Webinar Q&A

Low-carbon hydrogen – when will it be competitive?

Around 2,500 people registered for the Argus webinar: *Low-carbon hydrogen – when will it be competitive?*. Almost 300 questions were submitted by registrants and webinar hosts Joyce Grigorey and Dale Hazelton have answered the most frequently asked questions below.

General

Will your analysis look at the competitiveness at specific sites (eg industrial hubs) as well as in a broader market sense?

The analysis presented during the webinar and in the Argus Low Carbon Hydrogen Strategy Report models a generic example (i.e. using country-level feedstock prices for natural gas or electricity, country-average capacity load factors for renewables generation, etc.) rather than being site-specific. This is because the assumptions to model a specific site can be wide-ranging, not all of which would be relevant for the broader audience.

However, our in-house models have been developed to be able to alter a number of parameters to more accurately represent a specific site. This type of modelling is often required to support our bespoke consulting work.

Policy

Does Argus have any insight or views on the EU's decision to accept 'blue' hydrogen into the bloc? Is there a possibility that singular Member States will allow 'blue' hydrogen for a period of time, even if the EU rules against it? What is considered low carbon?

The EU has moved away from 'colours' (i.e. green, blue) to distinguish hydrogen, and rather refers to an emissions-intensity (CO2 content contained in the hydrogen) to determine whether the hydrogen meets its definition of low-carbon.

According to its announced hydrogen standard, the EU has set a 3.38kg CO2e/kg H2 threshold for the hydrogen to be certified as 'low carbon'. For reference, 'grey' hydrogen (produced via natural gas) has a carbon intensity of 11kg CO2e/kg H2; thus, this standard equates to a 70% reduction in CO2 emissions versus fossil fuels. This also means that 'pink' hydrogen (produced from nuclear) can also be considered low-carbon in the EU.

Countries around the world are adopting their own hydrogen standards. For instance, the US Department of Energy Clean Production guidance targets 4.0kg CO2e/kg H2, while the UK targets a more stringent 20g CO2e/MJLHV H2 (equivalent to 2.4kg CO2e/kg H2).

If Argus were to advise any EU member state government, wouldn't you encourage them to go after the low-hanging fruits first; ie incentivize the decarbonisation of the chemical/fertilizer industry? And make it easy for them to switch from grey ammonia use to low-carbon or a green one?

It would seem an obvious place to start with decarbonising existing end-uses, such as refining and chemicals, given the infrastructure already exists and these sectors are already large, existing consumers of hydrogen. Getting large consumers to adopt hydrogen first could, in theory, create a large baseload of demand that would encourage low-carbon hydrogen to scale as quickly as possible. Indeed, European countries are creating decarbonised industrial hubs that centre around existing refineries, and policies such as REDIII (and penalties such as CBAM) are supporting the decarbonisation of these sectors.

However, there's also the factor of declining refinery capacity in Europe and the fact that there are other options to decarbonise the transport industry, for example electrification or biofuels, as well as overcoming public perception that blue is still not green!

There is the argument that hydrogen should be reserved for use in sectors where electrification is not possible, for example, steel and aviation. Regardless of your view, it is generally accepted that it will be necessary to deploy a range of decarbonisation technologies to reach our net zero goals and making even small strides now is better than waiting for a perfect solution to materialise.

How will such new US policies affect Europe?

Initially, when the US announced its Inflation Reduction Act (IRA) and 45V tax credit initiative, there were concerns this would undermine the hydrogen projects that were already being planned in Europe. Indeed, the IRA has generated much interest in developing hydrogen projects and associated supply chain facilities such as electrolyser manufacturing in the US, and export hubs are being planned that aim to produce hydrogen derivatives, such as ammonia and methanol, to target the European market.

However, participants are waiting for further clarity around the 45V tax credit, specifically to understand how it will be implemented and whether there will be any flexibility or changes to the rules.

In addition, the US is not the only country looking at exporting to Europe. The Middle East, Australia, Africa and South America also have ambitions to become major export hubs. The H2Global programme is incentivising investment in green hydrogen production outside of the European Union, which it then intends to import into the block, via this global state-backed tender.

Any hydrogen imported into the block will be subject to the Carbon Border Adjustment Mechanism (CBAM). After 2026, the EU will begin to levy a tariff on the carbon embedded in hydrogen imports.

REPowerEU also incentivises EU countries to develop domestic hydrogen projects – in addition to 10mtpa of hydrogen imports, Europe is also targeting 10mtpa of domestic production.

In terms of UK policy to accelerate low-carbon hydrogen's competitiveness, what low-hanging fruits are available to the next government after the election?

The UK government has already made much progress in hydrogen to date. It has set firm targets in a clear hydrogen roadmap, identified key industrial hubs for decarbonisation, finalised its Hydrogen Production Business Models and announced the results of its first green hydrogen allocation round. Momentum needs to continue and the first projects need to be deployed.

However, there are important milestones that still need to be met, for example, the completion of the Hydrogen Transport and Storage Business Models and a decision on hydrogen into heating. Political instability or uncertainty is likely to deter investors and lead to further project delays. Investors will be looking for signals or reaffirmation from the next government that they will continue to support hydrogen use in the industrial heartlands. Thus, the earlier that reassurance can be provided, the sooner projects can become realised, which will act to further encourage future projects.

Pricing / Costs

How is technology choice and sourcing location impacting the cost structure of green H2?

Having access to abundant, low-cost renewable energy is one of the primary factors helping to drive down the cost of green hydrogen production and support the commercial viability of a project.

However, since the lowest cost hydrogen supply is not necessarily co-located with large centres of demand, the delivered cost of hydrogen, which includes additional costs, such as conversion, transport and distribution, is arguably the more important consideration.

Countries that can leverage or repurpose existing infrastructure can potentially achieve a lower delivered cost of hydrogen versus another country that has access to low-cost renewable energy but requires other associated facilities or infrastructure to be built, such as ammonia production, pipelines, ports, storage, etc. which increases the total cost of production and reduces overall competitiveness.

What hydrogen price will be offered by hydrogen hubs funded by DOE in the United States?

Of the DOE's total $8.5bn of funding, $7bn is dedicated to establishing seven hydrogen hubs, and up to another $1bn is reserved for providing revenue certainty for the hydrogen projects within those hubs. The hubs are still in the early planning stage, which is expected to take 12-18 months.

The DOE is currently designing a demand-side support mechanism, which could include a contracts for difference (CfD) mechanism similar to the UK and the Netherlands, a fixed $/kg similar to the European Hydrogen Bank auction, or a combination of mechanisms. The mechanism is expected to be finalised in Q3 2024.

Supply

Which countries/regions would most likely be key suppliers to Asia? From where do you think the green hydrogen will be procured by users like Japan since they cannot produce the total consumption on their own by 2030 / 2040?

Generally, we see Australia, the Middle East and the Americas to be the most likely suppliers to Asia, but the timing and quantity of available supply varies by geography.

Our Argus Low Carbon Hydrogen Strategy Report provides our clients with details of the pipeline of projects (location, developers, announced offtake agreements, capacity, date of operation, status, integration with renewables, expansion plans, etc.). The report also forecasts the demand that is expected to materialise in key consuming countries, like Japan and South Korea, by sector out to 2050.

Demand

What is the current demand for hydrogen and who are the key buyers? How are prices being set in the market currently?

Global hydrogen demand was estimated to be 95mn t in 2022 (IEA). The majority of current hydrogen demand is into the refining and chemicals (ammonia, methanol) sectors.

Within a refinery, hydrogen is used in the hydrotreating process to remove impurities, such as sulphur, from transport fuels to comply with regulations. While refineries produce their own hydrogen, this may not be enough to meet their needs and hence the requirement for additional hydrogen. The introduction of ultra-low sulphur diesel requirements has increased the demand for hydrogen from refineries.

Large industrial gas companies, such as Air Products, are key buyers and distributors of merchant hydrogen. A study by the US DOE estimates that between 5-14% of global hydrogen production is for the merchant market, while within Europe, the European Observatory estimates that around 13% of its hydrogen production is for the merchant market.

Current prices are set on a cost+ basis (Argus Hydrogen and Future Fuels service publishes current hydrogen production costs.) A transparent pricing mechanism for green and blue hydrogen is still to be established. This will evolve as more players enter the market but, for now, there have been very few pricing details publicly disclosed in the offtake agreements that have been made.

The US DOE announced it wants to provide price transparency and is considering publicising "standard offer terms" for projects it supports in its seven hubs and publishing pricing in the hopes of stimulating the development of a liquid, transparent market.

Do policies guiding subsidies favour use of hydrogen in hard to abate segments such as replacing carbon in reduction of iron?

We briefly discussed on the webinar that policies in Europe, such as REDIII, FuelEU Maritime and FuelEU Aviation are encouraging hydrogen demand in some hard to abate segments.

REDIII mandates that 42pc of hydrogen used in industry should come from renewable fuels of non-biological origin (RFNBOs) by 2030, which increases to 60pc by 2035.

FuelEU Maritime legislative proposal aims to reduce GHG emissions from both domestic and international shipping by 2pc in 2025 (versus 2020), increasing to 80pc by 2050. In July 2023, the EU Parliament and Commission published new provisions on the use of renewable and low-carbon fuels in maritime transport, calling for additional measures, including the use of a multiplier, to support the uptake of sustainable RFNBO and the need for a RFNBO sub-target (suggesting 2pc to apply from 2034).

FuelEU Aviation mandates a 1.2pc blending target for synthetic fuels in aviation by 2030, 5pc in 2035 and 35pc by 2050.

Green Steel

Any updates on hydrogen use in green steel making? Or the use of hydrogen in blast furnace iron making?

The Argus Low Carbon Hydrogen Strategy Report provides analysis of the use of hydrogen in the steel sector. The report includes details of announced green steel projects and initiatives (i.e. developers, company-specific green steel commitments, status of trial initiatives, subsidies awarded, announced offtake agreements, capacity, date of operation, etc.

In Europe, we are seeing a lot of project announcements to convert coal-based blast furnaces to direct reduced iron (DRI). Many of DRI units will initially be natural gas based, with a view of switching to hydrogen in the future.

The Argus Low Carbon Hydrogen Strategy Report provides the breakeven price (BEP) for steel in Europe, comparing hydrogen versus a traditional coal-based blast furnace, as well as hydrogen versus natural gas DRI. The BEP analysis also takes into account the impact of carbon pricing when the Carbon Boarder Adjustment Mechanism (CBAM) becomes implemented.

Distribution / Midstream / Infrastructure

Are there any crucial barriers to adopting hydrogen as an energy carrier as well as feedstock? Is there a potential bottleneck that infrastructure could pose for the development of a real market of H2?

We have already seen that policy and subsidies are key enablers to stimulating production, demand and cost competitiveness. In addition to these, factors such as the readiness of the associated technology, supply chain and infrastructure are also critical elements, although the requirement and current status of each of these factors varies by sector.

As we saw in the case of road transport, subsidies are required to make hydrogen fuel-cell EVs competitive versus the incumbent (diesel/petrol or battery), but this needs to be accompanied by a significant buildout of hydrogen refuelling infrastructure. Both Japan and South Korea are subsidising hydrogen refuelling stations (HRS), while Europe is also looking to build HRS every 200km along the Trans-European Transport Network (TEN-T), which will link major cities across Europe.

For hydrogen as a carrier (i.e. in the form of ammonia), it is necessary to consider the ammonia vessel fleet capacity, storage tanks, cracking facilities and access to a pipeline distribution network to link supply with demand. While ammonia cracking technology is not seen as a bottleneck, it also has not been done at large-scale.

For hydrogen to be considered as an option for long-duration flexibility, the ability to store large volumes of hydrogen is a crucial component. Converting a salt cavern to hydrogen storage is a lengthy process, which is estimated to take between 7-10 years to become operational. For a full ecosystem to be realised, storage must be built in parallel.