Australia's ENERGY FUTURE: 55 BY 35

Hydrogen

AUSTRALIAN ENERGY COUNCIL

Executive Overview

The AEC has proposed an economy-wide interim emissions target of 55 per cent reduction on 2005 levels by 2035 as a milestone on the way to net zero. This paper is one in a series of papers exploring the implications of the 55 by 35 target. This paper looks at the opportunities for emissions reduction using green hydrogen - hydrogen produced from the electrolysis of water using zero emissions electricity.

Hydrogen is both a potential substitute for liquid fuels and an emerging complementary technology to intermittent renewable energy (wind and solar). Surplus electricity produced by renewables can be converted into hydrogen via electrolysis. Hydrogen is a fuel, albeit challenging to manage. Green hydrogen will need to be compressed, stored, transported to where it is needed and then consumed to produce electricity, provide heat for industrial processes or power engines. Developing a low-cost hydrogen supply chain could, in theory, be able to replace much of the existing fossil fuel supply chain.

Hydrogen is not a single technology. It requires multiple processes: production, compression, storage, transport and use in generators and other industrial processes. Each of these stages is challenging.

Independent reviews of the cost of producing, compressing and storing hydrogen vary, as is common for nascent technologies. There is wide diversity in what is considered the most efficient technique for storage: low pressure tanks, cryogenics or underground salt caverns?

Moving hydrogen is challenging because it requires enormous amounts of energy for liquefaction (almost absolute zero), is small and light so is hard to compress (in pipelines), leaks easily and disperses quickly, embrittles metals and burns at high temperatures. It is ubiquitous and extreme, the antipode of most "conventional" resources.

Research into the various component parts of the hydrogen supply chain is important and should continue. Its potential is considerable; however, it is prudent to take a considered perspective of the technology as it is still a long way away from delivering on its potential. Policymakers should temper their enthusiasm when promoting hydrogen as a panacea to the challenges in the energy transition.

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Introduction

Hydrogen is the smallest, lightest, least dense and most abundant element in the universe. It is the antipode of most conventional resources: ubiquitous yet difficult to manage and contain. It is part of some of the most common materials on earth: water, sugars, oil and gas, coal, timber and plastics. Isolated as hydrogen gas it featured prominently in many 20th century industrial and energy systems. Now it is being re-purposed and re-cast to solve new 21st century energy challenges.

Hydrogen as an energy commodity of the 21st century requires a re-think of conventional resource economics. It is not scarce nor geographically constrained. Anyone can make it, with caveats: access to abundant, low-cost renewables are likely to be an advantage in both scale and lower production costs. Access to large scale natural storage (like specific salt caverns in certain parts of the world) may also be an advantage.

The challenge with hydrogen is not scarcity and extraction, it is in the transformations: from water to hydrogen, hydrogen to power station or to storage, and transforming hydrogen so it can be moved safely and cost-effectively to where it's needed. Handling hydrogen is not easy. Research into hydrogen is all about how to isolate it, compress it, store it, use it and move it.

Hydrogen is a gas that liquefies at -253°C, just above "absolute zero" (-273°C), which is the lowest temperature possible in the universe. This is extreme. It is much less dense than air (0.09 kg/m^3 compared to 1.13 kg/m^3). Compressing hydrogen, let alone liquefying it, requires enormous amounts of energy. By comparison, natural gas can be liquefied at -160°C for shipping overseas.

The attraction of hydrogen as a fuel is it has formidable energy density by weight: three times more energy per kilogram than petrol, but conversely it has a third as much energy per litre. Cost effective storing of pure hydrogen is technically challenging and energy intensive. This is important, because the primary role of hydrogen in a zero-emissions energy system is as a form of energy storage. It's a puzzle. Hydrogen is made up of big opportunities but even bigger barriers.

Hydrogen in the 20th century

Hydrogen was used to perform five important (and notorious) tasks in the 20th century:

1. as the main fuel in town gas (reticulated gas that preceded natural gas)
2. as a lifting gas used in airships (most famously the Hindenburg)
3. as the primary source of fuel in rocket science (including the Apollo program)
4. extracting sulphur and hydrocracking low grade hydrocarbons in the oil industry, and
5. as a feedstock in industrial ammonia production to make fertilisers.

These hydrogen production processes are insightful: town gas was made by heating coal without oxygen and the resultant mixture of hydrogen, carbon monoxide and methane was pumped directly into the gas reticulation system. The presence of carbon monoxide resulted in accidental poisoning. Hydrogen for airships was produced by a range of chemical processes and the gas was injected directly into the airship. Hydrogen used in making ammonia is reformed from natural gas via steam reforming and then injected direct into the ammonia production process (known as the Haber-Bosch process). The first liquid hydrogen production for US space exploration was expensive, costing around USD$30/kg.

The common feature of 20th century industrial and commercial hydrogen was that it was made and used simultaneously. The only exception was the highly specialised (and expensive) applications used in rocket science where hydrogen was stored in cryogenic tanks for use as rocket fuel.

All 20th century hydrogen was a derivative of fossil fuels: it was produced by reforming hydrocarbons, typically natural gas. This process produced carbon dioxide (the major greenhouse gas) as a by-product. The 21st century hydrogen challenge is to produce low-cost hydrogen at scale without these emissions.

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Making hydrogen

There are several methods or potential methods for making hydrogen, denoted by different colours. From Australia's perspective, there are three colours that are most relevant:

Grey hydrogen: produced from reforming fossil fuels like oil and gas, accounting for 98 per cent of current global hydrogen production, but the process produces significant greenhouse emissions.

Blue hydrogen: where hydrogen is split from methane (natural gas) most commonly using steam methane reforming, and the carbon dioxide produced is captured and sequestered. This requires access to cost effective carbon sequestration, which remains challenging.

Green hydrogen: is hydrogen made from the electrolysis of water, powered by clean energy sources. It is technically possible to make green hydrogen today, but the cost remains commercially prohibitive. Most research is focussed on reducing this cost to a target cost of around $2/kg.

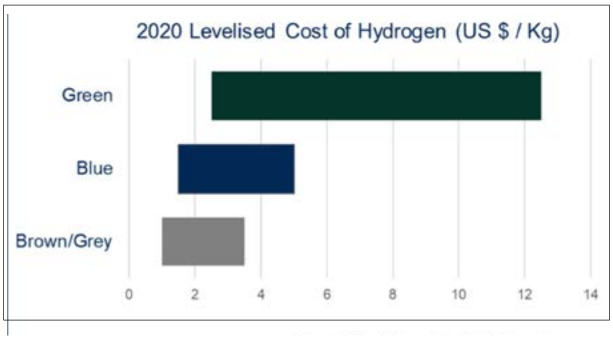
The clean technology focus is on development of blue and green hydrogen technologies.

Blue Hydrogen

Oil and gas companies like Shell and Woodside are keen to develop blue hydrogen technologies and utilise their own expertise and existing hydrocarbon resources. Three technologies are used to separate the hydrogen from the carbon in methane: steam methane reforming, autothermal reforming and gas partial oxidisation. The most cost-effective, steam methane reforming, is claimed to cost as little as USD$1/kg (A$1.50), assuming the cost of the methane feedstock is in the order of USD$5/GJ (A$7.50). The cost of sequestration is in addition to this, and only where it is geologically available.

Blue hydrogen is promoted by the gas industry as a more market ready advanced and lower cost source of clean hydrogen. The blue hydrogen market was more than USD$1 billion in 2021 and some analysts predict it will

Figure 1 *Levelized cost of hydrogen, $USD/kg 2020*



Source: GaffneyCline analysis of market consensus range

more than triple by 2030. Sequestration is a proven but expensive technology that consumes large amounts of energy in the extraction, compression and pumping of the carbon dioxide.

Analysts Gaffney Cline estimate the current cost of grey hydrogen (in the absence of a price on carbon) is around USD$1-2.50/kg, compared to USD$3-4/kg for blue hydrogen and USD$4-12/kg for green hydrogen.

Certification

There is an expectation that some customers will want – or need for regulatory purposes – to know the source or "colour" of their hydrogen, to understand its underlying emissions. To this end, several countries have begun developing a Guarantee of Origin (GO) scheme that will certify the source of hydrogen from their country. It will function in a similar way to renewable energy certificates (REC), although it is not directly associated with a compliance scheme like RECs are. International harmonisation of standards of certification will be important as a hydrogen export sector develops.

The Australian Government is developing a GO scheme for locally produced hydrogen. Following consultation, the Clean Energy Regulator (CER) has been chosen and funded to run the trials of a hydrogen GO scheme.

Green hydrogen

Green hydrogen is produced from the electrolysis of water using zero emissions electricity. This includes renewables, hydro and nuclear[1]. The green hydrogen electrolysis/production process has the potential to complement large scale intermittent renewable generation by converting surplus renewable electricity into hydrogen. This hydrogen could then be stored and used later as a source

1 Sometimes called "pink" hydrogen

of dispatchable clean electricity when solar and wind generation is insufficient to meet demand.

There are now five types of electrolyser currently under development in green hydrogen technology:

1. Alkaline electrolysers – mature technology, uses an electrolyte solution
2. Polymer electrolyte membranes (PEM) – commercial scale, uses membranes, high pressure, most advanced currently available
3. Anion Exchange Membrane (AEM) – lab scale, could be more efficient than PEM
4. Solid oxide electrolysers (SOEC) – lab scale, very high temperature, could be more efficient than PEM
5. Capillary-fed electrolysis cell – a new type of electrolyser developed at the University of Wollongong with ARENA funding, and now backed by hydrogen technology company Hysata.

The technologies have different cost and efficiency advantages in converting electricity to hydrogen, capturing the hydrogen and in the cost of building and operating the plant. These are some of the critical factors in reducing the final cost of green hydrogen production.

In total there are four critical factors that determine the production cost of green hydrogen:

1. The capital cost of the electrolysis technology (measured in $ per KW of capacity) – currently between $714 and $2571/kW.
2. The cost of green electricity (measured in $ per KWh). A dedicated renewables facility could deliver electricity in for around $0.041 to $0.06/kWh. One opportunity frequently cited is for electrolysers to connect to a grid such as the NEM and to run only when the electricity is very cheap or even negatively priced. This will affect its capacity factor (see below).
3. The conversion efficiency of electrolysis (measured in KWh needed to make 1 kg of H2 or as a percentage of the maximum heating value of hydrogen which is 142 MJ/kg which is equal to 39.4 kWh/kg). The IEA estimate a conversion efficiency of around 62 kWh/kg or 64 per cent.
4. The capacity factor (measured as a percentage of time the electrolysis equipment is operating) – depends on the renewables sourced. A standalone project based on either wind or solar would typically have a 20 to 40 per cent capacity factor, depending on the quality of resource. Most such projects, at least in Australia, are targeting combined wind/solar installations, so are likely to be targeting higher utilisation. Those electrolysers with access to hydropower resources to firm wind/solar may be targeting much higher capacity factors.

A grid connected electrolyser could run on 24/7, but it would typically incur some scope 2 emissions (i.e., the electricity powering it would not be carbon-free). This may be a plausible way of getting hydrogen costs down in the short to medium term. An alternative strategy might be to target low and negative wholesale prices, but this would mean operating at a much lower capacity factor.

The subject of the actual versus potential costs of hydrogen production remains highly speculative, and estimates vary for current costs let alone future costs. The Australian Renewable Energy Agency has estimated the potential cost of hydrogen to be $18.70/kg, falling to $11.30/kg if batteries were integrated in the process. The new Hysata electrolyser design is claimed to operate at a much higher efficiency than other technologies (98 per cent compared to 64 per cent). If replicable at scale, then this offers scope for lower costs.

Analysis prepared for the International Council on Clean Transportation estimated the current and future cost of hydrogen production ranged from between $10/kg and $32/kg now and $7/kg to $19/kg by 2050[2].

The International Renewable Energy Agency (IRENA) produced a report in 2020 suggesting the cost to make green hydrogen could be between $4.50 and $9/kg[3] right now but these costs could fall further. The International Energy Agency has also assessed the costs for production of green hydrogen.

2 Converted from US$ at current exchange rates and rounded to nearest $ for comparison with ARENA figures
3 Converted from US$ at current exchange rates

Scale up

While there is growing output and increased funding for development of green hydrogen, there remains a wide range in the forecasting of future costs and time frames for commercialisation of different technologies. This scale of uncertainty is consistent with immature technologies.

The scale of global hydrogen electrolysis and production growth is currently only a few megawatts of capacity each year, but the IEA are predicting global electrolysis capacity could be increasing by 1500MW a year by 2023, and global demand for blue/green hydrogen could reach 8 million tonnes a year by 2030. In 2019 the Australian Renewable Energy Agency announced a $70 million Renewable Hydrogen Development Funding Round with seven (mostly 10MW electrolyser) projects shortlisted and the successful projects announced in 2021. There are reportedly 69,000MW of hydrogen electrolyser projects proposed in Australia alone. Proposed does not mean delivered.

The largest electrolyser in the world was commissioned in January in Canada by Air Liquide. The 20MW PEM electrolyser will run continuously using hydroelectricity to produce green hydrogen. The choice of hydro to power the facility is to reduce cost and increase output, but is not a practical example of how hydrogen would complement intermittent renewables.

The largest electrolyser in Australia is currently a 1.25MW PEM electrolyser built by Siemens and installed by the Australian Gas Infrastructure Group (AGIG) in the Hydrogen Park in Adelaide. It is a high-cost, demonstration project to blend 5 per cent of hydrogen gas into the local natural gas network. Fortescue Future Industries has commenced construction of a 2GW electrolyser factory in Queensland.

Using hydrogen

Hydrogen burns differently to methane (natural gas), providing an immediate release of energy, like an explosion, which poses safety and engineering challenges, particularly when using high concentrations of hydrogen. Some engineers believe this makes it difficult to use hydrogen above around 25 per cent blend with methane by volume without changing the equipment it will be combusted in (power station turbines, cookers etc). Because of its lower density, this means hydrogen can only contribute about 8 per cent of the energy in a blended system. Hydrogen is highly sensitive to any sort of spark and will combust almost immediately.

Hydrogen is also about three times less energy-dense than methane. That means that as the ratio of hydrogen rises, the volume of energy being delivered through the same pipelines decreases. Prolonged hydrogen contact with metals makes them brittle. Some pipeline systems will thus not be suitable for transporting hydrogen and other equipment may need to be upgraded or replaced if hydrogen is used at high concentrations.

Hydrogen combusts at a similar temperature to methane (natural gas), but only produces water as a by-product. Hydrogen can therefore be used as a substitute for gas in industrial applications like electricity generation, high temperature kilns (cement, brick), industrial ovens and other high temperature applications. It may also be able to replace coking coal as the reductant in steel making. The technologies required to utilise hydrogen in these applications are still immature. It is not as simple as just fuel-switching from gas to hydrogen, given the different properties of the two gases.

Hydrogen fuel burns with a higher flame temperature than methane, increasing emissions of poisonous nitrous oxide (NOx) emissions. It releases energy more suddenly (explosively) and will ignite with almost any spark. Hydrogen is corrosive when it is put in prolonged exposure to metals.

Electricity generation

A small but growing number of energy utilities, governments and entrepreneurs have been proposing incorporating hydrogen as a fuel into new or existing gas power stations. These include:

1. In 2018 Swedish government owned utility Vattenfall proposed to convert one of the three 440MW combined cycle gas turbines at its Magnum power station in the Netherlands by 2023. Mitsubishi Hitachi Power systems would provide the turbine conversion technology.

2. A "letter of intent" has been signed by Vattenfall, Mitsubishi, Shell and the Port of Hamburg to build a 100MW electrolyser on a former coal fired power station site.

3. ENGIE and INEOS Phenol are looking to develop a commercial scale gas-hydrogen cogeneration plant (using 10 per cent blend of hydrogen) in Doel, Belgium.

4. Plug Power has plans to build a 125MW electrolyser to co-power a 450MW gas power station in New York state.

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5. US energy company Black and Veatch claim to be retrofitting a 485MW CCGT gas power station at Long Ridge in Ohio to run on a gas-hydrogen blend by the end of 2021.
6. Mitsubishi Hitachi Power Systems will build hybrid gas-hydrogen turbines for the Intermountain Power Project in Utah, with plans to be on-line by 2025.
7. Danskammer Energy is proposing to upgrade an existing New York State power station into a 535 gas and hydrogen hybrid.
8. In Australia resources company Fortescue has raised the possibility of building a gas-hydrogen turbine at Port Kembla.

The South Australian Government has a "Hydrogen Jobs Plan" which includes 250MW of hydrogen electrolysers to fuel a 200MW hydrogen power station, supported by 3600 tonnes of liquefied hydrogen storage (there is no consideration of the need to build a hydrogen liquefier in the plan). It has now called for design and delivery concepts.

While hydrogen generation projects have been proposed since 2018, they have so far tended to stall between announcement and delivery. This may be due to commercial and technical differences between announcing hydrogen projects and delivering them.

Solutions to these technical challenges are being explored by world leading industrial technology development companies like Siemens, GE, Wartsila and Mitsubishi. They are competing to deliver world leading hydrogen technology to governments and energy companies, although their public comments on the cost and readiness of hydrogen generation vary significantly.

According to the European Turbine Network, no commercial scale turbine currently exists that can burn pure hydrogen. Siemens CEO Christian Bruch believes hydrogen will not be commercially viable before 2025 at the earliest, possibly not even until the next decade.

While Wartsila Energy is exploring how to build pure hydrogen power stations, they have said it cannot use conventional gas power turbine technology with more than 25 per cent hydrogen. GE claims it has been successfully blending more than 70 per cent hydrogen into a gas turbine in Spain and that hydrogen is market ready.

An alternative to combustion is a hydrogen fuel cell. This is effectively reverse electrolysis, using hydrogen and oxygen as inputs and producing water and electricity as outputs. Fuel cells have found a few niche uses in vehicles, for example, and are in principle more efficient than combustion turbines. The challenges to more widespread use of fuel cells will be bringing costs down and scaling up to utility scale if they are to play a role in the electricity sector. There are a few megawatt scale fuel cells in the US but these run on methane.

Green steel

The production of steel from iron ore currently requires coking coal as a key ingredient: it acts as a reducing agent (removes the oxygen from iron ore or iron oxide), as a source of carbon for the final steel product (steel is an alloy of iron and carbon) and to provide heat for these processes. The combustion of coal in blast furnaces is a major source of greenhouse emissions. Hydrogen can replace two of these three roles: as a reductant and to provide heat.

The process of replacing coal with hydrogen is under early development in Europe. A Swedish steel and energy conglomerate H2 Green Steel has announced plans to develop a pilot hydrogen fuelled steel milling in northern Sweden, using hydroelectricity to produce the hydrogen, with production scheduled to commence in 2024. Germany's largest steelmaker Thyssenkrupp has announced plans to build its first hydrogen fuelled pilot steel mill in Duisburg by 2025. As with electricity production, lowering the cost of green hydrogen production will be critical to the commercial viability of green steel.

Hydrogen for other industrial uses

The potential application of hydrogen in other industries is less developed than for energy and steel. Cement manufacture, like steel, produces greenhouse emissions both in the chemical reaction to make clinker – where limestone is converted to lime producing carbon dioxide. It also produces emissions from the use of fossil fuels to heat its kilns. Cement companies are exploring the feasibility of using hydrogen as a partial substitute for gas in firing cement kilns. Current thinking is that new chemistry for the cement making process will be required to fully decarbonise cement production.

Rio Tinto is investigating the use of hydrogen in place of natural gas in calcination, a key step in the alumina refining process. Given Australia is a major alumina producer, a successful outcome would greatly assist with emissions reduction.

Dutch food company AMF has claimed to have developed the world's first hydrogen fuelled tunnel oven for industrial food manufacture.

Transport

The use of hydrogen as a transport fuel was briefly covered in another paper in this series: Decarbonising Transport. There are trials of hydrogen powered fuel cells for almost all modes of transport, including cars, buses, trucks, ships and even planes, but it appears that electrification will prove superior to hydrogen for small vehicles, so the more likely use cases is for large trucks and potentially shipping.

Storing hydrogen

While there has been significant attention paid to the methods and cost of producing zero emissions hydrogen, there has been less discussion around cost effective methods of storing it. Storage of hydrogen is critical given it will be needed to fuel dispatchable electricity generators and large industrial processes that will need to operate continuously.

Hydrogen requires significant amounts of energy to compress and its small size makes it capable of escaping more easily through containers than many other substances. The very cold temperatures needed to keep in liquified can make containment metals brittle. It requires special engineering to compress and hold hydrogen at scale.

The National Hydrogen Roadmap identifies three different types of hydrogen storage:

1. Compression: low pressure tanks, pressurised tanks, underground storage and line packing in gas pipelines.
2. Liquefaction: Cryogenic tanks and cryo-compressed.
3. Material based: converting hydrogen to other materials, such as ammonia.

The roadmap claims storage is expected to add $0.3/kg to the cost of hydrogen, with liquefaction adding an additional $1.59-$1.94/kg and ammonia synthesis adding $1.10 to $1.31/kg. These more expensive types remain under consideration because they may facilitate the transport of hydrogen (see below).

There does not yet appear a global consensus on the most efficient and cost-effective hydrogen storage methods. The US Energy Storage Association observes that small amounts of hydrogen (a few MWh) can be stored in pressurised tanks, while they think the best option for much larger volumes is in large underground salt caverns with pressures around 2900PSI (200 BAR).

Potential locations for such salt caverns in Australia are mostly located in remote regions like the Pilbara and southwestern Queensland. No exploration licences have yet been issued to develop them, let alone exploratory work done on the cost and feasibility of such facilities. European researchers have identified up to 85 PWh worth of hydrogen storage in salt caverns. The HyStorIES project has been funded by the EU to explore hydrogen storage beyond salt caverns because of the geographical and economic constraints this imposes.

While in opposition, the SA government announced plans to store 3,600 tonnes of liquefied hydrogen in tanks costed at only $31 million. The biggest cost in storing liquefied hydrogen is likely to be in the liquefaction process itself: according to the US Department of Energy a 200 tonnes/day hydrogen liquefier would cost around USD$500 million – more than the hydrogen storage tanks or the electrolyser.

At achievable, cost-effective storage densities of 100 bar in aboveground vessels at 20 degrees Celsius, the density of hydrogen is 7.8kg/m3. This low density requires large volumes of storage tanks. So, the storage per tank is cheaper, but the number will need to be greater, which will increase costs. All methods to store hydrogen will require some sort of compression, and this will require some input of energy. The more compression, the more energy, the more cost.

Despite the accelerating list of hydrogen-fuelled electricity generation, technical research on hydrogen storage is less developed. Hydrogen storage requires the removal of residual oxygen, drying and compression, yet there is little technical information available on the steps of hydrogen conditioning.

It is also possible to store hydrogen in fuel cells, which were pioneered to power the command modules in the Apollo program. Fuel cells work like a rechargeable battery, charging and discharging electricity by converting water into hydrogen and oxygen (charging) and then releasing energy by recombining the hydrogen with oxygen.

Transporting hydrogen

Of all the four "tasks" of developing a hydrogen economy, the process of moving hydrogen at scale may be the most challenging. Like other technical discussions, the debate around how to move hydrogen is evolving. Proponents suggest transport of hydrogen by pipeline, by cryogenic storage or by converting hydrogen into other more easily movable substances including ammonia or radical new pastes.

Hydrogen can be transported in pipelines in the same way natural gas is currently moved. The Hyblend project by the US National Renewable Energy Laboratory (NREL) is exploring the technical challenges in blending hydrogen in natural gas pipelines.

Pipeline transmission of hydrogen is possible, but will require investment in specific infrastructure that uses polymers rather than steel, which are more resistant to the evasive nature of hydrogen atoms and their corrosive impacts on metals.

Cryogenic storage and transport is, to date, used mainly in rocket science where the high cost of storage is reflected in the high value of its use. The Hydrogen Energy Supply Chain (HESC) project in Victoria's Latrobe Valley has been exploring liquefying and shipping hydrogen to Japan.

Converting hydrogen into ammonia as a hydrogen carrier is being explored as a way of reducing the extreme physical properties of hydrogen. The cost of this is estimated in the National Hydrogen roadmap of $1.10-$1.33/kg. Lower liquefaction temperatures make it cheaper and easier to move ammonia than hydrogen. Ammonia could then be used itself as a future fuel.

The potential future of hydrogen in Australia

Discussion around the potential for green hydrogen has been accompanied by different modelling and scenario planning to consider what the energy future might look like under different conditions, and what role hydrogen may play.

AEMO has developed five scenarios that form the basis for its Integrated System Planning (ISP) and Electricity Statement of Opportunities. These were designed to reflect the range of possible future energy pathways. They are:

1. Slow change: slow economic recovery, load closures and continued PV uptake
2. Steady progress: future abatement framed by existing government and corporate commitments
3. Net zero 2050: Action through technology advancements, particularly industrial electrification
4. Step change: consumer led focus on energy efficiency and DER
5. Hydrogen superpower: Economy and technology led transformation with Australia exporting hydrogen

Under these scenarios, domestic consumption of hydrogen ranges from zero to 64 TWh by 2040. The increased electrification of the economy would increase underlying demand in the National Electricity Market from 200 TWh today to between 184 and 329 TWh by 2040.

The Hydrogen Superpower scenario is estimated to require an additional 221 TWh by 2040.

The AEMO analysis assumes that both domestic and export hydrogen is fuelled, at least in part, by NEM connected electrolysis powered by significant increases in renewable generation. In 2020/21 wind and all solar PV generated 43.4 TWh of electricity. So, under the most aggressive scenario the level of renewables needed to make hydrogen for the domestic economy would need to increase by about 50 per cent by 2040 and by about 500 per cent to power the export hydrogen market. This assumes almost 100 per cent electrolyser efficiency.

In this aggressive Hydrogen Superpower scenario, renewable generation would need to increase more than ten times its current size to supply domestic and hydrogen export needs. Of course, this is only one scenario.

In its hydrogen demand growth scenario analysis, Deloitte developed four scenarios from business as usual to hydrogen as the energy vector of the future. Under the most aggressive scenario it projected the Australian hydrogen market could reach around 2.5 million tonnes (83 TWh) by 2035, scaling up to 6 million tonnes (200 TWh) by 2040.

Hydrogen could be used in a future decarbonised economy to provide a replacement clean fuel for a wide range of industrial activities: dispatchable generation in the electricity sector, as an export fuel, as a fuel for transport from light to heavy vehicles including mining trucks, heavy rail, ferries, remote power, alumina calcining, steel milling and ammonia production.

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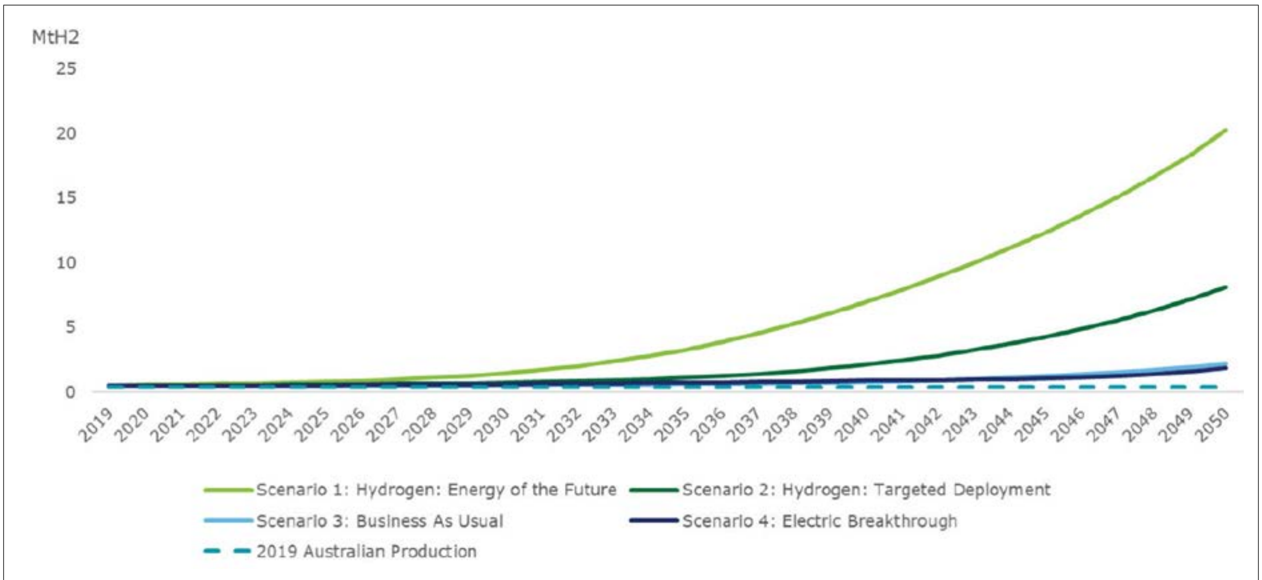
Figure 2 *AEMO scenario comparison, 2040*

	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
DEMAND					
Electrification					
- % of road transport that is EV by 2040	22%	44%	52%	58%	76%
- % of residential EVs still relying on convenience charging by 2040	68%	61%	57%	47%	40%
- Industrial electrification by 2040	-25 TWh	8 TWh	32 TWh	45 TWh	66 TWh
- Residential electrification by 2040	0 TWh	0 TWh	6 TWh	9 TWh	10 TWh
Energy efficiency savings by 2040	16 TWh	25 TWh	30 TWh	44 TWh	44 TWh
Underlying Consumption					
- NEM underlying consumption by 2040	184 TWh	245 TWh	276 TWh	279 TWh	329 TWh
- H2 consumption (domestic), 2040	0 TWh	0 TWh	2 TWh	15 TWh	64 TWh
- H2 consumption (export), including green steel, 2040	0 TWh	0 TWh	0 TWh	0 TWh	221 TWh
- Total underlying consumption by 2040	**184 TWh**	**245 TWh**	**278 TWh**	**294 TWh**	**614 TWh**
SUPPLY					
Distributed PV Generation	47 TWh	51 TWh	61 TWh	66 TWh	83 TWh
% of household daily consumption potential stored in batteries	4%	12%	17%	32%	35%
% of underlying consumption met by DER by 2040	26%	21%	22%	22%	13%
Estimate of % coal in generation mix by 2040	50%	20-25%	15-20%	5%	0%
Estimate of NEM emissions production by 2040 (MT CO2-e)	TBD	TBD	55 (~40% of 2020 NEM emissions)	10 (~7% of 2020 NEM emissions)	1 (~1% of 2020 NEM emissions)

Source: AEMO

Among the least likely outcomes is a wholesale switch from natural gas to hydrogen for small users. This would require a choreographed changeover of millions of appliances as well as significant expenditure to ensure the reticulated distribution networks are fit-for-purpose for pure hydrogen transport. Electrification remains the most likely approach for small users with the potential for some sub-networks to deliver biomethane if sufficient feedstocks can be obtained.

Figure 3 *Forecasted hydrogen production from Australia*



Source: Deloitte

Centralised vs decentralised hydrogen

The location and integration of future hydrogen production and storage is likely to be influenced by the future costs of different parts of the hydrogen supply chain and the stability and capacity of a high renewables electricity market. The option of centralised versus decentralised hydrogen production is discussed in the CEFC's Australian Hydrogen Market Study.

The challenges of storing and moving hydrogen mitigate in favour of a decentralised approach to hydrogen production, where facilities are located as close as possible to the end user (steel mill, port, power station) so that these costs are minimised. This requires a proximate supply of sufficient fresh water (9 litres per kilogram of hydrogen) and sufficient transmission infrastructure to move the electrons to the electrolysers.

A decentralised approach sees hydrogen electrolysers co-located with key inputs like water and then the hydrogen is piped to consumers, like the current gas pipeline network. This would require low transport costs and possibly geographic advantages (like water access or underground storage capacity) that make this more cost effective.

If hydrogen technologies enable large scale exports in the future, it is possible some if not most of these may not be located inside the current electricity grids (like the NEM and the WEM), optimising very low-cost high-capacity renewables in places like northern Western Australia to produce hydrogen solely for export. This could depend upon getting electrolyser costs low enough so that utilisation rates could be lower and the cost of the hydrogen produced still cost effective.

It may also be possible that evolving to high renewables electricity grids requires at least some of this export capacity to be co-located to domestic generators, to provide additional storage and energy to augment increased electricity supply during periods of sustained low renewable output. Such events would be temporary, and may delay export supply. It is likely to be politically challenging for future governments if Australia has a domestic energy crisis while at the same time Australian hydrogen exporters are supplying abundant surplus energy to other countries.

Domestic Hydrogen Policy

There have been several hydrogen related government announcements in recent years: a national hydrogen strategy was released in 2019. There is a South Australian Hydrogen Action Plan and a Tasmanian Action Plan. Hydrogen is part of the NSW Government's Net Zero Plan, while Victoria has a Hydrogen Investment Plan. Queensland has a Hydrogen Taskforce and Western Australia has a Renewable Hydrogen Strategy and Roadmap. The CSIRO has produced a National Hydrogen Roadmap. The Australian Renewable Energy Agency has produced a report on the opportunities for Australia from hydrogen exports. The Grattan Institute has proposed that green hydrogen be used to revive the Australian steel industry.

Australia has signed a letter of intent to develop a Hydrogen Action Plan with Korea, a Joint Statement on Cooperation with Japan, has become a member of the US Centre for Hydrogen Safety and is working with Singapore and Germany.

In April 2021 the Federal Government announced a further $539 million for "clean hydrogen" and CCS projects.

Currently there is an ad hoc network of funding and support for development of technologies in the hydrogen supply chain provided by state and national agencies. There is also aggressive hydrogen technology development around the world.

Australia may have a comparative advantage through its ability to scale up low-cost, large-scale renewables, which could lead it to developing an export industry in hydrogen production or in low carbon products produced with hydrogen. Australia's policy focus should therefore prioritise learning by doing – e.g. supporting pilot trials of hydrogen technologies.

Governments have shown interest in setting jurisdictional clean hydrogen targets (like the renewable energy target). A HET, like the RET, would create an early demand for pilot hydrogen. A key concern about such an approach, however, is that it results in current natural gas users cross-subsidising the development of an industry that they may not be the long-term beneficiaries of (given the challenges of converting reticulated networks and end user appliances to full hydrogen consumption).

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Summary

There is understandable global interest in the potential for hydrogen fuel technologies to provide a cost effective, clean energy storage solution and a new global energy vector. Genuine progress on hydrogen technologies is being made, but there is still uncertainty in key parts of the hydrogen supply chain over optimal technology (for electrolysers), costs and applications. These uncertainties are symptomatic of an immature technology development process and hydrogen does not appear to be anywhere near market-ready yet.

There is still a lot of work to do to realise the enormous opportunity of hydrogen as a large-scale clean energy vector for the 21st century.

APPENDIX 1: FURTHER READING

The National Hydrogen Roadmap, CSIRO

Australia's National Hydrogen Strategy, COAG Energy Council

South Australia's Hydrogen Action Plan

Victorian Hydrogen Investment Program

Queensland Hydrogen Taskforce

Tasmanian Renewable Hydrogen Action Plan

Western Australian Renewable Hydrogen Strategy and Roadmap

Opportunities for Australia from Hydrogen Exports, ARENA

Start with Steel: Grattan Institute

Australian and Global Hydrogen Demand Growth Scenario Analysis – COAG Energy Council

Australian Hydrogen Market Study – CEFC

2021 Inputs, Assumptions and Scenarios Report – AEMO

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