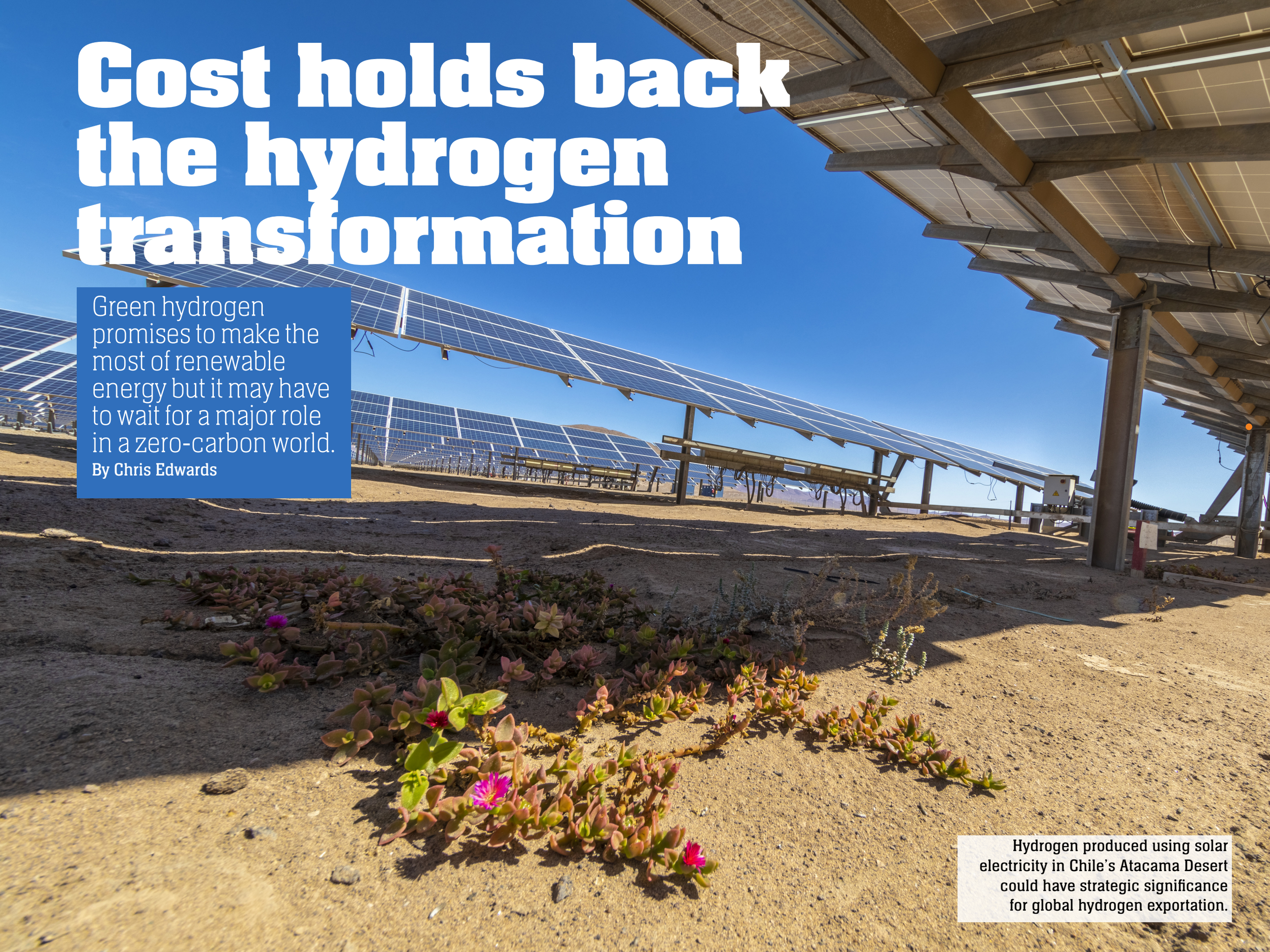
Cost holds back the hydrogen transformation

Green hydrogen promises to make the most of renewable energy but it may have to wait for a major role in a zero-carbon world.

By Chris Edwards



Hydrogen produced using solar electricity in Chile's Atacama Desert could have strategic significance for global hydrogen exportation.

If there is one fuel that provides a mechanism to alter the global balance of power in energy it is green hydrogen. It is a possibility that is not lost on the governments of Australia, Chile, and a number of African nations as they try to build national industries to put renewable energy to work on water: using electrolysis to split into molecular hydrogen and oxygen.

Late last year, the Chilean government set out its stall in a two-day conference, held virtually because of the Covid-19 pandemic. Sebastián Piñera pointed to the unusual geography of the country of which he is president, and how this would drive renewables investment in the country: solar on the high plains of the Atacama Desert and wind turbines at the tip of the southern peninsula.

Piñera pointed to the cost of solar already falling by 80 per cent as one of the reasons why he is so optimistic about the country's drive to build an economy around green hydrogen and of reaching the goal of, by 2030, being not just the most efficient green hydrogen producer in the world but the world's largest exporter of green hydrogen.

One thing that counts against Chile is the geography of supply and demand. The likely model proposed by a study performed by engineering group Ricardo is that the solar-produced hydrogen from the Atacama desert would head by ship to Asia and the west coast of the Americas. The wind-generated hydrogen would head eastwards to Europe and the American east coast. But both suggest sea journeys of well over 10,000km. Countries such as Australia, Morocco and Saudi Arabia do not quite have the same insolation benefits of Chile's Atacama desert but they benefit from being closer to major industrial customers. Japan backs Chile's plans and has signalled it will be an enthusiastic importer of hydrogen, but it will be cheaper to ship from Australia. Similarly, northern Africa and the Middle East have easier paths to Europe.

Though they add to the price, transportation costs may be, for at least a decade, a secondary issue for producers. A number of things have to go well for green hydrogen to approach the cost of today's transport fuels or even blue hydrogen: the form made from natural gas where carbon capture is used to prevent the emissions from leaking into the atmosphere. Suppliers will probably try to exploit natural gas reservoirs before they become stranded assets.

A new trend?

In an analysis produced by S&P Global Platts last year, the price per kilogram of so-called grey hydrogen gas, which is produced by today's dominant technology based on the steam reforming of methane, is around $1 (73p). Add carbon capture and the cost rises by around 50 US cents. The current price for green hydrogen is closer to $4 (£3). The hope of green-hydrogen proponents is to at least halve that over the coming decade.

Norwegian specialist NEL has set the ambitious target of

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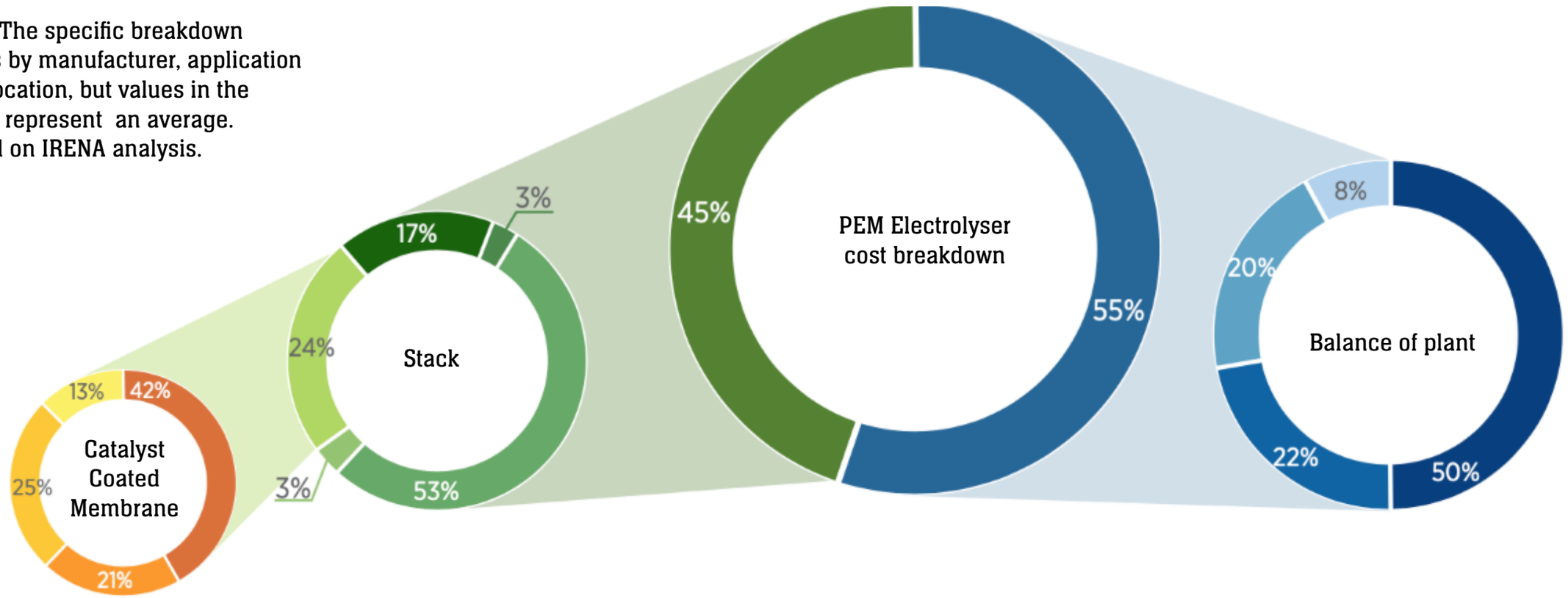
Cost breakdown

Based on a 1 MW PEM electrolyser, moving from full system, to stack, to CCM

Note: The specific breakdown varies by manufacturer, application and location, but values in the figure represent an average. Based on IRENA analysis.



- Manufacturing
- PFSA Membrane
- Iridium
- Platinum
- Porous Transport Layer (PTLs)
- Small parts (sealing, frames)
- Bipolar Plates (BPs)
- Stack assembly and end plates
- Catalyst Coated Membrane
- Protective coating BPs
- Balance of Plant
- Stack components incl. CCM
- Power Supply
- Deionised Water Circulation
- Hydrogen Processing
- Cooling

just $1.5/kg (£1/kg), which would achieve practical parity with blue hydrogen, although not with its more polluting grey cousin. Australian policymakers have adopted the slogan "H2 under 2" (A$2, £1.11) and Chile is pushing ahead in the expectation of a $2 price being realistic.

The capital and fixed costs of electrolysis based on today's prices account for around a third of the current green-hydrogen price. The lion's share of the cost is for the feedstock: the energy and, if we assume today's electrolysis technology will continue for the next decade or so, clean water. Short of a radical change in electrolysis technology to handle seawater directly, the cost of the distilled water also depends heavily on energy costs.

Platts estimates that for green-hydrogen production the difference between a 50 per cent capacity factor and 90 per cent, where the electrolyser is being used almost all the time for production, amounts to a difference of $1/kg in cost. To compete with blue hydrogen on a pure cost basis, the price per megawatt-hour of electricity has to be below $25 (£18) for the high-factor scenario and below $10 for the situation where an electrolyser is only active half the time. The Canadian state of Ontario has tracked electricity prices for close to two decades and predicts off-peak prices to fall to just under $11/MWh (£8) in the months of May to June this year. Peak prices in the winter climb to almost $30/MWh (£22). To hit its 2025 target of $1.5/kg, NEL says it needs the electricity price to be $20/MWh (£14.50) or lower.

As the second most significant factor in the cost of green hydrogen, electrolyser choice will be crucial. Unfortunately there is no clear winner when it comes to electrolyser technology, not least because duty cycles have a major influence not just on capital efficiency but how efficiently they operate when they are switched on.

There are four main types of electrolyser. NEL's primary choice, for example, is the alkaline cell that formed the mainstay of industrial production for chemicals such as ammonia for more than a century. As its name suggests, the cell relies on being fed with an alkaline solution rather than pure water: the hydrogen and oxygen are generated from these ions rather than the water, which just acts as a solvent. A permeable membrane between the two halves of the electrolyser feeds a hydrogen-rich mixture in one direction and an oxygen-rich one in the other.

Developed for space and military programmes, polymer electrolyte membrane (PEM) designs use specially formulated polymer membranes to let hydrogen ions pass through to the cathode while oxygen collects at the anode. Although they do not require the use of large quantities of alkali feedstocks, the PEM design today suffers from a higher cost, partly due to problems of scaling up the size of the cells and because of its reliance on precious-metal catalysts – not so much because of cost (likely to be no more than 10 per cent of the total) but because iridium is so rare there may simply not be enough to support a massive rollout of PEM designs. Acidic conditions in the cell shorten equipment lifetime partly through corrosion, forcing manufacturers to use expensive

structural materials such as titanium, as well as poisoning by water impurities. That in turn demands more input energy to fully distil and deionise the water that is being split.

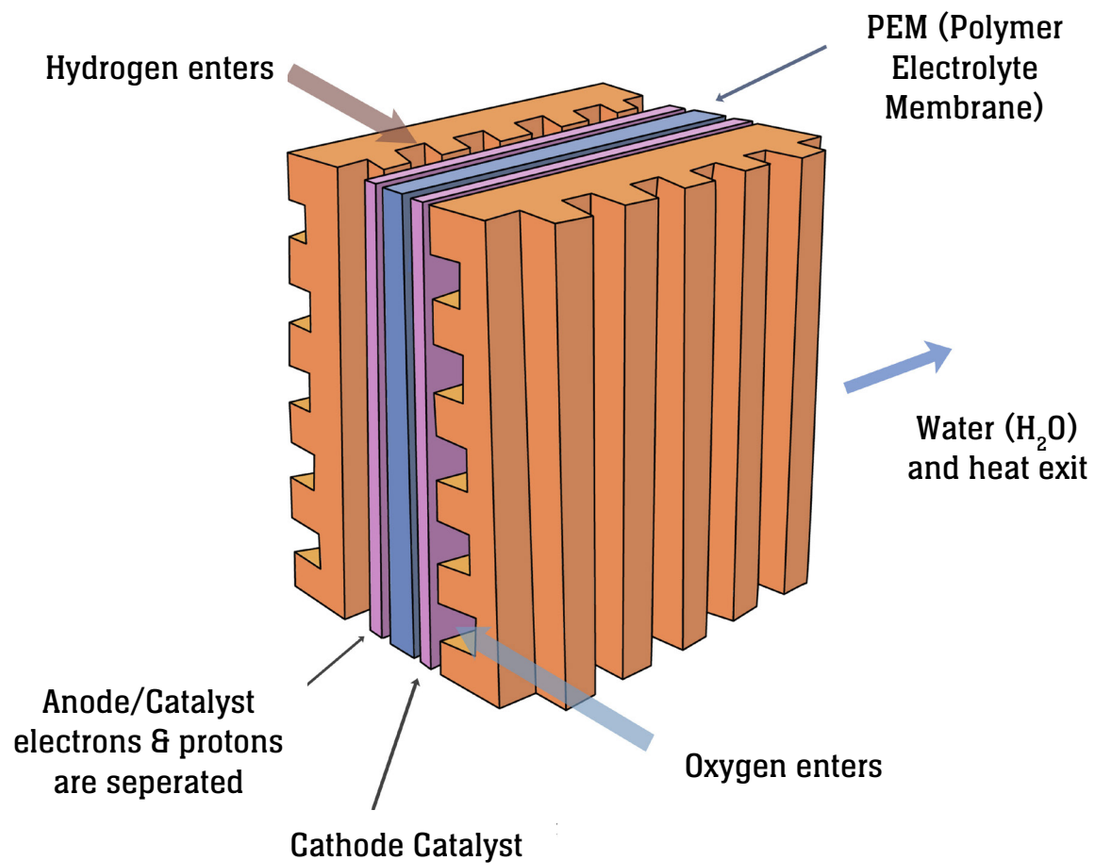
For a greener future

Two upcoming technologies are anion exchange membranes (AEM) and solid-oxide membranes that allow atomic oxygen to pass through. The AEM design has the key advantage of using cheap metals such as iron and nickel for catalysts. The solid-oxide design is effectively a fuel cell run in reverse. It has two potential drawbacks: it runs at temperatures as high as 1000°C, though it is very efficient at these levels, and may need comparatively rare elements such as yttrium, which places a heavy reliance on China as a source.

A major consideration will be how well the different constructions can react to changes in supply if operators try to chase the cheapest electricity. Alkaline cells can take about an hour to ramp up, as do solid-oxide cells, though their need for high levels of heat will likely exact an energy penalty if cycled frequently. PEM natively has a response time closer to 20 minutes and so it may become the preferred option for locations where hydrogen production is opportunistic, at least in the short term. A number of analysts have predicted PEM will ultimately overtake alkaline as its capital cost comes down. This is the strategy that NEL has said it will follow.

Expecting the capital costs of PEM to be higher than those of alkaline until 2030 at least, NEL's short-term plan is based on large-scale alkaline cells, with smaller plants using PEM.

Inside a fuel cell



China has itself pursued the alkaline option aggressively, commanding more than half of the installed capacity.

If solid-oxide technology becomes cost-competitive it may turn out to be the technology of choice for dedicated hydrogen plants in the global south where the heat from concentrator solar installations can readily support the temperatures needed for hydrogen production over long periods. For example, the Midelt project in northern Morocco will pair thermal storage based on molten salts with solar concentrators to support energy delivery after dark.

Although it is possible to eke as much as possible from renewables, a major factor that works against this kind of design is the sheer volume of capital spending that will be needed. On a per-kilowatt basis, the electrolyser costs as much as or more than the solar or wind generator. This leaves question marks over how much suppliers will endure the pain of curtailment before opting to try to use the seemingly wasted energy to make hydrogen gas. One option is to scale the electrolyser down and use battery and compressed-air storage to feed in excess energy more slowly to avoid curtailment. But a 2020 study by a group led by Dharik Sanchan Mallapragada, research scientist at the MIT Energy Initiative, found that unless the cost of storing hydrogen locally was extremely high, it made more economic sense to not buy the battery storage and simply accept some curtailment during peak generation periods with an electrolyser that is somewhat smaller than the peak generating capacity of the solar panels or wind turbines.

Groups such as the International Renewable Energy Agency (IRENA) have set out pathways for cutting the cost of electrolysis as volumes ramp, much of it through incremental improvements rather than in the expectation of a technological breakthrough. For the cell, the big drops in cost will probably come over several decades, partly because of a likely transition from alkaline, which is currently the cheaper option to PEM or one of the other options. Although its share reduces as plants get bigger, the post-processing stack is a significant contributor to both installation and operating costs. For the coming decade, economies of scale look more realistic for these components. For example, power electronics circuitry could be a major source of savings as it's the second largest capital cost. According to IRENA, by 2050, electrolyser cost could drop by 80 per cent.

Though it provides unprecedented opportunity for some nation states to remake the energy landscape in their favour, the scale of investment needed means green hydrogen will seem slow to take off. Installations have ramped up in the past few years to levels that were unthinkable in the past decade. But the sheer quantity of energy needed for hydrogen to even begin to match the capacity of the modern oil industry is enormous. It is a gap that, even with a following headwind, will take years to close. Platts, for example, predicts blue hydrogen production will outpace that of its green counterpart by close to 5:1 until at least 2028. Be prepared to see a lot of carbon capture being put to use in the meantime.