K&L GATES

The H_2 Handbook

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

INTRODUCTION

Hydrogen—the smallest molecule, but one that holds the potential to be an energy superhero and to play a significant role in reducing carbon emissions and slowing climate change. It is the most abundant element in the universe and can be produced from an impressive list of resources that could truly manifest an "all of the above" energy economy. It can be combusted, compressed, liquefied, stored, used to store electricity, and used to produce electricity. While modifications are needed to address its unique attributes, hydrogen also can be transported via pipeline (either on its own or as part of a commingled natural gas stream), by truck, rail, or vessel.

Companies ranging from utilities, to manufacturers and automobile companies, high tech, and even oil supermajors, are recognizing hydrogen's potential and taking an active role in the development of the nascent industry. Which countries participate in the initial stages of a hydrogen economy likely will depend on politics, the abundance and accessibility of natural resources, and availability of modes of transportation and distribution sufficient to match scale. Countries like Australia, Canada, China, Germany, India, Japan, and South Korea, as well as the European Union already have drafted or are drafting national level strategies for hydrogen—including government incentive programs and goals for stimulating demand and production. Other countries, like the United States and the United Kingdom, do not yet have a national strategy for hydrogen, but particular initiatives and strategies at the state and local levels are emerging.

Like other sources of energy, commercial-scale hydrogen will require clear, informed, and transparent regulatory regimes at the local, national, and international levels. These regimes will need to balance hydrogen's unique features and a desire to build out a robust hydrogen infrastructure that facilitates the penetration of hydrogen as a major global energy source.

While hydrogen already is used in limited applications, commercial factors and the development of global commercial standards undoubtedly will play a role in hydrogen's expansion into a global commodity as well. Cleverly and usefully, the industry has standardized a color-scheme nomenclature to identify the resource base used to produce hydrogen. The generally used colors are:

- Brown: Hydrogen produced from coal gasification;
- Grey: Hydrogen produced from natural gas (methane) via steam methane reformation, without the use of carbon capture and sequestration;
- Blue: Hydrogen produced from natural gas (methane) via steam methane reformation, coupled with carbon capture and sequestration; and
- Green: Hydrogen produced via electrolysis from renewable or other zero-emissions power source.

Agreement on a currency for international hydrogen trade also will be an important step. While U.S. dollars have been used for global energy commodities like petroleum, the United States' lack of a serious national hydrogen strategy in the near term may leave open the potential for other countries or jurisdictions to establish a particular currency as the standard for hydrogen transactions globally. But, regardless of the ultimate currency used, establishing a global hydrogen economy will require participation and coordination of multiple countries and jurisdictions.

The Hydrogen Handbook provides a summary of the regulatory, commercial, and policy issues that we believe hydrogen will face on its path to becoming a global commodity and a significant part of the energy mix. The issues facing the development of a robust, global hydrogen economy unsurprisingly differ by country and we have therefore organized this resource guide in that manner. We have chosen to kick-off *The Hydrogen Handbook* with coverage of Australia, the European Union, Germany, Japan, the United Kingdom, and the United States. Our global team of lawyers and public policy professionals who compiled *The Hydrogen Handbook* have drawn on their extensive experience in global energy markets and in particular disciplines. We intend to provide stand-alone updates, including written alerts and podcasts, to supplement *The Hydrogen Handbook* as matters develop. Visit our **Hydrogen Emerging Issues website page** regularly for new content.

We hope you find *The Hydrogen Handbook* to be useful and of course please contact us if we can be of assistance.

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AUSTRALIA

The H_2 Handbook

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PART I - INTRODUCTION

I. Background

Like many countries around the world, Australia is transitioning to a low-carbon future to reduce greenhouse gas emissions and combat climate change. Australia ratified the Paris Agreement in 2016, committing to a 26-28 per cent reduction in greenhouse gas emissions below 2005 levels by 2030. In addition, every Australian state and territory has committed to a net-zero emissions target (many of which are legislated).

As Australia undertakes this transition, the need for "clean" fuels that also meet safety, storage, and other commercial requirements is becoming increasingly necessary. Clean hydrogen (either green hydrogen, produced through electrolysis of water using renewable power, or blue hydrogen, made through thermochemical production alongside carbon capture technology) can meet these criteria and is expected to play a key role in the decarbonisation of energy in Australia.

Clean hydrogen can also assist Australia in addressing a number of energy security risks it currently faces.

Australia is in an ideal position to become a global leader in clean hydrogen, and the Australian hydrogen industry could generate an additional A$11 billion in GDP by 2050.[1] Australia's ability to lead the world in clean hydrogen is due to a number of key factors, including:

- **Abundant natural resources**

  These resources include coal and liquefied natural gas (LNG), renewables, and land mass.

- **Proven track record**

  Australia has significant experience in large-scale energy projects and development of energy industries, particularly with respect to LNG export projects.

- **Governmental support**

  The Australian federal government has shown its commitment to hydrogen through policy and funding. It has developed the National Hydrogen Strategy, committed A$146 million to the hydrogen industry since 2015[2], and has committed an additional

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1 Matt Judkins and John O'Brien, *Australian and Global Hydrogen Demand Growth Scenario Analysis*, DELOITTE 8 (Nov. 2019), http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-and-global-hydrogen-demand-growth-scenario-analysis-report-2019_1.pdf (last visited Sept. 8, 2020).

2 *Australia's National Hydrogen Strategy*, COAG ENERGY COUNCIL xvi (Nov. 2019), https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf (last visited Sept. 8, 2020) [hereinafter COAG 2019].

A$370 million in funding through various agencies.[3]

- **Skilled workforce**

  Australia has a technically skilled workforce with deep expertise in the energy sector and high-value or advanced manufacturing production processes.

- **Hydrogen expertise**

  Australia leads the world for research in storage, distribution, and use with over 30 pilot projects across Australia.

II. Australia's Competitive Advantage

Australia has a distinct competitive advantage in establishing and expanding its clean hydrogen industry, as well as being well placed for both the domestic use and export of hydrogen. Australia has particular comparative advantages due to the strength of its existing LNG production and export operations, the potential for synergies with its developed renewables industry, demand for hydrogen imports from Australia's largest trading partners in the Asia-Pacific region, and opportunities for domestic use of hydrogen due to Australia's reliance on the importation of liquid fuels and comparatively high price of LNG.

A. LNG and Natural Gas

Australia exports A$50 billion in LNG annually (the second-largest exporter of LNG in the world) and is host to many of the world's largest oil and gas companies, many of whom are looking towards transitioning to a future of hydrogen production for commercial and individual use. Australia has major international ports along its coastline, many with existing LNG and petroleum infrastructure that provide an ideal environment for developing "hydrogen hubs" and to then support the upscaling of hydrogen production for export and domestic use.

Australia also has an extensive network of major natural gas transmission and distribution pipelines, and, in many parts of Australia, a comparatively high price for natural gas. Replacing or blending natural gas with clean hydrogen in these networks has the potential to drive down natural gas prices and stimulate early hydrogen demand-side growth, which has the advantage of being able to be directly influenced by governments. With further R&D into the ability of these networks to transport hydrogen, as well as safety and regulatory matters, Australia can be in a position to capitalise on this infrastructure. The Australian government plans to complete its review in relation to these matters by the end of 2020.

B. Renewables

Australia is home to many high-intensity renewable energy resources. The Australian continent has the highest solar radiation per square metre of any continent, and some of the best wind resources in the world in the southern parts of the Australian continent.

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3 *Australia to be a world leader in Hydrogen*, MINISTERS FOR THE DEP'T OF INDUS., SCIENCE, ENERGY AND RES. (Nov. 23, 2019), https://www.minister.industry.gov.au/ministers/canavan/media-releases/australia-be-world-leader-hydrogen (last visited Sept. 8, 2020).

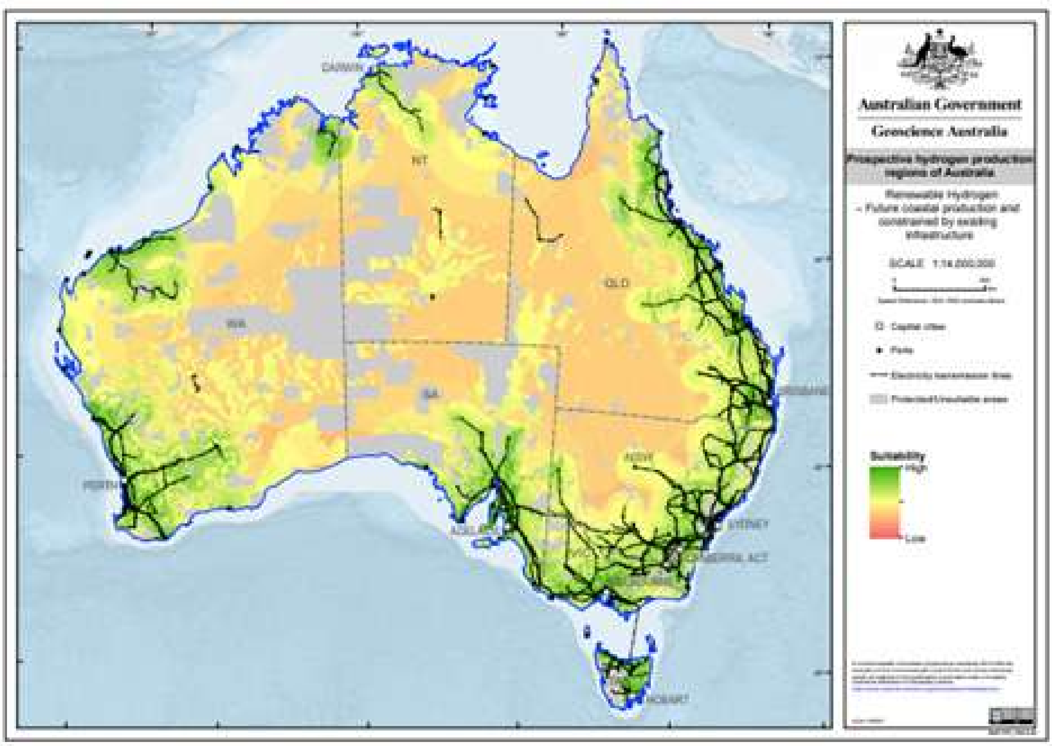
This presents a huge opportunity for Australia in sector-coupling the hydrogen industry with these vast renewables resources, combined with high land availability, given green hydrogen's requirement for access to low-cost, low-emissions electricity.

It is estimated that about 3 per cent of the Australian continent (about 262,000 square kilometres) would be suitable for green hydrogen production, with proximity to renewable resources, as well as the requirement for water—this amount of land, if utilised, could produce more hydrogen than the global demand predicted by the Hydrogen Council by 2050.[4]

C. Export Opportunities

Australia has a strong reputation as an energy exporter to Asia (with LNG exports to Southeast Asia, China, and Japan accounting for 97 per cent of Australia's total LNG export earnings),[5] and three of Australia's top four trading partners (namely, Japan, the Republic of Korea, and China) have committed to using clean hydrogen to decarbonise their energy systems.

With the global market for hydrogen expected to increase, Australia can capitalise on its proven track record in energy exports, especially to comparatively resource-constrained countries such as Japan, and its knowledge in order to progress the hydrogen industry.



[4] *See* COAG 2019, *supra* note 2, at 10.

[5] ARUP, *Australian Hydrogen Hubs Study*, 2 COAG ENERGY COUNCIL HYDROGEN WORKING GROUP (Technical Study) (Nov. 2 2019), http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf (last visited Sept. 8, 2020).

Australia has identified four key hydrogen export jurisdictions: Singapore, China, South Korea, and Japan; and assessed its potential market share in each of these markets and the target price of hydrogen required, to be competitive with other potential hydrogen-exporting countries such as Qatar and Norway.[6]

Australia has already entered, or plans to enter, into a number of bilateral agreements with trading partners to promote trade and investment in hydrogen, including with:

- **Japan**—Joint Statement on Cooperation on Hydrogen and Fuel Cells (January 2020)
- **Republic of Korea**—Letter of Intent to develop a Hydrogen Action Plan (2019)
- **Singapore**—Agreement to pursue a Memorandum of Understanding on low-emissions technologies (by end of 2020)
- **Canada**—Memorandum of Understanding to collaborate on the commercial deployment of zero-emission hydrogen and fuel cell technologies (2020)

There is also potential for Australia to blend hydrogen into a number of its existing export commodities (such as methanol and ammonia).

D. Domestic Use

Hydrogen also has a significant potential for use within Australia:

1. Natural Gas

Prices for natural gas remain high in many parts of Australia, particularly across the eastern coast, largely due to local gas supplies being committed to long-term export contracts, coupled with a moratorium on unconventional natural gas exploration in many areas. Hydrogen could replace or supplement natural gas for use in heating and cooking or as feedstock in industrial processes (subject to resolving the technical and regulatory issues as outlined in **II.A** above).[7]

2. Liquid Fuels Security

Australia is currently dependent on imported liquid fuels, and does not meet its domestic fuel reserve targets.[8] Hydrogen production presents an opportunity to localise liquid fuel supplies.

3. Management of Transition to Renewables

As Australia transitions to an electricity grid with a higher penetration of variable renewable energy, hydrogen could play a role in overcoming problems of energy intermittency by acting as a source of storage for renewable electricity.[9]

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[6] ACIL Allen Consulting, *Opportunities for Australia from Hydrogen Exports*, AUSTL. RENEWABLE ENERGY AGENCY 29 (Aug. 2018), https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf (last visited Sept. 8, 2020).

[7] *See The Hydrogen Handbook:* United States Part III, Section I.C. for additional details.

[8] *See generally*, Australian Petroleum Statistics, AUSTL. DEP'T OF THE ENV'T & ENERGY (2018) https://www.energy.gov.au/publications/australian-petroleum-statistics-2018 (last visited Sept. 8, 2020).

[9] *See The Hydrogen Handbook:* United States Part III, Section II for additional details.

PART II – GOVERNMENTAL SUPPORT

I. Commonwealth – Australia's National Hydrogen Strategy and Other Policy

Released in 2019, Australia's National Hydrogen Strategy (Strategy) sets out Australia's vision to become, and strategy to establish, a hydrogen industry that is "clean, innovative, safe and competitive," and to position Australia as "a major global player by 2030."[10]

The Strategy identifies 57 strategic actions to achieve this vision, and centres on an adaptive approach to industry development. Some key elements of the Strategy to 2025 are designed to set the foundations for the growth of the industry:

- Advance priority pilots, trials, and demonstration projects
- Assess supply chain infrastructure needs
- Build demonstration-scale hydrogen hubs: being clusters of large-scale demand to promote cost-efficiencies, synergies, and focus innovation as a "springboard to scale"
- Develop supply chains for prospective hydrogen hubs

The key elements of the Strategy beyond 2025 are designed to create large-scale market activation by looking to:

- Identify signals that large-scale hydrogen markets are emerging;
- Scale up projects to support export and domestic needs;
- Build Australian hydrogen supply chains and large-scale export industry infrastructure;
- Build and maintain robust and sustainable export and domestic markets, and supply chains; and
- Enable competitive domestic markets with explicit public benefits.

Separately, in its Technology Investment Roadmap Discussion Paper released in May 2020, the Commonwealth Government identified hydrogen as a "key technology need" as a part of its Long Term Emissions Reduction

[10] *See* COAG 2019, *supra* note 2, at 76.

Strategy.[11] This paper also set a goal of "H2 under $2," an economic goal for hydrogen to reach a price of at or under A$2 per kilogram, which is considered to be the point at which hydrogen becomes competitive with alternatives in large-scale deployment.

Alongside the Strategy, the federal government has made the following commitments:

- Between 2015-2019, A$146 million has been committed to hydrogen projects.
- In 2019, a A$70 million "Renewable Hydrogen Deployment Funding Round" was announced for the Australian Renewable Energy Agency (ARENA) to provide grants to demonstrate the technical and commercial viability of hydrogen production at a large-scale using electrolysis.
- In 2020, A$300 million was allocated to the "Advancing Hydrogen Fund" administered by the Clean Energy Finance Corporation (CEFC), to support the growth of a clean, innovative, safe, and competitive Australian hydrogen industry via concessional finance.

Australia's existing regulations will require review to support the development of a world-leading hydrogen industry in Australia (as identified in the Strategy). Currently, technical regulations for the transport of gaseous materials provide broad coverage regarding the use of hydrogen and related technologies, but the legislation will need to develop to provide for hydrogen-specific regulations.

The current regulatory framework for the commercial use of gas in Australia does not specifically reference hydrogen. The existing gas regulations could be expanded to include hydrogen, providing a framework for distribution of hydrogen. Natural gas distribution networks in Australia are largely regulated assets with fixed volumetric pricing. If operated in a similar way, this would mitigate many risks associated with investment, ensuring a steady revenue stream.

Workplace health and safety regulations are governed by each state and territory jurisdiction but are broadly consistent and would cover hydrogen.

[11] *Technology Investment Roadmap Discussion Paper*, AUSTL. DEP'T OF INDUS., SCI., ENERGY & RES. (May 2020), https://consult.industry.gov.au/climate-change/technology-investment-roadmap/supporting_documents/technologyinvestmentroadmapdiscussionpaper.pdf (last visited Sept. 8, 2020).

II. State and Territory – Regulation and Policy

Most Australian jurisdictions have a combination of existing industry incentives that could apply to the hydrogen industry (such as concessional finance, funding for new public infrastructure, favourable zoning and approvals, entry into public private partnerships), as well as hydrogen-specific strategies and funding, including the following:

State	Projects
Victoria	• Victorian Hydrogen Investment Program (2018), Victorian Green Hydrogen Discussion paper (2019) and Zero Emissions Vehicle Roadmap (due for release in 2020) • Hydrogen Energy Supply Chain pilot—the world's largest hydrogen demonstration project, with hydrogen production from brown coal and transportation to Japan
NSW	• Net Zero Plan Stage 1: 2020-2030 (2020)
Queensland	• Queensland Hydrogen Industry Strategy 2019-2024 (2019) • A$15 million Hydrogen Industry Development Fund • Memorandum of Understanding with the Japan Oil, Gas and Metals National Corporation (JOGMEC) to cooperate on hydrogen and a Statement of Intent with the University of Tokyo's Research Center for Advanced Science and Technology • Fuel Cell Electric Vehicle fleet trial
WA	• Western Australian Renewable Hydrogen Strategy (2019) • Renewable Hydrogen Fund
SA	• South Australia's Hydrogen Action Plan (2019)
Tasmania	• Tasmania Renewable Hydrogen Action Plan (2020), including an A$50 million funding round.
ACT	• The ACT is on track to achieve 100 per cent renewable electricity by 2020 and will then look to decarbonise its natural gas, and transport and develop plans in respect of these.

PART III – COMMERCIAL ISSUES

I. Production

The Australian government has demonstrated its commitment to ensuring that Australia can become a major global player in the hydrogen market. It has committed over A$146 million to hydrogen projects.[12] There is great potential for hydrogen production in Australia, with predictions that Australia could produce more than three million tonnes a year, worth up to A$10 billion a year.[13]

The Australian government estimates that approximately 262,000 square kilometres of Australia's coastal areas are suitable for hydrogen production.[14] The Hydrogen Council estimates that utilising such land would prove highly effective and could provide more than the entirety of global demand by 2050. On the basis of the quality of Australia's solar, wind, and hydropower resources, approximately 872,000 square kilometres of overall land in Australia could be suitable for renewable hydrogen production.[15]

Hydrogen hubs are the key to industry success and allow producers to take advantage of infrastructure and innovation. Over 30 ports have been identified as potential hub locations.[16]

Looking specifically at the various means of hydrogen production, following is an exploration of some commercial issues to be addressed:

A. Green Hydrogen—Electrolysis

1. Electricity Requirements

There are additional electricity requirements to produce hydrogen. Unlike thermochemical production of hydrogen, alkaline electrolysis and PEM electrolysis ensure there are no associated operational emissions of CO_2. However, there is an increased demand for electricity with these types of production.

12 *See* COAG 2019, *supra* note 2, at xvi.

13 Sam Bruce, et al., *National Hydrogen Roadmap: Pathways to an economically sustainable hydrogen industry in Australia*, CSIRO xix (Austl.) (2018), https://www.csiro.au/en/Do-business/Futures/Reports/Energy-and-Resources/Hydrogen-Roadmap (follow "Main report [pdf • 5mb]" hyperlink) (last visited Sept. 8, 2020) [hereinafter CSIRO].

14 *See* COAG 2019, *supra* note 2, at 10.

15 *Id.*

16 *See* ARUP, *supra* note 5, at 2.

A report calculates that the demand for additional electricity is between 1 TWh by 2025 in a low-demand scenario and 200 TWh by 2040 in a high hydrogen-demand scenario.[17] The Australian Energy Market Operator has predicted that the Australian National Energy Market will grow by 10 TWh into 2036-2037. Thus, additional electricity is needed and will need to be supplied from renewable or traditional energy sources.

2. Power Purchase Agreements

To source this electricity, developers will need to enter into power purchase agreements (PPAs) to secure long-term supply and drive projects further down the cost curve. Sourcing electricity from the grid can still be utilised while ensuring low emission electricity via PPAs.

PPAs also may be used to secure low emission electricity supply from renewable sources. Australia has a strongly developing renewable energy sector that provides hydrogen developers with a unique opportunity to scale up and participate in the future global hydrogen market.

In the last two years, **Corporate Renewable PPAs** (Corporate PPAs) have grown in the Australian energy market. The Business Renewables Centre Australia has estimated in its report that there have been more than 58 Corporate PPAs for 2.3GW of capacity with over 60 per cent being made with new solar and wind farms[18] with strong market interest and activity.

3. Commercial Energy Sourcing

Hydrogen producers should be aware of the potential trade-offs of electricity pricing and capacity of electrolysers when considering their commercial energy sourcing.

Currently, grid-connected electrolysis has the highest average capacity[19] and therefore produces the cheapest levelised cost of hydrogen when utilising PPAs for low carbon electricity supply. As a result, producers should carefully consider the location of the electrolyser in relation to electricity transmission infrastructure.

In addition, the use of otherwise curtailed renewable energy should be considered given such generation capacity would otherwise not be utilised and would allow increased electrolyser utilisation.

A key example is the Port Lincoln green hydrogen plant in South Australia. The A$117.5 million project will utilise a grid-connected alkaline electrolyser, as well as hydrogen turbines and fuel cells. This will balance services to the transmission grid to supply 18,000 tonnes of green

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[17] *See* ACIL Allen Consulting, *supra* note 6, at 50.

[18] Chris Briggs, Finnian Murphy and Jonathan Prendergast, *Corporate Renewable Power Purchase Agreements: State of the Market*, BUS. RENEWABLES CENTRE-AUSTRL. 1 (Nov. 2019), https://businessrenewables.org.au/wp-content/uploads/2019/11/BRC-A-State-of-the-Market-2019.pdf (last visited Sept. 8, 2020).

[19] *See* CSIRO, *supra* note 13, at 15.

ammonia to agriculture and industry sectors.[20]

4. Accessibility to Water

Accessibility to water also will be a key consideration for alkaline and PEM electrolysis. For every 1 kg of hydrogen produced, 9 kg of high-purity water is required,[21] unless a deioniser has been integrated.

Focus groups routinely indicate that water concerns are particularly significant in farming communities and will need to be addressed to gain social acceptance and community support.[22]

The cost of water usually makes up less than 2 per cent of the cost of hydrogen production.[23] Estimates place water needed for Australian exported hydrogen by 2040 in the range of 5.6 gigalitres in a low-demand scenario to 28.6 gigalitres in a high-demand scenario.[24] With total consumption of water in Australia in 2015-2016 being 16,132 gigalitres and industries using a total of 2,014 gigalitres,[25] hydrogen production demands far less water than other industries. Therefore, the amount of water will not likely be prohibitive. Instead, the location of hydrogen hubs will be key in ensuring social acceptance and success of hydrogen production.

B. Steam Methane Reforming (SMR)

1. Emissions

Currently, SMR is the most widely used method for producing hydrogen, representing 48 per cent of global production,[26] and is an established, mature technology.[27] If thermochemical hydrogen production is increased in Australia, emissions domestically will increase. The Commonwealth Scientific and Industrial Research Organisation (CSIRO) has estimated that thermochemical production of hydrogen operationally emits 0.76 kilograms of CO_2 per kilogram of hydrogen produced.[28] Therefore, though the use of hydrogen is a means of reducing global greenhouse emissions and air pollution, thermochemically produced hydrogen must consider carbon capture and storage (CCS) strategies, management, and storage.

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20 *Port Lincoln hydrogen and ammonia supply chain demonstrator,* GOV'T OF S. AUSTL.: RENEWABLESSA (July 16, 2020), http://www.renewablessa.sa.gov.au/topic/hydrogen/hydrogen-projects/hydrogen-green-ammonia-production-facility (last visited Sept. 8, 2020).

21 *See* CSIRO, *supra* note 13, at 12.

22 *See* COAG 2019, *supra* note 2, at 60.

23 *See* CSIRO, *supra* note 13, at 17.

24 *See* ACIL Allen Consulting, *supra* note 6, at 37.

25 *Id.*

26 *See* CSIRO, *supra* note 13, at 19.

27 It should be noted that other similar processes, including auto thermal reforming and partial oxidation, are also currently in use and may become more heavily used in the future.

28 *Id.* at 67.

The effect of the cost of CCS on the levelised cost of hydrogen is not significant where production and storage plants are reasonably proximate in "hubs" and therefore CO_2 transporting costs can be absorbed.[29] Location considerations are significant for thermochemical production of hydrogen as proximity to resources and CO_2 storage reservoirs are integral.

2. Pricing Risks

One major consideration for SMR is the risk associated with the pricing of natural gas, which remains high on the east coast of Australia in contrast to some overseas markets. There are concerns about future cost trajectories due to significant reductions in domestic gas supplies.

The North West Shelf of Australia presents opportunities with large natural gas reserves and depleted gas fields that could be utilised as potential CO_2 storage reservoirs. However, there are difficulties with the reserves being committed to long-term LNG export contracts and moratoriums on unconventional gas exploration in the eastern states of Australia.[30]

C. Coal Gasification

Hydrogen production from coal gasification is reliant upon location of coal feedstock.

1. Australian Brown Coal

Although globally thermal black coal is most commonly used for gasification, brown coal is cheaper in the Australian context. It has the disadvantage of slag buildup and some reduced efficiencies. Brown coal presents an early opportunity to develop industry capabilities with modelling demonstrating a levelised cost of hydrogen at approximately A$2.14-$2.74 per kilogram.[31]

The Hydrogen Energy Supply Chain (HESC) project utilises Victorian brown coal in its gasification to produce hydrogen-rich syngas. The proposal is for this to be purified, liquefied, and transported on a tanker to Japan, with the first delivery of hydrogen to be completed in 2021.The hydrogen is to be transported by road, with a view to moving to a pipeline in future commercial phases, and utilises liquefaction and loading resources at the Port of Hastings. If the pilot program is successful, the project aims to begin commercial operations in the 2030s.[32]

2. CO_2 Storage

Hydrogen production through gasification requires a CCS solution to manage emissions. The Victorian and Australian governments have developed a CarbonNet Project,

29 *Id.* at 20.

30 *Id.* at 3.

31 *Id.* at 22.

32 *Id.* at 17.

which has the potential to deliver a CCS solution.[33]

In New South Wales and Queensland, there may be associated issues for coal gasification in relation to CO_2 storage as the storage reservoirs face social licence risks. This may be compounded when considering the social issues associated with continued concerns over fossil fuel use and uncertainty around long-term effectiveness of CO_2 storage.[34] Therefore, it will be key for thermochemical producers of hydrogen to continue to manage and direct resources towards gaining the support of the broader Australian community and local specific communities.

II. Transportation/Delivery

A. Infrastructure

Australia is uniquely positioned in the global market to become a leader in the future clean hydrogen market.[35]

- Australia currently exports LNG and consequently has experience in establishing energy export markets in key markets.
- Australia has already established infrastructure with existing ports, compression facilities, and strong experience with working with supply chains.
- The location and positioning of Australia in the Asia-Pacific region provides a key advantage for supplying Asian markets with hydrogen, as other potential competitors would be disadvantaged by additional transport costs.

It has been asserted that Australia's existing gas infrastructure and distribution network in Australia is capable of being utilised for the transport and storage of volumes of hydrogen through blending up to 10 per cent.[36] Modelling has suggested that utilising hydrogen with existing infrastructure may be up to 40 per cent less expensive than a full electrification of Victoria's gas network.[37] Unfortunately, the use of existing infrastructure and pipelines is somewhat limited, given concerns that higher percentages of hydrogen could significantly impact residential and commercial consumer appliances, industrial user plant and equipment, and degrade the existing distribution network infrastructure due to hydrogen embrittlement (depending on pipe material composition and operation pressure).

For higher hydrogen percentages, or pure hydrogen gas, new pipelines, mains, meters, and appliance replacements would be required. High-density polyethylene (HDPE) pipe has been identified as suitable for transporting higher percentages of hydrogen and has already begun being installed in Australia through replacement programs.[38] In particular, ACT and

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33 *Hydrogen Communities: Assessment for suitability of communities for conversion to hydrogen*, KPMG 25 (June 2019), https://arena.gov.au/assets/2019/10/hydrogen-communities.pdf (last visited Sept. 8, 2020).

34 *See CSIRO*, *supra* note 13, at 25.

35 *See* Deloitte, *supra* note 1.

36 *See* ARUP, *supra* note 5, at 73.

37 *See* COAG 2019, *supra* note 2, at 31.

38 *See* ARUP, *supra* note 5, at 74.

Tasmania already have HDPE distribution networks in place. Pending further testing, complete HDPE pipe could be deemed as suitable for 100 per cent hydrogen and presents an opportunity to replace existing distribution networks.

B. Liquefaction

As hydrogen is not dense enough for long-distance transport to be commercially viable, producers need to utilise liquefaction by way of sufficient cooling (to very low temperatures) and compression or conversion to ammonia or combination with a chemical liquid carrier for effective transportation and delivery. The facilities necessary for liquefaction would likely be best located at export hubs. However, conversion to ammonia or combining with liquid chemical carriers could occur further upstream so that subsequent road and rail infrastructure could be utilised.

There is particular interest in ammonia as an early pathway, as it allows for easy handling in shipping due to the high energy density compared to liquid hydrogen. For greater distances of transport required for hydrogen exports, liquefaction or ammonia storage is typically used to allow for shipping. Though shipping costs are varied due to the extent of compression and carrier used, they are estimated to be in the range of A$0.03 and $0.61 t/km.[39]

However, this will need to be balanced against the associated energy output for the initial conversion of hydrogen to ammonia and the subsequent reconversion for end-use. This process may see cost reductions as technological developments are introduced to the market, with the CSIRO having developed technology for the conversion of ammonia into high purity hydrogen at point of use through the use of vanadium membranes.[40]

There would also need to be additional consideration of the end-user of the exported hydrogen, as they may not have the facilities necessary at ports to convert the ammonia to hydrogen or remove the liquid chemical carrier. Pilot studies are currently being carried out in Australia with an aim to develop the shipping of liquid hydrogen (LH2) on tankers.[41] If successful, LH2 tankers could be facilitated through the use of existing, expanded, or additional infrastructure at existing ports in Australia that have capabilities in handling gas- and liquid-petroleum products.

Even where shipping is utilised for exported hydrogen, rail and road transport will likely be necessary for hydrogen delivery. A consideration of distances for input or output product carriage is a significant driver for producers to consider. In the United States and Europe, it is relatively common for LH2 to be transported by road, utilising liquid tankers. However, this has not yet occurred in Australia. There are challenges to transporting liquefied hydrogen by road, but larger masses of hydrogen are able to be transported

39 *See* ACIL Allen Consulting, *supra* note 6, at 38.

40 *See* COAG 2019, *supra* note 2, at 40.

41 *See* ARUP, *supra* note 5, at 60 n. 5.

than in its gaseous form. While there are some considerations regarding boil-off during transport, use of chemical liquid carriers enables less complex storage engineering.[42]

C. Hydrogen Hubs

One of the biggest cost implications for hydrogen producers is the cost of processing, storage, and transport pathways. Hydrogen hubs are a cornerstone of Australia's National Hydrogen Strategy, as scale has been identified as the key to Australia becoming a globally competitive supplier. Over 30 potential ports have been identified in Australia as being potential hub locations, with analysis delivered according to key criteria such as gas transmission pipelines, electrical transmission lines, transport access, and port infrastructure.

D. Shipping, Road, and Rail

Refuelling stations are a specific focus for states and territories, particularly for freight and public transport. The increase in private hydrogen-powered vehicles will be limited by the number and availability of refuelling stations. The Council of Australian Governments identified that the greatest opportunity for fuel cell electric vehicles (FCEVs) is in the heavy vehicle market due to the competitive weight advantage in comparison to a battery electric vehicle (BEV) truck, as well as shorter refuelling times.[43] Preliminary work has begun to identify the requirements for refuelling stations as governments seek to support developments on major freight and passenger road corridors.[44]

[42] *Hydrogen for Australia's Future*, HYDROGEN STRATEGY GROUP FOR THE COAG ENERGY COUNCIL 21 (Briefing Paper) (Aug. 17 2018), http://www.coagenergycouncil.gov.au/publications/hydrogen-australias-future (last visited Sept. 8, 2020).

[43] *Id.* at 31-33.

[44] *Hydrogen as a Transport Fuel: Location options for a freight-based limited initial deployment of hydrogen refuelling stations*, BUREAU OF INFRASTRUCTURE, TRANSP. & REG'L ECON. (Information Paper) (Oct. 2019) [hereinafter BITRE].

III. Use

Hydrogen is a clean, versatile, and safe energy carrier that can be used for multiple purposes. It can be used to generate electricity; power vehicles; generate heat; produce chemicals such as ammonia, methanol, and alkenes/olefins; as well as for export. Figure 1 illustrates these potential uses.

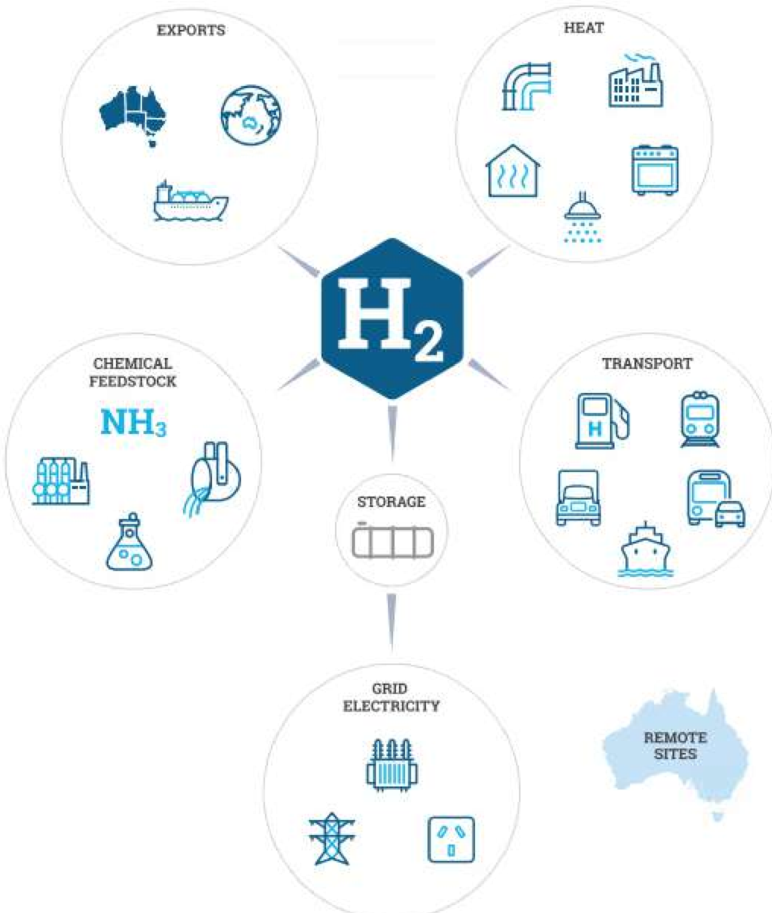

Figure 1: Potential uses of Hydrogen[45]

A. Transport and Fuel Cells

Instead of combustion, fuel cells produce electricity via an electrochemical reaction that combines hydrogen and oxygen to generate an electric current with water as a by-product. This is the reverse of an electrolysis procedure. Fuel cells are preferable as they are quiet, have very low emissions, and are two to three times more efficient than traditional combustion technologies.[46]

45 *See* COAG 2019, *supra* note 2, at 4.

46 *Fuel Cells for Stationary Power Applications*, U.S. DEP'T OF ENERGY 1 (Oct. 2017).

1. Emerging Fuel Cells

Reversible fuel cell systems combine the electrolysis and fuel cell process into a single system. This will result in a system that operates similarly to a battery, allowing for reductions in capital cost.[47] Subsequently, reversible fuel cells may potentially disrupt the broader hydrogen value chain.

Hydrogen can also power FCEVs. The advantages of hydrogen-powered transport compared to BEVs are faster refuelling times and the ability to travel longer distances carrying larger loads before refuelling. Refuelling hydrogen vehicles requires a network of refuelling stations, similar to what exists for petrol and diesel.

2. Vehicles

Passenger FCEVs consist of an electric drive train powered by a proton exchange membrane (PEM) fuel cell stack and hydrogen storage tank pressurised to 700 bar. They may be more suitable for consumers who travel longer distances (i.e., 400-600km without refuelling), expect shorter refuelling times, and are without easy access to BEV recharging infrastructure.

3. Hydrogen Refuelling Stations (HRS)

HRSs consist of a standard overall system (Figure 2), with key differences regarding the hydrogen delivery method, dispenser pressure, and capacity. This can impact the configuration and consequently the cost. Hydrogen is delivered in gaseous form, which is compressed for intermediate storage with pressures of up to 500 bar.

Due to the high operating pressures of hydrogen delivery, refuelling requires additional equipment considerations. An increase in electricity is required to meet the precise temperature requirements that are needed for a fast fill.[48] Furthermore, additional control systems are necessary to monitor volume, temperature, flow rate, and pressure. Current dispenser nozzles also cost up to 100 times more than the petrol equivalent.[49]

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47 *Id.* at 3.

48 K. Reddi, et al., *Impact of hydrogen SAE J2601 fuelling methods on fuelling time of light-duty fuel cell electric vehicles*, 42 INT'L J. OF HYDROGEN ENERGY 26, 16675 (June 29, 2017) https://www.sciencedirect.com/science/article/abs/pii/S0360319917316853 (last visited Sept. 8, 2020).

49 *US DRIVE Hydrogen Delivery Technical Team Roadmap*, U.S. DEP'T OF ENERGY 27 (Jul. 2017), https://www.energy.gov/eere/vehicles/downloads/us-drive-hydrogen-delivery-technical-team-roadmap (last visited Sept. 8, 2020).

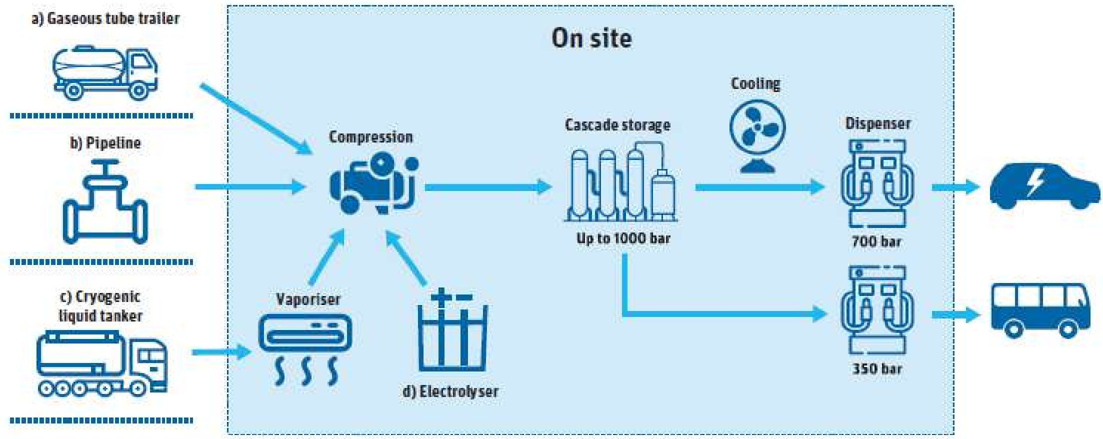

Figure 2: Standard refuelling station configuration[50]

4. Materials Handling

Hydrogen fuel cell powered materials handling is becoming a favourable technology option over battery and diesel equivalents for a number of operations. Currently, large warehouses with 24/7 operating requirements that rely on battery-driven equipment require additional batteries to be purchased. This creates a hazard, increases in capital costs, and storage space issues as well as the release of odours when charging the batteries, which may damage warehouse inventory. Consequently, the rate of hydrogen refuelling and absence of odours make FCEVs more attractive in these types of operations.

5. Other Emerging Technologies

Fuel cell trains are comparable in cost with electrification, given the capital requirements for overhead rail as compared with being able to use existing infrastructure.[51] With only 10 per cent of Australia's railway tracks electrified, hydrogen-powered rail could have a place in future rail infrastructure considerations.[52]

Pure hydrogen-powered marine passenger ships are gradually emerging to combat air and water quality issues. Similarly, fuel cells are beginning to be adopted by Unmanned Aerial Vehicles (UAV) or drones to power propulsion mechanisms. Fuel cells can provide 8-10 times more flight time in some UAV models and have shorter refuelling times than batteries.[53]

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50 *See* CSIRO, *supra* note 13, at 40.

51 *Id.*

52 Jeremy Dornan, Peter Kain and John Ryan, *Trainline 2: Statistical Report*, Canberra ACT, BUREAU OF INFRASTRUCTURE, TRANSP. & REG'L ECON. v (Nov. 2, 2014) https://www.bitre.gov.au/publications/2014/train_002 (last visited Sept. 8, 2020).

53 *Horizon launches Hycopter fuel cell multirotor UAV*, 2015 Fuel Cells Bulletin 6, (June 2015), https://www.sciencedirect.com/science/article/pii/S1464285915301450?via%3Dihub (last visited Sept. 8, 2020).

Although fuel cells have been used to power small manned aircraft, their application to large-scale passenger transport appears to be distant.

6. Opportunities

Australia currently lacks sufficient FCEV refuelling infrastructure to incentivise domestic adoption of FCEVs. While the commercial benefits to operators are yet to be proven and the likely potential uptake remains uncertain, there is likely to be little commercial incentive to provide the necessary infrastructure to support a nascent FCEV market. Some assistance may be required to support the necessary refuelling infrastructure while the technology is maturing.[54]

Furthermore, a current lack of education and awareness appears to be an impediment to the potential adoption of FCEV technologies. There is general consensus that electric vehicles are needed to decarbonise the transport sector. However, the public is largely unaware that FCEVs fall within this category and incentive and educational schemes will be needed to create public awareness and normalisation of FCEVs.

7. Policy and Regulation

Given the lower-cost and more readily available infrastructure for internal combustion engines and BEVs, various policy and regulatory provisions are required to assist in the creation of a market for FCEVs in Australia. Emission or "clean air" standards on vehicles are an important policy consideration, as they represent a long-term commitment to decarbonise the transport sector by limiting the types of vehicles available. Specific incentives, however, are also likely to be needed to stimulate uptake of FCEVs. These could be in the form of direct subsidies, taxation (e.g., fuel excise), and registration discounts (or a combination of all options) that can increase the rate of uptake (see Parts V and VI for further commentary on Australian tax issues that may affect hydrogen project developments and investments).

B. Chemical Feedstock

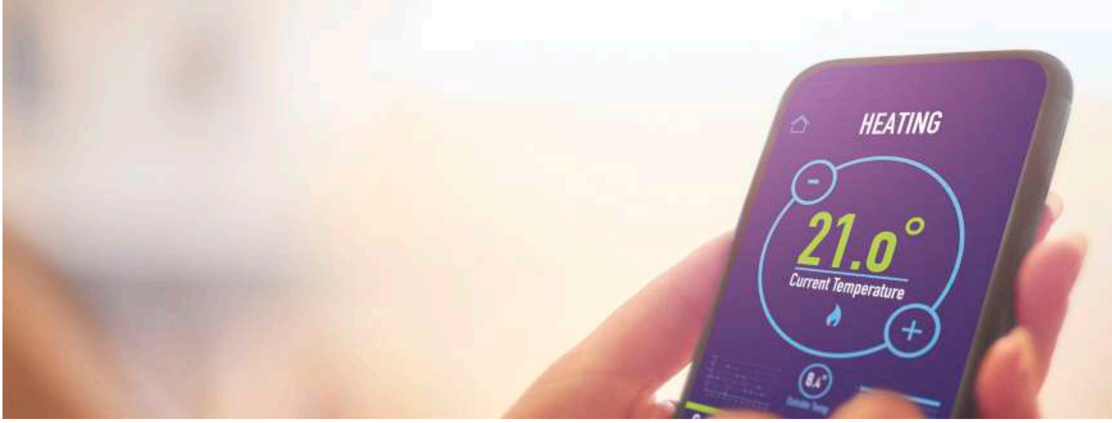
Hydrogen can be used in industrial applications as a chemical feedstock, which includes refining petrochemicals, ammonia production, as well as the manufacture of chemicals.

1. Petrochemical

The demand for hydrogen is increasing in the petrochemical and the bio-crude industry due to the increased importance of air quality and emission requirements, as well as a need to decarbonise both sectors.[55] Hydrogen is used for hydrotreating to refine petrochemicals and hydrocracking to produce jet fuel, kerosene, and diesel.

[54] *See* BITRE, *supra* note 43, at 9.

[55] Tom Campey, et al., *Low Emissions Technology Roadmap*, INT'L ENERGY AGENCY 214-25 (Austl. June 2017), https://www.csiro.au/en/Do-business/Futures/Reports/Energy-and-Resources/Low-Emissions-Technology-Roadmap (last visited Sept. 8, 2020).



2. Ammonia

Ammonia derived from clean hydrogen can be used in fertilisers and as a potential energy carrier. Research will be required to develop the synthesis of ammonia using electrolysis, instead of from the Haber-Bosch Process.

3. Methanol

Synthesis gas, which consists of hydrogen, carbon monoxide, and carbon dioxide, can be converted to produce methanol and its derivatives. Renewable methanol also may be synthesised via the hydrogenation of CO_2. Although its synthesis will be undertaken at half the efficiency of the previous process, there is an increasing global interest in the technology.[56]

4. Alkenes/Olefins

Alkenes are usually produced via the steam cracking process to produce various products such as plastics, fibres, and other chemicals. Alternatively, the hydrogenation of CO_2 in the presence of specific catalysts may be used instead to reduce the dependence on hydrocarbons and create a greater demand for hydrogen.[57]

C. Grid Electricity

Hydrogen produced from renewables via electrolysis can be blended with natural gas and injected into the gas grid. This will reduce emissions related to natural gas usage.

Gas grid injection is a low-value, low-investment stepping stone to support the early-stage scaling-up of hydrogen.[58] In the long run, injecting hydrogen into the gas grid will allow large amounts of renewable energy to be stored. Furthermore, the system will be able to cope with large swings in demand and

[56] Sukhvidner P.S. Badwal, et al., *Emerging technologies, markets and commercialization of solid-electrolytic hydrogen production*, 7 WIRES ENERGY AND ENV'T 3 (Mar. 2, 2020), https://onlinelibrary.wiley.com/doi/abs/10.1002/wene.286 (last visited Sept. 8, 2020).

[57] Lisheng Guo, et al, *Directly converting carbon dioxide to linear a-olefins on bio-promoted catalysts*, 1 COMMC'N CHEMISTRY 11, 4-7 (Mar. 22, 2018), https://www.nature.com/articles/s42004-018-0012-4 (last visited Sept. 8, 2020).

[58] C. Chardonnet, et al., *Study on early business cases for H_2 in energy storage and more broadly power to H_2 applications*, HINICIO AND TRACTEBEL ENGIE (June 16, 2017), www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf (last visited Sept. 8, 2020); Emanuele Taibi, et al., Hydrogen from renewable power: Technology outlook for the energy transition, INT'L RENEWABLE ENERGY AGENCY 39 (Sept. 2018), https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power (last visited Sept. 9, 2020).

be an option for inter-seasonal storage to meet varying demand peaks.

Using low hydrogen concentrations of up to 10-20 per cent in volume may not require major investment or modifications to the current infrastructure.[59] In contrast, blending concentrations greater than 20 per cent would require significant changes to existing infrastructure and end-use applications. Accordingly, it may be more practical to convert the entire infrastructure and applications to be compatible with pure hydrogen.[60]

More research is required to better understand the technical impact of different levels of hydrogen blending and injection into existing gas infrastructure and the required modifications and investment.[61] Following this, Australian regulations will need to be amended to adapt to hydrogen blending and set new limits on the hydrogen content of natural gas.

D. Heat

Hydrogen may be combusted to generate heat in residential homes, as well as for commercial and industrial uses. A concentration of hydrogen of up to 20 per cent by volume can be tolerated by household appliances,[62] and a 10-15 per cent by volume hydrogen blend in industrial cases,[63] without the need for significant infrastructure upgrades. Regardless, existing appliances will need to be upgraded or replaced to accommodate for the complete substitution of natural gas with 100 per cent hydrogen.

1. Residential

Changes to domestic appliances are set out in the table below.

Table 1: Domestic Residential Heating Appliances[64]

TYPE	HARDWARE	DESCRIPTION
Boiler	Water heater	Natural gas is burned to heat water either through continuous flow or a storage mechanism
Cooker	Cooktop	Natural gas is supplied through the cooktop for cooking
Cooker	Grill/oven	Natural gas is supplied through burners for cooking
Heater	Gas heating	Can be centralised with ducted heating or wall mounted. May be flued (vented outside) or non-flued (by-products released into room).

59 Alexander Körner, et al., *Technology Roadmap: Hydrogen and Fuel Cells*, INT'L ENERGY AGENCY (June 2015), https://www.iea.org/reports/technology-roadmap-hydrogen-and-fuel-cells (last visited Sept. 8, 2020).

60 Emanuele Taibi, et al., *Hydrogen from renewable power: Technology outlook for the energy transition*, INT'L RENEWABLE ENERGY AGENCY 39 (Sept. 2018), https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power (last visited Sept. 9, 2020).

61 *Id.* at 40.

62 *First Project Progress Report*, HYDEPLOY PROJECT 2 (Dec. 2017), https://hydeploy.co.uk/app/uploads/2018/02/13894_HYDEPLOY_PROJECT_REPORT_LR-1.pdf (last visited Sept. 8, 2020); COAG Energy Council, 'Hydrogen in the Gas Network' Kickstart Project (2019), https://consult.industry.gov.au/national-hydrogen-strategy-taskforce/national-hydrogen-strategy-issues-papers/supporting_documents/NationalHydrogenStrategyIssue6HydrogeninGasNetwork.docx (last visited 5 September 2020).

63 Progressive Energy Ltd., *The Liverpool-Manchester Hydrogen Cluster: A Low Cost Deliverable Project*, CADET (Aug. 2017).

64 *See* CSIRO, *supra* note 13, at 46.

2. Commercial and Industrial Use

The industrial heat appliances that may require an upgrade are set out in Table 2. This poses a greater challenge,[65] as it may consist of the reconfiguration of an entire plant.

APPLIANCE	DESCRIPTION	USE
Furnace/kilns	May be low temperature (<650°C) or high temperature (650°C-1500°C). At higher temperatures, care needs to be taken with furnace degradation and higher NOx emissions.	Low temperature: industrial ovens/ dryers High temperature: glass and ceramics industries
Boilers	Includes both fire-tube (3-5MWth) and water-tube (>5MWth). Can burn different fuels but would likely require a plant redesign for 100% hydrogen.	Steam production, space heating, pulp and paper industry
Combined heat and power	Includes reciprocating engines and gas turbines. For the former, preliminary research shows safe operation up to 80% H2 but requires NOx treatment. For the latter, there are already examples of IGCC running at 60-100% H_2 with permissible NOx levels. When running at high concentrations, a diluent (usually nitrogen or steam) is added to bring hydrogen concentration down to 65%, thereby lowering the temperature.	Various heat and electrical applications

Table 2: Industrial Heat Appliances Upgrade[66]

3. Opportunities

An alternative to the displacement of natural gas with hydrogen is electrification. This may be undertaken through electrification technologies such as heat pumps or electrical heating. Heat pumps require constant connection to the electrical grid and could be used for low-grade heating operations such as in households. Electrical heating requires connection to an electrical power source and has a temperature range of 3000°C. Although electrification may prove to be economically favourable, the complete substitution of energy from the gas network will be subject to space constraints and may be unfeasible due to the cost of upgrading and facilitating a hydrogen gas network.[67]

4. Policy and Regulation

There is a need to upgrade industrial appliances with the changeover in gas supply. Such an upgrade is associated with technical complexities where any transitions are likely to be ad hoc and site specific. Subsequently, clear policy directions and legislation will be required to assist with the coordinated roll out of hydrogen combustion systems on industrial sites. Following this, manufacturers in Australia will gain confidence to begin producing relevant appliances at scale. Therefore, legislation regarding the manufacture and installation of standardised appliances

65 Dan Sadler, et al., H21, LEEDS CITY GATE (2016) https://www.h21.green/wp-content/uploads/2019/01/H21-Leeds-City-Gate-Report.pdf (last visited Sept. 8, 2020).

66 *See* CSIRO, *supra* note 13, at 47.

67 2050 Energy Scenarios, KPMG (July 2016), https://www.energynetworks.org/gas/futures/the-uk-gas-networks-role-in-a-2050-whole-energy-system.html (last visited Sept. 8, 2020).

prior to the transition will reduce changeover times and labour costs.

E. Exports

Finally, hydrogen can be exported, either as an energy carrier or for use as a chemical feedstock. As noted, the four key hydrogen export jurisdictions include Singapore, Japan, the Republic of Korea, and China.[68] Furthermore, Australia already has established trading relationships and free trade agreements with these countries, including significant trade in energy and resources products. Consequently, this may provide Australia with a competitive advantage in comparison with other potential suppliers of hydrogen.

Further agreements between Australia and the above four countries will be required in relation to the export and receipt of hydrogen. This will attract investment, which is important because a significant injection of capital is required to meet the export and hydrogen production demands. Such resources are best pooled from various companies in a joint venture.

IV. Pricing Models

The hydrogen industry will need to go through a number of stages for industry development and market activation. Australia will be able to realise its hydrogen opportunity if producers are able to produce at scale, in order to capitalise upon cost efficiencies and lower the unit cost of delivered hydrogen.

While this presents some barriers, Australia has a strong track record at rising to the challenge in similar industries. For example, after the first exports of LNG in the late 1980s, Australia has recently overtaken Qatar as the world's largest LNG exporter,[69] with increasing export values growing from A$31 billion in 2017-2018 to A$50 billion in 2018.[70]

Currently, there are relatively mature production, transport, and storage technologies for hydrogen. However, these technologies have not yet been tested at scale, as part of a viable global supply change. There will need to be further technological commercialisation to bring down the current cost of production, transport, and storage.

Cost estimates vary significantly depending upon the method of transportation, distance transported, and end-user requirements. Cost modelling has predicted that for distances up to 1,500km gas by pipeline will be the cheapest method for large volumes of hydrogen. Over this distance, cost modelling has predicted shipping hydrogen as ammonia or as a liquid

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[68] *See* ACIL Allen Consulting, *supra* note 6, at C-5, 31.

[69] Jessica Jaganathan, *Australia grabs world's biggest LNG export crown from Qatar in Nov.*, Reuters (Dec. 10, 2018), https://www.reuters.com/article/us-australia-qatar-lng/australia-grabs-worlds-biggest-lng-exporter-crown-from-qatar-in-nov-idUSKBN1O907N.

[70] Cole Latimer, *Coal is Australia's most valuable export in 2018*, THE SYDNEY MORNING HEAD (Dec. 21, 2018), https://www.smh.com.au/business/the-economy/coal-is-australia-s-most-valuable-export-in-2018-20181220-p50nd4.html.

organic hydrogen carrier will be more cost effective.[71]

The Japanese government has stated through its Basic Hydrogen Strategy that it is targeting a delivered cost of hydrogen to be US$3/kg by 2030. By comparison, the International Energy Agency predicts that by 2030 exporting hydrogen from Australia to Japan as ammonia will cost around US$5.50/kg with transport and handling US$1.50/kg. This pricing discrepancy demonstrates the need for a focus on innovation and efficient supply chain development in order to bring the cost of Australia's exported hydrogen down.

There are a number of national funding mechanisms that could be utilised to provide support to the hydrogen industry to increase technology research, lower barriers to market entry, and reduce investment risks. These include ARENA, CEFC, NAIF, and EFIC.[72] Further, the Australian government has demonstrated a willingness to share knowledge and lessons learned from research and demonstration projects to encourage industry development.[73]

The Australian government is focused on the development of hydrogen hubs to provide co-utilisation of infrastructure to minimise losses and allow for a ramp up in production when demand increases. Further, using existing port and rail infrastructure that currently serves oil and gas industries would allow hydrogen to be more readily used in populated areas, leveraging existing coastal industrial clusters. Australia's substantial road, rail, storage, and port infrastructure already supports a globally competitive extractive export industry, valued at A$278 billion in 2018/2019.[74]

71 *The Future of Hydrogen, seizing today's opportunities*, INT'L ENERGY AGENCY at 67 (June 2019).

72 *Hydrogen at Scale*, COAG ENERGY COUNCIL at 4 (July 2019), https://consult.industry.gov.au/national-hydrogen-strategy-taskforce/national-hydrogen-strategy-issues-papers/supporting_documents/NationalHydrogenStrategyIssue1HydrogenatScale.pdf (last visited Sept. 8, 2020).

73 *Id.* at 5.

74 *Resources and Energy Quarterly – March 2019*, DEP'T OF INDUS., INNOVATION & SCI. 8 (Mar. 2019) https://publications.industry.gov.au/publications/resourcesandenergyquarterlymarch2019/index.html (last visited Sept. 8, 2020).

PART IV - ENVIRONMENT AND PLANNING

I. Australian Elements

Australian laws require planning and environmental approvals to authorise most new developments and uses of land, including for the purpose of hydrogen projects. While each state and territory has its own land-use planning and environmental laws, it is possible to identify the following common themes across all Australian jurisdictions.

As approval requirements vary between jurisdictions and can be complex, we recommend seeking specific advice on the approval pathway and timelines that will apply to your hydrogen project.

II. Planning Approval

A. General

Planning approval will almost always be required to authorise the construction and operation of a hydrogen project.

B. Application Process

An application for planning approval must be made to the relevant consent authority (typically either the local council or the state government minister or department, depending on the state and territory and the specifics of the project).

An application for planning approval will need to be accompanied by a detailed environmental assessment prepared by suitably qualified consultants, which describes the hydrogen project in detail and assesses the impacts of the project and the measures proposed to mitigate any such impacts. The environmental assessment will provide a justification for the hydrogen project and will consider matters such as:

- Potential alternatives to the project
- Social and economic impacts, including the energy benefits of the project and the impacts on the local community
- Potential hazards and risks associated with the project, including, for example, the safety implications of transporting hydrogen
- Impacts on biodiversity, for example, through the clearing of native vegetation
- Impacts on water, including water supply and use, impacts on water quality and quantity, considerations of the use of waste water or recycled water, stormwater management, erosion, and sedimentation

- Heritage impacts, including impacts on Aboriginal cultural heritage
- Waste generation and disposal
- Noise impacts during construction and in operation
- Impacts of the project on air quality
- Visual impacts
- The traffic impacts likely to be generated by the construction and operation of the project, including any upgrades required to the road networks

Applications for planning approvals are usually, though not always, placed on public exhibition, during which time submissions may be made by interested stakeholders, including neighbouring landholders and the community.

In addition, the regime in all states and territories requires some level of consultation with stakeholders in the project as part of the environmental assessment of the project. Stakeholders are likely to include relevant government authorities, local councils, community groups, and affected landholders and Aboriginal land councils or corporations.

Applicants are typically provided with an opportunity to amend the project or provide further information in response to the issues raised in public consultation or submissions.

The application will then be assessed by the consent authority, who will determine whether to grant approval and, if so, on what conditions.

C. Conditions

Planning approvals are typically issued subject to detailed conditions regulating all aspects of the construction and operation of the project, including requiring offsets for any native vegetation cleared for the project.

A failure to comply with a condition imposed on a planning approval is a criminal offence.

D. Appeal Rights

Most jurisdictions allow the proponent of a project to commence legal proceedings to appeal a decision to either refuse planning approval for a project or to approve the project subject to unfavourable conditions.

In some jurisdictions there are statutory rights given to some third parties, such as people who have made submissions objecting to the project, to appeal a decision to approve a project on its merits where they are dissatisfied with the approval. Where third-party merit appeals are not available, there will usually be rights for a third party to challenge the validity of the planning approval if they believe a reviewable error of law was made by the consent authority in approving the project.

III. Secondary Approvals

In addition to planning approval, a range of additional environmental-related approvals may also be required for hydrogen projects. These vary depending on the specifics of the project and the state and territory, but may include:

- Environment licences from the Environment Protection Authority or equivalent regulator to carry out the project and authorise discharges to land, air, or water
- A major hazard facility licence from safety regulators if the amount of hydrogen generated or stored exceeds certain thresholds
- Pipeline licences to authorise construction and operation of a pipeline for transporting hydrogen
- Heritage permits for activities that will impact on historic or cultural heritage artefacts
- Approvals to authorise the upgrade of roads
- Approvals to clear native vegetation
- Water licences and approvals to authorise the taking and use of water from natural water sources
- Approvals to permit the construction and occupation of buildings or any subdivision of land required for the project

IV. Commonwealth Approvals

If a hydrogen project is likely to have a significant impact on matters of national environmental significance, it will also require referral to the commonwealth minister for environment under the *Environment Protection and Biodiversity Conservation Act 1999* (Cth). Matters of national environmental significance are, relevantly:

- Listed threatened species and ecological communities
- Listed migratory species
- Wetlands of international importance
- The commonwealth marine environment
- World Heritage properties
- National heritage places
- The Great Barrier Reef Marine Park

Once a project is referred, the commonwealth minister for environment will release the referral to the public, as well as to relevant state, territory, and commonwealth ministers, for comment on whether the project is likely to have a significant impact on matters of national environmental significance.

The minister or the minister's delegate will then decide whether the likely environmental impacts of the project are such that it should be assessed and approved under the *Environment Protection and Biodiversity Conservation Act 1999* (Cth).

There are agreements in place between the commonwealth government and each state and territory, whereby the commonwealth minister for the environment may rely on the planning approval assessment processes of the state or territory to assess the impacts of a referred project under the Environment Protection and Biodiversity Conservation Act 1999 (Cth) and determine whether to approve the carrying out of the project.

V. Consequence of Breach

In general, if all required planning and environmental approvals have not been obtained or are not being complied with for a hydrogen project, there is a risk that:

- The relevant governmental authority may prosecute the proponent of the project;
- The relevant governmental authority may issue an order requiring that the project be stopped; and
- In some jurisdictions, a third party may commence civil enforcement proceedings to restrain any breach of environmental or planning legislation.

PART V - FEDERAL TAX

I. Overview

This section provides a high-level overview of common tax considerations for non-resident businesses considering undertaking a new venture in Australia, including hydrogen energy production. The comments that follow are focused on tax issues for corporate and trust entities, not individuals.

Tax is imposed in Australia at both a federal and state (or territory) level. The Australian Taxation Office (ATO) is charged with addressing the tax laws that are imposed at the federal level—primarily income tax and goods and services tax (GST). The states and territories each have their own administrative body for the laws imposed in their jurisdiction.

II. Income Tax

Companies, including non-resident companies, carrying on business in Australia or deriving Australian-sourced income that is not subject to withholding tax or otherwise exempt, are taxed at 30 per cent (although a 27.5 per cent rate applies to some companies with an annual turnover of less than A$50 million).

Australia has a self-assessment income tax system where taxpayers are required to lodge annual income tax returns for the 12 months to 30 June each year and to pay tax in accordance with those returns.

Returns may be subject to a subsequent audit by the ATO, generally for a period of four years subsequent to lodgement of the returns. Subsidiaries of non-resident companies often obtain permission from the Commissioner of Taxation to lodge tax returns with a year-end other than 30 June (a "substituted accounting period") corresponding with the accounting and tax year end of their parent.

A distinction is drawn between residents and non-residents, with residents being liable to pay tax on their worldwide income and non-residents generally only on their Australian-sourced income. Rather than impose a separate tax on capital gains, Australia's Capital Gains Tax (CGT) legislation is incorporated in the income tax legislation and net capital gains are included in a taxpayer's assessable income.

Entity	Residence Test
Company	A company is a resident of Australia if it: • Is incorporated in Australia, or • Carries on business in Australia and either: » its central management and control is in Australia; or » voting power is controlled by Australian resident shareholders.
Trust	A trust is a resident of Australia if: • The trustee is an Australian resident; or • Central management and control of the trust is in Australia.
Trust for CGT purposes	For non-unit trusts, the test is the same as the normal trust residence test. For unit trusts, residence for CGT purposes will exist where: • Trust property is located in Australia; or • The trust carries on business in Australia; and either: » central management and control of the trust is in Australia, or » Australian resident beneficiaries hold more than 50 per cent of the income or property of the trust.

III. Capital Gains Tax (CGT)

Capital gains are taxed as part of the income tax regime. For residents, the CGT rules bring into the tax net gains from the disposal of assets acquired (or deemed to have been acquired) on or after 20 September 1985. Net capital gains are included in a taxpayer's overall assessable income.

For non-residents, CGT applies only in respect of gains arising from a disposal of an asset that is taxable Australian property. This includes:

- Direct interests in Australian land
- Shares, units, or other interests in entities whose principal assets are interests in Australian land
- An asset used in carrying on a business in Australia at or through a permanent establishment
- Options to acquire any of the above-mentioned assets

Capital losses can only be offset against capital gains. To the extent that capital losses exceed capital gains, the excess can be carried forward to offset capital gains made in future years. They cannot be offset against revenue gains.

Net capital gains, on the other hand, can be set off against revenue losses.

When a non-resident becomes a resident for tax purposes, the law deems the former non-resident to have acquired those assets that were not already subject to CGT and that were actually acquired on or after 20

September 1985 to have been acquired at the time of the change of residence for their then market value.

When a resident taxpayer becomes a non-resident for tax purposes, the taxpayer is deemed to have disposed of all assets that are not taxable Australian property and that were acquired on or after 20 September 1985, for their current market value, unless certain elections are made.

IV. Foreign Source Income

There are special rules for the taxation of foreign source income of residents. In addition to a system of foreign income tax offsets (in essence, foreign tax credits), Australia operates a controlled foreign companies (CFC) system and a controlled foreign trust/transferor trust (CFT) system. The aim of the CFC and CFT systems is to tax foreign source income accumulated offshore at low rates of tax in the hands of Australian controllers of the offshore entity. These systems allow Australia to tax certain income and gains that have not been repatriated to Australia.

V. Tax Consolidation

Wholly owned groups of companies (and certain other entities) may elect to form a tax consolidation group. This means that the group is treated as a single entity for tax purposes.

VI. Imputation

Australian tax paid by resident companies gives rise to franking credits that attach to dividends paid from those taxed profits to shareholders.[75] Such dividends are "franked dividends." Resident shareholders include both the cash dividend and the franking credit in their income, and can then apply the franking credit against their tax liability. Individuals and superannuation funds are eligible to claim refunds of franking credits where their franking credits exceed the tax otherwise payable on their income. Non-resident shareholders receive franked dividends free of withholding tax (discussed below).

VII. Withholding Tax

Unfranked dividends, interest, and royalties paid to non-residents are subject to withholding tax. If withholding tax is paid, then no further tax is payable in Australia on that income.

The general rates of withholding tax are set out below:

- Interest – 10 per cent
- Unfranked dividends – 30 per cent
- Royalties – 30 per cent

Note that lower rates (especially for dividends and royalties) usually are prescribed in applicable tax treaties, and certain domestic exemptions may also apply (for example, interest paid on

[75] If dividends are paid from an Australian company's profits that have already borne Australian company tax, the dividends are "franked" by the company when paid to shareholders. This means the dividends carry a tax credit reflecting underlying Australian corporate tax paid. If the dividends are not franked, or only partly franked (and this can happen to the extent that corporate profits are not taxed in Australia, because of a tax concession, or because they are from foreign sources), the unfranked portion carries no tax credit.

certain types of offshore debt is exempt from withholding tax).

Withholding tax also may apply to distributions from managed investment trusts (MITs). Those distributions may be subject to withholding at either 10 per cent, 15 per cent, or 30 per cent, depending upon the classifications of the relevant MIT and the nature of the income being distributed.

Additionally, where a non-resident disposes of certain types of taxable Australian property, the purchaser will be required to withhold a non-final withholding tax at a rate of 12.5 per cent of the purchase price, and remit the amount withheld to the ATO.

VIII. Conduit Foreign Income Rules

Special rules allow "conduit foreign income" to flow through Australian resident companies to foreign shareholders without being taxed in Australia. "Conduit foreign income" is foreign income that is ultimately received by foreign residents, through one or more interposed Australian resident companies.

Australian resident companies that receive an unfranked distribution that is declared to be conduit foreign income will not pay Australian tax on that income if the conduit foreign income is on-paid to shareholders within a certain period. In such cases, the conduit foreign income will not be assessable to the Australian resident company. Conduit foreign income is also exempt from dividend withholding tax when it is on-paid to a foreign resident as an unfranked distribution.

Foreign sourced income generally flows through a trust to foreign beneficiaries without Australian tax, as do foreign sourced capital gains, provided a fixed trust (such as a plain unit trust) is involved.

IX. Losses

Losses can be carried forward indefinitely by corporate taxpayers, subject to the taxpayer satisfying one of two tests. The first is the continuity of ownership test, which requires that a majority underlying ownership of the company is maintained in the same hands in the loss recoupment year as was the case in the year the losses were incurred. The alternative test is the same business test, which requires that the same or a similar business is conducted in the loss recoupment year as was conducted immediately prior to the failure of the continuity of ownership test.

Different and more complex tests apply for the recoupment of losses by trusts.

Revenue losses can be offset against assessable income, which may include both income and capital gains. Capital losses can only be utilised against capital gains.

X. Thin Capitalisation

Broadly, Australia's thin capitalisation rules operate to disallow deductions for interest paid on loans from related parties, where the amount of related offshore debt exceeds a permitted level, having regard to the amount of related offshore equity capital. The rules apply to both foreign controlled Australian entities and to Australian entities with offshore operations.

XI. Transfer Pricing

Australia's transfer pricing rules are broadly in accordance with the Organisation for Economic Co-operation and Development (OECD) model. These rules require that related party cross-border transactions are conducted on arm's length terms. Taxpayers undertaking related party cross-border transactions are required to disclose details of these transactions with their annual income tax return.

The ATO has undertaken a number of audits and other reviews that have resulted in substantial adjustment to the taxable income of taxpayers where it has been found that the rules have not been complied with.

Companies are required to maintain contemporaneous documentation in relation to related party cross-border transactions, and a transfer pricing policy.

XII. Double Tax Treaties

Australia is a party to many bilateral double tax treaties dealing with income and, in most cases, capital gains. These treaties set out to regulate the taxing rights between the countries involved. Most of the treaties follow the OECD model agreement and provide for reduced rates of withholding tax as well as relief from double taxation by either foreign tax credit or exemption. Business profits earned by a resident of one country from sources in the other country are generally exempt from tax in the source country, unless the profits have been earned through a permanent establishment in the source country.

XIII. Goods and Services Tax (GST)

GST is a form of valued added tax. It applies at a rate of 10 per cent to most supplies connected with Australia, at each step along the production chain. It also applies to most importations. Registered suppliers are obliged to remit GST on supplies they make. For the most part, registered recipients of supplies will be entitled to a credit for any GST included in the price of acquisitions they make. Non-residents may be entitled to register, thereby enabling input tax credits to be claimed in relation to expenses incurred in Australia.

GST does not apply to limited categories of goods and services, including (among others) exports and financial supplies. From an administrative perspective, the GST system relies on registration of businesses and the issuance of tax invoices by the suppliers of taxable goods and services.

XIV. Fringe Benefits Tax (FBT)

FBT is imposed on employers at 47 per cent on the grossed up value of benefits provided to employees in respect of employment. The effect of taxing fringe benefits in this way is that employers pay FBT equivalent to the income tax that an employee in the top marginal rate of tax receiving the benefit would have paid had they purchased the benefit themselves from their after-tax income. FBT is deductible to the employer for income tax purposes. Certain benefits, such as superannuation, are exempt from FBT, while other benefits, such as motor vehicles, are concessionally taxed.

XV. Research and Development Incentive

A tax incentive is available for eligible entities that undertake qualifying research and development (R&D) activities in Australia, which could include participants in the hydrogen sector.

The two core components of the incentive are:

- A refundable tax offset for certain eligible entities with an aggregated annual turnover of less than A$20 million; and
- A non-refundable tax offset for all other eligible entities.

To claim an R&D tax offset, an entity must first register its R&D activities with Innovation and Science Australia, via AusIndustry.

Generally speaking, an eligible entity must be a company that is:

- Incorporated in Australia; or
- Incorporated under a foreign law, but resident in Australia for tax purposes; or
- Incorporated under a foreign law and both:
  - » Resident in a country that has a double tax agreement with Australia that includes a definition of "permanent establishment"; and
  - » Carrying on business in Australia through such a permanent establishment.

Generally, trusts will not qualify, with an exception for public trading trusts with a corporate trustee.

Corporate limited partnerships and exempt entities do not qualify. There are special rules for tax consolidated groups and R&D partnerships.

PART VI - STATE TAXES

The states and territories also impose taxes. These include stamp duty, payroll tax, and land tax.

I. Stamp Duty

Stamp duty, or "duty," is generally a tax payable on transactions, including the transfer or conveyance of property or assets situated in, or attributable to, that state or territory.

The amount of duty payable is calculated on the higher of the consideration or the unencumbered value of the property transferred. Duty is usually payable by the purchaser or transferee. The duty rates vary between each state and territory. Duty is an important factor in any purchase of land, or purchase of an interest in a company or trust that has interests in land.

Duty must also be considered in the context of the purchase of a business. However, the rules on which assets are dutiable vary from state to state, and can operate differently if a different mix of assets is acquired (for example, an asset may be exempt from duty if acquired in isolation, but brought into the duty net if acquired along with land).

II. Payroll Tax

Payroll tax is a tax levied in each state and territory on the gross salaries and wages paid by an employer for services rendered by employees in the state or territory. Certain payments to contractors may also be deemed to be wages. The tax is payable on a monthly basis, with a final reckoning at the end of the year. The rates vary across the states and territories, as do the thresholds from which point the tax becomes payable.

III. Land Tax

Land tax is a tax levied annually on the unimproved value of freehold land held within a state. Some lessees may be deemed to own the freehold land for tax purposes. The rate of land tax varies from state to state. Generally, land tax is calculated using a progressive tax scale; however, the threshold level for the imposition of the tax also varies from state to state.

Foreign investors can be liable for land tax surcharges (including in respect of commercial property) in some jurisdictions, such as Queensland and Victoria. There are some surcharge exemptions available for projects that significantly benefit a state's economy.

ANNEXURE AUSTRALIA

LIST OF AUSTRALIAN PROJECTS FROM THE IEA HYDROGEN PROJECT DATABASE

Project Name	State/ Territory	Proponents	Announced Start Date	Currently Operational (Y/N)	Technology	Product
Arrowsmith Hydrogen Project	WA	Infinite Blue Energy	2022		Unknown PtX	H_2
Asian Renewable Energy Hub	WA	ICE, CWP Energy Asia, Vestas, and Macquarie	2027	N	Unknown PtX	H_2
ATCO Clean Energy Innovation Hub	WA	ATCO	2019	Y	PEM	H_2
Australian Hydrogen Centre, Vic	Vic, SA	AGN, Neoen, AusNet Services, ENGIE		N	Unknown PtX	H_2
BP Ammonia WA	WA	BP Australia		N	Unknown PtX	NH_3
Collie Synfuel West Australia Project	WA	Collie Synfuels Pty Ltd		N	Coal gasification + CCS	H_2 Synthetic hydrocarbons
Crystal Brook Energy Park, SA	SA	Neoen Australia		N	Unknown PtX	H_2
Engie-Yara Pilbara test	WA	Yara and ENGIE	2021	N	Unknown PtX	NH_3
Fenosa Canberra Hydrogen Demo Project	ACT	Neoen, Megawatt Capital, Union Fenosa		N	Unknown PtX	
Hazer Group CH4 Pyrolysis	NSW	Hazer Group Ltd	2020	N	Biogas pyrolysis	H_2
HESC (Liquefied hydrogen energy supply chain)	Vic	HEA	2030	N	Coal gasification + CCS	H_2
Hydrogen Park Gladstone	Qld	AGIG	2021	N	PEM	H_2
HyPSA	SA	AGIG	2020	N	PEM	H_2
Jemena Gas Network – H2GO project	NSW	Jemena	2020	N	PEM	H_2
Kidman Park in Adelaide depot	SA	AGN	2018	N	Unknown PtX	H_2

Project Name	State/ Territory	Proponents	Announced Start Date	Currently Operational (Y/N)	Technology	Product
Moranbah	Qld	Dyno Nobel Moranbah Pty Ltd		N	Unknown PtX	NH_3
Moreland garbage truck filling station	Vic	Moreland Council	2018	N	Unknown PtX	H_2
Moura	Qld	QNP, Neoen, Worley		N	Unknown PtX	NH_3
Murchison Renewable Hydrogen Project	WA	Hydrogen Renewables Australia		N	PEM	H_2
Port Lincoln Project, Eyre Peninsula	SA	H2U	2021	N	PEM	H_2 NH_3
Sir Samuel Building Griffith Center, Brisbane	Qld	Griffith University	2013	Y	ALK	
Toyota Australia, Altona, Victoria	Vic	Toyota Australia	2020	N	Unknown PtX	H_2
UniSA, Mawson Lakes Campus	SA	UniSA	2020	N	Unknown PtX	H_2

GLOSSARY AUSTRALIA

AGIG	Australian Gas Infrastructure Group
AGN	Australian Gas Network Limited
ALK	Alkaline Electrolysis
Coal gasification + CCS	Hydrogen production from coal gasification (all types of coals and derivatives) coupled with CO_2 capture
H_2	Hydrogen in molecular form
H2U	Hydrogen Utility
HEA	Hydrogen Engineering Australia (a consortium comprising Karasaki Heavy Industries, J-Power, Iwatani Corporation, Marubeni Corporation, Sumitomo Corporation, and AGL)
ICE	InterContinental Energy
NH_3	Ammonia
PEM	Proton exchange membrane electrolysis
QNP	Queensland Nitrates Pty Ltd
Synthetic hydrocarbons	Synthetic liquid fuels (e.g., gasoline, diesel, jet-fuel equivalent)
UniSA	University of South Australia
Unknown PtX	Undisclosed electrolysis type

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EUROPEAN UNION

The H_2 Handbook

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CONTENTS EUROPEAN UNION

PART I - INTRODUCTION

Climate change and environmental considerations are at the top of the European political agenda. A key demonstration of this was the December 2019 unveiling by European Commission (Commission) President Ursula Von der Leyen of the European Green Deal[1] (Green Deal) in her first 10 days in office. The Green Deal is Europe's strategy towards achieving carbon neutrality[2] by 2050. The plan integrates a variety of medium- and long-term policies designed to make Europe a global climate leader, support the transition for regions reliant on fossil fuels, and relaunch investments and competitiveness in the bloc. Following that announcement, the Commission launched its ambitious Hydrogen Strategy on 8 July 2020. Taken together, the Green Deal and the Hydrogen Strategy set Europe on a path to be a global leader in the development of a hydrogen economy.

[1] European Commission (2019), "The European Green Deal," Communication from the Commission to the European Parliament and the European Council, COM (2019) 640 final, Brussels, available at https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf.

[2] In other parts of the text, it can appear as climate neutrality. Climate neutrality can be achieved if CO_2 emissions are reduced to a minimum and all remaining CO_2 emissions are offset with climate protection measures.

I. Hydrogen in Light of the Green Deal

Taking into account the Green Deal's overarching objectives, it is clear that the energy industry will play a pivotal role in the EU's transition to climate neutrality. The energy industry can contribute significantly to reducing greenhouse gas emissions to ensure a sustainable future for the next generation. Importantly, Europe sees hydrogen as one of the top priorities in its energy transition.

Currently, hydrogen is mostly produced from fossil fuels such as gas and coal and is used to generate industrial heat or as feedstock, resulting in the release of 70 to 100 million tonnes CO_2 annually in the European Union. Against this backdrop, the EU hydrogen strategy has called renewable the "most compatible option with the EU's climate neutrality goal in the long term," as it is produced using mainly wind and solar energy.

II. Five Key Planks of the Green Deal

Five key planks of the Green Deal could facilitate hydrogen's potential in Europe's decarbonization:

A. The Strategy for Energy System Integration[3]

The Strategy for Energy System Integration creates better links in the EU's energy system across different sectors like gas, electricity, transport, buildings, and industry through (1) electrification; (2) greater use of renewable and decarbonized gases and fuels; and (3) a more circular energy system, in order to accelerate the decarbonization of harder-to-abate sectors, such as transport, buildings, parts of industry, and agriculture. Importantly, the strategy will allow new low-carbon energy carriers, such as green hydrogen, to emerge and facilitate the progressive decarbonization of the economy, including the gas sector. This is because green hydrogen can be used in areas where higher costs may prevent direct heating or electrification.

Moreover, the strategy also facilitates carbon capture, storage, and use, for two reasons: (1) the inability even in an integrated energy system to completely eliminate CO_2 emissions from all parts of the economy; and (2) the fact that there will not be adequate volumes of green hydrogen produced to meet the growing demand.

To this end, the strategy highlights the role of hydrogen in an integrated energy system. Hydrogen infrastructure can help integrate large shares of variable renewable generation by offloading grids in times of abundant supply and providing long-duration storage to the energy system. Overall, the strategy emphasizes that setting an efficient policy framework around green hydrogen is central to the Hydrogen Strategy (discussed below), which it complements.

[3] European Commission (2020), "Powering a climate-neutral economy: An EU Strategy for Energy System Integration," Communication from the Commission to the European Parliament and the European Council, COM (2020) 299 final, Brussels, available at https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf.

B. The Industrial Strategy[4]

The Industrial Strategy sets a goal to mobilize industry for a clean and circular economy. The Green Deal underlines the critical role emerging technologies play in achieving its ambitious 2050 decarbonization target. These technologies include clean hydrogen, carbon capture and storage, fuel cell, energy storage, and alternative fuels. The Industrial Strategy notes that Europe needs "climate and resource frontrunners" to develop the first commercial applications of these types of breakthrough technologies in key industrial sectors by 2030. Importantly, it also announced the development of the European Clean Hydrogen Alliance, which will bring together stakeholders and identify technology needs, investment opportunities, regulatory barriers, and enablers to build a clean hydrogen ecosystem in the European Union.

C. A Potential Carbon Border Adjustment Mechanism

In the context of the Green Deal, strict climate policies on the reduction of carbon emissions can cause a significant increase in carbon prices and lead to carbon leakage. This occurs when production is transferred from the European Union to other countries with lower goals for emissions reduction or when EU products are replaced by more carbon-intensive imports. To this end, the Green Deal puts forward a carbon border adjustment mechanism (CBAM) for selected sectors to reduce the risk of carbon leakage if differences persist in levels of commitment by non-EU nations to reduce carbon emissions. This would ensure that the price of imports reflects more accurately their carbon content and that non-EU companies importing goods into the European Union face the same costs of emissions as their European counterparts. In fact, the Commission[5] is currently consulting on a CBAM that can take the form of: (1) a carbon tax on selected products applicable on both imported and domestically produced products; (2) a new carbon customs duty or a tax on imports; or (3) the extension of the EU Emissions Trading Scheme (EU ETS) to imports. In particular, the Commission will evaluate whether the CBAM is complementary with the EU ETS. This stresses that any new measure should be in line with the internal EU carbon price. Concerning hydrogen in particular, the Hydrogen Strategy (discussed below) points out the need to provide incentives to produce green hydrogen, while taking into account the risk for carbon leakage for hydrogen production and industries using hydrogen. Even though this risk could be tackled by reducing the price difference between grey and green hydrogen, the Commission reiterates its commitment to propose a CBAM in 2021, with the view of potential implementation in 2023.

4 European Commission (2020), "A New Industrial Strategy for Europe," Communication from the Commission to the European Parliament and the European Council, COM (2020) 102 final, Brussels, available at https://ec.europa.eu/info/sites/info/files/communication-eu-industrial-strategy-march-2020_en.pdf.

5 European Commission (2020), "Carbon border adjustment mechanism Inception Impact Assessment," Ref. Ares (2020)1350037, Brussels, available at https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12228-Carbon-Border-Adjustment-Mechanism.

D. The Forthcoming Offshore Renewable Energy Strategy[6]

Europe has considerable offshore renewable energy potential (more than 250 gigawatt (GW) of installed offshore wind anticipated by 2050) and covers the North Sea, Baltic Sea, Black Sea, Mediterranean Sea, and the Atlantic Ocean. Notably, offshore renewable energy can be used to produce green hydrogen via electrolyzers in a comprehensive, integrated, and cost-efficient manner. Moreover, hydrogen can be used to facilitate long-duration storage for otherwise renewable resources.

E. The Circular Economy Action Plan[7]

The production of hydrogen from renewable or low-carbon sources requires a large amount of raw materials. The Circular Economy Action Plan (Action Plan) prioritizes reducing Europe's dependency on foreign materials by preventing waste, increasing recycling, and using secondary raw materials. The Action Plan, inter alia, envisages the uptake of material resources from recycled products and recovered materials, thus saving primary raw materials from being extracted. Taking into account Europe's dependence on raw materials imports, securing these materials for the production of low-carbon innovations should be looked at both in light of the circular economy and the upcoming Action Plan on Critical Raw Materials.

6 European Commission (2020), "Offshore Renewable Energy Strategy Roadmap," Ref. Ares (2020)3757650, Brussels, available at https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12517-Offshore-renewable-energy-strategy.

7 European Commission (2020), "Circular Economy Action Plan," Brussels, available at https://ec.europa.eu/environment/circular-economy/pdf/new_circular_economy_action_plan.pdf.

PART II - THE COMMISSION'S DEDICATED HYDROGEN STRATEGY

Hydrogen is not only an intrinsic element in Europe's decarbonization journey, but can also account for 24 percent of final energy demand and 5.4 million jobs by 2050.[8] In other words, hydrogen is a green growth engine, which has the potential to transform how the European Union generates, distributes, stores, and consumes energy. On 8 July 2020, the Commission launched its Hydrogen Strategy[9] with the goal of creating a full-fledged hydrogen ecosystem in the European Union.

8 Fuel Cells and Hydrogen 2 Joint Undertaking, (2019), "Hydrogen Roadmap Europe: A sustainable pathway for the European Energy Transition," Brussels.

9 European Commission (2020), "A hydrogen strategy for a climate-neutral Europe," Communication from the Commission to the European Parliament and the European Council, COM (2020) 301 final, Brussels, available at https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf.

The Commission takes the view that Europe needs the Hydrogen Strategy because:

- Hydrogen accounts for less than 2 percent of Europe's energy consumption and is still largely produced from fossil fuels.
- The production of green hydrogen is still considerably more expensive than the conventional highly carbon-intensive methods. In fact, conversion of renewable electricity to hydrogen is currently not as efficient as direct consumption of renewable electricity.
- There are barriers such as lack of production, infrastructure, high cost, and low efficiency hindering the development of a hydrogen ecosystem.
- An effective instrument is needed to avoid the risk of uncoordinated action by member states' fragmented regulatory approaches and industry initiatives towards hydrogen.

PART III - THE TIMELINE OF HYDROGEN DEPLOYMENT

The priority for the European Union is to develop hydrogen production from renewable electricity, which aligns with its zero-carbon footprint target.

Green hydrogen is produced using renewable sources of energy. Blue hydrogen is produced from fossil fuels where greenhouse gas emissions from the production process are captured. The Commission acknowledges that green and blue hydrogen are not as competitive as grey hydrogen, which is produced from fossil fuels but without any capture of greenhouse gas emissions.[10]

The Commission's ultimate goal is the development of green hydrogen, while it expects that both green and blue hydrogen will be cost-competitive against grey hydrogen from 2030. The Commission acknowledges that other forms of low-carbon hydrogen, such as blue hydrogen, are needed in the short to medium term, primarily to rapidly reduce emissions from existing grey and blue hydrogen production and to support the parallel and future uptake of green hydrogen.

Therefore, the Commission underscores that the hydrogen ecosystem will be developed gradually across the European Union and foresees three main phases:

I. Phase 1 (2020–2024)

The strategic objective is the decarbonization of existing hydrogen production. This translates into the installation of at least 6 GW of green hydrogen electrolyzers, the production of up to 1 million tonnes of green hydrogen, and the retrofitting of existing hydrogen production plants with carbon capture and storage technologies. Because the Hydrogen Strategy envisions that these electrolyzers would ideally be powered directly from local renewable electricity sources, local production will hold a key role. The policy focus is to establish a well-functioning regulatory framework for hydrogen and appropriate state aid rules to incentivize both supply and demand.

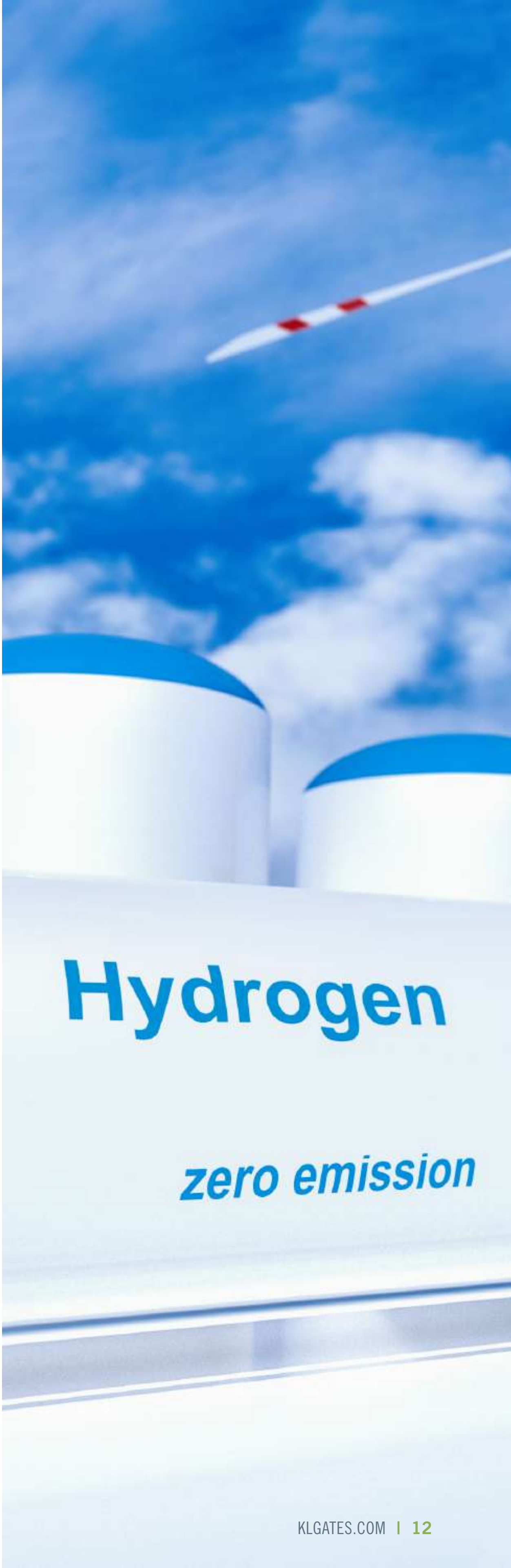
[10] Idem.

II. Phase 2 (2025–2030)

Hydrogen use will be expanded to new industrial applications, including steel making, trucks, rail, and some maritime transport. The Hydrogen Strategy provides for the installation of at least 40 GW of green hydrogen electrolyzers by 2030 and the production of up to 10 million tonnes of green hydrogen in the European Union. The ultimate objective of this period is to develop large logistical infrastructure and international trade.

III. Phase 3 (2030–2050)

The Commission envisages a mature and cost-competitive hydrogen ecosystem. At this stage, green hydrogen technologies should be deployed at large scale to reach difficult sectors, including those more challenged to decarbonize. In this phase, hydrogen and hydrogen-derived synthetic fuels can be used as an alternative fuel for a wider range of sectors such as aviation and shipping.



PART IV – THE MAIN PILLARS OF THE EU HYDROGEN STRATEGY

I. A Strong Hydrogen Investment Agenda

To help deliver its ambitious hydrogen roadmap, the Commission has put forward the following initiatives.

A. The European Clean Hydrogen Alliance[11]

The European Clean Hydrogen Alliance (Alliance) is a public-private partnership that aims to (1) contribute to the deployment of green and low-carbon hydrogen in terms of supply, demand, and distribution; and (2) build up a clear pipeline of viable investment projects along the hydrogen value chain, which will be structured around six industrial pillars (hydrogen production, transmission distribution, the energy sector, industrial applications, mobility, and residential applications). On a practical level, the Alliance will deliver 6 GW of green hydrogen electrolyzer capacity by 2024 and 40 GW of green hydrogen electrolyzers by 2030. It is worth noting that the estimated costs to achieve the 2024 target range between €5 and €9 billion, while the 2030 target will cost between €26 and €44 billion.[12]

B. The Sustainable Finance Regulatory Framework

The renewed sustainable finance strategy to be adopted by the end of 2020 and the EU sustainable finance taxonomy will guide investments in hydrogen across key economic sectors by promoting carbon-neutral activities and projects.

C. COVID-19 Recovery Instruments

In light of COVID-19, the European Union has reshaped parts of the European Green Deal into a recovery package, with significant support for hydrogen. More concretely, the Hydrogen Strategy asserts that investments will be supported through (1) the ReactEU instrument of €47.5 billion, a top up to the broader cohesion policy for the years 2020–2022;

[11] European Clean Hydrogen Alliance Declaration (2020), available at https://ec.europa.eu/docsroom/documents/42603.

[12] European Clean Hydrogen Alliance Factsheet (2020), available at https://ec.europa.eu/commission/presscorner/detail/en/fs_20_1297.

(2) the Strategic European Investment Window of InvestEU[13]; and (3) the ETS Innovation Fund, which for the period 2020-2030 may amount to about EUR 10 billion, depending on the carbon price.[14]

D. The Strategic Forum for Important Projects of Common European Interest (Strategic Forum)

Important Projects of Common European Interest (IPCEIs) comprise innovative research projects that often entail significant risks and require joint, well-coordinated efforts and transnational investments by public authorities and industries from several member states. The Strategic Forum will be tasked with the identification of cross-border hydrogen projects that may benefit from state aid. Furthermore, the Hydrogen Strategy underlines that the Alliance will simultaneously facilitate cooperation in a range of hydrogen-related IPCEIs.

The Hydrogen Strategy Investment Agenda

Investment Areas	Estimated Costs (based on the Hydrogen Strategy figures)
Scaling up solar and wind energy production capacity to the electrolyzers to 80–120 GW	€220 billion to €340 billion by 2030
Investments in retrofitting half of the existing plants with carbon capture and storage	Around €11 billion
Investments in electrolyzers	€24 billion to €42 billion by 2030
Development of hydrogen transport, distribution and storage, and refueling stations	€65 million
Investments in hydrogen production capacities	€180 billion to €470 billion by 2050
Transformation of an end-use sector, transport	400 small-scale hydrogen-refueling stations could require between €850 million and €1 billion

13 The new strategic European investment window will focus on building stronger European value chains in line with the strategic agenda of the European Union and the New Industrial Strategy for Europe, as well as supporting activities in critical infrastructure and technologies.

14 European Commission, ETS Innovation Fund, available at https://ec.europa.eu/clima/policies/innovation-fund_en.

II. Scaling Up Production and Boosting Demand

The Commission acknowledges that kicking off the hydrogen market requires a full value chain approach to ensure cost-competitive hydrogen production. Currently, the costs of fossil-based hydrogen are estimated to be around €1.5 per kg, while the costs for green hydrogen vary between €2.5 and €5.5 per kg. Indeed, costs for green hydrogen are rapidly decreasing. Electrolyzer costs have already been reduced by 60 percent in the past 10 years and are predicted to decline from €900/KW to €450/KW or less in the period after 2030, and €180/KW after 2040. In this regard, the Hydrogen Strategy will focus on the following areas.

A. Strengthening the EU ETS

The EU ETS is a "cap and trade" system, which works by capping overall greenhouse gas emissions of all participants in the system. The EU ETS legislation creates allowances, which are essentially rights to emit these emissions equivalent to the global warming potential of 1 tonne of CO_2 equivalent. In line with this, based on a benchmarking approach, it allocates some free allowances. In other words, purchasing allowances is contingent on whether there is a gap between a company's free allocation and its measured emissions.

- Hydrogen production falls under the scope of the EU ETS, which means that hydrogen producers should purchase allowances for each ton of CO_2 emitted.
- Hydrogen producers of clean hydrogen will purchase less quotas as its production emits significantly less CO_2.
- A potential extension of the EU ETS scope to the aviation and maritime sectors can incentivize cost-effective decarbonization in all its covered sectors through carbon pricing.
- In the upcoming revision of the EU ETS, the Commission may consider how the production of green and low-carbon hydrogen could be further enhanced while taking due account of the risk for sectors exposed to carbon leakage.

B. The Revision of the State Aid Framework

The state aid guidelines for energy and environmental protection, predicted to be revised in 2021, will enable decarbonization. These guidelines will include hydrogen.

C. Market and Carbon Contracts for Difference

The main barrier for large blue and green hydrogen production is that currently markets are not willing to pay the higher production cost of very low-carbon materials. In Europe, the EU ETS carbon price is considerably low to permit these technologies to compete with cheaper "high carbon" alternatives.[15]

[15] Sustainable Development and International Relations, SciencesPo (2019), "How Carbon Contracts-for-Difference could help bring breakthrough technologies to market," Oliver Sartor, Chris Bataille, available at https://www.iddri.org/sites/default/files/PDF/Publications/Catalogue Iddri/Etude/201910-ST0619-CCfDs_0.pdf.

To increase the production of green and blue hydrogen, the Hydrogen Strategy sets forth a tendering system of carbon contracts for difference (CCfD) providing investment or operating aid. Carbon contracts for difference would pay hydrogen projects the difference between the price of an EU carbon permit and the actual cost of reducing CO_2. In essence, they provide investors with a strike price (also known as a fixed price) for emissions reductions compared to grey hydrogen. These contracts can contribute substantially to the decarbonization of the industrial sector, without having to wait, until the European Union accepts much higher EU ETS carbon prices or international carbon border adjustments are implemented.[16] Importantly, the Commission envisages the application of a pilot scheme for CCfD to (1) accelerate the replacement of existing hydrogen production in refineries and fertilizer production, low carbon, circular steel, and basic chemicals; (2) support the deployment in the maritime sector of hydrogen and derived fuels such as ammonia; and (3) assist the deployment of synthetic low-carbon fuels in aviation.

The Commission emphasizes that measures to promote the use of hydrogen should also target the demand side. It is estimated that clean hydrogen could meet 24 percent of global energy demand by 2050, with annual sales in the range of €630 billion.[17] To this end, the Hydrogen Strategy indicates that two particular sectors (industrial applications and transportation) can play an important role in scaling up the production of hydrogen.

Nevertheless, the Commission notes that the higher costs of hydrogen technologies are a key limiting factor for the use of hydrogen in industrial applications and transport. Carbon prices in the range of €55 to €90 per tonne of CO_2 would be needed to make fossil-based hydrogen with carbon capture competitive vis-à-vis fossil-based hydrogen currently used.[18,19] For this reason, the Commission suggests the introduction of quotas and minimum shares as mechanisms to stimulate hydrogen demand in a targeted way.

Hydrogen presents significant potential to be used as a fuel in the transport sector (such as local city buses, taxis, specific parts of the rail network, and heavy-duty road vehicles). In the longer-term, it can help in the decarbonization of the aviation and maritime sector, through the production of liquid synthetic kerosene or other synthetic fuels. In the industrial sector, it can reduce and replace the use of carbon-intensive hydrogen in refineries, the production of ammonia, for new forms of methanol production, or to partially replace fossil fuels in the production of steel.

In light of the above, the Hydrogen Strategy emphasizes the importance of creating a taxonomy, which will provide clarity and certainty on (1) the hydrogen

16 Idem.

17 *See* note 8.

18 Idem. It refers to fossil-based hydrogen produced through a variety of processes using fossil fuels as feedstock, mainly the reforming of natural gas or the gasification of coal. This represents the bulk of hydrogen produced today.

19 Idem.

production technologies that need to be developed in Europe; and (2) the definition and categorization of green and blue hydrogen. This explanatory framework can be set out in either the Renewable Energy Directive or the EU ETS Directive and will consist of the following:

- A common low-carbon threshold/ standard for the promotion of hydrogen production installations based on their full life-cycle greenhouse gas performance.
- A comprehensive terminology and European-wide criteria for the certification of green and low-carbon hydrogen. One way to determine hydrogen's contribution in the decarbonization of the energy system is via Guarantees of Origin (GO), a credit-based chain-of-custody system that enables consumers to know what percentage of their energy supply comes from renewables. GOs are already widely used to guarantee that the source of electricity is renewable.
  - » The legislative framework upon which hydrogen standardization will be based is the Renewable Energy Directive, which extended the scope of GOs to hydrogen.
  - » The Renewable Energy Directive stipulates that the greenhouse gas emission savings from the use of renewable liquid and gaseous transport fuels of non-biological origin excluding recycled carbon fuels shall be at least 70 percent as of 1 January 2021.
  - » At this stage, the Hydrogen Strategy leaves many open questions around the development of a hydrogen GO scheme, such as (1) the type and origin of the gas, including hydrogen; (2) the system for generating, auditing, tracking, and exchanging GOs; and (3) how it will fit in a nascent hydrogen market.
  - » In this vein, the Council of the European Energy Regulators emphasized that pursuant to the Renewable Energy Directive's definition of a "renewable energy source," decarbonized gases (such as hydrogen) that are derived from natural gas through steam methane reforming or thermal methane pyrolysis "would not be considered as renewable gas but could be included in the national GOs systems as decarbonized gas, thereby making transparent to gas customers the low-carbon nature of this gas."[20]
  - » In Europe, there are already some hydrogen certification schemes in place, such as CertiHy[21] and ERGaR.[22]

[20] Council of European Energy Regulators (2019), "Regulatory Challenges for a Sustainable Gas Sector," Public Consultation Paper, Ref: C18-RGS-03-03, available at https://www.ceer.eu/documents/104400/-/-/274b3146-afb5-8c96-436e-4056f3636b31.

[21] CertifHY, available at https://www.certifhy.eu/.

[22] *See*: https://www.entsog.eu/certification-green-gases; and http://www.ergar.org/.

» The Commission is expected to present a methodology to better account for the share of renewable electricity used in hydrogen production using equipment connected to the grid by 31 December 2021.

III. Designing an Infrastructure Framework and Market Rules

Meeting the increased supply and demand needs for hydrogen in the near term requires an efficient energy infrastructure. Hydrogen can be transported via pipelines, but also via non-network-based transport options such as trucks or ships. In this regard, the increase of the availability of energy infrastructure at a regional, local, and supranational level to satisfy the demand for hydrogen can be achieved through the following options.

A. Review of the Trans-European Networks for Energy (TEN-E) Regulation[23]

The recast framework will foster the deployment of innovative technologies and infrastructure, such as smart grids, hydrogen networks or carbon capture, storage and utilization, and energy storage, also enabling sector integration. The Commission also contemplates the review of the Trans-European Transport Network[24] (TEN-T), which will contribute to meeting the transport demands through a network of fueling stations.

[23] The TEN-E Regulation identifies priority corridors and thematic areas of trans-European energy infrastructure and provides guidelines for the selection of Projects of Common Interest (PCIs). The main objective of this assignment was to provide an independent evaluation of the TEN-E Regulation and PCI framework. The evaluation focused on the distinct assessment criteria and evaluation questions and provided evidence especially in those aspects in which the PCI framework had not been delivering as expected.

[24] The TEN-T policy addresses the implementation and development of a Europe-wide network of railway lines, roads, inland waterways, maritime shipping routes, ports, airports, and railroad terminals. https://ec.europa.eu/transport/themes/infrastructure/ten-t_en.

B. Use of Existing Gas Transportation Systems to Transport Hydrogen

Taking into account that demand for natural gas will decline after 2030, repurposing may provide an opportunity for a cost-effective energy transition in combination with the newly built, hydrogen-dedicated infrastructure. For instance, the Hydrogen Strategy mentions that a hydrogen network in Germany and the Netherlands may consist of up to 90 percent of repurposed natural gas infrastructure. However, the key challenge of repurposing natural gas pipelines lies in the fact that existing pipelines are owned by network operators that may not be allowed to own, operate, and finance hydrogen pipelines. To this end, the Commission recommends the review of the internal gas market legislation for competitive decarbonized gas markets, integrating two main objectives: (1) facilitating third-party access to liquid markets on a nondiscriminatory basis for new producers and customers; and (2) removing barriers for efficient hydrogen infrastructure development (via repurposing of pipelines).

C. Blending of Hydrogen in the Natural Gas Network

The Commission indicates that blending of hydrogen into natural gas pipelines at a limited percentage may enable decentralized green hydrogen production in local networks in a transitional phase. However, the Commission also notes that it may be less efficient and diminishes the value of hydrogen. It also can cause differentiation in gas quality in the internal European natural gas market, particularly if neighboring member states accept different levels of blending and cross-border flows are hindered.

IV. Promoting Research and Innovation

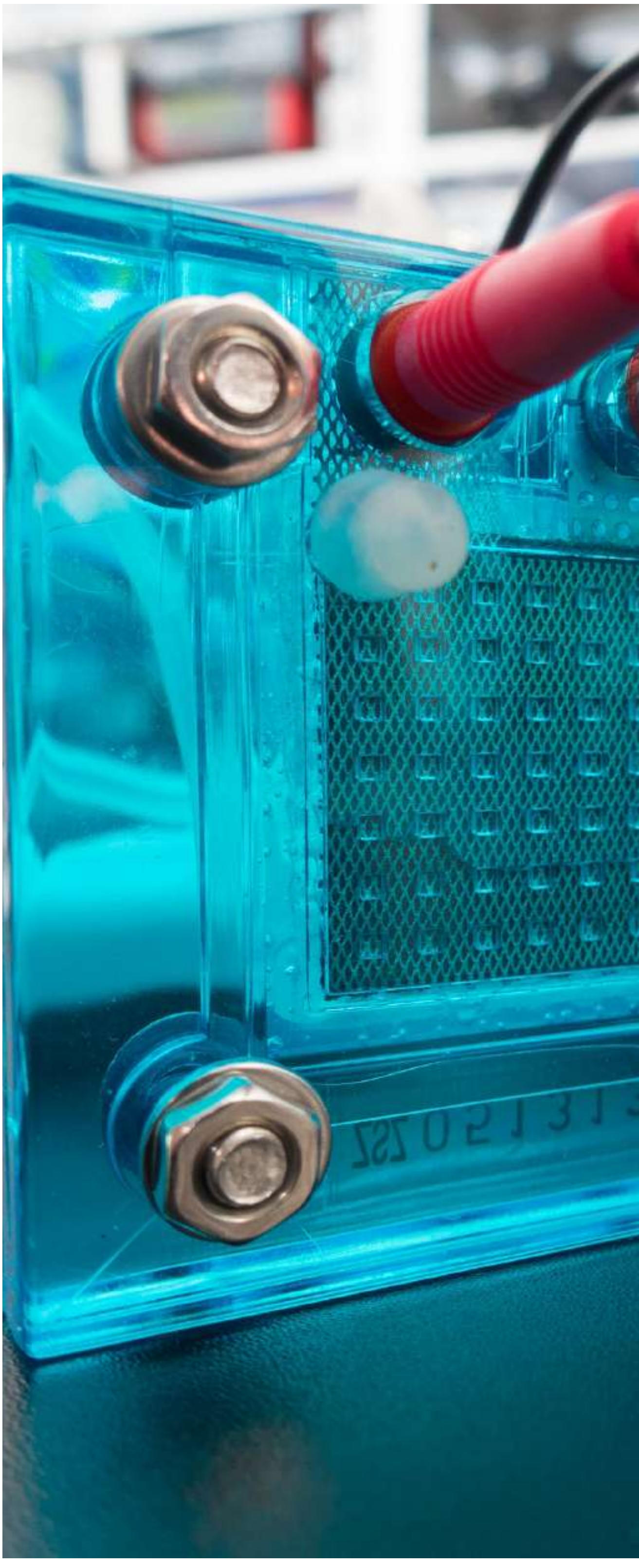
The Hydrogen Strategy recognizes that ensuring a full hydrogen supply chain demands further research and innovation. Even though Europe has been undertaking research efforts for many years, decarbonization calls for hydrogen deployment at large scale. The Hydrogen Strategy provides for the following:

- Scaling-up of larger size and more efficient production capacities. As a first step, a call for proposals for a 100 MW electrolyzer will be launched in Q3 2020.
- Support for large-scale, high-impact projects across the entire hydrogen value chain, such as green ports and airports.
- Further development of infrastructure to distribute, store, and dispense hydrogen at large volumes and possibly over long distances.
- Under the research and innovation framework program, Horizon Europe, establishment of a Clean Hydrogen Partnership focusing on supporting research and development of green hydrogen.
- Improved and harmonized safety standards.
- Targeted support to build the necessary capacity for preparation of financially sound and viable hydrogen

projects. This translates into the development of local hydrogen clusters, such as remote areas or islands, or regional ecosystems, the "Hydrogen Valleys."

V. International Cooperation with Fast-Accelerating Hydrogen Markets

The Commission stresses that "hydrogen diplomacy" is a top priority of its external energy policy agenda. Cooperation should focus on research and innovation, regulatory policy, direct investments, and fair trade in the hydrogen sector. The European Union could also benefit from an enhanced collaboration on hydrogen with its international partners, including Ukraine, the African Union, the Western Balkans, and neighboring countries of the Mediterranean. As Europe strives to be one of the central hubs of a new hydrogen marketplace, the Commission suggests the development of a benchmark for euro-denominated hydrogen trades by 2021. However, many industry executives point out that a single currency for hydrogen trades is less important than a directed, massive rollout of green hydrogen production and use.[25]



[25] S&P Global (2020), "EC plans euro-based hydrogen benchmark by 2021: draft EU strategy," Siobhan Hall, available at https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/062320-ec-plans-euro-based-hydrogen-benchmark-by-2021-draft-eu-strategy.

PART V – THE REGULATORY OUTLOOK OF THE HYDROGEN STRATEGY

The Hydrogen Strategy does not set forth any legally binding measures. The Commission notes that the Hydrogen Strategy in its current form is a roadmap for engagement with institutional and private-sector stakeholders. Against this backdrop, potential actions will take the form of both:

- Non-legislative measures; and
- Legislative measures to be further developed in the context of the June 2021 legislative proposals on energy and climate to enable more ambitious climate action.

It is important to note that any initiative will be complementary to those identified in the Strategy for Energy System Integration and reinforced by the work of the Alliance. With regard to any legislative initiatives, although no timeline of implementation is provided, they will undergo a 12-week consultation of interested parties before the Commission submits them for review to the European Parliament and the Council. Forthcoming proposed legislative actions include the following:

- **Revise the Energy Tax Directive scheduled for 2021.**

  The goal is to align the taxation of energy products and electricity with EU environment and climate policies, ensure a harmonized taxation of both storage and hydrogen production, and avoid double taxation. The Commission is already consulting on the energy tax directive (ETD) review and considering a number of policy options, such as (1) minimum excise rates, taking into account energy content and linkages to greenhouse gas emissions; (2) sectoral tax differentiation, taking into account existing differentiation between motor and heating fuel and focusing on tackling fossil fuel subsidies; and

(3) product coverage, taking into account that the use of hydrogen, among other new energy products, is currently discouraged because it can be taxed in the same manner as traditional energy products.

- **Ensure that the revision of the state aid framework supports the cost-effective decarbonization of the economy where public support remains necessary by 2021.**

  The State aid Guidelines[26] for environmental protection and energy (EEAG) 2014–2020 define energy from renewable energy sources as:

> Energy produced by plants using only renewable energy sources, as well as the share in terms of calorific value of energy produced from renewable energy sources in hybrid plants which also use conventional energy sources, and it includes renewable electricity used for filling storage systems, but excludes electricity produced as a result of storage systems.

  Neither hydrogen nor low-carbon gases are specifically covered under the EEAG. However, national subsidies to carbon capture and storage are permissible under the EEAG and could, under certain circumstances, favor blue hydrogen. In light of the above, it is evident that the revised EEAG will have to reflect the EU policy objectives addressing market barriers to the deployment of clean energy products, such as green hydrogen.

- **Review the legislative framework to design a competitive decarbonized gas market, fit for renewable gases, including empowering gas customers with enhanced information and rights by 2021.**

  Initially, a review of the Third Gas Directive was scheduled for 2020 and then replaced by the Energy Sector Integration Strategy. In practice, the Energy Sector Integration Strategy introduces "sector coupling" of the gas and electricity sectors. Sector coupling occurs when "the EU electricity and gas sectors, both in terms of their markets and infrastructure" are linked.[27] Further, the Commission points out the potential for linkage between the supply chains for hydrogen, methane, and natural gas, for instance, by blending of hydrogen or synthetic methane with natural gas, or competition for storage between hydrogen, methane, and CO_2.[28]

Apart from the Commission's strong commitment to embed hydrogen in Europe, many member states (including

[26] European Commission (2014), "Communication from the Commission Guidelines on State aid for environmental protection and energy 2014–2020," (2014/C 200/01), Brussels, available at https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628(01)&from=EN.

[27] European Commission (2019), COWI consortium (Frontier Economics, CE Delft, and THEMA Consulting Group): "Potentials of sector coupling for decarbonization: Assessing regulatory barriers in linking the gas and electricity sectors in the EU," Final Report December 2019, available at https://op.europa.eu/en/publication-detail/-/publication/60fadfee-216c-11ea-95ab-01aa75ed71a1/language-en.

[28] Idem.

the Netherlands, Germany, and Portugal) have an interest in advancing the hydrogen agenda.

Notably, Germany, which unveiled its national Hydrogen Strategy before the Commission, is expected to push the Hydrogen Strategy while holding the Presidency of the Council of the European Union until the end of 2020. Unsurprisingly, its Presidency program[29] underscores that it wants to win "partners for green energy imports." Portugal, which will hold the Presidency of the Council of the European Union in the first half of 2021, is also expected to push for a pro-hydrogen policy, having recently launched its ambitious hydrogen plans.

The European Parliament already has been working on its own initiative on the development of a hydrogen economy. Some days before the official launch of the Hydrogen Strategy, Members of the European Parliament of the Committee on Industry, Research and Energy (ITRE) endorsed a report[30] proposing ways to step up energy storage solutions, including hydrogen. The report, prepared by rapporteur Claudia Gamon *(Austria/ Renew Europe)*, concludes that there are serious regulatory barriers, which interfere with the swift exploitation of the European Union's energy potential.

Specifically, as regards hydrogen, the report:

- Highlights the potential of green hydrogen and urges the Commission to continue supporting research into and development of a hydrogen economy.
- Emphasizes that support measures are needed to reduce the cost of production of green hydrogen, while calling on the Commission to assess if retrofitting gas infrastructure to transport hydrogen is possible.
- Underscores that Europe needs to become a leader in the green hydrogen sector. The report mentions that green hydrogen can (1) provide significant flexibility to the electricity system; (2) capture a significant market share of the 15 metric tonnes of hydrogen used worldwide in refineries; and (3) be used as fuel for cars.
- Highlights the need for developing a hydrogen market.
- Calls for clear rules to avoid market distortion.

Interestingly, it is clear that the deployment of hydrogen has many allies in the EU policy arena, and there appears to be a high degree of consensus on the strategic priorities and future direction of the EU hydrogen economy.

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29 German Presidency Program (2020), available at https://www.eu2020.de/eu2020-en/programm.

30 European Parliament (2020), "Draft Report on a comprehensive European approach to energy storage," (2019/2189(INI)), Brussels, available at https://www.europarl.europa.eu/meetdocs/2014_2019/plmrep/COMMITTEES/ITRE/PR/2020/06-29/1198854EN.pdf.

PART VI –
HYDROGEN FUNDING OPPORTUNITIES

The European Commission estimates that the total capital expenditures for hydrogen production technologies could range between €140 and €400 billion by 2050.[31] Similarly, investments in green hydrogen in Europe could be up to €180 to €470 billion by 2050, and in the range of €3 to €18 billion for low-carbon fossil-based hydrogen.

[31] The European Commission's science and knowledge service (2019), "Hydrogen use in EU decarbonisation scenarios," Brussels, available at https://ec.europa.eu/jrc/sites/jrcsh/files/final_insights_into_hydrogen_use_public_version.pdf.

Funding Program	Program Description
InvestEU[32]	• The InvestEU builds on the successful model of the Investment Plan for Europe, the Juncker Plan. • The InvestEU program will provide crucial support to companies and ensure a strong focus of investors on Europe's medium- and long-term policy priorities, such as the Green Deal. • The InvestEU will mobilize public and private investment through an EU budget guarantee of €75 billion that will back the investment projects of implementing partners such as the European Investment Bank Group and others and increase their risk-bearing capacity.
The Strategic Investment Facility[33]	• The Commission added a fifth investment window in the InvestEU, the "Strategic European Investment Window," via the new Strategic Investment Facility. The new Strategic European Investment Window will focus on building stronger European value chains in line with the strategic agenda of the European Union and the New Industrial Strategy for Europe, as well as supporting activities in critical infrastructure and technologies. • It will generate investments of up to EUR 150 billion in boosting the resilience of strategic sectors, notably those linked to the green and digital transition, and key value chains in the internal market. • It will invest in technologies, which are key for the clean energy transition, such as, among other things, clean hydrogen, carbon capture and storage, and sustainable energy infrastructure. As such, the industry holds that it offers the most potential for hydrogen development.[34]

[32] European Commission (2020), "Questions and Answers: The proposed InvestEU Programme," available at https://ec.europa.eu/commission/presscorner/detail/en/qanda_20_947.

[33] European Commission Factsheet (2020), "An enhanced InvestEU Programme and new Strategic Investment Facility to help kick-start the economy," available at https://ec.europa.eu/info/sites/info/files/economy-finance/investeu-factsheet.pdf.

[34] Hydrogen Europe (2020), "Hydrogen in the EU's Economic Recovery Plans," available at https://hydrogeneurope.eu/sites/default/files/Hydrogen Europe_EU Recovery Plan Analysis_FINAL.pdf.

Funding Program	Program Description
Just Transition Mechanism It aims to facilitate the energy transition for those regions heavily reliant on fossil fuels. The identification of these territories will be carried out through a dialogue with the Commission. All investments under the Just Transition Mechanism will need to be implemented based on member states' territorial just transition plans. The Just Transition Mechanism is expected to mobilize at least €150 billion of public and private green investments.	The Just Transition Mechanism consists of three financing pillars: • **The Just Transition Fund.**[35] The overall budget of the Just Transition Fund is €17.5 billion. The funding of the Just Transition Fund will be used to alleviate the socioeconomic impacts of the green transition in the regions most affected, by supporting the re-skilling of workers, helping subject matter experts to create new economic opportunities, and generally investing in the future of the most affected regions. Access to the Just Transition Fund will be limited to 50 percent of national allocation for member states that have not yet committed to implement the objective of achieving climate neutrality, the other 50 percent being made available upon acceptance of such a commitment. • **A dedicated just transition scheme under InvestEU.** It will mobilize up to €45 billion of investments. It will seek to attract private investments, including in sustainable energy and transport, that benefit those regions and help their economies find new sources of growth. • **The public sector loan facility.**[36] The facility will be jointly implemented by the Commission and the European Investment Bank. It is expected to mobilize up to between €25 and €30 billion of public investment to the benefit of areas such as energy and transport infrastructure, district heating networks, public transport, energy efficiency measures, social infrastructure, and other projects that can directly benefit the communities in the affected regions and reduce the socioeconomic costs of the transition.

[35] European Commission (2020), "Proposal for a Regulation of the European Parliament and the Council establishing a Just Transition Fund," COM/2020/22 final, Brussels, available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020PC0022.

[36] European Commission (2020), "Proposal for a Regulation of the European Parliament and of the Council on the public sector loan facility under the Just Transition Mechanism," COM (2020) 453, Brussels, available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020PC0453.

Funding Program	Program Description
Connecting Europe Facility[37]	• It supports the development of high-performing, sustainable, and efficiently interconnected trans-European networks in the fields of transport, energy, and digital services. It offers financial support through grants, guarantees, and project bonds. • The Innovation and Networks Executive Agency runs the Connecting Europe Facility, with €4.6 billion dedicated for energy and €23.7 billion for transport. • The Connecting Europe Facility will be harnessed to fund dedicated infrastructure for hydrogen, repurposing of gas networks and carbon capture projects, and finance hydrogen refueling stations.
Important Projects of Common European Interest (IPCEI)[38]	• They are designed to bring together public and private sectors to undertake large-scale disruptive and ambitious research and innovation projects. • To receive funding from member states, an IPCEI should fulfill the following requirements: » Contribute to EU objective(s) and have a significant impact on competitiveness, sustainability, or value creation across the European Union. » Involve more than one member state. » Have positive spillover effects on the Single Market, whereas benefits should not be limited to participating member states and companies. » Involve co-financing by the project beneficiaries. » For research and innovation projects, the projects must be of a major innovative nature or of important benefit in light of the state of the art in the sector. If the project entails the first deployment of technology or innovations in industry, it should facilitate the deployment of either: (1) a new product of high research and innovation value; or (2) a fundamentally innovative production process.

37 Innovation and Networks Executive Agency, "Connecting Europe Facility," available at https://ec.europa.eu/inea/en/connecting-europe-facility.

38 European Commission (2014), "Communication on Criteria for the analysis of the compatibility with the internal market of State aid to promote the execution of important projects of common European interest" (2014/C 188/02), Brussels, available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52014XC0620(01)#:~:text=This%20communication%20gives%20guidance%20on,common%20European%20interest%20(IPCEIs).&text=They%20are%20designed%20to%20bring,the%20Union%20and%20its%20citizens.

Funding Program	Program Description
Projects of Common Interest[39]	• Projects of common interest are key cross-border infrastructure projects that link the energy systems of at least two member states. • They are regulated by the TEN-E Regulation, which is currently reviewed to ensure consistency with the climate neutrality objective of the Green Deal. To this end, the revision of the TEN-E Regulation might expand its scope to energy infrastructure projects other than electricity and gas. • The TEN-E Regulation lays out the conditions for identifying projects of common interest that will be eligible for EU funding under the Connecting Europe Facility.
Innovation Fund[40]	• The Innovation Fund is one of the first EU funding instruments tangibly supporting the vision for climate-neutral Europe by 2050. It is about unleashing low-carbon investments in all member states. • The revenues for the Innovation Fund come from the auctioning of 450 million EU Emissions Trading System allowances from 2020 to 2030, as well as any unspent funds coming from the NER300 program. The Fund may amount to about €10 billion, depending on the carbon price. • There is currently an open call of projects, which will be assessed based on (1) greenhouse gas emission avoidance; (2) degree of innovation; (3) project maturity; (4) scalability; and (5) cost efficiency.

[39] European Commission, "Projects of Common Interest," available at https://ec.europa.eu/energy/topics/infrastructure/projects-common-interest/key-cross-border-infrastructure-projects_en.

[40] European Commission, "Innovation Fund," available at https://ec.europa.eu/clima/policies/innovation-fund_en.

Funding Program	Program Description
European Regional Development Fund (ERDF) and the Cohesion Fund[41]	• It aims to redress the main regional imbalances in the European Union. • It benefits from a top-up in the context of the new initiative React-EU to support the green transition. • Financial instruments co-funded by the ERDF can potentially be used for all investment priorities outlined in the ERDF operational programs of the member states and regions, provided that they address an identified market gap. • The ERDF consists of a range of financial instruments: loans, grants, equity, microcredit, and guarantees.
European Agricultural Fund for Rural Development (EAFRD)[42]	• The EAFRD is the funding instrument of the Common Agricultural Policy that supports rural development strategies and projects. • The Commission has allocated in the EAFRD €77.85 billion. • Rural areas will have a vital role to play in delivering the green transition. • The EAFRD is co-managed by the Commission and member states, while funding is provided through the Rural Development Programs designed by member states.
Fuel Cells and Hydrogen Joint Undertaking[43]	• It is a public private partnership supporting research and technological development in fuel cell and hydrogen energy technologies in Europe. It launches open calls for grants annually. The call for 2020 is currently closed.

41 European Commission, "The European Regional Development Fund Financial instruments," available at https://www.ficompass.eu/sites/default/files/publications/ERDF_The_european_regional_development_fund_EN.pdf.

42 European Commission (2020), "Questions and Answers on the EU budget: the Common Agricultural Policy and Common Fisheries Policy," available at https://ec.europa.eu/commission/presscorner/detail/en/QANDA_20_985.

43 Fuel Cells and Hydrogen Joint Undertaking, "2020 Call for Proposals launched: EUR 93 million available for 24 topics," available at https://www.fch.europa.eu/news/2020-call-proposals-launched-%E2%82%AC93-million-available-24-topics.

Funding Program	Program Description
Recovery and Resilience Facility[44] It comprises a €672.5 billion budget consisting of: • €360 billion loans; and • €312.5 billion grants.	• It aims to support investments and reforms essential to a lasting recovery, to improve the economic and social resilience of member states, and to support the green and digital transitions. • Member states will have to prepare national recovery and resilience plans setting out a reforms and investments agenda for 2021–23. The plans will be reviewed and adapted as necessary in 2022. • The plans are presented by member states and should be consistent with the challenges and priorities identified in the European Semester, with the national reform programs, the national energy and climate plans, the just transition plans, and the partnership agreements and operational programs adopted under the European Union funds. • The grants and loans will be disbursed in installments upon completion of milestones and targets as defined by member states in their recovery and resilience plans.

[44] European Commission (2020), "Questions and Answers on the EU budget for recovery: Recovery and Resilience Facility," available at https://ec.europa.eu/commission/presscorner/detail/en/QANDA_20_949.

GLOSSARY EUROPEAN UNION

CBAM	carbon border adjustment mechanism
CCfD	carbon contracts for difference
EAFRD	European Agricultural Fund for Rural Development
EEAG	Environmental and Energy State Aid Guidelines
ERDF	European Regional Development Fund
ETD	Energy Tax Directive
EU ETS	EU Emissions Trading Scheme
GO	Guarantees of Origin
GW	gigawatt
IPCEI	Important Projects of Common European Interest
ITRE	Committee on Industry, Research and Energy
KW	kilowatt
MW	megawatt
PCIs	Projects of Common Interest
TEN-E	Trans-European Networks for Energy
TEN-T	Trans-European Transport Network

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GERMANY

The H_2 Handbook

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

HYDROGEN IN GERMANY – NEW POLITICS, MANY PUBLIC FUNDING PROGRAMS, AN EMERGING MARKET

On 10 June 2020, the German government announced its "**National Hydrogen Strategy**" outlining a broad package of measures and public funds to be made available for furthering the development of a national hydrogen industry in Germany.

On 1 July 2020, Germany took over the presidency of the Council of the European Union (EU Council). The EU Council presidency is limited to six months and rotates in a fixed order from one EU member state to the next. The member state chairing the EU Council is expected to coordinate and organize the broad political strategy of the European Union for the respective period. Member states commonly use this position to add certain of their own high-priority topics to the EU agenda or put them into focus. In the weeks before the change of the EU Council presidency, it had become apparent that hydrogen would be one of the core topics of the German presidency. On 16 July 2020, Federal Minister of Economics Peter Altmaier (Christian Democratic Union of Germany, or CDU) explicitly confirmed this priority, which is also demonstrated by the federal government's program for the German EU Council presidency published on 30 June 2020.

Even though the National Hydrogen Strategy focuses primarily on measures to support hydrogen projects and develop a domestic hydrogen market in Germany, the federal government in Germany explicitly acknowledges that some of the challenges in furthering and promoting hydrogen as an innovative energy source can only be resolved in the European Union context. German Development Minister Gerd Müller (CDU) also sees significant development potential beyond Europe. Following the federal government's decision on the National Hydrogen Strategy, he declared that green hydrogen can become the clean oil of tomorrow ("[…] grüner Wasserstoff kann so zum sauberen Öl von morgen werden.").

CONTENTS GERMANY

PART I - GERMANY IN (ENERGY) TRANSITION

Environmental awareness among the German population has increased in recent decades. Climate change has become one of the greatest concerns, in particular for young Germans involved in the "Fridays for Future" movement, demonstrating their willingness to change climate policy. There seems to be a growing interest among German citizens to consider new sustainable technology solutions in order to protect nature, the climate, and the planet.

German politics mirror these societal views. Chancellor Angela Merkel pushed Germany's withdrawal from nuclear energy after the incident in Fukushima, Japan, in 2011, thereby reversing her prior outspoken support of nuclear energy. This tragic event marked the beginning of the "energy transition" in Germany. Based on a long-term plan, nuclear (until the end of 2022) and coal-fired (by 2038 at the latest) power plants will be shut down and fossil fuels will be replaced by renewables to reduce carbon emissions and slow climate change. This "decarbonization" represents a goal to which Germany has also committed itself within the framework of the Paris Climate Protection Agreement. The new National Hydrogen Strategy clearly states that hydrogen will be an indispensable component in reaching the ambitious goals of climate neutrality and carbon neutrality.

Even though there are still many development needs regarding hydrogen production, storage, and use, hydrogen is seen as having advantages over pure electrical energy, in particular with regard to shortage of raw materials for and disposal of batteries, but also with regard to transportation. Hydrogen, which stores the energy obtained in gaseous form, can be easily transported, and Germany already has an extensive natural gas pipeline network. Additional advantages of hydrogen usually mentioned in the German discussion include conservation of resources, security of supply, and environmental and climate protection. However, the economic viability and the associated broader acceptance by the population still remain to be achieved.

To reach Germany's sustainability goals, several new pieces of legislation have already been implemented to create incentives for green energy production and consumption by way of public funding. For example, the federal government introduced a more favorable tax treatment for electric than for traditional company cars, as well as grants for the private purchase of electric cars and for the construction of charging stations. With the new National Hydrogen Strategy, the German government is now pushing forward a broad initiative supporting hydrogen production and use in Germany and establishing it as a competitive alternative energy source and decarbonization tool.

PART II - THE FEDERAL POLITICS REGARDING HYDROGEN IN GERMANY

The German government has been providing substantial hydrogen funding since 2007, when it launched its "**National Hydrogen and Fuel Cell Technology Innovation Programme**."

In June 2020, this focus was reconfirmed and substantially deepened and broadened with the new German National Hydrogen Strategy presented by the federal government right before the start of the German EU Council presidency. With the National Hydrogen Strategy, the German government is looking to secure German leadership in innovation with regard to climate protection technologies and to develop those technologies into a German hallmark.

The goal is to become a leading global supplier of modern hydrogen technology. However, the German government's goals extend beyond the national goal of further expanding it's already prominent position regarding hydrogen research and development (R&D) (based on research and investment in the field of hydrogen in the last decade) and upscaling the "home market" for hydrogen production and storage. It intends to motivate the rest of the European Union and the world to use hydrogen as the oil of the 21st century.

To achieve its goal of establishing hydrogen as a competitive option for decarbonization, the federal government envisions the implementation of numerous support programs and legislative initiatives in coordination with the various federal ministries responsible for innovation, industry, climate, and energy policy. One of the main drivers behind the National Hydrogen Strategy is, of course, to counter the effects of climate change; green hydrogen in particular enables carbon-neutral energy production. The main focus of the strategy is now to make hydrogen marketable through various measures and to foster the production of and industry for green hydrogen in Germany. However, Germany will still have to import hydrogen to meet its needs (at least for the foreseeable future), which is why the strategy also pursues international collaboration projects. The German government projects that national hydrogen demand will be approximately 90 to 110 terawatt hours (TWh) until 2030. In order to cover at least a part of this demand in Germany, hydrogen generation plants with a total capacity of up to 5 gigawatts, including the necessary offshore and onshore facilities, will be built in Germany by 2030. This corresponds to green hydrogen production of up to 14 TWh and required renewable electricity of up to 20 TWh.

According to the strategy, other secondary products such as ammonia, methanol, and methane should also be produced from hydrogen. Assuming green hydrogen is used, the strategy describes these products as Power-to-X (PtX) and, in the case of gaseous derivatives and liquids derivatives, they are described as Power-to-Gas (PtG) and Power-to-Liquid, respectively. Hydrogen can provide a valuable storage method for superfluous power (e.g., produced by wind farms), as it can be stored in highly pressurized tanks and be converted back into power when needed (PtG).

The new National Hydrogen Strategy is not only a necessary step towards the German energy transition, but it recently also has been described as a means to reduce the economic consequences of the COVID-19 pandemic. The Federal Minister for the Environment, Svenja Schulze (Social Democratic Party of Germany, or SPD), hopes that the new National Hydrogen Strategy will provide a "double thrust," not only for climate protection but also for the sustainable recovery of the economy from the COVID-19 crisis.

On 3 June 2020, the German government adopted an economic stimulus package to overcome the consequences of the COVID-19 crisis that provides for €9 billion to be made available for the construction of hydrogen plants. Of this amount, €7 billion is to be used domestically for the purpose of establishing climate-neutral, green hydrogen in Germany. The remaining €2 billion is to be used for international partnerships, including the production and import of blue hydrogen, which is hydrogen produced from natural gas that includes carbon capture and sequestration (CCS).

In addition to this mega-package for hydrogen promotion, numerous other federal funds are available within the framework of the National Hydrogen and Fuel Cell Technology Innovation Programme already mentioned. In addition, the individual German federal states also have launched funding programs (supplementing the federal funding or stand-alone). These federal state subsidies are not discussed in detail here, as they differ substantially and generally require that the (subsidized) investments be made in the respective state and, as such, are of interest mainly to companies looking to invest in the respective member state. There are a couple of developments worth highlighting, however. Specifically, the northern German states have ambitious plans regarding hydrogen and provide corresponding subsidies, which are likely due primarily to the local availability of wind energy in sufficient quantities for the energy-intensive production of green hydrogen. In particular, the city of Hamburg has shown big ambitions to present a lighthouse project soon—press reports have mentioned plans to build a sizable hydrogen production plant (electrolyser) in the Hamburg harbor. The project still seems to be in development, though, and investors are still needed.

Among numerous other measures, the new National Hydrogen Strategy also provides for the establishment of a 25-member National Hydrogen Council, which will advise the federal government on the hydrogen industry and technology. This council has a very diverse structure and consists of representatives from both industry and science appointed by the federal government. The council is chaired by Katherina Reiche, a former top politician from Chancellor Merkel's CDU, who moved to the private sector five years ago. Reiche's involvement and position send a clear signal that the National Hydrogen Council is to take on its role as an interface between politics and industry. While in the last decade hydrogen funding has been promoted primarily for research projects, the focus is now shifting to establishing hydrogen as an economically viable and competitive alternative energy source, storage means, PtX component, and basic material for industrial uses. The goal is to ramp up the German market and promote a competitive German hydrogen industry with a steady demand and supply of hydrogen.

PART III - THE (PREEXISTING) NATIONAL HYDROGEN AND FUEL CELL TECHNOLOGY INNOVATION PROGRAMME

The first National Hydrogen and Fuel Cell Technology Innovation Programme (NIP I) was introduced by the federal government in 2006 and is managed by the Federal Ministry of Transport and Infrastructure. It was first set until 2016. The successor program (NIP II) also runs for 10 years until 2026.

The federal government (in charge: the Ministry of Transportation) has commissioned Forschungszentrum Jülich (Project Management Jülich), in cooperation with the National Organisation for Hydrogen and Fuel Cell Technology (NOW GmbH), to implement the National Hydrogen and Fuel Cell Technology Innovation Programme. NOW GmbH (100 percent held by the Federal Republic of Germany) has been coordinating and steering the National Hydrogen and Fuel Cell Technology Innovation Programme since 2008.

Project Management Jülich (also 100 percent owned by the German state) conducts research in the field of hydrogen and uses its findings to advise German policymakers.

From 2007 to 2016, NIP I supported projects with a funding of €700 million and was intended to prepare for the establishment of a German hydrogen industry sector through stable framework conditions and funding opportunities. However, from 2016 to 2026, NIP II (with a total funding of €1.4 billion) aims to ensure the market launch of fuel cell products, to establish a hydrogen infrastructure for transportation, and to make hydrogen technology competitive in the energy market.

The subsidies are distributed by way of online calls for specific funded measures published by NOW GmbH with application deadlines. Interested parties can apply to receive support for the respective hydrogen projects. Potential interested parties can also register with the **e-mail service** to keep up to date on funding opportunities.

One important project under the NIP II is “HyLand,” through which 25 municipalities and regions have been identified as particularly important for the success of the implementation of the traffic transition in Germany. Under HyLand, these municipalities and regions will be supported financially in their endeavors to push towards low-emission public transportation, heat and electricity generation, and electricity storage. Several funding initiatives are gradually being launched and are sometimes repeated at certain intervals. Examples of the programs over the last several years include:

- Funding for fuel cell passenger cars in company or public fleets;
- Funding for fleets of industrial trucks with fuel cell drive;
- Funding for publicly accessible hydrogen filling stations in road traffic (2018 and 2019);
- Funding for fuel cell vehicles in public transportation and fleets (2017 and 2018);
- Funding for fuel cell systems for self-sufficient energy supply of critical or off-grid infrastructures; and
- Funding for trains and ships with fuel cell drive.

To date, a total of 212 projects have been completed through the National Hydrogen and Fuel Cell Technology Innovation Program, 22 of which are ongoing. The projects cover the areas of transportation, shipping, special markets, cross-sectional issues, and electricity-based fuel.

PART IV -
THE NEW GERMAN NATIONAL HYDROGEN STRATEGY 2020

The new German National Hydrogen Strategy aims to make carbon-free hydrogen economically viable, which will only be possible if a "home market" for hydrogen technologies is successfully developed.

The idea is to incentivize green hydrogen production in Germany to help ensure that German hydrogen will be attractive throughout the European Union and internationally. Under the strategy, carbon-free hydrogen will be established as an alternative energy carrier and fuel in transportation. Sustainably produced hydrogen will be used as the basis for synthetic fuels, particularly in air and heavy-duty transport. Hydrogen will be made sustainable as a basic material for industrial uses. The transportation and distribution infrastructure will be further developed. Science will be further promoted, and skilled workers will be trained to create global market opportunities for German companies. International markets and global cooperation for hydrogen will be established to realize the full potential of hydrogen solutions. In order to achieve these goals, the strategy envisages 38 concrete measures in six fields of action, namely:

- Production
- Primary focus application areas (especially transportation, industry, and heating)
- Supply infrastructure
- Research, education, and innovation
- The European need for action
- The international hydrogen market (including necessary imports of hydrogen into Germany)

The new National Hydrogen Strategy[1] provides clear examples of the focus points of future hydrogen policy in Germany.

Hydrogen Production

"The introduction of **CO2 pricing for fossil fuels used in transport and the heating sector** is an important element here, and will be complemented by a reduction of the [Renewable Energy Act] EEG surcharge." The EEG surcharge is used to finance the expansion of renewable energy in Germany. Operators of renewable energy systems that provide electricity into the public grid receive a fixed remuneration. The resulting additional costs are passed on to all electricity consumers.

Incentives for Green Hydrogen

- "Our analysis will also include the question as to whether it might be possible to largely **exempt electricity used for the production of green hydrogen from taxes, levies, and surcharges.** In particular, we are working towards exempting the production of green hydrogen from the EEG surcharge. As we do so, we will ensure that the EEG surcharge does not rise."
- "As part of our Climate Action Innovation Pact, we are also supporting the switchover to hydrogen in the industrial sector by providing **funding for investments in electrolysers.**"
- "We are also exploring potential tendering schemes for the production of green hydrogen, e.g. to help decarbonise the steel and chemical industries."
- "Potential adjustments that will be discussed include the **designation of additional areas that can be used for offshore production of hydrogen/PtX, the infrastructure necessary for this, and the potential for additional auction rounds for the production of renewables** (implementation starts in 2020)."

Transport

"An **ambitious GHG (greenhouse gas) reduction ratio** will increase the share of renewables in transport. If combined with specific other measures, it can provide incentives for the use of hydrogen or hydrogen products as an alternative fuel for transport."

Incentives for Green Hydrogen

- "The Federal Government has decided to make its objective to **increase the minimum share of renewables in Germany's final energy consumption in transport significantly** beyond what is required under EU rules by 2030."
- "**Market activation to boost investments in hydrogen-powered vehicles** (light and heavy-duty vehicles, buses, trains, inland and coastal navigation, car fleets)".
- "Development of and **funding for installations for the production of electricity-based fuels,** in particular electricity-based kerosene, and advanced biofuels."

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[1] *National Hydrogen Strategy*, FED. MIN. FOR ECONOMIC AFFAIRS AND ENERGY (June 2020), https://www.bmbf.de/files/bmwi_Nationale%20Wasserstoffstrategie_Eng_s01.pdf.

- "**Funding for the construction of a needs-based refueling infrastructure for vehicles,** including heavy-duty road haulage vehicles, vehicles public transport and in local passenger rail services."

- "Advocacy for an ambitious development of the European infrastructure facilitating cross-border transport powered by fuel-cells."

- "**Support for** the establishment of a competitive **supply industry for fuel-cell systems.**"

- "Target-driven transposition of the Clean Vehicles Directive (CVD) to support zero-emissions vehicles in local transport."

- "Advocacy for a **carbon-based differentiation of the truck toll** with reduced rates for climate-friendly drivelines under the Eurovignette Directive."

Industrial Sector

Many industrial processes already depend on the use of hydrogen today. In the chemical industry, for example, hydrogen is used as a starting material for the production of ammonia. In the production of primary steel, hydrogen is currently regarded as the most promising solution for replacing hard coal coke.

Incentives for Green Hydrogen

- "The tools available for this are the fund for 'Decarbonising the industrial sector' and the programs for 'hydrogen use in industrial production' (2020-2024) and '**avoiding and using CO2 in industries relying on base substances'**."

- "A **demand quota for climate-friendly base substances**, e.g. green steel, is being considered."

- **"Develop hydrogen-based long-term decarbonisation strategies** together with stakeholders—particularly from the energy-intensive industries—within sector-specific dialogue formats (beginning in 2020 for the chemical, steel, logistics, and aviation sectors, with others to follow step-by-step)."

Infrastructure/Supply

Incentives for Green Hydrogen

- "The possibilities for **using existing structures** (dedicated hydrogen infrastructure as well as parts of the natural gas infrastructure than can be adjusted and backfitted to make it H2-ready) […] The necessary regulatory basis for the construction and expansion of a hydrogen infrastructure will be prepared swiftly. For this purpose, **a market exploration procedure** is to take place shortly."

- "As a new infrastructure is being created, special attention must be given to a **needs based expansion of the network of hydrogen refueling stations** in road transport, at suitable locations within the **railway** network (e.g. Municipal Transport Financing Act), and for the **waterways (cf. fields of application). Target groups here include individual users and operators of a large fleet of hydrogen-powered or fuel-cell-powered vehicles."**

Research, Education, and Innovation

Incentives for Green Hydrogen

- "A joint hydrogen roadmap that is to serve as guidance: Germany wants to position itself as a lead provider of green hydrogen technology on the global market. For this purpose, **a roadmap for the German hydrogen industry** will be developed together with the science and business communities and civil society."
- "A new cross-ministry **research campaign entitled 'hydrogen technologies 2030'** will see a strategic bundling together of research activities into hydrogen- related key-enabling technology."

Need for Action at European Level

As noted above, the German National Hydrogen Strategy mentions in several instances that European, or even global, cooperation will be key for further developing commercial-scale hydrogen end-use. This is particularly clear from the two highlights below. For further information on the EU hydrogen plans, please refer to the European Union chapter of *The Hydrogen Handbook.*

Incentives for Green Hydrogen

- "The German EU Council Presidency offers a good opportunity in the second half of 2020 to proactively progress key hydrogen-related dossiers, e.g., in the context of the preparations for the **legislative package on sector coupling and gas market design.** These particularly include the Hydrogen Action Plan envisaged by the European Commission and the strategy on **Smart Energy System Integration."**
- "International cooperation in the field of hydrogen offers opportunities in the fields of economic policy, climate change mitigation, foreign policy and development policy. We aim to make use of this, and the coalition committee's 'package for the future' of 3 June 2020 offers an additional €2 billion for this. We are therefore stepping up our efforts to build up and intensify international cooperation on hydrogen at all levels."

PART V - WHERE ARE THE BUSINESS OPPORTUNITIES IN THE HYDROGEN INDUSTRY IN GERMANY?

Based on the German hydrogen strategy, interesting business opportunities in the hydrogen sector are opening up in Germany—for German and also for international companies.

At the same time, many international projects will also be initiated from Germany, for which stakeholders and partners are needed. The German hydrogen initiative could thus create national, as well as international, business opportunities.

Hydrogen Business Opportunities *in* Germany or *with* Germany?

International cooperation is key for the German hydrogen policy. While there is a clear focus on the production of green hydrogen in Germany, the National Hydrogen Strategy acknowledges that (at least for a potentially long interim period) the volumes that can be produced this way will not be sufficient to reach Germany's ambitious climate and carbon neutrality goals. Imports of hydrogen will be a substantial component of the mix for the foreseeable future, as production of the target volumes of green hydrogen likely is not achievable today with domestic resources alone. The production of green hydrogen by electrolysis still requires a significant quantity of renewable energy. And, even though wind and solar energy have grown significantly in Germany in recent decades, Germany alone cannot provide the renewable energy volumes required for the target amount of hydrogen.

The German government has considered potential partner regions from which hydrogen could be imported. For example, the Baltic Sea countries have sizable offshore wind energy areas, southern Europe has sunny and windy areas, as do many parts of Africa. The German Development Minister Gerd Müller (CDU) specifically mentioned that countries in North Africa would be suitable production sites for green hydrogen due to their climate conditions. Against this background, the joint development of the first industrial hydrogen plant in Africa already has kicked off in Morocco, supported by German funding from the COVID-19 package. The aim is to create jobs for many young people, strengthen Germany's technological leadership, and achieve compliance with international climate targets. The project in Morocco alone is expected to save 100,000 tons of carbon emissions annually. The German Development Minister also considers other partner countries in North Africa, as well as in South America, to be potential locations for production plants.

While green hydrogen is the primary goal of the German Strategy, blue hydrogen (produced from natural gas, with CCS) and even grey hydrogen (produced using fossil fuels and without CCS) could also be funded under the strategy. At the moment, it is not yet clear the extent to which Germany will support the import of each type of hydrogen. To date, the only identified project is the Morocco one discussed above, where green hydrogen will be produced and delivered to Germany with the help of German technology and knowledge. In addition, while the strategy mainly focuses on climate-neutral green hydrogen, it would also allow support for the import of blue and grey hydrogen, possibly even by using German subsidies. The direction in which the promotion of hydrogen imports in Germany will develop will be revealed in the coming months and years through the federal ministries' concrete projects.

In Which Industries Will Hydrogen Initially be Relevant in Germany?

The strength of the German government's promotion of hydrogen demonstrates its belief that hydrogen has the potential to revolutionize the energy, business, and industrial worlds in the long term. At the moment, however, hydrogen use is not yet economically viable in many areas. In the new National Hydrogen Strategy, some applications have, however, been singled out as being very close to economic viability. These relate to areas for which there are no alternative decarbonization options, in particular the chemical and steel industries, as well as the transportation sector and, in the long term, heat recovery in residential and nonresidential buildings. However, even these sectors can logically work successfully with hydrogen only if sufficient hydrogen supply is available and its reliable distribution is ensured.

Development of Domestic Hydrogen Production

The National Hydrogen Strategy is initially aimed primarily at establishing domestic green hydrogen production.

To this end, the German government has set up the Hydrogen Power Storage & Solutions East Germany (HYPOS), a project consortium dedicated to hydrogen, in the "Zwanzig20" innovation partnership program—"Twenty20" is a federal government project that promotes partnerships between economy and science in the eastern German federal states. The aim of the project is to advance the economic production of hydrogen via water electrolysis on a large scale. The comprehensive use of electricity from renewable energy sources is addressed, particularly the ability to use temporary power surpluses generated from renewable energy in a meaningful way in the future. HYPOS is researching various areas along the entire hydrogen value chain and is thus working on various joint projects, including the chemical conversion of electricity, transport, and storage, as well as the utilization and sale of hydrogen. Approximately 100 members have already come together under this framework to pursue the goal of an economically viable and socially accepted hydrogen infrastructure. Interested companies, universities, research institutes, associations, clubs, similar institutions, and private individuals are invited to contact HYPOS for a partnership.

The next important step will be to secure the availability of hydrogen throughout the country. This requires certain infrastructure, including pipeline and filling station systems. The National Hydrogen Strategy mentions some positive aspects in this respect:

- Hydrogen has favorable storage and transport characteristics. Renewable energy generated by wind turbines and solar plants can be stored in hydrogen and transported easily via pipelines. Green hydrogen can be produced in regions with significant wind, sun, and water and exported from there to meet the energy needs of the rest of the world.
- Germany already has a comprehensive system of gas service pipelines. It is possible that these could be used for hydrogen transport by rededication after adjustment and refitting. In addition, more new pipelines will certainly have to be built and the public hydrogen filling station system expanded in order to secure a solid supply network overall. The respective construction contracts will be tendered in the years to come and will be open to national, as well as international, companies.

Steel and Chemical Industry

The commercial use of hydrogen must be further developed in research projects. Companies likely will be motivated to produce more climate-neutral products in the future due to the European emissions trading system and the German obligation to purchase carbon certificates that will apply from 2021.

In the particularly energy-intensive chemical and steel industries, meaningful industrial processes using hydrogen are already conceivable as they are closer to being profitable relative to other industries. The hydrogen strategy therefore assumes that the following areas must be addressed in a sensible manner.

In the steel industry, alternative processes, such as the injection of hydrogen into blast furnaces to avoid greenhouse gas emissions or direct carbon reduction in special plants, can contribute significantly to reducing carbon emissions.

It is therefore not surprising that successful research projects already exist in this area. For example, the "Carbon2Chem" project is dedicated to a climate-friendly steel industry. It aims to use the waste gases produced in ThyssenKrupp's steel mill (so-called metallurgical gases) as raw materials—instead of allowing these emissions to escape into the atmosphere in a way that is harmful to the climate. To achieve this, it uses hydrogen from the steel mill gases, adds self-produced hydrogen, and finally produces fertilizers, plastics, and synthetic fuels from the resulting gas mixture.

The MACOR project is also part of the climate-friendly steel industry program. It is a feasibility study that uses the example of the steelworks in Salzgitter to investigate whether and how more environmentally friendly steel production is possible by using green hydrogen instead of coal for heating.

The chemical industry already has a high demand for hydrogen as a feed material. Currently, mostly grey hydrogen is used for this purpose. The goal of the National Hydrogen Strategy's focus on green hydrogen is to replace grey hydrogen with green hydrogen in future projects.

Furthermore, there are areas where hydrogen is produced as a byproduct, like chlorine-alkali-electrolysis. In light of the described difficulties producing sufficient hydrogen to reach the ambitious sustainability goals of both the German government and the EU Commission, the National Hydrogen Strategy puts emphasis on the development and implementation of new methods to transfer this unused potential into usability.

Transport Sector

In the transport sector, the National Hydrogen Strategy centers on public transportation with trains and buses and goods transportation with trucks. With regard to individual transportation by car, German car manufacturers and politicians seem to agree that, at present, too much energy has to be generated to produce hydrogen to make its use in cars economically viable. Therefore, it is mainly still assumed that battery-powered electric vehicles make more sense for private transport.

However, in local public transport with buses and trains and heavy goods traffic on the road with trucks, as well as commercial vehicles (e.g., for use in the construction industry, in agriculture and forestry, or in logistics with forklifts), the introduction of hydrogen fuel cell vehicles is being considered as a viable option to complement battery-powered electromobility in the future and to help significantly reduce air pollution and carbon emissions.

Here, too, many research projects have been initiated and continue to be promoted through public funds to drive forward the market launch of hydrogen in the transport sector. For example, the NAMOSYN project for climate-friendly fuel is dedicated to the analysis and evaluation of synthetic fuels produced using green hydrogen.

Many see the transport sector as the first industry sector where hydrogen is leaving the laboratory and results are being implemented. More and more public tender opportunities have been published in Germany for trains or buses for public transportation (and the respective fueling infrastructure) in which either it has been left open whether those are diesel, battery, or fuel-cell powered (technology-neutral tenders) or where hydrogen has even been explicitly requested. Several public transportation authorities have procured hydrogen buses, and tenders also have been issued for the respective infrastructure (hydrogen filling stations). Many more such tenders can be expected to follow in the coming months. While demand is high and continuing to grow, vehicle manufacturers, construction companies with a focus on hydrogen infrastructure, and hydrogen suppliers do not seem to have entered the German market in big numbers yet; consequently, there is still high potential.

Longer-Term Goal: Heat for Residential and Nonresidential Buildings

In the long term, the National Hydrogen Strategy in Germany also pursues the goal of using fuel cells in the basements of residential and nonresidential buildings to generate electricity and heat. Even though this is still a long-term goal, there are already projects and test programs to get closer to this goal.

Under the HYPOS project at the Bitterfeld-Wolfen Chemical Park, the infrastructure for using hydrogen as an energy carrier for buildings is being tested and further developed. On a 12,000 square meter test field, called "H2-Netz," the distribution of hydrogen is simulated up to the connection to private households. More than 100 scientific institutes, research facilities, and companies from all over Germany are part of the HYPOS alliance. As noted above, the Federal Ministry of Education and Research has been supporting this initiative for over five years as part of the "Zwangzig20" (Twenty20) program.

On a European level, the German-French projects BRIDGE and LivingH2 are also noteworthy. These projects are investigating how hydrogen fuel cells could be improved and what a complete home energy supply with hydrogen could look like.

PART VI – WHICH PUBLIC FUNDS ARE AVAILABLE?

There are currently many support programs for the purpose of market ramp-up in the hydrogen sector. Not only the federal government but also the governments of the German states have been aware of the potential of hydrogen technology for many years. As noted above, within the framework of the National Innovation Program for Hydrogen and Fuel Cell Technology, around €700 million in funding has been approved between 2006 and 2016, and a total of €1.4 billion will be made available by the federal government between 2016 and 2026.

In addition, the federal government has used the funds provided under the Energy Research Program to establish an excellent research landscape in the last couple of years.

Between 2020 and 2023, the Energy and Climate Fund will provide €310 million for practice-oriented basic research on green hydrogen, and a further €200 million is planned during this period to strengthen practice-oriented energy research on hydrogen technology. The fund is administered by the Federal Ministry of Finance, which then releases the funds for the respective ministries, which, in turn, invest the amounts in concrete projects.

In addition, between 2020 and 2023, a total of €600 million will be made available to promote "Regulatory Sandboxes for Energy Change," which will help to accelerate the transfer of technology and innovation from the laboratory to the market. These real-life laboratories (Reallabore der Energiewende) function as test rooms for innovation and regulation and should serve as a source of inspiration. In this way, companies, research institutions, and administrations will be able to test innovations that would not yet be permitted under the current legal framework. For example, the federal government is supporting a real laboratory that will focus on the establishment of a regional hydrogen economy on the west coast of Schleswig-Holstein with €30 million. According to the responsible consortium, the "West Coast 100," the notice of approval of the Federal Ministry for Economic Affairs and Energy was issued in summer 2020.

The 10 partners in the consortium are looking to produce green hydrogen from wind power, transport it in the gas grid, use it in industrial processes, and interlink different material cycles within an existing infrastructure. The project is expected to cost a total of €89 million.

The German Decarbonisation Program supports investment in technologies and large-scale industrial plants that use hydrogen to decarbonize their production processes. More than €1 billion will be made available for this purpose between 2020 and 2023. The Federal Ministry for the Environment, Nature Conservation and Nuclear Safety has lead responsibility, with the participation of the Federal Ministry for Economic Affairs and Energy and the Federal Ministry of Education and Research.

As already mentioned, the most important federal funding program is certainly the "package for the future" adopted by the coalition committee on 3 June 2020, which provides €7 billion to accelerate the market introduction of hydrogen technology in Germany and another €2 billion to promote international partnerships. The exact amounts available for each of these programs depend on the budget estimates of the responsible ministries.

Opportunities for engagement by and benefits to the private sector will be case-specific. There are, for example, opportunities to obtain government contracts, subsidies, and support with regard to hydrogen R&D, production, manufacture of vehicles or vessels, or delivery of hydrogen. The funding varies from project to project.

In some cases, such as in the transport sector, subsidies are paid out to the state authorities and then passed on to a company as remuneration for products and services delivered after winning a respective tender procedure. German tenders are generally open to any company interested in and able to provide the tendered services—foreign bidders may not be discriminated against. One of the challenges in early hydrogen-related tenders has been helping public contracting authorities determine how best to tender new solutions with regard to hydrogen projects in a way that allows for a meaningful competition. Market players can and should voice their ideas about how hydrogen-related tenders could be structured. The public procurement rules allow for such interaction if done the right way.

In other sectors, such as the steel and chemical industries, usually the public funds flow directly to companies. These funds may be used for things like amending companies' current production processes by using hydrogen or developing new innovative technologies that can then be used in such industries. Again, national, as well as international, initiatives can apply for such hydrogen-related federal or state grants. There is, unfortunately, no complete overview of all funds available for hydrogen projects; however, overviews of at least some of the programs can found at **www.now.gmbh.de** and **www.ptj.de**.

If you have further questions about business opportunities in the German hydrogen industry, please do not hesitate to contact us.

GLOSSARY GERMANY

CCS	carbon capture and sequestration
CDU	Christian Democratic Union of Germany
CVD	Clean Vehicles Directive
EU Council	Council of the European Union
GHG	greenhouse gas
HYPOS	Hydrogen Power Storage & Solutions East Germany
NIP I	National Hydrogen and Fuel Cell Technology Innovation Programme
NOW GmbH	National Organisation for Hydrogen and Fuel Cell Technology
PtG	Power-to-Gas
PtX	Power-to-X
R&D	research and development
SPD	Social Democratic Party of Germany
TWh	terawatt hour

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JAPAN

The H_2 Handbook

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

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PART I - POLICY OVERVIEW

Japan, a net importer of energy with a self-sufficiency rate consistently around 6 to 7 percent[1] in the past several years, recently has begun to implement energy policies that focus on hydrogen.

While Japan quickly exhausted its limited carbon-based resources to generate power domestically, its reliance on imported fuels was exacerbated by the Fukushima earthquake and nuclear disaster in 2011. The nuclear disaster eliminated one of the few reliable sources of power generated in Japan. Pre-earthquake, nuclear energy accounted for 30 percent of electricity generation in Japan, but the figure dropped to zero in the following years.[2] Transportation represents 23.2 percent of Japan's energy consumption, with less than 5 percent of that total powered by the electrical grid and the remainder by fossil fuels.[3]

In these circumstances, Japan announced its fourth Strategic Energy Plan in 2014 to kick-start its move toward a "hydrogen-based society."[4] The announcement was followed by the "Basic Hydrogen Strategy" in 2017, which set forth both broad objectives and specific numerical targets to be met by 2030. This was the first government-backed hydrogen energy plan in the world, and similar initiatives by the European Union, France, and South Korea quickly followed.[5] The Basic Hydrogen Strategy was formulated not only to reduce reliance on imported fossil fuels, but also to reduce greenhouse gas emissions as required by the Paris Agreement.

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1 Ministerial Council on Renewable Energy, Hydrogen and Related Issues, *Basic Hydrogen Strategy 5*, MINISTRY OF ECON., TRADE AND INDUS. (Dec. 26, 2017), https://www.meti.go.jp/english/press/2017/pdf/1226_003b.pdf.

2 *Nuclear Power in Japan*, WORLD NUCLEAR ASS'N, (last updated March 2020), https://www.world-nuclear.org/information-library/country-profiles/countries-g-n/japan-nuclear-power.aspx.

3 Agency for Nat. Resources and Energy, *Energy White Paper*, MINISTRY OF ECON., TRADE AND INDUS. (2019), https://www.enecho.meti.go.jp/about/whitepaper/2019pdf/whitepaper2019pdf_2_1.pdf.

4 Agency for Nat. Resources and Energy, S*trategic Energy Plan*, MINISTRY OF ECON., TRADE AND INDUS. (Apr. 2014), https://www.enecho.meti.go.jp/en/category/others/basic_plan/pdf/4th_strategic_energy_plan.pdf.

5 Hydrogen and Fuel Cell Strategy Council, *The Strategic Road Map for Hydrogen and Fuel Cells*, MINISTRY OF ECON., TRADE AND INDUS. (Mar. 12, 2019), https://www.meti.go.jp/english/press/2019/pdf/0312_002b.pdf.

Following are some of the targets set forth in the Basic Hydrogen Strategy:[6]

- Reduce the cost of hydrogen to 30 yen/Nm3 by 2030 and to 20 yen/Nm3 thereafter
- Develop a liquefied hydrogen supply chain for commercialization by 2030
- Establish and commercialize organic hydride after 2025
- Introduce CO_2-free ammonia by the mid-2020s
- Develop technology that reduces the unit cost of water electrolysis systems to 50,000 yen/kW by 2020
- Reduce the unit hydrogen power generation cost to 17 yen/kWh by 2030 (which requires procuring 300,000 tons of hydrogen annually)
- Increase the number of fuel cell vehicles (FCVs) to 40,000, 200,000, and 800,000 units by 2020, 2025, and 2030, respectively
- Increase the number of hydrogen stations to 160 by FY2020 and 320 by FY2025
- Increase the number of fuel cell buses to around 100 by FY2020 and to around 1,200 by FY2030
- Increase the number of fuel cell forklifts to around 500 by FY2020 and to around 10,000 by FY2030
- Lower the price of residential fuel cell systems to 800,000 yen for a standard polymer electrolyte fuel cell and to 1 million yen for a standard solid-oxide fuel cell by FY2020

In 2019, Japan continued its hydrogen push by creating a strategic roadmap to reach its hydrogen goals. The roadmap includes four big-picture goals: (1) develop a hydrogen supply chain, (2) increase the use of hydrogen across different sectors, (3) promote technological innovation and public buy-in, and (4) promote international collaboration concerning hydrogen technology.

I. Hydrogen Supply Chain

In developing a low-cost hydrogen supply chain, the strategic roadmap mainly calls for the development of technology that will reduce hydrogen costs. It also focuses on building relationships with foreign governments to procure inexpensive overseas energy resources, transporting overseas hydrogen supply sources to Japan, and assessing hydrogen supply capabilities of domestic byproduct hydrogen and other unused resources.

The roadmap also calls for obtaining hydrogen supply through the use of cheap and abundant foreign resources. In November 2019, Japanese electricity generation and transmission company J-Power, in conjunction with Japanese and Australian government agencies, began construction of a hydrogen development project involving the gasification of brown coal in Victoria, Australia. Coal gasification

[6] Ministerial Council on Renewable Energy, Hydrogen and Related Issues, *Basic Hydrogen Strategy* (Key Points), MINISTRY OF ECON., TRADE AND INDUS. (Dec. 26, 2017), https://www.meti.go.jp/english/press/2017/pdf/1226_003a.pdf.

produces synthesis gas (which consists of hydrogen and carbon monoxide) by reacting coal and oxygen. The carbon monoxide reacts with steam to produce carbon dioxide and more hydrogen. The hydrogen is separated for electricity generation, while the carbon dioxide is captured and stored to prevent emission into the atmosphere.[7]

In May 2020, a group of Japanese companies, with support from the Japanese and Brunei governments, created the world's first international hydrogen supply chain.[8] In that project, hydrogen produced in Brunei is bound to a liquid organic hydrogen carrier (usually a petrochemical) and shipped in liquid form to Japan, where it is dehydrogenated in a reactor and mixed with natural gas to generate electricity. Domestically, a group of Japanese companies, with support from the government, completed the construction of a hydrogen production facility in Fukushima that utilizes power-to-gas technology (electricity generated by renewable energy stored as hydrogen).[9] The facility was completed in February 2020, and the hydrogen will be distributed for use in Fukushima, Tokyo, and other regions.

II. Hydrogen Utilization

In order to reduce the 23.2 percent of Japan's CO_2 emissions that emanate from the transportation sector, Japan is encouraging the development and use of hydrogen-based FCVs for both personal and commercial use.[10] As of December 2018, approximately 3,000 FCVs were registered in Japan, and the aim is to increase the number to 800,000 by 2030. Efforts will be made to reduce the price differential between FCVs and electrical vehicles or hybrid electric vehicles. Also, new types of FCVs such as SUVs and minivans will be introduced by 2025. Japan also aims to increase its network of hydrogen refueling stations by building 320 stations by FY2025.

Further, Japan will expand the use of fuel cell technology in other areas, such as for household and industrial purposes. Ene-farm is Japan's prevailing household fuel cell system, with around 274,000 units in use as of January 2019. Japan aims to increase its use to 5.3 million units by 2030 by reducing construction and installation costs. While Japan's large-scale push for hydrogen is a relatively recent phenomenon, Japan has devoted a considerable amount of resources to fuel cell technology since the start of the century. From 2003 to 2015, Japan

[7] Office of Energy Efficiency & Renewable Energy, Hydrogen and Fuel Cell Technologies Office, *Hydrogen Production: Coal Gasification*, U.S. DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-coal-gasification (last visited Aug. 1, 2020).

[8] *The World's First International Hydrogen Supply Chain realised between Brunei and Japan*, MINISTRY OF ENERGY (May 5, 2020), http://www.memi.gov.bn/Lists/News/NewDispForm.aspx?ID=214.

[9] *The world´s largest-class hydrogen production, Fukushima Hydrogen Energy Research Field (FH2R) now is completed at Namie town in Fukushima*, TOSHIBA ENERGY SYS. AND SOLUTIONS CORP., (Mar. 7, 2020), https://www.toshiba-energy.com/en/info/info2020_0307.htm.

[10] See Ministerial Council on Renewable Energy, Hydrogen and Related Issues, supra note 1, at 31-32.

spent a total of US$12.3 billion on fuel cell research and development (R&D), of which US$4.1 billion was government funded and the rest funded by corporations (mostly automakers[11]). In the same period, the EU's total fuel cell R&D spending was US$5.7 billion (of which US$1.9 billion was state-funded), and the United States spent a total of US$3.8 billion (of which US$1.9 billion was state-funded).

III. Technological Innovation and Public Buy-in

In a June 2018 meeting, the Japanese cabinet called for collaboration among industry, academia, and government in developing technology related to the production, transportation, storage, and use of hydrogen. With regard to hydrogen production, Japan will conduct research on highly efficient water electrolysis, artificial photosynthesis, and high-temperature water vapor electrolysis. There also will be research on energy sources that are currently not used in hydrogen production. For transportation and storage, Japan will work to develop efficient hydrogen liquefiers, as well as low-cost energy carriers. For hydrogen use, the emphasis will be on fuel cell technology with a specific focus on the development of solid oxide electrolysis cells that can operate efficiently even at temperatures below the current 700-1000°C range,[12] as well as fuel cells that can operate without the use of rare metals as catalysts.

In addition to the development of new technology, Japan will try to promote public awareness and the use of hydrogen energy. Demonstrations during global events like the Tokyo Olympics, Paralympics, and EXPO 2025 in Osaka are one of the ways in which awareness may be increased.

The government has previously created incentives to purchase hydrogen-powered technology through subsidies. In 2015, the government offered a US$25,000 subsidy to buyers of the hydrogen-fueled 2016 Toyota Mirai, which was priced at US$68,000 before incentives. A variety of incentives also are available for users of a range of residential fuel cells. The Japanese government granted over US$80 million in subsidies for purchases of residential fuel cells in FY2018. Local governments also have granted subsidies for the installation of residential fuel cells with the Tokyo Metropolitan Government, offering to cover up to one-fifth of the equipment cost.

IV. International Collaboration

In addition to developing the hydrogen market locally, Japan is looking to expand its technology globally and create a new growth industry. Japan has led international discussions on the use of

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[11] Noriko Behling, Mark C. Williams, & Shunsuke Managi, *Fuel cells and the hydrogen revolution: Analysis of a strategic plan in Japan*, 48(C) ECON. ANALYSIS AND POLICY 204-21 (2015).

[12] Solid Oxide Electrolysis Cells, TECHNICAL U. OF DEN. DEP'T OF ENERGY CONVERSION AND STORAGE (last updated Jan. 31, 2019), https://www.energy.dtu.dk/english/Research/Electrolysis-Cells/Solid-Oxide-Electrolysis-Cells#:~:text=A%20Solid%20Oxide%20Electrolysis%20Cell,makes%20the%20efficiency%20very%20high.&text=An%20SOEC%20can%20also%20electrolyze,to%20carbon%20monoxide%20(CO).

hydrogen by hosting the first Hydrogen Energy Ministerial Meeting in 2018 and the second in 2019. Japan has cemented its status as a leader in hydrogen growth through a consistent focus on hydrogen policy, regardless of changes in administration.

PART II - REGULATIONS

The High Pressure Gas Safety Act (Act) regulates all activities related to the handling of high-pressure gas including production, storage, and transportation.[13] The Ministry of Economy, Trade, and Industry (METI) administers the Act, which is especially relevant to Hydrogen Refueling Stations (HRSs).

The Act classifies hydrogen as a type-2 gas. If a manufacturer's daily hydrogen production capacity exceeds 100Nm^3, the manufacturer is treated as if it were producing a type-1 gas (such as helium or carbon dioxide) and therefore must obtain prior approval from the prefectural governor to produce hydrogen. If a manufacturer's daily hydrogen production capacity is less than 100Nm^3, approval is not required, but the manufacturer must still notify the prefectural governor of its hydrogen production. Similar reporting and approval requirements exist for the storage of hydrogen, where a daily hydrogen storage capacity of over 1000Nm^3 requires approval from the governor, a capacity of 300-1000Nm^3 requires notification but no approval, and a capacity of less than 300Nm^3 requires neither approval nor notification.[14]

The Act also requires HRSs to dedicate a minimum eight meter distance between a hydrogen fuel dispenser and a public road, between a high-pressure gas facility and any flammable substance, and between a high-pressure gas facility and the property boundary of the HRS.[15] The minimum distance is reduced to six meters if the pressure of the dispenser is less than 40MPa. The higher land cost resulting from this regulation may be problematic in urban areas where land prices are high.

Another regulatory limitation is that ordinary drivers are prohibited from self-refueling hydrogen fueled vehicles. This means that each hydrogen refueling station must employ licensed specialists to be available throughout the day, significantly increasing the day-to-day cost of operating an HRS as compared with a traditional gasoline station. Under the Act, an ordinary HRS requires one certified supervisor to oversee operations while an HRS with hydrogen shipping capabilities

[13] HIGH PRESSURE GAS SAFETY ACT, Act No. 204 of 1951, Art. 1 (Japan).

[14] *Report on the Hydrogen Supply Chain*, MINISTRY OF THE ENV'T (March 2020), https://www.env.go.jp/seisaku/list/ondanka_saisei/lowcarbon-h2-sc/support-tool/PDF_Excel/support-tool_report_202003_2.pdf.

[15] GENERAL HIGH PRESSURE GAS SAFETY ORDINANCE, Art.7.3.2 (Japan).

requires at least three supervisors. While these regulations are restrictive, the Act was amended in February 2020 to broaden the definition of a certified supervisor, hinting at more liberal HRS regulations to come in the future. Prior to the amendment, certification was conditioned on prior experience in the production of pressurized or liquefied hydrogen, but it now treats experience in the production of pressurized or liquefied natural gas as sufficient, provided that the supervisor undertakes six months of training specific to HRSs.[16]

The Act also applies to the manufacturing, sales, and use of drones powered by hydrogen fuel cells. The Act provides that "companies should not engage in any reckless handling of tanks of high pressure gas in order to not drop or have such tanks fall resulting in causing any impacts on the tanks or damages to valves thereof." Drones that fly above a predetermined altitude have a significant risk of falling and being "recklessly handled." Companies that manufacture and sell such drones are required to obtain special approval from the METI Minister. In April 2020, METI released guidelines to help drone manufacturers, sellers, and users comply with these approval requirements and the Act itself. The guidelines call for manufacturers to secure the safety of hydrogen tanks if a drone were to fall during flight. Possible solutions proposed in the guidelines include the installation of a protective device such as an airbag around the drone or a parachute.[17] The guidelines also call for hydrogen storage tanks made for drones to be stored in a location with adequate airflow and to be maintained below 40°C.[18]

The Building Standards Law, regulated by the Ministry of Land, Infrastructure, Transport, and Tourism, allocates land based upon designation of "use districts," such as those reserved for solely residential or industrial use. Within these districts, the Building Standards Law specifies an upper limit on the amount of hydrogen that can be stored. Under the current law, there are no limits for storing hydrogen in purely industrial areas, but residential districts are subject to strict limits that may be problematic in building HRSs in urban areas. The current law limits hydrogen storage to 3500Nm^3 in "semi-industrial" districts, 700Nm^3 in commercial districts, and 350Nm^3 in some residential districts, and imposes an absolute ban in other residential districts.[19] A related law is the Noise Regulation Act, which requires enumerated producers of excessive noise to report to the relevant local authority before production. Hydrogen producers may be subject to the Act if the producer

16 *Amendments to the High Pressure Gas Safety Act*, MINISTRY OF ECON., TRADE AND INDUS., (Feb. 28 2020), https://www.meti.go.jp/policy/safety_security/industrial_safety/sangyo/hipregas/files/20200228_3.pdf.

17 *Guidelines for Safe Use of High Pressure Gas in Drones Driven by Hydrogen Fuel Cells*, MINISTRY OF ECON., TRADE AND INDUS., (Apr. 10 2020), https://www.meti.go.jp/press/2020/04/20200410002/20200410002-2.pdf.

18 *Guidelines for Safe Use of High Pressure Gas in Drones Driven by Hydrogen Fuel Cells*, MINISTRY OF ECON., TRADE AND INDUS., (Apr. 10 2020), https://www.meti.go.jp/english/press/2020/0410_001.html.

19 Building Standards Law Enforcement Order, Art.130.9, *Hydrogen standards*, laws, and guidelines, ENG'G ASS'N OF JAPAN, https://www.enaa.or.jp/WE-NET/rule/ht/syohi.html (last visited Sept. 4, 2020).

employs air compressors or ventilators that have a prime mover with a drive power of over 7.5 kW. Similar to the Building Standards Law, local regulations generally designate a permissible level of noise pollution based on use districts. For example, the city of Yokohama restricts noise levels in industrial districts to 70 decibels from 8am-6pm, 65 decibels from 6am-8am and 6pm-11pm, and 55 decibels from 11pm-6am.[20]

The Fire Service Act, regulated by the Fire and Disaster Management Agency, regulates gasoline stations that also have hydrogen refueling facilities. The ability to add hydrogen refueling facilities to existing gasoline stations will be a major positive factor in facilitating the large-scale commercialization of hydrogen.

The Fire Service Act limits the ability of gasoline station operators to add an HRS, as hydrogen stands must be located some distance away from the gasoline pumps. Moreover, the presence of a hydrogen pump limits the volume of gasoline and kerosene that can be stored, which may require larger storage tanks to be replaced, thus limiting the commercial viability of co-location.

The Road Act of Japan prohibits large trucks carrying more than a specified amount of pressurized material through tunnels.[21] This will constrain road transport, as Japan has thousands of kilometers of tunnels on key arteries in both urban areas and the mountainous areas between them.

20 *See* MINISTRY OF THE ENV'T, *supra* note 14.

21 ROAD ACT OF JAPAN, Art. 46 (Japan).

GLOSSARY JAPAN

FCV	fuel cell vehicle
HRS	Hydrogen Refueling Station
METI	Ministry of Economy, Trade, and Industry
R&D	research and development

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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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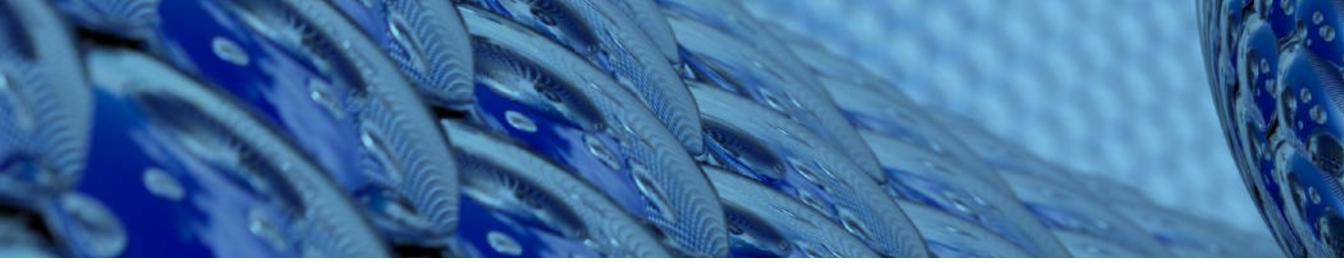
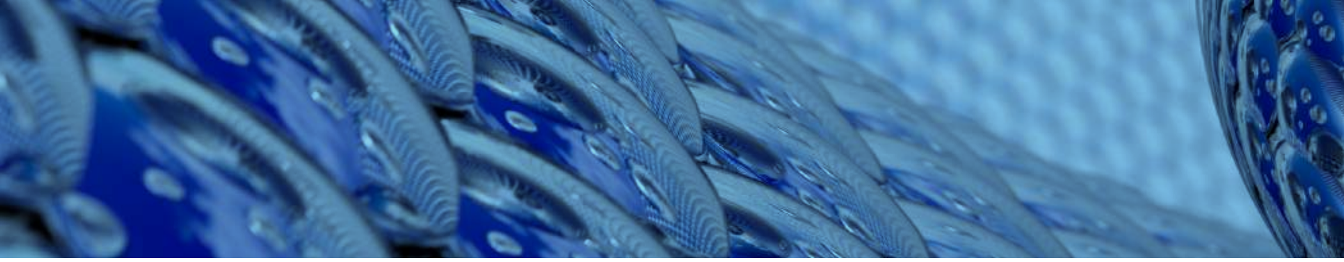




PART I - INTRODUCTION

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**

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:

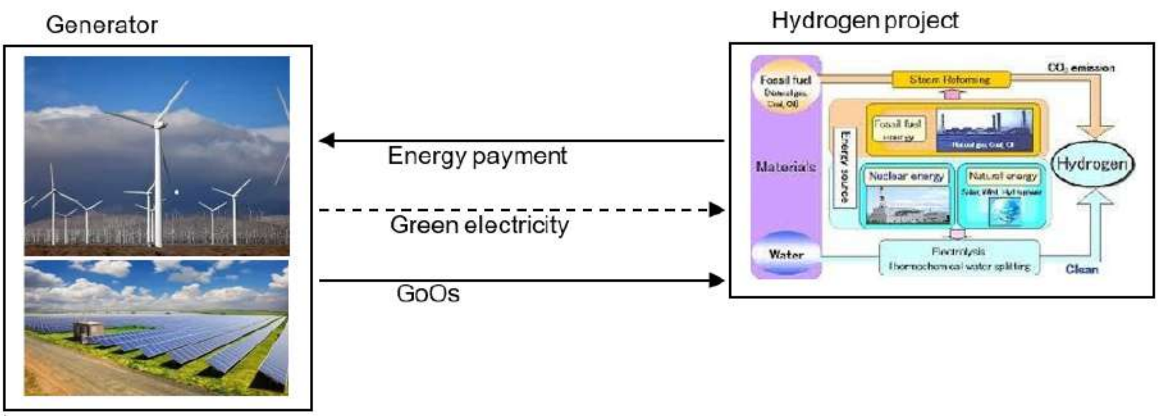
- Receive directly from a renewable energy project and offtake the green electricity produced from the project by way of a direct power purchase agreement (PPA); or
- Receive the supply of green electricity from a renewable energy generator by way of: (1) a physical power purchase agreement, if the generator's 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



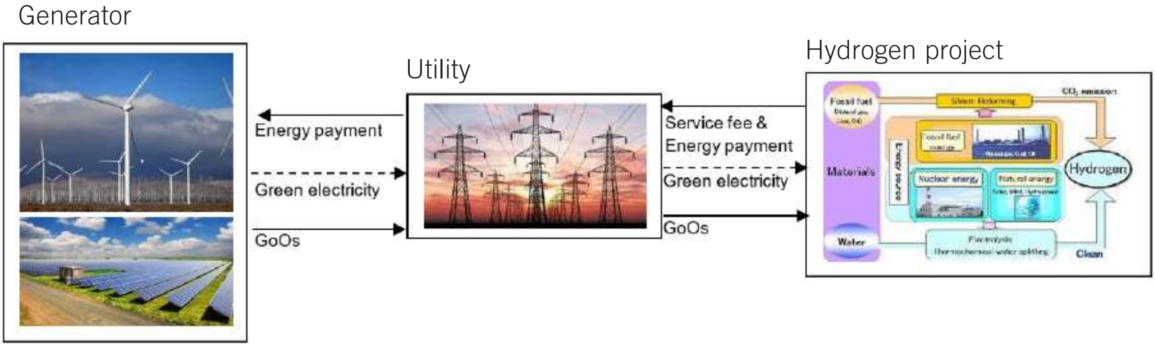
b. Physical PPAs

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]

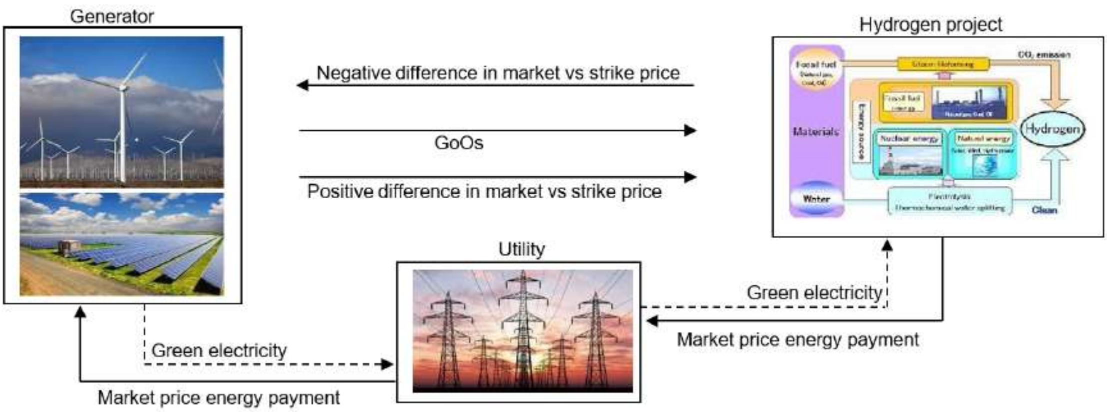
The challenge with a VPPA structure is that the electricity that is physically supplied to the hydrogen project pursuant to the agreement with the Utility may not have actually been produced from a renewable energy source. For example,

[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

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[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

[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

[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.

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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;
- H100, which is assessing the

[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).

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.

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.

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.

c. 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.

d. 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.

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 CerifHy, 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.

[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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UNITED STATES

The H_2 Handbook

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

While hydrogen has been used in industrial applications in the United States for decades, the potential for development of a global hydrogen economy seems more probable each day as countries and companies announce investment and support of hydrogen as part of the path to a cleaner energy future. With its substantial domestic energy demand, growing renewable energy markets, vast domestic natural gas reserves, experience with both energy imports and exports, and mature energy markets, the United States has a prime opportunity to play a significant role in this exciting piece of the energy puzzle.

When and to what degree the United States develops a domestic hydrogen market and advances the global hydrogen economy on a commercial scale will depend on a number of factors, including political support at federal, state, and local levels; development and expansion of federal and state regulatory regimes to ensure clear, transparent, intentional regulation; the ability to leverage existing energy infrastructure to produce, transport, and store hydrogen; the availability of project finance; and the resolution of various open commercial questions. While U.S. federal support for hydrogen already exists, more intentional and substantial federal government engagement could be tied to the outcome of the November 2020 presidential election. Nonetheless, the ability to produce hydrogen from a number of sources presents a unique opportunity for bipartisan support. In addition, a number of U.S. states also are taking action to incentivize the production and use of hydrogen.

This portion of *The Hydrogen Handbook* explores the regulatory, commercial, and policy issues that will shape the development of a U.S. hydrogen market and the United States' participation in a global hydrogen economy. In the sections that follow, we discuss existing laws, regulations, and government programs related to hydrogen and identify areas where further development is needed, as well as important considerations for industry participants. This discussion is driven by our team's deep understanding of U.S. energy regulation and policy, as well as our significant commercial experience in the energy sector.

We begin this discussion in **Part I** with several overarching issues that will impact the U.S. hydrogen economy more broadly, including federal and state incentives, and consideration of high-level commercial issues, project finance, insurance coverage, and stakeholder engagement. **Part II** explores regulatory, policy, and commercial issues related to hydrogen production, including production using wind and solar, natural gas and renewable natural gas, biomass, coal, and nuclear. Finally, in **Part III**, we discuss regulatory, policy, and commercial issues related to hydrogen transportation, distribution, storage, and end-use.

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PART I - OVERARCHING CONSIDERATIONS

As discussed in greater detail below, a number of overarching issues will be critically important to the development of a hydrogen economy in the United States and for participants to bear in mind as this industry expands.

From a financial perspective, these include the availability of federal and state incentives, such as grants, loan guarantee programs, rebate programs, and tax incentives. In addition, accessibility to project finance will be an important issue for new hydrogen projects, particularly those proposing use of new technology or technology that has not yet been tested at scale. Given the risks—both real and perceived—that hydrogen presents and the nascent nature of large-scale deployment of hydrogen, insurance coverage considerations also will play an important role for the industry and industry participants.

Arguably, one of the most critical overarching issues will be stakeholder engagement. Energy is in our headlines on a daily basis—it is both vital to nearly every facet of our lives and hotly debated as a political, environmental, and personal financial issue. Hydrogen will be no different, and the industry will need to continue to invest in educating and engaging with the public and lawmakers to help ensure continued and expanded support, as well as promulgation of well-reasoned and transparent laws and regulations.

I. Government Incentives

While still in its nascence, the U.S. federal government and many state governments already have recognized the potential that broader-scale deployment of hydrogen holds. Support for continued and increased development exists in the form of grant programs and tax incentives. These programs offer significant opportunity for the type of research and development (R&D) that is needed to make hydrogen cost competitive and drive demand. Continuation and expansion of these programs will be a critical factor in the development of a U.S. hydrogen economy.

A. U.S. Department of Energy Programs

The federal government's main hydrogen R&D entity is the U.S. Department of Energy's (DOE) Hydrogen and Fuel Cells Program.[1] This program funds R&D in hydrogen production, delivery, infrastructure, storage, fuel cells, and multiple end-uses across transportation, industrial, and stationary power applications. The program also manages activities in technology validation, manufacturing, analysis, systems development and integration, safety, codes and standards, education, and workforce development.

With appropriations from Congress, the DOE Hydrogen and Fuel Cells Program regularly announces solicitations for proposals. The focus of recent grants has been proposals that would advance hydrogen fueling technologies for medium- and heavy-duty fuel cell vehicles and also proposals that address technical barriers to hydrogen blending in natural gas. In July 2020, DOE announced 18 awards for a total of $64 million for proposals in these priority areas.

Hydrogen technologies also would qualify for the DOE Improved Energy Technology Loans through the DOE Loan Guarantee Program. Eligible projects for this program would reduce air pollution and greenhouse gas emissions and support early commercial use of advanced technologies, including biofuels and alternative fuel vehicles. The program is not intended for R&D projects, but instead to accelerate commercial use of improved energy technologies. DOE may issue loan guarantees for up to 100 percent of the amount of the loan for an eligible project. Eligible projects may include the deployment of fueling infrastructure, including associated hardware and software, for alternative fuels.[2]

Additionally, DOE has announced its intention to invest up to $100 million over five years in two new DOE National Laboratory-led consortia to advance hydrogen and fuel cell technologies R&D.[3] These consortia are dependent on federal appropriations. One consortium

1 *About the Hydrogen and Fuel Cells Program*, DEP'T OF ENERGY, http://www.hydrogen.energy.gov/about.html (last visited Aug. 7, 2020). 2019.

2 *Alternative Fuels Data Center: Hydrogen Laws and Incentives*, DEP'T OF ENERGY, https://afdc.energy.gov/fuels/laws/HY?states=US (last visited Aug. 7, 2020).

3 Michael Bates, *DOE to Invest in Advancements in Hydrogen and Fuel Cell R&D*, NGT NEWS (June 25, 2020), https://ngtnews.com/doe-to-invest-in-advancement-of-hydrogen-and-fuel-cell-rd.

would conduct R&D to achieve large-scale, affordable electrolyzers, which use electricity to split water into hydrogen and oxygen, and can be powered by various energy sources, including natural gas, nuclear, and renewables, as discussed in greater detail in **Part II**. This R&D will complement and support large industry deployment by enabling more durable, efficient, and low-cost electrolyzers. The other consortium will conduct R&D to accelerate the development of fuel cells for heavy-duty vehicle applications, including long-haul trucks. This initiative will have a five-year goal of proving the ability to manufacture a fully competitive heavy-duty fuel cell truck that can meet all of the durability, cost, and performance requirements of the trucking industry.

B. Other Federal Programs

In addition to the DOE programs, there are several other existing federal programs that support the production and deployment of hydrogen in the United States.

- The Airport Zero Emission Vehicle (ZEV) and Infrastructure Incentives is managed through the Federal Aviation Administration (FAA). Through this program the FAA can award Airport Improvement Program (AIP) grants for the acquisition and operation of ZEVs at an airport. This program provides funding to airports for up to 50 percent of the cost to acquire ZEVs and install or modify supporting infrastructure for acquired vehicles. Grant funding must be used for airport-owned, on-road vehicles used exclusively for airport purposes.[4]
- Hydrogen technologies also qualify for several federal tax credits, including the Alternative Fuel Infrastructure Tax Credit (set to expire 31 December 2020), and the Alternative Fuel Tax Exemption, as discussed in greater detail in the Tax section of **Part I (Section I.D.4)** below.
- The Alternative Fuel and Advanced Vehicle Technology Research and Demonstration Bonds program allows qualified state, tribal, and local governments to issue Qualified Energy Conservation Bonds subsidized by the U.S. Department of Treasury at competitive rates to fund capital expenditures on qualified energy conservation projects. Eligible activities include research and demonstration projects related to non-fossil fuels, as well as advanced battery-manufacturing technologies.[5]
- The Low and Zero Emission Public Transportation Research, Demonstration, and Deployment Fund provides financial assistance to local, state, and federal government entities; public transportation providers; private and non-profit organizations; and higher education institutions for research, demonstration, and deployment projects

[4] *Alternative Fuels Data Center: Hydrogen Laws and Incentives*, DEP'T OF ENERGY, https://afdc.energy.gov/fuels/laws/HY?states=US (last visited Aug. 7, 2020).

[5] *Id.*

involving low or zero emission public transportation vehicles.[6]

C. State Programs

As many states look to reduce carbon emissions, promote renewable energy and clean transportation, and investigate seasonal energy storage, programs that help support hydrogen production and distribution have emerged. The list below provides a high-level overview of several state-level programs, though it is not an exhaustive list.

California

California has several regulations and incentives related to the production, distribution, and use of hydrogen. Most of these regulations and incentives are tied into broader clean transportation programs administered by the California Air Resources Board (CARB) or local air districts or utilities. The California Energy Commission (CEC) also periodically makes significant grant funding available for the R&D of new hydrogen technologies and fueling stations.

The CARB and local air district programs include several rebate programs and mandates for ZEVs, which include hydrogen-powered vehicles, and/or grant preferential treatment for infrastructure required for hydrogen fueling stations (e.g., the Alternative Fuel Vehicle Parking Incentive Program). CARB also must periodically evaluate the need for publicly available hydrogen fueling stations and submit a report to the CEC. In turn, CEC can then make funding decisions for fueling infrastructure required to meet California's goal of 100 publicly available hydrogen fueling stations. Such stations are eligible to generate credits under California's Low Carbon Fuel Standard (LCFS).

California also requires its state agencies and utilities to more broadly consider the energy landscape through the middle of the 21st century. Every two years, the CEC must submit an Integrated Energy Policy Report (IEPR). Utilities also must submit Integrated Resource Plans (IRPs) to the California Public Utilities Commission (CPUC). In the last several years, the IEPR and IRPs have considered different types of energy storage technologies to integrate into California's renewables-heavy electricity sector. We anticipate that hydrogen will begin to play a larger role in the IEPR and IRPs over the next several years. One high-profile example is the Los Angeles Department of Water and Power's plan to convert the Intermountain Power Plant in Delta, Utah, from coal to a blend of natural gas and green hydrogen sourced from nearby wind and solar generators and stored seasonally in giant salt caverns.

Oregon

Like California, Oregon's regulations and incentives for hydrogen tie closely to its clean transportation and ZEV programs. Hydrogen used as a transportation fuel also can generate credits under Oregon's Clean Fuels Program, which is similar to California's Low Carbon Fuel Standard.

In September 2019, Oregon took a significant step in greening its natural

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6 *Id.*

gas infrastructure with the passage of Senate Bill 98 (SB 98). SB 98 sets targets for utilities to deliver an increasing percentage of "renewable" natural gas to retail customers and allows utilities to include the higher cost of obtaining renewable natural gas in their rate base. Critically, SB 98 includes renewable hydrogen in its definition of renewable natural gas. Renewable hydrogen is hydrogen produced from excess wind, solar, and hydropower, and can be used by itself for use in the transportation sector and for industrial use, or can be blended into the natural gas pipeline system and delivered to traditional gas-fired resources.

Washington

Like Oregon and California, Washington state has several hydrogen incentives embedded in its clean transportation initiatives. Most of these programs, including grant funding for fueling infrastructure, are administered by the Washington State Department of Transportation.

Washington state also adopts tax relief for key components of the hydrogen economy. For instance, sales and use taxes do not apply to the sale of property used for hydrogen fueling infrastructure. Washington's 6.5 percent retail sales and state use tax does not apply to the sale or lease of new or used hydrogen-powered passenger vehicles, light-duty trucks, and medium-duty passenger vehicles.

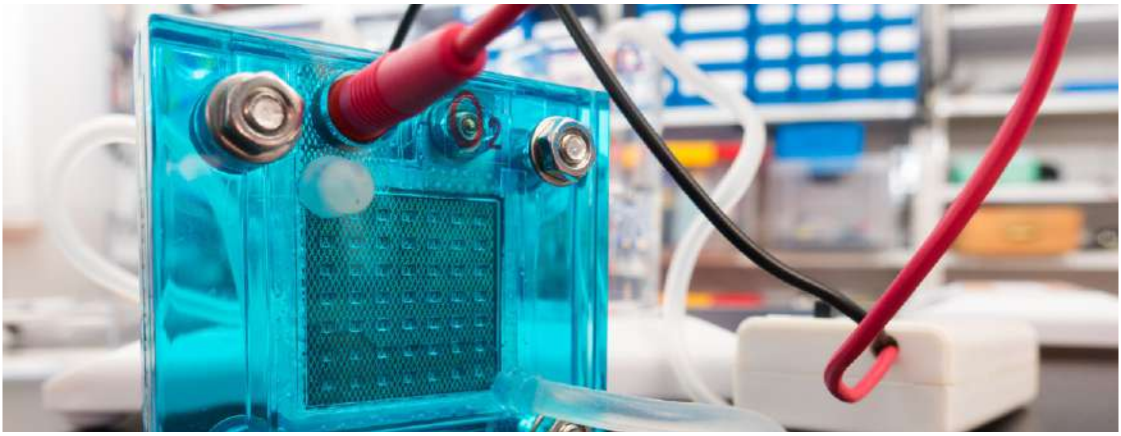
Finally, in April 2019, Substitute Senate Bill 5588 authorized Washington's public utilities to produce, distribute, and sell hydrogen produced from renewable resources like wind, solar, and hydropower. The bill was seen as a win for environmentalists, as well, because utilities would use excess midday wind and solar power and reduce excess spill from hydropower facilities, which has the potential to harm fish. While utilities may include the higher cost of acquiring green hydrogen in their rate base, the Washington bill (unlike Oregon's SB 98) stops short of setting targets for the delivery of renewable natural gas or renewable hydrogen to retail customers.

South Carolina

Because it hosts several domestic and foreign automobile manufacturing facilities interested in positioning themselves for hydrogen fuel cell vehicles, South Carolina was an early adopter of hydrogen-friendly regulation and incentives. In 2006, several universities, federal labs, and state agencies founded the South Carolina Hydrogen and Fuel Cell alliance to advance the cause of hydrogen fuel cells in the state. In June 2010, South Carolina passed the Hydrogen and Fuel Cell Permitting Law that placed statewide permitting authority within the Office of the State Fire Marshall. Until 2012, the South Carolina Research Authority administered the South Carolina Hydrogen Infrastructure Development Fund, although that program appears to have expired. As discussed in the **Government Incentives section of Part II (Section I)**, South Carolina also offers a sales tax exemption that helps to promote hydrogen production and fuel cell technologies.

D. Tax

Several U.S. federal income and excise tax credits encourage investment in



hydrogen projects. These credits include the investment tax credit (ITC) available under Code[7] Section 48 for qualified fuel cell property that generates electricity, a federal income tax credit for fuel cell motor vehicles placed in service during a given tax year under Code Section 30B, a federal income tax credit for placing alternative fuel vehicle refueling property into service during a given tax year under Code Section 30C, and a federal excise tax credit on the sale or use of liquefied hydrogen under Code Section 6426(d).

1. ITC for Fuel Cells

The ITC for qualified fuel cell property provides a percentage credit (subject to a per-kilowatt cap) against U.S. federal income tax for property placed in service before 1 January 2024.[8] Property is qualified fuel cell property if it is a "fuel cell power plant" with a nameplate capacity rating of at least 0.5 kilowatts (kw)[9] and has an electricity-only generation efficiency greater than 30 percent.[10] For this purpose, a fuel cell power plant is "an integrated system comprised of a fuel cell stack assembly and associated balance of plant components which converts a fuel into electricity using electrochemical means." Thus, an operational hydrogen fuel cell with a nameplate capacity of at least 0.5 kw generally qualifies for the ITC.

The percentage of ITC available varies depending on when construction of the property began, as shown in the table below.

Year Construction Began	Year Property Placed in Service	Credit Rate
2019 or before	2023, generally	30%
2020	2023	26%
2021	2023	22%

Regardless of the maximum credit amounts allowed above, the credit is capped at $1,500 for each 0.5 kilowatts of capacity of the qualified fuel cell property.[11]

7 All references to the "Code" herein are to the Internal Revenue Code of 1986, amended.

8 Code § 48(a)(7)(B).

9 *Id.* at 48(c)(1)(A)(i).

10 *Id.* at 48(c)(1)(A)(ii).

11 *Id.* at 48(c)(1)(B).

Construction of ITC property may begin either by spending at least 5 percent of the total cost of the ITC property (the 5 Percent Safe Harbor) or completing significant physical work on the ITC property (the Physical Work Test), in each case, in the applicable year.[12] The 5 percent Safe Harbor is relatively straightforward for cash-method taxpayers. For accrual-method taxpayers, it is possible to pay 5 percent of the cost and take delivery or title up to 3.5 months after payment.[13] This delayed delivery or title transfer method is an accounting method that must be available to the purchaser. The Physical Work Test does not require that a minimum amount be spent, but does require that work on material components of ITC property be completed in the applicable year. The amount of work is not specifically delineated in guidance. Taxpayers should consult with experienced practitioners to develop a strategy using the Physical Work Test.

Financing structures involving fuel cells vary depending on the size of the fuel cell and financing facility. Taxpayers who have the need for both the electricity produced by hydrogen fuel cells (e.g., datacenter operators) and the ITC should consider owning the fuel cells outright, but should plan ahead for asset retirement and disposition. For all other taxpayers, sale-leaseback structures are particularly useful for smaller fuel cells, e.g., cells used to power warehouse equipment, and may also be used for larger, stationary fuel cells if the right counterparty can be obtained. Partnership flip structures and lease passthrough structures are also available.

A taxpayer that claims the ITC must reduce its basis in the ITC property by the amount of ITC claimed.[14] In addition, the ITC claimed in respect of qualified fuel cell property may be recaptured if the property is sold or ceases to be used for qualified purposes or at all within five years after the property is placed in service.[15]

2. New Qualified Fuel Cell Motor Vehicle Credit

New qualified fuel cell motor vehicles placed in service after 31 December 2009 generally qualify for a credit up to a per-vehicle maximum of $4,000 to $40,000 depending upon the gross vehicle weight rating of the vehicle.[16] The allowable credit amount will be increased by between $1,000 and $4,000 per vehicle if such vehicle achieves a fuel efficiency of between 150 percent and 300 percent of a statutory baseline fuel efficiency standard.[17] This credit is currently available only for motor vehicles placed in service through 31 December 2020.

A motor vehicle is a new qualified fuel

12 Notice 2018-59.

13 Treas. Reg. § 1.461-4(d)(6)(ii).

14 Code § 50(c)(1).

15 *Id.* at 50.

16 *Id.* at 30B(b).

17 *Id.* at 30B(b)(2).

cell[18] motor vehicle if (1) it is powered by a hydrogen fuel cell, (2) it meets applicable clean air standards,[19] (3) its original use commences with the taxpayer claiming the credit,[20] (4) it is acquired for use or lease by the taxpayer rather than for resale,[21] and (5) it was made by a manufacturer.[22] For this purpose, a motor vehicle is a vehicle that is capable of operating on public roads (or exclusively on rails) and that has four wheels.

Like the ITC, this credit is available to the owner of the new qualified fuel cell motor vehicle. However, if the motor vehicle is sold to a tax-exempt entity (e.g., a local government) and is not leased, the seller of the motor vehicle may claim the credit after clearly disclosing their claim in writing to the tax-exempt entity.[23] Taxpayers should note that their basis in any new qualified fuel cell motor vehicle will be reduced by the full amount of the credit available, regardless of whether the taxpayer can fully utilize the credit.[24] Thus, if it is more advantageous to retain the basis, the taxpayer should consider electing out of the credit[25] or use a financing structure whereby the refueling property may be owned directly or indirectly by a taxpayer that can use the credit. In addition, the new qualified fuel cell motor vehicle credit is subject to recapture, but guidance regarding recapture has not yet been issued.[26]

Portfolio transaction structures are attractive in the context of the new qualified fuel cell motor vehicle credit because of the caps on the available credit and relatively small acquisition cost of qualified property.

3. Alternative Fuel Vehicle Refueling Property Credit

A credit is also available in respect of qualified alternative fuel vehicle refueling property that is placed in service no later than 31 December 2020.[27] The credit is up to 30 percent of the cost of the property,[28] subject to a cap of $30,000 for depreciable property (i.e., property used in a trade or business) and $1,000 for any other property placed in service by the taxpayer "at a location."[29] It is not clear what is meant by a location in this context.

18 *Id.* at 30B(b)(3)(A).

19 *Id.* at 30B(b)(3)(B).

20 *Id.* at 30B(b)(3)(C).

21 *Id.* at 30B(b)(3)(D).

22 *Id.* at 30B(b)(3)(E).

23 *Id.* at 30B(h)(6).

24 *Id.* at 30B(h)(4).

25 *Id.* at 30B(h)(9).

26 *Id.* at 30B(h)(8).

27 *Id.* at 30C(g).

28 *Id.* at 30C(a).

29 *Id.* at 30C(b).

Qualified alternative fuel vehicle refueling property must (1) be depreciable, (2) be owned by the taxpayer that put it to original use, (3) be used for the storage or dispensing of, among other things, fuel the volume of which is composed of at least 85 percent hydrogen, and (4) not be installed on property that is used as the principal residence of the taxpayer claiming the credit.[30] To the extent that all or a portion of this credit is attributable to property for which a Code Section 38(b) credit is allowed (for example, new markets tax credit property), the alternative fuel vehicle refueling property credit is not available.[31]

Like the credits discussed above, this credit is available to the owner of the refueling property. However, if the refueling property is sold to a tax-exempt entity (e.g., a local government) and is not leased, the seller of the motor vehicle may claim the credit after clearly disclosing their claim in writing to the tax-exempt entity.[32] Taxpayers should note that their basis in any new qualified fuel cell motor vehicle will be reduced by the full amount of the credit available, regardless of whether the taxpayer can fully utilize the credit.[33] Thus, if it is more advantageous to retain the basis, the taxpayer should consider electing out of the credit[34] or use a financing structure whereby the refueling property may be owned directly or indirectly by a taxpayer that can use the credit. In addition, the new qualified fuel cell motor vehicles credit is subject to recapture.[35]

Portfolio transaction structures are also attractive in the context of the qualified alternative fuel vehicle refueling property credit because of the caps on the available credit and relatively small acquisition cost of qualified property. However, the cap on a per location basis should be carefully evaluated.

4. Alternative Fuel Credit

The alternative fuel credit is available as an offset to the Code Section 4041 fuel excise tax. The credit is $0.50 per gallon equivalent of an alternative fuel (including liquefied hydrogen) produced in the United States and sold by a taxpayer for use as a fuel in a motor vehicle or motorboat, or for use as fuel in aviation, or consumed by the taxpayer.[36] Such fuel must meet carbon recapture requirements, which can be done by the fuel being certified as having been derived from coal produced at a gasification facility that separates and sequesters not less than 75 percent of such facility's total carbon dioxide emissions.[37] This credit

30 *Id*. at 30C(c), 179A(d).

31 *Id*. at 30C(d)(1).

32 *Id*. at 30C(e)(2).

33 *Id*. at 30C(e)(1).

34 *Id*. at 30C(e)(4).

35 *Id*. at 30C(e)(5).

36 *Id*. at 6426(d)(1), (d)(2)(D), (i)(2).

37 *Id*. at 6426(d)(4)(A), (d)(4)(B)(ii).

will available for fuel produced through 31 December 2020.[38]

Tax-exempt entities such as state and local governments that dispense qualified fuel from on-site refueling stations for use in vehicles should generally qualify for this credit, but must register with the IRS. The credit must first be taken against the entity's alternative fuel tax liability, with any excess claimed as a direct payment from the IRS.[39]

II. Project Finance

While hydrogen investing has been heating up, project financing for hydrogen has been very limited outside of select government-supported projects and small niche applications. In a recent paper, Barclays suggests hydrogen could be a $1 trillion market by 2050.[40] If the growth projections for new hydrogen applications over the next two decades are to become reality, then a massive expansion of hydrogen project financing options and expertise will be necessary.

As with any nascent industry or technology, leveraging existing project finance tools will be difficult until market and technological certainty has become more widely accepted. This is especially true for hydrogen because hydrogen production, particularly green and blue hydrogen, currently is more expensive than natural gas. Cost reductions will require scale, which will almost certainly require continued and potentially expanded government investment or subsidies similar to those discussed in the **Government Incentives sections (Part I, Section I; Part II, Section I; and Part III, Section V)**, for the initial commercial-scale growth of the industry. In fact, the Hydrogen Council recently estimated that the hydrogen market requires $70 billion of investment over the next decade to become competitive with the lowest-cost

38 *Id.* at 6426(d)(5).

39 *Alternative Fuels Data Center: Alternative Fuel Excise Tax Credit*, DEP'T OF ENERGY, https://afdc.energy.gov/laws/319 (last visited Aug. 7, 2020).

40 *The Hydrogen Economy: Fuelling the Fight Against Climate Change*, BARCLAYS, https://www.investmentbank.barclays.com/our-insights/the-hydrogen-economy-fuelling-the-fight-against-climate-change.html (last visited Aug. 18, 2020).

low-carbon alternative.[41] Some of this investment, including investment in the buildout of necessary supporting infrastructure, will be in the type of capital-intensive assets that are well-suited for project finance structures.

Project finance refers to financing with limited recourse from lenders directly to the owner/sponsors. Financing is based on the economic viability of the project itself and relies on project revenue to service financing payments. With capital-intensive projects, project financing typically requires some form of long-term revenue certainty. The preferred approach to establishing revenue certainty is through long-term offtake contracts with fiscally strong counterparties. However, as markets mature, hedges and other financial arrangements can be used to support long-term revenue certainty. As the hydrogen industry initially develops, there will be opportunities to find these long-term agreements as buyers, sellers, and transporters all will need each other to support revenue certainty.

Historically, this isolated approach to financing has made it easier to raise large amounts of project debt and equity, and project finance has been vital for building projects where the capital demands of a project are larger than the capacity of an owner or sponsor. Lenders find this approach appealing because it allows them to isolate project credit risk from the sponsor owner and the project credit risk can be considerably lower than a sponsor's individual credit risk. Project finance is attractive to project developers because it insulates the developer's other corporate assets from project-specific risks and allows the developer to take on a significant amount of debt while preserving the parent company's debt-to-equity ratio and corporate borrowing capacity.

In the near-term, new hydrogen projects will carry market and regulatory uncertainty and will rely on technology that is new or not proven at scale, which will add risk, making traditional project finance difficult, and certainly much more expensive. Government support that offsets project level risk or provides subsidies to create higher returns likely will be necessary to support project financing. Even with government support, non-traditional project financing sources will be key to early successful financings. Innovation and hybrid approaches to financing likely will define the early hydrogen project finance market, and recent examples in renewable and LNG financing illustrate how these new financing tools may evolve. The renewable power industry was built with financing that incorporated and monetized tax incentives and other government supports, while tapping into long-term offtake contracts, which mitigated the market risk for financiers. Project finance for large-scale LNG export projects has required the construction and operation of the liquefaction facility, feed gas pipelines, natural gas supply contracts, and shipping and offtake agreements all to be aligned to prove

41 *Path to Hydrogen Competitiveness: A Cost Perspective,* HYDROGEN COUNCIL, p. vi, https://hydrogencouncil.com/en/path-to-hydrogen-competitiveness-a-cost-perspective/ (last visited Aug. 7, 2020).

project economics and revenue. One solution has been large upfront equity investments from private capital, such as hedge funds, until all project components were secured, followed by more traditional project financing once long-term revenue certainty was established through long-term take-or-pay offtake agreements.

The long-duration energy storage market for hydrogen may be more attractive to project financiers than the distributed hydrogen market, for several reasons. First, there is a clear model for financing power generation projects—investors provide capital for the construction of a single generation asset, and the asset generates revenue based on power prices. Second, the relative cost of long-duration hydrogen storage is expected to decrease significantly over the next 10 years. The Hydrogen Council recently predicted that "the cost of low-carbon and/or renewable hydrogen production will fall drastically by up to 60 per cent over the coming decade."[42] The Hydrogen Council attributes this significant decrease in costs to the falling costs of renewable electricity generation, which will be used to produce hydrogen via electrolysis, the cost of which will decrease because of the anticipated scaling up of electrolyzer manufacturing, for long-duration power storage.[43]

Beyond economics, public perception (as discussed in the **Stakeholder Engagement section below (Part I, Section IV)**) and politics likely will define the development of financing markets for the hydrogen economy as investors and lenders are, in significant numbers, searching for access to the growing renewable energy economy. Although more environmentally friendly than grey hydrogen, green hydrogen needs a material reduction in the cost of electrolysis technology and blue hydrogen needs a material reduction in the cost of carbon capture and sequestration technology to be competitive. Nevertheless, the broad trend among financial institutions of re-assessing the climate risk associated with energy investments may make grey hydrogen less attractive and green and blue hydrogen more attractive in the medium-term. Unless the economic challenges facing blue hydrogen diminish much more rapidly than those facing green hydrogen, green hydrogen may draw more interest than blue hydrogen. In the medium- to long-term, green hydrogen appears more likely to be the focus of the government support that will be necessary for the economics of financing hydrogen projects to work. In the near-term, the degree of U.S. federal government support for green hydrogen in particular likely will depend to some extent on the outcome of the November 2020 U.S. presidential elections, as well as the relative pace at which green hydrogen becomes a global commodity (which could compel further federal action). In addition, as discussed in the **Natural Gas/RNG section of Part II (Section II.D.5)**,

42 *Id.* at p. iv.

43 *Id.*

efforts are underway to advance carbon capture and sequestration technology as well. Ultimately, the perceived value of a zero carbon economy likely will be a driver for the flow of hydrogen project financing dollars.

III. Insurance Coverage

The energy industry is among the most dynamic in the world, as are the risks that it faces. Those risks have materialized into some of the most devastating and costly losses of any industry. Significant losses affecting the energy industry include the 2011 destruction of the Fukushima Daiichi nuclear power plant caused by a tsunami and earthquake; the 2010 BP Deepwater Horizon incident; the 1968 coal mine explosion in Farmington, West Virginia; the 1989 Exxon Valdez incident in Prince William Sound, Alaska; and the 1988 Piper Alpha oil and gas drilling rig incident in the North Sea. The Piper Alpha loss, valued at greater than $2 billion, is the largest property damage loss experienced within the hydrocarbon extraction, transportation, and processing industry.

More specific to hydrogen, the diverse methods of its production carry high risk, such as the release of harmful or flammable gasses, including carbon monoxide, carbon dioxide, and methane. Additional risks for all forms of hydrogen production, transportation, storage, and end-use include design flaws, human error, equipment failure, and natural disasters. As such, the development of opportunities in any segment of the energy industry, including the hydrogen market, carries with it the need for careful and sophisticated risk management.

The transfer of risk through insurance is a critical part of any enterprise's risk management program. Moreover, insurance is an important corporate asset and is often a company's largest source of contingent capital. Companies participating in the hydrogen market must carefully construct their insurance programs to meet the considerable risks of their operations. Insurance programs for energy companies also will reflect the complexity of their operations. This will require the placement of an insurance program of sufficient breadth (i.e., with appropriate lines of coverage), and likely will require spreading the risk across multiple insurers so as to provide sufficient amounts of coverage (i.e., limits of liability). Consideration also must be given to incorporating appropriate deductibles or self-insured retentions and may include the use of captive insurers.

Attention also must be paid to policy wording. Insurance policies are complex documents and most insurers write insurance through the use of standard "package" policies, incorporating a wide variety of forms that are drafted from the insurer's perspective. Further, insurance contract law varies by jurisdiction and in certain areas, such as notice of loss, may disproportionately favor the insurer. Opportunities exist, however, to negotiate for improved policy wording. Accordingly, it is important to review policy wording carefully to ensure that identifiable risks are covered.

Many companies are unaware—sometimes until it is too late to address—that they have gaps in their insurance policies and programs. These gaps may arise from a number of causes, including: (i) inadequate and unclear policy wording; (ii) inconsistencies within and among primary and excess layers of coverage; (iii) inadequately coordinated placements among complimentary lines of coverage; and (iv) insufficiently understood risks inherent in the insurance application process. Companies participating in the hydrogen market would be well advised to adopt a proactive approach during the underwriting process to avoid unexpected gaps in coverage and to spot opportunities to improve upon the wording of insurance policy terms and conditions.

In addition to a sophisticated insurance approach, another important risk management tool for companies in the hydrogen market is the proactive and coordinated management of contract-driven relationships with contractors and suppliers. Vendor contracts routinely include indemnification obligations and insurance requirements, including the requirement that the company be identified as an additional insured under various policies held by the contractors and suppliers. These contract provisions should be managed for consistency across vendors and for coordination with the company's own insurance program. Additionally, the insurance obligations that a company imposes upon its vendors should be routinely monitored for compliance. In sum, insurance coverage plays an important role in risk management for the hydrogen industry and should be proactively assessed and employed.

IV. Stakeholder Engagement

As the United States begins to adopt and integrate hydrogen as an energy source into the national infrastructure, public stakeholder engagement could be one of the most critical elements to ensure success. A lack of familiarity and experience with hydrogen on the part of the general public could lead to distrust and open opposition. For most of the U.S. public, the mention of hydrogen conjures up images of the Hindenburg Airship disaster in New Jersey in the 1930s. Moreover, opposition movements to infrastructure—NIMBY (Not In My Back Yard), NOPE (Not On Planet Earth), and BANANA (Build Absolutely Nothing Anywhere, Near Anybody)—do not discriminate against the infrastructure they oppose, as many U.S. wind and solar power developers have experienced.

Opportunities will abound for interests adverse to hydrogen to present challenges to various aspects of the industry and its robust development in the United States. The hydrogen industry, regulators, public policy leaders, and elected officials must develop robust education initiatives to counteract what is likely inevitable as hydrogen and the infrastructure to develop and deliver it become more present in our society—public opposition based on incomplete or inaccurate information. Engagement is key.

Much of the U.S. legal structure is built on the idea of public engagement in the democratic process, whether that is through special interest lobbying in Washington, D.C., regulatory proceedings before federal agencies, or civic engagement in local issues and elections. Frequently, defined processes afford opportunities for stakeholder engagement on safety and security issues, in particular. It will be no different for the build-out of a vibrant and integrated hydrogen economy. Such processes will include opportunities for written comments, public scoping meetings, technical conferences, and legal challenges and appeals to agencies' or executives decisions. Industry participants that will develop hydrogen infrastructure must: (1) understand any existing regulatory framework for engaging hydrogen safety and security issues; (2) establish a baseline understanding of hydrogen safety and security issues applicable to each particular project; and (3) identify key safety and security messages that are critical to convey to stakeholders.

As cities, local communities, and utilities adopt strategies to invest in and embrace hydrogen in order to meet sustainability objectives, particularly the use of fuel cells and other hydrogen transportation technologies, citizens and stakeholder groups are likely to become increasingly engaged in legal and regulatory processes, debates, and proceedings. Public officials and hydrogen project developers and advocates should actively map out all of the key stakeholders and develop a strategy to engage transparently with the identified stakeholders throughout the lifecycle of a particular project proposal.

Regulators and other governmental decision-makers should intentionally explain the regulatory processes, highlighting elements that factor in to the decision-maker's conclusions, including a focus on:

- Coordination requirements between a project developer, and state and local officials with regard to safety and security issues;
- Development of any emergency response plans that may be required, including any procedures required for notification of the public and identification of any evacuation routes in the event of an incident; and
- Mitigation strategies that a developer may be required to develop to supplement the standard safety and security practices employed by the developer, including any ongoing training programs and any customized public action plans.

There will be no way to eliminate public participation and opposition in the development of the hydrogen economy in the United States. Each hydrogen infrastructure project will present new and different challenges requiring tailored engagement plans and outreach. As a result, the hydrogen industry must be deliberate and intentional about educating and engaging thoughtfully with impacted stakeholders and the general public.

PART II - HYDROGEN PRODUCTION

As the United States seeks to advance a hydrogen economy, government incentives promoting production likely will play a key role. A summary of several current incentive programs is provided in **Section I**, below. In addition, ability to access the resources required for hydrogen production will be critically important. As discussed in greater detail in **Section II** below, this access will depend on both the abundance of the resources required, as well as the politics and regulation of such resources.

I. Government Incentives to Promote Production

While the DOE Improved Energy Technology Loans discussed in **Part I (Section I.A)** are the only federal incentive to promote hydrogen production, many states have their own hydrogen production incentives, including those listed below.

Hawaii

Hawaii supports production of renewable fuels, including hydrogen, through the Renewable Fuels Production Tax Credit. Under this tax credit, renewable fuels produced from renewable feedstocks, such as hydrogen, ethanol, biodiesel, and biofuel; may qualify for an income tax credit equal to $0.20 per 76,000 British thermal units (BTUs) of renewable fuels sold for distribution in Hawaii. The facility must produce at least 15 billion BTUs of its nameplate capacity annually to receive the tax credit and may claim the tax credit for up to five years, not to exceed $3,000,000 per calendar year. Qualifying renewable fuel production facilities must provide written notification of their intent to produce renewable fuels before becoming eligible for the tax credit.[44]

New Mexico

New Mexico provides the Biofuels Production Tax Deduction, where the cost of purchasing qualified biomass feedstocks to be processed into biofuels, as well as the associated equipment, may be deducted in computing the compensating tax due under the New Mexico Gross Receipts and Compensating Tax Act. Accepted fuels include biofuels that include hydrogen, ethanol, methanol, and methane.[45]

North Dakota

In North Dakota, the sale of hydrogen used to power an internal combustion engine or a fuel cell is exempt from sales tax under the Sales Tax Exemption for Hydrogen Generation Facilities. In addition, any equipment used by a hydrogen generation facility for the production and storage of hydrogen is exempt from sales tax. Stationary and portable hydrogen containers or pressure vessels, piping, tubing, fittings, gaskets, controls, valves, gauges, pressure regulators, and safety relief devices are included as eligible equipment.[46]

South Carolina

South Carolina offers a sales tax exemption for "any device, equipment, or machinery operated by hydrogen or fuel cells, any device, equipment or machinery used to generate, produce, or distribute hydrogen and designated specifically for hydrogen applications or for fuel cell applications, and any device, equipment, or machinery used predominantly for the manufacturing of, or research and development involving hydrogen or fuel cell technologies."[47]

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[44] *NC Clean Energy Technology Center - Database of State Incentives for Renewables & Efficiency*, NC Clean Energy Technology Center, NC STATE UNIVERSITY, https://www.dsireusa.org/ (last visited Aug. 7, 2020).

[45] *Id.*

[46] *Id.*

[47] *Id.*

Utah

In Utah, the Hydrogen Fuel Production Incentive gives an oil and gas severance tax credit to businesses that convert natural gas to hydrogen fuel, or produce natural gas solely for use in the production of hydrogen fuel ZEVs. Each eligible applicant may receive a tax credit equal to the amount of the severance tax owed, up to $5 million per year. Entities that produce hydrogen fuel for use in ZEVs or hydrogen-fueled trucks may also qualify for grant funding or loans from the Community Impact Fund.[48]

II. Hydrogen Production Sources

Hydrogen production and the resources used in the process implicate various regulatory, policy, and commercial issues that are important for industry participants to bear in mind. The sections that follow briefly address these issues.

A. Water

As the industry scales towards producing green hydrogen, the availability of water resources is almost certain to create constraints, particularly with regard to the siting of facilities. Understanding where and how the necessary amounts of water will be available will be critical, as will understanding the administrative regimes that govern water use and how best to work with them to use and leverage this resource.

Using water as a feedstock for hydrogen production raises unique issues depending on the water rights regime in the jurisdiction in which the hydrogen is being produced. Water use in the eastern United States is primarily managed as a riparian resource, which means that if water runs through or abuts the land on which production occurs, it may be "reasonably used" as long as the use does not harm other users. This generally less-restrictive concept does not mean that water use is uncontrolled or abundantly available; many, if not all, riparian states have some form of monitoring or reporting requirements, particularly for large consumptive needs. However, compared to the mixed riparian or pure appropriative regimes of the Midwest, mountain states, and West Coast, riparian regimes generally offer more water and more flexible water use arrangements.

In most states west of the Mississippi, riparian use is either more regulated, mixed with "prior appropriation," or eliminated entirely. Prior appropriation is a more restrictive regime, requiring water rights or permits for nearly every type of use of groundwater or surface water. These "paper" rights have specific points of withdrawal and places and purposes of use, and are subject to relinquishment for periods of non-use. They are also highly regulated in times of scarcity—those with more "senior" rights have priority over those who obtained their rights later in time; during droughts, "junior" rights holders may see their water reduced significantly, sometimes to none at all.

48 *Id.*

Obtaining water rights in prior appropriation states is not impossible, but requires familiarity with the legal water rights landscape just as much as with the hydrogeological landscape. Rights can be bought, sold, transferred, leased, and banked; but nearly all forms of ownership transfer require legal advice, hydrogeological support, and navigation of regulatory processes, sometimes with multiple layers of agencies, to accomplish.

It is also worth noting that interstate water use is governed by interstate compacts, several of which have been under legal challenge for many years. As of the time of drafting, the United States Supreme Court is set to hear arguments on four cases involving interstate water rights disputes, governed by all types of water use regimes. These cases will set precedent regarding the management of large watershed resources as they seek the balance between ever-changing economic needs. As an emerging large-scale industry, hydrogen production will likely be impacted by these decisions.

All of this must be taken into consideration even before limits and permits required by the Clean Water Act (CWA) and the Safe Drinking Water Act (SDWA) come into play.

B. Solar, Wind, and Hydropower

Hydrogen production powered by renewable energy presents a compelling opportunity for commercialization, which is not lost on many of the most savvy energy project developers. The success of the market in driving down the cost of electricity produced by clean renewable resources has created an abundance of inexpensive power in certain markets at certain times. Where "grid parity" economics was a dream and rallying call of renewable energy not so many years ago, the reality is now that wind-, solar-, and hydropower-generated electricity is frequently the cheapest and easiest way of producing electricity. Producing hydrogen with cheap clean electricity has the potential of multiplying the benefits of decarbonization across the electricity market into the vast potential hydrogen market.

Market forces are driving opportunities for investment in new technology to meet the demand of hydrogen produced via renewable resources. The significant advantage of using renewable resources in hydrogen production is that not only can the production process occur with zero greenhouse gases, but also the hydrogen fuel can be stored to address the inherent intermittency that plagues solar and wind resources.[49] Moreover, recent corporate investor-perspective modeling demonstrates that the stark decline in the cost of renewable resources portend a competitive economic shift for power-to-gas hydrogen production.[50]

[49] Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019; *see also Hydrogen: A Renewable Energy Perspective*, INT'L RENEWABLE ENERGY AGENCY at 25 (Sept. 2019), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf.

[50] Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019 ("The recent precipitous decline in the cost of renewable power now suggests that the economic fundamentals of [power-to-gas] facilities are about to change.").

1. Technologies for Hydrogen Production from Renewable Resources

Over a decade ago, the FreedomCAR & Fuel Partnership, involving the DOE and major U.S. car manufacturers, published a report that highlighted seven hydrogen production technologies in development under three broad categories: thermal processes (i.e., using heat to produce hydrogen); electrolytic processes (i.e., splitting water molecules to produce hydrogen); and photolytic processes (i.e., splitting water by using light energy).[51] Today, many of these technologies are much further developed, and some are commercially available.[52] Two types of commonly used renewables-to-hydrogen technology available are (1) water electrolysis and (2) steam reforming of biomethane or biogas, as discussed in greater detail in the **Natural Gas/RNG section below (Part II, Section II.D)**.

Other hydrogen production technologies in development include biomass gasification (as discussed in the **Biomass section below (Part II, Section II.E)**), photocatalysis, thermochemical water splitting, and supercritical water gasification of biomass.

For renewable resources such as wind, solar, and hydropower, hydrogen production via electrolysis is currently the most commercially viable option.[53] During electrolysis, electricity splits water molecules into hydrogen and oxygen within a device, called an electrolyzer.[54] Each electrolyzer includes an anode and cathode divided by an electrolyte, which splits the water molecules. There are three primary electrolyzer technologies: (1) proton exchange membrane (PEM) electrolysis, in which a semipermeable membrane conducts protons, often with the electrolyte made of a thin specialty plastic; (2) alkaline (ALK) electrolysis, in which the electrolyte is a liquid ALK solution with two electrodes; and (3) solid oxide electrolysis, in which the electrolyte is a solid oxide or ceramic wall that selectively transfers oxygen ions with negative charges at increased temperatures.[55]

The chemical industry's use of ALK electrolysis dates back to the 1920s

51 *Hydrogen Production: Overview of Technology Options*, DEP'T OF ENERGY, https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/h2_tech_roadmap.pdf.

52 *Hydrogen Production Processes*, DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-processes.

53 Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen,* 4 NATURE ENERGY 216, Feb. 25, 2019 ("[E]lectrolysers are already commercially available and entail the immediate potential of creating a buffer for the growing volume of intermittent wind and solar power."); *see also* Public Utility District No. 1 of Douglas County, "Renewable Hydrogen," available at https://douglaspud.org/Pages/Renewable-Hydrogen.aspx#:~:text=Traditionally%20hydrogen%20is%20produced%20using,or%20consumption%20of%20the%20fuel (last visited Aug. 23, 2020) (discussing production of hydrogen from hydropower).

54 *Hydrogen Production: Electrolysis*, DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

55 *Id.; Hydrogen from Renewable Power: Technology Outlook for the Energy Transition*, Int'l Renewable Energy Agency at 19 (Sept. 2018), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf.

and the more modern PEM electrolysis recently reached commercial deployment.[56] While ALK is the most mature form of electrolysis, PEM electrolysis offers a more flexible and reactive technology that can serve differing load needs of varying industries.[57] PEM technology may participate directly in an electric market,[58] but ALK technology also made recent progress by becoming more compatible with grid services.[59] In 2018, the opinion of the International Renewable Energy Agency (IRENA) was that "[a]t present . . . ALK technology remains less flexible than PEM technology . . ."[60] In the future, solid oxide electrolysis may also provide an even more efficient electrolysis technology than other types, but it is currently in development and not yet commercially viable.[61]

Renewable power for hydrogen production provides three key advantages: it is cheaper, it is cleaner, and it allows efficiencies in the power generation system that will continue to drive down the cost of hydrogen production. The rapid growth and ongoing advancement of wind and solar power generation technology continues to drive down the cost of renewable energy. Cheaper and cleaner renewable power is the prime driver in the wave of retirements of the aging coal and gas-fired plants across the country. Renewable projects paired with battery storage capabilities are the next wave of cost compression and will continue to drive higher-cost facilities that emit carbon out of the market.

A challenge for renewable energy project development economics continues to be the intermittency and unpredictability of generation. Solar panels produce energy when the sun shines, wind energy flows when the wind blows, and hydropower projects can require instream flows. Energy storage has long been the ideal solution to this challenge. Development of equipment for energy storage remains a focus of the industry, and the price for lithium ion and flow battery solutions continues to fall rapidly. However, hydrogen production is another solution to this problem. Electrolyzers can be run in times of power abundance, for example when the wind is blowing and local wind generation is plentiful, and be curtailed when the opposite is true. With time-of-day pricing for electricity, this coincides nicely with cheap power prices. Electrolyzers also can cycle on and off quite rapidly. This is useful in regulating the frequency fluctuations on the electricity grid. In many markets, the facility can earn a payment for this type of "ancillary service."

Hydrogen production presents a real opportunity to leverage clean renewable

56 *Id.*

57 *Id.* at 20.

58 *Id.* at 24.

59 *Id.* at 21.

60 *Hydrogen from Renewable Power: Technology Outlook for the Energy Transition*, Int'l Renewable Energy Agency at 19 (Sept. 2018), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf.

61 *Id.* at 23.

power generation through production of an end-product that is not electricity, thus expanding the potential application of renewable energy projects out of the electricity market and into the commodity market.

2. Forecast for Cost Competitiveness of Renewable Energy Powered Hydrogen Production

In September 2019, IRENA estimated a "global economic potential for 19 [exajoules] of hydrogen from renewable electricity in total final energy consumption by 2050[,]" and renewables-based hydrogen making-up eight-percent of the total electricity consumption.[62] As reported in April 2020, the number of electrolyzer projects tripled in the preceding five months.[63] As of March 2020, one study found that planned electrolyzer capacity had increased to 8.2 gigawatts.[64] This increase is 31 times greater than the cumulative installed capacity in April 2020.[65]

Recent trade press forecasts an advantage for investors that pair renewable energy with a power-to-gas facility to convert a variable amount of power, depending on the peak and off-peak generation, to hydrogen.[66] Such an investor would have the power to either sell the power in real-time at market or convert it into hydrogen for later use or sale.[67] The September 2019 IRENA study found that "lowest cost wind and solar projects can provide hydrogen at a cost comparable to that of hydrogen produced from fossil fuels."[68]

This cost-competitiveness was exemplified in a recent case study that modeled the economic impact of pairing a PEM electrolyzer with wind facilities in Texas.[69] As wind energy often reaches peak production at night during off-peak hours with little demand from the grid, wind power prices remain uncompetitive against current wholesale energy prices.[70] The power-to-gas electrolyzer complements this offset production by allowing for its conversion to hydrogen, which can be stored for later use. Moreover, the PEM electrolyzer "can be ramped up rapidly and attain

62 *Hydrogen: A Renewable Energy Perspective*, INT'L RENEWABLE ENERGY AGENCY at 22 (Sept. 2019), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf.

63 Jason Deign, *Green Hydrogen Pipeline Surges on a Wave of Announced Mega-Projects*, GREENTECH MEDIA (Apr. 9, 2020), https://www.greentechmedia.com/articles/read/mega-projects-help-double-green-hydrogen-pipeline-in-just-five-months

64 *Id.*

65 *Id.*

66 Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019.

67 *Id.*

68 *Hydrogen: A Renewable Energy Perspective*, INT'L RENEWABLE ENERGY AGENCY at 28 (Sept. 2019), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf.

69 Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019.

70 *Id.*

a near-constant efficiency once a small threshold utilization has been reached."[71] Based on the modeling data for Texas, renewable hydrogen production would be cost competitive for small- and medium-scale hydrogen supply, though not yet cost competitive with current industrial fossil fuel-based hydrogen supply.[72]

The study found the data suggests a strong continued decline in the price of electrolyzers, and when paired with the likely increase in the capacity factor of wind turbines, it presents a compelling opportunity for system-wide power-to-gas hydrogen production facilities.[73] As the study concludes, "[t]he central finding is that renewable hydrogen is projected to become cost competitive with large-scale fossil hydrogen supply within the next decade."[74] In certain niche applications, the study found renewable hydrogen is already cost-competitive, but predicts that hydrogen at an industrial-scale supply will be competitive by 2030.[75]

The co-development of renewable energy generating facilities paired with hydrogen production is likely to be a significant emerging trend. Electrolyzers located proximately to cheap renewables benefit most from low (or virtually no) costs of transmission and interconnection and may reap the upside of co-development efficiencies. A developer with both electricity generating assets and an electrolyzer maximizes its commercial position by having the ability to sell into either the electricity market or the hydrogen market, or both. For example, in late July 2020, NextEra Energy Inc. announced plans to build a green hydrogen pilot facility in Florida for $65 million, which will utilize unused solar power to create hydrogen via electrolysis.[76]

3. Environmental Regulation

The environmental regulation of these technologies is likely to be similar to the regulation of the facilities that are used to generate electricity. With respect to solar:

- Thermochemical production of hydrogen will involve the construction and use of utility-scale infrastructure to concentrate sunlight onto a reactor tower using a field of mirrors "heliostats." Where project proponents require federal permits, or seek to use federal land, the entire project would be subject to review under the National

[71] *Id.*

[72] *Id.*

[73] *Id.* ("Our projects for the system prices of electrolysers are based on hand-collected data from manufacturers, operators of [power-to-gas] plants, articles in peer-reviewed journals and technical reports.").

[74] Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 Nature Energy 216, Feb. 25, 2019.

[75] *Id.*; *see also Hydrogen to become a source of cleaner power on a massive scale*, GLOBALDATA ENERGY (June 23, 2020) (describing a study that estimates the cost of hydrogen fuel prices "could drop to $10 to $8/kg during the 2020-2025 period").

[76] Karl-Erik Stromsta, *NextEra Energy to Build Its First Green Hydrogen Plant in Florida*, GREENTECH MEDIA (July 24, 2020), https://www.greentechmedia.com/articles/read/nextera-energy-to-build-its-first-green-hydrogen-plant-in-florida

Environmental Policy Act (NEPA).[77] NEPA review would entail creating a detailed analysis of the anticipated environmental impacts of the project, including impacts to land, water, and wildlife. Potential impact to wildlife under the Endangered Species Act (ESA) must also be considered and accounted for, and other environmental statutes also may be applicable depending on the project and location.

- Photolytic production of hydrogen likely will require the same level of environmental review as solar thermochemical hydrogen production. On a large scale, photolytic production of hydrogen would require the construction and use of utility-scale infrastructure with the potential for environmental impacts on the surrounding land, water resources, and wildlife. The projects would also potentially be subject to environmental review imposed by NEPA and the ESA, which includes a detailed assessment of the potential for environmental impact and the corresponding need to develop mitigation strategies.
- Additionally, the two processes described above create water as a byproduct. On a commercial scale, the disposal of this byproduct water may implicate issues under the CWA if the water will be discharged locally. Any federally permitted project that will discharge into navigable waters must obtain certification from the state in which the project is situated ensuring that it complies with state environmental laws.[78]

Effective integration of commercial hydrogen production with renewable wind energy or hydropower would likely require the construction and use of utility-grade electrolyzers adjacent or directly connected to wind farms or hydropower facilities. If subject to federal permit requirements, the construction and use of electrolyzers would require environmental review under NEPA, including an assessment of the environmental impacts involved in construction and operation of the electrolyzers.

As noted, these environmental regulatory processes usually involve opportunities for interested stakeholders to comment, and, if opposed to the project, file a protest. Developers must be thoughtful and engaged in planning to site a hydrogen facility.

C. Nuclear

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, struggling to remain competitive.

Nuclear power plants can produce hydrogen by generating both steam and electricity. The high-quality steam produced by nuclear reactors can be electrolyzed and split into pure hydrogen and oxygen. Nuclear paired with

[77] *See 40* C.F.R. § 1501.1.

[78] 33 U.S.C. § 1341(a)(1).

electrolyzers located adjacent to reactors can offer flexibility to the market.

DOE estimates that a conventional 1,000 MW nuclear reactor can produce more than 200,000 tons of hydrogen annually. Ten nuclear power plants could produce about two million tons every year, or 20 percent of the current hydrogen used in the United States.[79] This would allow utilities to produce and sell hydrogen as a commodity in addition to providing reliable baseload electricity for the grid. The new revenue source may be just what is needed for reactors to justify continued operation in the marketplace, which has seen nuclear lose its competitive edge given low-priced natural gas and the increasing growth of renewables like wind and solar.

The potential of using nuclear energy assets for hydrogen production has attracted interest from the private sector and DOE. The DOE is supporting at least four utilities in the development of pilot projects to demonstrate low-temperature electrolysis (LTE) and high-temperature steam electrolysis (HTSE) technologies using nuclear reactors to produce hydrogen. For instance, a consortium of three utilities, Energy Harbor, Xcel Energy, and Arizona Public Service, is starting a two-year pilot project to demonstrate hydrogen production using a two MW LTE technology at Energy Harbor's Davis-Besse nuclear power station in Ohio. The same consortium has also developed a proposal for a HTSE demonstration at one of Xcel Energy's nuclear units in Minnesota. Moreover, Exelon, which has the nation's largest nuclear fleet, is scheduled to commence later in 2020, a three-year $7.2 million pilot project to demonstrate hybrid nuclear-hydrogen systems, with a 50 percent DOE cost share. Despite the utilities' interest, there is uncertainty whether nuclear hydrogen production systems, especially HTSE technology, can scale to be commercially viable.[80] The scaling issue is critical since generating hydrogen using electrolyzers at existing nuclear power plants is not yet cost-competitive.[81]

Assuming it can scale to be cost-competitive, nuclear power offers a major advantage over the current predominant methods of producing hydrogen: it is 100 percent carbon free. The steam produced and the electricity generated that can be used for electrolysis do not result in carbon dioxide. Most of the hydrogen produced in the United States results from transforming the methane in natural gas, a process that releases carbon dioxide. The nuclear process of generating steam and electricity for the electrolysis process does not result in carbon dioxide emissions. Use of nuclear for hydrogen production could reduce carbon dioxide emissions for certain sectors of the economy, like heavy industry, manufacturing, and

79 Department of Energy, Office of Nuclear Energy, *Could Hydrogen Help Save Nuclear?*, https://www.energy.gov/ne/articles/could-hydrogen-help-save-nuclear (last visited June 22, 2020).

80 Sonal Patel, *Hydrogen May Be a Lifeline for Nuclear – But it Won't Be Easy*, POWER, June 11, 2020, https://powermag.com/hydrogen-may-be-a-lifeline-for-nuclear-but-it-wont-be-easy/.

81 US Nuclear Fleet Must Adapt by Operating Flexibly, Making Hydrogen: Officials, S&P GLOBAL PLATTS, Aug. 11, 2020.

aviation, which are among the most challenging to decarbonize.

Nuclear power obviously has other concerns regarding public perceptions of its risk, potential catastrophic accidents, and nuclear waste in the form of spent nuclear fuel, which is being stored awaiting the elusive answer on permanent disposal. These concerns can be somewhat addressed by a new generation of advanced nuclear reactors being developed. The new reactors are intended to use passive safety systems to reduce the risk of runaway accident scenarios. Many of the advanced reactors also would produce less spent nuclear fuel and other radioactive waste.

The next generation of advanced reactors offers further advantages to producing hydrogen. They will likely operate at higher temperatures and would therefore more efficiently generate steam for hydrogen production.[82] The advanced reactors also likely would be smaller than conventional reactors, and could be built as modules. These Small Modular Reactors or Microreactors could be built more quickly than today's reactors and placed strategically where there is a demand for hydrogen to minimize transport and distribution.

The environmental regulation of hydrogen electrolysis using nuclear energy will be closely related to the environmental regulation of nuclear power plants as a whole. Integration of commercial hydrogen production with existing nuclear power plants likely would require the construction and use of utility-grade electrolyzers adjacent or directly connected to the power plants. If subject to federal permit requirements, the construction and use of electrolyzers would require environmental review under NEPA, including an assessment of the environmental impacts involved in construction and operation of the electrolyzers. The Nuclear Regulatory Commission (NRC) may also have a role given that all commercial reactors are licensed by NRC and the large-scale, at-reactor production of hydrogen, given its explosive nature, may raise potential safety risks.

D. Natural Gas/RNG

Natural gas contains methane (CH4) and can be used to produce hydrogen via steam-methane reforming (SMR).[83] In the United States, the abundance of technically recoverable natural gas, as well as the growing biogas and renewable natural gas (RNG) markets, highly interconnected natural gas pipeline system, and developed natural gas commercial market make natural gas an attractive feedstock to produce hydrogen. However, with the presidential elections in November 2020, there is the potential for a change in administration and, with it, changes to the regulation of fossil fuels.

[82] Department of Energy, Office of Nuclear Energy, 3 Ways Nuclear is More Flexible Than You Might Think, June 23, 2020, http://www.energy.gov/ne/articles/3-ways-nuclear-more-flexible-you-might-think.

[83] While there are other pathways for producing hydrogen from natural gas, we have focused on SMR, as it appears to currently be the preferred method. Other pathways, including autothermal reforming, may gain increased popularity in the future.

1. Steam-Methane Reforming (SMR)

In SMR, the methane in natural gas reacts with steam under high pressure in the presence of a catalyst to produce hydrogen, carbon monoxide, and small amounts of carbon dioxide. The carbon monoxide and steam are then reacted using a catalyst to produce carbon dioxide and more hydrogen, in a process called the "water-gas shift reaction." Finally, carbon dioxide and other impurities are removed from the gas stream, leaving essentially pure hydrogen, in a process called "pressure-swing absorption." SMR is the most common method of producing hydrogen and can be used to produce blue or grey hydrogen from natural gas, depending on whether carbon capture and sequestration (CCS) technologies are employed. SMR can be used to separate hydrogen from methane at different points in the overall value chain. For example, SMR can be utilized closer to the point of natural gas production, which may require longer-haul transportation of hydrogen to the point of consumption. Alternatively, SMR can be used closer to the point of hydrogen consumption, which may require longer-haul transportation of natural gas to the SMR project and shorter distance transportation of hydrogen to the point of consumption.

2. Environmental Considerations for SMR

Producing hydrogen from either natural gas or biogas/RNG will be subject to similar environmental regulations, primarily to address the significant amount of carbon dioxide resulting from this process. For example, hydrogen production facilities are required to monitor their emissions and submit annual greenhouse gas reports to the Environmental Protection Agency (EPA).[84] The EPA does not presently require that stationary sources that produce only greenhouse gases obtain an operating permit under Title V of the Clean Air Act (CAA).[85] However, sources that already are subject to permitting under the CAA due to emission of conventional pollutions may be required to take measures to control greenhouse gas emissions. Additionally, individual states may impose more stringent controls on the release of greenhouse gases and place limitations on SMR operations to meet statewide goals to reduce greenhouse gas emissions.

Because of the carbon dioxide produced by SMR, successfully pairing SMR-produced hydrogen with CCS will be critical to securing a long-term role for this method of hydrogen production in decarbonizing industry sectors.

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84 *See 40* C.F.R. §§ 98.2, 98.6, 98.160(c).

85 *See* EPA, Next Steps and Preliminary Views on Application of Clean Air Act Permitting Programs to Greenhouse Cases Following the Supreme Court's Decision in *Utility Air Regulatory Group v. Environmental Protection Agency 2* (July 24, 2014), https://www.epa.gov/sites/production/files/2015-12/documents/20140724memo.pdf. *See also Util. Air Regulatory Grp. v. E.P.A.*, 573 U.S. 302, 134 S. Ct. 2427, 189 L. Ed. 2d 372 (2014).

The EPA has established regulations under the SDWA governing the underground injection of carbon dioxide for the purposes of geologic sequestration.[86] The regulations impose requirements for the permitting, siting, construction, operation, financial responsibility, testing and monitoring, post-injection site care, and site closure of carbon capture and storage injection wells.[87] It seems inevitable in light of increasing environmental concerns that large-scale production of hydrogen from natural gas would inevitably involve construction of CCS facilities, including underground injection wells. These wells would have to be built and operated according to EPA regulations.

Biogas, or RNG, can be reformed to produce hydrogen in a process similar to natural gas reforming. This process ultimately produces both hydrogen and large amounts of carbon dioxide, likely would be subject to greenhouse gas reporting requirements, and CCS likely will need to be employed to offset the carbon dioxide impact of biogas reforming, subjecting projects to EPA permitting requirements for underground CCS wells. However, biogas is derived from plants that consume carbon dioxide from the atmosphere, which acts as an offset to the carbon dioxide produced during the gasification process. Coupled with CCS technology, biogas reformation has the potential to produce little to no carbon footprint.

3. Natural Gas and RNG Supply

a. Natural Gas

The United States has seen a significant expansion in natural gas proved reserves and marketed production in recent years from onshore and offshore resources.[88] Much of this increase in estimated natural gas proved reserves, unproved reserves, and marketed production can be attributed to increased horizontal drilling and hydraulic fracturing techniques in shale and other tight geologic formations. U.S. shale formations, or plays, are found in about 30 states, with Texas, Pennsylvania, Oklahoma, Louisiana, and Ohio taking the lead. The largest dry shale gas production areas in the United States by formation include the Marcellus Shale, the Permian Basin, the Utica Shale, the Haynesville Shale, the

86 *See 40* C.F.R. pts. 124, 144, 145 et seq.

87 *Id.*; *see also* Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration Wells, 75 Fed. Reg. 77,230, 77,246 (Dec. 10, 2010).

88 In 2018, estimated U.S. natural gas proved reserve capacity increased 9 percent year-over-year and increased just over 106 percent over the last decade according to the U.S. Energy Information Administration (EIA). U.S. ENERGY INFO. ADMIN., *Open Data, Natural Gas Reserves*, *United States, Annual*, https://www.eia.gov/opendata/qb.php?sdid=INTL.3-6-USA-TCF.A (last visited July 19, 2020). Of the total U.S. natural gas proved reserves, the EIA reported that in 2019 dry gas (primarily methane) comprised 474.821 trillion cubic feet (Tcf), an increase of about 8.3 percent year-over-year from 438.46 Tcf in 2018. Id. The EIA estimates that, as of 2019, the United States has about 2,137 Tcf of unproved dry natural gas resources. U.S. ENERGY INFO. ADMIN., *Natural Gas Explained: Where Our Natural Gas Comes From*, https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php (last updated Nov. 13, 2019).

Eagle Ford Shale, the Barnett Shale, and the Woodford Shale.[89]

Technological advancements in natural gas identification, accessibility, and recovery and extraction methods have fueled increasing energy independence in the United States. Total natural gas imports have been declining steadily since 2007.[90] At the same time, natural gas exports have been increasing since 2000.[91] With the very recent emergence of the United States as a significant LNG exporter, the result is that the United States is now a net exporter of natural gas.

Onshore production of conventional natural gas generally is regulated by the states in which the activity occurs or will take place. Each state has its own regulatory regimes related to well spacing, production quotas, safety regulations, and other health-related considerations.[92] Offshore natural gas production, production on federal onshore lands, and production on Native American lands are regulated by the U.S. federal government through the U.S. Department of the Interior (DOI). Within the DOI, the Bureau of Land Management regulates and manages the production of natural gas on onshore federal lands; the Bureau of Ocean Energy Management manages federal outer continental shelf leasing programs and conducts resource assessments; and the Bureau of Indian Affairs regulates and manages the production of natural gas on Native American territories, in addition to local tribal laws.

b. The Politics of Natural Gas

The political environment and policy goals in the United States have the potential to drive natural gas production and demand in the future. Natural gas often has been considered a bridge fossil fuel for a clean energy future due to its lower greenhouse gas emissions and may provide the link between

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89 *Id.*

90 U.S. ENERGY INFO. ADMIN., *Natural Gas Explained: Natural Gas Imports and Exports*, https://www.eia.gov/energyexplained/natural-gas/imports-and-exports.php (last updated July 21, 2020).

91 *Id.*

92 While the doctrine of supremacy does not allow local governments (i.e., cities and counties) to regulate the natural gas industry, zoning and district ordinances may limit natural gas production within certain areas of a municipality or near residences.

the two policy positions. With the abundance of U.S. natural gas, maintaining energy independence is likely achievable during this transition process. The use of natural gas to produce hydrogen (particularly blue hydrogen) could provide an opportunity for bipartisan support and advancement of legislation and regulations that encourage blue hydrogen production.

Public sentiment on hydraulic fracturing has altered the drilling landscape in the United States. To date, New York, Maryland, and Vermont have banned hydraulic fracturing, often citing health risks as the predominant factor. State regulations and public sentiment on this recovery method likely will continue to be a factor in natural gas production in the future.

Upcoming U.S. elections have the potential to significantly change the trajectory for fossil fuels. On one end of the spectrum, the Green New Deal[93] and measures announced in Democratic presidential nominee Joe Biden's climate change task force report[94] have the potential to greatly reduce the production of natural gas in the United States, with a stated goal for the United States to be emissions-free by 2030. On the other end of the spectrum, President Trump has executed on a number of agenda items beneficial to natural gas development in the United States, including directing DOI to expand offshore oil and gas drilling, opening more leases to develop onshore and offshore resources, eliminating methane emissions limitations for drilling on federal lands, and promoting infrastructure to increase exports to foreign markets.

c. Biogas and Renewable Natural Gas

Biogas is produced from biomass from a variety of sources[95] and can be used to produce RNG by removing constituent elements including water, carbon dioxide, hydrogen sulfide, and other trace elements, leaving only pure methane. RNG is comparable to natural gas produced by conventional methods and can be transported through pipelines, trucks, or other methods in the same way as conventional natural gas.

By 2018 estimates, there are more than 2,200 sites across the United States in all 50 states producing

[93] Recognizing the Duty of the Federal Government to Create a Green New Deal, H.R. Res. 109, 116th Cong. § 4 (2019), https://www.congress.gov/116/bills/hres109/BILLS-116hres109ih.pdf.

[94] *Biden-Sanders Unity Task-Force Recommendations: Combating the Climate Crisis and Pursuing Environmental Justice*, July 8, 2020, https://joebiden.com/wp-content/uploads/2020/08/UNITY-TASK-FORCE-RECOMMENDATIONS.pdf (last visited Aug. 7, 2020).

[95] Sources of biogas include landfills, animal waste, wastewater, and industrial, institutional, and commercial organic waste. *Energy Analysis: Biogas Potential in the United States*, U.S. DEP'T OF ENERGY, Office of Energy Efficiency and Renewable Energy, National Renewable Energy Laboratory (October 2013), https://www.nrel.gov/docs/fy14osti/60178.pdf.

biogas.[96] This includes 250 anaerobic digesters on farms, 1,269 water resources recovery facilities using an anaerobic digester, 66 stand-alone systems that digest food waste, and 652 landfill gas projects.[97] By far, the largest contributor to the biogas volume comes from landfills. The states with the largest biogas production are California, Texas, Wisconsin, Pennsylvania, and North Carolina,[98] and many states have programs to incentivize biogas and RNG production.[99] It is estimated that there are over 14,958 new sites ripe for development, which could reduce emissions equivalent to removing 117 million passenger vehicles from the road while creating over 25,000 new permanent jobs.[100]

Regulations under the CAA require municipal solid waste landfills to install and operate gas collection and control systems. While some landfills capture and burn the landfill gas through flaring, others capture it, remove the carbon dioxide and other constituents, and sell the resulting methane to third-party purchasers. The federal government provides a number of incentive programs for biogas production, including an Alternative Fuel Excise Tax Credit for the use of biogas as a transportation fuel and the Federal Renewable Energy Production Tax Credit for electricity generated by qualified energy resources including biogas.

4. Transportation of Natural Gas

Two primary methods of transporting natural gas in the United States are by pipeline, in a gaseous state, and by truck, either as compressed natural gas (CNG) or liquefied natural gas (LNG). While there has been interest in LNG by rail, the use of cryogenic railcars is still nascent in the United States.[101]

96 *Biogas Market Snapshot*, AM. BIOGAS COUNCIL, https://americanbiogascouncil.org/biogas-market-snapshot/ (last updated Apr. 26, 2018).

97 *Id.*

98 *Id.*

99 For example, in 2012 California passed legislation requiring the California Public Utilities Commission to develop standards for certain constituents found in biogas to protect human health and ensure pipeline safety. H.B. 1900, 2011-2012 Gen. Assemb., Reg. Sess. (Ca. 2012) (enacted). From 2012 through 2019, the Oregon Department of Energy promulgated a system of incentives established by the Oregon legislature known as Renewable Energy Development Grants to promote and foster renewable energy development to reduce greenhouse gas emissions. H.B. 3672, 76th Leg. Assemb., Reg. Sess. (Or. 2011) (enacted). More specifically, this grant system awarded over $9 million for 92 renewable energy projects statewide, including biogas facilities. In May 2018, the North Carolina Energy Policy Council draft report included specific recommendations for bioenergy research. Currently, Duke University, through a R&D grant, has budgeted $250,000 each year for two years to research biogas inventory and quantify the amount of technically recoverable biogas. The South Carolina Energy Office provides funding through a loan program to incentivize renewable project development, including biogas and biomass. South Carolina also provides tax credits and incentives for the purchase and installation of equipment used to create heat, power, steam, electricity, or other forms of energy for commercial use consisting of no less than 90 percent biomass resources. S.C. ENERGY OFFICE, South Carolina Tax Incentives, http://www.energy.sc.gov/lpage?m=701 (last visited July 19, 2020).

100 *Id.*

101 Pipeline and Hazardous Materials Safety Administration issued a final rule on July 24, 2020, authorizing the bulk transportation of LNG by rail in specialized railcars. Hazardous Materials: Liquefied Natural Gas by Rail, 85 Fed. Reg. 44,994 (July 24, 2020) (to be codified at 49 C.F.R. pts. 172–74, 179, and 180).

a. Natural Gas Pipelines[102]

In addition to a significant domestic supply of natural gas, the United States also has a highly developed and heavily interconnected natural gas pipeline system. It is currently estimated that there are over 300,000 miles of natural gas transmission pipelines[103] and over 1.2 million miles of natural gas distribution pipeline systems[104] in the United States. These pipeline systems provide the opportunity for efficient natural gas transportation from the wellhead to an SMR project site. However, these pipelines and the capacity that they offer also are subject to significant regulation.

In addition to understanding natural gas quality specifications, which are discussed in the **Pipeline section of Part III (Section I.C.2.b)**, it is critical that entities looking to ship natural gas via pipeline understand the applicable regulatory regimes to assess potential economic impacts to the commerciality of a particular hydrogen production development project.

Under the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) regulates the siting, construction, and operation of interstate natural gas pipelines and storage, the rates and terms and conditions of service offered, and sales for resale of natural gas in interstate commerce. FERC's regulation does not include gathering pipelines or local distribution pipelines. These pipelines are instead regulated by state agencies.

Importantly, interstate natural gas pipeline and storage capacity holders must abide by FERC's regulations and policies. Interstate natural gas pipelines must offer capacity on an open access basis, meaning that capacity must be made publicly available and pipelines cannot discriminate between or among similarly situated shippers. As part of its jurisdiction over interstate natural gas pipelines, FERC regulates capacity holders, imposing restrictions on how shippers can use and resell their capacity. Overall, these restrictions are aimed at promoting a transparent, non-discriminatory, efficient capacity market. Notably, FERC has civil penalty authority of up to $1 million per day per violation, as well as criminal penalty authority; thus, any entity that seeks to develop natural gas-based hydrogen production facilities needs to be very familiar with laws and regulations governing access to and transportation of natural gas in the United States and seek guidance from legal experts prior to finalizing any transaction.

102 A discussion of transportation of hydrogen by pipeline is in Part III, Transportation and Distribution — Pipeline (Section I.C).

103 *Annual Report Mileage for Natural Gas Transmission & Gathering Systems*, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN. (July 1, 2020) https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems.

104 *Id.*

b. Natural Gas Trucking

Another significant method for transportation of natural gas in the United States is by truck. FERC has found that its NGA jurisdiction does not include the interstate transportation of natural gas by truck.[105] CNG and LNG trucking are regulated by the Federal Motor Carrier Safety Administration (FMCSA), which requires, among other things, that CNG and LNG motor carriers obtain a Hazardous Materials Safety Permit to transport in bulk.[106] While transporting natural gas by truck can be efficient, particularly when pipeline transportation to an end-user is not feasible, there are constraints to bear in mind. For example, FMCSA prescribes vehicle weight limits that can constrain the quantity of natural gas that can be transported by truck. In addition, transporting natural gas as LNG by truck presents the potential for product loss as a result of boil-off.

5. CCS

Concerns regarding climate change are driving a resurgence of interest in hydrogen derived from natural gas paired with CCS. According to the CCS Association, "The CCS chain consists of three parts; capturing the carbon

105 *See, e.g., Southern LNG Inc.*, 131 FERC ¶ 61,155 at p. 17 (2010) (FERC declined to assert NGA jurisdiction over LNG trucking, finding that "[its] NGA section 3 jurisdiction over LNG import facilities and services would not follow the LNG tanker trucks after they exit the boundary of the terminal . . . .").

106 49 C.F.R. § 385.403.

dioxide, transporting the carbon dioxide, and securely storing the carbon dioxide emissions, underground in depleted oil and gas fields or deep saline aquifer formations."[107] Capturing the carbon dioxide from an energy or industrial source can be done one of three ways: pre-combustion; post-combustion; and oxy-fuel combustion.

- Pre-combustion carbon capture occurs, as the name suggests, before combustion of the feedstock is complete. Pre-combustion occurs through the production of a syngas from the original feedstock using gasification. The syngas then undergoes the water-gas shift reaction described above, resulting in a mixture of hydrogen and carbon dioxide, with levels of carbon dioxide ranging from 15 percent to 50 percent. According to DOE, commercially available pre-combustion carbon capture technologies are expensive at approximately $60/ton. DOE is researching technologies that can improve the affordability of pre-combustion capture, targeting $39/ton.

- Post-combustion carbon capture is the capture of carbon dioxide from the flue after the feedstock has been combusted. The main challenge with post-combustion capture is separating the carbon dioxide from large amounts of nitrogen found in flue gas. DOE is working to advance a solution by focusing R&D on advanced solvents, solid sorbents, and membrane systems.

- Finally, Oxy-fuel combustion combusts the feedstock in oxygen diluted with recycled flue-gas, rather than air. This process results in flue-gasses that mainly consist of carbon dioxide and water. The carbon dioxide is more concentrated and easier to purify than alternative carbon capture processes.

Following capture, the carbon dioxide is compressed into a liquid and transported by pipeline or ship to be stored in geological rock formations typically located several kilometers below the earth's surface.

DOE's Office of Fossil Energy (FE) is the main federal entity supporting R&D to improve carbon capture and sequestration. Recently, FE announced selected proposals for the first solicitation of the Coal FIRST (Flexible, Innovative, Resilient, Small, and Transformative) initiative. Coal FIRST is aimed at R&D to develop the zero-emission coal facility of the future through cost-shared projects. Coal FIRST power plants will use CCS to generate carbon neutral energy or hydrogen.

In addition to R&D, the federal government supports CCS through the 45Q tax credit, which was expanded and reformed in the 2018 Balanced Budget Act. The 45Q tax credit can be claimed by the owner of the carbon capture equipment, but it may also be transferred by the owner to another entity that would store or beneficially utilize the carbon. To receive the credit, a threshold amount of carbon dioxide must be captured and sequestered or utilized. The Balanced

[107] THE CARBON CAPTURE AND SEQUESTRATION ASS'N, http://www.ccsassociation.org/ (last visited Aug. 21, 2020).

Budget Act increased the value of the 45Q credits to $35/ton for enhanced oil recovery and beneficial use and $50/ton for carbon sequestration. 45Q is intended to incentivize carbon capture deployment across a variety of industries including electric power production, steel and cement manufacturing, ethanol and fertilizer production, and natural gas production.

A number of fossil fuel and industrial companies, governments in Europe, Japan, and Australia, and the state of California are in the early stages of exploring blue hydrogen technologies that capture and store carbon emitted from the hydrogen production process. In theory, the low-carbon hydrogen would then be used for indoor heating, as a transportation fuel, for industrial processes, or potentially even to provide electricity to balance out intermittent renewable generation.

E. Biomass

Like wind, solar, and biogas/RNG, biomass can be a renewable source of or feedstock for hydrogen generation. Biomass is organic material often collected from municipal organic solid waste and can also include agriculture crop residue, forest residues, and energy crops.[108] There are several methods for converting biomass into hydrogen, which can be described as either biological or thermochemical.[109] The biological methods include anaerobic digestion, fermentation, and metabolic processing, while the thermochemical methods include gasification, high pressure aqueous, and pyrolysis.[110]

The most common method of producing hydrogen from biomass is gasification. The conversion of organic material or fossil carbon from biomass occurs at a high temperature (>700 degrees Celsius) without combustion and in conjunction with a specific amount of oxygen or steam, which breaks down the material into hydrogen, carbon dioxide, and carbon monoxide. The reformed gas undergoes a water gas shift reaction, converting it into hydrogen, and often is paired with a pressure swing adsorption for purification.[111]

Historically, the hurdle of making biomass-to-hydrogen technology cost-competitive with natural gas steam reforming was considered high.[112] Today, however, the pilot projects are proving out new technologies,[113] and the cost

[108] *Hydrogen Production: Biomass Gasification*, DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification (last visited Aug. 4, 2020); Havva Balat and Elif Kirtay, Hydrogen from biomass – Present scenario and future prospects, 35 Int'l J. of Hydrogen Energy 7416, 7418 (2010).

[109] Havva Balat and Elif Kirtay, *Hydrogen from biomass – Present scenario and future prospects*, 35 INT'L J. OF HYDROGEN ENERGY 7416, 7418–19 (2010).

[110] *Id.*

[111] *Id.*

[112] *Id.* at 7421.

[113] *See* Mark Luth, Hydrogen Production from Biomass and Organic Waste, Fuel Cell & Hydrogen Energy Assoc. (July 8, 2019) http://www.fchea.org/in-transition/2019/7/8/hydrogen-production-from-biomass-and-organic-waste (describing pilot projects currently exploring electricity generation from biomass).

of equipment and feedstocks continues to decline.[114] Research indicates that there is potential for both methods for converting biomass to hydrogen to be cost-competitive with other forms of hydrogen production.[115]

As with steam methane reforming of natural gas, gasification of biomass produces carbon dioxide as a byproduct. The regulatory constraints on biomass gasification are likely to mirror those on natural gas SMR. Any gasification process will have to account for and accommodate greenhouse gas reporting requirements and potentially will require constructing and operating CCS facilities in accordance with EPA regulations.

F. Coal

Hydrogen also may be produced from coal by a process called "gasification," but the use of coal to produce hydrogen faces many hurdles both in process as well as in perception. Globally, China and Australia use coal to produce hydrogen more than any other nation, since both have abundant coal reserves, but the use of coal is still relatively small when compared to other hydrogen production methods such as natural gas and renewables discussed previously. Coal gasification creates a significant amount of carbon dioxide—approximately four times as much as natural gas. As a result, hydrogen producers are left with an emissions problem without effective—and likely expensive—carbon capture technologies. Moreover, in the United States, there has been a substantial decline in coal production in recent years and an even more precipitous decline in demand with the country's aging fleet of coal-fired power plants and the corresponding decommissioning of many of those plants. In short, the future of coal is uncertain at best, and public opinion and a focus on climate change further compound this uncertainty and likely will limit any robust use of coal for hydrogen production.

1. Coal Gasification

Coal is used to create hydrogen through coal gasification. Hydrogen is produced by first reacting coal with oxygen and steam under high pressures and temperatures to form synthetic gas, consisting primarily of carbon monoxide and hydrogen. The carbon monoxide is then reacted with steam (again) through the water-gas shift reaction to produce additional hydrogen and carbon dioxide. This results in a highly concentrated carbon dioxide stream. DOE's Office of Energy Efficiency and Renewable Energy anticipates that hydrogen production through coal gasification could be deployed in the mid-term time frame.[116] However, the DOE notes that carbon capture and other technologies will need

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[114] *Hydrogen Production: Biomass Gasification*, DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification (last visited Aug. 4, 2020).

[115] Bamidele Victor Ayodele, et al., *A Mini-Review on Hydrogen-Rich Syngas Production by Thermo-Catalytic and Bio-conversion of Biomas and Its Environmental Implications*, FRONT. ENERGY RES. (Oct. 25, 2019) https://doi.org/10.3389/fenrg.2019.00118/full.

[116] *Hydrogen Production: Coal Gasification*, U.S. DEP'T OF ENERGY https://www.energy.gov/eere/fuelcells/hydrogen-production-coal-gasification (last visited July 27, 2020).

more R&D to produce hydrogen at target costs and with near-zero emissions, noting that there are still several challenges to overcome.

Regulation of coal gasification will be similar to that of traditional coal-fired power production. The gasification process, like traditional coal burning, produces carbon dioxide, as well as coal ash and slag. The emission of carbon dioxide is regulated under the CAA, and provides specific reporting requirements for greenhouse gas emissions from hydrogen production sources. Similarly, the byproducts of the gasification process, such as coal ash, are regulated in the same way as those produced at traditional power plants, including disposal requirements under the Resource Conservation and Recovery Act (RCRA), and discharge requirements of the CWA. State-level regulation of energy production from coal also would likely apply to gasification production.

2. Hydrogen Production through Coal Gasification: Emissions

Using coal gasification to produce hydrogen produces around four times the amount of carbon dioxide compared to natural gas, requiring higher carbon sequestration volumes. Therefore, the tradeoff is between the cheap cost of coal and the costs of carbon dioxide sequestration and residual emissions.[117] However, with public opinion changing as climate change becomes a top priority—and without large-scale, widely available, effective carbon capture technologies to handle these large amounts of carbon dioxide—coal gasification faces many hurdles.

3. U.S. Coal Reserves and Production

The United States has the most proved coal reserves in the world with 22 percent of the world share in 2017.[118] The country with the next largest share of proved coal reserves is Russia

[117] *Path to Hydrogen Competitiveness, A Cost Perspective,* HYDROGEN COUNCIL at 25, Jan. 20, 2020, https://hydrogen-council.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf (last visited July 27, 2020).

[118] *Coal Explained: How Much Coal is Left,* U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/coal/how-much-coal-is-left.php (last updated Nov. 12, 2019).

at 15 percent.[119] The United States' demonstrated reserve base coal reserves was 474 billion short tons; however, the United States has seen a precipitous decline in production as a result of cheap natural gas and decreasing cost of commercial-scale renewables.[120]

U.S. coal production decreased 2.4 percent year-over-year to 756.2 million short tons (MMst) in 2018 when compared to 2017.[121] U.S. coal production further decreased 7.2 percent year-over-year to 705.3 MMst in 2019 when compared to 2018.[122] U.S. coal production was 9.8 percent lower in the first quarter of 2020 than the previous quarter (4Q of 2019) and 17 percent lower than the first quarter of 2019.[123] U.S. coal production estimates for the second quarter of 2020 were 113 MMst, down 37 percent from the same period a year ago.[124]

4. Economic Outlook for Coal

The average U.S. coal-fired power plant is over 40 years old,[125] and there are no commercial coal plants under construction in the United States as of July 2020.[126] Some scenarios have coal generation remaining flat over the next few decades, but as clean energy initiatives begin to take hold and market conditions continue to respond to changing public opinion, further declines should be expected.[127] Approximately 546 coal-fired power units have announced their retirement in just the past decade alone.[128] It is further estimated that over 85 percent of existing coal plants will be uneconomic compared to local renewables by 2025.[129]

5. The Politics of Coal

As with natural gas, the U.S. elections in November 2020 have the potential to shape the coal industry for years to come. In 2016, President Trump campaigned on ending the Obama administration's "war on coal," and since taking office has rescinded

119 *Id.*

120 *Id.*

121 *2018 Annual Coal Report,* U.S. ENERGY INFO. ADMIN. (Oct. 3, 2019), https://www.eia.gov/coal/annual/.

122 *Table 1. U.S. Coal Production, 2014–2020*, U.S. ENERGY INFO. ADMIN. (Mar. 2020), https://www.eia.gov/coal/production/quarterly/pdf/t1p01p1.pdf.

123 *Quarterly Coal Report January–March 2020,* U.S. ENERGY INFO. ADMIN. (July 1, 2020), https://www.eia.gov/coal/production/quarterly/.

124 *Short-Term Energy Outlook July 2020: Coal,* U.S. ENERGY INFO. ADMIN. at 16 (July 2020), https://www.eia.gov/outlooks/steo/archives/Jul20.pdf.

125 *Today in Energy: Most Coal Plants in the United States were Built Before 1990,* U.S. ENERGY INFO. ADMIN. (Apr. 17, 2017), https://www.eia.gov/todayinenergy/detail.php?id=30812.

126 *Global Coal Plant Tracker*, GLOBAL ENERGY MONITOR, https://endcoal.org/tracker/ (last visited July 27, 2020).

127 *Today in Energy: EIA Projects Generation from Coal and Nuclear Power Plants will Plateau after 2025,* U.S. ENERGY INFO. ADMIN. (Feb. 7, 2020), https://www.eia.gov/todayinenergy/detail.php?id=42755.

128 *Today in Energy: More U.S. Coal-Fired Power Plants are Decommissioning as Retirements Continue*, U.S. ENERGY INFO. ADMIN. (July 26, 2019), https://www.eia.gov/todayinenergy/detail.php?id=40212.

129 Joshua Rhodes, *Is the U.S. Coal Industry Completely Burned Out?*, FORBES (Feb. 12, 2020), 11:25 AM, https://www.forbes.com/sites/joshuarhodes/2020/02/12/is-the-us-coal-industry-almost-completely-burned-out/#29a5a65e594f.

former President Barack Obama's Clean Power Plan and taken steps to try to limit the transition away from coal. Nonetheless, despite the Trump Administration's deregulation agenda, including rescinding methane emissions reductions and relaxing fuel standards, these policies have done little to stem the market transition away from coal.

In contrast, former U.S. vice president and Democratic presidential nominee Joe Biden has issued an energy and environmental plan that includes a stated intention to achieve net-zero emissions by no later than 2050. As part of his vision for a clean energy future, Biden intends to achieve a carbon pollution-free power sector by 2035. With heavy investment proposals in renewable, carbon-free emission energy production, as well as the production of carbon-free hydrogen through renewable feedstock and innovative technologies, it is unlikely that coal will play a major role, if any, in America's energy future under a Biden administration.

The use of coal to produce hydrogen faces many hurdles. The United States has seen large declines in coal production over the past decade, and this trend is likely to continue over the next few decades as natural gas and renewable energy resources become less expensive and continue to build their market share. Shifting public opinion and awareness on climate change will likely exacerbate this downward trend. The future of coal is uncertain, but advances in technology to reduce emissions and generate coal-produced hydrogen at target costs have the potential to change the narrative of this important feedstock in the future.

PART III -
TRANSPORTATION, DISTRIBUTION, END-USE, AND STORAGE

The United States has a highly developed and evolving energy economy that includes a range of modes of transportation, distribution, and storage. The United States already has robust regulatory regimes that apply to these transportation, distribution, and storage modes to help ensure safety and reliability, as well as to provide both access and competition. However, as discussed in greater detail in the sections that follow, regulation and policies in these areas likely will need to evolve to accommodate and include hydrogen, and industry participants will have an opportunity to play a role to ensure clear, transparent, and focused regulations and policies.

In addition, how and where end-uses of hydrogen develop likely will influence the growth of and policies applicable to hydrogen transportation, distribution, and storage. Government incentives to promote end-use will be an important piece to this puzzle, and several current incentives are discussed below.

I. Transportation and Distribution

This section discusses the current and potential future regulatory regimes that apply to four modes of U.S. hydrogen transportation and distribution: motor carrier, rail, pipeline, and vessel. As the U.S. hydrogen economy continues to develop and grow, regulation of these modes of hydrogen transportation may as well.

At the outset, while regulation of these modes of hydrogen transportation and distribution may be robust, there appear to be far fewer traditionally "environmental" regulatory regimes that apply. Unlike concerns with direct water and ground pollution with heavy hydrocarbons and other compounds in crude oil or petroleum liquids products, hydrogen in gaseous or liquefied form is "lighter than air." Hydrogen gas does not linger near the earth's surface and also is not a direct greenhouse or other deleterious gas in the earth's atmosphere. Hydrogen in liquefied form "boils off" almost instantaneously when depressurized.

Perhaps unsurprisingly then, hydrogen is not listed as an "extremely hazardous substance" or a "toxic chemical" under the Emergency Planning and Community Right-to-Know Act (EPCRA), a "hazardous substance" under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), or a "hazardous waste" under the RCRA. For nearly all forms of hydrogen transportation, this is notable. Similarly, hydrogen might not fall under the CWA definition of "pollutant" given that hydrogen cannot linger in water or other liquids unless contained at extremely high pressures, but the EPA's stance on this issue is not known with certainty at this time. This will, of course, be relevant for shippers and transportation providers going forward. Hydrogen does appear on the CAA list of regulated substances under Section 112(r), which triggers EPA's Risk Management Plan (RMP) rule for certain larger storage quantities of hydrogen, but hydrogen appears on this list only due to its flammability.[130]

While hydrogen has been on regulators' radar for decades given its use in industrial metallurgical, crude oil refining, and semiconductor applications, transportation of hydrogen by motor carrier, rail, pipeline, and vessel has not been considered as environmentally sensitive as transportation of other materials. As the hydrogen economy evolves, it is possible that all regulatory regimes that touch on hydrogen transportation—safety, environmental, and others—may as well. In addition, as hydrogen is touted by many as indispensable to decarbonizing the world economy, environmental regulators may have renewed interest in the transportation of this resource as well.

A. Motor Carrier

Hydrogen currently is transported by truck in the United States in compressed gaseous form using tube trailers and in liquid form in cryogenic tanker trucks.

130 40 C.F.R. § 68.130 (Table 3).

Considerations for truck transport include volume limitations resulting from the U.S. Department of Transportation's (DOT) pressure and vehicle weight restrictions, as well as the potential product loss due to boil-off during transport for liquid hydrogen (LH2) given the extremely low temperature required to liquefy hydrogen.

The Federal Motor Carrier Safety Administration (FMCSA) is the agency with primary jurisdiction over the transportation of hydrogen and related hazardous materials via commercial trucking. FMCSA's authority is outlined in the federal regulations at 49 C.F.R. Parts 390–397, Subtitle B, Chapter III, Subchapter B. Part 397 provides guidance on the transportation of hazardous materials, including instruction for compliance with federal motor carrier safety regulations (§397.2), routing of non-radioactive hazardous materials (Subpart C), and preemption procedures (Subpart E). In addition, general federal motor carrier regulations (Part 390) provide guidance for obtaining hazardous material safety permits and providing intermodal equipment provider identification reports (§390.19).

Additionally, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for regulatory oversight of the carriage of hazardous materials by rail, aircraft, vessel, or public highway under its Hazardous Materials Regulations (49 C.F.R. Parts 171–180, Subtitle B, Chapter I, Subchapter A). More specifically, PHMSA provides material hazard class guidance for Class 2.1 flammable gases (§173.115) and Class 3 flammable and combustible liquids (§173.120). It also outlines general requirements for loading, inspection, and lading pressure associated with hazardous materials in cargo tank motor vehicles (§173.33). Part 177 also provides PHMSA with the authority to regulate carriage by public highway, including inspection procedures (§177.802), compliance with federal motor carrier safety regulations (§177.804), and unacceptable hazardous materials shipments (§177.801).

Federal regulation of hazardous material transportation is applicable to all intrastate, interstate, and foreign commerce. State regulation may also apply, however, pursuant to the Hazardous Materials Transportation Act of 1975, which provides that state directives that are inconsistent with federal law are preempted unless they afford equal or greater protection to the public.

Advancements in tube trailers and cryogenic tanker technologies may push reconsideration or revision of these regulatory requirements, particularly as the U.S. hydrogen economy continues to grow and over-the-road transportation increases.

B. Rail

As noted above, hydrogen has been used in industrial applications in the United States for decades. As such, there already is interest in transporting hydrogen by rail and current U.S. regulations address hydrogen transportation by rail. As discussed further in this section, current regulations impose restrictions that rail carriers and shippers should bear in mind as the U.S. hydrogen economy expands and the need to ship hydrogen by rail in greater volumes increases.

As noted above, PHMSA governs the carriage of hazardous materials by rail, aircraft, vessel, or public highway under its Hazardous Materials Regulations (HMR).[131] Under 49 U.S.C. §§ 5101–5127, the Secretary of Transportation has the authority to promulgate regulations that govern the transportation of hazardous materials in commerce. The HMR applies to any person that transports or causes to be transported or shipped hazardous materials in interstate, intrastate, and foreign commerce. The Federal Railroad Administration enforces the HMR, as promulgated by PHMSA, as they pertain to rail transportation.

PHMSA's regulations at 49 C.F.R. Part 174 contain provisions addressing the carriage of hazardous materials by rail, including necessary inspections and safety precautions. Compressed hydrogen and refrigerated LH2 are both defined as hazardous materials under PHMSA's regulations at 49 C.F.R. § 172.101. Further, all flammable cryogenic liquids, which includes liquefied hydrogen, are also defined as hazardous materials within PHMSA's regulatory scope. Certain cryogenic flammable liquids, including hydrogen, may be transported by rail. PHMSA's regulations provide for special handling requirements, including precautions against loading, transporting, or storing flammable liquid materials in rail cars that are equipped with any type of lighted heater or open-flame device, or in rail cars that utilize an internal combustion engine.

Notably, flammable liquids can only be transported by rail if the original consigned party or the subsequent consigned party has a private track on which the liquid will be delivered and unloaded, or if the flammable liquids will be consigned or reconsigned to a party using specialized railroad siding facilities. There are also regulations governing routing, speed restrictions, standards for new tank cars, and more with which parties transporting flammable liquids, such as liquefied hydrogen, by rail need to comply.[132]

Finally, the HMR authorizes transportation of cryogenic flammable liquids in specialized tank cars.[133] DOT-113 class tank cars currently are authorized under the HMR to move flammable liquids like hydrogen. However, according to recent comments, PHMSA "does not believe cryogenic hydrogen UN1966 is currently transported in this manner in the United States" [in DOT-113 rail cars].[134]

PHMSA is considering similar railcars for the movement of LNG. PHMSA recently published a final rule that allows for the bulk transportation of LNG in

131 49 C.F.R. §§ 171–180 (2020).

132 49 C.F.R. § 174 (2020).

133 49 C.F.R. § 179 (2020).

134 PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., SP 20534 SPECIAL PERMIT TO TRANSPORT LNG BY RAIL IN DOT113C120W RAIL TANK CARS, FINAL ENVIRONMENTAL ASSESSMENT (2019).

DOT-113 specification tank cars that have enhanced outer tank requirements.[135] The final rule also requires remote monitoring of the pressure and location of LNG tank cars and additional requirements for trains that are transporting several LNG tank cars on the same train. Similar tank cars as those proposed to carry LNG have been authorized to carry hydrogen for decades. In the Final Environmental Assessment for the movement of LNG by rail, PHMSA highlighted this long-standing authorization as support for allowing the movement of LNG by rail as well.[136]

C. Pipeline

Gaseous hydrogen is currently transported in the United States through a few existing hydrogen-specific pipelines. At the federal level, hydrogen pipelines currently are regulated by the DOT as a flammable gas.[137] State-level regulations related to pipeline safety may also be applicable. Construction of new, commercial-scale hydrogen pipelines in the United States will give rise to a range of issues. This section addresses a few of the more challenging issues related to a robust deployment of pipeline transportation for hydrogen in the United States.

1. Use of Existing Pipelines

One of the major considerations for the robust development of a hydrogen economy in the United States is the potential use of existing natural gas pipelines for transportation of hydrogen, either blended with the existing natural gas stream or alternatively through the conversion of natural gas pipelines to ship hydrogen exclusively. Given that there are hundreds of thousands of miles of natural gas transportation pipelines and over a million miles of natural gas distribution pipelines across the United States,[138] this presents a very real, potentially lower-cost opportunity[139] for the hydrogen industry to deliver commercial-scale volumes of hydrogen. Note that, unlike interstate natural gas pipelines, there is not presently a centralized federal regulatory regime applicable to the siting, construction, and operation of interstate hydrogen pipelines. While the issue has not been raised squarely before FERC, based on years of precedent it appears clear that FERC considers its jurisdiction under the NGA, as currently drafted, to apply specifically to interstate natural gas pipelines.

The DOE's National Renewable Energy Laboratory found in a 2013 study that blending in the range of 5 percent-15 percent hydrogen in the natural gas stream could result in "only minor

135 Hazardous Materials: Liquefied Natural Gas by Rail, 85 Fed. Reg. 44994 (July 24, 2020).

136 PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., SP 20534 SPECIAL PERMIT TO TRANSPORT LNG BY RAIL IN DOT113C120W RAIL TANK CARS, FINAL ENVIRONMENTAL ASSESSMENT at 20–21 (2019).

137 49 C.F.R. pt. 192.

138 *Annual Report Mileage for Natural Gas Transmission & Gathering Systems*, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN. (July 1, 2020) https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems.

139 The capital cost of long-haul, larger diameter, new build hydrogen pipelines and the hydrogen-specific compression required to ship hydrogen through such pipelines is significant.

issues … depending on site-specific conditions and particular natural gas compositions," and noted that with appropriate mitigation and modifications (likely to end-user equipment and household appliances) even up to 50 percent hydrogen in the natural gas stream could be acceptable.[140] The International Energy Agency (IEA) indicates that blending hydrogen into a natural gas pipeline stream would require "upper … limits of around 20 percent to 30 percent, depending on the pipeline pressure and regional specification of steel quality."[141] As noted in the **Government Incentives section of Part I (Section I.A)**, DOE recently solicited proposals and awarded grants for programs addressing technical barriers to hydrogen blending in natural gas. Given the extensive geographic coverage of the entire United States with natural gas pipelines, this could represent a significant means to effectuate broader distribution of hydrogen.

There are significant barriers, however, to implementing such a shift in the U.S. natural gas pipeline grid, including practical, safety, and legal issues. The existing natural gas pipeline system in the United States is fully optimized to transport methane, and intentionally injecting hydrogen into the stream poses many operational and safety challenges.[142] Both interstate natural gas transportation lines and local natural gas distribution lines are heavily regulated and, as a result, to the extent the hydrogen industry desires to utilize such lines for the transportation of hydrogen, there are a number of issues and challenges that the industry will need to address. Most importantly, two key threshold issues include the development of practices for nominating hydrogen to flow on a particular natural gas pipeline and the establishment of specifications for gas composition.

a. Nominating Hydrogen to Interstate Natural Gas Pipelines[143]

Interstate natural gas pipelines are regulated by FERC, which has plenary jurisdiction over interstate natural gas pipelines and storage pursuant to the NGA.[144] Every interstate natural gas pipeline has a "tariff" that is publicly filed with FERC. The tariff is the physical document that provides nearly all the operating documents for the

140 Melaina, M.W. et al. "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues," National Renewable Energy Laboratory, (Mar. 2013), https://www.nrel.gov/docs/fy13osti/51995.pdf (herein 2013 NREL Pipeline Study).

141 *Technology Roadmap: Hydrogen and Fuel Cells*, INTERNATIONAL ENERGY AGENCY (2015), at p. 23, https://www.iea.org/reports/technology-roadmap-hydrogen-and-fuel-cells.

142 For example, it is well understood that hydrogen can "embrittle and accelerate crack growth" in welds in steel pipes and can more easily permeate typical elastomer seals and plastic pipe than natural gas leading to a greater leak rate. *See* PG&E Gas R&D and Innovation White Paper, "Pipeline Hydrogen," (Sept. 18, 2018), at pp. 14–15, https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/Whitepaper_PipelineHydrogenAnalysis.pdf; and Hydrogen Delivery Infrastructure Options Analysis, U.S. DEP'T OF ENERGY, https://www.energy.gov/sites/prod/files/2014/03/f11/delivery_infrastructure_analysis.pdf.

143 Intrastate natural gas pipelines are usually regulated by each state's public utility commission.

144 *See* 15 U.S.C. §§ 717 et seq.

pipeline, including the schedule setting the rates for service, the general terms and conditions of service (GT&C), and pro forma agreements for service on the pipeline. Included in all GT&Cs for every pipeline are provisions outlining how a customer requests and receives service from the pipeline, including prescriptive guidelines for nominating gas to flow on the pipeline. Therein lies the barrier for any effort to move hydrogen by existing natural gas interstate (and likely intrastate) pipelines—the system currently is set up to only allow for natural gas to be nominated to the pipeline. As a result, for any business interested in utilizing a FERC-regulated interstate natural gas pipeline for hydrogen, there will be a threshold issue of whether they are even able to put hydrogen on the pipeline.

As discussed further below, there may be a few pipelines that allow hydrogen as an ancillary element in the natural gas injected into the pipeline, but currently there does not appear to be any interstate natural gas pipeline that would accept nominations of hydrogen gas for the pipeline. A company that wishes to do so will need to engage with the pipeline first. The pipeline company will not be obligated under current law to accept hydrogen on the system, nor will it be obligated to change its operating GT&Cs to allow hydrogen. Moreover, to make such a change, the pipeline would be required to seek authorization from FERC. The proceeding would be public and likely would generate significant scrutiny and engagement from many interested stakeholders, including utilities, industrial manufacturers, end-users, and trade associations who represent different interests, who will have the opportunity to file comments in the proceeding and challenge or support such a proposal. Given the potential complexity of the issues involved, the proceeding likely would be contentious and would not be resolved quickly.

If the U.S. hydrogen industry wants to pursue the possibility of using existing interstate natural gas pipelines to allow some blending of hydrogen into the existing natural gas stream, the hydrogen industry will need to engage extensively with the natural gas industry to try and develop some path forward to avoid protracted regulatory proceedings that delay hydrogen blending.

2. Construction of New Pipelines

As the hydrogen economy in the United States continues to mature, the need for dedicated hydrogen pipelines likely will increase. Pipelines offer an economy of scale relative to trucking and are able to reach inland areas that cannot be served directly by vessels.

DOE estimates that there are 1,600 miles of hydrogen pipeline operating in the United States.[145] While there has been opposition to natural gas and oil/oil products pipeline construction, the opposition has been based on a variety of underlying arguments, not all of which may be present with hydrogen. More specifically, some opposition groups have focused on fossil fuel infrastructure as part of a broader argument against fossil fuel production. As described in **Part II** above, hydrogen can be produced from a variety of sources, including renewable energy. Consequently, while landowner, pipeline routing, environmental protection, and safety concerns likely will remain for hydrogen pipelines, it is possible that these projects will not face the same level of opposition as natural gas and oil/oil products pipelines.

Given the extremely low temperature required to liquefy hydrogen (-252.8 degrees Celsius or -423 degrees Fahrenheit), absent technological advancements, distribution and transmission pipelines most likely will carry hydrogen in a gaseous state. A number of studies have recognized several potential challenges to transporting hydrogen by pipeline, including steel embrittlement, the need to develop odorization or a similar method for leak detection, and the need for less permeable seals.[146]

Development of new hydrogen gas pipelines could be subject to federal permitting regimes, which could include permits under the CWA, the Rivers and Harbors Act, the Endangered Species Act, as well as environmental review under NEPA, if federal funding or permits are required. A state water quality certification may also be required if construction of the pipeline requires a federal permit and has the potential to discharge into state waters. Other state and local permits may also be required for construction. Ultimately, the regulation of existing, and future, hydrogen pipelines will depend, in part, on whether the pipelines are intrastate or interstate.

a. Intrastate Pipelines

As hydrogen demand increases, it is likely that dedicated intrastate hydrogen pipelines will be needed to transport hydrogen from production

145 *Hydrogen Pipelines,* DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines (last visited Aug. 21, 2020).

146 *See* PG&E Gas R&D and Innovation White Paper, "Pipeline Hydrogen," (Sept. 18, 2018), at pp. 14–15, https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/Whitepaper_PipelineHydrogenAnalysis.pdf; and *Hydrogen Delivery Infrastructure Options Analysis,* DEP'T OF ENERGY, https://www.energy.gov/sites/prod/files/2014/03/f11/delivery_infrastructure_analysis.pdf (last visited Aug. 21, 2020).

sites to various end-users. In states that do not currently have a regime applicable to hydrogen pipelines, the regulatory regimes that exist for intrastate natural gas pipelines could serve as a model for intrastate hydrogen pipelines, though modifications may be required to address hydrogen's relative characteristics, including its smaller molecule size and higher flammability.

The siting, construction, and operation of intrastate pipelines generally are regulated by the individual states and the specific requirements vary by state. This regulation typically includes state public utility commission approval of rates for transportation and storage service, as well as terms and conditions of service (which may include the terms of interconnection). However, some states currently permit hydrogen pipelines to operate as proprietary pipelines and therefore do not require state public utility commission approval of rates and terms of service.[147] As discussed in **Gas Composition and Issues of Interchangeability below (Part III, Section I.C.2.b)**, U.S. pipelines generally maintain product quality standards to help ensure system safety and reliability. Industry stakeholders and states likely will develop similar standards for hydrogen.

With respect to pipeline safety, the PHMSA regulates the safety of the transportation of natural and other gas by pipeline and prescribes minimum federal safety standards applicable to such pipelines under 49 C.F.R. Part 192. Through partnerships with PHMSA, states may regulate intrastate gas pipelines if their regulations are at least as stringent as the federal minimum safety standards.[148]

PHMSA's jurisdiction includes pipelines that transport flammable gas, like hydrogen, and PHMSA has regulated hydrogen under 49 CFR Part 192 since 1970.[149] In discussing its role in a developing hydrogen economy, PHMSA has noted that it will "need to focus on supporting activities to ensure that hydrogen is transported safely. This will include: a clear technical focus regarding the safety implications of infrastructure materials, designs and systems; preparation to address any regulatory barriers towards a hydrogen economy; research in support of additional industry consensus standards; [and] efforts to educate and prepare emergency responders."[150] Consequently, while PHMSA's regulations currently cover hydrogen, it is possible that the

147 Nexant, Inc., Hydrogen Delivery Infrastructure Options Analysis: Final Report, Task Report: Task 1: Data and Knowledge Base, p. 56 (Dec. 2006) (explaining "Hydrogen pipelines in the U.S. are currently operated by the companies which own the hydrogen being transported. . . there are no common carrier companies").

148 49 U.S.C. §§ 60105–60106.

149 *Hydrogen*, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., https://primis.phmsa.dot.gov/comm/Hydrogen.htm (last visited July 25, 2020).

150 *Id.*

agency will develop additional or supplemental regulations as hydrogen demand and the need for pipeline transportation further develop.

b. Gas Composition and Issues of Interchangeability

Relatedly, in the event that hydrogen could flow on the interstate natural gas pipelines, one of the most significant challenges may be addressing gas composition issues. In order to address gas quality issues, participants in the hydrogen industry will need to understand how such pipelines are regulated and some recent history related to gas composition issues.

As the United States began to ramp up its imports of LNG in the early to mid-2000s, questions emerged in the industry and among end-user groups about "foreign gas" and the risks it posed to infrastructure in the United States. Concerns over differences in composition and the ability to blend the imported natural gas with historical U.S. Gulf Coast supplies ("interchangeability") prompted natural gas industry stakeholders to convene over the course of many months to try and develop an industry-sponsored, science-based approach. While there were commercial reasons for this approach, one of the most significant factors that led to this effort was a desire to forestall overly simplified federal regulatory engagement on the issue by FERC.

After significant industry input, FERC developed a set of five principles intended to facilitate the introduction of broader range of supplies of natural gas to the United States and protect existing infrastructure from differences in supply while providing a road map for all participants on how to move forward.[151] These principles are:

1. Only natural gas quality and interchangeability specifications contained in a FERC-approved gas tariff can be enforced.
2. Pipeline tariff provisions on gas quality and interchangeability need to be flexible to allow pipelines to balance safety and reliability concerns with the importance of maximizing supply, as well as recognizing the evolving nature of the science underlying gas quality and interchangeability specifications.
3. Pipelines and their customers should develop gas quality and interchangeability specifications based on technical requirements.
4. In negotiating technically based solutions, pipelines and their customers are strongly encouraged to use the Natural Gas Council Plus interim guidelines filed with FERC as a common reference point for resolving gas quality and interchangeability issues.

151 "Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs," *Natural Gas Interchangeability,* Docket No. PL04-3-000 (June 15, 2006) (herein 2006 Policy Statement).

5. To the extent pipelines and their customers cannot resolve disputes over gas quality and interchangeability, those disputes can be brought before FERC to be resolved on a case-by-case basis, on a record of fact and technical review.[152]

With the advent of the U.S. shale gas revolution and the production of domestic natural gas with sometimes significantly different compositions than historical gas streams, these five principles served as the foundation as many interstate pipeline companies initiated complex, lengthy negotiations with their shippers and related proceedings at FERC in order to develop more robust gas quality specifications in their FERC-approved tariffs. The goal was to accommodate additional gas supplies while also providing more detailed guidance to customers as to acceptable gas streams. These proceedings frequently involved dozens of interested parties, including interconnecting pipelines, local distribution companies, utilities, large industrial end-users with direct connects to the pipeline, and LNG importers. Settlements often were hard-fought and occasionally disputes resulted in FERC-litigated proceedings. In all cases, all interested parties spent substantial economic resources and time advocating for their particular position and providing data backing up their position.

Since the mid- to late-2000s, there have been few disputes related to the natural gas quality issues and the industry generally seems to have acclimated to the gas specification changes that were implemented. As the hydrogen industry considers the possibility of flowing hydrogen gas on natural gas pipelines, this context should guide its approach.

A recent review by K&L Gates of more than 40 major interstate natural gas pipeline companies' FERC tariffs indicates:

- only five pipelines include a hydrogen specification in the pipeline's tariff;[153]
- four include a reference to hydrogen with no particular specification or limitation;[154] and
- two others include a limitation on "non-hydrocarbon gases,"[155] which presumably would include hydrogen, though it is not specifically identified.

152 *See* 2006 Policy Statement at p. 2.

153 The five pipelines are Gulf South Pipeline, Enable – Mississippi River Transmission, Natural Gas Pipe Line Company of America, Southern Star Central Gas Pipeline, and Texas Gas Transmission.

154 The four pipelines are Midcontinent Express, Midwestern Gas Transmission, Trailblazer Pipeline, and Viking Gas Transmission.

155 The two pipelines are Algonquin Gas Transmission and Maritimes & Northeast Pipeline.

For example, Gulf South Pipeline's tariff provides that "[t]he gas shall contain no carbon monoxide, halogens or unsaturated hydrocarbons, and no more than four hundred parts per million (400 ppm) of hydrogen."[156] Texas Gas Transmission's tariff states that natural gas delivered to the pipeline shall contain 0% hydrogen.[157] The two pipelines that provide specifications for "non-hydrocarbon gases," Algonquin and Maritimes & Northeast, state that any gas tendered to the system "[s]hall not contain more than four percent (4.0%) by volume of a combined total of any non-hydrocarbon gas including, without limitation carbon dioxide, nitrogen, krypton, helium, argon, xenon, and neon."[158] While there is no specific reference to hydrogen, it is reasonable to infer that it would be included and, therefore, the limitation of four percent would apply to a customer that wanted to flow hydrogen on the system. The remaining 30 pipelines contain no provisions at all addressing hydrogen, and most pipelines' tariffs give the pipeline discretion to exclude gas from the system that could harm pipeline operations.

As a result, there is significant work that the hydrogen industry will need to undertake to effectively accomplish hydrogen blending in the U.S. natural gas pipeline transmission grid. The industry should understand inflection points for the various stakeholders in the natural gas industry looking to these prior gas quality and interchangeability issues and engage technical, economic, and legal advisors to develop and execute a strategy to achieve its pipeline blending objectives.

c. Interstate Pipelines

Interstate hydrogen pipelines also may play a role in the growth of a U.S. hydrogen economy. As noted above, it does appear likely that FERC

[156] Gulf South Pipeline Company, LLC, FERC NGA Gas Tariff, Seventh Revised Volume No. 1, Version 1.0.0, General Terms and Conditions, § 6.3.1(j) – Quality of Gas, https://infopost.bwpipelines.com/?tspid=1.

[157] Texas Gas Transmission, LLC, FERC NGA Gas Tariff, Fourth Revised Volume No. 1, Version 4.0.0, General Terms and Conditions, § 6.3.1(d) – Quality of Gas, https://infopost.bwpipelines.com/?tspid=100000.

[158] Algonquin Gas Transmission, LLC, FERC Gas Tariff, Sixth Revised Volume No. 1, Version 6.0.0, General Terms and Conditions, § 6.4.3(f) – Quality of Gas, https://infopost.spectraenergy.com/infopost/AGHome.asp?Pipe=AG; Maritimes & Northeast Pipeline, L.L.C., FERC Gas Tariff, Second Revised Volume No. 1, Version 3.0.0, General Terms and Conditions, Section 12.3(c) – Quality of Gas, https://infopost.spectraenergy.com/infopost/MNUSHome.asp?Pipe=MNUS.

would regulate interstate hydrogen pipelines under the NGA nor does it appear that there is presently a centralized federal regulatory regime applicable to the siting, construction, and operation of interstate hydrogen pipelines. Consequently, the regulatory regime for the construction of new interstate hydrogen pipelines is likely to be more akin to the regime applicable to interstate oil/oil products pipelines, as described below. As such, interstate hydrogen pipeline developers likely would need to obtain certificates of public convenience and necessity (or similar permits) from each state that the pipeline project traverses.

While the NGA likely does not currently apply to hydrogen, there are certain advantages to the federal regime that it establishes that are worth industry consideration as the U.S. hydrogen economy evolves, particularly as compared to interstate oil/oil products pipelines. More specifically, under the NGA, a single federal agency—FERC—issues the certificate of public convenience and necessity required for an interstate natural gas pipeline project. FERC's order authorizes the facility as a whole, subject to receipt of other required federal authorizations (e.g., air and water permits under the CAA and CWA, respectively). Further, FERC serves as the lead agency for the federal environmental review required under NEPA and coordinates with other federal and state agencies with jurisdiction over the project. While other federal agencies with jurisdiction, and state agencies with delegated federal authority, will issue separate permits and associated NEPA documents, the overall process is largely coordinated through FERC.

With respect to state and local authorities, the U.S. Supreme Court has ruled that the NGA preempts state law for the construction and operation of natural gas facilities.[159] FERC has since clarified that projects must "comply with appropriate state and local regulations where no conflict exists," but "state and local regulations are preempted by the NGA to the extent they conflict with federal regulation, impose conditions above the federal requirements, or would delay the construction and operation of facilities approved by this Commission."[160] In addition, the NGA provides approved project developers with eminent domain authority across the entire project, helping to streamline the process of obtaining rights-of-way from landowners.

By contrast, permitting for interstate oil/oil products pipeline facilities is more of a patchwork. Federal jurisdiction focuses more on the specific resources that may be impacted, as opposed to the project as a whole. FERC has jurisdiction over oil/oil products pipeline

159 *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 299–301 (1988).

160 *Dominion Transportation, Inc.*, 143 FERC 61,148, at p. 21 (2013).

companies under the Interstate Commerce Act—but its jurisdiction pertains only to the rates and terms of service and does not extend to the siting, construction, and operation of oil/oil products pipelines. While the U.S. Army Corps of Engineers may act as the lead NEPA agency, it also does not have jurisdiction over the pipeline project as a whole. Instead, individual states issue the certificates of public convenience and necessity (or similar permits) for these projects. This less-centralized approach means that project developers must meet the varied filing requirements in each of the states that their projects cross, each state's decision on an application for authorization to construct the pipeline is subject to challenge, and one state or state court's decision can significantly affect or even halt the overall project. A recent example is the Keystone XL pipeline, which faced litigation of its state permits in several states. While it appears that the current approach to interstate hydrogen pipeline project development is more akin to the oil/oil products pipeline model, the NGA demonstrates that a more centralized approach for project developers is possible.

As noted above with respect to intrastate pipelines, it is likely that industry participants and regulators will develop quality specifications for interstate hydrogen pipelines. Further, PHMSA's regulations under 49 C.F.R. Part 192 apply to interstate hydrogen pipelines and, as noted, PHMSA may seek to promulgate additional regulations as demand for hydrogen increases and the need for hydrogen pipelines further increases.

D. Vessel

The potential to transport hydrogen in bulk by vessel presents significant opportunities to reach markets that cannot be reached easily by pipeline or efficiently by truck. Given that LH2 has a volume ratio of 1:848 compared to hydrogen in a gaseous state, tremendous economies of scale can be realized if hydrogen is transported in a liquid state, as has been done with natural gas. This section discusses the requirements that may apply to the bulk transportation of LH2 by vessel in the United States.

1. Liquefaction

a. Permitting and safety

A critical aspect of the development of a long-term, sustainable, global hydrogen economy is the establishment of a robust import and export market. As the United States considers its role in capturing a share of a hydrogen market, it is well-placed to be a significant exporter of hydrogen. However, in the absence of a consistent regulatory framework for hydrogen export facilities, a patchwork of state regulatory regimes and standards for the construction and operation of coastal export facilities likely will emerge. Such a regulatory patchwork could create uncertainty for project developers and the investment community and, ultimately, present a challenge to the United States' ability to achieve sizable market share.

One possible solution could be the utilization of the country's proven regulatory framework for the export of natural gas as a regulatory foundation for the export of hydrogen. Like natural gas, hydrogen gas can be converted to LH2 through a process that cools the gas to -252.8 degrees Celsius (or -423 degrees Fahrenheit).[161] Like LNG, the transportation of LH2 is more efficient than transporting hydrogen gas because LH2 occupies 1/848th the volume as its gaseous form.[162] While there are, of course, major differences between LNG and LH2, similarities in the overall scope of facilities for export could be sufficient to allow for existing federal LNG and natural gas regulations to be applied to the export of hydrogen. Doing so likely would require congressional action to amend the NGA, which governs the export of natural gas.

LNG generally is exported from the United States in one of two ways: (1) the construction and operation of coastal LNG terminals at which LNG is produced and transferred by pipeline directly onto LNG tankers; and (2) less commonly, the production of LNG at inland liquefaction facilities that is then loaded into ISO containers that are trucked to ports and exported on general cargo vessels. Based on early market indicators, the export of LH2 may take the same form. Consider, for example, Australia's pilot LH2 export project described in the Australia portion of *The Hydrogen Handbook.* The project plans both to develop a carrier specifically designed for transporting LH2 in bulk, like LNG carriers that are used to export LNG in bulk, and to store LH2 in containers that will be loaded onto a standard shipping carrier for smaller-scale exports. Further, the United States already is home to eight hydrogen liquefaction facilities from which LH2 is transported via LH2 tube trailers to industrial end-users[163] that could also be used for export.

The export of LNG from the United States is governed primarily by Section 3 of the NGA.[164] Over time and through both executive branch and judicial precedent, that authority is now bifurcated between DOE and FERC. DOE is responsible for authorizing the export of the commodity,[165] while FERC is responsible for authorizing the siting, construction, operation, and expansion of coastal LNG facilities. That authority involves a robust environmental and safety review

161 *See, e.g.,* Port of Hastings, HYDROGEN ENGINEERING AUSTRALIA, https://hydrogenenergysupplychain.com/port-of-hastings/ (last visited Aug. 21, 2020).

162 *Id.*

163 *Hydrogen Delivery Technical Team Roadmap,* U.S. DRIVE at 7 (Jan. 2017), https://www.energy.gov/sites/prod/files/2017/08/f36/hdtt_roadmap_July2017.pdf.

164 15 U.S.C. §§ 717, *et seq.* (2018).

165 As described in Part III, Export Controls (Section III), *infra*, the Department of Commerce's export regime covers hydrogen.

pursuant to the NGA and NEPA, for which FERC serves as the lead federal authority coordinating with other federal and state agencies that act as cooperating agencies within their sphere of authority. This process allows for a more streamlined approach that is more manageable for project developers. In several orders over the last few years, FERC has limited its authority to coastal facilities only and has not exercised NGA Section 3 jurisdiction over the inland facilities associated with ISO container exports. The same approach should be taken with respect to LH2 exports.

In addition to potentially expanding FERC's approval authority over LNG under the NGA to include LH2, the development of an LH2 export industry would benefit from the development of a unified safety regime. Such a regime should be under PHMSA's jurisdiction, which already applies to hydrogen pipelines,[166] and the transportation of hazardous materials, including hydrogen, by other means, such as truck, railcar, and vessel.[167] The Natural Gas Pipeline Safety Act (NGPSA)[168] grants PHMSA the authority to develop safety regulations specific to LNG production facilities,[169] including coastal LNG facilities and other inland LNG facilities that are connected to the interstate gas transmission system.[170] LNG facilities that only are connected to intrastate gas transmission and distribution systems are typically regulated by the relevant state government through an agreement with PHMSA.[171] Like the NGA, amending the NGPSA to add hydrogen liquefaction facilities to PHMSA's jurisdictional purview would be a streamlined and effective way of having the agency with the relevant expertise develop a hydrogen safety regime.

Each of these opportunities to establish unified, consistent regulatory frameworks for hydrogen exports likely will require action by the U.S. Congress to amend existing laws, including the NGA and NGPSA, to accommodate hydrogen. Doing so will provide the regulatory certainty needed for U.S. project developers and investors to compete effectively in the hydrogen export market.

Of course, regardless of the overall regulatory framework for LH2 liquefaction facilities, liquefaction plants will be subject to a wide

166 49 C.F.R. pt. 192 (2020). *See also Hydrogen*, U.S. DEP'T OF TRANSP. PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., https://primis.phmsa.dot.gov/comm/Hydrogen.htm?nocache=4348 (last visited Aug. 21, 2020).

167 49 C.F.R. §§ 171–180 (2020). For example, PHMSA has design specifications for cylinders used to transport cryogenic liquids, including LH2. 49 C.F.R. § 173.316 (2020).

168 49 U.S.C. §§ 60101, *et seq.* (2018).

169 49 C.F.R. § 193.2001(a) (2020).

170 *LNG Regulatory Documents,* U.S. DEP'T OF TRANSP. PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-regulatory-documents (last visited Aug. 21, 2020).

171 *Id.*

array of environmental laws and regulations. This will be the case regardless of whether the plants are near vessel ports or are inland. As noted above, construction of large liquefaction facilities could implicate NEPA and Endangered Species Act concerns, just as any other major construction project would. Because hydrogen's flammability qualifies it under Section 112(r) of the CAA, it is subject to EPCRA's risk management programming for on-site storage of hydrogen at 10,000 pounds or greater. It is likely that liquefaction facilities would trigger this risk management requirement of the CAA. Other major safety-related laws surrounding workplace safety, including those falling under the Occupational Safety and Health Administration's (OSHA) jurisdiction, and local fire or explosion hazards will apply to liquefaction facilities, likely including state and local parallels to federal safety laws as well as local fire codes. While energy intensive, however, the liquefaction process does not appear to pose environmental hazards that facility owners should be concerned with regarding other substances that are regulated by CERCLA, RCRA, and other similar environmental laws.

2. Vessel Transits

There are several important areas of consideration for those looking to transport hydrogen by vessel within, to, or from the United States. As noted above, hydrogen is listed in the CAA list of regulated substances under Section 112(r). While hydrogen appears on the list as a result of its flammability, the listing may trigger EPA's RMP rule for certain larger storage quantities of hydrogen.[172] Consequently, for storage or staging of hydrogen at ports, docks, and other stationary facilities integral to vessel transportation, shippers and carriers will want to be aware of its RMP obligations.[173]

a. International Requirements - Foreign Flag Vessels Calling on U.S. Ports

As a general matter, the transportation of liquefied gas in bulk by vessels that operate on international voyages is regulated under the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code). Pursuant to Chapter VII, Part C, of International Convention for the Safety of Life At Sea, the IGC Code is mandatory for all vessels that carry liquefied gas or other products listed in Chapter 19 of the IGC Code. For example, this includes vessels carrying LNG, anhydrous ammonia, propane, and other similar liquefied gas products in bulk.

As with all similar international maritime conventions and codes, enforcement is carried out by inspectors in "port states" in the ports where the vessel calls, and by "flag states" where the vessel is registered, with the assistance of vessel classification societies. Under U.S. law, foreign flag vessels calling on U.S. ports that carry liquefied gas products in bulk must have an International Certificate of Fitness issued by the vessel's flag state, pursuant to the IGC Code.[174] Additionally, such vessels must be inspected by the U.S. Coast Guard (USCG) and obtain a Certificate of Compliance with the proper endorsement for the carriage of liquefied gas in bulk. The Certificate of Compliance is issued by the USCG after the foreign flag vessel has been examined and found to be in compliance with applicable international and U.S. regulatory requirements. This requires, among other things, that foreign flag vessels submit vessel plans and other information for review by the USCG, at least seven days before arrival in the U.S. prior to completion of the Certificate of Compliance exam.[175] In some areas, the applicable U.S. regulations may exceed that which is required under the IGC Code.

The general requirements above apply to all foreign flag vessels calling on U.S. ports that carry certain liquefied gas products in bulk. However, the IGC Code currently does not address specific requirements for the carriage of liquefied hydrogen in bulk. In 2016,

[172] 40 C.F.R. § 68.130 (Table 3).

[173] PHMSA regulates shipment of "cryogenic liquids" on board vessels within its regulatory scope regarding packaging design and filling, as well as storage requirements for portable tanks, cargo tanks, and tank cars. 49 CFR 176.76(g); *see also* 49 CFR 176.83 (segregation of, among other materials, flammable liquids on board vessels).

[174] *See* 46 C.F.R. § 154.24.

[175] *See* 46 C.F.R. § 154.22; 46 C.F.R. § 154.1802.

with a recognition of the emerging interest in the transportation of LH2 in bulk, and a lack of requirements in the IGC Code, the International Maritime Organization (IMO) adopted interim recommendations for the carriage of liquefied hydrogen in bulk by vessel.[176] The IMO Recommendations set forth various special considerations and hazards in connection with the carriage of LH2 in bulk. For foreign flag vessels carrying LH2 in bulk in the United States, the USCG will consider the IMO Recommendations, and other applicable requirements in 46 CFR Subchapter O, in its process to conduct the Certificate of Compliance examination. Additionally, any commercial vessel carrying hazardous materials, such as hydrogen, in the navigable waters of the United States must comply with PHMSA regulations in 49 CFR § 176, which provide additional requirements for operations and cargo stowage and handling.

The carriage of liquefied hydrogen in bulk in all transportation sectors is an evolving practice.[177] Accordingly, the IMO Recommendations will most certainly evolve over time to accommodate industry changes, but will serve as a baseline standard, in conjunction with the IGC Code, to be applied by flag states and port states, including the United States, to help ensure the safe and efficient transportation of LH2 by sea.

b. U.S. Law and Regulation Applicable to U.S. Flag Vessels

Construction and operation of U.S.-flag commercial vessels carrying certain bulk dangerous cargos, in either liquid or compressed gas form, are regulated by the USCG under 46 C.F.R. Parts 151, 153, and 154 of Subchapter O. For example:

- Part 151 provides hull construction, equipment, operating, cargo tank, cargo transfer, environmental control, and temperature and pressure control requirements for commercial barges carrying bulk liquid hazardous materials.
- Part 153 provides general requirements, equipment design requirements, operations requirements, and procedures for stripping liquid residues from cargo tanks for self-propelled commercial vessels carrying bulk liquid, liquefied gas, or compressed gas hazardous cargoes.
- Part 154 provides safety standards for commercial self-propelled vessels carrying liquefied liquid bulk gasses.

Additionally, any commercial vessel carrying hazardous materials, such as hydrogen, in the navigable waters of the U.S. waters must comply

176 *See* IMO Resolution MSC.420(97), *Interim Recommendations for Carriage for Liquefied Hydrogen in Bulk* (IMO Recommendations).

177 In December 2019, the world's first LH2 carrier—the SUISO FRONTIER—was launched in Japan.

with regulations in 49 C.F.R. § 176, enforced by the USCG, which provide additional requirements for operations and cargo stowage and handling.

The USCG has not yet developed specific regulations for the carriage of hydrogen in either compressed gas or liquid form. Consequently, any U.S.-flag vessel being designed to do this would need to receive technical approval from USCG Headquarters instead of the local USCG Captain of the Port. The USCG is likely to use the IMO Recommendations as a starting point for U.S.-flag vessels that will carry LH2 in bulk. Vessel operators considering constructing a U.S.-flag vessel for this purpose should consult with the appropriate legal and regulatory advisors and then USCG Headquarters staff early in the design process. Note that if the hydrogen is converted to ammonia for shipment, then the requirements of Parts 151, 153, and 154 would apply.

c. Jones Act Considerations

The **"Jones Act"** generally refers to several provisions of United States law known as the coastwise laws that impose limitations on foreign flag vessels operating in U.S. territorial waters. The agency responsible for enforcing and administering the coastwise laws is U.S. Customs and Border Protection (CBP) within the Department of Homeland Security. The USCG is responsible for implementing the vessel documentation requirements for U.S.-flag coastwise qualified vessels.

Importantly, with respect to the potential development of a U.S. coastwise hydrogen market, the coastwise laws prohibit the transportation of merchandise and passengers between any two points in the United States embraced within the coastwise laws in any vessel other than a vessel (1) built in the United States (and never rebuilt abroad), (2) documented under U.S. law with a "coastwise endorsement," and (3) owned by U.S. citizens.[178] The term merchandise is broadly defined to include goods, wares, and chattels of every description including valueless material, as well as merchandise owned by the U.S. government. A passenger is any person carried on a vessel who is not connected with the operation and navigation of the vessel or the ownership or business of the vessel. Other provisions encompassed in 46 U.S.C. Chapter 551 deal with particular aspects of domestic waterborne transportation and are generally classified in the family of laws known as the Jones Act.

U.S. territorial waters include all inland navigable waterways and extend three nautical miles seaward of the territorial sea baseline. The coastwise laws also apply to certain artificial islands and similar structures, and include mobile oil drilling rigs, drilling platforms, and other devices attached to the seabed

[178] 46 U.S.C. 55102, 55103.

of the outer continental shelf for the purpose of resource exploration operations.[179]

Coastwise transportation is broadly defined to include "any part of the transportation of merchandise by water, or by land and water," between any two U.S. points embraced by the coastwise laws. These generally include U.S. territories, but not the U.S. Virgin Islands, America Samoa, and the Northern Mariana Islands, which are exempt from the coastwise laws.[180] Therefore, foreign-flag vessels can transport cargo between these islands and other U.S. points.

CBP has interpreted the coastwise laws with respect to "lightering" activities, for example, such that a tanker to be lightered that is anchored to the seabed within three nautical miles of shore is a U.S. point requiring vessels lightering product from that tanker to a U.S. port to be coastwise qualified. CBP also has determined that if merchandise is transformed (manufactured or processed) into a new and different product at an intermediate foreign port, the vessels transporting the original product from a U.S. port to this foreign port and transporting the transformed product from the foreign port to a U.S. port do not to need to be coastwise qualified.

For the vessel itself to be coastwise qualified it must be documented under U.S. flag with a coastwise endorsement, which in turn requires the vessel to be built in the United States and to be owned by U.S. citizens.[181] The USCG National Vessel Documentation Center is responsible for implementing these requirements.

In order to be considered U.S. built, all major components of the hull and superstructure must be fabricated in the United States and the vessel must be assembled entirely in the United States. The vessel cannot be subsequently rebuilt outside of the United States without permanently losing its coastwise endorsement.

In order to qualify as a U.S. owner, the corporation or owning entity must be organized under the laws of the United States, and the Chief Executive Officer, by whatever title, and the Chairman of the Board, as well as a majority of the Board of Directors, must be U.S. citizens, and at least 75 percent of the equity in the entity must be owned and controlled by U.S. citizens.[182]

In addition, the licensed officers on a U.S.-flag vessel must all be U.S. citizens and unlicensed crew must be either U.S. citizens or lawfully admitted to the U.S. for permanent residence (i.e., "green card holders") subject to a 25 percent cap.[183]

179 43 U.S.C. 1333(a).

180 46 U.S.C. 55101.

181 46 U.S.C. 12112.

182 46 U.S.C. 50501(d).

183 46 U.S.C. 8103.

Advance CBP rulings are available should there be any question about compliance with the coastwise laws. This is particularly advisable given the significant penalties for violations. The penalty for transportation of merchandise on a non-coastwise vessel is forfeiture of the merchandise so transported, or the value thereof.[184] Transportation of passengers in violation of the coastwise laws is $778 per passenger so transported. In addition, there are daily civil penalties for vessels operating in violation of the USCG documentation regulations, as well as the potential seizure and forfeiture of the vessel and its equipment under certain circumstances.

The navigation laws, including the coastwise laws, can be waived by the Secretary of Homeland Security under very limited statutory authority when requested by the Secretary of Defense and only then to the extent considered necessary in the interest of national defense. Such waivers have been granted in connection with hurricane relief efforts, for example, and other extraordinary circumstances.[185]

d. U.S. Law and Regulation Applicable to U.S. Marine Terminal Operations

USCG regulations for commercial waterfront facilities in the U.S. handling hazardous cargoes, including liquefied gasses, do not list hydrogen as a cargo to which those regulations apply. Therefore, waterfront facility operators in the United States that are considering handling hydrogen as vessel cargo should consult with USCG Headquarters for guidance. Most likely, such operators will be required to comply with the below USCG requirements applicable to other compressed or liquefied hazardous gasses.

A commercial waterfront facility in the United States that handles certain compressed hazardous gasses as cargo must comply with the regulations in 33 C.F.R. Part 154 regarding the handling of bulk dangerous cargoes at waterfront facilities. These regulations provide general, operations manual, equipment, and operations requirements for facilities transferring bulk dangerous cargoes other than liquefied hazardous gasses. Note that these regulations would apply if the hydrogen was converted to ammonia for shipment before arriving at the waterfront facility.

Commercial waterfront facilities in the United States that handle certain liquefied hazardous gasses as cargo must comply with the regulations in 33 C.F.R. Part 127, Subparts A and C. Subpart A provides general requirements regarding USCG oversight of waterfront facilities handling hazardous cargoes. Subpart C provides regulations on design, construction, equipment, operation, maintenance, fire protection, and firefighting equipment for waterfront facilities transferring liquefied hazardous gasses.

184 46 U.S.C. 55102(c).

185 46 U.S.C. 501.

3. Commercial Issues in Contracting for Bulk LH2

While there are alternatives to bulk transactions of hydrogen in a liquid state, most of these alternatives are still in early stages of development and, as a result, the approaches to contracting for these alternatives can be difficult to predict. In contrast, transacting in bulk LH2 has a readily available precedent.[186]

Transactions for the bulk purchase and sale of LH2 are likely to have much in common with LNG contracts. As noted in the **Project Finance section of Part I (Section II),** for example, the infrastructure to produce, store, and transport bulk LH2 requires massive capital investments across the supply-chain much like that required in the not-so-distant past for LNG, and these capital requirements, at least initially, will drive the type of long-term contracts that the LNG sector required in its early stages. In addition, as the process technology and safety principles that are applicable to LNG also are generally applicable to LH2,[187] the contracts for LH2 likely will be based on the precedent created in the LNG industry.[188]

As the history of LNG contracting has shown, LH2 contracting is unlikely to lead to a standard form of contract in the near term. While the LNG industry has attempted to develop industry forms, the sector is still dominated by forms that are generally the products of the larger market participants.

As a result of the precedent set by LNG, however, it is possible that many of the shorter-term solutions for contracting in LNG can provide commercial support for LH2 much sooner than occurred in the case of LNG. As the market for hydrogen grows and more alternatives are available for supply and offtake, for example, some of the unique revenue sharing products that have sped the development of LNG may also make their way into the hydrogen marketplace.

However, some of the characteristics of hydrogen that differ from LNG should drive differences in the contracts and the eventual development of a more robust trading market. For example, the very low boiling temperature of hydrogen[189] may slow development of long-distance offtake alternatives as losses over long routes may deter sales to more distant destinations. If so, both buyers and sellers likely will have less flexibility in dealing with non-performance by the other party until alternatives for supply and demand

[186] As noted, there are other bulk methods of moving LH2, but transactions involving this method of delivery either require further development at present and/or will involve transactions on a much smaller scale. As a result, the discussion below is limited to bulk transactions involving vessel delivery.

[187] A number of the hazards associated with liquid hydrogen are still being studied. Interestingly, the LNG industry was in a similar position about 20 years ago. As these hazards are defined and the associated safety requirements are codified, compliance with those requirements can be built into the sale and purchase agreements.

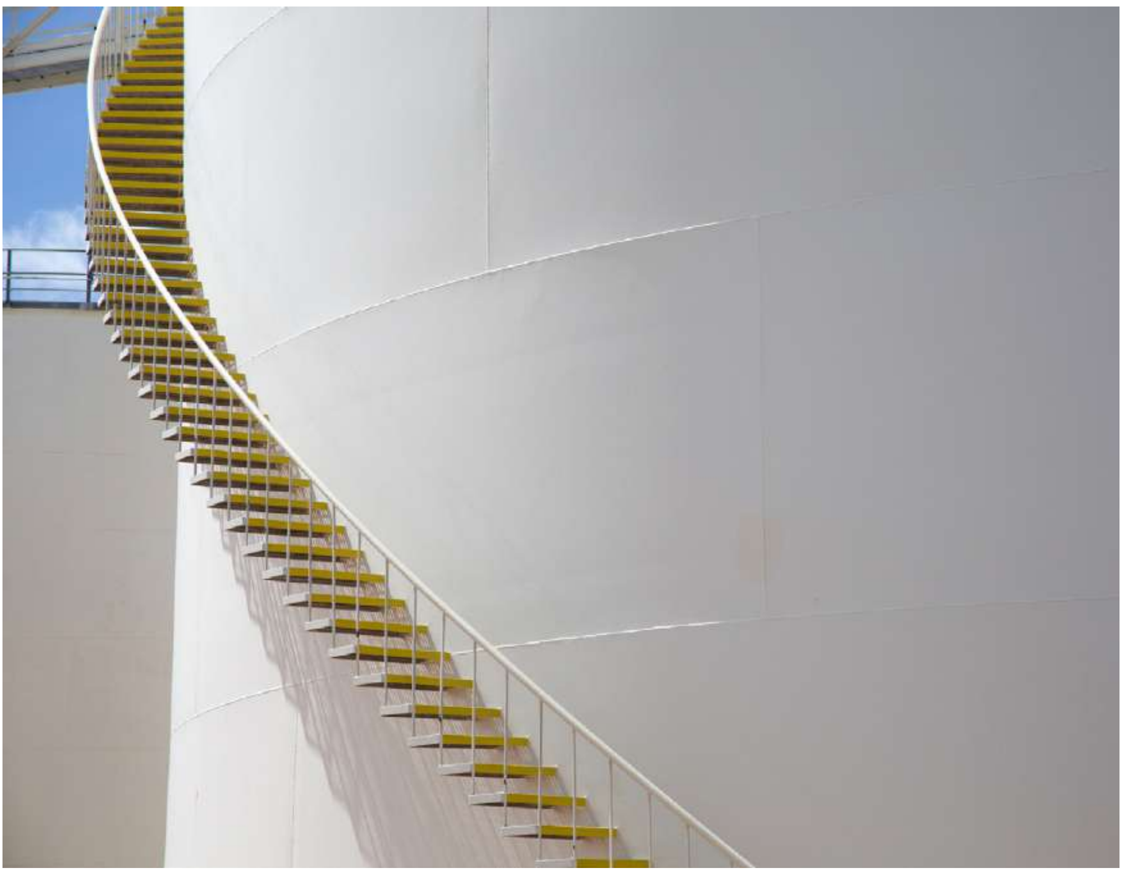
[188] The applicability of the LNG contract models assumes that the liquid hydrogen will be transported as a cryogenic liquid. If hydrogen is compressed, then CNG model agreements would be an appropriate reference point. CNG model agreements, however, are less developed than their LNG counterparts.

[189] *See, e.g., From LNG to Hydrogen? Pitfalls and Possibilities,* THE MOTORSHIP, https://www.motorship.com/news101/alternative-fuels/from-lng-to-hydrogen-the-pitfalls-and-the-possibilities (last visited Aug. 21, 2020).

are available. While this was obviously also true in the early years for LNG, the ability to move LNG long distances with limited losses from boil-off has certainly accelerated the ability to contract in LNG for shorter term supply.

Another characteristic of hydrogen that differs from LNG is that hydrogen has a much lower energy density by volume, approximately 40 percent compared to LNG.[190] In other words, one needs 2.5 vessels of hydrogen to carry the same energy moved in the same size of vessel carrying LNG. Given that hydrogen also needs greater insulation to maintain its much colder temperature requirements for a liquid state and better equipment to avoid the escape of the smaller hydrogen molecules, this vessel math, albeit simplistic, provides a sense of the magnitude of the challenge.

Even if the economics of this difference can be overcome, from a contracting standpoint, the scheduling, loading, and unloading constraints become even more critical than they are for LNG. Already complicated matters for LNG, like berth constraints, inventory management, and planning horizons, will take on an even greater level of importance with LH2



190 *See, e.g., id.*

with more vessels having to use limited dock and storage facilities. Considering the complexity of this process and real-world likelihood of disruption events, contracting around these issues with hydrogen will be as challenging, if not more so, than it has been for LNG.

A related constraint on transacting in bulk LH2 arises from the additional safety issues associated with hydrogen and the limits this currently places on transport. Unlike the numerous LNG carriers currently traversing the globe, the first LH2 transport vessel is a relatively small vessel by LNG standards and is still under construction.[191] The extremely wide range of hydrogen's flammability limit in air has generated calls for testing the flammability of liquid pools and gas leaks of hydrogen under working and emergency conditions, as was done with LNG pools and natural gas leaks, long before large tankers are commissioned.[192] In any event, this, and other safety issues unique to hydrogen, may put large-scale vessels of the type typically relied on by bulk LNG traders as something for the future. In the meantime, bulk hydrogen purchases likely will remain the product of the particular projects to which the purchases are tied and contracts will be drafted to meet the peculiar needs of these specific projects. More standardized contracts incorporating general market expectations will thus need to wait until there is a larger market than exists today.

Further, the fact that the amount of energy required to liquefy hydrogen is multiples of the energy required to liquefy LNG also will have an impact on contracting. As a result of this additional energy input, contracts for the supply of hydrogen will be more sensitive than LNG to energy price changes, particularly for the producer in the market where the liquefaction occurs. Where the LNG has been indexed to a price in the liquefaction market, it creates a problem for buyers because there is no correlation to competing energy sources in their domestic market at the point of destination. This potential disconnect between the energy costs in the supply market and the destination market presents an even bigger potential for disputes for hydrogen as tying the price to energy prices at the point of liquefaction will be harder to index, and this benchmark has the potential to have a great deal of volatility. We note that a number of LNG agreements are now indexed to a price in the regasification market, and that likely will be an attractive option for buyers of LH2 as well, but the same seller issues

191 One estimate is that there are approximately 360 LNG vessels moving on the high seas and some vessel sizes exceed 260,000 m3. *See, e.g.,* LNG Tankers – Different Types And Dangers Involved, https://www.marineinsight.com/types-of-ships/lng-tankers-different-types-and-dangers-involved/. In contrast, Kawasaki expects completion of the first such vessel for hydrogen in late in 2020 and it is an anticipated cargo capacity of only 1,250 m3. *See* Kawasaki announces World's First Liquefied Hydrogen Carrier SUISO FRONTIER Launches Building an International Hydrogen Energy Supply Chain Aimed at Carbon-free Society, https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487.

192 *See, e.g.,* Bulk Storage and Shipping of Liquid Hydrogen Is Hazardous (arguing that the existing IGC Code entitled "Draft Interim Recommendations for Carriage of Liquefied Hydrogen in Bulk" interim recommendations for carriage of liquefied hydrogen in bulk are not adequate), https://cryogenicsociety.org/34991/news/bulk_storage_and_shipping_of_liquid_hydrogen_is_hazardous/.

will be present as well—especially concerns about a disconnect with the seller's production costs and lender requirements.

One approach to addressing this indexing issue in the LNG market has been to include price review mechanics.[193] Not surprisingly, the specific triggers for the application of the price review mechanism are heavily negotiated and are prone to dispute. These also can complicate project financing as lenders are not in the business of taking the market risk that these might create. As a result, if included, these must be negotiated in such a way as to ensure that revenue generation remains sufficient to cover any debt and tax equity that might be associated with the relevant infrastructure projects at both the point of sale and the delivery point.

In short, while the contracting for hydrogen will benefit greatly from the precedent created in the LNG sector, it will have its own set of issues and challenges that are unique to hydrogen. Much like LNG, early market participants will create precedents that will eventually be used by later market participants. To speed hydrogen's adoption as an energy alternative, however, these early market participants need to focus on the differences between these two products or risk the possibility that their contracts will do little more than fit their square hydrogen peg into a round LNG hole.

II. Storage

As the U.S. hydrogen industry matures, the ability to store hydrogen safely and cost-effectively will offer critical commercial flexibility. Hydrogen storage, especially large-scale or "bulk" storage methodologies, need further development and investment before they are ready for broad deployment. This necessary development is underway and there are several pathways for building out hydrogen storage infrastructure in the coming years. Existing regulatory programs apply to these nascent storage approaches, but further regulatory certainty will help assure project developers and operators that they

[193] For a discussion of LNG price reviews, *see* "Taming Price Review Clauses: Lessons from the Transactional and Arbitration Battlefields," LNG18, Apr. 2016.

understand and can comply with legal and regulatory requirements.

A. Very Long Duration Energy Storage

Most of the electric energy storage technologies that have been deployed to date are capable of discharging stored electricity for a relatively short period of time. The instantaneous capacity of the storage system is combined with the duration of discharge to produce a short-hand description of the system's capabilities: thus, a 10 MW system that can discharge for four hours is described as a 10MW/40MWh system. Batteries may be capable of discharging for two to eight hours, depending on the technology deployed. Pumped storage hydroelectric facilities and compressed air energy storage systems may be able to discharge for 10 hours or more. Longer duration systems can take advantage of peak shifting and price arbitrage, charging the system when prices are low (e.g., on a weekend), and then discharging during peak hours when prices are high.

However, most existing storage systems will cycle fairly often (usually at least once per day), which means that they store electricity only for a relatively short period of time. For example, an energy storage system coupled with a solar photovoltaic generator may charge when surplus solar energy is being generated during peak daylight hours and then discharge later in the day to partially offset the decline of solar generation in the late afternoon and evening. The difference between the quantity of energy stored and the amount available for discharge is known as the system's "round-trip efficiency." Discharge of electricity within a few hours after being stored in the system has the added benefit of reducing the electricity lost during storage.[194]

The growing penetration of variable renewable energy resources, such as wind and solar, is creating a need for "very long duration storage" (which is also known as "seasonal storage"), and the storage technologies currently being deployed do not address this need. For example, a utility's demand for electricity might decline in the spring, when heating load is tapering off and air conditioning load has not yet begun to ramp up.[195] But variable renewable resources, such as wind and hydroelectric, may achieve peak generation at the same time that the system's load is low. The system must remain in balance, so surplus generation that cannot be used by the load must be curtailed. This results in a loss of revenue for the generators affected and produces even more significant problems for wind projects relying on the production tax credit, which the generator can only earn by generating and selling electricity. The challenge for variable renewable energy as it seeks higher levels of penetration will be to move excess generation from the months where it is not needed to months where it can be used to serve as a "decarbonized" source of fuel or electricity.

194 For a discussion of energy storage generally, *see* K&L Gates, Energy Storage Handbook (5th ed.)(2019).

195 PAUL DENHOLM & TRIEU MAI, TIMESCALES OF ENERGY STORAGE NEEDED FOR REDUCING RENEWABLE ENERGY CURTAILMENT (2017).

Hydrogen is a synthetic fuel that can be used to accomplish very long-duration storage by a number of means. For example, an electrolysis unit could be co-located with a wind or solar generator where variable electricity is being curtailed. Instead of curtailing the surplus electricity, the generator continues to produce it and sells it to a co-located electrolysis unit to produce hydrogen. The hydrogen could be delivered directly to a natural gas pipeline (subject to limits required to address safety, leakage, or gas quality concerns as discussed previously in the **Pipeline section of Part III (Section I.C)**), or it could be used as a feedstock for a methanization process that produces methane suitable for injection to the pipeline.[196] If the local geology is favorable, the hydrogen could also be stored in depleted hydrocarbon reservoirs or salt caverns for later use (as discussed below). The stored hydrogen could later be used in fuel cells to generate electricity directly or as fuel for hydrogen cars, or it could be used to produce an intermediate product in order to overcome hydrogen storage and transportation challenges.[197]

The economic case for seasonal storage in a given region depends on a number of variables, including renewable energy penetration, resource adequacy needs, the growth of carbon taxes or other carbon regulation, the price of natural gas, and seasonal or annual variation in generation or in loads.[198] The prospects are daunting at this point, and very long-duration hydrogen storage may not be economically viable in the United States for some time, although several European projects are underway.[199] That said, those who have followed the development of the wind, solar, natural gas, and energy storage industries in the United States know that cost barriers can tumble quickly and unexpectedly. At least one consortium of developers is pursuing a large-scale storage project in Utah: the Advanced Clean Energy Storage project is intended to provide storage services for 1,000 MW of wind in the form of compressed air or hydrogen stored in a salt cavern.[200]

B. Hydrogen Storage Strategies

As noted above, hydrogen can be compressed or liquefied and, in a compressed or liquid state, the same number of hydrogen molecules take up less volume, decreasing the footprint necessary for hydrogen storage facilities. Compressed hydrogen is hydrogen placed under pressures of 5,000–10,000 pounds per square inch (PSI).[201] By

196 KEN DRAGOON, POWER TO GAS: OPPORTUNITIES FOR GREENING THE NATURAL GAS SYSTEM at 19–21 (2018).

197 ROB VAN GERWEN, MARCEL EIJGELAAR, & THEO BOSMA, THE PROMISE OF SEASONAL STORAGE at 27 (2020).

198 *Id.*

199 DRAGOON, *supra* note 79, at 27–28.

200 Umar Ali, *How Salt Caverns Could Transform Renewable Energy Storage for the US*, POWER TECHNOLOGY, Aug. 29, 2019, https://www.power-technology.com/features/how-salt-caverns-could-transform-renewable-energy-storage-for-the-us/#:~:text=A%20new%20project%20called%20Advanced,or%20compressed%20air%20by%202025. (last visited Aug. 13, 2020).

201 U.S. DEP'T OF ENERGY OFFICE OF ENERGY EFFICIENCY & RENEWABLE ENERGY, https://www.energy.gov/eere/fuelcells/physical-hydrogen-storage (last visited Aug. 9, 2020).

comparison, liquefied hydrogen is cryogenically cooled hydrogen so that the hydrogen reaches -252.8 degrees Celsius (or -423 degrees Fahrenheit) and condenses to a liquid.[202] Compressed hydrogen contained in high-pressure tanks is the technology of choice for mobile transportation applications, especially for light-duty vehicles.[203] Liquefied hydrogen storage is often used for bulk stationary hydrogen storage in above-ground tanks and truck transportation of liquefied hydrogen.

In addition to storing pure hydrogen through compression or liquefaction, there are other methods for storing hydrogen. Hydrogen can be deposited on the surfaces of or within solid materials by absorption.[204] Some project developers envision storing hydrogen molecules in other compounds, like ammonia, during transportation and storage, then breaking those intermediary materials down to access the hydrogen closer to the point of end use.[205] For the purposes of *The Hydrogen Handbook,* we are focusing on storing hydrogen as its own substance and not interposed with other materials or as constituent parts of other substances.

C. Bulk Hydrogen Storage

Hydrogen can be stored in bulk in a variety of ways, depending on the requirements of the storage system (e.g., the cycling frequency, or the frequency of withdrawals and refills) and geologic availability. For hydrogen production and end-use locations on small and medium scales, operators often use high-pressure cylinder tanks. These tanks can be transported relatively easily and sized for specific applications.

For larger-scale storage on-site, large cryogenic tanks store liquefied hydrogen since they have a higher volumetric density than pressurized gas storage systems.[206] The U.S. National Aeronautics and Space Administration has used spherical tanks to store very large volumes of liquefied hydrogen for decades.[207] Most industrial or commercial applications do not require such large volumes of hydrogen and instead they employ large cylindrical cryogenic tanks to store liquefied hydrogen.[208]

These tank solutions are useful for applications that do not depend on the region's geology and require frequent

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202 *Id.*

203 *Id.*

204 *Id.*

205 Krystina E. Lamb, *Ammonia for Hydrogen Storage; A Review of Catalytic Ammonia Decomposition and Hydrogen Separation and Purification*, 44 INT'L J. OF HYDROGEN ENERGY 3,580 (2019), https://www.sciencedirect.com/science/article/abs/pii/S0360319918339272?via%3Dihub; Ola Osman & Sgouris Sgouridis, Optimizing the Production of Ammonia as an Energy Carrier in the UAE, 5TH INTERNATIONAL CONFERENCE ON RENEWABLE ENERGY: GENERATION AND APPLICATIONS (2018) https://ieeexplore.ieee.org/document/8337611.

206 U.S. DRIVE PARTNERSHIP, HYDROGEN DELIVERY TECHNICAL TEAM ROADMAP at 18, https://www.energy.gov/sites/prod/files/2017/08/f36/hdtt_roadmap_July2017.pdf (last visited Aug. 21, 2020).

207 *Id.* at 19. Spherical tanks are useful because they have lower surface areas compared to cylinders and therefore decrease the liquefied hydrogen's rate of evaporation. *Id.*

208 *Id.*

withdrawals and refilling of the storage tanks. But, where very large hydrogen storage would be required, such as to replace the output of a wind farm or utility-scale solar generation facility during an outage, underground storage in geologic formations can be used. Commonly used to store hydrocarbons like oil or natural gas, underground salt caverns and aquifers can store hydrogen gas as well. For example, an underground salt cavern, which could contain up to 500,000 cubic meters of hydrogen at 2,900 PSI, could produce some 100 gigawatt hours of electricity.[209] In addition to salt caverns, depleted oil and gas wells are also under consideration as options to store hydrogen underground.[210] These depleted well assets could be particularly useful if the wells are connected to pipeline infrastructure that could be repurposed to transport hydrogen.

To date, there are two salt cavern storage facilities for hydrogen in Texas[211] and opportunities for further development of underground storage across the United States and around the world.[212] But, there are challenges that must be addressed. Hydrogen is a small molecule compared to conventional hydrocarbons and it therefore has a higher potential to leak into the walls of depleted wells, which would decrease the inventory of hydrogen and potentially introduce impurities to the hydrogen.[213] Frequently cycling hydrogen inventories at an underground storage facility could also damage the integrity of the rock formation. As such, cycling may be limited to once or twice per year at a facility, limiting use cases to seasonal storage rather than to address acute supply-demand mismatches. Additionally, although there are opportunities to develop underground storage in some places, salt cavern or other geologic formations useful for hydrogen storage are not located near every market, so significant transportation infrastructure (e.g., pipeline, trucking, or marine transport) will be needed to make efficient use of bulk underground storage in salt caverns.

D. Regulatory Oversight of Hydrogen Storage

Multiple U.S. federal agencies exercise jurisdiction over hydrogen storage equipment and facilities and likely will have a role in regulating hydrogen storage in the future. As explained in the **Pipeline section of Part III (Section I.C)**, PHMSA exercises regulatory oversight of interstate gas pipelines, including hydrogen gas pipelines.[214]

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209 *Hydrogen Energy Storage,* ENERGY STORAGE ASS'N, https://energystorage.org/why-energy-storage/technologies/hydrogen-energy-storage/ (last visited Aug. 9, 2020).

210 Justin Gerdes, Enlisting Abandoned Oil and Gas Wells as "Electron Reserves," Greentech Media (Apr. 10, 2018), https://www.greentechmedia.com/articles/read/enlisting-abandoned-oil-and-gas-wells-as-electron-reserves#gs.ByNEEjY.

211 *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*, NEXANT, INC. ET AL. at 2–82 (May 2008), https://www.energy.gov/sites/prod/files/2014/03/f9/nexant_h2a.pdf.

212 Emiliano Bellini, *Hydrogen Storage in Salt Caverns*, PV MAGAZINE (June 16, 2020), https://www.pv-magazine.com/2020/06/16/hydrogen-storage-in-salt-caverns/.

213 *Storing Hydrogen Underground Could Boost Transportation*, Energy Security, SANDIA NATIONAL LABORATORIES (Dec. 9, 2014), https://share-ng.sandia.gov/news/resources/news_releases/underground_hydrogen/#.Wsp9GIjwY2w.

214 *Hydrogen*, PIPELINE & HAZARDOUS MATERIALS SAFETY ADMIN., https://primis.phmsa.dot.gov/comm/Hydrogen.htm?nocache=4348 (last visited Aug. 9, 2020).

In the natural gas and oil contexts, PHMSA exercises exclusive jurisdiction over storage facilities that serve interstate natural gas or oil pipelines. In accordance with its final rule issued in February 2020, PHMSA is applying its new safety rules for underground natural gas storage facilities to intrastate storage facilities.[215] Although the new rule on underground natural gas storage facilities does not explicitly mention hydrogen storage, it is conceivable that PHMSA would apply this rule to hydrogen storage facilities that are connected to pipelines since the agency uses the same statutory authority to regulate natural gas pipelines as hydrogen pipelines. But, to date, PHMSA has not explicitly extended this rule to underground facilities storing hydrogen.

Although it does consider hydrogen storage to be a form of energy storage,[216] FERC has indicated that it considers bulk storage of hydrogen in underground to be outside the agency's jurisdiction.[217]

PHMSA, OSHA, and the EPA all have regulations that apply to hydrogen storage equipment and facilities that are not part of pipeline transportation. For storage of hydrogen in containers that would be transported, like compressed hydrogen in cylinders or spherical pressure vessels, PHMSA applies 49 C.F.R. § 173.301.[218] For the storage of hydrogen in stationary facilities, like large compressed or liquefied hydrogen storage tanks, OSHA applies its regulations at 29 C.F.R. Part 1910 for hazardous materials and hydrogen-specific rules at 29 C.F.R. § 1910.103. In addition, the EPA applies its RMP program requirements to hydrogen storage facilities that hold 10,000 pounds or more of hydrogen.[219]

Although there are some regulatory programs addressing hydrogen in the United States, these programs likely will need to expand to address the growing hydrogen market. For example, systematizing the ways that project operators can transition existing assets, such as existing hydrocarbon storage facilities to store hydrogen, will streamline the expansion of the hydrogen sector. Providing clear regulatory guidance will support investment in hydrogen storage infrastructure, which in turn will support development of the hydrogen sector.

Clear regulatory treatment will also assist stakeholders, like local governments

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215 Pipeline Safety: Safety of Underground Natural Gas Storage Facilities, 85 Fed. Reg. 8,104 (Feb. 12, 2020).

216 *Final Rule: Third-Party Provision of Ancillary Services*, 144 FERC ¶ 61,056 at p. 172 (Jul. 18, 2013) (indicating that FERC would consider hydrogen storage to be a form of energy storage for accounting purposes).

217 *Magnum Gas Storage, LLC*, 171 FERC ¶ 61,069 at p. 2 and n. 4 (Apr. 23, 2020) (suggesting that it agrees with the applicant that underground storage of hydrogen in salt caverns is not within FERC's jurisdiction).

218 Pipeline and Hazardous Materials Safety Admin, Interpretation Response #16-0010 (Apr. 5, 2017), https://www.phmsa.dot.gov/regulations/title49/interp/16-0010 (last visited Aug. 9, 2020).

219 *List of Regulated Substances Under the Risk Management Plan (RMP) Program*, U.S. ENVTL. PROTECTION AGENCY, https://www.epa.gov/rmp/list-regulated-substances-under-risk-management-plan-rmp-program (last visited Aug. 9, 2020). EPA's RMP program requires operators of facilities that hold the threshold quantity or more of a regulated substances, such as 10,000 pounds for hydrogen, to prepare and submit an RMP to EPA that identifies the potential effects of a chemical accident, identifies steps the facility is taking to prevent an accident, and spells out emergency response procedures if an accident occurs. Risk Management Plan (RMP) Rule Overview, U.S. ENVTL. PROTECTION AGENCY, https://www.epa.gov/rmp/risk-management-plan-rmp-rule-overview (last visited Aug. 9, 2020).

and neighbors of facilities with hydrogen storage, to understand the potential risks and significant investments that project developers and operators have made in safe operations of their storage facilities. Above-ground storage facilities, especially those with large hydrogen storage tanks, will attract the attention of local stakeholders.

To the extent that hydrogen storage facilities re-use the same facilities previously used by the hydrocarbon industry, those communities likely will be familiar with storage infrastructure. However, as the hydrogen economy expands across regions that have not had high visibility hydrocarbon infrastructure in the past, local communities may have more questions about the safety of hydrogen storage facilities. Clear regulatory guidance that project developers can point to will help developers, operators, and local stakeholders understand safety requirements and operational expectations.

III. Export Controls

As noted above, hydrogen does not appear to be regulated by the NGA, pursuant to which DOE regulates imports and exports of natural gas. However, the United States imposes export controls on a wide array of commodities under the Export Administration Regulations (EAR) administered by the U.S. Department of Commerce, Bureau of Industry and Security (BIS). Commodities that are subject to specific licensing requirements under the EAR are described in the Commerce Control List under a particular Export Control Classification Number (ECCN). Commodities not described under an ECCN are classified under the catch-all "EAR99." Hydrogen is EAR99 and, therefore, hydrogen generally does not require a license for export to most countries. One exception is that licensing requirements apply for hydrogen derived from the Naval Petroleum Reserves of the United States (NPR) and for hydrogen that has become available for export as a result of an exchange of any NPR produced or derived commodities.

It should also be noted that even EAR99 commodities, like hydrogen, generally require a license from BIS (and sometimes from the Office of Foreign Assets Control) before they can be exported: (1) to any embargoed country (i.e., Iran, Cuba, Syria, North Korea, Sudan, and the Crimean region of Ukraine); (2) for any prohibited end-users (e.g., parties on BIS's "Entity List"); or (3) for any restricted end-use (e.g., certain nuclear, missile, military, chemical, or biological weapons uses).

IV. End-Use

Hydrogen has many end-uses, including industrial, transportation, heating, and as a medium for storing energy. While historical end-uses for hydrogen focused on industrial applications, hydrogen technologies are increasingly being explored across different forms of transportation and energy. More recently, entrepreneurs and well established companies are looking into the application of hydrogen fuel cell technology in air transportation. Government incentives, commercial considerations, and regulatory regimes for transportation and distribution will help shape how the United States and other countries use hydrogen over the next century.

A. Road Vehicle Fuel

There is heightened interest in the use of hydrogen in the road transportation sector, and in particular in the heavy-duty vehicle market segment. Hydrogen fuel cell electric vehicles (FCEVs), which are considered zero-emission vehicles, are attractive replacements for internal combustion engine vehicles because they can offer performance similar to that of conventional vehicles, along with several additional advantages. These advantages include enhanced environmental performance, quiet operation, rapid acceleration from a standstill, and lower maintenance requirements. Furthermore, FCEVs can potentially perform functions for which conventional vehicles are poorly suited, such as providing remote electrical power and acting as distributed electricity generators when parked and connected to a fuel supply.

Light-duty FCEVs are now available in limited quantities to the consumer market. The market is also developing for fleet vehicles, material handling equipment, ground support equipment, medium- and heavy-duty vehicles, and stationary applications. As discussed in the **U.S. Department of Energy Programs section in Part I (Section I.A)**, federal programs, like DOE's grant programs and federal investment in a consortium to focus on development of heavy duty FCEVs, will be important to grow this sector. The success

of hydrogen in the transportation sector will depend on developing and commercializing competitive FCEVs. Researchers continue to develop increasingly lightweight and compact automotive fuel cell systems that are tolerant to rapid cycling and on-road vibration; reliable for hours of non-continuous, all-weather use; able to respond rapidly to transient demands for power; and able to use hydrogen of varying purity.

Further cost reductions in hydrogen fuel cell technology and the construction of hydrogen refueling infrastructure will be required for the FCEV market to expand. Policy, regulation, and government incentives, like those discussed in the **U.S. Department of Energy Programs section in Part I (Section I.A)**, are likely to play an important role in the development of hydrogen refueling infrastructure, particularly in the early stages of adoption.

California leads the nation in funding and building hydrogen fueling stations. As of 2019, there were 40 retail hydrogen stations in California and 20 more in various stages of construction or planning. The California Energy Commission is authorized to allocate a maximum of $20 million annually through 2024, until there are at least 100 operational stations in the state. In addition, 12 retail stations are planned for the northeast United States. Non-retail stations also continue serving FCEVs, including buses, for research or demonstration purposes. Multiple stakeholders have announced plans regarding the production of heavy-duty vehicles such as line-haul trucks that will push fueling stations to have much higher capacities than existing light-duty stations.

B. Marine Fuel

Hydrogen is also being explored as a maritime fuel. The shipping industry primarily relies on diesel engines, with oceangoing vessels using heavy fuel oil or marine diesel to power propulsion. A small fraction of vessels use LNG or CNG. However, the use of high-emission fuels is increasingly regulated as pollution and greenhouse gas emission concerns mount. On 1 January 2020, the IMO required all shipping fuels to contain no more than 0.5 percent sulfur. This recent cap is a significant reduction from the prior sulfur limit of 3.5 percent and is well below the industry average of 2.7 percent.

Powering ships with hydrogen fuel cells could curb emissions of pollutants in maritime applications. Such fuel cells, however, also must 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 considered cost competitive. In addition, international technical standards still need to be developed to use gaseous fuels like hydrogen for transoceanic shipping.

The first zero-emission vessels are expected to be powered by a hybrid of fuel cells and batteries. Even for smaller passenger ships, ferries, or recreational crafts, the use of hydrogen-powered fuel cells for ship propulsion is still at an early design or trial phase. Fuel cells have yet to be scaled for and used on large merchant vessels. Despite the nascence of marine propulsion applications, fuel cells can serve other purposes for such vessels. Because fuel cells deliver substantial direct current (DC) power, they can also serve on-board electric loads, and surplus heat generated by the fuel cells could be used to heat water for HVAC, laundry, and other systems.

C. "Hydrail" Hydrogen as Rail Fuel

The EPA regulates the exhaust emissions from locomotives by establishing different tiers depending on the construction year of the locomotive. The EPA's increasingly stringent emission reduction requirements have presented challenges to locomotive manufacturers. Other countries have begun to reduce rail emissions by electrifying route miles, meaning those routes are zero-carbon if powered by a renewable source of electricity. U.S. railroads, however, are a regulated private sector industry, which makes financing electrification upgrades more difficult for railroad companies. As a result, electrified rail is currently used on less than 1 percent of U.S. railroad tracks, compared to the more than one-third of the electric energy that powers trains globally.

Because rail is already among the lowest greenhouse gas emitting modes of transportation, the massive overhaul required to electrify railroad systems may provide only incremental benefits and not justify the costs. On the other hand, hydrogen-powered trains could play a role in decarbonizing rail systems without incurring the high cost of electrifying tracks. Hydrogen-powered trains are less expensive, do not require massive track overhauls, and commenters predict that they can be created by retrofitting existing diesel trains.

Hydrogen-fueled trains pose a host of benefits and hurdles. Like electric trains, they are much quieter than their diesel counterparts. Hydrogen-powered trains have additional benefits, such as the ability to switch to fuel cells when electricity lines are down. Given relative volumes of freight volume in the United States, the ability to convert freight trains to hydrogen power will be key to implementing this technology on a mass scale.

D. Industrial and Manufacturing Feedstock

According to the IEA, 33 percent of hydrogen is used in oil refining, 27 percent is used for ammonia production (principally for fertilizer), 11 percent for methanol production, and 3 percent for steel production via the direct reduction of iron ore. There is significant potential for green hydrogen to clean up the production of ammonia for fertilizer. Currently, fertilizer consumes 3-5 percent of global natural gas production and causes 1.5 percent of global carbon emissions. Ammonia made from hydrogen produced by renewable electricity could significantly reduce emissions as almost 90 percent of ammonia goes into fertilizer production. With fewer stakeholders and less reliance on associated infrastructure, green fertilizer solutions can be developed and implemented comparatively quickly.

The direct reduction of iron ore uses hydrogen and synthesis gas to separate oxygen from iron. Green hydrogen could serve an important industrial process in steel manufacturing, compared to the traditional blast furnace method that releases large amounts of carbon. While direct reduction with natural gas is well-established in steel production, production methods based on hydrogen exist only in pilot programs.

Hydrogen is also used to process crude oil into refined fuels, such as gasoline and diesel, and also to remove contaminants, such as sulfur. Hydrogen use in refineries has increased in recent years due to regulations requiring low sulfur in diesel, the increased consumption of low quality ”heavy” crude oil (which requires more hydrogen to refine), and the increased oil consumption in developing economies. Hydrogen is also an important basic component for producing methanol, which can be used directly as a fuel in internal combustion engines. Methanol is also used to produce fuel additives and transesterify vegetable oils to form biodiesel. Hydrogen’s other industrial applications include metalworking, flat glass production, the electronics industry, and applications in electricity generation, for example, for generator cooling or for corrosion prevention in power plant pipelines.

E. Heating

While the generation of low-carbon electricity has increased dramatically, heating systems still rely significantly on fossil-based fuels and are significantly less green. The IEA estimates that nearly 28 percent of global energy-related carbon dioxide emissions result from energy use in buildings. Hydrogen could reduce these heating-related emissions if green hydrogen is blended with natural gas to reduce the carbon intensity of the feedstock. Trials have used blends

of up to 20 percent hydrogen, but the production costs of low-carbon hydrogen—although decreasing—are likely to be an initial barrier to wider adoption. Overall, however, the decreasing costs of hydrogen and related technologies will be the most important factors in galvanizing widespread adoption for heating uses.

F. Very Long Duration Energy Storage

Once hydrogen is produced through electrolysis, it can be stored as a compressed gas, cryogenic liquid, or wide variety of loosely bonded hydride compounds for later use. Unlike batteries, which suffer from storage degradation and can store a limited amount of energy, hydrogen fuel can be stored for long periods of time and in quantities only limited by the size of the storage facility. Hydrogen compares well to other long-duration storage technologies, like pumped water storage, that can only be used in limited geographic areas and require vast areas of land. Hydrogen offers the potential to provide energy-storage solutions for off-grid electricity systems and to balance electric grids. For the time being, use of large-scale hydrogen storage and dispatchable hydrogen power generation systems remains expensive due to significant energy losses. Current technologies only allow for the re-electrification of hydrogen in fuel cells with efficiencies of up to 50 percent or burning in combined cycle gas power plants with efficiencies of up to 60 percent. As discussed in the **Project Finance section of Part I (Section II)**, the cost of very long duration energy storage for hydrogen is expected to drop significantly in the next decade.

V. Government Incentives for Hydrogen Use

In addition to the federal incentives discussed in the **U.S. Department of Energy Programs section in Part I (Section I.A)**, several states have implemented incentive programs that will help promote the use of hydrogen. Examples of such programs are discussed below.

Arizona

Arizona offers several incentives, including the Reduced Alternative Fuel Vehicle (AFV) License Tax, the State Vehicle Acquisition and Fuel Use Requirements, and the Alternative Fuel and Alternative Fuel Vehicle Use Tax Exemption. Under the Reduced AFV License Tax program, the vehicle license tax for an AFV registered in Arizona is $4 for every $100 in assessed value. The minimum amount of the annual AFV license tax is $5. AFV assessed values are determined as follows:

- AFVs registered prior to 1 January 2022: 1 percent of the manufacturer's suggested retail price (MSRP).
- AFVs initially registered between 1 January 2022 and 31 December 2022: 20 percent of the MSRP.
- For each succeeding year, for the purpose of calculating the license tax, the value of the AFV is reduced by 15 percent from the value for the preceding year.

For the purpose of this tax, AFVs include those powered exclusively by propane, natural gas, electricity, hydrogen, or a blend of hydrogen with propane or natural gas.[220]

The State Vehicle Acquisition and Fuel Use Requirements directs Arizona state agencies, boards, and commissions to purchase hybrid electric vehicles, AFVs, or vehicles that meet set greenhouse gas emissions standards. At least 75 percent of light-duty state fleet vehicles operating in counties with a population of more than 250,000 people must be capable of operating on alternative fuels. If the AFVs operate in counties with populations of more than 1.2 million people, those vehicles must meet EPA emissions standards for Low Emission Vehicles. Alternatively, the state fleet may meet AFV acquisition requirements through biodiesel or alternative fuel use or apply for waivers. For the purpose of these requirements, alternative fuels include propane, natural gas, electricity, hydrogen, qualified diesel fuel substitutes, E85, and a blend of hydrogen with propane or natural gas.[221] The Alternative Fuel and Alternative Fuel Vehicle Use Tax Exemption exempts Arizona use taxes on natural gas or propane used in an AFV, AFVs converted to operate on alternative fuels, or the equipment used to convert

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220 *NC Clean Energy Technology Center: Database of State Incentives for Renewables & Efficiency*, NC STATE UNIVERSITY, https://www.dsireusa.org/ (last visited Aug. 7, 2020).

221 *Id.*

a diesel vehicle to an AFV. Recognized alternative fuels include propane, natural gas, electricity, hydrogen, and a blend of hydrogen with propane or natural gas.[222]

California

In California, several localities have offered incentives for alternative fuels, including hydrogen. The Sacramento Emergency Clean Air and Transportation Program provides grants to offset the costs of zero-emission heavy-duty vehicles that reduce on-road emissions within the counties of El Dorado, Placer, Sacramento, Sutter, Yolo, and Yuba in California. Eligible projects include the purchase of battery electric or hydrogen fuel cell trucks, buses, and shuttles. Other advanced technology implementation projects may also qualify.[223] Additionally, the San Joaquin Valley Air Pollution Control District (SJVAPCD) administers the Drive Clean! Rebate Program, which provides rebates for the purchase or lease of eligible new vehicles, including qualified natural gas, hydrogen fuel cell, propane, all-electric, plug-in electric vehicles, and zero emission motorcycles. The program offers rebates of up to $3,000, which are available on a first-come, first-served basis for residents and businesses located in the SJVAPCD.[224]

Connecticut

The Connecticut Hydrogen and Electric Automobile Purchase Rebate Program offers rebates for the incremental cost of the purchase or lease of a hydrogen FCEV, all-electric vehicle (EV), or plug-in hybrid electric vehicle (PHEV). The manufacturer suggested retail price for eligible vehicles may not exceed $60,000 for FCEV models and $42,000 for EV and PHEV models.[225]

District of Columbia

The District of Columbia offers the Alternative Fuel Vehicle Conversion and Infrastructure Tax Credit. This tax credit makes businesses and individuals eligible for an income tax credit of 50 percent of the equipment and labor costs for the conversion of qualified AFVs, up to $19,000 per vehicle. A tax credit is also available for 50 percent of the equipment and labor costs for the purchase and installation of alternative fuel infrastructure on qualified AFV fueling property. The maximum credit is $1,000 per residential electric vehicle charging station and $10,000 per publicly accessible AFV fueling station. Qualified alternative fuels include ethanol blends of at least 85 percent, natural gas, propane, biodiesel, electricity, and hydrogen.[226]

Indiana

Indiana's Alternative Fuel Vehicle Inspection and Maintenance Exemption exempts dedicated AFVs from inspection and maintenance requirements if they operate exclusively

222 *Id.*

223 *Id.*

224 *Id.*

225 *Id.*

226 *Id.*

on natural gas, propane, ethanol, hydrogen, or methanol.[227]

Massachusetts

The Massachusetts Department of Energy Resources' Clean Vehicle Project offers grants for public and private fleets to purchase alternative fuel vehicles and infrastructure, as well as idle reduction technology. Eligible vehicles include those fueled by natural gas, propane, and electricity, including hybrid electric and hydraulic hybrid vehicles. Eligible infrastructure includes natural gas and hydrogen fueling stations as well as electric vehicle supply equipment (EVSE), including solar powered EVSE.[228] Moreover, the Massachusetts Department of Environmental Protection's Volkswagen Open Solicitation Grant Program provides up to 80 percent of the cost of new diesel or alternative fuel replacements and repowers for eligible government entities. For eligible non-government entities, the program provides up to 40 percent of the cost of a new diesel or alternative fuel repower, up to 25 percent of the cost of a new diesel or alternative fuel vehicle, and up to 75 percent of the cost of an all-electric repower or replacement, with associated charging infrastructure. Qualifying alternative fuels include, but are not limited to, natural gas, propane, hydrogen, and diesel electric hybrid.[229]

Michigan

The Michigan Department of Environmental Quality requirement to obtain an installation permit does not apply to qualified natural gas, hydrogen, and propane storage and handling equipment at dispensing facilities.[230]

Missouri

Missouri offers an Alternative Fuel Vehicle Emissions Inspection Exemption for vehicles powered exclusively by electricity, including low-speed vehicles, hydrogen, or fuels other than gasoline that are exempt from motor vehicle emissions inspection under federal regulation.[231]

New Mexico

The New Mexico Energy, Minerals and Natural Resources Department's Alternative Fuel Acquisition Revolving Loan Program provides loans to state agencies, political subdivisions, and educational institutions for AFV acquisitions. Funds must be used for the purchase of vehicles that operate on natural gas, propane, electricity, or hydrogen.[232]

New York

Under New York's Alternative Fueling Infrastructure Tax Credit, residents can gain a tax credit for 50 percent of the cost of alternative fueling infrastructure, up to $5,000. Qualifying infrastructure includes

227 *Id.*

228 *Id.*

229 *Id.*

230 *Id.*

231 *Id.*

232 *Id.*

electric vehicle supply equipment and equipment to dispense fuel that is 85 percent or more natural gas, propane, or hydrogen. Unused credits may be carried over into future tax years.[233]

Pennsylvania

The Pennsylvania AFV Program offers rebates to assist eligible residents with the incremental cost of the purchase or lease of new AFVs, including EVs, PHEVs, FCEVs, CNG vehicles, electric motorcycles, and propane vehicles. Eligible FCEVs must have a total purchase price not exceeding $75,000, and all other eligible AFVs must have a total purchase price not exceeding $50,000. An additional rebate of $1,000 is available for all vehicles if an applicant meets the low-income requirement, as defined by the U.S. Department of Health and Human Services.[234] Additionally, the Alternative Fuels Incentive Grant Program provides reimbursement grants for the installation of alternative fuel infrastructure along Pennsylvania interstate highway corridors. Grants are available for reimbursement of 50 percent of the cost, up to $500,000, to install public electric, hydrogen, propane, and compressed natural gas fueling infrastructure along "Signage Ready" or "Signage Pending" highway corridors in Pennsylvania, as defined by the U.S. Department of Transportation.[235]

Pennsylvania also offers the Electric Vehicle Supply Equipment and Hydrogen Fuel Cell Infrastructure Grants through the Pennsylvania Department of Environmental Protection. Under this program, grants are offered for the acquisition, installation, operation, and maintenance of publicly available DC fast charging equipment and hydrogen fueling infrastructure. Eligible project locations are transportation corridors, destination locations, and locations that serve as community charging or fueling hubs.[236]

South Carolina

South Carolina offers a sales tax exemption for "any device, equipment, or machinery operated by hydrogen or fuel cells, any device, equipment or machinery used to generate, produce, or distribute hydrogen and designated specifically for hydrogen applications or for fuel cell applications, and any device, equipment, or machinery used predominantly for the manufacturing of, or research and development involving hydrogen or fuel cell technologies."[237]

Texas

The Texas Commission on Environmental Quality (TCEQ) administers the Light-Duty Motor Vehicle Purchase or Lease Incentive Program for the purchase or lease of a new light-duty vehicle powered by CNG, propane, hydrogen, or electricity. CNG and propane vehicles, including bi-fuel vehicles, are eligible

233 *Id.*

234 *Id.*

235 *Id.*

236 *Id.*

237 *Id.*

for a rebate of $5,000 for the first 1,000 applicants. Electric drive vehicles powered by a battery or hydrogen fuel cell, including plug-in hybrid electric vehicles with a battery capacity of at least 4 kilowatt hours, are eligible for a rebate of $2,500, for the first 2,000 applicants.[238] TCEQ also provides funding for eligible medium- and heavy-duty on-road alternative fuel vehicles or engine repowers and replacements, as well as for associated electric vehicle and hydrogen fueling infrastructure. Both government and non-government entities that own and operate diesel fleets and equipment are eligible for funding.[239]

Additionally, Texas exempts propane, natural gas, electricity, and hydrogen, also known as clean fuel or special fuel, used to operate motor vehicles from state fuel taxes, but subject to a special fuel tax at the rate of three-nineteenths of the conventional motor fuel tax. A reduction in special fuel tax is permissible if the fuel is already taxed by the Navajo Nation. Retailers, wholesalers, and suppliers of special fuel are eligible for a refund of the special fuel tax if dyed diesel fuel is mixed with special fuel and the mixed special fuel is returned to the refinery.[240]

Utah

In Utah, qualified taxpayers are eligible for a tax credit for the purchase of a qualified heavy-duty AFV. Qualifying fuels include natural gas, electricity, and hydrogen. At least 50 percent of the qualified vehicle's miles must be driven in the state. A single taxpayer may claim credits for up to 10 AFVs or $500,000 annually. If more than 30 percent of the total available tax credits in a single year have not been claimed by May 1, a taxpayer may apply for credits for an additional eight AFVs. Up to 25 percent of the tax credits are reserved for taxpayers with small fleets of less than 40 vehicles.[241]

Virginia

Under Virginia's Green Jobs Tax Credit, qualified employers are eligible for a $500 tax credit for each new green job created that offers a salary of at least $50,000, for up to 350 jobs per employer. The credit is allowed for the first five years that the job is continuously filled. For the purposes of this tax credit, a green job is defined as employment in industries relating to renewable or alternative energy, including hydrogen and fuel cell technology, landfill gas, and biofuels.[242]

Virginia also offers the Alternative Fuel and Hybrid Electric Vehicle (HEV) Emissions Testing Exemption. This exemption is offered to vehicles that are powered exclusively by natural gas, propane, hydrogen, a combination of compressed natural gas and hydrogen. Qualified HEVs with EPA fuel economy

238 *Id.*

239 *Id.*

240 *Id.*

241 *Id.*

242 *Id.*

ratings of at least 50 miles per gallon (city) are also exempt from the emissions inspection program unless remote sensing devices indicate the HEV may not meet current emissions standards.[243]

Washington

Washington state offers the most incentives for alternative fuel in the country. The Plug-In Electric Vehicle (PEV) and Fuel Cell Electric Vehicle Infrastructure and Battery Tax makes public lands used for installing, maintaining, and operating PEV infrastructure exempt from leasehold excise taxes. Additionally, the state sales and use taxes do not apply to PEV and FCEV batteries or fuel cells; labor and services for installing, repairing, altering, or improving PEV and FCEV batteries or fuel cells and PEV and hydrogen fueling infrastructure; the sale of property used for PEV and hydrogen fueling infrastructure; and the sale of zero emission buses.[244]

The Alternative Fuel Commercial Vehicle and Fueling Infrastructure Tax Credit allows businesses to receive tax credits for purchasing new alternative fuel commercial vehicles and installing alternative fueling infrastructure. Eligible alternative fuels are natural gas, propane, hydrogen, dimethyl ether, and electricity. Tax credits for qualified alternative fueling infrastructure are for up to 50 percent of the cost to purchase and install the infrastructure. Commercial vehicle tax credit amounts vary based on gross vehicle weight rating and are up to 75 percent of the incremental cost. This exemption also applies to qualified used vehicles modified with an EPA-certified aftermarket conversion, as long as the vehicle is being sold for the first time after modification. Modified vehicles are eligible for credits equal to 30 percent of the commercial vehicle conversion cost, up to $25,000. Each entity may claim up to $250,000 or credits for 25 vehicles per year.[245]

Additionally, the Washington state Department of Transportation (WSDOT) offers competitive grants to strengthen and expand the West Coast Electric Highway network by deploying electric vehicle supply equipment with Level 2 and DC fast chargers and hydrogen fueling infrastructure along highway corridors in Washington. Eligible project costs include siting, equipment purchases, electrical upgrades, installation, operations, and maintenance.[246] WSDOT will also establish a green transportation capital grant program to fund projects to reduce the carbon intensity of the Washington transportation system, including fleet electrification, modification, or replacement of facilities to facilitate fleet electrification and hydrogen fueling, upgrades to electrical transmission and distribution systems, and construction of charging and fueling infrastructure. In order to receive funding for a project, a

243 *Id.*

244 *Id.*

245 *Id.*

246 *Id.*

transit authority must provide matching funding for that project that is at least equal to 20 percent of the total cost of the project.[247]

Finally, Washington state also offers the Retail Sales and Use Tax Exemption whereby the retail sales and state use tax of 6.5 percent does not apply to the sale or lease of new or used passenger vehicles, light-duty trucks, and medium-duty passenger vehicles that are exclusively powered by an alternative vehicle fuel or are capable of running solely on electricity for at least 30 miles. Eligible alternative fuels are natural gas, propane, hydrogen, and electricity. Vehicles must not have a selling price plus trade-in property value that exceeds $45,000 for new vehicles and $30,000 for used vehicles. The maximum eligible amount for used purchased or leased vehicles is $16,000.[248]

247 *Id.*

248 *Id.*

GLOSSARY UNITED STATES

AFV	Alternative Fuel Vehicle
AIP	Airport Improvement Program
ALK	alkaline electrolysis
Bcf	billion cubic feet
BIS	U.S. Department of Commerce, Bureau of Industry and Security
BTU	British thermal unit
CAA	Clean Air Act
CARB	California Air Resources Board
CBP	U.S. Customs and Border Protection
CCL	Commerce Control List
CCS	carbon capture and sequestration
CEC	California Energy Commission
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CNG	compressed natural gas
CPUC	California Public Utilities Commission
CWA	Clean Water Act
DC	direct current
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
EAR	Export Administration Regulations
ECCN	Export Control Classification Number
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ESA	Endangered Species Act
EV	all-electric vehicle
EVSE	electric vehicle supply equipment
FAA	Federal Aviation Administration
FCEVs	fuel cell electric vehicles
FE	U.S. Department of Energy's Office of Fossil Energy
FERC	Federal Energy Regulatory Commission
FMCSA	Federal Motor Carrier Safety Administration
GT&C	general terms and conditions of service
HEV	hybrid electric vehicle
HMR	Hazardous Materials Regulations
HTSE	high temperature steam electrolysis
IEA	International Energy Agency

IEPR	Integrated Energy Policy Report
IGC Code	International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk
IMO	International Maritime Organization
IRENA	International Renewable Energy Agency
IRPs	Integrated Resource Plans
ITC	investment tax credit
kw	kilowatts
LCFS	Low Carbon Fuel Standard
LH2	liquid hydrogen
LNG	liquefied natural gas
LTE	low temperature electrolysis
Mcf	million cubic feet
MMst	million short tons
MSRP	manufacturer's suggested retail price
NAESB	North American Energy Standards Board
NEPA	National Environmental Policy Act
NGA	Natural Gas Act
NGPSA	Natural Gas Pipeline Safety Act
NPR	Naval Petroleum Reserves of the United States
OFAC	Office of Foreign Assets Control
OSHA	Occupational Safety and Health Administration
PEM	proton exchange membrane electrolysis
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSI	pounds per square inch
R&D	research and development
RCRA	Resource Conservation and Recovery Act
RMP	EPA's Risk Management Plan
RNG	renewable natural gas
SDWA	Safe Drinking Water Act
SJVAPCD	San Joaquin Valley Air Pollution Control District
SMR	steam methane reforming
TCEQ	Texas Commission on Environmental Quality
Tcf	trillion cubic feet
USCG	U.S. Coast Guard
WSDOT	Washington State Department of Transportation
ZEV	zero emission vehicle

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