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National Hydrogen Roadmap

Pathways to an economically sustainable hydrogen industry in Australia

CITATION

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Acknowledgements

CSIRO acknowledges the Traditional Owners of the lands that we live and work on across Australia and pays its respect to Elders past and present. CSIRO recognises that Aboriginal and Torres Strait Islander peoples have made and will continue to make extraordinary contributions to all aspects of Australian life including culture, economy and science.

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We are grateful for the time and input of the stakeholders from industry, government, academia and the CSIRO who were consulted throughout this project. A full list of stakeholders consulted may be found in Appendix D.

* Engie exclusively supports the production of hydrogen via use of renewable energy

Foreword

CSIRO has long been a leader in solar and battery solutions for energy, recently deploying Australia's first large-scale, off-grid solar storage system, and using the UltraBattery to stabilise part of the US electricity grid in support of renewables. But despite these breakthroughs, Australia has yet to create our own solar or storage industry, relying instead on solutions from across the seas. There remain serious sustainability challenges to broad adoption of lithium batteries. Hydrogen offers a new, sustainable energy storage and transport future.

As Australia transitions to a low-emissions energy future, there is vast potential for a new industry in hydrogen, building on our national technological advantages, export capabilities and strong relationships with key international energy markets. We have an opportunity to turn our significant natural resources, including coal, gas, and renewables like solar and wind energy, into a uniquely Australian low-emissions energy product and ship it around the world – in some cases literally exporting Aussie sunshine.

This National Hydrogen Roadmap provides a blueprint for the development of the hydrogen industry in Australia, by informing investment so the industry can scale in a coordinated manner. National leadership is critical to connect up key players and capabilities across the value chain, and as Australia's national science agency, CSIRO is partnering with key stakeholders to frame this dialogue and develop a path for hydrogen in Australia.

CSIRO has established a strong network of partners and collaborators that supports current, practical research and technology initiatives across the hydrogen energy value chain. We've already made early gains with partners in industry, government and the research sector, like developing an innovative membrane to separate hydrogen from ammonia for fuel cell vehicles. The membrane itself is another example of turning a commodity into a unique, higher value material to support jobs of the future. Moreover, easy conversion from gaseous hydrogen to liquid ammonia offers a simple storage and transport of safe, high energy density liquid fuel using existing global infrastructure. Liquid renewable fuel offers rapid refueling along existing paradigms versus slower electrical charging.

We're also investing in breakthroughs of the future through our Hydrogen Energy Systems Future Science Platform (FSP), de-risking new hydrogen technologies and supporting development of new energy markets including in chemicals and transportation sectors.

Continuous improvement in cost and performance of hydrogen-related technologies has accelerated over the past three years along the entire value chain. At the same time, commercial demand from nations such as Japan and South Korea is rapidly improving and will reach a tipping point in the next few years, unlocking growth and jobs for Australia. Nevertheless, obstacles need to be overcome before the full benefits of hydrogen can materialise. The Roadmap charts a course for navigating the critical partnerships and investment needed to seize this opportunity.

Bottling Australian sunshine to power Asia is an opportunity to build our next great export industry, lead global innovation, contribute to the global energy transition, and grow Australia's grid stability. We look forward to continuing to work with Australian and international partners to guide this burgeoning energy source, while enabling the transition to a lower emissions future that will benefit us all.

This all may seem like a bit of a moonshot, but CSIRO has been delivering the moonshots for 100 years, creating a better future for all Australians.

Dr Larry Marshall
Chief Executive
CSIRO

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Glossary

AE	Alkaline electrolyser
Anode	A positively charge electrode
ARENA	Australian Renewable Energy Agency
AUD	Australian dollar
BEV	Battery electric vehicle
BoP	Balance of Plant
C&I	Commercial and Industrial
Cathode	A negatively charge electrode
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CEFC	Clean Energy Finance Corporation
CO_2	Carbon dioxide
CRI	Commercial readiness index
CST	Concentrated solar thermal
Current density	The flow of electrical charge higher current densities mean smaller footprints
DBT	Dibenzyltoluene
DME	Dimethyl ether
Drop-in fuels	A synthetic fuel that is compatible and interchangeable with a conventional fuel, e.g. synthetic diesel
Electrochemical (hydrogen production)	Involves the use of an electrical current to split water into hydrogen and oxygen
EOR	Enhanced oil recovery
EPC	Engineering procurement construction contractors
FC	Fuel cell
FCEV	Fuel cell electric vehicle
FRP	Fibre reinforced plastic
H_2	Hydrogen gas
HESC	Hydrogen Energy Supply Chain Project in the Latrobe Valley
HHV	Higher heating value, the amount of heat released by a specified quantity of product that takes into account latent heat of vaporisation of water
HRS	Hydrogen refuelling station
HVDC	High voltage direct current
Hydrail	Hydrogen fuel cell powered trains

ICE	Internal combustion engine
IEC	International Electrotechnical Commission
IGCC	Integrated gasification combined cycle
ISO	International Organisation for Standardization
JV	Joint Venture
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LCOT	Levelised cost of transport
LH_2	Liquid hydrogen
LHV	Lower heating value, the amount of heat released by a specified quantity of product where latent heat of vaporisation of water has been assumed not to have been recovered
LNG	Liquefied natural gas
MCC	Moreland city council
MCH	Methylcyclohexane
NOx	Nitrogen oxides, polluting emissions that can cause acid rain and smog
NREL	US National Renewable Energy Laboratory
O_2	Oxygen gas
OEM	Original equipment manufacturer
PHES	Pumped hydro energy storage
PPA	Power purchase agreement
Prosumer	Customer who consumes and produces hydrogen or electricity
PSA	Pressure swing adsorption,
PV	Photovoltaics
R&D	Research and development
RAPS	Remote area power systems, e.g. diesel generators
RD&D	Research, development and demonstration
SOE	Solid oxide electrolyser
SUV	Sports utility vehicle
Syngas	A mixture of carbon monoxide and hydrogen
Synthetic fuels	Fuels derived from syngas
TCO	Total cost of ownership
TRL	Technology readiness level

UAV	Unmanned aerial vehicle
USD	US dollars
Virtual pipelines	Trucks that transport gas
Volumetric density	Mass per unit volume
VRE	Variable renewable energy

Volume

L	Litre
GL	Gigalitre (1,000,000,000 litres)
m^3	Cubic metres

Area

ha	Hectare (10,000m^2)

Distance

vkm	Vehicle kilometres
tkm	Travelled kilometres

Mass

kg	Kilograms
t	Tonne (1,000 kilograms)
kt	Kilotonne (1,000 tonnes)
Mt	Megatonne (1,000,000 tonnes)

Energy

J	Joule, basic measure of energy
MJ	Megajoule (1,000,000 Joules)
GJ	Gigajoule (1,000,000,000 Joules)
PJ	Petajoule (1,000,000,000,000,000 Joules)
kW	Kilowatt, (1,000 watts of electrical power)
MW	Megawatt (1,000,000 watts of electrical power)
kWh	Kilowatt hour, a kilowatt of power used in an hour (3.6MJ)
MWh	Megawatt hour, a megawatt of power used in an hour
MWth	Megawatt thermal, measures thermal power production

Pressure

Bar	Equal to 100 kilopascals (kPa) or 0.1 megapascals (MPa), about equal to atmospheric pressure on Earth at sea level, used to measure gas pressure

Executive summary

Introduction

WHY HYDROGEN?

Clean hydrogen is a versatile energy carrier and feedstock that can enable deep decarbonisation across the energy and industrial sectors.

Hydrogen gas ('hydrogen') is a versatile energy carrier and feedstock, derived primarily by splitting water or by reacting fossil fuels with steam or controlled amounts of oxygen. While hydrogen has served mostly as an input into a range of industrial processes, it has the potential to be used across a number of applications as shown below. Further, if produced using low or zero emissions sources, ('clean') hydrogen can enable deep decarbonisation across the energy and industrial sectors. Clean hydrogen is the focus of this report.

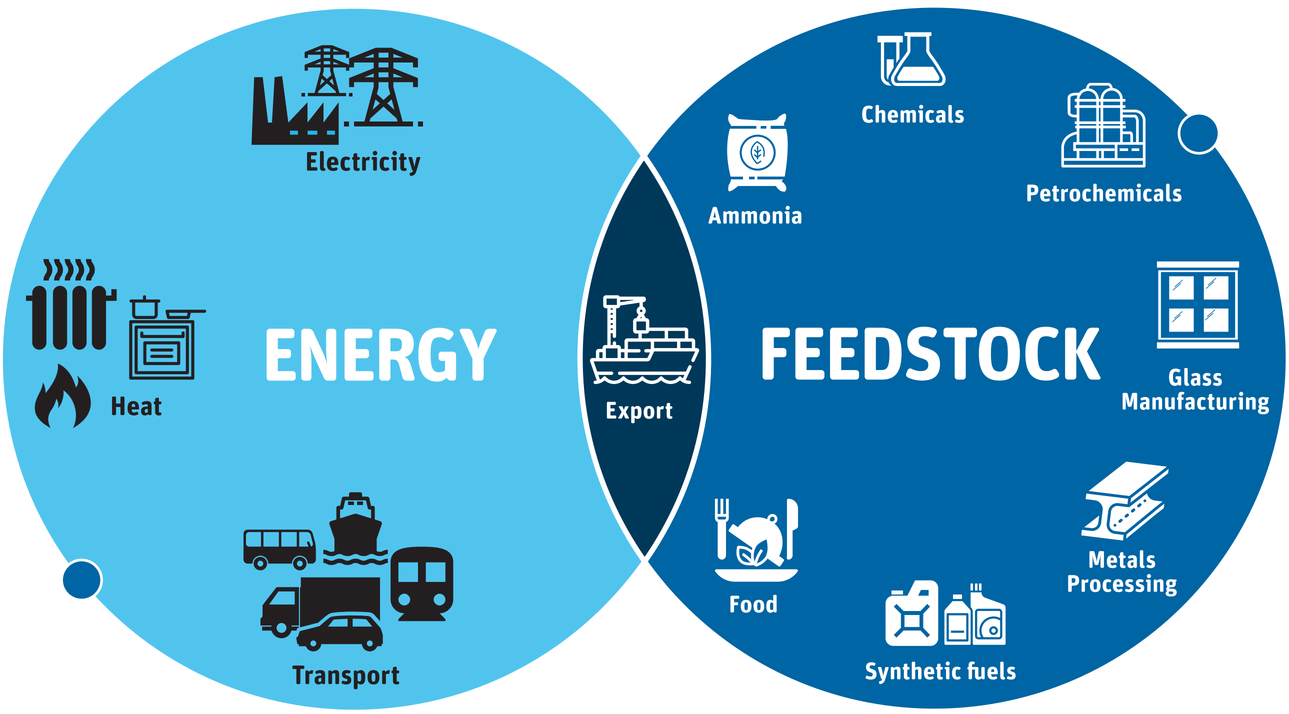
WHY AUSTRALIA?

Australia has the resources and skills to build an economically sustainable domestic and export hydrogen industry which can help meet agreed emissions targets and address concerns around energy security.

In 2016, Australia ratified the Paris Agreement, committing to achieve a 26-28% reduction in greenhouse gas emissions below 2005 levels by 2030. While use of hydrogen across the energy and industrial sectors is one of a suite of technology options that can play a role in helping Australia meet the prescribed decarbonisation targets, there are a number of other domestic trends and characteristics that favour its widespread use. These include:

- **Natural gas supply**: Particularly on the east coast of Australia, gas prices currently remain high ($8-10/GJ) compared to some overseas markets, with some uncertainty regarding future cost trajectories. Hydrogen could replace natural gas as a low emissions source of heat as well as a potentially cost competitive low emissions feedstock for a number of industrial processes.

APPLICATIONS FOR HYDROGEN



- **Changing electricity sector**: Hydrogen can help manage the transition to a higher proportion of variable renewable electricity (VRE) in the electricity network by overcoming challenges associated with energy intermittency. Hydrogen also offers an opportunity for optimisation of renewable energy use between the electricity, gas and transport sectors (i.e. 'sector coupling').
- **Liquid fuels security**: Australia has long been dependent on imported liquid fuels and at present, is not meeting domestic fuel reserve targets. Hydrogen can play a key role in protecting Australia from supply shocks by localising liquid fuel supplies (e.g. by producing synthetic fuels) or by displacing their use in both stationary and transport applications.
- **Skilled workforce**: Australia has a technically skilled workforce with deep expertise across the energy sector as well as in high value or advanced manufacturing production processes. There is a strong need for these skills across the hydrogen value chain and so this represents an opportunity to transition the workforce to a growth market.

In relation to export markets, Australia has a rich history of generating economic opportunities through export of its natural resources. Some of these markets, for example uranium, have suffered downturns as a consequence of a changing energy mix abroad. Others such as thermal coal, could be at risk in the future if global trends continue to lead towards a low carbon economy.

In contrast, the global market for hydrogen is expected to reach USD155 billion by 2022[1], with a number of Australia's existing trading partners such as Japan, who are comparatively resource constrained, currently implementing policy commitments for hydrogen imports and use. **Australia's extensive natural resources, namely solar, wind, fossil fuels and available land lend favourably to the establishment of hydrogen export supply chains.**

WHY NOW?

Globally, the hydrogen industry is underpinned by a series of mature technologies and relevant markets are on the verge of reaching a 'tipping point'.

While interest levels in the development of global hydrogen industries have fluctuated over recent decades, today there are a number of trends and activities that distinguish the renewed focus on hydrogen from what has been observed previously. This includes policy commitments from countries across Europe and Asia as well as increasing investment from multinational technology manufacturers and energy companies.

The primary difference however is that the hydrogen value chain is now underpinned by a series of mature technologies that are being demonstrated in pilot projects globally. Although there is considerable scope for further R&D, **this level of maturity has meant that the narrative has shifted from one of technology development to market activation**. This involves the transition from emerging technologies to bankable assets, similar to what has recently been observed in the solar PV industry.

This report

Recently there has been a considerable amount of work undertaken (both globally and domestically) that seeks to quantify the economic opportunities associated with hyrdogen. This report takes that analysis a step further by focussing on how those opportunities can be realised.

The primary objective of this report is to provide a blueprint for the development of a hydrogen industry in Australia (i.e. market activation). With a number of activities already underway, it is designed to help inform the next series of investment amongst various stakeholder groups (e.g. industry, government and research) so that the industry can continue to scale in a coordinated manner.

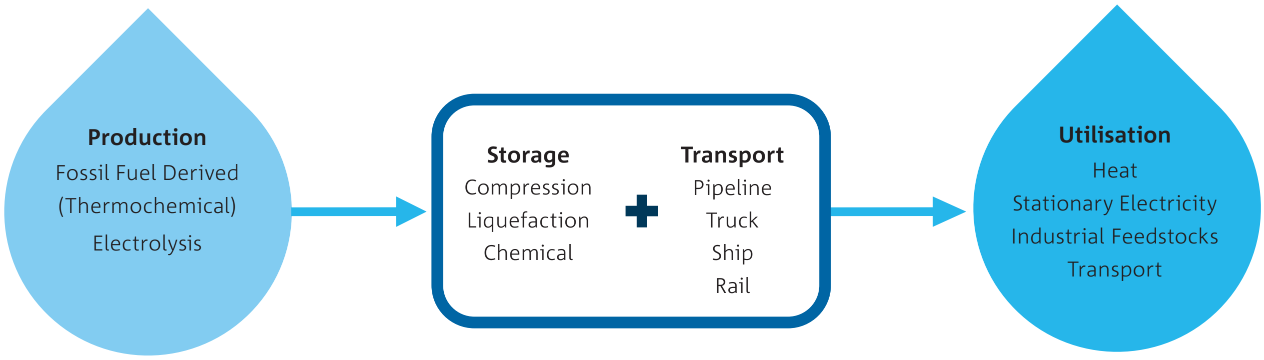
Development of a hydrogen industry

Barriers to market activation stem from a lack of supporting infrastructure and/or the cost of hydrogen supply. However, both barriers can be overcome via a series of strategic investments along the value chain from both the private and public sector.

1 International Energy Agency Hydrogen Technology Collaboration Program 2017, Global Trends and Outlook for Hydrogen

A snapshot of the underpinning hydrogen value chain is set out below.

Hydrogen value chain

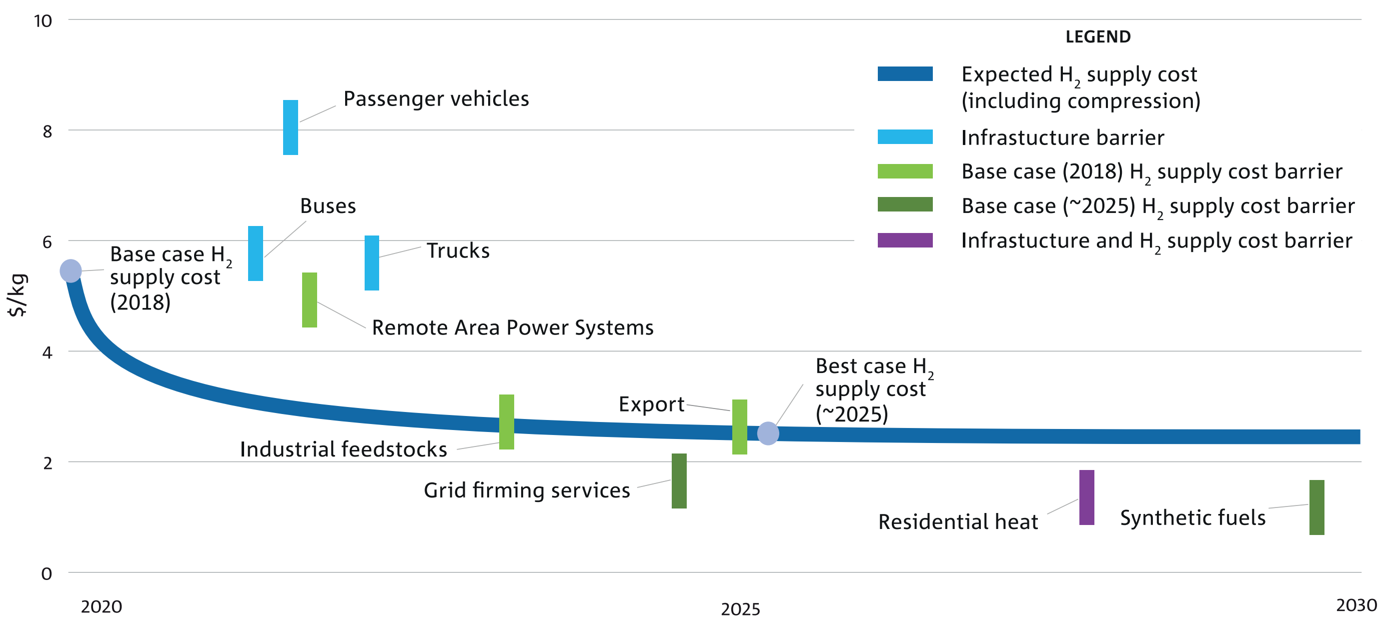


Barriers to market activation stem from a lack of infrastructure required to support each application and/or the cost of hydrogen supply when compared to other energy carriers (e.g. batteries) and feedstocks (e.g. natural gas). **It is expected however, that development of an appropriate policy framework could create a 'market pull' for hydrogen. Investment in infrastructure, hydrogen production, storage and transport is then likely to follow.**

Implementation of the key investment priorities identified through the report could see the hydrogen industry scale in a manner depicted in the figure below. This demonstrates the expected reductions in the cost of hydrogen supply and the progression of target markets based on when hydrogen could be **commercially competitive** with alternative technologies. It also identifies where the barrier to market is infrastructure (i.e. above the hydrogen cost curve) and/or the cost of hydrogen supply (i.e. below the hydrogen cost curve).

The competitiveness of hydrogen against other technologies is likely to then improve when considering factors such as localisation and automation of supply chains, energy supply and carbon risk as well as the establishment of a hydrogen export industry. Further, while each application has been assessed individually, a unique advantage of hydrogen is that it can simultaneously service multiple sources of demand. Thus in practice, a single hydrogen production plant could secure offtake agreements in a number of applications depending on available infrastructure, policy and demand profiles.

Hydrogen competitiveness in targeted applications



The following sections illustrate how each element of the hydrogen value chain can develop according to the above figure. Key investment priorities across the value chain are subsequently outlined in the 'summary of priorities' table.

Hydrogen production

Hydrogen may be produced via two mature pathways:

- **Thermochemical**: Uses a fossil fuel feedstock to produce hydrogen. This process must be paired with carbon capture and storage (CCS) to produce clean hydrogen. Mature technologies include steam methane reforming (SMR) which relies on natural gas as an input, and coal gasification
- **Electrochemical**: Involves the use of an electrical current to split water into hydrogen and oxygen. Requires the use of low or zero emissions electricity to produce clean hydrogen. Mature technologies include polymer electrolyte membrane (PEM) and alkaline electrolysis (AE)

THERMOCHEMICAL

Thermochemical hydrogen production must be built at scale (i.e. > 500,000kg/day) to offset the capital cost of the generation plant and accompanying CO_2 storage reservoir. While the industry is in a development phase, projects of this scale would very quickly saturate a domestic market and so rely on the development of a hydrogen export industry in order to secure the requisite offtake agreements.

Although SMR is currently the cheapest form of hydrogen generation, investment in new large scale demand may prove challenging given the current state of the natural gas industry in Australia (as discussed previously). Further, black coal gasification has challenges in an Australian context due to coal reserves being concentrated in NSW and Queensland where there are either no well-characterised, or only onshore CO_2 storage reservoirs that carry a higher social licence risk.

Hydrogen production via brown coal in Victoria's Latrobe Valley therefore represents the most likely thermochemical hydrogen production project. A prospective plant would have the advantage of an extensive brown coal reserve sitting alongside a well characterised CO_2 storage reservoir in the Gippsland Basin. This project is most likely to be commercialised via the proposed Hydrogen Energy Supply Chain (HESC).

Pending successful demonstration in 2020/2021 and subsequent improvements in efficiencies, hydrogen could be produced in the region for approximately $2.14 -2.74/kg[2] once the commercial scale production and CCS plant come online in the 2030s.

ELECTROCHEMICAL

Electrolysis provides a more modular, distributed option that can scale according to demand. It is therefore more likely to meet the majority of hydrogen demand prior to 2030 and the expected cost curve is reflected in the hydrogen competitiveness figure.

AE is currently the more established and cheaper technology (~$5.50/kg) and will therefore continue to play an important role in the development of the industry. Despite its level of maturity, incremental improvements in AE can still be achieved through subtle gains in efficiency.

Although currently more expensive, PEM electrolysis is fast becoming a more competitive form of hydrogen production. It also offers a number of other advantages over AE including faster response times (which makes it more suitable for coupling with VRE) and a smaller footprint for scenarios in which there are limitations on space (e.g. hydrogen refuelling stations). RD&D is expected to lead to improvements in PEM plant design and efficiencies. Increases in production economies of scale are also likely to reduce technology capital costs.

The cost of hydrogen from both types of electrolysis can be significantly reduced via the scaling of plant capacities (e.g. from 1MW to 100MW), greater utilisation and favourable contracts for low emissions electricity (e.g. 4c/kWh). With a number of demonstration projects likely over the next three to four years needed to de-risk these assets at scale, it is expected that costs could reach approximately $2.29-2.79/kg by 2025.

2 This modelling was undertaken by CSIRO and only contains information that has been made publically available by members of the HESC project

Storage and transport of hydrogen

Hydrogen storage technologies can be broadly classified as:

1. **Compression**: Gaseous hydrogen stored at higher pressures to increase volume. Includes large scale underground storage (e.g. salt caverns) and 'line packing' in gas pipelines
2. **Liquefaction**: Pressurising and cooling hydrogen to -253˚C so that it is in a liquid state
3. **Chemical**: Molecules such as ammonia, metal hydrides and toluene that carry hydrogen. All retain an additional energy penalty and cost associated with the recovery of hydrogen prior to use

STORAGE OF HYDROGEN

Storage of hydrogen represents a key component in hydrogen supply. Due to the low volumetric density of hydrogen in its gaseous state, a series of technologies may be utilised in order to improve the economics of storage (i.e. higher volumetric densities allow for greater quantities of hydrogen to be stored inside a tank of fixed size). Selection of the most appropriate storage technology represents a trade-off between the quantity of hydrogen, storage footprint (e.g. tank size) and energy usage.

Compression of gaseous hydrogen generally represents the most attractive option for stationary storage given the comparatively lower cost and greater availability of space. With likely improvements in compression efficiencies, storage of hydrogen is expected to add ˜$0.3/kg to the cost of hydrogen produced by 2025 (as reflected in the hydrogen competitiveness figure).

Other storage technologies including liquefaction and material carriers such as ammonia have a superior volumetric density but higher cost. These technologies therefore become more financially viable when storing (or transporting) larger quantities of hydrogen where there are stringent space limitations in place. With expected improvements, liquefaction is likely to add an additional $1.59-1.94/kg to the cost of hydrogen produced by 2025.

As an alternative, ammonia synthesis (via the traditional Haber-Bosch process) could add an additional $1.10-1.33/kg to the cost of hydrogen, albeit with ammonia as the product[3]. A direct comparison with liquefaction cannot be made at this stage given that there is an additional energy and capital cost associated with recovery of high purity hydrogen from the ammonia at the point of use. Relevant hydrogen separation technologies currently being developed represent a key piece in the supply chain but are not yet mature enough to gain a meaningful assessment of cost.

TRANSPORT OF HYDROGEN

Hydrogen can be transported via truck, rail, ship and pipeline utilising the storage techniques identified. Although not reflected in the hydrogen competitiveness figure due to variability, greater distances between the point of generation and use increases supply chain costs.

Coupling of storage and transport technologies typically requires consideration of a number of factors including hydrogen demand, available infrastructure and distance. While compression has been commonly used for trucks, liquefaction is now also increasingly utilised where distances approach 1000km.

For domestic use, pipelines are also important for transport of larger quantities of compressed gaseous hydrogen over long distances (i.e. transmission) as well as distribution to multiple points of use in a network (i.e. distribution).

As round trip distances (i.e. >4000km) and demand for hydrogen increase, technologies with greater hydrogen densities such as ammonia synthesis and liquefaction are likely to be preferred. These technologies are being developed further given their potential role in export of hydrogen via ship.

3 This refers to the cost of the hydrogen carried within the ammonia product rather than simply the cost of ammonia

Applications for hydrogen (utilisation)

HYDROGEN FUELLED TRANSPORT

Hydrogen fuelled transport represents an early target market in the development of a hydrogen industry. This is particularly true if there is a zero emissions or air quality target for the sector, given the applicability of hydrogen to all forms of transport.

In the passenger vehicle market, fuel cell electric vehicles (FCEV) represent a potentially more favourable option (compared with battery electric vehicles (BEVs)) for consumers that travel longer distances (i.e. 400-600km without refuelling) and expect shorter refuelling times. For heavier vehicles such as buses and trucks with stringent payloads, the relative weight of hydrogen (compared with batteries) also allows for greater distances travelled without the need for refuelling. The primary barriers to market however are the current capital cost of FCEVs and lack of infrastructure supporting their use.

While R&D into the improvement of FCEVs is ongoing, the most material reductions in capital costs will stem from economies of scale in manufacture and through dedicated and automated production lines. For the passenger vehicle market in particular, given that Australia currently comprises approximately 2% of the global market, it is expected that increases in scale will be dictated by consumer trends overseas. Globally, leading car manufacturers expect to reach requisite targets, allowing for mass market vehicle production by 2025. However, vehicle uptake will still need to be stimulated in Australia through the implementation of vehicle emissions standards and/or specific incentives.

The success of the FCEV market in Australia rests largely on the strategic deployment of hydrogen refuelling stations. Depending on the configuration, current costs range from USD1.5 to USD2.0 million per station. With an extensive deployment of refuelling stations ongoing in jurisdictions such as Germany, it is likely that there will be a shift away from ad hoc demonstrations to standard roll out of reliable equipment. This is expected to lead to a significant reduction in capital (i.e. USD0.5 to USD1.0 million) and operating costs by 2025.

Deployment of refuelling stations require a high degree of coordination between station operators and car manufacturers (i.e. to match hydrogen supply and demand). This has been achieved overseas through the use of joint ventures that are responsible for the roll out of a high volume of stations in a specified region (e.g. 100 stations in a 3-5 year period). Within these arrangements, there is also a key role for Government in underwriting initial demand risk and facilitating the development of relevant operating standards.

Australia has the benefit of rolling out station models that have already been developed overseas. If a series of demonstration projects were to be implemented in the next 5 years, these stations could be commonplace by 2025.

REMOTE AREA POWER SYSTEMS (RAPS)

Diesel based RAPS currently have a high cost due to the need to import fuel via truck to remote communities. These systems also have an adverse environmental impact.

With expected reductions in the cost of hydrogen and fuel cells (needed to generate electricity), hydrogen based RAPS (using dedicated renewable energy inputs) could be commercially competitive with diesel equivalents before 2025. Key targets for demonstration over the next three to four years should include smaller remote mining operations due to the ability for hydrogen to service multiple operations on a single site (e.g. materials handling, transport, heat and wastewater management).

INDUSTRIAL FEEDSTOCKS

Use of clean hydrogen as an industrial feedstock involves direct displacement of hydrogen derived from SMR as the incumbent source of production. The breakeven point will be driven by the price of natural gas against reductions in the cost of hydrogen via electrolysis. This is expected to occur before 2025. Thus there is less that must be done in terms of market activation other than incentivise use of clean hydrogen in these processes before it is commercially competitive.

Use of hydrogen in the petrochemical industry, as a means of treating and refining crude oil has been declining due to Australia's growing dependence on imported refined fuel products. However with increasing concern over the need to reduce Australia's dependence on liquid fuel imports and decarbonise the transport sector, there could be a role for hydrogen in treating fuels derived from biomass.

Input of clean hydrogen into ammonia and other chemicals such as methanol could renew demand for these products as the world transitions to a low carbon economy.

EXPORT

Export of hydrogen represents a key opportunity for Australia. Potential demand for imported hydrogen in China, Japan, South Korea and Singapore could reach in the order of 3.8 million tonnes in 2030[4] (~AUD9.5 billion) with Australia well positioned to play a key role in the export market.

Development of this industry is largely dependent on the production, storage and transport technologies identified above with many lessons to be gained from the export of LNG. Given that commercial scale production of hydrogen from brown coal in Victoria is only likely to be available after 2030, the majority of prior demand is expected to be met by electrolysis coupled with dedicated renewables and/or grid connected electricity. A target hydrogen production price of $2-3/kg (excluding storage and transport) is likely to be needed for Australia to compete with other exporting countries.

ELECTRICITY GRID FIRMING

Hydrogen systems can provide both electricity grid stability (i.e. seconds to hourly storage) and grid reliability (i.e. seasonal storage) services. There is likely to be an increasing demand for these services as the proportion of VRE in the network continues to increase over the next five years.

In the first instance, grid connected electrolysers provide a flexible load that can be ramped up and down to help manage grid stability. On the other hand, hydrogen systems consisting of storage and fuel cells are unlikely to be constructed for the sole purpose of grid stability, due to the need for a hydrogen price of less than $2/kg to compete with batteries, pumped hydro and gas turbines.

However, for grid reliability, hydrogen systems (along with gas turbines) present one of the only technological solutions to overcoming challenges with seasonal intermittency. While gas turbines are likely to be cheaper, the price differential could be minimised when considering carbon and natural gas supply risks associated with building new natural gas assets.

HEAT

Direct combustion of hydrogen for the purpose of generating heat is unlikely to compete with natural gas on a commercial basis before 2030. This form of utilisation would therefore need a clear policy signal from government focussed on decarbonisation of the gas networks in order for this conversion to occur.

Hydrogen enrichment of the natural gas network provides an early market for hydrogen and a shorter term option for decarbonisation of the sector without the requirement for a significant upgrade of existing infrastructure. However, due to different burner properties and characteristics of the gases, a move to 100% displacement of natural gas with hydrogen will require an upgrade to existing appliances and possibly pipelines.

Industrial appliances such as furnaces and kilns are complicated due to integration with other systems on a single site. Upgrading from natural gas to hydrogen in this sector is therefore likely to be more ad hoc.

In contrast, upgrading residential appliances is technically more straightforward and a widespread roll out could be possible in or around 2030. The challenge is coordinating the appliance change with the switchover in gas supply. This has been demonstrated in Australia with prior conversions from town gas (consisting of ~50% hydrogen) to natural gas in the 1970s.

Where possible, this risk can be somewhat mitigated by the placement of electrolysers at the pipeline distribution network and by mandating the manufacture and installation of standardised and more easily convertible appliances before the switchover occurs.

SYNTHETIC FUELS

Synthetic fuels are unlikely to compete with crude derived fuels on a purely commercial basis. However as discussed in the context of biofuels, this could change if there is an identified need for a localised fuel supply.

This may be achieved through the production of syngas as an intermediary via coal gasification and/or SMR, which can then be used to produce higher order synthetic fuels. However, this process still has a significant emissions profile. As an alternative, 'power-to-liquids', which combines hydrogen with a waste stream of CO_2, could be used to synthesise lower emissions fuels that are likely to play an important role in heavier forms of transport such as aviation and shipping.

4 ACIL Allen Consulting, 2018, Opportunities for Australia from hydrogen exports, Australia (ARENA Report)

SUMMARY OF PRIORITIES

VALUE CHAIN ELEMENT	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
General	• Implement vertical integration along the supply chain to optimise technology selection and use • Implement joint ventures to allow for allocation of risk and coordination of resources • Provide access to lower cost financing for low emissions projects	• Implement targeted policies to stimulate hydrogen demand • Develop hydrogen specific regulations based on best practice global standards. These should be uniform across the States and Territories • Establish inter/intragovernmental hydrogen authorities	• Continue demonstration projects for mature technologies to overcome 'first of kind' risk • Establish centralised RD&D bodies consisting of researchers, industry and government to coordinate RD&D funding appropriately (e.g. 'Hydrogen Centre of Excellence') • Implement incentives for local manufacturing	• Develop engagement plans and undertake demonstration projects to showcase hydrogen and ensure communities understand all aspects of its use
Supply				
Production	• Position production plant to accept multiple offtakes for hydrogen • Secure cheap low emissions electricity	• Develop 'Guarantees of Origin' scheme • Government to secure long-term storage liability for CO_2 storage • Allow for compensation for grid firming services from electrolysers	• Continue RD&D into improving plant efficiencies and asset life • Continue development of less mature technologies such as high temperature electrolysis and methane cracking	• Undertake stakeholder engagement on technical viability and safety of CCS
Storage and Transport of H_2	• Position plants close to point of hydrogen use where possible	• Review gas pipeline regulations to consider including gaseous hydrogen	• Develop capabilities in liquefaction materials • Continue R&D in 100% hydrogen capable pipeline materials and pressures • Develop higher efficiency compression technologies and underground storage	• Develop communication plans regarding hydrogen pipeline easements

VALUE CHAIN ELEMENT	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
Applications				
Hydrogen fuelled transport	• Establish refuelling station joint ventures and undertake strategic roll out of stations	• Implement emissions standards on vehicles and specific incentives for FCEVs	• Demonstrate viability of refuelling stations with 'back to base' vehicles or vehicles with known driving patterns	• Improve recognition of FCEVs as electric vehicles • Conduct ongoing station safety demonstrations for refuelling stations
Industrial feedstocks	• Install new clean hydrogen inlets into facilities during plant shutdowns	• Implement incentive schemes regarding use of clean hydrogen as an industrial feedstock		• Create awareness of emissions embodied in commodities to help inform consumer choice
Export (as per production, storage and transport plus)	• Implement government to government agreements for export to give industry confidence • Establish 'take or pay' export offtakes • Undertake land appraisal assessments for dedicated renewables • Invest in domestic labour force • Negotiate favourable tariffs for hydrogen export (including in the existing FTAs)	• Implement regulations supporting use of unutilised land for dedicated renewables • Engage bodies such as the International Maritime Organisation to ensure appropriate regulatory frameworks for hydrogen shipping	• As per hydrogen production, storage and transport	• Continue to promote hydrogen as a low emissions export commodity
Electricity grid firming and RAPS	• Undertake remote communities appraisal for RAPS	• Implement incentives for use of hydrogen in remote mining sites and communities	• Continue RD&D into fuel cells to improve capital costs and asset life • Demonstrate hydrogen in RAPS in mining activities and remote communities	• Develop engagement plans regarding use of hydrogen systems in remote communities
Heat	• Invest in 100% hydrogen capable workforce and appliance fitters • Coordinate with non-Australian governments to give multinational appliance manufacturers more certainty	• Implement clear policy direction for enrichment and subsequent displacement of natural gas • Legislate manufacture and use of standardised and easily convertible appliances	• Continue R&D in 100% hydrogen appliances • Continue trials for natural gas enrichment with hydrogen • Undertake feasibility study over designated town for 100% hydrogen • Begin development of pilot project for designated town	• Undertake hydrogen enriched natural gas demonstrations to familiarise consumers with burning hydrogen
Synthetic fuels		• Mandate local and low emissions fuel supply targets • Implement incentives for use of synthetic fuels in aviation and shipping industry	• Invest in 'power-to-fuels' technologies	

PART I

Introduction

1 Why hydrogen?

Hydrogen gas ('hydrogen') is a versatile energy carrier and feedstock, derived primarily by splitting water molecules or by reacting fossil fuels with steam or controlled amounts of oxygen. While hydrogen has served mostly as an input into a range of industrial processes, it has the potential to be used across a number of applications as shown below. Further, if produced using low or zero emissions sources, ('clean') hydrogen can enable deep decarbonisation across the energy and industrial sectors. Clean hydrogen is the focus of this report.

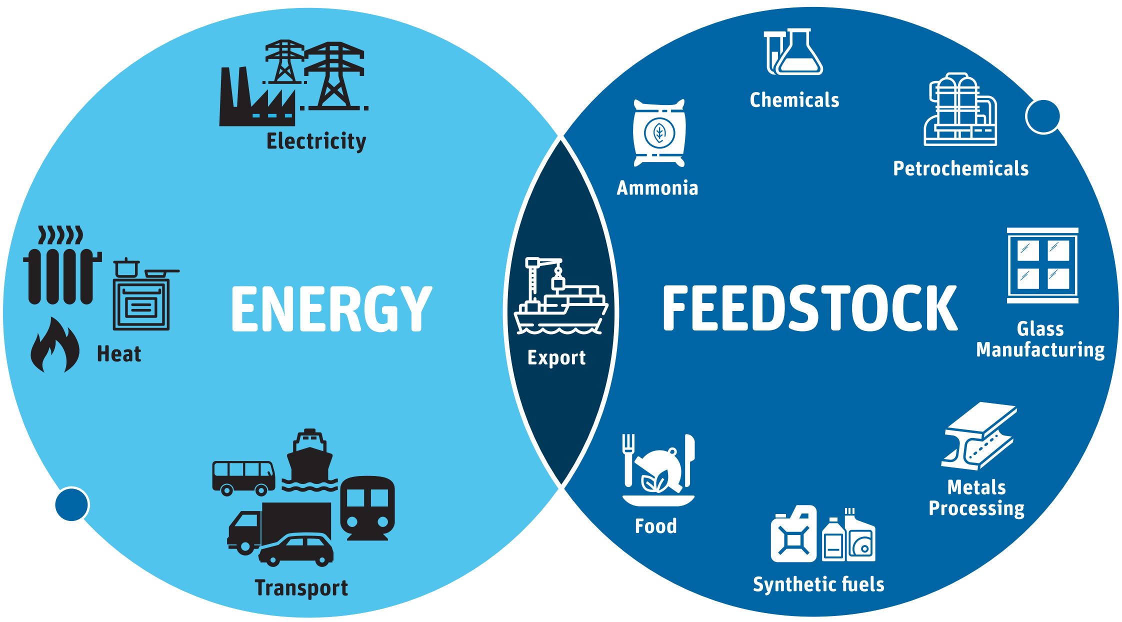


Figure 1. Applications for hydrogen

The technologies that underpin the hydrogen value chain can be broadly classified as:

1. **Production**: Technological pathways for generating hydrogen
2. **Storage and transport**: Technologies that store and distribute hydrogen from the point of generation to end use
3. **Utilisation**: Technologies that allow for hydrogen to be used in the applications presented in Figure 1.

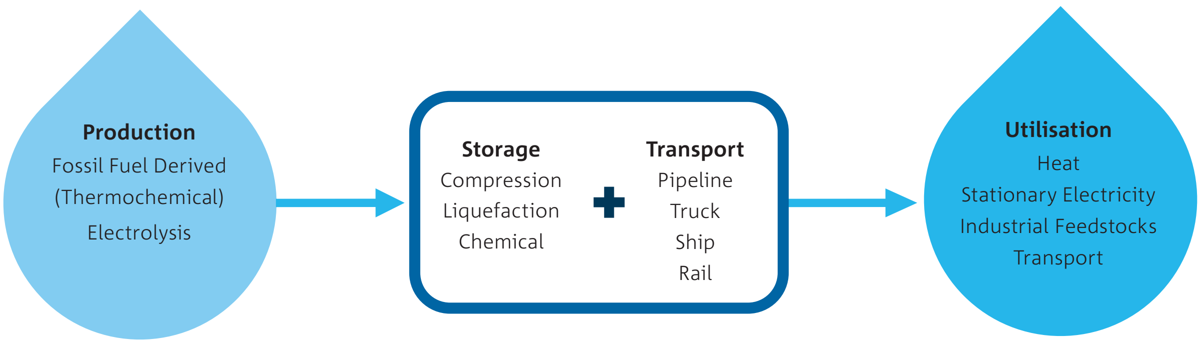


Figure 2. Hydrogen technology value chain

2 Why Australia?

2.1 Uniquely Australian context

In 2016, Australia ratified the Paris Agreement, committing to achieve a 26-28% reduction in greenhouse gas emissions below 2005 levels by 2030 (energy and industrial emissions set out in Figure 3).

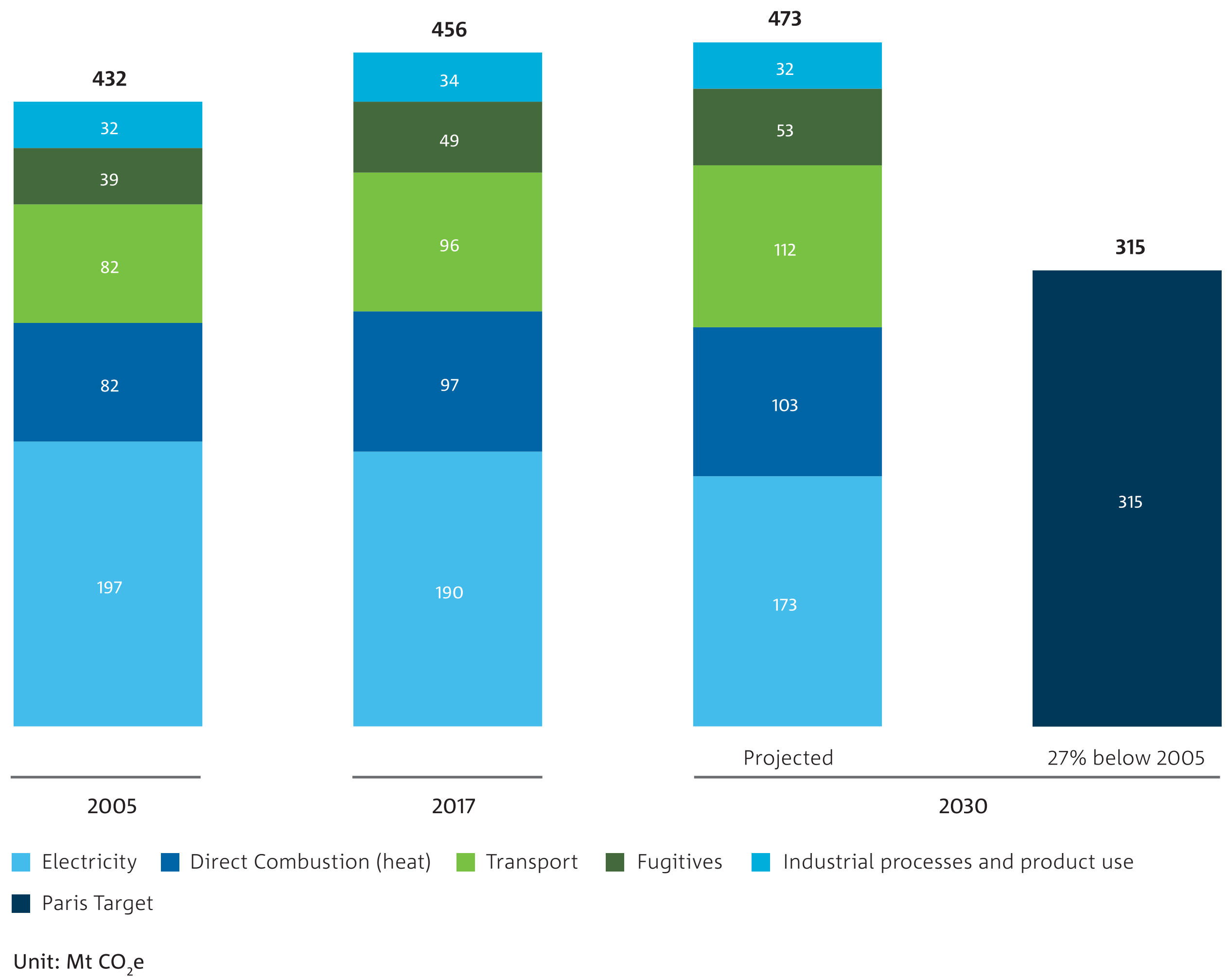


Figure 3. Australian current and projected (2030) energy and industrial emissions[5]

5 Department of the Environment and Energy 2017, Australia's emissions projections 2017

While use of hydrogen across the energy and industrial sectors is one of a suite of technology options that can play a key role in helping Australia meet the prescribed decarbonisation targets, there are a number of other domestic trends and characteristics that favour its widespread use. These include:

Natural gas supply

On the east coast of Australia, natural gas prices remain high ($8-10/GJ) compared to overseas jurisdictions such as the United States ($2-4/GJ). This is largely due to significant reductions in local gas supplies, with reserves on the North West Shelf tied up in long term contracts for LNG export and a moratorium on unconventional gas exploration in the eastern states.

With some uncertainty around future price trajectories, natural gas costs are impacting the competitiveness of a number of industrial processes including ammonia production, which relies on natural gas both as a feedstock and a source of heat. Hydrogen could replace natural gas as a low emissions source of heat as well as a potentially cost competitive low emissions feedstock for a number of industrial processes.

Changing electricity sector

The Australian electricity sector is undergoing a significant transformation with a move away from conventional thermal generation towards an increasing proportion of variable renewable energy (VRE). As a low emissions energy carrier, hydrogen can help manage this transition by overcoming challenges associated with short term (seconds) to long term (seasonal) energy supply intermittency. Thus hydrogen can help solve the 'energy trilemma'- energy security, affordability and environmental sustainability.

Hydrogen also offers an opportunity for 'sector coupling' between the electricity, gas and transport sectors. For example, hydrogen produced from renewable energy can be injected into the gas network and used as a fuel input into different types of vehicles. This flexibility allows for greater optimisation regarding use of renewable electricity across the different sectors.

Liquid fuels security

Australia has long been dependent on imported liquid fuels but at present, is not meeting its domestic fuel reserve targets. As at January 2018, Australia's total fuel reserves were at 49.6 days with diesel oil at 21 days[6]. This is below the 'equivalent of 90 days' obligation set for members of the International Energy Agency. This supply risk is heightened by the fact that Australia's fuel import routes rely on shipping corridors that can be impacted by potential regional conflicts.

Hydrogen can play a key role in protecting Australia from supply shocks by localising liquid fuel supplies (e.g. by producing (bio) synthetic fuels) and displacing their use in both stationary and transport applications.

An established manufacturing base

Australia has an established manufacturing base and expertise in high value or advanced manufacturing production processes[7]. Given that the global hydrogen industry is still in a development phase, many global technology manufacturers are yet to establish large scale operations and retain flexibility in selecting where to deploy production facilities.

Australia therefore remains an attractive investment proposition due to this and other factors such as government stability and the availability of land and natural resources. One comparative disadvantage is the cost of labour. However as demand for hydrogen continues to grow, this disadvantage could be overcome through the implementation of automated production lines. Domestic manufacture could see the emergence of new local industries and potential for technology export to Asia.

Skilled workforce

Australia has a technically skilled workforce with deep expertise across the energy sector, particularly in oil and gas. There is a strong requirement for these skills across the hydrogen value chain. Thus with the right training and accreditation programs, Australia is well placed to transition the existing workforce away from potentially declining markets to growth opportunities in hydrogen.

6 Department of the Environment and Energy 2018, Australian Petroleum Statistics
7 Withers, G., Gupta, N., Curtis, L. and Larkins, N. 2015, Australia's Comparative Advantage, report for the Australian Council of Learned Academies

2.2 Export

Australia has a long history of generating economic opportunities by exporting its natural resources. Some of these markets, for example uranium, have suffered downturns as a consequence of a changing energy mix abroad. Others such as thermal coal could be at risk in the future if global trends continue to lead towards a low carbon economy.

In contrast, the global market for hydrogen is expected to reach USD155 billion by 2022[8], with a number of Australia's existing trading partners, who are comparatively resource constrained, implementing policy commitments for hydrogen use (discussed further in Section 3.2).

Australia's extensive natural resources lend favourably to the establishment of hydrogen export supply chains. Notable resources include solar, wind, fossil fuels and underutilised land. Hydrogen therefore provides a means for both commoditising such resources (i.e. solar and wind) and/or leveraging other underutilised assets such as brown coal.

Hydrogen also has the potential to be embodied in some of Australia's existing export commodities (e.g. methanol and ammonia) and may also be used in the production of steel. Further, by overcoming the need for natural gas, hydrogen may improve the competitiveness of a number of export industries particularly where there is increasing demand for lower emissions products.

2.3 Current activities

There are currently a number of projects and activities underway within Australia aimed at building local capabilities and demonstrating the use of clean hydrogen across a number of applications (summarised in Figure 4).

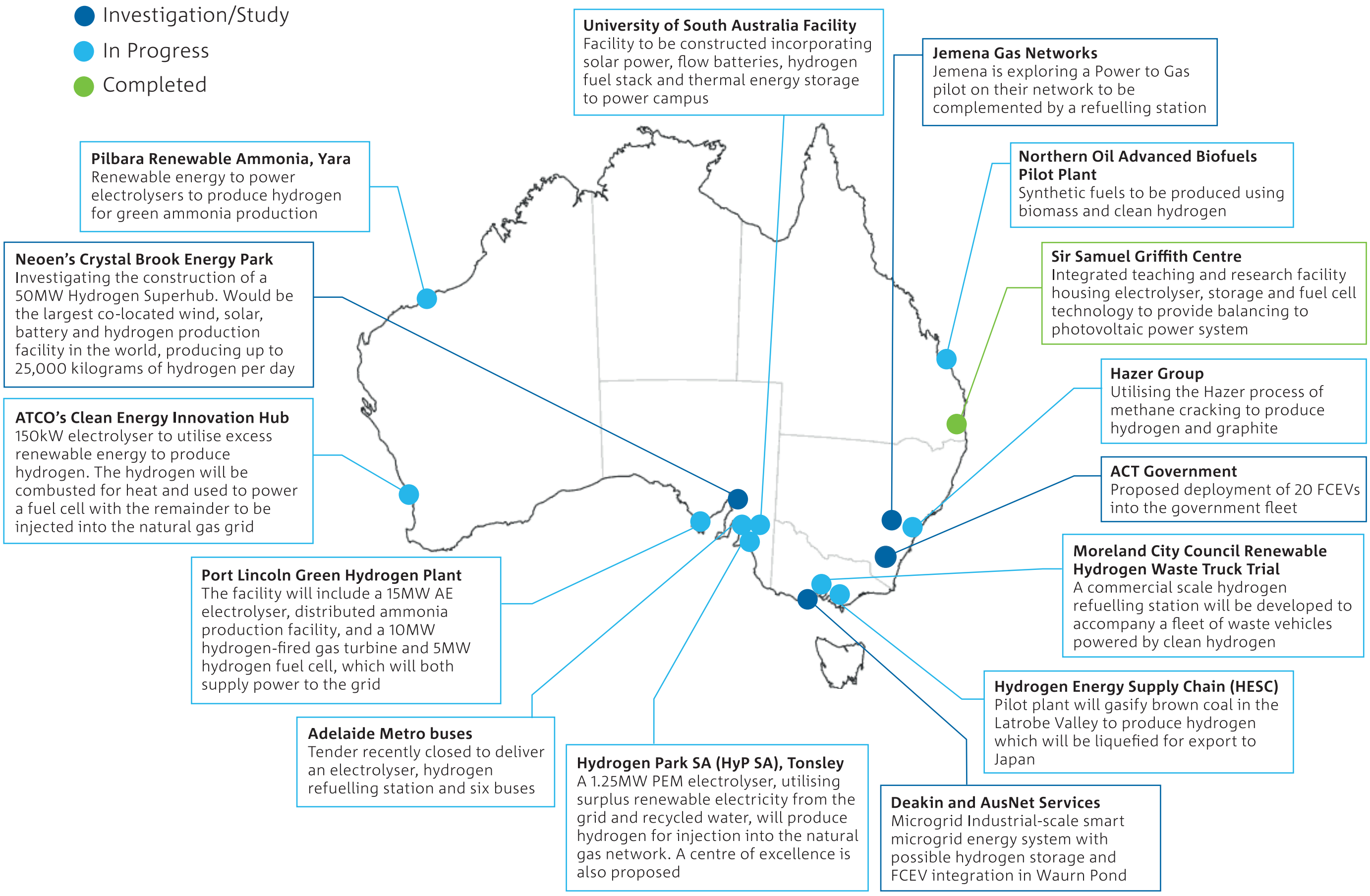


Figure 4. Summary of current Australian demonstration projects

8 International Energy Agency Hydrogen Technology Collaboration Program 2017, Global Trends and Outlook for Hydrogen

3 Why now?

Interest levels in the development of global hydrogen industries have fluctuated over recent decades. Today however, there are a number of global trends and activities that distinguish the renewed focus on hydrogen from what has been observed previously.

3.1 Technological maturity

The hydrogen value chain now consists of a series of relatively mature technologies with a high 'Technological Readiness Level' (TRL) but low Commercial Readiness Index (CRI) (according to the scale depicted in Figure 5). This is evidenced by the number of pilot projects demonstrating use of hydrogen across multiple applications globally.

While there is considerable scope for further R&D, this level of maturity has meant that the narrative has shifted from one of technology development to market activiation. As distinct from previous hydrogen roadmaps[9], a considerable portion of this report therefore focuses on the transition from commercial trials (CRI 2-3) to a bankable asset class (CRI 6).

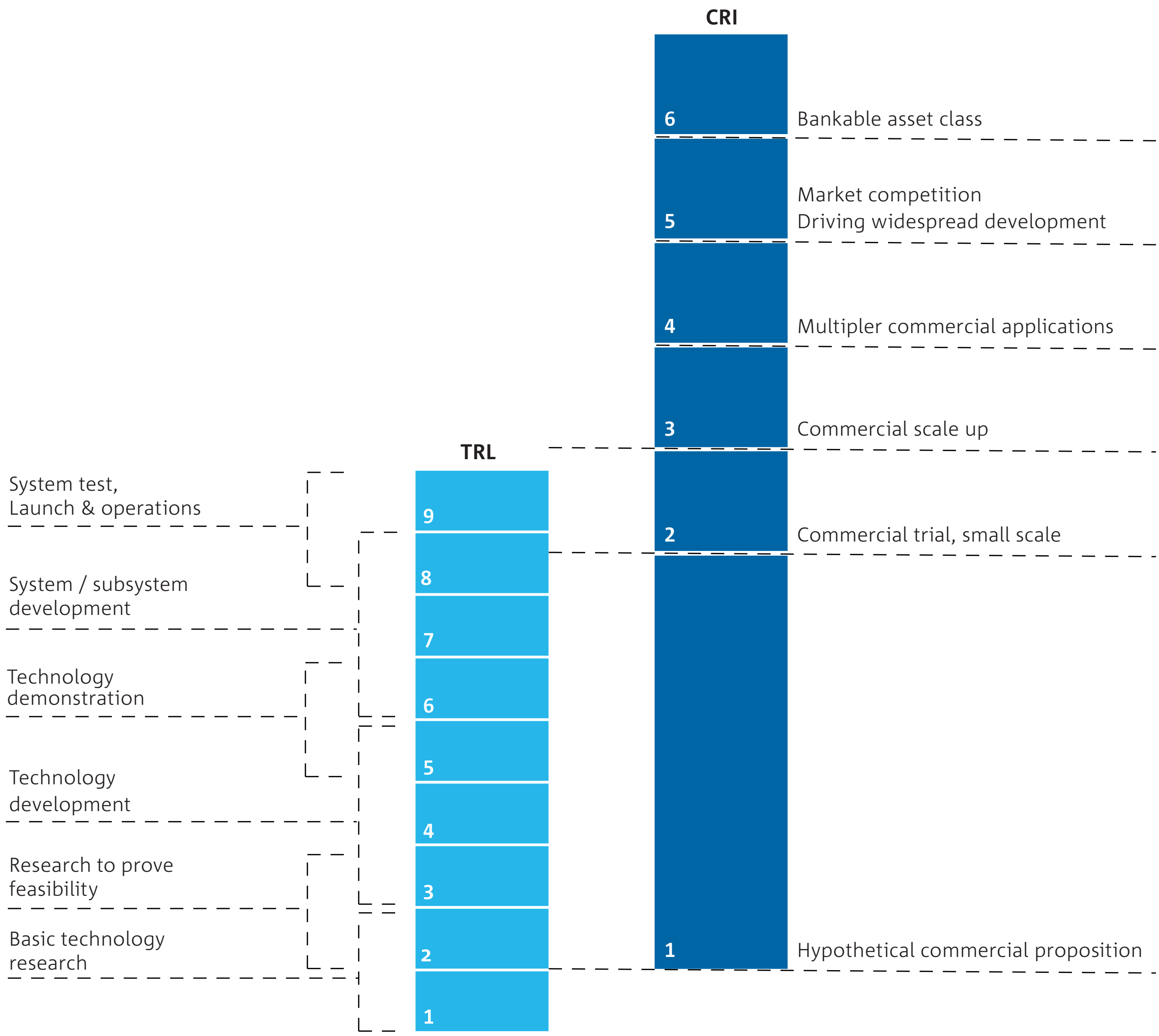


Figure 5. Technological and commercial readiness index[10]

9 For example ' Towards development of an Australian scientific roadmap for the hydrogen economy' produced by the Australian Academy of Science in 2008

10 ARENA 2016, Technology Readiness Levels for Renewable Energy Sectors, Australia

This development has recently been observed in relation to solar PV, where relevant markets became economically sustainable once production economies of scale reached a 'tipping point', particularly in China. Utility scale solar PV, operating without government assistance, is now generating attractive returns on investment[11].

3.2 Government policy commitments

A number of countries, including several members of the EU, the United Kingdom and Japan have identified the need for hydrogen in order to achieve deeper decarbonisation across the energy and industrial sectors. Consensus around transport as a key application has led governments worldwide to collectively announce plans for approximately 2800 hydrogen refuelling stations (HRS) to be built by 2025[12].

Through a series of clear policy initiatives, China has also recently emerged as a proponent for hydrogen, earmarking its use as part of its transition to distributed energy systems[13] and decarbonisation of the transport sector[14]. As demonstrated in relation to solar PV, this development is likely to have a material impact on global supply chains.

Countries such as Japan have also gone so far as to signal a need for specified hydrogen import targets, which are set to increase over the coming decades. This has increased the potential for a global hydrogen export market in which Australia is well positioned to participate.

3.3 Industry driven

In light of global decarbonisation efforts and new technological trends, large multinational oil, gas and energy companies, heavy industry and vehicle OEMs have begun to embrace hydrogen as an emerging opportunity. Consequently, many are diversifying their company portfolios by continuing to invest millions into its growth.

Members of the Hydrogen Council, which is comprised of leading energy, transport and manufacturing companies from across the globe, currently invest a combined AU$2.2 billion per year in hydrogen solutions. Previously this investment had been heavily weighted to R&D. Now however, council members are planning to increase this investment to at least AU$3 billion per year over the next five years and change the prioritisation of funding to focus on market introduction and deployment[16].

As a further indication of the economic reality of hydrogen applications, fuel cell electric vehicles have been recognised as the number one automotive trend through to 2025, surpassing BEVs[17].

BASIC HYDROGEN STRATEGY – JAPAN:

In 2017, under the direction of Prime Minister Shinzo Abe, Japan's Ministerial Council on Renewable Energy, Hydrogen and Related Issues developed a Basic Hydrogen Strategy[15]. This proposal mapped out long term goals in hydrogen production and consumption for 2020, 2030 and beyond.

In time for the 2020 Olympics, Japan sees hydrogen demand reaching 4,000t/pa. Following the establishment of an international hydrogen supply chain coupled with production technology improvements, demand by 2030 is predicted to require an annual procurement of 300 kilo tonnes (kt). The final 2050 scenario sees Japan's annual hydrogen procurement at greater than 10 mega tonnes (Mt).

11 EY 2016, Capturing the sun- the economics of solar investment
12 Hydrogen Council 2017, Hydrogen scaling up: A sustainable pathway for the global energy transition, Europe
13 International Energy Agency (IEA) 2017, Prospects for distributed energy systems in China
14 Si, M. 2018, 'Fuel-cell cars set to get more impetus', China Daily, 13 February, accessed May 2018 from http://www.chinadaily.com.cn/a/201802/13/WS5a823ca6a3106e7dcc13c6f4.html
15 Ministry of Economy, Trade and Industry 2017, Basic Hydrogen Strategy Determined, media release, accessed 21 March 2018, http://www.meti.go.jp/english/press/2017/1226_003.html
16 International Energy Agency Hydrogen Technology Collaboration Program 2017, Global Trends and Outlook for Hydrogen
17 KPMG 2018, Global Automotive Executive Survey 2018

4 This report

Recently there has been a considerable amount of work undertaken (both globally and domestically) seeking to quantify the economic opportunities associated with hydrogen. This report takes that analysis a step further by focussing on how those opportunities can be realised within Australia.

The primary objective of this report is therefore to provide a blueprint for the development of a hydrogen industry in Australia. It is designed to help inform investment amongst various stakeholder groups (e.g. industry, government and research) so that the industry can continue to scale in a coordinated manner. The approach to meeting this objective is iterative, but can be considered in two parts.

First, the report assesses the potential applications for hydrogen that could exist in an Australian context by 2030. In doing so, the assesment sets out the target price of hydrogen needed for it to be competitive, i.e. by disrupting incumbent energy carriers (e.g. liquid fuels, batteries and natural gas) and competing with existing uses of higher emissions ('brown') hydrogen.

Second, the assessment considers the current state of the industry, namely the cost and maturity of the underpinning technologies and infrastructure. It then identifies the material cost drivers and consequently, the key priorities and areas for investment needed to make hydrogen competitive in each of the identified markets. These key priorities have been broken down into four categories:

1. **Commercial**: Includes an assesment of the commercial models, implications and opportunities as well as the role of government in underwriting investment risk.
2. **Policy/Regulatory**: Includes an assessment of where policy is needed to stimulate relevant markets together with the technical/economic regulations that are required to faciliate deployment of relevant technologies.
3. **RD&D**: Includes an assessment of where incremental improvements to mature technologies are needed as well the potential for less mature technologies (non-exhaustive) to provide the next wave of disruption. Identification of demonstration projects needed to overcome first of kind risk are also considered.
4. **Social licence**: Assessment of the initatives required to ensure communities are properly engaged and understand all aspects of hydrogen use.

Although the roadmap is written for the Australian context as a whole, comparative advantages between States and Territories are drawn out where applicable.

Report modelling

As part of the techno-economic modelling undertaken in this report, underlying assumptions and key cost drivers for the more mature hydrogen technologies have been clearly identified when determining the current state of the technology or 'base case' (2018). The key priorities and areas for investment identified in the analysis then inform how these cost drivers can improve. The cumulative impact that these improvements have on the cost of the technology is subequently assessed. The overall result is a 'best case' which could be achieved by ~2025.

Rather than apply learning rates to the technologies, this approach was chosen to help coordinate investment in each technology area as well as validate assumptions and modelling results with industry. All supporting modelling assumptions have been included in Appendix C.

While modelling results are generally shown in dollars per kilogram ($/kg), results can be converted to dollars per gigajoule ($/GJ) using the following conversion factors:

- 0.142GJ/kg - Higher heating value (HHV)[18]
- 0.120GJ/kg - Lower heating value (LHV)[18]

Gas pressures are also represented using the unit 'bar' (1 bar = 100 kilopascal (kPa))

18 As defined in glossary

PART II

Value chain analysis

1 Overview

This section of the report provides a detailed analysis of the current state (2018) of the hydrogen industry (i.e. cost and maturity of technologies and infrastructure). It then draws out the key areas for invesment and assesses their cumulative impact on the hydrogen value chain according to the methodology in Figure 6.

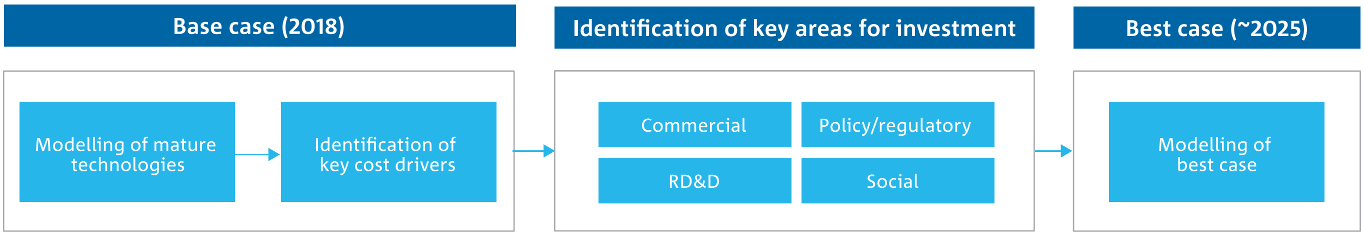


Figure 6. Value chain analysis methodology

2 General considerations

While each element of the hydrogen value chain will be considered separately in the following subsections of the report, there are a number of general considerations that apply to the industry as a whole.

2.1 Commercial implications and opportunities

SCALE

Increasing the size or capacity of hydrogen projects will generally allow for reductions in capital and operating costs and improved system efficiencies. For upstream technologies (i.e. production, storage and transport) in particular, this can be achieved by securing larger or multiple offtake agreements for the hydrogen produced. The ability for hydrogen to simultaneously service a number of markets enhances scope for this upsizing and therefore the positioning of hydrogen production plants as close to different points of use should be done where possible.

That said, in most instances a threshold is likely to be reached where cost reductions achieved from increasing the capacity of a single plant will be more incremental. In this case, building multiple smaller plants could allow for greater diversification of technical and financial risk.

Whole of system approach

Technology selection, sizing and utilisation can have a material impact on the cost of hydrogen. During the growth phase of the industry in particular, efficiencies and improved economics can be realised through the establishment of vertically integrated business models and whole of system solutions. Such models increase scope for greater utilisation of assets, data aggregation, arbitrage opportunities and removal of margin at each intersection point along the supply chain.

Further, the required characteristics for hydrogen (e.g. pressure and purity) can vary depending on the application and vertically integrated business models should help ensure that the technologies selected are appropriate for the specific end use.

RISK ALLOCATION

As with other emerging industries, there is a general acknowledgment of the need to accept greater risk (e.g. technical, financial, stranded asset) in hydrogen investments when compared with mature assets. However, even with this acceptance, that risk must be capped.

As shown in the subsequent sections of analysis, the establishment of joint ventures allows for both risk-sharing and a more coordinated pooling of resources based on the comparative advantage of each company involved. However, while the industry is in early stages of development in Australia, governments will most likely be required to underwrite 'first of kind'[19] risk as a means of helping to secure private investment.

FINANCING

As a low or zero emissions energy resource, there may be scope for proponents of hydrogen to access lower cost financing through entities such as the Clean Energy Finance Corporation (CEFC) or through green bonds. The modelling conducted for this report indicates that while generally not a material driver of cost, access to low cost finance can improve the overall economics of a given project.

With Australia likely to be an importer of relevant technologies in the earlier stages of industry development, the exchange rate with the exporting jurisdiction could have some impact on cost. While risk mitigation measures such as hedging will be relevant for specific projects, a deeper analysis of this is out of scope of this report.

2.2 Policy and regulation

Given the embryonic state of the hydrogen industry in Australia, there is an important role for all levels of government in helping address barriers to market. Policies may include specific incentives and/or legislative requirements that reduce the risk of hydrogen demand and supply for industry proponents. Such policy support may assist in obtaining the required economies of scale to enable the industry to reach a tipping point and become economically sustainable thereafter.

Both economic and technical regulations will also play an important role. Economic regulations such as the National Gas Law (discussed further in Appendix B) refer to the need for hydrogen assets to be able to realise their full commercial value in various markets. Technical regulations relate to ensuring that the design, construction and operation of relevant assets meets appropriate safety and environmental standards.

In Australia, there is an existing set of technical regulations (e.g. for transport of gaseous materials) that provide broad coverage regarding use of hydrogen and related technologies. However as the industry continues to scale, hydrogen specific regulations will be required.

In this context, best practice global standards need to be incorporated into Australian regulation wherever possible and be uniform across the different States and Territories. Hydrogen specific standards are being developed internationally through organisations such as the International Organisation for Standardisation (ISO) and International Electrotechnical Commission (IEC). However, these standards are voluntary until properly codified into Australian regulation.

This is important in ensuring that new regulations are not disproportionately burdensome and discourage investment. It is also critical that technical regulations do not deviate significantly from overseas jurisdictions given that a requirement for overseas manufacturers to accommodate different specifications will only add to the cost of imported/exported technologies.

While a detailed review of standards and regulations for Australia is still needed, a high level analysis of existing regulations and standards to be considered as the industry matures is captured in Appendix B. Other policy and regulatory implications are considered throughout the analysis.

Need for a centralised hydrogen authority

An economically sustainable hydrogen industry will exist across multiple sectors and have a broad range of infrastructure requirements. For instance, a single hydrogen project may need access to electricity and water networks as well as pipeline easements in order to simultaneously provide for a series of transport operations.

Federal, State and Local government entities typically have their own portfolio of priorities and time spent by technology proponents in acquiring multiple approvals can constrain development and increase costs. An inter/intragovernmental authority with the power to make decisions within a reasonable time frame will therefore be important in facilitating industry growth. This could provide a 'one-stop-shop' for gathering all the required licences for a specific hydrogen project. It could also serve as an important signial to potential global investors that Australia is utilising appropriate governance structures in developing the local industry.

19 Even if a technology has been demonstrated overseas, each country will have a different risk profile that can be reduced through a series of pilot projects.

2.3 RD&D

The hydrogen value chain is underpinned by a series of mature technologies (TRL 9) that are being demonstrated in pilot projects globally. Successful demonstrations have allowed these technologies to be de-risked from a technical standpoint, overcome relevant investment hurdles and continue to attract funds to improve their performance and achieve further reductions in cost.

However, as shown through this report, there are also a number of less mature technologies that offer potential for disruption (e.g. by using low cost energy sources). That said, without securing appropriate funding, it will be challenging for such technologies to mature.

Centres of Excellence have been found to be effective in addressing these issues by coordinating funding and increasing knowledge sharing and collaboration amongst researchers, industry and government. Long term funding commitments through these entities also allow researchers to accurately plan and prioritise funding across different projects. A successful example can be found in the establishment of the National Innovation Programme Hydrogen and Fuel Cell Technology (NIP) in Germany.

2.4 Social licence

One of the primary challenges associated with the adoption of hydrogen and associated industry development is the 'normalisation' of risk. For example, consumers today are comfortable driving petrol cars despite the flammability of the fuel, but may be resistant to hydrogen powered cars due to a perception that hydrogen is more dangerous.

These perceptions are important, not just for the purpose of stimulating uptake of the technologies, but also for ensuring that the regulations and standards imposed are commensurate with the level of risk. As stated above, overregulation can increase the cost of specific projects (e.g. restricting access to preferred pipeline easements, thus forcing the buildout of longer or more expensive hydrogen pipelines with higher insulation requirements).

Strategic demonstration projects are therefore critical, not only in assessing the viability of the technologies, but for demonstrating the safety of their operation. For larger infrastructure type projects, detailed community engagement plans are needed to assist in obtaining a social licence to operate.

CASE STUDY: **NIP, GERMANY**

NIP was founded in 2006 with the primary objective of establishing Germany as a market leader in hydrogen and fuel cells, accelerating market development and strengthening industry involvement across the value chain. The programme consisted of researchers, industry leaders as well as policy makers. A total of EUR710 million was granted from 2006 and 2016 which resulted in 750 R&D projects. Grant recipients also invested an additional EUR690 million and raised an EUR20 million from third parties.

Following review of the first 10 year programme, the focus has now shifted from coordinating the R&D sector, with the next round of funding designed to facilitate market activation through incentives and larger scale commercial projects.

20 NOW: National Organisation Hydrogen and Fuel Cell Technology 2016, Evaluation of the National Innovation Program Hydrogen and Fuel Cell Technology Phase 1, Germany

3 Hydrogen Production

Hydrogen can be produced via a number of technological pathways that fall under 3 primary categories:

1. **Electrochemical**: Involves the use of an electrical current to dissociate water into hydrogen and oxygen. This pathway requires the use of low or zero emissions electricity to produce clean hydrogen.
2. **Thermochemical**: Uses a fossil fuel feedstock to produce hydrogen. This process must be paired with CCS to produce clean hydrogen (unless a biomass feedstock is used).
3. **Emerging**: Involves less mature alternative methods for extracting hydrogen from water. These technologies have therefore been assessed in conjunction with the electrochemical pathway.

3.1 Electrochemical and emerging production technologies

3.1.1 OVERVIEW

Electrochemical hydrogen production, or electrolysis, occurs in a device known as an electrolyser (or 'stack') that has a positive (anode) and negatively (cathode) charged pole. Positively charged hydrogen ions gravitate to the cathode to form hydrogen gas and negatively charged oxygen ions gravitate to the anode to form oxygen gas[21], both of which may be then collected. An electrolyser also requires balance of plant (BoP) (e.g. compressors, heat exchangers and pumps) to support continuous production of high purity hydrogen.

Hydrogen production via electrolysis requires water as one of the major inputs. For every 1kg of hydrogen produced, 9 litres of water is required. Most electrolysis cells require high purity water in order to limit side reactions caused by ions (salts) found in naturally occurring water. The majority of commercial electrolysers therefore have an integrated deioniser allowing them to use fairly low grade potable water as an input.

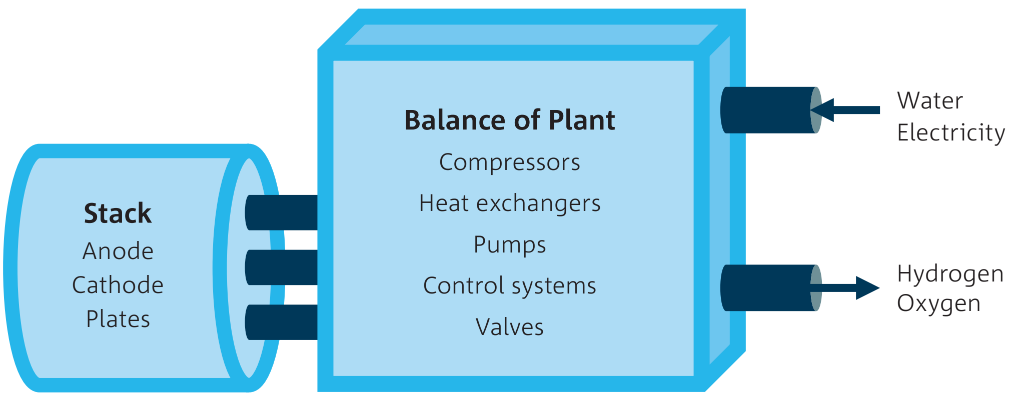


Figure 7. Electrolyser configuration

21 BCC Research 2015, Building the global hydrogen economy: technologies and opportunities, USA

3.1.2 MATURE TECHNOLOGIES

To date, alkaline electrolysers (AE) have been the most commercially mature method for electrochemical hydrogen production. Its component parts are currently produced at scale given that they are similar to those used in the commercial manufacture of chlorine and sodium hydroxide (i.e. the Chlori-alkali process).

Recently however, the industry has witnessed the emergence of the PEM electrolyser which has a number of distinct advantages over AE. This includes a smaller footprint and faster dynamic response time which is preferred for coupling with variable renewable energy (VRE). Combined with anticipated cost reductions, PEM electrolysis is fast becoming a more competitive technology. A comparison of both electrolyser technologies is captured in Table 1.

Hydrogen is produced via electrolysis up to 35 bar (for PEM) and once dried (PEM) or deoxygenated (AE), is close to the fuel cell required purity of 99.9999%.

Base case 2018 costs

The levelised cost of hydrogen (LCOH) for both AE and PEM is set out in Table 2. The base case considers the option for grid connected electrolysis where electricity pricing is reflective of current premiums paid for renewable energy.

TABLE 2. BASE CASE ELECTROLYSIS COSTS (2018)

	AE	PEM
LCOH ($/kg)	4.78-5.84	6.08-7.43

TABLE 1. COMPARATIVE DIS/ADVANTAGES: AE AND PEM ELECTROLYSERS

ELECTROLYSER	DESCRIPTION	DIS/ADVANTAGES
AE	Electrochemical cell that uses a potassium hydroxide electrolyte to form H_2 at the negative electrode and O_2 at the positive electrode	+ Currently lower capital costs + Benefits from Chlori-alkali process improvements + Well established supply chain and manufacturing capacity - Poor current density/larger footprint - Oxygen impurity in the hydrogen stream - Low pressure hydrogen product
PEM	Also known as a proton exchange membrane. Water is catalytically split into protons which permeate through a membrane from the anode to the cathode to bond with neutral hydrogen atoms and create hydrogen gas.	+ Smaller, flexible and modular + Faster dynamic response and wider load ranges[22] + Lower temperature operation + Higher power cycling capability + Higher current density + Higher purity hydrogen - Currently higher capital costs

22 Dodds, P. E. and Hawkes, A. (Eds.) 2014, The role of hydrogen and fuel cells in providing affordable, secure low-carbon heat. H2FC SUPERGEN, London, UK

Identification of material cost drivers

Figure 8 enables the identification of material cost drivers by varying values by a set percentage and testing the consequent impact on the LCOH. Based on this figure, material cost drivers for electrolysis using PEM as an example are:

1. **Electricity price**: Accessibility to cheaper low emissions electricity pricing can have a material impact on LCOH
2. **Capacity factor**: The more the electrolyser is used, the greater the potential to derive revenue and pay back the capital investment
3. **Plant size**: Increasing the size of the stack and number of stacks in a plant decreases capital costs and enables greater utilisation of BoP which can improve system efficiencies
4. **Capital cost**: Capital costs can be improved by increasing the plant size as well through increases in production economies of scale
5. **Efficiency**: Efficiency increases with the size of the plant but improvements can also be achieved via R&D and operation optimisation. Current electrolyser efficiencies are between 54-58kWh/kg depending on the technology. Note that the thermodynamic efficiency limit for electrolysis is 40 kWh/kgH_2 (the higher heating value of hydrogen). It is generally considered that efficiencies better than 45 kWh/kg are unlikely to be achieved.

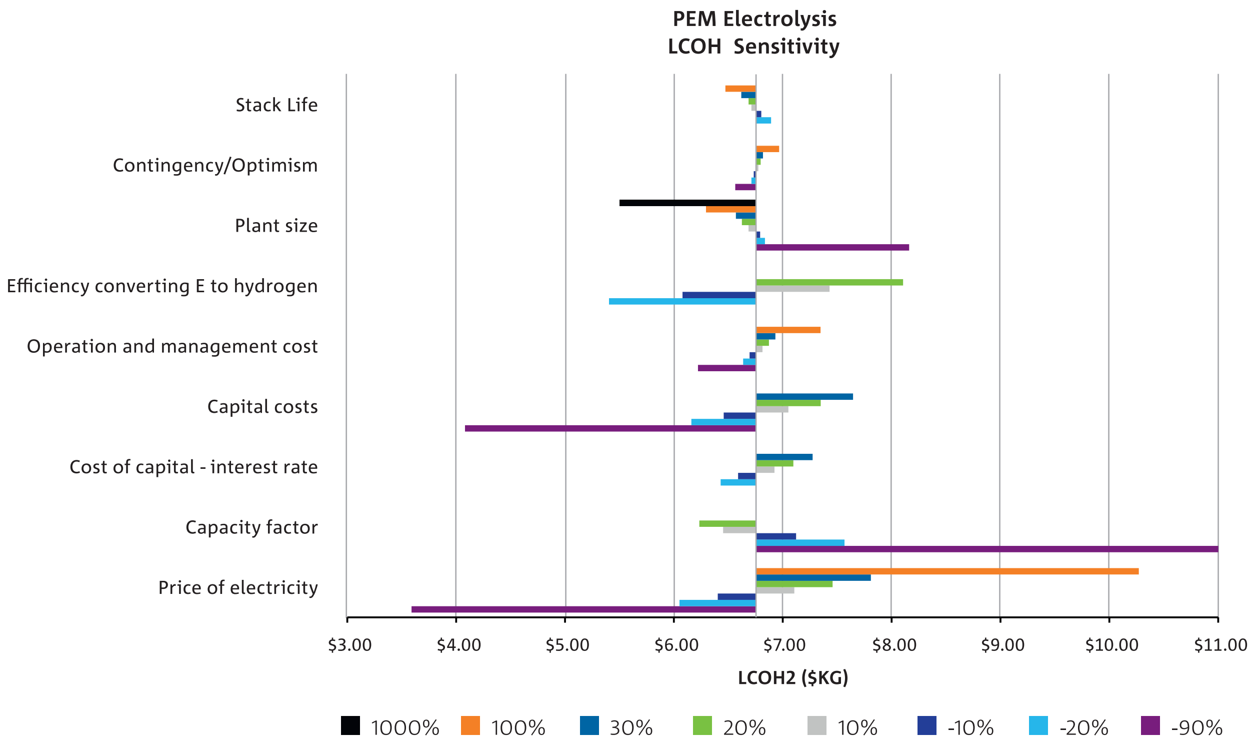


Figure 8. PEM electrolysis tornado chart

3.1.3 COMMERCIAL IMPLICATIONS AND OPPORTUNITIES

Electricity input and electrolyser capacity factor

Electricity input can be considered in the context of 3 options:

1. **Grid connected**: Electrolysers draw electricity directly from the network. Despite the emissions intensity of the network, low emissions electricity can still be utilised by securing power purchase agreements (PPAs) with utilities for low carbon electricity.
2. **Dedicated renewables**: Behind the meter (or off grid) electrolyser connection to dedicated renewable energy assets such as solar PV and wind. Electrolysers co-located with both solar PV and wind will allow for a higher capacity factor.
3. **Curtailed renewable energy**: Energy is sourced directly from the grid but only when there is surplus renewable energy available (or sourced directly from renewables when the economics do not favour export to the grid).

The three options outlined above represent a trade-off between electricity pricing and capacity factor as presented in Table 3 below.

TABLE 3. ELECTRICITY INPUT SCENARIO COMPARISON PEM (2018 COSTS)

	GRID CONNECTED	DEDICATED RENEWABLES	OTHERWISE CURTAILED ENERGY
Average electricity cost (c/kWh)	6	6	2
Average capacity factor (%)	85	35 (Co-located PV and wind)	10
LCOH ($/kg)	˜$6.60/kg	˜ $11/kg	˜$26/kg

Positioning of the electrolyser in a way that allows for the optimisation of these three options will lead to the most favourable economics. However, in practice this may not always be possible. In relation to the individual scenarios, while 'behind-the-meter' electrolysis provides for the cleanest business model, it does not necessarily lead to the most favourable LCOH.

Currently, grid connected electrolysis provides the cheapest LCOH due to its significantly higher capacity factor. Here, positioning of the electrolyser as close to the source of generation or along the transmission lines is also critical. The further downstream the asset is placed, the greater the risk of market distortion and consequent increases in electricity pricing. Retail pricing for electricity (e.g. 25c/kWh) could increase the cost of hydrogen by approximately 50%.

When using curtailed renewable energy, although the price of electricity is at or around 2c/kWh, the relatively low capacity factor is driving the cost of hydrogen. However, as the proportion of VRE in the network continues to increase, so too will the quantity and frequency of surplus renewable energy and in turn, the utilisation of the electrolyser. In this scenario, electricity pricing should also remain low as long as there is no spike in demand at these times (i.e. if other energy storage technologies are competing for the same electricity).

The modelling in Figure 9 undertaken by Hydricity, provides an example of how an increasing proportion of wind energy in the South Australian network has and could continue to impact the price and frequency of surplus renewable energy.

Scale of plant

Electrolysis represents a modular and therefore distributed option for hydrogen production. This provides the additional advantage of being able to position electrolysers in a way that simultaneously services multiple markets.

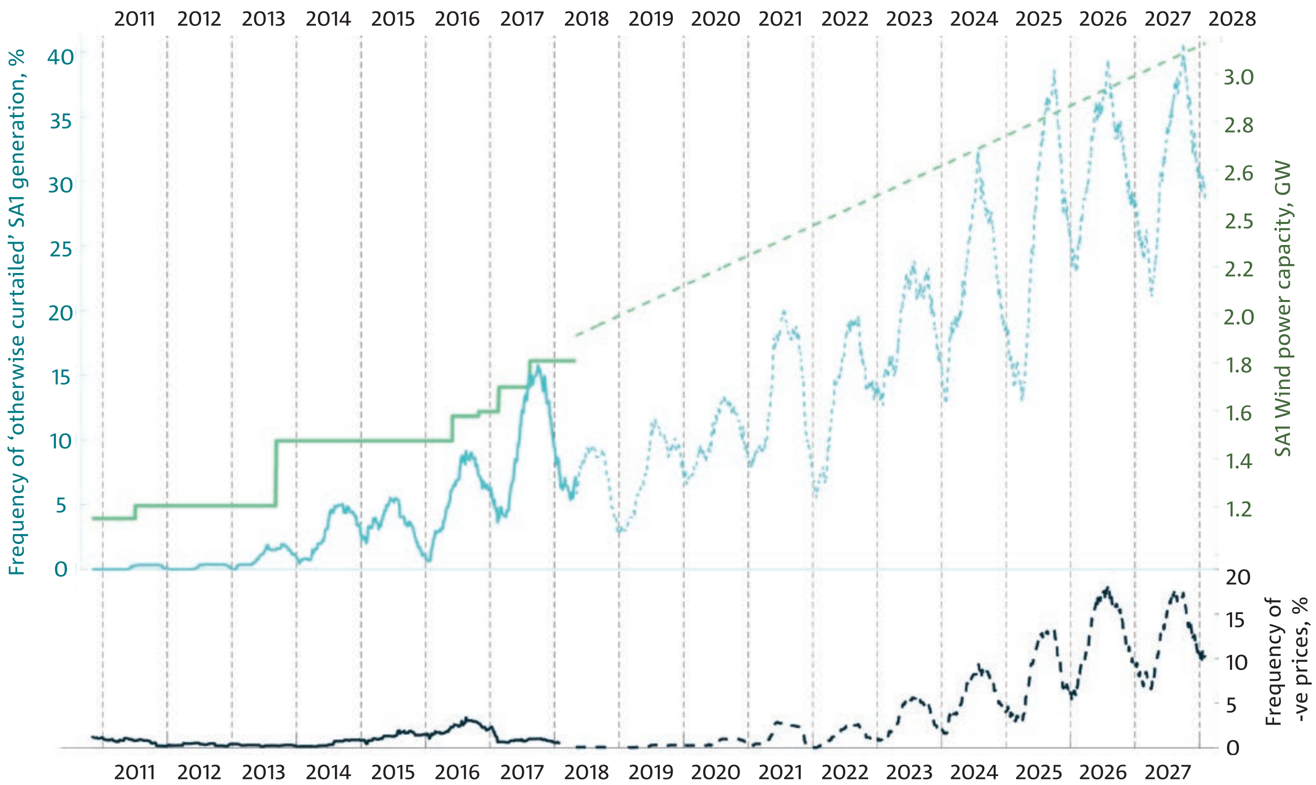


Figure 9. Hydricity systems model of pricing and electrolyser utilisation in South Australia

CASE STUDY:
PORT LINCOLN GREEN HYDROGEN PLANT

In 2018, the South Australian government announced Australia's first clean hydrogen plant. The $117m facility will produce hydrogen using a grid connected 15MW AE electrolyser. The facility also includes a 10MW hydrogen turbine, a 5MW fuel cell which will provide balancing services to the transmission grid and a decentralised green ammonia facility. Further, the facility will support two new solar farms as well as a nearby micro-grid which will be utilised by local aqua agriculturists who have been affected by aging back up power generation. The project will also allow universities and research groups to access a range of hydrogen technologies in an operating commercial environment.

As mentioned, scaling benefits can be achieved via increasing the capacity of the stack as well as the number of stacks while reutilising existing BoP. However as shown in Figure 10 below, using PEM as an example, while significant reductions in direct capital costs can be realised by increasing the number of stacks when scaling from a 1MW to 100MW plant, only incremental gains are achieved thereafter. Depending on the specific project, the technical and commercial risk associated with construction of a larger plant might outweigh the benefit of any additional reductions in capital cost.

Other revenue sources

Grid connected electrolysis has the added benefit of providing a new form of flexible load to the electricity network. It therefore has the potential to provide, and be financially compensated for a number of grid firming services. Currently in the UK for instance, electrolyser operators can receive £10/MWh for frequency control (i.e. short term (seconds) intermittency) and £60-75/MWh for ramping up production during specified periods throughout the day[23]. This becomes a more important consideration as the proportion of VRE in the grid continues to increase.

A by-product of the electrolysis process is oxygen which is currently sold at a premium for various uses within the health sector. While large scale electrolysis would very quickly saturate this market, other potential offtakes for oxygen could include a growing aquaculture industry with a need to continually oxygenate fish farms as well as wastewater treatment plants.

Location

The primary consideration for hydrogen production via electrolysis is access to low cost and low emissions electricity. All of Western Australia, Queensland, South Australia, Victoria and the Northern Territory (NT) have a high solar PV and/or wind resource and combined with land availability, represent attractive areas for investment. Tasmania is a somewhat unique locality as it offers the potential to combine a high grade wind resource with hydro-electric generation which would lead to a high capacity factor.

Additionally, South Australia has fast become a global test bed for the integration of new energy technologies. With a high proportion of VRE already in the network and a pipeline of hydrogen demonstration projects, continued investment in hydrogen production and use is likely to be a significant enabler for other Australian states in developing their own local industries.

Of similar importance is the proximity of the electrolyser to the end use for hydrogen and the utilisation of existing infrastructure where possible. As shown in subsequent sections of the report, extensive storage and transport requirements can impact the cost of hydrogen delivered.

Accessibility to water should also be considered. As a general rule, the higher the treatment requirements, the more expensive the price of water. For instance, fresh water is cheaper than purifying ground water and desalination. Despite this variability, the cost of water typically makes up less than 2% of the cost of hydrogen production.

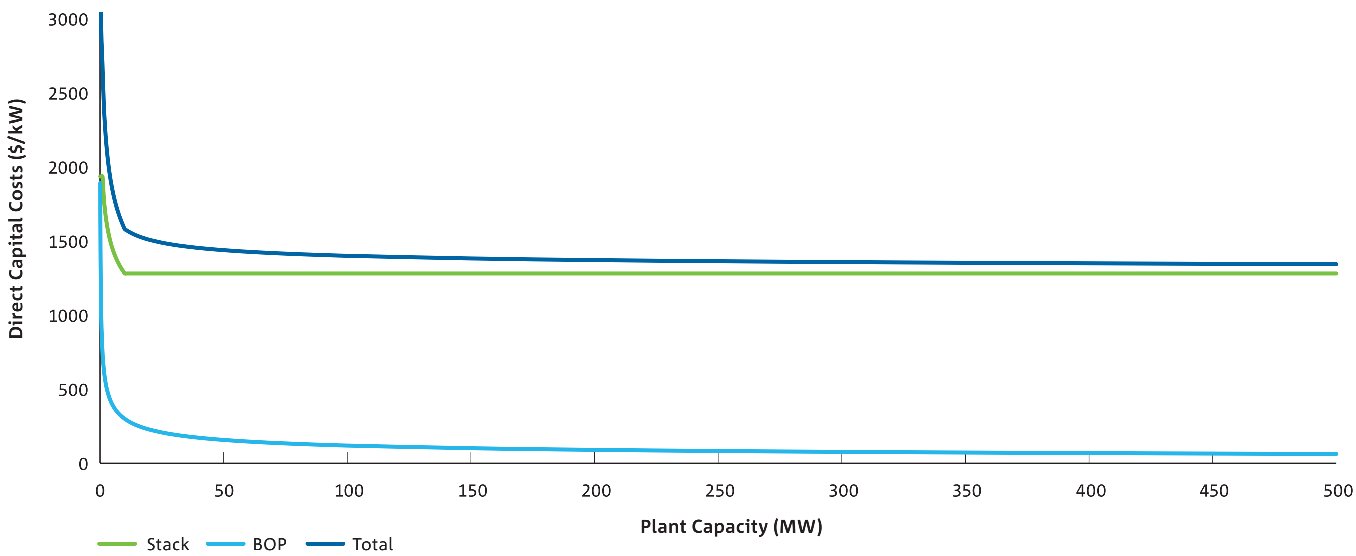


Figure 10. Impact of scale on LCOH for PEM

23 National Grid 2016, Demand Turn Up 2016, United Kingdom

3.1.4 POLICY/REGULATORY

Incentive/legislative schemes

As mentioned above, given the importance of scale in lowering the cost of hydrogen, policy designed to stimulate investment needs to focus on ensuring that markets for hydrogen exist and grow in accord with local production capabilities. This may be achieved either through incentive or legislative schemes which are discussed further in Section 5.

Where incentives are provided directly to hydrogen production facilities, it is critical that they are done so in a coordinated way. For instance, an incentive might only be provided for a pilot plant where the flow on effect can be clearly demonstrated or where there is a minimum number of entities pooling resources in a coordinated way.

Guarantee of origin

Given the importance of clean hydrogen in enabling decarbonisation across the energy and industrial sector, a 'guarantee of origin' scheme could be considered to properly verify and reward clean hydrogen production[24]. This scheme would apply equally to all forms of hydrogen production and the threshold for what is considered 'clean' could be raised as the industry continues to mature. An example of how this scheme might develop is the CertifHy project in Europe.

3.1.5 RD&D INVESTMENT PRIORITIES

Recent studies involving a number of industry stakeholders showed that a majority believed PEM will be the dominant electrolyser technology by 2030[26]. This, combined with the fact that AE is a relatively mature technology would suggest that PEM electrolysis is likely to continue to attract considerable RD&D investment.

However, there are also a series of less mature technologies such as high temperature electrolysis that have the potential to provide significant benefits and therefore should continue to be developed. These technologies, their maturity and potential for disruption are assessed further in Appendix A.

CASE STUDY: **CertifHy**

Launched in 2014, CertifHy aims to "[Design] the first EU-wide Green Hydrogen Guarantee of Origin for a new hydrogen market"[25]. This project has allowed the development of a definition for green and low-carbon hydrogen (referred to as Premium Hydrogen), and has produced a software accreditation system/trading platform ('GO scheme') with a roadmap for implementation.

Through the GO scheme, CertifHy aim to decouple the green attribute from the physical flow of the hydrogen, enabling transferability and consumption of Premium Hydrogen across Europe, irrespective of its production site. These features are intended to empower consumers and create a market pull for Premium Hydrogen.

CertifHy are currently undertaking a pilot demonstration, testing the GO scheme with four hydrogen production plants across Europe, each with differing production pathways. 2018 will see the first hydrogen GOs issued and subsequently traded and used on a commercial basis.

PEM RD&D priorities

RD&D priorities required to lower the cost of hydrogen are primarily focussed on reducing the physical stack size (via an increase in current density) and lowering the power consumption of the BoP. Specifically, these can be achieved by:

- Improvements in materials: e.g. lower resistance membranes, improved catalysts and more optimised gas diffusion layers
- Lower cost BoP design concepts (where BoP is combined and/or removed) and,
- Gradual improvement of various BoP components (e.g. heat exchangers, water gas separators, gas cleaning plant, etc).

24 International Energy Agency (IEA) 2015, Technology Roadmap: Hydrogen and Fuel Cells, Paris.

25 CertifHy 2017, Designing the first EU-wide Green Hydrogen Guarantee of Origin for a new hydrogen market, media release, accessed 2 April 2018, http://www.certifhy.eu/news-events/150-designing-the-first-eu-wide-green-hydrogen-guarantee-of-origin-for-a-new-hydrogen-market.html

26 Schmidt, O., Gambhir, A., Staffell, I., Hawkes, A., Nelson, J. and Few, S. 2017, Future cost and performance of water electrolysis: An expert elicitation study

Improvements can also occur via an increase in the lifetime of electrolyser stacks. Current PEM electrolyser stacks (as opposed to BoP) have been limited to lifespans of 80,000 hours due to regulations in jurisdictions such as Germany that require all pressurised vessels to be opened and inspected once this threshold has been reached. After opening, these vessels are no longer viable.

In the absence of similar regulations being imposed on electrolyser use in Australia, current technologies could operate for 120,000 hours without replacement. Further improvements in catalyst layers and membranes could see the stack life extend to 150,000 hours. Here, issues relating to corrosion of system components, catalyst preservation and failures in seals may also need to be addressed.

Emerging electrochemical technologies: High temperature electrolysis

One of the more notable emerging hydrogen production technologies is high temperature electrolysis. This technology is based on a solid oxide electrolyser (SOE) and has the advantage of electrolysing steam (at higher temperatures) rather than liquid water. This requires a lower electrical energy input. Depending on the scale and application, SOEs are currently at a TRL of 3-5. Further, operating at high temperatures allows for some product diversity where water inputs may be combined with CO_2 to produce syngas, an important building block in synthetic fuels production (described further in Section 5.4.2).

However, the higher efficiencies achieved only make sense economically if the heat source is received at no cost. Thus SOEs, once commercially available, would most likely be implemented at industrial sites or concentrated solar thermal (CST) plants where excess heat is available. Further, as with the alkaline electrolysers, SOEs do not respond well to a fluctuating energy input and so have limited use with VRE.

3.1.6 SUMMARY

The cumulative impact of the key priorities identified in this section on the LCOH for both PEM and AE are set out in Figure 11 below. It is expected that the cost of PEM and AE could be reduced to 2.29-2.79/kg and $2.54-3.10/kg respectively.

3.2 Thermochemical hydrogen production

Thermochemical hydrogen production, involves the interaction of heat and chemicals with hydrocarbons, coal or biomass to first produce syngas, a combination of hydrogen and carbon monoxide/carbon dioxide gas. The syngas is then reacted with water through the 'water-gas shift reaction', which increases the concentration of carbon dioxide and hydrogen gas. As carbon dioxide is produced as a by-product, carbon capture and storage (CCS) is necessary to facilitate a low emissions pathway.

3.2.1 MATURE TECHNOLOGIES

To date, steam methane reforming (SMR) represents the most widely used method for hydrogen production, currently comprising 48% globally[27]. This together with coal gasification have had the highest level of interest in Australia and are therefore the focus of this subsection. A description of other mature thermochemical production technologies can be found in Appendix A.

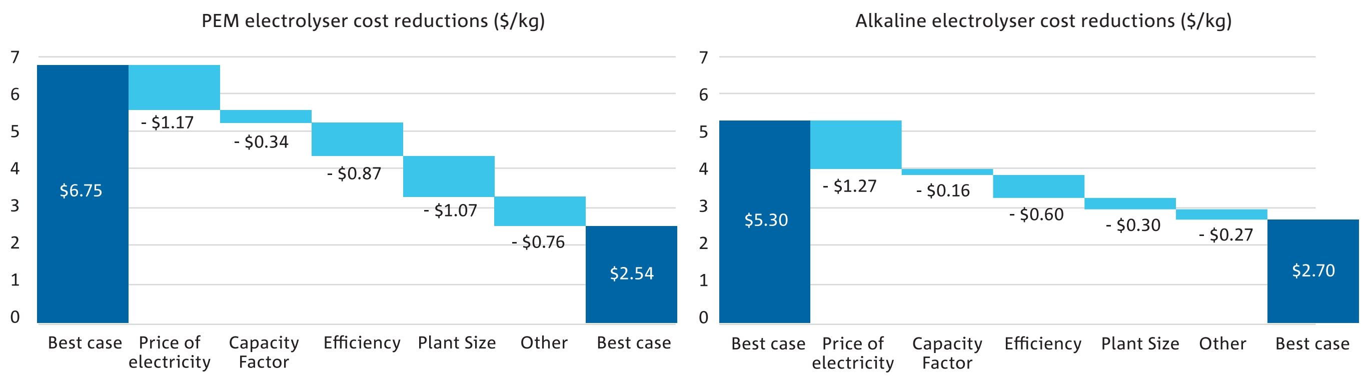


Figure 11. Cumulative impact of key investment priorities for PEM and AE

27 Weger, L., Abánades, A. and Butler, T. 2017, Methane cracking as a bridge technology to the hydrogen economy, International Journal of Hydrogen Energy, Volume 42, Issue 1, Pages 720-731

TABLE 4. MATURE THERMOCHEMICAL HYDROGEN PRODUCTION TECHNOLOGIES

PROCESS	DESCRIPTION	DIS/ADVANTAGES
Steam Methane Reforming (SMR)	Light hydrocarbons, such as natural gas or biomethane (upgraded biogas), are mixed with steam in the presence of a catalyst at high temperatures (~750°C) and moderate pressure to produce syngas. SMR on its own uses approximately 4.5L of water per kgH_2[28].	+ Established technology - Requires purification - High temperature required
Coal Gasification	Gasification involves reacting dried and pulverised coal with oxygen and steam or controlled amounts of oxygen in a gasifier at high temperatures and pressure to produce syngas. To date, black rather than brown coal has been the dominant fuel sourced globally. This currently comprises 18% of global hydrogen production[27]. Coal gasification uses approximately 9L of water per kgH_2[28].	+ Abundant fuel - Requires purification

For each of the technologies mentioned above, hydrogen purity at the point of production needs to be increased using various methods such as pressure swing adsorption (PSA) and gas separation membranes which can achieve purity levels of 99.9999%[29]. The pressure of the hydrogen produced ranges from 8 to 28 bar depending on the type of PSA performed[30].

The CO_2 generated as a by-product can be captured and stored in underground geological reservoirs. Depending on the technology being used, capture rates can be between 90-100%[31].

Base case costs (2018)

Base case costs for SMR and coal gasification (with CCS) are presented in Table 5. While black coal has been modelled under the base case scenario, brown coal gasification, with specific reference to current activities in the Latrobe Valley in Victoria is considered further in Section 3.2.2.

TABLE 5. BASE CASE LCOH FOR SMR AND COAL GASIFICATION (2018)

	SMR	BLACK COAL GASIFICATION
LCOH ($/kg)	2.27-2.77	2.57-3.14

Identification of material cost drivers

As shown in FIgure 12, the cost of CCS has a relatively low impact on the LCOH. This is primarily due to the fact that capture of CO_2, typically the most expensive CCS component, is embedded in the hydrogen extraction and purification process. This scenario assumes that the production and storage plants are reasonably proximate and therefore the CO_2 transport costs are absorbed into the overall storage cost of $10-40/t[31, 32].

Both SMR and black coal gasification are relatively mature technologies. Key drivers of cost therefore include:

1. **Price of energy input**: For both SMR and coal gasification, the LCOH can be impacted by the cost of gas and coal. While significant fluctuations in the price of black coal are low risk, trends relating to the price of natural gas, particularly in an Australian context, is likely to be of greater concern.

2. **Plant size**: Thermochemical production plants are typically built at scale (>500,000kg/day) when combined with CO_2 storage.

28 Mehmeti, A. 2017, Life cycle assessment and water footprint of hydrogen production methods: From conventional to emerging technologies, Italy
29 Keller, T. and Shahani, G. 2016, PSA technology: Beyond hydrogen purification
30 Sircar, S. and Golden, T.C. 2000, Purification of Hydrogen by Pressure Swing Adsorption, Separation Science and Technology, p 667-687
31 CO2CRC 2015, Australian Power Generation Technology Report
32 CO2 reservoirs have been modelled to accept 2MT CO2 per year for 30 year asset life as per CO2CRC 2015.

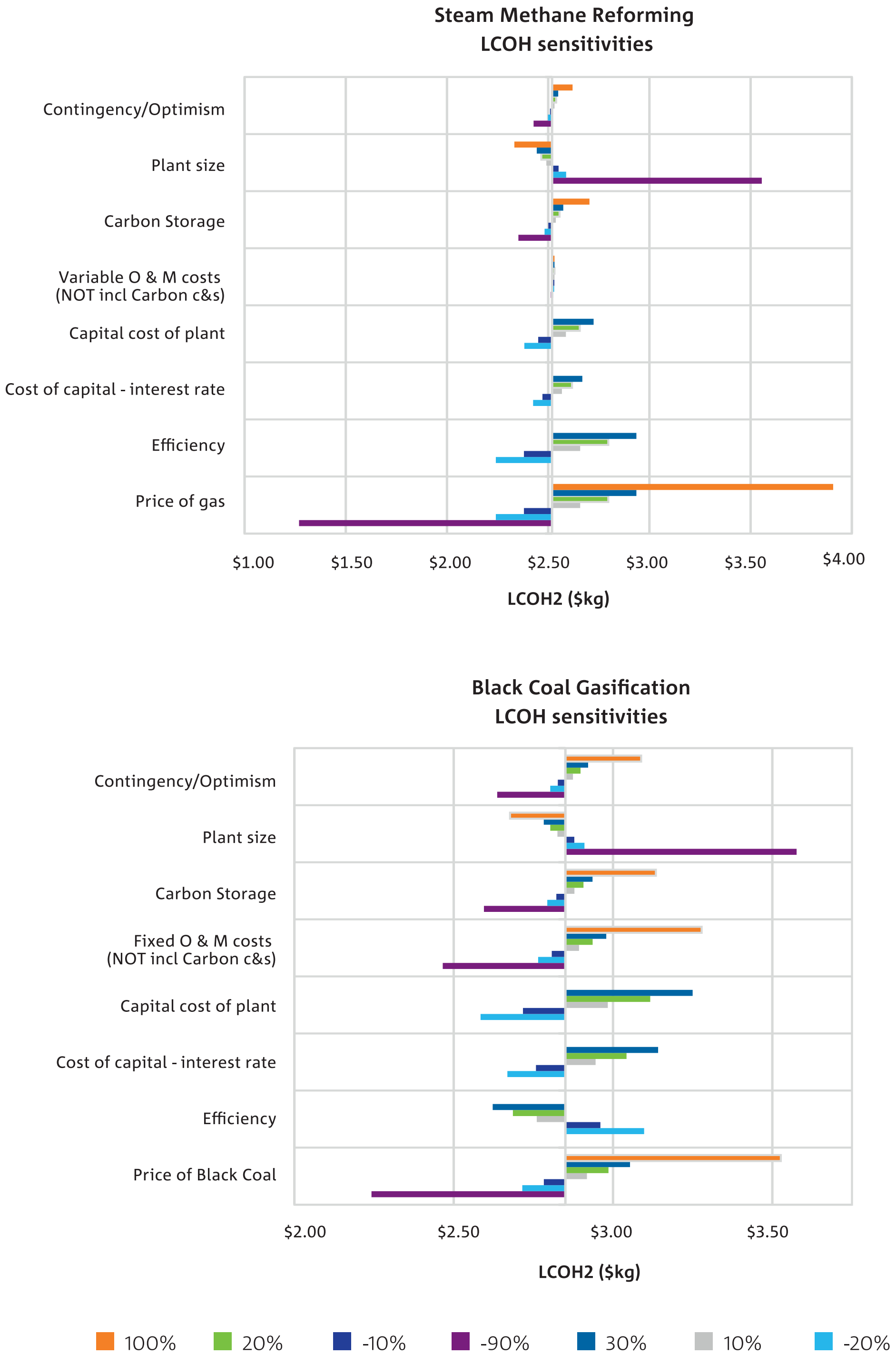


Figure 12. SMR and black coal gasification tornado charts

3.2.2 COMMERCIAL IMPLICATIONS AND OPPORTUNITIES

Energy input

Although SMR is currently the cheapest form of hydrogen generation, investment in new large scale demand may prove challenging given the current state of the natural gas industry in Australia (as discussed previously).

Globally, thermal black coal is the most commonly used energy input for gasification. In an Australian context, black coal remains a higher priced commodity (~$3/GJ) than brown coal due to servicing demand from the export market and local coal-fired power stations.

Victorian brown coal is cheaper (~$1.50/GJ) and although demonstrated in a number of gasification projects overseas, has less favourable characteristics including high water content and volatility. Use of brown coal can also result in a greater build-up of slag in the gasifier, reducing efficiency and increasing O&M costs.

Location requirements

The potential for both SMR and coal gasification in Australia is somewhat dictated by the location of the resource as well as the availability of a properly characterised CO_2 storage reservoir.

For SMR, the North West shelf of Australia contains extensive natural gas reserves (if made available) as well as a number of potential CO_2 storage reservoirs in the form of nearby depleted gas fields[33].

CO_2 storage from coal gasification is less straightforward. While black coal may provide a preferred gasification feedstock, it is concentrated in New South Wales and Queensland where storage reservoirs are either not well characterised or situated onshore and therefore face a greater social licence risk. In Victoria however, there are significant brown coal reserves in the Gippsland region and a developed offshore reservoir with known subsurface geology suitable for CCS. These factors have prompted the development of the Hydrogen Energy Supply Chain (HESC) project in the Latrobe Valley.

Modelling was undertaken as part of this study to assess the competitiveness of brown coal to hydrogen production with reference to Kawasaki Heavy Industries' feasibility study on clean hydrogen[34]. If successful at demonstration, it is expected that the LCOH for the commercial plant will be in the order of $2.14-$2.74/kg[35].

CASE STUDY:
HYDROGEN ENERGY SUPPLY CHAIN (HESC)

The HESC is being led by Kawasaki Heavy Industries (KHI) in collaboration with Electric Power Development Company (J-Power), Iwatani Corporation (Iwatani), Marubeni Corporation (Marubeni) and AGL. In addition, it is being supported by the Australian, Victorian and Japanese governments.

During the pilot phase, brown coal will be gasified in the Latrobe Valley to produce hydrogen-rich syngas which will subsequently be purified, enabling Victoria to find new markets for brown coal. The hydrogen will then be transported to the Port of Hastings to be liquefied and loaded onto a specialised tanker for transport to Japan.

As part of the pilot project, the first delivery of hydrogen is scheduled to be in 2020-2021. Depending on the successful completion of this phase, lessons learnt will be applied to the design and construction of the commercial scale facilities. For the commercial scale facility, the Victorian Government's CarbonNet project may also provide the carbon capture and storage solution needed to reduce emissions. Operation of the commercial phase of the project is expected to begin in the 2030s.

33 CSIRO 2017, Low Emissions Technology Roadmap, Australia
34 Yoshino, Y., Harada, E., Inoue, K., Yoshimura, K., Yamashita, S. and Hakamada, K. 2012, Feasibility Study of "CO2 Free Hydrogen Chain" Utilizing Australian Brown Coal Linked with CCS, Energy Procedia, Volume 29, Pages 701-709
35 This modelling was undertaken by CSIRO and only contains information that has been made publically available by members of the HESC project

Scale

SMR and coal gasification plants are capital intensive, and therefore must be built at scale in order to offset the cost of the asset. In the context of low emissions hydrogen, CCS represents an additional interdependent asset with a high capital cost that requires a constant stream of CO_2 in order to generate sufficient revenue. In practice, it will most likely be the capacity of the CO_2 storage reservoir that drives the size of the SMR/gasification plant.

According to KHI's feasibility study, the coal gasification plant scale will also be driven by the required capacity and economics of the liquefaction shipping vessel which is intended to transport 238,000 tonnes per annum (tpa) to Japan[36].

As the local hydrogen industry develops, the deployment of SMR/gasification plants with CCS at the scales required to be economic could very quickly saturate a domestic hydrogen market. For instance, a small scale plant producing 100,000kgH_2/day would require approximately 235,000 passenger FCEVs on the road. With this, it would be difficult to establish the domestic offtakes needed to manage the risk of investment in this plant type. Therefore, in the first instance, these plants are likely to depend on the success of the hydrogen export market (as discussed further in Section 5.5). However, once the export offtakes and infrastructure have been established, there may well be scope to service the domestic market.

Multiple revenue streams

Production of syngas as an intermediary step has the potential to create additional revenue streams for SMR and gasification plants. This includes the production of synthetic fuels (discussed further in Section 5.4.2) and direct combustion in a gas turbine for electricity. SMR and gasification plants could be built with the added flexibility of being able to adapt products based on changes in demand and commodities pricing.

Further, the risk of investment in large scale CCS projects may be mitigated by forming CO_2 offtake agreements with other emissions intensive entities. This would require the development of a potential CCS reservoir alongside multiple sources of CO_2, as is the case with the CarbonNet project in Victoria's Gippsland Basin as well as a number of natural gas and LNG refineries in Western Australia.

Integration and allocation of risk

As highlighted above, a vertically integrated approach will allow for greater optimisation of assets. However given the high capital cost, the investment risk is most likely to be shared under a joint venture arrangement. The addition of CCS however may also require an additional consortium.

Given that CO_2 capture is an integrated part of thermochemical hydrogen production, it is likely that the SMR/gasification plant operator would form a 'take or pay' arrangement with a separate entity responsible for transporting and storing the CO_2, as illustrated in Figure 13. This allows for further de-risking of the assets and increases the flexibility of the reservoir operator to accept CO_2 from multiple sources.

While a third party could be engaged to build and operate the CO_2 pipeline and storage, as discussed in Section 3.2.3, there is still an important role for government in managing the long term risk associated with CO_2 storage in underground aquifers, a risk that is unlikely to be accepted by the private sector.

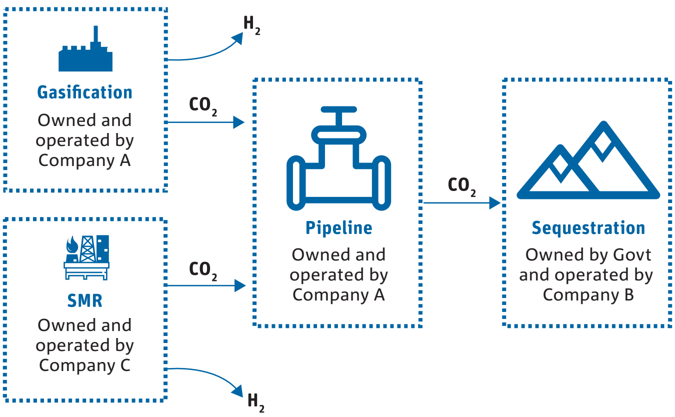


Figure 13. Potential business model diagram for coal gasification/SMR with CCS

36 Yoshino, Y., Harada, E., Inoue, K., Yoshimura, K., Yamashita, S. and Hakamada, K. 2012, Feasibility Study of "CO2 Free Hydrogen Chain" Utilizing Australian Brown Coal Linked with CCS, Energy Procedia, Volume 29, Pages 701-709

3.2.3 POLICY AND REGULATION

Policy

In the absence of proponents willing to pay a premium for hydrogen production using CCS, a legislative requirement or long term pricing signal would be needed to incentivise investment. The Gorgon project in WA provides an example of a legislative requirement, wherein CCS was enforced under the Barrow Island Act due to the emissions intensity of the offshore gas wells being mined.

Long term liability for CO_2 storage

A regulatory framework for CCS is also required to support the long term liability associated with storage of CO_2[37]. The Quest Project in Canada provides an example of how clear, long term legislation can facilitate liability transfer and government pore ownership, which has been critical in allowing large scale CCS development.

3.2.4 RD&D INVESTMENT PRIORITIES

Current RD&D priorities for thermochemical production are focussed on reducing the energy and costs associated with breaking water molecules in steam, separating the CO_2 and purifying the hydrogen. These energy and cost reductions are being considered through both incremental developments in existing technology and other emerging systems (assessed further in Appendix A).

Other key RD&D priorities involve the substitution of coal with biomass as a lower emissions input to gasification.

CO_2 Separation and Purification

Hydrogen separation from syngas in thermochemical production can make up half of the production costs[40], with the separation of CO_2 alone accounting for more than 20% of total expenditure[41].

The incumbent method of purification, pressure swing adsorption (PSA) has the primary drawback of low hydrogen yields. Hydrogen selective membranes however are an emerging technology with the potential to displace the current methods. This technology acts as a filter, allowing only hydrogen to pass through. This allows for reduced energy use, continuous operation, higher conversion and a smaller footprint[42]. It is also projected to have a lower investment cost as compared with PSA.

Process Intensification

Process intensification uses novel design and manufacturing techniques that allow a process to be made smaller without the loss of production capacity, thereby allowing for reductions in capital cost. This has been applied to the synthesis of dimethyl ether (DME) which is a closely associated reaction to thermochemical hydrogen production. By improving the catalyst selection

CASE STUDY: QUEST PROJECT

In the Quest Project Canada, hydrogen is produced via SMR and the resulting CO_2 is stored underground. In 2010, the Albertan Government passed the *The Carbon Capture and Storage Statutes Amendment Act*[38]. Within the act, provisions were established to:

- Identify that pore space for the purpose of CCS is solely owned by the Government, ensuring that the government had the property rights to meet its CCS goals
- Transfer long-term liability to the Government so that upon completion of sequestration, the ownership of the CO_2 is adopted by the government
- Establish a fund, paid into by CCS operators and managed by the Alberta government, to service ongoing monitoring costs for CCS projects

Following the passage of this CCS legislation and subsequent approval applications, Shell began construction in 2012 with carbon capture beginning in 2015. After three years of operation, the Quest project has captured and stored three million tonnes of CO_2[39].

37 This overarching requirement has been legislated under s400 of the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cth)
38 Carbon Capture and Storage Statutes Amendment Act, 2010 (Alberta, Canada)
39 Shell Canada 2018, Quest Carbon Capture and Storage available at https://www.shell.ca/en_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html#vanity-aHR0cDovL3d3dy5zaGVsbC5jYS9xdWVzdA [Accessed 14 June 2018]
40 Al-Mufachi, N.A., Rees, N.V. and Steinberger-Wilkens, R. 2015, Hydrogen selective membranes: A review of palladium-based dense metal membranes, Renewable and Sustainable Energy Reviews, Volume 47, Pages 540-551
41 Ryu, H. and Jin, G. 2007, Chemical-looping hydrogen generation system: Performance estimation and process selection, Korean Journal of Chemical Engineering, Volume 24, Issue 3, Pages 527-531
42 Yin, H. and Yip, A. 2017, A Review on the Production and Purification of Biomass-Derived Hydrogen Using Emerging Membrane Technologies, Catalysts 2017, Volume 7, Page 297

and combining the distillation reaction and separation into a single unit using a dividing wall column design, energy requirements were reduced by 28% and equipment costs by 20%[43]. Utilisation of process intensification could allow for an economically viable decentralised thermochemical hydrogen production plant that can benefit smaller, remote hydrogen consumers, as long as the resulting CO_2 can be appropriately stored or utilised.

Biomass gasification

Biomass such as wood chips, agriculture and forestry residue, can be gasified at high temperatures (600-1000°C) to produce syngas (TRL 6-8). While this process has been used primarily for power generation, it could allow for lower emissions hydrogen production without the need for CCS. Individual technologies within this process are generally mature, however further RD&D is required in connecting them for the primary purpose of producing hydrogen. Challenges also remain in understanding the characteristics of different biomass feedstocks and in process handling due to high temperatures required[44].

Other emerging thermochemical hydrogen production technologies

Of the other emerging thermochemical hydrogen production technologies (summarised in Appendix A), chemical looping (TRL 3) could solve the challenge of costly purification as it produces ultra-pure hydrogen using either coal, natural gas or biomass as a feedstock. This technology is gaining more attention as it incorporates CO_2 capture at no energy penalty[45] and allows for the CO_2 to be easily removed for sequestration. The last few years have seen an increased R&D focus on this process with results evident in the demonstration of a 50kW system[46].

Depending on the availability of natural gas, methane cracking, which removes the need for CCS by producing solid carbon as a by-product also offers significant potential for disruption.

Concentrating solar fuels is another potential area of interest (TRL 4 -6). Hydrogen may be produced by converting a feedstock to a chemical fuel using high-temperature thermochemical reactions, powered by concentrated solar radiation. Where the feedstock is a carbonaceous fuel (e.g. natural gas, coal or biomass), it is converted into syngas using solar energy. It is also possible to use concentrated solar to directly dissociate water using catalysts at extremely high temperatures. However this process is currently at a lower TRL level compared with when a carbon feedstock is used.

3.2.5 SOCIAL LICENCE

When compared with other hydrogen production pathways, thermochemical production coupled with CCS is likely to carry additional social licence challenges. This is due to the risk associated with the capital intensive nature of these types of projects, concerns over continued use of fossil fuels and perceived uncertainty regarding the long term effectiveness of CO_2 storage.

Stakeholder engagement efforts intending to gain support for thermochemical hydrogen production should be targeted to both the broader Australian community and communities adjacent to prospective plants.

3.2.6 SUMMARY

Hydrogen production from brown coal in Victoria, most likely to be commercialised through the successful demonstration of the HESC project, could see hydrogen produced at approximately $2.14 – 2.74/kg when the commercial plant comes online in the 2030s. Should SMR and black coal gasification projects also be developed, given they are mature technologies, incremental improvements could be achieved (SMR: $1.88 – $2.30/kg, black coal gasification: $2.02 – $2.47/kg) assuming energy input prices remain constant and that the points of hydrogen generation and CO_2 sequestration are reasonably proximate.

43 Azizi, Z., Rezaemanesh, M., Tohidian, T. and Rahimpour, M. 2014, Dimethyl ether: A review of technologies and production challenges, Chemical Engineering and Processing: Process Intensification, Volume 82, Pages 150-172

44 Chang, A., Chain, H., Lin, F., Lin, K. and Chen, C. 2011, Biomass gasification for hydrogen production, International Journal of Hydrogen Energy, Volume 36, Issue 21, Pages 14252-14260

45 Luo, M., Yi, Y., Wang, S., Wang, Z., Du, M., Pan, J. and Wang, Q. 2018, Review of hydrogen production using chemical-looping technology, Renewable and Sustainable Energy Reviews, Volume 81, Pages 3186-3214

46 Voitic, G. and Hacker, V. 2016, Recent advancements in chemical looping water splitting for the production of hydrogen, RSC Advances, Issue 100

4 Storage and Transport (of hydrogen)

In its unpressurised gaseous state, hydrogen retains a relatively low volumetric density (kg/m^3). There are therefore a number of technologies that improve the economics of storage by increasing the volumetric density of hydrogen (i.e. higher volumetric densities allow for greater quantities of hydrogen to be stored inside a tank of fixed size). Once stored, hydrogen can then be transported from production to point of use via a number of methods.

4.1 Storage

4.1.1 OVERVIEW

The most common hydrogen storage method is compression via pressurisation in steel or carbon composite cylinders[47]. However, the lower hydrogen density associated with pressurisation has encouraged the use of liquefaction and exploration of other chemical carriers such as ammonia, particularly in the context of hydrogen transport.

Although material carriers have a higher hydrogen density, all retain an additional energy penalty and cost associated with the recovery of hydrogen from the carrier molecule. Liquid organic hydrogen carriers (e.g. toluene) are considered more emerging technologies and discussed further in Section 4.1.5.

47 Makridis, S. 2016, Hydrogen storage and compression, Methane and Hydrogen for Energy Storage

TABLE 6. MATURE HYDROGEN STORAGE TECHNOLOGIES

TECHNOLOGY	DESCRIPTION[48, 49]	DIS/ADVANTAGES
Compression		
Low pressure tanks	No additional compression needed from hydrogen production. Only used for stationary storage where lower quantities of hydrogen are needed relative to available space.	+ Established technology - Poor volumetric energy density
Pressurised tanks	A mechanical device increases the pressure of the hydrogen in its cylinder. Hydrogen can be compressed and stored in steel cylinders at pressures of up to 200 bar. While composite tanks can store hydrogen at up to 800 bar[49], pressures typically range from 350 to 700 bar. Compression is used for both stationary storage and transport of hydrogen.	+ Established technology - Low volumetric energy density - Energy intensive process
Underground Storage	Hydrogen gas is injected and compressed in underground salt caverns which are excavated and shaped by injecting water into existing rock salt formations.[50] Withdrawal and compressor units extract the gas when required.	+ High volume at lower pressure and cost + Allows seasonal storage - Geographically specific
Line packing	A technique used in the natural gas industry, whereby altering the pipeline pressure, gas can be stored in pipelines for days and then used during peak demand periods.	+ Existing infrastructure + Straightforward hydrogen storage technique at scale
Liquefaction		
Cryogenic tanks	Through a multi-stage process of compression and cooling, hydrogen is liquefied and stored at -253˚C in cryogenic tanks. Liquefaction is used for both stationary storage and transport of hydrogen.	+ Higher volumetric storage capacity + Fewer evaporation losses - Requires advanced and more expensive storage material
Cryo-compressed	Hydrogen is stored at cryogenic temperatures combined with pressures approaching 300 bar.	+ Higher volumetric storage capacity + Fewer evaporation losses - Requires advanced and more expensive storage material
Material based		
Ammonia (NH_3)	Hydrogen is converted to ammonia via the Haber Bosch process. This can be added to water and transported at room temperature and pressure. The resulting ammonia may need to be converted back to hydrogen at the point of use.	+ Infrastructure is established + High hydrogen density (17.5% by weight) - Almost at theoretical efficiency limit - Plants need to run continuously - Energy penalty for conversion back to hydrogen - Toxic material

48 Preuster, P., Alekseev, A. and Wasserscheid, P. 2017, Hydrogen Storage Technologies for Future Energy Systems, Annual Review of Chemical and Biomolecular Engineering, Volume 8, Page 445-471

49 Makridis, S. 2016, Hydrogen storage and compression, Methane and Hydrogen for Energy Storage

50 Khaledi, K., Mahmoudi, E., Datcheva, M. and Schanz, T. 2016, Stability and serviceability of underground energy storage caverns in rock salt subjected to mechanical cyclic loading, International Journal of Rock Mechanics and Mining Sciences, Volume 86, Pages 115-131

The mature storage technologies are set out in Table 6 and discussed further in the following subsections. While methanol synthesis from hydrogen should also be considered mature, in Australia there is currently minimal activity relating to its use as a potential hydrogen carrier and it has therefore not been included here.

Selection of the most appropriate storage technology represents a trade-off between the quantity of hydrogen required, tanks size (m^3) (or number of tanks) and energy usage. Other considerations that can impact storage technology selection include the hydrogen purity and speed of release. Table 7 below shows the hydrogen density and corresponding energy requirements for each of the technologies at different operating environments.

4.1.2 COMPRESSION TECHNOLOGIES

As mentioned, hydrogen is produced via electrolysis up to 35 bar (depending on the technology used). While hydrogen can be stored at this pressure (i.e. without additional compression), it is likely to only be economically viable for lower volumes of hydrogen. This is due to plant space limitations as well as the higher capital cost of larger or additional tanks. In contrast, as the plant scale increases, the overall cost of compression is reduced on a per kgH_2 basis.

For the purpose of illustration, Table 8 represents the cost of compression at different pressures for a production plant with a capacity of 210,000kgH_2/day (a mid-sized hydrogen production plant). The 35 bar option is the most expensive in this scenario due to the number of tanks required at this scale.

TABLE 7. COMPARISON OF ENERGY USAGE AND HYDROGEN DENSITY

STORAGE TECHNOLOGY	HYDROGEN DENSITY, KG/M³	ENERGY REQUIRED
No pressure (30-35 bar and 25˚C)	2.77	Current PEM electrolysers can produce hydrogen at this pressure
Low pressure (50-150 bar and 25˚C)	3.95 – 10.9	0.2 – 0.8 kWh/kgH_2
High pressure (350 bar and 25˚C)	23	4.4 kWh/kgH_2
Liquid Hydrogen (liquefaction) (-253˚C), 1 bar	70.8	10 – 13 kWh/kgH_2
Stored as liquid ammonia (-33˚C), 1 bar	121	2 – 3 kWh/kgH_2 based on 12 kWh/kg ammonia produced[51]. Additional ~8k Wh/kgH_2 required to recover the hydrogen from ammonia (discussed in s. 4.1.4)
Stored as liquid ammonia (25°C), 10 bar	107	

TABLE 8. COMPARISON OF COMPRESSION COSTS AT DIFFERENT PRESSURES (2018)[52]

	35 BAR	150 BAR	350 BAR
LCOH ($/kg)	0.43-0.53	0.30-0.37	0.34-0.42

51 Giddey, S., Badwal, S., Munnings, C. and Dolan, M. 2017, Ammonia as a Renewable Energy Transportation Media, ACS Sustainable Chemistry and Engineering, 5 (11), Pages 10231-10239rock salt subjected to mechanical cyclic loading, International Journal of Rock Mechanics and Mining Sciences, Volume 86, Pages 115-131

52 Modelling assumes that the storage capacity is charged and discharged on a daily basis from tanks of 100m^3 capacity each

Where large volumes of hydrogen storage are required (e.g. in the order of 210,000kg/day for 30 days), underground storage such as salt caverns (if available) are likely to be the most cost effective at approximately $0.20/kg (with pressure at 45 bar). Line packing also becomes more relevant at scale, particularly if hydrogen is already being distributed by pipe.

Both underground storage and line packing provide important opportunities in hydrogen storage for export or for overcoming variations in seasonal demand for gas (i.e. winter gas usage can be more than triple[53] that of summer).

RD&D investment priorities

Significant compression related energy costs can be saved if hydrogen is first produced at elevated pressures. However there are numerous challenges to this approach as electrolysers typically operate better at lower pressures (typically up to 35 bar maximum).

Ionic compressors have the potential to generate a 40% energy saving over the incumbent mechanical compressors. Although currently expensive, ionic compressors are available commercially and are already in operation at several hydrogen fuelling stations around the world. Bearings and seals, which are two of the most common sources of failure in mechanical compressors, are not required for ionic compression[54].

Another method for reducing the energy cost associated with hydrogen compression is through the use of an electrochemical compressor (TRL 3). These devices work in an identical manner to an electrolyser but instead of water on one side of the membrane, hydrogen is used. This hydrogen is "pumped" electrochemically across the membrane from a low pressure side chamber to a high pressure chamber. Electrochemical compression has the potential to displace mechanical compression by operating at higher efficiencies (70-80%), with a smaller footprint and the benefit of no moving parts. This can result in lower maintenance costs and noiseless operation.

For underground storage, although there is a high level of confidence in the ability of salt caverns to store hydrogen, a feasibility analysis would be needed to assess potential storage capacity in an Australian context. A preliminary study undertaken for the purposes of storing natural gas showed that most sites are concentrated in Western Australia[55].

There is also potential for hydrogen to be compressed and injected into depleted gas fields (TRL 2). Australia's east coast is estimated to have the capacity to store approximately 205PJ of natural gas in its gas fields, and further investigations are currently underway[56]. With far larger volumes and more available distributions than salt caverns, depleted gas fields may provide a more suitable long term storage option in the future. Current challenges to this form of storage include impurity gases already contained within the gas field and diffusion of the hydrogen[57].

Summary

With expected improvements in efficiencies via the technologies described above, compression in tanks is likely to add an additional ~0.3/kg to the cost of hydrogen produced by 2025.

4.1.3 LIQUEFACTION TECHNOLOGIES

Liquefaction (including cryo-compression) has a higher cost than compression. However, as mentioned previously, liquefaction becomes more economically viable where there are stringent limitations on plant space and high hydrogen demand. These plants are yet to be built at large scale and so base case costs for a 50,000kgH_2/day plant were found to add an additional ~$2.57-3.14/kg to the LCOH.

RD&D

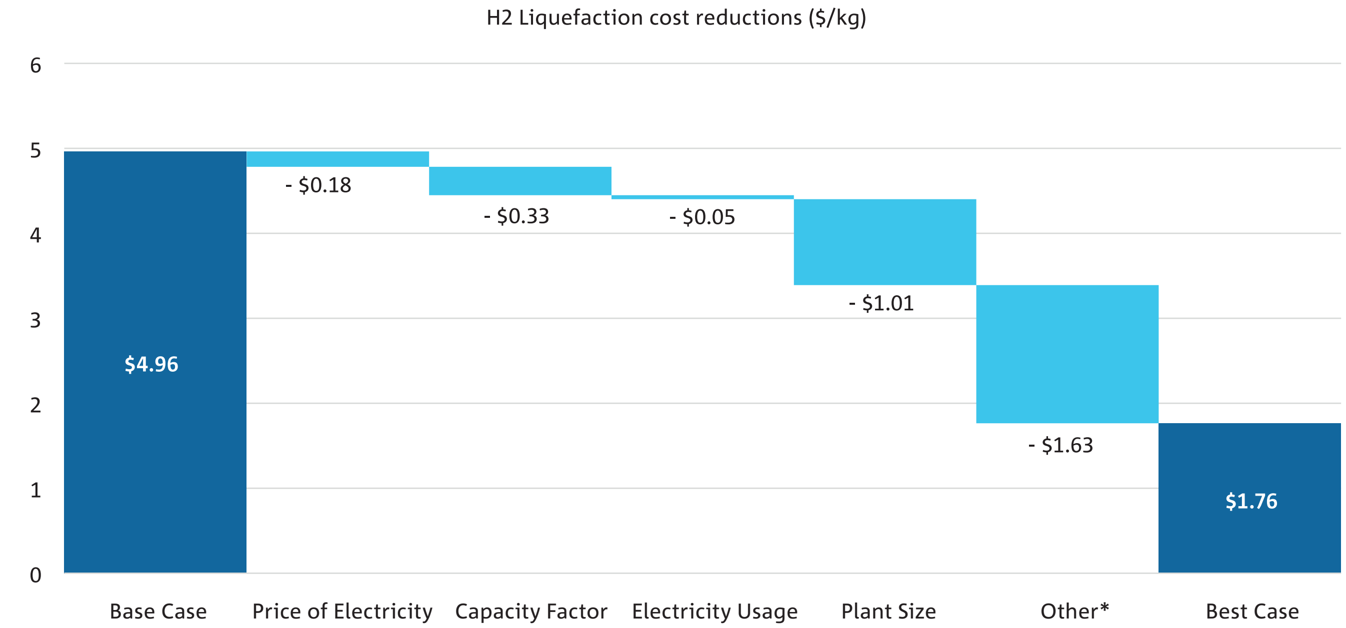
R&D priorities are largely focussed on improving the efficiency (or energy usage) for liquefaction. This can be achieved via:

- Reductions in boil-off (i.e. vaporisation) rates
- Improvements in engineering, insulation, heat exchangers and coolants
- Improvements in hydrogen compression technology
- Larger and better insulated storage tanks

Summary

The cumulative impact of plant size increases (to 210,000kg/day), favourable electricity pricing and listed R&D improvements on the cost of liquefaction is shown in Figure 14. Liquefaction is expected to add approximately $1.59-1.94/kg to the cost of hydrogen produced by 2025.

53 Australian Energy Market Operator 2017, Victoria Gas Planning Report
54 U.S. Department of Energy, Gaseous Hydrogen Compression, accessed 14 June 2018, https://www.energy.gov/eere/fuelcells/gaseous-hydrogen-compression
55 Gill, G. 2016, Optimising CSG Production with Underground Gas Storage Facilities, Innovative Energy Consulting
56 Core Energy Group 2015, Gas Storage Facilities, Eastern and South Eastern Australia
57 Amid, A., Mignard, D. and Wilkinson, M. 2016, Seasonal storage of hydrogen in a depleted natural gas reservoir, International Journal of Hydrogen Energy, Volume 41, Issue 12, Pages 5549-5558



* Other consists of improvements in capex and opex as a result of plant size increases

Figure 14. Cumulative impact of improvements for liquefaction

4.1.4 AMMONIA

Utilisation of ammonia as a hydrogen carrier also represents an important opportunity, particularly in the context of hydrogen export. While energy requirements of ammonia synthesis are relatively low when compared with liquefaction, traditional Haber Bosch plants are capital intensive and so must be built at scale in order to be competitive. For comparison against the other storage technologies already considered, a 210,000kg H_2/day plant adds approximately $0.24-0.29/kg as a levelised cost of ammonia (LCONH$_3$). This is equivalent to an LCOH of $1.39-1.68/kg as the cost of hydrogen stored within the ammonia[58].

However, given that the product is ammonia, there is an additional energy penalty (~ 8 kWh/kg H_2[59]) and cost associated with separating the hydrogen at the point of use. This cost is not reflected in the modelling due to the current maturity of the hydrogen recovery technology (discussed further in the subsection below).

While existing ammonia plants are likely to require some modifications to incorporate clean hydrogen, there is potential to reduce capital costs for ammonia as a hydrogen transport method by leveraging current infrastructure. In 2016, Australia produced 1.3 million tonnes of ammonia (for use in fertilizers and chemicals) with a limited increase to 1.4 million tonnes predicted for 2025[60,61]. This increase in production is not expected to reach the production capacity of the six ammonia plants currently operating in Australia which have a total capacity 1.74 million tonnes per annum[62].

RD&D Investment priorities

There are a number of emerging technologies designed to improve the cost and efficiency of ammonia synthesis. For example, although early stage, ‘direct ammonia synthesis’ via electrolysis presents an opportunity for modular and distributed ammonia production that by-passes the traditional Haber Bosch process. This and other emerging ammonia synthesis technologies are assessed further in Appendix A.

As mentioned, the success of ammonia as a storage mechanism for hydrogen is largely dependent on being able to recover hydrogen at the point of use. While ammonia cracking reactors that separate hydrogen are available, metal membranes using catalysts (currently TRL 6) are needed to produce the high-purity hydrogen required of fuel cells. These membranes are modular in design and so can be utilised at small scale, such as at a refuelling station, or at large scale import terminals.

58 Assumed hydrogen density of 107kg/m3 at 25˚C and 10 bar

59 Giddey, S., Badwal, S., Munnings, C. and Dolan, M. 2017, Ammonia as a Renewable Energy Transportation Media, ACS Sustainable Chemistry and Engineering, 5 (11), Pages 10231-10239

60 Chemicals Technology, Burrup Fertilisers Ammonia Plant, retrieved from http://www.chemicals-technology.com/projects/burrup_fert/ on March 20 2018; Chemical Manufacturers Australia (CSBP), retrieved from https://www.csbp.com.au/products/AAN/ammonia on March 20 2018;

61 This growth projection excludes potential for new demand for low emissions ammonia if renewable hydrogen can be successfully integrated

62 Calculated using a range of resources from each ammonia plant

Summary

While the Haber-Bosch process is relatively mature, incremental improvements in processes such as air separation and purification could allow for a reduction in cost. In the best case, this would add \$0.19-\$0.23/kgNH_3 (1.10 – 1.33/kgH_2) to the cost of hydrogen produced (with ammonia as the product).

4.1.5 OTHER EMERGING STORAGE TECHNOLOGIES

Liquid organic hydrogen carriers

Through hydrogenation (i.e. adding hydrogen), organic liquids can be loaded with hydrogen, and subsequently dehydrogenated via the application of heat or catalysis. This enables the storage and transport of hydrogen as a liquid at ambient temperature and pressure at over 6% weight[63]. After dehydrogenation, the organic liquid can be re-used.

Toluene is one such carrier that has been studied since the 1980s. As a technically viable technology, a number of companies are exploring toluene's potential for large scale hydrogen storage and transport. One pathway involves the conversion of toluene to methylcyclohexane (MCH) (TRL 7) via hydrogenation. Current challenges include the high operating temperature, pressure and purification requirements. MCH is also a considered a toxic substance.

Dibenzyltoluene (DBT), an alternative to MCH, is also being developed as a hydrogen carrier (TRL 6-7) and is reported to be safer, easier to handle and cheaper[64]. That said, temperatures of 250˚C are still required[64] for the dehydrogenation process.

Metal Hydrides

Metal hydrides are metals that bond to hydrogen to form a new compound. While they have long been known as a hydrogen carrier, their unsuitability for mobility applications has restricted their uptake. Mobility problems are largely due to the temperature requirements, weight of storage units and poor speed of hydrogen release. Currently, metal hydrides are being re-examined for niche applications.

Attaching hydrogen to metal results in a heavy storage unit, however this can be used to the unit's advantage where stability is seen as a key requirement. In a natural-disaster prone area for example, a fuel cell system incorporating metal hydride storage could prove more resistant to damage than a lithium battery or pressurised hydrogen tank system. The slow and consistent release of hydrogen by metal hydrides (i.e. similar to a battery discharge curve) is also advantageous for low and prolonged power requirements such as medical equipment in remote areas.

Military applications are another potential niche role for metal hydrides. Delivering diesel to war zones is difficult, and self-sufficient hydrogen energy systems could prove suitable. Metal hydride's safety and reliability could see them used more widely in this type of application.

Metal hydrides and other complex hydride technologies are considered further in Appendix A.

4.2 Transport of hydrogen

4.2.1 COMMERCIAL IMPLICATIONS AND OPPORTUNITIES

The starting point for selection of the most appropriate method for transport of hydrogen is a contract between a supplier and offtaker. Once the points of supply and demand have been established, the storage technology selection (described above) can be considered in conjunction with the most appropriate transport method.

Hydrogen may be transported via truck, ship, rail and pipeline. Possible pairings of transport and storage mechanisms as well as likely distance thresholds are summarised in Table 9.

The costs for each of truck, rail and shipping are presented in Table 10. Transport of hydrogen via pipeline however is more complex and examined further in the following subsections.

63 Preuster, P., Papp, C. and Wasserscheid, P. 2016, Liquid Organic Hydrogen Carriers (LOHCs): Toward a Hydrogen-free Hydrogen Economy, Accounts of Chemical Research, Volume 50 (1), Page 74-85

64 Hydrogenious Technologies, 2018, Hydrogen – stored as an oil, Germany

TABLE 9. HYDROGEN TRANSPORT METHODS

VEHICLE	STORAGE TYPE	INDICATIVE DISTANCES	DESCRIPTION/USE
Truck (Virtual pipelines)	Compression, liquefaction, ammonia	<1000km[65]	Transport of liquefied and compressed hydrogen as well as ammonia is available commercially. Ammonia is less likely as a hydrogen carrier here given the scale requirements and need to convert back to hydrogen for use. Higher pressures/liquefaction are typically used for trucking distances greater than 300km.
Rail	Compression, liquefaction, ammonia	>800-1100km[66]	As per trucks but for greater distances travelled
Pipeline	Compression	1000-4000km	More likely to be used for simultaneous distribution to multiple points or for intercity transmission
Ship	Ammonia, liquefaction	>4000km	Unlikely to use compression storage for shipping given cost of operation, distance and lower hydrogen density. Likely vehicle for export.

TABLE 10. TRANSPORT COSTS[67,68]

METHOD	COMPRESSION ($/tkm H_2) 430 bar	LIQUIFICATION ($/tkm H_2)	AMMONIA ($/tkm NH_3)
Truck	2.33	0.92	0.33
Rail	0.55	0.28	0.04
Shipping	0.52	0.09[69]	0.03

Pipeline

There are two potential scenarios for transporting hydrogen via pipeline:

1. Methane enrichment: Injection of hydrogen into existing natural gas pipelines up to specified concentrations
2. Transport of 100% hydrogen via new or existing pipelines

Both scenarios are considered in the subsections below. Note that deeper consideration of a network upgrade supporting use of hydrogen for residential heat is discussed further in Section 5.3.

In addition to its primary driver as a mechanism for transporting larger quantities of hydrogen, the use of pipelines can provide a number of ancillary benefits:

1. **Improving gas supply**: With uncertainty surrounding natural gas supply constraints on the east coast of Australia, hydrogen substitution could provide a more near term opportunity to offset increasing demand for gas.
2. **Convergence of the electricity and gas network**: With an increasing proportion of VRE in the electricity grid and the reliability/stability challenges it brings, hydrogen provides a new avenue to optimise the generation of renewable energy by feeding it into the gas supply at times of peak energy demand. This concept is known as ‘power-to-gas’.
3. **Energy storage**: As mentioned above, gas pipelines provide an additional storage option for hydrogen via line packing or by ‘shifting energy in time’.
4. **Decarbonisation of the gas network**: Hydrogen injection in natural gas pipelines increases the scope for decarbonisation across the energy sector.

65 US Drive 2017, Hydrogen Delivery Technical Team Roadmap
66 Seedah, D., Owens, T., Bhat, C. and Harrison, R. 2013, Evaluating Truck and Rail Movements along Competitive Multimodal Corridors
67 Modelled distances: Truck (166,330km per annum), Rail (based on average interstate rail distance), Shipping (9000km – distance to Japan)
68 Capital costs for vehicles included in modelling results
69 This includes the cost of the terminal, storage tanks for 770tpd, loading and shipping with a capacity of 1250m^3 of hydrogen

Methane enrichment

The key driver for enrichment of natural gas with hydrogen is the opportunity to achieve some decarbonisation in the gas sector without the requirement for material upgrades to existing infrastructure. Hydrogen concentrations of 20% by volume have been regarded as acceptable with the key limitation being the ability of end use appliances to accommodate higher concentrations of hydrogen (discussed further in Section 5.3). Trials for hydrogen injection into the natural gas grid are occurring in a number of jurisdictions globally, including in Tonsley, South Australia (refer to Table 4).

One notable problem with the inclusion of hydrogen in the natural gas network is the impact it has on metering. Traditionally, metering and the consequent pricing of gas in pipelines is based on the flow rate and energy content of the gas being used. Pipeline meters would therefore need to be adjusted to reflect the percentage of hydrogen within the natural gas, and their differences in energy density.

Transport of 100% hydrogen

Transport of 100% hydrogen via pipeline can raise issues relating to pipe embrittlement depending on the operating pressure and pipeline material. While the risk of embrittlement is higher in the transmission network due to increased operating pressures, use of steel and fibre reinforced plastic (FRP) pipes are reported to be able to accommodate hydrogen at pressures of 70-105 bar.

The risk of embrittlement would be significantly reduced in the domestic gas distribution network where pressures range from (<1-7bar). High density polyethylene (PE) is likely to be the preferred pipeline material with anticipated upgrades across Australian gas distribution networks expected to occur over the next decade irrespective of a transition to hydrogen. An outline of hydrogen capable piping materials, costs and operating pressures is set out in Table 11. Although distribution networks are more expensive, they allow for simultaneous distribution to multiple points of demand.

CASE STUDY: **HyDeploy (UK)**

The aim of HyDeploy is to demonstrate an additional option for reducing emissions by 80% by 2050 in the UK. With a target of 20% by volume concentration of hydrogen, testing is currently underway to determine a safe concentration which will require no changes to appliances or customer behaviour. Pending approval from the Health and Safety Executive, a 12 month live trial is scheduled to be conducted on the Keele University campus in 2019.

Keele University was chosen as the trial site because it owns a private gas network and is the largest university campus in the UK. With both residential and commercial buildings, it can provide a simulation of a small UK town. Access is also being provided to research facilities to monitor and test the trial progress[70].

70 HyDeploy 2017, HyDeploy Project report

TABLE 11. HYDROGEN PIPELINE CAPABLE MATERIALS AND PRESSURES

	CONDITIONS[71]	MAX PRESSURE	SIZE (DIAMETER)	COST
		bar	mm	$/tkm
Steel	Transmission	103	200	0.82
FRP	Transmission	103	3 x 115	0.61
PE	Distribution	20	150	2.58

Comparison against High Voltage Direct Current (HVDC)

HVDC cables may also be used where there is an extended distance between the point of energy generation and use of hydrogen. For electrolysis using dedicated renewables in particular, electricity may be transported from solar PV or wind assets to an electrolyser plant, effectively displacing the need for construction of a hydrogen pipeline.

Modelling undertaken as part of this report suggests that construction of hydrogen transmission pipelines is more cost effective when transport distances are less than approximately 2,600km[72]. It is important to note however that this cost comparison does not include the dual benefit of hydrogen pipelines in being able to both transport and store hydrogen.

4.2.2 POLICY AND REGULATIONS

While policy and regulations relating to the injection of hydrogen into the existing gas network (or the operation of a pure hydrogen network) varies between the states, none expressly prohibit it[73].

Regulated assets

Natural gas distribution networks in Australia are largely regulated assets, with fixed volumetric pricing. Such regulations de-risk the asset by ensuring a steady revenue stream and provide pipeline operators with benefits such as ease of access. Relevant regulations could be updated to include hydrogen and thereby ensure that pipelines transporting hydrogen are operated in a similar manner to natural gas.

4.2.3 RD&D INVESTMENT PRIORITIES

Hydrogen additives: Odourisation and flame enhancement

Odourants are injected into gas networks as a leakage detection mechanism for odourless gases. While transport of gaseous hydrogen would have similar requirements, use of conventional odourants in hydrogen would act as contaminants which can damage fuel cells. Investment is needed to develop odourants that do not impact subsequent hydrogen use. Flame enhancement additives may also be required to ensure that the flame is visible enough to ensure safety for stove cookers and other in-home appliances.

Liquefaction shipping

In a first of its kind design, KHI in collaboration with Shell, is developing a purpose built liquefied hydrogen tanker capable of shipping 1250m^3 (88,500kg) liquid hydrogen (LH_2) from Victoria to Japan in 16 days. Backed by the New Energy and Industrial Technology Development Organisation (NEDO), the carrier is forecast to be ready to make its first shipment in 2020/2021. The development of this tanker utilises previous research undertaken by KHI into LNG carrier shipbuilding, LH_2 storage tanks and vacuum insulation technology.

KHI will borrow standards and guidelines from the American Institute of Aeronautics and Astronautics concerning the handling of bulk liquid hydrogen. Key technical challenges include insulation of the liquefaction tanks as well as loading and unloading at the port. Extensive testing will therefore be undertaken before the maiden voyage[74].

71 Transmission = Distance assumed 1000km with flow of 135,000 kg/day, Distribution = distance 500km, flow 5,000kg/day
72 This calculation was performed assuming hydrogen quantities of 210,000kg/day. Modelling includes compression/booster costs
73 Refer to legal review on Injection of hydrogen into the gas grid undertaken for Energy Networks Australia (ENA) and available on the ENA website
74 Takaoka, Y., Kagaya, H., Saeed, A. and Nishimura, M. 2017, Introduction to a liquefied hydrogen carrier for a pilot hydrogen energy supply chain (HESC) project in Japan

5 Utilisation

As described in Part 1 Section 1, there are a number of potential applications for hydrogen across the energy and industrial sectors. This is discussed further in the following sub-sections.

5.1 Stationary electricity

The efficiency and costs associated with hydrogen systems is significantly less favourable than direct conversion from energy generation (e.g. wind, solar PV) to electricity. Therefore, the primary use for hydrogen in the electricity sector is as an alternative means of energy storage. Stored hydrogen may then be used to generate electricity using the following technologies:

- **Fuel cell**: An electrochemical cell that combines hydrogen and oxygen to generate an electric current with water as a by-product. This is the reverse of the electrolysis process
- **Turbine**: Combustion of hydrogen rich gases (e.g. co-firing) to produce steam and subsequently electricity (similar to a conventional gas turbine)

Relevant systems are likely to consist of VRE, electrolysis, storage (as discussed in Section 4), plus a hydrogen fuel cell and/or turbine. These options are illustrated in Figure 15 below.

5.1.1 MATURE TECHNOLOGIES

Electricity generation

There are a number of commercially available fuel cells (listed in Appendix A) where hydrogen, as well as other inputs such as natural gas and ammonia can be used. Depending on the technology, the fuel cell stack size can range from kilowatts to megawatts, making them suitable for more distributed applications (e.g. at an industrial facility). Many of these systems also offer the benefit of combined heat and power (i.e. use of waste heat from fuel cells that can be used for low temperature heating in boilers etc).

For centralised large-scale energy systems (i.e. >100MW), hydrogen or ammonia turbines are more likely to be deployed than fuel cells. However, these technologies are less mature and addressed separately in Section 5.1.3.

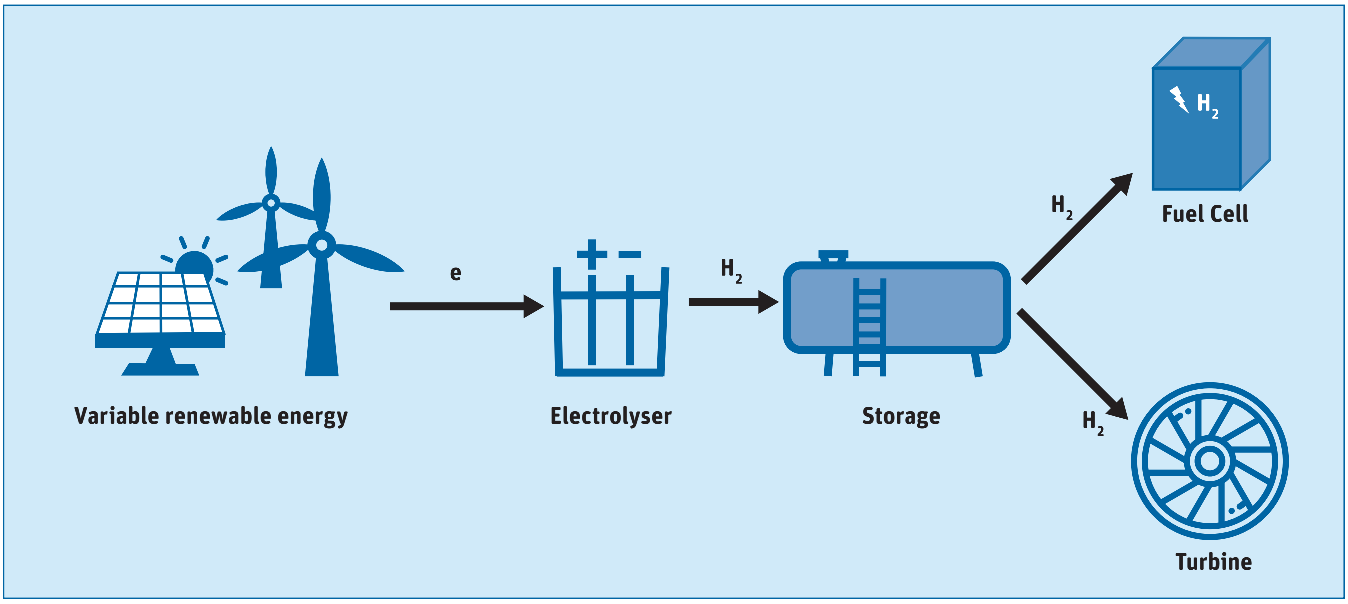


Figure 15. Potential stationary hydrogen electricity system

In an Australian context, PEM fuel cells are likely to be the most widely used systems due to their global market size, various applications and faster start-up times. PEM has therefore been used as the basis for the modelling undertaken below.

Projected fuel cell costs

Current and projected PEM fuel cell costs, assessed on a levelised cost of electricity (LCOE) basis, are set out in Table 12. While PEM fuel cells are a relatively mature technology, key improvements are likely to stem from increased capacity, reductions in capital cost, improved stack life as well as expected improvements in the price of hydrogen.

TABLE 12. CURRENT AND 2025 FUEL CELL COSTS

	2018	2025
LCOE ($/MWh)	330-410	120-150

5.1.2 COMMERCIAL IMPLICATIONS AND OPPORTUNITIES

Grid firming services

Hydrogen represents one of a number of energy storage technologies with the potential to balance short to long term intermittency issues associated with VRE.

Hydrogen storage and fuel cell systems, which also have high ramp rates, have the potential to play a role similar to that of utility-scale batteries. In the fast frequency response market (i.e. storage in seconds), the electricity generated (or hydrogen used) is comparatively low and so the competitiveness of the system (when compared with batteries) is based on the comparative capital cost of each asset. Table 13 shows that for a 100MW system, the capital costs of battery and fuel cell storage systems in 2025 are comparable. The storage technology used in this scenario is hydrogen compression at 150 bar.

TABLE 13. COMPARISON OF 2025 BATTERY AND FUEL CELL SYSTEM COSTS

2025 FOR 100MW SYSTEM	BATTERY	FUEL CELL
Capital cost ($/kW)	687-840	738-902

In relation to hourly storage, the competitiveness of the fuel cell system with other energy storage or generation technologies is presented in Figure 16. The price of hydrogen required to be competitive with gas turbines, pumped hydro (PHES) and batteries, varies based on the capacity factor (i.e. extent to which the asset is used). Asset capacity factors for this scenario are typically between 10-20%, suggesting that the price of hydrogen needs to be approximately $1.30-1.60/kg to compete with batteries and PHES.

In relation to seasonal storage, batteries are unlikely to be used due to energy losses when fully charged for days at a time. Lithium-ion batteries in particular are subject to self-discharge and are expensive to scale given the need to combine multiple battery banks.

Similarly, PHES is unlikely to be used in this way given new dams for on-river systems are unlikely to be constructed and off-river systems are comparatively small scale. Thus for seasonal storage, hydrogen systems using salt caverns as storage are most likely to compete against natural gas turbines. Typical capacity factors are approximately 6%, and so in the absence of a proxy carbon price, hydrogen would need to also cost around $1.60/kg (as shown in Figure 17).

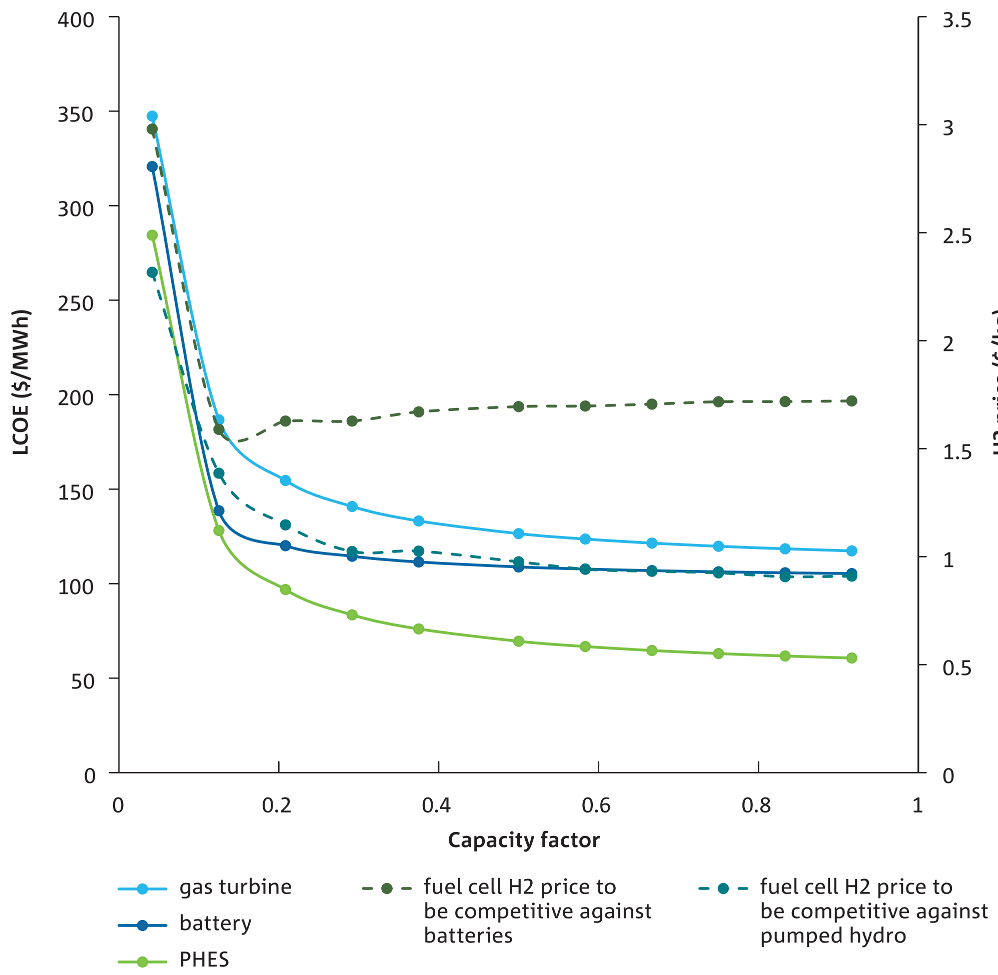


Figure 16. 2030 Comparison of different storage technologies for hourly storage[75]

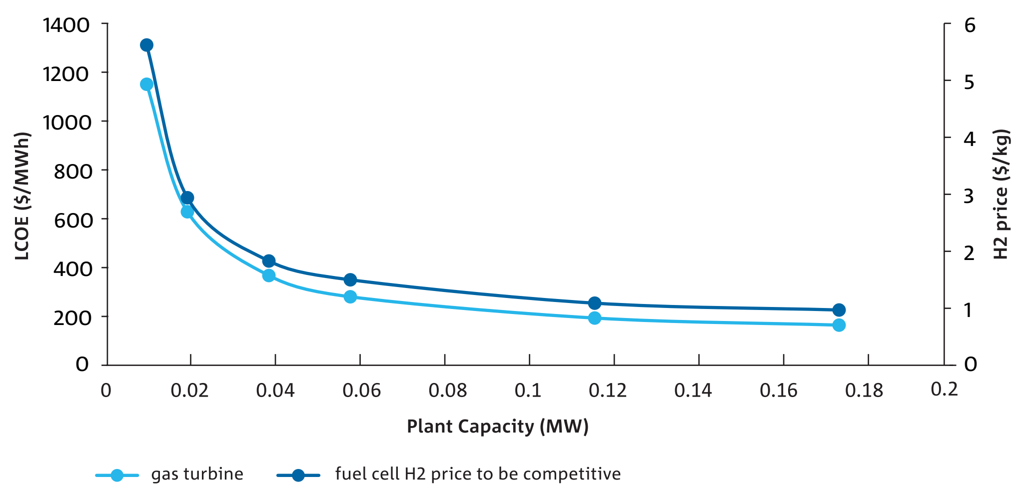


Figure 17. 2030 seasonal storage comparison

75 Calculation for hydrogen systems assume compression at 150 bar for storage

Remote area power systems (RAPS)

Remote area or stand-alone power systems rely heavily on imported diesel to power local generation sets ('gensets') for electricity. The cost of these systems can be in the order of $440/MWh[76] due to the cost of transporting diesel to remote communities. Use of diesel generators also has an adverse impact on air quality.

A RAPS consisting of hydrogen generation, low pressure storage (including batteries for short term frequency control) and a fuel cell could potentially displace the use of diesel gensets[77]. In contrast to equivalent systems that rely solely on batteries, hydrogen has the added benefit of being more cost effective at scale, longer storage periods and is able to tolerate harsher operating conditions commonly seen in remote areas of Australia.

Depending on the energy and load profiles, there is potential for both centralised and decentralised RAPS models. In the former, hydrogen could be generated by large scale renewables and electrolysis, with the resulting hydrogen being fed into a centralised fuel cell/turbine to generate electricity, or distributed via pipeline to consumers with localised fuel cells. Although reliant on natural gas, a precedent for this type of system has been observed in the ENEfarm in Japan.

CASE STUDY: **Japan ENEfarm**

Over 230,000 Japanese homes have installed residential fuel cells to provide heat and power. The ENEfarm initiative is supported by a public-private partnership between the Japanese government and residential fuel cell manufacturers. Available as either PEM or solid oxide, the units process natural gas to supply hydrogen to a fuel cell to produce electricity and heat. Onsite electricity production eliminates transmission losses and some models are able to achieve 95%[78] combined heat and electrical efficiency. Japan's Basic Hydrogen Strategy targets a market penetration of 10% (5.3m units) by 2030[79].

Alternatively, a more localised model could in the longer term (i.e. post 2030) involve hydrogen generation via rooftop PV and electrolysis, where the hydrogen is consumed onsite and/or distributed via pipeline under a 'prosumer' model. While the economics are likely to favour the more centralised model in the early stages of development, site specific feasibility studies should be undertaken to compare the benefits of both.

Smaller mining operations without direct access to the electricity network present a favourable demonstration site for a hydrogen RAPS. This is due to the need for a continuous energy supply to support mining operations, as well as the potential for numerous applications in a single site, i.e. heat, stationary electricity, transport and materials handling.

5.1.3 RD&D INVESTMENT PRIORITIES

Turbines

Turbines are an emerging technology that may be preferred for larger scale electricity production from hydrogen. Burning up to 100% hydrogen in a gas turbine is technically possible, but currently faces a series of technical challenges associated with high combustion temperatures and nitrous oxides (NOx) emissions. A world first was achieved in 2018 wherein a hydrogen turbine successfully generated 1,100kW of electricity and 2,800kW of heat for adjacent facilities in Kobe, Japan[80].

Turbines that combust ammonia are also being examined and could play a key role in a hydrogen export value chain given that it overcomes the need for ammonia to be separated into its component parts at the point of use. These technologies are assessed further in Appendix A.

Emerging fuel cells

There are a number of emerging fuel cell technologies (also listed in Appendix A) that offer some potential to displace the more mature technologies. However, the fuel cell market is crowded and less mature technologies may face difficulty in attracting the requisite levels of investment.

Although early stage, one emerging set of technologies that could play a key role after 2030 are reversible fuel cell systems. These have the potential to disrupt the broader hydrogen value chain by combining the electrolysis and fuel cell process into a single system, operating much like a battery and allowing for significant reductions in capital cost.

76 Hayward, J., Sayeef, S., Sethuvenkatraman, S., Ward, J. and Sparkes, B. 2016, JORN Future Energy System: Techno-economic feasibility study
77 This calculation assumes 1 week of storage at 150 bar
78 Ellamala, H., Staffell, I., Buijlo, P., Pollet, B. and Pasupathi, S. 2015 Current status of fuel cell based combined heat and power systems for residential sector
79 Ministry of Economy, Trade and Industry 2018, Basic Hydrogen Strategy (key points), Japan
80 NEDO: New Energy and Industrial Technology Development Organisation, 2018 World's First Heat and Electricity Supplied in an Urban Area Using 100% Hydrogen, Press release, http://www.nedo.go.jp/english/news/AA5en_100382.html, retrieved on April 20, 2018

Aiding other forms of energy storage

Hydrogen also has the potential to be used to enhance other forms of energy storage as shown in the examples below:

1. **Thermal Energy Storage**: Hydrogen may be utilised in metal hydrides to displace molten salts in concentrated solar thermal. Metal hydrides can be 50% cheaper and 20-30 times more energy dense than salts if adequate temperatures can be achieved[81].
2. **Proton Batteries**: A hybrid between a fuel cell and a battery based system, proton batteries offer the potential for a round trip efficiency similar to lithium ion batteries. Electricity charges the system by splitting water molecules, generating protons which bond with a carbon electrode, storing hydrogen in an atomic rather than molecular gaseous form. The advantage of this system over lithium ion batteries is the opportunity to utilise low cost and widely available materials[82].

5.2 Hydrogen fuelled transport

5.2.1 MATURE TECHNOLOGIES

Vehicles

Passenger fuel cell electric vehicles (FCEVs) consist of an electric drive train powered by a PEM fuel cell stack and hydrogen storage tank pressurised to 700 bar. These vehicles became commercially available in 2013[83] and by the end of 2017, 6364 fuel cell cars had been sold globally.

FCEVs are seen as a complementary technology to battery electric vehicles (BEVs). They may be more suitable for consumers who travel longer distances (i.e. 400-600km without refuelling), expect shorter refuelling times[84] and are without easy access to BEV recharging infrastructure (e.g. apartment dwellers without off street parking). Currently, a 6kg tank can allow FCEVs to travel between 500-800kms[85].

Heavier FCEVs such as trucks and buses, have a much more favourable energy density by mass than BEVs and operate using different size fuel cell modules depending on the vehicle payload and range requirements (as set out in Table 14). Heavy vehicles also typically accept hydrogen at 350 bar due to the greater on board storage space, although 700 bar models are currently being developed.

TABLE 14. PAYLOAD AND FUEL CELL MODULE SIZE

VEHICLE	MODULE SIZE (KW)	NUMBER OF MODULES (KW)	SUM OF MODULES (KW)
Car	30-100	1	30-100
Bus	30-100	1	30-100
3.5t Truck	30-60	1	30-60
40t Truck	200	1	200

As discussed below, the higher hydrogen demand of heavy vehicles and typical ‘back to base’ transport routes can make them a more favourable target market than passenger vehicles during the scale up of refuelling stations. For instance, a bus can accept 30-40kg of hydrogen when refuelling as compared with passenger vehicles that take between 3-6kg.

Globally, intercity heavy duty trucks have seen less FCEV uptake due the lack of refuelling infrastructure across highways.

Hydrogen refuelling stations (HRS)

Hydrogen refuelling infrastructure is critical to the uptake of FCEVs in Australia. HRSs consist of a standard overall system (as depicted in Figure 18), with key differences regarding the hydrogen delivery method, dispenser pressure and capacity, all of which can impact configuration and consequently cost. Current costs range from USD1.5m to USD2.0m per station[86].

Hydrogen delivered (or generated onsite) in gaseous form is compressed for intermediate storage with pressures of up to 500 bar. To facilitate the dispensing pressures required for passenger vehicles, a cascade compression and storage system is required to progress the hydrogen from intermediary storage to higher pressures of up to

81 Sheppard, DA et al. 2016, Metal hydrides for concentrating solar thermal power energy storage

82 Heidari, S., Mohammadi, S., Oberoi, A. and Andrews, J 2018, Technical feasibility of a proton battery with an activated carbon electrode, International Journal of Hydrogen Energy, Volume 43, Issue 12, Pages 6197-6209

83 Information Trends 2018, Hydrogen Fuel Cell Vehicles - A Global Analysis

84 Note that superchargers for BEVs still require 30mins to recharge 80% as compared with FCEVs where refuelling takes 5 minutes. The impact of longer refuelling times could be more significant as the uptake of BEVs increases

85 Hyundai, NEXO: The next-generation Fuel Cell Vehicle from Hyundai, https://www.hyundai.news/eu/model-news/nexo-the-next-generation-fuel-cell-vehicle-from-hyundai/?L=0

86 International council on clean transportation 2017, Developing a hydrogen fuelling infrastructure for fuel cell vehicles: A status update.

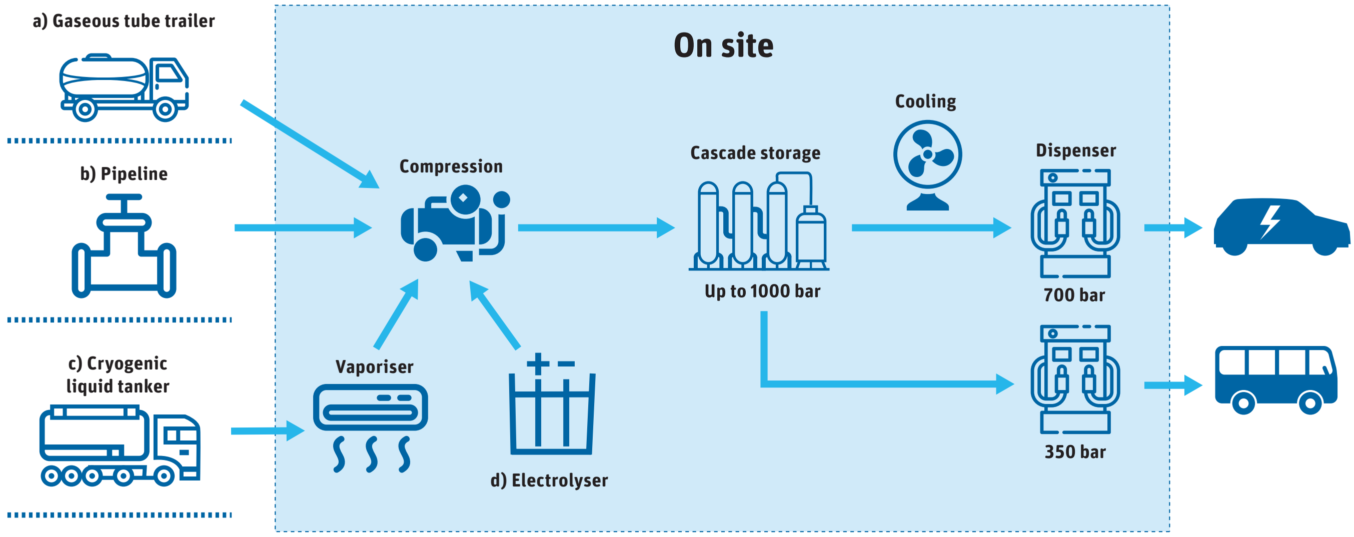


Figure 18. Standard refuelling station configuration

1000 bar. Hydrogen delivered in liquid form requires an alternative station setup wherein the liquid hydrogen is delivered via truck, stored cryogenically onsite, vaporised and then dispensed[87].

Due to the high operating pressures under which hydrogen is delivered, refuelling requires additional equipment considerations. To facilitate a fast fill, the hydrogen needs to be pre-cooled to -40°C prior to dispensing to ensure the vehicle tank temperature stays below 85°C[88], leading to increased electricity costs. Due to these precise temperature range requirements, additional control systems are necessary to monitor volume, temperature, flow rate and pressure. Current dispenser nozzles also cost up to 100 times more than the petrol equivalent[89].

Materials handling

Hydrogen fuel cell powered materials handling is becoming a favourable technology option over battery and diesel equivalents for a number of operations. This includes counterbalanced forklifts, narrow aisle lift trucks, pallet jacks and stock pickers which have been equipped with PEM and Direct Methanol Fuel Cells[90].

Warehouse materials handling has stricter requirements on air quality due to poor ventilation in indoor operations. This has made the use of electric/battery driven machines common for warehouse use. However, for companies that manage large warehouses and who have twenty four seven operating requirements, reliance on battery driven equipment has a number of problems. These include the purchase of additional batteries (e.g. three battery sets per vehicle) which creates a hazard and increases both capital costs and storage space requirements. Further, battery charging can also release odours that can damage warehouse inventory (particularly perishable goods) and time spent charging can lead to lost productivity.

The speed of hydrogen refuelling and absence of odours therefore make FCEVs more attractive in these types of operations. As distinct from batteries, fuel cells also offer the advantage of maintaining a consistent power output when energy reserves are low and are not impacted by the low temperatures experienced in refrigerated facilities. It is for these reasons that in 2017, Walmart and Amazon signed deals of up to $AUD770m for fuel cell powered material handling machinery[91].

Analysis conducted by the Fuel Cells and Hydrogen Joint Undertaking shows in 2017, the total cost of ownership (TCO) of FC forklifts was 5-10% less than battery powered forklifts, with the potential for 10-20% lower lifetime costs[92].

87 National Renewable Energy Laboratory (NREL) 2015, H2FIRST Reference Station Design Task
88 Reddi, K., Elgowainy, A., Rustagi, N. and Gupta, E. 2017, Impact of hydrogen SAE J2601 fuelling methods on fuelling time of light-duty fuel cell electric vehicles
89 US Drive 2017, Hydrogen Delivery Technical Team Roadmap
90 U.S. Department of Energy: Fuel cell technologies office 2016, Early Markets: Fuel Cells for Material Handling Equipment
91 E4Tech 2017, The Fuel Cell Industry Review
92 Development of Business Cases for Fuel Cells and Hydrogen Applications for regions and cities 2017, Fuel Cells and Hydrogen 2 Joint Undertaking

The challenge may however be greater for heavy duty materials handling wherein haulage (in mining operations for example) requires higher power densities. These mining operations also typically run continuously, relying on the use of on-board diesel storage to meet heavy refuelling requirements. Significant RD&D would be required to develop equivalent systems for hydrogen.

5.2.2 COMMERCIAL IMPLICATIONS AND OPPORTUNITIES

Fuel cell vehicles

Although passenger FCEVs currently have a higher levelised cost of transport (LCOT) than internal combustion engines (ICEs) and BEVs, it is expected that FCEVs could reach parity in or around 2025. This is shown in Table 15 for passenger vehicles and buses. Trucks have not been represented here due to variability in payload.

TABLE 15. COMPARISON OF VEHICLE TYPE BY LCOT

	LCOT 2018 ($/vkm)	LCOT 2025 ($/vkm)	LCOT 2018 ($/vkm)	LCOT 2025 ($/vkm)
	Passenger Vehicle		Buses	
ICE	0.71	0.73	1.83	1.85
BEV	1.19	0.68	2.66	1.80
FCEV	**1.43**	**0.70**	**2.96**	**1.84**

For passenger vehicles in particular, in the early stages of deployment, the higher capital cost of FCEVs means they are likely to be targeted towards the higher end consumer market. To successfully compete in this market, vehicle OEMs are ensuring that all the latest technology features are included (e.g. keyless entry, level 2 autonomy etc). Model preferences (e.g. SUVs) are also dictated by consumer trends and feedback.

While R&D investment in FCEV technologies is ongoing, the biggest cost reductions for all FCEVs are expected to come from the establishment of automated, dedicated productions lines and manufacture of FCEV specific components at scale. This will only occur once the global demand for mass vehicles has been established. In relation to passenger vehicles, manufacture of ~200,000 vehicles per year for a given OEM would likely see construction of a dedicated FCEV facility. Notably, given the comparatively small size of Australia in the global vehicle market (~2%), achieving the requisite scales of production will be driven by demand overseas.

Refuelling stations

Car OEMs are unlikely to invest heavily in the Australian market without a minimum number of refuelling stations. The first series of stations are likely to be co-located with existing petrol stations and 'clustered' in metropolitan areas[93], specifically in more affluent regions considering the current higher cost of FCEVs. Clustering is important due to fact that having multiple station options within a reasonable distance of one another gives consumers greater confidence and autonomy in deciding when and where to refuel.

Other jurisdictions such as France have been careful to tie FCEV infrastructure requirements to the number of vehicles in a given area[94]. This is achieved by focussing less on privately owned cars and more on fleet (e.g. taxis or delivery vans) with known demand and driving patterns. Areas with a high density of ride sharing operations should also be a key consideration for HRS site selection.

Once there is sufficient infrastructure in metropolitan areas, key intercity highways could become the next target for investment. As a general rule, a station is required for every 90km travelled. Other considerations include population density, region size and existing petrol infrastructure[95].

The biggest cost reductions in refuelling infrastructure are likely to come from a move away from demonstration stations which tend to be ad hoc and one-of-a-kind, to standardised, robust, reliable and low cost equipment. It is anticipated that this could allow for a capital cost of USD0.5m to USD1.0m depending on the station capacity and design[87]. Increasing competition, pricing transparency and the establishment of a localised supplier base are also key to achieving material reductions in costs.

The preferred hydrogen generation and storage combination is likely to be project/site specific (i.e. onsite generation vs hydrogen receipt by pipe or truck). While subject to potential space constraints, onsite generation reduces the delivery risk (e.g. due to a breakdown of a delivery truck), decreases transport costs and provides station operators with greater autonomy in how they manage the asset. Modular designs that can be scaled as demand increases could also help mitigate fuel supply risk.

Once critical mass has been achieved in terms of the number of HRSs in metropolitan areas, a hub and spoke model, wherein hydrogen is generated on the city outskirts and transported via pipeline to a series of stations could also be a preferred option. However, a scenario in which a

93 International Council on Clean Transportation (ICCT) 2017, Developing hydrogen fuelling infrastructure for fuel cell vehicles: A status update, Berlin.

94 Mobilité Hydrogène France 2016, 10 hydrogen stations being deployed and first wave of fuel cell vehicles now in operation as the rollout continues [Press Release] Retrieved from http://www.afhypac.org/documents/divers/Draft%20press%20release%20end%20of%20year%20update%20EN%20V3.pdf

95 International Council of Clean Transportation (ICCT) 2017, Developing hydrogen fuelling infrastructure for fuel cell vehicles: A status update, Berlin.

100% hydrogen gas network has been set up to supply both residential heat in the home as well as HRSs is unlikely to occur before 2030.

The roll out of HRSs is also likely to require a high degree of coordination between infrastructure proponents and OEMs. As with conventional petrol refuelling stations, OEMs are likely to have limited financial interest in the required infrastructure, only assuming a level of risk necessary to protect their customers.

HRSs are most likely therefore to be built owned and operated under a joint venture operation with a key role for Government in underwriting the initial demand risk (i.e. during scale up of FCEVs). Under these arrangements, a coordinated pooling of resources is important. For example, traditional hydrogen gas producers may lack the expertise required in fuel retail, particularly under a franchise model, and so may be better off entering into a joint venture with a traditional refuelling station operator.

Vehicle leasing models

FCEV leasing models may offer a mutual benefit to the consumer and HRS operator. For the consumer, leasing provides a lower cost entry point into a vehicle market that currently has a high upfront capital cost. Customer packages that include a monthly fee that covers fuel, insurance, road tax and maintenance also simplifies the purchasing process. Further, OEMs benefit from this arrangement by maintaining control of the asset.

Leasing models that include the cost of fuel provide an avenue for the sharing of risk between HRS operators and OEMs. The OEM can purchase hydrogen fuel upfront and then recoup that investment once the vehicle is leased. It is likely however that OEMs will only assume this additional risk if an appropriate policy framework is in place, i.e. an emissions standard on vehicles or other incentive scheme (discussed further in Section 5.2.3).

CASE STUDY:

H2 Mobility

H2 Mobility is a German initiative jointly formed by car manufacturers, gas companies and fuel retailers to progress and coordinate the roll out of hydrogen refuelling stations across Germany. H2 Mobility, with support and advice from government, own and operate the stations which enhances the proponents' ability to synchronise and optimise the location of the stations. By delivering a new station every two weeks on average, H2 Mobility is on track to deliver 100 stations in Germany by Q1 2019.

Similar arrangements exist throughout the world such as H2 Mobility UK, the Scandinavia Hydrogen Highway Partnership, California Fuel Cell Partnership and H2Korea.

CASE STUDY:

Nikola Complete Lease Program[96]

Nikola offers two hydrogen fuel cell powered truck models that provide longer range (800-1500km), faster refuelling and more horse power than conventional diesel trucks. Due to capital cost of the vehicle being nearly double that of a conventional truck, Nikola has developed a leasing program to attract customers. The program includes hydrogen fuel, warranty and scheduled maintenance as well as the option of trade-ins every 84 months. This program provides insulation against fluctuating fuel prices and miles driven.

American brewing company Anheuser-Busch placed an order for 800 Nikola trucks in 2018 citing their aim to reduce value chain emissions by 25%[97].

96 Nikola, https://nikolamotor.com/one

97 Johnson, E (2018, May 3) Anheuser-Busch orders up to 800 hydrogen-fueled big rigs, Reuters, Retrieved from https://www.reuters.com/article/us-ab-inbev-orders-nikola/anheuser-busch-orders-up-to-800-hydrogen-fueled-big-rigs-idUSKBN1I41JI

5.2.3 POLICY/REGULATION

Given the lower cost and more readily available infrastructure for ICEs and BEVs, a series of policies and regulations are needed to assist in the creation of a market for FCEVs in Australia.

Emission (or 'clean air') standards on vehicles are an important policy consideration as they represent a long term commitment to decarbonise the transport sector by limiting the types of vehicles available. As discussed earlier, this has the benefit of providing OEMs with increased investment confidence regarding the distribution of electric vehicles in Australia.

Specific incentives however are also likely to be needed to stimulate uptake of FCEVs. These could be in the form of direct subsidies, taxation (e.g. fuel excise) and registration discounts (or a combination of all options) which can increase the rate of uptake depending on how much they are valued by consumers. This is particularly important for heavy vehicles given that logistics companies that run on fine margins are unlikely to be able to absorb the higher capital cost of FCEVs before mass production reduces prices.

5.2.4 RD&D INVESTMENT PRIORITIES

Pilot/demonstration projects

Strategic pilot projects are likely to play an important role in stimulating uptake of FCEVs, by providing the initial infrastructure and demonstrating the usability and safety of FCEV technologies.

Local council and government fleets that operate 'back to base' vehicles are preferred options for demonstration projects as they obviate the need for the roll out of multiple refuelling stations. Further, the known driving profiles, including loads, temperatures and operating hours of fleet vehicles can help optimise the deployment of relevant technology. As long as vehicle usage rates are high enough, university precincts are potentially more attractive as they may provide the added benefit of being able to test integrated technology.

Heavier vehicles, in particular buses due to their shorter distance and lighter payload (as compared with trucks) should also be prioritised given that their superior demand for hydrogen has the potential to improve the economics of refuelling infrastructure. Heavier vehicles also have lower hydrogen compression requirements which allows for reductions in HRS operating costs.

Longer demonstration projects (i.e. 3-7 years) may help lower costs as they provide proponents with longer periods of amortisation which reduces the risk associated with not being able to sell buses in a secondary market should the project not succeed.

Given the number of components to a fleet demonstration project (i.e. refuelling infrastructure and vehicles), a turnkey leasing arrangement may be preferred. This option is common in scenarios where a number of relatively new technologies are involved. Turnkey arrangements allow engineering procurement construction contractors (EPCs) responsible for the project roll out to accept the bulk of project risk but also benefit from technology improvements and lessons learned.

CASE STUDY:

Moreland City Council (MCC)

Moreland City Council in Victoria is currently in the process of developing a pilot project that involves the replacement of existing rubbish collection fleet with fuel cell truck equivalents. The overall project is managed by EPC Hydrogen Utility (H2U) and truck design and manufacture is currently being undertaken by Iveco. In the first instance, hydrogen will be generated at the MCC site via grid connected PEM electrolysers, with the energy input to be supplemented following the construction of dedicated rooftop solar.

Under the turnkey arrangement, much of the risk is shifted to H2U, wherein MCC is purchasing a method of picking up waste from H2U with a fixed price expressed in $/km. However, once up and running, it is intended that with a production capacity of 550kg/day, H2U will be able to service additional demand within the immediate region (e.g. neighbouring council trucks and buses) and absorb the benefits of learnings and reductions in the cost of the technologies.

It is uncommon for a private consortium to operate a business and turn a profit while on council land. However, in this case, it provides a mutual benefit as it allows H2U to service a broader market which strengthens the MCC business case for this refuelling infrastructure and reduces MCC costs on a $/km basis.

Refuelling stations

Other key challenges facing HRSs are asset lifetimes and demanding operating conditions (in terms of temperature and pressure). This combination of factors has encouraged collaborative problem solving with the National Renewable Energy Laboratory (NREL) in the US working closely with global OEMs to provide testing environments and research resources to overcome cost and durability problems[98].

Accurate metering of hydrogen dispensed at refuelling stations is another operational challenge given that flow rates at 700 bar reportedly lead to discrepancies of approximately 4% and impedes a station owner's ability to accurately price the hydrogen sold[99]. This challenge is also currently being addressed through an NREL collaborative project.

Connected and autonomous vehicles

It is important for vehicle type (i.e. drive train and energy storage) to be considered in the context of broader technological changes impacting the transport sector. Connected vehicles (e.g. ride sharing) represent a favourable option for FCEVs because they reduce the need for a high volume of refuelling stations but still allow for optimised refuelling time and greater distances travelled.

FCEVs may also be plugged into and used as a source of energy for the home, enabling more flexible demand side energy management. Water as a by-product could also be used for non-potable uses such as gardening.

Further, the computing power requirements for autonomous vehicles have been shown to significantly increase the energy demand of BEVs. Autonomous vehicles may therefore be more suited to hydrogen FCEVs which have superior energy densities by mass.

5.2.5 OTHER EMERGING FUEL CELL TRANSPORT

Rail

Of the other potential fuel cell transport modes, hydrogen powered rail, known as Hydrail, has seen the highest levels of activity globally, with four hydrogen powered trains operating across Europe.

The first commercial train is set to commence operations in Germany in the second half of 2018, with a completed rollout of 14 trains by 2021 and the option for 33 more subsequently[100]. In a collaborative arrangement between manufacturers and gas providers, the contract includes 30 years of maintenance and fuel. Powered by PEM fuel cells, the trains will be able to travel 1000km on a single fuelling and achieve speeds of 140km/h[101].

While challenges remain in terms of the positioning of hydrogen production infrastructure along a rail network, interest in Hydrail is spreading globally, particularly in several European countries and North America. In a recent study undertaken by Metrolinx in Canada, it was found that fuel cell trains are comparable in terms of cost with electrification given the capital requirements for overhead rail as compared with being able to use existing infrastructure. Initial sensitivity analysis shows the introduction of Hydrail could cost between 1-7% more than electrification. However a parallel socio-economic impact study showed qualitative and quantitative results in favour of Hydrail. Due to these results, the Ontario government have chosen to progress the Hydrail project to a concept stage[102].

With only 10%[103] of Australia's railway tracks electrified, Hydrail could have a place in future rail infrastructure considerations.

98 National Renewable Energy Laboratory (NREL) 2016, 700 bar Hydrogen Dispenser Hose Reliability Improvement
99 US Drive 2017, Hydrogen Delivery Technical Team Roadmap
100 E4Tech 2017, The Fuel Cell Industry Review
101 Fuel Cells Bulletin Volume 2017, Issue 12, 2017, Alstom building 14 Coradia iLint fuel cell trains, Linde for fueling
102 Regional Express Rail Program Hydrail Feasibility Study Report 2018, Metrolinx
103 Bureau of Infrastructure, Transport and Regional Economics (BITRE) 2014, Trainline 2, Statistical Report, Canberra ACT

Marine

As cities continue to combat air and water quality issues as well as noise pollution, pure hydrogen powered marine passenger ships have recently begun to attract attention[104]. Ferries which have a 'back to base' operating route could be a suitable early mover market and are currently being explored in Norway and San Francisco[105].

For larger ships such as those used for freight, use of synthetic 'drop in fuels' derived from hydrogen (discussed in Section 5.4.2) rather than fuel cells may be more suitable because of their greater power density requirements.

Air-independent propulsion systems in submarines are currently utilising fuel cells to allow for longer submersion durations. Here, PEM or Phosphoric Acid Fuel Cells are being used to power on-board systems and generate propulsion while submerged, thereby negating the need for nuclear power[106].

Aviation

Fuel cells have been adopted for Unmanned Aerial Vehicles (i.e. UAV/drones) to power propulsion mechanisms. They are currently available commercially and are sought by both military and civilian UAV operators. Fuel cells can provide 8-10 times more flight time in some UAV models and have shorter refuelling times than batteries[107]. Currently, fuel cells are used in tandem with lithium ion batteries which allow peak power to be generated during take-off.

Fuel cells have been used to power small manned aircraft, but their application to large scale passenger transport appears to be distant. Alternative fuel cell applications for aircraft are being developed, including on-board power generation and airport taxiing propulsion. However, due to power density requirements of aviation, synthetic and bio "drop in" jet fuels are likely to be preferred.

5.2.6 SOCIAL LICENCE

Vehicles

Generating public awareness of FCEV technology remains a key challenge for the sector. While there is a general consensus regarding the need for electric vehicles to decarbonise the transport sector, there is limited appreciation of the fact FCEVs also fall into this category. It is important that incentive schemes encouraging the uptake of electric vehicles are not limited to BEVs.

Effort is also needed to 'normalise' the risk associated with driving a vehicle with a compressed hydrogen tank. Ongoing demonstration of FCEV operation and safety therefore represent an important area for investment on the part of government and OEMs.

Refuelling stations

Basic safety education is critical for potential HRS operators, with a lack of education shown to be a key impediment in the rollout of stations in California[108]. There, education and engagement of local fire brigades has been found to be particularly effective in making consumers comfortable with use. This is especially relevant under a franchise model, wherein the cost and benefits need to be made clear to operators of privately owned stations.

104 Fuel Cells Bulletin 2017, Fiskerstrand wins Norwegian funding to design fuel cell ferry, Volume 2017, Issue 1

105 Purchia, R., June 27 2018, SF's new hydrogen ferry could fuel clean energy market, San Francisco Examiner retrieved from http://www.sfexaminer.com/sfs-new-hydrogen-ferry-fuel-clean-energy-market/

106 Explained : How Air Independent Propulsion (AIP) Works, July 6 2016, retrieved from https://defencyclopedia.com/2016/07/06/explained-how-air-independent-propulsion-aip-works/

107 Fuel Cells Bulletin 2015, Horizon launches Hycopter fuel cell multirotor UAV, Volume 2015, Issue 6

108 Based on discussions with California Fuel Cell Partnership

5.3 Heat

Hydrogen enriched natural gas and pure hydrogen may be combusted for the purpose of generating heat in residential, as well commercial and industrial (C&I) applications.

As discussed in Section 4.2, hydrogen enrichment involves the injection of hydrogen into the natural gas grid as a means of decarbonising the gas sector without the requirement for significant infrastructure upgrades and with reduced social licence risk.

Preliminary studies, progressing as part of the HyDeploy project in the UK suggest a concentration of hydrogen of up to 20% by volume can be tolerated by conventional appliances[109]. For C&I, recent studies have found that in most industrial heat application cases, 10-15% by volume hydrogen blends are achievable with minimal changes to appliances[110]. However, each site would need to be examined on a case by case basis to ensure safe operation.

Given that residential appliances can operate within the range of 0-20% by volume without upgrades, supply of hydrogen can fluctuate without interrupting a customers' ability to generate heat in the home. This range feature could allow for flexible and progressive rollouts of decentralised hydrogen production at distribution points.

The remainder of this section focuses on the complete substitution of natural gas with 100% hydrogen.

5.3.1 MATURE TECHNOLOGIES

In order to accommodate 100% hydrogen, existing appliances need to be upgraded or replaced due to the difference in the properties of hydrogen as compared with natural gas. Large variations in flame speed (or rate of expansion of the flame) as well as emissivity (or measured thermal radiation) will require changes to the valve and burner design from what is used for natural gas.

Residential

As compared with the C&I, design changes for residential appliances are relatively straight forward. Appliances suitable for modification for hydrogen use in the residential context are set out in Table 16 below.

TABLE 16. DOMESTIC RESIDENTIAL HEATING APPLIANCES

TYPE	HARDWARE	DESCRIPTION
Boiler	Water heater	Natural gas is burned to heat water either through continuous flow or a storage mechanism
Cooker	Cooktop	Natural gas is supplied through the cooktop for cooking
Cooker	Grill/oven	Natural gas is supplied through burners for cooking
Heater	Gas heating	Can be centralised with ducted heating or wall mounted. May be flued (vented outside) or non-flued (by-products released into room).

109 HyDeploy 2017, HyDeploy Project report
110 Progressive Energy Ltd 2017, The Liverpool-Manchester Hydrogen Cluster: A Low Cost Deliverable Project

C&I

Due to the variability in appliances, heat and flame profiles, design specifications and control systems, the conversion of C&I appliances poses a greater challenge[111]. In some instances, conversion of C&I appliances could involve the reconfiguration of an entire plant. C&I heat appliances with the potential to be upgraded are listed in Table 17.

COMMERCIAL IMPLICATIONS AND OPPORTUNITIES

Given the technical complexity associated with upgrading C&I appliances, it is difficult to envisage a coordinated roll out of hydrogen combustion systems on industrial sites. Any transitions are likely to be site specific and ad hoc. Without a clear policy direction, the economics may only support such an upgrade if there is a proximate pre-existing hydrogen supply.

In contrast, the relative simplicity of upgrading residential hydrogen capable appliances would make a widespread coordinated roll out in specified areas more feasible. This is currently being considered in Leeds, UK.

CASE STUDY: Leeds City Gate, H21

In an effort to decarbonise the domestic heat sector, the UK is embarking upon the H21 Leeds City Gate project. By converting the natural gas network in Leeds to pure hydrogen by the 2030s, it will act as a blueprint for a national conversion. The program will see the construction of four SMRs with the CO_2 captured and stored offshore. Salt caverns will enable seasonal storage and a new hydrogen transmission pipeline will connect the facilities to the town of 660,000 residents. Conversion is expected to occur over 3 years in several zones to minimise customer interruption.

TABLE 17. C&I HEAT APPLIANCES WITH POTENTIAL FOR UPGRADE

APPLIANCE	DESCRIPTION	USE
Furnace/kilns	May be low temperature (<650˚C) or high temperature (650˚C-1500˚C). At higher temperatures, care needs to be taken with furnace degradation and higher NOx emissions.	Low temperature: industrial ovens/ dryers High temperature: glass and ceramics industries
Boilers	Includes both fire-tube (3-5MWth) and water-tube (>5MWth). Can burn different fuels but would likely require a plant redesign for 100% hydrogen.	Steam production, space heating, pulp and paper industry
Combined heat and power	Includes reciprocating engines and gas turbines. For the former, preliminary research shows safe operation up to 80% H2 but requires NOx treatment. For the latter, there are already examples of IGCC running at 60-100% H_2 with permissible NOx levels. When running at high concentrations, a diluent (usually nitrogen or steam) is added to bring hydrogen concentration down to 65%, thereby lowering the temperature.	Various heat and electrical applications

111 Dan Sadler et al. 2016, Leeds City Gate H21

The H21 study sets out three appliance transition options:

1. **Replacement with hydrogen only appliances**: This process is both costly and labour intensive with some appliances taking up to 12 hours to changeover[111]. Hydrogen fuelled appliances are currently produced at a small scale in a limited range in Europe.
2. **Replacement with dual fuel appliances**: Duel fuel appliances can run on both natural gas and hydrogen. Appliances are expected to be more expensive and installation more complex[112].
3. **Replacement with standardised appliances**: To reduce eventual upgrade and labour costs, the mandating of new natural gas appliances to be manufactured with standardised back plates and connections can minimise the number of appliances that would require an expensive and lengthy upgrade in the future (e.g. via replacement of standard natural gas back plates with standard hydrogen back plates). In this scenario, replacement time could be reduced to 2 hours or less[113].

There is an obvious need to coordinate the appliance upgrade with the changeover in gas supply. Given the higher cost associated with dual fuel appliances and the difficulty and time associated with installing hydrogen only appliances, option 3 is likely to be preferred (unless dealing with a greenfield site). Installation of standardised appliances allows for greater flexibility in timing of the transition. A comparison of the switchover costs from standardised appliances against a direct replacement with hydrogen capable appliances is set out in Table 18.

TABLE 18. DOMESTIC HEATING APPLIANCE SWITCHOVER LABOUR AND HARDWARE COSTS COMBINED (GBP)

TYPE	HARDWARE	UPGRADE USING STANDARDISED APPLIANCES	DIRECT HYDROGEN UPGRADE
Boiler	Water heater	850	950-1100
Cooker	Cooktop	300	750
Cooker	Grill/oven	300	450
Heater	Gas heating	300	450

The importance of standardised appliances has been demonstrated in previous large scale gas conversions in Australia and the UK.

CASE STUDY: **UK Town Gas to Natural Gas Conversion**

From 1967 to 1977, 14 million customers and 40 million appliances were converted from town gas to natural gas. Although low pressure pipes remained mostly unchanged, new high pressure transmission and distribution networks needed to be built[113]. To ease the appliance conversion process, a policy was introduced in 1966 to ensure new appliances were readily adaptable to both town and natural gas. Conversion kits were also developed by the gas association's research group to facilitate the conversion of older appliances whose manufacturers were no longer operating[112].

To assist in the transition to hydrogen appliances, governments in designated locations may need to legislate that all new appliances should be standardised well before a planned roll out is expected to occur. A policy direction would provide manufactures dealing in Australia with the confidence to begin producing relevant appliances at scale. This could allow for parity to be achieved in terms of capital cost with common natural gas appliances. Here, coordination with non-Australian Governments (e.g. Leeds) may provide added certainty to multinational appliance manufactures servicing multiple markets and allow them to scale operations more rapidly.

As distinct from the H21 project which is set to rely on SMR paired with CCS, a more likely scenario in Australia would involve electrolysers feeding hydrogen into the distribution network. This would be a modular design, allowing for a more progressive transition to hydrogen in designated areas and negate the need for additional transmission infrastructure. Any extensive roll out however would be unlikely to occur before 2030.

Further, with the capital cost of standardised appliances likely to be on par with conventional natural gas appliances if the appropriate regulations are in place, government could be required to absorb changeover costs set out in Table 18.

112 Dorrington, M. et al. 2016, DECC Desk study on the development of a hydrogen-fired appliance supply chain
113 Dodds, P. and Demoullin, S. 2013, Conversion of the UK gas system to transport hydrogen

An alternative way of overcoming challenges associated with timing of changes in gas supply with appliances would be to localise hydrogen generation through use of rooftop solar and electrolysis. However, as mentioned in the context of RAPS, widespread roll out of these systems is unlikely to occur prior to 2030 with a centralised system more likely to be preferred on an economic basis in the shorter term.

Upgrading the pipeline network

If required, upgrading or reinforcing pipeline infrastructure to support gas usage across a residential network is commonplace in Australia. Upgrades to the network tend to occur incrementally, with the bulk of construction undertaken during the summer months when gas demand is lower. Customers with a need for continuous gas supply would likely be accommodated by either using portable tanks or by front loading gas downstream and sealing off a pipeline.

Comparison against electrification

One alternative to displacement of natural gas with hydrogen is electrification. The available technologies and relevant operating thresholds are set out in Table 19. For low grade heating operations, it is expected that heat pumps could be used, particularly for residential heat.

However, these systems typically have a larger footprint and maybe subject to space constraints. Other challenges associated with electrification include energy storage and variability in demand for heat in the winter and summer months. As discussed further in Section 5.1.2, it is generally cheaper to store energy for longer periods (i.e. days to months) in gaseous form (as opposed to electrical energy in a battery), particularly in a pipeline that is already being used to distribute gas to the home.

For higher temperatures (i.e. > 100˚C), electrical heating systems such as laser or microwave are available. These technologies can reach up to 3000˚C but generally require a direct connection to an electrical power source (i.e. generation system and turbine) at these scales.

While in some instances, electrification may prove economically favourable, complete substitution of energy provided from the gas network is unlikely to be feasible, due to the increase in demand and consequent cost of reinforcing the electricity network. While electrification is likely to be more feasible in Australia than the UK due to differences in heat demand, a 2016 report by KPMG analysing UK energy scenarios calculated that electrification could cost up to £170-196bn (AU$300-350bn) more than upgrading and facilitating a hydrogen gas network for heat[114].

5.3.2 POLICY/REGULATION

As alluded to above, hydrogen enrichment or displacement of natural gas is likely to require a clear policy direction from relevant governments. In order to then facilitate the transition, legislation regarding manufacture and installation of standardised appliances prior to changeover will reduce changeover times and labour costs.

TABLE 19. ELECTRIFICATION TECHNOLOGIES

TECHNOLOGY	SIZE RANGE (HEAT OUTPUT)	TEMPERATURE RANGE	REQUIRED PROXIMITY TO PRIMARY ENERGY SOURCE
Heat pumps	1kW to 30MW (water) 700kW (air)	Typically below 100°C	Requires constant connection to electrical grid.
Electrical heating	1 mW to MW scale	Few degrees above ambient to 3000°C. Temperatures above 3000°C can be obtained in arc melting and radiative heating (such as laser or microwave)	Requires connection to electrical power source. Can be used with intermittent power source in some instances.

114 KPMG 2016, 2050 Energy Scenarios; The UK Gas Networks role in a 2050 energy system

5.3.3 RD&D INVESTMENT PRIORITIES

Feasibility study and demonstration

It is recommended that a feasibility study be undertaken that focuses on upgrading the gas network and residential appliances in a specified town[115]. Some of the key characteristics to be considered in the study site selection include:

1. **Hydrogen supply and demand**: A proximate source of hydrogen supply is critical to assessing the suitability of a particular site. Areas that have strong solar or wind resources for energy input would be most favourable. The energy input resource will also impact decisions relating to the number of possible hydrogen connections placed on the network.

   Greenfield sites with new building developments that have flexibility in the design and implementation of appliances would also be preferred. Further there may be an opportunity to combine hydrogen capable appliances and infrastructure as part of a broader 'smart cities' initiative.

2. **Existing infrastructure**: Existing pipeline infrastructure that can accommodate a pure hydrogen gas stream, or require minimal upgrades, would be preferred over building a new pipeline.

3. **Hydrogen storage**: Depending on the demand profile, large scale hydrogen storage may be needed to accommodate inter-seasonal variation. In the more immediate term, pressurised storage tanks are likely to be sufficient. However there may be a longer term need to identify and situate a pilot city alongside salt caverns or potentially depleted gas reservoirs.

R&D support for manufacturers

Recent stakeholder engagement studies undertaken in the UK highlight a willingness of appliance manufacturers to cooperate with a transition to hydrogen for residential heat[116]. They do however express concerns that the R&D requirements of a transition are burdensome and would require governmental support. This would be similar to what was provided during the transition from town to natural gas.

Stakeholders cited significant costs associated with the product development stage, increased demand for R&D expertise, as well as the investment required to reach the level of scale needed to produce hydrogen appliance components at a reasonable cost.

5.3.4 SOCIAL LICENCE

Australia's most recent gas conversion from town gas to natural gas occurred in the 1970s. Thus with the majority of the Australian population unlikely to have experienced the combustion of hydrogen blends in the home, a public outreach and education process will be required to normalise the introduction of hydrogen into gas networks.

HyDeploy's UK blending trials include free appliance safety checks, drop in sessions, a media campaign, a hotline and numerous online resources[117]. At low concentrations, a blending project will present an opportunity to gradually exhibit the safety qualities of combusting hydrogen.

Upgrades to 100% hydrogen are likely to require a more extensive and engaging public outreach program. For the Leeds Gate H21 project, it is suggested that an external company be procured to handle education and public perception. Topics to consider would include managing trial information, media engagement and public education[118].

5.4 Industrial feedstocks

With the exception of iron ore processing (discussed in Section 5.4.6), the application for clean hydrogen as an industrial feedstock involves the displacement of brown hydrogen produced via SMR. The role of hydrogen in each of these sectors and potential demand is considered below.

5.4.1 PETROCHEMICAL

Hydrogen is used in the petrochemical industry for two main purposes, hydrotreating and hydrocracking. Hydrotreating uses hydrogen gas to catalytically remove sulphur, nitrogen and other contaminants from petrochemicals to create a cleaner fuel. This process is of increasing importance as emission and air quality requirements become more stringent globally[119]. Hydrocracking is a process that cracks long chained heavy hydrocarbons like crude oil into unsaturated light hydrocarbons. These hydrocarbons are then saturated by adding hydrogen gas to create more valuable products like jet fuel, diesel and kerosene[120].

115 A number of R&D measures here have been assumed by the recently announced Future Fuels CRC (http://epcrc.com.au/about/news/future-fuels-crc-bid-successful)

116 Dorrington, M et al. 2016, DECC Desk study on the development of a hydrogen-fired appliance supply chain

117 HyDeploy 2017, HyDeploy Project report

118 Dan Sadler et al. 2016 Leeds City Gate H21

119 International Energy Agency (IEA) 2017, Renewable Energy for Industry: From green energy to green materials and fuels, France

120 Robinson, P. and Dolbear, G. 2007, Practical Advances in Petroleum Processing

Australia has long been dependent on the importation of crude oil as the basis for various liquid fuels. More recently however, Australia has become increasingly dependent on refined fuel imports with four of the eight remaining oil refineries closing since 2000. With the potential for additional refinery closures, it is likely that there will be a reduced demand for hydrogen within this market.

Use of hydrogen in treatment for biofuels

The continued development of a local bio-crude (derived from biomass) industry could lead to a renewed demand for clean hydrogen in this sector. To date, this industry has been slow to develop due to factors such as global crude oil prices and the absence of a coordinated incentive scheme. However with growing acceptance, particularly within aviation and shipping, of the need for 'drop-in' biofuels[121] in order to decarbonise both sectors, demand for bio-crude refining could continue to increase[122]. This could also enable Australia to mitigate its dependence on imported fuels as discussed further 5.4.2.

Growth in a bio-crude industry could lead to higher demand for hydrogen given that biomass hydrotreating consumes considerably more hydrogen than crude oil due to the higher number of oxygen molecules that require displacing[123]. Southern Oil and Licella are two emerging Australian companies looking to develop domestic bio-crude production facilities using a biomass carbon source and low emission hydrogen.

5.4.2 SYNTHETIC FUELS

Synthetic fuels are derived from 'syngas' and traditionally produced via steam methane reforming and coal/biomass gasification. A number of technologies (e.g. Fischer Tropsch, methanol to gasoline) can then be used to produce higher order synthetic 'drop –in' fuels. Theoretically, all fuel products derived from crude can be produced synthetically.

'Power-to-liquids' is another means of producing syngas via the reaction of hydrogen gas (produced via electrolysis) with CO_2[124] (i.e. reverse water-gas shift reaction). CO_2 would likely be sourced as a waste stream from fossil fuel processes, thereby allowing for a reduction in lifecycle emissions. These fuels also have a lower emissions profile when combusted due to their being less impurities in the fuel as compared with crude products.

Liquid fuel supply

With the current status of global crude oil prices, drivers for production of synthetically derived fuels are unlikely to be strictly economic. Costs for synthetic fuels are somewhat levelised however if the risk of supply and decarbonisation are incorporated into pricing structures.

In this context, if the primary concern is fuel supply, then coal or gas to liquids plants may be more economical. However, where there is an additional need to decarbonise the sector, syngas production via the 'power-to-liquid' process described above may be preferred.

5.4.3 CHEMICALS

Ammonia

As noted previously, renewable ammonia (i.e. ammonia derived from clean hydrogen) can be used in the fertilizer and chemicals markets and as a potential energy vector in the near future. As a vector, ammonia can be both a hydrogen carrier or an input to a high temperature fuel cell or turbine (more likely in the context of export). R&D relating to the development of direct ammonia synthesis via electrolysis (discussed in Section 4.1.4) and a move away from the Haber-Bosch process could enable new distributed ammonia production to service both the fertilizer and energy markets.

Methanol

The production of methanol and its derivatives relies on the conversion of syngas. As a result of rising natural gas prices, Australia's only methanol plant ceased production in 2016[125]. As natural gas price forecasts remain uncertain, the mothballed plant is projected to be dismantled and shipped to the US[126].

Renewable methanol can be synthesised through hydrogenation of CO_2, although at half the efficiency of the incumbent process. Globally, interest appears to be increasing for this technology, evidenced by the development of a commercial operating facility in Iceland that utilises geothermal energy[127].

121 'Drop-in' fuels can be blended with crude derived equivalents and/or utilised in current equipment

122 CSIRO 2017, Low Emissions Technology Roadmap, Australia.

123 Wang, H., Elliott, D., French, R., Deutch, S. and Lisa, K. 2016, Biomass Conversion to Produce Hydrocarbon Liquid Fuel Via Hot-vapor Filtered Fast Pyrolysis and Catalytic Hydrotreating

124 Schmidt, P et al. 2017, Power-to-Liquids as Renewable Fuel Option, Germany for Aviation: A Review

125 Ibisworld 2018, retrieved from http://clients1.ibisworld.com.au/reports/au/industry/productsandmarkets.aspx?entid=183

126 Potter, B., March 8 2017, Energy: Gas crisis pushes methanol plant to the US, The Australian Financial Review, retrieved from http://www.afr.com/news/energy-gas-crisis-pushes-methanol-plant-to-us-20170308-gutfms

127 Badwal, S., Giddey, S. and Munnings, C. 2018, Emerging technologies, markets and commercialization of solid-electrolytic hydrogen production

Olefins

Olefins are used as a feedstock in the production of various products such as plastics, fibres and other chemicals. In an alternative to the standard steam cracking process, the production of olefins can occur through hydrogenation of CO_2 in the presence of specific catalysts[128]. This reduces the dependence on hydrocarbons and could create additional demand for hydrogen.

5.4.4 FOOD

Through catalytic hydrogenation, hydrogen can be used to harden oil to produce margarines and other semi-solid fats like shortening which is used in baking[129]. Hydrogenation helps prevent oxidation and provides thermal stability for the product. Margarine producers utilise on-site hydrogen production through small scale SMR[130] or electrolysers[131]. With an approximate market size of $1bn, the Australian margarine manufacturing industry is expected to grow at 2% per annum to supply domestic and Asian markets[132], providing demand for small-scale onsite hydrogen production.

5.4.5 GLASS MANUFACTURING

Hydrogen plays an important role in glass manufacturing, where in combination with nitrogen it is used to provide an atmosphere that prevents oxidation to help minimise flaws in the glass. Australia's glass and glass product manufacturing industry is worth an estimated $3.6bn, with approximately 50% of that market dedicated to float and architectural glass which require hydrogen as part of their production processes[133].

5.4.6 METALS PROCESSING

Although unlikely to occur before 2030 due to the current technology maturity, steel production could become a significant application for hydrogen. The transition from iron ore to steel relies heavily on its reaction with coking coal inside a blast furnace. This allows for the reduction (removal of oxygen) of the ore. A similar reduction reaction can occur using hydrogen (a reducing agent) with the resulting 'directly reduced iron' then placed in an electric arc blast furnace to produce steel. Use of hydrogen in iron processing is being considered further in Europe.

CASE STUDY: **HYBRIT**

In a joint venture entitled HYBRIT, SSAB (Swedish steel makers), LKAB (Europe's largest iron ore producer) and Vattenfall (one of Europe's largest electricity producers), who currently source their coal from Australia, are aiming to convert their steelmaking process from blast furnace steelmaking to electric arc furnace steelmaking which utilises direct reduction. This is motivated by a domestic and European push for emissions reduction.

The HYBRIT project will commence the design of their pilot plant in 2018, with construction to start in 2020. By 2025, demonstration plant trials are set to begin with a view to having the plant entirely converted to direct reduction by 2035.

5.5 Export

5.5.1 HYDROGEN

Target price and market share

A recent report undertaken by ARENA has identified four key hydrogen export jurisdictions: Singapore, China, South Korea and Japan[134]. The ARENA report has also assessed Australia's potential market share in each of these markets and the target price of hydrogen required to be competitive with other exporting countries such as Qatar and Norway.

TABLE 20. PROJECTED EXPORT MARKET DEMAND AND PRICE AS PER MEDIUM SCENARIO IN THE ARENA REPORT[135]

	2025	2030
Target H_2 production price (excluding storage and transport) ($/kg)	$2-3	$2-3
Total imported hydrogen demand per annum (tonnes)	840,042	3,793,182
Projected imports from Australia per annum (tonnes)	136,491	502,133

128 Guo, L., Sun, J., Ji, X., Wei, J., Wen, Z., Yao, R., Xu, H. and Ge, Q. 2018, Directly converting carbon dioxide to linear α-olefins on bio-promoted catalysts, Communications Chemistry, Volume 1, Article number: 11

129 Konkol, M., Wrobel, W., Bicki, R. and Golebiowski, A. 2016, The influence of the hydrogen pressure on kinetics of the canola oil hydrogenation on industrial nickel catalyst

130 HyGen, On-site hydrogen generation system brochure http://hygear.com/wp-content/uploads/2015/10/HYGEAR_HyGEN_Hydrogen-Generation.pdf

131 Nel, Hydrogen Electrolyser brochure http://nelhydrogen.com/assets/uploads/2017/01/Nel_Electrolyser_brochure.pdf

132 IBISWorld 2018, Cooking Oil and Margarine Manufacturing in Australia

133 IBISWorld 2018, Glass and Glass Product Manufacturing

134 ACIL Allen Consulting, 2018, Opportunities for Australia from hydrogen exports, Australia (ARENA Report)

135 Average capacity factors for wind and solar PV across Australia have been used

Meeting demand

This report considers the potential for all hydrogen production pathways to participate in the export market. Assuming that the HESC project comes online after 2030, prior demand is likely to comprise of electrolysis coupled with dedicated renewables and/or grid connected low emissions electricity. Optimisation of energy input will be needed to maintain high capacity factors.

To meet the expected demand in 2030, Table 21 shows the quantity (MW) and footprint of either solar PV or wind needed as an input to electrolysis. Total water required for electrolysis in the 2030 scenario is 4.5GL. Note that the land requirements for wind are considerably lower than for solar PV due to the fact that land adjacent to the turbines can be used for alternative purposes (e.g. cattle grazing).

Location requirements

Areas with favourable solar and wind resources and extensive land availability provide the most suitable locations for hydrogen export. Proximity to established export terminals, particularly for ammonia, would also be preferred. SA, Qld, NT, Vic and WA all meet these requirements, with WA and NT having the added advantage of proximity to Asia. For large scale hydrogen production, accessibility to desalinated sea water on the coast of Australia may also be required. Use of HVDC cables connecting electrolyser plants on the coast to dedicated renewables inland could be utilised in this context.

For solar PV in particular, detailed land surveys and approvals would be required to ensure adequate space for servicing both the export and domestic market.

Scaling up the industry: Lessons learned from the LNG industry

A key first step in the development of a hydrogen export industry is a government to government agreement for export and receipt of hydrogen. This would provide industry with the confidence it needs to source offtake agreements with industry partners and then attract investment into the hydrogen production, storage and transport assets needed to service demand. These agreements could also support the negotiation of favourable trade tariffs. Australia has a number of existing relationships with companies in each of the identified export destinations which can be built on in establishing new contracts.

Meeting the export demand profiles mentioned above requires a significant injection of capital. In the first instance, this is likely to demand long term 'take or pay' agreements (20-25 years) which have a flat demand profile to encourage investment. However, as the industry progresses and capital costs are amortised, shorter term offtakes (5-10 years) are likely to be preferred.

Sharing of the investment risk as part of a vertically integrated (refer to Section 2.1) joint venture is also critical. Joint ventures allow for the pooling of resources of companies with different capabilities. It is also important for the offtake company to have a stake in the joint venture to provide comfort regarding how the operation is run (this was the case with South Korean company Kogas in the Queensland LNG projects).

Achieving the roll out of infrastructure needed to support the export market may result in constraints on the local workforce and could require the mobilisation of additional resources. Such constraints can force labour costs to rise and impact the economics of related projects. Adequate planning regarding demands on the local workforce would therefore be needed.

Lastly, entities such as the International Maritime Organisation would most likely be responsible for establishing regulations associated with shipping of hydrogen. They should therefore be engaged by both government and industry to ensure that an appropriate regulatory framework is in place as the export industry develops.

5.5.2 AMMONIA

As mentioned previously, an increase in the number of ammonia plants set to come online in Asia in the next few years may lead to a glut in the global ammonia market. However, production of ammonia from clean hydrogen may allow for renewed global demand for ammonia produced in Australia as both a fertilizer and energy vector.

TABLE 21. MEETING AUSTRALIA'S EXPORT MARKET SHARE THROUGH EITHER DEDICATED WIND OR SOLAR PV IN 2030

	QUANTITY (MW)	LAND ELECTRICITY (HA)	LAND ELECTROLYSERS (HA)	TOTAL LAND (HA)
Solar PV	9,173 – 10,274	25,685 – 28,767	27.15 – 30.41	25,712 – 28,798
Wind	6,115 – 7,339	20 – 24.46	18.10 – 21.72	38.49 – 46.18

PART III

Roadmap synthesis and summary of actions

A series of strategic investments from both the private and public sector could see hydrogen become an economically sustainable industry. Current barriers to market activation stem from a lack of infrastructure required to support each application and/or the cost of hydrogen supply when compared with other energy carriers and feedstocks. It is expected however, that development of an appropriate policy framework could create a 'market pull' for hydrogen. Investment in infrastructure, hydrogen production, storage and transport is then likely to follow.

Implementation of the key investment priorities identified through the report could see the hydrogen industry scale in a manner depicted in Figure 19 below. This figure demonstrates the expected reductions in the cost of hydrogen supply and progression of target markets based on when hydrogen could be commercially competitive with alternative technologies (supporting assumptions set out in Appendix C). It also identifies where the barrier to market is infrastructure (above the hydrogen cost curve) and/or the cost of hydrogen supply (below the hydrogen cost curve).

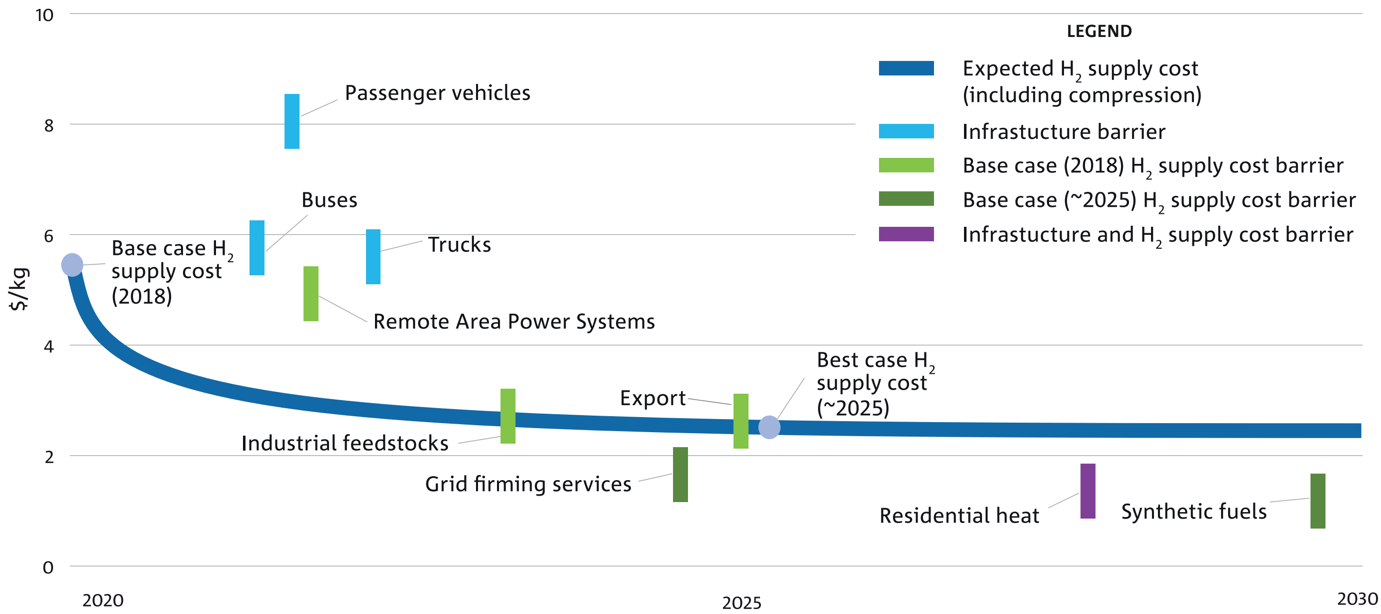


Figure 19. Hydrogen competitiveness in targeted applications

The competitiveness of hydrogen against other technologies is likely to then improve when considering factors such as:

1. **Localisation of relevant supply chains**: As demand for hydrogen increases, it is anticipated that global technology manufacturers will continue to invest in Australia and localise their operations. This is likely to lead to greater supply chain efficiencies, upskilling of the local workforce, increasing competition and improved pricing transparency.
2. **Industrialisation and manufacture automation**: Scaling of the industry will allow for greater investment in dedicated manufacturing facilities which can impact the capital cost of relevant technologies. Automation of supply chain requires an additional level of investment but can be done if demand for the technologies is sufficient.
3. **Establishment of an export industry**: This represents a potential 'game changer' for the industry, triggering the localisation and automation of supply chains. Importantly, it would also likely place downward pressure on the price of renewable electricity, a material driver of the cost of hydrogen production.
4. **Environmental cost/carbon risk**: Increasing trends towards sustainable business practice has made corporations more aware of the cost of using fossil fuels. Additionally, many will price in the risk of a future carbon policy in their investments which can help levelise the cost when compared with higher emissions alternatives.
5. **Energy supply risk**: Australia's dependence on imported liquid fuels and current gas constraints may also serve to levelise costs with clean hydrogen alternatives. This may be via the inclusion of priced in risk or other risk mitigation strategies such as hedging.

This curve should not be seen as the only driver for assessing initial target markets for hydrogen. Investment decisions may also be influenced by stakeholder interest, particularly where there are few other technological options available that allow for material emissions reduction (e.g. industrial feedstocks). Further, while each application has been assessed individually, an advantage of hydrogen is that it can simultaneously service multiple sources of demand. Thus in practice, a single hydrogen production plant could secure offtakes with a number of applications depending on available infrastructure, policy and demand profiles.

The following sections summarise how each element of the value chain can develop according to Figure 19.

Hydrogen production

THERMOCHEMICAL

Thermochemical production of hydrogen, namely coal gasification and SMR, are typically large infrastructure assets that must be built at scale (>˜500,000kgH_2/day) in order to offset the high capital cost of the generation plant and accompanying CO_2 reservoir. While the industry is in the development phase, projects of this scale would very quickly saturate a domestic market and so rely on the development of a hydrogen export industry in order to secure the requisite offtake agreements.

While CCS carries a different risk profile, once operating, it is not a material driver of cost given that the CO_2 capture component is an embedded part of hydrogen production. This stands so long as the production plant and storage reservoir are in close proximity due to the additional cost of transporting CO_2 long distances.

Although SMR is currently the cheapest form of hydrogen generation, investment in new large scale demand may prove challenging given the current state of the natural gas industry in Australia. Further, although more widely used on a global scale, black coal gasification has challenges in an Australian context due to coal reserves being concentrated in NSW and Queensland where there are either no well-characterised or only onshore CO_2 storage reservoirs.

Hydrogen production via coal gasification in Victoria's Latrobe Valley therefore represents the most likely thermochemical hydrogen production project.
A prospective plant would have the advantage of an extensive brown coal reserve sitting alongside a well characterised CO_2 storage reservoir in the Gippsland Basin. Pending the success of the proposed HESC demonstration plant in 2020/2021 and subsequent improvements in efficiencies, hydrogen could be produced in the region for approximately $2.14 -2.74/kg under a commercial scale plant when it comes online in the 2030s.

Once the export offtakes have been secured for the commercial scale thermochemical production projects, there may be scope to oversize the plant so that it can service the domestic market. This may be through the provision of hydrogen, synthetic fuels derived from syngas and/or electricity generation.

TABLE 22. SUMMARY OF ACTIONS: THERMOCHEMICAL HYDROGEN PRODUCTION

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025	• Secure export offtakes • Implement vertical integration under a JV, 'take or pay' arrangement with CO_2 storage operator	• Government to secure long term liability for CO_2 storage reservoir • Implement 'Guarantees of Origin' scheme	• Improve efficiencies in water and CO_2 separation through hydrogen selective membranes • Further process intensification research	• Continue stakeholder engagement regarding safety and technical viability of CCS
2025-2030	• CO_2 reservoir operator to establish offtakes with multiple sources of CO_2 • Secure multiple revenue sources for gasification or SMR plant		• Continue to develop emerging technologies such as chemical looping, methane cracking, biomass gasification and solar fuels • Continue CO_2 storage reservoir appraisal and demonstration	

ELECTROCHEMICAL

Electrolysis provides a more modular, distributed option that can scale according to demand. It is therefore more likely to meet the majority of hydrogen demand prior to 2030 and the expected cost curve is reflected in Figure 19.

Of the more established electrolysis technologies, AE is currently cheaper, largely due to its widespread use in the chlori-alkali industry and its components currently being manufactured at scale. As a relatively mature technology, AE is expected to continue to play a key role in the development of the industry and incremental improvements are still expected to be achieved through subtle gains in efficiency.

Although currently more expensive than AE, PEM electrolysis is fast becoming a more competitive form of hydrogen production. It also offers a number of other advantages including faster dynamic response (which makes it more suitable for coupling with VRE) and a higher current density (or smaller footprint) for scenarios in which there are limitations on space (e.g. refuelling stations).

Material cost reductions can be achieved for both forms of electrolysis by ensuring a favourable PPA (i.e. 4c/kWh) while maintaining a high capacity factor (e.g. ~85%). This scenario becomes more probable with the expected increase in renewable energy over the next five years.

Increases in the capacity of an electrolyser can also lead to material reductions in the LCOH. For PEM in particular, the most rapid gains are expected in the scale up from 1MW to 100MW, with more incremental improvements achieved thereafter. Increases in technology production economies of scale will also have a significant impact on capital costs.

The recently announced Port Lincoln project is intended to de-risk the deployment of a 15MW alkaline electrolyser. It is expected that projects of similar scale could demonstrate the viability of PEM in the next few years, making projects of this size or larger, commonplace by 2025.

With PEM electrolysis likely to attract the most RD&D investment, ongoing research will focus on improvements in plant efficiency. These improvements are anticipated to come through cost reductions in or removal of BoP and upgrades in membranes and catalysts in the stack. Combined with the improvements stated above, it is expected that the LCOH from electrolysis could reach approximately $2.29-2.79/kg by 2025.

TABLE 23. SUMMARY OF ACTIONS: ELECTROCHEMICAL HYDROGEN PRODUCTION

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025	• Secure favourable low emissions PPAs • Position electrolyser for multiple hydrogen offtakes • Optimise plant operation with grid connected and dedicated renewables where possible • Establish verticals for optimisation across the value chain • Secure offtake for oxygen and revenue from grid services	• Implement regulations that provide appropriate compensation for grid firming services from electrolysis • Implement coordinated incentives for demonstration schemes with clear flow on learnings	• Improve PEM efficiencies via catalysts, lower resistance membranes • Implement lower cost and removal of BoP concepts • Improve lifetime of stacks by developing catalyst layers and membranes and by reducing corrosion of system components • Progress emerging high temperature electrolysis	• Develop engagement plans dedicated to normalising risk of hydrogen production to secure appropriate land

Storage and transport of hydrogen

STORAGE OF HYDROGEN

Due to the low volumetric density of hydrogen in its unpressurised gaseous state, a series of technologies may be utilised in order to improve the economics of storage. Selection of the most appropriate storage technology represents a trade-off between the quantity of hydrogen, storage footprint and energy usage.

Compression of gaseous hydrogen generally represents the most attractive option for stationary storage given the comparatively low cost of the process and greater availability of space. With likely improvements in compression efficiencies achieved through further development of ionic and electrochemical compression, depending on scale, storage adds approximately $0.3/kg to the cost of hydrogen produced.

If available, underground storage is likely to be more cost effective for hydrogen storage at scale (i.e. 210,000kg/day for 30 days) due to the lower capital cost (compared with scaling multiple tanks) and lower pressures used. Early studies suggest that Australia has a number of areas suitable for construction of salt caverns but they are less concentrated on the east coast of Australia where the majority of the population resides. Further R&D is therefore required into the potential for underground aquifers and depleted gas fields to store large quantities of hydrogen. Similarly, where hydrogen is delivered via pipeline, line packing (i.e. increasing pipeline pressure) represents a key option for large scale storage.

Other storage technologies including liquefaction and material carriers such as ammonia have a higher cost but superior volumetric density. These technologies therefore become more financially viable when storing (or transporting) larger quantities of hydrogen where there are stringent space limitations in place (e.g. delivery and storage at hydrogen refuelling stations). The cost of storing liquefied hydrogen at scale is expected to be in the order of $1.59-1.94/kg (~2025) following expected improvements in liquefaction technologies and refrigerants.

Ammonia synthesis via the Haber-Bosch process is capital intensive and must be done at scale to be cost competitive. Increases in capacity and improvements in air separation and purification could reduce the cost of ammonia so that it adds an additional \$0.19-\$0.23/kgNH_3 (1.10 – 1.33/kgH_2), to the cost of hydrogen carried within the ammonia product.

While ammonia can be utilised as an energy vector it its own right, there is an additional energy and capital cost associated with recovery of hydrogen at the point of use and therefore a direct comparison with liquefaction cannot be made at this stage. Relevant membrane technologies that allow for recovery of high purity hydrogen, and therefore represent a key piece in the supply chain, are currently being developed but are not yet mature enough to gain a meaningful assessment of cost.

TRANSPORT OF HYDROGEN

Hydrogen can be transported via truck, rail, ship and pipeline utilising the storage techniques identified above. Although not reflected in Figure 19 due to variability, greater distances between the point of generation and use increases supply chain costs.

With no set thresholds in place, coupling of storage and transport technologies typically requires consideration of a number of factors including available infrastructure and distance. Compression has been the most widely used method for transporting hydrogen via truck with higher pressures generally used when the distance travelled exceeds ˜300km. Liquefaction, including cryo-compression is now also increasingly utilised where trucking distances approach 1000km.

As distances and demand for hydrogen increase, technologies with greater hydrogen densities such as hydrogen liquefaction and ammonia synthesis are likely to be preferred. These technologies are being developed further given their potential role in export of hydrogen via ship.

For domestic use, pipelines are important for transport of larger quantities of compressed gaseous hydrogen (i.e. transmission) as well as distribution to multiple points of use in a network (i.e. distribution). While the risk of pipeline embrittlement arising from transporting hydrogen is minimised at the low operational pressures in distribution networks (<1-7 bar), issues can arise at higher operating pressures depending on the pipeline materials used. For transmission pipelines, pressures of between 70-105 bar would be suitable for steel or fibre reinforced plastic pipes.

TABLE 24. SUMMARY OF ACTIONS: HYDROGEN STORAGE AND TRANSPORT OF HYDROGEN

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025	• Position production plants close to point of use where possible • Optimise technology selection in context of broader supply chain • Undertake feasibility studies and projects to leverage existing ammonia infrastructure where possible	• Review gas pipeline regulations to consider including gaseous hydrogen	• Further R&D on hydrogen capable pipeline materials and operating pressures • Improve compression efficiencies (including ionic and electrochemical) • Conduct salt cavern surveys and test depleted gas reservoirs for suitability of hydrogen storage • Develop liquefaction catalysts, coolants and materials • Develop ammonia cracking (cheaper catalysts) and electrochemical synthesis	• Implement communication plans regarding hydrogen pipeline easements

Applications for hydrogen

HYDROGEN FUELLED TRANSPORT

Transport represents an early target market in the development of a hydrogen industry. This is particularly true if there is a zero emissions target for the sector, given the applicability of hydrogen to all forms of transport.

In the passenger vehicle market, FCEVs represent a potentially more favourable option than BEVs for consumers that travel longer distances (i.e. 400-600km without refuelling) and expect shorter refuelling times. For heavier vehicles such as buses and trucks with stringent payloads, the superior energy density by mass (in comparison with batteries) also allows for greater distances travelled without the need for refuelling. The primary barriers to FCEV uptake are the capital cost and lack of infrastructure supporting their use.

While R&D into the improvement of FCEVs is ongoing, the most material reductions in capital costs are expected to stem from economies of scale through dedicated and automated production lines. Given that Australia currently comprises approximately 2% of the global vehicle market, this will be dictated by consumer trends overseas. Globally, leading OEMs expect to reach requisite targets, allowing for mass market vehicle production by 2025.

However, efforts are still needed to stimulate uptake in Australia. A two pronged approach of an emission standard on vehicles and incentive scheme targeted specifically towards FCEVs may be required. Both of these methods would likely give stakeholders the confidence to distribute vehicles and invest in infrastructure (e.g. HRSs). These steps are crucial in terms of familiarising potential consumers with the technology, demonstrating its operational performance and normalising the risk associated with driving hydrogen fuelled cars.

The success of the FCEV market in Australia however rests largely on the strategic deployment of HRSs. Depending on the configuration, current costs range from USD1.5m to USD2.0m per station. However, with an extensive deployment of refuelling stations ongoing in jurisdictions such as Germany and California, there will be a shift away from ad hoc demonstrations to standard roll out of reliable equipment. This is likely to lead to a significant reduction in capital (i.e. USD0.5 to USD1.0 million) and operating costs by 2025.

Deployment of refuelling stations require a high degree of coordination between station operators and car OEMs (i.e. to match hydrogen supply and demand). Overseas, joint venture arrangements have been found to be successful in allowing for the requisite level of coordination to be achieved. Within these arrangements, there is also a key role for Government in underwriting initial demand risk and enhancing the proponent’s ability to synchronise and optimise the location of stations.

A series of pilot projects demonstrating successful operation of refuelling stations and their integration with vehicles is needed in Australia. Fleet or ‘back to base’ vehicles with known driving profiles, payloads and operating hours should be prioritised for pilot projects as they overcome the need for multiple refuelling stations. Heavier vehicles such as buses could also be considered given that they accept 30-40kg of hydrogen per refuel (as compared with passenger vehicles at 4-6kg) and provide greater demand certainty for HRS operators.

TABLE 25. SUMMARY OF ACTIONS: TRANSPORT

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025	• Establish JVs with HRS operators, suppliers and OEMs with role for Government in underwriting demand risk • Undertake mapping of HRS clusters • Implement leasing models for FCEVs • Facilitate use of FCEV materials handling in warehouse operations • Start roll out of HRS clusters	• Implement emissions standards on vehicles • Implement FCEV specific incentives (incl direct subsidies, rebates, registration)	• Roll out pilot projects for HRSs using government or university fleets with known driving profiles • Conduct ongoing testing and optimisation of HRS operations	• Facilitate recognition of FCEVs as electric vehicles • Conduct safety demonstrations including fire brigade • Develop education plants for franchisee fuel station operators on safety and benefit of hydrogen
2025-2030	• Roll-out of intercity HRSs		• Demonstrate rail and network planning	

Of the other emerging applications for transport, rail has seen the most activity with the first hydrogen powered train to start operating commercially in Germany in June 2018. While likely to require a significant level of investment, demonstration projects for trains could occur in Australia prior to 2030, increasing the scope for subsequent roll out.

REMOTE AREA POWER SYSTEMS (RAPS)

Diesel driven RAPS have a high operating cost due to the need to import fuel via truck to remote communities. These systems also have an adverse environmental impact. On the other hand, RAPS with hydrogen storage (350 bar) and fuel cells could be commercially competitive before 2025 with expected reductions in the cost of hydrogen and relevant technologies. When compared with battery systems, hydrogen also performs better under harsher conditions commonly experienced in remote communities.

Key targets for demonstration of hydrogen driven RAPS over the next three to four years would ideally include smaller remote mining operations due to the ability for hydrogen to service multiple operations (e.g. stationary electricity, transport and heat).

(A summary of investment priorities for RAPS is combined with grid firming services below)

INDUSTRIAL FEEDSTOCKS

Use of clean hydrogen as an industrial feedstock involves direct displacement of hydrogen derived from SMR as the incumbent source for production. The breakeven point will be primarily driven by the price of natural gas against reductions in cost of hydrogen via electrolysis. This is expected to occur before 2025. Thus there is less that must be done in terms of market activation other than incentivise use of clean hydrogen in these processes before it is commercially competitive.

Use of hydrogen in the petrochemical industry as a means of treating and refining crude has been declining due to Australia's increasing dependence on imported refined fuel products. However growing concern over the need to reduce Australia's dependence on liquid fuel imports and decarbonise the sector, may provide a growing role for hydrogen in the treatment fuels derived from biomass.

Input of hydrogen into ammonia and other chemicals such as methanol could also create new opportunities for local industry which is currently losing its global competitiveness due to higher natural gas prices. For ammonia in particular, despite a potential glut due to a number of plants set to come online in Asia, there may be renewed demand for Australian renewable ammonia as the world transitions to a low carbon economy. Further, while unlikely to carry the same value as when used as a fertilizer, total demand may also be increased by the potential additional market for ammonia as an energy vector.

In relation to other industrial uses, demand for hydrogen as an input into food products such as margarines to prevent oxidation and improve thermal stability may also continue to grow with population and exports to Asia. However, while hydrogen can be used as a means of processing iron ore for steel production, this technology is relatively early stage, high cost and unlikely to be rolled out at scale by 2030.

TABLE 26. SUMMARY OF ACTIONS: INDUSTRIAL FEEDSTOCKS

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025	• Construct new inlets during plant shut downs to allow for clean hydrogen • Prolong and redevelop existing ammonia infrastructure	• Implement localised fuel supply regulations • Implement incentive schemes regarding use of clean hydrogen as an industrial feedstock	• Demonstrate clean hydrogen as an input into existing plants • As per ammonia for storage	• Create awareness of emissions embodied in commodities to help inform consumer choice
2025-2030			• Demonstration of iron ore reduction using hydrogen for steel	

EXPORT

Export of hydrogen represents a key opportunity for Australia. Potential demand for imported hydrogen in China, Japan, South Korea and Singapore could reach in the order of 3.8 million tonnes in 2030[136] (~AUD9.5 billion) with Australia well positioned to play a key role in the export market.

Development of this industry is largely dependent on the production, storage and transport technologies identified above with many lessons to be gained from the export of LNG. Given that the commercial scale production of hydrogen from brown coal in Victoria is only likely to be available after 2030, the majority of prior demand is expected to be met by electrolysis coupled with dedicated renewables and/or grid connected electricity. A target hydrogen production price of $2-3/kg (excluding storage and transport) would be needed for Australia to compete with other exporting countries.

TABLE 27. SUMMARY OF ACTIONS: HYDROGEN EXPORT

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025	• Establish government to government agreements between countries to give industry confidence • Establish JVs (incl importing companies) to allow for vertical integration • Undertake land appraisal assessments for dedicated renewables and electrolysis • Establish long term take or pay agreements • Invest in local labour force • Negotiate favourable tariffs for hydrogen export (including in the existing FTAs) • Position production plants close to existing export terminals where possible	• As per production, storage and transport • Develop regulations permitting use of unutilised land for dedicated renewables • Engage bodies such as the International Maritime Organisation to ensure appropriate policy framework for shipping hydrogen	• As per production, storage and transport	• Continue education on potential for hydrogen as new low emissions export commodity

136 ACIL Allen Consulting, 2018, Opportunities for Australia from hydrogen exports, Australia (ARENA Report)

ELECTRICITY GRID FIRMING

Hydrogen systems can provide electricity grid stability (i.e. seconds to hourly storage) and grid reliability (i.e. seasonal storage) services. There is likely to be an increasing demand for these services as the proportion of VRE in the electricity network continues to increase over the next five to 10 years. In the first instance, use of grid connected electrolysers provide a flexible load that can be quickly ramped up and down to help manage grid stability and potentially improve the economics of hydrogen production by generating an additional revenue stream.

Hydrogen systems consisting of storage and fuel cells (or turbines once developed further) are unlikely to be constructed for the sole purpose of providing grid stability services due to the need for a price of $1.30-1.60/kg to compete with batteries, PHES and gas turbines. In practice however, grid stability could be seen as an ancillary revenue source if the economics favour use (e.g. refuelling stations with fuel cells) and the hydrogen system is appropriately positioned.

An increasing proportion of VRE in the electricity network may also result in a need for grid reliability services (e.g. seasonal storage). Hydrogen storage and fuel cell systems present one of the only technological solutions to overcoming challenges with seasonal intermittency, particularly if underground storage (e.g. salt caverns) is available. Batteries are more expensive to scale given the need to combine multiple battery banks. They also suffer energy losses when fully charged for extended periods. Similarly, PHES is unlikely to be used in this way given that new dams for on-river systems are unlikely to be constructed and off-river systems are comparatively smaller scale.

To compete with gas turbines on a commercial basis, salt cavern and fuel cell systems would require a hydrogen price of ~1.60/kg. However that price differential may be minimised if carbon and natural gas supply risks costs are considered in relation to the construction of new turbines.

TABLE 28. SUMMARY OF ACTIONS: ELECTRICITY GRID FIRMING AND RAPS

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025	• Position fuel cell systems to allow for export to the grid where economics favour use	• Develop economic regulations valuing services from hydrogen in short to long term storage markets • Incentivise hydrogen RAPS on mining sites and other remote communities	• Continue R&D in fuel cells, improving capital costs and lifetime of stack • Conduct feasibility studies over specified regions for RAPS • Demonstrate RAPS in mining activities • Continue RD&D in ammonia/hydrogen turbines and reversible fuel cells	• Undertake community engagement in remote regions on benefits and risks of hydrogen

HEAT

Direct combustion of hydrogen for the purpose of generating heat is unlikely to compete with natural gas on a commercial basis before 2030 (i.e. it would require a hydrogen price of ~$1.40/kg). This form of utilisation would therefore need a clear policy signal from government focussed on decarbonisation of the gas networks in order for this conversion to occur.

Hydrogen enrichment of the natural gas network provides an early market for hydrogen and a nearer term option for decarbonisation of the sector without the requirement for a significant upgrade of infrastructure. However, due to different burner properties and characteristics of the gas, a move to 100% displacement of natural gas with hydrogen will require an upgrade to existing appliances and possibly pipelines.

Industrial appliances such as furnaces and kilns are complicated due to integration with other systems. Here upgrading from natural gas to use of hydrogen may therefore be more ad hoc, and will most likely require an existing proximate supply of hydrogen.

From a technical perspective, upgrading residential appliances is more straightforward and therefore a widespread roll out could be possible in or around 2030. The challenge is coordinating the appliance changeover with the switch in gas supply.

Changeover risk can be mitigated somewhat by the placement of electrolysers at the distribution network where possible (as opposed to having large-scale centralised generation and transmission) which would reduce the need for pipeline upgrades and allow for a modular scale up of appliances. Regulations concerning the use of standardised appliances in the lead up to an upgrade is also critical as it gives manufactures the confidence to produce relevant appliances at scale (which reduces capital costs) and minimises installation times once the changeover occurs.

TABLE 29. SUMMARY OF ACTIONS: HEAT

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025	• Invest in hydrogen capable pipelines where upgrades to existing networks are required • Invest in local skills and changeover workforce • Coordinate with non-Australian governments to give multinational appliance manufacturers more certainty	• Legislate manufacture of standardised appliances • Implement policy directives for natural gas displacement • Implement R&D incentives for appliance manufacturers	• Continue research on 100% hydrogen capable appliances • Continue ongoing trials for natural gas enrichment with hydrogen • Undertake feasibility study over designated town • Begin development of pilot project for designated town • Demonstrate use of hydrogen on industrial sites	• Enrich natural gas supply to make consumers comfortable burning hydrogen in the home
2025-2030		• Determine entities responsible for absorbing appliance changeover costs	• Plan for coordinated rollout of residential appliances	• Conduct detailed education programs for 100% hydrogen in the home

SYNTHETIC FUELS

Synthetic fuels are unlikely to compete with crude derived fuels on a purely commercial basis. However as discussed in the context of biofuels, the narrative could change if there is an identified need for a localised supply.

This may be achieved through the production of syngas as an intermediary via coal gasification and/or SMR. A number of technologies (e.g. Fischer Tropsch, methanol to gasoline) can then be used to produce higher order synthetic 'drop–in' fuels. However, this process still has a significant emissions profile given that the CO_2 is utilised in the process rather than sequestered. As an alternative, power-to-liquids, which combines a waste stream of CO_2 with hydrogen could be used to synthesise low emissions fuels. This option could become competitive with syngas if carbon risk is considered in relevant investments and increase the scope for use in the aviation and shipping industries.

TABLE 30. SUMMARY OF ACTIONS: SYNTHETIC FUELS

TIMEFRAME	COMMERCIAL	POLICY/REGULATORY	RD&D	SOCIAL
2018-2025		• Mandate local and low emissions fuel supply targets	• Undertake R&D regarding efficiency improvements in reverse water gas shift reaction	• Continue engagement regarding benefits of localised fuel supply

APPENDICES

APPENDIX A – **Technical**

Hydrogen production

LIFECYCLE EMISSIONS

TABLE 31. LIFECYCLE EMISSIONS FOR HYDROGEN PRODUCTION TECHNOLOGIES

PRODUCTION PROCESS	PRIMARY ENERGY SOURCE	OPERATING CO_2 EMISSIONS kg CO_2/kgH_2
Steam Methane Reforming with CCS	Natural Gas	0.76[137]
Coal Gasification with CCS	Coal	0.71[138]
Alkaline Electrolysis	Renewable Electricity	0.00
PEM Electrolysis	Renewable Electricity	0.00

OTHER MATURE THERMOCHEMICAL PRODUCTION TECHNOLOGIES

TABLE 32. MATURE THERMOCHEMICAL HYDROGEN PRODUCTION TECHNOLOGIES

PROCESS	DESCRIPTION	DIS/ADVANTAGES
Partial Oxidation (POX)	Hydrocarbons, primarily heavy oil fractions, react with a limited amount of oxygen producing heat and hydrogen.	+ Good for small scale + Rapid response - Less efficient than SMR - Requires purification
Autothermal Reforming	A combination of SMR and POX, where steam is added to the oxidation process. The heat from the oxidation component fuels the steam reforming process. Process can be localised to a single unit[139].	+ Rapid response - Extensive control system required - lower efficiency that SMR or gasification
Pyrolysis	Occurring at lower temperature than gasification, coal is pyrolysed in a range of 200-760°C in the absence of oxygen, leaving char and ash as by-products to produce fuel gas. Hydrogen only comprises 25% of potential yield (75% coke) and so it would be difficult to establish a business case for hydrogen production as the primary product.	+ Relatively simple technology which reduces capex required - The H_2 content is generally low

137 Calculated with reference to the CO2CRC Australian Power Generation Technology report (2015)
138 Internal CSIRO calculation
139 Kalamaras, C. and Efstathiou, A. 2013, Hydrogen Production Technologies: Current State and Future Developments

Emerging production technologies

THERMOCHEMICAL

TABLE 33. EMERGING THERMOCHEMICAL HYDROGEN PRODUCTION

TECHNOLOGY	DESCRIPTION	TRL	POTENTIAL FOR DISRUPTION
Methane Cracking	Without oxygen present, hydrogen is separated from methane at high temperatures leaving solid carbon as a by-product. Due to the absence of oxygen, no CO_2 is produced.	6-7	Although not a new process, its uptake has been limited due to the solid carbon clogging equipment. However a new method that passes methane through liquid tin allows the removal of carbon without affecting production, but is yet to be scaled[140]. The Hazer Group has built a demonstration plant in Western Sydney, utilising iron ore as an affordable catalyst. With a recent successful capital raising, Hazer is looking to move to commercial scale.
Chemical Looping	By splitting H_2O in the presence of a metal, hydrogen is produced. This results in a metal oxide which is transferred to a neighbouring system to be reduced in the presence of a gaseous fuel, where CO_2 is produced and immediately captured. This reduced metal is fed back into the H_2O system on a loop.	3	With no energy penalties for CO_2 removal, chemical looping has the potential to remove an energy and money intensive step of the process.
Concentrating Solar Fuels (CSFs)	CSFs are produced by converting a feedstock to a chemical fuel using high-temperature thermochemical reactions, powered by concentrating solar radiation. In the case where the feedstock is a carbonaceous fuel (e.g. natural gas, coal or biomass), the feedstock is converted into syngas using solar energy and then syngas can be converted into hydrogen and carbon dioxide, which can be captured.	4-6[141]	There is ongoing research into receiver/reactor designs, thermochemical processes and improving efficiency and scale-up of fuel production and materials for high temperatures. CSF are produced using a specialised form of CST and thus improvements in CST such as in heliostat design also benefit CSF processes.

140 Wegerab, L., Abánadesac, A. and Butlera, T. 2017, Methane cracking as a bridge technology to the hydrogen economy

141 Hinkley, J., Hayward, J., McNaughton, R., Edwards, J. and Lovegrove, K. 2016, Concentrating Solar Fuels Roadmap: Final Report

Photolytic and microbial production

Photolytic production relies on the interaction of light and water to produce hydrogen using either a semiconducting photo catalyst or biological process[21]. As shown in Table 34, other biological pathways for hydrogen production exist that do not require the presence of light. These technologies are at an early stage of development and without material breakthroughs in terms of cost and efficiency, would need a significant increase in investment in order to disrupt incumbent production technologies.

TABLE 34. EMERGING PHOTOLYTIC AND MICROBIAL PRODUCTION OF HYDROGEN

TECHNOLOGY	DESCRIPTION[142]	TRL	POTENTIAL FOR DISRUPTION
Photoelectrochemical or photocatalytic water splitting	Semiconductors use sunlight to dissociate water molecules into hydrogen and oxygen.	3	Can be developed in thin films not unlike photovoltaic cells and are able to operate at low temperatures. Such systems offer great potential for cost reduction of electrolytic hydrogen, compared with conventional two-step technologies.
Photobiological water splitting	Micro-organisms use sunlight to split water into hydrogen and oxygen. Some microbes use sunlight as a driver to break down organic matter.	1-2	Potential for wastewater to be utilised to produce hydrogen.
Microbial biomass conversion (fermentation)	In the absence of light, microorganisms break down organic matter to produce hydrogen through dark fermentation.	1-2	Biomass is an abundant resource. Many fermentation scaling issues have been addressed by the biofuel industry, enabling researchers to focus on less variables.
Microbial electrolysis	Combines an electric current with protons produced by microbes breaking down organic matter to produce hydrogen at the cathode.	4[143]	Could utilise materials that otherwise cannot be used for fuel like wastewater.

142 US Department of Energy, Fuel Cell Technologies Office, Retrieved 2018 https://www.energy.gov/eere/fuelcells/hydrogen-production
143 Abhijeet, P et al. (2017) Renewable Hydrogen Production from Biomass Pyrolysis Aqueous Phase

Hydrogen storage

EMERGING HYDROGEN STORAGE TECHNOLOGIES

TABLE 35. EMERGING AMMONIA SYNTHESIS TECHNOLOGIES

TECHNOLOGY	DESCRIPTION	TRL	POTENTIAL FOR DISRUPTION
Electrochemical ammonia synthesis	Ammonia is directly synthesised with water and nitrogen in an electrochemical reactor. Depending on the electrochemical synthesiser, operating temperature ranges from room temperature to 800˚C[144].	1-2	While this path has similar energy requirements to the electrolyser hydrogen production and Haber Bosch process, it operates at milder conditions and in a single reactor. Ammonia recovery rates at this stage are poor due to the preference of hydrogen ions to bond with one another to produce hydrogen gas.
Membrane based ammonia synthesis	The technology is based on hydrogen permeating metal membrane, that converts the hydrogen produced by an electrolyser into ammonia at much lower pressures compared to Haber-Bosch process.	3	The low pressure operation allows the synthesis reactor directly coupled to an electrolyser and air separation unit eliminating much of the balance of plant. The technology is thus, less capital intensive and suited for use for distributed as well as centralised ammonia production.
Offshore ammonia synthesis	Onshore renewable electricity is connected via HVDC cable to an offshore platform. Here, a desalination plant, electrolyser, nitrogen production plant and Haber-Bosch/electrochemical plant facilitates ammonia synthesis and storage at the point of export.	3	Similar in concept to floating LNG terminals, reduces transport costs. Cost could be reduced by completing the process offshore, reducing the need for land and infrastructure such as transport pipeline and terminals.

144 Giddey, S et al, 2017, Ammonia as a renewable energy transport media, Australia

TABLE 36. OTHER EMERGING STORAGE TECHNOLOGIES

TECHNOLOGY	DESCRIPTION	TRL	POTENTIAL FOR DISRUPTION
Metal Hydrides	Metals, such as magnesium, chemically bond with hydrogen gas to be transported as a metal hydride. When the hydrogen is required, heat is applied to release it from the metal.	7-9	Metal hydrides can have higher hydrogen-storage density than pressurised or liquefied hydrogen. Storage can occur at moderate temperature and pressures increasing the safety[145].
Complex Hydrides	Hydrogen chemically bonds with complex molecules such as $LiAlH_5$. As per metal hydrides, when required the hydrogen must be released from the hydride.	1-3	Hydrogen storage capacity potential is very high. Although not new, the difficulty in removing the hydrogen from the hydride has hindered advancement. Can require heat of up to 1000°C for release. Development of new catalysts could encourage more investment in R&D.
Physisorption	Hydrogen physically binds to either the surface of a molecule or is held within pores. Many materials are currently under examination including MOFS, zeolites, carbon nanotubes etc[146]	2	The materials used are very light, release is endothermic negating risk of explosion. Hydrogen can be released quickly[147].
Synthetic Methane	Waste CO_2 is reacted with clean hydrogen to produce methane which is then liquefied for transport. Hydrogen can then be extracted from the synthetic methane at the point of use via cracking or steam reforming. Although the separate processes are industrially mature, this is yet to have been demonstrated as part of an integrated supply chain.	1-2	Synthetic methane can be mixed with traditional LNG and so existing infrastructure can be leveraged. There is also already an existing market for which synthetic methane could be supplied. The CO_2 could be sourced from high CO_2 gas fields, thermal power stations, incineration facilities and ethanol plants which can enable reductions in life cycle emissions.

145 Sakintuna, B., Lamari-Darkrim, F. and Hircher, M. 2007, Metal hydride materials for solid hydrogen storage: A review
146 Niaz, S., Manzoor, T. and Pandith, A. 2015, Hydrogen storage: Materials, methods and perspectives
147 Ding, F. and Yakobsob, B. 2011, Challenges in hydrogen adsorptions: from physisorption to chemisorption

Utilisation

MATURE FUEL CELL TECHNOLOGIES

TABLE 37. MATURE FUEL CELL TECHNOLOGIES

TECHNOLOGY	DESCRIPTION [148]	(DIS) ADVANTAGES	TYPICAL STACK SIZE[149]	USES[150]
Polymer Electrolyte Membrane (PEM) FC	Also known as a proton exchange membrane fuel cell. Hydrogen is catalytically split into protons which permeate through the membrane from the anode to the cathode to create an electrical current.	Low operating temperature Low noise High power density Quick start-up Small size Expensive catalyst Sensitive to impurities	<1-100kW	Backup power, portable power, distributed generation, transportation and specialty vehicles
Alkaline FC (AFC)	Uses a liquid potassium hydroxide electrolyte and can utilise non-precious catalysts. Suitable for small scale (<100 kW) applications. It has a low cost, low temperature and short start up time.	Low temperature Quick start up Lower cost components Sensitive to CO_2 in fuel and air	1-100kW	Military, space, back- up power, transportation
Solid Oxide FC (SOFC)	Fuel cell that uses a solid oxide or ceramic electrolyte and high temperatures (up to 1000°C) negating the need for a catalyst. It is suitable for both industrial and residential applications and can run using fuels other than hydrogen (i.e. syngas, ammonia). However, it has a long start time and therefore needs to be run continuously.	High efficiency Fuel flexibility Suitable for CHP High operating temperatures Corrosion Long start-up time Limited number of shutdowns	1-2000kW	Auxiliary power, electric utility, distributed generation
Molten Carbonate FC	Use a molten carbonate electrolyte and runs at high temperatures, so non-precious catalysts can be used. It does not require hydrogen or a reformer (i.e.it can run off natural gas and CO_2). It is suitable for industrial and grid scale applications (i.e. tens of MW). It is also relatively low cost but has a short lifespan and low power density.	High efficiency Fuel flexibility Suitable for CHP High operating temperatures Low durability, susceptible to corrosion Long start-up time Low power density	300-3000kW (300kW modules)	Electric utility, distributed generation
Phosphoric acid FC	Uses a liquid phosphoric acid electrolyte and has typically been applied in commercial, combined-heat power systems. It requires a temperature of between 150-200°C to operate, has a long start time and relies on expensive catalysts.	Increased tolerance to fuel impurities Suitable for CHP Expensive catalysts Long start-up time Sulphur sensitivity	5-400kW	Distributed generation
Direct Methanol FC	Instead of methanol being reformed within the system, methanol is fed directly to the anode. DMFC's suffer from low efficiency and power density and are most likely to be used for small portable applications. Runs at operating temperatures of 50-120°C.	Fuel is cheap, safe and easy to transport Expensive catalysts Low efficiency Low power density	<1kW	Small scale portable power[151]

148 Kirubakaran, A., Shailendra, J. and Nema, R. 2009, A review on fuel cell technologies and power electronic interface
149 Department of Energy, 2016 https://www.energy.gov/sites/prod/files/2016/06/f32/fcto_fuel_cells_comparison_chart_apr2016.pdf
150 Fuel Cell Technologies Office, 2016, Comparison of Fuel Cell Technologies
151 Kamarudin, S., Achmad, F. and Daud, W. 2009, Overview on the application of direct methanol fuel cell (DMFC) for portable electronic devices

EMERGING FUEL CELL AND TURBINE TECHNOLOGIES

TABLE 38. EMERGING TURBINES AND FUEL CELLS

TECHNOLOGY	DESCRIPTION	TRL	POTENTIAL FOR DISRUPTION
Hydrogen gas turbines	Likely to be used in IGCC power plants. These are turbines that can run off hydrogen or a hydrogen-rich syngas mixture. There are technical challenges associated with the high combustion temperature of hydrogen[152]. Burning gas mixtures with hydrogen concentrations of up 5-60% is possible in certain gas turbines, depending on the degree to which they have been modified.	6-7	A carbon free turbine technology with potential for larger scale electricity production as compared with fuel cells
Ammonia turbines	Involves the combustion of ammonia, a methane mixture or ammonia mixed with hydrogen. NOx emissions from the combustion of ammonia need to be removed which creates additional costs[153]. Still in early development.	3	Possible to utilise domestic ammonia production to burn green ammonia resulting in carbon free power generation. Development of the turbine could open up additional demand for ammonia.
Alkaline Anion Exchange Membrane FC (AEMFC)	Similar design to a PEM FC, but AEMFC's membrane is solid alkaline instead of acidic. Instead of protons, OH- anions are transported from anode to cathode providing certain advantages, such as the potential for non-precious metal catalysts[154].	4	Offers the potential for cheaper catalysts and polymers. Can also accept a wider range of fuels but has low oxidation reaction rates and unstable conducting materials.
Microbial FC	Microorganisms are used to oxidize fuel, such as glucose or biomass, and transfer acquired electrons to the anode. This oxidation has at extremely low rates, limiting application. Wastewater as a fuel is also being explored	3-4[155]	Fuel is cheap, safe and plentiful but these systems currently have a low power density
Unitised Reversible / Regenerative Fuel Cell System	A fuel cell, capable of producing hydrogen and oxygen when in regenerative mode and delivering electricity when in fuel cell mode. Providing a system with operating conditions optimal for both modes is an engineering challenge, for example one reaction is exothermic and the other, endothermic. PEM and solid oxide are two reversible technologies under development currently.	2-5	Opportunity to combine the electrolysis and fuel cell process into a single system

152 Kraftwerk Forshung, 2016 Hydrogen gas turbines http://kraftwerkforschung.info/en/hydrogen-gas-turbines/
153 Valera-Medina A et al., 2017, Ammonia–methane combustion in tangential swirl burners for gas turbine power generation
154 Dekel, D, 2018, Review of cell performance in anion exchange membrane fuel cells
155 Microbial Fuel Cells for Powering Navy Devices, 2014, Naval Research Laboratory

APPENDIX B – **Regulations and standards**

Current regulations gap analysis

Three types of regulation are needed to support the hydrogen industry in Australia:

1. **Commercial**: Regulations needed to provide a commercial framework for hydrogen use
2. **Safety**: Regulations that ensure the production, transportation, storage and use of hydrogen is as safe as practicable
3. **Functional**: Regulations that specifically reference and codify use of specific standards

COMMERCIAL REGULATION

Current regulations

Current regulatory frameworks supporting the commercial use of gas in Australia include the:

1. **Gas Supply Act** – Leading to the Gas Supply Regulations

The main purposes of this Act are to:

- promote efficient and economical processed natural gas supply; and
- ensure the interests of customers are protected

2. **National Gas Law**

Following from the Gas Supply Act, the National Gas Law mandates the commercial regulation of gas in the National Gas Rules within the defined gas market for Northern and Eastern Australia. A separate national gas law is applicable in WA.

Current gaps

Hydrogen is not specifically referenced under these regulations. Current gas definitions regarding quality and value will therefore not support an emerging hydrogen market. Gas definitions will therefore need to be expanded to include hydrogen.

SAFETY REGULATION

Current regulations

Current regulatory frameworks supporting the safe use of gas in Australia include the:

1. **Workplace Health and Safety Regulation:** Mandated through the Commonwealth Work Health and Safety Act (2011). While variations of this Act exist across the States, the overarching objective is to provide for a balanced and nationally consistent framework to secure the health and safety of workers and workplaces by—
   - protecting workers and other persons against harm to their health, safety and welfare through the elimination or minimisation of risks arising from work or from particular types of substances or plant; and
   - provide for a range of employment support functions, laws and regulations that support and continuously improve workplace health and safety.

Major Hazard Facilities (MHF) are classified according to the various state regulations and provide guidance as to the type of facilities that require further licensing, regulation and safety studies.

Gap

Relevant safety regulations are broad enough to include gas, flammable gases and gas storage without making specific reference to hydrogen. Hydrogen carrier products such as ammonia, will similarly be included as known chemical hazards.

Further modelling and analysis will be required to assess the facility size and volume of product stored that will categorise a hydrogen facility as a MHF.

FUNCTIONAL REGULATION, GUIDANCE AND CODES

Functional regulation outlines the technical, safety and environmental codes and standards to be applied when using hydrogen.

Gap

Broad gaps exist and best practise international standards should be referenced where possible. A high level review of relevant standards is set out below.

Applicable standards

A detailed gap analysis is likely to be required to determine the extent to which existing standards are appropriate for use with hydrogen gas technologies, or whether any hydrogen specific revisions would need to be undertaken. Similarly, stakeholder consultation would be necessary to determine which international hydrogen specific standards would need to be adopted in the Australian market in order to help facilitate the development of a hydrogen industry in Australia.

A non-exhaustive summary of applicable Australian and international standards is set out below.

EXISTING AUSTRALIAN STANDARDS AND COMMITTEES RELEVANT TO HYDROGEN

TABLE 39. EXISTING STANDARDS RELEVANT TO HYDROGEN

STANDARD	DESCRIPTION
AS 2885	Pipelines – Gas and liquid petroleum (5 parts)
AS4645	Gas distribution networks Part 1: Network Management (3 sub-parts)
AS 4568	Preparation of a safety and operating plan for gas networks
AS4564	Specification for general purpose natural gas
AS/NZS 5263.0	Gas appliances – General requirements
AS/NZS 5601.1	Gas installations – Part 1: General installations
AS 3814	Industrial and commercial gas-fired appliances

GENERAL INTERNATIONAL SAFETY STANDARDS

Safety is a critical factor to be considered and is vital for satisfying community expectations, but also ensuring workforce and environmental health and safety. The following international standards have already been developed specifically to ensure minimum safety requirements for the hydrogen gas industry:

- *ISO/TR 15916 – Basic considerations for the safety of hydrogen systems*
- *ISO 26142 – Hydrogen detection apparatus – Stationary applications*

Neither of the above standards are currently adopted as Australian Standards.

INTERNATIONAL HYDROGEN PRODUCTION STANDARDS

A number of international standards currently exist, or are being developed, specifying requirements for hydrogen production techniques. The most relevant standards relating to electrolysis as a production method are

- *ISO 22734-1 – Hydrogen generators using water electrolysis process Part 1: Industrial and commercial applications and*
- *ISO 22734-2 – Hydrogen generators using water electrolysis process Part 2: Residential applications*.

No international standards relevant to hydrogen production have been adopted in the Australian market as Australian Standards to date.

Another critical factor relevant to hydrogen production technologies and their commercial viability is the availability of carbon capture technologies. A number of international standards exist in this field, outlining the minimum requirements for carbon capture systems, carbon transportation systems and geological storage requirements.

TABLE 40. HYDROGEN PRODUCTION STANDARDS

STANDARD	DESCRIPTION
ISO/DIS 14687 [Under development]	Hydrogen fuel quality – Product specification
ISO/DIS 22734 [Under development]	Hydrogen generators using water electrolysis process – Industrial, commercial, and residential applications
ISO 14687-1:1999	Hydrogen fuel – Product specification – Part 1: All applications except proton exchange membrane (PEM) fuel cell for road vehicles
ISO 14687-2:2012	Hydrogen fuel – Product specification – Part 2: Proton exchange membrane (PEM) fuel cell applications for road vehicles
ISO 14687-3:2014	Hydrogen fuel – Product specification – Part 3: Proton exchange membrane (PEM) fuel cell applications for stationary appliances
ISO 16110-1:2007	Hydrogen generators using fuel processing technologies – Part 1: Safety
ISO 16110-2:2010	Hydrogen generators using fuel processing technologies – Part 2: Test methods for performance
ISO/TS 19883:2017	Safety of pressure swing adsorption systems for hydrogen separation and purification
ISO 22734-1:2008	Hydrogen generators using water electrolysis process – Part 1: Industrial and commercial applications
ISO 22734-2:2011	Hydrogen generators using water electrolysis process – Part 2: Residential applications

TABLE 41. CARBON CAPTURE AND STORAGE STANDARDS

STANDARD	DESCRIPTION
ISO/TR 27912:2016	Carbon dioxide capture – Carbon dioxide capture systems, technologies and processes
ISO 27913:2016	Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems
ISO 27914:2017	Carbon dioxide capture, transportation and geological storage – Geological storage
ISO/TR 27915:2017	Carbon dioxide capture, transportation and geological storage – Quantification and verification
ISO 27917:2017	Carbon dioxide capture, transportation and geological storage – Vocabulary – Cross cutting terms
ISO/TR 27918:2018	Lifecycle risk management for integrated CCS projects
ISO/TR 27912:2016	Carbon dioxide capture – Carbon dioxide capture systems, technologies and processes
ISO 27913:2016	Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems
ISO 27914:2017	Carbon dioxide capture, transportation and geological storage – Geological storage
ISO/TR 27915:2017	Carbon dioxide capture, transportation and geological storage – Quantification and verification
ISO/DIS 27916 [Under development]	Carbon dioxide capture, transportation and geological storage – Carbon dioxide storage using enhanced oil recovery (CO2-EOR)
ISO 27917:2017	Carbon dioxide capture, transportation and geological storage – Vocabulary – Cross cutting terms
ISO/TR 27918:2018	Lifecycle risk management for integrated CCS projects

INTERNATIONAL STORAGE AND TRANSPORT STANDARDS

There are long established national and international standards for natural gas and liquid petroleum gas (LPG) storage. However, there are now international standards being developed specifically for both stationary and portable storage of hydrogen, critical for developing the hydrogen industry. *They are ISO19884 [Under development] – Gaseous hydrogen – Cylinders and tubes for stationary storage and ISO 16111 – Transportable gas storage devices – Hydrogen absorbed in reversible metal hydride*. These combined with existing gas storage and transportation standards, provide a technical infrastructure. Neither of the above mentioned standards are currently adopted as Australian Standards.

INTERNATIONAL UTILISATION STANDARDS

Of the many potential hydrogen applications in the Australian and global markets, most standards exist for hydrogen fuelled transportation, with either fuel cell technologies or gaseous hydrogen fuel. For heat applications of hydrogen, existing gas standards for appliances would likely need to be revised in order to accommodate the introduction of hydrogen into the network.

TABLE 42. STANDARDS FOR HYDROGEN FUELLED TRANSPORT

STANDARD	DESCRIPTION
ISO/DIS 17268 [Under development]	Gaseous hydrogen land vehicle refuelling connection devices
ISO/DIS 19881 [Under development]	Gaseous hydrogen – Land vehicle fuel containers
ISO/DIS 19882 [Under development]	Gaseous hydrogen – Thermally activated pressure relief devices for compressed hydrogen vehicle fuel containers
ISO/DIS 19880-1 [Under development]	Gaseous hydrogen – Fueling stations – Part 1: General requirements
ISO/FDIS 19880-3 [Under development]	Gaseous hydrogen – Fuelling stations – Part 3: Valves
ISO/DIS 19880-5 [Under development]	Gaseous hydrogen – Fuelling stations – Part 5: Hoses and hose assemblies
ISO/DIS 19880-8 [Under development]	Gaseous hydrogen – Fuelling stations – Part 8: Fuel quality control
ISO 13984:1999	Liquid hydrogen – Land vehicle fuelling system interface
ISO 13985:2006	Liquid hydrogen – Land vehicle fuel tanks
ISO/TS 15869:2009	Gaseous hydrogen and hydrogen blends – Land vehicle fuel tanks
ISO 17268:2012	Gaseous hydrogen land vehicle refuelling connection devices
ISO/TS 19880-1:2016	Gaseous hydrogen – Fuelling stations – Part 1: General requirements
ISO/DIS 17268 [Under development]	Gaseous hydrogen land vehicle refuelling connection devices

APPENDIX C – **Modelling Summary**

Methodology

MODEL PARAMETERS AND INPUT COSTS

Table 43 below provides a summary of model parameters used in this analysis. As seen in the table, it was decided to run the model for a period of 40 years to compare each of the technologies on a 'like for like' basis.

It was also assumed that these projects were funded by 100% debt. While unlikely to occur in practice, this was designed to understand the impact of a lower cost of capital that may be accessible for low emissions projects.

TABLE 43. MODEL PARAMETERS

PARAMETER	UNIT	VALUE
Capital borrowed	% cost	100
Discount rate[156]	%	7
Base Interest rate on borrowing	%	7
Length of loan	Years	30
Years of Production	Years	40
Hours in Year	Hours	8760

Energy and water input costs used throughout the model for the base case and best case are presented in Table 44.

TABLE 44. INPUT PRICES USED FOR THE BASE CASE AND BEST CASE[157,158,159]

INPUT PRICING	UNIT	BASE CASE	BEST CASE
Gas	$/GJ	8	8
Electricity	c/KWh	6	4
Black Coal	$/GJ	3	3
Brown Coal	$/GJ	1.5	1.5
Water	$/lit	0.00182	0.00182

The formulas used to calculate the levelised cost can be found in CSIRO's Low Emissions Technology Roadmap: Technical Report.

Production technologies

PEM

Several sources were used to develop the PEM cost and performance data as shown in Table 45 (refer to footnotes 160-176) as well as advice from stakeholders and CSIRO technology experts.

Degradation in the stack was included, where the stack reached 80% of usable capacity by the end of the stack life.

156 Department of Premier and Cabinet (DPC) 2016, Office of Best Practice Regulation. Guidance Note for Cost-benefit analysis. 15pp
157 Campey, T., Bruce, S., Yankos, T., Hayward, J., Graham, P., Reedman, L.., Deverell, J. et al. 2017b, Low Emissions Technology Roadmap: Technical Report. Australia: CSIRO.
158 Barron 2016, Desalination technologies: are they economical for urban areas? In S. Eslamian, Urban water re-use handbook (pp. 341-353). CRC Press.
159 CO2CRC. (2015). Australian Power Generation Technology Report. http://www.co2crc.com.au/dls/Reports/LCOE_Report_final_web.pdf.
160 Hayward, J. 2018, The economics of producing H2 from electrolysis in Victoria (Commerical in Confidence). CSIRO.
161 Ainscough, C., Peterson, D., and Miller, E. 2014, Hydrogen Production Cost From PEM Electrolysis. DOE Hydrogen and Fuel Cells Program Record.
162 Al-Sharafi, A., Sahin, A. Z., Ayar, T., and Yilbas, B. S. 2017, Techno-economic analysis and optimization of solar and wind energy systems for power generation and hydrogen production in Saudi Arabia. Renewable and Sustainable Energy Reviews, 69, 33-49
163 Babic, U., Suermann, M., Büchi, F. N., Gubler, L., and Schmidt, T. J. (2017). Review - Identifying Critical Gaps for Polymer Electrolyte Water Electrolysis Development. Journal of the Electrochemical Society, 164(4), F387-F399.
164 Bertuccioli, L., Chan, A., Hart, D., Lehner, F., Madden, B., and Standen, E. (2014). Study on the development of water electrolysis in the EU. E4tech Sàrl with Element Energy Ltd for the Fuel Cells and Hydrogen Joint Undertaking.
165 Darras, C., Bastien, G., Muselli, M., Poggi, P., Champel, B., and Serre-Combe, P. (2015). Techno-economic analysis of PV/H2 systems. International Journal of Hydrogen Energy, 40, 9049-9060.
166 Felgenhauer, M. F., Pellow, M. A., Benson, S. M., and Hamacher, T. (2016). Evaluating co-benefits of battery and fuel cell vehicles in a community in California. Energy, 114, 360-368.
167 Ferrero, D., Gamba, M., Lanzini, A., and Santarelli, M. (2016). Power-to-Gas Hydrogen: techno-economic assessment of processes towards a multi-purpose enregy carrier. Energy Procedia, 101, 50-57.
168 Guinot, B., Montignac, F., Champel, B., and Vannucci, D. (2015). Profitability of an electrolysis based hydrogen production plant providing grid balancing services. International Journal of Hydrogen Energy, 40, 8778-8787.
169 Hydrogenics . (2017, Apr 25). News and Updates. Retrieved from Hydrogenics: http://www.hydrogenics.com/2017/04/25/hydrogenics-unveils-3-megawatt-pem-electrolyzer-stack/
170 Parra, D., Zhang, X., Bauer, C., and K, P. M. (2017). An integrated techno-economic and life cycle environmental assessment of power-to-gas systems. Applied Energy, 193, 440-454.
171 Shaner, M. R., Atwater, H. A., Lewis, N. S., and McFarland, E. W. (2016). A comparitive technoeconomic analysis of renewable hydrogen production using solar energy. Energy and Environmental Science, 9, 2354-2372.
172 Siemens AG. (2015). Silyzer 200 (PEM electrolysis system). Retrieved from siemens.com/hydrogen-electrolyzer
173 Smolinka, T., Thomassen, M., Oyarce, A., and Marchal, F. (2016). Project MEGASTACK: Stack Design for a Megawatt Scale PEM Electrolyser. JU FCH.
174 Walker, S. B., van Lanen, D., Fowler, M., and Mukherjee, U. (2016). Economic analysis with respect to Power-to-Gas energy storage with consideration of various market mechanisms. International Journal of Hydrogen Energy, 41, 7754-7765.
175 Marchenko, O. V., and Solomin, S. V. (2017). Modeling of hydrogen and electrical energy storages in wind/PV energy system on the Lake Baikal coast. International Journal of Hydrogen Energy, 42, 9361-9370.
176 Peters, M. S., Timmerhaus, K. D., and West, R. E. (2003). Plant design and economics for chemical engineers. New York, USA: McGraw Hill.

TABLE 45. BASE CASE AND BEST CASE FOR PEM

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Av electricity price	c/kWh	6	Optimise electrolyser position and secure favourable PPAs	4
Capacity factor	%	85	Optimised operation	95
Scale/Capacity	MW/day	1	Secure offtakes, aggregate demand, risk sharing	100
Scale/Capacity	Kg H_2 / day	444	As above	53,333
Asset life	Years	40	No change	40
Capex (less risk)	$/kW	3496	Scaling benefits, smaller footprint of stack, lower cost BoP	968
Capex (less risk)	$/kg H_2/year	7,865	As above	1,814
Opex	$/kW/y	75	Improve lifetime of components through R&D	19
Opex	$/kg H_2/year	169	As above	36
Stack replacement interval	hours	120,000	Improved catalyst layers and membranes	150,000
Efficiency	kWh/kgH_2	54	Reduction in current densities, improved system components, more efficient BOP, more efficient catalysts, etc.	45
Risk	%	10	First of kind demonstration at scale	5
Real discount rate	%	7	No change expected	7
Cost of capital	%	7	Utilise green bonds and CEFC support	5
LCOH	**$/kg**	**6.08-7.43**		**2.29-2.79**

ALKALINE ELECTROLYSER

Several sources were used[177,178,179]. As with PEM, stack degradation was included, where the stack reached 80% of usable capacity by the end of the stack life.

TABLE 46. BASE CASE AND BEST CASE DATA FOR AE

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Av electricity price	c/kWh	6	Optimise electrolyser position and input	4
Capacity factor	%	85	Optimised operation	95
Scale/Capacity	MW/day	44	Secure offtakes, aggregate demand, risk sharing	100
Scale/Capacity	Kg H_2/day	15,476	As above	20,473
Asset life	Years	40	No change expected	40
Capex (less risk)	$/kW	1347	Scaling benefits, lower cost BoP	1012
Capex (less risk)	$/kg H_2/year	3,255	As above	2,066
Opex	$/kW/y	28	Improve lifetime of components through R&D	21
Opex	$/kg H_2/year	4.83	As above	4.08
Stack replacement interval	hours	90,000	No change expected	90,000
Efficiency	kWh/kgH_2	58	Scale, improved heat exchangers etc.	49
Risk	%	5	No change expected	5
Real discount rate	%	7	No change expected	7
Cost of capital	%	7	Utilise green bonds and CEFC support	5
LCOH	**$/GJ ($/kg)**	**4.78-5.84**		**2.54-3.1**

177 Saba, S. M., Müller, M., Robinius, M., and Stolten, D. (2018). The investment costs of electrolysis – A comparison of cost studies from the past 30 years. International Journal of Hydrogen Energy, 43(3), 1209-1223.

178 Schmidt, O., Gambhir, A., Staffell, I., Hawkes, A., Nelson, J., and Few, S. (2017). Future cost and performance of water electrolysis: an expert elicitation study. International Journal of Hydrogen Energy, 42(52), 30470-30492.

179 Viesi, D., and Crema, L. T. (2017). The Italian hydrogen mobility scenario implementing the European directive on alternative fuels infrastructure (DAFI 2014/94/EU). International Journal of Hydrogen Energy, 42, 27354-27373.

Steam Methane Reforming with CCS

Several sources were used[180,181,182,183,184]. A range from \$10-40 \$/tCO_2 was assumed for the cost of transporting and storing CO_2[181].

TABLE 47. BASE CASE AND BEST CASE DATA FOR SMR WITH CCS

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Gas price	\$/GJ	8	No change expected	8
Capacity factor	%	95	No change expected	95
Scale/Capacity	kg H_2/day	210,000	Secure export offtake agreements	500,000
Asset Life	Years	40	No change expected	40
Capex (less risk)	\$/kg H_2/year	6.04	Scaling benefits, process intensification	3.85
Fixed opex	\$/kg H_2/year	0.21	Scaling benefits	0.16
Variable opex	\$/kg H_2	0.01	No change expected	0.01
Cost of CO_2 storage	\$/t CO_2	7-40	As per CO2CRC. No change expected	7-40
Efficiency	kg NG /kg H_2	3.73	R&D Process improvements, reused heat, membrane separation	3.65
Other revenue	\$/year from electricity sold	207k	Scaling benefits	493k
Risk	%	20	Reduced risk of CO_2 capture	15
Real discount rate	%	7	No change expected	7
Cost of capital	%	7	Access to CEFC funding includes CCS	5
LCOH	**\$/kg**	**2.27-2.77**		**1.88-2.30**

180 Collodi, G., Zaaaro, G., Ferrari, N., and Santos, S. (2017). Techno-economic evaluation of deploying CCS in SMR based merchant H2 production with NG as feedstock and fuel. Energy Procedia, 114, 2690-2712.

181 Peters, M. S., Timmerhaus, K. D., and West, R. E. (2003). Plant design and economics for chemical engineers. New York, USA: McGraw Hill.

182 Hinkley, J., Hayward, J., McNaughton, R., Edwards, J., and Lovegrove, K. (2015). Concentrating solar fuels roadmap: final report. Australia: CSIRO

183 Rutkowski, M. (2008). Longer term (2020-2030) hydrogen from coal without CO2 Capture and Sequestration. NREL.

184 CO2CRC. (2015). Australian Power Generation Technology Report. http://www.co2crc.com.au/dls/Reports/LCOE_Report_final_web.pdf.

Black Coal Gasification with CCS

Several sources were used[185,186,187]. The base and best cases have been based on a single gasifier system.

TABLE 48. BASE CASE AND BEST CASE DATA FOR BKGGAS WITH CCS

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Coal price	$/GJ	3	No change expected	3
Utilisation factor	%	85	No change expected	85
Scale/Capacity	kg H_2/day	500,000	Successfully demonstrate black coal gasification + CCS at scale, export off take agreements (scale to match brown coal)	770,000
Asset Life	Years	40	No change expected	40
Capex (less risk)	$/kg H_2/year	8.84	RD&D Process intensification and scale	8.28
Fixed opex	$/kg H_2/year	0.36	Scaling benefits, Improvements in build-up of slag and ash	0.34
Variable opex	$/kg H_2	0.04	No change expected	0.04
Cost of CO_2 storage	$/t CO_2-e	7-40	As per CO2CRC, no change expected	7-40
Efficiency	%	63	R&D improvements of purification, ASU and CO_2 removal	70
Other revenue	$/year	16.5m	Sell surplus power to grid (or synthetic fuels)	25.5m
Risk	%	25	First of kind demonstration	15
Real discount rate	%	7	No change expected	7
Cost of capital	%	7	Utilise green bonds and CEFC support	5
LCOH	**$/kg**	**2.57-3.14**		**2.02-2.47**

185 Rutkowski, M. (2008). Longer term (2020-2030) hydrogen from coal without CO2 Capture and Sequestration. NREL.
186 IEAGHG. (2014). CO2 capture at coal based power and hydrogen plants. Cheltenham, UK: IEA
187 CO2CRC. (2015). Australian Power Generation Technology Report. http://www.co2crc.com.au/dls/Reports/LCOE_Report_final_web.pdf.

Brown Coal Gasification with CCS

Modelling based on a desktop study of the HESC project in the La Trobe valley and a cost comparison between black and brown coal gasification with CCS for electricity generation from the Australian Power Generation Technology Report[188].

TABLE 49. BASE CASE AND BEST CASE DATA FOR BRGAS WITH CCS

KEY COST DRIVER	UNIT	COMMENTS	BEST CASE
Coal price	\$/GJ	N/A	1.5
Utilisation factor	%	N/A	85
Scale/Capacity	kg H_2/day	• Successfully demonstrate brown coal gasification + CCS at scale • Export offtake agreements	
	770,000		
Asset Life	years	As per other technologies	40
Capex (less risk)	\$/kg H_2/year	Based on commercial plant scale	10.45
Fixed opex	\$/kg H_2/year	Improvements in reducing build-up of slag and ash	0.41
Variable opex	\$/kg H_2	No change expected	0.04
Cost of CO_2 storage	\$/t $CO2^{-e}$	As per CO2CRC	7-40
Efficiency	%	R&D improvements of purification, ASU and CO_2 removal	67
Other revenue	\$/year	Sell surplus power to grid	25.5m
Risk	%	Assuming pilot project success but CCS risk remains	15
Real discount rate	%	N/A	7
Cost of capital	%	Utilise green bonds and CEFC support	5
LCOH	**\$/kg**		**2.14-2.74**

188 CO2CRC. (2015). Australian Power Generation Technology Report. http://www.co2crc.com.au/dls/Reports/LCOE_Report_final_web.pdf.

Storage of hydrogen

COMPRESSION AND STORAGE IN TANKS

It has been assumed that the quantity of hydrogen storage capacity required is 210 tpd which is the base case output for the SMR with CCS plant. Modelling also assumed that the storage capacity is charged and discharged on a daily basis from tanks of 100m^3 capacity each. The input pressure of the incoming hydrogen was assumed to be 35 bar (i.e. 35 bar scenario contains no compression). The Capex includes the tanks, compressors and associated infrastructure and installation costs[189].

TABLE 50. BASE CASE AND BEST CASE DATA FOR COMPRESSION AND STORAGE IN TANKS

KEY COST DRIVER	UNIT	BASE CASE			KEY ACTIONS	BEST CASE		
		35 BAR	150 BAR	350 BAR		35 BAR	150 BAR	350 BAR
Av electricity price	c/kWh	6	6	6	Secure long term favourable PPAs	4	4	4
Utilisation factor for compressor	%	91	91	91	Depends on production	91	91	91
Utilisation factor for storage	%	100	100	100		100	100	100
Scale/Capacity of storage	m^3	75,309	18,789	9,007	No change	75,309	18,789	9,007
Asset life	Years	40	40	40	Based on other technologies	40	40	40
Capex (less risk)	\$/kg H_2/d	1,662	1,032	1,089	Improved due to improvements in compressor efficiency	1,662	1,031	1,087
Opex	\$/kg H2/d	35	22	26	Based on % of installed capital	35	22	24
Efficiency of compressors	%	75	75	75	Ionic compression	80	80	80
Risk	%	5	5	5	Demonstration at scale	5	5	5
Real discount rate	%	7	7	7	No change	7	7	7
Cost of capital	%	7	7	7	Utilise green bonds and CEFC support	5	5	5
LCOH	**\$/kg**	**0.43-0.53**	**0.30-0.37**	**0.34-0.42**		**0.37-0.45**	**0.23-0.28**	**0.24-0.29**

189 Turton, R., Baille, R. C., Whiting, W. B., and Shaeiwitz, J. A. (2009). Analysis, synthesis and design of chemical processes. Boston, MA, USA: Pearson Education Inc.

Compression and Storage in Salt Caverns

It has been assumed that the quantity of hydrogen storage capacity required is for production from a 210 tpd steam methane reforming plant for a period of 30 days. Compressors have been sized with an input pressure of 45 bar. The Capex includes the cavern, compressors and associated infrastructure, installation costs and risk. The cost of hydrogen to be stored has not been included. Several sources were used[190,191,192].

TABLE 51. BASE CASE AND BEST CASE DATA FOR COMPRESSION STORAGE IN SALT CAVERNS

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Av electricity price	c/kWh	6	Secure long term favourable PPAs	4
Utilisation factor for compressor	%	91	Depends on production	91
Utilisation factor for storage	%	100	No change	100
Scale/Capacity of storage	m^3	1,826,446	No change	1,826,446
Asset life	Years	40	Based on other technologies	40
Capex (less risk)	$/kg H_2/d	712	No change due to capital cost of cavern	712
Opex	$/kg H_2/d	17	Based on % of installed capital	16
Efficiency of compressors	%	75	Ionic compression	80
Risk	%	20	Demonstration at scale	10
Real discount rate	%	7	No change	7
Cost of capital	%	7	Utilise green bonds and CEFC support	5
LCOH	**$/kg**	**0.22-0.26**		**0.16-0.20**

190 Turton, R., Baille, R. C., Whiting, W. B., and Shaeiwitz, J. A. (2009). Analysis, synthesis and design of chemical processes. Boston, MA, USA: Pearson Education Inc.

191 James, G., and Hayward, J. (2012). AEMO 100% Renewable Energy Study: Energy Storage. CSIRO for AEMO.

192 Lord, A. S., Kobos, P. H., and Borns, D. J. (2014). Geologic storage of hydrogen: scaling up to meet city transportation demands. International Journal of Hydrogen Energy, 39, 15570-15582.

Ammonia production and storage

This assumes no input cost for hydrogen; it is the cost of conversion to ammonia with on-site storage. Several sources were used[193,194].

TABLE 52. BASE CASE AND BEST CASE DATA FOR AMMONIA STORAGE

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Av electricity price	c/kWh	6	Secure long term favourable PPAs	4
Capacity factor	%	85	Optimised operation	90
Scale/Capacity	kg NH_3/day	210,000	No change	210,000
Asset life	Years	40	No change expected	40
Capex (less risk)	\$/kg NH_3 /y	1.56	Scaling benefits	1.00
Total opex	\$/kg NH_3 /y	0.05	Scaling benefits	0.03
Electricity usage	kWh/kg NH_3	0.486	Improvements in air separation and purification and compression considering scale	0.437
Risk	%	10	Establish export offtakes	5
Real discount rate	%	7	No change expected	7
Cost of capital	%	7	Utilise green bonds and CEFC support	5
LCONH$_3$ (LCOH)	**\$/kg**	**0.24-0.29 (1.39-1.68)**		**0.19-0.23 (1.10–1.33)**

193 Idaho National Laboratory. (2010). Nuclear-integrated ammonia production analysis. Project No 23843. US Department of Energy.
194 Hinkley, J., Hayward, J., McNaughton, R., Edwards, J., and Lovegrove, K. (2015). Concentrating solar fuels roadmap: final report. Australia: CSIRO.

Liquefied H2 production and storage

As with the other types of storage, no cost of hydrogen has been included[195,196].

TABLE 53. BASE CASE AND BEST CASE DATA FOR LIQUEFIED H2

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Av electricity price	c/kWh	6	Secure long term favourable PPAs	4
Utilisation factor	%	85	Optimised operation	92
Scale/Capacity	kg H_2/d	50,000	Increase in hydrogen production plant	210,000
Asset life	Years	40	No change expected	40
Capex (less risk)	\$/ kg H_2 /y	10.63	Scaling benefits	7.97
Total opex	\$/ kg H_2 /y	0.92	Scaling benefits	0.69
Electricity usage	kWh/kg H_2	9.05	Improved compression and refrigeration	7.88
Risk	%	5	No change expected	5
Real discount rate	%	7	No change expected	7
Cost of capital	%	7	Utilise green bonds and CEFC support	5
LCOH	**\$/kg**	**2.57-3.14**		**1.59-1.94**

195 Peters, M. S., Timmerhaus, K. D., and West, R. E. (2003). Plant design and economics for chemical engineers. New York, USA: McGraw Hill.

196 Stolzenburg, K., Berstad, D., Decker, L., Elliott, A., Haberstroh, C., Hatto, C., Walnum, H. T. et al. (2013). Integrated design for demonstration of efficient liquefaction of hydrogen (IDEALHY). FCHJU (Fuel Cells and Hydrogen Joint Undertaking).

Transport of hydrogen

It has been assumed that trucks travel an annual distance of 166,330 Km (from CSIRO transport modelling work). The volume of hydrogen transported in the compressed gas cases is 36.2 m^3 and the volume in the liquefied H_2 case is 56.2 m^3 [197], except in the case of shipping where it is assumed that a specialised tanker is used[198,199]. Ammonia is assumed to be carried as a liquid at 15 bar and the volume transported is 36.2 m^3. The total weight of ammonia carried in any one trip is 21.72 tonnes, the amount of compressed hydrogen carried at 430 bar is 1.042 tonnes, while the amount of compressed hydrogen carried at 350 bar is 800 kg. Finally, the mass of liquid H_2 transported is 10,840 tonnes per trip[200].

Several sources were used[198,200,201,202].

TABLE 54. BASE CASE DATA FOR TRANSPORT

TRANSPORT METHOD	LCOT	BASE CASE LCOH			
		COMPRESSION 350 BAR	COMPRESSION 430 BAR	LIQUIFICATION	AMMONIA
Truck	$/tkm	2.98	2.33	0.92	0.33
Rail	$/tkm	0.62	0.55	0.28	0.04
Shipping	$/tkm	0.59	0.52	0.09	0.03

197 Argonne National Laboratory. (2006). HDSAM model . US Department of Energy

198 You, H., Ahn, J., Jeong, S., and Chang, D. (2018). Effect of ortho-ara conversion on economics of liquid hydrogen tanker with pressure cargo tanks. Ships and Offshore Structures, DOI:10.1080/17445302.2018.1426526.

199 Kamiya, S., Nishimura, M., and Harada, E. (2015). Study on Introduction of CO2 Free Energy to Japan with Liquid Hydrogen. Physics Procedia, 67, 11-19.

200 BITRE. (2017). Freight rates in Australia. Canberra: Department of Infrastructure and Regional Development.

201 Hayward, J. A., Foster, J. D., Graham, P. W., and Reedman, L. J. (2017). A Global and Local Learning Model of Transport (GALLMT). MODSIM , (pp. 1-7). Hobart.

202 Sharpe, B., and Muncrief, R. (2015). Literature review: real-world fuel consumption of heavy-duty vehicles in the United States, China and the European Union. Washington DC, USA: International Council on Clean Transportation.

Utilisation

FUEL CELLS

It has been assumed that fuel cells are operated as a peaking plant and thus operate at a capacity factor of 20%. No hydrogen storage has been included in this calculation. Several sources were included[203,204,205,206,207].

TABLE 55. BASE CASE AND BEST CASE FOR FUEL CELLS

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Average hydrogen price (taken from PEM)	\$/kg H_2	6.75	Improvements to PEM electrolysers and lower electricity feed prices	2.54
Capacity factor	%	20	No change as it is a peaking plant	20
Scale/Capacity	MW/day	1	No change as it is a peaking plant	1
Asset life	Years	20	No change	20
Capex (less risk)	\$/kW	2109	Scaling benefits, smaller footprint of stack, lower cost BoP	568
Opex	\$/kW/y	58	Improve lifetime of components through R&D	12.5
Membrane life	hours	10,000	Improved catalyst layers and membranes	30,000
Efficiency	kgH_2/kWh	0.05427	No change expected as looking at reduction in cost rather than efficiency improvement	0.05427
Risk	%	10	First of kind demonstration at scale	5
Real discount rate	%	7	No change expected	7
LCOE	**\$/MWh**	**330-410**		**120-150**

203 Marchenko, O. V., and Solomin, S. V. (2017). Modeling of hydrogen and electrical energy storages in wind/PV energy system on the Lake Baikal coast. International Journal of Hydrogen Energy, 42, 9361-9370.

204 Loisel, R., Baranger, L., Chemouri, N., Spinu, S., and Pardo, S. (2015). Economic evaluation of hybrid off-shore wind power and hydrogen storage system. International Journal of Hydrogen Energy, 40, 6727-6739.

205 You, S., Hu, J., Zong, Y., and Lin, J. (2016). Value assessment of hydrogen-based electrical energy storage in view of electricity spot market. J. Mod. Power Syst. Clean Energy, 4, 626-635.

206 Ozden, E., and Tari, I. (2016). Energy-exergy and economic analyses of a hybrid solar-hydrogen renewable energy system in Ankara, Turkey. Applied Thermal Engineering, 99, 169-178.

207 Campey, T., Bruce, S., Yankos, T., Hayward, J., Graham, P., Reedman, L.,. Deverell, J. et al. (2017b). Low Emissions Technology Roadmap: Technical Report. Australia: CSIRO

Fuel Cell Electric Vehicles

Fuel cell electric vehicles (FCEVs) have been assumed to cost the same as equivalent internal combustion engine vehicle in the best case. Consequently, the insurance, registration and maintenance costs are also assumed to be equivalent. The only difference is in the fuel consumption and cost. The base case vehicle cost is higher than for internal combustion engine vehicles and the insurance cost is also higher. The assumptions and levelised cost of transport (LCOT) for passenger cars and buses are shown in Table 56[208].

TABLE 56. BASE CASE AND BEST CASES FOR FUEL CELL ELECTRIC VEHICLES

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
		Passenger vehicle		
Average hydrogen price (taken from PEM)	$/kg H_2	6.75	Improvements to PEM electrolysers and lower electricity feed prices	2.54
Investment cost vehicle	$	58,550	Development of supply chains and scaling up in production	25,000
Registration cost vehicle	$/year	335	No change expected	335
Insurance cost vehicle	$/year	1492	Reduction in investment cost	1030
Maintenance cost vehicle	$/1000Km	116	Development of supply chains and experience with vehicles	49
Annual vehicle kms travelled car	vkm/year	12,800	No change expected	12,800
Fuel cost vehicle	$/km	0.18	Improvements in fuel efficiency and lower price of hydrogen	0.09
LCOT car	**$/vkm**	**1.29-1.57**		**0.63-0.77**
		Bus		
Average hydrogen price (taken from PEM)	$/kg H_2	6.75	Improvements to PEM electrolysers and lower electricity feed prices	2.54
Investment cost bus	$	300,000	Development of supply chains and scaling up in production	180,000
Registration cost bus	$/year	517	No change expected	517
Insurance cost bus	$/year	7675	Reduction in investment cost	5300
Maintenance cost bus	$/1000Km	260	Development of supply chains and experience with vehicles	135
Annual vehicle kms travelled bus	vkm/year	29,700	No change expected	29,700
Fuel cost bus	$/km	0.86	Improvements in fuel efficiency and lower price of hydrogen	0.44
LCOT bus	**$/vkm**	**2.66-3.25**		**1.66-2.02**

208 Reedman, L. J., and Graham, P. (2016). Transport Sector Greenhouse Gas Emissions Projections 2016. CSIRO Investigation Report No. EP167895.

Hydrogen competitiveness in targeted applications

The following assumptions were used in understanding the competitiveness of hydrogen against alternative technologies to develop Figure 19.

TABLE 57. HYDROGEN COMPETITIVENESS ASSUMPTIONS

APPLICATION	COMPARISON DETAILS
Buses	Comparison with diesel fuelled internal combustion engines on a levelised GJ/km basis. Refuelling stations assumed to have standardised model and price of hydrogen sold at the pump includes cost of fuel (80%), owning and operating station (20%) with additional 20% margin. Also assumed same tax benefits for all fuels.
Light duty vehicles	Comparison with petrol fuelled internal combustion engines on a levelised GJ/km basis. Refuelling stations assumed to have standardised model and price of hydrogen sold at the pump includes cost of fuel (80%), owning and operating station (20%) with additional 20% margin. Also assumed same tax benefits for all fuels.
Trucks	Comparison with diesel fuelled internal combustion engines on a levelised GJ/km basis. Refuelling stations assumed to have standardised model and price of hydrogen sold at the pump includes cost of fuel (80%), owning and operating station (20%) with additional 20% margin. Also assumed same tax benefits for all fuels.
Remote Area Power Systems	The price of a diesel remote area power system ($440/MWh) based on costs over the lifetime of the asset and delivery of fuel
Industrial Feedstock	This price is based on the incumbent price of SMR generated brown hydrogen assuming a gas price of $8/GJ.
Grid Firming services	Competition with gas turbine, PHES and battery in 100MW systems
Export	Sourced from ARENA/ACIL Allen report into hydrogen exports price needed to be competitive in global markets
Residential Heat	Natural gas transmission and wholesale price average of $10/GJ (HHV)
Synthetic Fuels	Cost of producing syngas from SMR at natural gas price of $8/GJ

APPENDIX D – **Stakeholder consultations**

Representatives from the following organisations were interviewed as part of the stakeholder consultation process

- Australian Gas Infrastructure Group (AGIG)
- Air Liquide
- Australian Pipeline and Gas Association (APGA)
- Australian Petroleum Production and Exploration Association (APPEA)
- ATCO
- BHP
- BOC Group
- Bollard
- California Fuel Cell Partnership
- Caltex
- CarbonNet
- Caterpillar
- Curtin University
- Department of Defence: Science and Technology (DST)
- E4Tech
- Energy Australia
- Energy Networks
- Energy Pipelines CRC
- Engie
- EVO Energy
- Fraunhofer Society
- Fuel Cell and Hydrogen Energy Association
- GE Power
- Global CCS Institute
- Griffith University
- H2H Energy
- Heraeus
- Hydrogenics
- Hydrogenious Technologies
- Hyundai
- International Partnership for Hydrogen and Fuel Cells in the Economy
- ITM Power
- Jemena
- JPower
- Linde
- Ludwig-Bölkow-Systemtechnik
- Monash University
- Moreland Council
- New Energy and Industrial Technology Development Organization (NEDO)
- NOW: National Organisation Hydrogen and Fuel Cell Technology
- Renewable Hydrogen Pty Ltd
- Renewable Hydrogen Fuel Cell Collaborative
- RMIT
- Shell
- Siemens
- Southern Oil
- Thyssenkrupp
- Toyota
- Transit Systems
- U.S. Department of Energy
- University of Hawaii
- University of Melbourne
- University of NSW
- University of Queensland
- Yara

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