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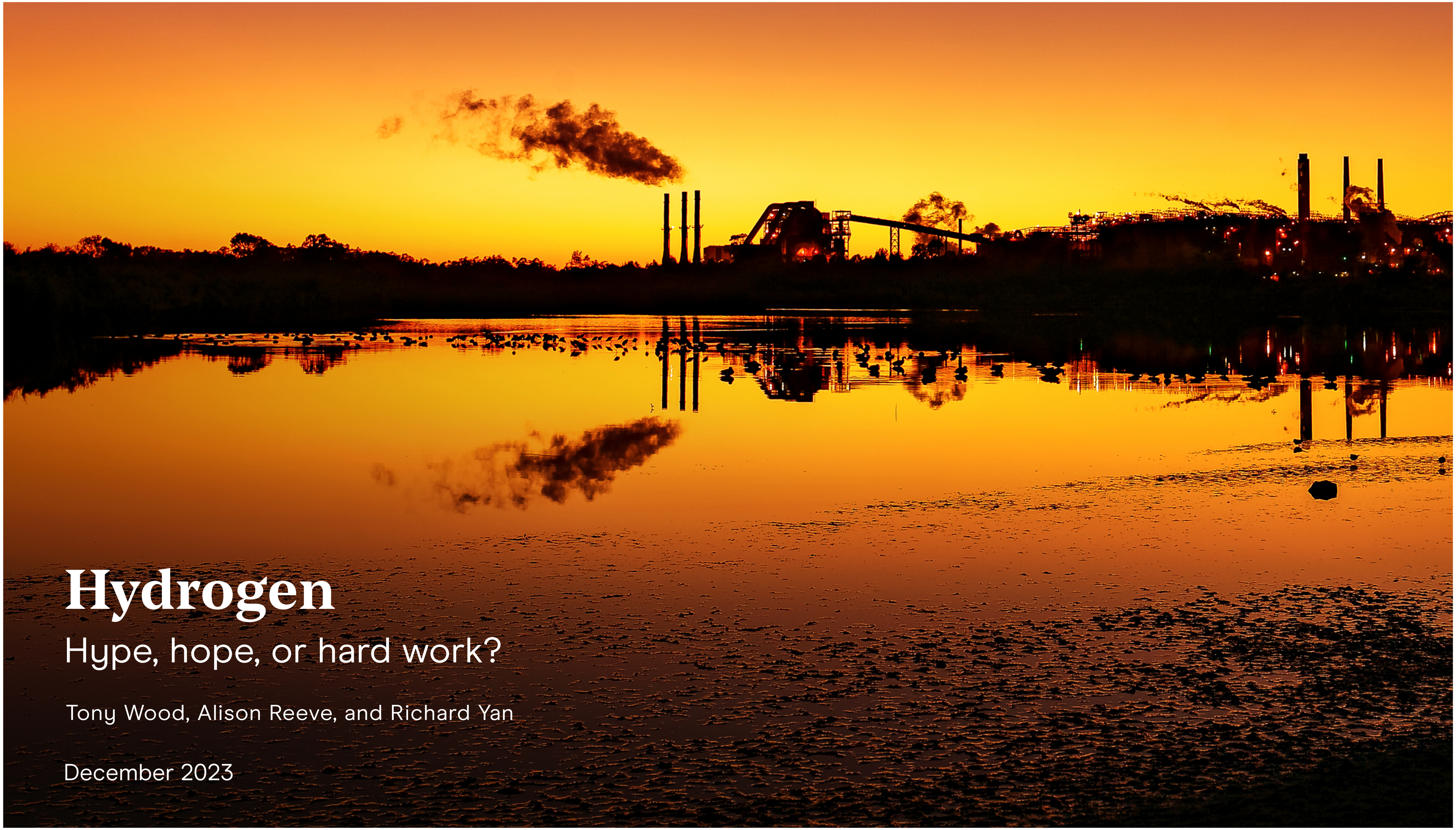

Hydrogen

Hype, hope, or hard work?

Tony Wood, Alison Reeve, and Richard Yan

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Overview

Hydrogen can help meet Australia's emissions reduction targets and underpin economic growth opportunities. But to date, governments have seemed more concerned with hyping Australia's hydrogen prospects and hoping for the best, rather than doing the hard work to establish integrated industry policy for proportionate, targeted, and timely support.

The best way to seize the hydrogen opportunity is to make strategic choices about its industrial applications that can leverage Australia's comparative advantage in renewable energy resources and minerals, and build on existing export industries.

The most promising uses of hydrogen are in the production of ammonia, alumina, and iron. These applications could use hydrogen efficiently and cost-effectively at a scale that could support a viable, long-term hydrogen industry that won't require subsidies.

But in each of these cases, hydrogen still faces a 'green premium' – the gap between the cost of using hydrogen for zero-emissions production, and the cost of conventional production.

Three things can close that gap. First is cheaper electricity. Hydrogen costs are driven by electricity costs, and each hydrogen producer will need to understand its specific electricity supply chain, including potential links to development of Australia's renewable electricity transmission grid.

Second is higher carbon prices. Heavy industry is covered by the Safeguard Mechanism, which imposes a carbon price to drive down emissions. But under the Safeguard's current settings, this price isn't likely to be high enough to close the cost gap before 2040.

Third is support for 'green' versions of these commodities. The best support would be an industry policy that evolves from the federal government's Hydrogen Headstart program and uses contracts-for-difference – contracts designed to support investment by underwriting part of the additional cost of production – to help industry grow.

This program should be broadened to form part of a comprehensive Australian green industry policy. It should also support green commodity production using technology beyond hydrogen.

The cost to the government would probably be between $600 million and $2 billion per year. The prize would be reduced emissions from domestic production of green ammonia, alumina, and iron, and export industries with a robust future for all three commodities.

Other uses of hydrogen, where the opportunities are less certain, tend to have complex supply chain logistics or face competing technologies, or both. These uses should be supported through policies that remove barriers to both hydrogen and competitor technologies.

It's time to get serious about hydrogen. The reforms recommended in this report would give Australia the best chance to build a viable hydrogen industry that leverages our comparative advantages, is proportionate to our fiscal capacity, and won't lead to inefficient subsidies and trade distortions.

Recommendations

Be strategic about the hydrogen opportunity

- Set a clear objective to develop a hydrogen industry capable of supplying reliable low-cost hydrogen for the Australian industries where it would add greatest economic value.
- Focus first on producing green ammonia, green alumina, and green iron as the most promising hydrogen uses.

Use neutral contracts-for-difference to close the green premium gap

- Transform the Hydrogen Headstart program into a contract-for-difference program, to support the growth of green commodity production in Australia. Conduct reverse auctions every year for 10 years.

Deliver cheap, green, reliable electricity

- Embed green hydrogen production and use more fully in electricity-system planning, including the role of hydrogen as fuel for back-up power in the electricity grid.
- Continue to reduce the cost of renewable electricity in Australia, through new renewable energy generation, storage, and transmission.

Unblock construction constraints

- State governments should co-ordinate and sequence major construction projects to avoid labour, material, and equipment constraints.

Use carbon pricing appropriately

- The 2026-27 review of the Safeguard Mechanism should consider how steeper baseline declines, higher price caps, and a lower threshold could reduce green premiums.
- The Carbon Leakage Review should consider the role a Carbon Border Adjustment Mechanism (CBAM) could play in developing viable green commodity production.

Remove barriers to hydrogen use in other sectors

- Use sector-wide policy to encourage decarbonisation of industrial heat, sustainable aviation fuel, methanol, back-up electricity generation, and long-distance road freight.

Rule out further government investment in uses that appear less likely to prove viable

- Do not invest further in hydrogen for homes and commercial buildings, light vehicles, and oil refining.

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1 Why hydrogen matters

Hydrogen is a molecule that can help the world to decarbonise. It is a light-weight, and energy-dense (by weight) molecule that can be produced and burned with zero emissions. Like traditional fuels, it can be stored and transported for use at a different time and location. It is also an irreplaceable component of important chemicals, including nitrogen fertilisers that help feed the world.

These advantages must be set against the current high cost of hydrogen production and supply. Hydrogen should be used where it makes the most sense technically and economically. Those uses are likely to be fewer than had been hoped.

Where hydrogen will play a role in global decarbonisation, it is likely Australian hydrogen will play an outsized role. Australia is endowed with a significant, but untapped, clean-energy comparative advantage – that is, we have a larger endowment of renewable energy resources but smaller domestic demand than many other countries. Our significant mineral reserves and proximity to large Asian markets are also important factors. In a future decarbonised world economy, some energy-intensive processes could shift to Australia, and hydrogen will be key to some of these opportunities.

The initial hype around hydrogen is settling into realism. Since Australia's first National Hydrogen Strategy was published in 2019, understanding of the role that hydrogen is likely to play in decarbonisation has improved.

1.1 Hydrogen is one tool in the decarbonisation toolkit

The interaction between the technical and economic characteristics of hydrogen and its derivatives will determine the role it plays in the future decarbonised economy (see Box 1 on the following page).

Often, this means that decarbonising through electrification is cheaper than using hydrogen, for several reasons:

- Hydrogen-based processes often involve multiple energy conversion steps along the chain. Energy losses at conversion mean that hydrogen-based processes will be less efficient and hence more costly.
- Green hydrogen production requires renewable electricity as an input. In many cases, it may make more sense to use the renewable electricity directly, given energy conversion penalties.
- Electricity can take advantage of significant existing infrastructure in the form of the grid, which can be made bigger to meet future demands. Hydrogen often requires an entirely new and specialisedinfrastructure.
- Renewable electricity technologies have become cheaper through research, development, and deployment, whereas low-emissions hydrogen production technologies have barely started on this journey.

Given these realities, the best decarbonisation decision will usually be 'electrify everything we can and use hydrogen where we can't'.

But it is likely that hydrogen will play a part in decarbonising some activities, because:

- Hydrogen is needed as a molecule or feedstock in some industrial processes. In these cases, there is no alternative.
- Hydrogen may be able to replace fossil fuels in some applications to achieve high-temperature industrial heat at lower cost than electricity.

Box 1: What is hydrogen?

Hydrogen is the lightest element in the periodic table. Compared with fossil fuels such as natural gas, petrol, and diesel, it is more energy-dense by weight, but less so by volume. Burning hydrogen releases energy in the form of heat, while leaving nothing but water as a byproduct.

The world produced about 95 million tonnes (Mt) of hydrogen in 2022 – overwhelmingly using carbon-emitting production processes with natural gas and coal as the feedstock – leading to more than 900Mt CO_2-e (carbon dioxide-equivalent) in emissions.[a] Australia produces about 0.5Mt of hydrogen a year using natural gas, creating about 5Mt CO_2-e in emissions.[b]

Hydrogen is currently used for the production of ammonia (used in fertiliser and commercial explosives), methanol, and other chemicals; and to refine crude oil for transport fuels.

Hydrogen can contribute to decarbonisation in two ways:

- Decarbonising the production of hydrogen intended for its current uses.
- Using zero-emissions hydrogen to replace fossil fuels in other energy-intensive processes. Hydrogen can be:
  - burned to create heat for manufacturing
  - burned to generate electricity using a steam turbine;
  - used in hydrogen fuel cells to generate electricity;
  - combined with other elements to produce chemicals such as ammonia and methanol. These can then be burned as fuels;
  - synthesised with carbon to create synthetic hydrocarbons (such as kerosene, which is used as jet fuel).

For more information on these use cases of hydrogen, see Appendix A.

Currently, the most common method for producing hydrogen uses natural gas as a feedstock, a process which creates CO_2 emissions – this is often called 'grey hydrogen'. Low-emissions hydrogen can be produced by capturing and storing CO_2 (CCS) – this is often called 'blue hydrogen' – but this process is not in widespread use. Zero-emissions hydrogen can be produced through electrolysis, using water and 100 per cent renewable electricity – this is commonly called 'green hydrogen'.

a. IEA (2023a, p. 13).
b. DCCEEW (2023a).

- Hydrogen may be able to cost-effectively replace fossil fuels in some transport applications, and as a way to store energy to balance a grid that has a high proportion of variable renewable energy generation.
- Hydrogen and its derivatives are a way to transport energy. Where there are severe imbalances in energy availability, it could make economic sense for countries to trade energy using hydrogen as the vector.

1.2 Hydrogen can help Australia decarbonise

Australia's commitment under the 2015 Paris Agreement to reach net-zero carbon emissions by 2050 will requires a wide range of actions across all of the sectors that contribute to our domestic emissions.

Zero-emissions processes using hydrogen will play a role in Australia's decarbonisation. We estimate that hydrogen could help reduce Australia's emissions by up to 8.6 per cent (see Figure 1.1).

1.3 Hydrogen will help the world decarbonise, and Australia can play an outsized role

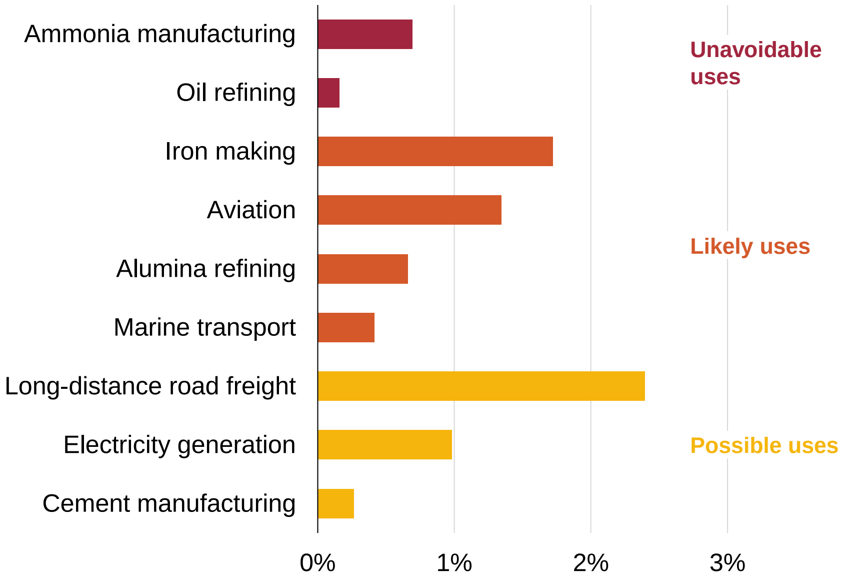
Australia is well-placed to prosper in a decarbonised world. In future, Australia could host more energy-intensive economic activity, because we have significant, but latent, clean-energy comparative advantages. They include:

- a higher ratio of renewable energy resources to domestic demand than many other countries;[1]

1. Wood et al (2020, p. 15). Our renewable energy resources include large amounts of land that are high in solar photovoltaic and wind potential. Our domestic demand is a function of population and energy-intensive exports, noting that both may increase in the future.

Figure 1.1: Hydrogen-based processes could help to abate some carbon-intensive processes in Australia

Emissions due to processes that could be replaced with hydrogen-based processes, % of Australian emissions



Notes: All numbers are for 2020 or 2019-20 except oil refining, which is for 2022. This is a scenario analysis of the maximum scope 1 domestic emissions abatement that can be achieved if all carbon-emitting processes that could technically be replaced by zero-emissions hydrogen-based processes are replaced (see Appendix A). Marine transport and aviation use total domestic marine and aviation emissions. The categorisation of processes is by whether they are likely to require green hydrogen to decarbonise. Some minor uses are omitted for space. This is not a prediction of the abatement that will be achieved by the adoption of zero-emissions hydrogen-based processes.

Source: Grattan analysis of ABS (2020), Cement Industry Federation (2023), DCCEEW (2023a), DCCEEW (2023b), DCCEEW (2023c), DCCEEW (2023d), Deloitte and ARENA (2022), International Aluminium Institute (2023), Kildahl et al (2023), McConnell et al (2023), Rocky Mountain Institute (2020), Pardo and Moya (2013), USGS (2022), VDZ (2021, p. 11), and World Steel Association (2023).

- an endowment of mineral resources that will remain in demand (including some that are crucial to the energy transition), and existing expertise in mining them; and
- proximity to growing Asian markets.

But Australia also has competitive disadvantages, such as higher labour and construction costs, as well as challenges in firming the electricity grid at low cost.[2]

The balance of these factors means Australia can play an outsized role in the world's decarbonisation, especially where energy- and capital-intensive processes are involved.

Hydrogen is likely to be the molecule at the centre of two key opportunities: exporting clean energy embedded in energy-intensive products, and replacing some high-carbon imports with domestic production of green alternatives for domestic use. It may also bring employment opportunities, sometimes in the places that are facing the loss of carbon-intensive industries such as coal mining and production of liquefied natural gas (LNG).

This would be a significant economic prize.

1.4 The structure of this report

Chapter 2 shows that supplying hydrogen is expensive and complex, and that the government needs to engage in industry development for hydrogen to succeed.

Chapter 3 surveys the potential uses of hydrogen and explains why governments should focus their industry development efforts on some uses and not others.

Chapter 4 presents information on the uses government should focus on first: ammonia, alumina, and iron.

Chapter 5 recommends industry policy to target initial support to these priority uses.

Chapter 6 suggests policy approaches for other uses where relevant technologies and case-specific barriers mean the case for hydrogen appears less compelling for now.

2. Herd and Hatfield Dodds (2023, p. 40). Firming refers to maintaining a steady supply of electricity, when it is largely supplied by a variable source, such as solar or wind. Zero-emissions firming can be achieved through the storage and release of energy in batteries, traditional hydro power, or pumped hydro systems. Costs for these depend on access to low-cost technologies and installation and – in the case of hydro – suitable geography.

2 Hydrogen needs policy support to succeed

Supplying green hydrogen increasingly appears to be more expensive and complex than previously hoped.

The cost of electricity drives the cost of hydrogen at the point of production, so the key to low-cost hydrogen production is reducing wholesale prices for electricity.

The full cost of the hydrogen supply chain also includes the cost of getting the hydrogen to where it is needed for use. This involves a choice between ‘moving molecules’ or ‘moving electrons’, with each pathway having different costs. The lowest cost solution will be project-specific, but the supply chain adds significantly to the cost of delivered hydrogen.

A thriving hydrogen industry in Australia will need policy support to succeed. The federal government’s National Hydrogen Strategy should continue to focus on the things that stand in the way of Australia realising its green energy potential. The government should also make the hard choice of ruling out some potential uses for hydrogen and focusing attention on others.

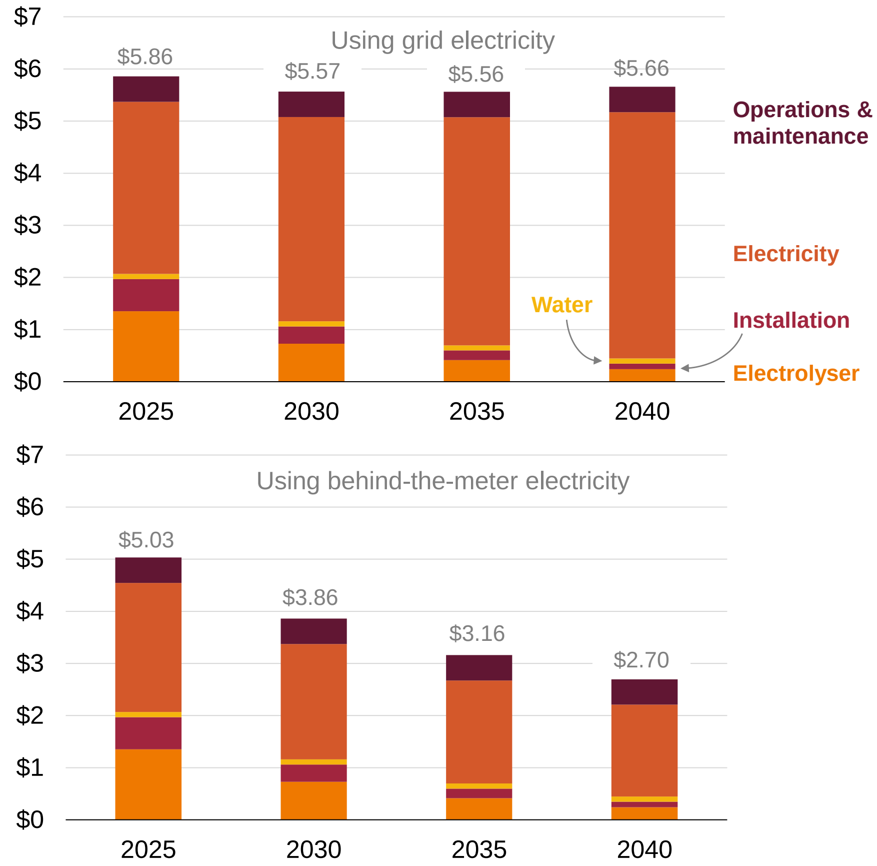
But it also makes sense for the federal government to develop a more comprehensive green industry policy, to support industry to develop into the form suggested by Australia’s competitive advantages in clean energy, regardless of the technology used.

2.1 Supplying hydrogen is expensive and complex

The cost of hydrogen production could fall over the next two decades. This would in part be driven by the decline in the cost of electrolysers, including their installation costs.

Figure 2.1: Hydrogen costs will only fall if electricity costs at the point of production fall too

AU$/kg of hydrogen



Notes: Hydrogen costs are in real 2023 dollars, levelised over 20 year project life.

Source: Grattan analysis. A full list of assumptions and data sources is in Appendix B.

But the largest part of the cost of green hydrogen production is the cost of electricity to run the electrolyser (see Figure 2.1 on the previous page).[3] While using grid electricity may allow the hydrogen production to be co-located with the hydrogen user, the cost of such hydrogen is not expected to fall (see the top chart), because the delivered cost of electricity taken from the grid is expected to remain higher.

Where an electrolyser uses electricity supplied by co-located, dedicated renewable generation and firming, the 'farm gate' cost of hydrogen production is expected to fall in the future (see the bottom chart in Figure 2.1 on the preceding page).[4] This is driven by a forecast reduction in the cost of dedicated generation and firming.

2.1.1 Getting hydrogen to where it is needed

Hydrogen is cheaper if produced with dedicated renewable energy.

But this doesn't take account of the full costs of the hydrogen supply chain. Dedicated renewables can only be economically built in areas that have a low opportunity cost for land use, and which have significant solar and wind potential. Accounting for the additional cost of getting the hydrogen to where it is needed has a significant effect on the total cost.

Where co-location of hydrogen production with the hydrogen user is possible, it is often a good choice, since it can be cheaper to transport the resulting commodity (such as iron, steel, or alumina) on trucks, trains, and ships than to move the hydrogen or the electricity to produce the hydrogen. But where the end use can't easily be co-located with the renewables, the choice is between moving molecules or electrons (see Figure 2.2 on the next page).

'Moving molecules' involves producing the hydrogen close to the renewable generation, and then transporting it to its ultimate user. This means paying less for electricity transmission, but more for pipelines, trucks, and storage.

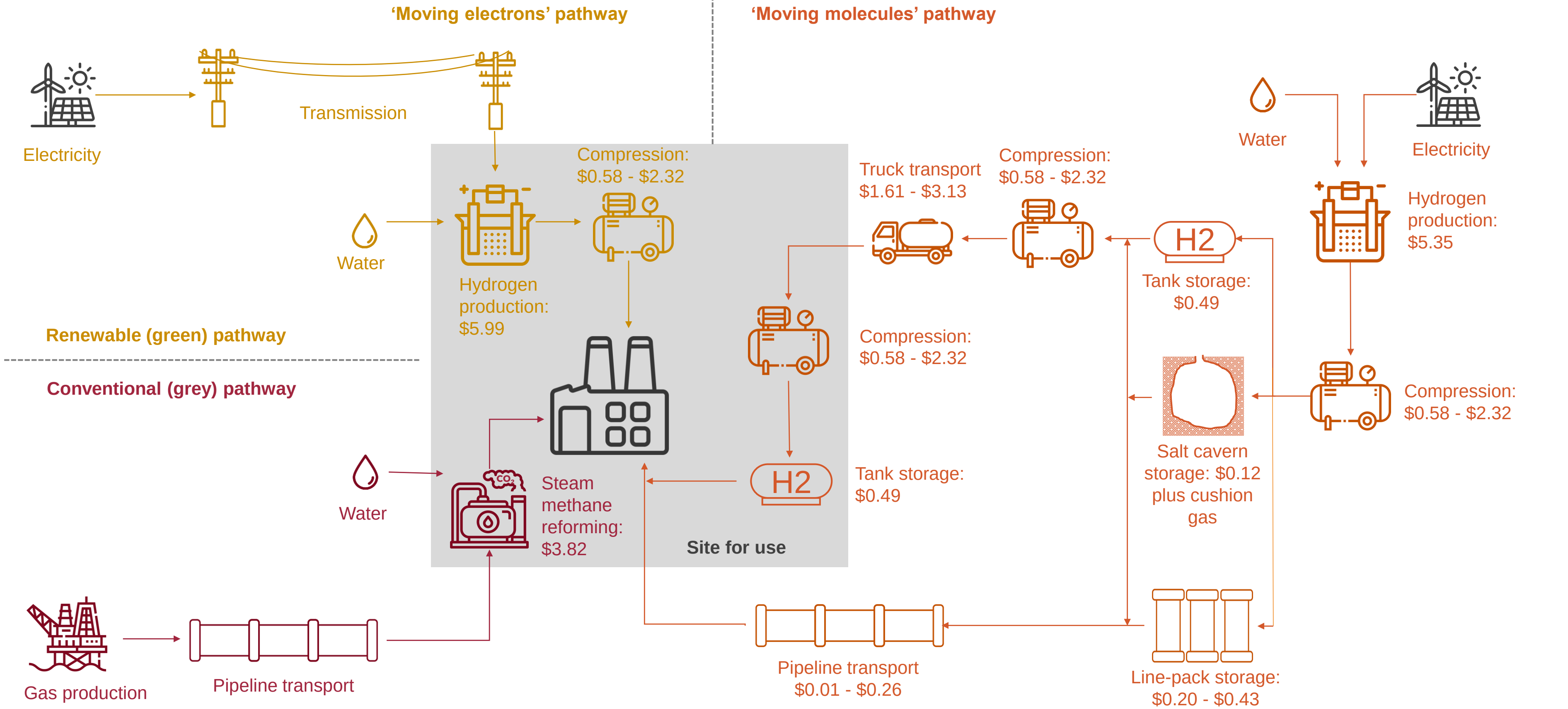
'Moving electrons' involves producing the hydrogen closer to its ultimate user, with renewable electricity transported via power lines from where the renewable generation is located. This means paying more for electricity transmission, but less for pipelines, trucks, and storage. Using grid-supplied electricity with an electrolyser close to an alumina refinery is one way to do this.

Supply chain choices are also influenced by the hydrogen user. Some hydrogen users will need a continuous supply to feed a continuous process. Others will want batches of hydrogen at intervals. If hydrogen production is intermittent – for example, because it uses dedicated renewable energy with no storage or back-up power – storage and transport have to supply the buffer to allow continuous use. The amount users require also plays a part: small users of hydrogen can use tank storage and truck transport; large users will want larger storage capacity. Location also matters: salt caverns don't exist everywhere, and there are likely to be safety concerns surrounding large-scale hydrogen storage near built-up areas.

The best combination of infrastructure will be project-specific and require an assessment of: operational flexibility at both the production and use stage; the cost of grid electricity compared with dedicated (or 'behind-the-meter') generation; construction costs; location; and the logistical challenges of other inputs, such as water (Box 2 on page 13) and, possibly, an ore body.

3. Throughout this report, unless otherwise noted, hydrogen costs are given as levelised costs. Levelised costs are calculated by taking all of the costs over the lifetime of a plant, discounting them by the year in which they occur, and dividing the total by the discounted total amount of hydrogen produced over the same period. A full list of assumptions and data inputs can be found in Appendix B.
4. Farm gate cost refers to production cost at the point of production.

Figure 2.2: Hydrogen supply chains and associated costs
AU$/kg of hydrogen



Notes: Hydrogen production costs are for a project starting in 2024. The hydrogen production cost for the 'moving electrons' pathway assumes grid electricity is used. The hydrogen production cost for the 'moving molecules' pathway assumes behind-the-meter electricity is used. Lower compression costs are for 4,500kg/day, upper for 200kg/day. Lower pipeline costs are for 25km, upper for 500km, assuming throughput of 417 tonnes of hydrogen a day and no storage. Line-pack costs are for 24 hours. Lower truck costs are for 200 kg/day, upper for 1,000 kg/day. Cushion gas is hydrogen or another gas that remains in salt cavern storage to maintain working pressure. Additional costs from cushion gas will vary with the gas used, the year the storage facility opens, its volume, the expected length of useful life, and the expected end-of-life value of the cushion gas.

Source: Electrolytic hydrogen production: see Appendix B. Steam methane reforming: Grattan analysis of Platts S&P Global (2023a), Rocky Mountain Institute (2023), Saulnier et al (2020). Tank storage, compression, and truck transport costs from Wolfe and Cassano (2023). Pipeline transport and line-pack storage costs from GPA Engineering (2022). Salt cavern storage costs from ARUP (2023). Icons from flaticon.com.

2.2 Hydrogen needs policy support to succeed

Hydrogen will not be the sole clean fuel of the future. Instead, hydrogen's role will probably be limited to the activities that are more difficult or more costly to abate using alternatives.

There are sufficient barriers to growing a viable hydrogen industry to warrant keeping a national strategy in place, so that the opportunities it presents can be realised. But it is now time to become truly strategic about hydrogen – to rule out some potential uses and focus attention on others, and to consider the development of a hydrogen industry in the broader context of Australia's transition to net zero.

The federal government's National Hydrogen Strategy, which is currently being revised, should focus on the factors specific to hydrogen that stand in the way of Australia realising its green energy potential.

But it also makes sense for the federal government to develop a more comprehensive green industry policy. This industry policy should allow the government to take a wide portfolio of bets on industries and applications based on a broad view of our advantages in clean energy, regardless of the clean energy technology or fuel that is used.

The case for a 21st Century industry policy in Australia has been made in previous Grattan reports.[5] There are three arguments for government playing a role:

- First, markets do not generally provide adequate incentives for research and development of new technologies, because knowledge is often intangible, risky, and difficult to appropriate. Low-emission technologies and the payoffs from developing them are particularly complex and uncertain.
- Second, many of the technologies that might produce large emissions reductions are expensive and high-risk. Early investors

5. Wood et al (2022), Wood et al (2021), Wood (2012).

Box 2: Water availability could become a constraint

Water is a key input into green hydrogen production. To produce 1kg of hydrogen requires 9 to 11 litres of highly pure water for the electrolyser to split into oxygen and hydrogen, as well as anywhere from 3 to 60 litres of water for cooling (depending on the local climate).[a]

Water availability will be a determining factor for where green hydrogen can be produced. Making the green hydrogen required to decarbonise current ammonia, alumina, and iron production in Australia (consistent with the volumes set out in Table 5.1 on page 34) would require about 23 gigalitres of water every year (assuming 17 litres of water are used per kg of hydrogen, including feedstock and cooling water).[b]

Hydrogen production facilities of a globally competitive size will probably put pressure on local water supplies. The industry needs to focus on efficient water use if it is to gain support from local communities.[c]

Community acceptance has already emerged as an issue for the hydrogen power plant in Whyalla, South Australia.[d] Governments should ensure planning approval decisions take account of community concerns about water access and use.

a. Arup (2022, p. 6).
b. Grattan calculation.
c. Lester et al (2022).
d. Holder (2023).

face high costs, low returns, and the risk of competitors free-riding on their initiative. Investors require a reliable, long-term carbon price to underpin their investments. Yet a carbon price is inherently uncertain because it depends on the decisions of governments. For both these reasons, investment in low-emission technologies is, and will remain, critically inadequate.

- Third, the clock is ticking. Australia and other developed economies are striving to achieve net-zero emissions by 2050 or earlier. Market forces are not good at managing structural transformations in heavy industry at high speed when the future is deeply uncertain. Moreover, the long-lived nature of industrial assets means that industry is particularly poorly suited to fast changes.

These arguments hold for a hydrogen industry, as well as for industries that might use hydrogen, as we will show in later chapters.

3 Assessing the opportunities

Hydrogen could be used for many things, but it won't always be the best decarbonisation option. Australia should develop its hydrogen industry to provide Australian users that will most likely use hydrogen with a reliable, competitively-priced supply. Attempting to do everything and support every end use now would risk diluting effort and spending limited funds ineffectively.

Governments will need to make choices about where to focus. In this chapter, we recommend criteria for making these choices, focused on technical alternatives, supply chain complexity, abatement potential, and export readiness. We identify use cases where the opportunity is clear and where the government should act now – ammonia, alumina, and iron. We recommend more considered action where things are less certain – manufacturing, electricity, synthetic fuels, methanol, and long-distance transport. And we advise ruling out uses where the case against using hydrogen is strong – replacing natural gas in homes and commercial buildings, replacing petrol and diesel in light vehicles, and replacing grey hydrogen used in oil refineries with green.

3.1 Australia should be strategic about where and how it uses hydrogen

To produce and use hydrogen on a large scale, Australia will need to build an industry. Currently Australia produces about 0.5 million tonnes of hydrogen each year – equivalent to 60 petajoules (PJ) of energy.[6] This is about 1 per cent of total final energy consumption in Australia.[7]

Building an industry almost from scratch in a short time is an expensive and complex undertaking. It makes sense for governments and industry to focus efforts on building a hydrogen industry for those uses where hydrogen is the best tool for the job and can bring the largest benefits to Australia.

Being selective about which applications to support is not 'picking winners': it is a strategy to maximise the value of government policy and support within a limited fiscal envelope. Government policy should create a portfolio of considered 'bets' where the future value of the overall portfolio is expected to be positive.

Australian governments should choose the hydrogen applications to support based on these criteria:

- Technical alternatives: the activity is likely to end up using hydrogen rather than another zero-emissions energy source as there are few promising alternatives.
- Supply chain complexity: the level of complexity – and hence likely cost – of the logistical task of getting hydrogen to its end uses.
- Abatement potential: there is significant domestic abatement potential from the use of hydrogen.
- Export readiness: Australia has or could easily build an export industry for the end use.[8]

Our assessment of hydrogen applications against these criteria is summarised in Figure 3.1 on the following page, and in detail in Chapter 4 and Chapter 6.

6. DCCEEW (2023a).
7. DCCEEW (2023e).
8. See Wood et al (2022) for a longer discussion about why Australian industry policy should be export-focused.

Figure 3.1: Potential uses for hydrogen in Australia

Application	Technical alternatives	Supply chain complexity	Abatement potential	Export readiness
Ammonia manufacturing: replace grey hydrogen with green hydrogen in the Haber-Bosch process				
Alumina refining: replace natural gas with green hydrogen for high-temperature heat for calcination				
Iron making: replace blast furnace and coal with direct reduction using green hydrogen				
Electricity generation: replace gas generators with green hydrogen for back-up electricity				*N/A*
Synthetic fuel: replace fossil fuels with fuels synthesised using green hydrogen and carbon for aircraft				
Methanol manufacturing: replace grey hydrogen with green hydrogen in the methanol synthesis process				
Long-distance road freight transport: replace diesel vehicles with green hydrogen in fuel cell vehicles				*N/A*
Cement manufacturing: replace fossil fuels with green hydrogen for high-temperature heat for clinker calcination				
Other manufacturing: replace natural gas with green hydrogen for medium- and low-temperature heat				
Residential and commercial heating and cooking: replace natural gas with green hydrogen for combustion				*N/A*
Oil refining: replace grey hydrogen with green hydrogen for lowering the sulfur content of diesel				
Light vehicles: replace petrol and diesel vehicles with green hydrogen in fuel cell vehicles				*N/A*
Liquid hydrogen exports: produce hydrogen for export in liquid hydrogen tankers			*N/A*	

Note: Darker colours are for more promising uses. Several minor uses are omitted for space. Abatement potential only considers current domestic emissions.

Source: Grattan analysis.

3.1.1 Criteria 1: Technical alternatives

This criteria answers the question: is hydrogen the best *technical* option to replace fossil fuel use?

In applications that score well, hydrogen will either have only one or two competitors – and hydrogen looks like the better option; or there will be no alternative to using hydrogen because the process uses the molecule rather than the energy content. Examples of applications that have a high technical score include high-temperature industrial heat, and chemicals manufacturing.

For some applications, it is not yet clear whether hydrogen will be the clear winner. An example is power generation. As the power generation sector becomes dominated by solar and wind, the key challenge is ensuring that the system remains reliable. Overbuilding renewable generation to the extent required to ensure reliability, and greater deployment of transmission and battery storage, will become very expensive.[9] Likely solutions include pumped-hydro storage, natural gas with offsets or carbon capture and storage, or hydrogen used in turbines.

Applications that score poorly are those in which hydrogen will have only a small niche application, or those that have competitor technologies that are more efficient than hydrogen at delivering the same service. Examples include light vehicles (battery-electric cars out-compete hydrogen fuel-cell cars), and residential heating and cooking (heat pumps and induction cooktops out-compete hydrogen heaters and stoves).

3.1.2 Criteria 2: Supply chain complexity

A given use for hydrogen may be the best option on technical grounds, but if the supply chain required to get hydrogen to the end user is complicated or lengthy, the use of hydrogen may not be commercially viable.

Applications that score highly are those where large volumes of hydrogen are used continuously, such as for an industrial process. It would be worthwhile building a supply chain for such applications.

Those where large volumes will be needed, but on an intermittent basis (for example, exporting ammonia), could be attractive, although dealing with storage adds complexity.

Applications that score poorly are those where the potential volumes of hydrogen required by the end use are small. Small uses tend to be geographically dispersed, which makes it challenging to build supply chains to support them. Small continuous users may be able to piggy-back on supply chains for larger users. Some small intermittent users can do the same where they are located near a large user, but others – such as long-distance road users refuelling in remote areas – will require a significant investment of capital and effort into a supply chain to provide the hydrogen they need.

3.1.3 Criteria 3: Abatement potential

A core rationale for using hydrogen is to reduce Australia's emissions.

It would be speculative to attempt to quantify how Australian hydrogen might decarbonise activity beyond our shores. At present, only current domestic emissions should be considered.

In cases such as power generation, where the emissions from gas peaking generation will fall with the further roll-out of renewables, using current emissions as a benchmark is likely to overstate the potential for reducing emissions.

9. Wood and Ha (2021).

3.1.4 Criteria 4: Export readiness

One of the potential opportunities from hydrogen is to expand Australia's export industries, taking advantage of our abundant renewable energy and mineral resources.[10]

But it is easier to develop a future export industry from an existing base, rather than building new industries where Australia has no experience. If governments have limited capacity to support industry growth, it is a better bet to support established industries.

Applications that score poorly on this criteria are those where Australia does not produce the relevant commodity, or where none of it is currently exported. Those that score highly are applications where Australia already produces the commodity, either for a mix of domestic uses and exports (such as alumina or ammonia), or predominantly for exports.

3.2 Where governments should focus

Applying these criteria to the many possible uses of hydrogen in Australia reveals a group of applications that can be ruled out, and another group where hydrogen appears to be promising and may warrant government support.

To best target policy to these more promising uses, we need to then assess those that should be supported with specific policy interventions now, and those where governments should proceed more cautiously. To do that, three further criteria should be considered:

- Does Australia have a significant existing industry? Where there is an existing industry, it is a safer bet that comparative advantage will persist with the decarbonised versions of those industries.
- Are significant technological developments needed before we are sure about the likely role of hydrogen?
- Does the role of hydrogen depend significantly on government decarbonisation policy in other realms – such as the electricity sector and road transport?

3.2.1 Move immediately on ammonia, alumina, and iron

Ammonia, alumina, and iron look like the commodities most likely to make good use of hydrogen.

Since Australia already has significant industries producing these commodities, we have comparative advantages that are likely to carry over to the decarbonised versions of those industries. These commodities have a strong demand outlook, including for exports. And they can be a source of significant, early demand for hydrogen (see Table 5.1 on page 34 for an estimate) – large enough to build a viable, long-term hydrogen supply industry.

Chapter 4 discusses ammonia, alumina, and iron in more detail.

3.2.2 Move slowly on manufacturing, synthetic fuels, electricity, methanol, and long-distance transport

There are five uses for hydrogen that may become viable options in future, but at present are unclear: manufacturing, synthetic fuels, electricity, methanol, and long-distance transport.

Significantly boosting these uses will not provide the scale and steady demand needed to build a viable hydrogen supply industry. However, if ammonia, alumina, and iron production expands using green hydrogen produced in Australia, these five uses will have their best chance of playing a role in decarbonising the economy.

10. This is explored more fully in Wood et al (2022).

Hydrogen could be used as a fuel for industrial heat in manufacturing, but because it is inefficient and expensive, it has competitors for both low and high temperatures.

Hydrogen could be an input for synthetic fuels to replace fossil jet fuel, doing the heavy lifting for decarbonising aviation in future, but biogenic jet fuels currently seem like a better prospect.

Hydrogen may be a substitute for natural gas for use in dispatchable peaking generation in a high-renewables electricity grid. But its role, in a field of alternatives, is uncertain.

Methanol produced using green hydrogen is a potential substitute fuel for shipping, but Australia has no manufacturing base, and there are potential competitor fuels such as ammonia.

Hydrogen fuel cell trucks could replace diesel trucks for long-distance road freight. But the supply chain for hydrogen in this case is currently non-existent, and battery electric trucks may yet develop to meet this demand.

Chapter 6 discusses these potential uses of hydrogen in more detail.

3.2.3 Proceed no further with residential and commercial heating and cooking, oil refining, and light vehicles

Using hydrogen for heating and cooking in homes and commercial buildings is unrealistic. Efficient heat pumps and induction cooktops using electricity are already far more effective, cheaper to run, and cleaner.[11] Waiting for hydrogen to become commercially viable would be costly and delay abatement.[12]

Hydrogen for oil refining has been a source of grey-to-green hydrogen industry development in other countries. There is no substitute for hydrogen in the refining process, and the supply chain is not complex. But Australia only has two oil refineries, and between them they supply only 9 per cent of Australia's liquid fuels. Neither has committed to stay open past 2027,[13] and the shift towards zero-emissions transport means refining will be a shrinking business.

Light vehicles using hydrogen have failed to gain market share. In the passenger car and light SUV category, only 38 hydrogen fuel cell vehicles were sold in Australia in 2021, compared with 8,147 battery and plug-in hybrid electric vehicles.[14] These figures are mirrored in most international markets.

3.2.4 Focus on supporting hydrogen use for domestic industry before considering liquid hydrogen exports

When Australia's first National Hydrogen Strategy was published in 2019, liquid hydrogen was considered a potential large export opportunity for Australia. This view reflected significant commitments by governments in energy-poor Asian countries, in particular, to begin replacing gas and coal imports with zero-emissions alternatives. And, at the time, Australia had no commitment to net zero and no policies to drive decarbonisation that would have justified domestic use of hydrogen.

But moving hydrogen long distances by ship is difficult and expensive. To be shipped economically, hydrogen must be in liquid form due to its low volumetric energy density. This requires compression and cooling to -253°C, an extremely low temperature, which consumes large amounts of energy. Liquid hydrogen also requires bespoke import and export terminals.

11. See the Grattan Institute report *Getting off gas: When, how, and who should pay* for the full case against using hydrogen in homes: Wood et al (2023).
12. Ibid (pp. 10–11, 15).
13. Jose and Paul (2021).
14. National Transport Commission (2022, p. 61).

Moving hydrogen-containing commodities such as ammonia or methanol – or energy-intensive commodities that use hydrogen in production, such as iron and alumina – is easier and cheaper.[15] These commodities are already globally traded, and logistics and pricing are well understood.

Global liquid hydrogen supply chains will only develop if there are countries that are willing to import very large amounts of hydrogen rather than make it themselves or relocate parts of heavy industry supply chains. As is the case with LNG, only a buyer willing to buy large amounts of hydrogen for a long period would be able to provide the certainty to underwrite the capital required for the infrastructure.

If such a buyer were to appear – one who wanted to buy Australian-produced hydrogen for export, and was willing to underwrite the capital for the supply chain – then Australia should welcome that investment. But if governments are seeking the best return for effort, they should not go chasing after liquid hydrogen exports at the expense of domestic uses that could build a viable industry.

15. Ammonia exports can be used as is, or converted back to hydrogen for use. In the latter case, although transport of ammonia is easier and cheaper, there are significant energy conversion losses associated with cracking it back into hydrogen. Regardless, shipping ammonia seems to be the most economic way of transporting hydrogen over long distances: IRENA (2022).

4 Start with ammonia, alumina, and iron

Ammonia, alumina, and iron are the three uses for hydrogen on which Australian governments should focus their initial efforts.

All three commodities are likely to remain in demand (or have growing demand, in the case of ammonia) in a future net-zero world. These are bulk materials that will remain important for building and feeding the world, and which are crucial for building the infrastructure necessary for the world's energy transition.

These three commodities already have an industrial base in Australia, a source of domestic demand from which to grow, and are economically valuable.

Australia produces ammonia, for instance, but most of our fertilisers come from overseas because of cheap natural gas available elsewhere. But as demand for green ammonia grows, Australian production could help supply the world instead. In the case of aluminium and steel, Australia is already a globally significant supplier of their raw inputs of bauxite, alumina, and iron ore. Australia's competitive advantage in renewable energy may allow it to move further down the value chain.

Green hydrogen is expensive. To use it in the production of these commodities requires either existing plants to be retrofitted or new ones to be built. There will probably be a production cost gap between grey products and green products produced using hydrogen – a green premium (see Box 3) – for a considerable time to come.

Currently, carbon prices in Australia, and emerging market premiums for green products, are not sufficient to make producing these three commodities with hydrogen commercially viable. Both of these factors are also highly uncertain, which means high risk will be an investment barrier for some time.

Box 3: What are green premiums and market premiums?

The term 'green premium' commonly refers to the extra cost to a producer of reducing the environmental impact of their production process.

In this report, we mainly consider the green premium related to carbon emissions resulting directly from production, but green premiums can also cover other environmental impacts of production and supply chains.

Some analysts also use green premium to denote the extra amount a customer is willing to pay for a product with lower environmental impact. In this report we refer to this as the 'market premium' for a green product.

4.1 Ammonia

Ammonia is a chemical composed of nitrogen and hydrogen, and is currently an important feed-stock for the production of nitrogenous fertilisers and commercial explosives.[16] Because it is cheaper to transport than hydrogen, and doesn't contain carbon, ammonia also has potential uses in a future net-zero economy in power generation and as a shipping fuel. Respectively, this involves replacing fossil fuels with ammonia in power plants, and burning ammonia in place of carbon-intensive shipping fuel.

16. The most commonly used nitrogenous fertiliser in Australia is urea, followed by ammonium phosphates. Ammonium nitrate is used for commercial explosives, and can be used as a fertiliser, although that use is now banned in Australia and some other countries because it can be hazardous.

Today, ammonia is made from grey hydrogen derived from natural gas, with carbon dioxide as a by-product. Green ammonia could instead be made from green hydrogen. Appendix A provides further detail on how this process works.

4.1.1 Demand outlook for ammonia

Demand for ammonia will endure, because about half the world's population relies on synthetic nitrogen fertiliser.[17] Income growth and the corresponding increase in demand for fertiliser-intensive meat and dairy products will also push up per-capita fertiliser use.[18]

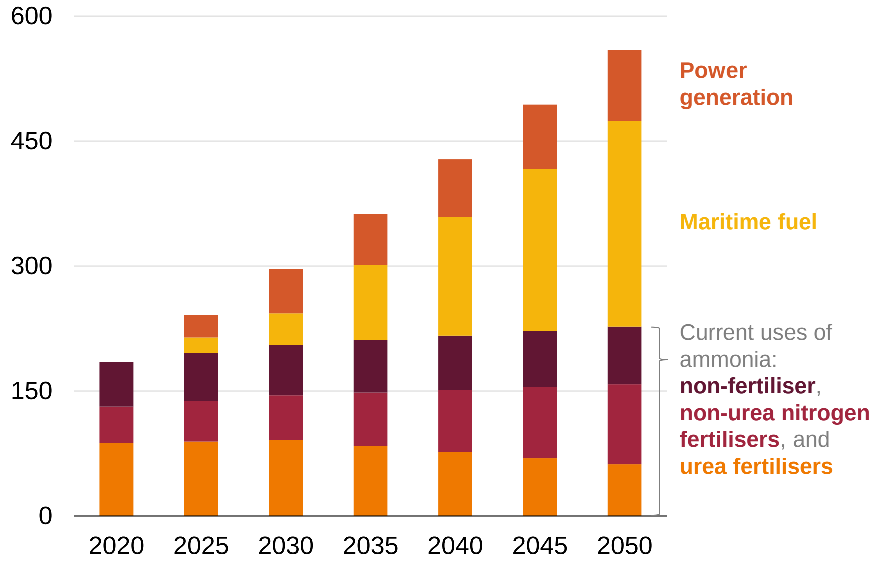
But the use of nitrogenous fertiliser has been associated with environmental problems such as algal blooms and soil acidification. Nitrogenous fertilisers also create significant greenhouse gas emissions when they're used – about double the emissions generated during their production.[19]

These concerns have led to changes in farm practices and to the development of products without those negative impacts, which is putting some downward pressure on the demand outlook for nitrogenous fertilisers. Further downward pressure will result from the Kunming-Montreal Global Biodiversity Framework, an international treaty agreed in December 2022 that commits signatories to halving excess nutrients in the environment by 2030.[20]

Globally, demand for commercial explosives and hence ammonium nitrate will fall with a net-zero-driven decline in coal mining.[21] But this may be partly offset by growth in mining for critical minerals.

17. Ritchie (2017).
18. IEA (2021).
19. Dwyer (2023).
20. Excess nutrients can damage aquatic ecosystems. They result from over-use of fertiliser, and poor management of human and animal waste: Convention on Biological Diversity (2022).
21. IEA (2021, p. 69).

Figure 4.1: World ammonia demand will remain steady across its current uses, and probably grow for new uses in shipping and power generation
Demand for ammonia, million tonnes



Note: Projections from the International Energy Agency's 2021 Net Zero Emissions by 2050 Scenario.

Source: Grattan analysis of IEA (2021).

Balancing these factors, the International Energy Agency's (IEA) Net Zero Emissions by 2050 Scenario sees global ammonia demand for existing agricultural and industrial uses growing slightly by 2050 (see Figure 4.1 on the preceding page).[22]

In the IEA's scenario, power generation and shipping become much more significant drivers of future demand growth for ammonia.[23] To what extent this projection is realised depends on the technological and economic development of other low-carbon alternatives. Co-firing ammonia with coal is an option for some renewable energy-poor countries with newer coal-fired power stations, such as Japan.[24] For shipping fuel, ammonia will compete with other low-carbon alternatives such as biofuels, green methanol, and green hydrogen.[25]

4.1.2 The Australian context

Australia currently has five ammonia production facilities. These facilities use natural gas to produce ammonia intended mainly for domestic ammonium nitrate production, or for direct export as ammonia.

Nitrogenous fertilisers

Australian farms used about 1.3Mt of nitrogenous fertiliser in 2021.[26] Nearly all of this is now imported, with Australia's only urea plant, at Gibson Island in Queensland, having closed at the end of 2022. Some locally produced ammonium nitrate is mixed with imported urea to produce urea ammonium nitrate, which is used as a liquid nitrogenous fertiliser.

Total dependence on imported urea will change with Perdaman's development of a large-scale urea plant using natural gas at Karratha in the Pilbara region of Western Australia. Incitec Pivot Fertilisers has signed a 20-year offtake agreement for up to 2.3Mt of urea per year from mid-2027, when the plant is expected to open.[27] Incitec Pivot Fertilisers intends to market up to 50 per cent of this urea in Australia, and export the remainder.[28] If this plan eventuates, this is enough to replace as much as 40 per cent of our current agricultural demand for nitrogenous fertiliser.[29] Perdaman intends to make its new plant net-zero by 2050.[30]

Net-zero urea production could be accelerated with favourable policies. As the world moves towards green fertiliser, Australian green ammonia may enjoy a cost advantage, leading to a shift toward more local production. This would be a significant source of demand for green hydrogen. To produce all the nitrogenous fertiliser used in Australia for agriculture would require about 0.3Mt a year of hydrogen.[31]

22. The IEA's Net Zero Emissions by 2050 Scenario achieves net zero CO_2 emissions from the energy sector by 2050, leading to limited overshoot of the 1.5°C limit set out in the 2015 Paris Agreement, but the increase in global average temperature falls below 1.5°C by 2100: IEA (2023b, p. 56).
23. IEA (2021, p. 72).
24. BloombergNEF (2022).
25. IRENA (2021a, p. 15).
26. Food and Agriculture Organization of the United Nations (2023). There are different types of nitrogenous fertiliser; 1.3Mt is the weight of contained nitrogen across all types of nitrogenous fertiliser.
27. Incitec Pivot Limited (2023).
28. Ibid.
29. Assuming demand remains constant. As a signatory to the Global Biodiversity Framework, Australia is obliged to reduce excess nutrients, including fertiliser, by half by 2030. As yet, no policy has been implemented to give effect to this commitment.
30. Perdaman Chemicals and Fertilisers Pty Ltd (2023).
31. Grattan analysis of Food and Agriculture Organization of the United Nations (2023). All synthetic nitrogen fertilisers require atmospheric nitrogen to be fixed with hydrogen in ammonia.

Commercial explosives

In Australia, annual demand for ammonium nitrate for commercial explosives (2.6Mt) is almost entirely satisfied by domestic production.[32] These explosives are used in thermal and metallurgical coal mining in central Queensland and in the Hunter Valley in NSW; and in iron ore, gold, and nickel mining in WA.

The outlook for domestic ammonium nitrate demand is likely to be determined by the same factors driving international demand for minerals.

It is likely that Australian miners will continue to rely on domestic production of ammonium nitrate. Imported ammonium nitrate is more expensive than the domestic product because of the additional freight, storage, and regulatory compliance costs associated with importing this hazardous substance.[33] This will probably continue to be the case, and the cost-competitiveness of domestic production could be further improved by Australia's cost advantage in renewable energy as miners work on reducing their scope 3 emissions.[34]

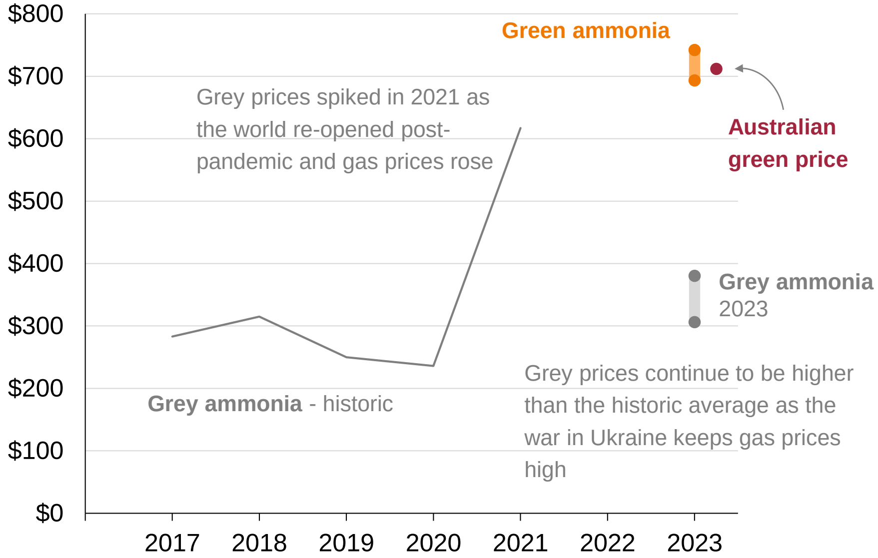
4.1.3 The economics of ammonia

Ammonia prices are linked closely to gas prices, because conventional ammonia production is so reliant on gas. Current ammonia prices are higher than the historic average (Figure 4.2).

At present, only about 0.004 per cent of world ammonia production is green, and this trades at a much higher price than conventional ammonia – a market premium of about 90 per cent.[35] Australian green

Figure 4.2: Even with elevated world grey ammonia prices, green ammonia is significantly more expensive

Global ammonia prices, US$/t ammonia



Notes: Grey ammonia prices are cost-and-freight. Green ammonia prices are assessments of delivered prices less an average shipping cost of US$60/tonne ammonia, as at August 2023, and assume alkaline electrolysis. No price data available for 2022. 2023 prices vary by region, chart shows lowest and highest prices.

Source: Grattan analysis of Platts S&P Global (2023b), Shiozawa (2020), Statista (2023).

32. Anti-Dumping Commission (2021, pp. 25, 31) and Australian Industry Energy Transitions Initiative (2023, p. 108).
33. Anti-Dumping Commission (2021, pp. 27–28).
34. Scope 3 emissions are those which are produced upstream or downstream of a point in a supply chain.
35. Platts S&P Global (2023b).

premiums are currently consistent with market premiums globally – in other words, the cost of producing green ammonia in Australia is consistent with what international markets are willing to pay for green ammonia.

But most of the deals struck for green ammonia seem to be associated with large producers familiarising themselves with the technology via pilots and trials. Many green ammonia projects are subsidised heavily by governments. A market premium of 90 per cent is unlikely to be sustained in the long term.

There is a wide spread between the best- and worst-case scenarios for the green premium associated with retrofitting ammonia plants to use green hydrogen in Australia (see Figure 4.3). Using debt finance to finance these retrofits thus carries significant financial risk.

Between half and two-thirds of the green premium is accounted for by the cost of green hydrogen. The remainder is capital expenditure to retrofit facilities, and additional electricity costs to replace natural gas used for heat.

Retrofitting an ammonia plant to use green hydrogen avoids the need to buy natural gas for feedstock. There is also a saving for avoiding the carbon costs imposed by the Safeguard Mechanism.[36]

Under current policy settings, even if hydrogen costs fall, and carbon costs increase (the best-case scenario in Figure 4.3), the additional cost of using green hydrogen to produce ammonia is not offset by avoided gas and carbon costs. Australian green ammonia production costs look likely to remain well above conventional (grey) production into the 2040s, particularly if hydrogen costs stay high, and carbon costs remain low (the worst-case scenario in Figure 4.3).[37]

Figure 4.3: Under current policy settings, using green hydrogen to produce ammonia adds a considerable green premium

AU$/tonne ammonia, above current grey production cost

Notes: Existing ammonia plants face two choices: they can pay to emit carbon, or switch to using green hydrogen. For using hydrogen to be cost-competitive, the cost of emitting carbon must be higher than the green premium, which is the cost of using hydrogen less the money saved from not using gas. That is, the grey-green production cost gap should be close to zero or negative. Detailed descriptions of best- and worst-case scenarios can be found in Appendix B.

Source: Grattan analysis. See Appendix B for assumptions and sources.

36. The Safeguard Mechanism requires large industrial facilities to gradually reduce their emissions every year, either by adjusting their operations or using offsets.
37. These calculations are based on east coast gas and electricity prices.

4.2 Alumina

Australia is the world's largest alumina exporter, owing in large part to its abundant bauxite reserves. Bauxite is the raw aluminium ore that is refined to become alumina (aluminium oxide), and that is then converted to aluminium in an electrical smelter. Appendix A provides further detail on these processes.

4.2.1 Demand outlook for aluminium

World demand for aluminium is likely to grow slightly to 2050, though much of this will be satisfied by increased recycling of aluminium (see Figure 4.4).

As a key input into energy transition technologies, such as electric vehicles, solar panels, and the electricity grid,[38] as well as many other high-value goods, demand for aluminium is expected to continue to grow strongly.[39]

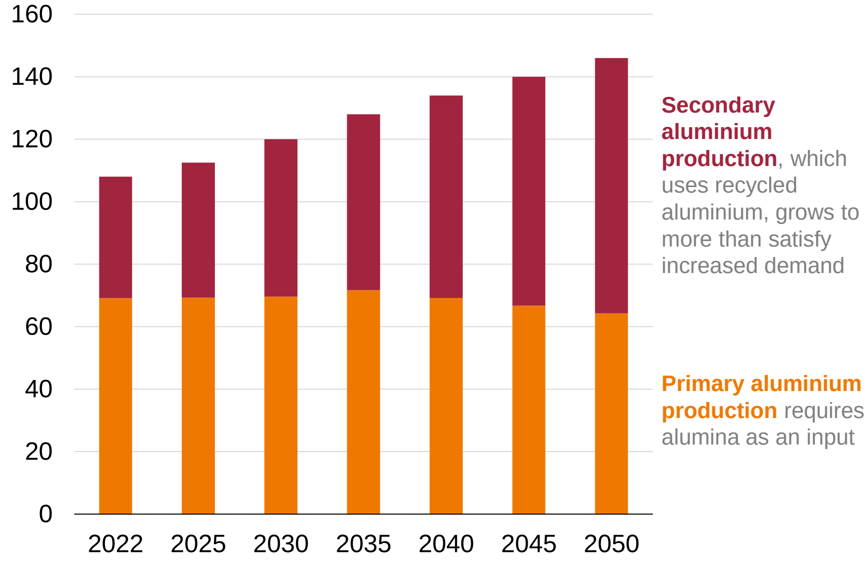
The IEA sees demand for aluminium (from both primary and secondary production)[40] increasing by about 35 per cent from 2021 to 2050, driven largely by its increased use in electric vehicle manufacturing and in electricity generation and grids.[41]

But much of this growth in demand will be met by increased recycling rather than primary production. The IEA estimates the share of aluminium recycling – secondary production – will increase from 36 per cent today to reach 56 per cent in 2050.[42] Taken together, world demand for primary aluminium will fall slightly. The International Aluminium Institute has put forward a similar, but slightly more

38. IEA (2023c, p. 154).
39. IEA (2023d).
40. Primary production is production from raw ore. Secondary production is production from recycled or scrap material.
41. IEA (2023c, pp. 154–155).
42. IEA (2023b, p. 95).

Figure 4.4: Global aluminium production will increase due to demand for energy transition technologies, but will increasingly use recycled aluminium

Aluminium production (million tonnes)



Notes: Projections from the International Energy Agency's 2023 Net Zero Emissions by 2050 Scenario.

Source: Grattan analysis of IEA (2023b).

optimistic, outlook for primary aluminium demand under a 1.5°C of global warming scenario – demand grows by a modest 6.25 per cent from 2020 to 2050.[43]

4.2.2 The Australian context

Competitive advantage along the aluminium value chain is built on the basis of:

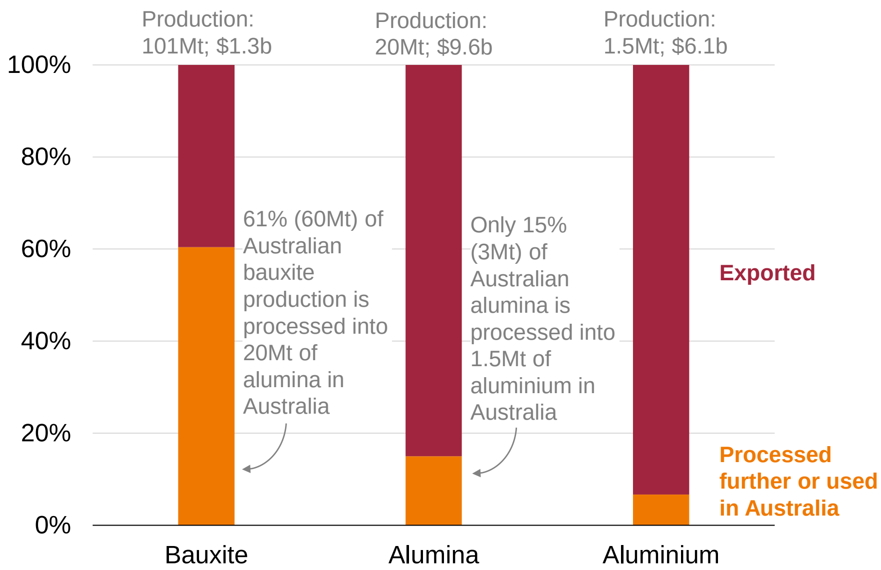
- Bauxite: bauxite resources and mining productivity.
- Alumina: proximity to bauxite mines and low-cost gas and coal for digestion and calcination (energy makes up 30-to-40 per cent of refineries' cost base).
- Aluminium: low-cost, uninterrupted electricity supply for smelting (electricity makes up 30-to-40 per cent of smelters' cost base).[44]

Australia has a significant, existing footprint along the bauxite-alumina-aluminium supply chain, owing to its historical advantages in the above factors.

For alumina refining, digestion and calcination are the key carbon-intensive steps that will need to be decarbonised. The most promising technologies for decarbonised digestion do not use hydrogen. High-temperature calcination is the key step that could be cost-effectively replaced with a hydrogen-based process. Calcination typically requires temperatures exceeding 1,000°C and consumes about a third of the energy required for alumina refining.[45] Currently, Australian refineries use natural gas for calcination, producing about 3.5 million tonnes of CO_2-e emissions a year.[46]

Figure 4.5: Australia is a significant producer of bauxite and alumina, but exports most of its alumina for smelting into aluminium overseas

% of Australian production



Note: Export figures for bauxite and alumina contain a small amount of each commodity not intended for use in aluminium metal production.

Source: Grattan analysis of Australian Aluminium Council (2023).

43. International Aluminium Institute (2021).
44. Australian Aluminium Council (2023).
45. Deloitte and ARENA (2022).
46. Ibid.

But calcination can also be achieved with electricity. Electric and hydrogen-powered calcination are at a similar technology-readiness level; both require further development before they can be implemented at a commercial scale. Alcoa and Rio Tinto are looking to deploy first-of-a-kind electric and hydrogen calcination technologies, respectively.[47]

A key benefit of hydrogen calcination is that it can be cheaper to retrofit to existing plants than electric calcination, meaning lower upfront capital expenditure.[48] While it's more efficient to generate heat using electricity than hydrogen,[49] the future evolution of hydrogen and electricity costs, including transmission, transport, and storage, could push the economics in favour of one or the other. These factors also mean that the decision to adopt one over the other is likely to be highly facility-specific, with industry needing to pursue both options.[50]

Replacing all natural gas-based calcination with hydrogen calcination in Australian refineries would require about 0.5 million tonnes of hydrogen annually (Table 5.1 on page 34). But not all companies are pursuing hydrogen calcination.[51] Taking this into account, demand is more likely to be in the order of 0.18Mt of hydrogen.[52]

Australia's hydrogen competitive advantage may allow a further push along the value chain to produce more alumina domestically than it currently does, using the bauxite that is mined here (see Figure 4.5 on the preceding page).

47. Ibid.
48. Ibid (p. 29).
49. Ibid (p. 29).
50. Ibid (p. 20).
51. Ibid.
52. Grattan analysis of Deloitte and ARENA (ibid).

Australia's renewable energy advantage could also be conducive to cheap, clean aluminium production. But aluminium smelting is dependent on *firmed* electricity and is significantly more electricity-intensive. It may be difficult for Australia to compete on cost with countries that have better traditional hydropower endowments.[53] The scale of the renewable generation build-out required for a sizeable green aluminium manufacturing industry is also significant.[54]

4.2.3 The economics of alumina

There are fewer data on global markets' willingness to pay a significant market premium for green alumina or aluminium. For low-carbon aluminium (up to 4t CO_2-e/t aluminium measured over scope 1 and scope 2 emissions), estimates of the market premium range from US$10 to US$40 per tonne for European sales.[55] This compares with a global price of more than US$2,000 per tonne for the aluminium itself.[56]

Alumina sells for about AU$500 per tonne.[57] Future green premiums for alumina production range from 18 to 28 per cent in 2030, but could be as low as 10 per cent in 2040 (see Figure 4.6 on the next page).

For Australian production of alumina, hydrogen itself makes up 80 per cent of the green premium for calcination, with the rest being the relatively cheap cost of retrofitting the calciner ($19/tonne of alumina). The gas consumption for calcination that the hydrogen is substituting

53. Zero-emissions firming can be achieved through the storage and release of energy in batteries, traditional hydro power, or pumped hydro systems. Of these, traditional hydro power is the cheapest, but Australia lacks significant geographical potential for traditional hydro power, making firmed electricity more expensive to supply here: Herd and Hatfield Dodds (2023, p. 41).
54. Australia's four aluminium smelters used about 24.3 terawatt hours of electricity in 2018-19 (about 10 per cent of Australia's total annual electricity consumption): Butler (2020).
55. Bone and Dudman (2023).
56. London Metals Exchange (2023a).
57. London Metals Exchange (2023b).

for, however, is modest (3.4GJ of gas per tonne of alumina) – meaning that there are few fuel savings to be had by switching from natural gas. Avoided carbon costs are correspondingly small, because only one-third of emissions of alumina production come from calcination.

Under current policy settings, the cost of producing Australian alumina with hydrogen is likely to remain 18 to 28 per cent higher than current world prices in 2030, and 10 to 28 per cent higher in 2040 (see Figure 4.6).[58]

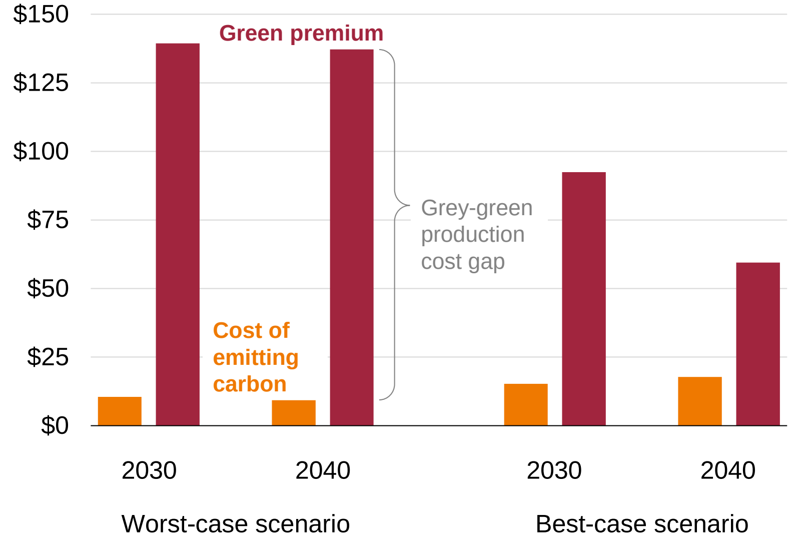
4.3 Iron and steel

Australia is a global leader in the mining and export, largely to Asia, of iron ore and metallurgical coal.

These materials are combined in blast furnaces to make iron, which is then further processed into steel. Steelmaking in this way results in about 7 per cent of global emissions.[59] Green hydrogen can be used with iron ore in an alternative process, called direct reduction, to produce low-emissions iron.[60] This green iron can then be processed into steel either in Australia or overseas, depending on where production costs are lowest. Appendix A provides further detail on these processes.

Figure 4.6: Under current policy settings, using green hydrogen for alumina calcination will not be competitive by 2040 even in the best-case scenario

AU$/tonne alumina, above current grey production cost



Notes: Existing alumina plants face two choices: they can pay to emit carbon, or switch to using hydrogen. For using hydrogen to be cost-competitive, the cost of emitting carbon must be higher than the green premium, which is the cost of using hydrogen less the money saved from not using gas. That is, the grey-green production cost gap should be close to zero or negative. Detailed descriptions of best- and worst-case scenarios can be found in Appendix B.

Source: Grattan analysis. See Appendix B for assumptions and sources.

58. These calculations are based on east coast gas and electricity prices.
59. Mission Possible Partnership (2022, p. 10).
60. Industrial-scale direct reduction iron facilities that use natural gas already exist around the world, and have a lower carbon intensity than blast furnaces. These facilities produced about 114Mt of direct reduced iron in 2021, compared with total world pig iron production of 1,354Mt (iron produced using iron ore and coke in a blast furnace): World Steel Association (2022). These direct reduction facilities can be retrofitted to use hydrogen instead.

4.3.1 Demand outlook for iron and steel

World demand for steel is likely to remain strong but flat, and a larger share of future demand will be met by increased recycling of steel scrap, reducing the demand for new iron (see Figure 4.7).

Demand for consumer and industrial goods that contain steel is likely to rise with incomes. As more economies reach maturity, steel demand for buildings and transport is expected to decline as new-build infrastructure tapers off, and replacement of existing infrastructure becomes a larger source of demand.[61]

While steel is important for the construction of energy infrastructure and electricity generation technologies, such as wind turbines, these uses are only a small share of current steel demand, so their expected future growth will not contribute significantly to overall steel demand.[62]

Further, the energy and emissions intensity of steel produced using new iron is much greater than recycled steel. For this reason, future steel production will use more steel scrap, leading to a reduction in the use of iron manufactured from iron ore. The IEA estimating that the share of scrap in metallic inputs to steel will increase from 33 per cent in 2022 to 48 per cent in 2050.[63]

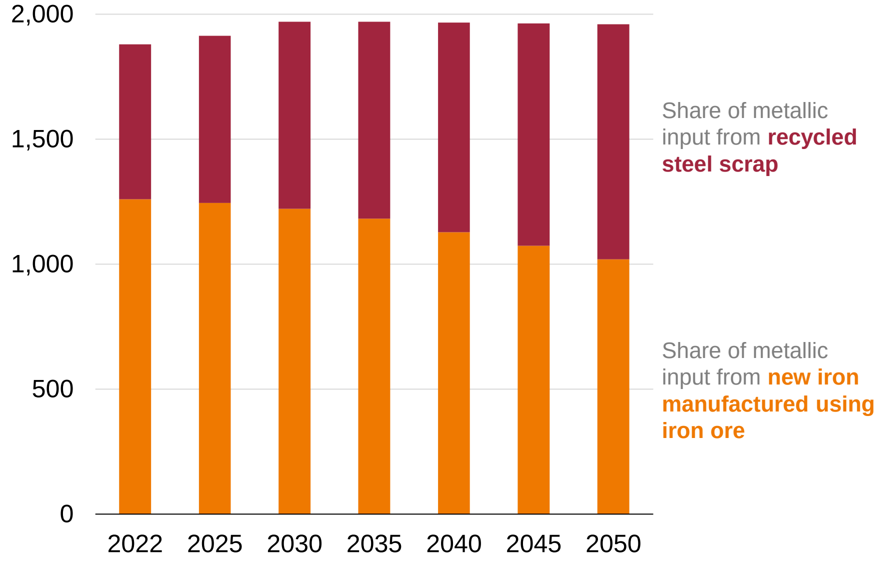
Taken together, world demand for primary steel is expected to be less than it is today, though still significant.

4.3.2 The Australian context

Though world demand for primary steel is likely to fall, iron is arguably a larger economic prize for Australia than the other two commodities

Figure 4.7: World steel production is likely to remain flat, and will increasingly use scrap rather than new iron manufactured using iron ore

Crude steel production, million tonnes



Notes: Projections from the International Energy Agency's 2023 Net Zero Emissions by 2050 Scenario.

Source: Grattan analysis of IEA (2023b).

61. IEA (2023c, pp. 154–155).
62. Ibid (pp. 154–155).
63. IEA (2023b, p. 95).

explored in this chapter (ammonia and alumina). Australia is the world's largest exporter of iron ore, with exports worth $123.5 billion in 2022.[64]

Australia currently produces 37 per cent of the world's iron ore[65] and 18 per cent of its metallurgical coal.[66] Yet it only produces about 0.3 per cent of the world's steel.[67] This is because it is cheaper to ship the iron ore and coal to major manufacturing and steel-consuming countries, such as China, Japan, Korea, and India.

Shipping typically adds less than 10 per cent to the total cost of Australian coking coal delivered to major Asian markets.[68] The costs saved by avoiding shipping ore is too small to overcome the disadvantages of producing steel in Australia, mainly high wages. Consequently, Australia has only two integrated steelworks, which together produces two-thirds of Australia's steel demand.[69]

The world's need to decarbonise steel production will change this supply chain model. The most promising low-carbon production method for making iron (in the form of direct reduced iron) requires hydrogen, which is much more expensive to transport than metallurgical coal.[70] Combined with Australia's likely comparative advantage in green hydrogen production, an opportunity exists for it to move further along the value chain to iron production.

Grattan Institute's 2020 report, *Start with steel*, showed that for the bulk of iron ore mined in Australia, iron production is probably the right place to stop along the value chain, and that Australia could produce green iron cheaper than many of its neighbours. A compacted form of direct reduced iron (DRI), hot briquetted iron, is easy to ship, and turning it into steel requires more labour and less energy than the direct reduction process, giving low-wage countries an advantage in that step of the process.[71]

To capture this opportunity also requires access to the right type of iron ore. The direct reduction process requires a processed iron ore product that contains more iron content and fewer impurities than does a blast furnace. Currently, however, the overwhelming majority (96 per cent) of the iron ore mined and exported from Australia is hematite, which is not well-suited for feeding a direct reduction process.[72]

Magnetite is the type of iron ore that is better suited for direct reduction. While 38 per cent of Australia's economic demonstrated resources[73] of iron ore are magnetite (primarily located in WA and SA), it is currently not mined as extensively.[74] The availability of magnetite and high quality renewable resources also may not be aligned geographically.

It is possible to process hematite to be suitable for direct reduction, but the technologies are immature.[75] Australia will probably have to expand efforts on both fronts if it is to succeed in capturing a larger slice of the green iron pie.

4.3.3 The economics of iron and steel

For the other priority uses discussed in this chapter, ammonia and alumina, production with hydrogen involves retrofitting an existing operation. For iron and steel, a hydrogen retrofit option is only available for existing direct reduced iron (DRI) plants, where it can replace the

64. Grattan analysis of DFAT (2023).
65. USGS (2022, p. 85).
66. IEA (2023e).
67. World Steel Association (2020).
68. Wood et al (2020, p. 22).
69. Smith (2021).
70. Wood et al (2020, p. 22).
71. Ibid (p. 24).
72. Geoscience Australia (2023).
73. Economic demonstrated resources are resources for which profitable extraction or production are possible under certain investment assumptions.
74. Australian Industry Energy Transitions Initiative (2023, p. 57).
75. Ibid (p. 57).

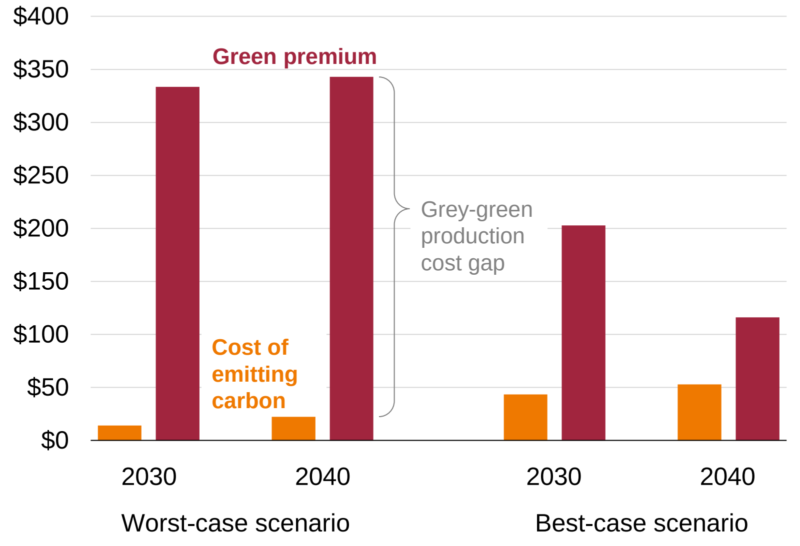
use of natural gas. For steel plants that use a blast furnace, there is no retrofit option that uses hydrogen.[76] This means making green iron in Australia will involve building new DRI plants.

Overseas, emerging market premiums for green steel have been estimated to be between €150 and €300 per tonne.[77] Offtake agreements are largely driven by the automobile manufacturing sectors, seemingly because European car manufacturers face 'lifecycle' – rather than 'tailpipe' – emissions regulation.[78] In addition, using green steel adds very little to the retail price of a car – between 0.1 per cent and 1.6 per cent.[79]

Australia's economic advantage lies in iron production rather than steel production, when competing with low-wage countries.[80]

Under current policy settings, Australian green premiums for iron production are significant through to 2040 in the worst-case scenario (see Figure 4.8). Because a new DRI plant using gas and one using hydrogen have approximately the same capital and operating costs, the green premium comes entirely from using hydrogen, and because in our worst-case scenario, hydrogen costs do not fall much, the green premium does not fall either. In our best-case scenario, where hydrogen costs fall consistently to 2040, the green premium for iron reduces to about $116 per tonne of iron. While this is considerably less than in the worst-case scenario, it is still a significant premium on the world price of iron, which is currently about $721 per tonne.[81]

Figure 4.8: Under current policy settings, Australian production costs for green iron could approach cost-competitiveness in the 2040s
AU$/tonne iron, above current grey production cost



Notes: A company building a new iron plant faces two choices: it can use gas (and pay to emit carbon), or use hydrogen. For using hydrogen to be cost-competitive, the cost of emitting carbon must be higher than the green premium, which is the cost of using hydrogen less the money saved from not using gas. That is, the grey-green production cost gap should be close to zero or negative. Details of best- and worst-case scenarios can be found in Appendix B.

Source: Grattan analysis. See Appendix B for assumptions and sources.

76. An emissions reduction of up to 20 per cent can be achieved by injecting hydrogen into a basic oxygen furnace after the blast furnace stage: Santis et al (2022).
77. Bolotova and Yeo (2023).
78. Attwood (2023).
79. Prasad (2021).
80. Wood et al (2020).
81. SMM (2023). Price given for pig iron (produced in blast furnaces) rather than direct-reduced iron (DRI). DRI is denser, has a lower carbon content, and higher purity than pig iron.

5 What governments should do

An Australian hydrogen industry should be capable of providing the industries that most need hydrogen with reliable low-cost supply, without long-term subsidies.

Governments should focus on industries that will be long-term users of large volumes of hydrogen. These industries should mostly be export-focused – or have the potential to become so in a net-zero global economy – because the domestic Australian market is too small to generate sufficient hydrogen demand for a viable industry in the long term. Establishing strong, viable demand will position the Australian hydrogen industry to expand into other opportunities, should those arise.

There are two areas where government can confidently act now because these will be essential both for hydrogen and for broader industrial transformation: first, delivering a reliable, green, low-cost, electricity system; and second, unblocking construction constraints.

But the cost gap between green commodity production and incumbent (grey) production will persist unless further steps are taken. There are two, complementary, ways to close this gap: push up the carbon price; and use industry policy to underwrite production of green commodities. The government should increase the ambition of Safeguard Mechanism settings, to decrease the burden on taxpayers of closing the cost gap. And the government's Hydrogen Headstart program should evolve into an effective industry policy that uses contracts-for-difference to share the risk of transforming Australian heavy industry to 'superpower' status.

The National Hydrogen Strategy should be revised to complement an evolved Headstart, and focus on factors specific to hydrogen that stand in the way of creating a viable industry capable of supplying Australian users. And the government should rule out further investment of time and money into hydrogen uses that are dead ends.

5.1 Smart investments in fundamental factors for success

Developing a hydrogen industry is just one part of a larger industrial transformation that must take place in Australia over the next two-and-a-half decades.

Two factors will underpin the success or failure of this transformation: reliable green electricity, and unlocking constraints on construction. Delivering these will benefit the whole industrial sector, whether its pathway to net zero lies with hydrogen or with electrification.

5.1.1 Cheap and reliable green electricity is the backbone

Renewable electricity will be in demand from all sectors of the economy in the transition to net-zero emissions by 2050. And Australia's renewable energy superpower ambitions rely on an abundance of low-cost renewable electricity.

Australia's latent renewable energy competitive advantage comes from having a lot of renewable resources, and lower opportunity costs in making use of them than is the case in many other countries. These lower opportunity costs largely arise because of our low population density: the likelihood of there being a more economically valuable use of a particular piece of land is lower in Australia than in other, more crowded, countries. But Australia will maintain a competitive advantage only if the marginal cost of another megawatt of renewable generation is lower than in other countries.

Electricity demand will grow regardless of whether key energy-intensive processes end up using green hydrogen, because the key competitor to hydrogen-based technologies across almost all uses is a form of electrification.

It will take a lot of renewables just to build the first stage of a viable hydrogen industry

Even a modest level of ambition for a hydrogen industry requires a lot of renewable electricity, and transmission. Based on 2022 Australian production volumes, simply replacing the 'hydrogen-replaceable' processes in ammonia, alumina, and iron production would require 1.02 to 1.34Mt each year of hydrogen and 23.8 to 31.5 gigawatts (GW) of renewable generation capacity (see Table 5.1). If it is all sourced from solar photovoltaics (PV), this would require about 853 square kilometres of land.[82] For comparison, only about 19GW of grid-scale solar and wind was connected to the National Electricity Market by the end of 2022.[83]

The future users of green hydrogen will often also have significant demand for renewable electricity themselves. Zero-emissions steel-making using electric arc furnaces, and aluminium smelting will both require significant amounts of renewable electricity.

Getting electricity costs down is critical for a viable hydrogen industry

The cost of green hydrogen depends heavily on the cost of green electricity, and largely for that reason, Australia is not presently a low-cost location for hydrogen production.

Most large planned hydrogen projects are looking to connect their electrolysers to dedicated renewable generation, rather than to the grid (see Figure 5.1 on the next page). This enables these projects to

Table 5.1: A lot of electricity would be needed to make the green hydrogen for decarbonised ammonia, alumina, and iron production

			For hydrogen production:	
	Australian production (Mt)	**Hydrogen required (Mt H_2)**	**Electricity required (TWh)**	**Generation capacity required (GW)**
Ammonia	2.1	0.36	18.7	8.5
Alumina	7.0 - 20.1	0.18 - 0.50	9.0 - 25.8	4.1 - 11.8
Iron	6.6	0.48	24.5	11.2
Total		1.02 - 1.34	52.1 - 69.0	23.8 - 31.5
Comparison: NEM in 2022			*177TWh operational consumption*	*19GW of solar and wind*

Notes: TWh = terawatt hour. GW = gigawatt. Hydrogen required is only that for 'hydrogen-replaceable processes', assuming production activity at 2022 levels. Hydrogen-replaceable processes are: steam methane reforming hydrogen production for ammonia; calcination of aluminium hydroxide for alumina; blast furnace smelting of iron ore for iron. These processes are detailed further in Appendix A. For alumina, the low end of the range is for production at Rio Tinto's facilities only (because currently only Rio Tinto is investigating hydrogen), the high end of the range is for all Australian refineries. Assumes 65 per cent electrolyser efficiency and solar photovoltaic generation is used with a 25 per cent capacity factor. 6.6Mt is the volume of direct reduced iron required to produce enough crude steel to match Australian production in 2022 (5.7Mt).

Source: Grattan analysis using calculations in Figure 1.1, and AEMO (2023a), AEMO (2023b), Deloitte and ARENA (2022, p. 27), and Wood et al (2020, p. 44),

82. Co-located wind and solar would require less land, but the amount would be site-specific. Solar is used here for illustrative purposes.
83. AEMO (2023a).

get cheaper electricity, although they need to balance this against the need to manage the intermittency of renewable generation. Going with dedicated renewable generation also unlocks locations not well-served by the grid for hydrogen production, but it is not possible everywhere – especially where there is a high opportunity cost for using land for generation.

In other cases, green hydrogen producers may prefer to connect to the electricity grid – if the electricity is clean, and if the wholesale price, including transmission, is cheap enough. This would enable producers to save on transport and storage of hydrogen, and avoid having to deal with the intermittency of renewable generation.

These considerations reinforce the need for a high level of coordination between hydrogen and broader energy system planning.

Recommendation 1

Continue to reduce the cost of renewable electricity in Australia. Accelerate rollout of renewable energy generation and storage, and deployment of transmission.

For grid-connected projects, embed green hydrogen's electricity demand into electricity-system planning through the Australian Energy Market Operator's Integrated System Plan, and into the design and development of Renewable Energy Zones.

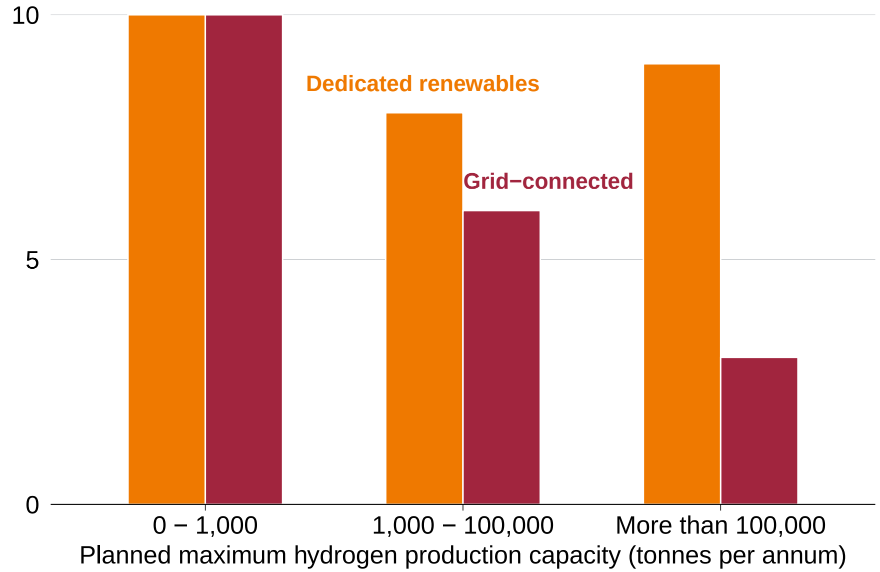
5.1.2 Unblocking construction constraints

At present, governments and the private sector are building a large number of infrastructure projects all at once, contributing to high construction costs and widespread project delays.[84] Australia's

84. Infrastructure Australia (2022).

Figure 5.1: Larger planned hydrogen projects are more likely to be using dedicated renewables

Number of projects



Notes: Includes all electrolysis hydrogen projects that were under construction or under development as at 5 September 2023. Projects without a reported hydrogen production capacity or power source are excluded.

Source: Grattan analysis of data from CSIRO (2023a).

high construction costs already detract from our renewable energy superpower competitive advantage.[85] And the problem is exacerbated when significant domestic competition for labour and materials means the construction sector runs up against capacity constraints.

Australia's labour shortages will only be exacerbated by additional competition for skilled labour as the rest of the world decarbonises and also seeks to capture green export opportunities.[86]

There is no simple solution to these issues, but, given better coordination, and the right price signals, markets will ultimately be the best mechanism for allocating resources throughout the economy.

Recommendation 2

State and territory governments should manage demand by coordinating and sequencing major construction projects.[a]

a. Terrill et al (2021).

5.2 Closing the cost gap requires carbon pricing to align investment with climate goals

Even with cheaper electricity (and therefore cheaper hydrogen) and with improvements to make construction easier, the green premium for ammonia, alumina, and iron is likely to persist for some time. The gap between what it costs to produce green commodities, and what buyers are willing to pay for them can be closed using two, complementary tools: raising the carbon price to make non-green production more expensive; and using industry policy to make green production cheaper.

85. Herd and Hatfield Dodds (2023).
86. Jobs and Skills Australia (2023, p. 132).

Australia needs carbon price signals that are strong enough to give industry the incentive and the signal to decarbonise. Carbon signals can be explicit prices – such as those in the Safeguard Mechanism – or implicit ones, such as those created by emissions standards.

But carbon signals are not industry policy. Decarbonisation policy should focus on reducing emissions at least cost. A separate industry policy is the best way to focus on industry development.

The three commodities identified in this report as a good basis for a viable Australian hydrogen industry – ammonia, alumina, and iron – are all produced in facilities subject to the Safeguard Mechanism. They are required to reduce their emissions each year in line with a declining baseline, and offset any emissions above the baseline. Also, new facilities must be built to world's best practice emissions intensity.

Chapter 4 showed that the carbon price generated by declining Safeguard Mechanism baselines will not make green ammonia, alumina, and iron cost-competitive with existing carbon-intensive processes by 2040.

While this is partly because the costs of producing green hydrogen and retrofitting or building green commodity production facilities are high, it is also because the price of emitting carbon in Australia is too low (see Figure 5.2 on the following page).

The incentive to switch to green hydrogen depends on the price of carbon. If the price of carbon is low, the incentive to switch to green hydrogen is weak. Under current policy settings, Safeguard facilities only make small savings by avoiding liability for carbon, compared with the cost of hydrogen itself. The balance would change if the Safeguard had a cost of carbon consistent with keeping global average temperature rises to 1.5°C.

The planned 2026-27 review of the Safeguard Mechanism is a natural opportunity to consider ways to establish stronger carbon price trajectories beyond 2030. These could include steeper baseline declines, and higher price caps (through the cost containment measure) to increase the carbon liability.

Outside the industrial sector, changes should be made to the Safeguard Mechanism – or an alternative policy put in place – to ensure other uses of hydrogen face a sufficient signal to decarbonise. For example, while some aviation and road freight transport businesses, and energy-intensive manufacturing facilities are included under the 100,000 tonnes of CO_2-e threshold for the Safeguard, not all of them are.[87] Lowering the threshold to capture more of these emitters would increase incentives to switch to low carbon fuels, including hydrogen. Similarly, electricity remains effectively untouched by Safeguard Mechanism reforms.

Policy recommendations for these sectors are detailed in Chapter 6.

Recommendation 3

The review of the Safeguard Mechanism in 2026-27 should consider the role that steeper baseline declines, higher price caps, and a lower threshold could play in closing the cost gap on green commodity production.

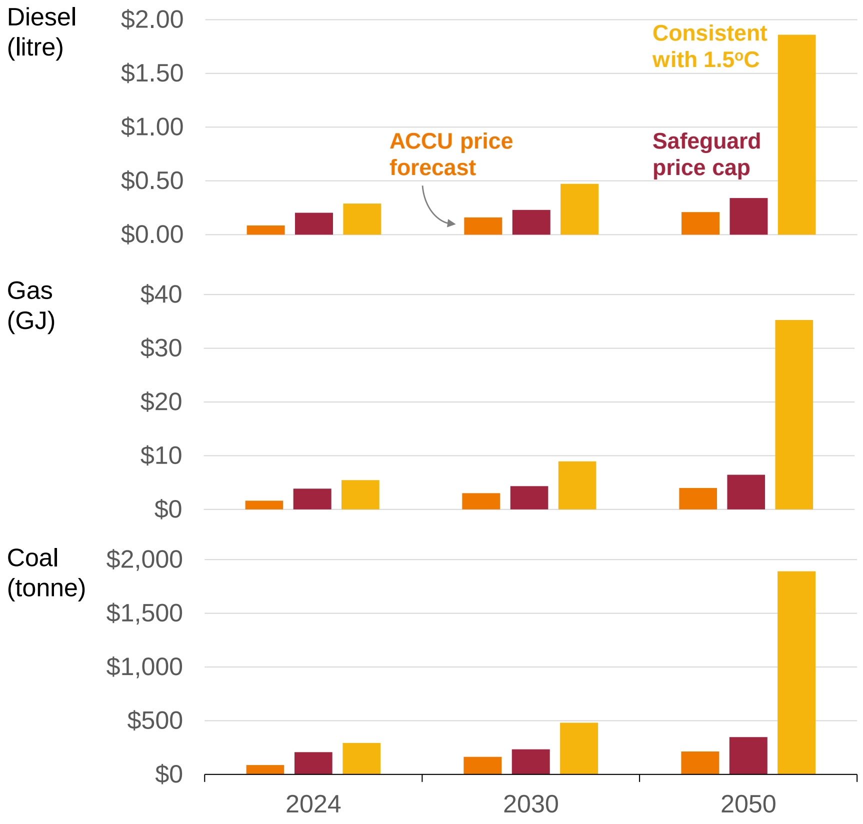
Carbon border adjustment mechanisms

Calculations of the impact of carbon prices implied by the Safeguard Mechanism in this report assume that ammonia, alumina, and iron are not eligible for concessions because of trade exposure.[88]

87. Clean Energy Regulator (2023a).
88. Eligibility for trade exposure concessions is determined on a facility-by-facility, year-by-year basis, depending on the cost of Safeguard compliances compared to Earnings Before Interest and Taxes (EBIT): DCCEEW (2023f). This is separate to

Figure 5.2: Under current Australian policies, minimal savings result from avoiding carbon costs

Carbon costs from fossil fuels, AU$



Notes: ACCU = Australian Carbon Credit Unit. Gas carbon costs are per gigajoule for combustion, not feedstock. Diesel carbon costs are per litre for use as transport fuel in a heavy duty vehicle meeting Euro IV standards. Coal carbon costs are per tonne of metallurgical coal.

Source: Grattan analysis of data from DCCEEW (2023c), Herd and Hatfield Dodds (2023), and Network for Greening the Financial System (n.d.).

If these concessions are granted, the cost gap between grey and green production will be larger.

A carbon border adjustment mechanism (CBAM) ensures imported goods are subject to a carbon price equal to that faced by domestic producers of the same goods. Where Australia is a net commodity importer, such as for ammonia and steel (but not alumina), this would replace the need for trade exposure concessions, and mean domestic production would face the full impact of carbon pricing, which would help close the cost gap for green production.

In conjunction with a strengthened Safeguard Mechanism or other carbon signal mechanism that works on domestic supply, a CBAM could help ensure that domestic demand works to decarbonise domestic industry without destroying it – that is, without leading to so-called carbon leakage, where firms move their operations from Australia to countries with less-stringent emissions policies.

The government is considering policy options through its Carbon Leakage Review, due to report by 30 September 2024.[89] The review will look at carbon leakage risks and policy options to address those risks across key products, with a particular focus on steel and cement.[90]

Recommendation 4

As part of the Carbon Leakage Review, consider the role a carbon border adjustment mechanism could play in developing viable green commodity production.

Emissions-Intensive Trade Exposed (EITE) concessions under the Renewable Energy Target, which shield ammonia, alumina, and iron production from the electricity cost impacts of that policy: Clean Energy Regulator (2023b).

89. DCCEEW (2023g).
90. Ibid.

5.3 Industry policy should underpin development of a hydrogen industry

Australia's clean energy opportunities are large, but they are far from certain. Governments cannot single-handedly drive the creation of new global-scale industries, nor invest the hundreds of billions of dollars required. But the federal government can and should implement policies that plan for, and facilitate, this future.

Once the fundamentals of reliable, green, low-cost electricity, competitive construction, and stronger carbon pricing are in place, the role of a green industry policy is to bring down the production costs of low-carbon commodities sooner, by reducing the green premium.[91]

Closing the gap between green and grey production costs is essential because the size of the market premium[92] is highly uncertain, as is the length of time that the gap will persist. This makes it harder to use debt to finance facility upgrades or new facilities to produce green commodities, because future uncertainty increases the cost of borrowing. As long as capital prefers the certainty of return from traditional production, low- and zero-carbon transformation will be held back.

Industry policy shifts the green premium risk from industry towards government or consumers. This can be via green mandates imposed on consumers of the end-product (creating guaranteed demand); production credits paid to producers (reducing the gap by subsidising production); or contracts-for-difference (CFDs), which partly fill the green premium gap.

Green mandates are only suitable for products that are not subject to import competition, unless they are complemented by Carbon Border Adjustment Mechanisms. Production credits and CFDs could be

91. See Box 3 on page 21 for the definition of green premium.
92. See Box 3 on page 21 for the definition of market premium.

used where demand for Australian products is driven more by some combination of global markets, policies, and private investment.

5.3.1 Extending Hydrogen Headstart risks encouraging overly expensive decarbonisation alternatives

Through its Hydrogen Headstart program, the federal government has recognised the need to close the green premium gap.[93] The government will enter into contracts to underwrite hydrogen projects by providing a production credit equivalent to the gap between an expected future market price and the expected production cost.[94]

This is a good start. But if Headstart is extended while solely focused on hydrogen and retaining eligibility for all end uses, it may encourage uses of hydrogen that are uneconomic and inefficient in the long term. As we showed in Chapter 3, for many applications, hydrogen is currently a second-best option, and future technological and economic developments could make hydrogen more or less competitive as a tool to decarbonise.

Currently Headstart relies on a funding cap and merit assessment criteria to weed out uneconomic uses of hydrogen. This is the right thing to do – not doing so could result in a hydrogen industry where demand is permanently dependent on subsidies, which would waste taxpayer dollars, and probably lead to persistently higher prices and smaller-scale production. But it is not the best long-term solution. Meanwhile, other programs that support industrial decarbonisation, such as the Powering the Regions fund, focus on upfront capital costs. As we explain in Section 5.3.3, capital grants don't always address the most pressing problems.

93. See more information on the Hydrogen Headstart program at ARENA (2023).
94. Ibid.

5.3.2 Production credits are expensive

Production credits help bridge the gap between the market premium and the green premium, by providing a per-unit subsidy to green commodity producers. The US Inflation Reduction Act makes production credits available for hydrogen producers, providing a subsidy of up to US$3 per kilogram of hydrogen.

Production credits are a risk to governments because they lock in a fixed subsidy. If green premiums fall faster than expected, governments end up paying more than they need to. In the case of the US, some forecasters predict that the maximum hydrogen production credit will be greater than the total cost of production by 2030.[95] Where production credits are made generally available to all producers, as in the US tax credit example, governments can also be exposed to an uncapped draw on the budget.

5.3.3 Capital grants are expensive, and don't solve the right problem

Making capital grants available may nudge plant replacement decisions towards low- or zero-carbon technology. But an upfront capital grant does nothing to help with the ongoing cost of the hydrogen, which is a large part of the additional cost for all three of the priority uses of hydrogen identified in this report (see Figure 5.3 on the following page).

5.3.4 Contracts-for-difference are a better risk-sharing mechanism

Where capital replacement is funded by debt, a higher cost of production post-replacement is risky, unless the future selling price of the commodity is also going to be consistently higher. For ammonia, alumina, and iron, market premiums for green commodities are well

95. Bhashyam (2023).

below Australian green premiums, and future market premiums are highly uncertain.

Contracts-for-difference would be an ideal way to share some of this risk. These contracts are based on the difference between the market price for a commodity, and an agreed price, known as the 'strike price'.[96] If, during the term of the contract, the market price is lower than the strike price, a third party (in this case the government) pays the producer the difference. If the market price is higher than the strike price, the producer must pay the difference to the third party.[97]

Because the strike price is known in advance, this arrangement gives the producer certainty over future revenue. But unlike with a production credit, the producer has an incentive to seek out buyers that are willing to pay higher prices for a green product.

Contracts-for-difference shift some, but not all, market price risk onto government.

5.3.5 Pursue a technology-neutral green industry policy

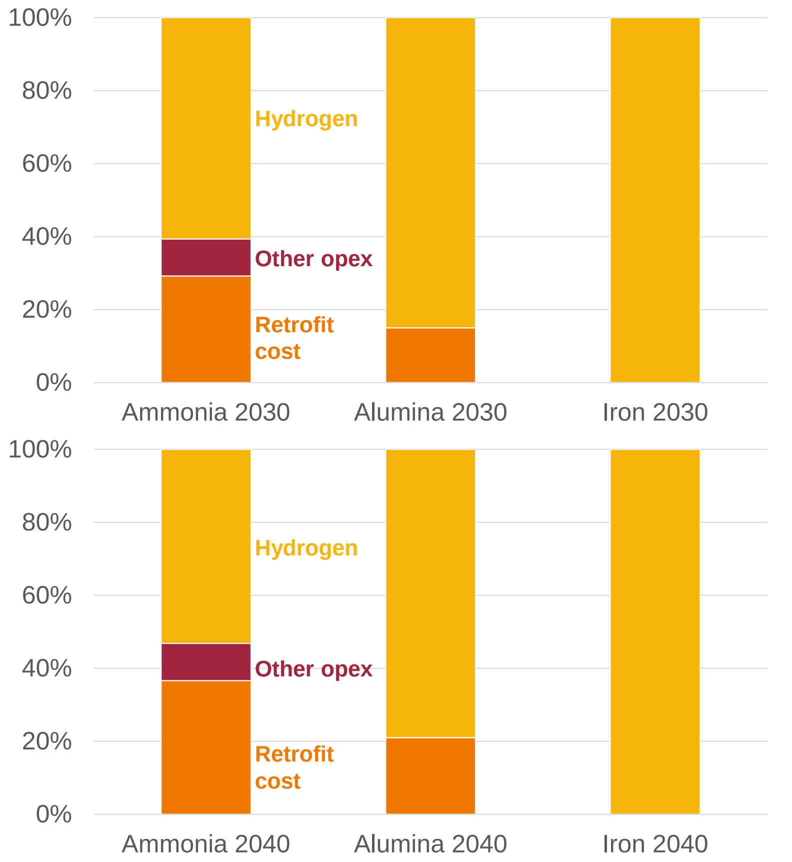
If Australia is to maintain a thriving industrial sector in a net-zero global economy, it needs to produce green commodities. These might be produced using green hydrogen, or they might be produced using green electricity. Ultimately, what matters is that the production is competitive. It also doesn't matter to the economy what mix of green commodities Australia ends up producing, provided they are all delivering economic value.

As noted above, though Hydrogen Headstart may well be the right tool for now, expanding the program could skew investment towards

96. Ideally, the strike price is closely linked to a producer's cost of production, including a justifiable return on capital.
97. Additional features such as proportional upside sharing, and caps and collars on differences, can be used to manage the amount of risk held by each party, but these are optional.

Figure 5.3: Hydrogen costs dominate the green premium for ammonia, alumina, and iron

Breakdown of cost of using hydrogen



Note: No capex or other opex costs shown for iron because DRI plants have the same capex and non-fuel opex regardless of whether they use gas or hydrogen.

Sources: Grattan analysis. See Appendix B for assumptions and sources.

hydrogen at the potential expense of other industrial transformation projects. It would also be inefficient to establish multiple Headstart programs for different commodities, particularly given that each commodity sector has only a few players and only a few facilities.

What Australia needs is a single, technology-neutral program that shares risk on private debt-financing of industrial transformation, regardless of the commodity being produced, using contracts-for-difference. This would help build a viable hydrogen industry and it would also give effect to the government's broader 'renewable energy superpower' vision. Hydrogen Headstart could evolve into such an overarching, technology-neutral program.

Underwriting green commodity production for a limited period would increase the chances of positioning Australian producers to be globally competitive. Using contracts-for-difference means subsidies naturally fall away over time. Ideally, when contracts end, global carbon prices have risen and hydrogen costs have fallen so that Australian producers can continue producing without needing further subsidies.

How should the program be designed?

An evolved Headstart program should be available for 20 years. Every year for the first 10 years, the government should hold a reverse auction to allocate contracts. For each reverse auction, it would indicate ahead of time an indicative upper limit for the total value of contracts it is prepared to enter into. The contracts would last 10 years, giving the program an overall lifespan of 20 years. Providing clarity on the availability of yearly auctions will give industry the predictability it needs.[98]

98. The federal government's expanded Capacity Investment Scheme, which intends to underwrite new renewable generation, sets out a schedule of six-monthly auctions for this reason: Wood (2023).

Bidders in each reverse auction would nominate an independent reference price and their proposed strike price, and projected production amounts for the next 10 years. Eligible bidders would have to commit to using transformative technology that can achieve large-scale emissions reductions, not simply small tweaks to plant operations.

Above all else, the program should only be made available for projects for green commodities that genuinely have a chance at being cost-competitive to produce in Australia.

To ensure that risks to government are hedged, the merit criteria and assessment process should also be designed to ensure a diversity of commodities, technologies, and proponents is in the resulting portfolio of projects being supported. This includes, but isn't limited to accounting for the future cost reduction potential of a technology, even where the current green premium cost gap is large.

Doing so would also attract a larger and more diverse set of bidders for the reverse auctions, and put competitive pressure to work to ensure government gets value for money.

As is currently the case with Hydrogen Headstart, there could be sharing of upside gains, and provision for clawing back windfall gains. Contracts could be capped at a total dollar amount or a number of years, whichever is reached first.

What would it cost?

Determining the full cost of a policy open to all green commodities is beyond the scope of this report.

But, for an indication of the scale of support needed, we calculate the cost of a contracts-for-difference program that underwrites nearly all existing ammonia, alumina, and iron producers to move to using hydrogen. Specifically, we look at the replacement of the two existing steelworks with two green iron facilities, and the retrofit of the five existing ammonia facilities, and two existing alumina facilities in Australia, to use hydrogen.[99] Such a program could cost between $11.6 billion and $36.8 billion over 18 years in 2023 dollars (see Figure 5.4).

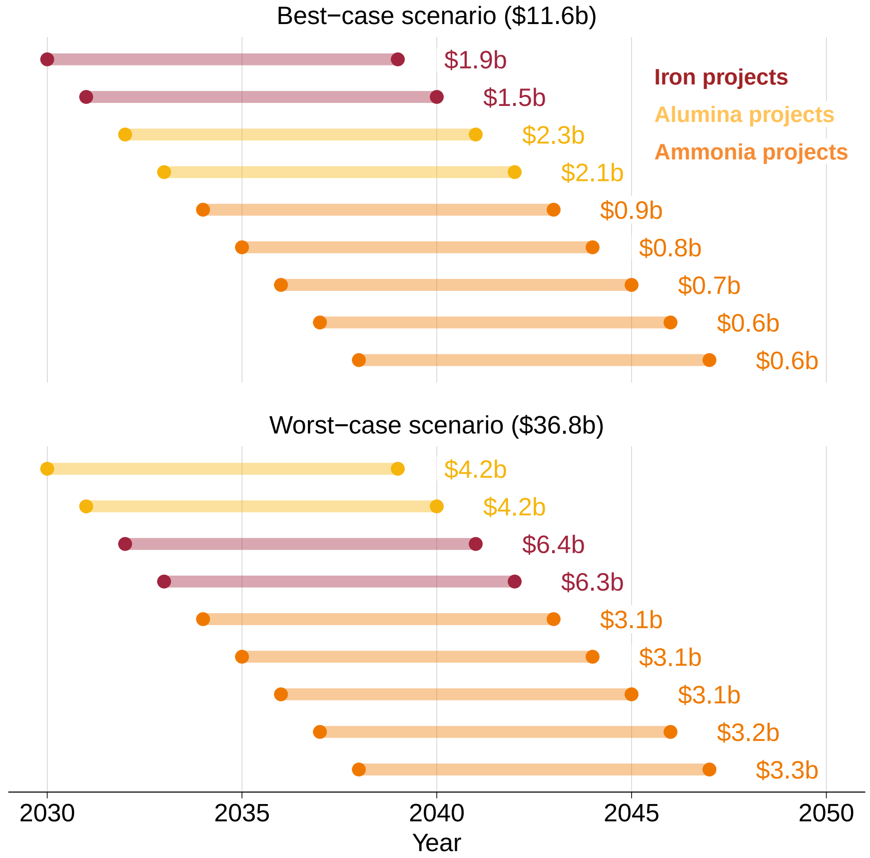
This scenario assumes that the project proponents use hydrogen-based processes to decarbonise the production processes analysed in Chapter 4 only, and do not propose to engage in other decarbonisation activities as part of their bid for a contract-for-difference. It also assumes that successive contracts-for-difference are awarded each year, each to support one project for 10 years of production, and that the government begins making payments from 2030 onwards.

This cost-estimate range reflects the best- and worst-case scenarios for the size of green premium gaps across the three commodities, as determined by reasonable best- and worst-case forecasts of electricity costs and carbon prices.[100]

Our cost estimate assumes that one contract is signed for a project for producing the commodity that has the lowest expected green premium cost gap (in percentage terms) in each year, with no cap on the cost of each contract or of the program overall. In each scenario, once the number of facilities we assume will be supported for each commodity is reached, the commodity is removed from contention for future contracts-for-difference. We also assume that half of the recently observed market premium for green ammonia, and green iron persists into the future.

Figure 5.4: Supporting existing ammonia, alumina, and iron facilities to use hydrogen could cost between $11.6 billion and $36.8 billion over 18 years

Cost of support by project, AU$



Notes: Assumes facilities supported have production volumes equivalent to the average Australian facility in operation today. That is, ammonia plants average 0.4Mt of ammonia per year, alumina refineries average 3.4Mt of alumina per year, and iron facilities average 3.3Mt of direct reduced iron, which is what is needed to achieve the average crude steel production of an Australian integrated steelmaking facility (2.8Mt).

Source: Grattan analysis of scenarios described in Figure 4.3, Figure 4.6, and Figure 4.8. Full assumptions in Appendix B.

99. There are currently five ammonia, six alumina, and two integrated iron/steel production facilities in Australia. We assume that only two alumina facilities are supported, because Rio Tinto is the only alumina refiner to have publicly announced that it is investigating hydrogen calcination.
100. These best- and worst-case scenarios directly correspond to those presented in Figure 4.3, Figure 4.6, and Figure 4.8.

The cost of a CFD program that is open to all green commodities and all decarbonisation technologies may be lower, especially if other commodities and other decarbonisation technologies have smaller green premium gaps. The cost of the policy will also depend on the eligibility criteria. Criteria that achieve more significant transformational change will require greater government support.

The cost of the policy will be different if our estimated green premium gaps are not realised in the future. Our costing is a central estimate of two reasonable potential scenarios for electricity prices and carbon prices, and does not account for market price and production-cost risk. These risks are explored below.

What are the risks to government?

Governments should design contracts-for-difference policy to mitigate and manage risks where possible.

Given the small number of likely project proponents in Australia, one risk is that there won't be enough competitive pressure to ensure that only the projects that make most economic sense in the long term (even in the absence of government support) are supported by the CFD program. This risk can be mitigated by the design of the eligibility criteria.

The government's exposure to market risks can be mitigated in several ways. Rather than adopting a pure CFD arrangement, the government could put in place a 'cap and collar', to get the project proponent to bear more risk.

Another way to control risk is to impose hard caps on maximum government liabilities, such as a limit on the cost of the entire program or of a particular facility. The optimal design of the policy may be different in the future, but a policy with some of these features (similar to Headstart) could be appropriate initially.

A common way of reducing the risk of any investment strategy is to take a portfolio approach. For this policy, a portfolio approach is consistent with supporting a range of commodities. But the problem with taking the lowest bidder in each reverse auction is that the CFD program may end up skewed towards particular types of commodities. The government could choose to overlay supporting the lowest bidder in each auction with an assessment of how each additional project will support the overall portfolio management objectives of the CFD program.

There is also a risk that a CFD program could displace or increase emissions rather than reduce them. For example, if a project wins a CFD on the basis of using blue hydrogen,[101] which then fails to achieve high levels of carbon capture. Or if a project wins a CFD on the basis of using 100 per cent renewable electricity but fails to maintain a power purchase agreement.

To mitigate this risk, CFDs should be voided if they displace or increase emissions.

> **Recommendation 5**
>
> Make Hydrogen Headstart a contracts-for-difference program, to support the growth of green commodity production in Australia. Conduct reverse auctions every year for 10 years to allocate contracts.

5.4 Some issues can be put off for now

Growing a viable hydrogen industry is a long-term project. Not every issue needs to be solved today. In particular, two issues that may be

101. See Box 1.

important for a large-scale industry can be deferred for now: further development of hydrogen hubs, and embodied carbon standards.

5.4.1 Hydrogen hubs are unlikely to drive growth

The federal government's Hydrogen Hubs grants program provides funding to facilitate the co-location of various producers and users of hydrogen. This co-location was designed to create and share a pool of skilled labour, and to generate opportunities for common, larger-scale hydrogen production, or transport and storage infrastructure.[102] This could lead to material cost savings.

But a note of realism is important here. The hydrogen hub model for Australia was devised in 2019, when it seemed hydrogen could be a simple low-emissions replacement for natural gas and used for the same large range of applications, including exports. As noted throughout this report, however, we now know that this is unlikely to be the case.

It is more likely that, in Australia, hydrogen will be used for specific, large industrial uses. And, in the medium term, these uses will probably be locked into 'single producer, single offtaker' arrangements. Co-location with other hydrogen users will matter less than other determinants, such as the availability bauxite or iron ore.

If a case for co-location and common-use hydrogen infrastructure emerges, governments should also ask what its role, if any, should be. There is no reason industry can't coordinate itself. The role of government may just be to set up the regulatory environments, such that any potential benefits of co-location are realised.

102. DCCEEW (2023h).

5.4.2 Embodied carbon standards can be implemented later

In Grattan Institute's 2022 report, *The next industrial revolution*, we recommended state governments implement embodied carbon standards for construction, to support demand for cement, steel, and aluminium with a green premium. State and federal governments have taken the first step in this direction, agreeing to develop consistent national standards for measuring embodied carbon in infrastructure projects and to consider further policy to reduce these emissions.[103]

If embodied carbon standards are to drive increased demand for green commodities produced in Australia, there will need to be enough production of these commodities to meet the standard; and the commodities will need to be cheaper than imported ones. The standards should therefore be implemented after contracts-for-difference have been used to kick-start production.

Otherwise, the effect of an embodied carbon standard will simply be to increase imports of green commodities. That would contribute to global decarbonisation, but it won't bring about industrial transformation here.

5.5 State governments should rethink green gas targets

One policy that has been raised as a potential mechanism to support hydrogen production is a green gas target. In its simplest form, a green gas target would require gas retailers to buy a percentage of gas from 'green' sources (typically biomethane and hydrogen), with this percentage rising over time.

Alternatively, governments can issue certificates for every kilogram of hydrogen produced – regardless of whether it replaces natural gas or not – and require gas retailers to buy and surrender these certificates.

103. Infrastructure and Transport Ministers' Meeting (2023).

In both cases, the cost of the green premium of hydrogen is passed on to gas consumers.

This raises questions about who should bear these costs: those who will need green gas in the future, or those who won't.

We have made the case in this report that the bulk of future hydrogen use will be in a few niche industrial applications. Biomethane use is likely to be limited to industrial users, too, but they are more likely to be smaller users than those producing ammonia, alumina, and iron.

Most households, as well as small business, the commercial sector, and light manufacturing, will be economically better off today if they replace gas use with electricity.[104]

The NSW Government has established a green gas target which uses certificates. The cost of these is recouped from NSW households and small businesses.[105] The Victorian Government is considering introducing a green gas target.[106]

It is inequitable to ask households to bear the cost of creating a hydrogen or a biomethane industry if they are not going to be the ultimate beneficiaries. Both governments should rethink. They should ensure that the costs of green gas targets are borne by the industrial sector.

104. Wood et al (2023).
105. NSW Climate and Energy Action (2023).
106. DEECA (2023).

6 Other potential uses of hydrogen

This report identifies three uses of hydrogen that Australian governments should focus on initially: ammonia, alumina, and iron. These are relatively discrete uses that are economically valuable, and are large enough to help underwrite a viable, broader industry.

This chapter identifies five other potential applications of hydrogen that are less certain: heat for manufacturing; synthetic fuels; energy storage for electricity; methanol; and long-distance road freight. These applications are too uncertain to warrant specific policy support at this stage, for one or more of the following reasons:

- There is no existing base of industrial and technical expertise to rely on in Australia.
- They are too small and/or have complicated logistics that will be easier to solve once there's an existing, steadier supply of cheaper hydrogen underwritten by other uses.
- There is significant technical uncertainty and competition between hydrogen-based technologies and other zero-carbon technologies.
- The groundwork for the use needs to be set by broader energy and decarbonisation policy frameworks.

These five applications should be supported with sector-wide decarbonisation policies, and by assessing and planning for the role of hydrogen in other, broader energy and decarbonisation policy frameworks.

Implementing the recommendations in this chapter would create an industrial base that would benefit other uses if a stronger case for them emerges.The goal should be to ensure that these hydrogen uses develop to play an economic role in domestic decarbonisation, and to set Australia up for success, if and when the economic opportunities from these uses eventuate.

6.1 Industrial heat

Hydrogen is often seen as a zero-carbon fuel for energy-intensive manufacturing that can be burned in place of fossil fuels for heat. In reality, it faces significant competition from other technologies, depending on the temperatures required.

For low-temperature heat (up to about 250°C), heat pumps and other electrical heating technologies have the market cornered.[107] They are mostly commercially available and highly efficient. Most energy demand for process heat in Australia is at these lower temperatures (see Figure 6.1).

But, at present, medium-temperature heat (250-800°C) and high-temperature heat (more than 800°C) are difficult to achieve with heat pumps.[108] This is where hydrogen may remain a competitive option, although even for very high temperatures there are other zero-emissions competitors, including electric technologies, and bioenergy.[109] There are also more bespoke solutions that could make sense, such as greater use of waste heat.

The three most promising uses for hydrogen identified in this report – ammonia, alumina, and iron – all require significant amounts of high-temperature process heat (see Figure 6.1 on the next page).

107. Australian Alliance for Energy Productivity (2023, p. 4).
108. IRENA (2023, p. 88).
109. Liebreich (2023).

Cement

The other key user of high-temperature process heat in Australia is the cement industry. The industry uses about 20PJ of high-temperature heat, mostly for producing clinker, a crucial, but very carbon-intensive, input into cement. In Australia, most of this energy demand is currently met by coal and natural gas.[110]

Most of the cement used in Australia is domestically manufactured. About 60 per cent of the clinker required for this is also produced in Australia, and the rest is imported.[111] Very little clinker or cement is exported from Australia.[112]

As it stands, low-carbon cement is difficult to produce, and hydrogen seems unlikely to play a role, even if other parts of the production process can be decarbonised.

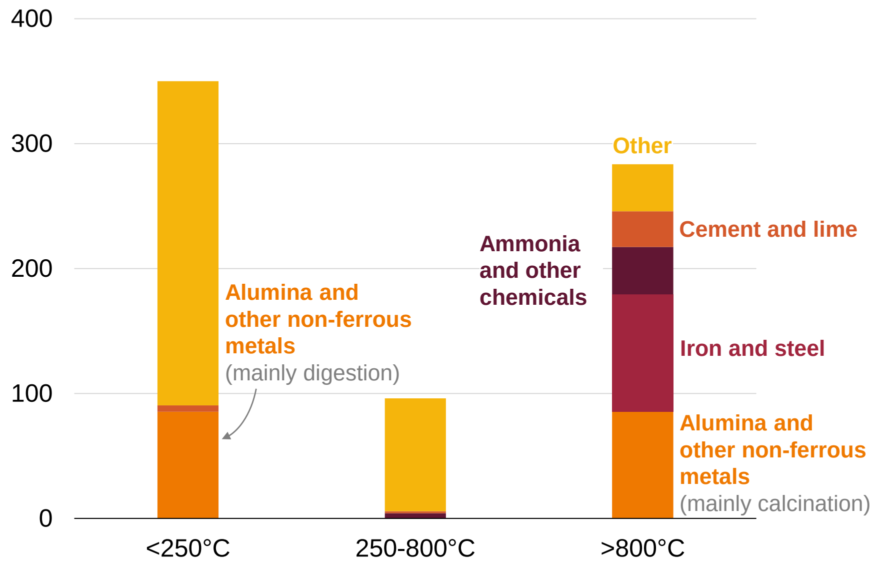
Hydrogen can, technically, produce the heat required for clinker production, and the necessary supply chain would be relatively easy to manage since the process uses large volumes of hydrogen continuously. But replacement of fossil fuels with combustion of biomass (such as refuse-derived fuels) seems more likely at this stage. Waste is cheap, and it is already used as a fuel at some facilities; cement production is an application that can accept refuse-derived fuels that have impurities.[113]

But cement production can't be fully decarbonised just by finding alternatives to fossil fuel. Process heat only makes up 26 per cent (or about 1.3Mt CO_2-e of emissions) of the cement and concrete industry's total emissions.[114] More than half of the industry's total emissions (55

110. ITP Thermal (2019, pp. 29, 129–131).
111. VDZ (2021, p. 8).
112. Grattan analysis of DFAT (2023).
113. ITP Thermal (2019, p. 132).
114. Grattan analysis of VDZ (2021). Includes upstream electricity emissions and some downstream emissions.

Figure 6.1: Most energy demand in Australia for process heat is for low-temperature heat; high-temperature heat demand is dominated by ammonia, alumina, and iron and steel

Energy use for heat, petajoules per year



Notes: For low-temperature heat (<250° C), the largest sources of demand in the 'Other' category are food and beverages, oil and gas extraction, and petroleum refining. For medium-temperature heat (250-800° C), the largest sources of demand in the 'Other' category are petroleum refining, food and beverages, and pulp and paper. For high-temperature heat (>800° C), the largest sources of demand in the 'Other' category are bricks and ceramics, glass and glass products, and petroleum refining.

Source: Grattan analysis of ITP Thermal (2019).

per cent) are process emissions, largely due to the CO_2 emitted by the chemical transformation of limestone into clinker during calcination.[115]

There are currently few technologies that can capture these process emissions. Globally, the first full-scale project using carbon-capture technologies is planned for 2024.[116] In the Australian context, the most promising technologies for CCS currently imply a relatively high cost per tonne of carbon avoided, compared with current carbon prices.[117] In addition, functioning infrastructure for CO_2 transport, storage, and use is still to be developed in Australia.[118]

These difficulties associated with decarbonising clinker are leading cement producers to look instead at substituting clinker with supplementary cementitious materials.[119] Any potential role for hydrogen will diminish if manufacturers have success reducing clinker-to-cement ratios.

Recommendation 6

For low-temperature heat, encourage take-up for energy-intensive manufacturing of proven low-carbon technologies where commercially available. Provide low-cost finance through the Clean Energy Finance Corporation, or encourage the private sector to provide finance for capital-constrained gas users.

For medium- and high-temperature heat, continue to fund research, feasibility studies, and knowledge-sharing on renewable heat options through the Australian Renewable Energy Agency and bodies such as Cooperative Research Centres.

115. Ibid (p. 8).
116. IEA (2023c, p. 195).
117. VDZ (2021, p. 32).
118. VDZ (2023).
119. VDZ (2021).

6.2 Synthetic fuels

Synthetic fuels, otherwise known as e-fuels, are liquid hydrocarbons (for example, kerosene, gasoline, and diesel) that are manufactured (synthesised) using hydrogen and CO_2.

Synthetic fuels are a drop-in replacement for liquid fossil fuels. Burning them still leads to carbon emissions, but if the synthetic fuels are produced using renewable hydrogen and captured carbon, there is a net carbon-emissions reduction over their lifecycle.[120]

But synthetic gasoline is an uneconomical way to reduce emissions, compared with alternatives such as battery electric vehicles.[121] The economics of synthetic diesel compared to batteries are less clear at this point, and depend on where and how vehicles are used.

The main, and most promising, use of synthetic fuel for decarbonisation is in aviation. Modern commercial airliners run on fossil jet fuel mainly comprised of kerosene derived from crude oil. In Australia, emissions from domestic aviation, largely from the use of jet fuel, were about 8.5Mt CO_2-e in 2019.[122] Most of the jet fuel sold in Australia is imported, rather than being refined here, and very little of our product is exported directly overseas.[123]

The pathway to aviation decarbonisation around the world is still highly uncertain. But in the short term, a significant part of the task will probably fall to the adoption of sustainable aviation fuel (SAF). SAF can be synthesised (synthetic SAF), or produced using organic feedstocks such as waste and biomass residues (biogenic SAF).

Regardless of which kind, SAF is essentially a direct replacement for fossil jet fuel: it works in existing airliners and infrastructure, and

120. CSIRO (2023b, pp. 22–23).
121. Collins (2023).
122. DCCEEW (2023d).
123. DCCEEW (2023i).

is currently being tested in blends with fossil jet fuel of up to 50 per cent.[124]

In the short term, biogenic SAF will probably play a more significant role than synthetic SAF. The biogenic version is currently cheaper to produce, and organic feedstock production in Australia is already enough to satisfy 60 per cent of current jet fuel demand – if Australia had the facilities to produce it.[125]

But wider use of SAF will probably rely more on synthetic SAF, because production of its feedstocks is easier to ramp up than for the organic feedstocks required for biogenic SAF.[126]

If synthetic SAF is to be a realistic option in the future, work needs to start now. Its two key inputs will both be in short supply if it is produced at a level that matters. A lot of green hydrogen – and, therefore, renewable electricity – is needed to produce a meaningful amount of synthetic SAF.[127] Lufthansa, for example, has estimated that it would require half of Germany's entire electricity production to switch its fleet to green fuels such as synthetic SAF.[128]

Economical access to the other key input, CO_2, is also not easy. Ideally the source would be captured carbon from unavoidable emissions (such as captured process emissions, as discussed in Section 6.1 on page 46), or, in future, direct air capture (DAC). These technologies are as yet both costly and difficult to scale.

A leader in this area, the European Council, has issued a mandate that jet fuel available to aircraft operators at all EU airports contain a minimum share of biogenic and synthetic SAF, aligning the aviation sector to the EU's climate targets for 2030 and 2050.[129]

124. CSIRO (2023b).
125. Ibid (p. 8).
126. IRENA (2021b, p. 19).
127. CSIRO (2023b, p. 53).
128. Wilkes (2023).

Recommendation 7

The federal government should implement a mandate on the use of sustainable aviation fuel (SAF). This mandate should not specify whether the SAF be biogenic or synthetic.

6.3 Electricity

Variable renewable energy (VRE), such as solar and wind, will be the lowest-cost zero-emissions source of generation. Firmer supplies will be required to balance intermittent solar and wind, and that requirement will increase as more intermittent generation comes online.[130]

Battery technology is rapidly developing to a stage where it can be a cost-effective source of short-term storage and help meet grid stabilisation requirements. But weather and seasonal patterns mean there will be infrequent but extended periods in winter when high electricity demand coincides with shorter days, low wind, and cloudy skies. This means that as much as 10 per cent of electricity demand is unlikely to be economically served by VRE.[131]

Options to meet this challenge include building more interconnecting transmission; storage, such as pumped hydro or long-duration batteries; and gas with offsets. Grattan Institute's 2021 *Go for net zero* report found that, based on current information, lowest-cost net-zero

129. European Council (2023).
130. Wood and Ha (2021).
131. Ibid.

in the electricity sector would be achieved by using around 90 per cent renewables, and using gas (with offsets) for the last 10 per cent.[132]

Green hydrogen power plants using turbines or fuel cells could play a similar role to gas peakers,[133] and would avoid the need for offsets or carbon capture and storage (CCS). As with the uses described in Chapter 4, the case for hydrogen in this context will depend on the techno-economics of the hydrogen supply chain, and these will vary with location.

A dedicated hydrogen power plant, and several natural gas plants with the potential to convert to hydrogen, are progressing in Australia. The South Australian Government is planning a 200 megawatt hydrogen generator to be commissioned in Whyalla in 2025.[134] The Kurri Kurri and Tallawarra B gas-fired power plants in NSW are both planning for a level of green hydrogen blending.[135]

The federal government has begun to implement its Capacity Investment Scheme, a mechanism designed to fund dispatchable, zero-emission electricity and VRE through government tenders.[136] Hydrogen generators are eligible to participate in the scheme, but it is not yet clear whether they will be able to compete with other capacity to achieve funding support.

132. Ibid.
133. Gas peakers are generators that are only used at peak times.
134. Office of Hydrogen Power South Australia (2023).
135. Snowy Hydro (2023) and CSIRO (2023c).
136. DCCEEW (2023j).

Recommendation 8

The role of hydrogen in providing long-duration storage and dispatchable capacity should be included for assessment in the longer-term perspectives of the Australian Energy Market Operator's Integrated System Plan.

6.4 Methanol

Methanol is currently used mainly as a feedstock for important industrial chemicals and consumer products such as formaldehyde and plastics, and to a lesser extent as a fuel for transport and heat.

Around the world, the most common process for manufacturing methanol uses natural gas or coal and produces significant emissions.

'Green methanol' can be produced using biomass or through the synthesis of green hydrogen and carbon dioxide. Lifecycle emissions, from production through to use, are significantly lower for these green processes, but they are not zero, because burning methanol creates CO_2.[137] But the benefit of synthesised green methanol is that is offers a way for captured CO_2 to be re-used to produce a useful chemical or fuel.

Globally, the decarbonisation opportunity for methanol is in using green methanol to help decarbonise existing methanol uses, and to displace heavier-emitting fossil fuels for transport, most notably in the shipping industry.

In Australia, the first opportunity is small. Australia currently has next-to-no existing industrial base in methanol manufacturing and

137. IRENA (2021c, p. 63).

also very little demand for it, as evidenced by minimal imports of the commodity.[138]

The larger potential opportunity for Australia is in producing green methanol for use as a lower-carbon shipping fuel. Large shipping companies such as Maersk are already ordering ships that can run on methanol, as a way of decarbonising their operations.[139] Some ports, including Singapore and the Port of Melbourne, are also moving to enable ship refuelling using methanol.[140]

But methanol faces significant competition from zero-emissions alternatives for shipping fuel, such as ammonia. Though ammonia requires more substantial engine modifications, methanol production requires CO_2 as a feedstock, and the CO_2 would have to come from technologies such as bioenergy carbon capture and storage and direct air capture, and is likely to be costly to acquire at scale.[141] For that reason, ammonia will probably play a much larger role in decarbonising shipping.[142]

6.5 Long-distance road freight

Long-distance road freight transport runs on diesel combustion engines, and resulted in about 12Mt CO_2-e of emissions in 2020.[143]

Hydrogen used in a fuel cell or combustion engine could substitute for these diesel combustion engines. For trucks, hydrogen fuel cells have two advantages over batteries: they are lighter and take up less space, meaning more weight and space can be allocated to freight. But development of both technologies is still at an early stage, so it's hard to see a clear winner yet.

At present, a hydrogen truck can refuel more quickly than a battery electric truck can recharge: 20 minutes for sufficient fuel to travel 1,000km, versus an hour or more to recharge an electric truck to cover the same distance. And the fuel is portable, which is useful for a truck if it runs short of fuel with no refuelling point nearby.

The logistics for refuelling both electric and fuel-cell long-distance trucks are complex, especially in remote areas. Both require an electricity source that can provide enough electricity to recharge the truck, or to make the hydrogen to refuel the truck. The fuel must also be available on demand – just as truckies do not want to wait for hours while a battery charges, they do not want to wait while an electrolyser makes enough hydrogen to fill their truck.

Roads in remote areas, such as the Stuart Highway or the Great Northern Highway, have limited electricity infrastructure. This is a challenge for both hydrogen and electric trucks, and will need to be solved whichever technology comes to dominate. These remote roads also run through areas with limited water, which means hydrogen production prospects are limited.

Unlike the other potential uses in this chapter, hydrogen trucks have one advantage: their higher upfront cost is balanced by cheaper running costs, even while hydrogen is still comparatively expensive. Indeed, under the right conditions, the fuel costs of a hydrogen truck could be lower than a diesel truck as early as 2029 (see Figure 6.2 on the next page). This is because diesel engines are inefficient at turning fuel into useful work. Electric motors – whether powered by a fuel cell or a battery – waste much less energy. They also have lower maintenance costs.

138. Coogee (2023), and Grattan analysis of DFAT (2023).
139. Maersk (2022).
140. Wiggins (2023) and Neo and Ng (2023).
141. IRENA (2021a, p. 80).
142. Ibid (p. 80).
143. Grattan analysis of ABS (2020) and DCCEEW (2023c). Calculated using diesel consumption by articulated and rigid trucks that had an interstate or non-urban intrastate area of operation in ABS (2020).

As a result, at some point, switching away from diesel is likely to become the most cost-effective option. In the early years of building a hydrogen truck fleet, a larger fleet can reduce per-truck costs for the same hydrogen costs (the difference between the red and dark orange lines in Figure 6.2). But no single truck breaks even on fuel costs, unless hydrogen costs come down. Making hydrogen cheaper still matters.

Under current policy settings, carbon pricing makes almost no difference to the economics of a hydrogen (or electric) truck. This is partly because carbon costs are so low (adding less than $2.60 to the cost of a Sydney-Melbourne truck trip at present, for those companies that are subject to the Safeguard Mechanism), but also because much of the sector is not subject to any price at all.

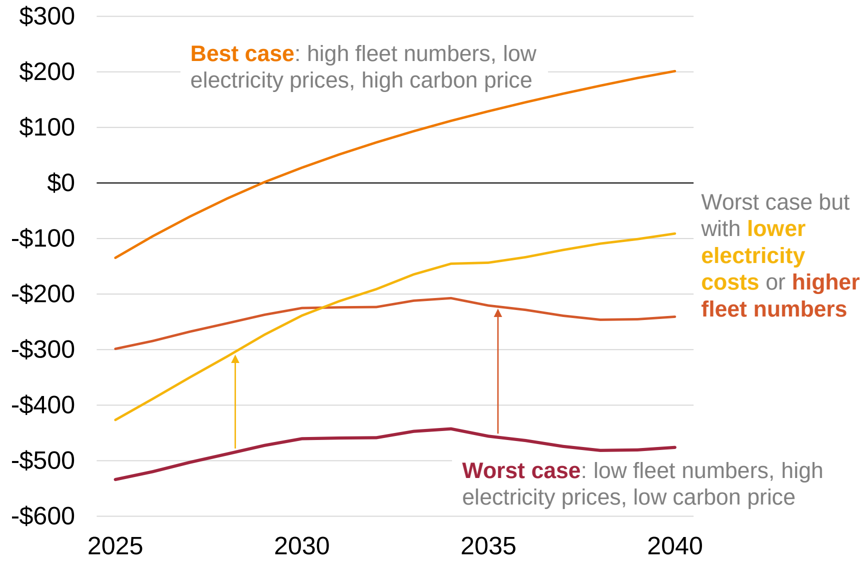
Currently less than 2 per cent of heavy vehicle emissions are subject to regulation to reduce them: those emitted by the two logistics companies whose total emissions are large enough to bring them under the Safeguard Mechanism.

Emissions from road freight also need to be considered in the context of a wider strategy for decarbonising all transport.

All of the above favours technology-agnostic policy that levels the playing field between zero-carbon trucks and diesel trucks, and removes barriers to adoption of zero-carbon trucks.

Figure 6.2: Initially, fleet size has more impact on fuel cost savings than hydrogen costs, but this will change

Fuel cost savings for a Sydney-Melbourne road freight trip



Notes: See Appendix B for assumptions and data sources.

Source: Grattan analysis.

Recommendation 9

To accelerate the switch to zero-emissions trucks:

- The federal government should apply progressively tighter carbon-emission standards on the engines of new diesel trucks, and set binding sales targets for zero-emissions trucks, reaching 70 per cent of articulated truck sales by 2040.
- Both federal and state governments should ensure electricity infrastructure is sufficient along all major freight routes to support either charging points or on-site production of hydrogen.

The Grattan truck plan, published in 2022, contains other recommendations to reduce pollution from trucks, including a proposal to assist early adopters with the upfront cost.[a]

a. Terrill et al (2022).

Appendix A: Uses of hydrogen

This appendix describes in greater detail the industrial applications in which hydrogen is likely to play a role in decarbonisation.

A.1 Ammonia

Ammonia (NH_3) production requires hydrogen as a feedstock (see Figure A.1). The key process that needs to change to decarbonise ammonia production is the hydrogen production process itself.

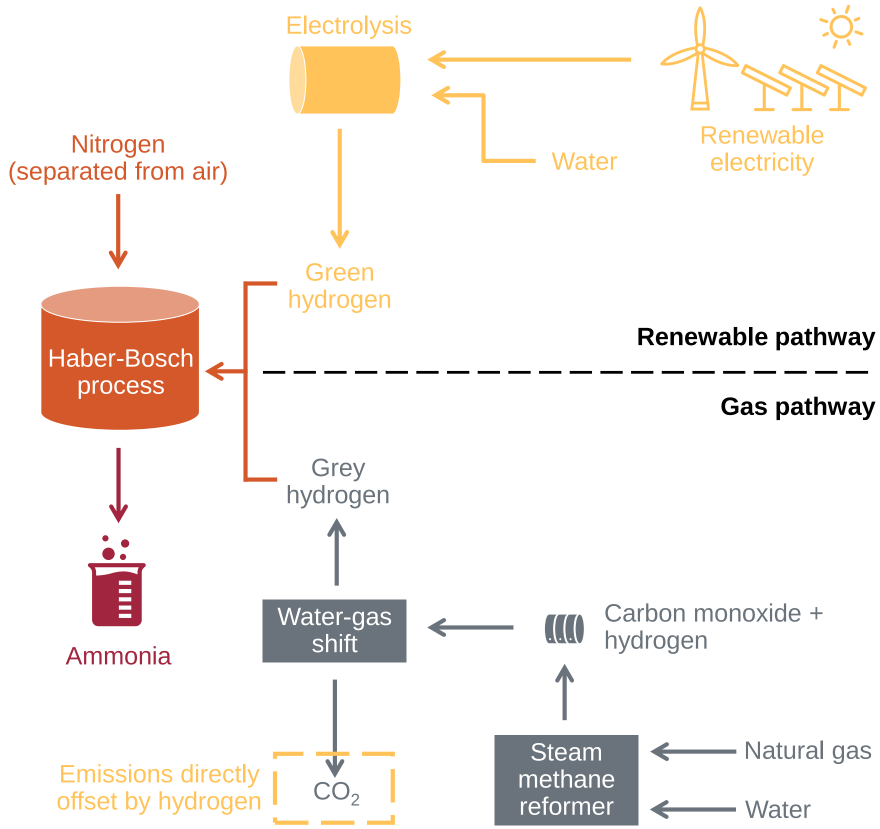
Currently, nearly all world hydrogen production uses fossil fuels. In Australia, all commercial hydrogen is produced using natural gas through the steam methane reforming process. This process separates the hydrocarbons to isolate the hydrogen molecules from the carbon molecules, producing carbon dioxide which is vented into the atmosphere in the process.

The alternative, low-carbon, process is to replace the grey hydrogen feed with a green hydrogen feed. This is relatively simple, but requires the retrofit of ammonia plants to allow them to receive a pure stream of hydrogen rather than natural gas, since ammonia plants are set up to have integrated hydrogen and ammonia production.[144] Once this is done, the hydrogen can be produced on-site, or sourced from elsewhere and transported to the facility. The facility also requires extra electricity for steam.

A.2 Alumina

Alumina (aluminium oxide, or Al_2O_3) is produced from bauxite, and is the precursor to aluminium (see Figure A.2 on the following page). Two key processes that need to change to decarbonise alumina refining are digestion and calcination.

Figure A.1: Ammonia can be produced using either grey or green hydrogen



Source: Grattan analysis. Icons from flaticon.com.

144. Australian Industry Energy Transitions Initiative (2023, p. 111).

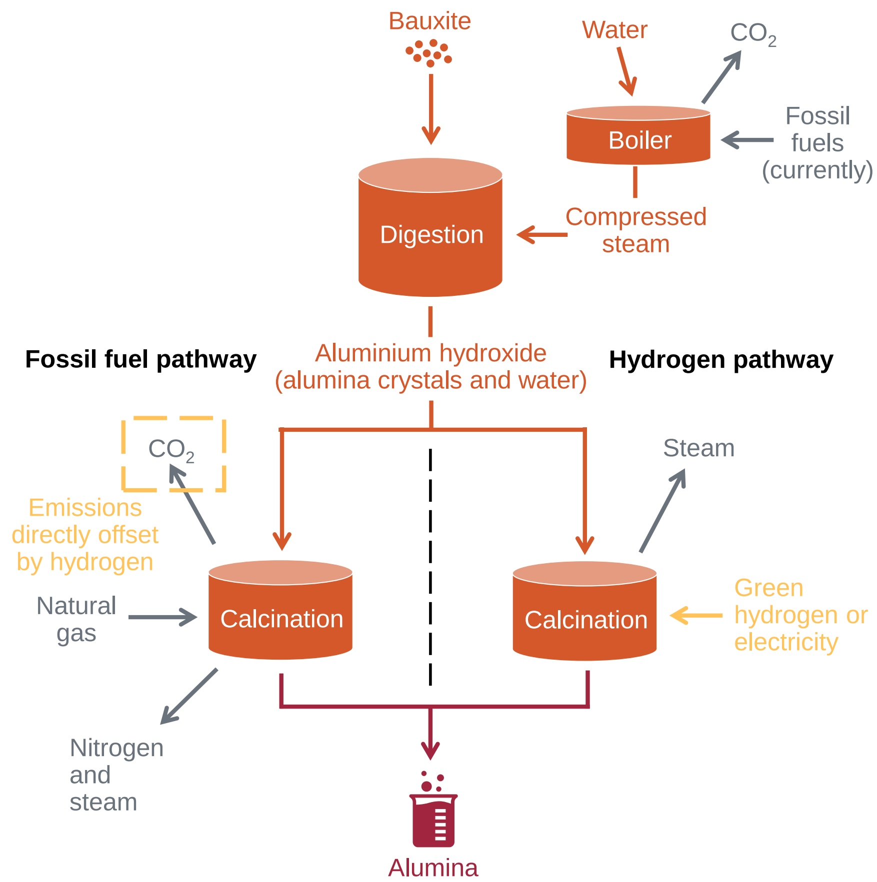
Digestion uses compressed steam at anywhere between 175°C and 400°C (depending on the specific chemical composition of the bauxite) to heat a bauxite and caustic soda slurry to dissolve the alumina content of bauxite.[145] The emissions from this step are from the combustion of coal or gas in a boiler to create steam. Hydrogen-based technologies will not help to economically decarbonise this process. Instead, digestion will be decarbonised through the use of electric boilers and mechanical vapour recompression (MVR) using renewable electricity. MVR recompresses waste water vapour that would otherwise be lost for reuse, saving on fuel requirements.[146] The resulting product is aluminium hydroxide, a chemically bound mixture of water and alumina.

The calcination process involves heating aluminium hydroxide at temperatures exceeding 1,000°C to remove the water, leaving the final white, powdery alumina product. As is the case with the digestion process, the emissions from this step come from the combustion of fossil fuels for heat – in Australia, this is natural gas.

Hydrogen calcination is a promising method to replace the use of fossil fuels. This involves the combustion of hydrogen with oxygen to achieve the high-temperature heat required, which leaves only a pure steam waste stream. This steam can also be used in other parts of the alumina refining process using MVR, if it is installed.

Electric calcination is the key competitor zero-emissions technology, with many of the same benefits. Electric calcination is likely to be able to generate heat more efficiently than hydrogen given the same amount of renewable electricity. But electric calciners will probably require more upfront spending on retrofitting existing refineries.[147]

Figure A.2: Hydrogen can replace natural gas at the calcination step for alumina refining



Source: Grattan analysis. Icons from flaticon.com.

145. Deloitte and ARENA (2022, p. 24).
146. Ibid (p. 24).
147. Ibid (p. 29).

A.3 Iron and steel

Iron ore (iron oxide) is processed into iron (iron metal), and then further processed to steel (see Figure A.3 on the next page). The vast majority of the world's primary steel (steel made from iron ore rather than scrap) is made using the blast furnace-basic oxygen furnace (BF-BOF) method.[148] Currently, all primary steel in Australia is produced at two integrated steelworks using the BF-BOF process, though LIBERTY Steel is moving towards commissioning a direct reduction plant in Whyalla.[149]

The BF-BOF method is a carbon-intensive process that uses metallurgical coal as an input for both its fuel and chemical properties. The method leads to carbon emissions at various stages, but emissions from the blast furnace are by far the most significant.[150]

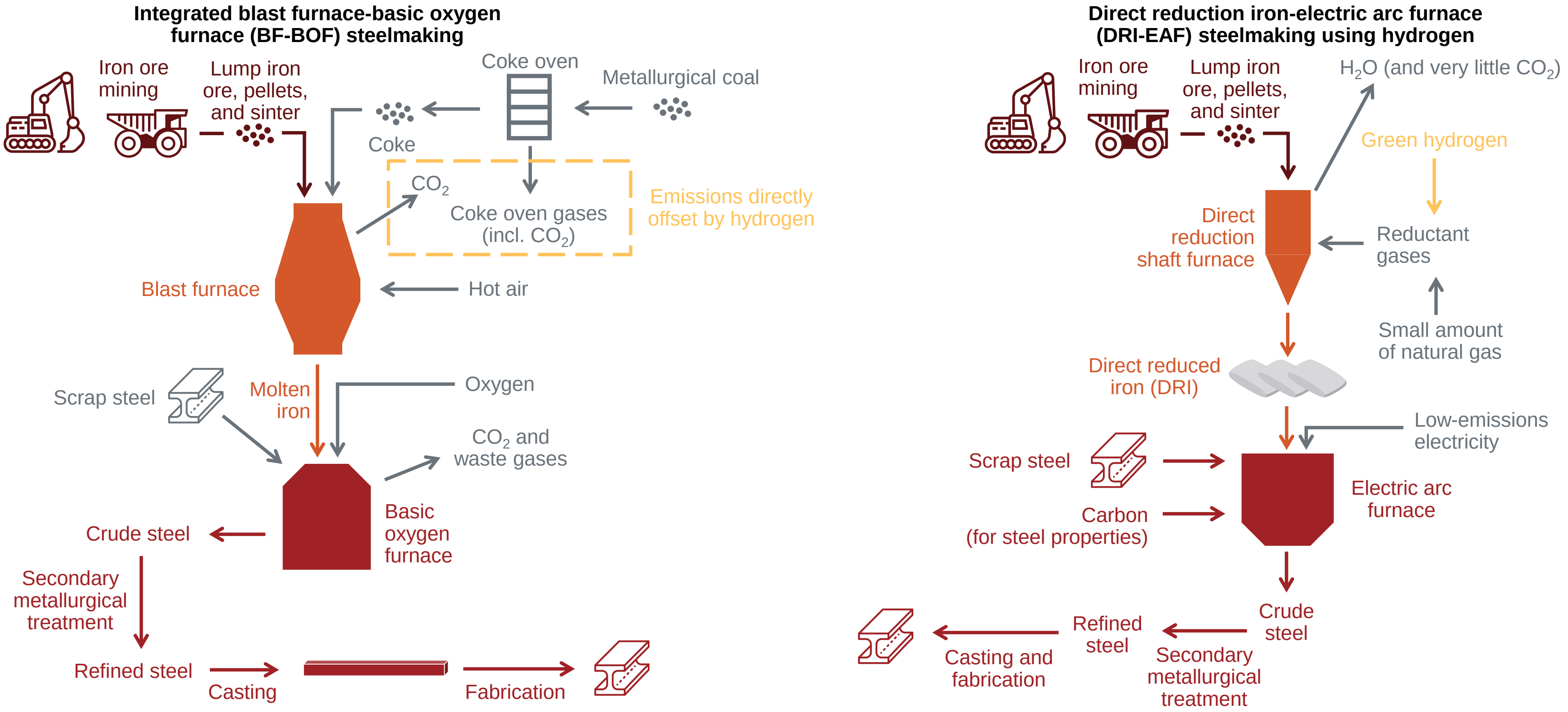
In the blast furnace, iron ore is stripped of oxygen (a process called 'reduction') and then melted. This is done by blowing heated air into the base of the furnace, and burning coke (lumps of mostly carbon made from metallurgical coal in coke ovens) to produce heat and make the gases necessary for reduction to occur. The resulting waste gas is carbon dioxide and carbon monoxide, and a small amount of hydrogen.

The main promising low-carbon alternative to BF-BOF steelmaking is the direct reduction iron-electric arc furnace (DRI-EAF) process. For DRI-EAF, a direct reduction shaft furnace replaces the blast furnace. The direct reduction shaft furnace can use green hydrogen as a 'reductant gas' for the direct reduction part of the process, playing the role that coke plays in a blast furnace and stripping oxygen from the ore. By keeping the inputs mostly free of carbon, the resulting outputs are water and a little bit of carbon dioxide. The DRI-EAF process can also use natural gas as an input rather than green hydrogen. This is a proven process – industrial-scale facilities produced about 114Mt of direct reduced iron in 2021, compared with total world pig iron production of 1,354Mt (iron produced using iron ore and coke in a blast furnace).[151]

The DRI-EAF process also avoids the need to heat metallurgical coal in a coke oven, and the resulting coke oven gas emissions. This can be considered another source of emissions directly avoided by the use of hydrogen in the DRI-EAF process. The use of an electric arc furnace avoids the use of a basic oxygen furnace, but abatement from this substitution is not considered a direct effect of using hydrogen, because renewable electricity is used.

148. IEA (2020, p. 29).
149. LIBERTY Steel (2023).
150. DCCEEW (2023b, pp. 10–11).
151. World Steel Association (2022).

Figure A.3: Iron ore can be processed into low-emissions iron using the direct reduction method



Source: Grattan analysis. Icons from flaticon.com.

A.4 Other hydrogen uses

For potential uses of hydrogen, the specific 'hydrogen-replaceable processes' that we assume for the purposes of calculating potential hydrogen demand and potential abatement are as below:

- Electricity generation: green hydrogen is used in turbine or fuel cell generators in place of gas-fired peaking generators, to provide zero-emissions dispatchable storage.
- Synthetic fuel: green hydrogen is synthesised with carbon dioxide to create synthetic kerosene, and used in place of fossil jet fuel.
- Methanol manufacturing: green hydrogen replaces grey hydrogen produced using natural gas-based steam methane reforming in the methanol production process.
- Long-distance road freight transport: green hydrogen is used in fuel cell trucks in place of diesel in internal combustion engine vehicles.
- Cement manufacturing: green hydrogen is used in place of natural gas for high-temperature heat in the clinker calcination process.
- Other manufacturing: green hydrogen combustion replaces fossil fuel combustion for medium- and low-temperature heat.
- Residential and commercial heating and cooking: green hydrogen combustion replaces natural gas combustion for space and water heating, and cooking.
- Oil refining: green hydrogen replaces grey hydrogen for use in the diesel desulphurisation process.
- Light vehicles: green hydrogen is used in hydrogen fuel cell light vehicles in place of petrol and diesel in internal combustion vehicles.

Appendix B: Scenario assumptions

Throughout this report, we present scenarios for future hydrogen production costs, carbon costs, and green commodity production costs. Results are shown in Figure 2.1, Figure 4.3, Figure 4.6, Figure 4.8, Figure 5.2, Figure 5.3, and Figure 5.4.

These scenarios are internally consistent, and use the same set of assumptions where relevant. All inputs were adjusted for inflation, discount rates, and exchange rates.

B.1 Hydrogen production costs

Hydrogen production costs are determined using a bottom-up project-based model. Production is assumed to be modular, that is, the cost for 10MW of production capacity is ten times the cost of 1MW of capacity.

Electrolyser: proton exchange membrane (PEM). Capital cost forecast from Graham et al (2023), assuming the global net-zero 2050 scenario. Installation costs start at 50 per cent of capital costs, consistent with Aurecon (2022), and fall by 3 per cent each year. Electrolyser efficiency 51.3kWh/kg hydrogen, consistent with IRENA (2020). No allowance for improvements in electrolyser efficiency. Operating and maintenance costs (other than electricity) of $75/kW, consistent with Aurecon (2022). Stack design life 80,000 hours. Capacity factor 90 per cent.

Electricity costs: two scenarios are used. Behind-the-meter electricity production co-located with electrolyser consistent with Graham et al (2023). Grid-connected electrolyser backed with renewable power purchase agreement consistent with Oakley Greenwood (2022).

Other: water consumption 17 litres per kg hydrogen, consistent with Newborough and Cooley (2021). No allowance for cooling water. Water costs consistent with NSW bulk unfiltered water prices, drought surcharges applying one third of the time (IPART (2020)). Project lifespan 20 years. Real discount rate 6.28 per cent.

B.1.1 Hydrogen production cost sensitivity analysis

Electrolyser efficiency

We assume an electrolyser efficiency of 51.3kWh/kg. This is equivalent to an electrolyser efficiency rate of 65%.

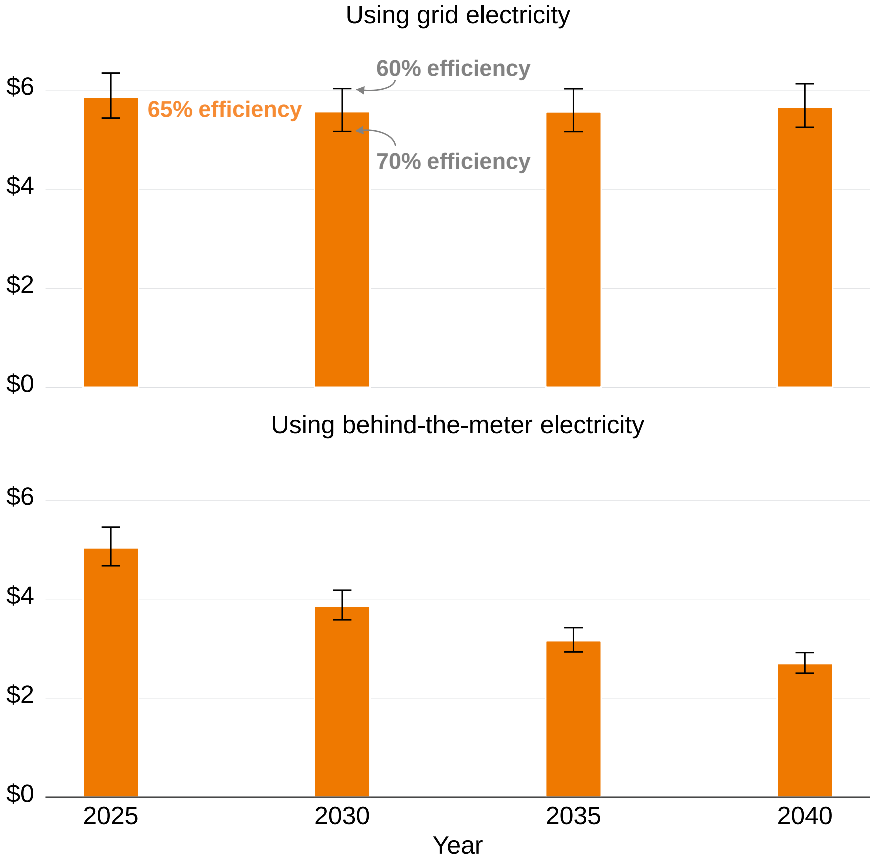
No efficiency improvements are assumed in our scenarios. Analysis of the sensitivity of hydrogen production costs to this assumption is presented at Figure B.1 on the following page. A 5 percentage point higher or lower efficiency rate does little to change the cost of hydrogen production in both the grid-connected electricity, and the behind-the-meter electricity scenarios.

Electrolyser technology

We assume PEM electrolysers are used to produce hydrogen. PEM electrolysers are currently more expensive than alkaline electrolysers, the main alternative.

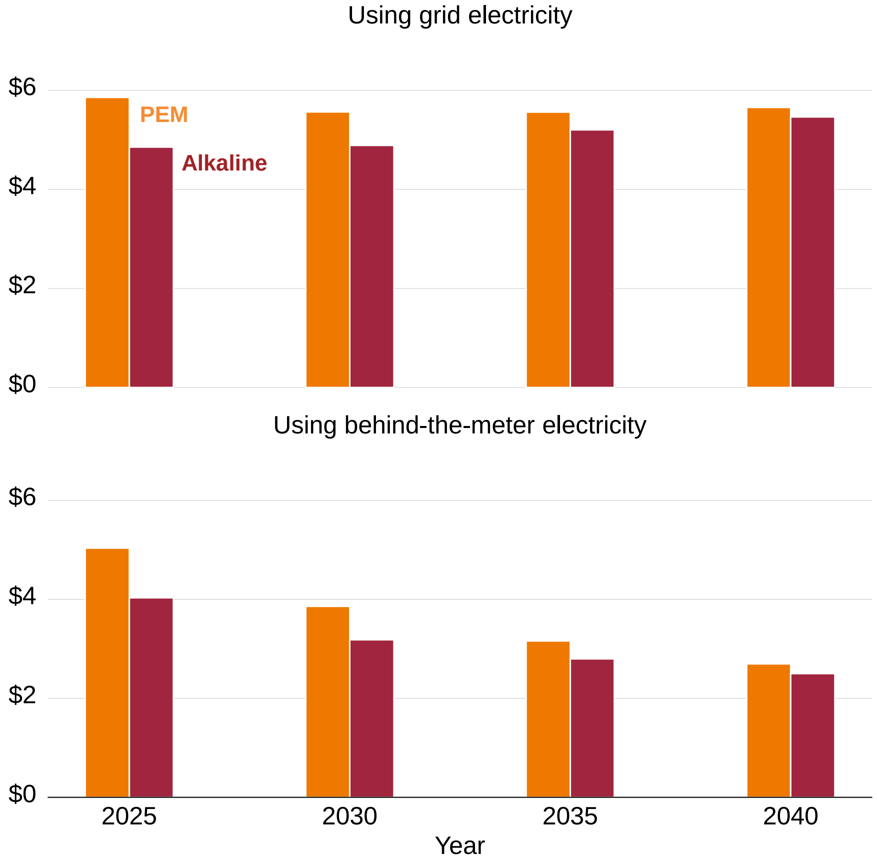
Analysis of the sensitivity of hydrogen production costs to the electrolyser technology used, holding electrolyser efficiency constant at 51.3kWh/kg, is presented at Figure B.2 on the next page. The cost of hydrogen produced using alkaline electrolysers is lower than for PEM initially, but has a negligible impact in 2040, as the price of PEM electrolysers converges with alkaline electrolysers (Graham et al (2023)).

Figure B.1: Small changes to electrolyser efficiency do little to change hydrogen production costs
AU$/kg of hydrogen



Source: Grattan analysis. Assumptions and data sources listed in this appendix.

Figure B.2: Hydrogen production costs converge for PEM and alkaline electrolysers
AU$/kg of hydrogen



Source: Grattan analysis. Assumptions and data sources listed in this appendix.

B.2 Carbon costs

Safeguard Mechanism cost-containment mechanism: carbon costs start at $75 per tonne in 2024 and increase by 2 per cent each year (DCCEEW (2023f)).

Australian carbon credit units: consistent with Herd and Hatfield Dodds (2023) central estimate.

1.5°C-consistent: Network for Greening the Financial System (n.d.), net-zero 2050 scenario.

B.3 Green commodity production costs

B.3.1 Ammonia

Best-case: hydrogen production co-located with 90% renewable energy with firming and storage, minimal transport of hydrogen, carbon costs consistent with a Safeguard Facility accessing the cost containment mechanism for all above-baseline emissions.

Worst-case: electricity sources at wholesale price, carbon costs consistent with a Safeguard Facility using Australian Carbon Credit Units (ACCUs) to offset all above-baseline emissions. Assumes retrofit for an existing plant.

Both cases: retrofit of existing plant. Fuel savings based on east coast gas prices.

Data sources: energy consumption from Bazzanella and Ausfelder (2017) and Australian Industry Energy Transitions Initiative (2023). Retrofit capex and non-fuel opex from Australian Industry Energy Transitions Initiative (ibid). Hydrogen costs as described in Appendix B.1 on page 59. Gas costs from Lewis Grey Advisory (2023), electricity costs for compression, air separation and stem consistent with electricity prices for hydrogen production. Emissions intensity from DCCEEW (2023c), carbon costs as described in Appendix B.2.

B.3.2 Alumina

Best-case: hydrogen production co-located with 90% renewable energy with firming and storage, minimal transport of hydrogen, carbon costs consistent with a Safeguard Facility accessing the cost containment mechanism for all above-baseline emissions.

Worst-case: electricity sources at wholesale price, carbon costs consistent with a Safeguard Facility using Australian Carbon Credit Units (ACCUs) to offset all above-baseline emissions.

Both cases: retrofit of existing plant. Fuel savings based on east coast gas prices.

Data sources: retrofit capex and non-fuel opex from Australian Industry Energy Transitions Initiative (2023). Hydrogen costs as described in Appendix B.1 on page 59. Gas costs from Lewis Grey Advisory (2023). Energy consumption from Australian Industry Energy Transitions Initiative (2023). Emissions intensity from DCCEEW (2023c) and DCCEEW (2023b), carbon costs as described in Appendix B.2.

B.3.3 Iron

Best-case: hydrogen production co-located with 90 per cent renewable energy with firming and storage, minimal transport of hydrogen, carbon costs consistent with accessing the Safeguard Mechanism cost-containment mechanism for all emissions.

Worst-case: electricity sources at wholesale price, carbon costs consistent with using ACCUs to offset all emissions.

Both cases: assumes new build with a new-entrant baseline of zero tonnes CO_2 per tonne of iron. Comparator is a direct-reduction iron plant using gas. Fuel savings are based on a long-run east cost gas price.

Data sources: capex and non-fuel opex from Australian Industry Energy Transitions Initiative (2023). Electric-arc component of DRI-EAF pathway assumed to cost the same as a stand-alone EAF. Hydrogen costs as described in Appendix B.1 on page 59. Gas costs from Lewis Grey Advisory (2023). Energy consumption from Sohn (2019). Emissions intensity from DCCEEW (2023c) and DCCEEW (2023b), carbon costs as described in Appendix B.2 on the previous page.

B.4 Long-distance freight transport

Best-case: hydrogen production co-located with 90% renewable energy with firming and storage. Carbon costs consistent with a Safeguard Facility accessing the cost-containment mechanism for all above-baseline emissions. Refuelling station throughput 45 trucks per day.

Worst-case: electricity sources at wholesale price. Carbon costs consistent with a Safeguard Facility using Australian Carbon Credit Units to offset all above-baseline emissions. Refuelling station throughput of two trucks per day.

Both cases: hydrogen consumption based on a Hyzon Hymax truck, diesel consumption on Australian average. No allowance made for cost of purchasing or maintaining the truck.

Data sources: long-run cost of diesel $1.33 per litre, heavy vehicle charge excluded as assumed to apply to hydrogen trucks in equivalent basis, diesel fuel excise not included as this is rebated to most operators. Hydrogen storage, truck transportation, compression and refuelling point costs from CSIRO (2023d). Carbon costs as described in Appendix B.2 on the preceding page. Hydrogen costs as described in Appendix B.1 on page 59. Average diesel consumption from ABS (2020). Hydrogen consumption from Hyzon (2023).

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