Clean Hydrogen Investment Is Still A Leap Of Faith For European Utilities

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Key Takeaways

- Clean hydrogen is becoming an increasingly important element in supporting Europe's energy transition and economic recovery, with a targeted increase in electrolyzer capacity of 40 gigawatts by 2030.
- However, we still see major hurdles to a large scale-up of clean hydrogen, including lack of cost competitiveness, still immature technology, insufficient regulatory support, uncertainty about future demand development, and the lack of renewable power infrastructure necessary to produce clean hydrogen.
- We therefore don't think clean hydrogen technology will significantly transform the European energy market or disrupt utilities' business models at least until 2025, and thereafter only if the numerous pilot projects, currently under way, are successful.
- We think European utilities will ultimately benefit from a rise in clean hydrogen industries because it would significantly increase demand for electricity to produce hydrogen. It would also create a new role for existing gas infrastructure assets, if they are adapted to store and transport hydrogen.

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Suddenly, hydrogen matters to the energy industry. Although long used in industrial production, energy players hope that new clean hydrogen technologies will help in Europe's decarbonization strategy, which aims to achieve net zero emissions by 2050. In the past few quarters in Europe, interest in clean hydrogen development has gained new impetus, for four main reasons:

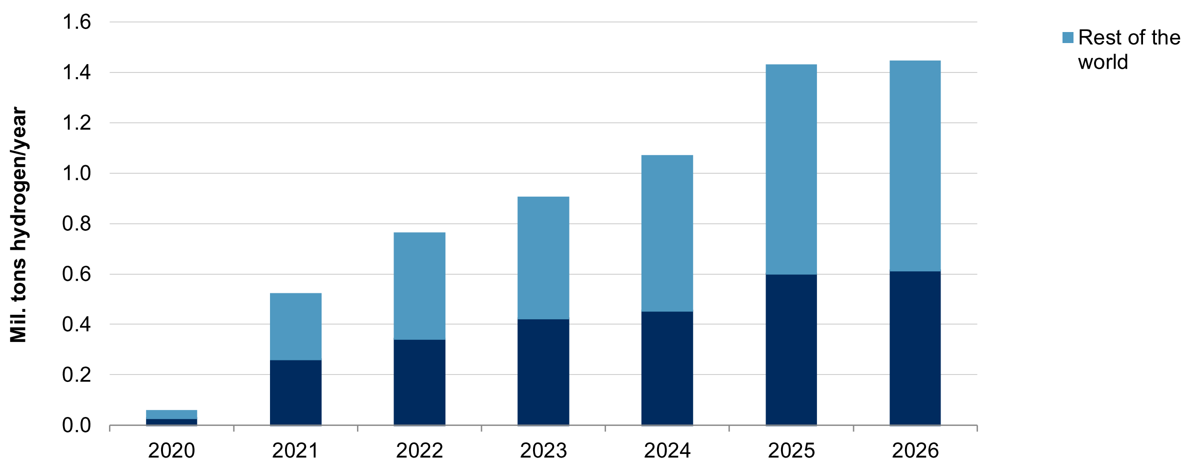
- European policymakers are giving a bigger role to the energy transition to support economic recovery from the COVID-19 pandemic shock, in which they have stated hydrogen development should play a part;
- Gas infrastructure network operators are more strongly supporting hydrogen development after the emergence of a European taxonomy last summer, which positions carbonized gas as a transition source of energy. This means that sustainable long-term growth prospects for gas networks may depend upon the success of a hydrogen economy repurposing current gas pipelines;
- Hydrogen has a large customer base among the most polluting industries that need to find

technological solutions to reduce their carbon footprint and improve their investors' perception of their environmental, social, and governance credentials; and

- As the hydrogen economy depends greatly on local production, it fits with a European desire to regain more energy independence.

Chart 1

Europe Plans To Ramp Up Clean Hydrogen Capacity Over The Next Five Years
Global cumulative planned electrolytic hydrogen capacity



Source:S&P Global Platts.

Immature Technology In Need Of Investment

Clean hydrogen comprises mainly two types: Green hydrogen, whereby electrolyzers are fueled by renewables to produce hydrogen; and blue hydrogen, whereby methane is used and carbon capture technologies allow for clean production. Carbon is then stored and/or utilized in specific industrial processes. Another type is turquoise hydrogen, but we understand it is a less competitive and less common process, consisting of splitting methane through pyrolysis into hydrogen and solid CO2. These processes contrast with grey hydrogen, which is directly produced from methane or coal. A cheaper but more polluting process.

Europe currently appears to favor development of a green hydrogen industry over blue. This means that the development of carbon storage solutions may not benefit from as much policy support in the coming years. Both technologies are still very expensive and far from competitive compared to grey hydrogen production and other fuels. Green hydrogen production currently costs twice that of blue. To speed the availability of hydrogen, we believe it will be important to promote both green and blue.

Challenges remain not just in producing both types of clean hydrogen cost-competitively at scale, but also in developing infrastructure and new industrial end-applications. Nevertheless, Europe seems ready to bear the costly ramp-up of this industry, until it reaches the scale and maturity to become a cost competitive decarbonization tool--just as it did for the development of renewables two decades ago. Western European countries currently have announced plans to invest over €32 billion in hydrogen projects over the next decade (see table 1).

Table 1

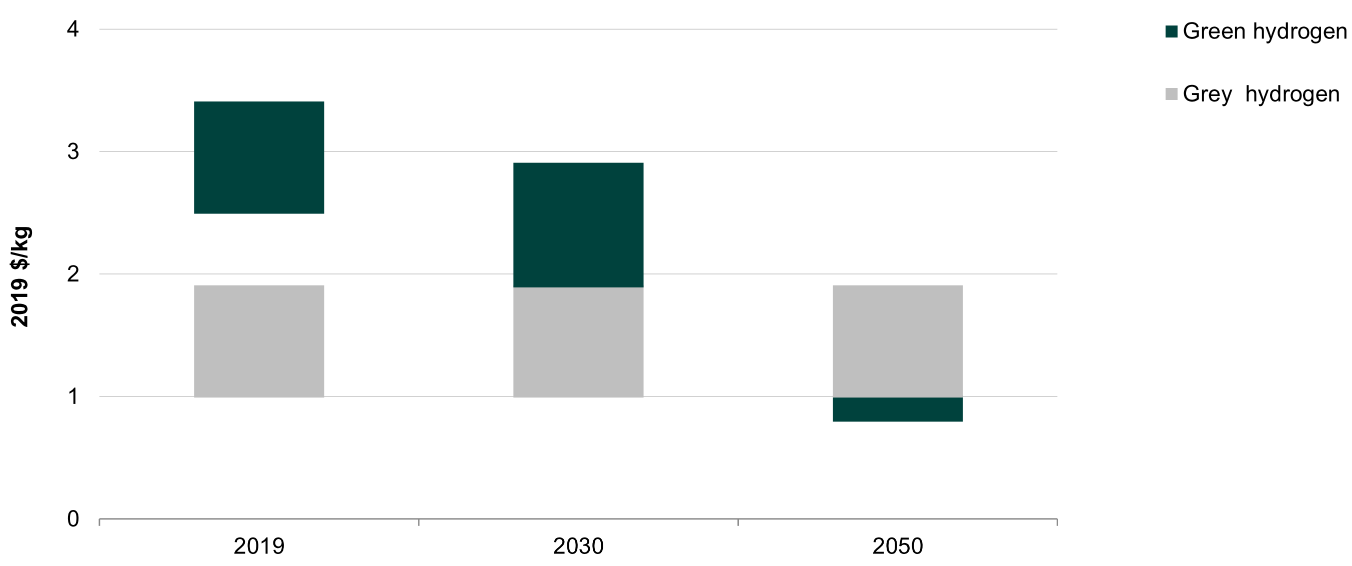
European Countries Target Hydrogen Capacity Increases Over The Next Decade

Country	Planned hydrogen investment	Targeted hydrogen capacity installed by 2030	Target capacity after 2030
Germany	€7 billion in new businesses and research. Additional €2 billion for international partnerships.	5 GW	An additional 5GW of capacity is to be added, if possible, by 2035, but no later than 2040. Although most government support will be toward building the green hydrogen industry and making Germany a market leader in this space, grey and blue hydrogen may also receive support in the short term.
The Netherlands		Up to 4 GW, about 500 MW installed by 2025	
Portugal	€7 billion	2.0-2.5 GW	
Spain	About €9 billion	4 GW	
France	€7.2 billion	6.5 GW	
Denmark		Large energy islands with offshore wind capacity of 5 GW by 2030, which could be partly/fully used to produce green hydrogen	
Norway	About €330 million of green technology investments, including hydrogen.		

GW--Gigawatt. MW--Megawatt.

Chart 2

Green Hydrogen Production Prices Are High But May Potentially Decline



Sources: Bloomberg New Energy Finance, International Energy Agency.

Little Disruption For Utilities For The Next Five Years As Players Test The Hydrogen Market

We do not expect new hydrogen technology to disrupt European utilities' business models over the next five years. Currently, most players are cautiously "testing the waters". To share the cost burden of clean hydrogen development, we believe industry players will allocate funds and incentives for pilot projects led by a consortium of industrial players, including utilities. Such projects to be developed over the coming three to five years are therefore likely to remain small scale, with capacity in the range of 10 megawatts (MW)-100 MW, and most are unlikely to be operational before 2023. What's more, the effective final investment decisions for these pilot projects greatly depend on the availability of support in the form of public funding. Our understanding is that on average 30% to 50% of a pilot hydrogen project budget would be covered by some form of public support mechanism, largely in the form of grants or subsidies.

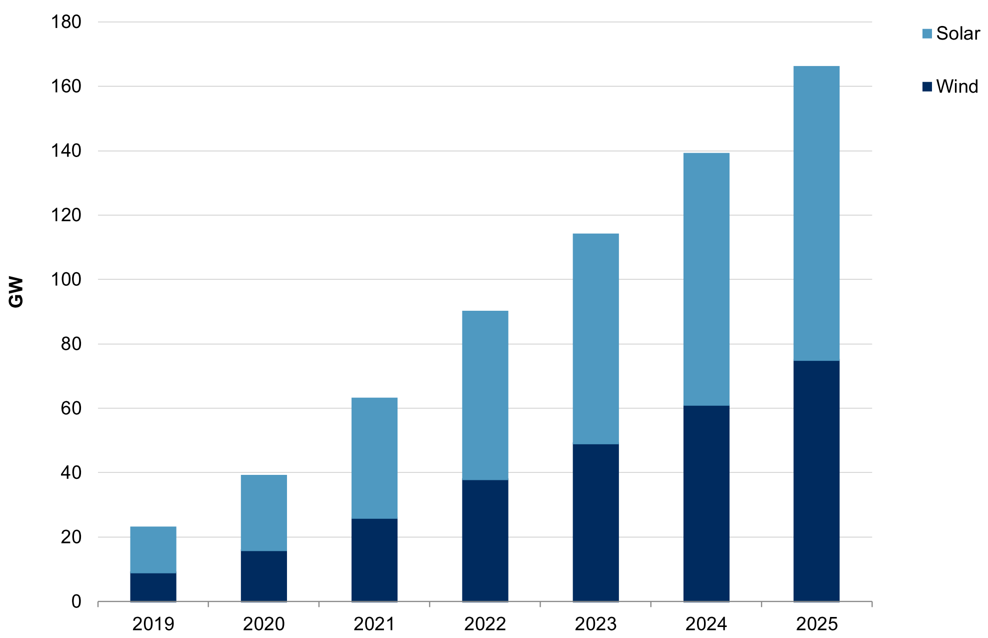
Yet, so far it is unclear how such incentive schemes will be deployed. They also may not facilitate effective launch of projects, notwithstanding local permitting hurdles. Ultimately, we estimate aggregate investments from the 15 major European utilities that we rate to be less than €1 billion per year over the next three years. This represents a marginal amount of the of aggregate total annual investments of about €65 billion per year by these utilities, according to our estimates. We also understand projects will be developed primarily through industrial partnerships as market players try to understand how a clean hydrogen deployment will play out, and where the value will come from. Hence, investing in a project today will not preclude future strategy while companies are in this test-and-learn phase.

We believe these pilot projects will validate technologies and support some efficiencies, while kickstarting the emergence of a hydrogen supply chain. But we don't believe they will be able to tackle the cost issue. This is because such necessary drastic cost reduction will primarily stem from production at scale, as was the case for renewables in the past decade--and will likely remain the case over the coming decade.

Adding to the slow scale of developments, we think business models are still unclear and players remain unsure of where in the value chain they will derive profitability. The pilot projects will aim to provide more clarity on this, in our view.

Chart 3

Wind And Solar Capacity In Europe Is Set To Grow By About 50% Over The Next Five Years



GW--Gigawatt. Source: S&P Global Platts.

Over the coming three years, we also see additional hurdles that will limit any larger changes in the utilities landscape toward clean hydrogen:

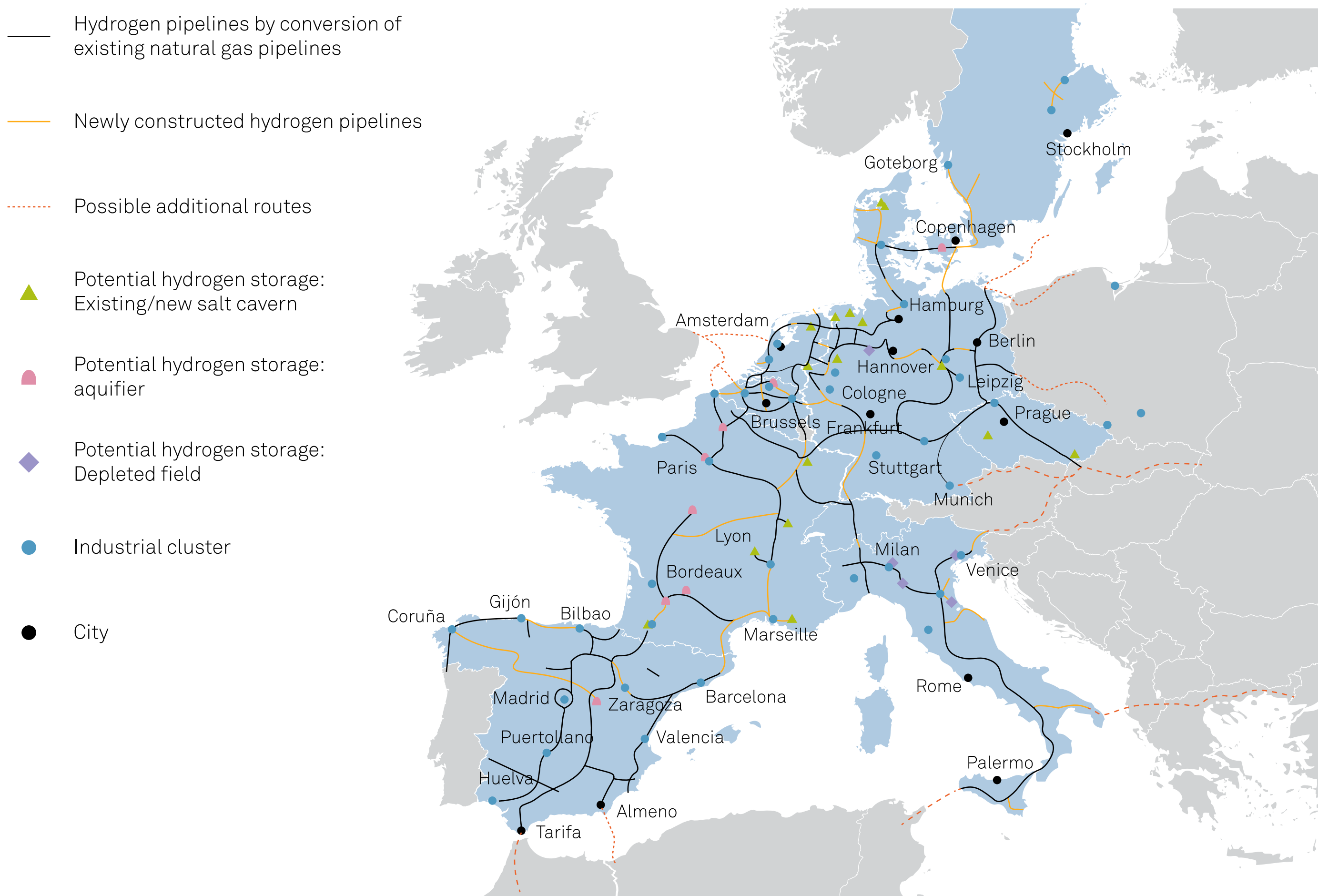
A need for renewables: Renewables capacity can hardly afford a rapid ramp up (see chart 3). The 2024 European target of 6 gigawatts (GW) of electrolyzer capacity already requires about 10 GW to 12 GW of dedicated renewables sources to produce clean hydrogen. This comes on top of what is needed to support fuel-switching within the power generation mix, given the rapid 67 GW coal and nuclear phase-out that is currently planned over the same period. Of course, it also means there is a strong case for more renewables to meet this additional demand and we expect an acceleration of renewables projects over the coming years as a result. Yet, we see that further massive growth in such a short period will become challenging from a clean resource perspective.

A need for infrastructure: We also believe the development of dedicated infrastructure from gas network operators is likely to be limited over that period. This is because we understand that hydrogen may generally require massive capex to create new routes. Existing gas pipelines bring methane from gas fields, while hydrogen pipelines will need to start from green hydrogen production sites. These sites are where renewables are, which generally differ from where gas fields are located. In addition, using existing methane pipelines for hydrogen or mixing hydrogen with methane may not always be technically possible, economically efficient over long distances, or compliant with currently existing regulations or contract terms. The "European hydrogen backbone" 2020 study by 11 large European gas grids estimates capex needs at €27 billion-€65 billion by 2040. Such a wide range may indicate that costs may be difficult to estimate precisely at this stage. This includes construction of 25% new routes and retrofitting of 75% existing gas pipelines. We believe this is a minimum estimate because it assumes a massive decline in methane usage and availability of free capacity at existing natural gas pipelines. In our view, this may not be possible in the next decade given the need for gas in Europe's energy mix in the face of massive coal and nuclear capacity retirements. Actual capex needs may therefore be even higher.

The absence of incentivizing network regulation: One major hurdle for gas network operators is the current absence of major hydrogen asset development within the current regulatory frameworks across Europe, while most of them have just started their new regulatory periods, generally ending towards 2025. Current European regulatory frameworks do not cover hydrogen transportation, so even tariff-setting rules have yet to be developed. While there may be some case reopenings here and there, we do not expect any major deviations from the current plans. As a result, major infrastructure investments from network operators to accompany growth of hydrogen will rather be realized post 2025.

Demand is yet to be developed: This will require significant technological shifts and capex at the customers' end. Hydrogen will have to compete with other decarbonization options, including direct usage of renewable electricity.

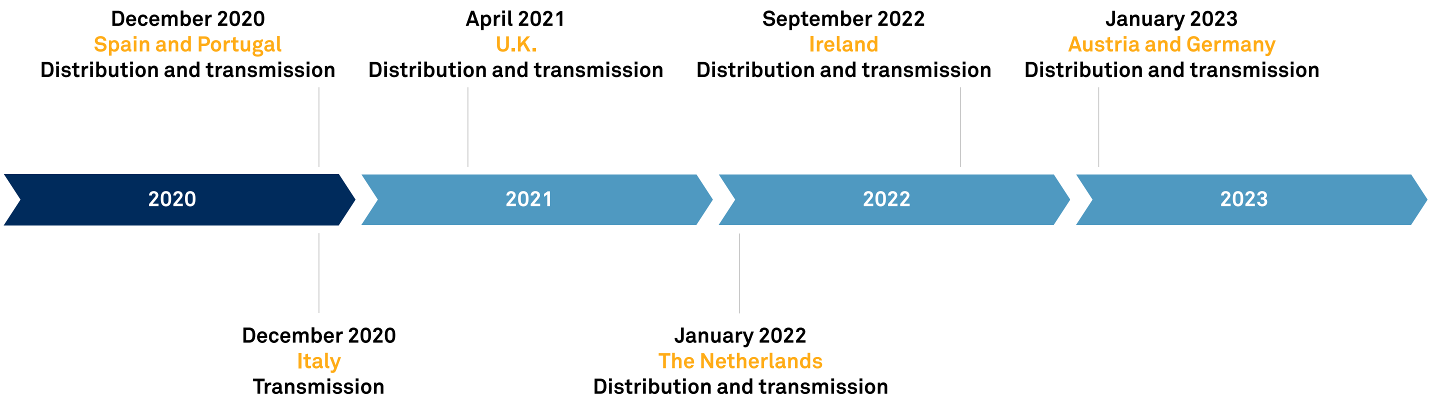
Mature European Hydrogen Backbone Can Be Created By 2040



Source: European Hydrogen Backbone Initiative.

Chart 5

Upcoming Gas Regulatory Reviews In Europe



Source: S&P Global Ratings.

A Leap Of Faith Post 2025

Major expansion of clean hydrogen over the next few years will depend massively on the realization of efficiencies and more stringent energy policies. A rapid growth will depend on whether the pilot phase is successful in showing a path to massive cost reduction over a foreseeable period. Many of the pilot projects have defined a path for transitioning to industrial scale. For example, the H2 Sines green hydrogen project in Portugal will be the subject of a feasibility study by EDP, Galp, REN, and the Danish wind turbine manufacturer Vestas. The project is expected to begin with a 10 MW pilot electrolysis installation and could be expanded to 1 GW this decade. In Germany, the national hydrogen strategy, agreed in mid-2020, raised hopes for two commercial scale electrolysis projects in a gas and electricity transmission system operator partnership by TenneT, Amprion, Open Grid Europe, Gasunie, and Thyssengas. The Element One and Hybridge projects, starting operation in 2022 and 2023, respectively, each entail a 100 MW electrolysis plant at a different site in Lower Saxony in northern Germany. Yet German legislators first need to create the legal framework for transportation network operators to build and/or operate power-to-gas facilities.

We believe growth in clean hydrogen will also depend on customer demand, given that they will also need to adapt and invest accordingly. We expect demand to depend on the scale and pace of support schemes, as well as more stringent regulations--including, but not limited to, a significant rise in carbon prices--and cost competition against other decarbonization options. The sectors most likely to transition to clean hydrogen (refining, heavy transportation, chemicals, steel) cannot easily afford the change without a clear economic rationale given their relatively low margins. These sectors are large-scale, energy-intensive, and large polluters, and they face increasing pressure to reduce their carbon footprint. But they are also generally commodity businesses, competing at global level against peers that may not face the same environmental pressures and where price--and hence the cost base--is a key success factor. It may therefore be difficult for these sectors to decide in favor of heavy investments to become greener.

We expect the power market will use hydrogen mainly to decarbonize certain heavy user sectors such as steel and chemicals. We don't believe there is a sufficient economic rationale for hydrogen to play a big role in the electricity mix over the coming decade. Rather, we see it mainly as long-term storage solution to compensate for seasonality (not short-term intermittency) of renewables. It could unlock value only in a scenario in which renewables represent a major share of the production mix--which we estimate to be above 70%. We generally do not expect this in Europe by 2030. Below this level, the cost of electricity production from hydrogen will most likely be higher than the value of the service stemming from security of supply and system stability. Similarly, we understand that, while transformation of existing gas plants (notably modern CCGTs) is technically possible, conversion costs remain high and ultimately the cost of output may prove prohibitive. Hydrogen has a round trip efficiency (which is defined as the energy left to convert power to hydrogen and then back to power) of about 40%, compared to 75% for pumped hydro and 95% for lithium ion battery storage.

As Europe's own production of green hydrogen will unlikely be sufficient for EU goals, its hydrogen strategy provides opportunities for blue and turquoise hydrogen as an interim solution, as well as for imports of green hydrogen. This could support the case for European hydrogen transmission grids, but only to the degree that economics work well for potential suppliers, because hydrogen transportation over long distances will be costly. Furthermore, it remains to be seen whether blue hydrogen producers--mostly methane producers--can generate adequate internal rates of return on their investments in electrolyzers and carbon capture, utilization, and storage within the regulatory window. Europe's hydrogen strategy includes turquoise hydrogen as a potential new technology to be tested, and it remains to be seen whether it can be treated as sufficiently green by the regulators. Turquoise hydrogen is produced by splitting methane into hydrogen and black carbon, without CO2 emissions, at a potentially lower cost than green, but higher than blue hydrogen. Gazprom is currently testing this technology in Russia.

We believe that regulatory frameworks will need to adapt to promote hydrogen. This will entail a need to rapidly ramp-up capacity to accompany growth, while recognizing that pipelines are unlikely to rapidly reach full capacity, resulting in a significant underutilization of the assets for some time. Remuneration will therefore need to adjust for technology uncertainties while incentivizing large investments. This is because new pipelines will need to be built alongside existing ones to allow both hydrogen and natural gas to flow separately, as we think it unlikely that the need for natural gas will be extinguished anytime soon. Investments will also be on new transit routes, because sourcing areas of clean hydrogen differ from those of natural gas: large renewables sites are generally very different from natural gas reserves. We believe this imbalance between large investments and low utilization over a long period of time will be a challenge for regulators.

Finally, industry experts estimate that about one-half of the cost of green hydrogen stems from the cost of renewables. As a result, to reach a degree of parity with grey hydrogen by 2030, the cost of renewables would need to drop significantly by one-half or even two-thirds. Even through carbon prices are likely to rise and renewables further decline over the next decade, this could still pose a big industry challenge.

Potential Benefits For Utilities Post 2030

If large-scale industrial efforts and incentive policies do become available to speedily ramp-up clean hydrogen production and use, we believe European utilities could benefit from it in three main ways:

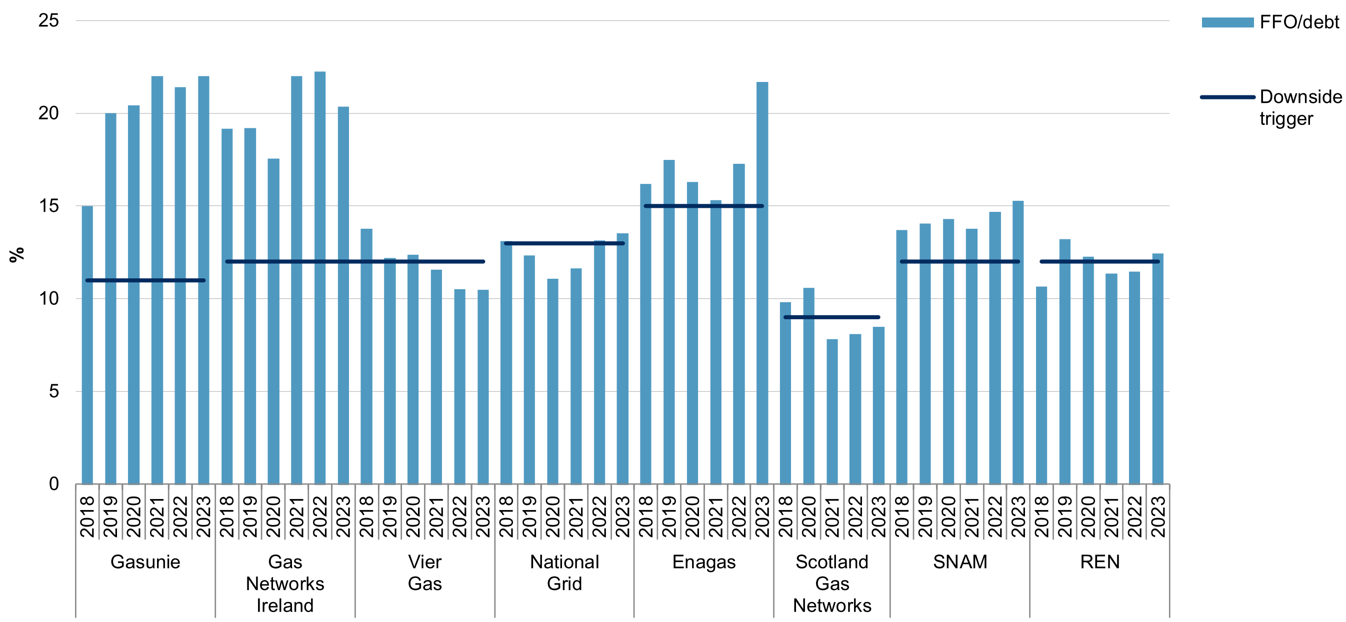
- It would boost demand for renewables and offer a significant growth trajectory for utilities. These renewables will stem primarily from solar, notably in Southern Europe and North Africa, and wind, onshore throughout the continent and offshore in Northern Europe.
- It would be a forced acceleration of long-term power purchase agreements on renewables to secure access to green energy, hence reducing the risk of having a large share of renewables going merchant.
- It would necessitate a transformation of gas networks to allow for hydrogen in the pipelines, which could increase the size of the regulatory asset base for network operators.

Transportation networks would benefit the most, in our view, if the regulatory frameworks treat hydrogen broadly similarly to gas. This is because demand will first come from the heavy industrial users, which are often directly connected to the transportation network rather than distributors. Furthermore, most likely routes will first require investments in large pipes to move hydrogen from production centers (where renewables are) to remote consumption areas. Existing pipelines do not allow simultaneous use for hydrogen and still-needed conventional gas at the same time, and mixing is not always possible. EU countries' rules differ on the maximum hydrogen content allowed in the pipeline, and existing contracts usually specify the quality and energy content of gas to be delivered, meaning that hydrogen is not covered. Still, we believe hydrogen transmission distances are likely to be shorter, because hydrogen transmission over long distances is too costly for the customers. Conversely, we believe distribution networks may face subdued demand for hydrogen, as the price for conversion may be too high for smaller consumers, including for heating purposes. It would also compete with heat pump technology, which offers similar carbon reduction but is often less costly. We also understand that plastic pipes, most often used by distribution network operators in recent years, are able to carry hydrogen already. Therefore, a larger share of gas distribution networks will already be ready to use and hence not require material additional capex.

Overall, large renewables players and those accelerating their capex are therefore best positioned to benefit in this scenario, to the extent they manage to focus on the more competitive European markets rather than expanding in other (today more profitable) regions. Such scenario also requires renewables players to prepare for an investment peak, and therefore strengthen their balance sheets to be able to accelerate investments without jeopardizing their credit quality. Similarly, we believe gas network operators would also need to prepare themselves by strengthening their balance sheets and through feasibility studies, to manage a potential rise in investments over a relatively short period of time (see chart 6).

Chart 6

Not All Gas Transmission System Operators Have Balance-Sheet Headroom Today



FFO--Funds from operations. TSO--Transmission system operator. Source: S&P Global Ratings.

Can Utilities Afford Not To Have A Hydrogen Strategy?

Given the significant technological, cost, and regulatory uncertainties, utilities may choose a "wait and see" strategy on hydrogen investment. Yet, overall, for large renewables players investments may pay off. This is because future success for hydrogen will depend not just on whether policymakers provide incentives to invest--via accommodative remuneration schemes, grants or subsidies--but also on more stringent regulations on carbon, such as higher prices or stricter environmental standards. We think these developments could create space for hydrogen. Power generators and network utilities that invest in pilot schemes now to test and develop technology or find niche applications in cooperation with large industrial users, will be ready to take advantage if and when attractive opportunities for hydrogen arise. Since investments remain relatively small, they won't lose much if these opportunities don't arise.

Furthermore, even if green hydrogen does not prove to be economically or technically viable by 2025, we believe it may not necessarily mean the end of a European hydrogen strategy. A blue hydrogen economy could still help reducing carbon emissions drastically, although to a lesser extent. Therefore, an understanding and experience of the technology may prove important for future business prospects.

We also see the potential for a change in the price for the renewables output, as green and local electricity may have more value than more polluting types to justify a greater value on the guarantee of origin. The current power market design does not necessarily allow for such upside and it may require a full transformation of the European power market design to reach this reality. Eventually a higher carbon price could also support more value for renewables output. Overall, renewables players would be major winners in such a scenario, raising the value of their existing assets.

For gas networks, downplaying hydrogen does not seem to be an option. Over the long term, European decarbonization targets do not suggest a bright future for natural gas as we know it. We see gas consumption in Europe remaining stable at best over the decade. As a result, remuneration, investments, and related incentives to invest would likely be subdued absent a hydrogen strategy. We therefore expect gas network operators will continue to lobby for the development of hydrogen technology and encourage projects to foster it.

Clean Hydrogen In The U.K. : Out Of The Blue?

We consider the U.K.'s commitments towards net zero carbon emissions generally more stringent and ambitious than most European peers. This is because the U.K. pledge to reduce net emissions of greenhouse gases by 100% relative to 1990 levels by 2050 has been enshrined in U.K. law since June 2019. In its Future Energy 2020 Scenarios, National Grid, the U.K. gas and electricity transmission networks operator, modelled the various pathways to reach net zero targets. The report not only emphasized that both hydrogen and carbon capture usage and storage (CCUS) will be required for the industrial and commercial sectors in all net zero scenarios, but also that industrial scale demonstration projects will need to be operational this decade. Yet, a hydrogen industry roadmap has, at this stage, not been defined.

We believe scalability of hydrogen, with a greater penetration in hard-to-electrify sectors (home heating, industry, and heavy goods vehicles), would require significant network and supply-chain transformation to help the U.K. meet its net zero target by 2050. Another credible alternative, for instance, would be much greater electrification coupled with drastic changes in energy consumption patterns. It would also likely be achieved predominantly through blue hydrogen production, with use of natural gas as an input and CCUS. In addition, the natural gas sector would continue to play a central role in the U.K. energy policy. The gas sector could leverage on high gas penetration, as an estimated 85% of homes are connected to Britain's network of 284,000 km gas pipelines, using natural gas for heating and other domestic uses. In the meantime, natural gas is the main source of primary energy consumption and the main fuel used for electricity generation in the U.K. The large hydrogen penetration path may also coincide with the repurposing of much of the U.K.'s existing gas infrastructures, originally built to pipe hydrocarbons from the North Sea, and the development of hydrogen clusters (industrial production sites coupled with CCUS--the U.K. has an estimated 80,000 million tons of CO2 storage accessible offshore) in the north and coastal areas.

The scalability of hydrogen will have to come with supportive measures from the government, as existing policies alone and market signals do not currently provide strong enough investment incentives to develop the sector. In this respect, the energy white paper expected to be published by the end of the year will provide the U.K. government's position on the design of energy market through to 2030 and 2050. The energy regulator, Ofgem, is still assessing the different pathways to reach net zero by 2050. The next five-year regulatory period for gas transmission and distribution networks will start in April 2021. In its draft determination for network operators published in July 2020, Ofgem acknowledged that significant support for research and development and innovation-led trial for technologies such as hydrogen may be needed. This means that the current framework rather envisages contribution for R&D with an announced minimum of £630 million in the form of innovation funding for technologies including hydrogen. The draft determination conditions the funding of those initiatives over the next regulatory period through re-openers. This may imply less uncertainty on their viability and delivery date.

Related Research

- The Energy Transition: COVID-19 Could Make 2020 Crucial For Renewables, Sept. 24, 2020
- Industry Top Trends Update: EMEA Utilities, July 16, 2020
- Credit FAQ: Energy Transition: The Outlook For Power Markets In The Age Of COVID-19, June 25, 2020
- Despite COVID-19 Disruption, European Utilities Are Set For Growth, June 25, 2020

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