Australian hydrogen market study

Sector analysis summary

24 May 2021

Australian Government

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PROJECT 411001-00078 - Australian hydrogen market study - Sector analysis summary

Rev	Description	Author	Review	Advisian approval	Revision date	Client approval	Approval date
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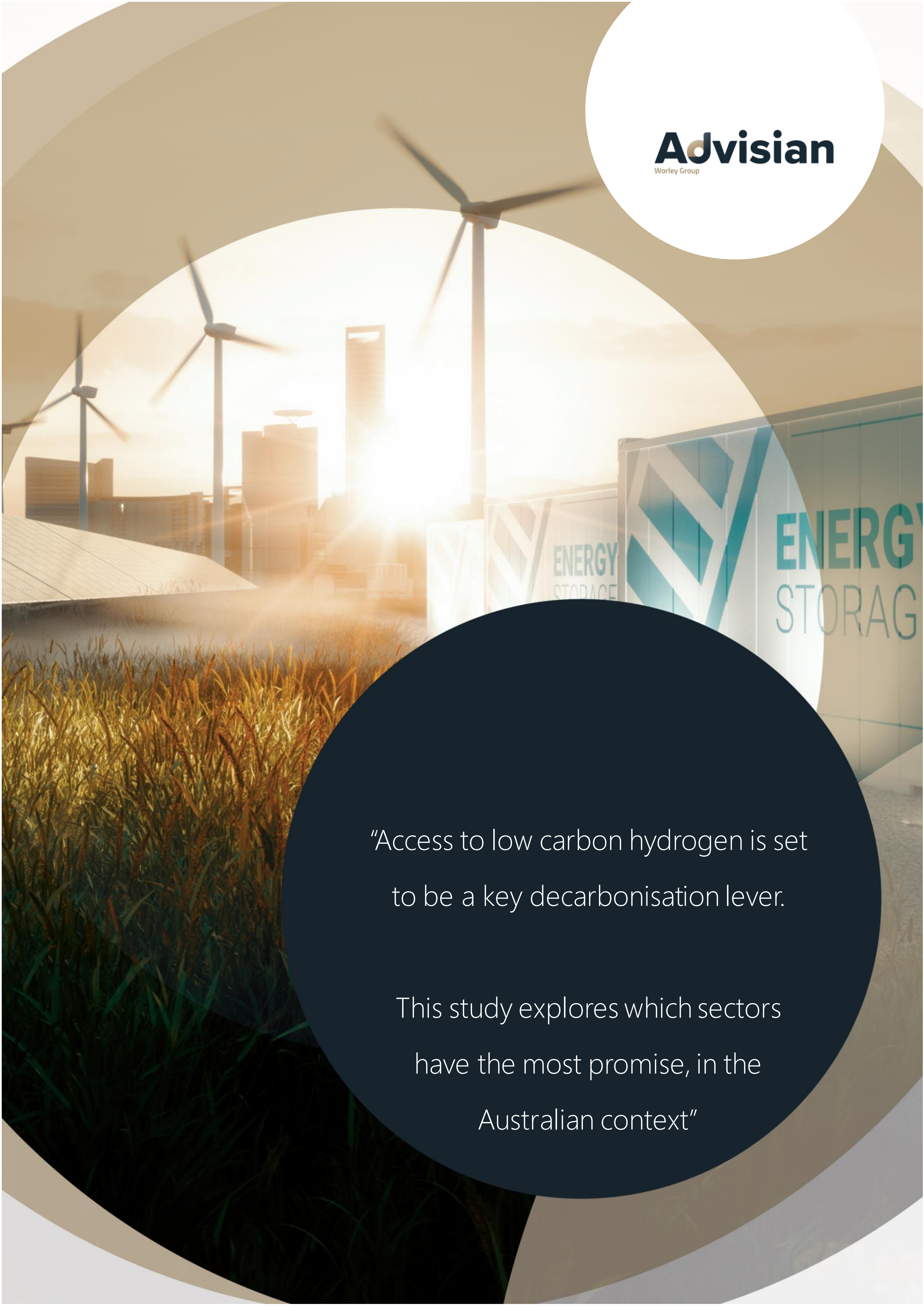

"Access to low carbon hydrogen is set to be a key decarbonisation lever.

This study explores which sectors have the most promise, in the Australian context"

Table of contents

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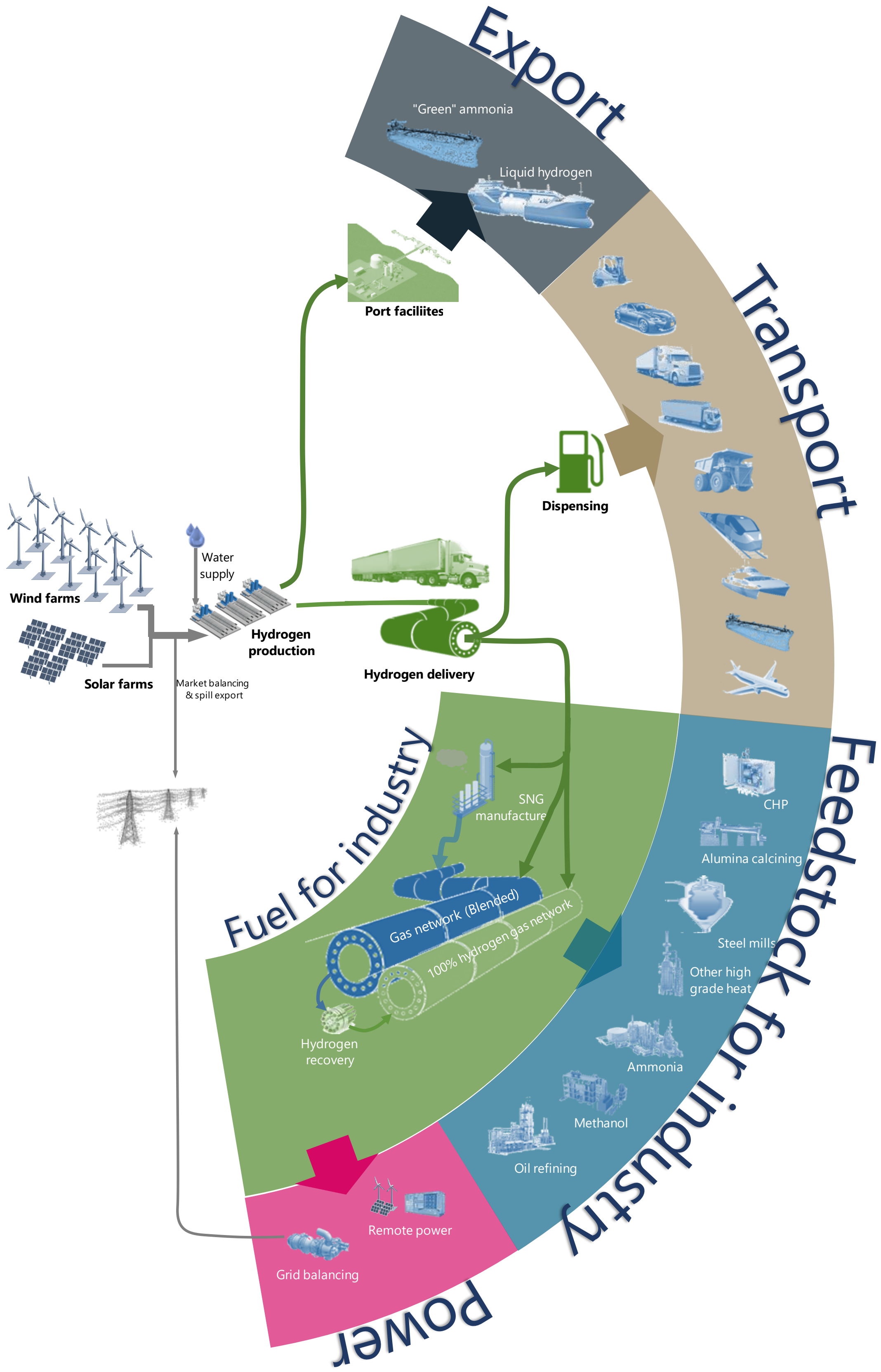
Executive summary

Figure 1-1 – Market study range of scope



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Executive summary

SECTION 1

CONTEXT

Low carbon hydrogen is emerging as a potential key vector for the future of the Australian energy transition and the industrial economy. To provide some insight on the potential competitiveness and key hurdles associated with advancing the low carbon hydrogen economy, this study explores the costs of production and the competitiveness of low carbon hydrogen in 25 Australian end-use sectors, relative to the incumbent technology.

The CEFC sought an appraisal of the economic gap between hydrogen supply and capacity to pay for each of the nominated demand sectors, both now and out to 2050.

To understand the potential use cases for low carbon hydrogen in the Australian context between 2020 and 2050, this study looked at:

- Hydrogen supply (technical and commercial);
- Hydrogen distribution and dispensing (technical and commercial);
- Hydrogen end-use technology limitations / efficiencies; and
- Costs of hydrogen technologies relative to incumbent technology pathways.

The considerations with greatest uncertainty are the supply side costs and end user dynamics. Consequently, this study directed the majority of focus towards these areas. As illustrated in Figure 1-1, this study explored hydrogen use in 25 sectors.

Grey hydrogen

- Produced by steam methane reforming (SMR) of natural gas or coal
- 8.5 -10 kg of CO_2 / kg of H_2

Blue hydrogen

- Produced by coupling SMR with carbon capture and storage
- 0.8 -4.4 kg of CO_2 / kg of H_2

Green hydrogen

- Produced by electrolysis of water
- Minimal GHG footprint

Due to the very low volumetric density of hydrogen, distribution of hydrogen is significantly more expensive than natural gas and other energy carriers. Recognising that the lowest cost renewable energy sites are often greater than 100 kilometres from hydrogen demand centres, it was appropriate for this study to differentiate between *farm gate* and *delivered hydrogen* cost. Farm gate is used to determine the cost of hydrogen at the output of the production process, that is electrolyser or gas reformer, and does not consider delivery costs. The two key delivery approaches that were reviewed were termed *movement of molecules* and *movement of electrons*.

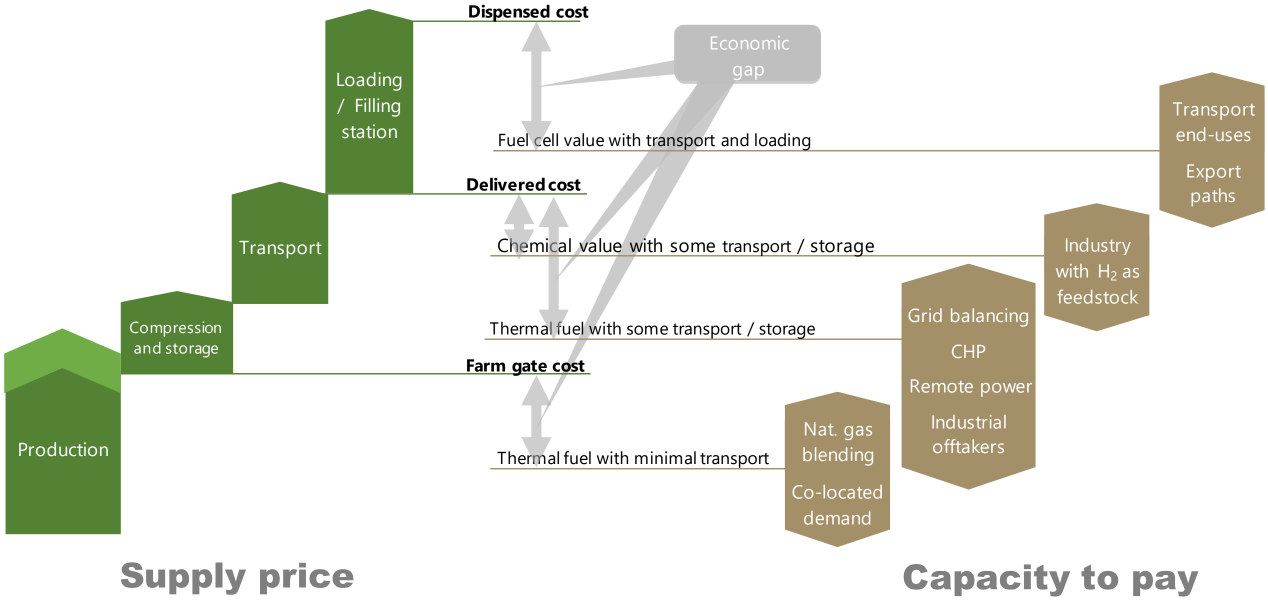
It is common practice to assign colours to different hydrogen production pathways recognising they have different carbon intensity levels – refer to the box at left and Section 2. This study addresses the potential for uptake of low carbon hydrogen pathways in the Australian marketplace. Both "green" and "blue" hydrogen are considered to yield low carbon intensity hydrogen. The primary focus of this study is the cost dynamics for "green" hydrogen relative to end-user "capacity to pay". Where carbon sequestration is possible, "blue" hydrogen can currently be produced more cheaply than green hydrogen and can be treated as a transition fuel.

Our analysis reflects the "best industrial" practice that is near lowest practical costs. The base production cost, that is farm gate cost, reflects the cost of production associated with hydrogen production adjacent to a mixed wind and solar renewable energy farm. If the hydrogen production is remote from the renewable energy source, then electricity delivery costs, such as Transmission Use of System (TUoS) and Distribution Use of System (DUoS) charges should be added to the production cost.

If the hydrogen is injected into a natural gas grid, then some compression maybe required, but storage would not be required. If the produced hydrogen is to be consumed at a remote location, transportation costs, such as trucking or a pipeline, are incurred. Most industrial users will require some hydrogen transport. If hydrogen is to be transferred into a vehicle for use as fuel, then loading / filling costs are also incurred.

The demand – supply cost framework that is used in this study is summarised below.

Figure 1-2 – Demand – supply cost framework used for this study



"

Hydrogen is today enjoying unprecedented momentum. The world should not miss this unique chance to make hydrogen an important part of our clean and secure energy future. "

Dr Fatih Birol

Executive Director, International Energy Agency

SECTION 2

PRODUCTION COST

In this study we forecast that green hydrogen can be produced for less than A$3.90/kg but when delivery costs for moving electrons and ~20 km of pipeline is added, the delivered cost are around A$5.82/kg. Out to 2050, large scale production costs could drop materially, and the decision to move electrons or move molecules will be case dependent.

Based on the forecast trend in the price of "industrial scale" natural gas supply and the cost of a steam methane reformer plant to convert this gas to hydrogen, we characterised the cost of grey hydrogen production on both East and West coasts of Australia. The incremental cost of carbon capture and storage was added to derive a farm gate production cost forecast for blue hydrogen. The production costs for grey hydrogen do not vary significantly out to 2050, commencing at A$1.70 per kg on the West coast, and A$2.20 per kg on the East coast.

Turning to green hydrogen, the key factors impacting the production cost are:

- Cost of renewable power;
- Electrolyser costs; and
- Intermittency of power supply.

The costs of electrolysis plants are forecast to decline rapidly as production scale escalates and technology is refined. The cost decline curve is subject to many assumptions and speculation. We have bounded the expected cost range using "base" and "accelerated" cost decline curves.

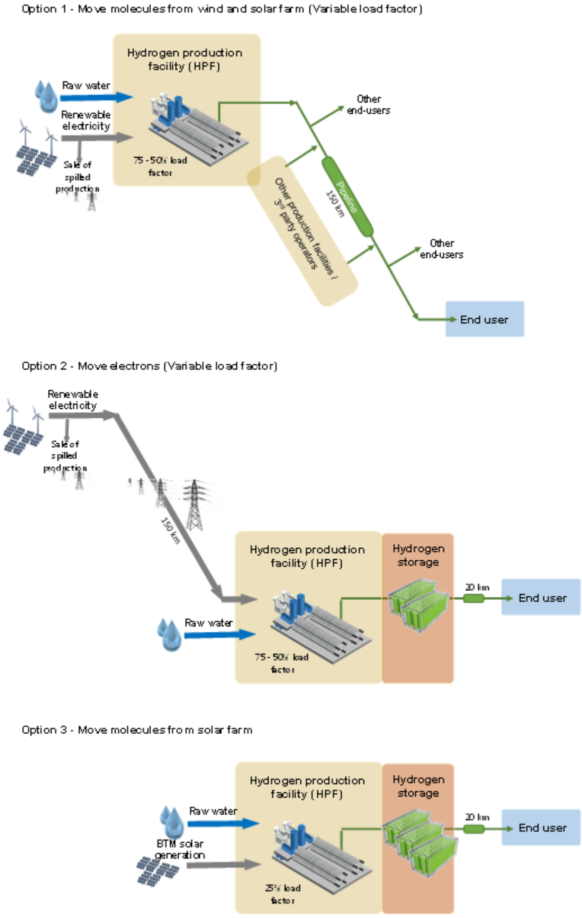
A key challenge for production of green hydrogen is the management of power supply variability. Systems with more variability and / or intermittency require larger electrolysis plants relative to those with continuous power availability to produce the same amount of hydrogen. The ratio of average production relative to electrolyser size is termed 'load factor'. This study has shown that in the near-term, higher load factor system designs provide the most cost-efficient balance between current market prices for renewable power and electrolyser capacity. In the longer-term - towards 2050 - lower renewable energy generation costs and the wider international uptake of green hydrogen production is likely to lower electrolyser costs with improved energy efficiency. This will likely enable cost effective green hydrogen production with lower load factor; solar only hydrogen generation may become cost effective.

The rapidly declining cost of solar power is one of the key triggers for interest in hydrogen production, however the "sunshine only" electricity supply results in very large electrolysis plants to achieve a given amount of hydrogen production relative to a hydrogen production facility with continuous power supply. Using solar to supply a continuous demand for hydrogen is therefore heavily penalised through the additional capital cost of electrolysis plant and hydrogen storage to provide continuous supply.

The development of delivered hydrogen costs considers the comparison of transport and storage requirements of three different options over a typical distance of 150 km from the point of renewable generation or farm gate, to a coastal end user – refer to Figure 1-3 . At industrial scale, pipelines are generally cost effective for "moving molecules", however if existing power infrastructure can be

Figure 1-3 – Schematic of delivery pathways

(Full size image is provided in Figure 2-11)



leveraged, it may be preferable to transport energy as electricity i.e. "moving electrons". In the "move molecules" case, the electrolyser is co-located with the renewable energy facility. In the "move electrons" case, the electrolyser is co-located with the end user/s. A third option - "behind the meter", considers co-location of a solar generation, electrolyser and the end user.

The move electrons approach has comparatively low cost per kilometre of infrastructure. However, the interfaces with the National Electricity Market and uncertainties regarding TUoS fees must be managed. Project TUoS fees associated with low load factor / utilisation are currently unclear and timelines for upgrades may not match project requirements.

The move molecules approach generally incurs higher initial capital costs, but the resulting pipeline infrastructure can provide storage functions through linepack and it may be possible to realise additional revenue from third party agreements to move hydrogen. The move molecules approach must also overcome challenges associated with sourcing water and disposing of wastewater associated with hydrogen production processes in remote locations.

In the near term, the scale of hydrogen production is unlikely to be able to justify the cost of a pipeline and trucking of hydrogen is very expensive, hence the move electrons approach is preferred for the "sub-industrial scale" (around 20 MW capacity) supply of hydrogen to industrial and transportation end-users. If a natural gas pipeline is adjacent to a renewable energy farm, then a behind the meter solution could be attractive. Our assessment of the industry best practice farm gate cost for green hydrogen production adjacent to a renewable energy farm is A$3.88/kg. If hydrogen is to be consumed at >100 km from the renewable energy farm, then a move electrons approach with a 20 km pipeline to the final end user is likely to yield hydrogen at a price of A$5.82/kg refer to "nominal" case in Table 1-1.

It should be noted that the farm gate and delivered costs defined in this report for the near term (i.e. 2020) will likely be considerably lower cost than currently proposed projects which are generally smaller than the 20 MW baseline and will require more first of a kind engineering for production facilities and supporting infrastructure.

Towards 2050, the best in class projects are likely to be approaching / in excess of 1 GW, with forecast farm gate costs dropping materially-to below $2.00/kg. For these larger scale developments, the preferred approach of linking optimal renewable energy generation sites to end-user demand is a key consideration with many uncertainties. Our analysis considered scenarios where the optimal renewable energy resources were over 150 kilometres from the end user. This analysis suggests that at industrial scale, moving molecules and moving electrons approaches are cost comparable, but with very

:

different non-economic considerations. These considerations include: national grid operations dependence, water logistics, expansion capacity and social license to operate.

A summary of the forecast cost ranges for "best in class" projects is provided below.

Figure 1-4 – Forecast hydrogen cost ranges (Real 2020, AUD/kg)

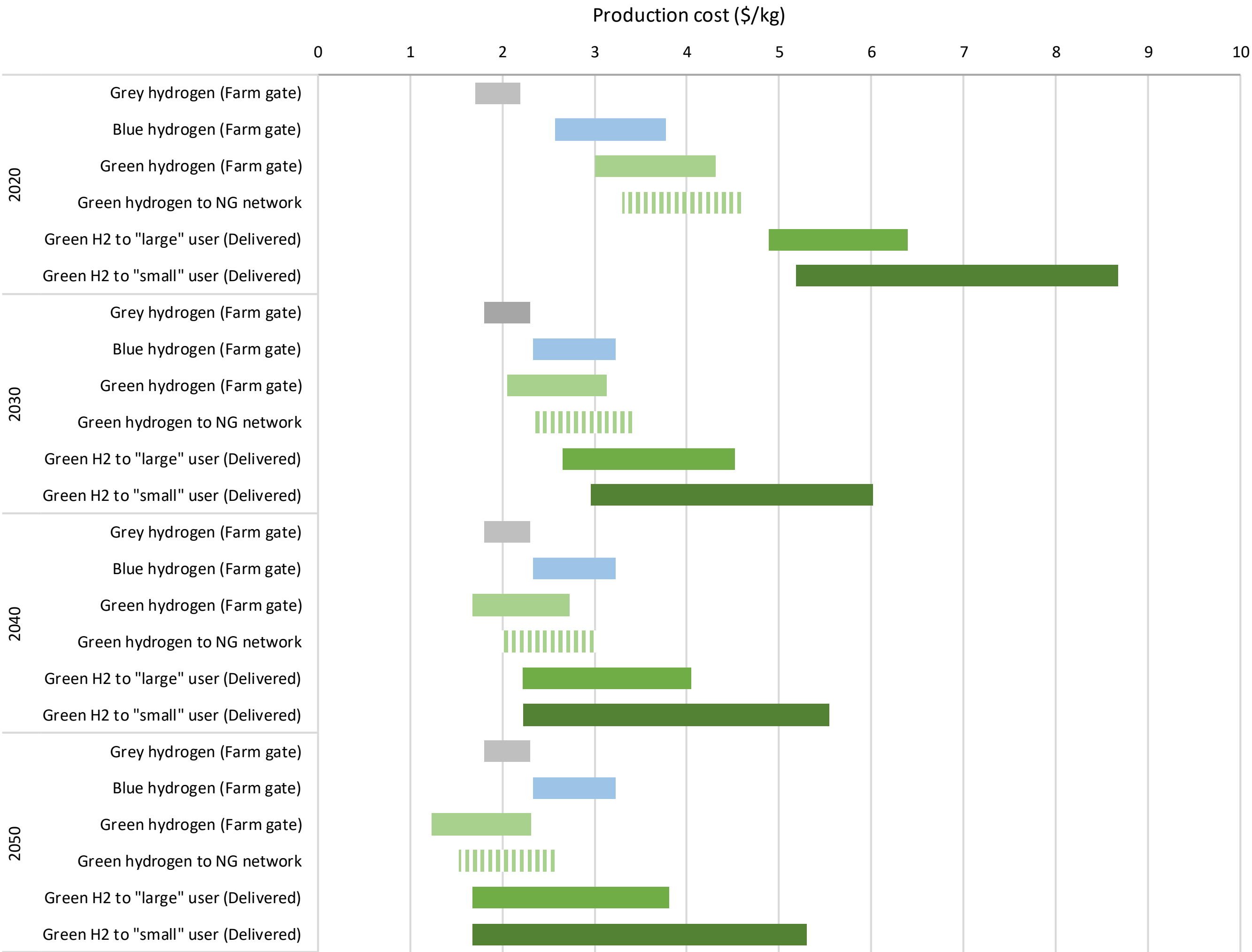


Table 1-1 – Forecast hydrogen cost summary

Metric	2020	2030	2050
"Grey" hydrogen farm gate cost ($/kg)	2.20	2.29	2.29
"Blue" hydrogen farm gate cost ($/kg)	3.02	2.80	2.80
"Base" Green H_2 farm gate cost ($/kg)	3.88	2.81	2.09
"Accelerated" Green H_2 farm gate cost ($/kg)	3.46	2.29	1.64
"Nominal" Green H_2 farm gate cost ($/kg)	3.88	2.76	1.98
"Base" Green H_2 delivered cost ($/kg)	5.82	3.48	2.72
"Accelerated" Green H_2 delivered cost ($/kg)	5.43	2.96	2.23
"Nominal" Green H_2 delivered cost ($/kg)	5.82	3.42	2.60

END-USE ECONOMIC GAP

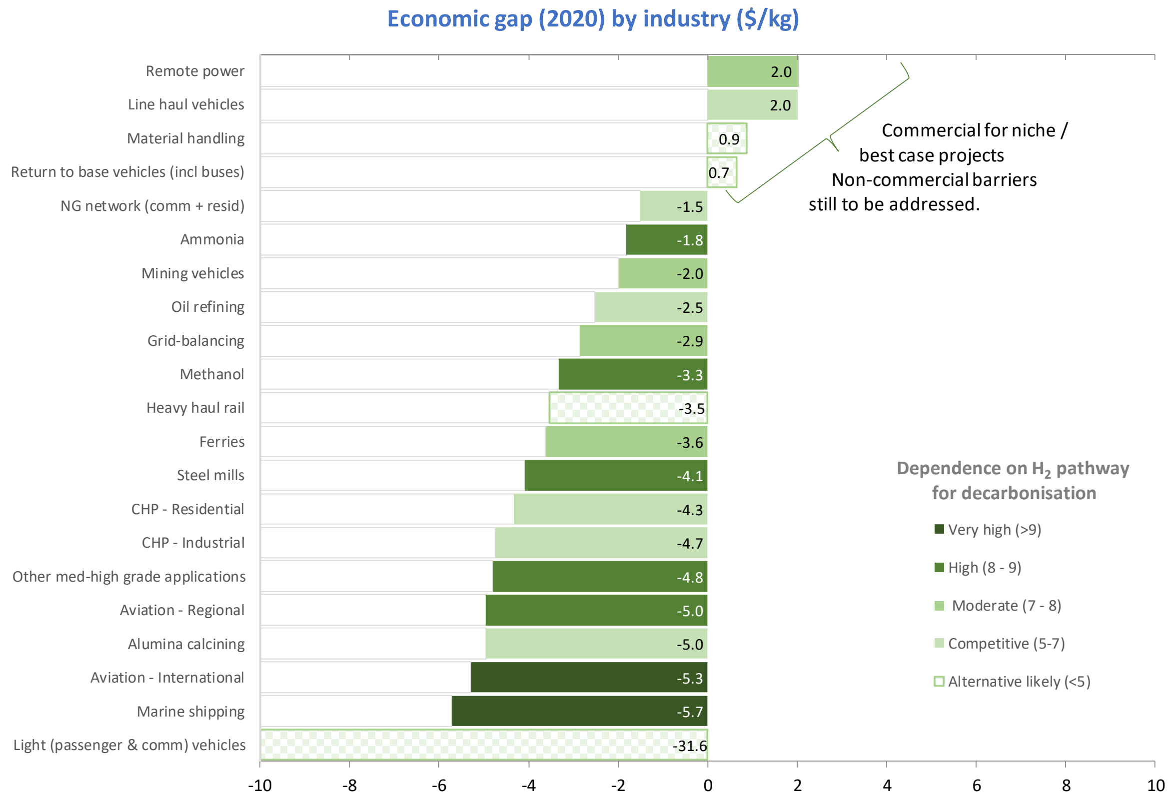
In the near term, remote power and a few transport sectors are close to achieving commercial parity with incumbent fuels. By 2030, nearly all transport sectors achieve cost competitiveness with the incumbent technology. Competitiveness is expected to improve in all sectors through to 2050 due to declining hydrogen production and distribution costs and end-use technology improvements.

The economic gap between likely delivery price and capacity to pay, based on incumbent technology, has been estimated for 20 industry end-use applications in 25 end use sectors. A positive economic gap indicates that hydrogen-based technology could be economically competitive with the incumbent technology for the given application. A negative economic gap indicates that the incumbent technology remains competitive.

Competing technology directions such as electrification and battery electric vehicles are not considered in the economic gap assessment, but dependence on hydrogen pathway for decarbonisation has been scored. For example, industries that would have significant challenges in electrifying are more dependent on hydrogen to decarbonise.

The transition in economic competitiveness of the reviewed end-use sectors for 2020, 2030 and 2050 is summarised in Figure 1-5 below. The extent that the industry end-use sectors are likely to be dependent on hydrogen in order to decarbonise is captured as a colour scale in the figures below.

Figure 1-5 – Transition in sector economic competitiveness over time



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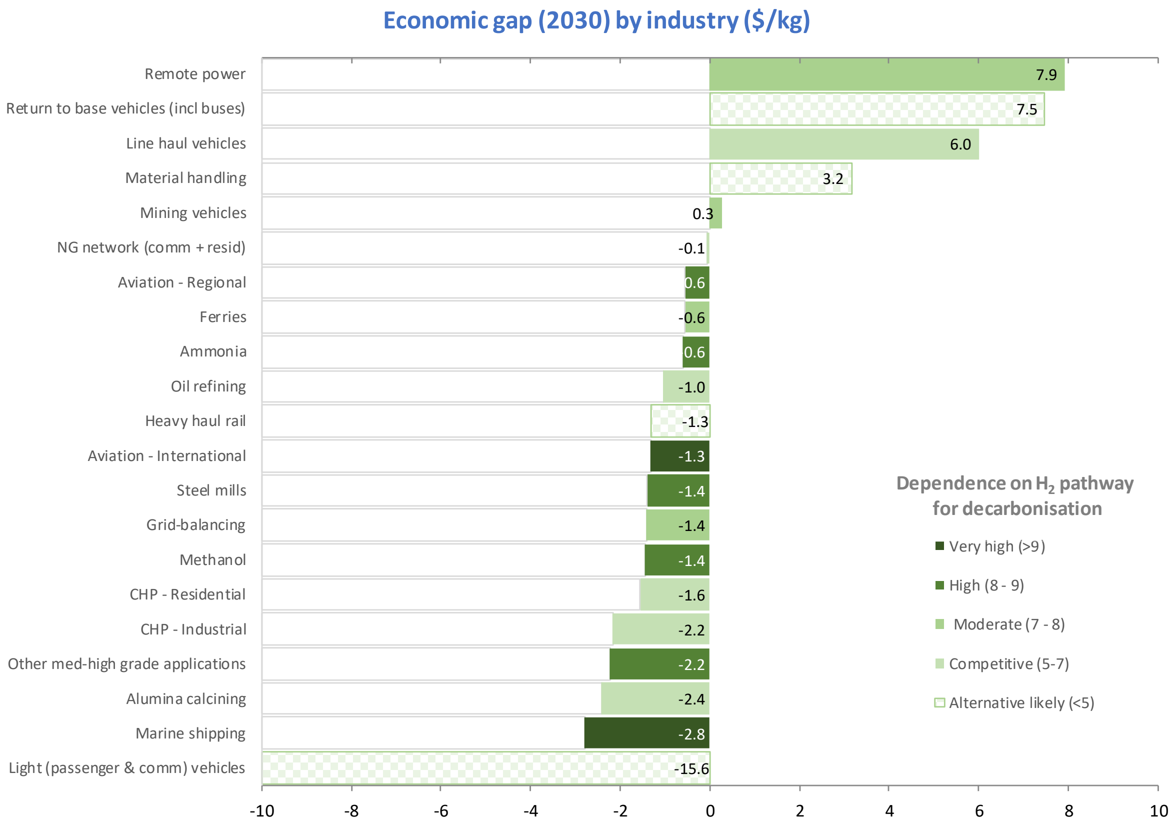
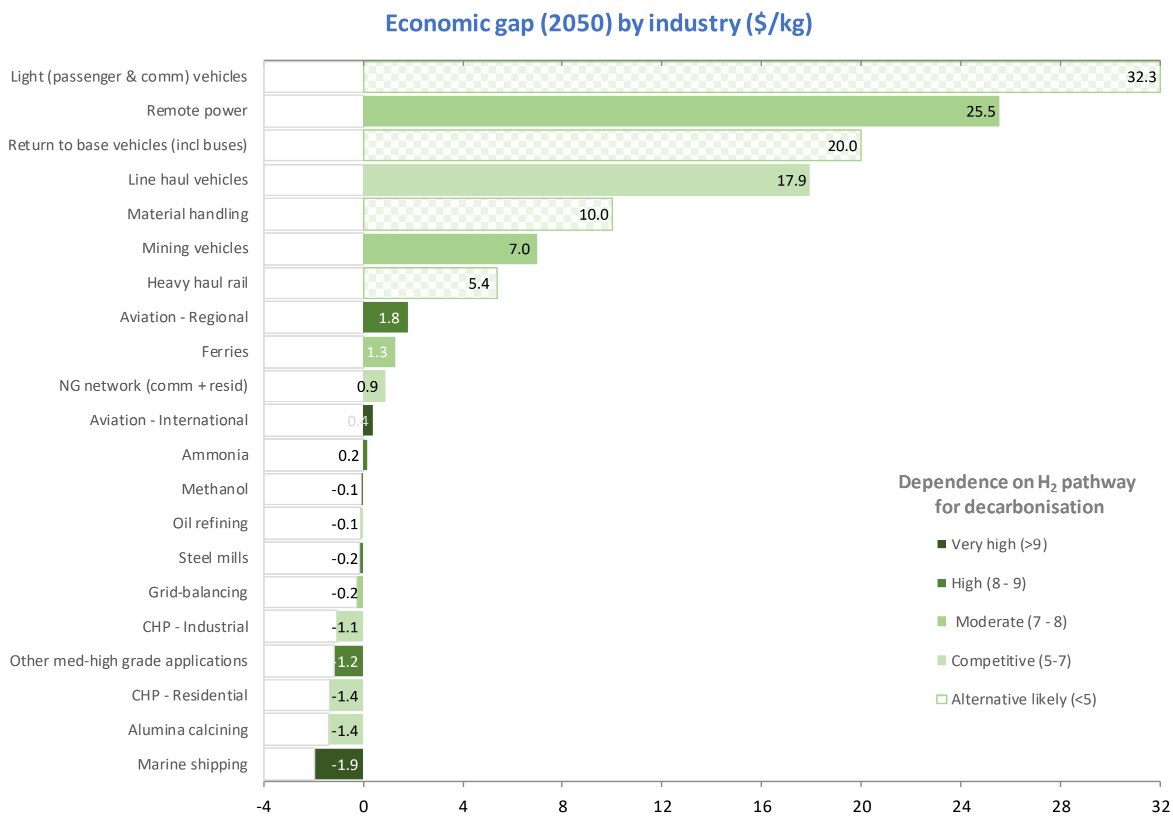


Economic gap (2030) by industry ($/kg)
Remote power
Return to base vehicles (incl buses)
Line haul vehicles
Material handling
Mining vehicles
NG network (comm + resid)
Aviation - Regional
Ferries
Ammonia
Oil refining
Heavy haul rail
Aviation - International
Steel mills
Grid-balancing
Methanol
CHP - Residential
CHP - Industrial
Other med-high grade applications
Alumina calcining
Marine shipping
Light (passenger & comm) vehicles
7.9
7.5
6.0
3.2
0.3
-0.1
-0.6
-0.6
-0.6
-1.0
-1.3
-1.3
-1.4
-1.4
-1.4
-1.6
-2.2
-2.2
-2.4
-2.8
-15.6
-10
-8
-6
-4
-2
0
2
4
6
8
10
Dependence on H2 pathway for decarbonisation
Very high (>9)
High (8 - 9)
Moderate (7 - 8)
Competitive (5-7)
Alternative likely (<5)



Economic gap (2050) by industry ($/kg)
Light (passenger & comm) vehicles
Remote power
Return to base vehicles (incl buses)
Line haul vehicles
Material handling
Mining vehicles
Heavy haul rail
Aviation - Regional
Ferries
NG network (comm + resid)
Aviation - International
Ammonia
Methanol
Oil refining
Steel mills
Grid-balancing
CHP - Industrial
Other med-high grade applications
CHP - Residential
Alumina calcining
Marine shipping
32.3
25.5
20.0
17.9
10.0
7.0
5.4
1.8
1.3
0.9
0.4
0.2
-0.1
-0.1
-0.2
-0.2
-1.1
-1.2
-1.4
-1.4
-1.9
-4
0
4
8
12
16
20
24
28
32
Dependence on H2 pathway for decarbonisation
Very high (>9)
High (8 - 9)
Moderate (7 - 8)
Competitive (5-7)
Alternative likely (<5)

In all sectors, low carbon hydrogen is expected to become more competitive towards 2050, due to parallel advances in production & distribution cost efficiency and end-use technology evolution.

In the near term, the sectors which are approaching commercial attractiveness are: line haul vehicles, remote power, material handling and return to base vehicles (including buses).

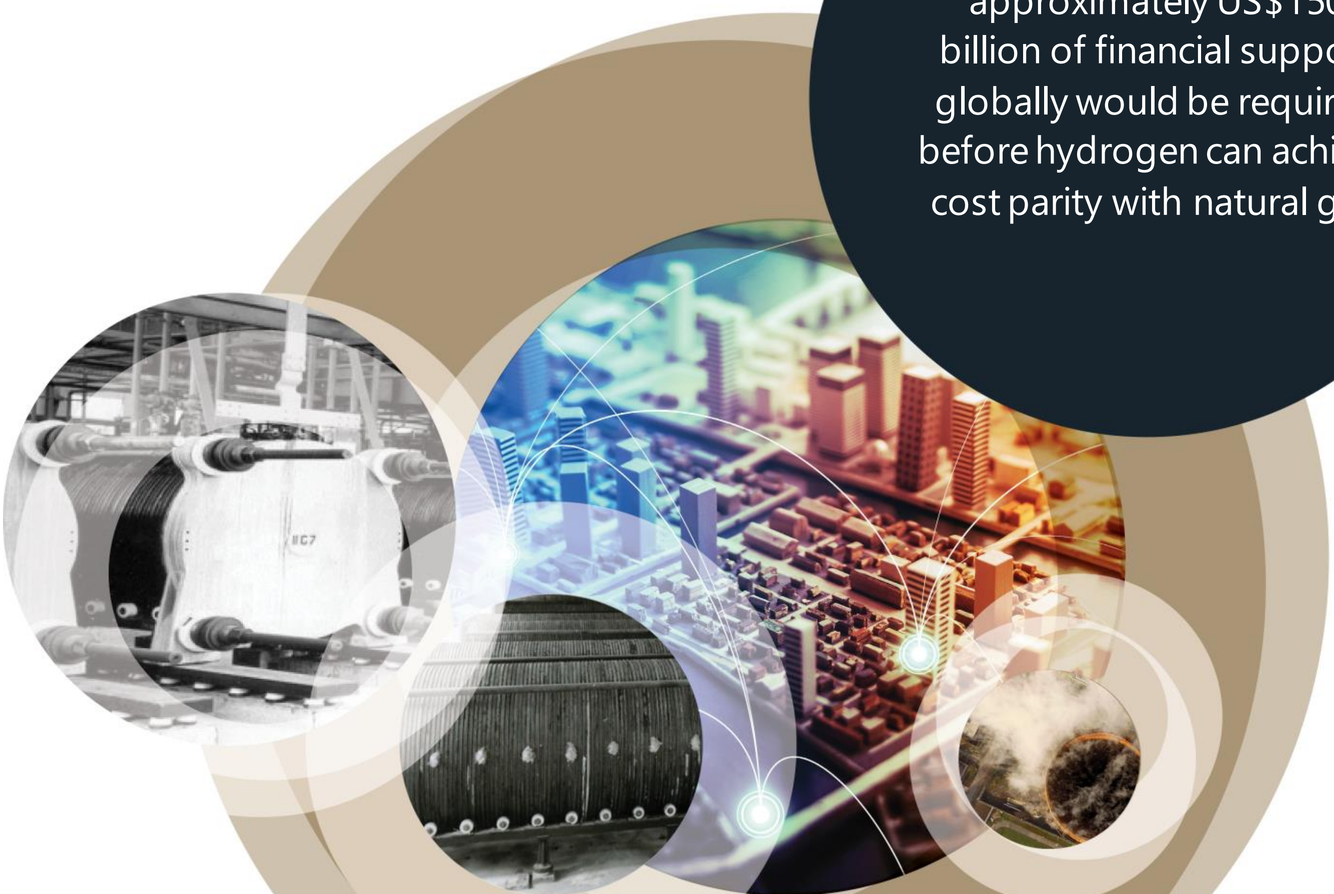
Towards 2030, the range of sectors where hydrogen is becoming commercially viable for adoption increases to include: mining vehicles.

As farm gate hydrogen costs approach grey hydrogen prices, around $2.30/kg, green hydrogen is expected to displace grey hydrogen production.

Out to 2050, the range of sectors where hydrogen may be commercially viable extends to include: light vehicles, heavy haul rail, aviation regional, ferries, natural gas network (commercial and residential), aviation international and ammonia.

This study found that the forecast costs for low carbon hydrogen will not achieve thermal cost parity with natural gas, of approximately $1.1/kg, before 2050. Hence the displacement of natural gas in industrial heating applications will not occur in this timeframe without either substantial regulatory or policy support or significantly more aggressive electrolyser and renewable energy cost declines than were assumed by this study.

Bloomberg estimates that approximately US$150 billion of financial support globally would be required before hydrogen can achieve cost parity with natural gas.

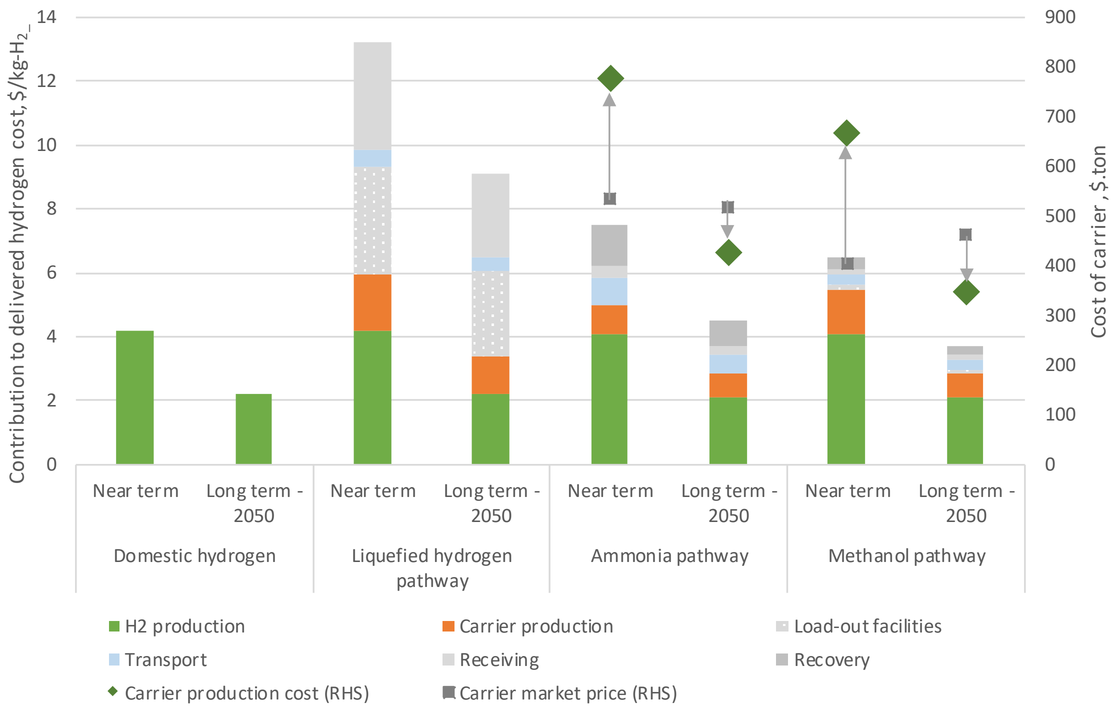


EXPORT PATHWAYS

'Hydrogen can be exported in a number of carrier forms. It is not clear whether a single carrier will dominate

The export of hydrogen is forecast to be a key enabler of the development of a global low carbon economy. However, the inherent very low density of hydrogen makes international export challenging. In this report, we compare the performance of three key export pathways for delivery of hydrogen to Japan. We evaluate both the expected delivered cost as well as the expected production cost of the carrier. The results of this analysis are illustrated in Figure 1-6 below.

Figure 1-6 – Forecast cost of delivered green hydrogen in Japan



Although the liquefaction pathway has comparatively higher energy demand for the liquefaction step, the biggest challenge for this pathway is the immense capital costs associated with load-out and receiving terminals.

The pathways involving chemical bonding, such as ammonia and methanol, appear to offer lower delivered hydrogen prices than the liquefaction pathway. In the near term, the "green" carrier cost is significantly more expensive than the conventional, high emissions product. But by 2050, the green product is forecast to be cheaper than the incumbent. The key challenges associated with the ammonia pathway relate to decomposition losses when liberating pure hydrogen and management of a toxic compound. The key challenges associated with the methanol pathway relate to securing carbon neutral carbon dioxide (refer to Section 6.1.6) and management of a toxic compound.

SECTION 5

ACCELERATING MARKET DEVELOPMENT

Support is needed for the domestic and export hydrogen industry to realise their potential. Sectors such as marine shipping, aviation, ammonia and methanol have a high dependence on hydrogen for decarbonisation and could benefit from early support to avoid the most severe impacts of future carbon constraints

The realisation of a vibrant hydrogen economy will require early intervention and significant government investment. Australia's opportunity to gain comparative advantage of our local industry requires progressive development of domestic end-use rather than waiting for industry and exports to drive the development of the industry.

Adopting an export only approach to the early advancement of the hydrogen economy is likely to yield less favourable commercial outcomes. Without global growth of hydrogen consumption, the cost of hydrogen electrolysers, fuel cells and storage systems are unlikely to decline rapidly and therefore the prospective end-use markets will remain uneconomic. The development of domestic markets will support the social licence for hydrogen manufacturing and add to decarbonisation efforts. If hydrogen is not accelerated, decarbonisation efforts will be more limited in scope and large-scale energy storage and distribution may be more challenging.

Some sectors may realise an earlier adoption of hydrogen than forecast by the economic gap assessment because they are willing to pay a green premium, receive grants / concessional finance or use is mandated by regulation / industry targets etc. The sectors most likely to be impacted in this way, are those with a very high dependence on hydrogen for decarbonisation, namely: marine shipping, aviation, ammonia, and methanol.

Some short-term actions could accelerate hydrogen uptake.

This study identified several areas which could accelerate the development of the Australian hydrogen market. The focus is on activities that will advance near commercial sectors toward economic viability and confirmation / definition of industry standards. Notable suggestions include:

- Confirmation of requirements relating to "out of phase" generation, renewable energy certificates and consumption of renewable electricity and their contributions to "origin certification" and "green" classifications;
- Clarification of "Origin certification" expectations - This was a priority action under Australia's National Hydrogen Strategy and should be progressed as soon as possible;
- Undertaking studies regarding the capacity of key sectors to accept intermittent / multi-day supply of excess hydrogen will enable hydrogen export projects to plan where to direct production in the event of export facility outage and builds knowledge around end-use sector readiness;
- Assess / define the value of common user infrastructure, such as pipeline and ports, to diversify opportunities towards decentralised solutions, and enables multiple producers and users to participate in the hydrogen economy without first mover disadvantage / cost burden;

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- Developing development guidelines in anticipation of social licence to operate requirements such as grid loading / pricing and water supply competition;
- Support the demonstration of hydrogen recovery from blended natural gas network projects which stabilise the H_2 concentration in a feed to a "gas peaker" power plant and yield locations with a capacity for high quality H_2 distribution / dispensing; and
- Support the reduction / removal of barriers for near economic opportunities.

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Study context

1 Study context

The foundations for a global low carbon economy are emerging. For the first time in history there is a sustained interest from both political and commercial sectors. The coupling of policy development and industry initiative has led to numerous forecasts of significant upward projections in hydrogen demand. For instance, the Hydrogen Council suggests that low carbon hydrogen demand could reach 80,000 PJ by 2050 with associated revenue potential of more than US$2.5 trillion per annum (Hydrogen Council, 2020).

In 2020, there were clear indications that societal forces are driving change in major corporations. Examples include major investor, BlackRock, now requiring all companies it invests in to adopt climate related reporting practices and Apple committing to carbon neutrality across its entire supply chain by 2030. As shareholders become less willing to accept the risks associated with market loss and stranded assets, major corporations are seeking to protect against such economic risks by future proofing their businesses through more sustainable investment practices and ambitious emissions reduction targets.

A number of countries have identified the economic and reputational opportunity of using hydrogen to complement and catalyse decarbonisation activity. Japan, Korea, China and the European Union have all announced ambitious decarbonisation policies which target the development of "green" hydrogen production and import as a key element of emissions reductions strategies (Future Fuels CRC, 2019).

At this stage few hydrogen market applications have reached commercial readiness, but the continued decline in the cost of renewable energy is expected to contribute significantly to the reduction in cost and increased commerciality of hydrogen production in the near term (Krukowska, 2020). This, coupled with huge investment and supportive government policies, provides the foundation for hydrogen production and distribution to scale-up to levels where it can become competitive with the incumbent fossil fuel industry. Bloomberg estimates that approximately US$150 billion of international financial support is required before hydrogen can achieve cost parity (Bloomberg NEF, 2020).

The cost of renewable energy ultimately defines the cost of green hydrogen. For those countries with abundant renewable energy resources, there is competition to become an early adopter and commence the development of export pathways. (Collins, 2020). If early investment fails to flow then the maturation of a hydrogen economy will progress much more slowly than forecast.

1.1 Current hydrogen use in Australia

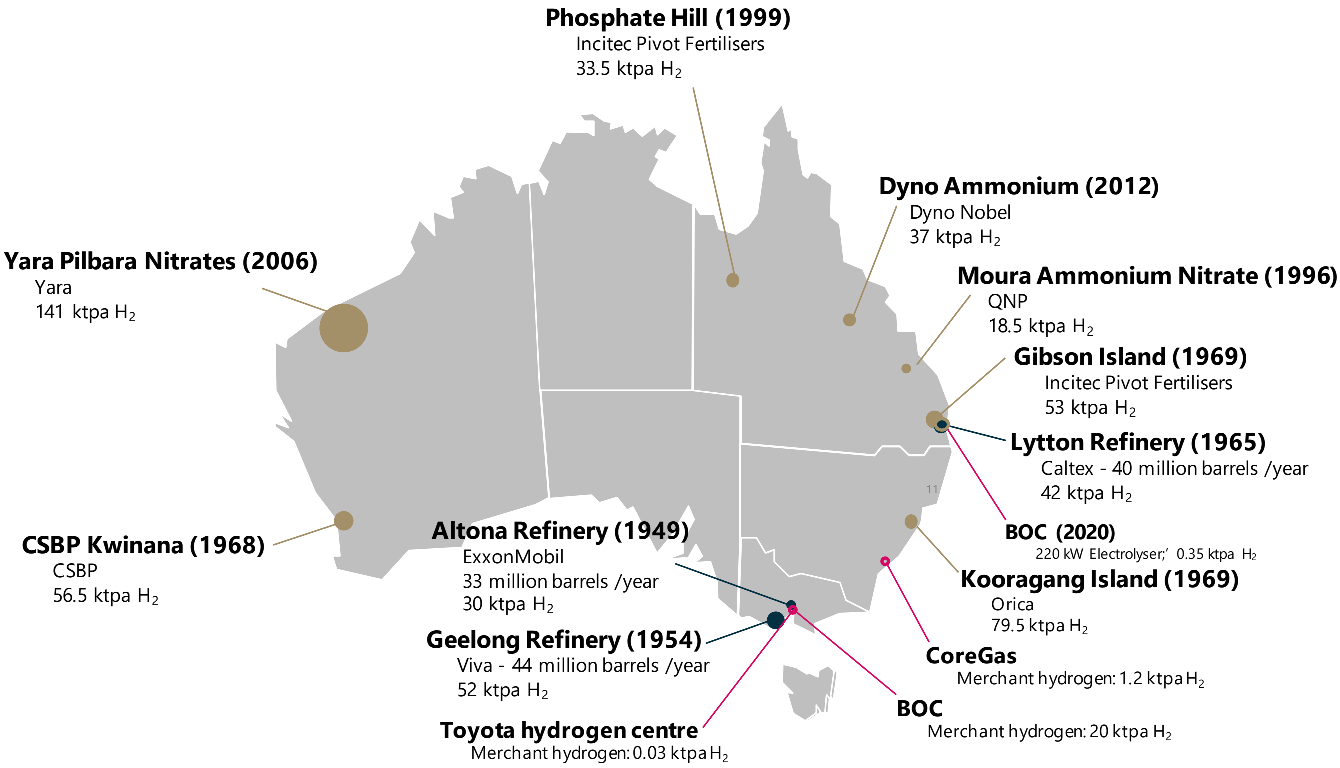
Hydrogen plays a small but important role in Australia's industrial processes. The merchant market for hydrogen in Australia is negligible, with virtually all hydrogen production closely coupled with end-use consumption. Australia's current hydrogen consumption can be broken into three categories:

1. Feedstock to ammonia plants;
2. Feedstock to crude oil refineries processes; and
3. Other minor applications (negligible).

Australia's current hydrogen production is around 650 ktpa and virtually all of this hydrogen is made using Natural Gas Steam Methane Reforming (NG SMR) and is immediately consumed by the associated ammonia synthesis (≈65%) and crude oil refining (≈35%) plant.

Based on the age of the current hydrogen producing assets, it is unlikely that these assets could be re-purposed for merchant hydrogen production – see Figure 1-1.

Figure 1-1 – Existing hydrogen production / use centres



1.1.1 Australian hydrogen regulations and policies

The National Hydrogen Strategy and Low Emission Technology statements, released in 2019 and 2020 respectively, are the clearest indication that the Federal government is committed to advancing hydrogen based economic growth. In support of the Federal government strategy, all Australian states and territories have released green hydrogen strategies which signal support for hydrogen developments.

The sector would benefit from further legislation and regulatory development and alignment

A recent review of the existing State and Commonwealth legislation and regulations identified 1,255 pieces of Australian law potentially relevant to the development of the hydrogen industry (Clayton Utz, 2019). Currently, over 70 Australian Standards relevant to the hydrogen industry already exist to enable the safe and streamlined introduction of hydrogen technologies. Additionally, around 50 international standards were identified as relevant, although no international standards relevant to hydrogen production have been adopted as an Australian Standard (Standards Australia, 2018).

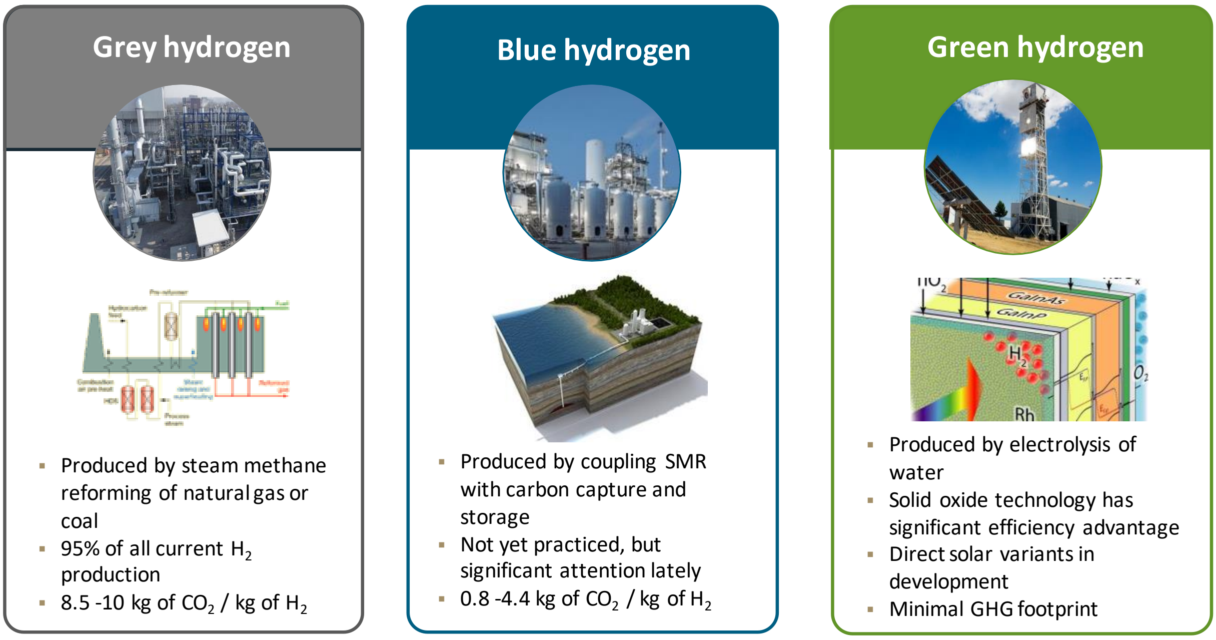
Markets demand clarification / certification of low emission credentials

Developing a common classification system e.g. CertiHy or origin labelling system is recognised a key enabler of international / multilateral trade (COAG Energy Council, 2019).

2 Hydrogen production

In an effort to socialise and improve communication regarding the carbon intensity of hydrogen, a colour spectrum is used to indicate the indicative carbon intensity. The IEA (IEA, 2019) descriptions are characterised below and summarised in Figure 2-1.

Figure 2-1 – Hydrogen carbon intensity spectrum



The colour spectrum is intended to characterise relative carbon intensity.

Black H_2: Hydrogen formed through coal gasification, where there is an unmanaged by-product of carbon dioxide.

Brown H_2: Hydrogen formed through lignite gasification, where there is an unmanaged by-product of carbon dioxide.

Grey H_2: Hydrogen formed through processing of hydrocarbons, such as via SMR, where there is an unmanaged by-product of carbon dioxide.

Blue H_2: Hydrogen formed through the same processes as grey, black and brown hydrogen but where the carbon dioxide by-product is captured and secured via an appropriate Carbon Capture Utilisation and Storage (CCUS) technology.

Green H_2: Hydrogen formed via electrolysis of water using renewable electricity source(s) having no process-related carbon emissions.

Hydrogen can be produced via a number of technological pathways. The primary focus of this report relates to the potential for electrolytic hydrogen production based on low cost renewable energy generation - green hydrogen production. In the nearer term only Alkaline Electrolysis (AE) and Proton Exchange Membrane (PEM) technologies are considered to be mature.

1. Alkaline electrolysis (AE) – is an electrochemical cell and a well-established technology that benefits from lower capital costs and process improvements than Proton exchange membrane

(PEM) technology. However, is often associated with poor current density, less dynamic operational capabilities and oxygen impurities in the hydrogen product.

2. Proton exchange membrane (PEM) – splits water catalytically into protons to eventually bond with hydrogen atoms to create hydrogen gas. This technology currently suffers from higher capital costs however offers greater flexibility and dynamic response, higher current density and purity of hydrogen.

2.1 Grey hydrogen

Currently, 95% of the world's hydrogen production is derived from the reforming of natural gas or other hydrocarbons, gasified coal or gasified heavy oil residues. The most widely applied technology is steam methane reforming (SMR), although auto-thermal reforming (ATR) is increasingly being applied for large-scale hydrogen production. SMR can be considered a mature technology and widely used across the refining and petrochemical industries. Improvements in recent years have included higher performing materials, improved heat recovery, lower pressure drop and higher conversion catalysts. Integration of SMR technology into the Haber-Bosch process for ammonia synthesis is mature technology with huge commercial competition driving continuous technology evolution. In comparison, numerous ATRs are in operation worldwide, but most operate as secondary reformers in ammonia plants in collaboration with SMR technology. Cost effectiveness and energy consumption of these reforming technologies varies considerably with scale. Capacities less than 50 ktpa H_2 are increasingly considered to be small / marginally cost effective in the world marketplace[1]. The carbon intensity resulting from modern SMR plants with natural gas feed, ranges from 8.5 to 10 kg CO_2-e / kg H_2.

SMR is more correctly described as the combination of two separate reactions; methane reforming and water-gas shift. Steam methane reforming is a multi-step chemical process, requiring:

- a series of pre-reformers to desulphurise the gas and remove longer hydrocarbons such as ethane;
- the methane reformer where methane and water are converted into hydrogen and carbon monoxide;
- 'Water Gas Shift' reactors downstream of the main reformer, to maximise the quantity of hydrogen in the syngas produced by the reformer;
- A complex furnace design to supply heat to the main reformer and ensure adequate gas conversion; and
- Expensive gas separation equipment, typically a Pressure Swing Adsorption (PSA) unit.

The first reaction takes methane and water (steam) and produces hydrogen (H_2) and carbon monoxide (CO) in the presence of a nickel catalyst. This reaction is endothermic and requires external heat input. The reactor operates a pressure between 14 and 40 bar. The water-gas shift reaction takes the newly formed CO and reacts with more water to form additional H_2 and CO_2. The net effect of the reactions is moderately endothermic.

[1] This scale is aligned with 300 ktpa ammonia scale plants. Chemea [Chinese] reference.

2.2 Blue hydrogen

In the early 2000's, it was often forecast that the development of the hydrogen economy would transition through blue hydrogen i.e. fossil fuel sourced with carbon capture. Many industry participants are promoting blue hydrogen, although there is potential that green hydrogen will achieve price parity with blue hydrogen within the next 10 to 15 years – see Figure 2-14 in Section 2.3.2.

The application of carbon capture and storage (CCS) to reduce the carbon intensity of the hydrogen product has been pursued in principle for nearly two decades. Carbon dioxide produced by the natural gas SMR process is captured via well-established technologies, including amine adsorption, drying and compression for pipeline transportation. Pipeline transportation and injection of CO_2-rich waste gases are also well-established technologies, as used in enhanced oil recovery activity.

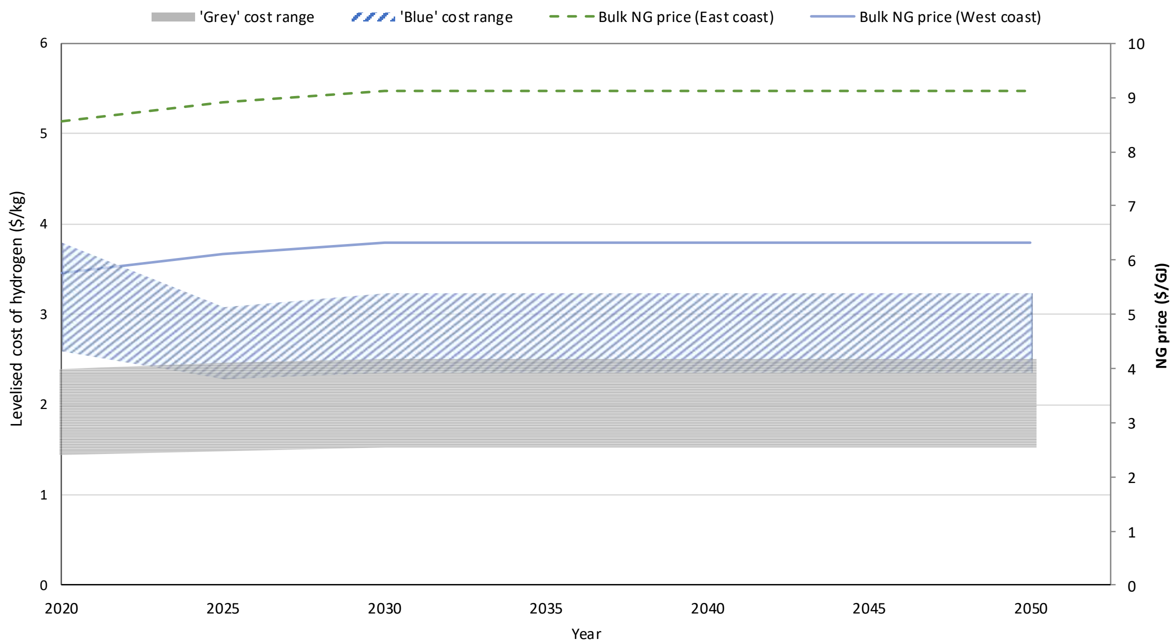
The key hurdles to broad application of this technology include:

- Weak utilisation market outside of enhanced oil recovery (EOR), hence Carbon Capture, Utilisation and Storage (CCUS) is often only CCS;
- Requirement to demonstrate that sequestered emissions remain in-place over geological time;
- Water / corrosion management in compression systems;
- Additional capital cost for capture, transport and storage infrastructure; and
- Additional operating costs for infrastructure and parasitic electricity demand.

With limited offtaker interest and a weak carbon market in Australia and globally, there has until now been limited motive to pursue this avenue of decarbonisation. The older natural gas SMR process schemes yield both dilute and rich carbon dioxide waste streams. The later stream is targeted by early carbon storage project developers and synthetic fuel proponents but is already often used to convert ammonia to urea.

A 99.8% stream purity specification from the CO_2 rich stream can often be achieved for blue hydrogen facilities without significant impact on the capital and operating cost of the reformer plants. Figure 2-2 summarises the range of costs between West coast and East coast with 60 to 90% CO_2 emissions avoidance.

Figure 2-2 – Forecast farm gate cost of grey and blue hydrogen (Real 2020, AUD/kg)



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2.3 Green hydrogen

The current optimism regarding green hydrogen as a future fuel and fossil fuel sector disruptor is based on the forecast that the supply costs of renewable energy and the capital costs of water splitting electrolysis units will follow steep cost decline curves, similar to those witnessed in the computer and solar photovoltaic (PV) industries.

2.3.1 "Farm gate" production cost

The term farm gate production cost refers to the cost required to produce hydrogen at a manufacturing facility. It does not include the cost of transport or storage.

In our assessment of the farm gate cost of green hydrogen, we considered the impact of four key drivers which are further discussed below:

3. Capital cost of the electrolyser and cost reduction rate over time;
4. Scale of development;
5. Efficiency of electrolysis units; and
6. Price and load factor of electricity supply.

Significant reductions in farm gate cost for green hydrogen production prior to 2050 will require the favourable alignment of the following key elements:

- Continuing rapid decline in the cost of renewable energy supply;
- Growing global demand for green hydrogen resulting in declining electrolyser costs;
- Technical evolution that improves electrolyser efficiency and results in lower operating costs;
- Contracting arrangements with renewable energy generators developed to share the risk of the intermittent wind / solar resource with the hydrogen generators;
- End user off-taker contracts are established to allow for flexibility in hydrogen production rate;
- Cost effective water supply and wastewater treatment;
- Social licence to operate and hydrogen policy context to be advanced; and
- Access to low cost finance.

Capital cost of the electrolyser

The impact of manufacturing scale and continued research and development are expected to support a rapid cost reduction curve for electrolysers, and in particular, the electrolyser stack. It is noted that more than half of the costs associated with the electrolyser unit are associated with mature technology, such as water coolers, separation vessels, transformers and instrumentation. These systems have many more elements and imbedded bulk costs than computer chips and solar PV systems, where micro-sizing provided significant cost leverage. As such, it should not be expected that continuous cost declines comparable to these industries can be achieved for the overall system.

In the longer term, it is expected that price reductions will occur in all categories identified, rather than occurring in a specific area. The least mature components, that is electrolyser stack, diaphragms / membranes and purification systems, will have the fastest learning curve in response to a growth in industrial demand.

The various electrolyser vendors provide different scopes of supply, from the core base components of stacks, control and purification, to the delivery of the full project including construction and installation. The capital costs reported for electrolysis units and power generation are on a Total Direct Cost (TDC) basis (often termed "delivered cost"), but calculations used to determine the levelised cost of hydrogen are based on Total Installed Cost (TIC). See Section 6.1.7 for the definition of TDC and TIC.

A summary of benchmark total direct costs from international research bodies is shown in Table 2-1.

Table 2-1 – Estimated 2020 total direct costs for electrolyser units

Source	Details	Reference (millions/MW)	Implied Australian cost[2] (millions/MW)
IEA	2019 price for generic alkaline electrolyser installed in US Gulf Coast	US$0.9	A$1.435
IRENA[1]	Alkaline electrolyser; balance of plant inclusions are not specified for 20 MW package	2017 - €0.75 2025 - €0.48	A$1.15
IRENA[1]	PEM electrolyser; balance of plant inclusions are not specified for 20 MW package	2017 - €1.2 2025 - €0.7	A$1.8
BNEF	2019 price for generic electrolyser produced by a European vendor	US$1.2	A$1.9
BNEF	2019 price for generic electrolyser produced by a Chinese vendor	US$0.2	A$0.32

[1] IRENA data is linearly interpolated between data from 2017 and 2025.
[2] 10% cost increase to account for Australian installation costs.

Advisian benchmarking for the cost of alkaline electrolysers in East Coast Australia is summarised in Figure 2-3, and is based on the following observations.

- Electrolysers at small scales, <50MW, were higher cost and not considered representative of the electrolyser market.
- Advisian does not have any evidence that Chinese electrolysers are an order of magnitude cheaper than European vendors.
- Although some Chinese electrolysers appear very cheap in the 0 to 50 MW range, the efficiency is not comparable to other electrolysers. The cost base for our modelling is aligned with the higher capital cost and higher efficiency electrolysers.
- Several key electrolyser vendors indicate a near-term cost reduction between 10% and 15% for electrolyser units, inclusive of balance of plant. These cost reductions are expected to result from design and footprint optimisation, hence, the equipment cost savings will likely translate to installed cost savings of a similar magnitude.
- The price of the electrolyser units is mildly dependent on scale. This is consistent with market expectations; although the cost of additional electrolyser cells is linear and therefore independent of scale, the balance of plant - compression, purification and cooling, is responsive to economies of scale.

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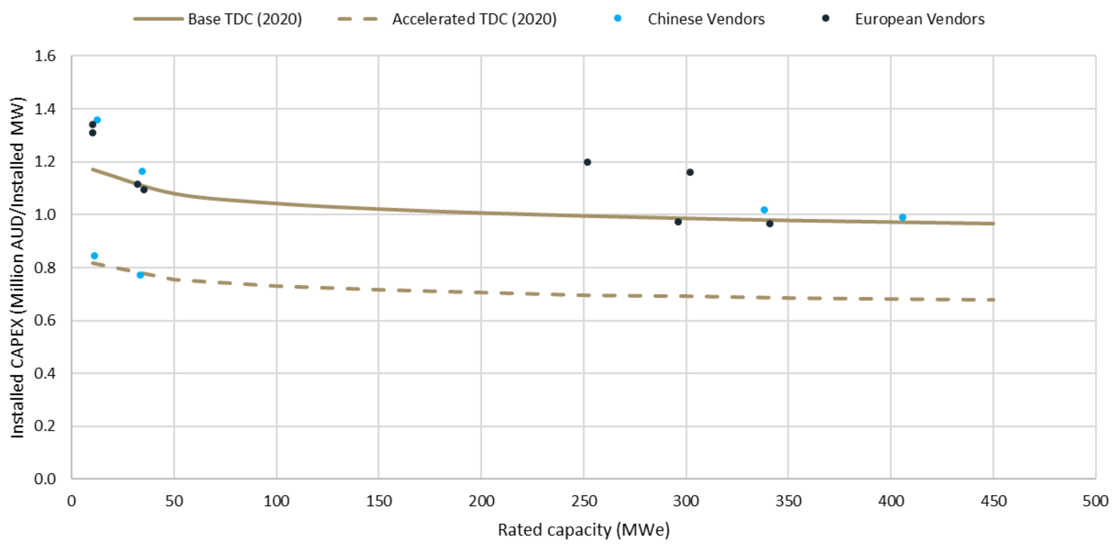
- Based on our knowledge of pricing at different scales, a scale factor of 0.95 has been applied. This means that doubling the capacity of the electrolyser reduces the cost per MW by 5%.
- Many manufacturers have assessed complementary low-cost manufacturing, and this is part of the near-term cost reduction potential.
- Our "base" interpretation of electrolysis plant cost response to scale is represented by a best fit through current data with a step-change 10% cost reduction in the near-term - the solid gold line in Figure 2-3.
- Our "accelerated" interpretation of electrolysis plant cost response to scale is represented by a lower specification electrolyser resulting in a 30% near-term reduction on Capex, operating with a comparable energy efficiency as the base case. This is represented by the dashed gold line.

Figure 2-3 - Advisian alkaline electrolyser cost (2020) benchmarking



The proposed total direct electrolyser price ranges between A$0.8 and A$1.2 million per MW, which are comparable to the estimates of the IRENA and International Energy Agency.

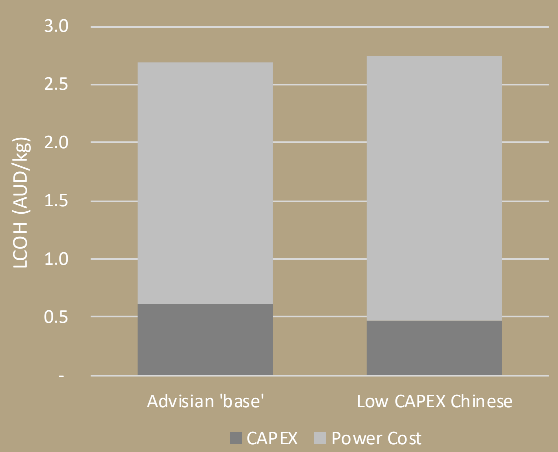
Optimising for lowest lifecycle cost

The concept that lowest capital costs does not translate to lowest lifecycle cost is especially true for electrolysis plants.

Figure 2-3 identifies two data points with ~30% lower capital cost than our baseline.

The efficiency of these units is at least 5 kWh/kg worse than the best available technology. On a levelised cost basis this increases the electricity price per kilogram of hydrogen by approximately 10%.

Using an optimistic electricity price for renewables of $40/MWh with an 80% load factor, the lower efficiency translates to higher levelized cost of production of $2.74/kg, compared to $2.68 using the higher capital cost



Note the figure above only incudes electrolyser capital and power prices; it excludes membrane replacement, other O&M, storage and transport.

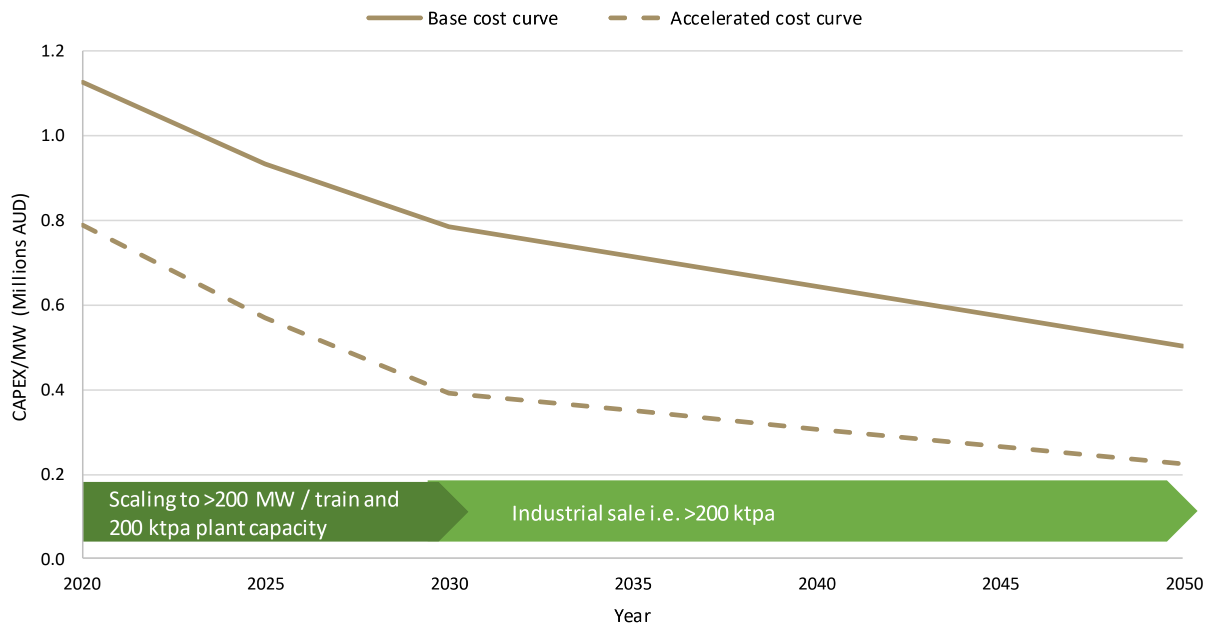
Scale of development

The price of the electrolyser is mildly dependent on scale. This is consistent with market expectations; although the cost of additional electrolyser stacks are linear and therefore independent of scale, the balance of plant - compression, purification and cooling, is responsive to economies of scale.

Alkaline electrolyser units are typically modular at 10 MW or 20 MW scale, hence underlying costs are almost linear with scale. There are scale advantages for the balance of plant, transport infrastructure and installation efficiency up to ≈300 MW capacity, hence our forecasts of the capital cost for electrolyser units over time are based on this industrial scale – see Figure 2-4.

To blend the cost behaviour with scale and electrolyser cost learning curves, Advisian interpreted the likely scale-up in Australian project size over time: demonstration scale projects between 2025 and 2027 to beyond 36.5 ktpa (100 tpd), approximately 290 MW at a 75% load factor, and then larger than 200 ktpa (~1.8 GW) around 2030. The combined outcome of project scale and technical development on the project capital cost is defined below in Figure 2-4.

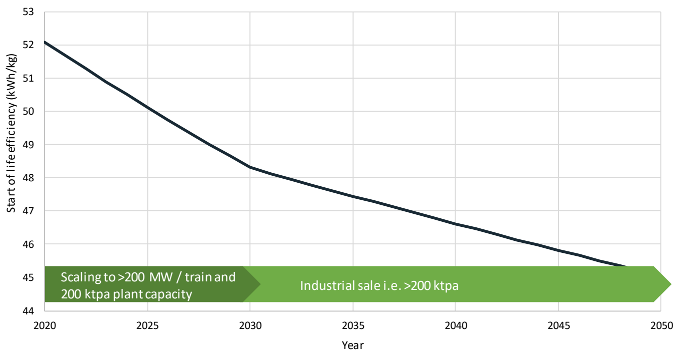
Figure 2-4 - Forecast electrolyser cost per MW as technology develops and project scale increases



Efficiency of electrolysis units

The effort to reduce capital costs may impact adversely on electrolyser unit efficiency, but this would be counter-productive. Most international literature forecasts a slow improvement in efficiency; hence this basis has been adopted. We have assumed that electrolyser efficiency will follow the base case, IEA forecast. The resulting learning curves are summarised in Figure 2-5.

Figure 2-5 - Electrolyser efficiency forecast



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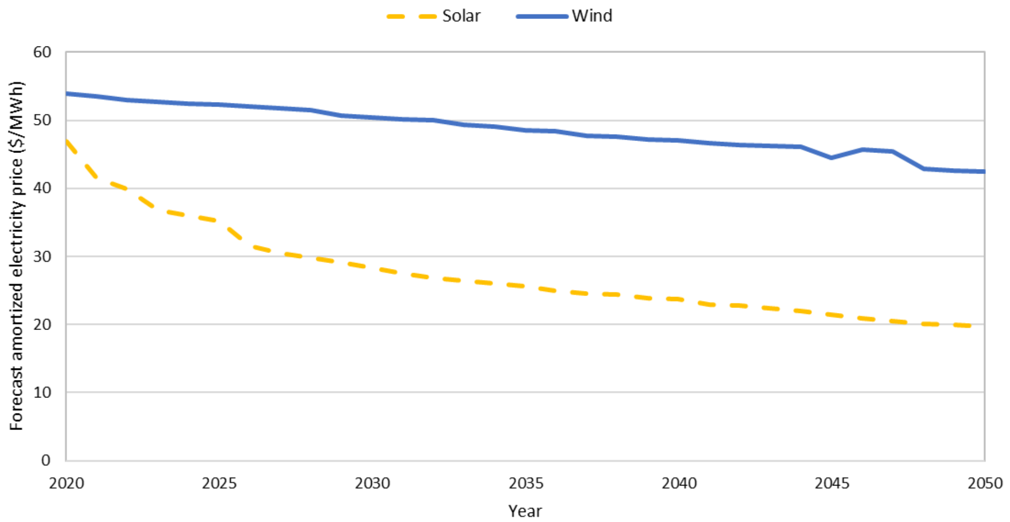
Price and load factor of electricity supply

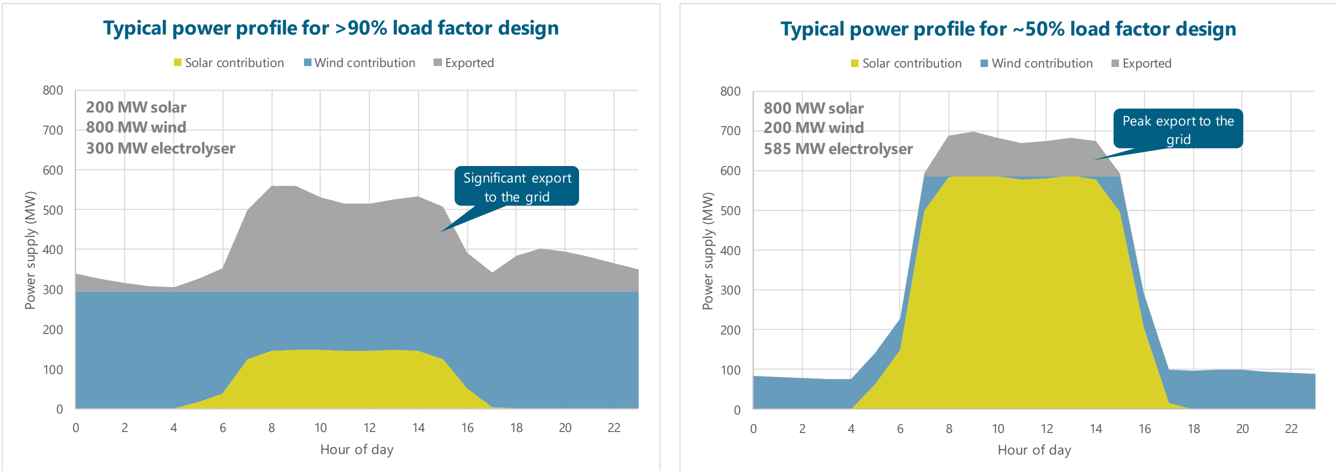
Renewable energy projects can often secure access to low cost capital, enabling low cost power generation. The levelised cost of electricity (LCOE) for solar and wind projects were assessed based on projects based in the Fitzroy REZ (Queensland) based on the AEMO ISP V1.4.. The weighted average cost of capital of 5% was used for assessing these projects, as agreed with CEFC, based on 10% equity return, 70% gearing and 4% cost of debt. The LCOE forecasts are shown in Figure 2-6. In practice, PPA pricing is often CPI indexed, up to 2.5% is typical, hence lower short-term pricing than is characterised below is often quoted.

Figure 2-6 - Forecast LCOE renewable energy prices (real without CPI, 2020) - Fitzroy, Queensland



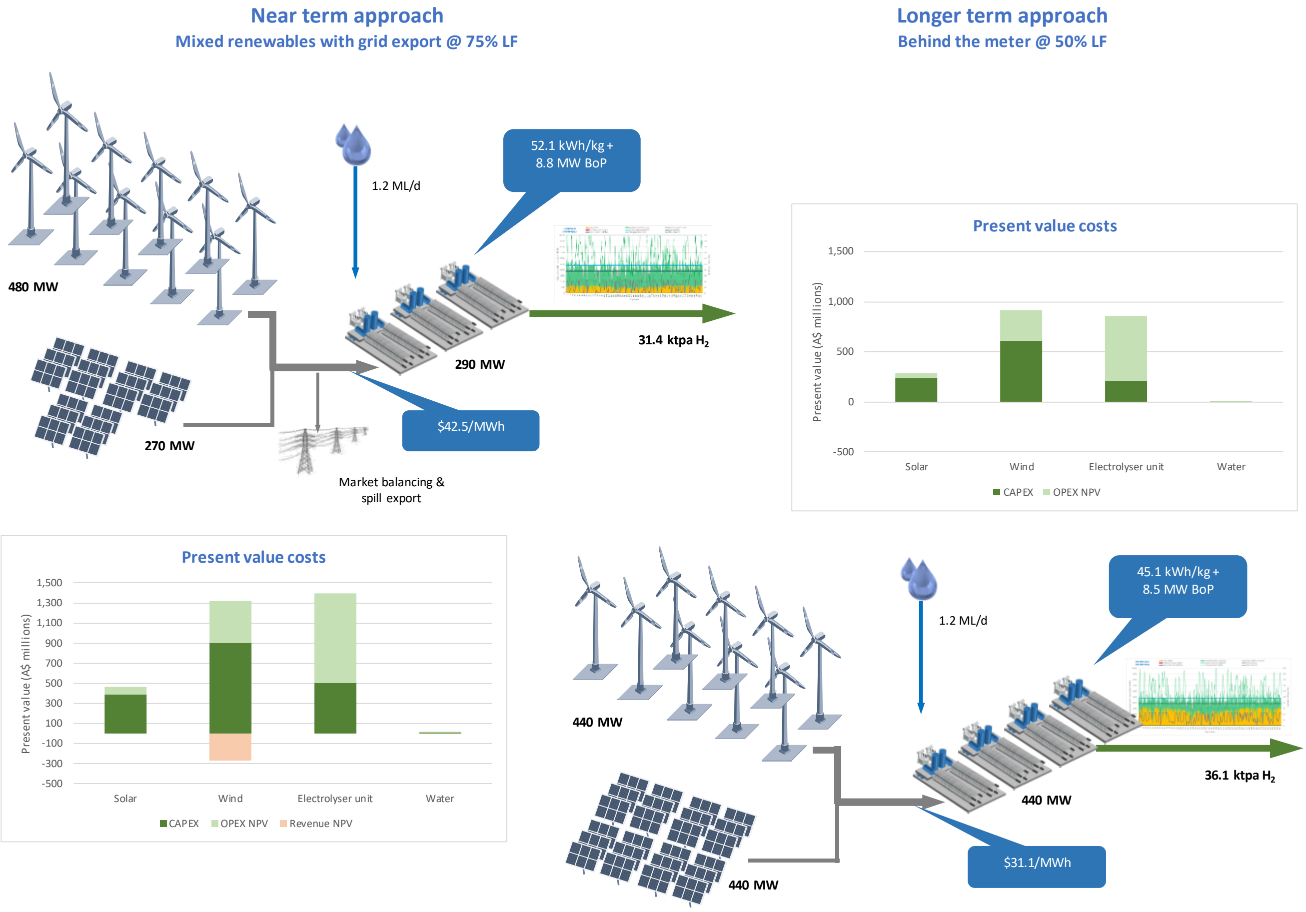
If solar power is the only source of power to an electrolyser, then hydrogen generation is limited to sunshine hours, and asset utilisation is poor, representing a low load factor. While the capital cost of electrolysers remains significant, solar only based hydrogen production is expensive due to the low asset utilisation. Access to renewable power sources with more consistent power flow, even at a higher price, provide significantly better economic outcomes. In the near-term, developments are targeting very high load factors of around 75%, utilising an overbuild of mostly wind generation capacity, with surplus generation being sold on the spot electricity market. Our analysis assumes that the renewable energy farms can export excess production to the grid and will provide coarse network balancing services, refer Figure 2-7. This means generation will be diverted to the grid when the electricity spot market price is greater than $150/MWh.

Figure 2-7 – Characterisation of the changing nature of hydrogen production facilities



It is evident that the relative cost decline curves for renewable power and electrolysis plants will impact the optimised load factor that is adopted over time. In the near term, electrolyser costs are comparatively higher than the cost penalties associated with higher capacity factor renewable power generation, hence higher load factor (e.g. >80%) developments are anticipated. If the cost of electrolysis plants decline rapidly it is possible to envisage green hydrogen production facilities based on lower load factor renewable power supply options. A summary of the potential changes that may result over time is captured below.

Figure 2-8 – Characterisation of the changing nature of hydrogen production facilities



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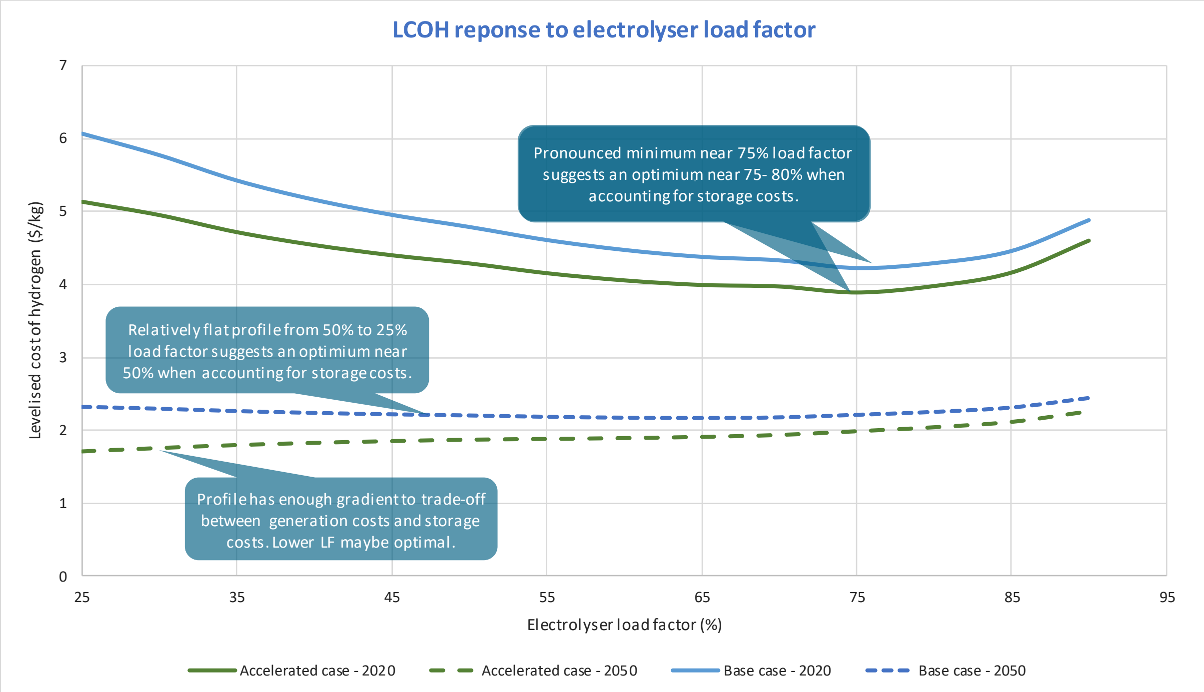
Based on a simplified hydrogen production cost model, the basic relationship between electrolyser load factor and levelised cost was characterised as shown in Figure 2-9. The model indicated that a 75% load factor in the near-term and a 50%, or lower, load factor in the longer term are likely optima for industrial scale green hydrogen facilities. This change is driven by falling solar power cost and electrolyser capital costs.

Figure 2-9 – Relationship between electrolyser load factor and LCOH (farm gate)



Forecast farm gate production cost

The results of our hydrogen production cost analysis are summarised in Figure 2-10 and Table 2-2 below. We note that the cost trends assume huge growth in the global and domestic demand for green hydrogen to drive industrial scale plants and equipment manufacturing volume, along with sustained declines in the price of renewable energy generation and electrolysers.

Our modelling suggests that with 2020 nominal case values, hydrogen can be produced for around $3.90 per kg at industrial scale, falling to just less than $2 per kg in the long term, driven by falling electrolyser costs and renewable energy costs. It is noted that the 2020 case includes credit for export of electricity to the market during high price periods and the long-term case assumes no export of electricity.

The farm gate and delivered costs defined in this report for the near term (i.e. 2020) will likely be considerably lower cost than currently proposed projects which are generally smaller than the 20 MW baseline and require more first of a kind engineering for production facilities and supporting infrastructure. Further our cost forecasts represent "industry best practice" with idealised access to capital and high quality, low cost renewable resources.

Figure 2-10 – Forecast farm gate cost of hydrogen (Real 2020, AUD/kg)

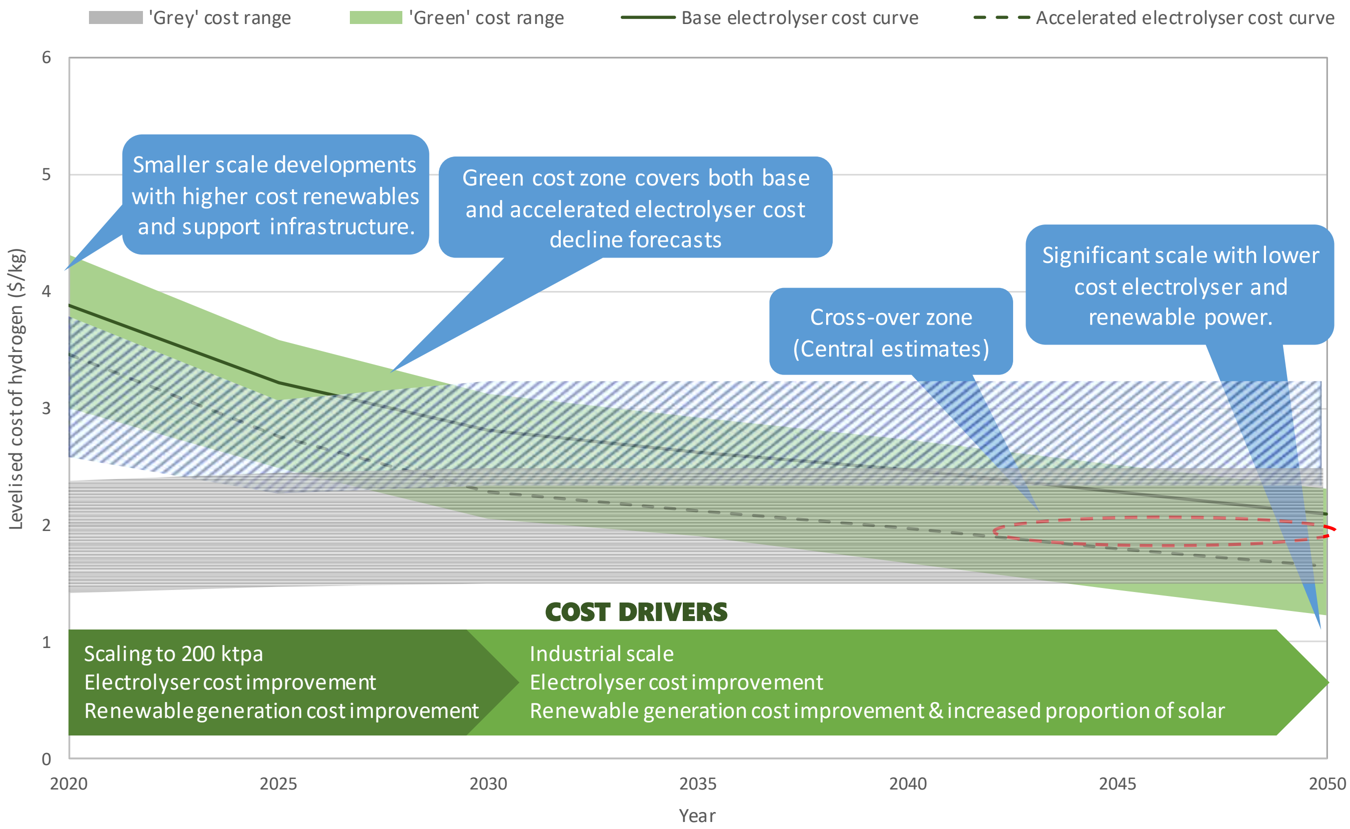


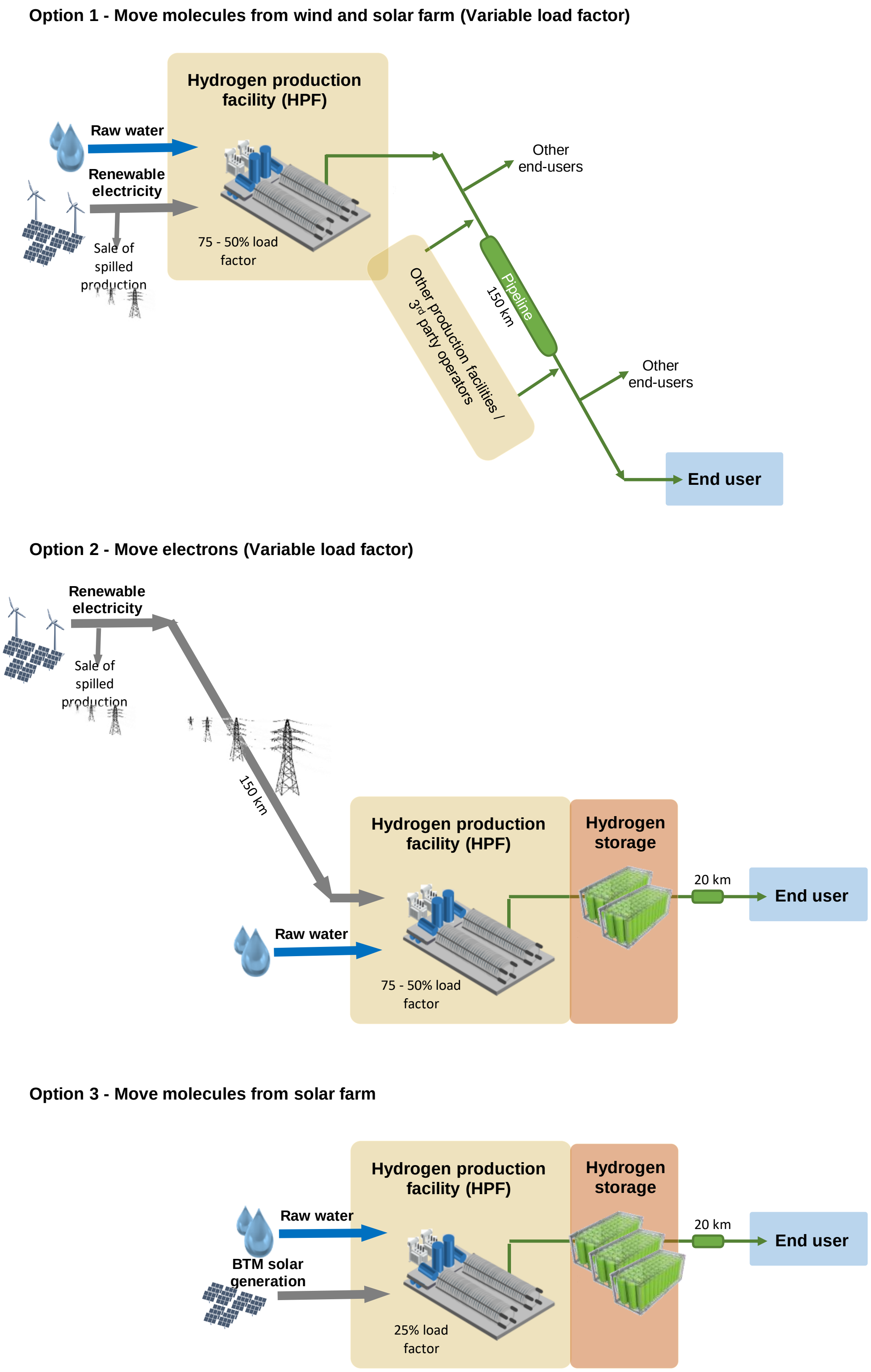
Table 2-2 – Key farm gate hydrogen production cost metrics

Metric	2020	2025	2030	2040	2050
Grey hydrogen farm gate cost ($/kg)	2.20	2.26	2.29	2.29	2.29
Blue hydrogen farm gate cost ($/kg)	3.02	2.76	2.80	2.80	2.80
Base electrolyser unit TDC (A$/kW)	1,125	932	783	644	504
Accelerated electrolyser unit TDC (A$/kW)	787	571	392	308	224
Renewable electricity cost* ($/MWh)	42.2	38.3	35.1	31.3	27.1
Load factor (%)	75	71	66	58	50
Base Green H_2 farm gate cost ($/kg)	3.88	3.22	2.81	2.47	2.09
Accelerated Green H_2 farm gate cost ($/kg)	3.46	2.76	2.29	1.98	1.64

* - Net renewable energy cost after accounting for export of spilled production and power diversion when spot market prices are > $150/MWh.

2.3.2 Delivered hydrogen supply cost

Figure 2-11 – Schematic of delivery pathways



In Australia, the distance between optimal renewable resources and end-use locations is often considerable. Typically, inland areas adjacent to mountain ranges provide more reliable wind and solar resources, whereas hydrogen demand by industry or export is typically at the coast. Electrolysers also require water, which is often progressively more constrained moving inland, with increased competition from settlements, agriculture and industry.

Our delivered hydrogen analysis considers the cost of transport or storage over a typical distance of 150 km from the point of generation, or farm gate, to a coastal end user. In the "move molecules" case, the electrolyser is co-located with the renewable energy facility. In the "move electrons" case, the electrolyser is co-located with the end user. A third option "behind the meter" considers co-location of a solar farm, electrolyser and the end user.

Our analysis of three "delivered" hydrogen supply pathways indicates that pipeline-based transport and storage, that is the "move molecules" option, has numerous non-economic advantages, but is not always economically advantageous. In the near term, the scale of hydrogen production is unlikely to be able justify the cost of a pipeline and trucking of hydrogen is very expensive, hence the move electrons approach is preferred for the "sub-industrial scale" (around 20 MW capacity) supply of hydrogen to industrial and transportation end-users. If a natural gas pipeline is adjacent to a renewable energy farm, then a behind the meter solution could be attractive.

The "move the electrons" option can be competitive if existing power infrastructure can be utilised, and "behind the meter" becomes competitive longer term.

Currently, most hydrogen cost forecasts are heavily caveated to represent the theoretical costs of production based on the electricity cost and the engineering, procurement and construction costs to determine the Total Delivered Cost[2] of the electrolyser plant.

The cost forecasts often exclude the costs for: storage, transport to the end user, additional compression, electricity transmission and indirect capital costs and profit margin. Through the pragmatic characterisation of different development options, we have developed some guidance regarding the impact of including this additional infrastructure within the scope of delivered hydrogen supply costs.

Figure 2-11 provides a summary schematic of the following the hydrogen supply options investigated:

1. Option 1: Move molecules from mixed renewables farm
2. Option 2: Move electrons from mixed renewables farm
3. Option 3: Move molecules from solar farm

[2] All costs that can be directly attributed to the design, procurement and installation of an asset, refer Section 6.1.7.

Delivered hydrogen supply option assessment

Our assessment recognises that the most cost effective solar and wind farms are located inland from the coast, hence we considered the movement of molecules, the movement of electrons and a solar only generation scenario as key mechanisms for delivering hydrogen from farm gate to a coastal end user.

The hydrogen yield from all assessed options is approximately 40 ktpa of hydrogen but varies between years with changes in load factor and electrolyser efficiency. Results have been levelised over the life of the plant to accommodate these differences.

The below Table 2-3 identifies key advantages and disadvantages identified for each of the three options.

Table 2-3 - Cases considered for hydrogen production

Option	Description	Advantages	Disadvantages
1	**Move molecules from mixed renewables farm (variable load factor)** The electrolysers are located at and powered by a mixed (wind & solar) renewables farm. Excess generation is exported for sale on spot market, and market stabilisation is provided when spot price > $150/MWh. Hydrogen is transported to users by 150 km pipeline.	High load factors are sustainable with a combined wind and solar supply. The pipeline can supply hydrogen storage. TUOS and grid connection fees are only required for export connection. Multiple industry participants are possible hence higher social license to operate.	Water supply may be difficult to guarantee if the renewable farm is inland. The pipeline Capex may be very high.
2	**Move electrons from mixed renewables farm (variable load factor)** As per option 1, but the hydrogen production facility is located at or near (<20 km) to the offtaker's site.	High load factors are sustainable with a combined wind and solar supply. Grid costs are often amortised by system operators. Transport costs of hydrogen are negligible.	Selection of renewable energy farm/s options and associated connection costs are heavily impacted by proximity to current grid. TUOS fees may be significant if significant grid augmentation is required. Additional Capex may be required for hydrogen storage, depending on end-use demand profile.
3	**Move molecules from solar farm** Electrolysers are located at or near the offtaker's site, and powered by DC electricity from a behind the meter large scale solar installation	Electrolysers could have increased efficiency if there is direct connection to solar and no requirement for DC/AC conversion. Solar energy is very low cost. No electricity or hydrogen transport costs.	DC to DC connection of solar and electrolysers is unproven at commercial scale. Solar power can only supply very low load factors; significant over investment in electrolyser capacity is required. As offtakers are likely to be coastal, solar generation capacity factors are reduced due to increased cloud cover. Further Capex may be required for hydrogen storage if semi-continuous demand is required.

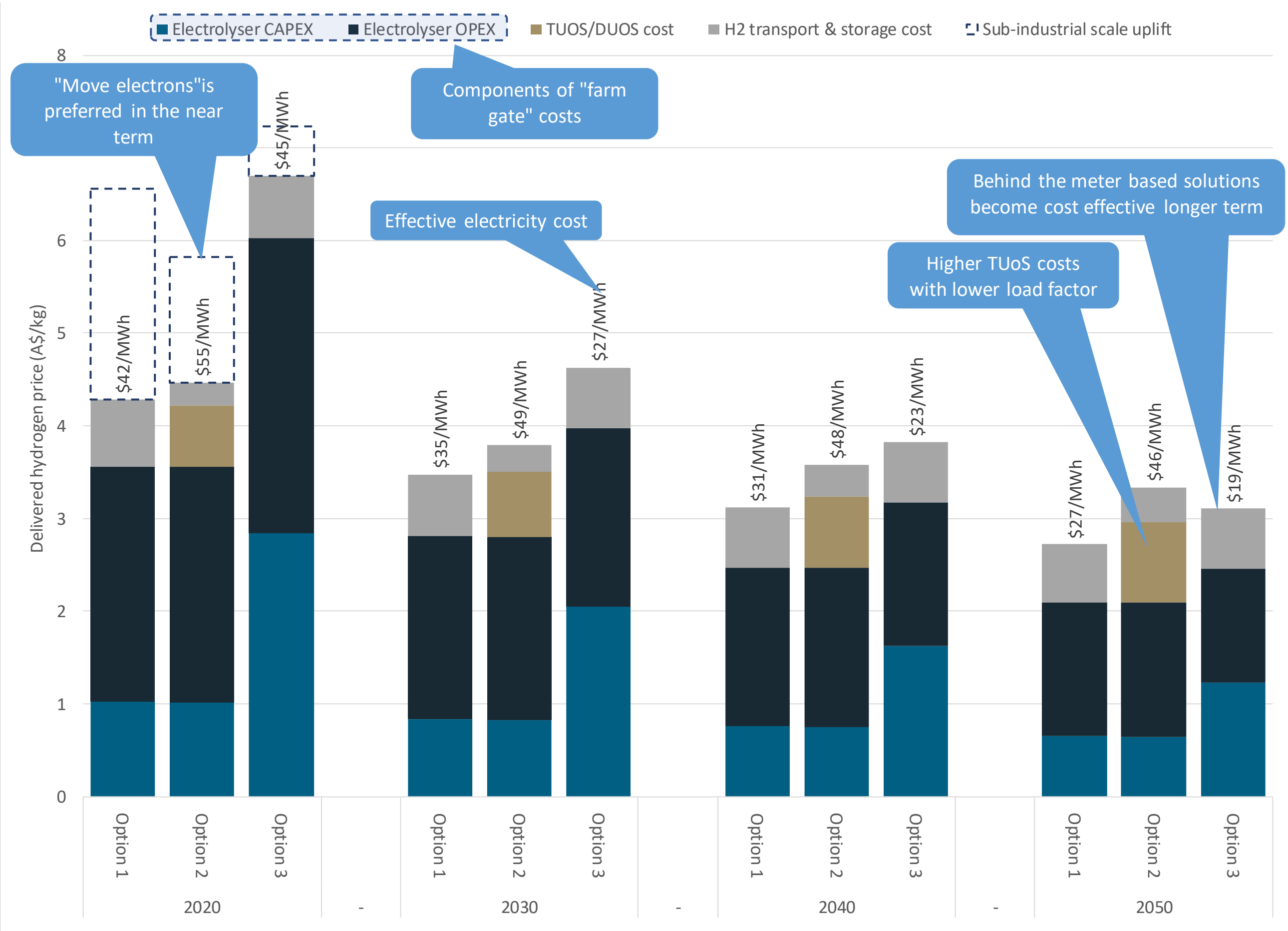
Delivered cost of hydrogen option assessment findings

The results of our modelling are captured in Figure 2-12. For industrial scale facilities, there is little commercial difference between moving the molecules (Option 1) and moving the electrons (Option 2) approaches. The decision regarding which option to adopt would depend on project specific elements such as:

- Required level of electricity or pipeline network augmentation;
- End user offtake flexibility;
- Overall availability and proximity of water resources; and
- Delivery schedules.

In the near-term, when traded hydrogen volumes are not sufficient to justify the installation of hydrogen pipelines, and a "move the electrons" approach with a 20 km pipeline to the final end user is the most commercially attractive. The delivered costs include farm gate costs plus power transmission fees (i.e. TUoS/DUoS) and hydrogen pipeline and storage costs. For the near term cases, a "sub-industrial scale uplift" adder is also included to account for the cost differential between truck based transport and pipeline based transport shown as on Figure 2-12.

Figure 2-12 – Levelised cost of hydrogen for different delivery cases



Option 1 - **Move molecules (75 → 50% load factor)** with grid export capacity. Hydrogen storage via. linepack in 100 km pipeline.
Option 2 - **Move electrons (75 → 50% load factor)** with grid export capacity. Fixed hydrogen storage.
Option 3 - **Solar only** with fixed hydrogen storage.
All options source raw water local to the hydrogen production facility.

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Non-economic advantages of the move molecules approach include:

a. Reducing entry barriers for other remote hydrogen producers / offtakers through establishment of common user pipelines – this is likely to increase the social licence to operate;
b. Hydrogen production facilities can play an electricity market support role;
c. Creates potential for a broader supply and demand market with multiple suppliers and offtakers from a given pipeline system;
d. Progressive hydrogen market expansion is possible through management of intermittent supply and demand through pipeline linepack; and
e. Pipeline Opex is lower than powerline Opex providing lower costs with extended asset life.

The analysis established that, towards 2050, behind the meter production (Option 3) becomes cost competitive. However, higher load factor options such as Option 1, can deliver near continuous production rates required for many downstream facilities, which includes liquefaction and ammonia synthesis.

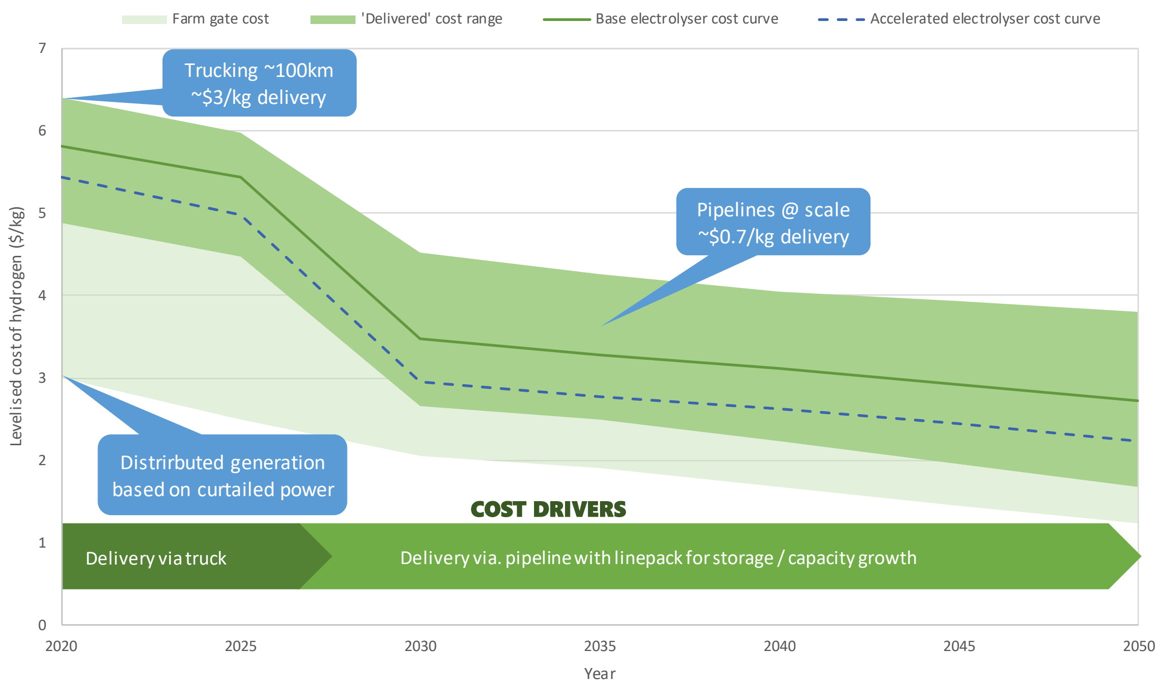
Based on 2020 Base case electrolyser costs, the results suggest that in the near "move electrons" is the preferred approach with a "best industrial" practice costs of \$5.82/kg. Mid-term and towards 2050, the "move molecules" approach is adopted with a "best industrial" practice costs of \$3.48 and \$2.72/kg. The "accelerated" electrolyser cost analysis suggests "best industrial" practice costs of \$5.43/kg (2020). \$2.96/kg (2030) and \$2.23/kg (2050).

The "nominal" costs for "large volume" delivered hydrogen adopts base electrolyser costs in the near term and transitions towards the accelerated electrolyser cost curve, with 75% base / 25% accelerated by 2050. These delver hydrogen costs are summarised in Table 2-4 and Figure 2-13 below.

Table 2-4 – Forecast delivered hydrogen cost summary

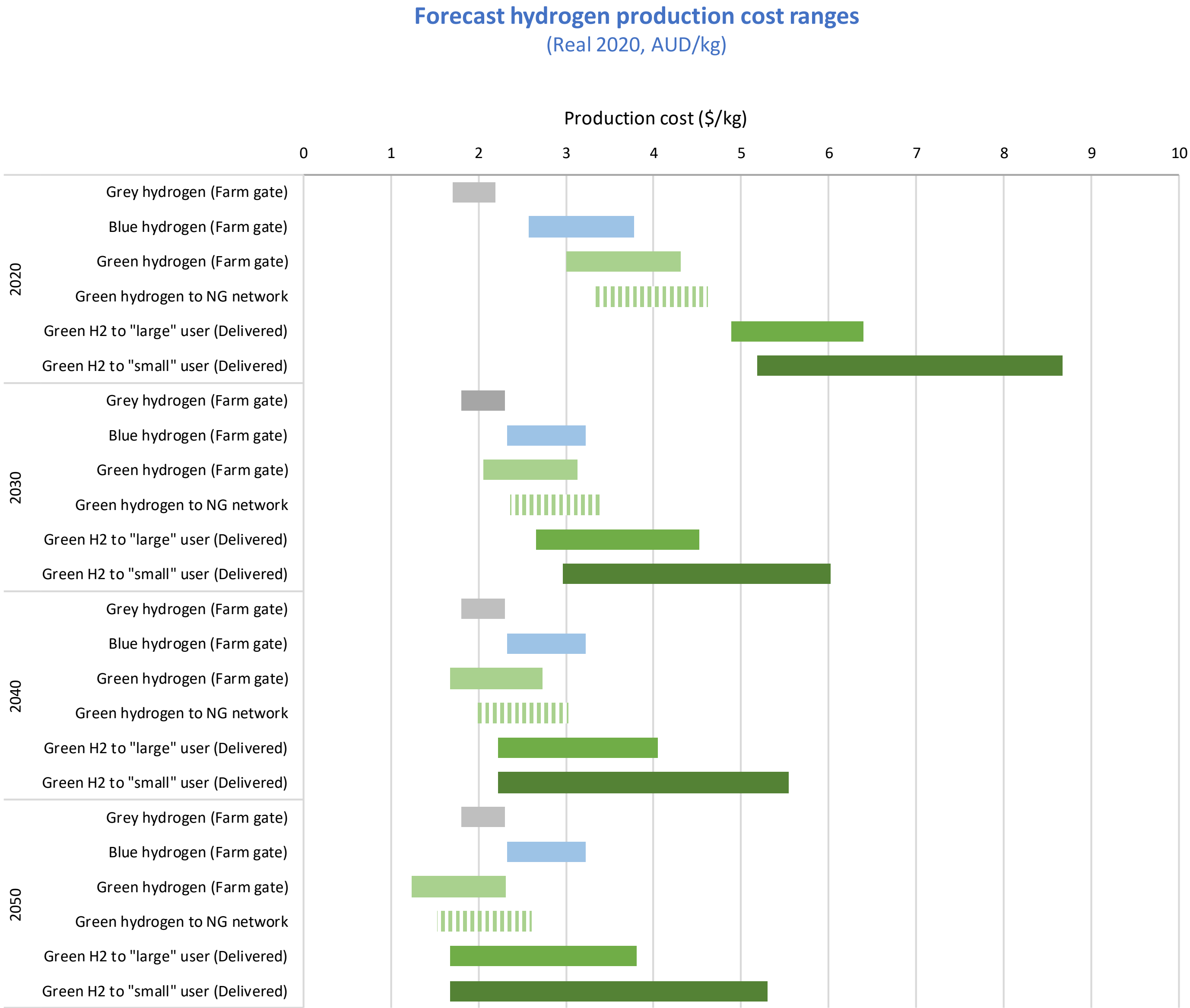
Metric	2020	2030	2050
"Base" Green H_2 delivered cost (\$/kg)	5.82	3.48	2.72
"Accelerated" Green H_2 delivered cost (\$/kg)	5.43	2.96	2.23
"Nominal" Green H_2 delivered cost (\$/kg)	5.82	3.42	2.60

Figure 2-13 – Forecast delivered cost of hydrogen



The forecast range of hydrogen production costs are provided in Figure 2-14.

Figure 2-14 – Forecast cost of hydrogen



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End-use economic gap assessment

3 End-use economic gap assessment

This section explores five classes of end-uses and 25 end-use cases. A high level summary of the end-use classes is provided below. These end-uses are discussed in greater detail below.

Table 3-1 – End-use classes addressed in this report

Class	Possible role of hydrogen	cases
Transport	Hydrogen can be used in fuel cells to efficiently generate electricity for an electric vehicle or converted into a denser form, such as ammonia, methanol and synthetic fuel, for use in combustions engines.	• Material handling • Light vehicles • Heavy vehicles – Line haul • Heavy vehicles – Return to source • Heavy vehicle – Mining • Rail • Ferries • Marine shipping – Methanol • Marine shipping – Ammonia • Aviation
Fuel for industry	Displacing natural gas as fuel source for industry.	• Synthetic natural gas • Gas network (i.e. Blending) • Gas network with hydrogen recovery • Hydrogen gas network • Combined heat and power
Power and grid balancing	Generation and storage of hydrogen when renewable power exceeds demand and then converting back to power when there is a power shortfall.	• Grid balancing • Remote power
Feedstock for industry	Taking advantage of the specific thermo-chemical properties of hydrogen rather than just heating value.	• Alumina calcining • Steel mills • Other high grade heat • Ammonia • Methanol • Oil refining
Export	Providing a carrier for exporting Australia's renewable energy.	• Liquid hydrogen • Ammonia

The capacity to pay metrics were not determined for the two export cases and three gas network based options, namely: SNG manufacture, blended gas network & H_2 recovery, 100% H_2 gas network, since these are not ultimate end-users.

3.1 Economic gap assessment key findings

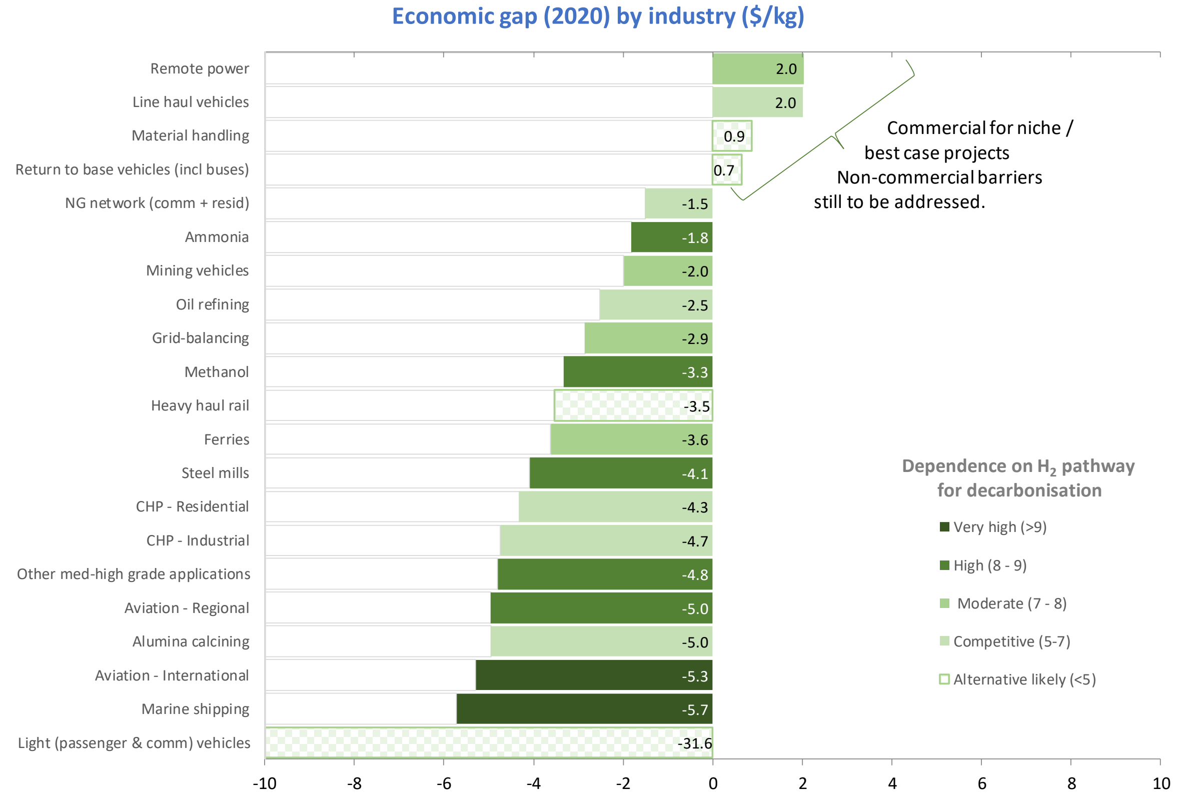
The economic gap assessment of hydrogen end-use cases assessed the price of hydrogen that would be competitive with the incumbent technology and likely supply price for "best industry practice" applications. This was undertaken for twenty industry sectors; for each sector the "economic gap" is determined by comparing lifecycle costs of incumbent technology relative to the equivalent hydrogen based service.

A positive economic gap indicates that the sector is commercially favourable for the use of hydrogen as an energy carrier, whilst a negative economic gap suggests a need for increased end user efficiency, reduced transport and dispensing costs or lower hydrogen supply costs. Refer to Section 6.1.2 for more detail.

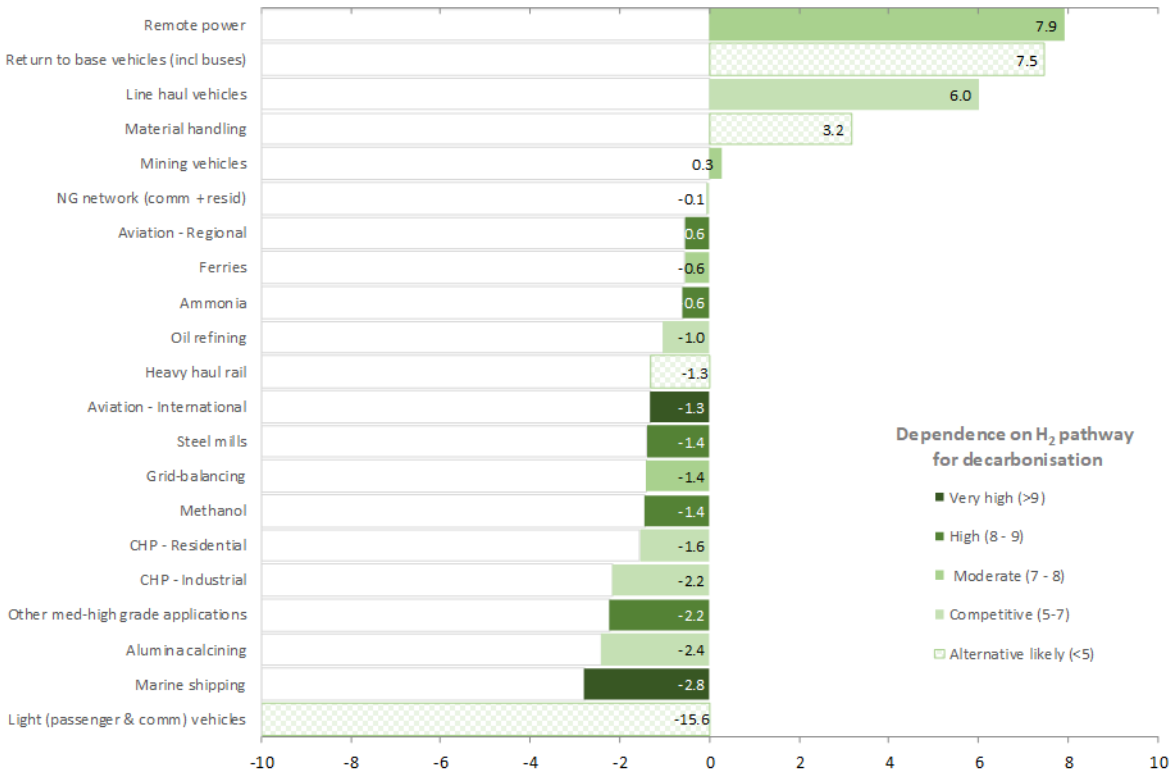
The transition in economic competitiveness of the reviewed end-use sectors across the: near, mid and long term is summarised in Figure 3-1 below.

This study indicates that of the 20 industry end-use applications reviewed, five appear to be commercially viable or approaching commercially viability by 2030. In all sectors, low carbon hydrogen is expected to become more competitive towards 2050, due to parallel advances in production and distribution cost efficiency and end-use technology evolution. More detailed analysis of each sector is contained in the following subsections.

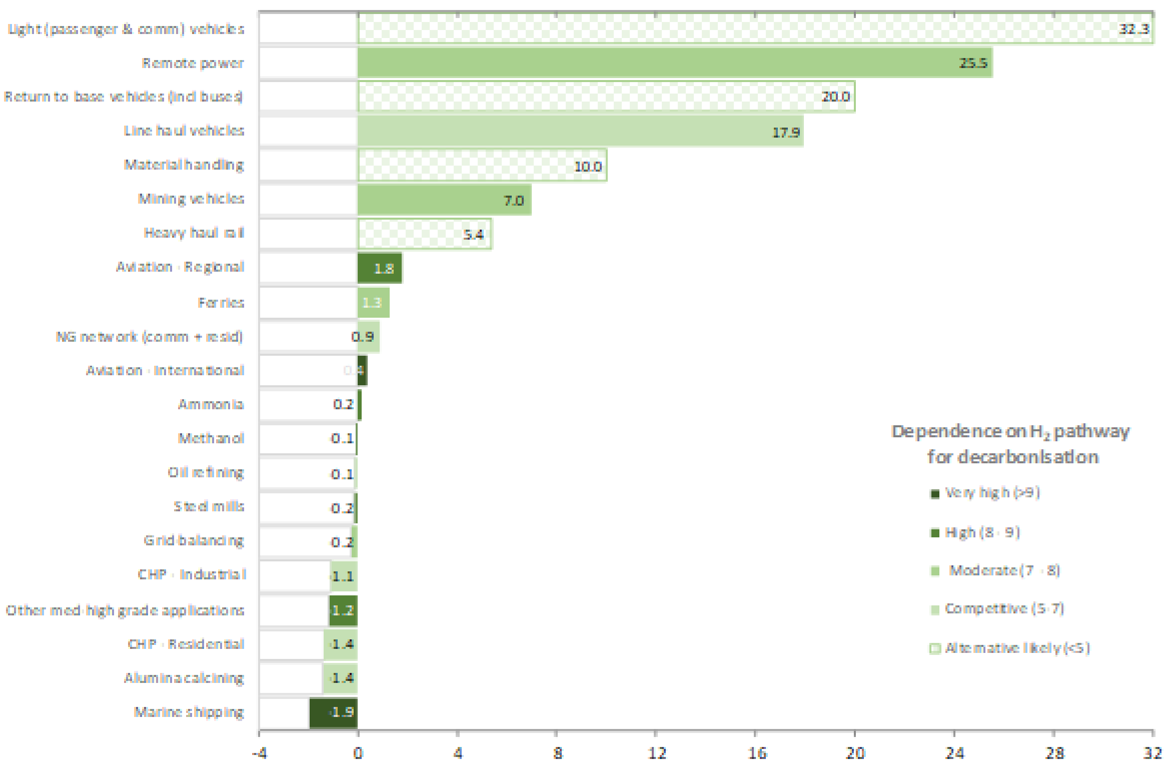
Figure 3-1 – Transition in sector economic competitiveness over time



Economic gap (2030) by industry ($/kg)



Economic gap (2050) by industry ($/kg)



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Sectors approaching competitiveness in the near term

Figure 3-1 shows those sectors which are approaching commercial attractiveness in the near term include: line haul vehicles, remote power, material handling and return to base vehicles (including buses) sectors.

The sectors which have a very high dependence on the green hydrogen pathway for decarbonisation but currently unfavourable economics are: ammonia, methanol, aviation regional, aviation international, marine shipping, steel and other med-high grade heat applications where electrification is difficult. The sectors which have a moderate dependence on the green hydrogen pathway that are also currently unfavourable economics are: mining vehicles, grid balancing and ferries. Except for aviation, which receives significant international attention, all the other sectors have unique "Australian" considerations that could be explored in order to reduce the economic gap in these sectors.

The comparatively high cost of liquid fuels supporting the transportation sectors, yields a high relative competitiveness. The distribution and dispensing costs for these sectors significantly erodes the gap between end user affordability and farm gate cost of hydrogen. However, hydrogen use in the line haul and return to source (including buses) trucking sectors are advantaged by much lower O&M costs, no fuel excise exposure, fleet-based hydrogen dispensing and high mileage that favours fuel efficiency. These differences explain why these sectors appear to be commercially favourable for hydrogen now, whilst light passenger vehicle sector is the least commercially viable.

Sectors showing promise in the medium term

Towards 2030, the range of sectors where hydrogen is becoming commercially viable for adoption has increased to include: mining vehicles.

The hydrogen production, storage and power generation cycle approaches parity with battery / diesel hybrid systems in remote power service.

The mining sector could also benefit from coupling hydrogen based remote power with hydrogen powered trucking.

Sectors which could become commercial long term

Towards 2050, the range of sectors where hydrogen may be commercially viable extends to include: light vehicles, heavy haul rail, aviation (regional), ferries, natural gas network (commercial and residential), aviation (international) and ammonia production. Of the sectors that have very high or high dependence on the hydrogen pathway for decarbonisation, methanol production, steel, other med-high grade applications and marine shipping remain economically not competitive while ammonia production and aviation (regional and international) become economically competitive.

When green hydrogen achieves cost parity with natural gas a huge range of industrial sectors, will be able to cost effectively switch to green hydrogen. The concept of thermal cost parity is further described in Section 6.1.3. This thermal energy price parity is achieved when the delivered cost of hydrogen is \$1.10/kg, assuming a \$9/GJ natural gas price. Steel manufacturing using hydrogen is expected to achieve commercial attractiveness at a price point above this, around A\$2 per kg.

Sector dependence on hydrogen for decarbonisation

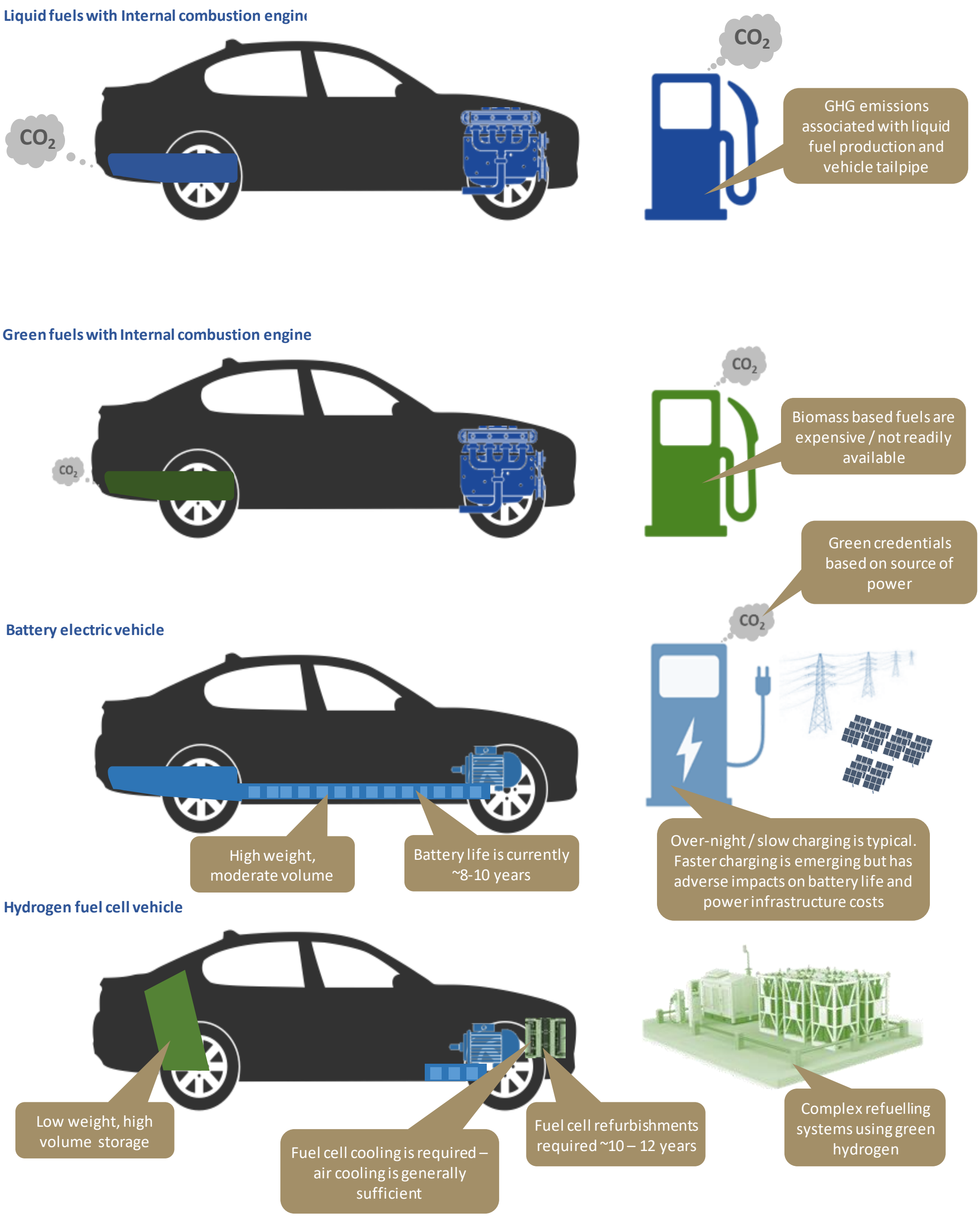
We rated how important hydrogen is likely to be for the decarbonisation of each sector using a scale from 1 to 10. A rating of 1 translates to no real dependence and other, more competitive alternatives being widely available. A rating of 10 means that hydrogen is essential for decarbonisation of the sector. Our estimates are qualitative, and base on interpretation only.

From our assessment, the sectors with the highest dependence on hydrogen for decarbonisation are aviation (international) and marine transport where alternatives such as carbon capture and battery electric systems are likely to be difficult. Steel, ammonia, methanol, aviation (regional) and high grade heat are also considered high dependence. The sectors with the lowest dependence are land transport and rail applications, where battery electric and overhead electrification are likely to be effective alternatives.

3.2 Transport

Following the discovery of oil in the 1860s, crude oil based liquid fuels have dominated the transportation industry. These fuels have high energy density, are cheap and abundant and can be handled safely and easily. The energy in these fuels is harnessed into movement with internal combustion engine (ICE) technology. In the last decade, powering of vehicles using electric motors and batteries has become popular based on the growing evidence that operation of these vehicles can have lower lifecycle cost and lower GHG emissions. Hydrogen has been noted as a key low carbon mobility option in the coming decades, but it would be inefficient to use hydrogen in an internal combustion engine. In hydrogen fuelled vehicles hydrogen is combined with air in a fuel cell to yield electricity, which then powers an electric vehicle platform. Both technologies use electric motors for motive force. The key differences between these vehicle technologies is summarised below.

Figure 3-2 - High level differentiation between vehicle technologies



Electrified vehicles are already competing with their ICE counterparts in some markets. The key reasons for this are:

- Higher torque and acceleration;
- Lower fuel costs;
- Reduced emissions and heat within enclosed environments, and
- Easier automation.

The key negatives associated with battery electric systems relative to ICE systems are:

- Longer recharge times;
- Uncertainty regarding the life of batteries, and
- Higher initial cost for long range capacity.

3.2.1 Light vehicles

Battery Electric Vehicles (BEVs) currently have advantage over Fuel Cell Electric Vehicles (FCEVs), but hydrogen will become progressively more competitive in the long-range portion of this market segment when a higher penetration of BEVs could impact on electricity network augmentation and create overnight charging congestion. Without a carbon price or low carbon vehicle mandate, hybrid vehicles will likely have the lowest cost of ownership in the short term.

In order to provide insight into the likely appetite for hydrogen fuelled vehicles between now and 2050, a high level comparison of light passenger ownership was undertaken using the IEA Hydrogen Futures framework, with tweaks to match Australian conditions. The analysis is based on the following assumptions.

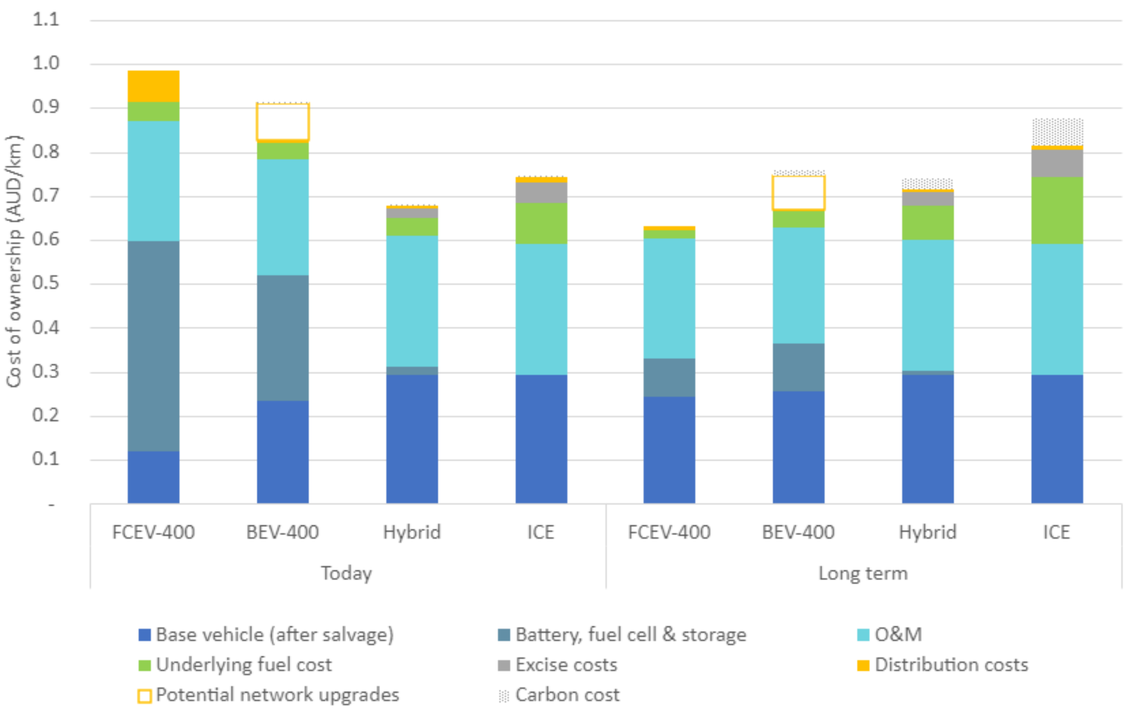
- The Australian vehicle fleet efficiency and cost market for vehicles imported to both countries is comparable to that of the US market which is characterised by the IEA analysis;
- Vehicle ownership costs will be assessed over an 8 year life – In line with extended warranties and only 20% decline in BEV battery life;
- Driving behaviours will remain comparable to current i.e. expected driving range of 400 km and 13,400 km travelled per vehicle per year;
- Hydrogen supply prices are based on industrial scale production taking advantage of low electricity prices and flexibility of demand. Delivered cost of hydrogen calculated is $15.04 per kg short term and $3.72 per kg long term;
- Petrol prices are based on $1.40 (short term) / $2.32 (long term) per litre retail price and hydrogen prices are based on forecasts from this report;
- BEVs will predominantly be charged with home charging systems using grid power. Network upgrades for public chargers have been estimated at $1,000 per kW based on information from Powercor - $330/kW for transformer upgrades and allowance of $770/kW for lines upgrades of 250m, between $600 and $1,400 for above ground and below ground respectively (PowerCor, 2015). Electricity prices are retail rates of $250/MWh;
- Excise revenue (on fossil fuels) will only be applied to ICE based vehicles, and will be progressively ramped upward from $0.42/L to $0.63/L to drive uptake of low carbon technology;
- Hydrogen refuelling stations will only be installed when there is sufficient collective demand. It is expected that a single station will serve at least 70 vehicles in the near-term based on 10%

utilisation, and 1,188 cars in the longer term at 50% utilisation. Station asset life is expected to be greater than 25 years;

- Capex of Hydrogen Refuelling stations are based on Hydrogen Refuelling Scenario Analysis Model, Gaseous refuelling; 600 kg/day dispensing; 350 bar cascade; 20 bar H_2 dispenser (Argonne, n.d.);
- Carbon cost follows IEA expectation for "advanced economies" trending towards A$230/t$CO_2$ by 2050;
- Operations and maintenance costs include: Insurance, registration, tyres replacement and servicing. Battery replacement and fuel cell refurbishment costs are not included within the 8 year assessment period but are factored into the salvage value;
- Salvage value calculated as follows:
  - ICE vehicles and non-drivetrain portions of BEV and FCEVs halve in value every 3 years;
  - Electric motors and hydrogen fuel cells halve in value every 6 years;
  - Batteries halve in value every 3 years.

The resulting cost of ownership profile, see Figure 3-3, is consistent with the international literature.

Figure 3-3 - Light vehicle cost of ownership



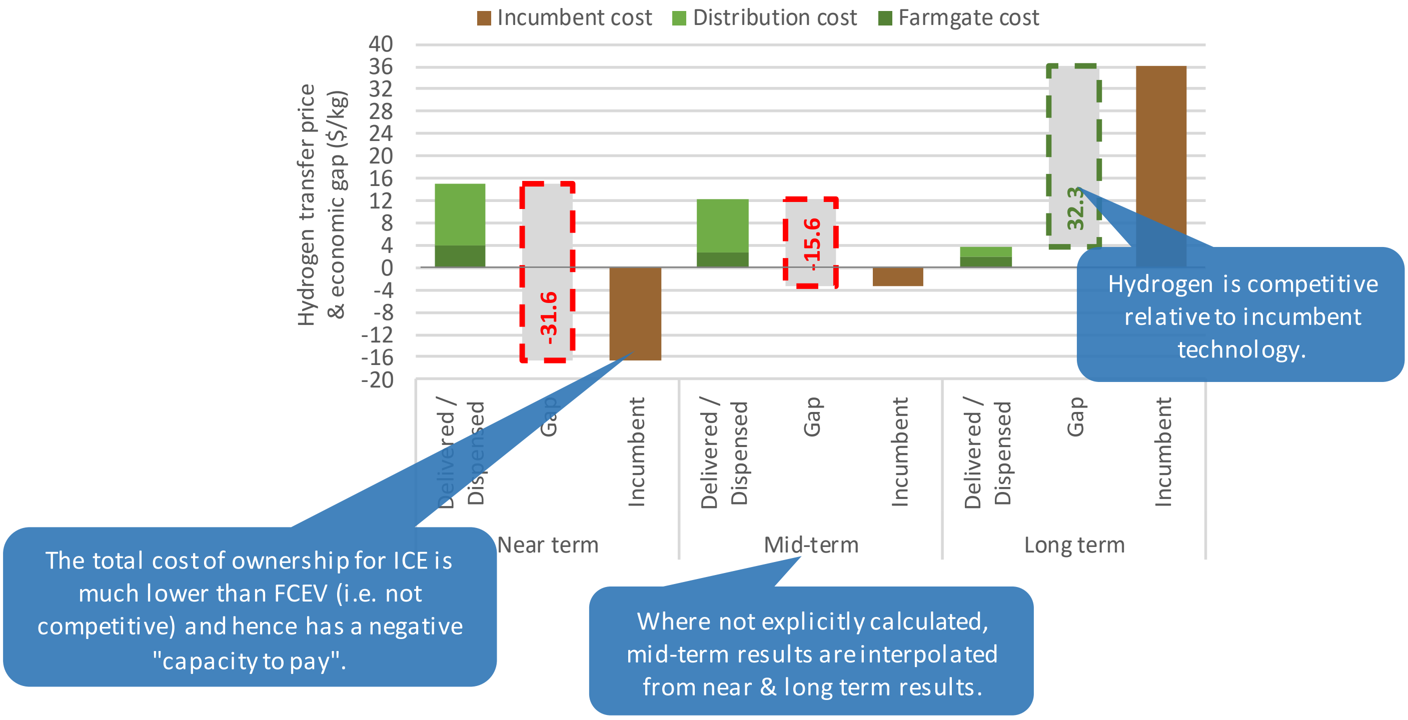
Currently, a typical Australian car uses 10.8 L/100 km (353 MJ/100 km) of petrol with a total dispensed fuel cost of $2,030 per year ($1.40/L). If this was replaced by an equivalent hydrogen fuel cell vehicle using 0.8 kg/100 km (107 MJ/100 km), the dispensed fuel cost would be $1,608 per year ($15/kg). Even if the hydrogen could be secured at $0/kg, the total cost of ownership of the hydrogen FCEV exceeds that of an ICE vehicle. The result is the relative competitiveness is negative $16.54/kg which, based on a fuel cost of $15 per kg, is a negative economic gap of $31.6/kg. The conclusion is that this sector is currently not commercially viable for the adoption of hydrogen.

The light vehicle sector is forecast to migrate from a negative economic gap to a positive economic gap across the time horizon as the cost of delivered petrol increases and the cost of FCEV vehicles and delivered hydrogen cost decreases. The hydrogen fuel cell electric vehicle (FCEV) can achieve a much higher fuel efficiency that the incumbent internal combustion engine (ICE) technology.

Towards 2050, the cost of petrol to supply an internal combustion engine is forecast to rise to $2.32/L (Graham & Smart (ACIL Tasman), 2011), and engine efficiency will improve to <3.2 MJ / 100 km. The FCEV total cost of ownership is now approaching parity with ICE vehicles showing fuel costs are the primary differences. The dispensed cost of hydrogen is forecast to be $3.72/kg. The net result is a positive economic gap of $32.3/kg showing this sector is commercially viable relative to ICE technology in 2050.

The sector snapshot for light vehicle sector, with descriptive commentary is provided below.

Figure 3-4 – Light (passenger & commercial) vehicle sector economic gap snapshot (TCO basis)



To potentially achieve competitiveness with ICE, ICE hybrids and BEVs in the future, light FCEVs will need:

- Lowering of delivered hydrogen costs through reticulated hydrogen supplies or other delivery technologies;
- Significant uptake of FCEVs, at least in concentrated areas, to justify the expense of hydrogen refuelling stations;
- To drive uptake, a variety of model options to suit Australian consumer choices, with much lower costs; and
- Proven operational cost benefits versus ICE and comparable with BEV.

The light vehicle sector is considered to have low dependence on hydrogen for decarbonisation, with a rating of 2 out of 10. Other alternatives, such as battery electric, are likely to be more important.

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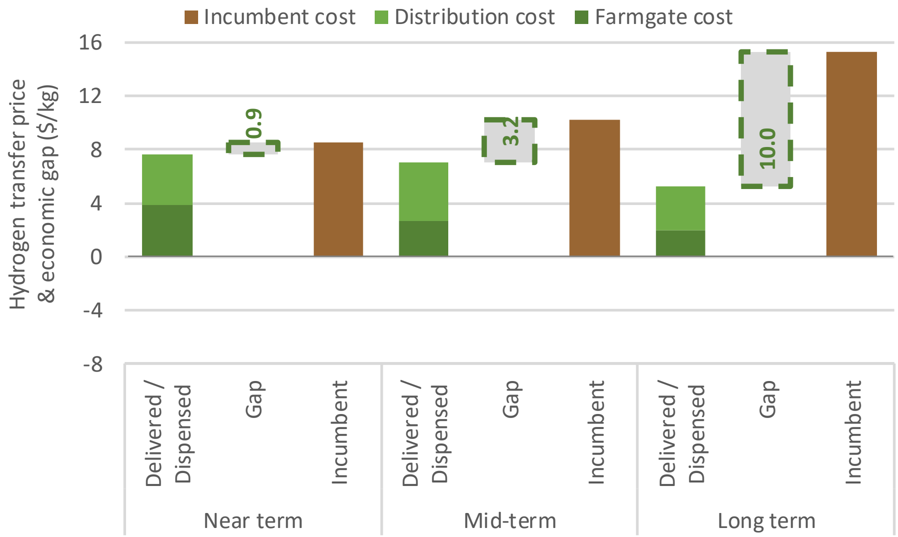
3.2.2 Materials handling

The materials handling sector is forecast to have a positive economic gap across the time horizon. FCEV based material handling units compete directly with Battery Electric Vehicles (BEVs) as a low noise and low pollution solution. The faster refuelling times of FCEVs are already leading to uptake of FCEVs in this application.

Figure 3-5 – Material handling sector economic gap snapshots (TCO basis)



To achieve this competitive position for material handling vehicles, the following conditions will need to be met:

- Low cost delivery of small quantities of hydrogen, likely less than 100 kg per day;
- Continued development of fuel cell technology in this application including models to suit a variety of applications;
- Achievement of BEV and ICE levels of reliability and operational costs; and
- Demonstrated superiority versus BEV as both technologies continue to develop.

The materials handling sector is considered to have low dependence on hydrogen for decarbonisation, with a rating of 3 out of 10. Hydrogen may become the dominant technology, however other alternatives, such as battery electric, are likely to be able to substitute if this does not occur.

3.2.3 Heavy-duty vehicles – Line haul

The heavy vehicle sector in Australia is subject to subtly different influences compared to other countries around the world. The key differences that might influence our selection and rate of uptake of low emission vehicles are:

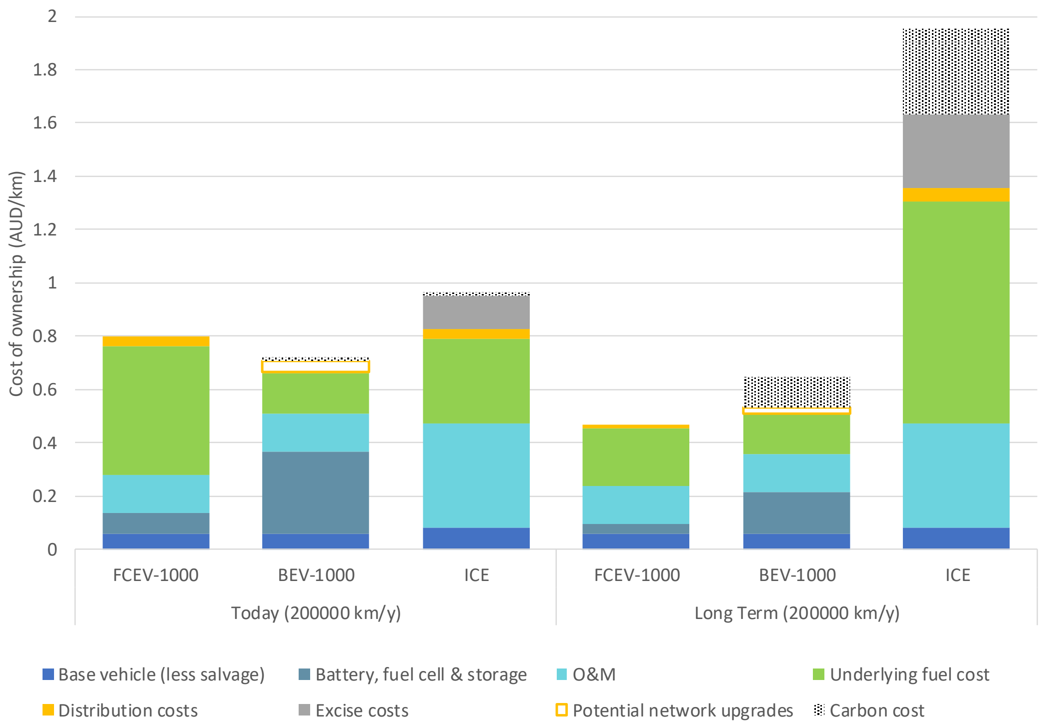
- Relatively long vehicle life;
- Less rail competition;
- Exposure to hot, low humidity environments for sustained periods;
- Minimal exposure to freezing / salt laden conditions; and
- Long stringy power grid with limited capacity to accommodate heavy electrical demand variation.

In order to provide insight into the likely appetite for hydrogen fuelled line haul vehicles between now and 2050, a high level comparison of the total cost of ownership was undertaken using the IEA Hydrogen Futures framework, with adjustments to match Australian conditions. The analysis is based on the following assumptions:

- The Australian cost market is comparable to that of the US market which is characterised by the IEA analysis;
- Fleet efficiency is taken as 36L / 100 km as is appropriate for this application but is considerably lower than the Australian average consumption (55L / 100 km) for articulated trucks;
- Vehicle ownership costs were assessed over a 12 year life – requiring replacement of ICE and FCEV systems. BEVs require a battery replacement at 8 years, which has been included in the costs as a 50% increase in battery cost;
- Fuel consumption and operational costs for BEVs and FCEVs are taken from projected manufacturer data, Tesla and Nikola, for vehicles that are not yet released to the market. These metrics are comparable with IEA metrics;
- The subset of articulated vehicles that are involved in line haul are likely to be travelling at least 200,000 km per year;
- The delivered diesel price of $1.33 per litre, increasing to $2.21 per litre in the long run. Electricity of $130 per MWh, based on industrial scale site, and hydrogen delivered prices of $6.25 per kg current and $2.78 per kg long term, based on the green hydrogen prices forecast by this report;
- Carbon cost follows IEA expectation for "advanced economies" trending towards A$230/t$CO_2$ by 2050;
- BEVs would be charged using dedicated or public stations using grid power. The cost of network upgrades to support these charging stations (1650 kW) is expected to be around $100,000 per vehicle in the short term and falling to half that figure in the future as utilisation is improved. Network upgrade costs have been estimated at $600 per kW based on lessons Learnt from the National Ultrafast EV charging infrastructure Network (EVIE Networks, 2019);
- Heavy ICE vehicles have a 16.5% exemption from standard excise costs;
- Salvage value has been calculated as 20% after 12 years for ICE and for the glider without powertrain for FCEV and BEV. Electric motors have 50% salvage after 12 years;

- Hydrogen refuelling stations will only be installed when there is enough collective demand. It is expected that a single station will serve at least 20 vehicles in the near-term, and 40 in the longer term, equating to around 20% and 40% utilisation rates. Station asset life is expected to be greater than 25 years;
- Capex of Hydrogen Refuelling stations are based on Hydrogen Refuelling Scenario Analysis Model, Gaseous refuelling; 600 kg/day dispensing; 350 bar cascade; 20 bar dispenser (Argonne, n.d.);
- Storage sizes have been updated relative to IEA refence statements in this report; and
- Operations and maintenance costs include: Insurance, registration, tyres replacement and servicing.

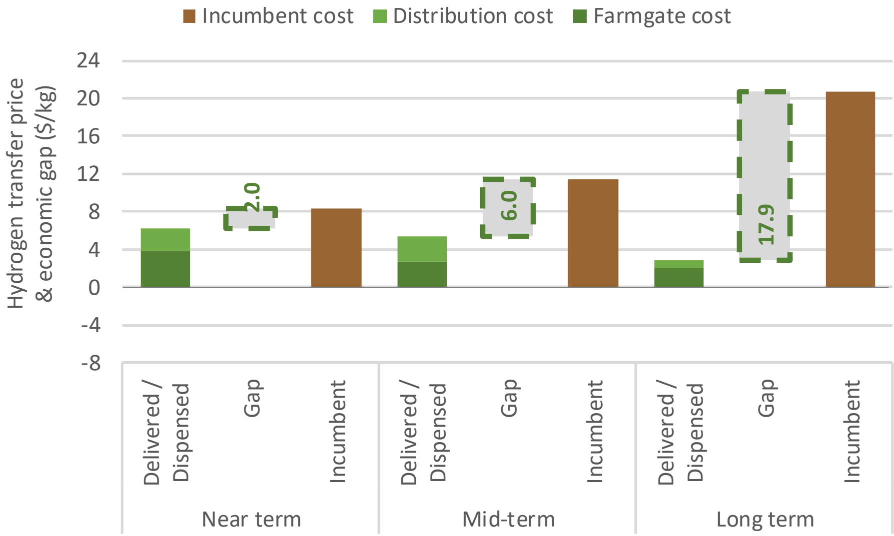
Figure 3-6 – Heavy-duty (Line haul) cost of ownership A$/km



In the near-term, hydrogen can be competitive with ICE vehicles on a total cost of ownership basis in the line-haul heavy vehicle sector. In this sector, hydrogen has lower fuel and O&M costs which offset the higher initial cost for the truck, fuel cells and storage systems. Nikola, Hyzon and others have announced development of hydrogen trucks. Hydrogen truck applications could be challenged by BEVs. The costs will likely favour FCEVs if long range operations with short recharging times or high operational flexibility are required.

The heavy-duty (line haul) sector is forecast to have a positive economic gap across the time horizon. This positive economic gap is dependent on enough demand being developed to allow for optimisation of the supply chain.

Figure 3-7 – Heavy-duty (Line haul) sector economic gap snapshots (TCO basis)



For line haul trucks to be competitive versus ICE and BEV there are a number of key aspects that will have to be realised:

- Supply from manufacturers of a variety of large trucks to suit Australia's freight needs and in quantities that can create Fleet sizes that justify the hydrogen distribution and refuelling infrastructure;
- Development of FCEV trucks need to meet industry standards for reliability and range;
- Proof of fuel consumption and operational cost benefits;
- Low cost hydrogen distribution; and
- Appropriate vehicle applications that provide operational benefits versus BEV alternatives.

The line haul vehicle sector is considered to have moderate dependence on hydrogen for decarbonisation, with a rating of 6 out of 10. Battery electric alternatives are likely to be lower cost but may not offer the flexibility of operating with hydrogen.

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3.2.4 Heavy-duty vehicles – Return to base

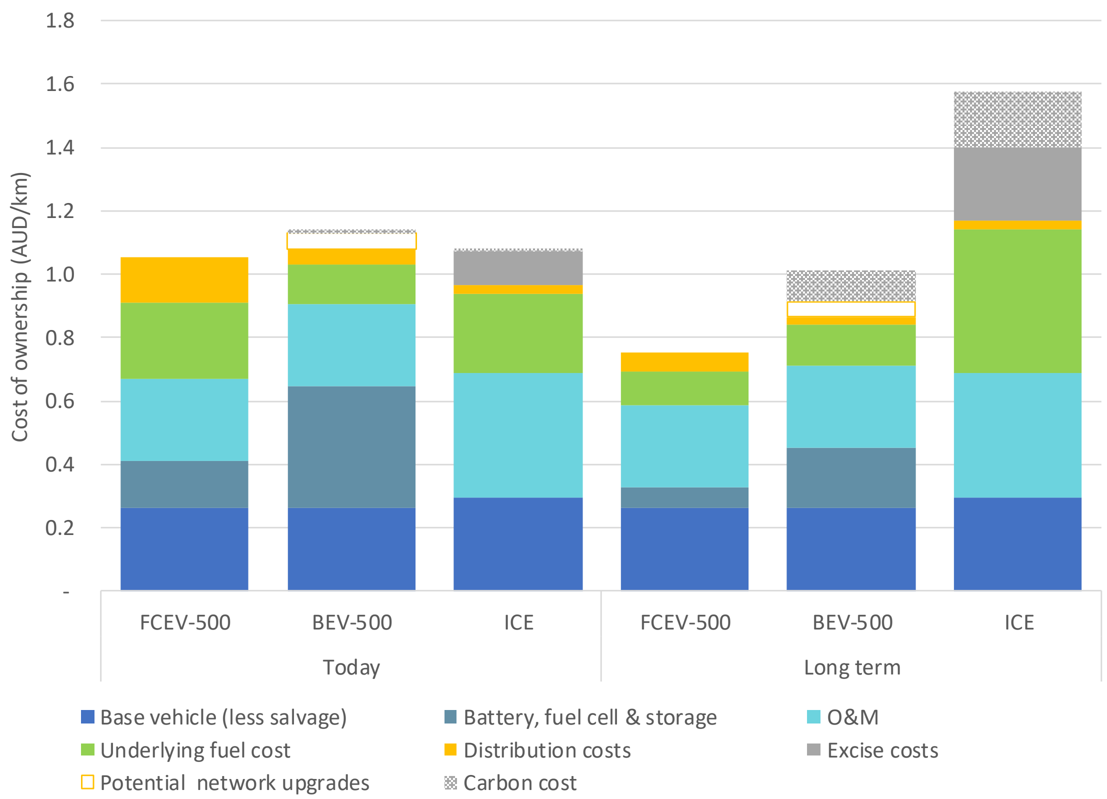
Return to base trucks were assumed to be the rigid truck class identified in ABS data (Australian Bureau of Statistics, 2019).

As with articulated trucks, the hydrogen refuelling infrastructure costs are a significant contributor to the cost of ownership. The low utilisation of the refuelling infrastructure further exacerbates the higher cost. Our analysis has assumed that early movers to hydrogen will need to provide dedicated refuelling systems as public hydrogen refuelling networks will not be developed enough to support a commercial business.

Figure 3-8 outlines the rigid truck cost of ownership ($/km). The assumptions are similar to those for the line-haul case except as described below:

- All vehicles would travel 50,000 km per year;
- BEVs would be charged overnight using a dedicated charger for each vehicle, 50 kW now and 100 kW long term;
- The cost of network upgrades to support these charging stations is expected to be around $30,000 per vehicle;
- Hydrogen delivered prices of $9.30/kg current and $4.07/kg long term are based on the green hydrogen prices forecast by this report;
- 20 trucks per hydrogen refuelling station short term, refuelling at the end of each day over an hour. 40 trucks per station long term, assuming greater utilisation of public refuelling.

Figure 3-8 Rigid truck (Return to base) cost of ownership ($/km)



In the near-term, hydrogen appears to be competitive with ICE vehicles on a total cost of ownership basis, since hydrogen has lower fuel and O&M costs which offset the higher initial cost for the truck, fuel cells and storage systems.

In the long term, the fuel cell trucks are forecast to be lower cost than the ICE vehicles as technology cost reduces and utilisation of infrastructure improves. It may be expected that refuelling will be done away from the depot using widely available public refuelling stations.

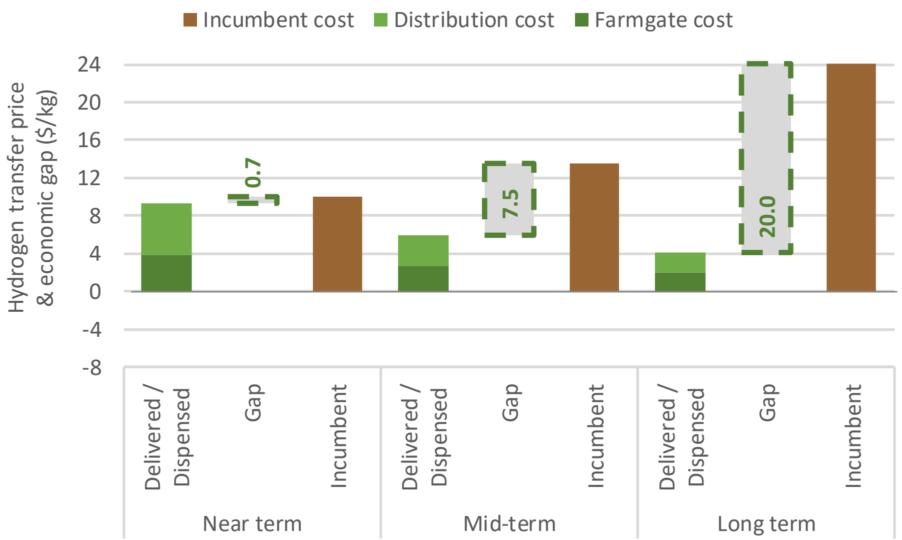
Battery electric trucks are forecast to be around the same cost as FCEV and ICE in the short and cheaper than ICE but more expensive the FCEV long term, when electricity network upgrades are excluded. Including these upgrade costs, BEV could be more expensive than both FCEV and ICE in the short term and continue to be more expensive than FCEV and cheaper than ICE long term.

The longer recharging times for electric trucks could be a deterrent to future owners and operators if there is not enough range to last a complete working day and allow overnight charging. Refuelling times for the hydrogen vehicles is unlikely to differ much from the time taken to refuel the ICE trucks.

The costs will likely favour FCEVs in the long term if refuelling infrastructure can be implemented and utilised to high levels.

The return to base sector is forecast to have a positive economic gap over a mid-term time horizon.

Figure 3-9 – Heavy-duty (Return to base) sector economic gap snapshots (TCO basis)



For return to base trucks to be competitive versus ICE and BEV the following requirements will be needed:

- Supply from manufacturers of a variety of medium size trucks to suit Australia's freight needs and in quantities that can create Fleet sizes that justify the hydrogen distribution and refuelling infrastructure;
- Development of FCEV trucks to meet industry standards for reliability and range;
- Proof of fuel consumption and operational cost benefits;
- Low cost hydrogen distribution;
- Restrictions on BEV charging due to network constraints, limiting utilisation of the vehicles or adding costs; and

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- Appropriate vehicle applications that provide operational benefits versus BEV alternatives.

The return to base vehicle sector is considered to have low dependence on hydrogen for decarbonisation, with a rating of 4 out of 10. Other alternatives, such as battery electric, are likely to be more important and could have a cost advantage for shorter routes.

3.2.5 Heavy-duty vehicles – Mining

Mining vehicles, in particular, mining haul trucks, provide a potentially attractive end-use for hydrogen. Mining companies with operations in Australia that have made commitments to lower emissions including zero emissions goals include: FMG (2030) BHP (mid-century), Rio Tinto (2050) and Anglo

The value of flexibility in mine planning

The trade-off between flexibility and cost efficiency of overhead cable systems.

Many sectors of the mining industry place a high value on the mine planning flexibility provided by the current diesel haul truck fleet and mobile excavators. This flexibility can allow changes to the grade of material being extracted or the location of overburden disposal at short notice, responding rapidly to market and operational requirements.

Alternatives to diesel vehicles can introduce constraints on the ability to quickly adapt; conveyor dominated systems require years of forward planning to be operated optimally, and similarly, overhead trolley assist systems cannot be moved to new mining areas at short notice and will incur significant cost. Although trolley assist with battery electric trucks appears to offer the lowest operational cost per hour of operation, there may be a significant difference in the value that can be extracted from the mine if mining methods are not flexible enough to realise these opportunities.

Hydrogen haul trucks offer the potential for fast refueling and flexible operations, comparable with current diesel trucks, with low emissions and noise. In the future it is likely that hydrogen will be operationally cost competitive with both diesel and BEV alternatives.

American (2040) (S&P Global Platts, 2020) and diesel consumption is a major source of emissions in the mining industry.

Conversely, the introduction of highly flammable hydrogen, particularly into underground mining fleets, is likely to face some safety and regulatory challenges.

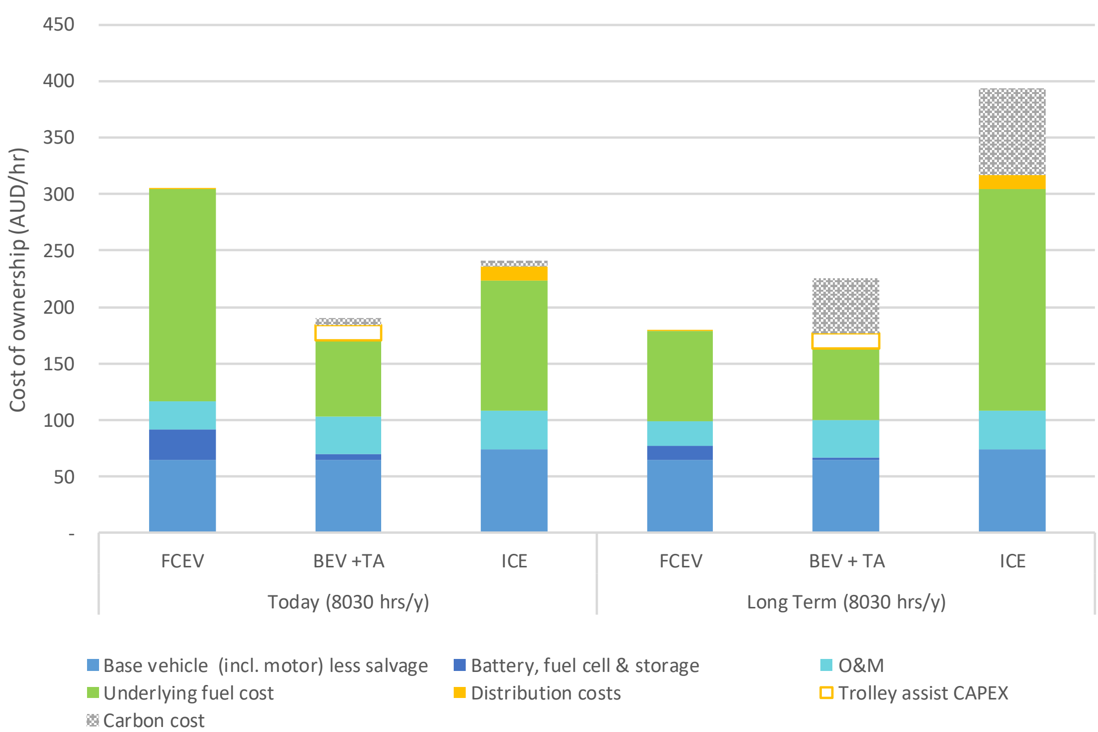
An emerging challenge to the incumbent technology is battery electric vehicles, most likely incorporating a trolley assist section to power the haul and recharge the batteries to reduce battery size. This technology is still under development for full scale implementation.

An analysis was conducted comparing a hydrogen haul truck to the ICE equivalent and a battery electric truck with trolley assist. The key assumptions are:

- Utilisation is 22 hours per day;
- Diesel price rises from $0.98/L to $1.68/L delivered to the truck (Graham & Smart (ACIL Tasman), 2011). No excise is applied;
- Electricity price for BEV/trolley assist $120 per MWh;
- Lifespan is 7 years for all truck types;
- Salvage value at the end of 7 years slightly favours BEV and ICE vs FCEV;
- The trolley assist system cost of $10 million per km / 10 km total required;
- BEV only requires one charger per 25 trucks as most charging is done on the trolley section;
- FCEV 14 trucks per refueller, two trucks per hour refuelled;
- If electrical network upgrades are needed for the BEV case, it will add $80 million for 100 km including transmission for a notional remote site (Advisian estimates);
- The salvage value of the trolley assist system and network upgrades is 80% at the end of 7 years; and
- Green hydrogen costs and emissions are used short term and long term.

The results of the analysis are shown in Figure 3-10.

Figure 3-10 - Mining truck cost of ownership ($/h)



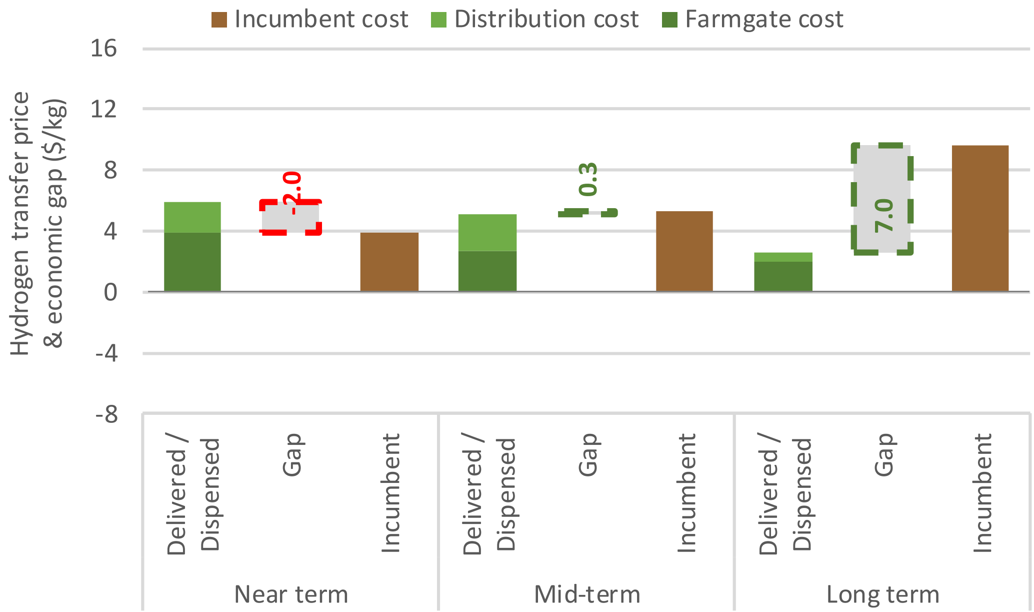
Advisian
Worley Group

Hydrogen fuel cell trucks may not be competitive with respect to ICE vehicles in the short term, potentially offering a lower emissions option but at higher cost. Battery electric trucks are expected to be the most cost competitive in the short term but could provide less flexible mining operations.

In the long term, hydrogen fuel cell trucks are expected to be lower cost than ICE, despite higher capital costs, through lower fuel and operation and maintenance (O&M) costs. BEV trucks with trolley assist are expected to be as low cost as hydrogen, although this could be challenged if significant network costs are incurred for the BEV option.

The economic gap associated with the heavy-duty (mining) vehicle sector is forecast to improve progressively across the time horizon.

Figure 3-11 – Heavy-duty (Mining) sector economic gap snapshots (TCO basis)



For mining trucks to be competitive versus ICE and BEV a number of key requirements will have to be met:

- Supply from manufacturers of mining trucks to suit the Australian mining industry in quantities that can create fleet sizes that justify the hydrogen distribution and refuelling infrastructure;
- Development of FCEV trucks to provide miners with comparable utilisation and reliability to ICE;
- Proof of fuel consumption and operational cost benefits;
- Low cost hydrogen distribution or local production; and
- Trolley assist systems for BEVs restrict the flexibility of mining operations and require significant network augmentations.

The mining vehicle sector is considered to have a moderate to high dependence on hydrogen for decarbonisation, with a rating of 7 out of 10. Battery electric trucks with trolley assist could be lower cost but may restrict mine operations significantly.

3.2.6 Heavy haul rail

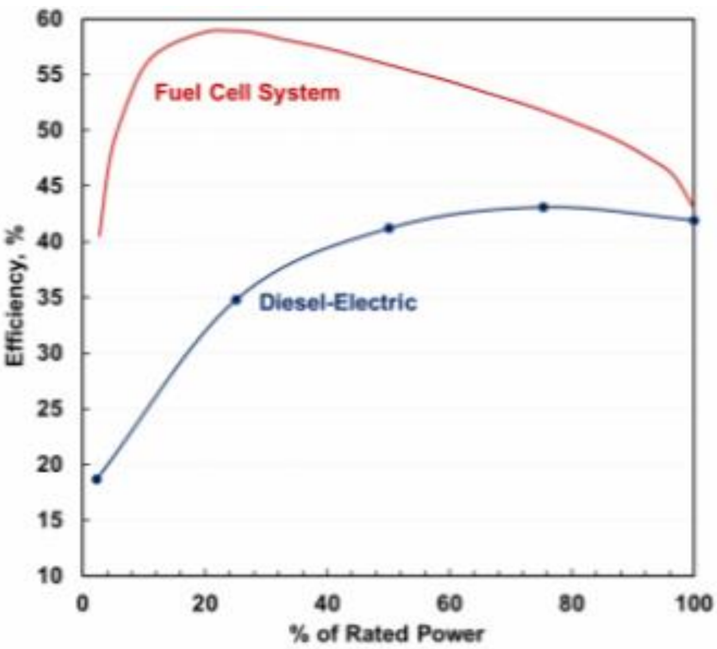
Heavy haul rail is a significant user of diesel fuel in Australia, in applications that include dedicated iron ore and coal haulage routes and general freight.

Hydrogen fuel cell locomotives are under development, building on the demonstration projects in passenger rail systems such as the Alstom iLint units, in service in Germany since 2018 (Alstom, 2018).

The Argonne Laboratory has undertaken a comprehensive study of fuel cell hydrogen versus diesel locomotives and some key metrics from this study have been used in our analysis (Argonne National Laboratory, 2019). Packaging of fuel cells and compressed hydrogen on a locomotive chassis is a challenge and this analysis has assumed inclusion of a fuel tender behind the locomotive to carry the hydrogen tanks.

A key aspect of the application of fuel cells to heavy haul rail is the decreasing efficiency as the level of power demand is increased. This contrasts with a diesel engine, where efficiency increases through most of the power output range. The power curves for both types of power unit are shown in Figure 3-12 (Argonne National Laboratory, 2019). Heavy haul rail locomotives operate near full power output for most of the haul route. At this condition, there is little efficiency differential between fuel cells and diesel engine locomotives.

Figure 3-12 - Efficiency comparison



In our analysis we compare hydrogen locomotives, current ICE locomotives, battery electric locomotives that are recharged at the destination and electric locomotives using overhead wires.

The battery electric locomotive will require very large batteries, some 25 MWh, to complete the 1,000 km route and is also likely to need a tender to contain the batteries. GE has announced the development of a 2.4 MWh battery locomotive and forecasts a 6 MWh version (GE, 2018). Overhead electrification will need supporting infrastructure for power supplies along the length of the route,

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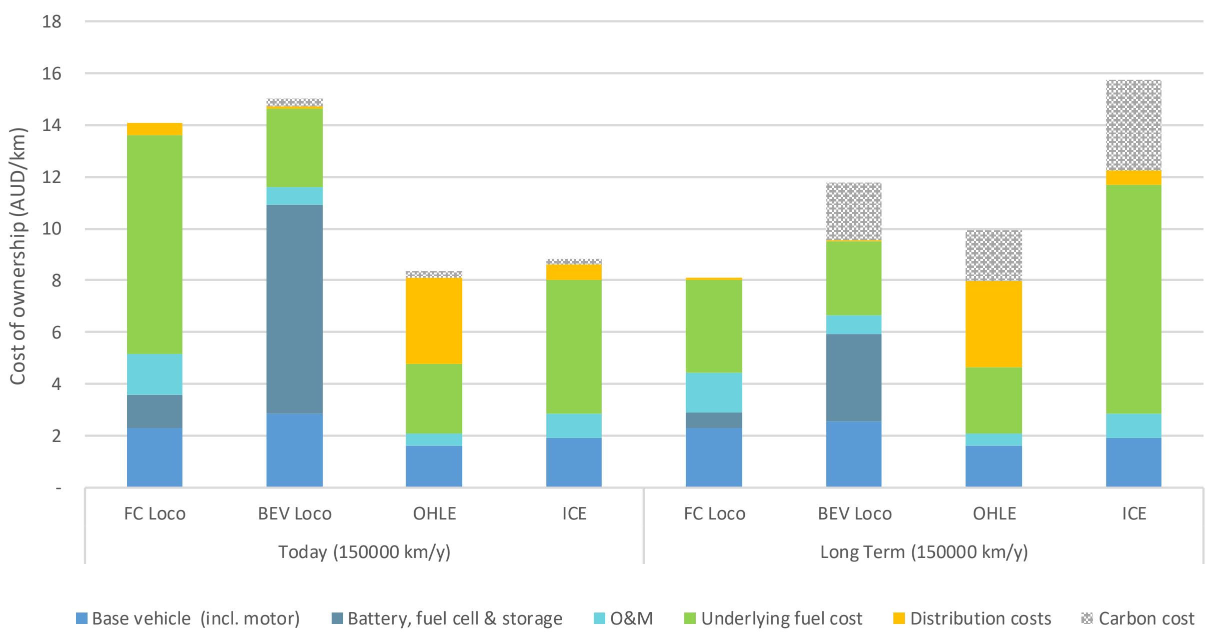
including connecting lines to the electricity grid and transformer systems. Overhead line electrification (OHLE) could also be used to address large battery sizes and long recharging time through intermediate recharging sections of the track.

The key assumptions used are:

- 15 year service life, 150,000 km per year. BEV requires battery replacement after 8 years;
- No excise applied to diesel fuel – delivered price $0.98 per litre, increasing to $1.68 per litre in the long term;
- BEV utilisation reduced by 20% to allow for recharging time;
- FCEV only 10% more efficient than ICE due to high average power requirements;
- 2 locomotives per train, 16 trains over the 1,000 km route;
- Overhead line infrastructure capital $2 million per km, O&M 0.5% of capital per year, salvage value 80% at end of 15 years;
- Carbon cost follows IEA expectation for "advanced economies" trending towards A$230/t$CO_2$ by 2050;
- 3 locomotives per BEV charger and 2 locomotives per hydrogen refueller short term. Greater utilisation long term to 6 and 10 for BEV and FCEV respectively; and
- No network upgrades are required to charge BEV locomotives due to terminating at industrial facilities.

Figure 3-13 - Heavy haul rail cost comparison ($/km)

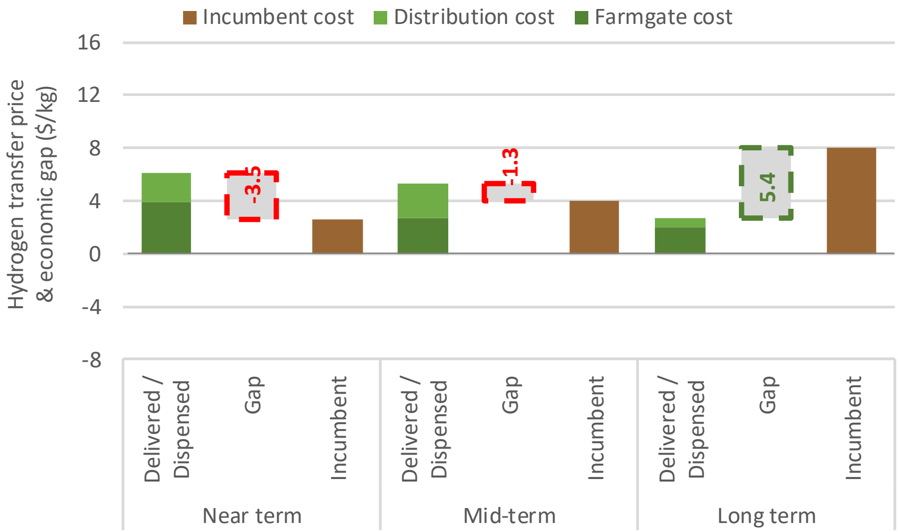


The results of the analysis are very sensitive to the assumptions regarding the number of locomotives on the route and the salvage value for the overhead electrification.

In the near-term, ICE locomotives are the lowest cost per kilometre, followed by overhead electrification. Battery electric are more expensive due to the huge cost for batteries to achieve the nominated 1,000 km range. The battery size and cost could potentially be reduced if charging is available at intermediate points of the route. Hydrogen fuel cell is the most expensive, driven by underlying fuel costs for a system without a significant efficiency advantage over ICE.

In the long term, hydrogen fuel cell locomotives look to be the cheapest and set to achieve a positive economic gap long term. Battery electric locomotives look to be marginally lower cost than overhead electrified. In this projection, it is the falling capital cost of the fuel cells and storage, and lower long-term hydrogen cost that makes hydrogen fuel cell locomotives the lowest cost.

Figure 3-14 – Heavy haul (Rail) sector economic gap snapshots (TCO basis)



For hydrogen heavy haul rail to be competitive, versus OHLE, ICE and BEV there are some requirements that need to be met:

- Hydrogen locomotives developed at appropriate size to suit Australia's heavy haul requirements;
- Manufacturers can supply enough locomotives to allow operators to implement a fleet, increasing utilisation of fuel supply and refuelling assets;
- Development of FCEV locos to provide operators with comparable utilisation and reliability to ICE;
- Proof of fuel consumption and operational cost benefits;
- Low cost hydrogen distribution or local production;
- Utilisation levels that don't justify OHLE infrastructure; and
- Low technical feasibility of BEV locos.

The heavy rail sector is considered to have low dependence on hydrogen for decarbonisation, with a rating of 3 out of 10. Other alternatives, such as overhead electrification and battery electric, are likely to be lower cost in the short to medium term where high continuous power rating impacts fuel cell efficiency.

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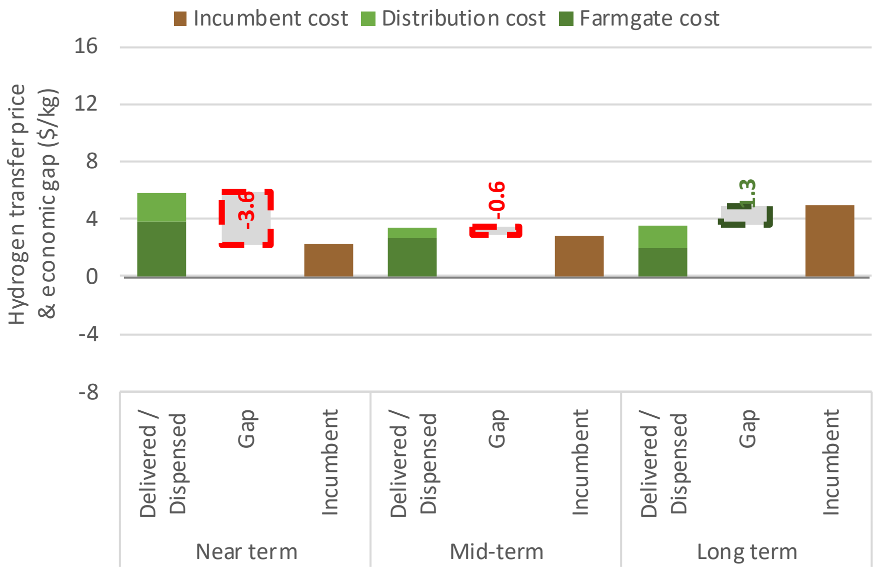
3.2.7 Ferries

Ferries are a marine shipping case where the requirements for fuel storage are significantly less than for coastal or international shipping. Ferry journeys are often only a few hours in duration, or in the case of commuter ferries, daily operation, providing opportunities for at least daily refuelling. The consequence of lower fuel storage is the likely preference for lower cost and higher efficiency fuels as opposed to those that offer the highest energy density. Gaseous and liquid hydrogen have much lower volumetric energy density than Marine Gasoil (MGO) but are significantly more energy dense than batteries.

Use of hydrogen derived fuels, such as ammonia and methanol, will require reciprocating engine technology until such time as direct ammonia and methanol fuel cells are commercialised – for more comment on this topic, please refer to marine shipping, Section 3.2.8. On the negative side, the fuel supply and fuel cell-based powertrains are expected to be considerably more expensive than the incumbent ICE technology. Our economic gap assessment was based on utilisation of gaseous hydrogen utilisation.

In the short term, hydrogen is unable to compete with ICE, but over time, the gap narrows, and in the long term it is expected to be competitive. Increasingly stringent emissions regulations are likely to apply to marine shipping, to drive operators towards lower pollution, lower GHG emissions fuels.

Figure 3-15 – Ferries sector economic gap snapshots (Fuel cost basis)



The commercial application of hydrogen and hydrogen-based fuels to ferries will be dependent on:

- Proof of application of hydrogen fuel cells, ammonia and methanol engines and, potentially, ammonia and methanol fuel cells in marine applications;
- Development of suitable fuel bunkering at the applicable ports;

- Fuel storage solutions that do not excessively impact freight and passenger carrying capability; and
- Continuation of current pollution and GHG emissions reduction regulations in the marine shipping sector.

The ferries sector is considered to have moderate to high dependence on hydrogen for decarbonisation, with a rating of 7 out of 10. Other alternatives, such as battery electric and biofuels, are likely to be important but not useful for long range and large-scale uptake respectively.

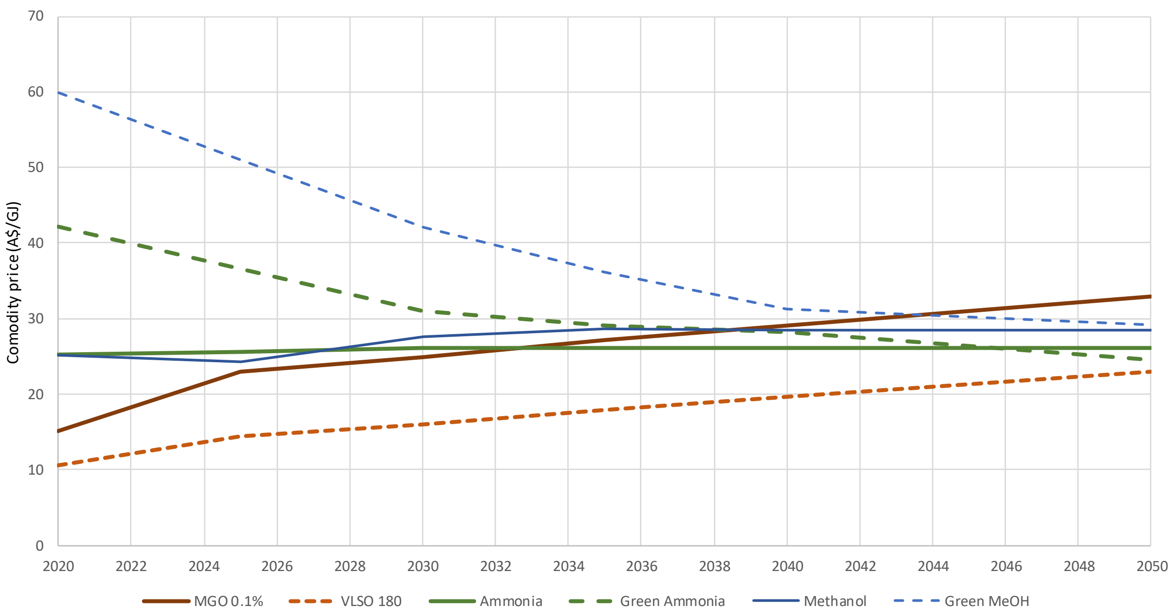
3.2.8 Marine shipping

The marine shipping industry consume 300 million tonnes per year of oil fuel - around 10% of global transportation fuel demand (Agarwal, 2019) and is a significant contributor to global GHG emissions. Heavy fuel oil (HFO) is the most widely used fuel today (Allied Market Research) followed by Marine Gasoil (MGO), while natural gas is only used by around 2% of the global fleet. In the near-term it is expected that MGO and very-low sulphur fuel oil (VLSO) will be the predominant marine fuels (Repsol, 2019) provided that they are able to comply with IMO sulphur emissions restrictions.

The use of alternative fuels such as green methanol and green ammonia offer some of the most cost-effective mechanisms for complying with GHG emissions reduction regulations.

The forecast cost trend of marine bunker fuels relative to green fuels under the IEA stated policies scenario is provided in Figure 3-16 below.

Figure 3-16 – Forecast of conventional and green marine bunker prices



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Green methanol

When used as a marine engine fuel, conventional methanol has 90-95% lower SOx, 30-50% lower NOx, 5% lower CO_2 and 90% lower PM than a Tier II compliant HFO engine (Man Energy Solutions.). When running with green methanol the SOx and PM emissions would be negligible, and CO_2 emissions would have been offset by the CO_2 capture required during production.

The cost of green methanol is forecast to decline rapidly and achieve cost parity with conventional methanol before 2040 – see Figure 3-16. Beyond 2040 there is potential for green methanol to be cost competitive with the incumbent bunker fuels. Even if methanol were to be cost competitive with conventional bunker fuels, the fuel density (being nearly half that of HFO) would represent a conversion hurdle. In the interim, it is expected that the predominant use of methanol will be as a low carbon blend component.

Green ammonia

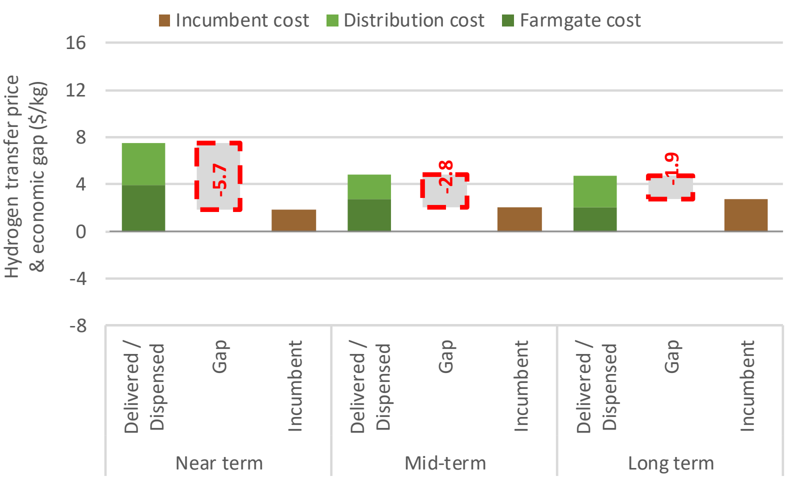
Ammonia has the key qualities of a low carbon economy fuel – higher energy density than hydrogen and zero carbon and sulphur free emissions when combusted.

There are no commercial ships running on ammonia. However, it is expected that bunkering limitations will be easily overcome. The ammonia storage and transport infrastructure is well developed globally with significant international trade. Ammonia's shipping routes are well established and there is a comprehensive network of ports globally able to handle ammonia shipments at a large scale.

The forecast prices of potential marine bunker fuels – see Figure 3-16, suggests that the cost of conventional ammonia as a bunker fuel is significantly more expensive than the incumbent HFO and MGO whilst the crude oil price remains below US$100 per barrel. An approach to price parity would be achieved by 2040 under the IEA sustainable development scenario, in which crude oil prices rise to US$130 per barrel. Even if ammonia were to be cost competitive with conventional bunker fuels, the fuel density (being ~35% that of HFO) and high costs of ammonia storage would represent a conversion hurdle for long range shipping options.

The forecast gap profile for marine shipping is similar to ferries with uptake of hydrogen and hydrogen fuels will require significant development. In the short term, per Figure 3-17 the higher costs of fuel outweigh the increase in efficiency from potential fuel cell powertrains. However, over time, hydrogen and hydrogen derived fuels are expected to become competitive versus MGO and other low sulphur fuels designed to meet pollution requirements but not address GHG emissions. The economic gap assessment considered switching from MGO to green ammonia using combustion engines.

Figure 3-17 – Marine sector economic gap snapshots (Fuel cost basis)



The marine sector is considered to have high dependence on hydrogen for decarbonisation, with a rating of 9 out of 10. Other alternatives, such as battery electric and biofuels are unlikely to be able to provide the required range and scale respectively.

3.2.9 Aviation

The Aviation sector has experienced huge growth in passenger demand and (prior to COVID-19) that was not expected to stabilise until the year 2075 (International Civil Aviation Organization, Civil Aviation Statistics of the World and ICAO staff, 2020). Despite some fuel efficiency improvements, this sector has experienced some of the highest growth in fuel demand and struggles to reduce its carbon intensity. There is significant pressure on the airline sector to decarbonise in order to retain social license to operate, and the industry is actively seeking commercially viable carbon intensity reduction solutions.

Our assessment of the potential to use liquid hydrogen and synthetic aviation fuel is based on adaption of CleanSky2 analysis (CleanSky2, 2020). The study concludes that the high mass but low volumetric energy density of liquid hydrogen means that it is only viable for regional aviation – using electrically driven turbo props. Longer haul flights are likely to still use jet engines fuelled by sustainable aviation fuels.

An illustration of the changes in cost and greenhouse gas impact of hydrogen based regional and international aircraft is provided below.

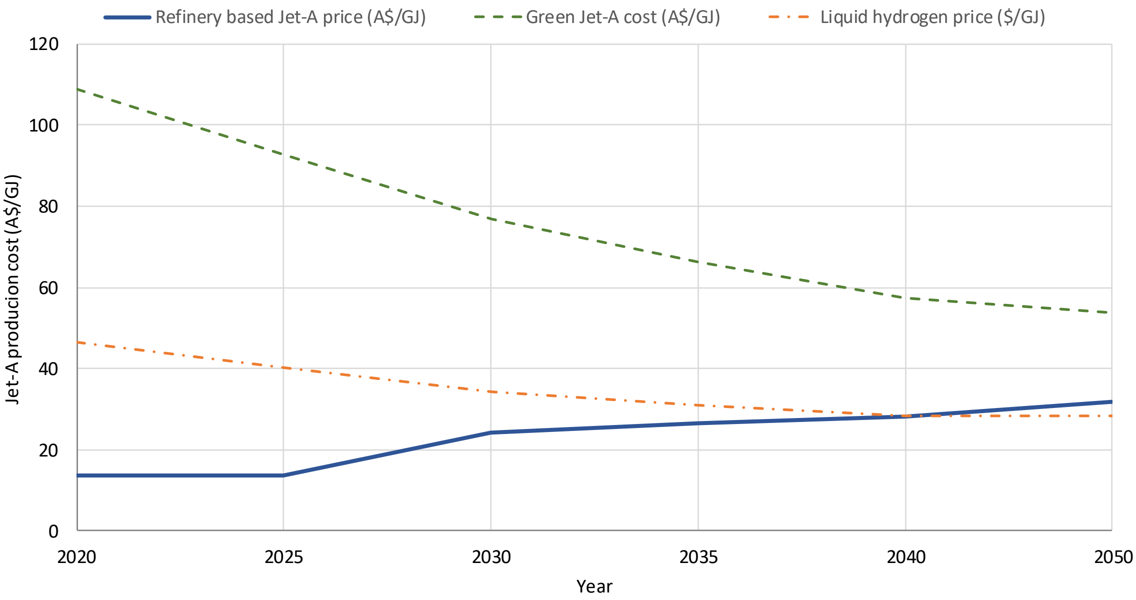
Figure 3-18 – Forecast cost and GHG impact of hydrogen based aviation

Service	Regional 20 - 80 PAX, 1000 km range	Medium range 166 - 250 PAX, 7000 km
		
Share of global fleet (%)	13%	18%
Share of GHG emissions (%)	0.0	0.4
Energy demand index (%)	92%	122%
Jet fuel load (tons)	1.8	32.8
Hydrogen fuel load (tons)	0.6	14.3
Jet fuel demand (MJ/y)	9,603,000	137,643,000
Hydrogen demand (MJ/y)	8,834,760	167,924,460
Climate impact index (%)	10 -20%	40 -50%
Additional cost - CASK (%)	5 - 15%	30 - 40%
Entry into service year	2030 -2035	2040
Minimum take-off weight index	110%	112%

Our analysis modified the underlying hydrogen price assumptions associated with the CleanSky2 study, to provide an Australianised interpretation over time. Our fuel price trend (see Figure 3-19) indicates LH2 pricing becoming competitive with refinery derived Jet-A near 2040. Although fuel price is the biggest contributor to the cost of aviation, the impacts of changed plane design and change-out / modification costs must also be considered.

The cost of Jet-A derived from low carbon hydrogen and carbon neutral carbon dioxide is not forecast to become competitive with refinery derived Jet-A. Indeed, sustainable aviation fuels derived from biofuels and municipal waste are likely to be more competitive than hydrogen based synthetic Jet-A.

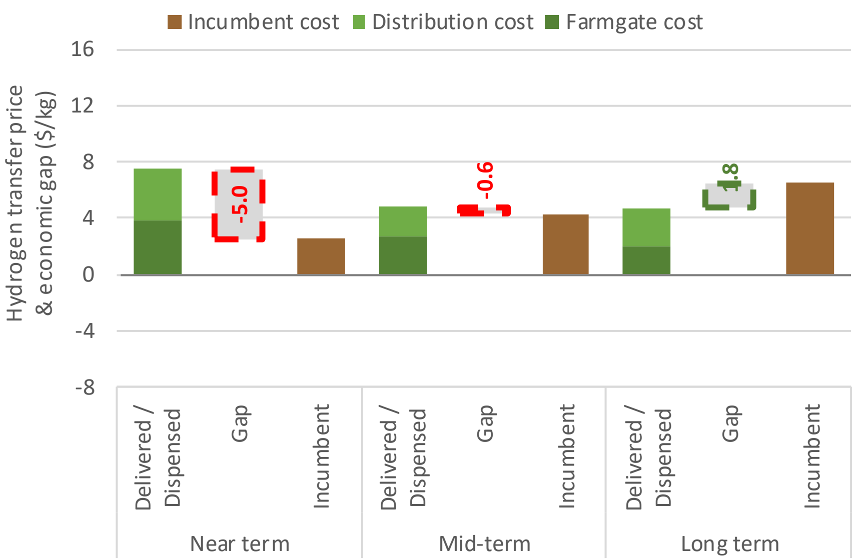
Figure 3-19 – Forecast of conventional and green aviation fuel prices



The above fuel price forecasts suggest that aviation industry will remain highly dependent upon the underlying cost of crude oil and refinery margins, unless pricing structures change. If the airline industry self-regulates on GHG emissions intensity, then higher cost fuels may be viable means of decreasing GHG emissions.

The economic gap assessment of the regional aviation sector, considers displacing Jet-A fuel use in jet engines with liquid hydrogen via fuel cells and turbo props. This analysis indicates that the sector transitions to being competitive with conventional Jet-A prior to 2050.

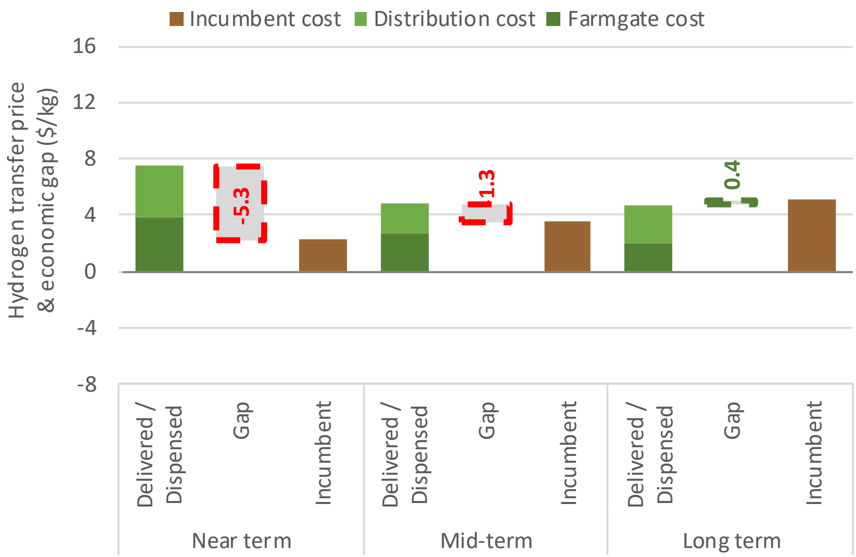
Figure 3-20 – Regional aviation sector economic gap snapshots (TCO basis)



The regional aviation sector is considered to have high dependence on hydrogen for decarbonisation, with a rating of 8 out of 10, since battery based technology and alternative fuel cells systems may become competitive.

The economic gap assessment of the international aviation sector considers displacing Jet-A fuel with liquid hydrogen in jet engines. The analysis indicates that the sector approaches competitiveness with conventional Jet-A prior to 2050. This sector is considered to have a high dependence on hydrogen for decarbonisation, with a rating of 9 out of 10 due to battery technology not being technically viable and volume of biofuels derived fuel being limited.

Figure 3-21 – International aviation sector economic gap snapshots (TCO basis)



The development of hydrogen and hydrogen derived fuels in the aviation sector face many technical and commercial challenges. Some of the key areas that will need to be addressed are:

- Aircraft designs that accommodate the lower volumetric density of gaseous and liquid hydrogen;
- Proof of application of hydrogen fuel cells and hydrogen turbines in aviation applications;
- Development of hydrogen production, storage and refuelling facilities at airports;
- Considerable weight reduction for LH2 storage and fuel cells (including cooling);
- For synthetic jet fuel, significant reductions are required in the cost of direct air CO_2 capture and production; and
- Aggressive aviation decarbonisation targets including international or regional regulations.

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3.3 Fuel for industry

3.3.1 Synthetic natural gas (SNG)

If green SNG could be produced commercially, the decarbonisation movement would be greatly simplified by just use green SNG in place of natural gas. However, this pathway is unlikely to become commercial before 2050. The creation of SNG is also challenged by the fundamental requirements for hydrogen and energy inputs, providing a higher cost but able to be fully blended with natural gas.

The commercial development of synthetic natural gas will require:

- Low cost hydrogen as a feedstock;
- Access to low cost CO_2 from GHG neutral sources;
- Prohibitive costs for replacement of natural gas infrastructure and appliances to take high percentage blends or pure hydrogen; and
- Accelerated transition from fossil natural gas driven by gas pricing.

The creation of synthetic natural gas is considered to have moderate dependence on hydrogen for decarbonisation, with a rating of 5 out of 10. Other alternatives, such as electrification and hydrogen blends / 100 % hydrogen, offer less complicated and costly decarbonisation opportunities.

3.3.2 Gas network – H_2 blends

Australia has extensive natural gas networks to transmit gas from the source and distribute to customers. This section explores the opportunity to utilise these existing assets to cost effectively deliver hydrogen and stimulate early hydrogen demand.

Hydrogen blending concentrations above 50% are not currently considered feasible in existing distribution networks due to increased impact on safety, leakage and material integrity. Adding more than 50% hydrogen to a distribution pipeline yields a significant increase in overall risk due to increase in probability and severity of ignition and explosion scenarios. The only feasible alternative to reach blending concentrations above 50% is to construct a dedicated hydrogen network or revamp the existing national infrastructure. A 100% hydrogen network could provide a low-cost source of feedstock for industry and mobility applications.

Blending hydrogen into the existing natural gas distribution network at low concentrations, less than 10% hydrogen by volume, is generally considered viable without significantly increasing risks associated with utilisation, overall public safety, or the durability and integrity of the existing natural gas pipeline network. Blending up to 20% is feasible and doesn't affect Wobbe index but may require some modifications of the supporting pipeline gas specification.

For blended hydrogen in natural gas networks beyond levels compatible with existing appliances and infrastructure to be viable:

- Conversion costs of infrastructure and appliances must not be prohibitive;
- Electrification options are not able to supply similar services; and
- The gas network provides significant and valuable energy storage to support renewable electricity deployment.

The blending of hydrogen into natural gas networks is considered to have moderate dependence on hydrogen for decarbonisation, with a rating of 5 out of 10. Other alternatives, such electrification and 100% hydrogen networks, are likely to be more important.

3.3.3 Gas network with hydrogen recovery

Hydrogen has quite different physical properties to natural gas, which predominantly composed of methane. Recovery of hydrogen from blends in natural gas networks has the potential to transmit hydrogen over long distances using existing gas network infrastructure, if the hydrogen can be cost effectively extracted at the point of use. It is possible to recover hydrogen from a hydrogen blended natural gas network with a variety of separation approaches, including:

4. Membrane separation;
5. Cryogenic separation;
6. Pressure Swing Absorption (PSA) inline;
7. PSA at letdown station; and
8. Electrochemical Hydrogen Separation (EHS) or hydrogen pumping.

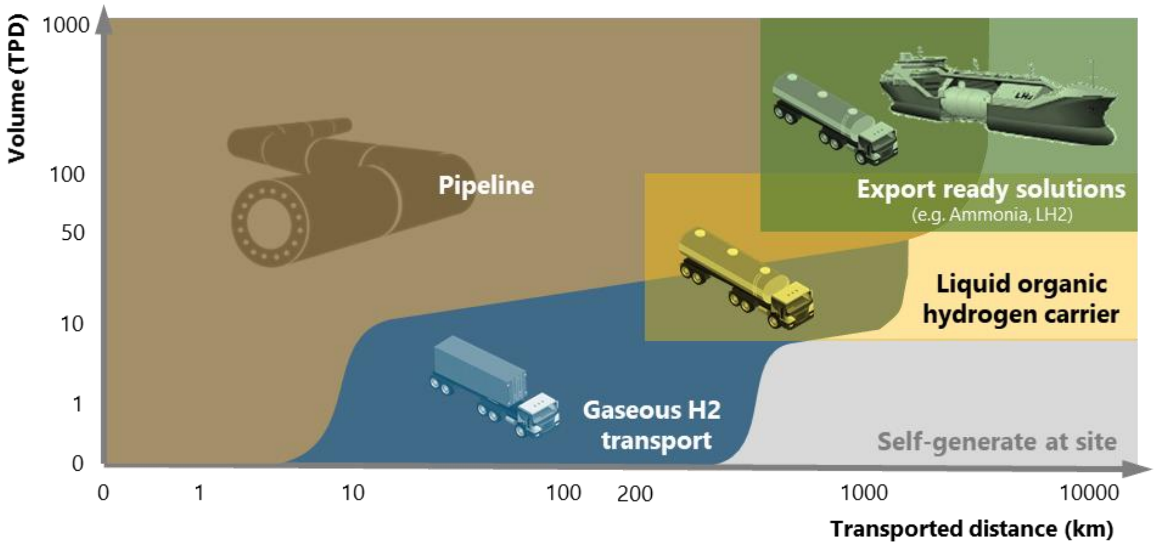
The most commercially ready technology is the PSA at a letdown station. PSA units are economically practical only at pipeline pressure reduction stations as the pressure drop of the natural gas is synergistic with hydrogen separation. Without this drop in pressure, uneconomically large amounts of compression energy and compressor capital would be needed to reinject hydrogen-depleted gas back into a pipeline.

However, blending of hydrogen into natural gas networks greater than 10% requires significant modifications to downstream user equipment and blend variability management for some users, such as peaking turbines. It is difficult to see hydrogen being competitive versus foreseeable natural gas prices.

3.3.4 100% hydrogen gas network

The low density of gaseous hydrogen makes transport comparatively expensive, with different preferred solutions dependent on scale, transport distance and end-use demand variability. A guideline on the appropriate distribution network based on scale and distance is provided in .Figure 3-22

Figure 3-22 – Matrix of preferred hydrogen transportation pathway options



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When production volumes exceed 10 tpd, pipelines are generally cost effective. A secondary benefit of pipeline transportation is the storage capacity that is can be achieved by varying the pipeline operating pressure. The high initial capital costs of new pipeline construction is the most significant barrier to this delivery approach. This approach does however have the benefit of enabling a multitude of smaller hydrogen producers and consumers to utilise common user infrastructure on an incremental basis.

Considerations associated with re-purposing natural gas distribution pipelines for 100% hydrogen service include:

- Development of a regulatory framework for 100% hydrogen pipelines;
- The potential for hydrogen to embrittle higher grade steel pipelines and welds;
- Replacement of seals where hydrogen permeation may occur; and
- Management of contaminants leaching out from the walls of the pipelines, in particular sulphur based odorants from natural gas transmission.

3.3.5 Combined heat and power

Combined heat and power (CHP) is the simultaneous production of electricity and useful thermal energy (heating and/or cooling) from a single source of energy, commonly CHP is based on natural gas.

Recognising that hydrogen is a more expensive fuel than natural gas, and that Opex cost is the dominant cost in CHP operation, the selection of hydrogen rather than natural gas as the CHP fuel source is predicated on either:

i. Hydrogen based CHP achieves higher efficiency than NG counterpart; or
ii. Fuel price parity is achieved.

Hydrogen based CHP would likely be based on fuel cell technology with an efficiency approaching 70% electricity yield. This would offer substantial advantages over the equivalent natural gas engine based technology which has approximately 30% efficiency, due to:

- Higher efficiency has higher commercial return i.e. higher electricity yield;
- A fuel cell has fewer moving parts and hence greater reliability and less maintenance;
- Minimal waste heat reduces system cost, size and complexity; and
- Broader range of applications since economics can be favourable at lower heat demand levels.

CHP based on hydrogen fuel cells could also provide a longer-term opportunity where the increased efficiency of fuel cells gives a cost advantage over natural gas based CHP systems and independent heating and power supplies. This opportunity is generally more attractive in cooler climates where the heating load is significant. Supplies of pure hydrogen are required.

The economic gap associated with the CHP sector is forecast to progressively improve, with breakeven expected towards the end of the time horizon.

Figure 3-23 – CHP (Residential) sector economic gap snapshot (Fuel cost only)

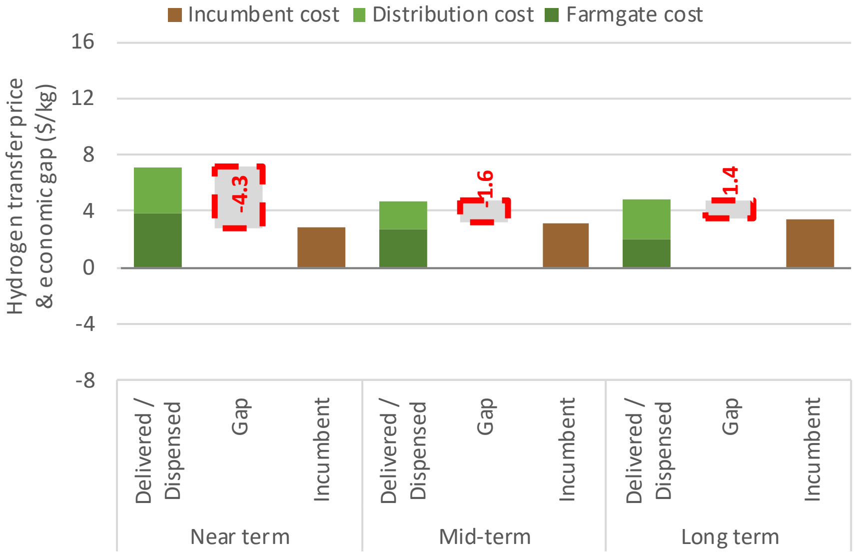
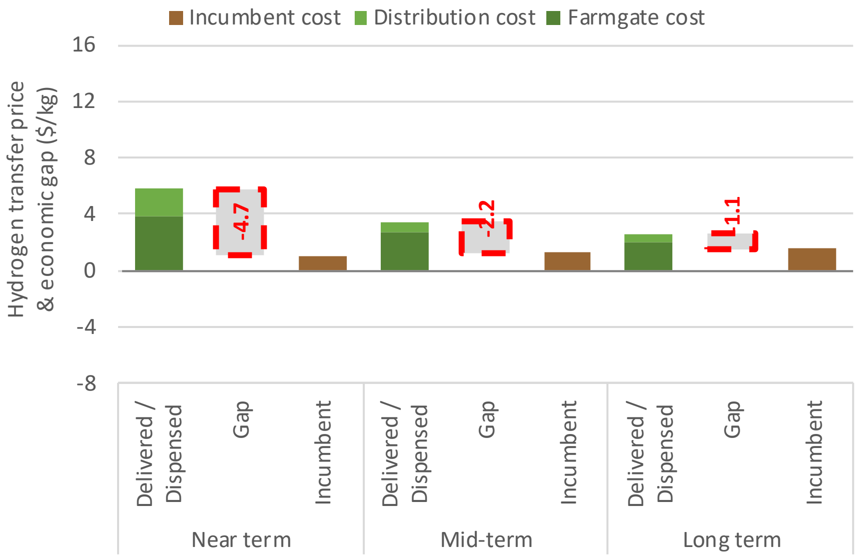


Figure 3-24 – CHP (Industrial) sector economic gap snapshot (Fuel cost only)



For hydrogen CHP to be a viable technology:

- A significant heat demand coupled with the electricity demand is required;
- Hydrogen fuel cells must provide higher efficiency than comparative natural gas based systems; and
- CHP is able to create a niche where the distributed heat and power generation provides value versus high efficiency electric heat pumps.

Residential CHP is considered to have moderate dependence on hydrogen for decarbonisation, with a rating of 5 out of 10. Other alternatives, such as electrification of all heating and cooling, are likely to be more important. Industrial CHP is rated 6 out of 10 and could provide an advantage over electrification where high temperatures and power are required.

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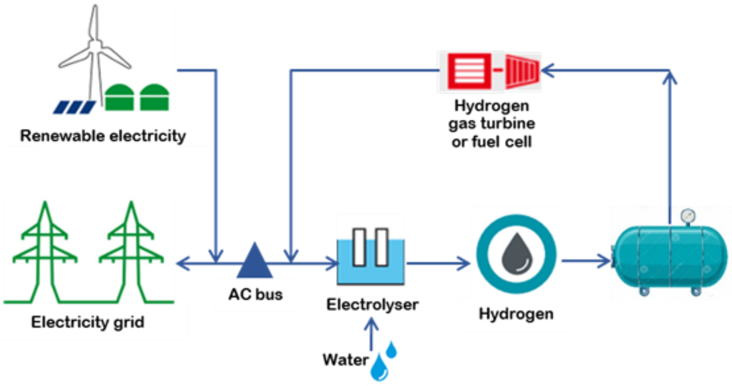
3.4 Power and grid balancing

The power and grid balancing section of this report investigates the opportunity for hydrogen based systems to provide excess power capture and power storage (akin to a battery) to enable grid balancing and emote power applications in light of the increased penetration of renewable power generation.

3.4.1 Grid balancing



Hydrogen for grid balancing involves storing renewable electricity as hydrogen when there is excess power causing lower prices and regenerating as power when there is a supply shortfall resulting in higher spot prices.

Recognising that hydrogen is a more expensive fuel than natural gas and that Opex cost is the dominant cost in Open Cycle Gas Turbine (OCGT) operation, this section identifies the following three potential ways hydrogen could compete with natural gas based OCGT:

i. Hydrogen based peaking units have substantially higher efficiency;

ii. Hydrogen based peaking units operate for more hours a year, with lower average cost;

iii. Fuel price parity is achieved.

Fuel cell technology offers the prospect of more efficient peaking generation with hydrogen compared with natural gas open cycle turbines. This advantage needs to overcome higher fuel, capital and maintenance costs for fuel cells.

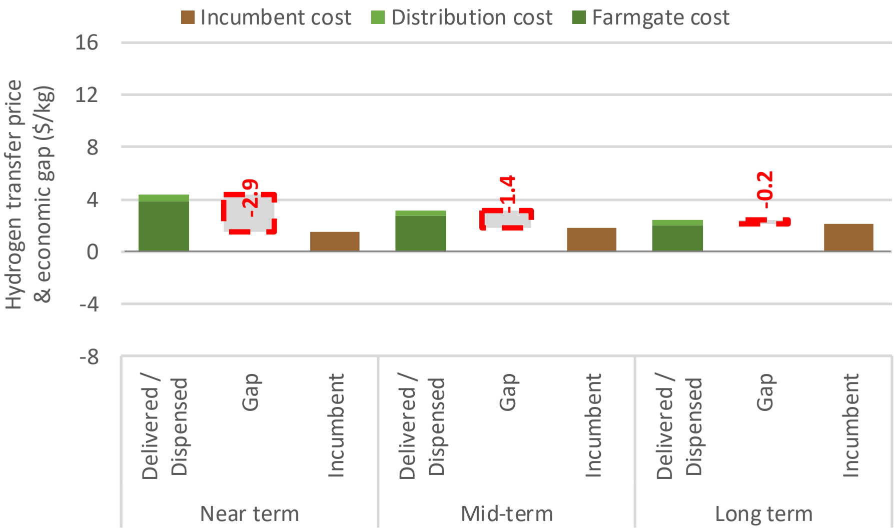
From a fuel cost perspective, a fuel cell operating at 70% efficiency could afford to pay nearly double the natural gas price for hydrogen and still achieve commercial parity. The current reality is not so favourable – the capital cost ($/MW) and operating costs ($/MWh) are currently significantly higher for these high efficiency systems than the incumbent natural gas turbine technology.

However, the economic gap associated with grid balancing application is forecast to progressively get more favourable across the time horizon but is not expected to reach parity with natural gas peaking before 2050.

There are a number of variables that could impact the viability of hydrogen for grid balancing:

- High natural gas prices providing a less competitive alternative;
- More volatile electricity prices and more high cost and low cost periods in the year;
- Greater value for network services and interseasonal storage; and
- Lowering hydrogen storage costs.

Figure 3-25 – Grid balancing sector (with H2 turbine) economic gap snapshots (TCO basis)



Grid balancing is considered to have moderate to high dependence on hydrogen for decarbonisation, with a rating of 7 out of 10. Other electricity storage alternatives, such as batteries for short term and pumped hydro for longer term, will be competitors. In Australia where opportunites for utility scale pump hydro are limited, hydrogen could be an important energy storage medium.

3.4.2 Remote power

Hydrogen production, storage and return to electricity has the potential to provide a more cost-effective remote power solution for towns or industrial sites, than more conventional diesel and solar with battery solutions.

To illustrate this potential, we modelled a remote power system of a small town with a peak population of around 6,000 people and a peak summer demand of 6.2 MW using current technology and fuel costs. In our estimates, the electricity consumption is just over 24,000 MWh per year.

Remote power systems offered an attractive opportunity for hydrogen production and storage to lower the costs and GHG emissions of diesel or natural gas based remote power systems.

To achieve 100% renewable energy on these sites is possible with hydrogen, potentially at lower levelised cost than diesel only systems. Hydrogen storage could also offer a lower cost option to batteries for longer duration storage. It is noted that the capital cost for a hydrogen system is higher than for competing diesel and solar, battery and diesel hybrid systems.

Fuel cell technology offers the prospect of more efficient peaking generation with hydrogen compared with natural gas open cycle turbines. This advantage needs to overcome higher fuel, capital and maintenance costs for fuel cells.

In our analysis using Xendee software, we established that a hydrogen-based system with very small diesel plant to manage <6% of the power generation provided the lowest cost of power – see Table 3-2.

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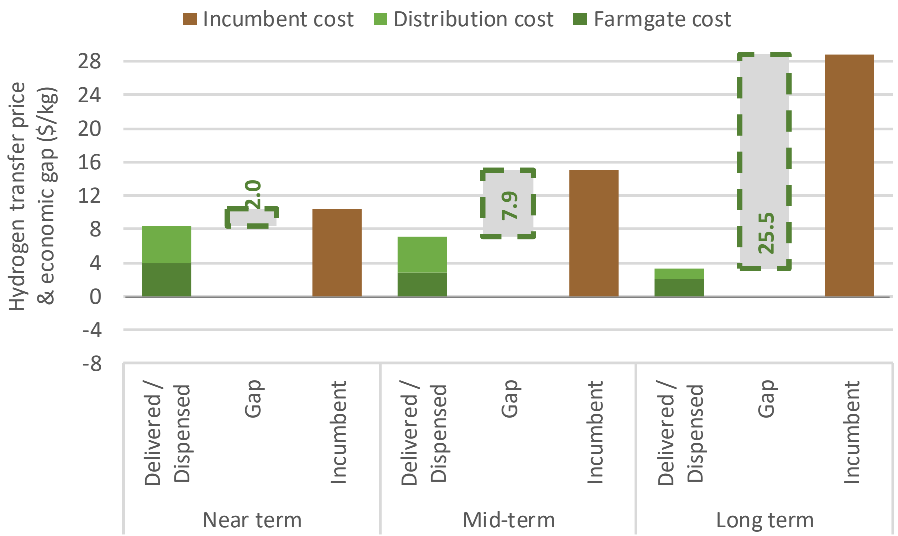
Table 3-2 - Remote power levelised cost assessment results (Real 2020)

System	Total Capex ($million)	Opex ($millions pa)	LCOE ($/MWh)	Emissions (tCO_2-e)
Solar + H_2	$98.5	$0.99	$387	0
Solar + H_2 + diesel	$69.9	$1.1	$290	970
Solar + BESS + diesel	$35.3	$2.45	$224	4,100
100% diesel	$11.1	$6.8	$318	17,600

This analysis has not considered options which import hydrogen, or hydrogen carriers like ammonia. Compressed or liquid hydrogen or liquid ammonia which could be stored to provide baseload fuel, replacing diesel in the hybrid options.

The economic gap associated with the remote power sector is forecast to progressively get more positive across the time horizon. This trend is consistent with the expectations of increasing diesel price (Graham & Smart (ACIL Tasman), 2011), whilst cost of hydrogen production and fuel cell technology decline.

Figure 3-26 – Remote power sector economic gap snapshots (using fuel cell with diesel back-up)



Hydrogen for remote power is likely to be viable under the following conditions:

- Alternatives are expensive, such as diesel that has to be trucked long distance;
- Battery costs for long duration storage remain prohibitive;
- Hydrogen electrolyser and storage costs decline rapidly; and
- Complementary applications for local hydrogen production are developed, such as mobility in mining operations.

Remote power applications for towns and industrial sites are considered to have moderate to high dependence on hydrogen for decarbonisation, with a rating of 7.5 out of 10. For zero emissions, offgrid systems, hydrogen energy storage could become a key technology, providing long duration energy storage. There could also be important integration opportunities with remote fleets such as mining trucks.

3.5 Feedstock for industry

3.5.1 Alumina calcining

Australia is a major global producer of alumina (Al_2O_3), which it refines from plentiful local reserves of bauxite, a mineral containing primarily alumina and iron oxides. The majority of Australian alumina is exported to aluminium smelters globally. A small fraction of Australian alumina is smelted domestically.

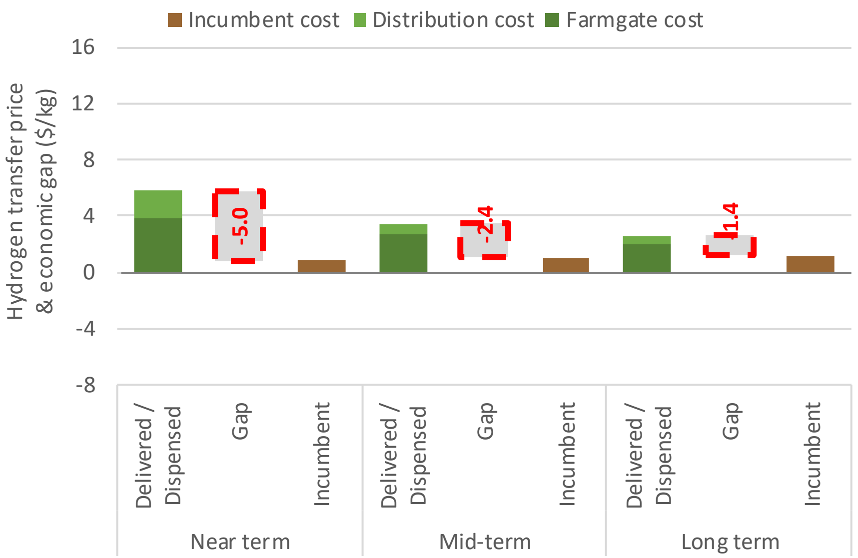
Alumina does not require the chemical properties of hydrogen, rather the heat source to drive digestion and drying processes. There is no chemical or efficiency advantage associated with using hydrogen instead of natural gas as a heat source in the Bayer or calcination process. As such it is expected that in the absence of carbon pricing, the uptake of hydrogen will depend on the thermal value of hydrogen approaching price parity with natural gas.

Although the economic cost of displacing natural gas with hydrogen can be significant, there are potential benefits:

- Blending hydrogen into natural gas up to a 10% by volume mixture could provide small carbon reductions in the short term without any capital investment;
- Because of their very large energy consumption, alumina consumers could provide demand for demonstration and larger scale domestic hydrogen consumption;
- Decarbonisation in the alumina sector is a complex task; producers in Australia may be willing to pay a premium for hydrogen if it is the only path to decarbonisation; and
- Parity with natural gas for alumina production requires a hydrogen price of around $1 per kg, assuming a $9/GJ natural gas price.

Incentives are required to overcome the energy cost gap that exists between natural gas and hydrogen, with the economic gap associated with alumina calcining not expected to be attractive during the period to 2050 per Figure 3-27.

Figure 3-27 – Alumina calcining sector economic gap snapshots



The alumina sector is considered to have moderate dependence on hydrogen for decarbonisation, with a rating of 6 out of 10, with alternatives being renewable heating from solar thermal or electrification. Hydrogen could become the key decarbonisation technology if the cost of production can reach parity with natural gas.

3.5.2 Steel mills

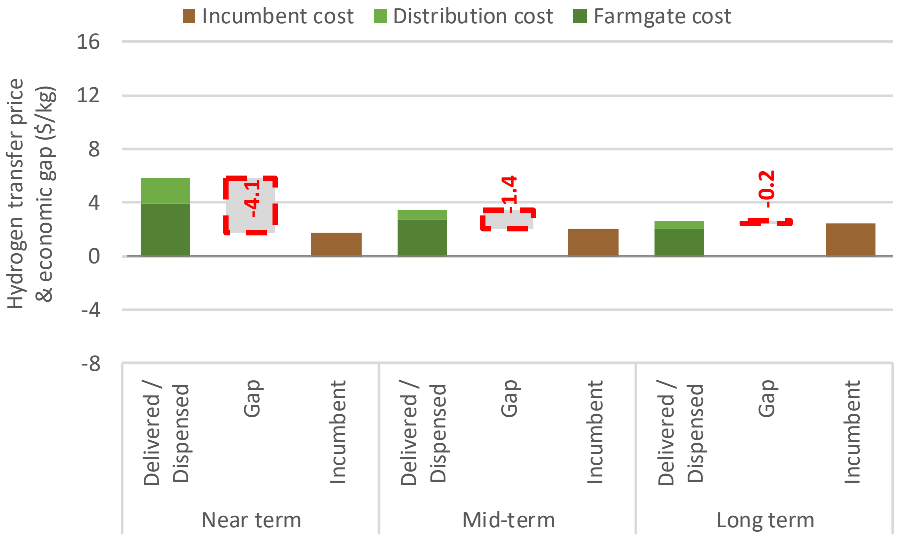
Australia is a major exporter of iron ore and metallurgical grade coal. Australian manufacturers of raw steel utilise the Blast Furnace / Basic Oxygen Furnace (BF/BOF) to make iron and steel.

Blast furnaces require periodic major upgrades to maintain operational efficiency. At the conclusion of each campaign the furnace will require relining and refurbishment. A campaign can last up to 20 years. The costs involved in the reline are significant and create a potential technology breakpoint where investment in a different technology such as the Direct Reduced Iron / Electric Arc Furnace (DRI/EAF) process can be more easily justified.

The hydrogen DRI/EAF route offers significant reductions in CO_2 emissions using natural gas as a fuel. This route also offers the potential for later conversion to a hydrogen process once hydrogen production costs have reduced to a level where natural gas can be displaced, noting that the value of hydrogen in this application is higher than just the heating value; hydrogen acts as a reductant and replaces reformed natural gas in the DRI process. This holds true of other processes where hydrogen has a value beyond heating, such as production of other metals including nickel and zinc.

The economic gap associated with the steel manufacturing sector is forecast to progressively get more attractive across the time horizon but is not expected to reach parity with natural gas supplied DRI processes before 2050.

Figure 3-28 – Steel mills sector economic gap snapshots



The application of hydrogen to steel manufacturing is dependent on:

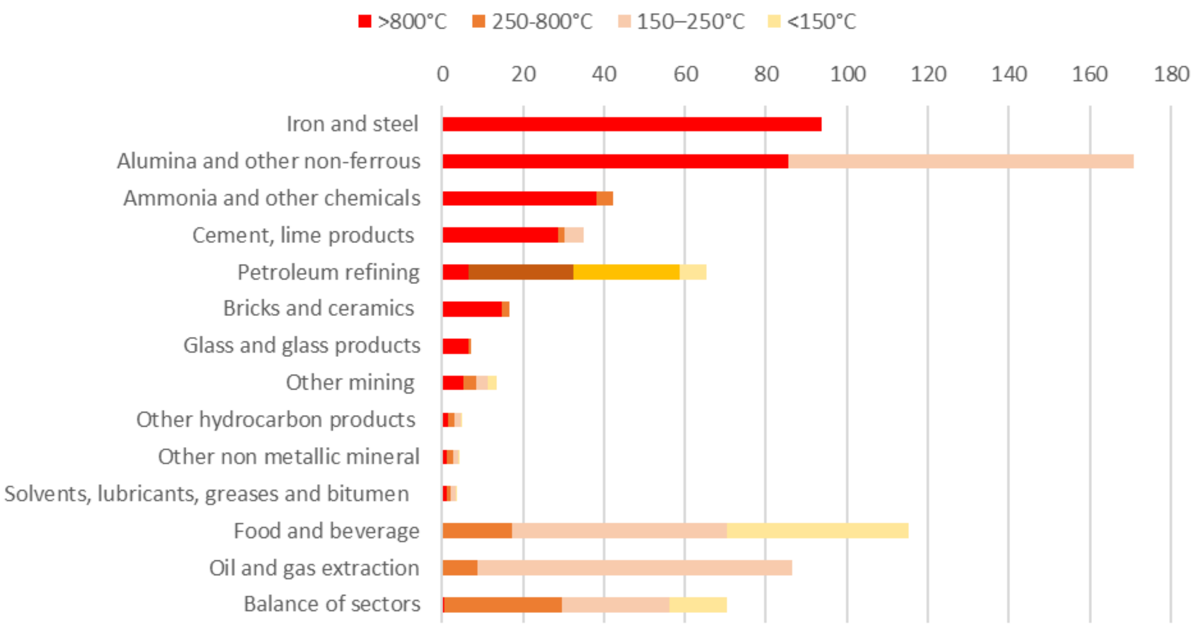
- The development and widespread uptake of lower emissions steel manufacturing, including DRI and hydrogen, to replace current coal based blast furnace operations;
- Green metals market premiums support higher energy input costs; and
- High natural gas prices reduce the competitiveness of natural gas.

The steel sector is considered to have high dependence on hydrogen for decarbonisation, with a rating of 8.5 out of 10. Other alternatives, such as CCS, are likely to be location specific and add cost to steel production.

3.5.3 Other high grade heat applications

Process heat demand in the medium temperature, that is 250-800°C, and high temperature, >800°C, ranges represent around 10% of total Australian energy consumption (ITP, Pitt and Sherry, Institute for Sustainable Futures, 2019)..The key sectors that use these grades of heat are summarised below.

Figure 3-29 - Breakdown of process heat consumption (PJ/y) in Australia

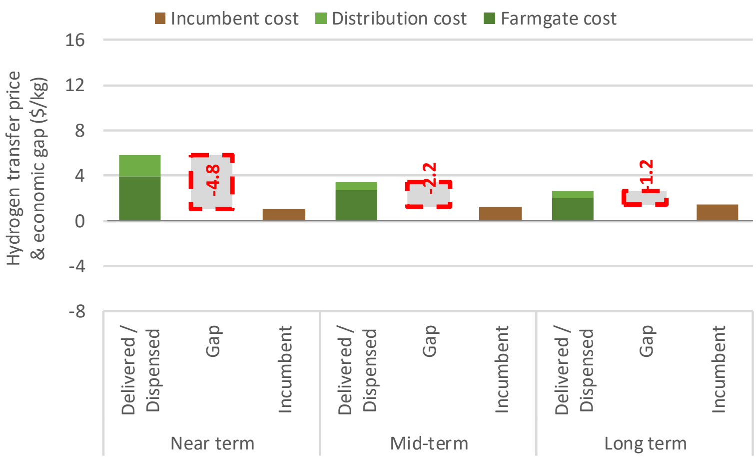


Source: ITP, Pitt and Sherry, Institute for Sustainable Futures

Low carbon hydrogen may be an attractive decarbonisation option for these industries, as its direct combustion can provide the required temperatures on a continuous basis, without the GHG implications.

In purely heating duties, even at high temperature, the efficiency of electrification is likely to be more cost effective. This will be particularly true where heat can be focused directly on the material, such as through induction heating or microwaves.

Figure 3-30 – Other high grade heat applications sector economic gap snapshots (Fuel cost basis)



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Although the economic gap for using hydrogen for high grade heat applications improves over the long term, it is not expected to be positive before 2050.

The application of hydrogen to high grade heat could be attractive if the following conditions were to occur:

- Electrification options prove not to be technically viable or are too expensive;
- Green markets emerge and these premiums support higher energy costs; and
- High natural gas prices reduce the competitiveness of natural gas.

The high-grade heat sector is considered to have high dependence on hydrogen for decarbonisation, with a rating of 8 out of 10. Electrification will also be important. However, once the production cost of hydrogen approaches cost parity with natural gas, hydrogen is likely to become a key technology.

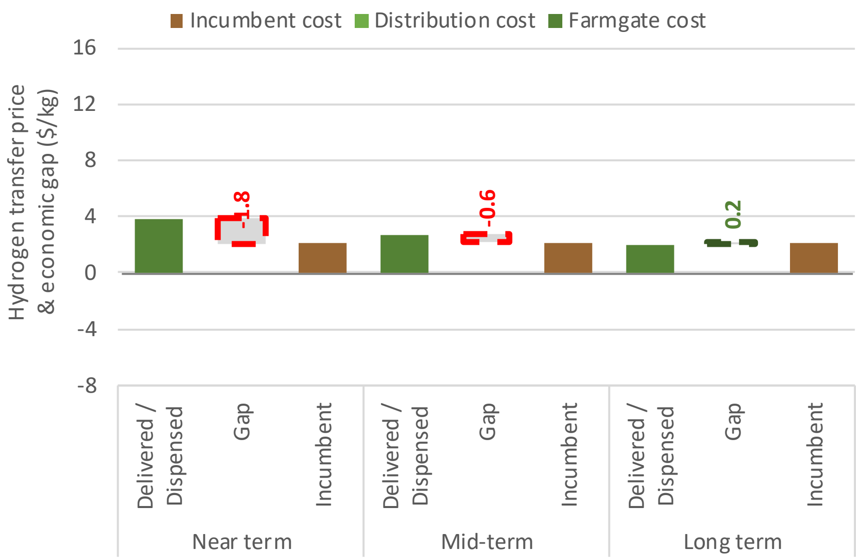
3.5.4 Ammonia

Historically, ammonia production has been a key consumer of hydrogen. Ammonia is a compound of nitrogen and hydrogen and therefore does not generate CO_2 emissions when combusted.

Industry is used to storing and transporting ammonia, including in oceangoing tankers. Ammonia can, in principle, be used as a fuel in various energy applications, for example for co-firing in coal power plants. None of these applications is being used commercially today.

A large portion of Australia's ammonia manufacturing capacity is beyond the initial design life of the facility and survives through judicious asset management and favourable domestic gas pricing. However, as the price of natural gas increases alongside the ageing of existing manufacturing plants, the viability of utilising renewable technologies to support the growth of the ammonia manufacturing industry will increase.

Figure 3-31 – Ammonia sector economic gap snapshots (TCO basis)

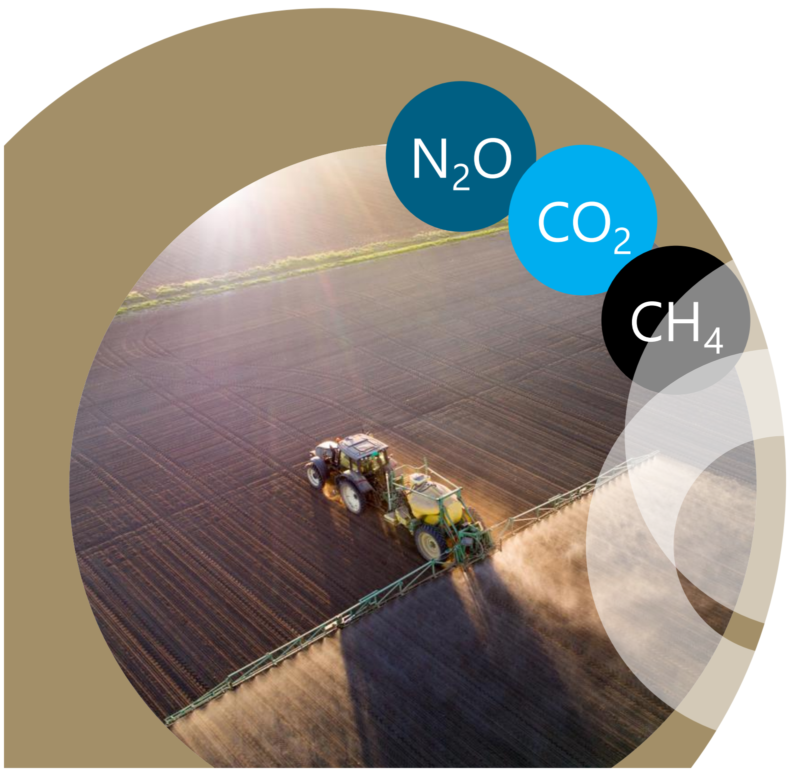


Under the base scenario Ammonia production using green hydrogen is not expected to be competitive against natural gas until around 2050, however the attractiveness improves over time where prior to 2050, niche applications may become commercially attractive.

The application of green hydrogen to ammonia production could become viable if:

- Ammonia becomes an energy vector for export of green hydrogen to South East Asia and other regions, attracting a premium price;
- The general ammonia market recognises a premium for green ammonia to produce fertilisers and chemicals;
- Technology advances more quickly than anticipated to create new pathways for green ammonia production, for example, high temperature electrolysis and improvements to the Haber-Bosch synthesis process;
- Long distance transport of ammonia feedstock or lack of natural gas infrastructure creates a niche production opportunity; and
- High natural gas prices reduce the competitiveness of natural gas.

The ammonia sector is considered to have high dependence on hydrogen for decarbonisation, with a rating of 8 out of 10. Other alternatives, such as CCS, may be used but are likely to add cost compared with hydrogen at gas parity prices.



Agriculture accounts for an estimated 11-15% of greenhouse gases (GHGs), approximately a third of which comprises nitrous oxide (N_2O)

International Fertilizer Association, 2018

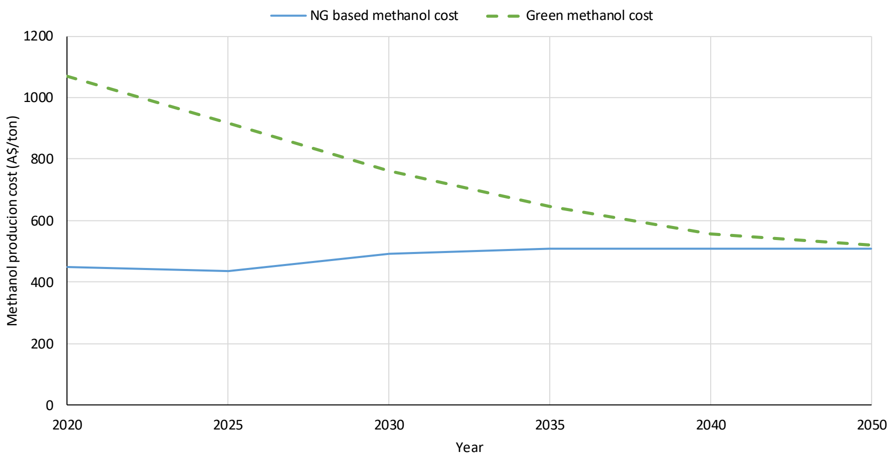
3.5.5 Methanol

Methanol is produced from natural gas by reforming with steam and then converting and distilling the synthesis gas mixture, carbon monoxide and hydrogen, to pure methanol. Methanol is used as a feedstock to industrial and consumer products market (~55% demand), and as an energy and fuel substitute (~45% demand). Today, the main application of methanol is feedstock for producing formaldehyde. There has been an increase in the consumption of methanol for the production of dimethyl ether (DME) and Methyl tertiary-butyl ether (MTBE), which are a diesel alternative and gasoline additive respectively.

Green methanol can be produced by replacing the reformer unit with electrolytic hydrogen production and carbon neutral carbon feed. To achieve low carbon emission status, the electrolyser plants must be supplied with renewable electricity.

Based on the IEA's 'the Future of Hydrogen' modelling basis, the forecast cost of conventional and Australian green methanol have been quantified in Figure 3-32. It suggests that green methanol is not expected to be cost competitive with conventional methods in the near-term and is not expected to meet price parity per Figure 3-32.

Figure 3-32 – Forecast green and conventional methanol production costs in Australia

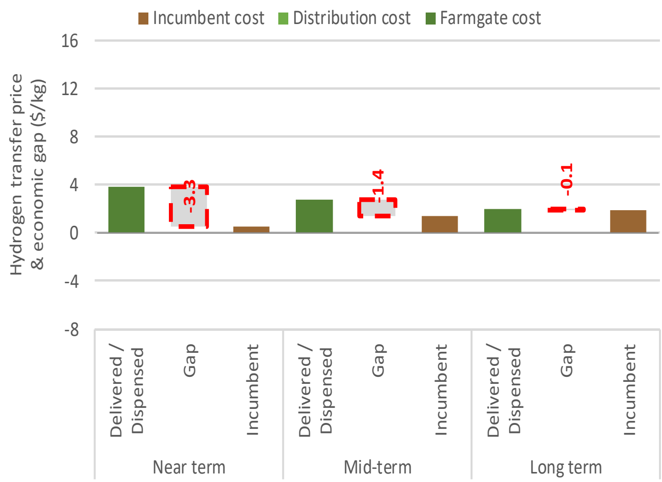


Green methanol could become viable if the following conditions are met:

- A green market develops for methanol and methanol derived products, such as plastics;
- Methanol becomes a hydrogen vector, gaining premium value as a low emissions energy carrier and fuel;
- Niche supply opportunities emerge that are stranded from natural gas supplies; and
- High natural gas prices reduce the competitiveness of natural gas.

The methanol sector is considered to have high dependence on hydrogen for decarbonisation, with a rating of 8 out of 10.

Figure 3-33 Methanol sector economic gap snapshots



Other alternatives, such as CCS, may be used but will only treat the portion of emissions associated with methanol production.

3.5.6 Oil refining

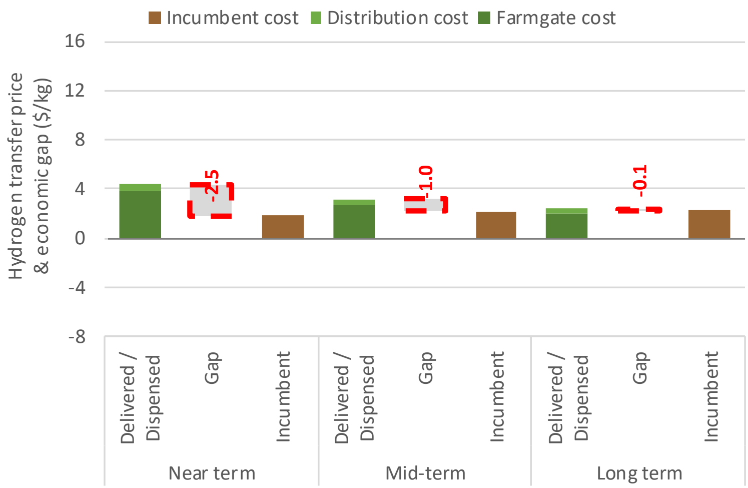
The majority of hydrogen consumed within a crude oil refinery typically occurs during the fractionation of the crude oil feed, naphtha reforming and heavy distillate cracking. Refineries that process light / sweet crudes, such as Lytton in Australia, often have no need for additional hydrogen production and utilise excess hydrogen from the process as heating fuel. Refineries that process heavy / sour crudes consume hydrogen in hydrotreating and sulphur removal steps.

When hydrogen demand exceeds internal production, additional hydrogen is typically produced using steam methane reforming of imported natural gas or excess fuel gas. The trend towards increased hydrogen consumption in refineries is related to tightening supplies and price premiums associated with sweet / light crudes, and progressive tightening of sulphur specifications on consumer fuels and marine bunkers.

Increased hydrogen consumption may also be required to produce low sulphur fuels for marine applications in the short term, and for land transport in the medium term. Additionally, schemes such as RED II in Europe allow green hydrogen feedstock to be counted towards renewable energy requirements in fuels (European Union, 2018), and this appears to be potentially cost effective compared to biofuel alternatives.

The oil refining sector is forecast to maintain a negative economic gap across the period shown in Figure 3-34, although the size of the gap decreases over time.

Figure 3-34 – Oil refining sector economic gap snapshots (Fuel cost basis)



The application of green hydrogen to oil refining could become viable if:

- Low emissions fuel standards are introduced in Australia along the lines of the European RED II scheme, creating a high value market for green hydrogen; and
- Future fuel sulphur level reduction regulations are predicated on the use of renewable hydrogen in the hydrotreating processes.

The oil refining sector is considered to have moderate dependence on hydrogen for decarbonisation, with a rating of 6 out of 10. Other alternatives, such as CCS, may be used but are likely to add cost compared with hydrogen at gas parity prices.

4

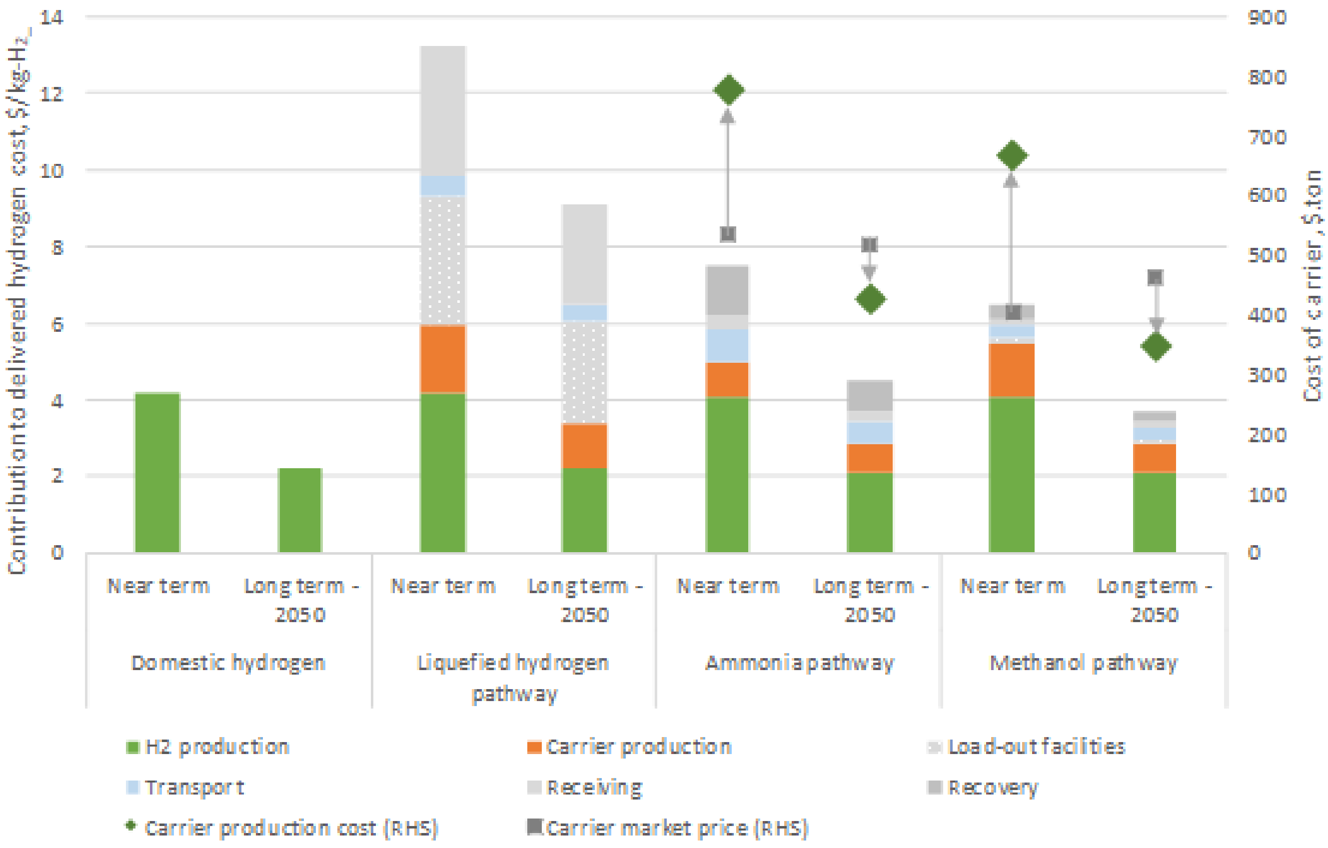
Export pathways

4 Export pathways

The export of hydrogen is forecast to be a key enabler of a global low carbon economy. The Australian National Hydrogen Strategy has set high expectations for the development of a hydrogen export economy by 2030. The key challenge to this ambition is the inherent very low density of hydrogen.

In this section of the report, we analyse liquid hydrogen and ammonia export pathways to compare current and future expected delivered hydrogen costs in Japan. In this analysis we evaluate both the expected delivered cost as well as the expected production cost of the carrier fluid. The results of this analysis are illustrated in Figure 4-1 below.

Figure 4-1 – Forecast cost of delivered green hydrogen in Japan

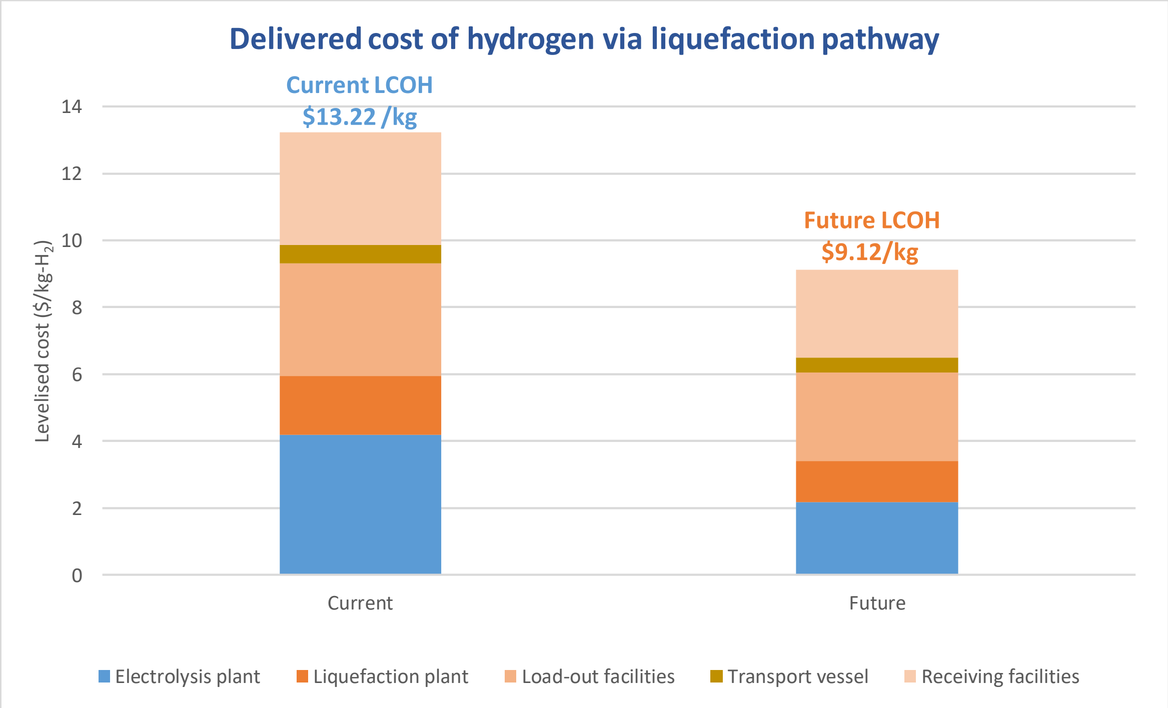


4.1.1 Export of liquid hydrogen

The liquid hydrogen export pathway is considered to have analogues with the liquefaction of natural gas. Commercial export of liquefied natural gas (LNG) commenced circa 1980, with only slow growth until early 2000s, when the volume of trade escalated dramatically. Liquefaction of hydrogen will likely require the development of a demand market before significant export scales are achieved.

The key advantages of liquefaction relates to the increased hydrogen density of 71 kg/m^3 and the ability to use the hydrogen directly at the point of delivery through simple gasification. Producing liquid hydrogen from gaseous hydrogen, export facilities, shipping and import facilities is currently expected to add more than $9/kg to the cost of hydrogen for a delivered cost of nearly $13 per kilogram as shown in Figure 4-2.

Figure 4-2 – Levelised cost profile for liquid hydrogen export to Japan



Although the liquefaction pathway has comparatively higher energy demand for carrier conversion, the biggest challenge for this pathway is the immense capital costs associated with load-out and receiving terminals and the early development status of liquid hydrogen shipping. In order to be cost effective, liquefaction projects need industrial scales and considerable capital expenditure. In the near-term, the anticipated minimum viable size is 400 tpd or 140 ktpa Technology for hydrogen liquefaction, storage, shipping and regasification are all in the process of being scaled to match export hydrogen requirements.

4.1.2 Export of ammonia

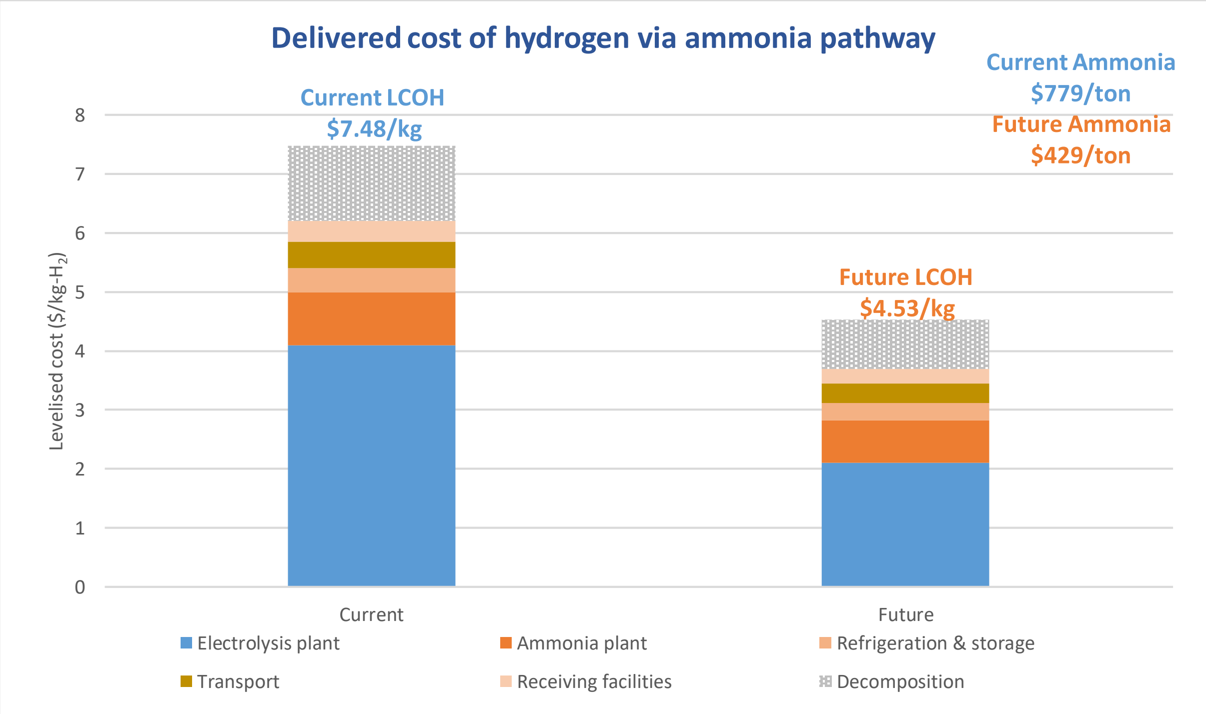
The key advantages of ammonia as an export fuel relate to the effective hydrogen carrying density of 158 kg/m^3, making up 18% of ammonia, and the ability to utilise of existing transport infrastructure and technology. The effective hydrogen density is more than double that which is achieved by liquefied hydrogen. If pure hydrogen is required by the end user, rather than direct ammonia use, then a portion of the hydrogen will be lost or consumed as fuel in the conversion process.

The manufacture of ammonia does not require dehydration and inert contaminants are acceptable, hence manufacture of ammonia from blue and green hydrogen has similar costs. In order to be cost effective, ammonia facilities larger than 500 ktpa are expected.

Ammonia generally raises more health and safety considerations than hydrogen, and its use would probably need to continue to be restricted to professionally trained operators. It is highly toxic, flammable, corrosive, and escapes from leaks in gaseous form. However, unlike hydrogen, it has a pungent smell, making leaks easier to detect.

The delivery costs associated with hydrogen delivery via ammonia pathway are significantly lower than via the liquefaction pathway, as is shown in Figure 4-3, at just under $8/kg for extracted hydrogen. However, the technology to extract high purity hydrogen from the ammonia feed is still in an early stage of development and costs are uncertain.

Figure 4-3 – Levelised cost profile of hydrogen export (via. ammonia) to Japan



The pathways involving chemical bonding, such as ammonia and methanol, appear to offer lower delivered hydrogen prices than the liquefaction pathway. In the near term, the "green" carrier cost is significantly more expensive than the conventional product, but by 2050 the green product is forecast to be cheaper than the incumbent. The key challenges associated with the ammonia pathway relate to decomposition losses and management of a toxic compound. The key challenges associated with the methanol pathway relate to securing carbon neutral carbon dioxide (refer to Section 6.1.6) and management of a toxic compound.

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5

Accelerating market development and sector competitiveness

5 Accelerating market development and sector competitiveness

5.1 Market development

The development of prospective and flexible domestic hydrogen consumption de-risks and facilitates export led pathways.

Given that there are several domestic end-use applications that approach commerciality before export markets do, adopting an export only mentality to the early advancement of the hydrogen economy is likely to yield less favourable commercial outcomes than a combined domestic and export approach. Without global growth of a hydrogen consumption market, the cost of hydrogen fuel cells and storage systems is unlikely to decline rapidly and therefore the prospective end-use markets will remain uneconomic. The development of domestic markets will support the social licence for hydrogen manufacturing, which might otherwise be perceived as inflating electricity prices for other users by consuming low cost renewable electricity from the market.

Hydrogen export facilities have downtime and may experience demand fluctuation. If Australia had some hydrogen swing consumers, for example ammonia synthesis or alumina calcining, then excess hydrogen could be used rather than idling facilities. The ability to spill excess hydrogen to a domestic end-use enables GHG reduction in Australia as well as providing a secondary revenue stream to industrial-scale hydrogen manufacturers.

Developing a flexible hydrogen market is unlikely to be readily advanced through corporate to corporate contracts. A market led approach using common infrastructure, akin to the electricity market, is likely to achieve faster update and greater diversity of outcomes.

As demonstrated in this study, heavy-duty line haul trucking and remote power and vehicles in the mining industry should be targeted as prospective end users for early development.

5.2 Complimentary business models

Stretching beyond just hydrogen production is likely to be a key differentiator and cost reduction lever.

Australia is a global leader in research supporting photovoltaic hydrogen production as well as direct ammonia synthesis and ammonia decomposition technology. These technologies align well with our solar and onshore wind resources competitive advantage. Linking resource competitiveness with "industrial" competitiveness could provide greater avenues for Australia's manufacturing sector.

Ensuring Australian content in manufacture and maintenance of electrolysers would also have strong secondary advantages.

The countries which develop a value stream for the oxygen by-product will have competitive advantage, so Australia should explore this prospect as well.

5.3 Sector competitiveness summary

A summary of the economic gap analysis and key considerations for each sector are captured in Figure 5-1.

KEY
- Economic gap score
- Non-economic attractiveness
- GHG emission reduction

Figure 5-1 – Key sector competitiveness parameters

Sector	Incumbent	Hydrogen	Alternative/s	Economic gap	Attractiveness 2030 (Relative to incumbent)	Dependance on H_2 for decarbonisation	Comment
Light vehicles	Internal combustion engine (10.8 L/100 km)	Fuel cell vehicle (0.77 kg /100 km)	Battery electric vehicle (15 kWh/100 km)	2020 2030 2050		2 (Alternatives are likely to be competitive)	Transitions from highly negative to moderately positive economic gap More attractive for long range applications Home based charging is possible long term Low emissions can be certified
Material handling	Internal combustion engine (1 refill per shift)	Fuel cell vehicle (Comparable refueling rates; Rapid electric motor based acceleration)	Battery electric vehicle (Batteries provide weigh to counterbalance loads; Rapid electric motor based acceleration)	2020 2030 2050		3 (Alternatives are likely to be competitive)	Comparable / positive economic gap No emissions / spark risk in confined spaces Low emissions can be certified. Faster charge times than BEV
Heavy vehicles – Line haul	Internal combustion engine (35 L/100 km) 200,000 km/y	Fuel cell vehicle (8.28 kg /100 km)	Battery electric vehicle (124 kWh/100 km)	2020 2030 2050		6 (Hydrogen can be competitive)	Comparable to positive economic gap More attractive for long range applications Possible liquid hydrogen fueling advantages Low emissions can be certified
Heavy vehicles – Return to base	Internal combustion engine (28.5 L/100 km) 50,000 km/y	Fuel cell vehicle (4.1 kg /100 km)	Battery electric vehicle (106 kWh/100 km)	2020 2030 2050		4 (Alternatives are likely to be competitive)	Positive economic gap (Most prospective) More attractive for long range applications Liquid hydrogen fueling could be simpler Low emissions can be certified
Heavy vehicle – Mining	Internal combustion engine (160 L/h)	Fuel cell vehicle (90% of ICE energy demand)	Battery electric vehicle (with and without trolley assist)	2020 2030 2050		7 (Moderate dependence.; Other options are possible)	Positive economic gap (Attractive) Flexible operation and short charge times give advantage over BEV in many applications Possible liquid hydrogen fueling
Rail	Internal combustion engine (150,000 km/y)	Consistent high power demand reduces efficiency advantage	Battery electric locomotive (with and without overhead line charging) - Charge time reduces travel distance	2020 2030 2050		3 (Alternatives are likely to be competitive)	Shifts to positive economic gap by 2050 More attractive for passanger and variable power demand applications Electrification is a clear alternative
Ferries	MGO fired Internal combustion engine	Fuel cell vehicle (Fuel storage volume may be 10× greater than MGO based approach)	Battery electric approach (Significant battery storage volume and weight)	2020 2030 2050		7 (Moderate dependence.; Other options are possible)	Shifts to positive economic gap by 2050 Battery based solutions have weight impediment Liquid hydrogen or GNH_3 based approaches may be attractive
Marine shipping – Methanol	MGO fired Internal combustion engine	Modified iternal combustion engine (Fuel density is 50% that of MGO)	Use of captured CO_2 (not carbon neutral) in methanol production	2020 2030 2050		9 (Very high dependence.; No easy alternatives)	Shifts to positive economic gap by 2050 Carbon dioxide must be carbon neutral Liquid hydrogen or GNH_3 based approaches may be attractive
Marine shipping - Ammonia	MGO fired Internal combustion engine	Modified iternal combustion engine (Pressurised or refrigerated storage @ 35% fuel density of MGO)	Fuel cell driven vessel (Comparable power demand)	2020 2030 2050		9 (Very high dependence.; No easy alternatives)	Comparable / positive economic gap Ammonia toxic management challenges are well known and managed Particularly attractive if carrying GNH_3 for export
Aviation - Regional	Jet-A fired turbines	Fuel cell based turbo props (Liquid hydrogen storage density is ~25% volumetric density of Jet-A, hence aircraft design and speeds are heavily modified)	Synfuel fired turbines (Minimal change to existing infrastructure)	2020 2030 2050		8 (Moderate dependence.; Other options are possible)	Negative economic gap Significant changes to infrastructure and speed expectations GHG impact reduced by 80%
Aviation - International	Jet-A fired turbines	Hydrogen fired turbines (Liquid hydrogen storage density is ~25% volumetric density of Jet-A, hence aircraft design and speeds are heavily modified)	Synfuel fired turbines (Minimal change to existing infrastructure)	2020 2030 2050		9 (Very high dependence.; No easy alternatives)	Negative economic gap Significant changes to infrastructure GHG impact reduced by 60%
Synthetic natural gas	Natural gas systems using natural gas	Natural gas systems using "green" synthetic natural gas	Use of captured CO_2 (not carbon neutral) in SNG production	2020 2030 2050		5 (Hydrogen can be competitive)	Consistently negative economic gap Carbon dioxide must be carbon neutral Could be a direct replacement for natural gas
Gas network (i.e. Blending)	Natural gas systems using natural gas	Natural gas systems using up to 20% blend of hydrogen	Natural gas systems using up to 20% blend of hydrogen and hydrogen recovery at key points	2020 2030 2050		5 (Hydrogen can be competitive)	Negative economic gap Can provide transmission vector for hydrogen & ideal for intermittent "spill" of hydrogen production. Temporal variability can disrupt end-users.
100% hydrogen gas network		100% hydrogen gas network	Distribution with hydrogen carrier	2020 2030 2050		N/A	Hydrogen transport is challenging due to very low density. Transmission of electricity with storage or hydrogen generation at terminus are competing options.
Combined heat and power - Residential	CHP using natural gas	CHP using H_2 fuel cell	Transmission of renewable electricity and solar based heat	2020 2030 2050		5 (Hydrogen can be competitive)	Negative to comparable economic gap Economic with lower heat demand Water delivery could be a benefit Clear GHG advantage
Combined heat and power - Industrial	CHP using natural gas	CHP using H_2 fuel cell	Transmission of renewable electricity and solar based heat	2020 2030 2050		6 (Hydrogen can be competitive)	Negative economic gap Economic with lower heat demand. High temperature applications need a hybrid combustion / FC solution. Water delivery could be a benefit
Grid balancing	Open cycle gas turbine using natural gas	H_2 fuel cell	Battery	2020 2030 2050		7 (Moderate dependence.; Other options are possible)	Negative economic gap Pipeline based delivery could support market development Water delivery could be a benefit Clear GHG advantage
Remote power	Diesel genset	"Green" hydrogen generation, storage and H_2 fuel cell + diesel support	Solar generation with battery storage	2020 2030 2050		7.5 (Moderate dependence.; Other options are possible)	Comparable to positive economic gap Supports self resilience and reduces handling of diesel Clear GHG advantage
Alumina calcining	Direct combustion of natural gas	Direct combustion of hydrogen	Electrification	2020 2030 2050		6 (Hydrogen can be competitive)	Negative economic gap until approaching natural gas parity Clear GHG advantage
Steel mills	Direct combustion and reforming of natural gas / coking coal	Direct combustion of hydrogen		2020 2030 2050		8.5 (High dependence.; No easy alternatives)	Negative economic gap until approaching natural gas parity (with reduction value) Clear GHG advantage
Other high grade heat	Direct combustion of natural gas	Direct combustion of hydrogen	Electrification	2020 2030 2050		8 (High dependence.; No easy alternatives)	Negative economic gap until approaching natural gas parity Clear GHG advantage
Ammonia	Reforming of natural gas or gasified coal to feed Haber-Bosch process	Direct use of hydrogen in Haber-Bosch process		2020 2030 2050		8 (High dependence.; No easy alternatives)	Shifts to positive economic gap by 2050 Provides hydrogen export potential and broad market Clear GHG advantage
Methanol	Reforming of natural gas or gasified coal to feed Haber-Bosch process	Direct use of hydrogen in Haber-Bosch process		2020 2030 2050		8 (High dependence.; No easy alternatives)	Shifts to positive economic gap by 2050 Provides hydrogen export potential and broad market Clear GHG advantage
Oil refining	Reforming of light ends		NG SMR with CCS; Lighter crude slate	2020 2030 2050		6 (Hydrogen can be competitive)	Shifts to positive economic gap by 2050 Supports directions for "green" shipping and aviation Clear GHG advantage
Liquid hydrogen export	None	Liquefaction of green hydrogen	Inernational power transmission & batteries	2020 2030 2050			Liquid hydrogen is a carrier and not an end-use.
"Green" ammonia export	Reforming of natural gas or gasified coal to feed Haber-Bosch process	Haber-Bosch process with "green" hydrogen	Blue ammonia	2020 2030 2050			Green ammonia is a carrier and not an end-use.

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5.4 Activities to accelerate hydrogen market development

Based on the analysis conducted during this study, the areas where pro-active and pre-emptive action are likely to accelerate and support the development of an Australian hydrogen economy were identified. We summarise our observations and rationale in Table 5-1 below.

Table 5-1 Summary of hydrogen economy enabling activities

Activity title	*Description of suggested activity*	*Likely impact and reason for action*	*Relative importance (0-10)*
TUoS and grid stabilisation service fee interpretation	Develop market guidance regarding forecast TUoS and grid stabilisation service fees as they relate to systems with more renewables / greater intermittency.	Provides certainty regarding costs / service revenues that are needed to underwrite business cases.	9
Enable common user pipeline infrastructure	Consider the potential for central investment in pipelines with commercial returns once assets fully utilised.	Enables multiple producers and users without first mover cost burden.	9
Definition of "Origin certification"	Clarify proposed "certification" method and target ranges	Provides definition of products for cost and GHG benchmarking.	9
Hydrogen recovery from blended networks	Demonstration of H_2 product quality after mingling with natural gas and odorants such as mercaptans.	H_2 recovery can be used to stabilse the H_2 concentration in a feed to a "gas peaker" plant and would yield locations for high quality H_2 distribution / dispensing for vehicles.	8
Demonstration of remote power systems	Demonstration of H_2 based remote power systems. Support for investment in a few larger scale (5 – 25 MW) systems.	Reduce anxiety about the high upfront costs and demonstrate the benefits.	8
Use of green energy certificates for green hydrogen	Confirm how much time-based alignment between generation and consumption of renewable electricity is required in order to be classified as green. This could be managed by the Clean Energy Regulator in a similar way to the LRET scheme.	Provides confidence that green energy certificates will remain as a regulatory provision post 2030. Provides clarity regarding approach to "origin certification".	8
Standardisation of electrolyser unit capacity definition	Standardised on basis of costing metrics – Start of Life (SOL), End of Life (EOL), Average or power demands at stack or unit level or flowrate (Nm^3/h / kg/h).	Improves reporting consistency and industry confidence.	8
Gaseous hydrogen (GH_2) and liquid hydrogen (LH_2) dispensing stations regulations	Confirm regulatory framework for design of GH_2 and LH_2 dispensing stations	Provides certainty regarding a key portion of near-term infrastructure.	7
Ammonia steel and alumina sector readiness	Undertake studies regarding the capacity of key sectors to accept intermittent / multi-day supply of excess hydrogen production.	Enable hydrogen export projects to plan where to direct production in the event of export facility outage and builds knowledge around end-use	7

		sector readiness. / management of excess renewable energy generation	
Establishment of hydrogen refuelling hubs	Use a baseline demand from a back to base, heavy vehicle fleet to establish refuelling facilities at strategic locations with costs shared in a way that supports demand development.	Enable investment in hydrogen fleets and support uptake by smaller operators of hydrogen vehicles	7
Establishment of hydrogen distribution networks for transport	Create the initial hydrogen distribution system to enable hydrogen refuelling for heavy transport back to base applications. Charge users on a volume delivered basis as demand is established.	Avoid first mover cost disadvantage for hydrogen based trucking and installation of truck filling stations.	7
Crude oil refinery diversification	Assess mechanisms for crude oil refineries to reduce dependence on aviation fuel margins and natural gas imports. Diversification into biofuel and hydrogen production.	Enable refineries to transition rather than scale back / shutdown. Unlocks the great potential of tankage and port access. Keeps vital infrastructure alive.	7
End user sensitivity to H_2 variability including gas peaker power generators	Assess the impact of changing H_2 concentration in blended networks of end users, in particular gas peakers.	Determines the practicality of high concentration H_2 / gas blends, and practicality of lowering emissions in the natural gas network	7
GH_2 and LH_2 transport regulations	Confirm regulatory framework for transport of GH_2 and LH_2.	Provides certainty regarding a key portion of near-term infrastructure.	6
Develop a value for oxygen	Demonstrate the role of electrolytic oxygen for wastewater treatment and sulphuric acid production.	Reduces hydrogen production costs by valuing by-product	6
Greening marine fuel infrastructure.	Conduct studies to determine what is needed to transition marine fuel system to low carbon green export centres.	Keeps vital infrastructure alive and validates public good interests.	6
Define green hydrogen	Define maximum GHG emissions associated with green pathway.	Enables standardisation and provides sector confidence.	6
Direct and photovoltaic hydrogen production	Support research behind direct solar (i.e. Heliostat) and photovoltaic hydrogen / carbon monoxide production.	Australia is a world leader and could gain IP / early adopter advantages.	5
Water offtaker social licence to operate obligations	Develop guidelines regarding when water must be sustainably sourced.	Reduces anxiety regarding competition for town water and agriculture.	5
AEMO ISP to include H_2 industry provisions	Support AEMO modelling to include H_2 generation and H_2 peaker generator plant provisions.	Greater visibility to industry participants yields greater investment confidence.	4
Direct ammonia production and decomposition	Support research behind direct ammonia production and decomposition.	Australia is a world leader and could gain IP / early adopter advantages.	4
H_2 based aviation	Enable H_2 based aviation using turboprop engines and fuel cells.	Hasten the arrival of low emissions aviation.	4

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Key concepts explained

6 Key concepts explained

The below explanation of key concepts provides a framework for the above analysis touching on key assumptions and definitions used to form the basis of the hydrogen production and economic gap assessments.

6.1.1 "Water splitting" electrolysis

Using electrolysers for water splitting is a technology that uses an electrical charge to split water (H_2O) into hydrogen (H_2) and oxygen (O_2). This is often termed green hydrogen, since the key inputs to this process - renewable electricity and demineralized water, can be produced sustainably.

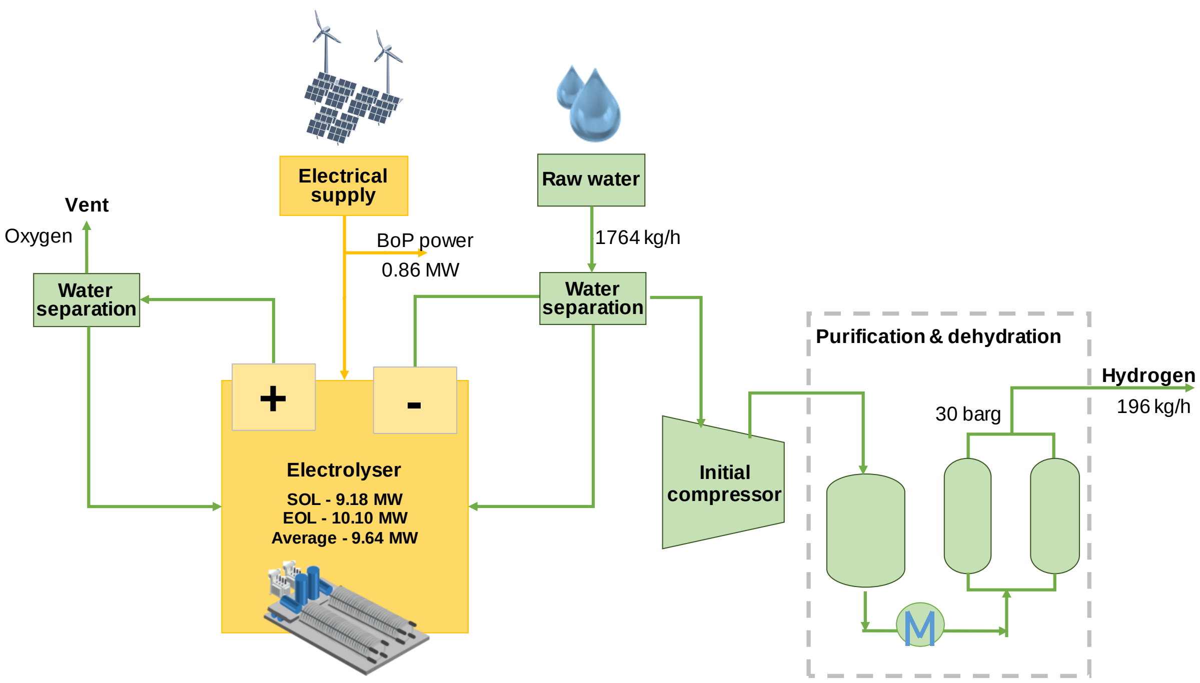
Fundamentally, the electrolysis process converts electrical energy into chemical energy stored in hydrogen, according to the reversible reaction:

$$2\ H_2O_{(l)} \rightarrow 2\ H_{2(g)} + O_{2(g)}$$

Theoretically, the minimum energy required to drive this reaction is equivalent to hydrogen's higher heating value (HHV) when combusted in air, which is 39 kWh/kg of hydrogen.

Figure 6-1 shows a simplified typical schematic of a typical water splitting electrolysis unit.

Figure 6-1 – Schematic of typical "water splitting" electrolysis unit



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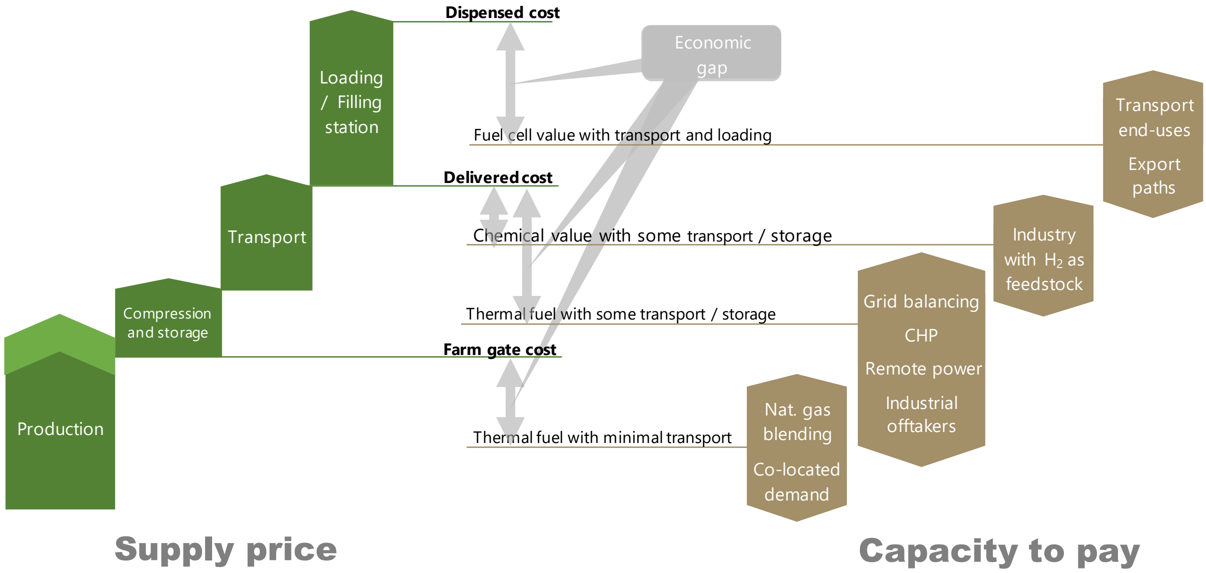
6.1.2 Demand – Supply framework

A key purpose of this study is to define the economic gap for different industry sectors. We define this as the difference between the rational price the users for key applications within a sector would be willing to pay and the potential supply price. The supply price is dependent upon where in the delivery pathway an end user sits.

In this assessment, the relative competitiveness is characterised by the equivalent cost of fuel using the incumbent technology.

The demand – supply cost framework that is used in this study is summarised in Figure 6-2.

Figure 6-2 – "Demand – supply" cost framework used for this study



6.1.3 Thermal price parity

The thermal value of a fuel characterises the cost to yield a quantum of energy via combustion. The prevailing thermal fuel source is natural gas. For large consumers, the cost of natural gas on the East coast of Australia currently ranges between $8 and $10/GJ. The price is expected to trend upwards towards $14/GJ by 2030 and remain at around this price up to 2050.

When hydrogen is combusted, it can yield 120 MJ/kg. Using this metric, it is possible to compare the thermal value of hydrogen for different supply prices – see insert.

The green hydrogen production cost that achieves cost parity with large scale natural gas on the East coast of Australia is ≈$1.1/kg.

Combustion value of fuels

If hydrogen is combusted for heat value it competes with coal and natural gas as heat providers. The relationship between hydrogen cost (on mass basis) as compared with other fuels is provided below.

	Reference units		Energy units	
Hydrogen	5	$/kg	41.7	$/GJ
Hydrogen	3	$/kg	25.0	$/GJ
Hydrogen	2	$/kg	16.7	$/GJ
Hydrogen	1.5	$/kg	12.5	$/GJ
Hydrogen	1	$/kg	8.3	$/GJ
Nat. gas - Large user (East coast)			8-10	$/GJ
Nat. gas - Small user			15 - 30	$/GJ
Coal - Large user	70	$/ton	3 - 5	$/GJ
Ammonia	535	$/ton	28.8	$/GJ
Petrol / Gasoline	1.40	$/L	40.0	$/GJ
Diesel (for trucking)	1.25	$/L	32.4	$/GJ
Nat. gas @ $10/GJ with carbo	100	$/ton CO	15.5	$/GJ

If hydrogen is used to yield electricity through a fuel cell with 65% efficiency, the energy yield is 218 MJ/kg. The fuel cost for such as system - with hydrogen at $2/kg, is comparable to large scale combined cycle gas turbine based electricity costs – see insert.

Electricity cost comparison

	Reference units		Energy units	
Electricity - Renewable farm	40	$/MWh	11.1	$/GJ
Electricity - Large user	100	$/MWh	27.8	$/GJ
Electricity - Residential	240	$/MWh	66.7	$/GJ
Fuel cell (η = 65%) with $2/kg	92	$/MWh	25.6	$/GJ

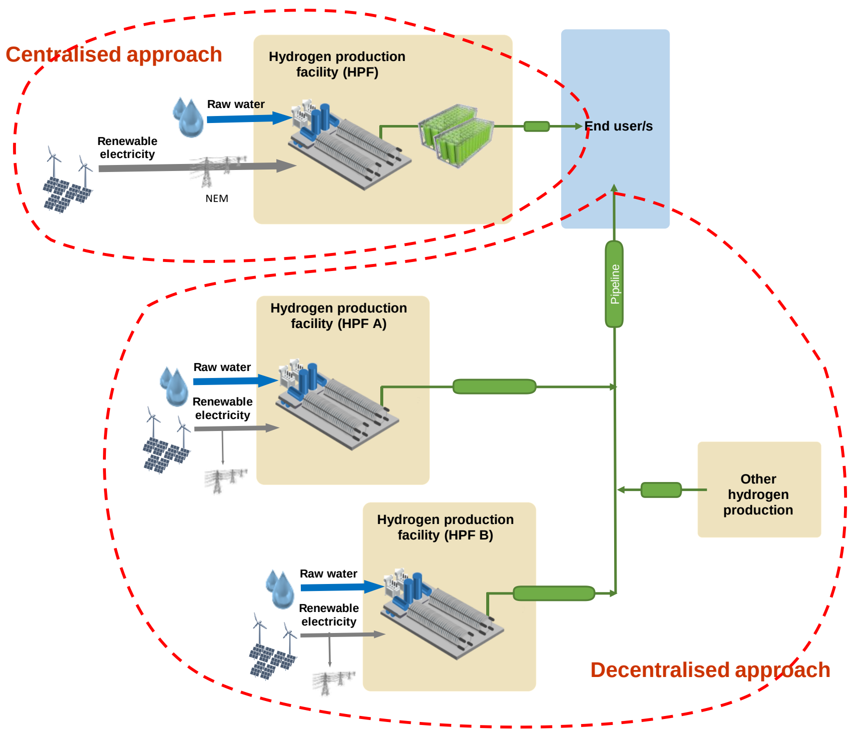
When comparing the time frame that fuel price parity is achieved against different fuels, the non-economic values such as: GHG emissions, safety, convenience, reliability and operability must be considered and will have a significant influence on user uptake.

6.1.4 Centralised Vs decentralised production

There are two potential pathways for the development of green hydrogen production facilities. A schematic illustrating the key differences between these approaches is provided in Figure 6-3.

The centralised approach transfers power from renewable farms as electrons to a single hydrogen production facility – termed "move the electrons". This approach is likely to be cost effective when the existing transmission network is strong enough to support the additional demand without significant augmentation. A development of this type will target higher load factors in order to minimise network impacts and minimise the hydrogen storage requirements. It will, however, require more continuous, and therefore more expensive, power supply, when demand is out of sync with available renewable generation sources.

Figure 6-3 – Comparison of centralised and decentralised approaches



The decentralised approach develops either one or multiple remote hydrogen production facilities adjacent to renewable energy farms. The hydrogen production facilities can be connected behind the meter. The resulting hydrogen is transported by pipeline to the end user or offtaker – termed "move the molecules". In the short term, this approach is likely to be most cost effective when network constraints do not impede the monetisation of excess electricity through the sale into the market of generated power above the capacity of the electrolyser.

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6.1.5 Capacity factor and load factor

Renewable energy generation is subject to variability and intermittency. Solar PV is comparatively predictable with generation constrained to daylight hours and subject to seasonal and cloud variations. Wind generation is responsive to wind speed with large inter-day variability. The amount of energy that renewable generators can produce is set by intermittency and variability.

Capacity factor is defined as the ratio of actual energy output over a given period to the rated capacity possible over that period. Usually this is over a one-year period encompassing all 8760 hours of the year. This factor is generally applied to renewable generation facilities to indicate how much power is generated relative to the rated capacity.

Load factor is essentially the same calculation as capacity factor however it is applied to the production output of the electrolysis plant. This is the ratio of the amount of hydrogen produced over a given time period over the maximum possible hydrogen that can be produced within that period – typically a year.

Note that the capacity factor of renewable generation and the load factor of the electrolysis plant are not always the same. For further explanation, refer to Section 2.3.1 and Figure 2-7.

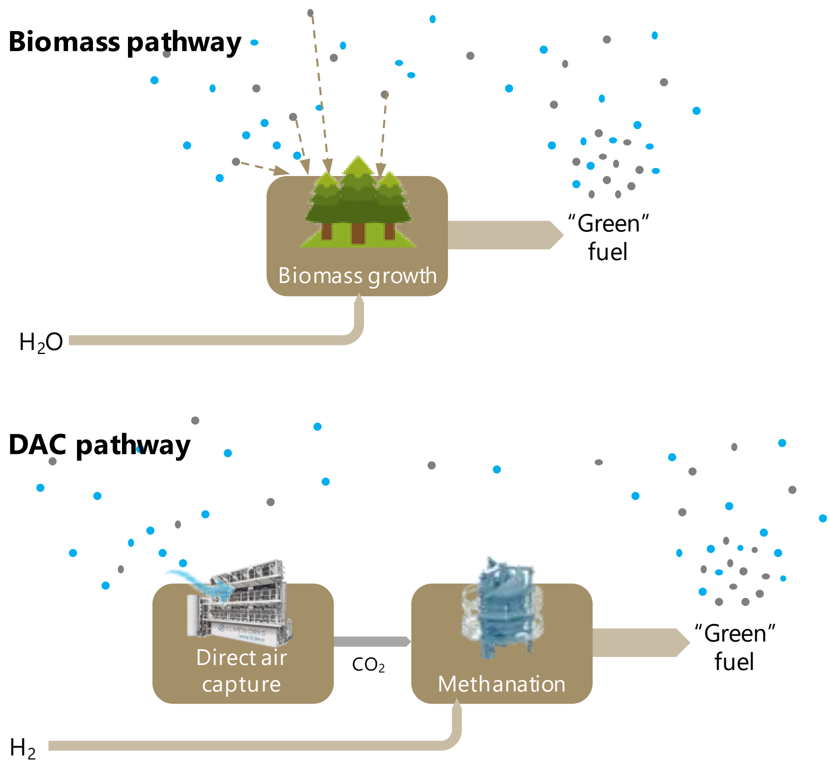
6.1.6 Carbon neutral carbon dioxide

The concept of carbon neutral carbon dioxide sounds perverse but is a relatively simple concept where carbon dioxide is captured from the atmosphere, directly offsetting carbon dioxide emitted from combustion of the resulting fuel. Biomass is a good example of a fuel which uses carbon neutral carbon dioxide to create the fuel. The carbon content in the biomass has been sourced from the atmosphere by the growing plants.

Direct Air Capture (DAC) is an industrial mechanism for capturing carbon dioxide from the atmosphere. If the carbon capture process uses renewable energy to drive the process, then the captured CO_2 is considered carbon neutral.

The biomass and direct air capture pathways are characterised in Figure 6-4.

Figure 6-4 – Comparison of carbon neutral fuel pathways



DAC is an emerging technology, with capture costs between US$94 - $232/ton CO_2 near-term, and predicted to drop below to drop below US$60 by 2040 (Hydrogen Council, 2020).

6.1.7 Total direct costs Vs total installed costs

Total direct costs (TDC) associated with an engineering project are all costs that can be directly attributed to the design, procurement and installation of an asset. Other synonyms for this metric are: Total delivered costs and "delivered" cost. The costs can generally be attributed based on capacity and activity count. Examples of direct cost elements include:

- Purchased equipment;
- Bulk materials;
- Scrapped and reworked product;
- Engineering contractor labour;
- Direct human labour – Civil work and equipment installation;
- Direct supervision of personnel.

Total installed costs (TIC) consist of the total direct costs plus all other costs which can be attributed to the project.

Examples of the indirect cost elements include the following:

- Utilities;
- IT systems and networks;
- Procurement and management services;
- Common distributables e.g. accommodation for contract labour;
- Taxes;
- Legal functions;
- Warranty and guarantees;
- Owners team and quality assurance costs;
- Accounting functions;
- Marketing and publicity;
- Contingency.

The capital costs reported for electrolysis units and power generation are on a Total Direct Cost (TDC) basis (often termed "delivered cost"), but calculations used to determine the levelised cost of hydrogen are based on Total Installed Cost (TIC).

Acronyms and abbreviations
References

Acronyms and abbreviations

Acronym / abbreviation	Definition
€	Euro = AUD / 0.621
A$	Australia dollar
ABS	Australia bureau of statistics
AC	alternating current
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AE	Alkaline Electrolysis
AEM	Anionic exchange membrane
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
AS	Australian Standard
ASTM	American Society for Testing Materials
barg	Unit of pressure
BAT	Best available technology
BEV	Battery electric vehicle
BF	Blast Furnace
Black (or grey) hydrogen	Hydrogen production pathway which yield hydrogen without managing the resulting GHG emissions
Blue hydrogen	Hydrogen production pathway which implies a reduction in GHG intensity though carbon dioxide capture and use / storage
BNEF	Bloomberg New Energy Finance
BOF	Basic Oxygen Furnace
BTM	Behind the meter
C	Celsius
CEFC	Clean Energy Finance Corporation
CO	Carbon monoxide
CO_2	Carbon dioxide
$CO_{2\text{-}e}$	Carbon dioxide equivalent
COAG	Council of Australian Governments
COPVs	Composite Overwound Pressure Vessels
CSIRO	Commonwealth Scientific and Industrial Research Organisation

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Capex	Capital expenditure
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
CHP	Combined heat and power
CNG	Compressed natural gas
DC	Direct current
DME	Dimethyl Ether
DoE	Department of Energy
DRI	Direct Reduced Iron
DUoS	Distribution use of system
EAF	Electric Arc Furnace
EEDI	Energy Efficiency Design Index
EHS	Electrochemical Hydrogen Separation
EOL	End of Life
EPC	Engineer Procure Construct
EU	European Union
FCEV	Fuel cell electric vehicle
GHG	Greenhouse gas
GJ	gigajoule (1,000,000,000 Joules)
Green hydrogen	Hydrogen production pathway which implies a high threshold based on renewable based power to yield electrolytic hydrogen.
GW	Gigawatt
HBI	Hot Briquetted Iron
HFO	Heavy Fuel Oil
HHV	higher heating value
HRS	Hydrogen refueling station
H_2	Hydrogen
IATA	International Air transport Association
ICE	Internal Combustion Engine
IEA	International Energy Agency
IMO	International Maritime Organization
IP	Intellectual Property
IRENA	International Renewable Energy Agency
ISO	International Organisation for Standardization

ISP	Integrated System Plan (AEMO document)
kgmol	kilogram-mole
km	kilometre
kV	kilo-Volt
ktpa	kilotonnes per annum
kW	kilo-watt (1,000 watts of electrical power)
kW h	kilo-watt hour (a kilowatt of power used in an hour (3.6MJ)
L	Litre
LCOE	Levelized cost of energy
LCOH	levelized cost of hydrogen
LNG	Liquefied Natural Gas
LPG	Liquified Petroleum Gas
LOHC	liquid organic hydrogen carrier
m	metre
mCHP	Micro Combined heat and power
MCPs	Multi-Cylinder Packages
MEPC	Marine Environment Protection Committee
MGO	Marine Gas Oil
MHFs	Major Hazard Facilities
MJ	megajoule (1,000,000 Joules)
ML	Mega litre
MLF	Marginal loss factor
MMBtu	Metric Million British Thermal Unit
Mtonnes	megatonnes
Mt	Millions of tonnes
Mtpa	Million tonnes per annum
MW	megawatt (1,000,000 watts of electrical power)
MWh	megawatt hour
NG	Natural gas
NOx	Nitrogen oxides
NPV	Net present value
NT	Northern Territory
NSW	New South Wales

OEM	Original equipment manufacturer
OHLE	Overhead line electrification
Opex	Operational expenditure
O&M	Operation and maintenance
O_2	Oxygen
PCEC	Protonic ceramic electrochemical cell
PEM	Proton Exchange Membrane
PEFC	Polymer electrolyte fuel cell
PJ	petajoule (1,000,000,000,000,000 Joules)
PHEV	Plug in hybrid electric vehicle
PM	Particulate matter
PPA	Power purchase agreement
PSA	Pressure Swing Absorption
psi	pound per square inch
PV	Photovoltaic
QLD	Queensland
RED II	Renewable Energy Directive II
SA	South Australia
SAF	Sustainable Aviation Fuels
SCR	Selective Catalytic Reactor
SEEMP	Ship Energy Efficiency Management Plan
SMR	Steam methane reformer/ reforming
SNG	Synthetic natural gas
SOEC	Solid oxide electrolyser cell
SOL	Start of Life
SOx	Sulphur oxides
TDC	Total delivered cost
TES	Thermal energy storage
TIC	Total installed costs
tpa	tonnes per annum
tpd	tonnes per day
TRL	Technology Readiness Level
TUoS	Transmission Use of System charges

TWh	terawatt hour
US	United States
US$	US dollar where USD = AUD / 0.695
USD	US dollars
VLSO	Very-Low Sulphur Fuel Oil
WA	Western Australia
v/v	Volume per volume percentage

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