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Glossary

AEMO – Australian Energy Market Operator
AGIG – Australian Gas Infrastructure Group
ARENA – Australian Renewable Energy Agency
BEV – Battery electric vehicle
BRF – Business ready fund
CHE – Container handling equipment
CRI – Commercial readiness index
CSIRO – Commonwealth Scientific and Industrial Research Organisation
DELWP – Department of Environment, Land, Water and Planning
DoT – Department of Transport
DRI – Direct reduction of iron
FC – Fuel cell
FCEV – Fuel cell electric vehicle
GPU – Ground power units
GSE – Ground support equipment
ICE – Internal combustion engine
LCOE – Levelised cost of energy/electricity
LCOH – Levelised cost of hydrogen
LGC – Large-scale generation certificate
LMV – Light motor vehicles
MAC – Marginal abatement cost of carbon
MCN – Melbourne Centre for Nanofabrication
NERA – National Energy Resources Australia
NZE – Net zero emissions
OEM – Original equipment manufacturers
PV – Photovoltaic
RCF – Renewable coincidence factor
RCV – Refuse collection vehicles
RES – Renewable energy supply
RTG crane – Rubber tyre gantry cranes
TCO – total cost of ownership
TEU – Twenty-foot container unit equivalent
WACC – Weighted average cost of capital
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Executive summary

Background

The objective of this feasibility study is to work with end-users in the Monash Technology Precinct and regional Victoria to develop the Victorian Renewable Liquid Hydrogen Supply Hub to provide renewable hydrogen to these end-users.

The feasibility study is sponsored by the Department of Environment, Water, Land and Planning (DELWP) as part of the Renewable Hydrogen Business Ready Fund (BRF). The study is being undertaken as a partnership between Monash University (lead grant applicant), Engie Impact (lead advisory company), and Cryoquip (hydrogen technology provider).

Hydrogen production

The feasibility study considers on-site renewable hydrogen production at the Monash Precinct as part of a liquid hydrogen and nitrogen co-generation facility, with the Australian Synchrotron being the key off-taker for the liquid nitrogen, having an existing demand of approximately 30,000 L per week that is currently supplied by trucks from external sources. The hydrogen facility will be comprised of an electrolyser, a liquefaction unit, and an on-site liquid hydrogen storage, powered by renewable energy to produce green liquid hydrogen at an anticipated production rate of approximately 5 tonnes per day.

Approach

The feasibility study involves a three-stage process that involves an off-taker quantification and screening assessment, optimisation of the equipment infrastructure sizing and the supply chain, and a competitiveness assessment of the use of green hydrogen compared to fossil fuels.

The off-taker screening assessment identified a shortlist of ideally suited potential hydrogen off-takers in Victoria, based upon the multicriteria assessment matrix that was developed by Engie Impact for this study. The key findings of the off-taker screening assessment feed into the recommendations by Engie Impact for the supply of liquid hydrogen to priority off-takers in Victoria.

The hydrogen production equipment sizing optimisation was modelled using Prosumer – Engie Impact’s in-house energy optimisation tool. The system was optimised under different energy supply configurations from utility-scale renewable energy assets and energy supplied from the grid (along with the procurement of LGCs to ensure 100% green energy supply). Based upon the configuration and sizing optimisation results, a cashflow analysis and cost-competitiveness assessment was completed to estimate the total net present cost of (NPC) and annualised cost for the hydrogen production facility and the corresponding levelized cost of hydrogen (LCOH).

Key findings

The off-taker assessment part of the study considers the suitability of liquid hydrogen from the Hydrogen Supply Hub across a range of applications including mobility, gas blending, heat, power, and commodity where hydrogen-based solutions have a competitive technological advantage over fossil based, or in certain cases, even battery electric mobility solutions.

The off-taker screening process considers several metrics for the assessment criteria: demand profile, commercial readiness index (CRI), location, application suitability, and off-taker interest level. Based upon this assessment matrix, gas grid injection, forklifts, waste
trucks, and buses were shortlisted as the ideally suited hydrogen off-takers from the Victorian Renewable Liquid Hydrogen Supply Hub. These potential off-takers were closely followed by other mobility applications – regional trains, concrete trucks, and long-haul transport. Based upon a set of assumptions and realistic uptake potential of each application, a mix of shortlisted off-takers were considered for their potential off-take demand quantities from the Hydrogen Supply Hub, shown in Figure 1 below.

The Supply Hub configuration optimisation and competitive assessment identified that an 82%-91% renewable coincidence factor (RCF) from utility-scale assets and remaining energy demand supplied from the grid with large-scale generation certificates (LGCs) was the most optimal and cost-competitive range for the sizing of assets and supply of green electricity. The results indicated that the 82% RCF scenario can be selected for enhanced cost robustness, whereas the 91% RCF scenario can be selected for the least cost of hydrogen. For the 82-91% RCF scenarios, the optimal configuration requires the installation of solar PV between 31-34 MW, utility scale wind between 29-35 MW, the electrolyser between 16-17MW, the off-site battery storage up to 6 MW/37 MWh and a hydrogen storage between 51-59 TH₂.

The levelised cost of hydrogen (LCOH) at the supply hub is in the range between 13.9-15.3 AUD/kg H₂ with the nominal price at 14.5 AUD/kg H₂. Approximately 60% of this cost is attributable to the cost of the electricity supply of which the grid and the market charges make up a significant portion. Addition to the Supply Hub LCOH, transportation and distribution costs add up to 8 AUD/kg H₂ which is based on the assumptions of the location of the demands, location of the refuelling stations, and the level of off-take from each refuelling facility.

Overall, the installation liquid hydrogen supply from the Victorian Renewable Supply Hub at Monash University is currently not a cost-competitive solution with the fossil fuel solutions for most applications except for forklifts due to the large spending towards grid and market-tariffs for the electricity supply. However, the hydrogen from the Supply Hub gains cost-competitiveness from subsidies from the government for 50% of capital expenditure for the various on-site assets and/or collocating the Supply Hub with the renewable energy generation facilities to reduce the operational expenditure by avoiding a significant share of the grid and the market tariffs for the electricity supply.

Both these interventions when applied together result in several applications having positive business cases from a fuel-cost perspective. For instance, buses have a positive business case with net savings on fuel cost (negative MAC), whereas both waste trucks and concrete trucks have cost-savings compared to diesel in the lowest hydrogen costs. Applications such as trains and buses have an additional spending towards fuels even in the case when the CAPEX subsidy is applied on a renewable collocated facility, however, the spending is lower than the expected carbon price for a below 2°C scenario @ 181 AUD/tCO₂ by at least 25% and 40% respectively.

**Next steps**

The Victorian Renewable Liquid Hydrogen Supply Hub aims to serve as a platform to accelerate the growth of the hydrogen ecosystem in Victoria by facilitating demonstration projects for multiple applications across the region. Based on the results of the off-taker assessment study and the screening process, the immediate next-step of this project is to identify a combination of the shortlisted off-takers whose combined hydrogen demand is to be catered by the Victorian Renewable Liquid Hydrogen Supply Hub at the Monash Technology precinct. In order to make the delivered cost of hydrogen more cost-competitive, either incentives and subsidies must be sought to reduce the operational and capital costs of the
facility or discussions must be held to enable the collocation of the hydrogen Supply Hub at the renewables supply to reduce the grid tariffs.

Figure 1. Schematic of the energy supply chain for the Victorian Renewable Liquid Hydrogen Supply Hub. All values on a per annum basis.
1. Introduction

Hydrogen is currently enjoying unprecedented political and business momentum for its potential contribution to a clean energy transition. Hydrogen fuel is light, energy dense and produces no direct emissions of pollutants or greenhouse gases. Additionally, its versatility as an energy carrier is a key advantage that enables energy export economies such as Australia to be at a unique position during the energy transition.

Hydrogen, which is historically used mainly in the chemical and the manufacturing sectors (e.g. ammonia, refineries, electronics), now also finds its way into numerous other end-uses such as land, sea, and air transport, as a commodity, and for heat and power generation, as evidenced through commercial-scale technology deployments and demonstrations globally. Particularly, the hydrogen produced from renewable sources (i.e. green hydrogen) holds a competitive advantage with several countries and organisations around the world committing to emission reductions or emission-neutral operations. Australia and the state of Victoria have committed to a net-zero emission target by 2050 and hydrogen will have a key role to play in achieving this target.

This study assesses the feasibility of the development of the Victorian Renewable Liquid Hydrogen Supply Hub at the Monash Technology Precinct, which would contribute beneficially to Victoria’s Renewable Hydrogen Development Plan. This facility will not only offer a steady and reliable supply of green hydrogen to local end-users, but also provide a supply of liquid hydrogen to state-based hydrogen clusters and other emerging hydrogen end-use applications. The liquid state makes hydrogen more cost-effective to store and transport, due to the high volumetric density of liquid hydrogen at 71 kg/m³, compared to compressed hydrogen (700 bar) at 42 kg/m³. Therefore, liquid hydrogen can be transported in a more economic manner to potential (industrial) end-users across Victoria.

The Liquid Hydrogen Supply Hub also provides flexibility towards different end users. This avoids the potential end-users having to invest themselves into the production of renewable hydrogen from the beginning, as they could source the hydrogen from the Liquid Hydrogen Supply Hub. This lowers the threshold to start developing hydrogen-using applications, as it avoids heavy upfront capital investments that would otherwise be required. For industries with smaller quantities of hydrogen demand (micro-electronics assembly, laboratories, etc.), the Liquid Hydrogen Supply Hub can provide a reliable and long-term supply. For applications with a potentially larger demand for hydrogen (e.g. public transport with fuel cell buses, logistic companies transitioning to fuel cell trucks), there is the option to subsequently invest and switch over to on-site renewable hydrogen production after initial trials, and therefore allowing the supply from the Liquid Hydrogen Supply Hub to be used elsewhere.

This study assesses the feasibility and the competitiveness of the development of the Victorian Liquid Hydrogen Supply Hub at the Monash Precinct. Powered by renewable electricity (including roof-top solar PV), the facility will house the electrolyser and the hydrogen liquefaction facility. Additionally, the Supply Hub will also produce liquid nitrogen catering to the leading technology and innovation centres at the Precinct (i.e. the Australian Synchrotron requiring ~30,000 L per week, the Melbourne Centre for Nanofabrication (MCN), and broader Monash Technology Research Platforms), which are currently supplied by trucks from external sources. The co-produced liquid hydrogen and nitrogen provides the opportunity for significant cost savings and efficiency gains.
1.1. Benefits of Liquid hydrogen

Although almost all hydrogen technologies (i.e. hydrogen fuel cells and hydrogen gas blending) today utilise hydrogen in the compressed (gaseous) form as the fuel, liquid hydrogen presents significant advantages over compressed hydrogen, particularly in relation to its storage, transport and distribution due to having a significantly higher density. Some of the benefits of liquid hydrogen are detailed below.

Storage:
- The density of compressed hydrogen at 700 bar is 42 kg/m$^3$ which equates to a volumetric storage size of 125 litres for 5 kg H$_2$. In contrast, liquid hydrogen (at -273 °C) has a density of 71 kg/m$^3$, in which 5 kg H$_2$ can be stored in a 75-litre tank.\(^1\)
- Liquid hydrogen therefore provides a key benefit for on-site storage considerations as it has a much lower physical footprint compared to the equivalent amount of compressed hydrogen.
- This consideration is important in the context of the Hydrogen Supply Hub at the Monash Precinct given the space constraints of the location.

Transport:
- The higher density of liquid hydrogen makes it much easier to transport than compressed hydrogen. This consideration provides a cost benefit for the distribution of hydrogen, which becomes significantly more economically desirable at medium-scale operations (i.e. larger than 500 kg H$_2$/day), or when longer transportation distances are involved. Liquid hydrogen truck delivery is also favourable when there is only a relatively low market penetration rate.
- Larger commercial-scale operations or higher market penetration rates would begin to favour pipeline distribution networks where the higher cost of infrastructure would only then start to become more economically feasible.
- Given that the Hydrogen Supply Hub at the Monash Precinct would only provide quantities of hydrogen suitable for supplying demonstration-level projects, liquid hydrogen transported by delivery trucks would be the easiest and most cost-competitive distribution option.

Refuelling:
- Cryo-compressors allow for faster loading of liquid hydrogen into containers for storage and transport compared to compressed hydrogen delivery systems.
- At the Monash Precinct, this would provide an advantage so that hydrogen delivery trucks can operate efficiently, minimising downtime due to refuelling and avoiding on-site queuing of vehicles where space is limited.

The production of liquid hydrogen at the Monash Precinct is also feasible due to cost saving benefits associated with scale economies. Given that a liquefaction facility will also be established at the location to produce liquid nitrogen to supply an existing local demand, capital costs can be minimised through the co-production of liquid nitrogen and hydrogen compared to the costs that would otherwise be involved to establish two separate liquefaction facilities.

\(^1\) Storing hydrogen, Air Liquide, 2022.
1.2. Project scope and objectives

The objective of this feasibility study is to work with end-users in the Monash Precinct and regional Victoria to develop the Victorian Renewable Liquid Hydrogen Supply Hub to provide renewable hydrogen to these end-users.

In line with this objective, the scope of the study would encompass the following aspects:

- A structured overview and assessment of liquid hydrogen off-takers in the Monash Precinct and the hydrogen clusters within Victoria, and their potential hydrogen off-take quantities.
- An assessment of the end uses supporting Monash's Net Zero ambitions, focusing on mobility, heating, and gas blending opportunities.
- The optimised Supply Hub sizing, including the renewable energy supply, electrolyser equipment, liquid hydrogen storage, and the logistics supply chain sizing from the Supply Hub to the envisioned hydrogen end users.
- A class 5 cost estimate of the optimised configuration. For example, in the case of hydrogen fuel cell vehicles, this includes the supply chain to the refuelling station, and the hydrogen refuelling station itself.
- A business case assessment of the envisioned end-use applications, comparing them to the current conventional application. This includes a levelised cost which can be compared to the conventional alternative. Additionally, it includes a waterfall breakdown of the levelised cost, which allows to distinguish the different cost-contributing factors. These outputs are key inputs for more detailed engineering studies that are to be conducted to obtain a higher accuracy costing estimate and required to make a final investment decision.

1.3. Overall project approach

The feasibility study is divided into three stages, i.e. liquid hydrogen off-taker assessment, Supply Hub configuration optimisation, and competitiveness assessment, as illustrated in Figure 2.

Figure 2. Overview of the project approach.

Stage 1 of the approach is covered in Section 2 (off-taker mapping and quantification) and Section 3 (off-taker screening) of this report. Stage 2 is summarised in Section 4 (scenario modelling and optimisation). Stage 3 is presented in Section 5 (results and discussion).
2. Off-taker mapping and quantification

2.1. Approach for off-taker assessment

The stepwise approach for the off-taker assessment is presented in Figure 3. The first step of the off-taker assessment is to identify key applications within Victoria where potential hydrogen off-take potential exists, particularly in those where the supply of liquid hydrogen will be beneficial. Subsequently, the demand for the off-taker application is quantified based on desktop research, complemented by the context and the insights provided by the various stakeholder interviews. The stakeholder interviews, spanning government, hydrogen clusters, original equipment manufacturers (OEMs), industry, research partners are intended to gather information on the hydrogen adaption appetite, technology availability and infrastructure growth required for the various applications.

Following the demand quantification, the off-taker screening is carried out to assess and shortlist the off-takers based on the criteria such as the off-take quantity, off-taker interest level, and the commercial readiness of end-use equipment. The final demands identified fed into the modelling for optimising the system configuration.

2.2. Overview of hydrogen off-taker applications

Hydrogen is an attractive and a competitive solution for decarbonisation and holds a unique position as it:

- offers a competitive decarbonisation solution where electrification is difficult or not possible;
- provides a scalable solution to replace natural gas use;
- offers faster refuelling that is suited for applications with longer uptimes.

Following the above rationale, hydrogen off-take applications have been mapped within the Monash precinct, Monash city council, the greater Melbourne metropolitan region and in regional Victoria. Broadly, it has been identified that hydrogen finds a niche for decarbonisation in three main application categories, namely:
- **Mobility**, including long-haul transport (freight and dairy) and applications in greater Melbourne region such as public transport and port and airport operations;
- **Gas blending** into the natural gas grid that cascades into decarbonising domestic, process heating application apart from using hydrogen in the gas power plants;
- **Commodity** use in industries such as fertilizer, iron and steel and chemical industry.

The hydrogen demand for these applications is estimated through desktop research on industry specific statistical data while contextualising the information as relevant for Victoria. The hydrogen uptake potential is also determined by considering criteria such as technological maturity, demand profile, competitive advantage of hydrogen versus electric (or vice versa), and off-taker interest level.

In many instances, due to the lack of industry-specific data, certain assumptions have been made based upon insights provided by industry stakeholders on their appetite for hydrogen deployment. Additional uncertainties are due to underpinning considerations such as industry-specific market adoption, technology advancement, and fuel cost evolution of hydrogen-related technologies. These estimates therefore serve to provide ballpark estimates on the order of magnitude of hydrogen uptake in Victoria. All assumptions are provided in the Appendix.

The following subsections describe each of the off-taker applications in further detail, specifying their relevant hydrogen demands and the assumptions made for this study. Additionally, case studies have been included to describe the use of hydrogen for the specific application and highlight the level of technological and commercial readiness for each.

### 2.3. Mobility

Hydrogen has a huge potential as a fuel for mobility applications, particularly for niche material handling applications such as long-haul transport, forklifts, waste and concrete trucks. Fuel cell electric vehicles (FCEVs) are better suited compared to battery electric vehicles (BEVs) for applications which demand long-range, large pay-load capacity, significant operational uptime and fast refuelling is critical (Table 1).

Furthermore, FCEVs also become a competitive solution where electrification or electric refuelling infrastructure are scarce. Nevertheless, BEVs are expected to fare better in applications where shorter distances are travelled and where frequent braking is involved, e.g. light motor vehicles (LMVs), due to higher efficiencies, energy recovery during braking and rapid development of refuelling infrastructure. Taking the above factors into consideration, the hydrogen off-take applications within mobility have been categorised below.

#### Public transport
- **V-line trains** offer an interesting application for hydrogen as the electrification of the regional network does not justify the large investment.
- **City buses**, especially those covering longer routes, would be an attractive application for FCEVs.

#### Material handling
- **Long-haul transport** including interstate logistical and freight operations are suited ideally for FCEVs due to the long-range operation and payload requirements.
• *Dairy trucks* also are attractive due to their back-to-base operations and longer operational distances.

• *Heavy-duty purpose-built vehicles* such as concrete/waste trucks could also be hydrogen fueled considering their longer uptime and stationary nature of operation.

• *Light-duty purpose-built vehicles* typically include forklifts particularly those that operate in warehouses where long-duty cycle is required.

**Maritime**

• Apart from hydrogen for shipping, the port operational equipment such as yard trackers, drayage trucks can be on hydrogen because of long uptimes.

**Aviation**

• While hydrogen aircrafts are still in their infancy; operations equipment such as aircraft tugs, ground power units (GPUs) could be hydrogen fuelled due to their longer uptimes.

*Table 1. Application requirements and suitability of FCEV.*

<table>
<thead>
<tr>
<th>Application</th>
<th>Long range</th>
<th>Payload</th>
<th>Significant uptime</th>
<th>Short-refueling</th>
</tr>
</thead>
<tbody>
<tr>
<td>Public transport</td>
<td>✔</td>
<td></td>
<td></td>
<td>✔</td>
</tr>
<tr>
<td>Material handling</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
</tr>
<tr>
<td>Airport and port operations</td>
<td>✔</td>
<td></td>
<td>✔</td>
<td>✔</td>
</tr>
</tbody>
</table>

2.3.1. Public transport

The extensive public transport sector in Victoria, that spans trains, trams and buses is an important energy consumer in the state. The tram network in the metropolitan Melbourne is electrified and therefore is not considered as an application for hydrogen. The V-line trains and a share of the public transport buses are expected have a significant demand for hydrogen, as shown in Figure 4. The applications and assumptions for the trains and buses are described below.
2.3.1.a Trains

Commuter trains offer an interesting application for switching to hydrogen from conventional internal combustion (IC) engine systems using diesel fuel. Diesel fuel is inherently correlated with poor resilience due to fuel supply uncertainties, and with the increasing prices of fossil fuels globally, green hydrogen provides an opportunity for trialling green fuel alternatives.

In Victoria, the V-Line trains could be an ideal application as they have not been electrified and continue to run on diesel. The electrification of these train lines, covering long distances into regional areas, is unlikely as it does not justify the large investment given the limited amount of trains per day. As the fuel consumption of V-Line trains produces 115,000 tCO₂ annually (85% of total V-Line emissions), the shift to green hydrogen would result in a significant emission reduction for rail operations.²

Some of the benefits of hydrogen trains include:

- Higher fuel efficiency compared to diesel alternatives;
- Zero tailpipe emissions of pollutants such as NOₓ and greenhouse gases especially CO₂;
- Reduced noise pollution and vibration;
- Avoids cost of future electrification, typically costing several million dollars per kilometre and resulting in service disruptions during the construction phase;
- Fuel savings compared to diesel.

The cost parity for hydrogen vehicles with diesel may be achieved over the medium term due to savings in the fuel expenditure. However, this is a function of parameters such as the fuel-cell train purchase price, hydrogen cost, and other infrastructure expenditure. A hydrogen fuel cost of less than ~$6/kg could result in hydrogen technologies becoming cost-competitive with diesel vehicles.³ The cost-competitiveness for hydrogen vehicles would increase with rising diesel prices. However, the deployment of fuel cell trains would require additional considerations. For instance, for use in Victoria, the trains must be customised to suit the

---

technical requirements of the network such as gauge. Additional considerations would include the logistics for hydrogen supply and strategic deployment of refuelling stations across the regional areas.

The hydrogen fuel cell train is expected to have a range between 600-800 km, while some claims from OEMs suggest that a range of up to 1,000 km can be achieved with a passenger capacity of 300. The reported fuel consumption for the fuel-cell train is 8.3-11.7 kWh/km which is lower than conventional diesel engines that consume between 12-14 kWh/km. Considering the fuel efficiency of hydrogen, the theoretical demand would be approximately 8,800 t H₂/year for the V-Line trains.

Case study

The Coradia iLint developed by Alstom (shown in Figure 5) is the world’s first low-floor fuel cell train. The electricity for the traction and on-board equipment is generated by a fuel cell, stored in a battery, and energy is recovered during breaking. The hydrogen is stored in gaseous forms in the holding tanks on the roof beside the fuel cell systems. The battery system is deployed at the floor which stores part of the extra energy produced by the fuel cell and recovered energy during breaking that can supply the train under normal operation and can be used to boost the acceleration when necessary.

The iLint train’s performance is comparable (including acceleration and braking) with regular regional trains with a maximum speed of 140 km/h, a range of 1,000 km, and a passenger capacity of 300. The hydrogen train was trialled in several countries in Europe, including in the Netherlands, Germany, UK, Sweden and France. In Germany, two 100% hydrogen trains entered commercial service in 2019 and covered more than 200,000 km. Based on this successful trial, 41 trainsets have been ordered in Germany.

Figure 5. Coradia iLint fuel-cell train by Alstom.

2.3.1.b Buses

The deployment of hydrogen fuel cell buses is increasing as the maturity of the technology continues to develop and both municipalities and transit companies move towards a net zero emissions future.

Buses are a suitable application for hydrogen given that there are limitations of electric battery alternatives regarding charge time and vehicle range capabilities. The benefits of hydrogen-powered buses include,5,6,7:

- High energy efficiency, approximately 30% more efficient than diesel-powered buses.
- High range capabilities of around 350 km between refuelling, based on the Solaris Urbino model with a 37 kg hydrogen tank.
- Quick refuelling times of approximately 5-7 minutes.
- No direct emissions which is important for urban mobility and air pollution concerns.
- Minimal additional refuelling infrastructure given that buses operate out of a single depot.

Hydrogen buses have the potential to be deployed across various applications, ranging from municipality and regional public transport services, university shuttle buses, charter operators, and company fleet vehicles. The Victorian Government has pledged that all new bus purchases will be zero emission buses from 2025 as part of the transport sector pledge. This would entail retiring 180 existing buses that are part of the government routes each year. Battery-electric buses are seen as a competitive option given the frequent breaking that can recharge the battery pack or along shorter routes that are able to cover the entire shift on a full-charge. However, hydrogen vehicles could be a favourable solution for longer routes where rapid refuelling and continuous up-time is essential.

The potential hydrogen demand for public transport buses in Victoria was estimated to be 1,433 t H₂/year, based upon past public transport bus usage in Melbourne and an assumption of 20% conversion of the total bus operations to hydrogen.8 This assumption accounts for the consideration that battery-electric buses would provide sufficient autonomy for most bus routes in Melbourne, and hydrogen fuel cell buses would only supplement them on more demanding routes. Further, conversion factors to estimate the hydrogen demand from diesel consumption is based on the data provided by Hyzon Motors, as shown in Table 2. It should be noted that the efficiency of diesel engines are lower at lower speeds which is the inverse in the case of hydrogen FCEVs, this results in the charter buses having lower fuel consumption factor (L diesel/kg H₂) compared to city buses.

Additionally, an approximate demand of 21 t H₂/year would be required to replace Monash University’s diesel intercampus shuttle buses with hydrogen buses, based upon Monash’s current operations and diesel fuel consumption. This makes up approximately 90% of the potential hydrogen demand for mobility applications at Monash University when considering the entire fleet that could be suitably replaced by FCEVs.

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8 Bureau of Infrastructure and Transport Research Economics, Yearbook, 2021.
### Table 2. Bus fuel consumption factors.

<table>
<thead>
<tr>
<th>Vehicular Types</th>
<th>Typical Values</th>
<th>Fuel Consumption Factor (L diesel/kg H₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Diesel</td>
<td>Hydrogen</td>
</tr>
<tr>
<td></td>
<td>L/100km</td>
<td>kg H₂/100km</td>
</tr>
<tr>
<td>Buses (charter)</td>
<td>35</td>
<td>8.0</td>
</tr>
<tr>
<td>Buses (city)</td>
<td>44</td>
<td>7.0</td>
</tr>
</tbody>
</table>

### Case study

SASA Bolzano is the public transport operator in Bolzano, Italy, and added 12 hydrogen fuel cell buses to its fleet in 2021. It was the first procurement and demonstration of Solaris’ new Urbino model hydrogen bus (shown in Figure 6), following a contract that was signed in May 2019.⁶

The buses are supported by a hydrogen refuelling station at the existing depot and is one of the largest hydrogen-powered bus fleets in Europe. The project was co-financed by the EU, contributing to 30% of the total cost of approximately 10 million euros.⁹ Approximately 300 high-performance hydrogen fuel cell buses like the Solaris buses have been ordered or deployed throughout Europe.⁹

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2.3.2. Material handling

Hydrogen finds important use in the material handling sector. Hydrogen is particularly useful for applications where long-range operations are desired without compromising on the payload capacity and the operational uptime. The main categories within material handling namely, long-haul, dairy transport, purpose-built heavy and light duty vehicles where together present by-far the largest demand for hydrogen in Victoria, as shown in Figure 7.

![Diagram of material handling categories and their estimated annual hydrogen demand potential.](image)

Figure 7. Overview of material handling categories and their estimated annual hydrogen demand potential.

2.3.2.a Heavy-duty purpose-built trucks

Waste trucks, or refuse collection vehicles (RCVs), have significant decarbonisation potential for mobility and are therefore a key area of focus for municipalities.\(^\text{10}\) Similarly, IC engine concrete trucks are highly inefficient, particularly while agitating cement during idle, and therefore have a large opportunity for efficiency improvements and decarbonisation potential. Given that both waste trucks and concrete trucks are heavy duty vehicles with large inefficiencies, they are ideally suited applications for liquid hydrogen and supported by the following additional considerations:\(^\text{11,12}\)

- Operate from a single depot, which allows liquid hydrogen fuel to be transported and stored at a single refuelling point.
- Generally, operate in urban and residential areas where air pollution needs to be significantly reduced for health reasons.

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\(^{11}\) Revive, https://h2revive.eu/.

• RCVs have a range of up to 200 km (with 1,500 bin lifts) on 20-25 kg H₂, providing the range and flexibility required for waste trucks to complete extended suburban and rural collection routes.
• Fast refuelling times of under 10 minutes, allowing for more uptime and continuity of operations.
• Successful application of hydrogen for garbage and concrete trucks would serve as a springboard for other heavy-duty trucks.

Hydrogen waste trucks could be deployed throughout suburban and rural councils in Victoria and Australia. The market for hydrogen waste trucks would include large precincts, councils, or contracted waste collection companies.

The total annual potential demand for hydrogen waste trucks was calculated based on the Victorian Government waste services data. In 2019-2020, 2.37 million tonnes of waste were collected from households by local government waste services.\(^\text{13}\) Given the assumptions of 9.5 tonnes load capacity of waste trucks, a 100 km average round-trip per load, a hydrogen fuel consumption of 10.5 kg/100 km (Table 3), and 50% of the trucks transitioning towards hydrogen, a total demand of 1,309 t H₂ would be required for municipality waste collection annually.

The calculated hydrogen demand for waste trucks at Monash University is approximately 2,000 kg per year and would be considered only a small off-taker of hydrogen for waste management compared to municipality-scale waste collection operations.

Victoria produces around 8 million m³ of cement annually, which is transported by cement trucks with approximately 10 m³ capacity, equating to approximately 800,000 cement truck operations in Victoria annually, highlighting a significant potential for hydrogen in cement transport applications.\(^\text{14,15}\) Considering an average travel distance of approximately 25 km per trip, a fuel efficiency of 13.5 kg H₂/100 km, and a 50% market penetration rate towards hydrogen, the potential demand for hydrogen would be approximately 1,346 t H₂ annually.

Table 3. Heavy-duty purpose-built trucks fuel consumption factor.

<table>
<thead>
<tr>
<th>Vehicles</th>
<th>Typical values</th>
<th>Fuel consumption factor (L diesel/kg H₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Diesel L/100km</td>
<td>Hydrogen kg H₂/100km</td>
</tr>
<tr>
<td>Waste collection trucks</td>
<td>78</td>
<td>10.5</td>
</tr>
<tr>
<td>Concrete trucks</td>
<td>100</td>
<td>13.5</td>
</tr>
</tbody>
</table>

\(^\text{14}\) Demand for concrete expected to rise over next five years, Roads and Infrastructure, 2018.
\(^\text{15}\) Amix Group Co., https://concretetruckmixer.net/concrete-mixer-truck-capacity/.
Case study

REVIVE (Refuse Vehicle Innovation and Validation in Europe) is a public-private partnership funded by Hydrogen Europe and the European Commission.

REVIVE is the largest demonstration of hydrogen fuel cell waste trucks (shown in Figure 8) in Europe with 15 trucks operating across 8 European cities: Amsterdam, Breda, Groningen, Noordenveld and Helmond (the Netherlands), Antwerp (Belgium), Bolzano and Merano (in South Tyrol, Italy) and Gothenburg (Sweden).

The objective of the initiative is to accelerate the techno-economic feasibility of hydrogen powered waste trucks to increase the viability of the technology as a net zero emissions solution for municipality waste collection.

The project was conducted over four years from beginning 2018 to end of 2021, with the trucks being trialled for at least 24 months. Results from the trials are yet to be released.

2.3.2.b Long-haul mobility

The decarbonisation of heavy-duty vehicles through the adoption of zero-emission technologies is crucial given that diesel trucks are the largest contributor of carbon emissions on roadways.16

Like other weight-critical heavy-duty applications, such as public transport and material handling, hydrogen fuel cells are perhaps better suited for heavy duty logistics and long-haul vehicles than battery-powered options since the battery pack’s weight would reduce the vehicle’s maximum total payload. Long-charging times of batteries would also not be suitable for long haul and logistics applications due to the distances involved and need for continuous uptime of the vehicles.16

The benefits of hydrogen for heavy duty applications are:¹⁷,¹⁸

- Quick refuelling times of approximately 15-20 minutes
- Very long ranges of approximately 680 km per 98 kg H₂ (64-ton truck)
- Lower weight compared to battery alternatives allows for larger payload capacities
- Significantly reduced noise pollution (approx. 60% quieter than diesel trucks)

Heavy duty trucks used for logistics and long haul have various applications across a range of different industries and geographic contexts, including the transport of minerals, wood, fuel, food and dairy products, construction equipment, and other materials.

With logistics and long-haul trucks having such widespread applications, their future demand is likely to be high compared to other mobility vehicles. For example, it is possible that by 2035, over 800,000 fuel cell heavy duty (and some medium to light duty) trucks will be sold.¹⁹

ABS data illustrates that there is a total of 105,139 articulated trucks (long-haul, high-volume freight) in Australia.²⁰ Victorian articulated vehicles travel an annual distance of 2,224 million kilometres, with an assumption that most of these long-haul vehicles travelling interstate.²¹ Based upon fuel consumption estimates of 14.5 kg H₂/100 km (Table 4) and 80% market share for hydrogen, there is an approximate demand of 258,000 t H₂/year for articulated vehicles across Victoria.

Table 4. Long Haul vehicle fuel consumption factor.

<table>
<thead>
<tr>
<th>Vehicles</th>
<th>Typical values</th>
<th>Fuel consumption factor (L diesel/kg H₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>L/100km</td>
<td>kg H₂/100km</td>
</tr>
<tr>
<td>Trucks (B double freight)</td>
<td>69</td>
<td>14.5</td>
</tr>
<tr>
<td>Trucks (council)</td>
<td>25</td>
<td>4.8</td>
</tr>
<tr>
<td>Trucks (drayage)</td>
<td>45</td>
<td>8.6</td>
</tr>
<tr>
<td>Trucks (rigid delivery)</td>
<td>30</td>
<td>5.6</td>
</tr>
</tbody>
</table>

Case study

Hyzon Motors – a global supplier of zero-emissions hydrogen fuel cell powered commercial vehicles – finalized an order in mid-2019 for five 154-ton heavy duty trucks from Ark Energy, the Australian subsidiary of Korea Zinc, the world’s largest zinc producer.  

The heavy-duty hydrogen trucks (shown in Figure 9) will be deployed in Townsville, Queensland before the end of 2022, and will likely be the first demonstration of Hyzon’s ultra-heavy-duty fuel cell trucks. The trucks will operate on a 30 km loop between the Port of Townsville and the Sun Metals zinc refinery and powered by renewable hydrogen produced on-site by a 1MW electrolyser connected to the existing 124 MW solar farm. Replacing their current diesel-powered counterparts, the trucks will result in an annual emissions reduction of 1,400 tCO₂-e.

Figure 9. Hyzon Motors’ fuel-cell freight vehicle.

2.3.2.c Dairy Tucks

The decarbonisation of dairy trucks could be crucial to decreasing carbon emissions in Victoria given that the state has the largest dairy industry nation-wide. The state accounts for 77% of all dairy production in Australia with approximately 5,800 farms nationally, further demonstrating the benefits for decarbonising the industry’s transport.

Similar to long-haul vehicles, dairy trucks require heavy loads to be carried over long distances between farms and drop-off points. Hydrogen fuel-cells would be much better suited for the vehicles compared to the battery electric vehicles. The major advantages of using hydrogen fuel-cells are:

- Shorter recharging times of approximately 15 minutes.

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22 Hyzon Motors to supply 154-ton fuel cell-powered hydrogen trucks to Australian subsidiary of Korea Zinc, world’s largest zinc producer, HYZON MOTORS, 2021.
23 Hydrogen powered prime movers to roll into Townsville, ARENAWIRE, 2021.
• Lighter weights compared to battery alternatives, increasing the maximum carrying capacity.
• Relatively low hydrogen demands annually per farm.
• 2-5 tons more carrying capacity than most battery powered alternatives.25

The average annual emission from the farm gate to the shelf of dairy products is around 337,000 tCO₂-e and the Victorian dairy industry being largest in Australia contributes to 63% of the total milk production.26,27,28 Further, applying a fuel conversion factor of 0.21 kg H₂/l diesel from Hyzon’s estimate for B-double freight trucks and an 80% market adoption, the total hydrogen demand for Victorian dairy trucks would amount to approximately 13,231 t H₂ annually.

**Case study**

In 2021 Friesland Campina ordered a fleet of 25 hydrogen fuelled milk trucks to improve their sustainability and accelerate the decarbonisation of their transportation as a part of their zero emissions campaign. The hydrogen fuel cell dairy trucks (in Figure 10) are expected to have up to a 520 km range with a 550kW capacity. The trucks can carry 2-5 tonnes more than battery electric trucks due to the vehicles being lighter than standard electric trucks of the same category. Hyzon claim that the fuel cell power density also has an advantage over both fuel cell and battery powered electric competitors.25

![Figure 10. Friesland Campina's Hyzon fuel-cell dairy truck.](image-url)
2.3.2.d Light Duty – forklifts

One of the most established applications for hydrogen in material handing is forklifts. Forklifts are utilized across a range of industries and operations, including waste management, logistics, warehouse operations, shipping and port operations, airports, and construction. Hydrogen fuel cell forklifts can therefore contribute to emissions reductions throughout various sectors of the economy.

Hydrogen forklifts are both technologically and commercially feasible, which can either be purpose-built or retrofitted internal combustion engine systems with a hydrogen fuel cell. The fuel cell forklift is typically designed as a hybrid system with the fuel cell stack as a power source and the battery or a supercapacitor system to handle the peak power using stored energy. The benefits of a hydrogen forklift include:

- Refuelling times of approximately 3 minutes, which is significantly faster than battery powered alternatives that take 8 hours to recharge.\(^{29}\)
- No direct emissions providing a healthy working environment in enclosed spaces, such as warehouses and factories.
- Significantly reduced operational downtime and handling issues that are associated with battery-powered alternatives.
- Fuel cells maintain a constant voltage, without the voltage drop towards end of shift or in cold locations, as observed for batteries.
- Total cost of ownership is currently 5-10% cheaper than battery-powered forklifts, with a potential for up to 20% lower costs.\(^{30}\)

The hydrogen demand from fuel cells have been estimated by considering a fuel-cell power train efficiency of 45%. This is by considering the fuel-cell efficiency of 56% and the remaining power train components such as motor and inverter have an efficiency of 80%.\(^{31}\) On the contrary, a forklift with a spark-ignition internal combustion engine is expected to have an efficiency of 20%.

At the national level, the market size in Australia is approximately 150,000 forklifts. 30,000 forklifts in Melbourne, when considering a daily fuel consumption of 2.1 kg H\(_2\) per vehicle (i.e. 0.15 kg H\(_2\) per hour, 14 hours per day) and assuming only 20% market capture, represents a potential demand of approximately 4,150 t H\(_2\)/year.\(^{32}\)

In the Albury/Wodonga region, three companies in the food and packaging sectors have a significant need for forklifts in their operations. Combined, the companies currently operate approximately 150-200 forklifts, which equates to a potential annual hydrogen demand of approximately 87 t H\(_2\).\(^{32}\)

\(^{30}\) National Hydrogen Roadmap, CSIRO, 2018.
\(^{31}\) Full fuel-cycle comparison of forklift propulsion systems, Argonne National Laboratory, 2008.
\(^{32}\) Hydrogen forklift: ENGIE Internal estimate
Case study

Toyota has developed hydrogen fuel cell forklifts which are commercially ready and have been demonstrated by the company as a part of the Toyota Ecopark Hydrogen Demonstration project in Altona, Victoria (Figure 11).33

The Ecopark site was previously used as a manufacturing plant before it was decommissioned in 2017 and converted into the hydrogen production and refuelling facility. Up to 80 kg of hydrogen is produced on site each day by a 200 kW electrolyser and stored in storage tubes under high pressure ready for refuelling the forklifts and other fuel cell vehicles.4

The forklifts offer a load rating of 2.5 tonnes and require about 1 kg H₂ for a complete refuel.

Figure 11. Toyota’s fuel cell forklift.

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33 Toyota unveils Victoria’s first hydrogen production and re-fuelling facility at Centre of Excellence, Toyota, 2021.
2.3.3. Maritime

With increasing pressure on organisations to reduce Scope 3 emissions, the maritime sector globally is at a crucial juncture in weighing the options available to decarbonise its operations. In this context, green hydrogen or its derivatives such as green ammonia are expected to play a transformative role in the coming decades. In this section, the expected hydrogen demand from shipping and the port operations at the Port of Melbourne and the Port of Geelong are investigated in detail. As depicted in Figure 12, the major hydrogen off-take is expected from port operations in the short- to mid-term while the shipping sector is yet to mature at a commercial scale.

![Figure 12](image)

*Figure 12. Overview of the maritime categories and their estimated annual hydrogen demand potential.*

2.3.3.a Shipping

Hydrogen presents one of the only feasible options for rapid decarbonisation and an emission-free maritime sector. However, hydrogen use as a fuel for shipping and maritime operations are yet to fully mature at a commercial scale and has thus far been limited to only few concept studies and several pilot projects being undertaken to date. Hydrogen-powered ferries have been identified as a potential early application for shipping, with some tests being piloted in Norway and San Francisco.\(^{34}\)

A key benefit of hydrogen fuel cells in shipping applications is the relative ease to retrofit existing diesel-powered ships and ferries. Therefore, most ships today could be converted and powered by hydrogen fuel cells without any significant impacts on current fleet operations.\(^{34}\)

:\(^{34}\) *Hydrogen: The Key to Decarbonizing the Global Shipping Industry?* CSIS, 2021.
In Victoria, one of the key opportunities to demonstrate hydrogen in shipping applications would be the Spirit of Tasmania’s ferry operations between Melbourne and Devonport – a 429 km one-way route. The existing fleet is comprised of two 28kt twin turbo diesel ships with four V16 engines. The fleet will be expanded to four ships by the end of 2024 with the addition of two LNG & diesel dual-fuel ships.\(^{35}\)

Hydrogen could be implemented for smaller scale marine operations or as a hybrid-fuel technology in the more immediate-term future. For example, tugs boats could be relatively easily converted to dual fuel (hydrogen and diesel) engines. Compagnie Maritime Belge (CMB) has already piloted this as a solution with their HydroTug in 2021 at the Port of Antwerp, Belgium.\(^{36}\)

### 2.3.3.b Ground operations

As ports begin the process of decarbonising, the search for a feasible energy source for their cargo handling equipment (CHE) will be a main source of concern. Based on the large loads expected to be handled by CHEs, hydrogen is an ideal replacement for the mostly diesel and petrol fuelled vehicles. CHEs encompass forklifts, Rubber Tyre Gantry (RTG) cranes, side/top handlers, yard tractors, etc.

Hydrogen has great potential in the decarbonisation of the shipping and maritime industry; particularly due to the heavy-duty operation (payload of over 4.5 tonnes) combined with long uptime during the days which would benefit from the quick refuelling times that the hydrogen vehicles offer. The main areas of opportunity are:

- Forklifts which may use Hydrogen fuel cells or hybrid hydrogen-electric systems.
- Shorter charging times.
- Lighter than battery-fuelled alternatives, increasing carrying capacity.
- Heavy-duty RTG cranes which are required to lift major loads, increasing the efficiency of hybrid over diesel.
- Liquid hydrogen vehicles tend to have fast refuelling times, increasing work efficiency and allowing for longer operating times.
- A successful application of hydrogen for CHEs would set an industry standard and be the first of its kind.

In Victoria, the Port of Melbourne and the Port of Geelong would be the most realistic takers of the Hydrogen.

In order to calculate the hydrogen demand, we also must assume that CHE’s operate at a thermal efficiency of 35% with diesel engines and hydrogen fuel cells would operate at 50%. Based on an approximation for the hydrogen demands for the Port of Melbourne and Geelong combined, approximately 1,407 t H\(_2\)/year would be required to meet the currently energy consumption for their CHEs. These assumptions were based on a 2019-20 Port of Long Beach air emissions report which quantified the total energy consumption of CHE. Using twenty-foot container units (TEU) it was determined that the Port of Melbourne is approximately 35% the size of the Port of Long Beach.

Using the values attained as well as a rough function for the energy consumption of CHE, it was determined that equipment such as forklifts and RTG cranes account for approximately

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\(^{36}\) CMB Tech, [https://cmb.tech/hydrotug-project](https://cmb.tech/hydrotug-project)
3% and 7% of the annual energy consumption. The contribution of forklifts and RTG cranes to the total energy expenditure was determined by their fractional output of CO₂ emissions compared to other CHEs. Based on the above calculations, forklifts and cranes would require approximately 37 t H₂ and 86 t H₂ respectively.

**Case study**

Near Zero Emissions (NZE) RTG Crane by Mitsui E&S Machinery developed to push for the decarbonisation of the Port of Kobe.

The Port of Kobe are working in conjunction with Mitsui to begin the development and implementation of hydrogen fuel cell CHE. They are introducing a sustainable hydrogen supply infrastructure with a major focus on hydrogen fuelled RTG cranes. The port authorities decided to introduce the NZE cranes since the engine capabilities in conjunction with a hydrogen FC make it possible to produce net zero emissions by replacing the diesel engines. Kobe International Container Terminal is the first port to implement the net zero RTG cranes (as shown in Figure 13) and is estimated to be introduces in May 2022.

![Mitsui's RTG Crane](image)

*Figure 13. Mitsui's RTG Crane.*

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2.3.4. Aviation

The aviation industry is one of the main contributors to the global carbon emissions. Hydrogen, particularly in its liquid form, is the only fuel that can replace the conventional fossil fuels for long-haul aircraft operations. However, this is still being trialled by companies such as Airbus. Nevertheless, as seen in Figure 14, there is also significant potential for hydrogen use in the short to mid-term timeframe in the airport’s ground support equipment which includes the baggage tractors, aircraft tugs, GPUs, and forklifts that can be expected in Victoria.

![Figure 14. Overview of the aviation categories and their estimated annual hydrogen demand potential.](image)

2.3.4.a Aircraft

In recent years there has been an acceleration in the development and research of the potential use of hydrogen in aviation. Companies such as Airbus have made strides in the development of the world’s first zero-emissions commercial aircraft under their new ZEROe project which would use liquid hydrogen and hydrogen fuel cells as their primary source of propulsion. Such investments into the potential for hydrogen come due to the increase in demand for the decarbonisation of aviation, with 3.2 times more energy being consumed by the industry globally than the entire country of Australia.39

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39 *Opportunities for hydrogen in commercial aviation, CSIRO.*
Based on Commonwealth scientific and industrial research organisation (CSIRO)’s research into the potential for hydrogen in aviation, there is great potential for the development of ‘Cryoplanes’ (jet engines which combust pure hydrogen). Some companies have developed concept aircrafts which are fully reliant on hydrogen as their primary source of fuel, however, these projects are in their infancy. Hydrogen seems like the most likely future fuel source for the aviation industry; however, most concepts are not expected to be ready for commercial use until approximately 2035.

Case study

Airbus ZEROe- The development of the world’s first zero-emissions commercial aircraft.  

In 2022, Airbus launched their zero-emissions initiative with the aim to test hydrogen combustion technology. The first concept uses two hybrid-hydrogen turbofan engines to provide thrust with the liquid hydrogen distribution and storage system being in the rear pressure bulkhead. The second concept uses two-hybrid-hydrogen turboprop engines as does the BWB with the location of the storage and distribution systems as well as the shape of the aircrafts providing the biggest differences.

With the concept aircrafts being in their infancy, there is limited information about the efficiencies of these projects. However, the development of these concepts illustrates the clear intention to decarbonise Airbus as well as the aviation industry.

![Figure 15. Airbus ZEROe concept hydrogen aircrafts.](image)

2.3.4.b Airport operations

Although applications for liquid hydrogen in aviation is still in its early technological infancy and unlikely to be commercialised for many years still, there are more near-term opportunities (up to 2030) for liquid hydrogen to be harnessed as a fuel for aircraft ground support equipment (GSE).  

GSE broadly incorporates equipment such as baggage/cargo tractors, belt loaders, aircraft tugs, generators/GPUs, forklifts, etc.

Using hydrogen fuel cells as a replacement fuel for GSE applications, which are conventionally powered by liquid fuels and batteries, has the potential to provide a range of benefits including:

- Longer-term cost savings of operations.
- Reduced dependency upon the import of liquid fuels if green liquid hydrogen is produced on-site.

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41 Opportunities for hydrogen in commercial aviation, CSIRO, 2020
• Providing a starting point to develop regulatory frameworks, safety standards and operating procedures for future applications of hydrogen in aviation.
• Quick refuelling times of tugs/tractors of 3-4 minutes.
• Up to 4 hours of continuous operations time of tugs/tractors.
• High energy efficiency of fuel cells for GSE of approximately 45%.

One of the fundamental challenges for the mainstream uptake of fuel cell GSE is supply limitations due to the scale of hydrogen required. However lower risk options and “easy wins” can be initially achieved with off-the-shelf fuel cell equipment including forklifts and stationary power units.

In Victoria, the potential sites for hydrogen-powered GSE applications are mainly at the Melbourne International Airport. Other airports such as Avalon, Essendon, Moorabbin, and Bendigo Airport are much smaller in operational volumes, hence not quantified in this analysis.

The approximate potential liquid hydrogen demand for GSE was calculated for Melbourne International Airport based on a study of Dallas/Fort Worth Airport undertaken by CSIRO. Calibrated by a scaling factor of 38% (based on annual aircraft operations) to account for size differences between the two airports, Melbourne Airport was assessed to have an annual potential demand of over 600 t H₂/year for GSE applications.

Case study

Plug Power is a company that develops hydrogen fuel cells for e-mobility in material handling applications. In partnership with GSE manufacturing company, Mulag, the companies piloted fuel cell cargo tractors at Hamburg Airport in Germany.

The success of the pilot project resulted in the procurement of 60 tow tractors by Hamburg Airport (shown in Figure 16) and the construction of an on-site hydrogen refuelling station.

Plug Power has since commenced trials of the fuel cell GSE at other international airports with promising outlooks for further adoption of the technology.

Figure 16. Mulag cargo tractors at the Hamburg airport.
2.4. Gas grid injection

Victoria is one of the largest consumers of natural gas in the eastern coast of Australia. Natural gas is being used for various applications such as domestic use, industrial heating, power production and as a commodity. For Victoria to achieve the 2050 net-zero emissions target, decarbonisation of applications that are reliant on natural gas is essential.

Blending of green hydrogen into the natural gas grid is a potential solution to decarbonise the natural gas grid which cascades into decarbonising end-uses such as the domestic use, industrial heating, and power production which account for nearly 99% of the gas use in Victoria.\(^{44}\) Hydrogen blending has been highlighted as an important lever by numerous policy makers in several countries. Historically, town gas (up to 60% hydrogen) from the gasification of coal was injected into the gas grid in Victoria and was phased out in favour of natural gas from 1969 due to the cost considerations.\(^{45}\) With renewed interest in pursuing decarbonisation, green hydrogen is expected to play a key role in substituting natural gas use in the coming decades. In Victoria, gas grid operators such as Australian gas infrastructure group (AGIG) are considering injecting 10 vol% green hydrogen into the gas grid by 2030 amounting to a cumulative demand of 41,000 t H\(_2\)/year (shown in Figure 17) and eventually have the entire gas grid on green hydrogen over the longer term.\(^{46}\)

Hydrogen injection into the gas grid presents short- and long-term benefits such as:

- Short term reduction in emissions from the grid.
- Long term transformation into a 100% hydrogen grid.
- Gas network can be a cost-effective medium for hydrogen transport.
- There is an opportunity for greater coupling between the electricity and gas networks to create a single integrated energy delivery system once 100% hydrogen is achieved.

![Figure 17. Overview of gas grid injection categories and their estimated annual hydrogen demand potential.](image)


\(^{46}\) Achieving 10% Renewable Hydrogen in Australian Gas Networks, AGIG, 2020.
An alternative opportunity for hydrogen in this domain would be in the development of hydrogen microgrids over the longer term in the remote and rural areas, where the regional network on 100% hydrogen can serve for domestic uses, industrial heating and for dispatchable power generation. This is pursued as a long-term opportunity when a significant cost reduction on hydrogen is expected. Demonstrations of the concept are underway in Western Australia in the rural town of Denham 800km north of Perth.\textsuperscript{47}

In the established gas networks, however, blending of 10 vol% of hydrogen is an immediate prospect. The hydrogen demand (10 vol% blend) for Victoria’s gas networks would be up to 42,000 t H\textsubscript{2} by 2030. The nearest injection point from Monash University is at Dandenong (17km) which is a suitable location for hydrogen off-take (as shown in Figure 18).

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{Figure18.png}
\caption{Main pipelines and injection sites in the Victorian gas transmission network published by Australian energy market operator (AEMO). \textsuperscript{48}}
\end{figure}

\textsuperscript{47} ARENA, Horizon power denham hydrogen demonstration.
\textsuperscript{48} Victoria gas planning report, AEMO, 2021
Case study
Gasunie is working in collaboration with the Dutch government to operate and develop a national hydrogen network and began blending trials for the network (as shown in Figure 19). The company says they are planning to construct the first large-scale retrofit of natural gas lines with 100% hydrogen compatible pipes. Gasunie is intending to use 85% of their existing pipelines to save cost, with the projected price of the project being US$1.77 billion.\(^{49}\) The project should allow for a Dutch “hydrogen hub” in Europe. The intention of the pipeline is to reach NZE whilst also reducing future costs for the transport and boost the development of the hydrogen market across Europe by connecting the suppliers to their potential consumers. The project is scheduled for completion in 2027.

![Gasunie’s hydrogen blending trials](image)

2.4.1. Heating

Heating contributes to nearly 91% of the total gas use in Victoria.\(^{44}\) It is a significant end use application both in the domestic and industrial sectors. The use of green hydrogen for decarbonising heating through natural gas is a prospect that is being investigated and demonstrated throughout. The potential use of hydrogen for heating purposes in domestic and industrial sectors is detailed below:

- **Domestic Use**- Thermal demands account for approximately 40% of all energy use in Australian households that includes space heating, cooking and hot water production.\(^{50}\) The domestic use of natural gas contributes to nearly 60.5% of the all the gas use in the state.\(^{44}\) The introduction of 10vol% of green hydrogen into the gas grid could enable the decarbonisation of domestic gas use. Therefore, the total potential for hydrogen attributable to the domestic sector is 24,805 t H\(_2\)/year. However, the share of gas based thermal systems are expected to reduce over the longer term due to the higher efficiency of the electric systems. Moreover, the rebates by the state and the federal governments towards electric thermal and solar PV systems are expected to further expedite the growth in favour of the electric systems.

- **Processing/ Industrial**- A 2019 Australian Renewable Energy Agency (ARENA) study demonstrates that the total energy use for heating in manufacturing in Victoria is 60PJ that

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\(^{49}\) The Netherlands to refit natural gas network for pure hydrogen, IHS Markit, 2021.

is nearly 30% of the state’s natural gas use.\textsuperscript{44,51} The main industries in Victoria which have the highest heat demands are the pulp, paper and converted paper industry, beverage and tobacco product manufacturing and food product manufacturing industries. Substitution of the boiler fuel (natural gas) with green hydrogen is a potent option for decarbonisation and this is especially suited for legacy boiler where replacement is not an option. In case of new facilities or boilers, electric alternatives will be favoured due to their higher efficiencies and the better process control. The theoretical demand for hydrogen in the industrial process heating is 12,300 t H\_2/year.

While green hydrogen is a potential option for the substitution of natural gas, its large-scale deployment depends on the cost competitiveness and the growth of the electric alternatives (which have higher thermal efficiencies). Considering the current cost of hydrogen at $5.50/kg corresponding to $38.80/GJ which is considerably higher compared to natural gas which equate to approximately $10/GJ.\textsuperscript{51} However, the hydrogen price is projected to decrease in price considerably beyond 2025 as Australia.

**Case study**

In 2019 the Eusebiuskerk church, shown in Figure 20, started using hydrogen as a source of heating. Large buildings such as the Eusebiuskerk Church is Arnhem have substantial energy requirements for heating and insulation is very challenging. The building will slowly move to 100% hydrogen dependence with initial stages focusing on shifting 50% of all heaters to green hydrogen. Part of the heat demand is currently being filled with hydrogen-based floor heating and natural gas- fired radiant panels. Eventually the panels will use hydrogen as the primary source of fuel.

The project is being led by HyMatters, a Dutch based company which specialize in hydrogen focused sustainable solutions.\textsuperscript{52}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure20.png}
\caption{Eusebiuskerk Church in Arnhem is heated using hydrogen.}
\end{figure}

\textsuperscript{51} Renewable energy options for industrial process heat, ARENA, 2019.
2.4.2. Power generation

Hydrogen may also be utilised for stationary power generation, however due to a lower system efficiency, it is much less favourable than electricity produced directly from other renewable energy sources, such as solar, wind, nuclear for base-load power generation. However, Power-Hydrogen-Power is an important concept that is being considered globally where hydrogen produced from renewables can provide a solution for seasonal storage. This is particularly applicable in situations where the access to pump-hydro and other seasonal generation assets are not available.

In Victoria, hydrogen finds application over the longer-term (beyond 2037) when the fossil fuel-based power plants are retired, which are currently being used for baseload and peak power production. While the renewables (wind and solar) generation are expected to cater to majority of the base load operation with a battery system, hydrogen can play a critical role in providing an alternative for the battery during the period with poor renewable production (night-time and winters). Previous analyses have shown that the use of hydrogen for the off-peak power production over the longer term leads to a lower system LCOE.\textsuperscript{53} The longer-term implementation of hydrogen for such application would also benefit from the significantly lower hydrogen costs.

Hydrogen also fits the niche of peak power production. Some peaking plants in Victoria are gas based and are being considered to run on a 10 vol % blend with green hydrogen over the short-term. The peak power production is attractive as the spot power prices tend to be higher during the peak times where the relatively higher cost of hydrogen may not have a significant effect on market competitiveness. An example of peaking plant is the Newport power station near Melbourne which is a 500 MW open cycle gas turbine (OCGT) plant. Figure 21 shows large variability in the capacity factor profile year-on-year which is typical for peaking power plants. From the hydrogen consumption point of view, the peaking power plants due to intermittency of their operation would not be a continuous off-taker. Additional consideration for hydrogen off-take for peak and seasonal off-take would be hydrogen storage. Boil-off management becomes an important issue in case hydrogen is procured in the liquid form. Therefore, for peak and seasonal power production, piped hydrogen or on-site hydrogen production may be more beneficial.

Victorian power plants consume 8.5% of natural gas for power production.\textsuperscript{44} Considering a 10% blend of hydrogen to start with, the theoretical potential for hydrogen is expected to be in the range of 3,485 t H\textsubscript{2}/year. The demand is projected to grow over the longer term as natural gas is gradually phased out.

\textsuperscript{53} ITP Analytics, Australian national energy market insights, 2022.
Case study

Smurfit Kappa is a leading paper and packaging manufacturer that is implementing the world’s first industrial-scale hydrogen gas turbine power generation facility at its Saillat Paper Mill (shown in Figure 22) in France as a part of the European Commission sponsored HYFLEXPOWER project.

The aim of the project is to demonstrate the feasibility of onsite renewable hydrogen generation and storage to power up to 100% of the natural gas demand for combined heat and power.

The project started in May 2020 and will run for 4 years, costing approximately 15 million euros. Engie is a key project partner, responsible for developing the plant concept for hydrogen storage and supply.55

Figure 21. Capacity factors for the Newport power station compared with the spot prices over 20-years.54

Figure 22. Engie Solutions’ Smurfit Kappa pulp-and-paper industrial site in Saillat-sur-Vienne.

55 Smurfit Kappa to participate in world’s first project on hydrogen energy storage, Smurfit Kappa, 2020.
2.5. Commodity

Hydrogen has important applications for use as a raw material in the process industry spanning from the manufacture of ammonia for the use in the fertilizer industry, various hydrogenation reactions used in the manufacture of chemicals such as methanol, and in the dairy industry for the hydrogenation of fats (e.g., production for margarine). Hydrogen being a reducing agent can replace the natural gas used for the steel manufacture in the Direct reduction of iron (DRI) process. Hydrogen also finds potential use in the process industry as a source of heat for example in the cement kilns.

For this analysis, we are only considering the direct use of hydrogen as a raw material as the heating application of may only be available over the longer term and electrification of heating is much more efficient. In Victoria, steel, fertilizer, and dairy industries are important sectors where hydrogen off-take is possible. These sectors are analysed in detail below:

- **Fertilizers** - Among the fertilizer industries, the ammonia and ammonium nitrate manufacturing sites would be potential off-takers for hydrogen. However, in Victoria, there are a few superphosphate facilities (e.g., Incitec Pivot’s Geelong plant), however, these processes do not require hydrogen as a feedstock. That said, there are facilities in Port Anthony in Victoria that are commissioning green ammonia for a facility for export purposes at a scale of 75,000 t NH₃/year that requires approximately 13,000 t H₂/year. Currently the hydrogen for the Port Anthony facility is being produced from biomass gasification due to lower hydrogen cost (~$2/kg). On the other hand, green hydrogen (generated from electrolyser) must become more cost competitive in the future to be viable to produce commodities such as ammonia.

- **Dairy** – Victoria boasts of the largest dairy industry in Australia with more than 54 processing sites across the state. For most dairy manufacturers, 80% of the energy needs are for thermal processes (i.e., heating and drying milk, hot water for cleaning). Most of the facilities are for milk and milk products (cheese, butter) production and less than 3% are for other products which may include margarine production. While green hydrogen has a potential application, for a highly commoditised and a competitive market, green hydrogen is likely to find off-takers over the longer term when the production costs have significantly reduced.

- **Iron and Steel** – The iron and steel industry one of the large sectors in Australia and accounts for 2% of Australia’s carbon emissions. Apart from the heat production, hydrogen can be used to replace natural gas as the reducing agent in Direct Reduction of Iron (DRI) process. The DRI process would require 136 kg of H₂ per ton of steel. Currently, the steel price from the hydrogen DRI process is at least 20-30% more than the market price. The price of hydrogen DRI steel would be at cost parity with the conventional steel price when the price of renewables is at $20/MWh. In Australia, the steel production centres are in NSW and SA. The Victorian steel industry is only focussed on the manufacture of finished steel production, therefore, the demand for hydrogen is minimal.

The use of hydrogen as a raw material for commodity production is required on a larger scale and has potential over the longer term when costs of hydrogen have significantly reduced.

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56 Hydrogen opportunities for dairy industries in Australia and Uruguay, Hycel Deakin University, 2021.
57 The destructive potential of Green steel, Rocky Mountain Institute, 2019.
Case study

Yara fertilizers in the Pilbara region (shown in Figure 23) are commissioning a green ammonia facility to replace their existing hydrogen from natural gas. The site aims to produce 800 kt of green ammonia per annum. The green ammonia will be produced from an on-site electrolyser and renewables production facility. The electrolyser is commissioned in three stages from 10 MW in 2023 to over 1000 MW by 2030 to completely substitute the steam methane reformer.

Figure 23. Yara fertilizers green ammonia facility in the Pilbara, Western Australia.

2.6. Summary of off-taker mapping and quantification

The off-taker mapping and quantification aims to identify the various off-take applications across Victoria spanning across three main categories – mobility, gas blending, and commodity. The overall hydrogen demand per application is quantified based on the inputs from the stakeholder organisations and complemented by desktop research. The quantification is done in two steps. Firstly, the overall hydrogen demand was calculated from the current diesel consumption for the application and applying a fuel conversion factor. The fuel conversion factors that are used in this study are detailed in Appendix A1. Demand assumptions summary. These have been obtained from OEMs or internal estimates. Secondly, the anticipated market share is applied to the application which is based on the insights gleaned from the various stakeholder interactions.

This section discusses the market insights on the various applications particularly the projected market share of hydrogen for each off-take application. Further, the demand quantification is also discussed from off-take timeframe and location perspectives. These insights aid in prioritising and screening the off-taker applications for the Victorian Renewable Liquid Hydrogen Supply Hub at the Monash Precinct.

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58 Yara Pilbara renewable ammonia feasibility study, ARENA, 2020
2.6.1. Market scoping

Hydrogen offers a competitive decarbonisation option for certain niche applications where it is expected to dominate the market against the competing technologies. The anticipated market share is based on the technical competitiveness and the insights from the stakeholder interactions. Table 5 presents the projected market share for hydrogen technologies ranked as low market share (less than 20%), medium market share (close to 50%), and high market share (more than 80%) as indicated by red, yellow, and green symbols, respectively.

Table 5. Projected hydrogen market share for each for the identified off-take applications.

<table>
<thead>
<tr>
<th>Application</th>
<th>End-use</th>
<th>Potential H₂ market share</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Mobility</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Public transport buses</td>
<td>[Red icon]</td>
<td></td>
</tr>
<tr>
<td>Regional trains (V-line)</td>
<td>[Yellow icon]</td>
<td></td>
</tr>
<tr>
<td>Concrete trucks</td>
<td>[Yellow icon]</td>
<td></td>
</tr>
<tr>
<td>Waste trucks</td>
<td>[Yellow icon]</td>
<td></td>
</tr>
<tr>
<td>Long haul mobility</td>
<td>[Green icon]</td>
<td></td>
</tr>
<tr>
<td>Dairy trucks</td>
<td>[Green icon]</td>
<td></td>
</tr>
<tr>
<td>Forklifts</td>
<td>[Red icon]</td>
<td></td>
</tr>
<tr>
<td>Port operations</td>
<td>[Yellow icon]</td>
<td></td>
</tr>
<tr>
<td>Airport GSE</td>
<td>[Yellow icon]</td>
<td></td>
</tr>
<tr>
<td><strong>Gas grid injection</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Domestic heat</td>
<td>[Red icon]</td>
<td></td>
</tr>
<tr>
<td>Industrial heat</td>
<td>[Red icon]</td>
<td></td>
</tr>
<tr>
<td>Power (peak/seasonal)</td>
<td>[Green icon]</td>
<td></td>
</tr>
<tr>
<td><strong>Commodity</strong></td>
<td>Green ammonia</td>
<td></td>
</tr>
</tbody>
</table>

Legend: [Red icon] Low market share (<20%); [Yellow icon] Medium market share (~50%); [Green icon] High market share (>80%)
High market share

High market share is expected for the application where green hydrogen holds a definite competitive advantage over other competing technologies. The applications include:

*Long-distance material handling* applications such as long-haul and dairy trucks which due to their payload requirements and operating ranges (~1000 km). Moreover, given their long operational cycles, would benefit from quick refuelling offered by hydrogen. Furthermore, with the development of liquid hydrogen fuelled vehicles (with an internal hydrogen vapouriser) would provide additional payload benefits further enhancing FCEVs competitiveness.

*Seasonal and peak power production* is an important application where hydrogen holds a competitive solution. This is the case in locations where seasonal dispatch options such as pumped hydro are not present. The peak power production is attractive as the spot power prices tend to be higher during the peak times where the relatively higher cost of hydrogen may not have a significant effect on market competitiveness.

*Commodity* products such as green ammonia are expected to have a huge demand over the next decade as organisations continue to take concrete steps to decarbonise. Green hydrogen will be a key raw material for producing green ammonia. Further, green ammonia will also play a part in the fertiliser industry which is an important sector for the Australian economy.

Medium market share

*Heavy-duty material handling applications* such as concrete and waste trucks provide good niches for hydrogen due to their long up-time, operational regime that requires long hours of idling and payload handling requirements, however, the market is divided on their adaption due to uncertainties in the refuelling infrastructure in the operational areas.

*Regional trains* particularly those that operate over long ranges would benefit from hydrogen locomotives. Electrification of these lines has traditionally been difficult due to the large capital costs involved in deploying the electric infrastructure. Hydrogen also has a competitive advantage over bio-fuel alternatives where scalability, supply chain feasibility, fuel quality variations are major causes of concern. However, the adoption of hydrogen is subject to the availability of locomotives that suit the Victorian rail network.

*Port and airport operations* could be hydrogen powered as both these sectors would eventually be large consumers for hydrogen (or its derivates) as fuel. Many shipping fleet companies see green ammonia as an attractive carbon-free fuel. Similarly, liquid hydrogen is a competitive solution for aircrafts in the longer term. For operations in both these sectors, hydrogen is nearly as competitive as the electric, however, the considering technologies such as battery-swapping and fast-charging are quickly picking up, hydrogen adoption may be restricted to a particular part of the fleet.

Low market share

*Light-duty material handling applications* such as forklifts on hydrogen are an attractive solution for warehouses with long duty cycles (>12hour). The faster refuelling times for hydrogen would be much beneficial in such cases. However, the share of forklifts operating in a high-intensity duty cycles is expected to be low.

*Public transport buses* and *light motor vehicles* are expected to go towards battery electric vehicles due to higher efficiency and energy recovery during braking. Further, the electric
recharging infrastructure is progressing at a much faster rate in Victoria. Hence the share of FCEV buses is expected to be low.

*Heating* (both domestic and industrial) can be decarbonised through the injection of the hydrogen into the gas grid. This will particularly work well in industrial settings where legacy assets are involved and replacing the existing infrastructure is difficult. However, the higher efficiencies of electric thermal equipment are expected to dominate over the longer term, hence the share of hydrogen for these applications over the longer term is expected to be low.

### 2.6.2. Temporal considerations of demand

![Diagram of various applications and hydrogen flow](image)

Figure 24. Quantified annual demand and associated timescale for commercial adoption of hydrogen for the various applications.

Figure 24 presents the various applications quantified in this study. In Victoria, some of the major applications that have been identified are in the mobility sector which spans across public transport (V-Line trains and buses), long-haul transport (freight and dairy), and heavy duty vehicles (waste trucks, concrete trucks, and forklifts). All of these categories contribute to a total of 350,000 t H$_2$ annually. Among the off-taker categories, long-haul transport is the most significant, contributing to nearly 73% of the demand. Concrete and waste trucks have a combined potential annual demand of ~2,700 t H$_2$ and are well suited for FCEVs due to the long operational uptimes, low average speeds, and the significant auxiliary loads that need to be catered to. Port and airport operations both combined contribute to a demand of 2,000 t H$_2$ due to their significant duty cycles throughout the day, where quick refuelling times give fuel-cell vehicles a competitive advantage.

There is widespread interest in the adoption of hydrogen into the various operations. However, the adoption is subject to factors such as commercial readiness of the technology, supply chain and refuelling infrastructure maturity. The applications have been classified as:
Short-term
Over the short-term, applications such as gas grid injection is expected to be the key off-taker with 10 vol% blends of hydrogen into the network by 2030. Further, several demonstration projects for mobility applications like waste/concrete trucks, buses and forklifts could be facilitated.

Mid-term
Over the mid-term, long-distance vehicles such as long-haul and dairy truck FCEV demonstrations are foreseen to scale up with the development of regional refuelling infrastructure. Moreover, hydrogen trains are foreseen for V-line routes as hydrogen costs become competitive and locomotives customised to the Victorian rail network become available.

Long-term
Commodity, aviation and maritime may develop over the long-term due to the significant cost reduction required hydrogen to be competitive and other competing technology options.

2.6.3. Locational considerations

Figure 25. Expected annual hydrogen off-take locations in Victoria for the various applications.

Figure 25 presents the expected hydrogen off-take locations for the various applications in Victoria. The off-take applications have been categorised based on the location as off-take within the Monash precinct, off-take in the greater Melbourne region and off-take in regional Victoria. Each of these categories are discussed below:
Monash precinct

- The Monash precinct is home to an education and innovation hub, consisting of universities, research institutes, manufacturing sectors etc. The principal applications for off-take in this location would be to facilitate demonstration projects for waste trucks and the inter-campus buses that are operated by Monash University.

Greater Melbourne region

- The gas grid injection is a significant off-taker over the near term. The closest injection point to the Supply Hub is at Dandenong (<20km) which present an interesting off-take prospect.
- The material handling applications around concrete trucks, forklifts and long-haul trucks are important applications in the Greater Melbourne region where off take can be expected through demonstration projects.

Regional Victoria

- The dairy truck operations are located to the dairy farms which are located in the Northern, Southwest, Gippsland regions of Victoria which are at least 250km from the Supply Hub.
- The green ammonia facilities (such as in Port Anthony Renewables) would be in the regional areas which are situated to access large scale renewables and port operations.
3. Off-taker screening

3.1. Off-taker screening methodology

Given the vast array of potential hydrogen applications across a range of sectors in Victoria, an off-taker screening assessment was undertaken to define a shortlist of suitable off-takers for the Monash Renewable Liquid Hydrogen Supply Hub. This involved the development of a multicriteria assessment framework to assess the various off-takers against a range of techno-economic metrics, which were then ranked accordingly.

The metrics used for the off-taker screening assessment include:

- **Application suitability** – the suitability of hydrogen for the defined application based upon whether other decarbonisation options exist and how feasible or competitive hydrogen is compared to other solutions.
- **Location** – the proximity of off-takers from the Monash University precinct to account for hydrogen transport, logistical considerations, environmental impact, and potential competition from other hydrogen supply hubs in the future.
- **Demand profile** – how closely the total demand quantity corresponds with the amount of hydrogen that can be supplied from the Monash precinct and the level of demand flexibility from off-takers.
- **Commercial Readiness Index (CRI)** – the commercial readiness of the hydrogen technology given that many technologies are still at the demonstration level and therefore demand may be relatively low until the application reaches full technological and commercial maturity.
- **Off-taker interest level** – the level of interest expressed from stakeholder engagement meetings and how far into the future it is anticipated that there will be sufficient demand.

The definitions for each of the criteria metrics are described in Table 6.
<table>
<thead>
<tr>
<th>Scoring Criteria</th>
<th>Demand profile</th>
<th>Commercial Readiness Index (CRI)</th>
<th>Location</th>
<th>Application suitability</th>
<th>Off-taker interest level</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Low</strong> (Score: 1)</td>
<td>Greater than 10,000 tH₂ annually and/or has limited flexibility</td>
<td>CRI 1: Hypothetical commercial proposition</td>
<td>State level: off-takers only exist in parts of Victoria</td>
<td>Not desirable against other alternatives</td>
<td>Interest is very low (potential interest beyond 2035)</td>
</tr>
<tr>
<td><strong>Medium</strong> (Score: 3)</td>
<td>Between 2,000 and 10,000 tH₂ annually and/or has moderate flexibility</td>
<td>CRI 2: Small-scale commercial trial</td>
<td>Regional level: off-takers are located within the Greater Melbourne district</td>
<td>Competitive with other alternatives</td>
<td>Some expressed interest for near-term future use (beyond 2025-2035)</td>
</tr>
<tr>
<td><strong>High</strong> (Score: 5)</td>
<td>Less than 2,000 tH₂ annually and/or has high flexibility</td>
<td>CRI 3: Ready for commercial scale-up</td>
<td>Local level: Off-takers are located within the Monash Precinct</td>
<td>Favorable against other alternatives</td>
<td>Current interest or demand (before 2025)</td>
</tr>
</tbody>
</table>
3.2. Off-taker screening assessment

For each of the assessment metrics, the range of hydrogen applications were scored according to the extent that they met the criteria definitions specified for each metric. The key off-takers were then determined from the total scores, derived from the sum of the scores given for each metric (Table 7).

Table 7. Multicriteria assessment scoring allocation for different off-takers.

<table>
<thead>
<tr>
<th>Scoring criteria</th>
<th>Demand profile</th>
<th>Commercial Readiness Index (CRI)</th>
<th>Location</th>
<th>Application suitability</th>
<th>Off-taker interest level</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waste trucks</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>3</td>
<td>3</td>
<td>21</td>
</tr>
<tr>
<td>Buses</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>3</td>
<td>3</td>
<td>21</td>
</tr>
<tr>
<td>Forklifts</td>
<td>5</td>
<td>5</td>
<td>3</td>
<td>5</td>
<td>3</td>
<td>21</td>
</tr>
<tr>
<td>Gas grid injection</td>
<td>5</td>
<td>5</td>
<td>3</td>
<td>3</td>
<td>5</td>
<td>21</td>
</tr>
<tr>
<td>Trains</td>
<td>5</td>
<td>5</td>
<td>3</td>
<td>5</td>
<td>1</td>
<td>19</td>
</tr>
<tr>
<td>Concrete trucks</td>
<td>5</td>
<td>3</td>
<td>3</td>
<td>5</td>
<td>3</td>
<td>19</td>
</tr>
<tr>
<td>Long haul transport</td>
<td>5</td>
<td>3</td>
<td>3</td>
<td>5</td>
<td>3</td>
<td>19</td>
</tr>
<tr>
<td>Airport GSE</td>
<td>5</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>1</td>
<td>15</td>
</tr>
<tr>
<td>Dairy trucks</td>
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<td>3</td>
<td>1</td>
<td>3</td>
<td>1</td>
<td>13</td>
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<tr>
<td>Port operations</td>
<td>5</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>1</td>
<td>13</td>
</tr>
<tr>
<td>Commodity</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>9</td>
</tr>
</tbody>
</table>

The assessment of the hydrogen off-taker applications demonstrated that many performed well against certain metrics and poorly against others. Most off-takers have suitable demand profiles which are either well-matched for the anticipated amount of supply from the Monash Precinct or would have a flexible demand that can substitute a portion of operations based upon the amount of hydrogen that is available.

Off-taker interest level was the lowest scoring metric across the range of applications. However, it should be noted that scoring for this metric is perhaps the most ambiguous as it is limited to the stakeholders engaged and scope of work undertaken within this assessment alone, and therefore does not accurately capture the entire market and other potential off-takers that were not directly engaged with during stakeholder meetings.

Based upon the multicriteria assessment framework developed and used for this study, the screening process identified gas injection, forklifts, waste trucks, and buses as the key hydrogen off-takers in Victoria (Figure 26). Other mobility-related applications including regional trains, concrete trucks, and long-haul transport, also scored relatively well in the screening process. The lower-scoring categories included airport GSE, dairy trucks, port operations, and commodity, mostly due to poor application suitability for hydrogen or low off-taker interest levels.
3.3. Off-taker demand estimation for scenario modelling

The Victorian Renewable Liquid Hydrogen Supply Hub aims to serve as a platform to accelerate the growth of the hydrogen ecosystem in Victoria by facilitating demonstration projects for multiple applications across the region. The first step following the off-taker screening assessment is to estimate the potential total demand (annually) the Supply Hub can cater towards over the near term. These demand estimates were then used to feed into Prosumer modelling and subsequently used to calculate the final delivered LCOH at end-use sites for each of the hydrogen applications, which is covered in Section 5.

Table 8 shows the breakdown of the hydrogen demand from the various shortlisted hydrogen applications. The number of units (e.g. forklifts, trains, etc.) allocated was approximated to provide a spread of hydrogen demand across the applications, and based upon an achievable outcome considering commercial readiness of the technologies and their demand profiles. For example, forklifts have a high commercial readiness and a relatively low fuel consumption per vehicle, and therefore a value of 200 units was allocated to this application (equating to 8% of the total available hydrogen supply). V-line trains have a significantly higher per unit fuel demand than forklifts, so 2 units were considered (representing the highest demand of 29% of the total available hydrogen supply). For each of the remaining mobility applications, 40 units were allocated, each of which has a total demand which corresponds with its operational use and demand profile.

Approximately 11% of the hydrogen available from the Hydrogen Supply Hub was allocated towards gas grid injection at AGIG’s gas injection facility at Dandenong. Although the gas grid injection is a flexible off-take application, the 11% demand towards gas grid injection is 8% in excess of the demand required to substitute 10% of Monash’s total natural gas demand at the Clayton campus. Using this approach, the total demand for hydrogen required is 5 t/day.
(~1800 t/year) which also offers economies of scale benefits (compared to other smaller test facilities) for the electrolyser and the storage assets required for the facility.

Table 8. Expected demand from the various shortlisted end-uses in the off-taker assessment of the study.

<table>
<thead>
<tr>
<th>Application</th>
<th>Parameter</th>
<th>Number of units</th>
<th>Demand per unit (tonnes)</th>
<th>Annual H₂ quantity (tonnes)</th>
<th>% of annual supply</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas injection</td>
<td>Monash total gas demand</td>
<td>(-)</td>
<td>N/A</td>
<td>51</td>
<td>3%</td>
</tr>
<tr>
<td></td>
<td>Additional for AGIG network</td>
<td>(-)</td>
<td>N/A</td>
<td>155</td>
<td>8%</td>
</tr>
<tr>
<td>Forklifts</td>
<td>No. forklifts</td>
<td>200</td>
<td>0.7</td>
<td>139</td>
<td>8%</td>
</tr>
<tr>
<td>Waste trucks</td>
<td>No. waste trucks</td>
<td>40</td>
<td>2.7</td>
<td>109</td>
<td>6%</td>
</tr>
<tr>
<td>Trains</td>
<td>No. trains</td>
<td>2</td>
<td>269</td>
<td>538</td>
<td>29%</td>
</tr>
<tr>
<td>Buses</td>
<td>No. buses</td>
<td>40</td>
<td>6.7</td>
<td>270</td>
<td>15%</td>
</tr>
<tr>
<td>Long Haul trucks</td>
<td>No. long haul trucks</td>
<td>40</td>
<td>11.3</td>
<td>454</td>
<td>25%</td>
</tr>
<tr>
<td>Concrete trucks</td>
<td>No. concrete trucks</td>
<td>40</td>
<td>2.7</td>
<td>109</td>
<td>6%</td>
</tr>
</tbody>
</table>
4. Scenario modelling and optimisation

4.1. Modelling approach

The scenario modelling and system configuration optimisation for the Victorian Renewable Liquid Hydrogen Supply Hub at the Monash precinct utilised Engie Impact’s in-house modelling software, Prosumer, which is an energy system optimisation tool with the goal of reducing emissions and minimising the total cost of ownership (TCO).

The TCO is optimised based upon the defined energy technologies and system configuration, energy demand profiles, and the techno-economic parameters and constraints of the technologies that are input into the model (Figure 27). These parameters include:

- CAPEX costs of infrastructure and installation,
- Variable and fixed OPEX costs for operation and maintenance,
- Electricity and fuel costs,
- Subsidies and taxes (e.g. cost of carbon),
- Production, consumption, and capacity constraints.

The techno-economic assumptions used are based upon the most recent science-based information available, cross-checked between different scientific research reports from academic institutions, research organisations, government bodies, and internal assumptions from Engie (described in Appendix A3. Techno-economic assumptions summary).

Outputs from Prosumer are post-processed in excel for a detailed financial analysis and competitiveness assessment, calculating KPIs such as net present cost (NPC), marginal abatement cost (MAC), levelised costs of energy (LCOE), and levelised cost of hydrogen (LCOH).

Figure 27. Schematic of the Prosumer modelling methodology specifying required inputs and outputs.
Figure 28. Prosumer model topology for the Victorian Renewable Liquid Hydrogen Supply Hub.

The system configuration for the Victorian Renewable Liquid Hydrogen Supply Hub is designed for the simultaneous production of liquid hydrogen and the liquid nitrogen (as shown in Figure 28). The energy supply chain consists of electricity supply sources which feeds into the electrolyser for the hydrogen production and the nitrogen pressure swing adsorption (PSA) column for nitrogen production from air. The nitrogen and hydrogen produced are fed into an integrated liquefaction unit for simultaneous liquid hydrogen and liquid nitrogen production which can be stored or dispensed as required.

The modelled energy supply chain has several features incorporated to obtain the lowest possible TCO while contextualising it to the location of the Supply Hub.

Firstly, the electricity supply is provided with three options:

1. Electricity from a mix of utility-scale solar PV and wind and an off-site battery energy storage system (BESS);
2. Electricity from roof-top solar PV and a behind-the-meter small scale BESS;
3. Electricity from the non-renewable grid electricity combined with self-surrendered large-scale generation certificates (LGC).

Options (1) and (3) in the electricity supply come with additional tariffs such as network and market charges and rolling peak demand charges. The model is setup for the optimisation to select the least cost option or a combination of options that offers the lowest cost of the supply to meet the end demand of hydrogen and nitrogen on an hourly basis.

Secondly, the liquefaction unit will run all year round to avoid start-up and shut-down losses and is capable of operating in load range of 40% to 100%. Further, the optimisation would decide on the ideal dispatch from the liquefier to have the least TCO. The operation of the electrolyser and the PSA, being upstream of the liquefaction unit, are considered to operate flexibly synchronising with the liquefier operation.
Finally, apart from electricity storage options, storage is also provided for the liquid hydrogen and liquid nitrogen, providing additional buffer option to absorb the supply during peak renewable production periods to minimise renewable curtailment. The synchrotron’s existing 72t liquid nitrogen tank is considered as an existing asset, but the solver is left with the choice to deploy additional nitrogen storage if required.

Based on all these options provided, the Prosumer tool provides the supply chain configuration, along with the sizing and the dispatch with the least TCO for the Victorian Renewable Liquid Hydrogen Supply Hub.
5. Results and discussion

5.1. Technical and economic KPIs

5.1.1. Asset sizing

Optimal asset sizing for the Hydrogen Supply Hub was modelled using Prosumer for different renewable coincidence factor (RCF) scenarios, i.e. 54%, 64%, 73%, 82%, 91%, and 98.2% utility-scale RES contributions. The RCF is the percentage of energy demand which is instantaneously met on an hourly base from renewable energy. The remaining electricity is supplied by non-renewable grid electricity with LGCs to ensure 100% green energy supply (Figure 29).

The total electricity demand for the Supply Hub is approximately 160,000 MWh, or an average of 18MW baseload. While a higher RCF indicates increased hourly matching with the renewable electricity supply, the grid electricity with LGC is considered green only on an annual basis. The scenario-based approach provides a range of options to decide on the most cost-effective electricity supply configuration for the Supply Hub.

![Green electricity supply (MWh)](image)

Figure 29. RCF scenarios and total electricity supply for each scenario as optimised by Prosumer.

Figure 30 provides the sizing of the various assets in the optimised energy supply chain as a function of the increasing RCF. Observations from the modelling show that both utility scale solar and wind assets increase in size as the RCF increases, with each renewable energy asset being sized for an optimal mix of clean energy supply. No roof-top PV installation is recommended for the Supply Hub due to the lower capacity factors and relatively high per-unit cost compared to the utility-scale assets.

Furthermore, the optimised electrolyser sizing ranges from 13.5 to 16.5 MW, depending upon the RCF scenario which is dictated by the operation of the liquefaction unit and the availability of the hydrogen storage. The liquefaction unit ranges from 9.5 to 11 MW across the RCF scenarios which is dispatched between 40-100% of operation based on the hourly availability of renewable energy.
The major factor of difference with increasing RCF is the increase in storage assets sizing. Off-site Li-ion battery installation is recommended only when higher RCF (>90%) are required, i.e. 59 and 95 MWh storage sizes for 91% and 98.2% RCF, respectively. This is because the available on-site storage (liquid nitrogen and liquid hydrogen) is deemed sufficient to capture the excess renewables to reduce the curtailment.

Furthermore, no additional LN$_2$ storage assets are required apart from the existing 72 t storage tank at the Synchrotron. However, LH$_2$ storage size increases for the highest RCF scenarios to cater for the higher variability and intermittency of energy supply from renewable assets. For example, the 98.2% RCF scenario has significantly higher LH$_2$ storage capacity (95 t) compared to the lower RCF scenarios (47-59 t).

5.1.2. Capital and operational expenditure

The capital expenditure (CAPEX) and operational expenditure (OPEX) were calculated for each of the RCF scenarios and shown in Figure 31. Since the electricity supply from the renewables will be supplied through a power purchase agreement, the CAPEX will be borne by the utility supplier and only an OPEX charge is applicable. Therefore, the total CAPEX is only comprised of LH$_2$ and LN$_2$ assets installed at the Supply Hub.
The CAPEX associated to the LH$_2$ production varies significantly, ranging from $48$ million under the 54% RCF scenario to $54$ million in the 98.2% scenario, which is mainly due to the difference in LH$_2$ storage sizes. The LN$_2$ CAPEX however remains consistent at $23$ million across scenarios due to the consistent sizing of LN$_2$ production assets and storage assets. The combined CAPEX costs range from $71$ million to $77$ million, with the costs increasing according to the RCF (Figure 31). As expected, the least CAPEX is required for the case with the least RCF.

The OPEX on the other hand contains three components, i.e., the fixed OPEX, the variable OPEX, and the carbon compensation cost. Given that higher RCF scenarios require higher CAPEX, the fixed OPEX (comprised of the operational and maintenance of the equipment) also increases with a higher RCF due to larger asset investment. In contrast, variable OPEX decreases according to a higher RCF since variable OPEX is primarily comprised of electricity supply charges including energy, network, and market charges from the various electricity supply sources. Further, as expected, with increasing RCF the carbon compensation cost (purchase of LGCs) decreases due to the reducing import from non-renewable grid electricity. The total OPEX generally decreases as the RCF increases, with a range from $25$ million to $30$ million including the cost of carbon (purchase of LGCs) across the scenarios.
5.1.3. Annualised and net-present cost (NPC) comparison

Based upon a 25-year discounted cashflow of the abovementioned CAPEX and OPEX, the total net present cost ranges from $359 million to $405 million, assuming a weighted average cost of capital (WACC) at 7% and excluding the cost for carbon compensation. The additional net present cost for carbon compensation ranges from $1 million in the 98.2% RCF scenario to $25 million in the 54% scenario (Figure 32). The NPC is low in between the range of 82%-91%, and the least NPC obtained for the case of 91% RCF where the higher CAPEX (compared to the lower RCF) is compensated by the lower variable OPEX due to the lower cost of electricity from the renewables and the lower cost for carbon compensation.

The resulting annualised costs, ranges from approximately $32 million/y to $36 million/y, including the carbon compensation cost. The annualised and net present cost are lowest for the 91% RCF scenario and highest for 54% RCF. This fact reiterates the importance of reducing the annual OPEX to reduce the total costs incurred over the lifetime of the project. However, at even higher RCFs the CAPEX contribution increases more than compensated by the OPEX savings from the increase in renewable energy supply. Therefore, very high (98.2%) and very low (54%) RCF scenarios, are the less cost competitive. The 91% RCF scenario is therefore the most cost-competitive scenario for the Supply Hub from a TCO point-of-view, when requiring a zero carbon and/or carbon-compensated approach.

Figure 32. Net present cost (NPC) and annualised cost for different RCF scenarios.
5.1.4. Levelised cost of hydrogen (LCOH)

The LCOH is calculated based on the costs that have been incurred to produce a kilogram of liquid hydrogen at the Supply Hub. The calculated LCOH ranges from approximately $14-16/kg H₂ (Figure 33) due to the varying investments in the hydrogen assets with increasing RCF. Further, the LCOH also corresponds with the annualised and NPC, and is underpinned by the levelised cost of energy (LCOE), all of which are the lowest under the 91% RCF scenario and highest under the 54% RCF scenario.

Figure 34 presents the breakdown of the LCOH at the Supply Hub. The CAPEX components of the electrolyser, the liquefier, and the liquid hydrogen storage contribute to less than 20% of the cost of hydrogen. The CAPEX allocation for the liquefaction unit is split between hydrogen and nitrogen on a mass-basis, according to the annual production of LH₂ and LN₂.

The OPEX associated with the electrolyser electricity consumption is the most significant contributor to the hydrogen production, being more than 47% of the total LCOH, followed by the electricity consumption for the hydrogen liquefaction (16kWh/kg H₂), being more than 32% of the total LCOH. The carbon compensation cost only contributes to approximately 3% of the LCOH in the 91% RCF scenario.
5.1.5. Sensitivity analysis

A sensitivity analysis was also undertaken for the LCOH of the Supply Hub for the different RCF scenarios to cater for the range of uncertainty in techno-economic assumptions used. Two cases, i.e. a favourable case (case 1) and an unfavourable case (case 2), were defined to evaluate and quantify the sensitivity of key techno-economic metrics to factors such as CAPEX fluctuations, commodity prices, weighted average cost of capital (WACC), and carbon compensation prices. The cases, as summarised in Table 9, considered the co-dependencies that exist within the price fluctuations of decarbonisation technologies.

Figure 34. LCOH breakdown for the 91% RCF scenario.
Table 9. Approach for the sensitivity analysis.

<table>
<thead>
<tr>
<th>Description</th>
<th>Case 1: Favourable case</th>
<th>Case 2: Unfavourable case</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Technology CAPEX</strong></td>
<td>A favourable case enables renewables adoption owing to cost competitiveness. This is designed to isolate the impact of technology CAPEX on key techno-economic KPIs</td>
<td>An unfavourable case considers that fossil fuels remain the mainstay of energy mix. This is designed to isolate the impact of technology CAPEX on key techno-economic KPIs</td>
</tr>
<tr>
<td><strong>WACC</strong></td>
<td>Low WACC (5%) was considered for the analysis to reflect any concessional financing that will be available to enable clean energy transition and the adoption of decarbonisation solutions</td>
<td>High WACC (9%) was considered to reflect lack of any concessional financing that will be available for clean energy transition and the adoption of decarbonisation solutions</td>
</tr>
<tr>
<td><strong>Carbon compensation cost</strong></td>
<td>Carbon compensation cost (cost for LGCs) were considered at the higher bound</td>
<td>Carbon compensation cost (cost for LGCs) were considered at the lower bound</td>
</tr>
<tr>
<td><strong>Grid energy costs</strong></td>
<td>High non-renewable grid energy price (network and distribution charges kept constant) estimates were considered, enabling clean energy adoption.</td>
<td>Low non-renewable grid energy price (network and distribution charges kept constant) estimates were considered, hindering clean energy adoption</td>
</tr>
</tbody>
</table>

Figure 35 shows that the largest range of uncertainty emerges for the high and low RCF scenarios. For example, in the 98% RCF scenario the range of uncertainty is $2.5 per kg H₂, with the low and high LCOH values corresponding $16.9 and $14.4 per kg H₂ respectively. The 73% and 82% RCF scenarios have much lower sensitivities to cost and therefore lower range of uncertainties for the LCOH, both having a range which is within $0.5 per kg H₂ between low- and high-cost assumptions.
The sensitivities for the for various RCF scenarios are dependent on the cost variances for the various economic factors such as WACC, CAPEX, OPEX, and the carbon compensation cost. The uncertainty estimation is underpinned by the assumptions on the cost variations. For instance, the uncertainty would be higher in the case when there is additional variance introduced on the grid network and distribution tariffs (assumed to be constant in this analysis).

The 82% RCF scenario will be a suitable target RCF in case of high robustness requirements whereas the 91% RCF scenario provides the lowest LCOH. However, for further analysis on the competitiveness assessment the results from the 91% RCF scenario have been considered.

5.2. Competitiveness assessment

5.2.1. LCOH at end-use

The LCOH at the end-use application is obtained by accounting for the costs incurred in addition to the liquid hydrogen production such as the liquid hydrogen transport costs and installation of hydrogen refuelling stations at the end-use point. The approach for determining the cost of these additional costs is described below.

**Liquid hydrogen transport**

The transportation is through trucks which have a cost of 0.92 AUD/t.km.\(^3\) The cost associated for the transport of liquid hydrogen is much lower compared to the transport of gaseous hydrogen (2.08AUD/t.km).\(^3\) The location of the various end-use applications is based on assumptions listed in Table 10. The rational of the assumptions is as follows:

- **Gas grid injection**: AGIG’s injection point for the gas grid is in Dandenong. Liquid hydrogen is to be transported to the site to vaporise the liquid and compress the gas for injection into the gas grid.
- **Forklifts**: Deer Park is one of Victoria’s largest warehouse sites and therefore is assumed to be the destination for 75% of hydrogen forklifts. Given the distance from
Monash Clayton, there is a requirement for a refuelling site in Deer Park to ensure that warehouses can continually utilise their forklifts. The remaining 25% of the forklift hydrogen demand is assumed to be met from the refuelling station at the Supply Hub which is expected to cater to the demand from the South-Eastern suburbs of the greater Melbourne area.

- **Waste Trucks:** Accelerating the demonstration of fuel-cell waste trucks requires the waste trucks to perform efficiently in longer duty schedule. Following this rationale, 50% of the waste truck demand is from the City of Casey which is Victoria’s largest municipality by population to meet its waste demands. The remaining 50% of the demand is expected to be catered from the Supply Hub.

- **Trains:** V-line trains are assumed to be fuelled at the Southern Cross station to facilitate the demonstration of FCEVs for this application. Southern cross is also a V-line train depot that is closest to the Supply Hub.

- **Buses:** The closest bus depot to Supply Hub is located at Oakleigh, which is expected to take two-thirds of the hydrogen demand allocate it for this application. The rest is allocated as a demand for Monash Universities inter-campuses bus services.

- **Long Haul:** In line with Victorian government’s announcement of marking the Hume Freeway as a location for developing hydrogen refuelling infrastructure for the freight sector, it is assumed that the refuelling station for long-haul trucks is located at Thomastown (closest Hume Freeway landmark to Monash)

- **Concrete Trucks:** 50% of the fuel-cell based concrete trucks are assumed to be refuelling from the Supply Hub to cater to the construction activity in the south-eastern suburbs. The remaining concrete demand is considered to be met by a refuelling station located at Melbourne.

Table 10. Assumption on the location of end-use point and the refuelling station infrastructure required.

<table>
<thead>
<tr>
<th>Application</th>
<th># of units</th>
<th>Transport Split</th>
<th>Route distance incl. return (km)</th>
<th># of refuelling stations</th>
<th>Location of refuelling station</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas grid injection</td>
<td>N/A</td>
<td>100%</td>
<td>27</td>
<td>1</td>
<td>Dandenong</td>
</tr>
<tr>
<td>Forklifts</td>
<td>150</td>
<td>75%</td>
<td>92</td>
<td>1</td>
<td>Deerpark</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>25%</td>
<td>-</td>
<td>1</td>
<td>Monash</td>
</tr>
<tr>
<td>Waste Trucks</td>
<td>20</td>
<td>50%</td>
<td>62</td>
<td>1</td>
<td>Casey</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>50%</td>
<td>-</td>
<td>1</td>
<td>Monash</td>
</tr>
<tr>
<td>Trains</td>
<td>2</td>
<td>100%</td>
<td>49</td>
<td>2</td>
<td>Southern Cross</td>
</tr>
<tr>
<td>Buses</td>
<td>26</td>
<td>33%</td>
<td>-</td>
<td>1</td>
<td>Monash</td>
</tr>
<tr>
<td></td>
<td>14</td>
<td>67%</td>
<td>10</td>
<td>2</td>
<td>Oakleigh</td>
</tr>
<tr>
<td>Long Haul</td>
<td>40</td>
<td>100%</td>
<td>106</td>
<td>2</td>
<td>Thomastown</td>
</tr>
<tr>
<td>Concrete Trucks</td>
<td>20</td>
<td>50%</td>
<td>50</td>
<td>1</td>
<td>Melbourne</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>50%</td>
<td>-</td>
<td>1</td>
<td>Monash</td>
</tr>
</tbody>
</table>
Figure 36. Delivered cost of hydrogen per end-use.

Hydrogen refuelling station

The number of refuelling stations required for each application and at each location are specified in Table 10. The refuelling at Monash University Precinct would require minimum infrastructure installation as the storage infrastructure would already be present at the Supply Hub. However, for refuelling at other location, a full-fledged hydrogen refuelling station would be required. The costs for the refuelling infrastructure and its amortisation thereof are dependent on the hydrogen demand at the location and the refuelling frequency. A mobile refuelling platform is possible to reduce costs for demonstration projects of short to medium term.

The total delivered cost of hydrogen at the end-use application is presented Figure 36. The overall delivered cost of hydrogen varies between 14-19 AUD/kg H₂ and is a strong function of the underlying assumptions especially on the refuelling infrastructure costs. The cost at the Supply Hub (even for the 91% RCF scenario) makes up to more than 76% of the total delivered cost for all the applications. The transportation cost contributes the least to the total delivered cost. Even in the worst case, i.e., delivery to Thomastown (~100km roundtrip), the transportation cost adds only 0.41 AUD/kg H₂.

The refuelling infrastructure costs vary largely per application, and this is a function of the off-take demand at each end-use location. The refuelling infrastructure with most demand, for example, long-haul and buses, cost the least on a LCOH (AUD/kg H₂) basis. The major emphasis to make the hydrogen most cost-competitive should be to reduce the cost at the production point and the refuelling and the transportation cost are not a cause of concern for liquid hydrogen.
5.2.2. Sensitivity of LCOH at end-use

In order to capture the variability of the costs at the end-use point, a sensitivity analysis was carried out to determine the best and the worst case delivered cost of hydrogen. The sensitivity analysis captures the variation only in the Supply Hub costs discussed in Figure 35. The variation in the refuelling cost due to differences in refuelling location is also incorporated. Figure 37 presents the variation in the delivered cost of hydrogen at the end-use point. The overall range for the variation is between 14 and 22 AUD/kg H₂.

It can be further observed that the lowest points in the various applications are identical due to the refuelling at the Supply Hub. Installation of the refuelling stations at an additional location which takes only a fraction of the total demand leads to much higher delivered hydrogen cost. This is particularly observed in the cases of forklifts, waste truck, buses, and concrete trucks. The cost of hydrogen and variability in costs for gas injection application are low because of minimum infrastructure requirement.

On the other hand, the variability for applications such as trains and long-haul transport is low due to the larger and concentrated demand for liquid hydrogen in those locations.

5.2.2. Options for reducing liquid hydrogen supply costs

The National Hydrogen Roadmap presents a view on the cost competitiveness of hydrogen for the various end-use applications. For instance, the cost-competitiveness for hydrogen for buses and trucks is expected to be in the range of 5-6 AUD/kg H₂ and for industrial feedstocks and export is around 2-3 AUD/kg H₂. This was further corroborated in the discussions with the OEMs such as Hyzon Motors where B-double trucks require a delivered cost of 7 AUD/kg H₂ to obtain an iso-TCO with the diesel vehicles over their lifetime. The delivered costs of hydrogen from the Supply Hub (when installed in 2025) are above these thresholds and require policy and strategic interventions to enhance the overall cost-competitiveness and to achieve the broader aim of facilitating the growth of hydrogen ecosystem in Victoria.

Figure 37. Sensitivity on the delivered cost of hydrogen at end-use.
### Table 11. Options for enhancing the cost-competitiveness of hydrogen from the Supply Hub (91% RCF scenario)

<table>
<thead>
<tr>
<th>Description</th>
<th>Technology scale</th>
<th>Electricity supply tariffs</th>
<th>Delivery supply chain</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base case</strong></td>
<td>The base case considers the Supply Hub to be located at the Monash University Precinct with the liquefaction facility providing hydrogen at 5t/d capacity</td>
<td>Network distribution and market tariffs are imposed on both non-renewable and RES electricity in addition to the energy charges</td>
<td>The liquid hydrogen Supply Hub is considered to be located 300km from all the refuelling station locations assumed in this study</td>
</tr>
<tr>
<td><strong>Option 1: 50% CAPEX subsidy</strong></td>
<td>Option 1 considers Supply Hub to be located at the Monash University precinct with CAPEX for the facility being subsidised by 50% through grants or other funding.</td>
<td>Network distribution and market tariffs are imposed only on the non-renewable electricity (18% of the electricity supply)</td>
<td>The liquid hydrogen Supply Hub is considered to be located 300km from all the refuelling station locations assumed in this study</td>
</tr>
<tr>
<td><strong>Option 2: Collocation of Supply Hub with Renewables</strong></td>
<td>Option 2 considers the Supply Hub to be located at the site of the utility scale renewables production, to eliminate the grid network and market tariffs for the electricity provided by the RES</td>
<td>Network distribution and market tariffs are imposed only on the non-renewable electricity (18% of the electricity supply)</td>
<td>The liquid hydrogen Supply Hub is considered to be located 300km from all the refuelling station locations assumed in this study</td>
</tr>
<tr>
<td><strong>Option 3: Collocation of Supply Hub with Renewables + 50% CAPEX subsidy</strong></td>
<td>Option 3 is a combination of Options 1 and 2 with the supply hub being located at the site of the utility scale renewables production along with the CAPEX being subsidised by 50% through grants or other funding.</td>
<td>Network distribution and market tariffs are imposed only on the non-renewable electricity (18% of the electricity supply)</td>
<td>The liquid hydrogen Supply Hub is considered to be located 300km from all the refuelling station locations assumed in this study</td>
</tr>
</tbody>
</table>

- **Description:** The base case considers the Supply Hub to be located at the Monash University Precinct with the liquefaction facility providing hydrogen at 5t/d capacity. Option 1 considers Supply Hub to be located at the Monash University precinct with CAPEX for the facility being subsidised by 50% through grants or other funding. Option 2 considers the Supply Hub to be located at the site of the utility scale renewables production, to eliminate the grid network and market tariffs for the electricity provided by the RES. Option 3 is a combination of Options 1 and 2 with the supply hub being located at the site of the utility scale renewables production along with the CAPEX being subsidised by 50% through grants or other funding.

- **Technology scale:** This is a medium scale facility to suit the requirements to supply 5t/d of liquid hydrogen. This is a medium scale facility to suit the requirements to supply 5t/d of liquid hydrogen. This is a large scale facility (>100 MW electrolyser) and a large-scale liquefaction unit providing both economies-of-scale benefits and efficiency improvements.

- **Electricity supply tariffs:** Network distribution and market tariffs are imposed on both non-renewable and RES electricity in addition to the energy charges. Network distribution and market tariffs are imposed only on the non-renewable electricity (18% of the electricity supply). Network distribution and market tariffs are imposed only on the non-renewable electricity (18% of the electricity supply).

- **Delivery supply chain:** The liquid hydrogen Supply Hub is considered to be located 300km from all the refuelling station locations assumed in this study. The liquid hydrogen Supply Hub is considered to be located 300km from all the refuelling station locations assumed in this study.
Figure 38. LCOH for the various options to enhance the cost-competitiveness of delivered cost of hydrogen

Table 11 details three options indicating the immediate possible strategic and policy interventions that aid in enhancing the cost-competitiveness of the delivered hydrogen for the various end-uses. In addition to the base-case-which considers the installation of the Supply Hub at the Monash Precinct (as currently planned); three options are considered as a part of this study, namely:

- **Option 1 – 50% CAPEX subsidy**
  This option considers the Supply Hub to be located at the Monash University precinct with CAPEX for the facility being subsidised by 50% through grants or other funding.

- **Option 2 – Collocation of Supply Hub with the (off-site) renewables**
  This option considers the Supply Hub to be located at the site of the utility scale renewables production, to eliminate the grid network and market tariffs for the electricity provided by the RES

- **Option 3 – Collocation of the Supply Hub with renewables combined with 50% CAPEX subsidy**
  Option 3 is a combination of Options 1 and 2 with the supply hub being located at the site of the utility scale renewables production along with the CAPEX being subsidised by 50% through grants or other funding

The options help reduce the costs associated with either the CAPEX (Option-1), OPEX through reduced grid network and market tariff exposure (Option-2) or a combination of both (Option-3).

The delivered LCOH from these three options and base-case for all the end-use applications is compared in Figure 38. The LCOH for the three options is lower than the base-case at varying levels. The 50% CAPEX subsidies (Option-1) result in the delivered cost of hydrogen of 13-22 AUD/kg H₂ reduce by 8%. On the other hand, the collocation of the Supply hub with the (off-site) renewables has a much larger cost decrease 9-18 AUD/kg H₂ indicating a reduction of 36% compared to the base case. Naturally, the combined case having both these interventions (collocation with renewables and 50% CAPEX subsidy) had the least cost of hydrogen at 8-17 AUD/ kg H₂.
5.2.3. Cost competitiveness of liquid hydrogen with fossil fuels

The cost-competitiveness for hydrogen compared to fossil fuels is determined through the fuel costs equivalents, which compares the fuel costs of using hydrogen-based solution with the fossil-fuel option. This metric inherently considers the efficiency gains associated with the hydrogen alternatives (applicable only for mobility applications). The fuel-cost equivalent in presented in Figure 39 compares the fuel cost with the hydrogen delivered cost range for the base-case and the possible strategic and policy interventions discussed above.

The use of hydrogen from the Supply Hub for gas grid injection application is particularly striking as the cost spend towards hydrogen is close to 120 AUD/GJ (for the base case) is more than 10 times the cost for natural gas. The cost reduction due to collocation with RES and 50% CAPEX subsidy case is not significant enough to compete with the natural gas costs. However, with the longer-term vision of substituting natural gas with hydrogen, the Supply Hub hydrogen could facilitate demonstration projects in the near-term.

On the other hand, with mobility applications, the hydrogen competitiveness varies for each application. The hydrogen has a huge cost-competitive advantage (even for base-case) compared to diesel due to high inefficiency of diesel forklifts. The competitiveness for forklifts
increases with other interventions results in a lower fuel spending of 30-50% compared to diesel.

For mobility applications such as waste trucks, concrete trucks and buses, hydrogen is a moderately competitive solution in the base-case. However, the competitiveness for waste trucks and concrete increases with the collocation with renewables as the current diesel costs is within the hydrogen cost range (which considers the cost of refuelling stations). Hydrogen buses become cost competitive when the Supply Hub is collocated to the site of the renewables resulting in a fuel cost roughly up to 15% cheaper than the diesel cost.

Other applications such as trains and long-haul transport, are not cost-competitive in the base-case. Even when collocation with renewables is combined with 50% CAPEX subsidy, the cost for hydrogen in trains and long-haul transport is higher than the diesel fuel by approximately 5% and 10% respectively.

From this analysis, forklifts could be expected to be early off-takers for the hydrogen from the Supply Hub followed by the buses, waste, and concrete trucks in the near-term. However, the large-scale commercial adaption of hydrogen-based solutions for these applications is dependent on the cost-reduction of the renewable electricity supply and the economies of scale associated with very large-scale hydrogen production.
5.2.4. Marginal abatement cost for end-use applications

The marginal abatement cost (MAC) range for each application presented in Figure 40 reflects the investments required to abate 1 tonne of CO\(_2\) at the end-use point by substitution from fossil-fuel based technologies to hydrogen-based.

In the base-case, the MAC is only favourable for the forklifts resulting in cost savings in the range of 400-500 AUD/tCO\(_2\). However, in the case of waste trucks and the concrete trucks, the MAC is negative only under the lowest cost of hydrogen for the respective applications. The MAC for all the other applications is positive in the case of base-case indicative of additional investments required to abate carbon emissions. The MAC for gas grid injection is the highest at approximately 2100 AUD/tCO\(_2\) which is due to the large cost difference between natural gas and hydrogen cost.

For the applications such as waste trucks and concrete trucks only when the Supply Hub is collocated with the renewables combined with 50% CAPEX subsidy a negative MAC is obtained. For base-case and for other cases (50% CAPEX only) it remains positive even higher than the carbon price of 181 AUD/tCO\(_2\). Buses have a negative MAC only in the case when the facility is collocated with the renewables.

Figure 40. Marginal abatement cost of carbon range for each end-use application.
On the other hand, applications such as trains and long-haul transport, the MAC remains positive in all the cases even with strategic and policy interventions, however, the cost towards hydrogen is expected to be lower (from a fuel cost standpoint) compared to the carbon price 181 AUD/tCO$_2$\textsuperscript{59} is spent annually over a 25-year lifetime. Therefore, their substitution to hydrogen-based solutions is subject to government incentives or the stakeholder demands for carbon-neutrality.

5.3. Societal benefits

The Victorian Renewable Liquid Hydrogen Supply Hub has multiple benefits spanning environmental benefits, socio-economic benefits and the Supply Hub would also benefit the local community in a strategic manner, as this is a state-of-the-art technological development that allows the development of future-proof skills for the local workforce.

There are several environmental benefits related to the use of green hydrogen, as the green hydrogen is substituting fossil fuels, i.e., natural gas and diesel. For all applications, the avoided CO$_2$ emissions have a societal benefit of limiting the global warming and other impacts of climate change.

- For gas grid injection, there are benefits in addition to avoided CO$_2$ emissions. Natural gas systems inherently have leakage rates associated with them and this leakage is avoided when less natural gas is used. As values for leakage rates vary, a lower and higher bound are considered, i.e., 1.5% and 4.5%. The CO$_2$-e Global Warming Potential varies as well, dependent on the time horizon, so a higher and lower bound is considered as well, i.e., 28 (100-year average) and 84 (20-year average) which is much higher than that of hydrogen of 11 (100-year average) and 33 (20-year average)\textsuperscript{60}. The respective lower and higher bounds are combined for obtaining a lower and higher bound of avoided equivalent CO$_2$ emissions due to reduced natural gas leakage.

- For the mobility applications, the reduction of harmful pollutants such as particulate matter (PM) and NOx is considered as an additional benefit besides the avoided CO$_2$ emissions. The fuel cell vehicles would substitute diesel-fuelled vehicles complying to the EURO V emission standard. Furthermore, the hydrogen-based mobility solution would benefit from lower noise levels for several applications particularly for waste trucks which drive around the residential areas.

Additionally, there are socio-economic benefits associated with the Supply Hub, as it will be designed to rely on locally produced renewable energy sources, eliminating the dependency on imported fossil fuels. Not only does it increase the resilience of the supply chain due to the reduced dependency on externally supplied fuels, but it also takes away the price volatility associated to fuel imports.

\textsuperscript{59} Carbon price for a Below 2$^\circ$C scenario obtained from the International institute of applied systems and analysis- network for greening the financial systems (IIASA- NGFS) scenarios

\textsuperscript{60} Atmospheric implications of increased hydrogen use, Department of Business, Energy and Business strategy, April 2022
6. Conclusions and recommendations

The technological and commercial maturity of hydrogen technologies is advancing rapidly, with the potential to become a versatile and cost-competitive to diesel and natural gas-based technologies across a range of applications. The Victorian Renewable Liquid Hydrogen Supply Hub aims to accelerate the transition towards a green-hydrogen economy. This feasibility report consolidates the findings from three-part study; off-taker assessment, scenario modelling, and competitiveness assessment.

The first part of the report assesses hydrogen’s competitiveness towards each application and quantifies the expected demands within Victoria based on inputs from the various stakeholder interactions, such as expected market share, timeline for hydrogen adoption, commercial readiness, and location of hydrogen off-take. Additionally, the key off-taker applications suitable for procuring green liquid hydrogen from the Victorian Renewable Liquid Hydrogen Supply Hub at the Monash University precinct were identified, which includes:

- gas grid injection;
- forklifts;
- waste and concrete trucks;
- regional trains;
- public transport buses;
- long-haul trucks.

Next, the feasibility of the Supply Hub was assessed by conducting scenario modelling and optimisation was carried out for six scenarios with varying RCF share in the electricity supply on ENGIE Impact’s Prosumer tool. The results indicated that the 82%-91% RCF range had provided lower TCO compared to the other scenarios offering a Supply Hub LCOH of ~14.5 AUD/kg H₂. While the 82% RCF scenario can be selected for enhanced cost robustness, the 91% RCF scenario can be selected for the least cost of hydrogen.

The major share of the Supply Hub cost is due to the electricity cost for the electrolyser and the liquefaction unit which are intensified by the grid and the market costs. The end-use hydrogen cost that includes transportation and refuelling costs was in the range of 14-22 AUD/kg H₂ which was dependent on factors such as location of refuelling station, number of refuelling stations and the demand. The delivered cost of hydrogen was found to be cost competitive with the fossil-fuel alternatives only for forklifts application if the facility were to be installed at Monash University Precinct.

The adaption of hydrogen-based solutions for other application would be subject to lowering the hydrogen costs. The hydrogen from the Supply Hub gains cost-competitiveness from subsidies from the government for 50% of capital expenditure for the various on-site assets and/or collocating the Supply Hub with the renewable energy generation facilities to reduce the operational expenditure by avoiding a significant share of the grid and the market tariffs for the electricity supply.
Combining these policy and strategic interventions result in several applications having positive business cases from a fuel-cost perspective. For instance, buses have a positive business case with net savings on fuel cost (negative MAC), whereas both waste trucks and concrete trucks have cost-savings compared to hydrogen in the lowest hydrogen costs. Applications such as trains and buses have an additional spending towards fuels even in the case when the CAPEX subsidy is applied on a renewable collocated facility, however, the cost is significantly lower than the expected 20-year average carbon cost of 181 AUD/tCO₂ for a less than 2°C climate scenario.

Based on the results of this feasibility study and the screening process, the recommended next steps for this project are:

- Engage with the government and other industry stakeholders to identify opportunities to subsidise the capital expenditure or collocate this facility with the renewable energy supply, thereby avoiding most of the grid fees;
- Identification of potential off-taker groups particularly for the forklifts application who may be near-term off-takers of hydrogen from the Victorian Renewable Liquid Hydrogen Supply Hub at the Monash Technology precinct.
### Appendix

#### A1. Demand assumptions summary

<table>
<thead>
<tr>
<th>Application</th>
<th>Source data</th>
<th>Consumption rates</th>
<th>$H_2$ market share (%)</th>
<th>Assumptions for the hydrogen market share potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Public transport buses</td>
<td>BITRE (2021); Hyzon Motors</td>
<td>7 kg $H_2$/100km</td>
<td>20%</td>
<td>Market share accounts for longer routes only as electrification would otherwise be preferred</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(44 L diesel/100km)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regional trains (V-line)</td>
<td>V-line annual report; FCH Europa</td>
<td>25 kg $H_2$/100km</td>
<td>100%</td>
<td>Hydrogen is more competitive than electrification for regional routes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(120 L diesel/100km)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Concrete Trucks</td>
<td>CCAA (2018); Hyzon Motors</td>
<td>13.5 kg $H_2$/100km</td>
<td>50%</td>
<td>Market is equally divided between hydrogen and electric fleet</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(100 L diesel/100km)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Waste Trucks</td>
<td>Sustainability Victoria; Hyzon Motors</td>
<td>10.5 kg $H_2$/100km</td>
<td>50%</td>
<td>Market is equally divided between hydrogen and electric fleet</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(78 L diesel/100km)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Long Haul Mobility</td>
<td>AHC, Hyzon Motors</td>
<td>14.5 kg $H_2$/100km</td>
<td>80%</td>
<td>Hydrogen fuel is more suitable for heavy-duty long-haul applications</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(69 L diesel/100km)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dairy trucks</td>
<td>CSIRO report; Hyzon Motors</td>
<td>14.5 kg $H_2$/100km</td>
<td>80%</td>
<td>Hydrogen fuel is more suitable for heavy-duty long-haul applications</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(69 L diesel/100km)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Forklifts</td>
<td>ENGIE internal estimates; FCH Europa</td>
<td>0.15 kg $H_2$/hour</td>
<td>20%</td>
<td>Hydrogen only considered for high-intensity operating schedules</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(2.8 L diesel/hour)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Port Operations</td>
<td>Engie Impact assumption based on efficiency of IC and FC engines</td>
<td>0.21 kg H₂/L diesel</td>
<td>100%</td>
<td>To have a conservative estimate, all the port observations are assumed to be on hydrogen</td>
</tr>
<tr>
<td>-----------------</td>
<td>---------------------------------------------------------------</td>
<td>---------------------</td>
<td>------</td>
<td>---------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Airport GSE</td>
<td>CSIRO – Opportunities for Hydrogen in Commercial Aviation</td>
<td>0.08-0.17 kg H₂/L diesel</td>
<td>100%</td>
<td>To have a conservative estimate, all the port observations are assumed to be on hydrogen</td>
</tr>
<tr>
<td>Gas grid injection</td>
<td>AGIG –Achieving 10% Renewable H₂</td>
<td>N/A</td>
<td>100%</td>
<td>Considering 10% vol. blend in Vic gas network</td>
</tr>
<tr>
<td>Commodities</td>
<td>Ammonia Energy Association</td>
<td>N/A</td>
<td>100%</td>
<td>Assuming all H₂ demand is green H₂</td>
</tr>
</tbody>
</table>
A2. Stakeholder organisations

Over the course of the study, representatives from several organisations were contacted and interviewed spanning over government, hydrogen clusters, industry, and research/consulting institutions. The interviews were intended to gather information on the H₂ adaption appetite, technology availability and infrastructure growth required for the various applications. The stakeholder engagement also revealed that hydrogen adaption in various sectors was tentative due to the uncertainty in the H₂ cost reduction, timeline and hydrogen refuelling infrastructure development. Further, in certain cases, the stakeholders also provided their operational details which included diesel consumption which enabled accurate quantification of the demands.

**Government departments**
- Victorian Government – DELWP
- Victorian Government – Department of Transport (DoT)
- Regional Development Victoria (RDV)
- City of Monash

**Hydrogen clusters**
- National Energy Resources Australia (NERA)
- Clayton Hydrogen Technology Cluster
- Victorian Hydrogen Hub (Swinburne University)
- Geelong Hydrogen Cluster (Startupbootcamp)

**Industry**
- Nikkiso Cryoquip
- Hyzon Motors
- AGIG
- Engie
- Country Wide Renewables
- Coregas
- Kawasaki
- Iwatani
- Food Innovation Australia Limited (FIAL)
- Boral
- Energy Australia
- Toyota
- BOC
- HAMR Energy

**Research/Advisory**
- Engie Impact
- Monash University
- CSIRO
- Deakin University (Hycel)
- Arup
- Brolga Co
### A3. Techno-economic assumptions summary

**Table A. 2. Summary of techno-economic assumptions used for the scenario modelling.**

<table>
<thead>
<tr>
<th>Data requirement for decarbonisation assessment</th>
<th>Source</th>
<th>Reference Year</th>
<th>Nominal value</th>
<th>Min value</th>
<th>Max value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity price</td>
<td>Monash University and ROAM consulting report</td>
<td>2025</td>
<td>0.167</td>
<td>0.143</td>
<td>0.236</td>
<td>AUD per kWh</td>
</tr>
<tr>
<td>Diesel price</td>
<td>CSIRO Possible Futures Report</td>
<td>2025</td>
<td>1.66</td>
<td>1.45</td>
<td>1.95</td>
<td>AUD/L</td>
</tr>
<tr>
<td>Gas price</td>
<td>AEMO</td>
<td>2025</td>
<td>9.76</td>
<td>9.23</td>
<td>9.76</td>
<td>AUD/GJ</td>
</tr>
<tr>
<td>Solar PV: Total installation costs</td>
<td>CSIRO Gencost Report 2020-21</td>
<td>2025</td>
<td>1,041</td>
<td>885</td>
<td>1,229</td>
<td>AUD per kW</td>
</tr>
<tr>
<td>Solar PV: FO&amp;M charge</td>
<td>CSIRO Gencost Report 2020-21</td>
<td>All</td>
<td>1.78%</td>
<td>1.21%</td>
<td>2.20%</td>
<td>% CAPEX</td>
</tr>
<tr>
<td>Roof-top PV: Total installation costs</td>
<td>CSIRO Gencost Report 2020-21</td>
<td>2025</td>
<td>1,118</td>
<td>861</td>
<td>1,256</td>
<td>AUD per kW</td>
</tr>
<tr>
<td>Roof-top PV: FO&amp;M charge</td>
<td>CSIRO Gencost Report 2020-21</td>
<td>All</td>
<td>2.04%</td>
<td>1.18%</td>
<td>2.68%</td>
<td>% CAPEX</td>
</tr>
<tr>
<td>Wind turbine: Total installation costs</td>
<td>CSIRO Gencost Report 2020-21</td>
<td>2025</td>
<td>1,913</td>
<td>1,904</td>
<td>1,923</td>
<td>AUD per kW</td>
</tr>
<tr>
<td>Wind turbine: FO&amp;M charge</td>
<td>CSIRO Gencost Report 2020-21</td>
<td>All</td>
<td>1.33%</td>
<td>1.28%</td>
<td>1.38%</td>
<td>% CAPEX</td>
</tr>
<tr>
<td>BESS (Li-ion): Total installation costs of battery and ancillary energy systems</td>
<td>CSIRO Gencost Report 2020-21, ENGIE Impact assumptions</td>
<td>2025</td>
<td>223</td>
<td>223</td>
<td>361</td>
<td>AUD per kW</td>
</tr>
<tr>
<td>BESS (Li-ion): FO&amp;M charge for batteries (kWh)</td>
<td>ENGIE Impact assumptions</td>
<td>All</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
<td>% of total installed battery costs</td>
</tr>
<tr>
<td>BESS (Li-ion): Total installation cost of power control systems and ancillary systems</td>
<td>Bloomberg and CSIRO Gencost Report 2020-21</td>
<td>2025</td>
<td>192</td>
<td>192</td>
<td>200</td>
<td>AUD per kW</td>
</tr>
<tr>
<td>BESS (Li-ion): FO&amp;M charge for power control systems and ancillary systems</td>
<td>ENGIE Impact assumptions</td>
<td>All</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
<td>% of total installed PCS costs</td>
</tr>
<tr>
<td>H₂ Pressurized alkaline 10 MW Electrolyser: Total installation cost</td>
<td>ENGIE Impact assumptions</td>
<td>2025</td>
<td>1,590</td>
<td>1,501</td>
<td>1,679</td>
<td>AUD per kW</td>
</tr>
<tr>
<td>Hydrogen Pressurized alkaline 10 MW Electrolyser: FO&amp;M cost</td>
<td>ENGIE Impact assumptions</td>
<td>All</td>
<td>0.7%</td>
<td>0.7%</td>
<td>0.7%</td>
<td>% CAPEX</td>
</tr>
<tr>
<td>-----------------------------------------------------------</td>
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<td>--------</td>
</tr>
</tbody>
</table>

Currency rate: 0.77 AUD/USD; Class 5 cost estimates: -50% to +100%
A4. Liquid hydrogen production facility visualisations

Figure A.1. CAD drawing of the Victorian Liquid Hydrogen Supply Hub (sizes in mm)
Figure A.2. Visualisation of the Victorian Renewable Liquid Hydrogen Supply Hub