ICIS Quarterly European Hydrogen Markets

Q1 2023 Update

May 2023

The ICIS Quarterly European Hydrogen Markets report is a quarterly overview aimed at updating market participants on key policy, regulatory, infrastructure and market developments. Utilising ICIS hydrogen pricing data, the Quarterly European Hydrogen Markets report provides market participants a snapshot of how power, gas and ammonia market prices have impacted hydrogen production costs over the previous three-month period.

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Introduction

Since the publication of the European Commission's hydrogen strategy in July 2020, the hydrogen market has taken the energy sector by storm, with numerous national strategies published, projects announced and the current level of demand for fossil fuels, over time, likely to be overhauled.

The hydrogen market itself remains nascent, but as governments continue to enhance support schemes and subsidy offerings, agreements between producers and offtakers are taking shape. In the first quarter of 2023, a clear new direction was set for the market, with participants given clear rules and targets for the use of renewable hydrogen.

In 2022, Europe saw a year of energy market uncertainty, as the tail-end of the 2021 price crisis overlapped with the major gas supply crisis caused by Russia's invasion of Ukraine. But the impact of near-full gas storage sites coming out of 2022 began to pressure energy commodity prices once again, which partially recovered to pre-war levels.

The actions taken in 2022 to accelerate the hydrogen market were necessary, however. Several key policy decisions were made in 2022 that ultimately catapulted the hydrogen market forward, not least of which was the REPowerEU package which quadrupled renewable hydrogen supply targets by 2030. And indeed, the first quarter of 2023 showed landmark political change as a further follow-on to a year of progress.

During the early years of the natural gas market, following the discovery of gas in the Dutch Groningen field in 1959, long-term contracts were the primary supply mechanism for the bloc. However, as natural gas emerged as a commodity with minimal price and information transparency, these early long-term contracts utilised indexation from a more established commodity, often oil.

With the progression of renewable and low-carbon hydrogen projects and government backing, the hydrogen market is now beginning to shape up in a similar manner, with negotiations between suppliers and buyers emerging in different forms. Just like natural gas markets in the early years, hydrogen market participants are regularly looking to alternative commodities to include in agreements. In the UK, the use of the natural gas front-month contract is key, following the setting by the government of the UK National Balancing Point (NBP) gas front month as a relative price floor for hydrogen sales agreements. When looking to international trade, market participants note potential indexation or reference to the current global spot ammonia market.

In Europe, the first quarter saw the emergence of the delegated act for renewable fuels of non-biological origin (RFNBO), ultimately setting the rules for producing renewable hydrogen. The development of these rules and the relative acceptance of them are pivotal to getting initial negotiations moving forward for projects in EU member states. The publication of the delegated act still came with criticism, but the establishment of rules of a kind was welcomed over no rules at all.

Alongside the development of RFNBO rules of production came the initial terms for the EU Hydrogen Bank, which has outlined a fixed subsidy over a 10-year period, awarded via auction with priority given to the lowest bidder. The bank will initially support renewable hydrogen, as defined by the delegated act for RFNBO, but could in the future support low-carbon hydrogen as regulation continues to develop.

As well as policy, the first quarter saw multiple announcements from gas transmission system operators aiming to develop or repurpose infrastructure for a future hydrogen network. Among the announcements reviewed by ICIS, most indicate initial transport capacity by the end of the decade, providing a key indication for when the hydrogen market could move from long-term contract agreements to potential pockets of spot trade, enabled by buyers seeking supply from alternative locations to producers in their immediate vicinity.

From a pricing perspective, ICIS hydrogen pricing information indicated key changes to the market following the price surges of power and gas in 2021 and 2022. Notably, amid bullish carbon markets, low-carbon hydrogen became cheaper to produce than unabated steam methane reforming (SMR), commonly referred to as grey hydrogen, for the first time in ICIS price history when accounting for capital cost recovery.

As well as this, upon reviewing the announced support mechanisms for renewable and low-carbon hydrogen in the EU and UK respectively, ICIS price information indicated that hydrogen prices could oscillate in the range of around €1-2/kg post subsidy.

General hydrogen production cost trends showed that the market was easing. However, upon looking at the far curve for power and gas markets, and their impact on hydrogen production costs, it is possible to see that market participants continue to price in some risk premium for the years ahead. However, this risk premium has also eased over the first three months of the year, indicating where production costs could be in the middle of the decade as Europe sees its first large-scale hydrogen projects enter operation.

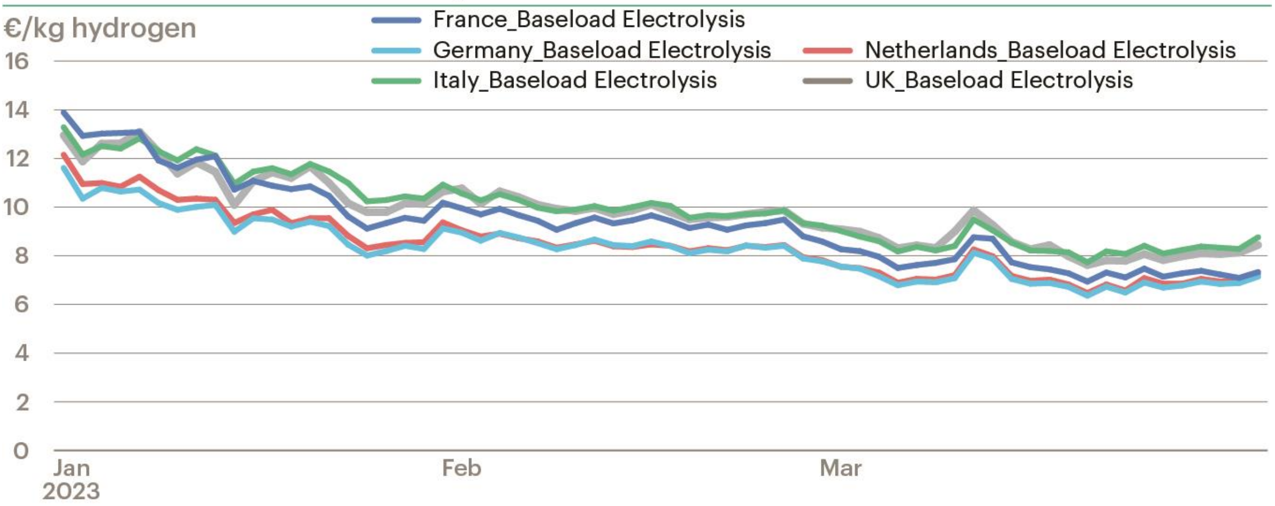
Price transparency is vital at any stage of a market. The greater the price transparency the more information market participants can utilise to make informed decisions both to help balance supply and demand while also investing for the longer term. In today's hydrogen market, calculated assessments are ultimately only a first step to price transparency, but they serve a purpose. By indicating the cost of producing hydrogen accounting for different commodities markets, would-be entrants can understand what the future market is likely to look like.

The first quarter of 2023 showed the impact of Europe's scramble to ensure adequate supply for winter across energy markets. Against this backdrop it is possible to see how the different parts of the hydrogen value chain responded.

European Hydrogen Market Trends Q1 2023

Electrolytic hydrogen production Q1 2023

Front-month Baseload Electrolysis Production Costs Eased Over Q1 2023



Source: ICIS

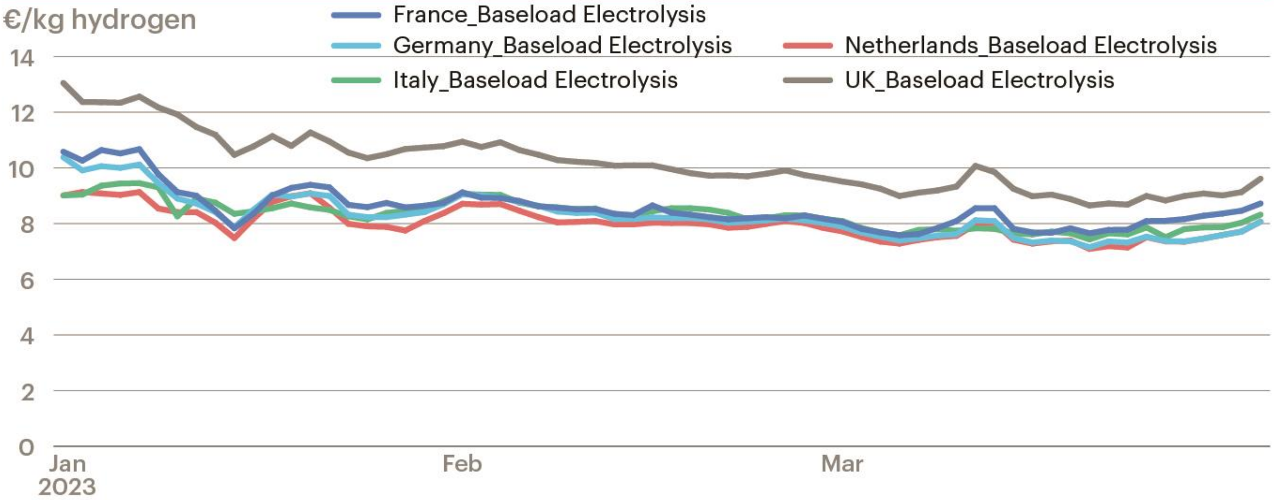
Prices at Europe's wholesale power markets eased substantially in the first quarter of 2023, continuing a trend of progressive drops since the start of winter 2022 amid an unseasonably warm start to the season. Hydrogen production costs based on wholesale market electrolysis using front month power contracts reached almost €50/kg in 2022.

However, following continued mild weather, abundant gas supply and at or above normal renewable power generation, front-month based electrolysis costs on project breakeven (full capital cost recovery) shifted from over €10/kg of hydrogen to around €7-8/kg by 31 March.

At the start of the year, of the markets ICIS produces hydrogen assessments for, the French power market resulted in the highest hydrogen production costs from electrolysis at €13.89/kg because of nuclear-related power market tightness.

As the quarter progressed with relatively mild winter conditions and good renewable output, risk premiums that had built up over the course of 2022 progressively fell back, resulting in wholesale power market electrolysis production costs averaging €7.78/kg using front month power contracts as feedstock across France, Germany, Italy, the UK and the Netherlands.

European Electrolytic Hydrogen Production Costs Based On Year+2 Power Market Values (Project Breakeven)



Source: ICIS

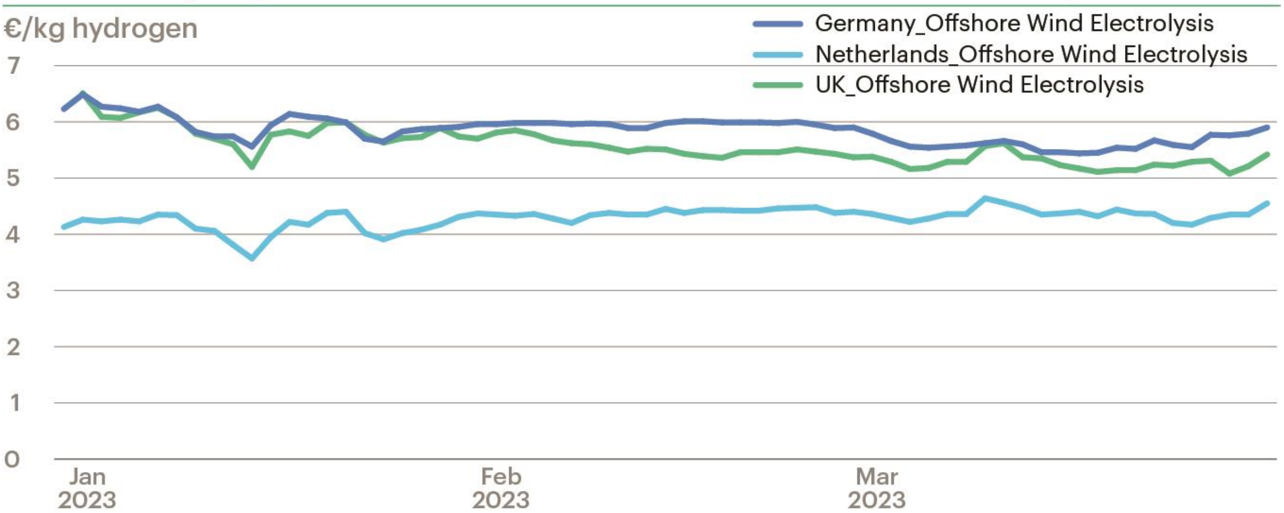
Wholesale power market contracts for delivery further into the future also showed relative decline in the first quarter of 2023, resulting in electrolytic hydrogen production costs falling from around €9-13/kg to around €7-10/kg based on year+2 values.

Production costs based on the far curve remained relatively high despite easing closer to delivery on the front month. This is because far-curve contracts often move in less aggressive ways to contracts nearer to delivery. In the case of electrolytic hydrogen, front-month based hydrogen production was assessed higher than year+2 values at the start of the quarter. However, despite a drop on each contract type across all hubs, the front-month values had switched to lower than year+3 by the end of March.

This price relationship generally indicates that the power market is still considering relative tightness in the years ahead following the absence of Russian piped gas supply and general decommissioning of nuclear assets in key markets such as Germany.

Far-curve production costs appear to have fallen below the peaks seen in 2022 but are still far-above the €5-6/kg range seen at the start of last year.

Renewable Hydrogen Production Costs Continued To Show Minimal Volatility Into Q1 2023

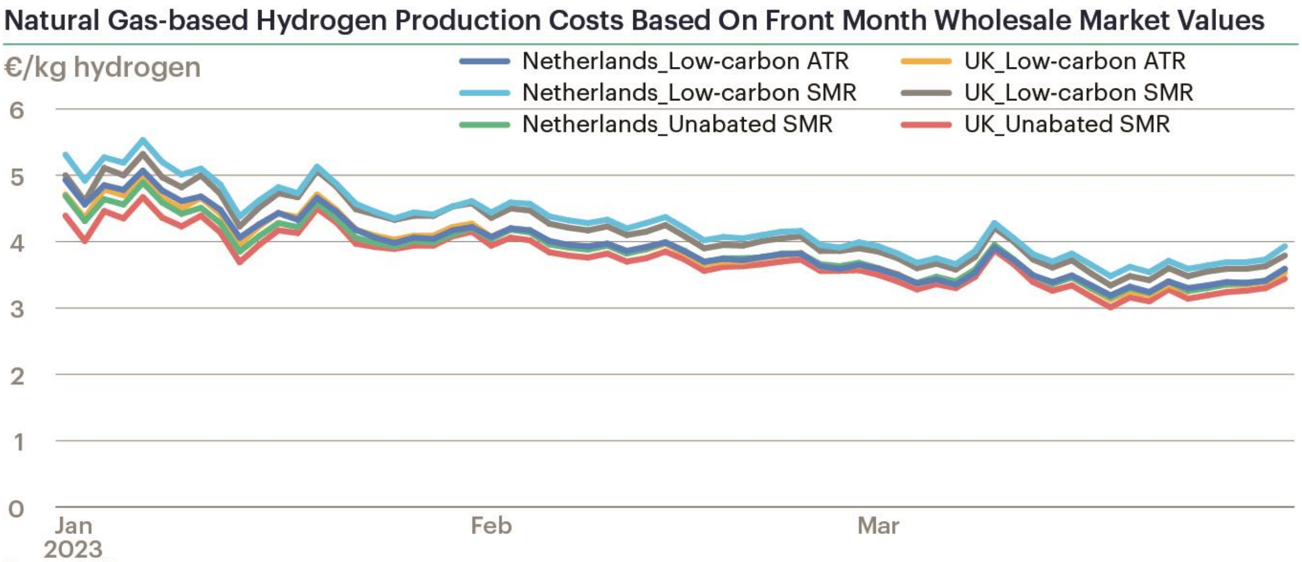


Source: ICIS

The long-term nature of PPA prices means that they were relatively protected from the substantial fluctuations of near-curve power contracts over 2022. As such, renewable hydrogen production costs using a PPA were far less volatile over the course of the year, and this pattern remained in the first quarter of 2023. As PPA prices are still derived from the wholesale power market, there were still fluctuations as shown from August, but relative easing of forward power prices in the final quarter softened renewable hydrogen production costs using offshore wind.

Overall, hydrogen production costs using a 10-year PPA for offshore wind across the Netherlands, the UK and Germany starting in 2026 oscillated around the €4-6/kg hydrogen mark over the quarter on project breakeven basis. This margin accounts for both the use of renewable power and the recovery of the investment in the electrolyser over the 10-year period, meaning production costs for the project would drop thereafter to solely account for constant operational costs and the PPA or power price used.

Natural gas-based hydrogen production costs Q1 2023



Source: ICIS

Natural-gas based hydrogen production costs remained the lowest of ICIS assessments over the start of 2023. This is because the impact of relatively mild temperatures, strong renewable output and abundant gas in storage fed into general easing of risk premiums across near-curve contracts.

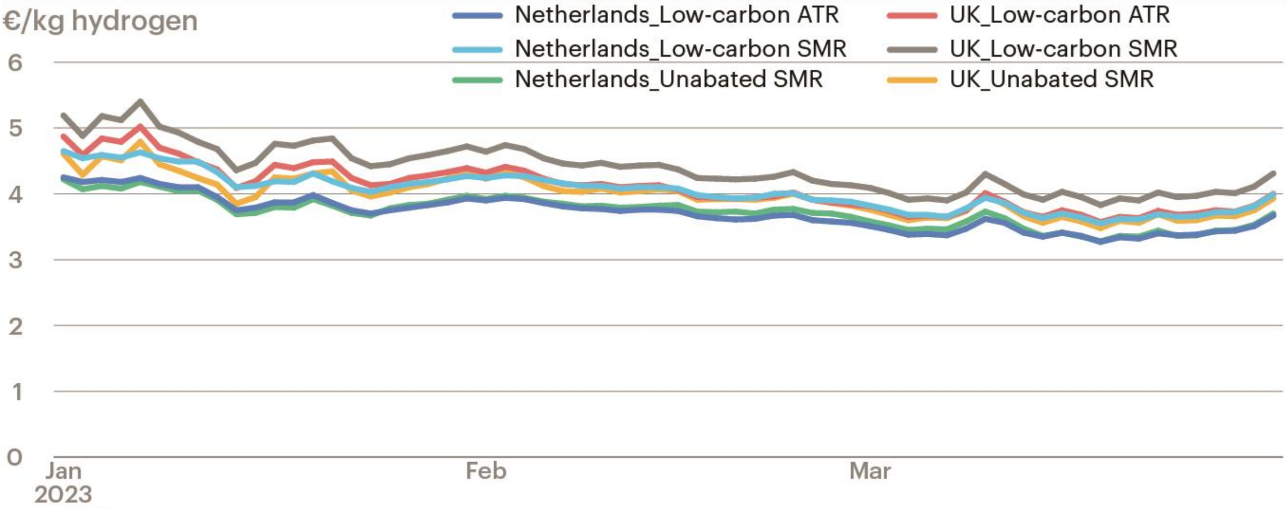
Production costs using natural gas front-month contracts showed a drop of around €2/kg over the first quarter, with low-carbon hydrogen with carbon capture and storage (CCS) infrastructure remaining below €4/kg.

The trend of easing gas-based hydrogen production is consistent with other production methods, which also showed progressive easing towards the end of 2022.

However, for the first time in ICIS assessment history, unabated steam methane reforming (SMR), commonly referred to as grey hydrogen, became more expensive to produce on a project breakeven basis in comparison to low-carbon hydrogen from autothermal reforming (ATR) with CCS.

This was due to spikes in the carbon price, making high-emissions hydrogen less economic on a full project basis. This meant that it was cheaper to invest in a gas-based hydrogen production unit with CCS capacity than paying for the carbon emissions resulting from grey hydrogen.

Far-curve Gas Prices Continue To Ease, Reducing Hydrogen Production Costs To Near Pre-war Levels

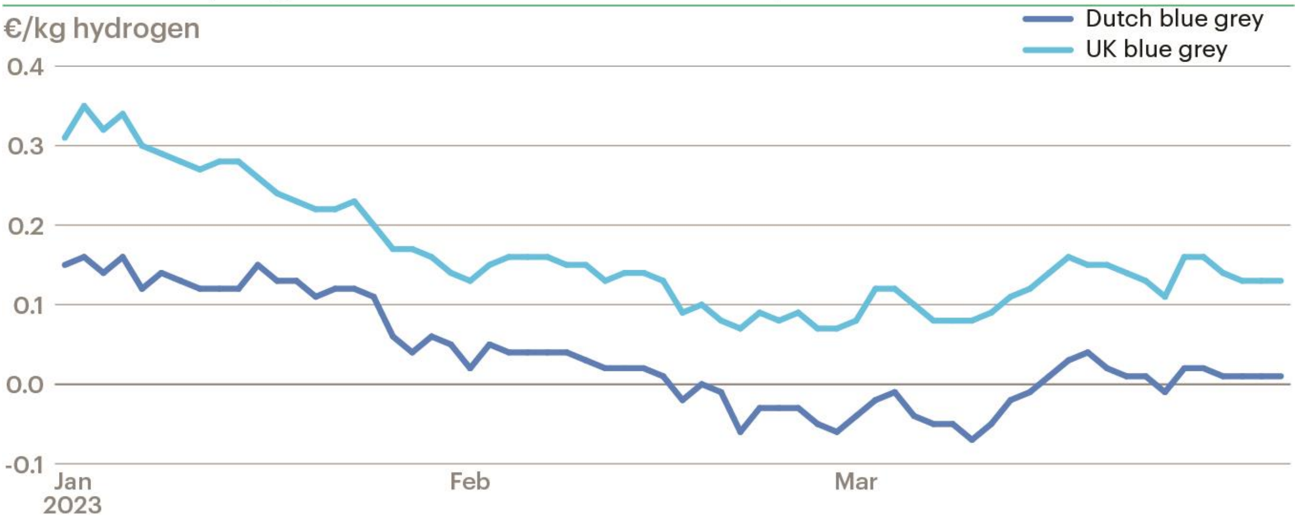


Source: ICIS

Looking further ahead on the forward curve, gas prices for 2025 also progressively dropped in the first quarter, resulting in would-be production costs moving from around €4-5/kg to €3-4/kg. The drop along the far curve indicated that some of the worst impacts of volatility from 2022 are starting to fade for hydrogen projects aiming to come online for the middle of the decade. However, costs still remain notably above the beginning of 2022 of around €2-3/kg hydrogen, ICIS data shows.

2025 values for production costs are particularly relevant in the UK, as this is when some of the initial low-carbon hydrogen projects could commence operation. As supply chains commence rebalancing over the years to come, and higher renewable capacity is deployed in Britain and Europe, gas prices for the middle and latter half of the decade could ease further ahead of delivery.

Low-carbon Hydrogen Production Cost Premium Drops Below Unabated SMR In Q1 2023



Source: ICIS

Note: Positive value indicates low-carbon hydrogen production costs at premium to unabated SMR

One of the key developments from a market perspective over the first quarter was that high carbon prices pushed unabated SMR above low-carbon hydrogen on a project breakeven basis in the first quarter of 2023 for the first time in ICIS assessment history.
Over the course of 2022 low-carbon hydrogen production costs using front year power, gas and carbon presented an important new picture of the interaction between low-carbon hydrogen and standard unabated SMR hydrogen production.

Towards the first quarter of 2022, carbon prices showed bullish trends, narrowing the premium low-carbon hydrogen held over unabated SMR on a Project Breakeven basis. This is important, as higher carbon prices would ultimately penalise unabated SMR more than low-carbon hydrogen producers, which counterbalances the investment in CCS technology and the power required to drive it.

However, in the first quarter of 2023 the premium switched to a discount, indicating that it was cheaper to build a new low-carbon hydrogen project with CCS units than to build an unabated SMR unit without abatement technology.

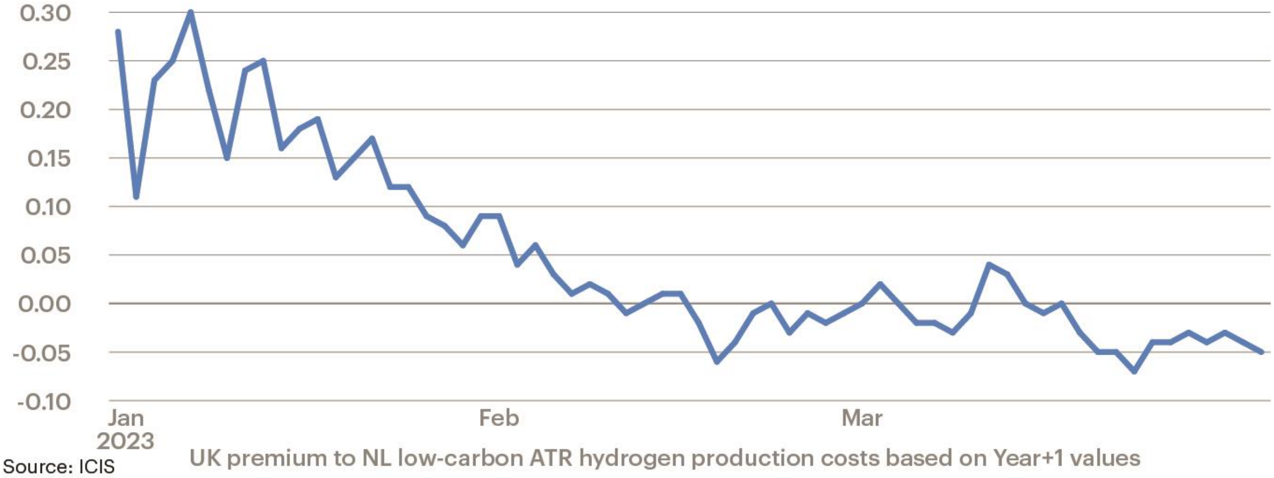
While this shows potential for the investment case for low-carbon hydrogen, it is important to note that current hydrogen production plants are already in operation. This means that capital investment may have already been recovered, whereas there are currently no low-carbon units in operation in Europe, meaning all project developers would need to apply capex recovery to the final price hydrogen buyers pay.

Another important takeaway over the last 18 months was that ATR units hold relatively better efficiency with respects to their use of natural gas. This means that higher gas prices make low-carbon hydrogen production more economical if using ATR.

However, one of the drivers of production costs is also power. With SMR, the hydrogen production process can produce power as a by-product, reducing the need for power import. However, with low-carbon hydrogen using ATR there is a requirement to import power for the CCS and for the air separation unit needed to provide the pure oxygen that’s required for the endothermic process.

UK Front Year Hydrogen Production Costs Flip To Discount To NL

€/kg hydrogen (positive value indicates UK at premium to NL)



Source: ICIS

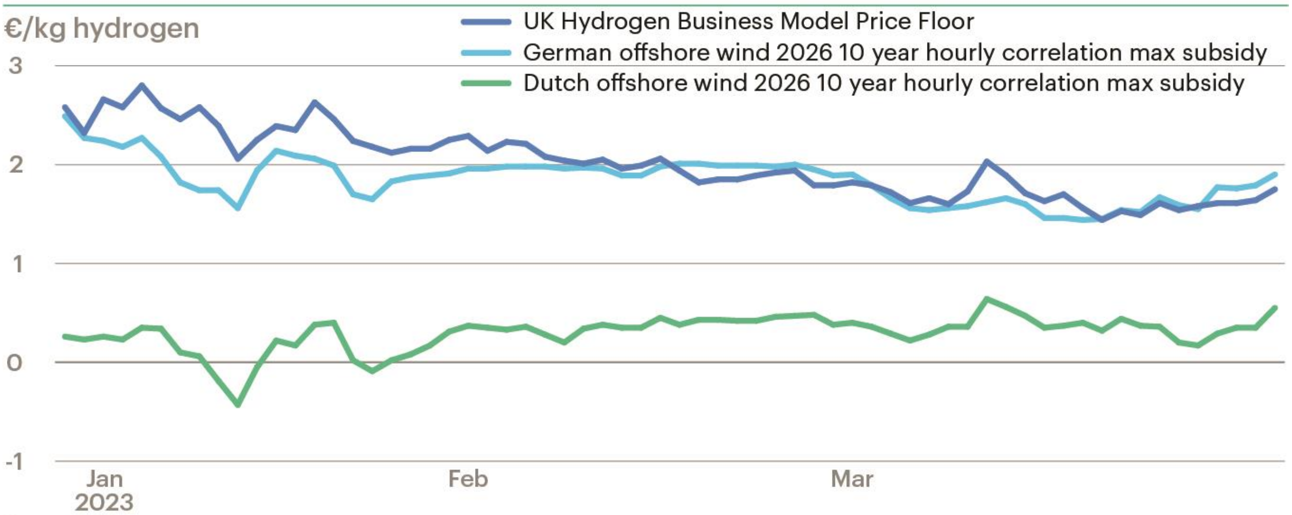
On a longer-term basis, the British NBP Year 2024 gas contract also switched from a premium to a discount compared with its Dutch TTF equivalent. The switch was a further result of LNG imports to Britain as Europe remained an optimal location for LNG cargo deliveries.

This meant low-carbon hydrogen production costs in the UK went from a premium to the Netherlands of around €0.30/kg to a discount of €0.05/kg. The switch to discount based on front-year values also occurred in 2022, however with much greater volatility on account of a substantial supply chain rebalancing.

However, the difference between the two countries narrowed towards the end of the year as the Netherlands began to install additional means of importing LNG. The installation of floating storage and regasification units (FSRUs) meant the Netherlands increased its overall LNG import capabilities.

The difference between production costs is important for future hydrogen producers and offtakers in both countries, as it shows the potential interplay shippers may utilise as the market develops, similar to how current gas shippers will nominate to export and import from the UK to the Netherlands and Belgium depending on gas market price spreads.

EU Hydrogen Bank, UK Hydrogen Business Model Show New Potential Price Points For Hydrogen



Source: ICIS

With the emergence of the European Hydrogen Bank towards the end of the first quarter, European hydrogen market participants were given a glimpse of where future renewable hydrogen prices could sit.

Reviewing ICIS renewable hydrogen production costs, based on production criteria set out in the delegated acts, it is possible to review how low hydrogen prices could sit if producers are awarded the maximum subsidy of €4/kg.

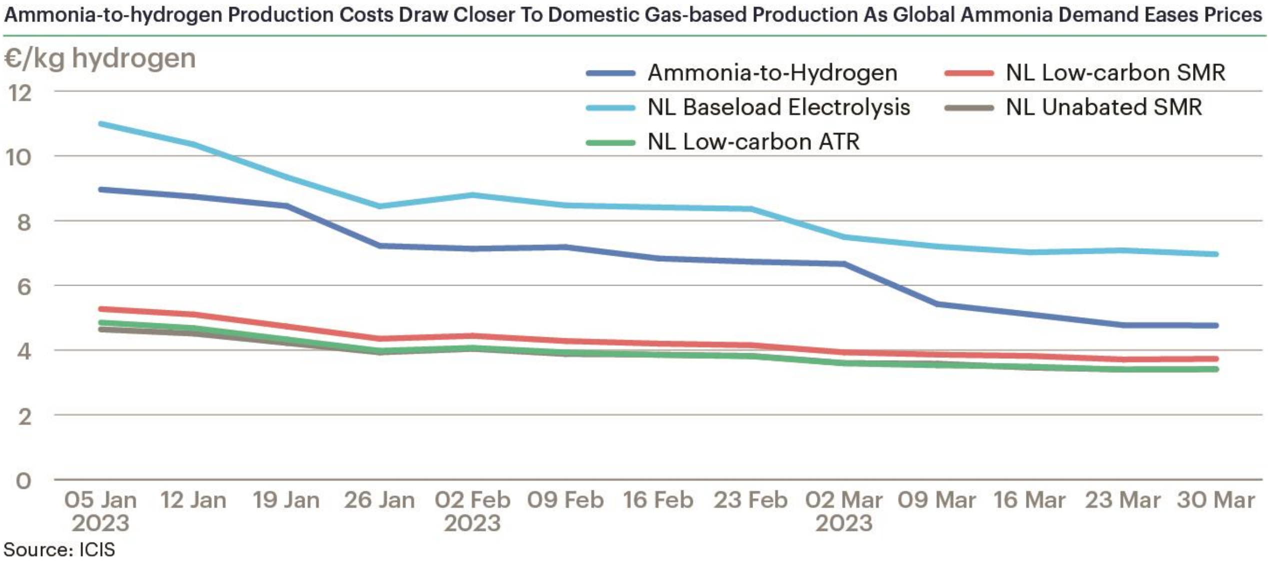
For the purposes of comparison, ICIS has applied the full subsidy to renewable hydrogen price history for 10-year offshore wind PPAs in the Netherlands and Germany starting in 2026. Further, ICIS has converted its benchmark ICIS NBP front month assessment to a €/kg hydrogen price.

The UK government aims to set the UK front month gas price as its support floor, meaning the gas price itself could become the relative price for low-carbon hydrogen buyers during the early years of the market. Future offtakers have previously indicated to ICIS that they intend to focus on the UK gas price as a key component of offtake agreements.

Taking the two support mechanisms into consideration, it is clear that although renewable hydrogen could be priced below UK low-carbon hydrogen, this needs to be balanced with the fact that the EU Hydrogen Bank operates with a competitive bidding mechanism. This means the EU Hydrogen Bank will prioritise subsidy to the lowest bidder.

This could mean that the UK Low Carbon Hydrogen Business Model results initially in some of the lowest-priced hydrogen in Europe. Indeed, based on unabated SMR production costs using front-month values in the UK, the business model would have resulted in low-carbon hydrogen sales prices averaging €1.74/kg below high emissions hydrogen over the course of the first quarter.

Ammonia as an import vector



Beyond the developments of the domestic hydrogen market in Europe, sentiment around the notion of global hydrogen trade has also been debated politically, with initiatives such as H2Global tendering for volumes of hydrogen and hydrogen derivatives, and the decision to include ammonia and hydrogen in the Carbon Border Adjustment Mechanism (CBAM).

Over the course of 2022 ICIS developed a new assessment reviewing the cost of importing hydrogen to Europe based on spot ammonia market values. The ammonia price is based on the ICIS NW Europe assessment, which delivers into the Port of Rotterdam, the Netherlands, and the Port of Antwerp, Belgium. ICIS price history showed that it is often consistently cheaper to produce hydrogen domestically than to import via ammonia and decompose into hydrogen, with 2022 average of the ammonia-to-hydrogen assessment at €10.91/kg hydrogen, compared to around €7-8/kg hydrogen for ATR and SMR with carbon capture and storage (CCS).

However, as the commodity price spike of 2022 reached its peak during the second quarter of last year, coinciding with the cessation of natural gas import flows via the Nord Stream pipeline linking Russia to Germany, imported hydrogen via ammonia production costs proved to be competitive to both low carbon hydrogen and unabated hydrogen based on front month power and gas prices, Project Breakeven.

This switch from premium to discount indicates that ammonia as an import vector could be used as a delivery mechanism which responds to market signals, supporting European hydrogen supply during future periods of tightness.

As the year progressed and European gas prices dropped rapidly over the winter months, ammonia-to-hydrogen became more expensive as a production method as global ammonia supply was yet to fully rebalance.

In the first quarter of 2023 however, as ammonia demand began to outstrip supply despite continued loss of production, the ammonia-to-hydrogen assessment indicated that importing hydrogen via ammonia was becoming more economic, moving from a premium of around €4/kg hydrogen at the start of the quarter, to around €1.50/kg hydrogen by 31 March 2023.

Q1 2023 Developments

Over the course of the first quarter, multiple policy, regulatory, transmission and market developments emerged. These developments ranged from support mechanisms to certification schemes.

ICIS has collated some of the key developments below.

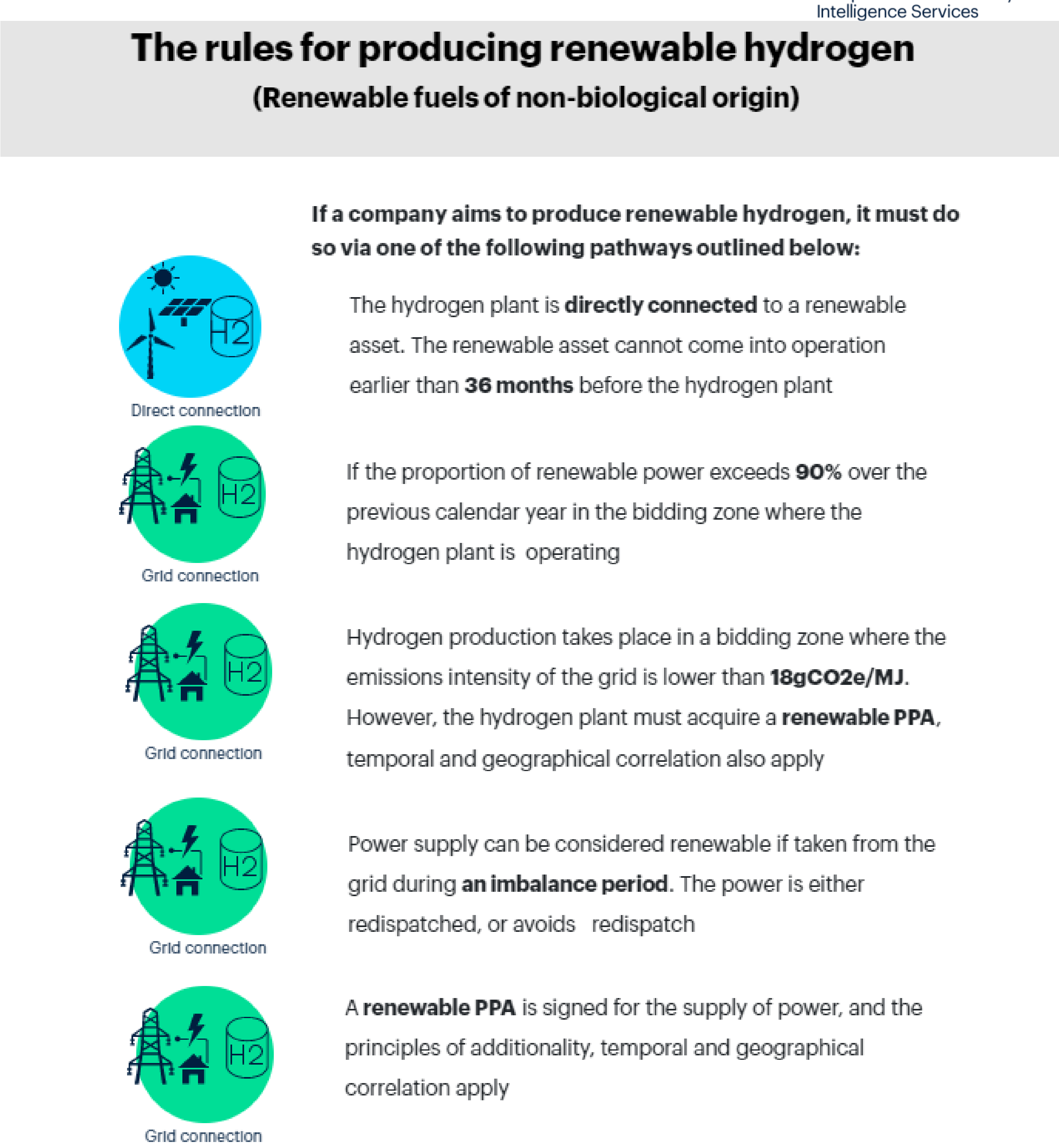
Regulation and Certification

Core updates
Of all regulatory developments in the first quarter, one of the most substantial not just for European hydrogen, but for future global hydrogen producers seeking to export to Europe, was the publication of the final delegated act for RFNBO on 13 February.

The rules apply to hydrogen producers seeking to label their product “renewable hydrogen”, if they wish for it to be purchased and recognised as such in Europe.

The announcement of the rules for RFNBO meant that project developers could aim to take final investment decisions (FID) on projects, as they can tailor final project design to a set standard.

To support transparency of the rules, ICIS produced the below infographic as a point of summary.



Further, ICIS has also produced a summary of associated conditions and sub conditions for the production of RFNBO.

Associated principles for the production of renewable hydrogen

Principle	Conditions		Exemptions
Additionality Article 5	The renewable asset came into operation not earlier than 36 months before the hydrogen plant. It also cannot have received operating or investment aid		Principle of additionality shall not apply until 1 January 2038 to hydrogen plants that come into operation before 1 January 2028
Temporal correlation Article 6	**Up to 31 December 2029** Hydrogen production occurs **within the same calendar month** as the renewable power was generated under the renewable PPA	**Beyond 1 January 2030** Hydrogen production occurs **within the same hour** as the renewable power was generated under the renewable PPA	Temporal correlation is considered always met if the hydrogen production occurs within the one-hour period where the clearing price for power resulting from the Day-ahead market is lower than or equal to €20/MWh, or lower than 0.36 times the EU ETS
Geographical correlation Article 7	**Considered met if one of the following are fulfilled:** • The renewable asset and hydrogen plant are in the same bidding zone • The renewable asset and hydrogen plant are located in interconnected bidding zones. The renewable asset is located in a bidding zone where the power price is equal to or higher than that of the hydrogen plant • The renewable asset is located in an offshore bidding zone to the hydrogen plant		

Most of the conditions for producing renewable hydrogen result in a producer entering a renewable power purchase agreement (PPA) or building a renewable energy asset. However, if the share of renewable generation meets 90% or more of total generation, then a hydrogen producer could purchase power from the wholesale market within that bidding zone and call it renewable, while avoiding the need to adhere to principles of additionality, temporal and geographical correlation.

ICIS conducted an analysis of this scenario and found that by 2030, nine countries would contain bidding zones with suitable shares of renewables meeting consumption levels.

The announcement of the delegated act meant that hydrogen certification could also take a step forward in Europe, and on 22 March hydrogen certification programme CertifHy announced that it had submitted its RFNBO European Union Voluntary Scheme documents for approval by the European Commission. The development of certification is key to market advancement, as appropriate certificate schemes will allow market participants to validate the sustainability criteria of their hydrogen molecule and can also be used to demonstrate the meeting of national targets.

A motion to object to the delegated act was rejected by the European Parliament's Committee on Industry, Research and Energy (ITRE) on 28 March. The decision indicates that the delegated act will now progress to parliamentary level for final discussion and voting, and suggest that the act may soon be finalised.

Another major regulatory development in Europe over the first quarter came on 15 March, when members of the European Parliament finalised their position on EU gas market reforms. The Decarbonised Gas Markets packages (directive and regulation) were first presented by the European Commission in December 2021. Over the first quarter, both the EU parliament and the European Council came to internal agreements over their positions on the packages, allowing for negotiations to begin. A key component of the decarbonised gas markets packages is that it will integrate hydrogen infrastructure and regulation into current EU energy systems.

Among the points included in the finalised position, MEPs opted to clarify the definition for “Low-carbon hydrogen” as a 70% emissions reduction against an upper limit of 94gCO2e/MJ. This gives a threshold of 28.2gCO2e/MJ, which is 8.2gCO2e/MJ above the UK standard. MEPs also recommended that 10-year gas market development plans include hydrogen.

The European Council agreed to its negotiating positions on the two gas market reform proposals on 28 March. The main suggestions raised by the Council were that rules for tariffs and tariff discounts be clarified, such as a 100% discount for renewable gases and a 75% discount for low-carbon gases in the gas networks. The Council also recommended a blend of 2% hydrogen in the gas system.

The council also recommended effective strengthening of definitions, with a general approach to refer to the fossil fuel comparator referenced in the Renewable Energy Directive. The council also suggested a transition phase for implementing detailed rules for hydrogen transmission systems until 2035.

Outside of the EU, on 9 February the UK government announced plans for a potential hydrogen certification scheme, issuing certificates for “low-carbon hydrogen”, in alignment with its Low Carbon Hydrogen Standard, which allows for an emissions threshold of 20gCO2e/MJ.

The certificate programme will work at an international level to align standards. The government’s minded-to position was to support a mass-balancing certification scheme, which means a system where certificates would be bundled with the sale of the hydrogen. This means that if an offtaker is purchasing 5MWh of low carbon hydrogen from a producer, that hydrogen would come with 5MWh of low carbon hydrogen certificates. This system allows for different types of hydrogen to be mixed into the transmission system as the offtaker would hold certificates to differentiate supplies at the point of offtake. The alternative book-and-claim system does not reflect a physical link between the hydrogen and the certificate.

Additional developments

On 25 January, Iberian energy transmission system operator Enagas GTS launched its platform for the registration to a system for guarantees of origin for renewable gases. The platform allows for the registration of account holders and the registration of production devices. The system applies to biogas, biomethane, and renewable hydrogen. The platform is in line with the Spanish Government's +SE Plan (More Energy Security Plan) which was presented in October last year.

Finally, the UK government published guidelines for hydrogen producers seeking to produce hydrogen using fossil fuels with carbon capture and storage (CCS) on 6 February. The guidelines cover those who produce hydrogen and aim to use it within the same installation or project, and for projects that aim to export and sell the hydrogen to third parties. The CO2 associated with the hydrogen's production should also be transported by pipeline or other means and stored in permanent underground geological storage facilities or used as a product itself.

The guidance for production is relevant for "large-scale industrial plants" that are either new hydrogen plants or retrofits of existing plants that are typically greater than 100 tonnes/day of hydrogen production capacity, equal to 140MW capacity at a lower heating value. However, the UK government said that "smaller plants should use this guidance until further guidance is available". The guidance said that overall CO2 emissions capture rates from hydrogen production should be "at least 95%" for average performance over an extended period.

Policy

Core updates

The first quarter saw substantial developments when it came to policy announcements, most notably concerning subsidy and support schemes in development for hydrogen production. Of the schemes announced, a key trend was to set a fixed level of support for an extended period of time, often 10 years.

The very nature of long-term, fixed support-level schemes indicates that the hydrogen market could operate on an initial basis of long-term contracts that mirror the duration of guaranteed support.

As well as this, the provisional agreement of the European Council and European Parliament on the Renewable Energy Directive recast meant hydrogen’s position in the European economy by 2030 was provided much greater certainty.

Early in the year, the first of several support scheme announcements came out. On 4 January, the Portuguese government announced it was tendering for the supply of renewable hydrogen and biomethane for the replacement of natural gas. The Portuguese government said it was aiming to establish 120GWh/year of renewable hydrogen and 150GWh/year of biomethane, offering a maximum subsidy of €127/MWh (€5/kg) for hydrogen and €62/MWh for biomethane. Contracts are expected to be valid for 10 years.

In Italy, the council of Italy’s Emilia Romagna region announced on 16 January a tender for renewable hydrogen projects that would be developed at abandoned industrial sites, offering support for production, storage and power generation. The maximum subsidy granted per project proposal cannot exceed €19.5m, but the allocation of funding can include use of the monies for storage, provided storage costs do not exceed 50% of total project costs, and for power generation so long as the generation is within 10km of the project and accounts for over 20% of the renewable hydrogen project's capacity. Projects can be in the range of 1-10MW, and would need to be completed by 30 June 2026 if successful. Total energy use per tonne of hydrogen cannot exceed 56MWh.

Following this, the Danish government was granted €170m (DKr1.25billion) to support the production of renewable hydrogen through Power-to-X (PtX) technologies. The technologies that will be supported by the funding will be the upscaling of renewable hydrogen production and derivatives, such as ammonia, methanol, and e-Kerosene by using PtX technologies.

PtX technologies in this context will cover electrolysers that will produce renewable hydrogen using electricity that has been sourced directly from renewable generation assets. Electrolysers are the primary technology for producing renewable hydrogen. The Danish scheme will support between 100MW and 200MW of electrolysis capacity and will be awarded via a competitive bidding process that will be concluded by the end of 2023 in the form of a direct grant for a 10-year period.

Early in the second quarter, the Danish government expanded on its support scheme, noting it would be a fixed-level subsidy awarded to the lowest bidder. The support would be granted over a 10-year period.

The largest support mechanism announcement came in March, when the European Commission gave full details of its much-anticipated European Hydrogen Bank. The bank was first mentioned in September 2022, and further details had trickled into the market following that time. It was understood that the bank was being developed to bridge the cost gap between unabated high-emissions hydrogen and renewable hydrogen, and that it may be a fixed-premium support scheme.

On 16 March, the commission answered many of these points. The bank will operate on a fixed support mechanism, providing a hydrogen producer with a €/kg subsidy for 10 years. The support will be granted via a competitive auction, prioritising the lowest bidder.

The first auction will be held in autumn 2023, with an auction allocation of €800m generated via returns from the Innovation Fund. Funding at this stage will be granted solely to renewable hydrogen, but future auctions may include low-carbon hydrogen. In April, the first heads of terms were released for the bank, which indicated that the maximum subsidy would be €4/kg.

In the UK, the government's "green day" on 30 March also progressed the country's potential for capacity of electrolytic hydrogen, as well as funding grants for multiple different programmes of support.

One of the key announcements was the shortlist for the much-awaited hydrogen electrolysis allocation round. The shortlist consisted of 20 electrolyser projects that could be online by 2025. In total, 408MW of capacity was narrowed down for selection over this first round. The ambition is to select 250MW of capacity to support over the round, which is due to be confirmed by the third quarter of 2023. The winners of the allocation will be provided long-term revenue support, allowing producers to reduce the price at which they need to sell hydrogen to recover capital investments. Following this, the UK government is launching a second electrolysis allocation round in the fourth quarter of this year. The aim for the second round is to allocate for 750MW of capacity.

At the end of the quarter, the European Council and European Parliament came to provisional agreements on two key matters of policy for the hydrogen market's demand growth.

On 28 March, the bodies jointly announced they had come to a provisional agreement surrounding the Alternative Fuel Infrastructure Regulation (AFIR). The agreement will allow for hydrogen refuelling stations every 200km, supporting the development of hydrogen in the transportation sector. The agreement will cover both recharging for electric heavy-duty vehicles and hydrogen refuelling, as well as recharging for light electric vehicles and the supply of electricity to ships.

Finally, at the end of March the Council and the Parliament came to a provisional agreement on the use of hydrogen within certain sectors as part of an update to the Renewable Energy Directive, where member states agreed a binding target under which 42.5% of all energy consumption will be expected to be renewable by 2030. The provisional agreement has large implications for hydrogen demand in Europe.

For the transport sector, a target of 5.5% of total consumption was to come from advanced biofuels, mostly non-food-based feedstocks, and renewable fuels of non-biological origin (RFNBO), mostly renewable hydrogen and hydrogen-based synthetic fuels. There is also a minimum requirement of 1% of RFNBO in the share of renewable energies supplied to the transport sector by 2030. For industry, the provisional agreement provides that industry increases its use of renewable energy by 1.6%/year, as well as an agreement that 42% of the hydrogen used in industry is to come from RFNBO by 2030 and 60% by 2035.

However, member states can discount the contribution of RFNBO to 20% if their contribution to the overall EU target is met, or the share of hydrogen from fossil fuels in the member state is not more than 23% in 2030 and 20% in 2035.

Additional developments
On 5 January, the German and Norwegian governments released a joint statement outlining plans to further strengthen hydrogen ties between the two countries, building on declarations made in 2022. The focus of the announcement was to support the development of a large-scale hydrogen supply route from Norway to Germany by 2030, likely a pipeline. Coinciding with the announcement, Norwegian producer Equinor and German utility RWE announced the signing of a memorandum of understanding (MoU) for the supply and offtake of hydrogen for use in the power sector.

Under the MoU, Equinor will produce both low-carbon hydrogen from natural gas with CCS, and renewable hydrogen. The approach from Equinor will be to first invest in low carbon hydrogen capacity, with a target of 2GW of capacity by 2030, with up to 10GW of total hydrogen production capacity by 2038. RWE and Equinor will also collaborate on the production of renewable hydrogen using offshore wind. Both companies are working together on AquaSector, a North Sea project aiming at building 300MW of offshore wind capacity which will have electrolysers built into it. According to RWE, the MoU includes joint investment in 3GW of hydrogen-capable gas-fired power plants.

On 10 January, the Spanish government outlined plans for the funding of four renewable hydrogen projects, H2B2, Nordex, SENER and IVECO, bolstering the projects with additional funding following their selection as part of the Important Projects of Common European Interest (IPCEI). Two of the projects, H2B2 and SENER, are focused on the development of electrolysers. The two projects have received a combined €35m of the grant allocation. The IVECO project, which received the largest funding allocation of the four at €27.05m, will develop demand-side technologies aimed for use in the transport sector. The primary focus is on heavy commercial vehicles for urban and regional use.

On the production side, the Nordex project aims to deliver a 5-10MW alkaline electrolyser which aims to utilise both solar and wind power. Projects combining the use of solar and wind generation for hydrogen are becoming more commonplace, as developers are aiming to benefit from higher hours of generation coming from a combination of the two technologies. Increasing the total hours of generation helps to reduce the impact of the capital cost recovery on the final cost of producing the hydrogen. Nordex is listed to receive €11.6m.

On 17 January, the Clean Hydrogen Partnership launched a hydrogen research call for proposals, with a total of €195m available for projects. The funding available will be split into €49m for renewable hydrogen production, €36m for hydrogen storage and distribution, €25.5m for transport, €19m for heat and power, €7.5m for **cost**-cutting, €38m for hydrogen valleys, and a further €20m for the strategic research challenge. The topics above will be split into 11 Innovation Actions, 13 Research & Innovation Actions, and two Coordinated & Support Actions, with five of the Innovation Actions considered of strategic importance and selected as flagship projects.

On 2 February the French government announced a total of 14 territorial hydrogen ecosystems had been allocated financial support. The total aid allocated was €126m following the closing of the last call launched back in 2020. The 14 territorial hydrogen ecosystems combined represent 8,400 tonnes of hydrogen per year, of which the vast majority, 91%, of the hydrogen produced will be intended for the transport of passengers through buses and coaches, and goods through commercial vehicles, heavy goods vehicles and rubbish trucks.

The European Commission announced on 17 February that financial support would be granted to steel manufacturer ArcelorMittal for decarbonisation of its operations with hydrogen. The approved support totalled €460m for operations in Spain, as well as €55m in Germany.

On 1 March, Norway and the UK announced plns for closer cooperation on hydrogen after an annex to the Norwegian-British memorandum of understanding (MoU) on carbon capture and storage (CCS) was signed between the two governments. The annex affirms an extended cooperation between the authorities of the two countries to "regularly exchange knowledge and experience related to the use of low carbon hydrogen on production, transport and storage as well as on developing standards and certification" the Norwegian government said.

On 17 March, the EU and Norway announced that the two bodies would increase cooperation on the green transition. The announcement included discussion to increase renewable power generation capacity, both for electricity demand and for renewable hydrogen production, with an aim to enhance competitiveness in the global marketplace.

Transmission, storage and import

Core developments
One of the key trends to emerge from an infrastructure perspective in the first quarter was the hydrogen market's focus on ammonia as an import vector. Interestingly, agreements made in the first quarter showed that ammonia will be used not just for transatlantic transportation, but also to move hydrogen across Europe in the absence of pipeline infrastructure. The emergence of ammonia infrastructure in such a manner reflects the development of the ammonia market itself.

This was indicated early on in the year when on 5 January Norwegian ammonia producer Yara International announced plans to modify its ammonia terminals in Germany, which will enable it to handle up to 3m tons of clean ammonia. Yara said this effort will equate to approximately 530,000 tons of hydrogen and can help to accelerate the hydrogen economy within Germany. Yara operates the largest ammonia storage in Germany and produces and consumes approximately 7% of European hydrogen.

Quickly following this came an announcement from BP on 19 January, when the company stated it was reviewing potential plans for a hydrogen hub at Wilhelmshaven, Germany. The project will potentially include an ammonia cracker with capacity to provide up to 130,000 tonnes/year of low-carbon hydrogen from renewable ammonia. The hub is expected to enter into operation by 2028.

On 20 February, Spanish energy company Cepsa and ACE Terminal (a development between Gasunie, HES International, and VOPAK), based out of the Port of Rotterdam, signed a memorandum of understanding (MoU) for the supply of renewable ammonia to ACE.
The MoU surrounds Cepsa supplying renewable ammonia to the ACE Terminal in Rotterdam for end-use applications in industry after decomposing of the ammonia back into hydrogen, or for direct use as ammonia. Cepsa said that the company is developing 2GW of renewable hydrogen production capacity at its two Energy Parks in Andalusia in southern Spain, which represent an investment of €3bn. First renewable hydrogen exports are forecast to commence in 2027, Cepsa said, which ties in with the ACE Terminal project timeline, due to be operational in 2026. Cepsa is set to export the ammonia produced at its San Roque Energy Park near the Bay of Algeciras.

Lastly, Air Liquide at the end of March announced plans to build an industrial-scale ammonia cracking pilot plant in the port of Antwerp, Belgium. The plant will use Air Liquide's proprietary technologies and is scheduled to come online in 2024, with financial support confirmed through the Flemish Government's Agency for Innovation and Entrepreneurship (VLAIO).

Transmission

Transmission system updates were plentiful in Europe over the first quarter, with transmission system operators (TSOs) of gas networks submitting plans to multiple funding mechanisms to establish repurposed or new-build infrastructure.

On 12 January, French natural-gas TSO GRTgaz announced a consultation to gauge economic interest in hydrogen infrastructure in the southern Fos-sur-Mer area. Fos-sur-Mer, to the west of Marseille in France's south, is home to heavy industries such as steel, refining, petrochemical and energy production.

The Junta de Extremadura and Spanish transmission system operator Enagas agreed to foster the development and promotion of renewable hydrogen and its derivatives within the region, as announced on 17 January. The deal will have the objective of developing renewable natural gas infrastructure, specifically renewable hydrogen, for the transport and storage of renewable hydrogen and its derivatives within the Extremadura region in southwest Spain on the border with Portugal. The region of Extremadura has set a goal of producing 20% of all renewable hydrogen produced in Spain by 2030, with the development of 3GW of electrolysis out of a country-wide total of 16GW within the region.

On 19 January, Italian grid operator Snam Rete Gas unveiled its Strategic Plan for 2022-2026, allocating €10bn to develop transport, storage and LNG infrastructure. The plan included an allocation of €100m for hydrogen transmission developments through the country's National Recovery and Resilience Plan. Snam projects that a hydrogen transmission system would be used to decarbonise hard-to-abate sectors, but expressed this would not be expected before 2026. Snam intends to develop the Italian hydrogen network over the 2020s by repurposing existing networks and storage.

On 23 January, Natural gas transmission system operators GASCADE and Fluxys applied to the European Commission for Project of Common Interest (PCI) status for the AquaDuctus project. The AquaDuctus hydrogen project is a pipeline due to be located in the North Sea, and will be over 400km long. The pipeline will take hydrogen produced at the German offshore coast into the onshore hydrogen network. The pipeline will begin taking hydrogen produced from the SEN-1 wind farm -- due to be operational in 2030 -- with other wind farms slated to be connected in the following years into Germany. The AquaDuctus project is due to have a capacity of 1 million tonnes/year by 2035.

On 24 January, as part of the Franco-German declaration on the 60th anniversary of the Elysee Treaty, Germany became a part of the H2Med hydrogen pipeline plan. The H2Med pipeline, forecast to become operational in 2030, will move renewable hydrogen between Portugal, Spain, and France. The capacity of the €2.5bn pipeline is slated at 2 million tonnes/year.

On 9 February, the Dutch natural gas transmission system operator Gasunie applied to the European Commission for the status of PCI for a section of hydrogen network in the German part of the North Sea that will be connected to the future **Dutch** hydrogen network. Gasunie said that the application "is part of the international partnership Clean Hydrogen for Europe in which it works together to realise the entire hydrogen chain for production, transport and storage".

On 23 February, transmission system operators Gasunie and Thyssengas outlined plans to develop a hydrogen pipeline between Wilhelmshaven and Wesseling, near Cologne, Germany. The 400km pipeline will be built by repurposing existing infrastructure as well as some new-build capacity. The line is expected to be ready for hydrogen transportation by 2028.

In March, Polish gas grid operator Gaz-System announced it was seeking EU funding for three hydrogen projects for the development of the hydrogen market in central Europe and the Baltic Sea regions. Gaz-System has applied for financial support under the EU's PCI programme for three projects including: Nordic-Baltic Hydrogen Corridor, which aims to establish a corridor to transport hydrogen from Finland through the Baltic states and Poland to Germany; Domestic hydrogen backbone including infrastructure connecting domestic hydrogen producers, import sources, and a hydrogen storage facility in Damaslawek with end users and possibly local distribution networks; the Damaslawek storage facility.

Storage

Hydrogen storage has been earmarked by participants as being a necessary requirement ahead of any hydrogen spot market trade. ICIS noted two key announcements for hydrogen storage in the first quarter.

Geomethane launched a call for expressions of interest regarding the construction of an underground hydrogen storage facility in French salt caverns on 2 February. According to Geomethane, there are seven operative salt cavities used for gas storage in Manosque, France, while a remaining two are unused but capable of storing about 6,000 tonnes of hydrogen. The call for interest was non-binding and aimed at assessing the needs of industries and consumers in the region.

On 21 February German utility RWE announced it had submitted planning approval for a hydrogen storage facility in Epe, Gronau in Germany to the Arnsberg District government. Completion of the facility is expected by 2026 and will consist of two salt caverns located close to hydrogen pipelines between Lingen and the Ruhr area. The first phase of the site will have capacity of around 6 million cubic metres (mcm), around 17GWh, before increasing to 28mcm.

Outlook

Hydrogen, particularly low-carbon and renewable hydrogen, often incurs a price premium against other, higher emissions fuels. Market participants say that in order to encourage true demand-side growth during the early years of the market, government subsidies are crucial. Now that key support mechanisms have been announced, the market is able to consider taking projects to FID.

However, the second quarter of 2023 may well not see substantial FID activity, as auction schemes and awarded subsidies are earmarked for later in the year.

What is likely to occur in the second quarter will be accurate forecasting of hydrogen production costs on a project-by-project basis, following the adoption of the final delegated act on RFNBO, which is due to occur in the summer months.

The benefit of advanced support schemes is already beginning to show in the UK, where the Vertex hydrogen project, a part of the HyNet hydrogen production unit and HyNet cluster in the northwest of England, has been signing heads of terms agreements for offtake.

Vertex Hydrogen and Pilkington UK signed a Heads of Terms agreement for low carbon hydrogen supply within the HyNet North West cluster on 4 January. The deal will see Vertex supply Pilkington UK, a glass manufacturer based in St Helens, with low carbon hydrogen. Pilkington said it completed the first two global trials of hydrogen being fired in a glass furnace.

As well as this, on 26 January, Tata Chemicals Europe signed its own heads of terms with Vertex for offtake of over 200MW of low carbon hydrogen.

The shape of these agreements, if they are accepted for UK government support, would likely reflect a long-term contract up to 15 years as per the support terms of the UK Hydrogen Business Model.

Expanding on the development of MoUs and heads of terms, the hydrogen market will likely see further demand-side clarity in the second quarter. Hydrogen can be used across a multitude of areas, but there are some prevailing sectors that have shown growth in recent months.

On 25 January Energy firm Mabanaft and shipping company Hapag-Lloyd signed a memorandum of understanding (MoU) to evaluate options for the supply of ammonia as bunker fuel at the Port of Hamburg in Germany and also to the Port of Houston in the US state of Texas. Mabanaft said it is in the process of developing infrastructure in Hamburg for import and supply of clean ammonia for a lead customer, along with a larger infrastructure investment program to create a platform for low carbon fuel alternatives.

Fossil-fuel alternatives for the transport sector appear to be growing, particularly across heavy duty transport. Although ammonia is likely to be used as a potential bunkering fuel, the growth in heavy duty road transport is also emerging. On 2 February, French industrial gases company Air Liquide said it plans to form a joint venture with energy and petrochemicals major TotalEnergies to develop a network of more than 100 hydrogen stations for heavy duty vehicles in Europe. The stations will be set up in coming years at major roads in France, Germany, Belgium, the Netherlands and Luxembourg.

Lastly, aviation developments are further emerging. BP has evidenced this with the development of its 28 renewable hydrogen production cluster in the Valencia region, HyVal, at its Castellon refinery. BP is set to develop 2GW of electrolyser capacity at Castellon, which is forecast for completion by 2030. The first phase will see at least 200MW of electrolysis plant being installed at Castellon by 2027, expected to produce up to 31,200 tonnes/year of renewable hydrogen. The renewable hydrogen produced would be used as a feedstock in the biofuel production process, specifically for the production of sustainable aviation fuel (SAF), in addition to being used close to the site by the ceramic industry and the chemicals industry.

From a policy perspective, some of the key potential changes will be approaching revisions to national hydrogen strategies. The French government announced in 2022 that by the end of the first half of 2023 it would have revised its national plan. Further, Germany, the largest hydrogen demand centre in Europe, is also projected to update its hydrogen strategy.

Some indications lean towards a greater penetration of low carbon hydrogen, either from natural gas or from low-carbon power grids. In the case of northwest Europe, where captured carbon from natural gas-based hydrogen could be stored in the North Sea, this is a growing potential. Up to now, the UK and the Netherlands have been leaders in low-carbon hydrogen technologies, but Belgium also shows space for development. Indeed, in February Norwegian producer Equinor announced it was moving ahead with its 1GW H2BE project in conjunction with French utility Engie.

With the indication that European low carbon hydrogen production costs can compete with unabated SRM, the economic case for new-build low carbon plants strengthens.

The pace of policy developments for Europe will likely require similar efforts to those seen in the first quarter of 2023. The ever-growing threat of industrial participants shifting operations to the US looms. The announcement of the Inflation Reduction Act (IRA) by the Biden-Harris administration in 2022 still acts as a strong incentive for hydrogen market development to move to the Americas.

As commodity markets continue to rebalance following supply chain disruption incurred after Russia's invasion of Ukraine, hydrogen production costs will also play a key role in supporting decisions for project locations. Much will now depend on Europe's ability to restock gas stores, testing whether the measures taken in 2022 for immediate security of supply can last ahead of the next winter.