the correct ADR/RID procedures, and that all required safety equipment is installed, regularly inspected, and fit for emergency use. Driver training must be carried out by an agency approved by the HSE.

3. Special Rules Applicable to Pressurised Cylinders Used for Transport

The Pressure Equipment (Safety) Regulations 2016 (PER) apply to the design, manufacture, conformity assessment, and reassessment of transportable cylinders, tubes, cryogenic vessels, and tanks for transporting gases. PER will apply to vessels and associated pipework for transporting and

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[53] *Accord européen relatif au transport international des marchandises Dangereuses par Route* (the European Agreement concerning the International Carriage of Dangerous Goods by Road). The treaty will be renamed to the "Agreement concerning the International Carriage of Dangerous Goods by Road" from 1 January 2021 to clarify that it is open to all countries, and not just European states.

[54] *Convention concerning International Carriage by Rail*, in particular Annex C, which is known as Regulations concerning the International Carriage of Dangerous Goods by Rail, or RID.

storing liquid and gaseous hydrogen, as well as the vaporisers for re-gasifying liquid hydrogen.

Under PER, vessels are required to be safe, suitably tested, go through conformity assessment procedures, and carry relevant markings. It has been noted by the hydrogen industry that the requirements under PER are onerous and are considered a barrier to transporting hydrogen.

4. Special Rules Applicable to Trucks Transporting Hydrogen

Trucks transporting hydrogen are not permitted to travel through certain tunnels. Nine tunnels across the United Kingdom have been classified under the ADR with a range of restrictions that apply to flammable or explosive cargoes, such as hydrogen. Trucks carrying hydrogen are not allowed through these tunnels due to the risk that vehicles transporting flammable or explosive cargoes could pose to human life or to the tunnel itself in an accident. Trucks carrying hydrogen are also not permitted in public car parks and must use a separate car park at motorway service stations.

C. Opportunities, Challenges, and Looking Forward

1. Social Licence

Increased use and transportation of hydrogen will mean increased presence and visibility on public roads and nonindustrial areas. Although hydrogen has been used safely in industrial processes for a long time in the United Kingdom and globally, and has a good track record where it has been used in the United Kingdom in recent years (for example, for hydrogen buses or in the Orkney Islands), this information is not necessarily widely known by the public. While petrol and diesel also bear safety risks, more than a century of gasoline reliance has led to a natural public familiarity and comfort with these fuels, which hydrogen does not yet have. It will be important to continue to build the safety case and the social licence for the production, storage, and transportation of hydrogen in the years ahead.

2. Relative Safety Risks

Petroleum is classified as UN Class 3; it is considered less hazardous than hydrogen. However, proponents of hydrogen argue it is no more or less dangerous than petroleum or other fossil fuels: petroleum accidents and spillages have far from trivial environmental consequences. The Health and Safety Laboratory argues that more research needs to be done into accidents involving hydrogen, as there have been relatively few experimental studies of hydrogen spills.

II. Transport by Pipeline

A. Application in Great Britain

Great Britain has a substantial gas network, with over 7,600km of high-pressure transmission pipelines and over 275,000km of lower-pressure distribution pipelines. Hydrogen proponents have suggested that the existing gas network could be repurposed to deliver hydrogen to a range of end-users, such

as residential consumers (for domestic heating), CCGT power stations and industrial users, and even hydrogen refuelling stations. We consider these use cases, as well as their associated complications and challenges, in further detail in **Gas Grid Injection (Part IV, Section I)**.

Injection and transportation of hydrogen in the natural gas network in Great Britain is not currently possible. However, work is ongoing to enable this in the future, either on newly built 100 per cent hydrogen pipelines or by repurposing existing networks for hydrogen transport (on a 100 per cent hydrogen basis or a blended hydrogen/natural gas basis).

B. Regulatory Framework in Great Britain

There is no dedicated regime for the transport of hydrogen on the natural gas grid. Instead, traditional access rules for gas will apply. The Gas Act 1986 (Gas Act) establishes a licensing system for the downstream gas market in Great Britain. It provides that certain key activities cannot be undertaken without a licence or, in some instances, a licence exemption.

The main regulated activities under the Gas Act that are relevant to hydrogen injection and transportation are:

- **Gas Transportation**
  The ownership and/or operation of a gas network. The owner/operator of the transmission network, the NTS, and each of Great Britain's gas distribution networks are required to hold a Gas Transporter licence;

- **Gas Shipping**

  Gas shippers are the wholesaler parties who purchase gas from producers, pay the gas transporter to transport it along the gas network, and sell it to other gas shippers or gas suppliers. They are required to hold a Gas Shipper licence; and

- **Gas Supply**
  Gas supply is the retail activity of selling gas to end-users. A supplier may act as its own shipper, or purchase gas (for on-supply) from another shipper. They are required to hold a Gas Supplier licence.

To facilitate effective competition, the Gas Act de-links transportation activities from shipping and supply activities (by prohibiting a person from holding a Gas Transporter licence with any other type of gas licence) and imposes a general duty on gas transporters (i.e., network operators) to provide access to the gas network.[55]

However, access is not currently possible for hydrogen streams due to a range of technical and legal issues related to the network's present gas specification rules. These issues are discussed in the following section (**Section II.C**).

C. Opportunities, Challenges, and Looking Forward

1. Gas Quality Rules

Gas quality requirements for injection into and transport on the gas grid are set out in the Gas Safety (Management) Regulations 1996 (GS(M)R).

These regulations restrict the quantity of hydrogen that can be transported on the gas system to 0.1 per cent (volume).[56] This effectively means that currently no hydrogen can be injected into the gas networks and any hydrogen projects must be "off-grid." For example, in the HyDeploy project, the HSE has given permission to run a live test of blended hydrogen and natural gas on part of the private gas network at Keele University campus in Staffordshire.

Changes to the GS(M)R require legislative action, following a detailed safety-case review by the HSE. The HyDeploy project is in the process of building up the relevant technical data to establish the safety case for a 20 per cent (vol) blend of hydrogen into the existing distribution network. The H21 projects are similarly seeking to assist in conversion of the UK pipeline network to transport 100 per cent hydrogen. These works, and the associated changes to the GS(M)R to support hydrogen transport, are supported by five of the major distribution network operators. There are also calls for the quality rules to be moved from legislation to a more flexible industry standard, which could be overseen by the Institute of Gas Engineers and Managers. This would allow changes to be made to hydrogen levels as the safety case for increasing levels develops, rather than requiring legislative action each time.

2. Pipeline Materials

Hydrogen cannot be transported in all types of pipeline because some materials, such as iron, are prone to hydrogen embrittlement.[57] Hydrogen is also a much smaller molecule than

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55 *See,* for example, *Gas Act 1986*, ss 7 and 9.

56 *Gas Safety (Management) Regulations 1996*, Schedule 3, Part I.

57 Embrittlement is the consequence of hydrogen being absorbed into the metal and decreasing the pipeline's ductile strength, which can lead to cracking and ultimately failure of the pipeline.

natural gas and, therefore, more prone to leaking during transport.

At the distribution network level, works are already being undertaken (through the Iron Mains Risk Reduction Programme) to upgrade the distribution network pipes from iron to polyethylene plastic. This work is expected to be completed by the early 2030s. Although the primary purpose of these works is to improve public safety and to reduce fugitive gas emissions, an associated benefit is that the pipes are hydrogen-ready. However, further works, such as changes to valves and compressors, will be required to make the whole distribution network hydrogen-ready. The possibility of converting gas distribution networks to 100 per cent hydrogen has been examined in detail by the H21 projects led by Northern Gas Networks, initially for Leeds and now across the North of England.

At the transmission network level, a similar pipeline upgrade project is not currently in place. However, the operator of the transmission network (National Grid) is working with the HSE to assess the capability of the transmission network to transport 100 per cent hydrogen or blended hydrogen. Current options include upgrading and repurposing parts of the existing transmission network, where possible, or building a dedicated hydrogen transmission pipeline for hydrogen transport.

3. Metering and Billing Rules

Metering and billing rules are currently set up under the Gas (Calculation of Thermal Energy) Regulations 1996 based on the volume of gas provided (using a carefully calculated average calorific value for the gas stream, based on readings at 13 “charging areas” of the gas network), rather than actual energy content received.

The introduction of significant quantities of hydrogen (which requires a larger volume to deliver the same energy content) into parts of the natural gas network could result in gas quality variations across the charging areas. Continuing to charge users based on an average network quality could therefore result in users being charged incorrectly for the amount of energy that they receive and could act as a barrier for entry for hydrogen producers.

Cadent, the operator of the gas distribution networks in the West Midlands, North West England, East of England, and North London, is leading an innovation project called the Future Billing Methodology. This project is looking at ways to update the metering and billing rules to allow greater volumes of low-carbon gas, including hydrogen, to enter the gas networks and end-users to be accurately billed for their energy use.

PART IV - DEMAND CASES FOR HYDROGEN

In this section, we will consider two forms of hydrogen use that, if developed, could represent significant hydrogen demand in the United Kingdom: gas grid injection and vehicular fuel. These are by no means the only expected forms of hydrogen demand that could occur in the United Kingdom in the years to come; however, they could have an impact on some of the United Kingdom's highest emitting sectors, including residential heat, industry, and surface transport, which together account for more than 60 per cent of the United Kingdom's annual carbon emissions.[58]

This section also briefly considers some of the other UK hydrogen use-cases, and the projects that go with them, in **Other Areas (Section III)**.

[58] 2020 CCC Progress Report, above n 2, page 21.

I. Gas Grid Injection

A. Application in Great Britain

Great Britain has a substantial gas network used to supply natural gas to around 40 CCGT power stations and large industrial users, as well as to over 22 million commercial and residential properties. In 2019, gas consumption in the UK economy amounted to 820 TWh.[59]

Given the emissions associated with natural gas combustion and consumption, a number of projects have begun considering ways to repurpose the natural gas grid for hydrogen, both on a 100 per cent replacement basis and on a transitional 20 per cent blending basis. Replacing even only 20 per cent (vol) of natural gas with hydrogen in the gas grid could reduce the grid's annual emissions by 4-6 per cent where blue hydrogen was injected (or slightly more with green hydrogen)[60] and could allow material hydrogen production to be brought online relatively quickly without requiring major infrastructure upgrades or domestic end-user appliance changes.

As discussed in **Transport by Pipeline (Part III, Section II)**, injection and transport of large quantities of hydrogen in the gas network (whether on a blended or 100 per cent hydrogen basis) is not currently possible. Work is ongoing, however, to enable the transport of hydrogen in the future.

Increasing the hydrogen content of gas supply in Great Britain is also not without precedent — Great Britain operated on "towns gas" (a mix of onshore gas and gasified coal, which was composed of around 50 per cent hydrogen) until the 1970s, when it was replaced by the current, methane-rich natural gas mix that was discovered in the North Sea. That said, a return to higher hydrogen volumes in the gas grid presents a range of challenges and opportunities for the network operators and their user base.

1. Injection for Domestic Heating

The heating needs of around 85 per cent of domestic properties in the United Kingdom are met by natural gas and gas boilers.[61] Carbon emissions from buildings in the United Kingdom represented 18 per cent of 2019 emissions.[62] In line with its net zero targets, the United Kingdom currently is considering the best way to reduce and remove these emissions from the economy. A range of options is being considered, including converting dwellings to use electric heat pumps and converting districts to district heating, as well as transitioning to a 20 per cent (vol) (and ultimately 100 per cent) hydrogen gas blend in the gas grid.

[59] Navigant, *Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain* (October 2019), page 6, available at https://www.energynetworks.org/gas/futures/pathways-to-net-zero-report.html.

[60] *2018 CCC Hydrogen Report,* above n 16, page 44.

[61] OGUK, Energy Transition Outlook 2019 (2019), page 33, available at https://oilandgasuk.co.uk/wp-content/uploads/2019/12/OGUK-Energy-Transition-Outlook-2019.pdf.

[62] *2020 CCC Progress Report*, above n 2, page 21.

Stated advantages of a hydrogen-based solution in this sector include the following:

- Great Britain already has a significant infrastructure asset, in the form of the gas grid, which could be repurposed to supply households with fuel and therefore reduce the upfront capital costs;
- Gas appliances for most[63] domestic users are already capable of operating on a 20 per cent (vol) hydrogen blend[64] without any changes; and
- Heating demand can be very "peaky," particularly on the coldest days. While spikes can be managed by the gas grid (as it is used to storing gas and delivering it rapidly at peak times), they are more of a challenge on the electricity grid.

On the other hand, counter-arguments include the following:

- While up-front capital costs might be lower for a hydrogen solution, modelling by Imperial College indicated that total system costs (including cost of fuel) were largely comparable for electric and hydrogen solutions;
- At some point beyond a 20 per cent (vol) hydrogen blend, existing gas appliances will need to be replaced with hydrogen-ready appliances, with associated capital costs for consumers; and
- As discussed in **Transport by Pipeline - Opportunities, Challenges, and Looking Forward (Part III, Section II.C)**, while some works are already being undertaken to upgrade distribution-level pipes to be hydrogen-ready, further upgrade works will be required at the distribution level as well as at the transmission level before the system as a whole is "hydrogen ready."

The UK government has not yet made a decision on which pathway should be adopted, though it is due to release a Buildings and Heat Strategy later this year, which is expected to provide policy direction. In the meantime, a range of pilot and demonstrator projects is underway to prove the safety case for hydrogen in the gas grid and to begin developing new end-user appliances in advance of a large-scale rollout across the United Kingdom. These include:

- HyDeploy, which includes a series of staged trials to establish the safety case for using a 20 per cent hydrogen blend in the gas grid without requiring changes to end-user gas appliances;
- H21, which is testing the suitability of the existing natural gas infrastructure to convey 100 per cent hydrogen;

[63] The UK HSE estimates that in 2020 only 2 per cent of gas appliances in the United Kingdom will date from before the Gas Appliance Directive, and therefore may not work with a hydrogen blend.

[64] As a result of the EU Gas Appliance Directive (implemented in the United Kingdom through the *Gas Appliances (Safety) Regulations 1995),* domestic appliances, such as gas boilers, are required to be tested at hydrogen blends of 8 per cent (energy) / 23 per cent (volume).

- H100, which is assessing the requirements of new-build (as opposed to re-purposed) 100 per cent hydrogen distribution infrastructure; and
- Hy4Heat, which includes work-streams focused on the development of prototypes for domestic and commercial 100 per cent hydrogen gas appliances (including “hydrogen-ready” gas boilers that could run on natural gas until the user’s gas stream changed to hydrogen), as well as pathways to convert industrial equipment to 100 per cent hydrogen.

2. Injection to Supply Other Users

In addition to heating, pipeline hydrogen could also be used by a range of other users, such as industrial facilities, CCGT power stations, and, in the future, hydrogen refuelling stations.

a. Industrial Users and CCGT Power Stations

The power generation and industrial and commercial sectors represent more than 60 per cent of annual energy demand from the gas grid.[65] Transitioning these users from piped natural gas to piped hydrogen could therefore have a significant impact on the United Kingdom’s overall emissions. However, CCGT power stations and industrial facilities are highly sensitive to gas quality requirements. The impact of increased quantities of hydrogen into their supply streams will therefore need to be carefully considered.

Work (such as the HyNet North West IFS Programme) is ongoing with individual users and facilities to determine safe levels of hydrogen for their operations, the costs of plant and equipment conversions, and to identify any detrimental impacts of hydrogen on their existing facilities. Where it is not possible for a facility to convert to hydrogen, or the facility is not able to convert on the same time schedule as the surrounding network, work is also being undertaken to consider the technical and economic viability of hydrogen de-blending stations so that the facility may continue with a traditional natural gas stream. This is discussed further in **Gas Grid Injection - Opportunities Challenges, and Looking Forward (Part IV, Section I.B)**.

b. Refuelling Stations

Hydrogen has the potential to meet a significant proportion of transportation demand by 2050. Where this occurs, it will be necessary to transport and distribute significant volumes of hydrogen to hydrogen refuelling stations. One option for delivery could be with piped hydrogen using natural gas grid infrastructure. However, to enable a long product lifetime, fuel cells currently require very high hydrogen purities. This presents an immediate challenge for a piped gas solution, in both blended and 100 per cent hydrogen scenarios, as the safety odorants that are added to pipeline gas, the blended

65 National Grid, *Gas Operational Forum presentation at London Radisson Grafton* (7 May 2019), slide 48, available at https://www.nationalgrid.com/uk/gas-transmission/document/127071/download.

natural gas stream, and even the repurposed gas pipelines themselves can introduce contaminants that render the resulting fuel unsuitable for fuel cell use. Purification technologies exist and are currently being tested in a range of projects, including the HyNet and HyMotion projects based in Leeds. To be viable, however, the costs of purchasing and transporting the hydrogen, de-blending it, and then purifying it will need to be cheaper than the cost of competing alternatives, such as on-site electrolysis

B. Opportunities, Challenges, and Looking Forward

1. Government Decision on Heating Solution

The UK government is due to release its Buildings and Heat Strategy later this year. This document is expected to set out the UK government's policy for decarbonising the United Kingdom's existing buildings, including measures to phase out traditional oil and gas boilers and enabling measures to support delivery of low-carbon heating alternatives. Separately, the Ministry for Housing, Communities and Local Government is also developing the Future Homes Standard, which will require newly built homes to be future-proofed with low-carbon heating; it is scheduled to be introduced by 2025. It is not yet clear how significant the role for hydrogen will be in the Buildings and Heat Strategy or the Future Homes Standard.

2. Process for Injecting Hydrogen into the Network

There is no framework in place to manage hydrogen injection into the gas network. For example, should hydrogen be pre-mixed with natural gas so that it is blended down to the acceptable blending limit, or should injection of 100 per cent hydrogen be permitted, provided that a homogenous mixture can be achieved within an appropriate distance?

3. Incentivising and Coordinating Hydrogen Injection

Bringing hydrogen production online in a coordinated way is expected to be challenging. The UK government has used a range of mechanisms to bring renewable electricity supply online in the electricity grid and to bring biomethane supply online in the gas grid, and these may offer some ideas on regimes that could be applied to hydrogen. However, while the Renewables Obligation (the initial mechanism used to increase renewable electricity supply into the electricity grid) and the Renewable Heat Incentive (the mechanism used to increase biomethane supply into the gas grid) may have been successful for those sectors, it is not clear if the same mechanisms will work for hydrogen. One of the reasons for this is that the new "product" introduced into those grids matched (or closely matched) the product that already existed (electrons from wind turbines are no different from electrons from gas turbines, and propane is added to biomethane so that it closely matches the calorific value of natural gas on the gas grid). The same cannot be said for hydrogen. As a result, at least initially, it may be difficult for shippers to balance their "ins" on one side of the network (i.e., their hydrogen injection) with their "outs" on the other (i.e., the blended stream of natural gas sold to gas suppliers). Leaving hydrogen balancing to gas shippers (as is currently the case for natural gas) may also make it more difficult for the Gas Transporters to achieve a specific blend of hydrogen and natural gas. A range of solutions to the coordination and balancing issue have been suggested, including the following.

a. Management by the Gas Transporters

Procurement of hydrogen and management of hydrogen balancing could be added to each Gas Transporter's sphere of responsibility, with injected volumes shared and added to the imbalance accounts of that day's shippers and associated costs passed back to those shippers accordingly. However, this structure would seem to run counter to the spirit of unbundling, which provides that Gas Transporters should not engage in gas procurement or supply activities.

b. Management by a Central Hydrogen Buyer

Same as the above, but with procurement of hydrogen performed by a separate, central entity rather than the Gas Transporter. While this would likely be more complex than the first option, it may avoid some of the unbundling concerns that could arise under that scenario.

Both proposals would require changes to the downstream gas market and gas regulatory regime if they are to be brought into effect. In addition, given the monopoly role that the Gas Transporters or central hydrogen buyer would play in each scenario, some form of hydrogen price regulation likely would be required.

4. Impact on Interconnectors and International Trade

The Great Britain transmission system is connected to international gas networks in the Republic of Ireland, Northern Ireland, and continental Europe. Where these networks and the Great Britain network transition to hydrogen or hydrogen blends at different speeds, the ability to trade gas between them may be impacted. If these interconnectors are to continue to play an important role in Great Britain's (and the island of Ireland's) gas supply going forward, careful coordination will be required.

5. Hydrogen De-Blending

Certain gas grid users will not be able to use blended hydrogen or may not be ready to use it at the same time as the broader set of users in their gas area. These users could become potential blockers to a rollout of blended hydrogen in their area. One solution that is being explored to manage these cases is the installation of hydrogen de-blending stations that would allow users who are not ready to convert to offtake the natural gas stream only. Conversely, de-blending stations could also allow users who want a 100 per cent hydrogen supply to offtake the hydrogen gas stream only. National Grid Gas Transmission is leading a project to test the technical and economic feasibility of using gas separation technologies to de-blend a blended hydrogen/methane gas stream into its component streams. The project (which is called HyNTS) is planning to build a hydrogen test facility from decommissioned assets to test and validate hydrogen de-blending technologies, among other things. The de-blending work is currently planned to be undertaken during 2022-2024. In addition to providing a potential pathway for CCGT power stations and industrial facilities to continue to operate on a blended gas grid, de-blending stations could also enable staged conversions of individual users or areas to blended hydrogen or 100 per cent hydrogen as and when they are ready.

II. Surface Transport

A. Application in Great Britain

In this section, we will explore the potential for the use of hydrogen as a fuel for vehicles (both light and heavy), issues in refuelling hydrogen-powered vehicles, and challenges and opportunities associated with hydrogen as a viable fuel source.

Carbon emissions from surface transport in the United Kingdom represented 24 per cent of 2019 emissions, making it the largest emitting sector in the United Kingdom.[66] At the end of 2018, only 0.5 per cent of all licensed vehicles in the United Kingdom were ultra-low emission vehicles, which are vehicles that emit less than 75 grams of CO_2 from their exhaust for every kilometre travelled.[67] As part of its drive to decarbonise transport, in 2018, the UK government launched the "Road to Zero" strategy, which aims to see at least half of new cars classified as ultra-low emission vehicles by 2030. In addition, the UK government is also considering banning the sale of new fossil fuel combusting cars by 2035.

The main contenders to decarbonise surface transport are battery electric vehicles and hydrogen fuel cells. There are currently two hydrogen fuel cell cars available in the United Kingdom. In comparison, there are over 50 models of electric cars and vans available, and the cost of these models is falling more rapidly than hydrogen fuel cell cars. While electric vehicles are in a strong position to decarbonise passenger cars and vans, the batteries that they use are not without their shortfalls. When an electric vehicle comes to the end of its life, its lithium-ion battery will need to be disposed of. These batteries are not yet widely recycled and, if damaged, toxic gases may be emitted. This means that landfill disposal is not an appropriate option either.

It is challenging to decarbonise heavier forms of transport because of the weight and size of the vehicles and the long distances in between refuelling. It is easier for smaller vehicles used in urban and regional transportation to switch to plug-in hybrid or fully electric vehicles compared to larger long-haul HGVs because of scheduled stops, the size of battery required, and the availability of re-charging stations.

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66 *2020 CCC Progress Report,* above n 2, page 21.

67 Office for National Statistics, *Road transport and air emissions* (16 September 2019), section 2, available at https://www.ons.gov.uk/economy/environmentalaccounts/articles/roadtransportandairemissions/2019-09-16.

Hydrogen fuel cells could have the potential to play an important role in the decarbonisation of long-haul HGVs. Hydrogen-powered HGVs may have a competitive advantage over their electric counterparts due to the faster refuelling speeds and the weight penalties that batteries suffer as vehicle sizes increase. While there are currently no hydrogen fuel cell HGVs on the road, several companies are advancing models.

It is worth noting that hybrid options can be created by pairing hydrogen fuel cells with batteries. As discussed above, HGVs are unlikely to meet long-haul travel requirements using batteries alone; if paired with hydrogen, hydrogen fuel cells could provide most of the energy to an electric motor and a very small battery.

The existing infrastructure for hydrogen refuelling stations in the United Kingdom is limited. Currently there are only 13 refuelling stations in operation across the United Kingdom, five of which are located within the M25 and the rest in the Southeast and the Midlands. There are only two hydrogen refuelling stations in Wales, one in the North of England, one in Scotland, and none in Northern Ireland.[68]

In 2017, the Office for Low Emission Vehicles launched the United Kingdom's Hydrogen for Transport Programme. Stage 1 of the programme will help fund four new hydrogen refuelling stations: two in London and one each in Derby and Birmingham. Stage 2 of the programme aims to fund 10 additional hydrogen refuelling stations. In order to support widespread use of hydrogen HGV fleets, the number of hydrogen refuelling stations will need to increase significantly. Stage 2 will also provide funding for 33 fuel cell electric buses and 73 fuel cell electric vehicles.

Fleets of hydrogen-powered buses are already in operation in the United Kingdom. While running costs are higher than electric buses, hydrogen buses are able to travel longer between refuelling stops. Buses are an important early market for hydrogen fuel cell vehicles because they are refuelled at bus depots and are not affected by the currently limited hydrogen refuelling infrastructure.

B. Regulatory Framework in Great Britain

1. Hydrogen Vehicles

Roadworthiness tests must be conducted on new categories of vehicles. Hydrogen-powered buses have already been tested, approved, and are in operation in the United Kingdom. Registered vehicles are subject to standard Ministry of Transport (MOT) testing in the United Kingdom, and the same testing will apply to hydrogen-powered vehicles.

2. Hydrogen Refuelling Stations

There is no dedicated regulatory framework for hydrogen refuelling stations. However, there are established environmental and planning regimes for traditional refuelling stations, as well as for hazardous activities and substances, which will be relevant.

68 *See,* for example, https://www.drivingelectric.com/your-questions-answered/1363/where-can-i-buy-hydrogen-and-where-my-nearest-hydrogen-filling-station.

a. Planning Approval for Use as a Refuelling Station

The primary legislation regarding the construction and operation of a hydrogen refuelling station is the TCPA 1990. High-volume hydrogen production at a centralised site is classified as an industrial activity and any new development is subject to formal (industrial) land use planning approval and site permitting under the TCPA 1990.

Planning approval must be obtained from the LPA for any site to be used for storage and handling of hydrogen in tanks, cylinders, or composite vessels in order that the site meets local land use zoning requirements and that the storage and handling comply with safety and hazardous substance requirements. When considering development proposals around hazardous installations, the LPA will seek technical advice on risks presented and the potential effects on people in the surrounding area and the environment and may involve the HSE and the local fire department, who can provide different perspectives on hydrogen safety aspects.

The Hazardous Substances Regulations and COMAH may also be a factor in determining planning applications for any on-site storage tanks and hydrogen production facilities (if hydrogen will be produced on-site), in the same way as they may apply to production facilities (which is set out in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom (Part II, Section I.B)**).

b. Dedicated Versus Multi-Use Refuelling Stations

Rather than constructing hydrogen-only refuelling stations, it may be possible to add hydrogen refuelling pumps to already existing petrol stations. The addition of hydrogen pumps will require an amendment to the station's existing planning approval in respect of the storage of hydrogen on-site so that it meets the local land use zoning requirements. Fuelling stations would incur similar planning permission and section 106 of the TCPA 1990 obligations as those imposed on conventional fuelling stations. To name but a few of the requirements that apply to such stations, a ground investigation report and site report would most likely be necessary, as well as any storage tank details. Additionally, an environmental noise report would most likely be required, as well as a travel plan and transport assessment.

The Blue Book is the established technical guidance on providing information about storage and dispensing of petroleum products used as fuels for motor vehicles (including petrol, diesel, and LPG). It provides information on civil, mechanical, and electrical installation issues for the planning, design, construction, commissioning, modification, maintenance, and decommissioning of filling stations, together with information aimed to minimise the risks from fire and explosion, to health and to the environment. The book is produced jointly by the Association for Petroleum and Explosives Administration and the service station panel of the Energy Institute. Technical input is also provided by the HSE and the UK Environment Agency, as well as professional organisations and trade associations.

In March 2017, a supplemental hydrogen fuelling aspect that provides specific guidance on hydrogen delivery systems for refuelling of motor vehicles, co-located with petrol fuelling stations, was added to the Blue Book. The supplement aims to ensure an acceptable level of protection for safety, health, and the environment when HRS and conventional refuelling stations are combined. It has been received positively and is expected to be a useful tool for the designing, approval, construction, and safe operation of hydrogen refuelling stations, whether dedicated or co-located, in the future.

c. Hydrogen Supply

Hydrogen could be supplied to refuelling stations in various ways, such as through on-site production or transportation from an off-site production facility via pipeline or by truck.

If the gas grid is converted to hydrogen, it may be possible to use the grid to distribute hydrogen to refuelling stations. However, this method may introduce impurities into the hydrogen and currently hydrogen refuelling stations need to be compatible with ISO 14687 standards for hydrogen purity. We discussed these concerns in further detail in **Gas Grid Injection - Application in Great Britain (Part IV, Section I.A)**.

Transport of hydrogen by truck is considered in further detail in **Transport by Truck and Rail (Part III, Section I)**.

Where hydrogen is produced on-site at a refuelling station from electrolysis, a range of additional planning permissions related to the production of hydrogen (such as an EIA and EP), as well as water and power supply arrangements, will also be required. **Please refer to Green Hydrogen (Part II, Section II)** for further information.

d. Automated and Electric Vehicles Act

Although the UK government has not yet made any regulations, the Automated and Electric Vehicles Act 2018 gives the UK government the power to make regulations in respect of hydrogen refuelling points in the future, including the ability to mandate that large fuel retailers provide public hydrogen refuelling points, and the ability to impose access, standards, and connection rules.

e. Health and Safety Issues

Operating a hydrogen refuelling station will enliven a wide range of health and safety issues for proponents to consider. Please refer to our discussion in **Key Issues for the Development of Blue Hydrogen Projects in the United Kingdom (Part II, Section I.B)** for more information.

C. Opportunities, Challenges, and Looking Forward

1. Transport Decarbonisation Plan

It is clear that hydrogen HGV fleets have the potential to make a significant contribution to the 2050 net zero emissions goal. However, bringing hydrogen HGVs to the UK market will require UK government support to encourage vehicle manufacturers to develop suitable hydrogen HGVs, developers to construct hydrogen refuelling stations, and energy suppliers to produce and supply hydrogen. The Transport Decarbonisation Plan is to be published by the UK government in late 2020, and it aims to set out in detail what the UK government, businesses, and society need to do in order to deliver net zero emissions in transportation by 2050. The UK government has said that the report will consider how UK technology and innovation can change transport. Hydrogen is said to be included, with the report highlighting that the United Kingdom has a number of world-leading centres that could readily test the viability of the hydrogen economy for transport. Once Stage 1 and Stage 2 of the Hydrogen for Transport Programme have been implemented, the number of refuelling stations and hydrogen-powered vehicles are anticipated to significantly increase.

2. Chicken and Egg

The development of nationwide hydrogen refuelling infrastructure faces many challenges, the main challenge being the high costs of equipment such as compressors, chillers, dispensers, and storage. Once more, we come across the chicken and egg scenario — which comes first? It will be difficult for developers to justify funding construction of hydrogen refuelling stations if there are not a sufficient number of hydrogen vehicles demanding refuelling stations. Conversely, it will be difficult for consumers to justify buying hydrogen vehicles, or for businesses to justify purchasing hydrogen HGV fleets, if there are not enough refuelling stations to meet the demands of their business.

3. Regulatory Hurdles for Small-Scale Production

Another challenge to the deployment of hydrogen refuelling infrastructure is that land use planning and associated zoning issues do not distinguish between large-scale industrial production and localised smaller-scale production via electrolysis. This means that on-site production via electrolysis at refuelling stations will be subject to potentially onerous planning restrictions, despite the fact that smaller volumes will be involved and electrolysis has little environmental impact and generates almost no emissions.

4. Hydrogen for Depot Fleets

It is possible that we will see an increase in hydrogen buses on London's roads in the years ahead. The Mayor of London's Environment Strategy requires that all new double-deck buses will be hybrid, electric, or hydrogen from 2018 and that all new single-deck buses will be electric or hydrogen from 2020.[69] Buses are refuelled at depots, meaning that they are not affected by the lack of refuelling stations. We may see this trend carry across into HGV transport. Companies with large HGV fleets may consider creating their own depots equipped with refuelling stations.

5. International Infrastructure Requirements

The decarbonisation of commercial transport cannot be considered in isolation from the rest of Europe. Given the number of HGVs travelling between the United Kingdom and the rest of Europe, suitable infrastructure must be available in all countries to which UK HGVs travel. The European Union has announced plans to establish a €10 billion fund to develop renewable energy and clean hydrogen projects and to significantly increase the number of hydrogen vehicle refuelling stations by 2025.

69 Greater London Authority, *London Environment Strategy* (May 2018), at page 76, available at https://www.london.gov.uk/sites/default/files/london_environment_strategy_0.pdf.

III. Other Areas

In the course of the UK chapter of *The Hydrogen Handbook,* we have touched on a number of interesting hydrogen projects going on in Great Britain. However, these projects only scratch the surface of the exciting work that is being done to try and make the hydrogen economy a reality in Great Britain or to take advantage of it in innovative ways once it arrives. A selection of these projects is set out below.

A. Hydrogen Trains

The UK government has set a target of decarbonising the United Kingdom's railways by 2040. Many of the United Kingdom's regional train lines are not electrified and are powered by diesel engines. Although some of these lines might be appropriate to electrify, that may not be the most cost-effective solution for all lines. Projects to convert diesel rolling-stock on UK lines to hydrogen are currently being undertaken as part of (1) the Hydroflex project, led by the University of Birmingham; and (2) research and conversion works being undertaken by UK rail operator Eversholt and French rail company Alstom.

B. Hydrogen Planes

The aviation industry is a challenging sector to decarbonise. Aircraft maker ZeroAvia, as part of a UK government-funded project called HyFlyer, has been developing a medium-range small passenger aircraft powered by hydrogen fuel cells. ZeroAvia hopes to be flying 20-seater planes within three years and 50-100 seater planes by the end of the decade. On 22 June 2020, ZeroAvia successfully completed the first-ever electric-powered flight of a commercial scale aircraft (a Piper M-Class six-seater) in the United Kingdom. The trials are intended to culminate in a 250-300 nautical mile demonstration flight from Orkney.

C. Industrial Clusters

Carbon emissions from industry in the United Kingdom represented 21 per cent of 2019 emissions.[70] The UK government has ambitions to establish the world's first net zero carbon industrial cluster by 2040, with at least one low-carbon industrial cluster by 2030. The UK government also intends to build two CCUS projects by 2030, with the first coming online by the mid-2020s, and the second by the end of the decade. Blue hydrogen is expected to play an important role in decarbonising the United Kingdom's industrial clusters, the production of which will be actively supported by the building of industrial-scale CCUS facilities in these regions.

D. Remote Islands

As discussed in **Green Hydrogen - Application in the United Kingdom (Part II, Section II.A)**, a localised hydrogen economy was successfully set up in the Orkney Islands in far North Scotland, utilising energy from local wind and tidal resources that was being regularly curtailed by the local electricity network. The experience in the Orkney Islands may be applied as a roadmap for other remote communities to harness the full potential of favourable local renewable resources.

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70 *2020 CCC Progress Report,* above n 2, page 21.

E. Ammonia

Hydrogen's low volumetric energy density inhibits its use as an economically viable energy vector, even when compressed to high pressures or liquefied. Globally, there are numerous projects considering whether ammonia, which already has a significant commercial and safety history, might be an appropriate liquid carrier for hydrogen. Local projects considering the potential that ammonia might play in the UK hydrogen supply chain, or as a potential import or export commodity, include the Siemens Green Ammonia Demonstrator, as well as research being led by Ecuity Consulting and Siemens on advanced ammonia cracker technologies to improve losses when reconverting ammonia back into hydrogen.

F. Hydrogen as an Export Commodity

Scotland has estimated offshore wind potential of in excess of 600 GW, according to a recent report by the Offshore Renewable Energy Catapult.[71] As a result, some proponents have flagged the potential for a green hydrogen export industry to develop, especially if offshore wind costs continue to fall as estimated. Utilising hydrogen in this way could create a significant opportunity to grow the offshore wind industry beyond simply domestic electricity supply. International customers could include countries such as Germany, which, as discussed in the Germany chapter of *The Hydrogen Handbook,* has indicated that it expects about 50 per cent of its green hydrogen demand to be imported.

G. Shipping

UK carbon emissions from the shipping industry represented 3 per cent of 2019 emissions.[72] The shipping industry primarily relies on diesel engines, with oceangoing vessels using heavy fuel oil or marine diesel to power propulsion. Alternatively, a small fraction of vessels use LNG or CNG. However, the use of high-emission fuels is increasingly regulated as pollution, and GHG emission concerns mount. On 1 January 2020, the International Maritime Organization required all shipping fuels to contain no more than 0.5 per cent sulfur. This recent cap is a significant reduction from the prior sulfur limit of 3.5 per cent and is well below the industry average of 2.7 per cent. The use of hydrogen fuel cells would curb emissions of pollutants in maritime applications. However, hydrogen fuel cells must also compete with low-sulfur marine gas oil and LNG combustion engines on the basis of total cost of ownership before they can supersede these technologies. While hydrogen's lower fuel mass can benefit the economics of oceanic transport, for the time being, hydrogen-powered vessels are not cost competitive. In addition, international technical standards still need to be developed in order to use gaseous fuels like hydrogen for transoceanic shipping.

[71] *See* shfca.org.uk/otherevents/2020/5/20/sdi-webinar-green-hydrogen-at-industrial-scale-for-a-zero-carbon-future.

[72] *2020 CCC Progress Report*, above n 2, page 21.

PART V - GOVERNMENT FUNDING

Over the past two or three years, the UK government has announced and deployed an increasing amount of funding to support the United Kingdom's decarbonisation ambitions, particularly in the industrial and transport sectors. While some of these funding pots directly target hydrogen technologies, most of the available funding for "green" and low-carbon technology solutions tends to be technology-neutral. UK government funding has also been made available to support the development and deployment of large-scale CCUS.

We set out in the table below brief summaries of a selection of the key funding sources that have been provided to hydrogen and other low-carbon industry projects to date in the United Kingdom, as well as a range of the funding sources that are currently on offer or announced by the UK government.

In July 2020, the UK government unveiled its summer "mini budget." Although £3 billion of funding for green building upgrades was announced (including over £1 billion to support the decarbonisation of public buildings), no measures were included for hydrogen, carbon capture, or other green sectors. Commentators were generally underwhelmed by the measures proposed, particularly in comparison to other European economies like Germany (which announced £36 billion of investment into green measures) and France (which announced £13.5 billion). Further measures to support the United Kingdom's coronavirus recovery, including funding for green sector infrastructure and other developments, are anticipated to be announced by the UK government later in 2020.

Funding Source	Description
Hydrogen Specific	
Hydrogen Supply Competition (£33 million)	• A two-phase programme run by BEIS aimed at accelerating the development of low-carbon bulk hydrogen supply solutions. • Phase 1 was awarded in 2018 and funded feasibility studies looking into accelerating the development of low-carbon bulk hydrogen supply solutions. Phase 2 was awarded in April 2020, and five projects were selected. These projects will be provided with funding to build demonstrator projects. The projects awarded Phase 2 funding are: » Dolphyn £3.12 million » HyNet £7.48 million » Gigastack £7.5 million » Acorn £2.7 million » HyPER £7.44 million
Hy4Heat Competition (£25 million)	• A project commissioned by BEIS to explore the feasibility of transitioning from natural gas to hydrogen for the heating needs of UK residential, commercial, and industrial users. It aims to define a hydrogen quality standard and to explore, develop, and test domestic and commercial hydrogen appliances. • The project runs from 2017 to 2021.

Funding Source	Description
Hydrogen for Transport Programme (£23 million)	• Launched in 2017 by the Office for Low Emission Vehicles. • Stage 1 awarded £8.8 million to a project to deploy four new hydrogen refuelling stations (one in Derby, one in Birmingham, and two in London) and to upgrade five existing stations. • Stage 2 awarded almost £14 million to five projects, with the combined contribution involving deployment of five new hydrogen refuelling stations (HRS), 33 fuel cell electric buses (FCEB), and 73 fuel cell electric vehicles (FCEV). The projects awarded stage 2 funding were: » Tees Valley Hydrogen Transport Initiative I (two new HRS, five FCEVs) £1,303,500 » Hydrogen Mobility Expansion Project II (one new HRS, 51 FCEVs) £3,070,000 » Northern Ireland Hydrogen Transport (one new HRS, three FCEBs) £1,953,937 » Riversimple Clean Mobility Fleet (17 FCEVs) £1,249,670 » Towards commercial deployment of FCEBs and hydrogen refuelling (one new HRS, 30 FCEBs) £6,419,038

Funding Source	Description
CCUS	
Carbon Capture and Utilisation Demonstration innovation programme (£20 million)	• A programme run by BEIS to design and construct carbon capture and utilisation (CCU) demonstration projects with a view to encouraging industrial sites to capture carbon dioxide for use in industrial applications. • Phase 1 was aimed at identifying potential host sites, carbon dioxide users, and technology suppliers to produce site-specific cost estimates for deploying CCU at UK industrial sites. • Phase 2 was awarded in 2019 and funded FEED studies to produce cost estimates for the construction and operation of demonstrating CCU at the host site. • Phase 3 offers £14 million grant funding for a number of construction and demonstration projects. This funding has not yet been awarded.
CCUS Innovation Programme (£24 million)	• A programme run by BEIS designed to fund research and innovation projects that offer a significant reduction in the cost of capturing and sequestering carbon dioxide and a quicker, more widespread deployment of CCUS in the United Kingdom and internationally. • Up to £24 million of funding was made available and was awarded to seven projects in February 2020.
CCS Infrastructure Fund (£800 million)	• The United Kingdom announced a CCS Infrastructure Fund of at least £800 million in March 2020. The fund would be used to establish at least two UK sites of carbon capture and storage clusters; the first is aimed to be built by the mid-2020s and the second by 2030. • Details are expected to be released in late 2020.

Funding Source	Description
Technology Neutral	
Industrial Decarbonisation Challenge (£170 million)	• The Industrial Decarbonisation Challenge is intended to support delivery of the UK government's Clean Growth Grand Challenge and the Industrial Clusters Mission, which have set an ambition to establish the world's first net zero carbon industrial cluster by 2040, with at least one low-carbon industrial cluster by 2030. • This challenge is run by UK Research and Innovation and will commit £170 million towards deploying technologies like carbon capture and hydrogen networks in industrial clusters. • The challenge is split into two streams: (1) Roadmaps, which is focused on the preparation of decarbonisation roadmaps for major UK industrial clusters; and (2) Deployment, which is focused on planning and delivery of significant emissions reductions in a UK industrial cluster by 2030. **Roadmaps** • In Phase 1, a share of £1 million of funding was made available to prepare plans for achieving low-carbon and net zero industrial clusters. • Phase 1 was awarded in April 2020, and is funding six industrial cluster roadmap projects. The Phase 1 winners were: » Net Zero Tees Valley - Decarbonising the Full Cluster: Roadmap Pathfinder » Scotland's Net Zero Roadmap » Humber Industrial Decarbonisation Roadmap » North West Hydrogen and Energy Cluster: Route to Net Zero » South Wales Industrial Cluster » Repowering the Black Country • Once Phase 1 is completed, these six projects will compete for up to £8 million of Phase 2 funding to develop a detailed roadmap detailing how a cluster could be decarbonised to net zero levels.

Funding Source	Description
	Deployment • In Phase 1, a share of £1 million of funding was made available to prepare a plan for deploying decarbonisation measures in an industrial cluster. • Phase 1 was awarded in April 2020, and is funding six industrial cluster deployment planning projects. The Phase 1 winners were: » Scotland's Net Zero Infrastructure » Net Zero Teesside Project » Humber Industrial Decarbonisation Deployment Project » HyNet Carbon Capture Utilisation and Storage » South Wales Industrial Cluster » Green Hydrogen for Humber • These six projects will compete for a total of up to £131 million of Phase 2 funding to deliver, or support delivery of, significant emissions reductions in a UK industrial cluster by 2030.
Industrial Energy Transformation Fund (£289 million)	• The fund is designed to help businesses with high-energy use, such as energy-intensive industries, to cut their energy bills and carbon emissions through investing in energy efficiency and low-carbon technologies. Applications for energy efficiency or deep decarbonisation studies that involve fuel switching may include switching from fossil fuels to hydrogen. Other applications may involve CCUS. • Phase 1 opened in July 2020 and invites companies with high energy use to apply for grants from a £30 million funding pot. • Phase 2 will launch in 2021, with the remainder of the fund.

Funding Source	Description
Industrial Fuel Switching Competition (£20 million)	• A three-phase competition run by BEIS to stimulate early investment in fuel-switching processes and technologies. The UK government's Clean Growth Strategy highlights the need for industry to begin to switch from fossil fuel use to low-carbon fuels such as biomass, hydrogen, and clean electricity. • Phase 1 was awarded in 2018 and was aimed at understanding the potential for industry to operate on low-carbon fuels and the innovation required to enable this to happen. • Phase 2 was awarded in 2019, and funded seven feasibility studies looking into developing technologies to enable the use of a low-carbon fuel for a particular industrial process or across an entire site. • Phase 3 was awarded in February 2020, and is funding four demonstration projects to guide the way for industry in the United Kingdom to switch to low-carbon fuel sources. The projects awarded Phase 2 funding are: » HyNet £5.27 million » Hydrogen Alternatives to Gas for Calcium Lime Manufacturing £2.82 million » Switching Fuels for Cement Production £3.2 million » Switching Technologies for the Glass Sector £7.12 million
Catalysing Green Innovation (£15 million)	• A funding competition run by the Office for Low Emission Vehicles UK Government in July 2020. • £15 million funding was available for businesses to apply for, in a drive to put green technology (and UK manufacturing capabilities) at the heart of the economic recovery from the COVID-19 pandemic. • Up to £10 million was available to support feasibility studies and research and development projects for zero emission vehicles. The projects needed to focus on a previous research project; work could include hydrogen technologies.

Funding Source	Description
Road to Zero strategy	• A strategy launched by the UK government in 2018, which sets out the UK government's ambition for at least 50 per cent (and as many as 70 per cent) of new car sales to be ultra low emission by 2030, as well as up to 40 per cent of new vans. • The UK government has committed to investing £1.5 billion in ultra-low emission vehicles and related infrastructure, including electric vehicle charging infrastructure and low-carbon vehicle funds. • The policy so far leans toward electric vehicles, but hydrogen, and hydrogen fuel cells, are included as zero emission technologies. These could therefore be captured by the strategy.
Rail Demonstrations: First of a Kind 2020 (£9.4million)	• A funding competition run by the Department for Transport in July 2020. • The aim of this competition was to demonstrate how proven technologies can be integrated into a railway environment for the first time ("first of a kind" demonstrations). • Two projects with a hydrogen element each won £400,000 funding: » Zero Emission Rail Freight Power (a project for a hydrogen-based steam turbine) » HydroFLEX (which involves funding for a hydrogen-powered train so that the hydrogen fuel cell and power pack can be installed underneath the train to minimise the loss of passenger saloon space)
National Bus Strategy	• In February 2020, the prime minister announced £5 billion of new funding to overhaul bus and cycle links for every region outside London. The package is stated to include ambitions for at least 4,000 new zero emission buses, which could include hydrogen fuel cell buses. • Details of the announced programmes will be included in the upcoming National Bus Strategy, which is expected to be published in late 2020.

PART VI - LOOKING AHEAD

I. A UK Hydrogen Roadmap

Although there have been a number of localised hydrogen strategies in various regions around the United Kingdom, such as in Aberdeen, Liverpool, and the Humber, there is currently no clear UK-wide hydrogen strategy. An independent hydrogen roadmap for the United Kingdom was commissioned by a variety of bodies, including BEIS, in 2016.[73] However, this was not formally adopted and the project only mapped a short-term plan up to 2025.

In contrast, numerous other countries have published clear roadmaps setting out their long-term infrastructure plans, target use-cases, and public funding commitments for hydrogen. The EU Hydrogen Strategy involves up to €500 billion of investment for hydrogen projects and associated infrastructure. Germany has announced its own €9 billion hydrogen strategy. Other countries like Japan, Australia, the Netherlands, and Portugal have also released long-term visions for hydrogen in their countries.

A UK hydrogen roadmap could set a coordinated direction for supported actions in the hydrogen sector, setting out the priorities and timing of actions that are desired and will be supported by the UK government. Having a UK-wide, long-term strategy can also build long-term investor confidence, enable robust supply chains to be created, raise public and industry awareness, drive economies-of-scale cost reductions, and steer industry (and related UK government departments) on future regulatory direction.

UK trade bodies such as the Hydrogen and Fuel Cell Association and RenewableUK have called for clarity on the UK government's future strategy. Hydrogen Strategy Now, which includes a group of over 40 industry players, has said it has £1.5 billion ready to invest in hydrogen in various forms once the UK government produces a strategy. The CCC has recommended that a coordinated national strategy be put in place, urging the UK government to deliver a strategy by June 2021.[74]

[73] E4tech and Element Energy, *Hydrogen and Fuel Cells: Opportunities for Growth - A Roadmap for the UK* (November 2016), available at https://www.e4tech.com/resources/126-hydrogen-and-fuel-cells-opportunities-for-growth-a-roadmap-for-the-uk.php.

[74] *2020 CCC Progress Report*, above n 2.

Recently the Environmental Audit Committee (a parliamentary committee that reviews governmental performance against environmental objectives) has gone further, calling for the UK government to publish their strategy even sooner, as part of the 2020 autumn budget.[75]

The United Kingdom will host the rescheduled 26th "Conference of the Parties" climate summit (COP26) in 2021. The core goal of COP26 is to raise the ambition of countries' climate targets, and, as COP President, there will be huge expectations on the United Kingdom to do so. In addition to the domestic benefits that a coordinated strategy would bring, the development and publication of a comprehensive and ambitious national hydrogen strategy ahead of COP26 would be a clear demonstration of the United Kingdom's ongoing role as a climate leader. It would also act as a clear marker to other countries of the United Kingdom's ambition to be a hydrogen economy "maker," rather than a hydrogen economy "taker."

II. A UK ETS

Carbon pricing schemes have an important role to play in supporting blue and green hydrogen production, as they apply a cost penalty for using polluting fuels (such as grey hydrogen, natural gas, or diesel) rather than cleaner alternatives.

Carbon schemes put a cost on carbon pollution to encourage polluters to reduce the amount of GHG that they emit. An emissions trading scheme (ETS) works by setting a cap on the total amount of GHG that can be emitted from certain sectors — in the United Kingdom's case, by energy-intensive industries such as steel, the power generation sector, and aviation. The cap is reduced over time so that total emissions fall. At the end of each scheme year, emitters are required to hold a number of "allowances" equal to the volume of emissions that they have produced. Allowances can be bought and sold on the secondary market (from companies who have emitted less than their scheduled allowance) or directly from EU member states through an auction process.

The United Kingdom is currently a member of the EU ETS. As a result of Brexit, the United Kingdom left the European Union on 31 December 2019. However, as a result of the withdrawal deal struck between the United Kingdom and the European Union, EU law (including the EU ETS) continues to apply until the end of the transition period, which ends on 31 December 2020. As it currently stands, this would mean that the United Kingdom will exit from the EU ETS on this date. The United Kingdom is the second-largest emitter of GHG in Europe, and its utilities and industry are among the largest buyers of permits in the ETS. As the United Kingdom is such a big buyer of ETS permits, analysts expect that the United Kingdom's exit from the scheme will impact permit prices.

75 Letter from Rt Hon Philip Dunne MP, Chairman of the Environmental Audit Committee, to Rt Hon Alok Sharma MP, Secretary of State, Department for Business, Energy and Industrial Strategy, *Support for developing a Hydrogen Strategy* (4 August 2020), available at https://committees.parliament.uk/publications/2245/documents/21021/default/.

Although the United Kingdom will leave the EU ETS, the UK government (through BEIS) is actively considering the future of UK carbon pricing after Brexit. The UK government has stated that it intends to replace the EU ETS with a UK ETS that allows for a seamless transition. Given it is already late 2020, there is a substantial amount of work to be done to achieve this.

Initial information on what a UK ETS might look like indicates the following:

- The UK ETS would cover over 1,000 UK participants. These businesses would need to put in place appropriate systems to comply with the UK ETS, including new trading arrangements and documentation.
- The UK government has indicated that the scheme should be consistent with the United Kingdom's net zero targets, and it may be more ambitious than the EU scheme (including setting the allowances cap under the UK ETS at 5 per cent less than they would have been under the EU scheme).
- Like the EU ETS, the UK version will apply to energy-intensive industries (such as heavy industry, refining, and manufacturing), aviation, and the power generation sector.
- No information has been provided on when the first auctions will be available, and no details are available on the trading framework and documentation to be used for trading. International credits will not be permitted in the UK ETS initially, but this will be reviewed over time.
- It is not yet clear whether the UK scheme will be linked to the EU scheme (to allow allowance trading between UK and EU companies), or whether it will be a stand-alone scheme. Potential advantages of a connected scheme would be increased liquidity from access to a wider market and confidence that the price would continue to be cost-competitive with the EU market.

III. A Hydrogen GoO

GoOs are a mechanism used in the electricity industry to label electricity from renewable sources as "green." Renewable energy generators are issued a GoO for each MWh of electricity that they produce. GoOs can be bought, sold, and consumed. When a company buys a GoO and takes delivery of electricity, the associated GoOs are cancelled in the electronic certificate registry. The system makes it possible to track ownership, verify claims, and ensure that GoOs are only consumed and counted once.

There is potential for an equivalent GoO scheme to be put into place for hydrogen. A hydrogen GoO scheme could improve the price of low-carbon hydrogen, as evidence that the relevant molecules are certified to be low-carbon (or "green") could allow for selective purchasing, leading to an increase in demand, a price premium, or both. A hydrogen GoO scheme could also allow UK hydrogen to be exported to international markets that want to know that the hydrogen they are purchasing is indeed low-carbon.

Such a system could provide an overall carbon intensity score for each unit of hydrogen produced, based on a standardised method for tracing and certifying hydrogen production. The European Union is currently considering whether and how to implement such a scheme. Design and planning work for a pilot scheme, called CertifHy, began in 2014, and the first hydrogen GoOs were issued in 2018.[76] Australia is actively considering an equivalent certification system.

With a number of countries gearing up to become substantial hydrogen importers, and others vying to take market share in the associated export market, this will definitely be a space to watch in the coming years.

IV. Planning Reforms

Planning legislation is currently in the process of change. On 6 August 2020, the UK government published its 84-page "Planning for the Future" document.[77] The new Planning White Paper puts forward a vision to radically overhaul England's current planning system and replace it with zonal planning, centralised decisions, and new local design codes.

The Planning for the Future consultation proposes reforms of the planning system to streamline and modernise the planning process, bring a new focus to design and sustainability, improve the system of developer contributions to infrastructure, and ensure more land is available for development where it is needed.

The consultation process closes on 29 October 2020. This is clearly a space that needs to be watched in terms of when and how the reforms mentioned above will impact the hydrogen industry.

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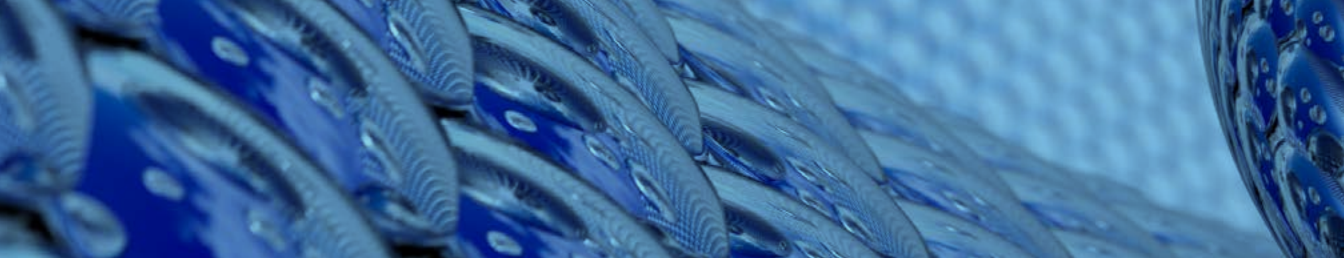
[76] *See* https://www.certifhy.eu/.

[77] Ministry of Housing, Communities & Local Government, *Planning for the Future: White Paper* (August 2020), available at https://www.gov.uk/government/consultations/planning-for-the-future.

GLOSSARY UNITED KINGDOM

Acronym	Word	Description
ADR	European Agreement concerning the International Carriage of Dangerous Goods by Road	A UN treaty that regulates the carriage of dangerous goods by road. ADR is incorporated into UK law by the CDG.
AEL	Alkaline Electrolysis	
BEIS	Department for Business, Energy & Industrial Strategy	UK government department with responsibilities for business, industrial strategy, science, innovation, energy, and climate change.
	Blue Hydrogen	Hydrogen that is produced using fossil fuels but is able to meet the low-carbon threshold through the use of CCUS.
CCC	Committee on Climate Change	An independent, non-departmental public body formed under the Climate Change Act 2008 to advise the United Kingdom and devolved governments and parliaments on tackling and preparing for climate change.
CCGT	Combined Cycle Gas Turbine	A power station that uses the combustion of natural gas or liquid fuel to drive a gas turbine generator to produce electricity. Heat from the exhaust gases is used to produce steam that drives a steam turbine generator and produces more electricity.
CCUS	Carbon Capture, Utilisation and Storage	A process by which the CO_2 produced in the combustion of fossil fuels is captured and is then either used in other process (such as industrial processes) or transported for long-term storage in geological formations (such as depleted oil and gas fields).
CDG	Carriage of Dangerous Goods and Use of Transportable Pressure Equipment Regulations 2009	UK legislation related to the carriage of dangerous goods.
CfD	Contract for Difference	A contract designed to reduce a producer or generator's exposure to volatile wholesale prices.
CO_2	Carbon Dioxide	The main greenhouse gas.
COMAH	Control of Major Accident Hazards Regulations 2015	
COP 26		The 26th "Conference of the Parties" climate summit that is due to be held in 2021.
DCO	Development Consent Order	The form of planning approval required for NSIPs.
DfT	Department for Transport	
	Electrolysis	The process of using electricity to split water into hydrogen and oxygen.
EIA	Environment Impact Assessment	
EP	Environmental Permit	
ETS	Emissions Trading Scheme	A system for trading greenhouse gas emission allowances with the goal of setting a carbon price.
EV	Electric Vehicle	A vehicle driven by an electric motor.
FCEV	Fuel Cell Electric Vehicle	Like EVs, FCEVs use electricity to power an electric motor. In contrast to EVs, FCEVs produce electricity using a hydrogen fuel cell, rather than drawing electricity from a battery.
FEED	Front End Engineering Design	
	Gas Act	The Gas Act 1986.
GB	Great Britain	England, Scotland, and Wales.



Acronym	Word	Description
	Green Hydrogen	Hydrogen that meets the low-carbon threshold and is generated using renewable energy sources such as wind or solar power.
GHG	Greenhouse gas	A gas in the atmosphere that absorbs and emits radiation within the thermal infrared range.
	Grey Hydrogen	Hydrogen that is produced using fossil fuels, without the use of CCUS.
GoO	Guarantee of Origin	A mechanism used in the electricity industry to label electricity from renewable sources as "green." GoOs can be bought, sold, and consumed.
GS(M)R	Gas Safety (Management) Regulations 1996	UK legislation related to safety standards for gas transport by pipeline.
HGV	Heavy Goods Vehicles	A truck weighing over 3,500 kg.
HSE	Health and Safety Executive	National regulator in Great Britain that is responsible for workplace health and safety.
LNG	Liquefied Natural Gas	Natural gas that has been super-chilled to liquid state.
NSIP	Nationally Significant Infrastructure Project	Major infrastructure projects that are dealt with at the national, rather than local, level under the Planning Act 2008.
Ofgem	Office of gas and electricity markets	The UK's independent National Regulatory Authority, a nonministerial UK government department. Their principal objective is to protect the interests of existing and future electricity and gas consumers.
PEM	Polymer Electrolyte Membrane	
PER	Pressure Equipment (Safety) Regulations 2016	
PPA	Power Purchase Agreement	An agreement for the sale and purchase of electricity from an electricity generator.
RHI	Renewable Heat Incentive	
RID	Regulations concerning the International Carriage of Dangerous Goods by Rail	Annex C of the Convention concerning International Carriage by Rail, which regulates the carriage of dangerous goods by rail. RID is incorporated into UK law by the CDG.
RTFO	Renewable Transport Fuel Obligation	
SOEC	Solid Oxide Electrolyser Cells	
TCPA 1990	Town & Country Planning Act 1990	
TWh	Terawatt-hour	A unit of energy equal to outputting one trillion watts for one hour. It is equal to 3.6x1015 Joules.
TWh/y	Terawatt-hours per year	
UK	United Kingdom of Great Britain and Northern Ireland	England, Scotland, Wales, and Northern Ireland.
VPPA	Virtual Power Purchase Agreement	An agreement for the sale and purchase of electricity from an electricity generator. However, unlike a physical PPA, with a virtual PPA the energy doesn't physically flow from the project to the buyer. Instead, electricity is fed from the generator into the local electricity grid. Also known as Corporate PPAs, Synthetic PPAs, and Financial PPAs.

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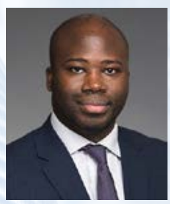

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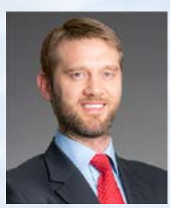

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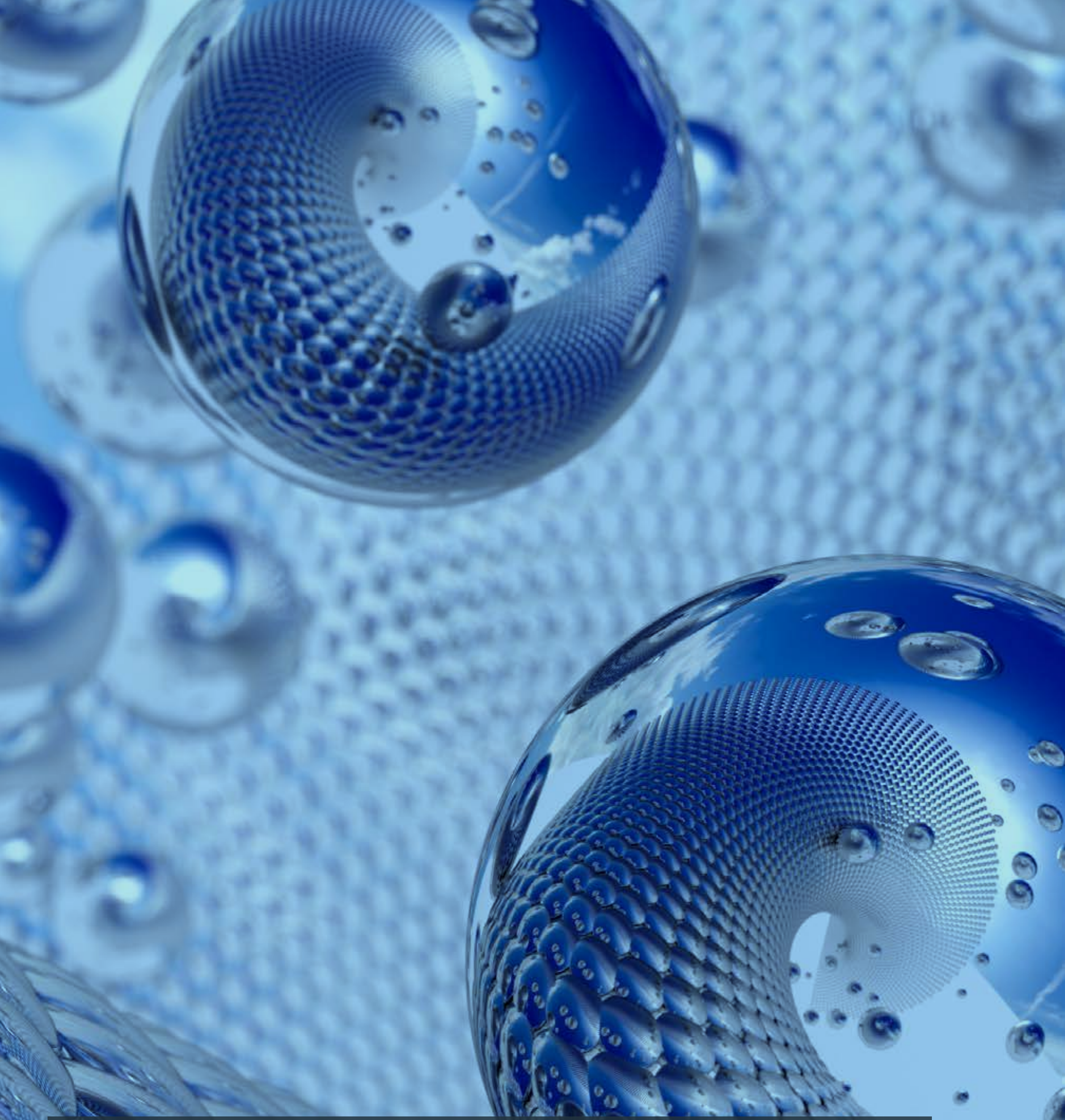

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