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Scaling up green hydrogen in Europe

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Executive Summary

Governments around the world are putting hydrogen produced by low carbon technology at the heart of their net zero energy and climate policies. Opinions differ on where low carbon hydrogen will contribute most to decarbonisation (for example, in transport, heavy industry or the power sector), but in any event the first step must be to scale up production and reduce the costs of this new commodity.

This paper, like the strategies of the EU and many national governments, focuses on so-called “green” hydrogen, produced by electrolysing water with renewable electricity. It should be possible to establish a European green hydrogen sector with the potential for long-term growth, but only with concerted effort by the different players in the supply chain and a supportive regulatory environment.

Our analysis is based on part of North-West Europe, including Germany, Belgium and the Netherlands. This region has high potential demand for green hydrogen (as a clean energy source or chemical feedstock), gas transportation infrastructure suitable for hydrogen use and favourable conditions for sourcing renewable electricity (and, in the longer term, importing of green hydrogen).

As a result, many potential green hydrogen projects have been proposed in this area. Starting in 2023, our business case looks at what it would take to move from these (typically) tens-of-MW-scale projects to investing in the tens of GW of production capacity that are likely to be needed to make green hydrogen cost-competitive with higher carbon alternatives, as it could be, in the 2030s.

Using realistic technology assumptions, we find that this is a challenging goal, but also one that is achievable if purposeful action begins now. A key question is at what point the bulk of the green hydrogen consumed in Europe will start to be produced in areas where renewable power is cheapest, which may be far away from the regions where it is consumed, and even outside Europe.

When connecting green hydrogen supply and demand over long distances, we expect pipelines to be more economical than ship transport (or importing cheap renewable power from outside Europe). Existing gas transportation infrastructure can often be adapted for this purpose at reasonable cost.

On both the industry and public policy sides, we identify a range of possible ways of addressing the potential commercial risks of scaling up green hydrogen. These include the following.

- **Matching supply and demand:** The value of early green hydrogen projects will depend on finding the best pairings of electricity generation and hydrogen production, and of hydrogen production and demand. We suggest ways of optimising these pairings and developing market liquidity.
- **Finding suitable investment, finance and trading models:** Commercial participants can do a lot to mitigate the risks, and maximise the upside, of green hydrogen projects. We describe how the structuring of PPA and offtake arrangements, use of storage, participation of investors at multiple levels, and suitable profiling of financing arrangements, can all help.
- **Regulated financial support for projects:** The (narrowing) price advantage of higher carbon alternatives needs to be reduced by regulated revenue support for green hydrogen producers, probably in the form of a contract for difference. All support, including for end-users’ conversion costs or other capex, should be allocated by a competitive process.
- **Supportive broader policy framework:** Hydrogen policy will not determine carbon prices, but support mechanisms will need to take their movements into account. Upcoming EU decisions on state aid policy and carbon pricing could stimulate supply and demand for hydrogen.



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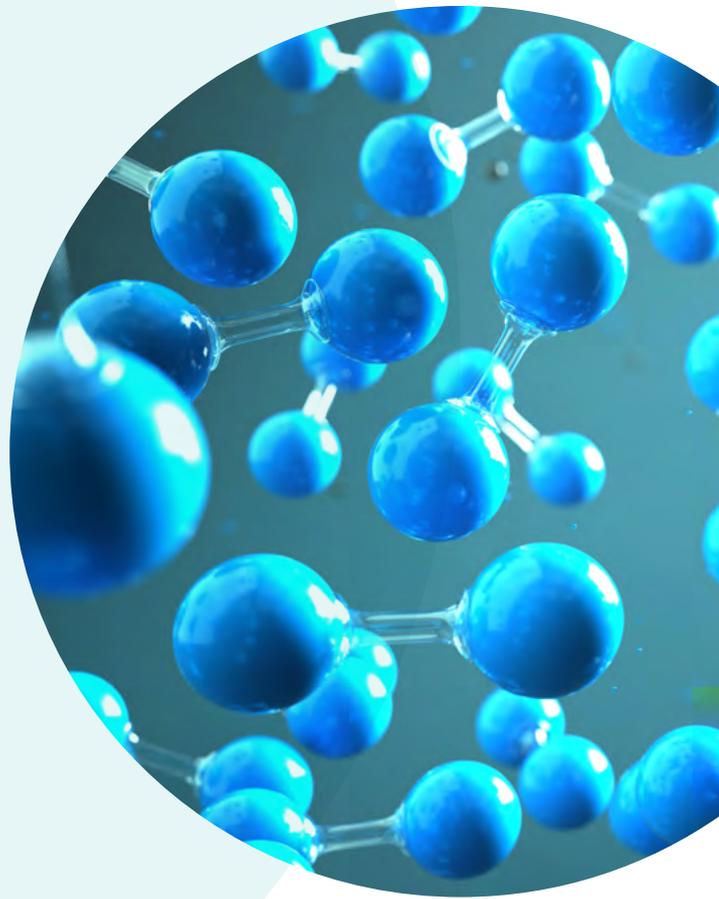
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1. Introduction

1.1 Global interest

1.1.1 From Chile to Canada, from Australia to South Korea, from Germany to Scotland, a new industry has grown up at spectacular speed in the last year or two: the production, by governments, of hydrogen strategies. These governments envisage that in five or 10 years, large quantities of hydrogen will be produced in (and, in some cases, exported from) their territories, using technologies that are currently uneconomic and barely commercialised. Further, they propose that significant amounts of this hydrogen will be used in applications where hydrogen is at present either not used at all, or is used on a much smaller scale.

1.1.2 What is going on? Hydrogen has come to be seen by many (though not by all – there are some hydrogen sceptics) as a key enabler of the kind of economy-wide decarbonisation goals that many governments and corporate groups are setting themselves in order to achieve, by mid-century, “net zero” greenhouse gas emissions, or “climate neutrality”.

1.2 Why hydrogen – and what kinds of hydrogen?

1.2.1 Hydrogen can be used in many of the applications where we currently use coal, petroleum products or natural gas. Unlike these hydrocarbons, it does not release CO₂ when burnt. Figure 1 illustrates some of the ways in which hydrogen could be used to avoid the CO₂ emissions currently associated with the use of hydrocarbons in these applications.

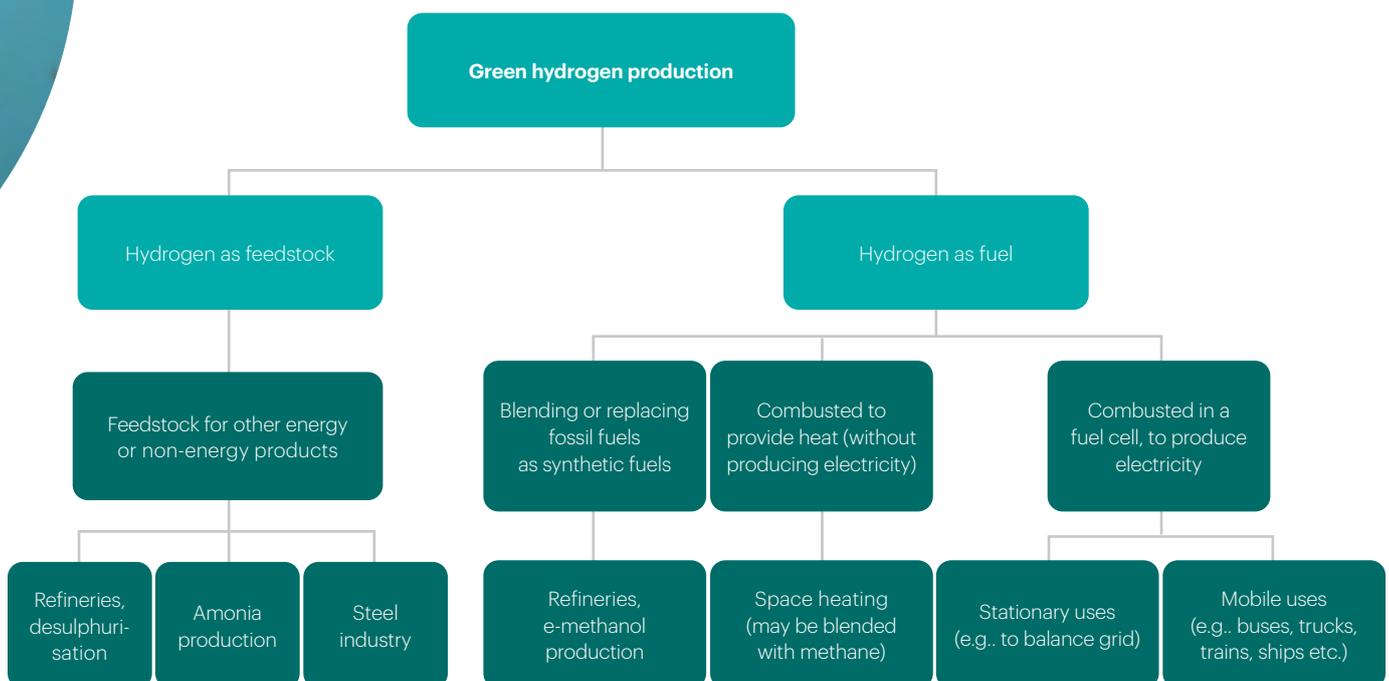


Figure 1 Classification of end-users of low carbon hydrogen

1.2.2 Using hydrogen in these applications may turn out to be a quicker, cheaper or more effective way of decarbonising them than directly applying other forms of “clean” energy, like renewable electricity. However, today, almost all hydrogen used worldwide is produced by carbon-intensive technologies. At present, just using hydrogen in the applications above would not reduce (and, in some cases, would increase) the overall greenhouse gas emissions associated with the industries concerned. To be part of the “Energy Transition”, hydrogen must be produced without (or with dramatically reduced) greenhouse gas emissions.

1.2.3 The processes by which most hydrogen is currently produced involve natural gas (methane) or other fossil fuel feedstocks, energy generated from fossil fuels, and processes that emit a lot of CO₂. Hydrogen produced in these ways is called “grey” hydrogen. There are more climate-friendly ways to produce hydrogen. Most involve either adapting the “grey” techniques, and capturing and using or storing the CO₂ emissions (CCUS), or using electricity that has been generated with few or no carbon emissions to electrolyse water into hydrogen and oxygen. Worldwide, the primary focus is on “blue” hydrogen (combining “methane reforming” technology with CCUS) and “green” hydrogen (electrolysing water with renewable electricity). For convenience, we refer to these technologies, collectively, as “low carbon hydrogen” (although, in principle, green hydrogen should be “zero carbon”, whereas producing blue hydrogen still has some emissions because CCUS is not currently 100% efficient).

1.3 Revolution

1.3.1 Creating a hydrogen economy, whether based on blue or green hydrogen, requires the rapid upscaling of technologies that are new or unfamiliar to many (notably electrolyser production, hydrogen storage and transport, and CCUS) and significant new infrastructure investments, not least by prospective users of low carbon hydrogen, many of whom will have to acquire new equipment to benefit from it.

1.3.2 How big the resulting technological and economic shift will be is a matter of opinion. Enthusiasts see it as comparable to those that occurred when coal replaced wood, or oil replaced coal, as the major energy source for individual economies. Even the more sceptical commentators would probably admit that it will be at least as significant as the shift towards renewable sources in the electricity industries of many countries over the last 20 years. Either way, to have the desired impact on emissions, it needs to happen quickly, on a global scale.



1.4 This paper

- 1.4.1 This paper focuses on green hydrogen. Blue hydrogen may also be important, but green hydrogen – although it is currently more expensive to produce than blue – is the primary focus of many national hydrogen plans, and of the [EU's hydrogen strategy](#). Even oil majors, who have a natural stake in blue hydrogen (as producers of feedstock methane and owners of depleted fields that can be used for storing captured CO₂) are also looking at green hydrogen.
- 1.4.2 In this paper, focusing on Europe, we look at the technical, financial and legal challenges that green hydrogen schemes need to overcome to make a significant contribution to decarbonisation goals. We set out a generic North-West European business case to show how a feasible transition to and upscaling of low carbon hydrogen could be achieved. We consider a mix of solutions in terms of production, transportation, the demand side, and finance, that could enable green hydrogen to overcome its current cost disadvantage compared with blue hydrogen and realise its greater potential for cost and greenhouse gas emission reductions, becoming cost-competitive in the longer term. In particular, we examine the relationship between the renewable electricity industry and the nascent green hydrogen sector, and the physical, contractual and regulatory infrastructure that will support it.
- 1.4.3 This is a highly technical area. However, this paper is not concerned with matters of technical detail such as the merits of different electrolyser technologies or the gas quality or wholesale electricity market rules of individual countries – important though these will be. Rather, we have focused on general principles. We have included a bibliography for those who wish to read more about some of the technical aspects of the subject.
- 1.4.4 The rest of this paper is organised as follows:
- section 2 considers at a high level why, in principle, scaling up green hydrogen presents such a challenge for policymakers and the industries and investors concerned, and sets out some basic assumptions about the sector;
 - section 3 looks in more detail at some of the commercial contexts of the green hydrogen projects that have been proposed to date and puts forward a generic business case around developing such projects in North-West Europe;
 - section 4 outlines how regulatory policies and appropriate private sector commercial and financial structures could support such projects; and
 - section 5 sets out some brief conclusions.

2. Green hydrogen: basic assumptions

2.1 The renewables playbook

- 2.1.1 Wind and solar electricity generation have grown dramatically because governments provided various forms of financial support for them. Demand was stimulated, and production of turbines and solar panels scaled up. Costs then fell, stimulating more demand, and so on.
- 2.1.2 If governments are prepared to offer the requisite support to early green hydrogen projects – and it appears that at least some are – this would seem to be the obvious template for the green hydrogen sector to follow. However, as we explain later in this paper, developing a thriving green hydrogen economy will require a wider range of actions by government and a more innovative approach on the part of commercial participants in the sector.

2.2 Cost is king

- 2.2.1 Following the lead of renewables means closing the gap between the costs of producing and using green hydrogen and those of producing and using grey hydrogen, natural gas and the other fossil fuels that it seeks to displace, or at least reducing it to a level where those who value its “green” qualities are prepared to pay the necessary premium to purchase it rather than alternatives.
- 2.2.2 There are two sides to reaching this goal. On the supply side, the future success of green hydrogen production depends on:
- reducing the lifetime costs of the electrolyzers that produce green hydrogen;
 - keeping the costs of accessing the “raw materials” of green hydrogen production – renewable electricity and water – as low as possible (currently, electrolyzers require processed water to run effectively, although in time they may be able to use seawater);
 - keeping the costs of transporting hydrogen as low as possible (particularly if the availability of cheap renewable power in locations far from centres of hydrogen demand means that hydrogen is produced a long way from where it is to be consumed); and
 - making any conversion that it goes through (for example, into ammonia for transportation purposes, and then back into hydrogen for use, or when it is reconverted into electricity in a hydrogen-fuelled power station) as economically efficient as possible.
- 2.2.3 Meanwhile, on the demand side, the speed at which green hydrogen or any other kind of low carbon hydrogen is adopted will depend on how quickly higher carbon prices, or other policy interventions, make fossil fuels more expensive relative to low carbon hydrogen.



2.3 Green hydrogen and renewable electricity

- 2.3.1 The renewable electricity sector has been growing at a rapid rate for some years. Electrolysis is not a new technology. Why has it taken as long as it has for green hydrogen to occupy the prominent place that it now does in the plans of many governments and businesses?
- 2.3.2 The cheapest and most widely deployable forms of renewable electricity are wind and solar power. These produce power when the wind blows or the sun shines – periods that are at best imperfectly, and sometimes not at all, correlated with demand for electricity. However, their zero marginal costs of generation, the structure of most systems of support put in place for renewables, and wholesale market rules based around short-run marginal costs, tend to encourage them to generate whenever they can – unless they actually face negative pricing.
- 2.3.3 As a result, wholesale power prices are falling in many markets, and forms of flexibility (storage, peaking plants, demand-side response) that can mitigate the increased imbalance risks in electricity systems that are supplied by ever larger proportions of intermittent generation can command a premium – which they receive through mechanisms such as capacity markets or various forms of ancillary services provided to system operators.

- 2.3.4 In this context, green hydrogen production offers the renewable electricity sector a number of particularly attractive prospects:
- the ability to absorb excess renewable electricity production at times when demand is low and wholesale prices may be negative or generation would otherwise be curtailed;
 - the ability to store energy in very large quantities, or over long time periods, for which current battery technology is not well suited – potentially addressing seasonal imbalances between electricity generation and consumption;
 - the possibility of extending the reach of renewable energy into areas where hydrogen may offer a quicker, cheaper or simpler alternative to direct electrification; and
 - the possibility, for countries whose potential to generate renewable electricity and produce green hydrogen significantly exceeds their domestic demand for either, of exporting energy to customers elsewhere by pipeline or ship, avoiding any lack of – or congestion in – electricity interconnections with those customers' countries.

2.4 Differences between green hydrogen and renewable electricity markets

- 2.4.1 There are useful lessons that can be applied from the evolution of renewable electricity support policies when seeking to reduce green hydrogen costs, and we consider these further in section 4 below. However, it is also important to be alive to the differences between scaling up renewable electricity generation and stimulating a mass market for green hydrogen.
- 2.4.2 Transporting their product to end-users presents little problem for renewable electricity generators in any jurisdiction with developed electricity networks and wholesale markets. The electricity that a wind or solar farm produces (subject to any necessary rectification or DC/AC conversion) is the same as that produced by any other generators. It can be exported onto and supplied from the same networks as their electricity and it find a buyer as long as there is demand. Depending on the grid connection regime, a renewable generator may be able to locate its plant (subject to network constraints) so as to maximise its output, knowing that it will be able to export that power and sell it to a buyer on the wholesale market.
- 2.4.3 To expand its share of the market, renewable electricity had to displace electricity generated by other means. The “fuel” of wind and solar power is free, so they are automatically competitive if their power sales and any government-mandated support allow them to meet the finance costs for their capex. This (coupled in some cases with “priority despatch” arrangements) means that (except in periods of overall low system demand when wholesale prices may turn negative) renewable electricity generators face virtually no demand risk.
- 2.4.4 The position of green hydrogen producers is different in a number of respects.
- Most prospective end-users of green hydrogen do not currently use hydrogen. They therefore face switching costs that have no counterpart among end-users of renewable electricity and will, in some cases, be substantial (for example, in the

case of a steelworks, investing in an entirely different production technology).

- There is no existing public transportation infrastructure for hydrogen. There is no liquid wholesale market for producers to sell into, as generators can do in any liberalised electricity industry, and there is, as yet, no general demand for green hydrogen.
- To begin with, therefore, green hydrogen producers must themselves find and contract with specific end-user customers. Initially there may be relatively few of these, meaning that producers will need some mitigation against the demand risk they may face if a customer suffers prolonged outages, becomes insolvent or switches away from hydrogen. There are a number of forms that such mitigation could take, as we discuss below.

2.5 Other precedent markets

- 2.5.1 As we focus on green hydrogen’s close links with and similarities to renewable electricity, we should not lose sight of the fact that it is a gas.
- 2.5.2 Research conducted by Cadent in the UK has found that the existing GB gas network can handle an 80/20 blend of methane and hydrogen, and that the same is true of the equipment and processes in which many end-users currently use gas. At first sight, an alternative to green hydrogen producers using dedicated hydrogen transportation networks to supply green hydrogen customers would appear to be for them to inject their green hydrogen into the gas grid – subject to receiving support in a form that recognises the higher production costs and lower energy value of green hydrogen as compared to an identical volume of methane. This could involve adaptation or extension of the schemes that have been established in a number of European jurisdictions where the production of biomethane for injection into the gas grid is subsidised – although the case of biomethane is more straightforward, since, unlike hydrogen, its chemical properties are the same as those of the fossil fuel it replaces.

2.5.3 As we will see later, a “blending” approach may well be a useful part of policy support for green hydrogen. However, a mixture of methane and hydrogen is technically unsuitable for some applications of green hydrogen and, given the 80/20 limit, is likely to decarbonise others too slowly. Support for green hydrogen also needs to address directly the needs of hydrogen producers supplying customers who want to use pure hydrogen as a fuel or feedstock.

2.5.4 We refer to the possibility of hydrogen/methane blending, and to the possibility of using existing natural gas transportation networks to transport hydrogen, at various points in this paper. The extent to which those networks, and any pipes, meters and appliances in domestic or commercial and industrial premises that currently operate on methane would require alteration, adjustment or replacement to deal with either a methane/hydrogen blend or pure hydrogen, is a technical matter beyond the scope of this paper. It is discussed in some of the items in the bibliography. We are concerned here not with quantifying such costs, but with identifying mechanisms by which they can be met. We have seen nothing to indicate that they are likely to be an insuperable barrier. They may, in some cases, exceed the costs of installing smart gas and electricity meters, but they should not, in most cases, exceed (or approach) the costs of replacing a boiler-based central heating system with one based on a heat pump.

2.5.5 Another, rather different parallel suggested by the fact that green hydrogen is a gas is with the LNG market. It may turn out that the best way for Europe, for example, to be supplied with sufficient quantities of green hydrogen at a competitive price, is to import it over considerable distances from countries with much better renewable resources. Whilst some of these (for example, in North Africa) could be connected by pipeline, in other cases (for example, Chile or Australia) transportation by ship would be necessary. Liquefaction may not be as practicable in the case of hydrogen as it is with methane, but the need for conversion into and from ammonia, or a liquid organic hydrogen carrier (LOHC), for shipping, would make long-distance green hydrogen supply similar to the LNG sector in some ways. As in that sector, it is likely that initial investments in the necessary infrastructure will need to be supported by long-term sale and purchase agreements, before a more flexible, spot market develops.

2.5.6 Finally, there is the precedent of the grey hydrogen sector, and perhaps particularly the supply of hydrogen on the largest scale to industrial customers, known as the “tonnage” market. This is often characterised by 15-20 year contracts with a take-or-pay element, and on-site production. If on-site production is not a disadvantage in the green hydrogen context (see further below on this), such an arrangement could provide a good basis for financing a green hydrogen project. However, the long duration of these contracts and market strength of incumbent grey hydrogen suppliers may make it hard for green hydrogen producers to break into this sector unless regulatory or commercial factors give tonnage hydrogen customers a reason to value the low carbon characteristics of their product.



H₂



2.6 Increasing the relative cost of higher carbon alternatives to green hydrogen

- 2.6.1 In a perfect world, carbon prices would rise rapidly to a level representing the full social and environmental costs of greenhouse gas emissions. In theory, this might be enough to prompt businesses and end-users to produce and consume green hydrogen at the levels required to meet net zero targets – and make the behavioural changes and capital investments necessary to meet such targets. However, we do not at present inhabit such a world.
- 2.6.2 Carbon pricing has helped to decarbonise electricity generation. In the EU, the EU Emissions Trading System (ETS) has compelled fossil-fuelled power stations to purchase EU allowances (EUAs), whose price has increased. This means that fossil fuel generators face an additional variable cost of production that renewable generators do not, further enhancing the competitiveness of the latter. A number of EU member states have also supplemented the EU ETS carbon price signal with additional taxes (for example, on the supply of fossil fuels).
- 2.6.3 The same disciplines can be – and are being – applied to other industries that produce significant greenhouse gas emissions or otherwise consume fossil fuels in large quantities, to encourage them to switch to green or other forms of low carbon hydrogen. However, there is always a risk that they may respond by relocating their manufacturing operations to countries where the carbon price (if any) is lower, in a way that a coal-fired power station or CCGT unit will not. Moreover, the *gilets jaunes* protests of 2018-2019 in France showed how carbon pricing measures can trigger a sharp political backlash. Although it is possible to design systems of carbon pricing that do not also either encourage “carbon leakage” to other jurisdictions or exacerbate economic inequalities and social tensions, governments may not wish to rely on them as the primary means of stimulating the green hydrogen sector.

3. Outline of a business case

3.1 Where to start?

3.1.1 What would it mean in practical terms to move from today, when the EU produces and consumes negligible amounts of green hydrogen, to the EU Hydrogen Strategy's goal of an EU in 2030 that has 40 GW of its own green hydrogen production capacity and potentially also imports the output of another 40 GW of capacity located outside the EU? If there is the political will to support green hydrogen, what kind of projects and infrastructure should be supported to produce value for money while moving decisively towards a hydrogen economy?

3.1.2 In this section we sketch a business case to show that it is possible to design, build and finance the hydrogen infrastructure required in a specific area of high potential demand for green hydrogen over the next decade. We consider the ramp-up of hydrogen production and transportation infrastructure year by year until 2050. Our analysis shows that such a plan would be ambitious. It would require immediate action and a common will to execute, but it would be a good starting point for scaling up green hydrogen to meet net zero targets in 2050.

3.1.3 We have focused on the region of North-West Europe (North-West Germany, Belgium, Netherlands, possibly Denmark) – not because we mean to suggest that this is the only or necessarily the best option, but because it is a concrete example of an area that happens to have the right characteristics for developing low carbon hydrogen supply chains.

- It has a high concentration of potential end-users of green hydrogen, including both refineries and petrochemical plants that already consume hydrogen as a feedstock, and other energy-intensive industries with the potential to switch to hydrogen

as a fuel. There is also a keen interest in hydrogen as a transport fuel (either on its own or in combination with other elements as a synthetic or e-fuel) for HGVs, trains, aviation and shipping.

- It has an extensive network of gas pipelines, which already have some surplus capacity, or which are looking for alternative use (such as L-gas pipelines).
- It is close to the North Sea, where offshore wind has the potential to provide large amounts of cheap, renewable electricity to green hydrogen producers located in the region, including as part of "Power to X" projects.
- Its geology is well suited to the underground storage of hydrogen, with large salt deposits and caverns across the region. Large-scale storage is likely to be a key part of the green hydrogen supply chain. For example, it would facilitate the use of hydrogen as a way to address seasonal imbalances between renewable electricity generation and demand.
- If hydrogen is to be imported from elsewhere in Europe, or beyond, the region is well connected by pipelines and inland waterways, as well as having large ports where hydrogen reception facilities could be constructed for cargoes shipped in by sea.

3.1.4 It is therefore not surprising that some of the largest and most significant pilot and demonstrator green hydrogen projects in Europe are proposed for locations in this region (see Figure 2 below). Examples include:

- projects involving oil majors' refineries at Rotterdam, the [GET H2 Nukleus](#) project (refineries and a chemical park), and [Tata Steel at IJmuiden](#);

- **Green Octopus's** proposals for an open access green hydrogen network connecting France, Belgium, the Netherlands and Germany, largely with existing infrastructure, that would be well placed to link into the **European Hydrogen Backbone** that has been proposed by a consortium of 11 gas transmission system operators (TSOs) – compare also the detailed plans for a “green gas scenario”, involving more than a dozen hydrogen-related projects on the Netherlands-Germany border, in the May 2020 **Network Development Plan consultation** of FNB Gas, the German TSOs’ association;
- offshore wind based projects and others aiming to optimise local renewable resources, such as **AquaVentus**, **NorthH₂**, **Hybridge** and Hyoffwind Zeebrugge; and
- the involvement in Portugal’s proposed **Green Flamingo** export project of the Port of Rotterdam, which could also provide reception facilities for imports by ship from further afield (for example, MENA), as well as the possibility of linking, via the Rhine-Main-Danube canal, to the **Blue Danube** project supplying green hydrogen from South East Europe.

3.2 Supply-side costs

3.2.1 The main supply-side costs of green hydrogen are electrolyzers, renewable electricity and transportation (of electricity or hydrogen). We consider each of these in turn below.

Electrolyzers

3.2.2 We have made what we think are realistic assumptions about the production capacities of electrolyser manufacturers, divided among the regions of origin in the proportions envisaged by the EU Hydrogen Strategy. We also assume that electrolyzers will become more efficient over time (from 60% today to 75%), and that the capital costs for hydrogen producers investing in electrolyzers will drop with larger plants and larger quantities.

Renewable electricity

3.2.3 Unless green hydrogen producers get a significant amount of the electricity they require from renewable generators operating at times when wholesale prices are negative or they would otherwise be unable to export power because of curtailment, it seems likely that renewable electricity will usually account for the largest share of green hydrogen supply-side costs.

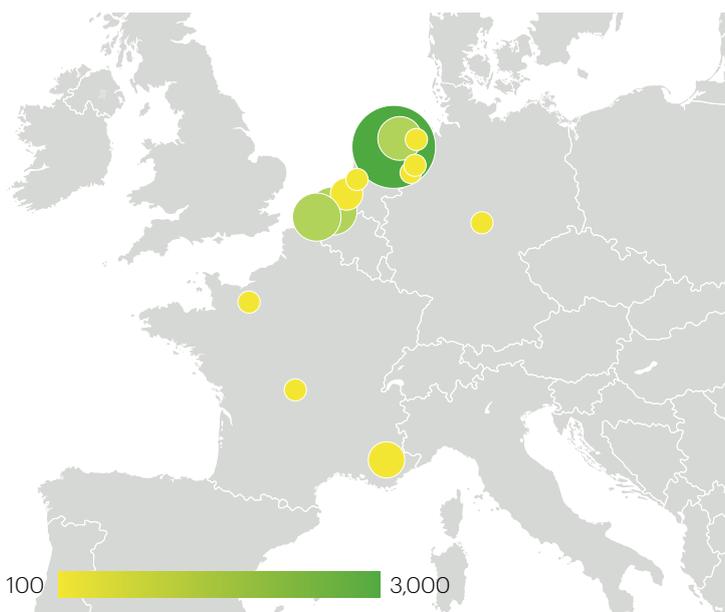


Figure 2 North-Western European Planned Hydrogen Projects in MW capacity [Source: IEA, Operis]

3.2.4 It follows from this that green hydrogen should be sourced from wherever renewable electricity is cheapest: hence the possibility of green hydrogen being supplied from outside Europe. However, we expect that the first major projects in the region may want to keep hydrogen transportation costs (and the risks of suitable transportation not being available) to a minimum by producing hydrogen relatively close to where it will be used. At the same time, in order to minimise network and other non-commodity costs associated with the supply of electricity, some projects may use renewable generation that is dedicated to green hydrogen production, and even co-located with it and demand. However, in our modelling we assume a gradual shift with increasing volumes being imported from increasingly distant sources.

3.2.5 We think it is reasonable to assume that, between 2023 and 2035, the levelised cost of renewable electricity (LCOE) produced in Northern Europe could fall from 5 Euro cents/kWh to 3 Euro cents/kWh or less, taking account of future corporate PPA markets. Over the same period, we assume a reduction in LCOE for renewable electricity produced in Southern Europe from 3.5 Euro cents/kWh to 2.5 Euro cents/kWh, and in MENA from 2 Euro cents/kWh to 1.5 Euro cents/kWh. We have reflected the possible impact of these changes, and of the expanding geographic range of green hydrogen supply chains feeding into North-West Europe, in the estimates of the cost of producing green hydrogen illustrated in Figure 3 below.

H2 sources – Specific cost development

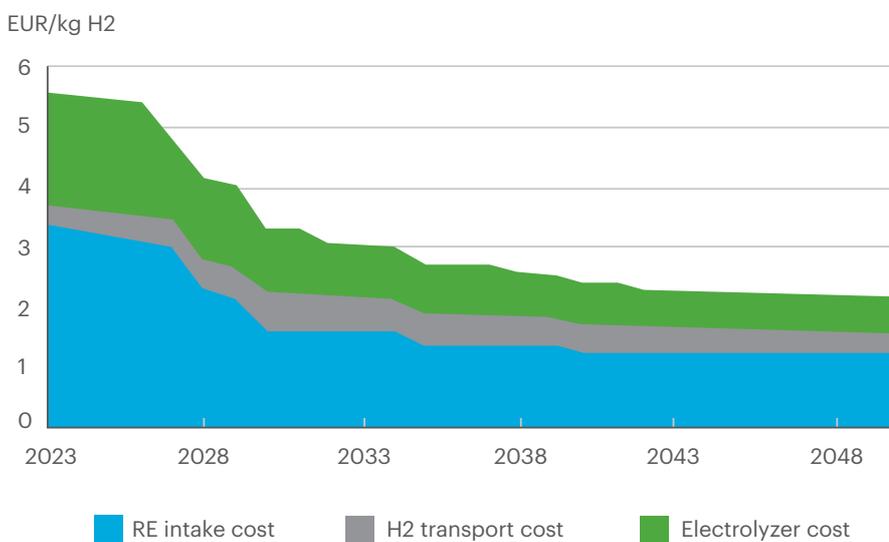


Figure 3 Levelised cost of hydrogen split into renewable electricity intake, transport and electrolyser cost [Source: ILF]

3.3 Transportation costs

3.3.1 Producing hydrogen anywhere other than in the exact location where it will be consumed requires a suitable mode of transport. In this paper, we do not offer a view on the form in which hydrogen can be best transported or, for example, about whether it is more efficient to transport hydrogen, or indeed to store energy more generally, in the form of ammonia (NH₃) rather than simply as hydrogen (H₂). Ammonia may have advantages in some contexts (although it would be unsuitable for some potential applications of low carbon hydrogen, such as blending in the natural gas grid), but similar transportation infrastructure will be required in either case. (Moreover, in the short term at least, if there is a market for “green” ammonia, those producing it from green hydrogen may find there is sufficient demand for their product in its own right, rather than as a low-carbon energy carrier.)

3.3.2 Assuming, then, that we are dealing primarily with a hydrogen, rather than an ammonia economy, there are some trade-offs to be made.

- A project that co-locates renewable electricity generation, hydrogen production and end-use has the advantage of zero transportation costs. However, such savings may not outweigh any disadvantages associated with the end-user’s location not being suitable for cost-effective on-site renewable generation. Moreover, even an apparently self-sufficient “island” project would be likely at least to require some assurance of being able to export its product if its on-site customer becomes insolvent or no longer requires hydrogen.
- Imports of hydrogen from countries not linked to the demand region by a dedicated hydrogen pipeline would be likely to have to be supplied by ship, which in turn means that transportation costs include either liquefaction and regasification, or conversion of hydrogen into and back out of a medium, such as ammonia. This would result in substantial additional costs (in terms of plants to convert the hydrogen into a transportable form, special ships and

energy). At least in the early stages of green hydrogen projects, these would be likely to outweigh the saving in terms of cheaper input electricity. Moreover, on a political level, too much reliance on long-distance supply chains may risk undermining the narrative that “green growth” is “good for jobs” and “promotes energy security” at a national level. (It is theoretically possible for hydrogen to be transported, blended with methane, in a natural gas pipeline, and the blend separated on exit, but, as with ship transport, there would be additional processing costs, and it seems unlikely that this would be a practicable option in the foreseeable future, at least where transmission across multiple networks within Europe is involved: Gazprom’s proposal to add hydrogen to the gas supplied via Nord Stream 2 may be a special case.)

- There is, of course, a broad middle ground of options between international hydrogen imports at one extreme and co-located renewable generation and production and consumption of hydrogen at the other. These include co-locating electricity generation and hydrogen production (for example, on a repurposed offshore oil and gas facility), with the hydrogen transported by dedicated pipeline to the end-user; and locating hydrogen production at the end-user’s site, using electricity sourced from the grid. In either case, there would be transportation costs, and the price at which the hydrogen producer can buy electricity may depend on how useful it is to a renewable generator as an offtaker (for example, in mitigating curtailment risk – which may in turn depend on location). We consider some of the other variables in these arrangements further in section 4 below.
- For the purposes of our business case we concluded that the most economically attractive option in the shorter term is to co-locate low cost renewable energy and hydrogen production and transport the hydrogen through dedicated pipeline networks, assuming that the hydrogen is produced within 3,000 km of the end-users’ location. However, as noted

below, the relative costs of pipeline and ship transport vary with both the distance travelled and the volume of hydrogen transported.

3.3.3 Without dedicated public hydrogen pipeline transportation networks, hydrogen production facilities may be unable to transport their product cost-effectively to end-users, meaning that they face a stranded asset risk if, for example, a co-located customer goes out of business. A hydrogen network also allows all end users to benefit from the cost reductions achieved by the most efficient hydrogen production facilities. Although there may be a place for individual “off-grid” projects, it is unlikely that an entire new sector can be efficiently supplied in this way.

3.3.4 In our modelling, we have predicted that transportation costs may contribute up to about 12% of the overall levelised cost of green hydrogen. The costs per kilo of hydrogen should decrease as the volumes of hydrogen being transported increase. Even if transportation costs make up only a minor

part of the hydrogen price in an advanced hydrogen market, infrastructure connecting supply and demand areas is indispensable to enable green hydrogen to compete with grey hydrogen and higher carbon fuels.

3.3.5 The present European gas transmission network (see Figure 4 below), with its interconnectors to regions beyond the EU, provides a good base from which to develop the hydrogen infrastructure, as the TSOs’ consortium’s report has pointed out. They conclude, perhaps unsurprisingly, that converting existing natural gas pipelines will be much cheaper than building a new dedicated hydrogen transportation system, but also that the core of a European hydrogen transportation network could largely be constructed out of converted, rather than new infrastructure, without detriment to either the hydrogen or natural gas industries. A pan-European, pipeline-based interconnected scheme would obviously require significant initial investments, but would then allow faster, economic upscaling at lower risk.



Figure 4 High level view of cross-border EU gas networks and LNG terminals [Source: ILF Consulting Engineers]

3.3.6 However, before long-distance networks are developed, we expect local clusters of hydrogen projects to interconnect with each other in order to compensate for bottlenecks, exploit local particularities or provide an outlet for surplus production. Once demand becomes large enough and the price pressure increases, longer pipelines and ship transport will be feasible.

3.3.7 Pipelines maximise their economic advantages when transporting large quantities of hydrogen. Ships are more flexible and can import hydrogen from distant regions, but the economic advantages of long-distance transport of hydrogen via pipelines prevails for larger transport volumes as illustrated in Figure 5 below.

3.3.8 Thanks to their lower LCOEs, the transportation of increasing volumes of hydrogen from high energy yield regions such as Southern Europe – and possibly also at a later date North Africa – should become economically feasible. In principle, the most obvious and certainly the fastest technically feasible pipeline route from North Africa to Europe starts in Tunisia and leads to North-West Germany, via SNAM’s Italian gas networks, through Switzerland and the TENP system (a route highlighted in Figure 6). However, it is not clear how soon any international pipelines could be converted to dedicated hydrogen transportation. In the long term, as some current users of methane switch to electrification (for example, heat pumps for domestic heating) or low carbon

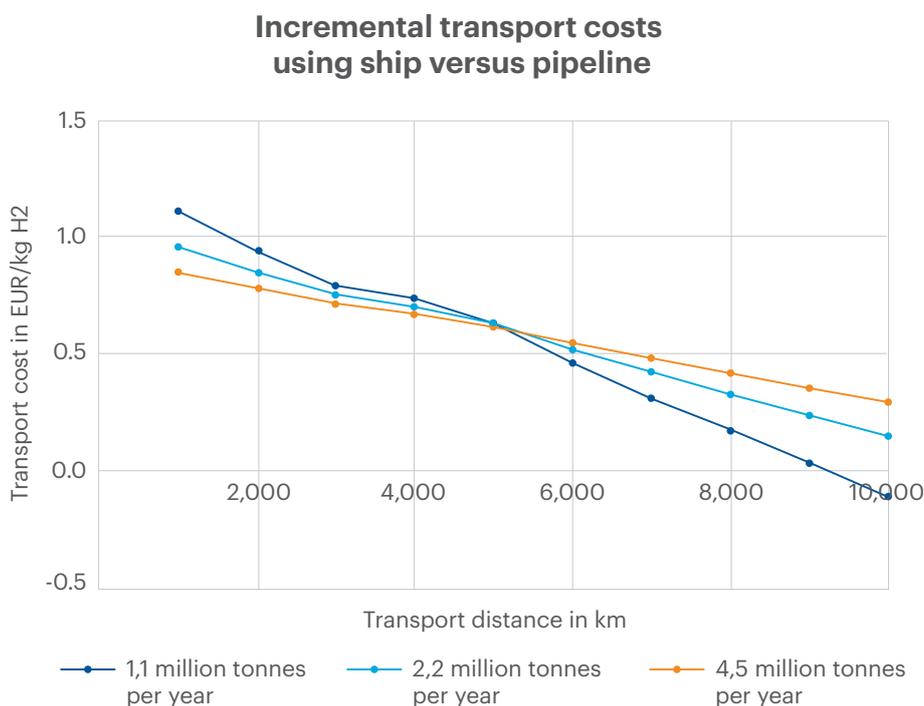


Figure 5 Difference in transport costs between pipeline and ship depending on volumes and distance [Source: ILF]

hydrogen, there should be plenty of spare pipeline capacity. In the meantime, it may be hard for hydrogen to displace methane traffic in pipelines, and blending hydrogen and methane, although it may work as a way of supporting low carbon hydrogen producers in a national market, presents technical and economic complexities in an international situation. Technologies for separating natural gas and hydrogen are being developed, but these are still expensive and involve significant energy losses.

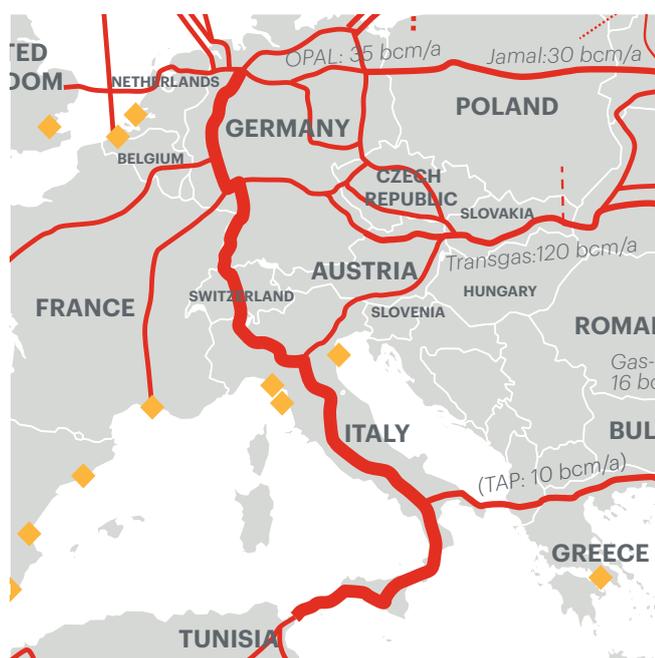


Figure 6 Potential pipeline route for hydrogen transport from North Africa to North-West Europe [Source: ILF]

3.4 Demand side

End-user conversion costs

- 3.4.1 Among those using hydrogen as a feedstock, petrochemical refineries and producers of ammonia already use large quantities of hydrogen. From a technical point of view, it would be very easy to replace their consumption of grey hydrogen with green hydrogen. Over time, declining use of fossil fuels may reduce the demand from refineries, but it is possible that this will be replaced by demand from producers of low carbon fuels and other chemical products that will be developed to substitute for petrochemicals. The key point in the short term is that this class of end-users will not need to incur any capital costs in switching to green hydrogen.
- 3.4.2 This will not generally be the case for those using hydrogen as a fuel. However, among them one group of potential future customers, those who own fleets of buses or HGVs, do at least hold portfolios of assets, a proportion of which is regularly replaced. Although vehicle numbers are currently small, switching existing hydrogen buses to a green supply and expanding the procurement of such vehicles could offer quick wins both for hydrogen producers and city transport authorities looking to reduce air pollution.
- 3.4.3 More generally, although various forms of transport have often been at the forefront of discussions about the use of hydrogen as an energy source, the development of battery technology, allowing cars and smaller trucks to be powered directly by electricity in an efficient and cost-effective way, seems to make it less likely that a mass market of smaller hydrogen road vehicles will emerge. However, hydrogen, or synthetic low carbon fuels made from it, are likely to play a part in decarbonising the maritime sector, and ultimately aviation. In each case, this will need to be supported by the development of sufficient filling stations and other infrastructure for the distribution of hydrogen or hydrogen-derived fuels.

3.4.4 In the long term, industries such as steel production will create demand for large quantities of hydrogen. However, they will have to switch from converters and blast furnaces to direct reduction. The costs of the new technology (possibly including write-downs of the value of existing plants) would be passed on in the price of steel. The industry has been under high economic pressure for years. There is as yet no demand for green steel, i.e. steel produced using renewable energy and green hydrogen, let alone customers willing to pay more for it. However, there are moves to provide support for “clean steel” – [for example in the UK](#).

3.4.5 As regards space heating, while it would be necessary to install new equipment in order to move to a system based entirely on hydrogen in a domestic or commercial property, the blending of hydrogen in the existing methane-based gas grid would allow existing appliances to continue to be used, and end-users’ capital costs of conversion to be deferred, although declining costs of heat pumps relative to hydrogen boilers may indicate that, in the longer term, more low carbon space heating will be provided directly by renewable electricity.

Possible synergies between green hydrogen production and existing industrial processes

3.4.6 However, as well as imposing conversion costs on some end-users, a switch to green hydrogen could also (as UK company Storelectric have argued in a successful patent application) bring material technical synergies in many cases – provided the production of the green hydrogen is co-located with demand. This is because so many of the industrial processes in which green hydrogen could be used (whether as fuel or feedstock) produce significant amounts of waste heat. Such waste heat can be used to heat the water used in the electrolysis process, which improves its efficiency – by up to 100% if it is hot enough.

3.4.7 By increasing the efficiency of the electrolysis process, this use of waste heat would reduce the cost per kWh of producing green hydrogen. At the same time, it may in some cases reduce the costs of existing manufacturing processes by removing the need separately to cool wastes or other product streams (or making it cheaper to do so) before they are discharged or stored. Finally, because chemical and petrochemical works are often located close to salt caverns or connected by pipeline to depleted oil and gas reservoirs, co-location of green hydrogen production areas where such facilities are clustered may also often open up large-scale storage options.



3.5 Carbon prices

3.5.1 The extent to which potential green hydrogen end-users are exposed to carbon pricing varies both by sector (for example, buses are not currently part of the EU ETS) and geographically (each country may have its own supplementary carbon tax regime). It is therefore hard to reach a precise view about the extent to which carbon pricing will contribute to the business case for green hydrogen by making higher carbon options less attractive on the demand side.

3.5.2 However, further reforms to the EU ETS, which are likely to increase the price of EUAs progressively during the 2020s and beyond, are expected. Some national governments have set out forward plans for the carbon prices under their own regimes to rise to particular levels by particular dates. For example, the Netherlands has set a target carbon price of €125-130/tonne by 2030. In Figure 7, we have included estimates of future increases in carbon prices in illustrating how the current cost advantage of grey hydrogen (using steam methane reforming) is likely to be eroded in the 2030s.

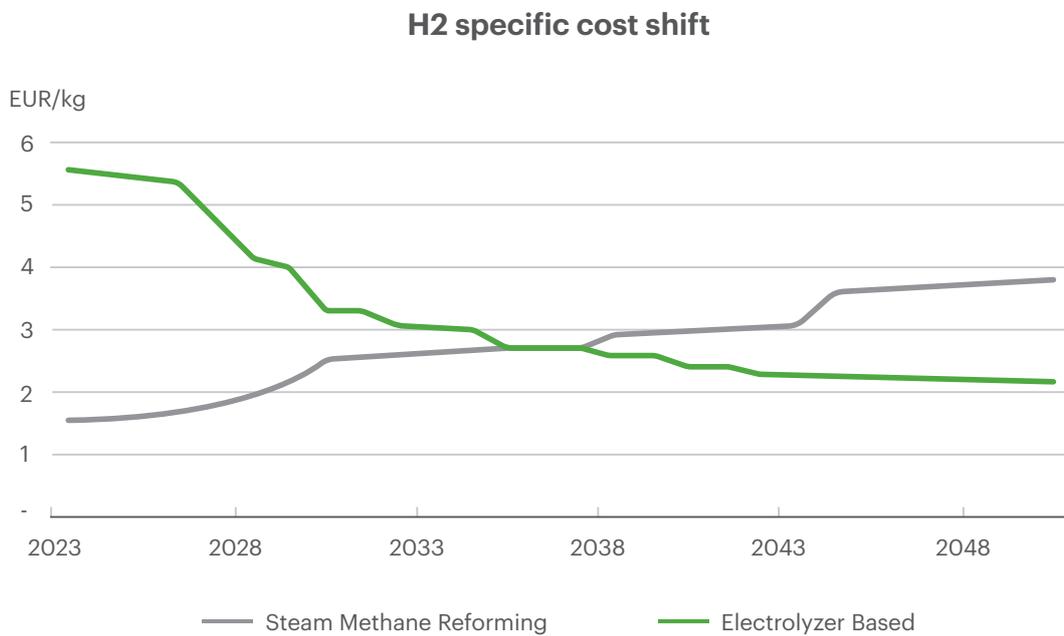


Figure 7 Cost shift for grey and green hydrogen [Source: ILF]

3.5.3 Considering the future ramp-up in electrolyser production by leading manufacturers, our business case foresees an installed green hydrogen capacity of 6 GW in the target demand region by 2030, growing up to 35 GW by 2050. These figures reflect a realistic view of the production capacities of electrolysers on the one hand and the development of hydrogen consumption patterns on the other. In the first few years, it is expected that government-mandated financial support or other public policy interventions on the supply and demand sides may be necessary in order to scale up as quickly as possible. In later years, the competitiveness of the electrolysers must lead to a repayment of the initial investment made.

3.5.4 Figure 8 illustrates the additional, though decreasing, green hydrogen costs to be covered during the first years of upscaling. The total cost for increasing volumes of hydrogen are shown for a green hydrogen pathway – in the form of renewables power production, electrolyser operations, and converted or new transport facilities – and compared to the total costs of grey hydrogen production through Steam Methane Reforming (SMR) for the same increasing volumes.

3.5.5 It is hard to imagine commercial structures that could make a project financeable against this background, at least in the short term, without some form of government-mandated financial support. Such support will certainly be required to achieve the early upscaling of green hydrogen production and consumption to meet national and EU targets, even in a region with characteristics favourable to green hydrogen adoption, such as North-West Europe.

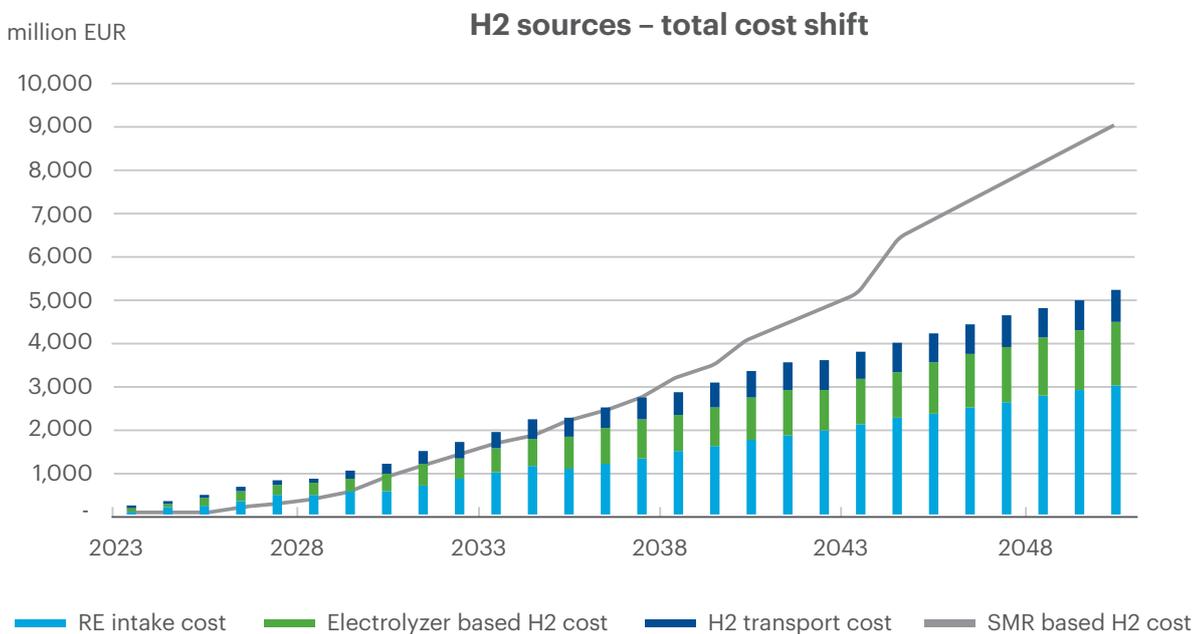


Figure 8 Total cost shift for grey and green hydrogen [Source: ILF]



4. Building blocks for scaling up fast

4.1 Economies of scale

4.1.1 In all aspects of the supply chain, economies of scale should improve the economic viability of green hydrogen production. In our target demand region of North-West Europe, and elsewhere, many different projects have been proposed to explore the potential of green hydrogen. Yet most of these are individually quite small (in the tens, rather than hundreds of MW capacity), and so will not in themselves realise economies of scale.

4.1.2 What, then, will drive the all-important economies of scale and bring production costs down? In this section, building on the high-level analysis of the economic challenges inherent in developing a low carbon hydrogen sector in section 2 and the brief review of what a regional hydrogen economy might look like in section 3, we suggest some options for how businesses and governments should go about scaling up green hydrogen production and consumption.

4.2 How much government intervention?

4.2.1 For 30 years or so, governments in most developed economies have been withdrawing from playing a direct role in energy markets, preferring less direct forms of regulatory intervention. However, the world has changed as governments have been writing their hydrogen strategies. The scale of financial interventions undertaken in response to the COVID-19 pandemic has put the use of public funding for net zero-related projects into a different perspective. Large sums may seem a little smaller now, particularly if they are associated with projects that are associated with economic recovery and “building back better”.

4.2.2 Moreover, if governments are serious about net zero targets and value for money, they may find that de-risking new projects and technologies by deploying direct public sector finance or ownership (themselves building new infrastructure assets which can be sold to the private sector later) is ultimately a cheaper, as well as a faster way to build up a new industry.

4.2.3 However, we cannot take radical government interventions for granted. So far, it looks as if most European governments who want to facilitate hydrogen production would prefer to deploy the kinds of market-based, but government-designed, support mechanisms that have characterised the renewable electricity sector in recent years, such as feed-in tariffs or premiums awarded by auction, tradable green certificate schemes, or contracts for difference (all of which we refer to for convenience as “regulated financial support”). These may, however, be supplemented by the kinds of additional support measures, such as guarantees and contingent equity support, that are designed to address specific risks and reduce the cost of developers’ capital in the context of the [UK’s next new nuclear project](#), for example, and aspects of its [development of CCUS clusters](#) (transport and storage assets).

4.2.4 Before we turn to the role of government-designed financial support and other policy interventions, we consider how the commercial players can facilitate the upscaling of green hydrogen. Leaving aside the possibilities of long distance supply chains and imports by ship, the key commercial players are renewable electricity generators; their offtakers, the hydrogen producers; the gas transportation network operators; and the end-users of hydrogen. In the following sections, we consider the perspectives of these groups.

4.3 Renewable electricity generators

4.3.1 For a renewable electricity generator, a green hydrogen producer is potentially an attractive offtaker for its output on a corporate PPA basis. Subject to the relative capacities of generator and electrolyser (including any storage facilities), the hydrogen producer should be able to take all (or a defined tranche) of the generator's output, whenever produced. As the producer of an explicitly "green" commodity itself, the hydrogen producer values the "greenness" of the generator's electricity. In this context, at least for an existing generator that has paid off its financing costs and no longer benefits from regulated financial support, even a short-term contract with a hydrogen producer may be attractive – always assuming that the hydrogen producer's arrangements with its customer(s) provide it with a secure demand for its output, at a price that allows it to agree terms with the generator that work better for both of them than selling/buying electricity on a purely merchant basis. Those arrangements would need to be very secure to provide the basis for a PPA that would support financing of a new renewable generation project. It is possible that an end-user with a strong motivation to display its "green credentials" would find it worthwhile to make a virtue of the fact that its use of hydrogen was supporting new renewable generation (extending the principle of "additionality" that is important to some corporate PPA offtakers). Some short- or mid-term storage of electricity or hydrogen may help to balance supply and demand as between generator and hydrogen producer and between hydrogen producer and end-user (as well as potentially facilitating arbitrage opportunities).

4.3.2 In individual cases, the pairing of a specific generator and a specific hydrogen producer may give rise to particular commercial advantages. One example would be geographical proximity or other circumstances allowing a direct wire connection (removing the burden of regulated network costs). Another would be the ability of a hydrogen producer to alleviate a generator's exposure to imbalance costs (depending on the extent to which and speed at which it can flex its demand) or to mitigate its risk of curtailment (if the hydrogen producer sits between the generator and a network constraint). Factors specific to a particular generator/hydrogen producer pairing are also likely, in part, to determine which form of corporate PPA is most appropriate – for example, physical (direct wire), sleeved (with a third-party utility making up shortfalls in supply or demand), or a synthetic hedging arrangement.



4.4 Hydrogen producers and end-users

- 4.4.1 Electricity generators already exist in a well-defined, vertically disaggregated market. Producers and end-users of green hydrogen do not. Will it make sense for the same entity to purchase renewable electricity, run the electrolyzers and sell to end-users? This “integrated model” may leave the hydrogen producer managing a lot of risks, which may make sense if it is also the focus of regulated financial support that mitigates many of those risks, but it is not the only possible model, and it remains to be seen if it is the one that the market will favour.
- 4.4.2 Viewed from another perspective, and taking things a step further, vertical integration could reduce risk. Some potential end-users of green hydrogen are among the largest manufacturing enterprises, with large balance sheets. It might assist with the upscaling of the new industry if the supply chain were to be vertically integrated from such end-users “upwards”.
- 4.4.3 Another approach would be a tolling model, where, for example, an energy company might be responsible for procuring or supplying renewable electricity and water and selling hydrogen to end-users, while an infrastructure operator would run the electrolyzers and be paid a tolling or conversion fee per kWh. If there are economies of scale to be derived from running large volumes of electrolyser capacity, this model might help to achieve them. Another approach might be for a third-party utility/intermediary to purchase from multiple hydrogen producers and sell on to multiple end-users, as in electricity and natural gas markets. At the very least, hydrogen producers with access to demand from a number of consumers located close to each other, such as in ports or industrial parks, should be able to reduce their demand risk by spreading it over a number of consumers, but in such cases there is often already an entity supplying products or services procured from one business on the site to others on the site. Such an entity could add the procurement and supply of hydrogen to its existing functions.
- 4.4.4 In the integrated model, the same entity has to cover the fixed costs of the electrolyzers whilst buying electricity in a market where there is a wholesale market price that varies considerably (intra-day and over longer periods) and selling in a market where customers are likely to want to pay the same price per unit of hydrogen at all times, and where there may well be no equivalent of the electricity market’s wholesale price. Theoretically, if the intra-day differential between prices at periods of high and low demand is sufficient and storage is readily available, one approach could be to have a very large electrolyser capacity and run it only or mainly at periods of low electricity prices, producing enough hydrogen to satisfy daily customer demand by making use of what has been stored. However, this would depend on the gains from maximising use of cheap power exceeding, over a number of years, the costs of financing the additional electrolyser capacity and storage. In practice, electrolyser and storage costs may make this oversizing approach unfeasible.
- 4.4.5 On the face of it (and ignoring for the moment any regulated financial support that may cover a hydrogen producer’s capital costs), whoever is responsible for the finance costs of the electrolyzers, if they are profiled evenly over time, may want to contract with end-users for a period that matches as closely as possible, or is no shorter than, the term of that finance, at least in the case of early projects. Against that, any end-user may have an incentive to contract over a shorter term, if it has the option of switching between hydrogen producers or between green and blue hydrogen (on the basis that green hydrogen will become cheaper because of falling technology costs), or between hydrogen and fossil fuels. Moreover, end-users who are switching to hydrogen from another source of energy will not be used to buying energy on long-term contracts, let alone ones that incorporate take-or-pay obligations (such as a hydrogen producer worried about demand risk might wish to include).



4.4.6 However, while the green hydrogen sector is still developing, hydrogen producers and end-users will need each other: an end-user that has made a commitment to “go green” and wants to stick to it may have limited alternative options. It may be possible to agree long-term contracts if a degree of flexibility on pricing can be arrived at with which both sides are comfortable. Pricing could, for example, incorporate elements of benchmarking against alternative fuels (high or low carbon) and be based on an assumed carbon price trajectory (taking into account assumed carbon price savings on the part of the end-user, with some potential to adjust, sharing upside or downside if the actual savings turn out to be more or less).

4.5 Consortium approaches

- 4.5.1 While the markets for and associated with green hydrogen develop, there may be considerable benefit in approaches that explicitly seek to share risks widely, both across and between the different levels in the supply chain. Collaboration may overcome some players’ nervousness about suffering “first mover disadvantage”, providing that this can be achieved in compliance with applicable anti-trust laws and without losing the benefits of competition.
- 4.5.2 One relatively simple step would be to set up a platform where relevant information about projects could be shared to facilitate the matching of hydrogen supply and demand (such as has already been launched by [Zeigo](#) and others to match renewable generators and prospective corporate PPA offtakers). Hydrogen producers or end-users could use such a platform to run mini-auction or tender rounds among generators and hydrogen producers. To be optimally user-friendly, such a platform would also provide template forms of contract for the supply of renewable electricity to hydrogen producers and of hydrogen to end-users which individual generators, hydrogen producers and hydrogen end-users could customise within defined parameters for the purposes of submitting bids.

4.5.3 The platform would make potential participants in the green hydrogen economy more visible to each other. Size, timing of commissioning, and location of new sources of supply and demand will be of acute interest to the growing industry. Making these more transparent may have considerable value as a planning tool, possibly coupled with appropriate forms of option. Using this, generators, hydrogen producers, end-users, and even electrolyser suppliers could plan and contract ahead (albeit on a conditional basis) with more confidence. Increasing the awareness that generators interested in supplying hydrogen producers, hydrogen producers, and potential have of each other should promote the growth and competitiveness of the green hydrogen market.

4.5.4 Another approach would be for end-users (or hydrogen producers) to aggregate their future hydrogen (or renewable electricity) requirements over a certain period, and set up a co-operative purchasing entity which could go out and procure on a mixture of short- and longer-term contracts, with the aim of spreading the supply-side and demand-side risks across a portfolio of individual transactions. This would resemble the function that a utility retailing gas or power to end-users typically performs in a liberalised and vertically disaggregated downstream gas or electricity market. However, unlike a third-party utility, a buyers' co-operative would not have its own shareholders, so that any "profit" that it made as a result of its dealings (and any risk associated with individual end-users) would be shared among its members (hydrogen producers or end-users as the case may be). Particular care would need to be taken in setting up the governance arrangements for such an entity, so as to comply with competition law restrictions on information sharing and various kinds of joint purchasing activity (it may also require clearance under merger control rules, as a form of joint venture).

4.5.5 Another strategy that some companies have investigated – which could also be combined with the buyers' co-operative model, by extending the activities of the "virtual utility" up the supply chain – would be for end-users to own a portion of the hydrogen production facility. This approach is not unknown in power supply to industrial customers. There are also obvious parallels with the way that upstream and midstream oil and gas infrastructure is often financed (although in the oil and gas sector it may be more common for participants ultimately to trade than to consume, or even sell their hydrocarbon shares to an end-user). An offtaker that was no longer going to pay for the supply would forfeit its equity stake, reducing other investors' potential downside risk. However, during normal operations the offtaker may be able to recoup some of its costs. Indeed, the shared ownership could go beyond the production facility to include electricity generation or other related infrastructure (private wires or pipeline networks). There may be scope to cross-finance and shift from profit units to cost units. Again, this sort of arrangement might work well in an industrial park or similar cluster.



4.6 Gas transportation network operators

- 4.6.1 Such arrangements could help to develop liquidity in the green hydrogen markets, but they would work best if there were adequate hydrogen transportation links between projects. For example, if there are 20 hydrogen producers but only one is in a position to transport its hydrogen to a given end-user, there is no point in that end-user running a tender round.
- 4.6.2 We assume that policymakers will want long-distance hydrogen transportation to be primarily a matter for regulated public monopoly operators, as for electricity and downstream natural gas. Gas network operators are obviously well placed to assume this role: indeed, moving from transporting natural gas towards transporting low carbon hydrogen (and biomethane) appears on one view to be their way to continue in business over the long term. We consider the regulation of hydrogen networks further below, in the context of public sector support.

4.7 Allocating regulated financial support

- 4.7.1 Subject to the points made above about possible changes of perspective in the wake of COVID-19, governments will want to target their support to make sure it is as cost-effective as possible. Their ultimate goal would be to create a competitive industry which is not reliant on high levels of support and, particularly in a post-pandemic world, they will want every bit of subsidy to deliver the greatest possible value (for example, in terms of greenhouse gas emissions avoided; hydrogen production capacity installed; or domestic jobs created). At worst, there is a risk the programmes of regulated financial support for green hydrogen could run into political opposition (for example, if they are perceived as unduly benefiting parts of the supply chain located abroad, and thus scoring low by measures of national green job creation).
- 4.7.2 This is not just a matter of policy preference. EU and other state aid and subsidy control rules may limit the kinds of support that can be given to green hydrogen projects (for example, funding for capital investment or for operating expenses) or the intensity of aid (measured in percentage-of-eligible-cost terms) that can be granted, where what are deemed to be state resources (which includes funds raised by a levy on end-users) are used to provide selective advantage to a particular firm, group of firms or sector. Although aid for environmental purposes is often recognised as a distinct category, it is not clear whether, for example, the relevant European Commission guidelines, which currently do not mention hydrogen, will be particularly generous to low carbon hydrogen projects when they are updated during 2021.



- 4.7.3 The Commission is likely to want to avoid any risk of support allocated to green hydrogen producers or end-users resulting in the renewable electricity generators with whom they are contractually linked benefiting from more generous subsidies than they already enjoy under their own support regimes (or from both regimes). Although various forms of “operating aid” are permitted currently under the guidelines “in order to cover the difference between the cost of producing energy from renewable energy sources and the market price of the form of energy concerned”, aid granted for capital expenditure would be deducted from this.
- 4.7.4 One hitherto relatively little-used area of state aid law that has been highlighted as potentially useful to green hydrogen projects is that of Important Projects of Common European Interest (IPCEIs). These enjoy greater flexibility on the form and intensity of state aid. Qualifying projects can receive both investment and operating aid, and support to cover up to 100% of “eligible costs”. In order to qualify as an IPCEI, a project must meet a list of criteria, including involvement of more than one member state. **Several green hydrogen projects** are being developed with the IPCEI criteria in mind. This may reduce its applicability to the initial regional projects with demand and supply co-located in the same region. Furthermore, there may be reasons not to exploit the freedom apparently conferred by the IPCEI principles to the full, because doing so might cause a problem under WTO subsidy rules.
- 4.7.5 It might be expected that some national governments would prefer not to be in the first wave of those offering subsidies, preferring to wait until costs have decreased before providing support. Some countries have clearly benefited by taking that approach in respect of renewable electricity – in effect, “free-riding” on the subsidy programmes of the first movers. On present evidence, this may not be such a risk, since many governments seem keen not to miss out on the potential for post-pandemic economic recovery associated with green hydrogen. However, one way to avoid this free-rider problem, and concerns about the intensity of competition among projects, could be to have investment at European rather than national level – although new legislation may be required to enable the EU to provide hydrogen projects with the kind of assistance given under many national renewables support regimes.
- 4.7.6 Whatever forms of public financial support are given, it will be important for the authority granting the aid to be alert to its impacts across the whole value chain.

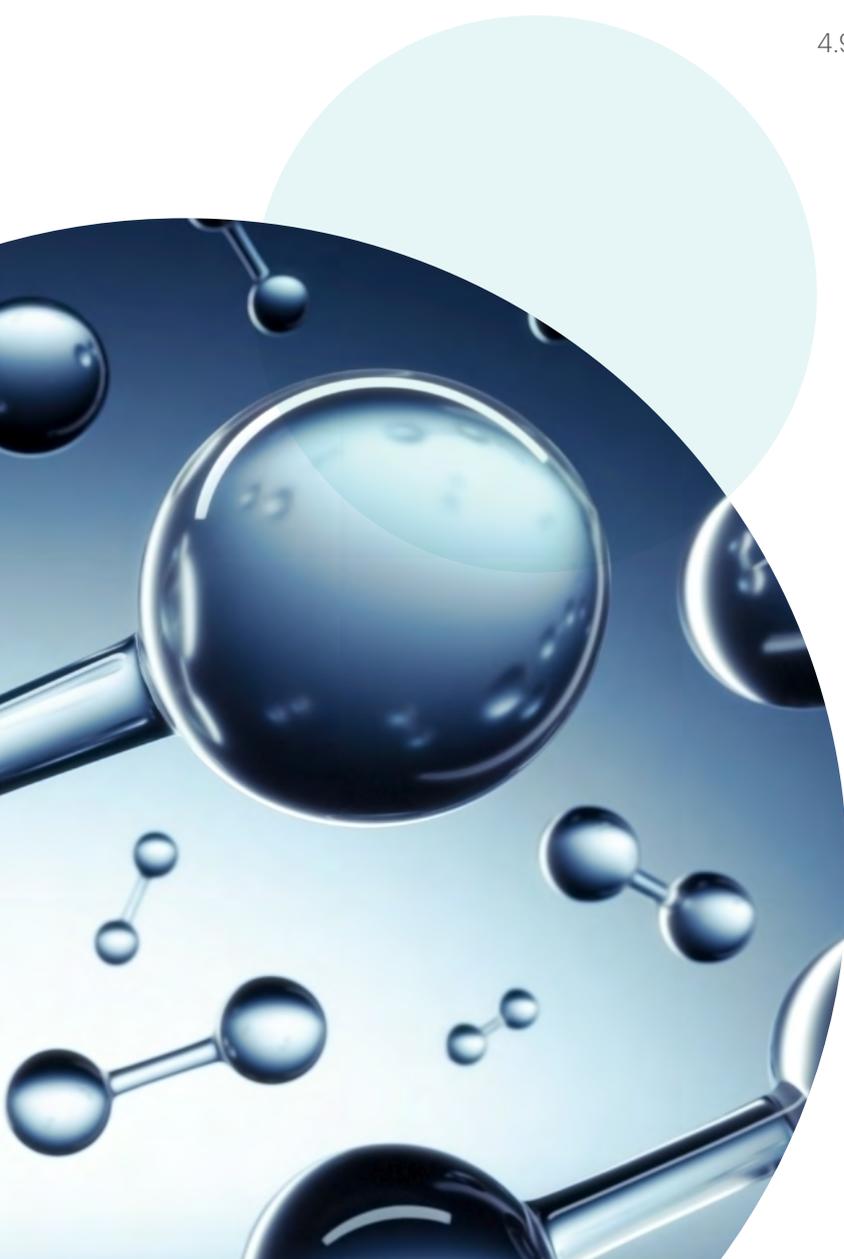


4.8 What forms could support take?

- 4.8.1 The support that the public sector can provide will not all need to come in the form of money. The creation of a supportive regulatory environment has other aspects as well. However, in order to generate higher demand for green hydrogen, the additional costs of producing green hydrogen (as compared with higher carbon alternatives) need to be met or reduced.
- 4.8.2 In principle, this could be done by increasing carbon prices on fossil fuels; incentivising efficiency in the hydrogen supply chain; paying some or all of the difference between the market costs of green hydrogen and a benchmark alternative to hydrogen producers or end-users; or by giving them grants or tax breaks for approved forms of capex incurred on, for example, electrolyzers or hydrogen-compatible demand-side equipment.

4.9 Carbon pricing

- 4.9.1 The policy of carbon pricing goes well beyond the encouragement of green hydrogen projects and, as noted above, it is also a politically difficult area, unless and until governments generally are prepared to implement the kind of economy-wide carbon pricing that many economists recommend (whose proceeds would be redistributed as part of a “just transition” approach). For present purposes, we do not seek to advocate any particular policy in relation to carbon prices (for example, taxation on a predictably rising scale as against cap and trade schemes with progressively reducing caps). However, any other form of support for green hydrogen will need to take into account the fact that carbon prices are almost certain to rise over the period when it applies. Potential changes in carbon price therefore need to be taken into account in designing other policies.
- 4.9.2 However, we note in passing that any measures which are introduced to improve the competitiveness of green hydrogen through higher carbon prices will need to be very carefully calibrated, and take account of EU plans to introduce a Border Carbon Adjustment (BCA – i.e., in effect, a tariff equivalent to EU ETS costs that would be levied on imports of certain carbon-intensive products from lower-carbon price jurisdictions). A BCA may considerably assist green hydrogen, depending on how it is designed.



4.10 Incentivising efficiency

- 4.10.1 In order to achieve a lower levelised cost of hydrogen, there would need to be improvements in either its production or transportation. Some estimates predict decreases of more than 60% in the cost of electrolyzers per kWh over the next 30 years, coupled with an expected 10% or 20% increase in electrolyser efficiency over the same time frame – driven by economies of scale and incremental technical improvements, similar to those seen with other renewable technologies when they have been exploited in a concerted way. These predictions suggest that significant savings could be made in green hydrogen production costs (and also that early adopters will need to be sure that their business models will be robust in the face of future competitors with a lower cost base).
- 4.10.2 The best way to stimulate these technological advances is less clear, unless it is by simply ensuring that there is a lot of demand for electrolyzers. However, this may be met with more, cheaper (but less efficient) electrolyzers rather than fewer, more efficient (but more expensive) ones. For example, China produces alkaline electrolyser units that are significantly cheaper than the proton exchange membrane (PEM) electrolyzers produced in Europe, which are more efficient and said to be better suited for use in green hydrogen projects.
- 4.10.3 Targeted grants or tax breaks for electrolyser research and development could be an efficient way for governments to support hydrogen becoming cost-competitive without finding themselves tied into longer-term obligations. The same may be true of funding R&D work on technologies that can make it easier to transport hydrogen by ship without incurring major reconversion costs. The UK and other EU governments are already using this model to fund some hydrogen R&D projects, as they have done with other technologies, such as CCUS.

4.11 Supporting hydrogen production

- 4.11.1 Broadly speaking, whether one looks at the supply side or the demand side, there are two kinds of additional costs that producers or end-users may face:
- one-off capital costs (to fund the development of a production facility or the conversion of end-user facilities in the case of end-users who are switching to hydrogen for the first time, rather than just substituting green for grey hydrogen); and
 - ongoing operating costs, where these are higher than those of competing high-carbon suppliers or those that the end-user would face if it stuck with a higher carbon alternative.
- 4.11.2 In principle, both kinds of cost could be fully addressed just by providing hydrogen producers or end-users either with a sufficiently heavy capital subsidy, or with sufficiently generous regulated financial support for each unit of hydrogen produced (the approach taken in many EU jurisdictions with renewable electricity support) or purchased. Alternatively, producer and end-user capex could be supported through a mixture of grants and government guarantees for debt financing and renewable-electricity style operating aid payments. The latter would aim to bridge the gap between the costs of producing green hydrogen and those of producing grey hydrogen or a benchmark high carbon alternative fuel. Such payments, if made to the producer, would allow the end-user to pay the grey hydrogen/high carbon fuel price, and the producer to meet its costs and make a profit on its green hydrogen production.

- 4.11.3 As noted above, both general economic policy considerations and state aid rules dictate that any form of subsidy granted in respect of a new market should aim to facilitate rather than dampen competition in it, and should be limited to the necessary minimum. Before resorting to grants or revenue support schemes, it is important to explore what advantages green hydrogen projects may enjoy in attracting commercial funding, and what assistance can be given on a more or less commercial basis by policy-led lenders such as the EIB.
- 4.11.4 If the EIB were allowed to offer specific loans to the hydrogen sector, rather than to the renewables sector as a whole, then this would allow for terms more tailored to the sector's needs. For example, the loans could recognise that the market is in its early stages of development and offer to delay payments of principal for a pre-specified number of years at the start of the project, coupled with restrictions on distributions to shareholders in this period. Alternatively, debt service obligations could be profiled to reflect expected growth in revenues, as was done (in a different context) with gas distribution networks in Northern Ireland.
- 4.11.5 Another approach would be for the EIB or national governments to take equity stakes in hydrogen production or network companies, providing upfront cash that they would look to recover by selling their stakes once the business is profitable. A competitive award process against rigorous objective criteria would need to be established for awarding such funding, to mitigate against the risks of government "picking winners". A variant would be to establish a fund in which public money is placed (perhaps with private money too) to invest in projects, with government providing assurance to the fund on risks that cannot economically be borne by investors. The fund could then be progressively privatised. EU state aid and WTO anti-subsidy rules may be a constraint in this context.
- 4.11.6 However, it is also important to remember that, while to some extent we are dealing with new technology, it will by no means be the case that all those involved are thinly capitalised start-ups. The possibility of issuing green bonds (perhaps with a discount of as much as 30bps to financing for traditional energy assets) backed by some form of guarantee from blue chip anchor hydrogen end-users seems, in principle, worth exploring.





4.12 A possible model

4.12.1 Competitive allocation of subsidies is the most obvious way to control costs and get best value for the public purse. It has worked well across a range of European jurisdictions in recent years as a means of providing funding to renewable electricity generators by auctioning contracts for difference (CfDs) or feed-in premiums (FiPs).

4.12.2 In the renewable electricity context, the subsidy that generators bid for is defined by reference to wholesale power prices. For example, in the GB CfD regime, a £/MWh strike price (representing a level at which generators expect to make an acceptable return) is set by auction, and generators receive a supplement to a benchmark wholesale price in respect of periods when that price is below the strike price, paying back any excess of the benchmark over the strike price (multiplied by their output) when the benchmark is above the strike price.

4.12.3 For green hydrogen subsidies awarded along similar lines, the wholesale price of natural gas could be the market reference price, as it would be the obvious alternative fuel for many of them. It may also be possible to allow hydrogen producers to bid for support based on another benchmark of their intended end-user's alternative input cost, which could be

something other than natural gas (for example, grey hydrogen). If, for example as a result of increased carbon pricing, the wholesale price of natural gas were to rise, the subsidy to the green hydrogen producer would reduce. If wholesale gas prices were to rise above the strike price level on a more or less permanent basis, it may be appropriate to suspend the obligation on green hydrogen producers to pay back the excess since, at this point, financial support is no longer required (by partial analogy with renewable electricity CfD regimes that suspend payments when wholesale prices go negative). It may also be necessary to consider how to deal with a situation where increased demand for hydrogen and reduced demand for natural gas causes the price of the latter to fall significantly on a permanent basis, increasing the long-term costs of regulated green hydrogen support.

4.12.4 Account would also be taken of the end-user's assumed avoided carbon costs and how both the reference input and carbon costs change over time. However, a [report prepared by Frontier Economics](#) for the UK government on potential regulated support mechanisms for low carbon hydrogen suggests that end-users' avoided costs are best captured by means of support to producers rather than to end-users directly.

- 4.12.5 All forms of publicly funded support should be competitively allocated – both support for capital investment and operating aid. One way of evaluating different kinds of project, that might involve different industries and different balances between capex and opex would be to have them all bidding in terms of their potential to reduce greenhouse gas emissions and the net amount of support they require to avoid each tCO₂ of emissions. For example, a hydrogen production facility with an input capacity of 1GW may put in a lower bid for capital investment support per MW of installed capacity than a facility with an input capacity of 50MW. Subject to any overall budget cap, and other things being equal (for example, both facilities have credible routes to market, assume similar utilisation rates and face similar consequences if their actual utilisation falls below those rates) the larger facility's bid should be ranked ahead of the smaller facility's bid. The CO₂ reduction element of the Netherlands' SDE++ regime may provide at least a partial precedent for this kind of approach.
- 4.12.6 When it comes to the allocation of operating support, bidders could be asked to bid on the basis of a supplement to the savings assumed to be made by end-users of green hydrogen on the basis of an assumed carbon price trajectory and a given methane/hydrogen energy value ratio. If the movement of the carbon price is such that the actual savings are less, the level of support provided would increase proportionately; if the actual savings are higher, the recipients of support would pay back some or all of the excess support. This could be structured as a CfD, with the support going to the hydrogen producer. However, the bids submitted by individual producers will reflect the arrangements that they make with end-users and their assumptions about the level of risk involved in those arrangements.
- 4.12.7 This is a complex area. There are many possible solutions. Governments are already studying their options – a process made more complex in some cases by the desire to incentivise both blue and green hydrogen production without favouring one technology at the expense of another: see, for example, the Frontier Economics report cited above. The important thing is to develop funding mechanisms as quickly as possible, consistent with their frameworks remaining broadly stable for a number of years once introduced, so as to give certainty to the market and establish a pipeline of projects.
- 4.12.8 The question remains, how the costs of such support should be met: for example, out of general taxation revenue, carbon pricing receipts, or government borrowing, or by imposing a levy on market participants that can ultimately be recovered from consumers of natural gas generally (compare the recovery of CfD and other regulated financial support costs from the bulk of GB electricity consumers)? These are political matters beyond the scope of this article. Existing renewable subsidy schemes are financed in a number of different ways, and different approaches may be required for each country's hydrogen support schemes, depending on the precedents set by their existing renewables (and other relevant) policies.

4.13 Transportation network options

4.13.1 As noted above, transportation networks will play a crucial role in the development of an efficient low carbon hydrogen economy. Existing infrastructure owned by gas network operators provides the obvious starting point for such networks. Although hydrogen places different demands on network infrastructure from those associated with methane, the features of the existing infrastructure (for example, what sort of steel the pipes are made of) vary between, and sometimes within, national systems and will determine how much, and what sort of, work is required to adapt them to hydrogen use. New infrastructure will also be required, for example, to connect new production facilities that are either not currently connected to the gas grid, or where a new pipeline is required in order to bypass part of the existing grid that will continue to be used for natural gas for the foreseeable future.

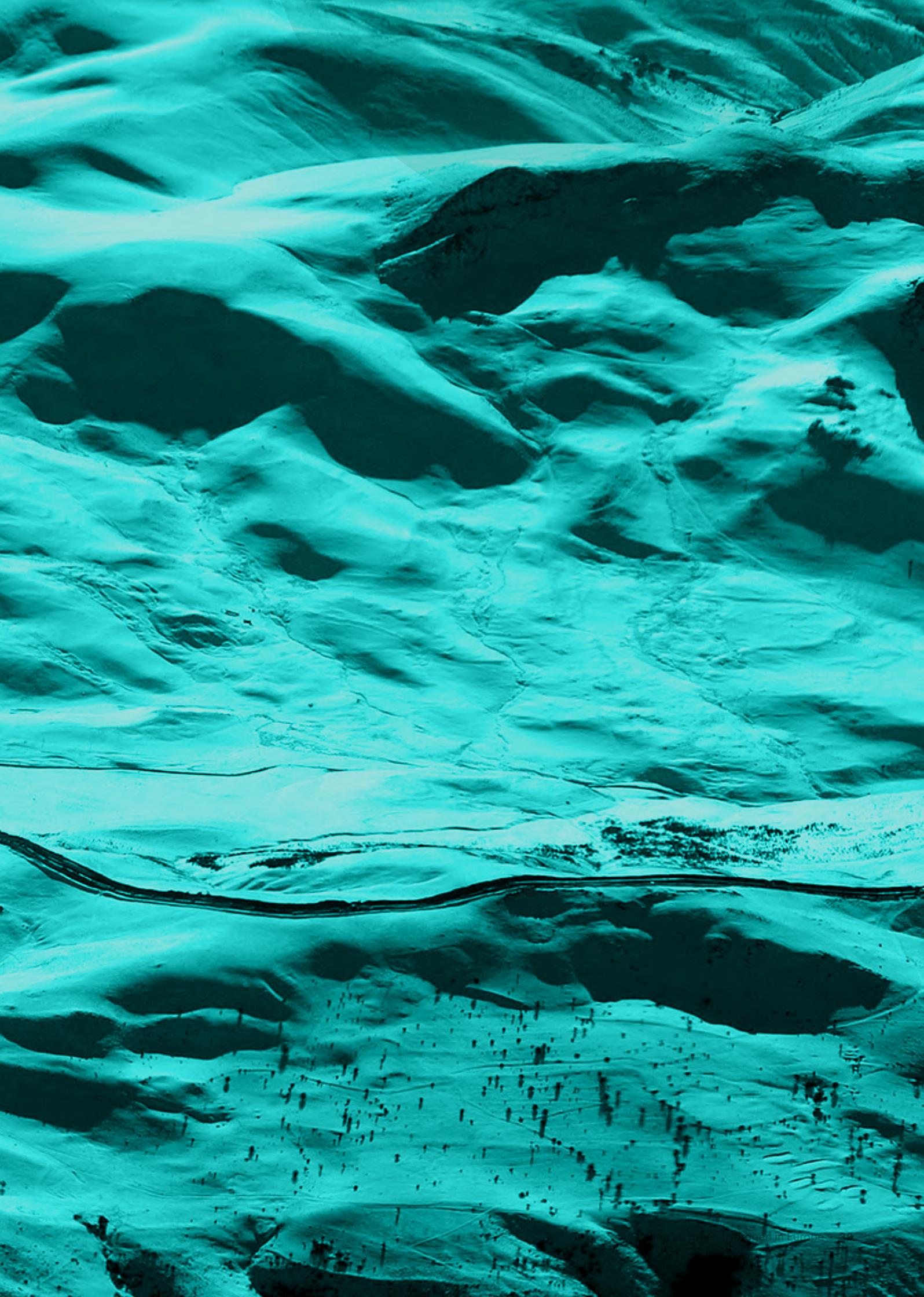
4.13.2 Broadly speaking, there are three possible models for the hydrogen transportation network.

- The model found in the upstream oil and gas industry, where the users of infrastructure are responsible for developing it in the first place and retain ownership of it.
- The classic “unbundled” ownership/operation models set out in EU internal energy market legislation on downstream gas network infrastructure. These require the infrastructure owner/operator, as e.g. proposed by the German Ministry of Economy recently as part of the draft revision of the German Energy Act, to be independent in one way or another from those who use its infrastructure. These rules are, in some cases, reinforced by stricter national rules and would likely apply by default, for example, to hydrogen blended in the gas grid.

- A hybrid model, perhaps based on the GB “OFTO” regime for offshore transmission links (and proposals to apply a similar regime to onshore transmission networks), where infrastructure assets can be built by the generator (or, as it would be in this case, the hydrogen producer) to export its output, but, after a defined “commissioning period”, they are auctioned off in a process administered by the energy regulator Ofgem, with bidders aiming to receive a guaranteed rate of return based on their cost of capital as long as the infrastructure assets are available for use.

4.13.3 Regulatory economists point out that, since most public energy networks are a natural monopoly, the kind of vertical integration found in the upstream model risks conferring undue market power if those who own the networks are free to set their own terms of use to customers who are their competitors in production or supply to end-users. This is why, even in the less intensely economically regulated world of upstream oil and gas, it is common to find mechanisms for regulatory intervention to ensure non-discriminatory third-party access.

4.13.4 It is arguable that the early development of a green hydrogen economy resembles the upstream environment (for example, a smaller number of commercially sophisticated end-users, often with commercial ties to the suppliers, rather than millions of residential and small business customers), so that a vertically integrated model is not necessarily inappropriate, at least as long as the infrastructure faces no capacity constraints. Until that point, the incentive on any user-governed network operator is likely to be to let new participants in wherever possible, in order to spread the costs of running the network beyond the initial participants. Much may depend on the facts of individual networks and projects seeking to use them.



- 4.13.5 However, the ownership of pipelines and other upstream oil and gas infrastructure by competitors of those seeking access to them starts with upstream players building infrastructure because without it they cannot convey their output to market. In the upstream context, there is no third-party network operator with an obligation to connect new users to a network offering universal service. That need not be the case for hydrogen. Incumbent gas network operators are operating networks that are either already capable of carrying, or can be adapted to carry, hydrogen or a blend of methane and hydrogen.
- 4.13.6 As noted above, for natural gas network operators, the development of a hydrogen economy is an existential necessity. The alternative to meeting net zero targets with the help of low carbon hydrogen would be a shift away from the use of gas networks in favour of much greater volumes of traffic on the electricity networks. Although there will be a number of difficulties in adapting existing regulatory and contractual arrangements for natural gas transportation to deal with a methane/hydrogen blend, less work may be required to use them when simply switching from methane to hydrogen. One advantage of the unbundled model is that it comes with ready-made tools for planning the development of the network, as well as procedures for providing and paying for new connections and other infrastructure. Already, gas network operators are using the network planning process (and associated mechanisms for seeking to finance the development of new infrastructure) to prepare for transporting hydrogen. It is a matter for consideration how far the costs of expansion or adaptation of the gas network to accommodate its use for hydrogen transportation should (if recovered from end-users) fall on the initially much smaller number of hydrogen end-users or the initially much larger class of natural gas end-users.
- 4.13.7 However, legislation will be required, probably at both national and EU levels, to acknowledge that in the future network operators may find themselves conveying different commodities in different parts of their network, and to ensure, so far as is practicable, that users of both networks, and end-users of both commodities, enjoy broadly the same rights. A fundamental question to be addressed is whether the conveyance of (i) natural gas and blended methane/hydrogen and (ii) (pure) hydrogen should be regulated separately or carried out by legally separate entities. The latter approach may be theoretically attractive, but managing methane to hydrogen conversion with different operators may be difficult in practice.
- 4.13.8 Ultimately, then, the extension of the unbundled model to the hydrogen transportation sector is inevitable and probably desirable. However, it may need to be applied with a degree of flexibility, and there may be circumstances where the upstream approach provides a useful temporary solution. For example, it may take time to establish new regulatory arrangements for hydrogen networks, and there may be cases where existing network operators cannot respond quickly enough to a demand for new infrastructure. Equally, where an existing private hydrogen network (perhaps built to supply a number of industrial sites with grey hydrogen) “goes green”, there may be a case for “adopting” it into the public hydrogen network, or applying a version of the “OFTO” model noted above.



4.14 Mitigating demand risk and blending

4.14.1 In the absence of a hydrogen network, an individual hydrogen producer is likely to have a business plan based around supplying specific end-users. In an industrial context, there may be relatively few of these, meaning that if one becomes insolvent or ceases to take hydrogen, the producer faces a potentially significant problem. As we have noted above, there are some commercial options for reducing this demand-side risk, and the development of a hydrogen transportation network will act as a further mitigation, since it opens up the possibility of finding alternative end-users quickly.

4.14.2 Such approaches could be supplemented by demand risk mitigation built into regulated support for hydrogen producers. For example, a CfD-based support framework could include, alongside any payments made in respect of hydrogen supplied, additional payments for availability (such as those made to capacity providers under electricity capacity markets, or those that are proposed as part of “dispatchable power agreements” under the [UK government’s favoured business model for CCUS power stations](#)).

4.14.3 Another, possibly more productive, way to mitigate demand risk for hydrogen producers may be to provide publicly funded incentives for feeding hydrogen into the gas grid to provide a blended, lower carbon mix of gases, if this is practicable and permitted under national rules.

4.14.4 In principle, there are two ways of looking at regulated financial support for hydrogen injected into the gas grid to be blended with methane:

- It could be treated as the “baseload” offtake covering a hydrogen producer’s entire output for a significant number of years (based on assumed project debt terms), but allowing some or all of the output to be diverted to a hydrogen end-user for the duration of any contract (supported on the same or a different basis) between the producer and that end-user. Such diversion would have additional costs, but may result in a higher rate of reduction in CO₂ emissions than applying a methane / hydrogen blend in, for example, domestic heating systems.
- It could be treated as a “backstop” offtake, similar to the “backstop PPA” arrangements under the UK’s CfD regime for supporting renewable electricity generators. This is a short-term contract on sub-market terms awarded to those that hold a CfD but have not yet succeeded in negotiating terms with a commercial PPA provider. In the hydrogen context, the backstop arrangement would be a short-term supplement or alternative to negotiating offtake arrangements with a hydrogen end-user.

4.14.5 If the priority is to begin the process of decarbonising the existing gas supply, there may be something to be said for the first of these options. However, it provides less of an incentive for hydrogen producers to contract with hydrogen end-users. If the priority is to build demand for hydrogen among industrial end-users, the second option is probably preferable.



- 4.14.6 In either case, under the blending approach, hydrogen could be sold directly to networks, or to a designated central counterparty, at a pre-agreed fixed price. This could be set on a competitive basis as the strike price in a CfD mechanism, where payments are made depending on the relationship of the strike price to a benchmark wholesale natural gas price.
- 4.14.7 Alternatively, a system based on renewable electricity “green certificate” schemes, such as the UK’s Renewables Obligation (RO) regime, may be appropriate. Gas suppliers could be required to surrender a certain number of “green gas” certificates, representing purchases of low carbon hydrogen or biomethane (complying with certain standards in each case) in proportion to the volumes of gas they sell to end-users in a given period (or to pay a specified “buy-out price” in lieu of each certificate they fail to surrender). Producers of the green gases would be issued with one (tradable) certificate per MWh of green gas injected into the gas grid. The sale of certificates to suppliers would give hydrogen producers a supplemental income stream. The amount of suppliers’ certificate purchase obligations and the level of the buy-out price could be set based on expectations of how the market, and hydrogen producers’ costs, will evolve. In the UK RO regime, the equivalent figures are set a few years in advance and, when the scheme was still open to new projects, the number of certificates awarded per MWh varied with the date of commissioning, and between technologies – both features which it might be appropriate to replicate in a green gas version. The disadvantage of this kind of scheme is that it appears inevitably to rely on the level of support being set by administrative calculation, rather than a competitive bidding process. In its report cited above, Frontier Economics points out that the risk of policy change inherent in such a scheme is likely to increase investors’ cost of capital, and the required level of regulated financial support, as compared with other approaches that provide more certainty.
- 4.14.8 The structure of support for green hydrogen injected into the gas grid is not the only regulatory challenge created by blending hydrogen with natural gas. The two gases have such different physical properties and energy values that a considerable amount of work will need to be done to adapt the commercial and regulatory arrangements for use with a mixture of gases. As an example of the kind of issues involved, see the papers by Dentons on adjustments that would be required in the GB gas system [here](#) and [here](#).
- 4.15 Guiding principles**
- 4.15.1 There are many options for regulated financial support for green hydrogen. Wherever possible, they should involve competitive allocation of support and setting of support levels. To the extent that levels of support are determined administratively, they should be initially high to incentivise early adopters, and then reduce at predictable intervals. For example, tax breaks to support capex could be available for a 5-10 year window. To avoid costs spiralling, a budget limit for each level of support allocated in given time periods should be set. There should be mechanisms to reclaim support that turns out to compensate recipients more than was expected when it was awarded, or make it subject to “gainshare” arrangements. However, any such mechanism should be clearly set out at the start of the process (for example, CfDs auctioned with a strike price that is scheduled to vary over time).
- 4.15.2 Although much of the discussion above has focused on revenue support, it may well be that the areas where incentives would have the biggest impact on the initial developing hydrogen market are in supporting the capex for shared infrastructure costs and encouraging the development of new or more efficient technologies for hydrogen production.

5. Conclusions and next steps

- 5.1** The strategies outlined at national and EU level assume that substantial upscaling of European green hydrogen supply chains is feasible over the next 10 years. Although there is a strong political impetus behind these strategies, this remains a plausible assumption (given the right kind of follow-up action by governments and industry) rather than a certainty.
- 5.2** Efforts to scale up should begin in areas with high potential on both the supply and demand sides. Our business case focused on one of these, but it is not unique. A pipeline network that offers the potential to develop a dedicated hydrogen transportation infrastructure at an early stage is a major, and probably indispensable, asset in this context.
- 5.3** There is much that the investors in and lenders to renewable electricity generation projects, hydrogen production facilities, and potential end-users of green hydrogen can do to help themselves – ranging from cross-shareholdings and joint ventures to the formation of a co-operative virtual utility structure to spread supply-side and demand-side risk. Not all solutions will work equally well for all market participants, but it is important to have an open dialogue and explore the range of possibilities thoroughly. This is a new industry, which has points of both similarity to and difference from other energy sectors: it should not be assumed that the default approach from one adjacent market is necessarily the right approach for hydrogen.
- 5.4** There is much in the EU and national strategies that will help the industry to scale up, as intended. However, legislative and regulatory processes take time – sometimes more time than planned – and those developing projects with a strong business rationale should not wait unnecessarily for public authorities to make progress if there are actions that they could be taking to carry their plans forward in the meantime.
- 5.5** Undoubtedly, a significant amount of regulated financial support, as well as a generally supportive regulatory environment, will be required to meet the targets set in the EU and national strategies. However, the indications are that at least at present there is the political will to deploy the necessary funds. Moreover, there is no shortage of potential templates on which support schemes can be based. Although there are differences between the renewable electricity and green hydrogen industries, the depth of recent experience of designing and administering renewable electricity and other clean energy support regimes should enable effective and efficient support frameworks to be designed and implemented at pace.
- 5.6** Ultimately, nobody knows exactly how important green or other forms of low carbon hydrogen will be in the Energy Transition, or in which applications it will feature most prominently in a net zero Europe. However, it seems very likely that it will be important enough to justify the kind of upscaling of green hydrogen technology envisaged over the coming decade, and that it will make sense for Europe to seek to play a full part in that upscaling by embedding some production and transportation capacity at an early stage.

Get in touch

If you are planning a green hydrogen project in Europe, we hope you have found this paper useful. We would be delighted to hear from you in any case. Do you agree with our analysis? What business model do you favour? What have we missed? Our three organisations have decades of experience of European energy and infrastructure markets and we would be happy to offer you either a general brainstorming session or a focused initial discussion of one or two key issues free of charge.



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