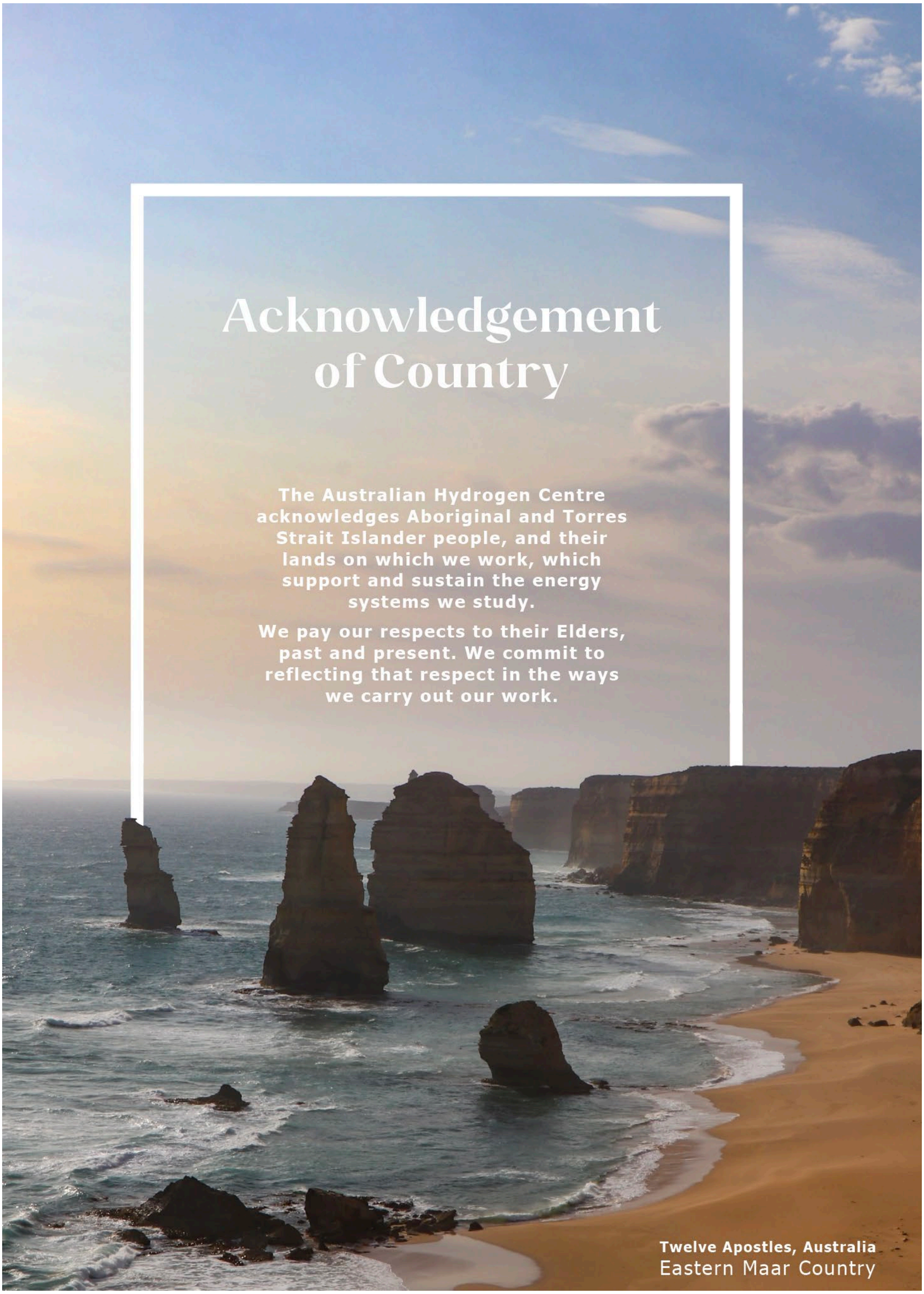
Australian Hydrogen Centre

100% Hydrogen Distribution Networks: Victoria Feasibility Study

Assessing the feasibility of delivering 100% renewable hydrogen in Victoria's gas distribution networks

May 2023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The Australian Hydrogen Centre acknowledges Aboriginal and Torres Strait Islander people, and their lands on which we work, which support and sustain the energy systems we study.
We pay our respects to their Elders, past and present. We commit to reflecting that respect in the ways we carry out our work.
Twelve Apostles, Australia
Eastern Maar Country

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This project received funding from the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program, and the Victorian Government's Victorian Hydrogen Investment Program (VHIP).

Executive Summary

The Australian Hydrogen Centre (AHC) was established to deliver Australian-first feasibility studies of how existing natural gas distribution networks could be used in a in a system to produce, store, and transport renewable hydrogen, decarbonising gas supply while still meeting the needs of millions of customers.

This follows the Australian National Hydrogen Strategy's identification of hydrogen in gas networks as one of three large-scale activation markets to build demand[1]. The Strategy outlined that taking early steps to use hydrogen in transport, industrial use and gas networks will complement and enhance the impact of hydrogen hubs on making hydrogen infrastructure more cost-effective, promoting efficiencies, fostering innovation, and encouraging sector coupling synergies[2].

The $4.15 million AHC project, supported by the Australian Renewable Energy Agency (ARENA), the Victorian Government and the South Australian Government, has brought together expertise and knowledge from across the energy supply chain including renewable electricity producers, electricity and gas infrastructure owners, and retailers to produce this comprehensive research.

The reports show that it is technically and economically feasible to use existing gas infrastructure for scaled hydrogen distribution. More specifically, 100% renewable hydrogen in Victorian gas distribution networks could:

- deliver a net zero carbon emissions gas distribution system.
- unlock the opportunity to harness underutilised renewable generation infrastructure to supply 12,000 MW of electrolyser capacity, and around 30 PJ of hydrogen storage.
- ramp up hydrogen production from almost 3 PJ/annum in a 10% hydrogen networks scenario to 171 PJ/annum strengthening demand for domestic hydrogen offtakes and creating 10,305 Victorian jobs during construction (5,380 ongoing).

Supported by a range of independent technical studies, the AHC's focus was to determine how a 100% renewable hydrogen distribution system could optimally be achieved for supply to households, businesses and industry and is not a detailed scenario analysis on decarbonising the wider economy.

The reports provide a better understanding of the opportunity to access Australia's world-class gas distribution infrastructure to unlock its hydrogen opportunity whilst retaining energy security and affordability and identifies a range of low-regret enablers that could trigger coordinated action by government and industry.

1 See page 33 of the National Hydrogen Strategy, found here: https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf

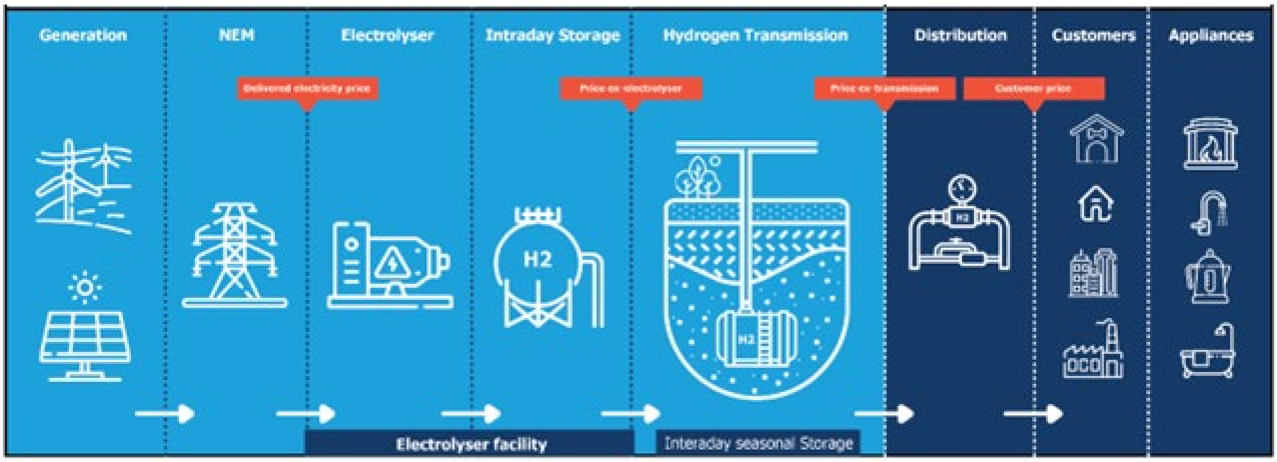
2 See page viii of the National Hydrogen Strategy, linked above.

Report Scope and Limitations

There are various plausible ways that renewable hydrogen production and distribution supply chains could develop to achieve 100% hydrogen in networks; however, the AHC considered the most plausible at this point in time.

Figure 1 indicates the key features of this supply chain, and also demonstrates the scope of this Study. It shows renewable electricity delivered by the National Electricity Market (NEM) to power electrolyser plants producing renewable hydrogen, which is then stored (as/if required), blended with natural gas at 10% volumes, and supplied through existing gas distribution networks for use by domestic, commercial, and industrial customers.

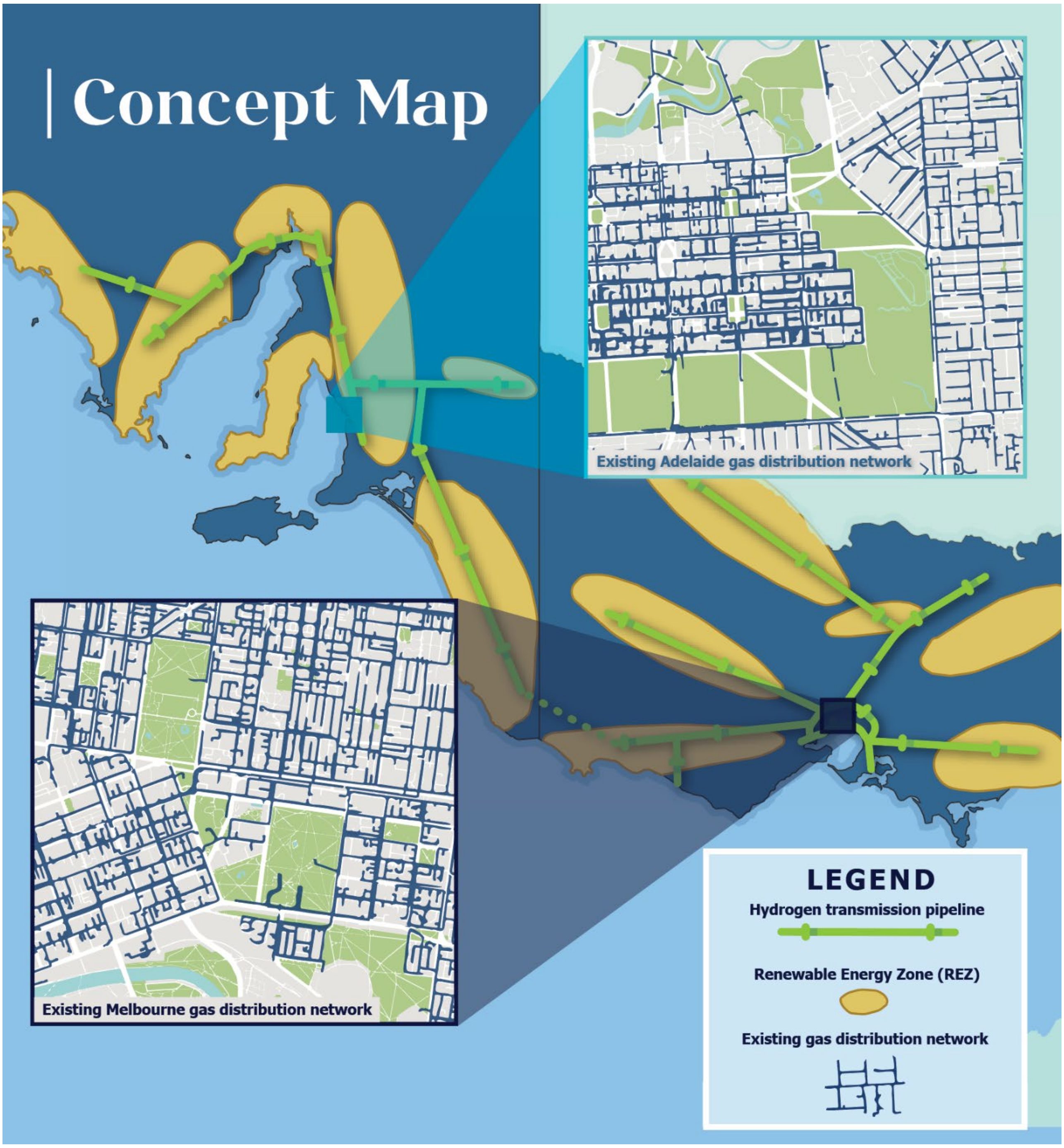
Figure 1: Proposed hydrogen energy supply chain



While this pathway is the focus of this Study, noteworthy limits to this model include that it:

- Investigates dedicated renewable hydrogen production for converting gas distribution networks to hydrogen. In reality, hydrogen could be produced for various end-uses that could also supply into networks as an additional market as part of a 'hydrogen hubs' model;
- Only considers hydrogen produced from electrolysis with renewable electricity. Other forms of renewable and carbon neutral gases, such as biomethane or hydrogen coupled with carbon capture and storage, were excluded from this scope.
- Has been produced at a 'point in time' primarily throughout 2021/22 and does not consider breakthrough technological advancement and research.

Further, the AHC does not provide a scenario analysis of pathways and associated costings to decarbonise energy consumption of South Australia and Victoria's wider energy systems encompassing electricity, transport, agriculture, and other relevant sectors. Noteworthy reports considering alternative pathways to decarbonising gas supply are summarised in Chapter 9.3 of this Study.



As part of the 100% hydrogen scenario, renewable hydrogen could be produced through electrolysis in REZ and transported to demand centres in new hydrogen transmission pipelines.

These pipelines will connect to existing gas distribution networks which, with minor modifications, supply renewable hydrogen to homes, businesses, and industry.

Table of Contents

Table of Figures

1. Introduction

The Australian Hydrogen Centre (AHC) is a joint initiative established at the end of 2019 with funding from the Australian Renewable Energy Agency (ARENA) to investigate the technical feasibility of supplying hydrogen through existing gas distribution networks. Its members are:

- The State of South Australia, as represented by the Department for Energy and Mining;
- The State of Victoria, as represented by the Department of Energy, Environment and Climate Action;
- AusNet Transmission Group Pty Ltd and AusNet Gas Services Pty Ltd. (AusNet);
- Australian Gas Networks Ltd (AGN), part of Australian Gas Infrastructure Group (AGIG).
- ENGIE Services – Hydrogen Business Unit (ENGIE); and
- Neoen Australia Pty Ltd. (Neoen).

The AHC's overall program of work involves the delivery of key feasibility studies as well as knowledge sharing reports.

Government of South Australia
Department for Energy and Mining

VICTORIA State Government
Energy, Environment and Climate Action

AusNet

Australian Gas Infrastructure Group

ENGIE

NEOEN

Regional Towns Feasibility Studies

Detailed feasibility studies that determine how 10% hydrogen might be delivered into the gas distribution networks of selected regional towns in South Australia and Victoria.

State-Wide 10% Hydrogen Studies

Feasibility studies that determine how the South Australian and Victorian gas distribution networks might deliver 10% renewable hydrogen.

State-Wide 100% Hydrogen Studies

Feasibility studies that determine how the South Australian and Victorian gas distribution networks might deliver 100% renewable hydrogen.

Hydrogen Park South Australia (HyP SA) Knowledge Sharing Reports

Presenting key learnings from HyP SA where renewable hydrogen has been blended into the gas networks in the suburb of Mitchell Park, Adelaide since May 2021.

Each study and the subsequent reports have been developed with support from several independent consultants selected in a competitive process by a Governance Committee of representatives from AHC Members.

Advisian Worley Group | ARUP | Ethos Urban | farrierswier

frontier economics | GPA ENGINEERING | Jacobs | Oakley Greenwood

2. Natural Gas Demand

In 2020, Victorian gas distribution networks, supplied more than 2.1 million connections with natural gas. This Chapter outlines the segmentation of those customers and considers the key industrial users of natural gas connected to the Victorian gas distribution network. This is an important input into the following chapters as it defines how much renewable hydrogen production will be required (Chapter 3) as well as the sectors (and appliances) in which this hydrogen needs to be used (Chapter 5).

As well as analysing the present gas usage of all customers, this Chapter draws on 2021 data from the Australian Energy Market Operator (AEMO) to outline gas consumption forecasts in Victoria. It explains the trends that influence gas consumption, including seasonal changes, which are a major factor in Victoria.

This Study assumes that existing natural gas demand is interchangeable with demand for hydrogen and adopts AEMO's Central Scenario as outlined in its 2021 Gas Statement of Opportunities (GSOO) as the basis of forecasts for hydrogen demand through to 2050. To achieve 100% hydrogen in networks for this level of demand, Victoria would need to produce 1.4 million tonnes of hydrogen annually.

Since this Study commenced AEMO has produced subsequent GSOO's reflecting the impact of international conflicts, inflation, COVID-19 and other market uncertainties that have triggered a wide range of plausible futures for gas demand. For this reason, the opportunity to update this analysis frequently could be considered.

Key findings

1. The Victorian gas distribution network supplies more than 2.1 million connections across a broad range of applications including residential (59% of demand), industrial (31%), and commercial (10%).
2. It was assumed that the overall demand for natural gas in distribution networks to 2050 could be supplanted by hydrogen.
3. There are a wide range of plausible futures for gas demand. AEMO's Central Scenario as outlined in its 2021 GSOO has been selected as the basis of forecast for hydrogen demand by 2050.

2.1. Current Gas Consumption

In 2020, the Victorian gas distribution network supplied more than 2.1 million connections with approximately 200 PJ of natural gas.

There are three key customer segments in Victoria, as follows:

1. **Residential** – Customers who use gas for residential purposes;
2. **Commercial** – Business customers who use less than 10 TJ of natural gas each year; and
3. **Industrial** – Large industrial customers who consume more than 10 TJ of natural gas per year.

Table 1 provides a breakdown of customer numbers and demand by customer segment.

Table 1: Total customer numbers and demand in Victoria, 2020

	Customer numbers		Annual Consumption (TJ)	
Segment	**Numbers**	**Percentage**	**Demand**	**Percentage**
Residential	2,117,755	98%	109,246	59%
Commercial	40,166	2%	17,559	10%
Industrial	884	0.04%	56,991	31%
Total	**2,177,434**	**100%**	**183,797**	**100%**

Victoria's gas distribution network supplies more gas than any other state, reflecting its relatively high population and cool climate[3]. Its residential gas consumption is the largest of the three sectors, as shown in Table 1.

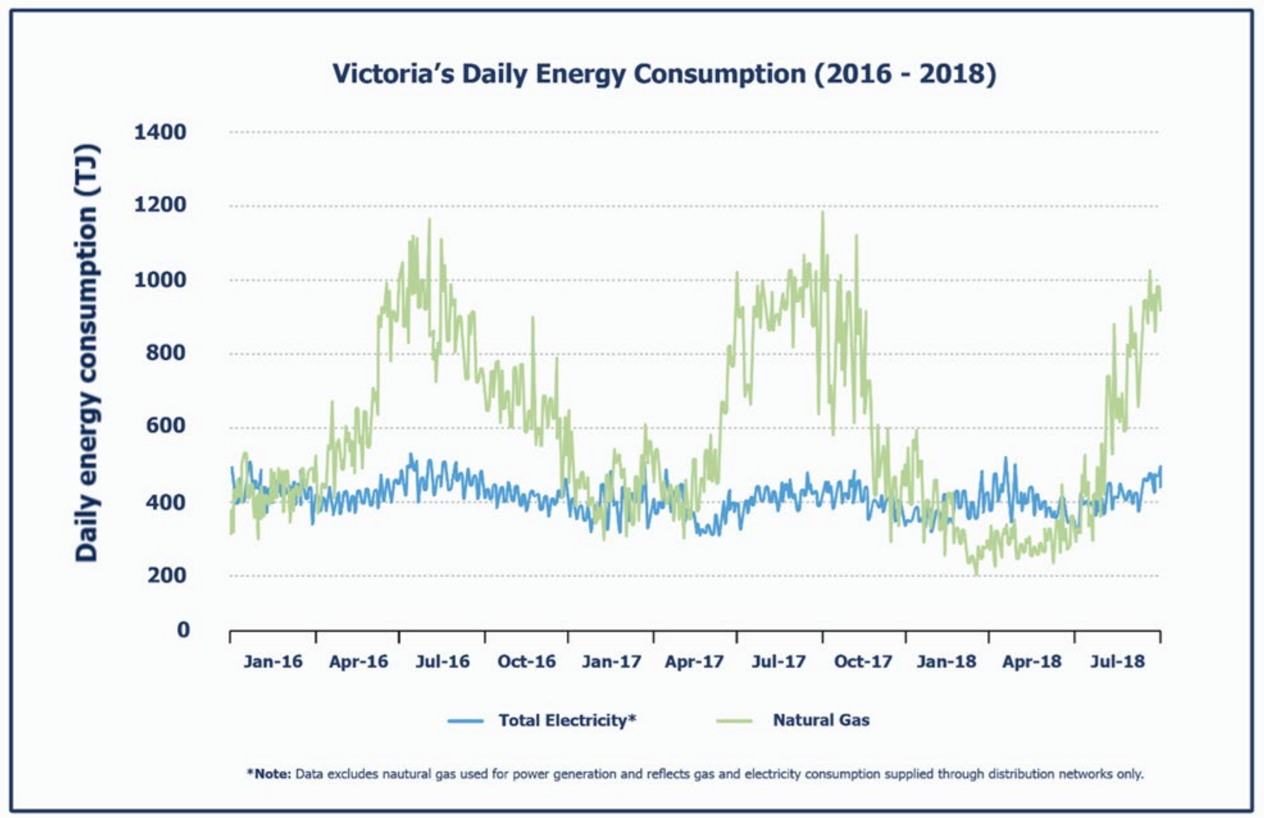
Commercial businesses connected to the Victorian distribution network typically use natural gas mostly for cooking, heating, and hot water.

There are also 884 industrial customers (also known as major gas users) connected to the gas network in Victoria. More information on these customers is set out in Section 2.2 on major gas users below.

The annual consumption profile of the Victorian gas distribution network reflecits large demand peaks in cooler seasons, and most of the gas consumption is for space heating, hot water, and cooking. This is evident in Figure 2 below in the peaks in demand in July 2016, 2017, and 2018.

3 State of Victoria, Department of Environment, Land, Water and Planning, 2022. More information can be found here: <https://www.energy.vic.gov.au/gas/about-the-gas-sector>

Figure 2: Victoria's daily energy consumption - 2016-2018



2.2. Major Gas Users

The AHC carried out a desktop analysis study to understand the suitability of Victorian major gas users to accept 10% or 100% hydrogen.

As shown in Table 1, there were 884 industrial customers connected to the Victorian gas distribution network in 2020. These customers represent 0.04% of Victorian connections yet account for approximately 31% of total gas delivered through the distribution network.

Manufacturing represents a sub-set of Victorian industrial gas use and is the second highest consumer of natural gas in Victoria, owing to the significant presence of diverse industries that are a key driver of the Victorian economy.

Residential customer segments account for 59% of gas consumption and 98% of connections, with commercial services also a significant consumer of the state's natural gas consumption.

Figure 3 and Figure 4 present consumption analyses of Manufacturing and Commercial sub-industries.

Figure 3: Gas consumption in Victoria by Manufacturing sub-industry, 2018-19

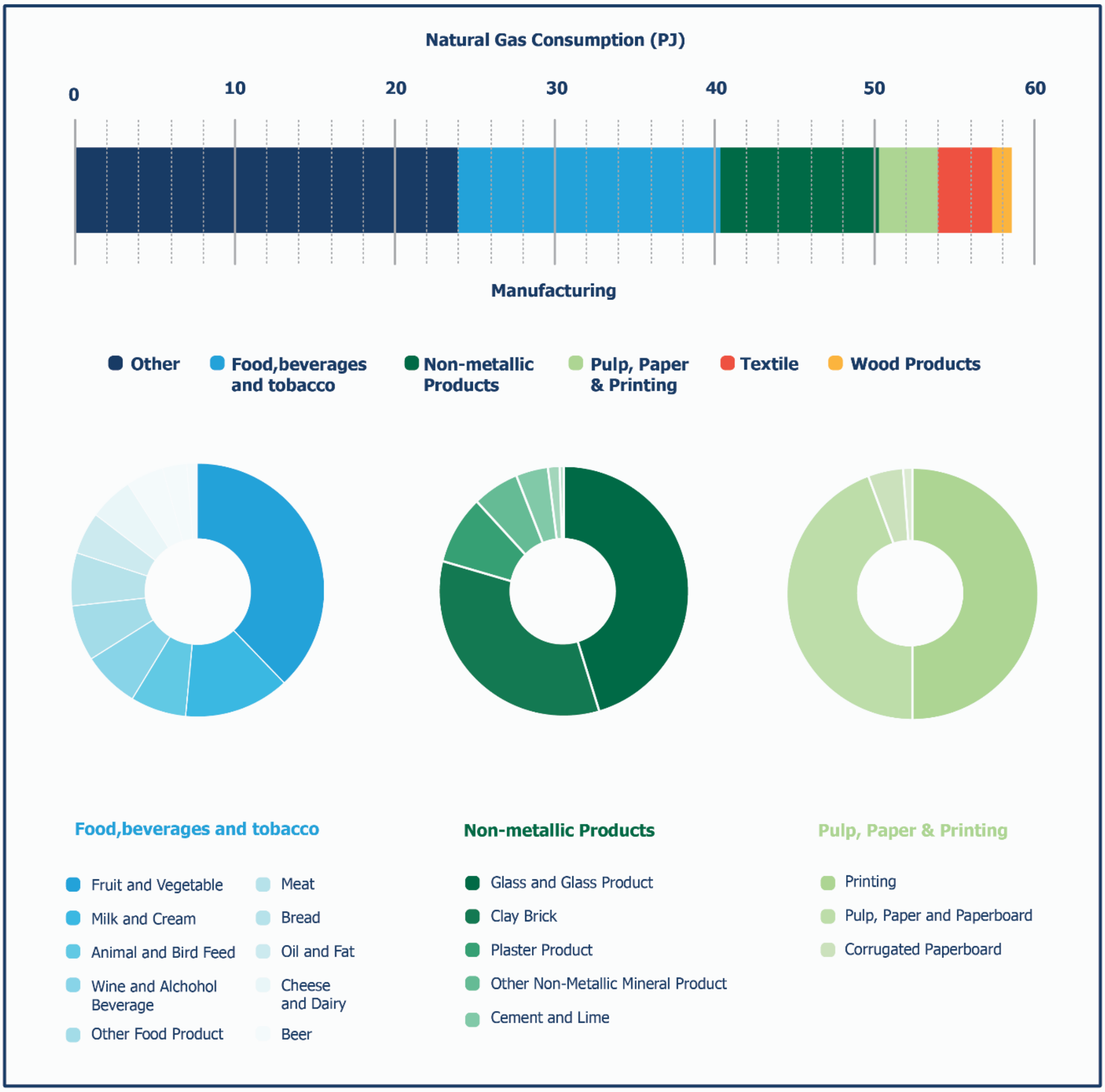
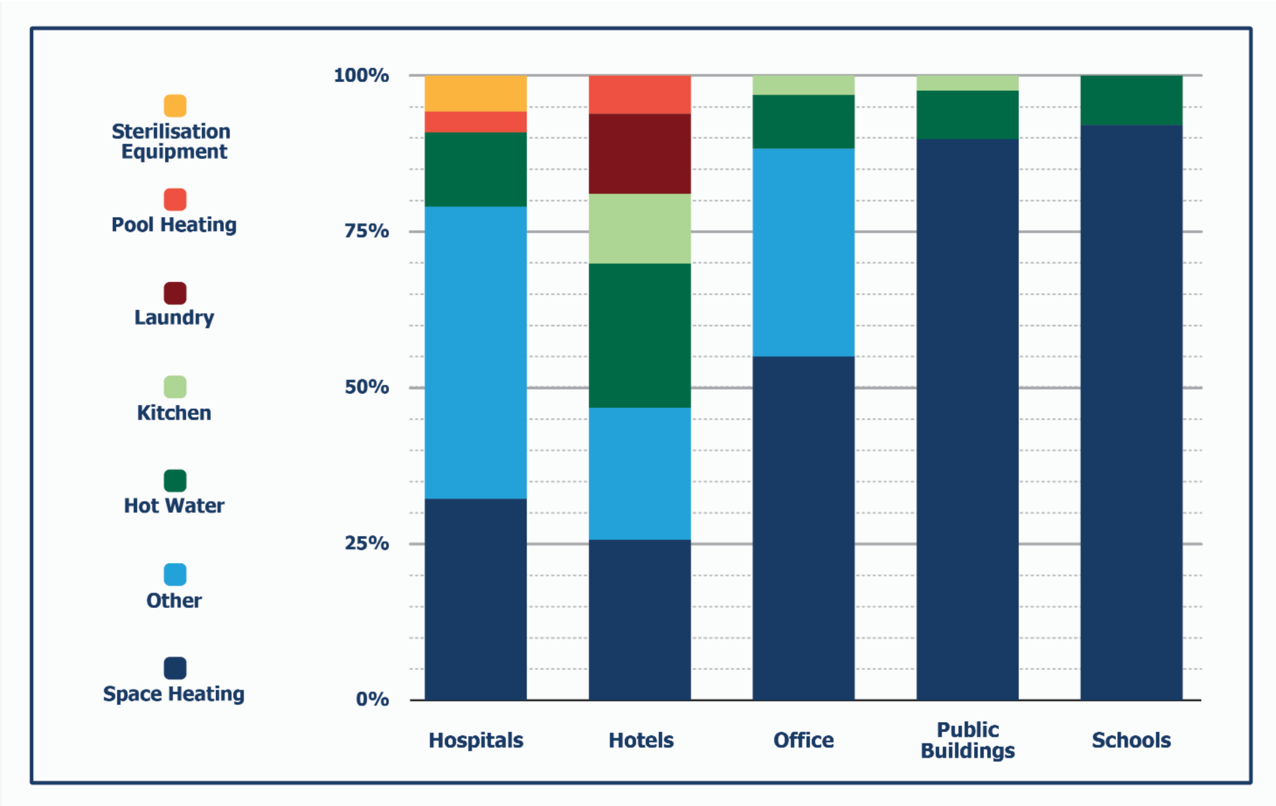


Figure 4: Gas consumption in Victoria by Commercial sub-industry, 2018-19



Because the fixed costs of distribution networks are shared across all users, the current model helps sustain affordable access to energy for major gas users to contribute to the Victorian economy effectively. Subsequently, the economic integration of gas demand and the coordinated abatement potential of residential, commercial and industrial customer segments are significant considerations for any approach to decarbonising gas supply.

Chapter 5 provides more detail on the appliances used by customers in these sub-industries, as well as assessing the suitability of these appliances for use with 100% hydrogen.

2.3. Forecast Gas Consumption

Determining a conservative forecast for natural gas demand, and therefore for hydrogen demand, was important to guide the analysis in the subsequent chapters. This Study adopts AEMO's Central Scenario as a conservative forecast of gas consumption for Victoria through to 2050, shown in Figure 5. This reflects the high-level assumption made throughout this Study that all existing uses of natural gas can be supplanted with 100% hydrogen.

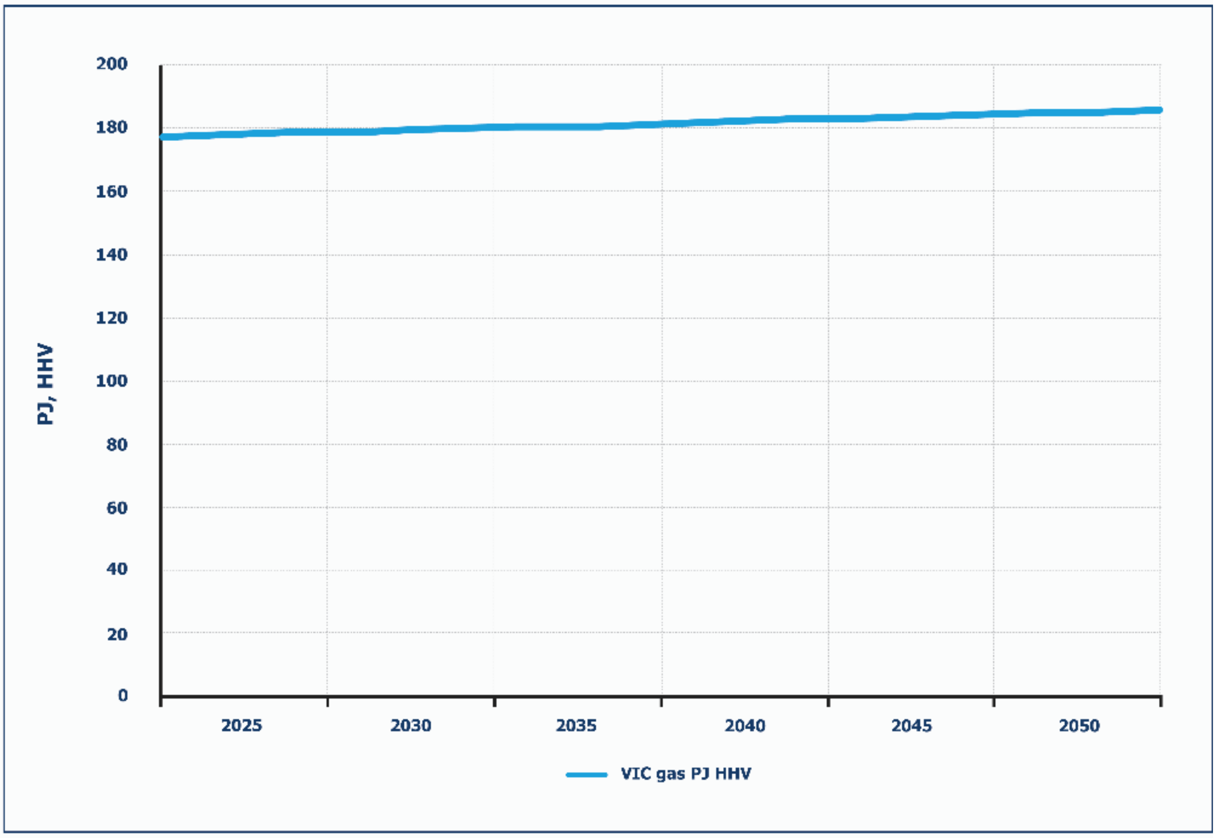
AEMO's 2021 GSOO uses gas data from producers regarding reserves and predicted production to forecast supply and demand measures as well as causes for a set of plausible scenarios. AEMO models three different forecast scenarios, "Slow change," "Central" and "Low gas price", which are based on a range of assumptions about the future evolution of energy use in Australia:

- **Slow change** – Explores reduced gas demand due to slowing economic activity and higher gas prices;
- **Central** – Uses AEMO's best view of future uncertainties; and

- **Low gas price (sensitivity)** – Explores potential impacts of lower gas prices on consumption by residential, commercial, and large industrial customers, and gas-powered generation.

The Central Scenario, as AEMO's conservative view of future potential scenarios, was considered the most appropriate demand forecast for the purpose of this Study.

Figure 5: Victorian gas consumption forecasts (2021 Central Scenario)



Since this Study commenced AEMO has produced subsequent GSOO's reflecting the impact of international conflicts, inflation, COVID-19 and other market uncertainties that have triggered a wide range of plausible futures for gas demand. For this reason, the opportunity to update this analysis frequently could be considered.

3. Renewable Hydrogen Supply, Storage and Transport

3.1. Technical Summary

This Chapter reviews the key supply chain components needed to deliver the volume of hydrogen required to transition natural gas distribution networks to 100% hydrogen, building on the foundations laid in *AHC's 10% Hydrogen Distribution Networks Study – Victoria* .

Natural gas loads for gas power generation and large industrial gas loads directly connected to the natural gas transmission system were excluded.

This analysis considers the hydrogen supply chain from production, storage and transport to the "gate station" between transmission and distribution pipeline systems[4].

The following sections review:

- electrolyser requirements;
- electricity requirements;
- water options;
- storage requirements; and
- transmission requirements.

The review found that to deliver 100% hydrogen in networks, several steps would need to be taken progressively:

Key findings

1. Electrolyser systems developed to large scale, such as 1 gigawatt (GW) units, with one-to-two 1 GW electrolysers being commissioned each year from the late 2040s installed in renewable energy zones (REZ) throughout regional Victoria.
2. Electrolyser water requirements could be provided with water sources not currently utilised by communities. The water would be treated to enable it to be utilised in the electrolysers.
3. Long-term hydrogen storage equivalent to 10% to 20% of annual gas demand could optimise Victoria's seasonal energy supply and demand profile. There is potential for existing geological stores to be used as cost-effective hydrogen storage technology options.
4. Factors of water, electricity and storage requirements drive siting and configuration of hydrogen production facilities. Newly constructed hydrogen transmission pipelines could connect supply to demand at gate stations.

4 Gate stations – which can also be referred to as injection points, City Gates, or custody transfer stations – are the gas transfer points between the gas transmission and distribution systems.

3.2. Hydrogen Production and Electricity Supply

3.2.1. Electrolyser Configuration

Detailed analysis was conducted to determine the optimum location of production facilities.

One option considered was downstream production connection in close proximity to load centres. This assumed seasonal demand could be delivered via the production facilities and long-term storage was not required. The production facilities would receive power from the REZ via new electrical transmission systems. This would require an expanded electricity transmission network.

Another option considered was locating production upstream in proximity to renewable electricity generation in the REZ, with hydrogen transported to storage by pipeline. The hydrogen would then be transported to demand centres via hydrogen transmission pipelines. This scenario adopted due to the analysis regarding storage requirements in Section 3.4.

3.2.2. Electrolyser Numbers and Capacity

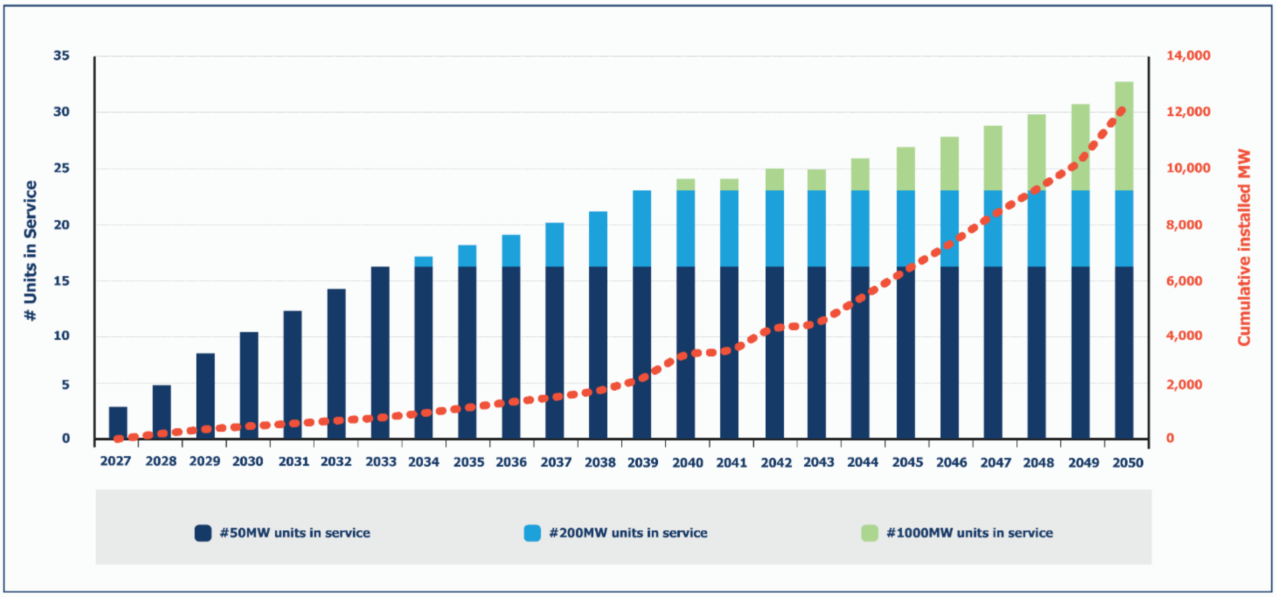
Modelled volume and size of required electrolysers to meet 100% of Victoria's load requirement is shown in Table 2.

Table 2: Indicative electrolyser configuration in 2050

Variable	
Aggregate electrolyser nameplate (MW)	12,000
Aggregate short-term storage (t)	1,000
Pipeline sales (t/year)	1,300,000
Service factor	73%
Load factor	89%
Capacity factor	65%
Total electrical load (GWh)	70,000

The rate of build-out of electrolyser capacity by assumed size of unit required to meet the load through to 2050 is shown in Figure 6.

Figure 6: Projected build-out of electrolyser capacity in Victoria



This rate does not include smaller scale units considered in the in the *AHC's Regional Towns Studies*. In these cases, regional production could supply to a hubs model of industry including power generation, transport, and agriculture, where gas distribution networks would represent a secondary offtake.

With electrolysers generally located in REZ, an indicative disposition of renewable capacity provides an indication of electrolyser capacity, shown in Table 3.

Table 3: Expected distribution of new renewable generation and subsequently of electrolyser capacity

REZ	Name	% Capacity
V1	Ovens Murray	0%
V2	Murray River	10%
V3	Western Victoria	32%
V4	South West Victoria	13%
V5	Gippsland	27%
V6	Central North Vic	18%

3.2.3. Renewable Electricity Supply

Section 3.2.2. outlines the total annual electricity load to achieve 100% renewable hydrogen in networks could be approximately 70,000 GWh. This Section summarises the modelling used for this Study to determine electricity prices for hydrogen production and the parameters besides electricity price that could enable a levelized cost of hydrogen (LCOH) of $2 per kg of hydrogen produced by 2040. The first is referred to as 'NEM Modelling' and the second, 'Standalone Modelling.'

The NEM Modelling of a 'with hydrogen' case is overlain onto a benchmark scenario (without hydrogen) that is based on AEMO's 'Central' Scenario in its 2020 Integrated System Plan (ISP). This provides insights into:

- additional renewable electricity requirements;
- cost of renewable electricity, including intra-day prices;
- use of electrolysers and storage to achieve optimal electricity prices.

The Standalone Modelling has been produced from the same parameters as the NEM Modelling but without connection of hydrogen production to the National Electricity Market (NEM). This gives insights into what parameters besides the price of electricity would lead to lower costs and reach optimal target costs for:

- hydrogen produced in Victoria;
- electrolysers, by capacity;
- storage; and
- transmission pipeline systems.

Following analysis, it was determined that a blend of the two models provided the optimal provision of electricity for generating hydrogen.

3.2.4. NEM Modelling

3.2.4.1. Approach

The NEM Modelling provides insights into intra-day prices of electricity and the simultaneous renewable transitions of the electricity and gas markets to 2050 and covers a 'with hydrogen' scenario and a benchmark 'without hydrogen' scenario.

3.2.4.2. Assumptions

The benchmark (without hydrogen) scenario incorporates relevant parameters from the AEMO Integrated System Plan (AEMO ISP) and new entrant generation to establish an outlook of the future of the electricity market without the load of hydrogen and extra generation added. A summary of these parameters is shown in Table 4.

Table 4: NEM Modelling assumptions

Assumption	Parameter	Benchmark scenario
Policy	Emission policy	26% emission reduction policy by 2050 on 2005 levels. No policy post 2030.
	Large Scale Renewable Energy Target	Implemented
	Victorian Renewable Energy Target	40% renewables generation by 2025 and 50% target by 2030
	Victorian Solar Homes Program	Implemented using AEMO Electricity Statement of Opportunities (ESOO) rooftop solar uptake for Victoria
	Victoria System Integrity Protection Scheme (SIPS) Project	Implemented
	Queensland Renewable Energy Target	50% generation target achieved by 2030.
	Snowy Hydro Expansion	Implemented in 2025
	NSW Roadmap	A lower weighted average cost of capital (WACC) (4%) for NSW projects is assumed until 2030. It is expected that the reduced costs of renewables determine the level of installed capacity.
	Tasmanian Renewable Energy Target (TRET)	Not implemented
	State policy after 2030	Only observable policies/market rules
Demand	Electric vehicle (EV) Growth	AEMO ESOO 2020 – Central scenario Compound annual growth rate (CAGR): 27.1%
	Photovoltaic (PV) and Storage	AEMO ESOO 2020 – Central scenario PV CAGR: 3.7%; Storage CAGR: 11.0%
	Demand growth	AEMO ESOO 2020 – Central scenario CAGR: 0.5%
	Demand side participation	AEMO ESOO 2020 – Central scenario CAGR: 4.5%
	Smelter closures	Continue operating
Fuel prices	Gas prices	AEMO Slow growth gas prices except with Australian Competition & Consumer Commission (ACCC)/ Japan Korea Marker (JKM) netback prices to 2025
	Coal prices	AEMO Central scenario
Technology costs	Renewable technology costs	AEMO/CSIRO Integrated System Plan (ISP) technology cost trajectories

Assumption	Parameter	Benchmark scenario
	WACC[5]	5.9%; NSW Government supported projects at 4%
Methodology	New entrant pricing for firm capacity	ISP Central for new coal and gas plant. Battery and pumped storage costs based on 2020 ISP Update.
	Renewable energy database update (list of committed and existing plants)	AEMO database of existing and prospective projects that have reached financial close
	Demand profiles	2013/14 hourly profile[6]
Interconnectors	Upgrades to Interconnectors	Planned and Actionable 2020 ISP projects implemented: Victoria to New South Wales Interconnector West (VNI-West) FY2028; Central timing for Queensland-New South Wales Interconnector (QNI) Medium and Marinus Link
Generator performance	Plant exit dates	In line with AEMO ISP expected closure years, or earlier if economic to do so under Central scenario conditions.
	Mothballing	Mothballing based on economic factors under Central scenario conditions.

The NEM Modelling has also been based on a requirement that electrolysers are supplied with renewable electricity, even though they would be grid-connected. It is proposed that this requirement would be met by requiring any additional generation in the 'with hydrogen' scenario beyond the amount in the 'without hydrogen' scenario to be renewable energy. Additional Battery Energy Storage Systems (BESS) and Pumped Hydro Energy Systems (PHES) were accepted in the analysis where this improved the overall price.

The model also factors in the progressive deployment of hydrogen to displace natural gas, that is, a transition to maximum 10% hydrogen by 2030 followed by a further transition to 100% by 2050. It is included in this analysis to explain the implications that steps required to achieve 10% hydrogen would have on 100% hydrogen activities.

5 AEMO 2020 ISP Inputs and Assumptions Workbook (note: pre-tax real), can be found here: <https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2019-input-and-assumptions-workbook-v1-5-jul-20.xlsx?la=en>

6 Adjusted for load growth and roof-top solar generation.

3.2.4.3. Results and Outcomes

The NEM Modelling reflects the impacts of long-term storage, plus the co-optimisation of the daily dispatch of electrolysers using short-term storage. This flexibility has an important impact in lowering the load-weighted prices that the electrolysers are expected to experience below the time-weighted average prices that would be experienced by a flat-load profile.

It also provided the following insights, which are especially relevant to this study:

- The potential spatial distribution of renewable electricity technologies and capacities between the REZ (see Table 4). This informs the conceptual layout of electrolysers and sizing of a potential hydrogen transmission system as described in Section 3.5.
- The 'with hydrogen' scenario appears to cause an increase in NEM time-weighted-average prices through the 2030s, although this impact in the 2040s is relatively neutral compared to the 'without hydrogen' benchmark scenario.
- The renewable hydrogen load in Victoria stimulates new renewable energy production in other states. About 25% of the extra capacity is in other NEM regions, showing the benefits of synergies with the broader market. Prices would be higher if the renewable generation were constrained to be only local to the electrolysers.
- The increase in generation energy appears to be less than the increase in load energy over the NEM. This is partly due to the hydrogen load reducing curtailment of renewable electricity that would have occurred in the 'without hydrogen' benchmark scenario. This was expected given that the electrolyser load was modelled with day-to-day flexibility provided by short-term storage.
- There appears to be a decrease in price volatility with the flexible hydrogen load. For example, there is more Demand Side Participation (DSP) dispatched under the 'without hydrogen' benchmark scenario, especially as the penetration of renewables increases sharply in the mid-to-late 2040s Where hydrogen production facilities are developed to incorporate flexible production, the hydrogen load itself appears as a form of low-cost DSP.

3.2.5. Standalone Modelling

3.2.5.1. Approach

A target levelized cost of hydrogen (LCOH) has been identified as $2 per kg of hydrogen by around 2040. The NEM Modelling identified the impact electricity prices and other parameters have on LCOH, and that these constrain the analysis from achieving all the synergies that might otherwise produce a lower cost.

Considering this, the Standalone Modelling was conducted to give insight into what other parameters could lead to lower cost options and reach optimal target costs for:

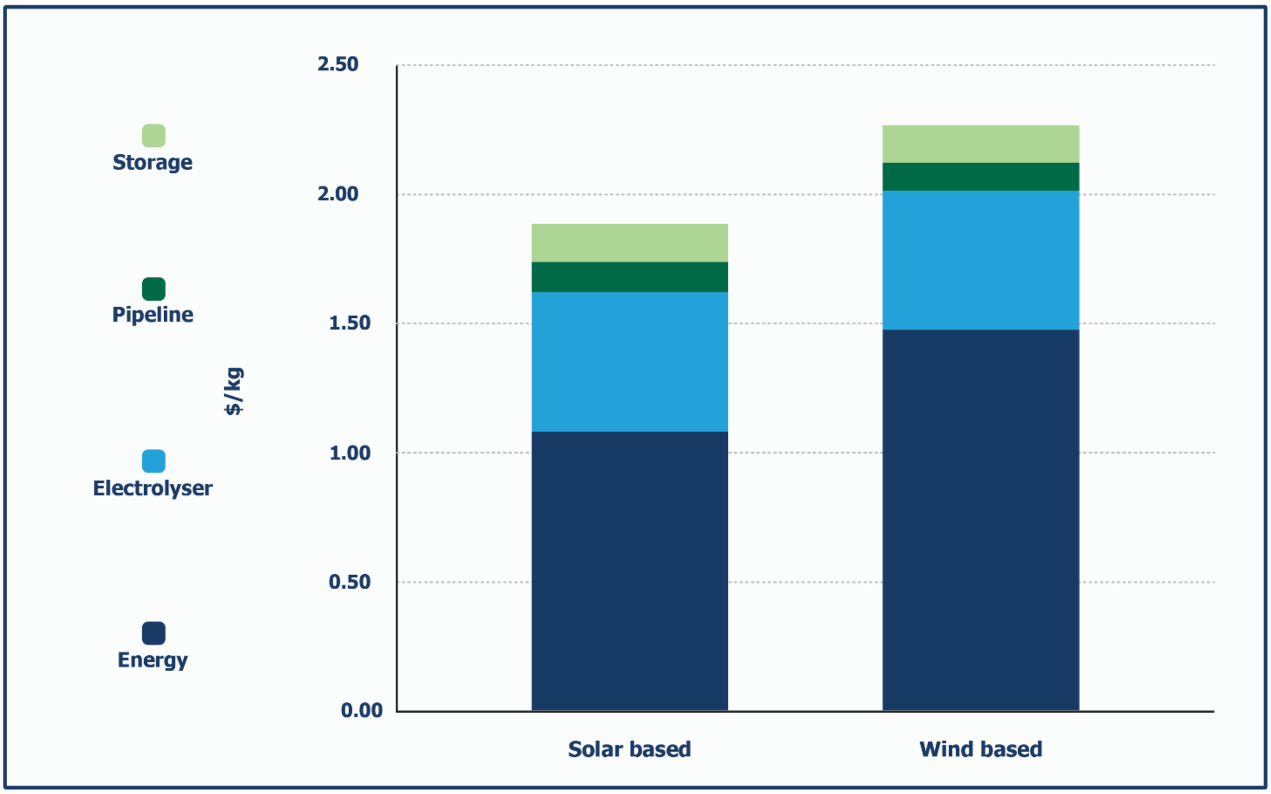
- hydrogen produced in Victoria;
- electrolyser capacity options;
- storage configuration options; and
- transmission pipeline systems.

Some of these insights are discussed below to inform subsequent investigations beyond the scope of this Study.

3.2.5.2. Results and Outcome

A general cost structure to achieve the $2 per kg of hydrogen target cost was produced using the Standalone Model, shown in Figure 7.

Figure 7: Indicative cost of hydrogen build-up by generation source



These electricity costs are based on the AEMO ISP parameters for 2050, with a 30% capacity factor for solar and 40% capacity factor for wind applied. Generation costs include connection costs but otherwise are on an ex-plant basis.

Electrolyser parameters also apply the 2050 assumptions but assume a 75% capacity factor. That this capacity factor differs from the capacity factor of supplying generation technologies implies that electrolysers need to be connected to the NEM to have the benefit of synergies across other power plants' operations, and other loads, rather than only being close coupled to a nearby solar or wind farm or both.

Connection costs are included both for the renewable energy plant and the electrolysers to connect to the grid, though it is assumed that no other electricity transmission cost or fee is applied.

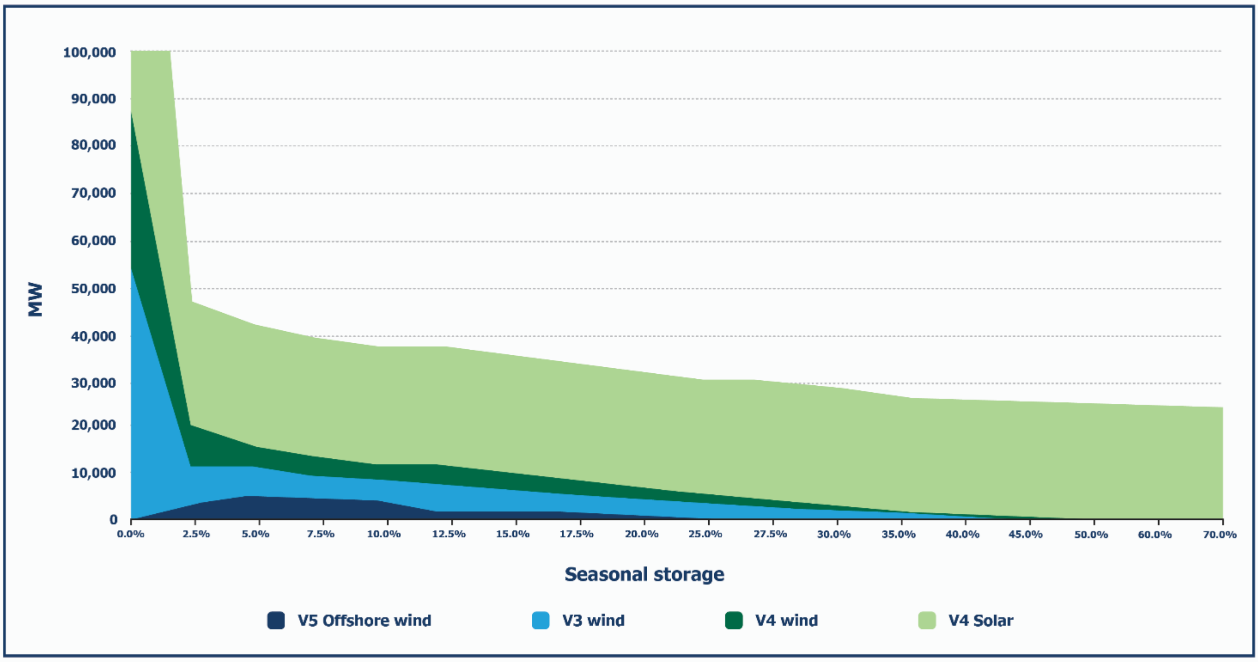
It is assumed that long-term storage can be developed at around $10 per kg of hydrogen stored, and that the transmission pipeline systems – when they are developed – can be built for a 40% lower cost than is indicated. This reflects that the starting costs for storage and pipelines are estimates for current technologies and specifications and would be lower with the benefits of developments in science or engineering, learning-by-doing, or scale economies, that would result from developments across the world, like advancements made in renewable power and electrolysers.

Using this cost structure, the system build-up shown in Figure 8 was modelled with wind and solar generation (across relevant REZ) in the optimal mix to meet the energy needs of daily gas load profiles in Victoria. This model optimises the mix of generation to achieve zero gas curtailment in the reference year (2019 gas flows) at minimum renewable energy cost and is a standalone system that is not integrated with the NEM or other markets.

From this system build-up model, the following key findings were made:

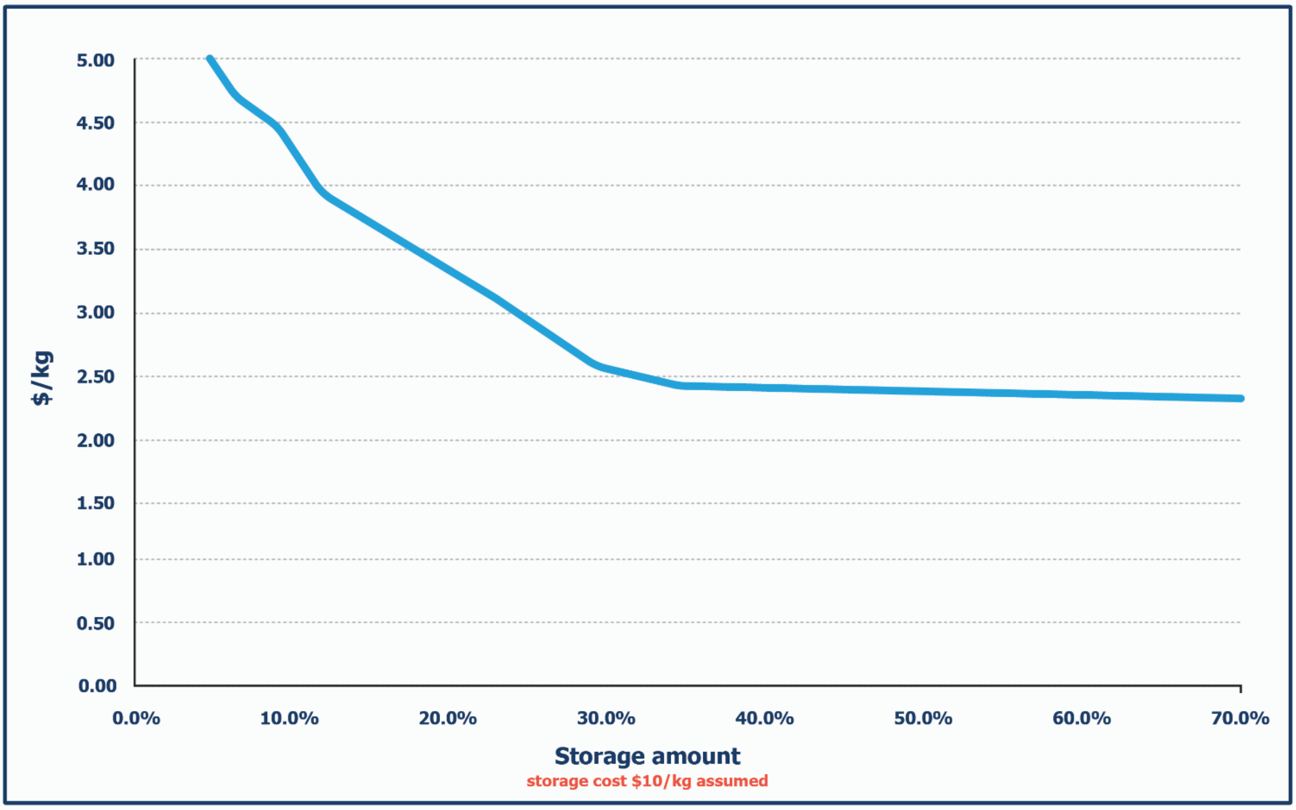
- The optimum mix of generation changes as more long-term storage becomes available.
- More storage allows less reliance on more expensive renewable energy sources that are otherwise necessary to match the daily load profile of gas.
- Solar PV is the cheapest form of electricity supply in 2050 and thus becomes the lower limit in generation capacity amount where sufficient long-term storage is provided (above approximately 60% annual storage in Victoria).

Figure 8: Renewable energy mix by REZ for a standalone hydrogen production system in Victoria



Using the assumptions discussed above, and for a stand-alone system, the projected costs for Victoria were modelled, as shown in Figure 9.

Figure 9: Projected costs of a stand-alone hydrogen production system in 2050 - Victoria



Actual outturn costs in the future could be in a broad range around the estimated values, but the estimates provide an indication of where particular attention should be directed to achieve lower costs for hydrogen production.

3.2.6. NEM | Standalone Modelling Comparison Conclusion

Electricity prices indicated by the NEM modelling 'with hydrogen' scenario in 2050 tend to be higher than those that could be produced by the standalone modelling, noted in Section 3.2.5.2. It may be that the standardised inputs used in the NEM modelling (e.g., the parameters of the ISP Inputs and Assumptions Workbook) are not suited to the scale of the renewable hydrogen load transition assessed in this study. However, the standalone model does not reflect the synergies of integrating electricity for producing hydrogen with the NEM.

As a result, analyses in subsequent chapters of this Study use energy prices from both the standalone model – that target the (approximate) $2/kg real hydrogen cost – and the NEM modelling. The latter prices were considered to have more relevance in the earlier period to 2030 when the impact of the extra load is much less, so energy prices from the standalone modelling were given a progressively heavier weighting in the assessed values from 2030 to 2050.

3.3. Sustainable Water Sourcing

Electrolysis requires water is treated at site to what is commonly referred to as ultra-pure water. Total untreated water requirements for hydrogen production will vary depending on a range of factors including the specific electrolysis technology used, the quality of untreated water, and the need for additional water for indirect production requirements such as cooling.

Water is a precious resource, and existing uses of high-quality already compete for limited sources of ground and surface water. Given hydrogen production requires the purification of any untreated water source regardless of its quality, the "raw" water could be sourced sustainably from lower quality options including sea water, brackish groundwater and recycled wastewater, which would avoid competition with existing demands for higher quality ground and surface water.

Key findings

1. About 26,000 ML of water would be required each year to produce sufficient hydrogen for 100% hydrogen in Victoria's distribution networks.
2. Recognising water is a precious resource, it could be sourced sustainably and avoid competition with existing demands by drawing on lower quality options including sea water, brackish water and recycled wastewater.
3. Treatment of low-quality water would be a small cost in compared to other factors, in the order of $0.014 per kilogram of hydrogen produced.

3.3.1. Water Requirements

In electrolysis, the basic chemical ratio of water required to produce hydrogen is 9:1. This is generally greater for utility scale electrolysis to account for treatment and production losses, which was factored in the analysis by assuming a target water consumption ratio of 20 L per kg.

On this basis, and with current technology, approximately 1,300,000 tonnes of hydrogen would need to be produced annually to support 100% hydrogen in Victorian networks. This volume of hydrogen would require 28,400 ML of water annually, set out in Table 5.

Table 5: Estimated annual water consumption for hydrogen production in Victoria

100% hydrogen by 2050	
Hydrogen production, tonnes	1,300,000
Water usage, ML	26,000

This equates to 0.26% of the annual physical water use in Victoria in 2019-20[7] and 6.7% of annual physical water use in Melbourne Water's network in 2019-20[8]. A comparison with other high water use industries in Victoria can be found in Table 6.

7 ABS Water Account Australia 2019-20, Physical Supply and Use, by Water Type, Victoria, <https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia>

8 Melbourne Water, Melbourne's Water Outlook, <https://www.melbournewater.com.au/media/15436/download>

Table 6: Physical water use of industries in Victoria versus water requirement for 100% hydrogen (Megalitres), 2019-20[9]

Industry	Water use (ML)	Proportion of total annual physical water use in Victoria	Approximate equivalent average household water consumption
100% hydrogen supply (projected)	26,000	0.26%	189,330 homes
Agriculture	1,995,624	18.5%	13,304,160 homes
Mining	20,585	0.19%	137,233 homes
Manufacturing – electricity and gas supply[10]	28,778	0.26%	189,330 homes

3.3.2. Sourcing options

In providing 100% hydrogen supply, water requirements for hydrogen production could increase alongside other demands on Victoria's water supply. Recognising water is a precious resource, it will be important to ensure that water for hydrogen production is sustainably sourced, even though it would require comparatively low volumes.

Given analysis in Section 3.2, water supply would generally be required in regional Victoria. Each region has unique water challenges and high-quality sources are generally fully utilised. Existing developed sectors place significant value in these sources and as a result, high-security entitlements of high-quality water are infrequently traded.

Recognising hydrogen production via electrolysis requires raw water to be treated to produce ultra-pure water regardless of starting quality, lower quality sources may be suitable for hydrogen production at a minor incremental cost further considered in Section 3.3.3. Water options and notes on availability are outlined in Table 7.

A high-level initial analysis of water options has carried out for North-West and Central and South-West Victoria and Gippsland. These can be found in Section A of the Appendix.

9 Note, water use included the following water types: self-extracted, distributed, wastewater, and reuse.

10 Note, ABS data on use of self-extracted water for Manufacturing – electricity and gas supply are not available for publication, and a breakdown of all water use by generation type could not be found. However, in February 2021 the Victorian Mine Land Rehabilitation Authority attributed an annual average of 78,000 ML of self-extracted water to coal-fired generation in the Latrobe Valley, with around 23,000 ML released back to the system as return flows. More information can be found here: <https://www.mineland.vic.gov.au/wp-content/uploads/2021/03/MLRA-Webinar-1_Action-3_DELWP-presentation.pdf>

Table 7: Water options and notes on availability or appropriateness

Water option	Main/current uses	Notes on availability/appropriateness
Surface water	The main uses of surface water and low-salinity groundwater are for agriculture, town water supply and, in regional areas, Stock and Domestic needs. These water sources are highly valued and needed by these existing sectors.	Availability is impacted by climate, stakeholder sentiment, and competing uses. Users also require an entitlement under the Water Act 1989 to access surface water and there is very little that has not already been allocated and or under entitlement. Any need for these resources could only be accessed via trade with existing entitlement holders. Suitable alternatives for hydrogen production exist, meaning the hydrogen industry does not need to compete with these users.
Recycled wastewater [11]	In Victoria, wastewater is allowed to be recycled for non-drinking purposes and treatment plants in the Melbourne Water network process sewage into Class A recycled water. In 2019-20, 84% of wastewater produced was released as return flows and consumption of the remaining 79 GL was: 7% for environmental benefit, 15% for water corporation processes, 25% urban and industrial uses, 53% agricultural uses. Oxygen, which is a fundamental by-product of hydrogen production, could be used in wastewater treatment processes.	Between 2004-05 and 2019-20, the volume of wastewater produced in Victoria increased in line with population growth. However, the amount of wastewater that was recycled remained around 100,000 ML per year, indicating underuse. The amount of wastewater produced in 2019-20 and released as return flows equates to approximately 493,750 ML. If any of this amount was not required for return flows, and provided it was of adequate quality, it could be sufficient for 100% hydrogen in networks by 2050. Government stakeholders have a good understanding of the barriers to using recycled water, which include public perception that it is a waste product rather than a potential water resource. Further study should investigate if this barrier would apply to using recycled water for 100% hydrogen by 2050. Further study should also examine the potential to integrate by-product oxygen from hydrogen production with wastewater treatment processes, which could yield efficiency gains and cost reductions. If available, these sources may prove more suitable and accessible for a hydrogen industry than limited surface and ground water.
Groundwater	Groundwater is a key feature of existing water use activities across Victoria and plays a significant or even dominant role in supplying water across the state. However, usage of higher salinity groundwaters is more limited, as these sources require desalination for use in potable or agricultural applications.	Victoria has been estimated to have a sustainable groundwater source yield of 998 GL/y 12 at a rate of 5000mg/L salinity or above. These sources are substantially untapped at present. Availability is impacted by climate, stakeholder sentiment, and competing uses. Users also require an entitlement under the Water Act 1989 to access ground water and there is very little that has not already been allocated and or under

11 Victorian Auditor General's Office (VAGO). 2021, Supplying and Using Recycled Water, viewed 1 February 2022 <https://www.audit.vic.gov.au/sites/default/files/2021-11/20211117-Supplying-Recycled.pdf>

12 National Centre for Groundwater Research and Training. 2014, Groundwater in Australia, viewed 11 November 2021 <http://www.groundwater.com.au/media/W1siZiIsIjIwMTQvMDMvMjUvMDFfNTFfMTNfMTMzX0dyb3VuZHdhdGVyX2luX0F1c3RyYWxpYV9GSU5BTF9mb3Jfd2ViLnBkZiJdXQ/Groundwater%20in%20Australia_FINAL%20for%20web.pdf>

Water option	Main/current uses	Notes on availability/appropriateness
		entitlement. Any need for these resources could only be accessed via trade with existing entitlement holders. Suitable alternatives for hydrogen production exist, meaning the hydrogen industry does not need to compete with these users.
Sea water	Sea water salinity tends to be 30,000 to 35,000 mg/L around Australia and once desalinated, can produce water suitable for either human consumption or for agricultural or industrial purposes.	The Victorian Desalination Plant in Wonthaggi is capable of desalinating seawater to produce 150GL/year – about 33% of Melbourne's water supply at full capacity. The Victorian government generally places an order each year, with a maximum lifetime cost of $5.7bn to 2039. Currently, there are no other desalination plants in Victoria operating or in development. Indicative costs are produced in Section 3.3.3.
Brackish and storm water	Brackish water sources have lower salinity than sea water	Reverse Osmosis desalination plants for brackish water have lower capital costs and lower power consumptions than for sea water and would be preferred water source provided that environmentally compatible disposal or appropriation for the brine/salt by-product could be identified. Currently, no such plants are operating or in development in Victoria. Indicative costs are produced in Section 3.3.3.

3.3.3. Cost and Energy Consumption

Desalinated brackish water may be a likely option, yielding a low electricity cost per tonne of hydrogen produced (0.1 MWh per tonne of hydrogen) compared with the overall cost of electricity used in an electrolyser and storage.

This would enable Reverse Osmosis (RO) plants to be run at lower capacity factors when there is excess renewable energy generation available, and for water to be stored in tanks or dams. At a 30% capacity factor, the cost of the RO-produced water would be approximately $1 /kL.

Purpose-built desalination facilities that are in proximity to demand centres or REZ might be most effective for meeting water requirements for production. A future hydrogen market could monitor other sectors that may be interested in desalination in these locations and seek to align the water requirements of both to limit costs and gain other efficiencies.

A recent example is the sea water desalination plant at Whyalla steelworks in South Australia, which was commissioned in 2011 and produces around 1.6 GL of desalinated water each year. Indicative costs for achieving RO desalination in 2050 are shown in Table 8.

Table 8: Indicative costs of reverse osmosis desalination[13]

	Sea water	Brackish water (15,000 mg/L)
Capital cost	$80 per kL/day capacity	$50 per kL/day capacity
Energy	5 kWh/kL	3 kWh/kL
Fixed operating costs	$0.03/kL	$0.03/kL
Membranes/chemicals	$0.01/kL	$0.01/kL

Assuming an electricity cost of $70 /MWh[14], a base-load desalination system would produce water at $0.70 /kL for sea water and $0.45 /kL for brackish water. For 20 kL/tonne hydrogen, the cost impact is expected to be of the order of $14 /tonne or $0.014/kg of hydrogen, which would not be material to the overall hydrogen system costs.

These costs include power recovery but not zero-water-discharge systems. The fixed opex in these costs is integrated into a larger plant operation (such as the electrolyser plants) on an incremental basis. The product water, at 400 mg/kL salinity, would still require final treatment for use in the electrolyser itself, and this has been costed and incorporated into the electrolyser plant cost assessment in Section 3.6.2 of this Study.

Desalinated water with salinity of 400 mg/kL would also be acceptable for many uses including town water (potable) and agriculture[15]. Any spare capacity built into a RO plant would have potential application, particularly in regional Victoria, subject to the variable cost being acceptable to the end user.

13 Source: Jacobs analysis for the Australian Hydrogen Centre

14 A desalination plant is considered more likely to run baseload with water storages and hence will pay a more time-weighted-average price for electricity than an electrolyser facility as desalination is strongly capital intensive instead of electricity usage dominated.

15 SA Health, Salinity and drinking water, viewed 20 October 2021
<https://www.sahealth.sa.gov.au/wps/wcm/connect/public+content/sa+health+internet/public+health/water+quality/salinity+and+drinking+water>

3.4. Storage Requirements

Long-term storage is key to achieving 100% hydrogen in networks efficiently for the following reasons:

- Ensures there is sufficient hydrogen available to meet demand in cooler months when consumer heating needs tend to increase (as shown in Figure 2) and outstrip production;
- Ensures electricity generation capacity and electrolyser capacity needed to produce hydrogen is balanced across the year; and
- Allows the electrolyser to operate efficiently using low electricity prices to produce hydrogen for storage which can be used to support distribution areas and the development of new hydrogen markets such as transport.

The location of long-term storage will also impact whether energy used for production is transferred via 'pipes' or 'wires'. This is partly dependent on the availability of cost-effective storage technologies that are location specific.

The purpose of this Section is to identify the need for long-term storage in 100% hydrogen and summarise potential and optimal storage technologies.

Key findings

1. Long-term storage equivalent to 10% to 20% of annual gas demand could optimise Victoria's seasonal energy supply and demand profile, lowering the overall cost of delivered hydrogen.
2. There are several potential cost-effective long-term hydrogen storage technology options, including geological stores such as salt caverns and depleted natural gas reservoirs, and liquid chemical hydrogen carriers.
3. Mitigating and leveraging 'spilled' renewable electricity would have cost implications for the storage configuration selected, and there is likely value in exploring the integration of long-term storage with other markets. Synergies with these markets may enable use of electricity that would otherwise be curtailed and would materially lower the cost of serving all the markets relative to their standalone market costs.
4. Further work is required to understand the most effective method of storing hydrogen at a low cost, and its implementation.

3.4.1. Definitions

Short-term storage

Short-term storage is used to refer to intra-day storage systems that are optimal for cycling (i.e., storing and retrieval of gas) on a daily or even hourly basis. Such systems are small-scale and useful for managing short-term challenges in hydrogen production, including electricity price spikes, load changes, and short-term redundancy requirements.

These systems would not typically attract economies of scale or perhaps benefits of learning-by-doing. Instead, regular cycling means the key economic requirement of short-term storage systems is that the cost of storing and retrieving gas is very low.

Long-term storage

Long-term storage is used to refer to inter-seasonal storage used to balance the winter-bias of the gas market load and the seasonal biases of wind and solar electricity generation. This type of storage enables less electricity generation capacity and electrolyser capacity requirements, as well as access to the lowest cost renewable electricity technology mix.

The key economic requirement of long-term storage is low cost per kilogram of hydrogen stored. In contrast to short-term storage, the cost of storing and retrieving gas in these systems is a secondary economic consideration. By the 2030s, the costs of long-term storage systems may have reduced due to technological developments, learning-by-doing, or scale economies.

3.4.2. Impact of Long-Term Storage on Load-Flattening

Demand analysis points to the need for long-term storage to manage the significant fluctuation in demand between winter and summer in Victoria. Currently, the natural gas load differential in Victoria between winter and summer is 5:1 and is balanced across the year by storage at Iona UGS and Dandenong LNG, which is capable of storing around 10% of Victoria's annual load. This process is called 'load-flattening'.

Preliminary analyses undertaken for this Study have demonstrated how, in the Victorian context, system-wide electrolysers would operate with different levels of long-term storage for hydrogen in 2050. In these analyses, storage behaviour options that were reviewed included:

- replicating current Iona injections and withdrawals;
- a simple summer-to-winter transfer; and
- a strict transfer from the minimum percentile gas days in the year to the maximum days (i.e., maximum gas load flattening).

The third option was found to provide the most benefit, and the impact on net daily load profiles is shown for 2%, 10%, and 19% annual storage volumes for Victoria in Figure's 10, 11, and 12 respectively, where the maximum level of storage capacity needed to completely flatten the net daily load profile is 19% of annual network flow in Victoria.

This indicates that the level of long-term storage which could aid with managing seasonal supply:demand variation is in the order of 10% to 20% of Victoria's annual gas load. If storage can be found at a low cost (i.e., ≤$10 per kg storage) then 20% or more storage could be beneficial.

Note, these figures are illustrative only as they reflect the use of the long-term storage in 'flattening' the load over the year, and the actual optimum operation would flatten the net load instead.

Figure 10: Impact of 2% storage optimally arranged to flatten Victorian 2019 gas usage profile

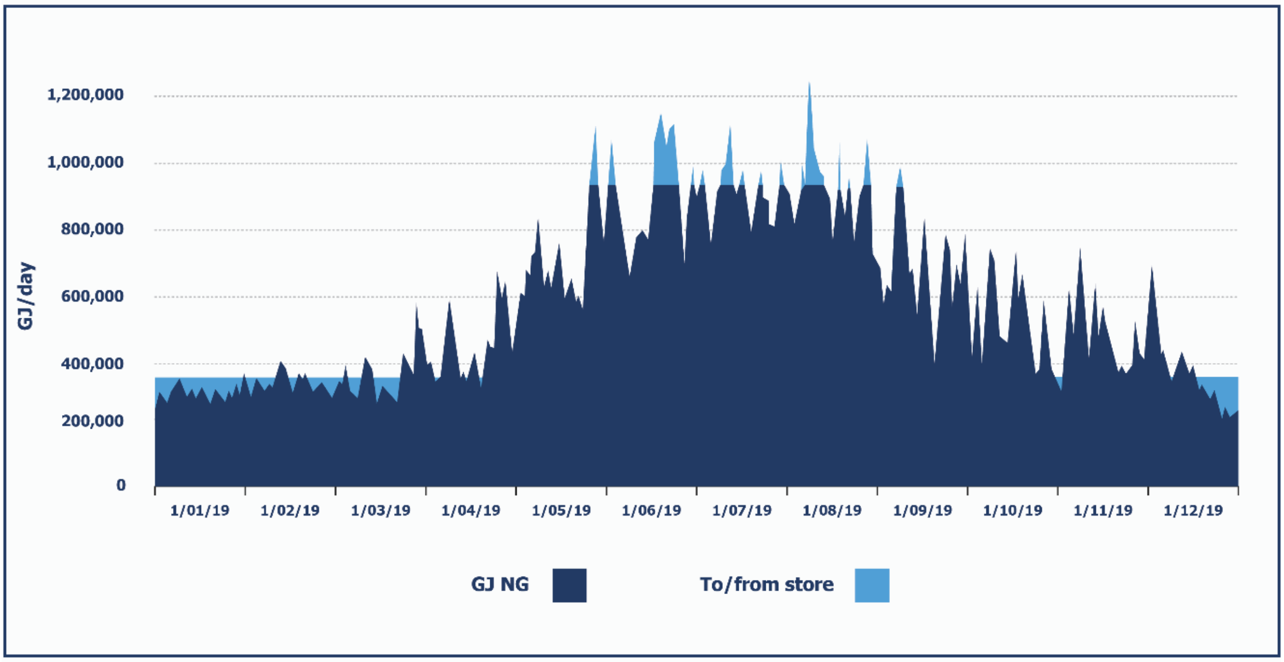


Figure 11: Impact of 10% storage optimally arranged to flatten Victorian 2019 gas usage profile

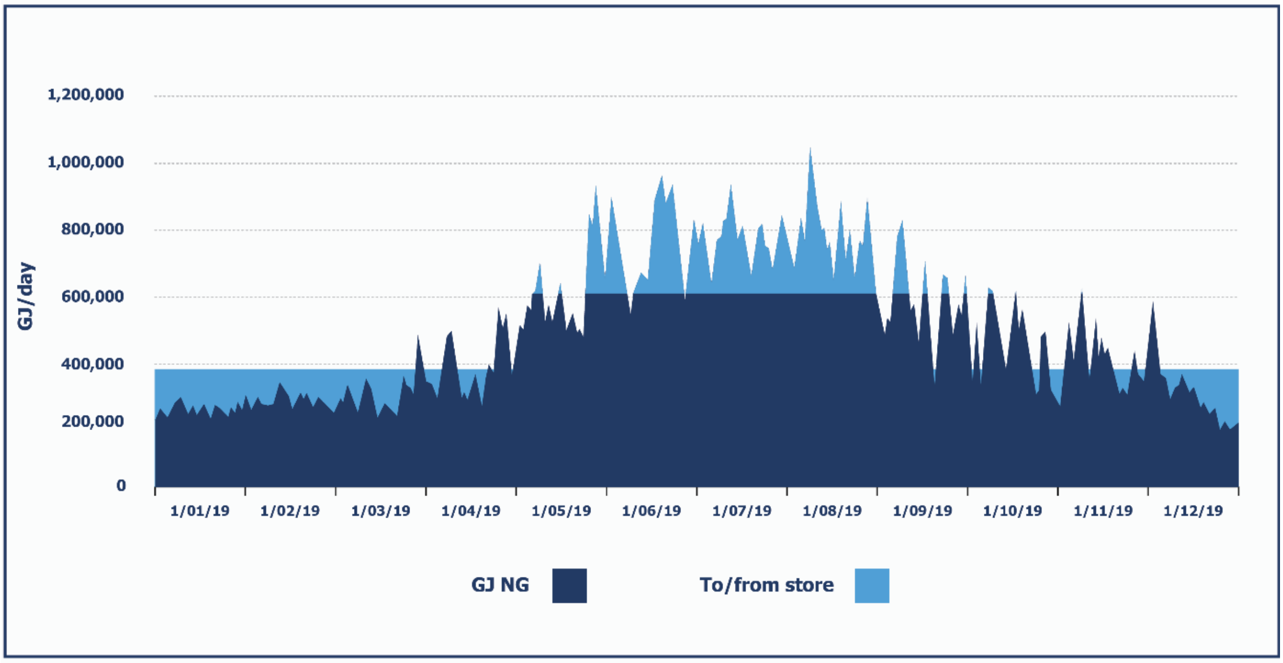
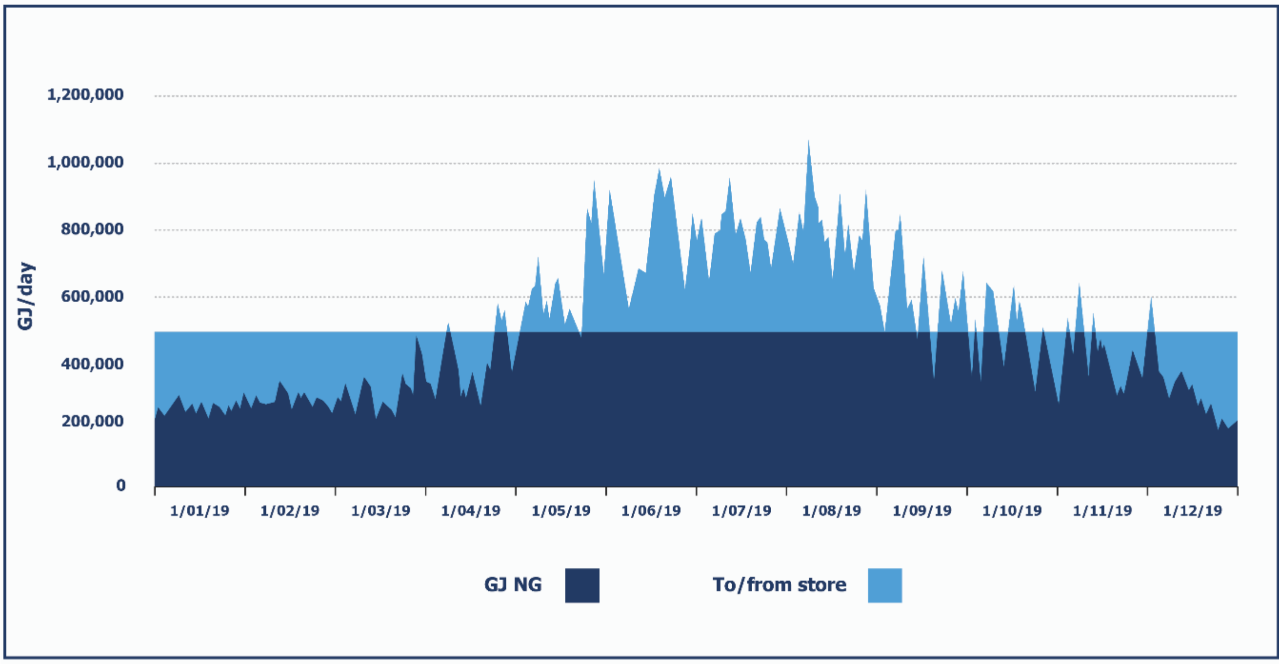


Figure 12: Impact of 19% storage optimally arranged to flatten Victorian 2019 gas usage profile



3.4.3. Impact of Long-Term Storage on Renewable Energy Spill

Long-term storage may be important for mitigating renewable electricity 'spill', as well as countering seasonal load differentials in the hydrogen use profile.

The term "spill" comes from hydroelectricity generation, where the water that does not go through the turbine to generate electricity is called 'spill'. The corresponding term for when wind and solar systems cannot generate electricity (either because of inadequate load or network issues) is 'being constrained'. 'Spill' refers to the lost opportunity to use the otherwise free marginal cost energy source at these times.

Even without the development of a renewable hydrogen market with its seasonality, the transition of the electricity market from dispatchable fossil fuel-based generation to intermittent renewables over a similar timeframe will be challenging.

Although some spill mitigations could be provided by battery energy storage systems (BESS), pumped hydro energy storage (PHES), and diversity in load and generation from a widespread electricity network, it is still likely to occur. Adding a renewable hydrogen market to the equation without significant storage capacity would dramatically increase that likelihood.

As the cost of electricity is the largest component of the levelized cost of renewable hydrogen production and supply, opportunities that utilise additional 'free' electricity in the hydrogen market should be explored.

3.4.3.1. Modelling Spill

NEM Modelling with combined storage

Utilising (i.e., reducing) what would otherwise be spilled electricity could be achieved by:

- adding more long-term storage;
- diversifying load/generation and shared infrastructure (e.g., storage) by integrating the electricity and hydrogen systems into larger markets.
- both of these.

The combined electricity and hydrogen modelling undertaken for this study (explained in Section 3.2.4) already has a component of these synergies applied. This was done in the electricity market modelling by allowing the electricity market to shift the hydrogen production load around using its short-term storage, and to optimise the addition of extra renewable generation (and added BESS/PHES) across the whole NEM, not just Victoria. However, this modelling becomes highly uncertain towards 2050 because of inbuilt constraints that do not suit the very different generation requirements to serve the hydrogen production load as well as the NEM load.

Standalone Modelling with storage

To see the impacts of changing storage capacity and observe the magnitude of the potential spill opportunity, a separate analysis has been undertaken based on the stand-alone system of the Victorian hydrogen market served by its own renewable electricity generation system. This model analyses how much renewable energy is added, the amount of spill, and the cost structures for hydrogen production based on the hydrogen demand identified in Chapter 2 and considering if the spill could be utilised in developing other markets for hydrogen, such as transport.

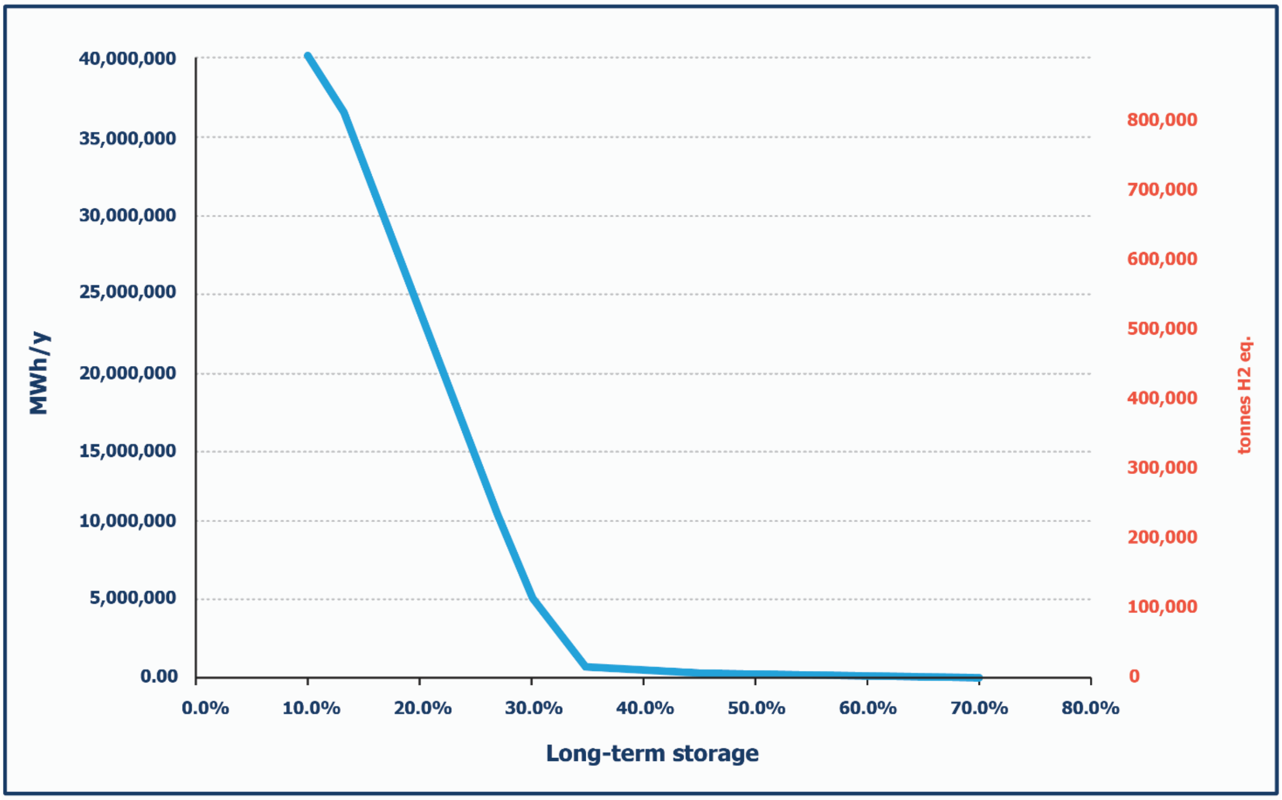
It found that additional electrolyser capacity would generally be required to process the otherwise spilled renewable electricity, and extra pipelines and renewable generation capacity would not be required.

At various levels of hydrogen storage, the standalone system model estimated:

- the amount of spilled renewable electricity; and
- the amount of hydrogen that could be produced if the spill were captured and converted for some valuable market use.

For the standalone model at various levels of hydrogen storage, Figure 13 shows the estimated amount of spilled renewable electricity and the amount of hydrogen that could be produced if the spill were captured and converted for some valuable market. The potential spill of renewable electricity is very large at low amounts of long-term storage.

Figure 13: Spilled renewable electricity in 2050 at varying storage levels and tonnes of hydrogen equivalent if converted, Victoria

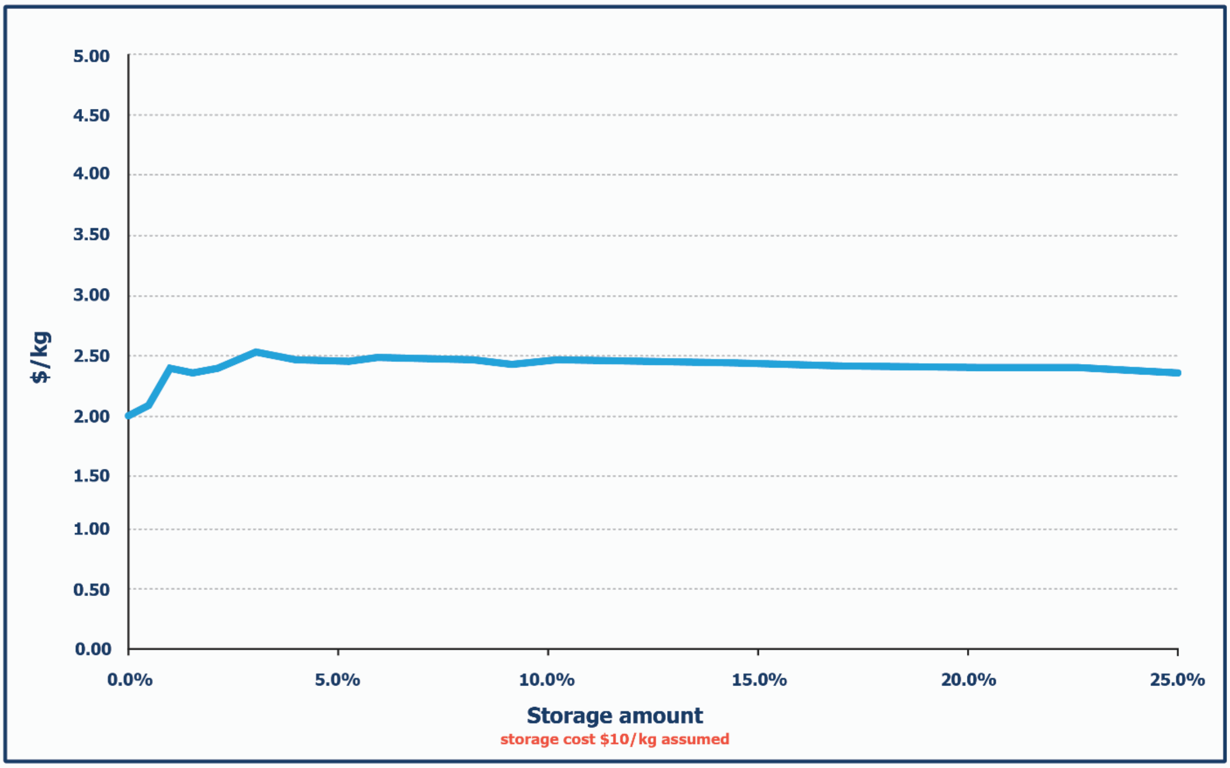


This demonstrates that long-term storage is important for reducing the amount of wasted renewable energy generation. Indeed, without any storage the amount of spilled electricity would approximate the total current electricity load of Victoria.

The impact of capturing spill on reducing the cost of hydrogen can be seen by calculating the costs using the standalone system model but spreading the costs over the unadjusted hydrogen flows and the spill. Assuming a high-capacity factor, additional electrolyser capacity would be required.

The resulting projected costs of hydrogen delivered to the network are shown in Figure 14. Costs of around $2.50 per kg are calculated for the delivered cost of hydrogen to the network under a range of storage amounts. However, if there is less long-term storage, the amount of hydrogen that would need to be sold to other markets becomes large.

Figure 14: Projected delivered cost of hydrogen for a "standalone" system in 2050 against varying levels of long-term storage, where all spill is captured and sold in other markets



If spill can be utilised, the optimal amount of storage quickly falls to zero as the cost of storage rises. Conversely, if spill cannot be utilised then the optimal amount of storage varies as storage cost rises but is generally 20%.

If the standalone system in this model was connected to the NEM, the optimal storage amount would be expected to reduce because the spill is reduced. The load diversity provided by the NEM and other flexibility elements all act to reduce the amount of spill otherwise attributable to hydrogen production.

3.4.4. Storage Technology Options

A range of hydrogen storage options have been considered, which are listed in Section A of the Appendix. Importantly, long-term storage has a once-per-year utilisation cycle, and low capital cost per unit of stored hydrogen is most important. This contrasts with short-term storage, and the costs of inserting or withdrawing gas are less important.

For some technologies, the components of the total cost that informs the cost per kilogram of hydrogen stored is not yet clear.

Of the technologies considered, underground storage in salt caverns and depleted gas fields, and MCH/toluene storage options have potential to be in the cost range below $50/kg of hydrogen stored.

Based upon the information available at the time of analysis, envisaged long-term storage in 2050 would be a small number of sites using depleted natural gas reservoirs and liquid chemical carriers. While the location of liquid chemical carriers can be flexible, depleted natural gas reservoirs are location-dependent, requiring the optimal configuration of the hydrogen supply chain to be connected by large pipeline networks.

Since this analysis was conducted, a halite accumulation in South Australia's Polda Basin has been identified by Geoscience Australia to have high potential for multiple salt caverns to be constructed in it to store hydrogen[16]. If determined to be feasible, this would likely be the lowest cost hydrogen storage option. The HyUnder Review in 2013 included an indicative capex for salt dome storage of approximately $11.30 per kg of hydrogen stored for a 'Greenfield design'[17].

3.4.5. Storage Level Options

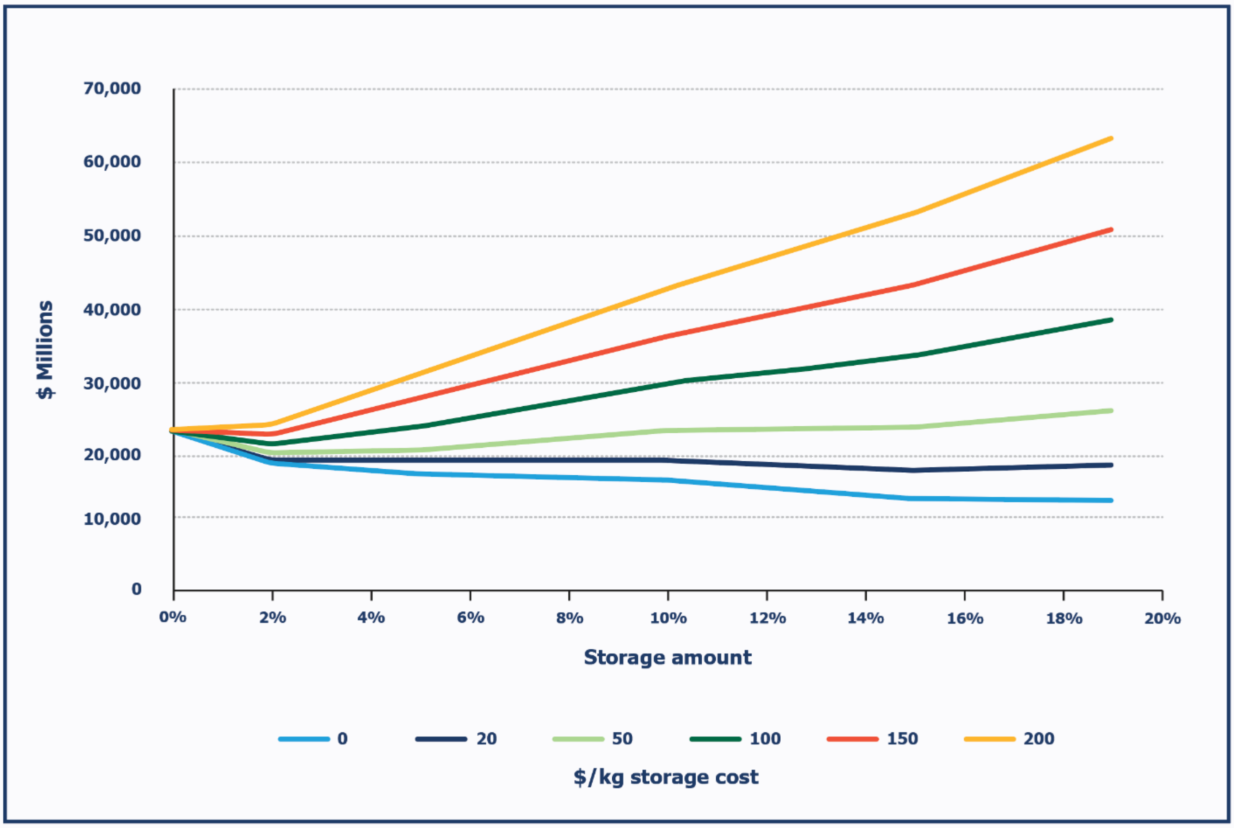
To evaluate various levels of long-term storage, a model of a notional single electrolyser plant with four hours short-term storage capable of covering the whole state load in 2050, and using 2050 parameters, was constructed, and run against Central Scenario pool price forecasts for 2050. The hourly gas demand profile was adjusted to reflect flows into and out of storage for various levels of storage.

The results are shown in Figure 15. These results demonstrate that there is a net benefit when costs of storage are below approximately $100 per kg. However, the optimum amount of long-term storage is small, at approximately 2%, if the cost of storage is between $50-100 per kg. The cost of the storage dominates when it becomes significantly more than $100 per kg.

16 Feitz, A., Wang, L., Rees, S., Carr, L. 2022. Feasibility of underground hydrogen storage in a salt cavern in the offshore Polda Basin. Geoscience Australia, Canberra. <https://dx.doi.org/10.26186/146501>

17 Kruck, O., Crotogino, F., Prelicz, R., Rudolph, T. Overview on all Known Underground Storage Technologies for Hydrogen. Germany. <http://hyunder.eu/wp-content/uploads/2016/01/D3.1_Overview-of-all-known-underground-storage-technologies.pdf>

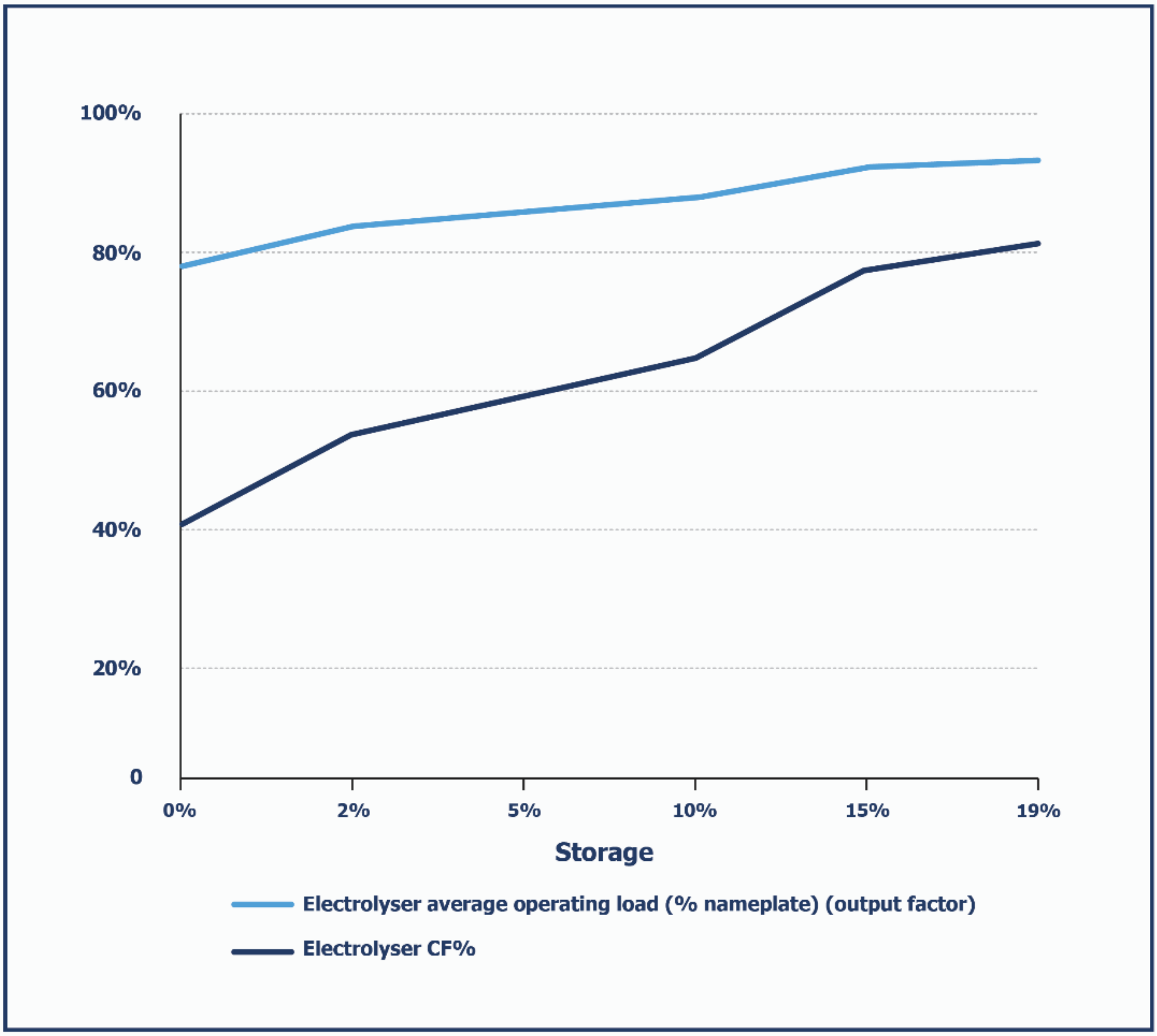
Figure 15: Relative benefit of storage for Victoria in 2050 (indicative)



In conducting the analysis, it was observed that:

- More storage reduces the need for electrolyser capacity, which saves capex.
- Where storage is used to reduce the electrolyser investment, the electrolyser capacity factor increases, as demonstrated in Figure 16. This is a benefit and consistent with less electrolyser capex being required.
- However, when electrolyser capacity is reduced, there is less flexibility to run the (oversized) electrolysers (and the associated long-term storage) during non-winter days to get the best electricity prices.

Figure 16: Capacity factor of electrolysers in 2050 versus long-term storage



3.4.6. Impact on System Configuration

Further work is required to determine the optimal mix of storage technologies, however likely concepts and estimates of the level of storage required means informed assumptions can be made about likely storage locations.

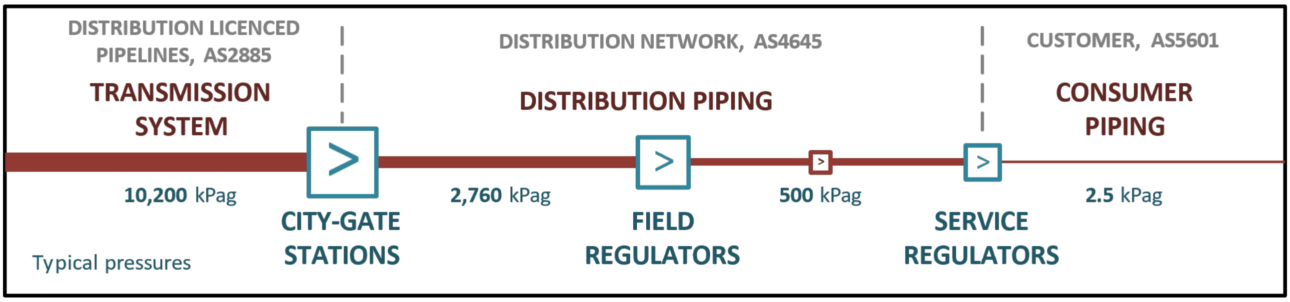
Given both electrolysers and loads would all be required to connect to storage by pipelines, the need for storage drives a spatial arrangement of configuration where electrolysers are located near to the REZ and a pipeline system connects electrolysers, load points, and storage sites together.

If electrolysers were located near the hydrogen distribution networks, then both hydrogen transmission pipeline and augmented electricity transmission systems would be required in the future.

3.5. Transmission Requirements

Previous sections outline that a pipeline-based hydrogen transmission system would be required to connect production, storage, and demand centres in a 100% hydrogen system. It was assumed existing natural gas transmission system would need to remain in service to maintain natural gas supply.

Figure 17: Typical gas distribution network diagram



This Section provides an assessment of the existing and future transmission system options for transporting 100% hydrogen based on optimal configuration needs, compatibility, practicality, and cost. Based on the assessments that can be made, it examines:

- Potential adaptation of current systems for use in the 100% hydrogen transmission system.
- Strengths and weaknesses of 'pipes' and 'wires' based transmission systems.
- Costings for the establishment of a new 100% hydrogen transmission pipeline system.

Key findings

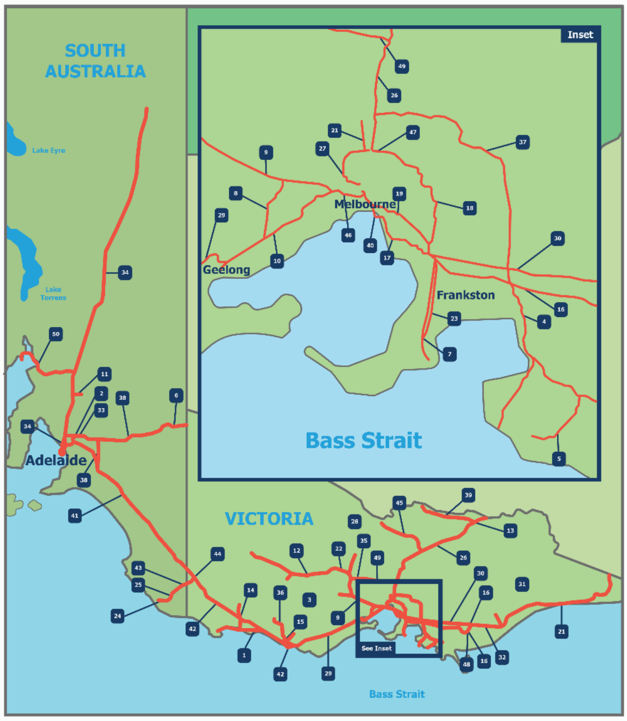
1. A new 100% hydrogen transmission system will likely be required to achieve 100% hydrogen in networks.
2. The existing transmission system would continue to be used to supply natural gas while 100% hydrogen in distribution networks is implemented.
3. It is likely that parts of the existing natural gas licensed distribution pipeline system could be utilised to transport hydrogen during the network conversion process.
4. Near-future advancements in pipeline engineering may improve the required specifications for hydrogen pipelines, which would lower potential costs before pipeline development begins.

3.5.1. Potential to Adapt Existing Natural Gas Transmission Network

Victoria's existing gas transmission network was designed to convey high-quality natural gas and the interactions of the gas with the material and components used in its construction are well understood. Hydrogen is known to interact with certain materials differently to natural gas and impacts that are subject to extensive research include accelerated fatigue and embrittlement .

Adapting Victoria's existing gas transmission network for hydrogen could be an important enabler for centralisation of hydrogen production to achieve 10% hydrogen in networks, and to potentially reduce the need for new electricity and/or gas transmission required for 100% hydrogen delivery. Victoria's existing transmission system is depicted in Figure 18.

Figure 18: Existing natural gas transmission system in Victoria



Number	Pipeline Name
1	Allnsford to Portland
2	Amcor lateral
3	Ballan to Ballarat
4	Bass Gas
5	Bass Plant to Leongatha and Wonthaggi
6	Berri to Mildura
7	BPO Westernport to Dandenong
8	Brooklyn to Lara
9	Brooklyn to Ballarat and Bendigo
10	Brooklyn to Corio
11	Burra Lateral (MAPS)
12	Carisbrook to Horsham
13	Chiltern to Rutherglen
14	Codrington to Hamilton
15	Curdievale to Cobden
16	Dandenong to Morwell
17	Dandenong to SE Melb
18	Dandenong to Templestowe
19	Dandenong to West Melbourne
20	Eastern Gas Pipeline (EGP)
21	Fawkner to Cragieburn
22	Guidford to Maryborough
23	Hastings to Altona
24	Katnook to Apoel
25	Katnook to Mt Gambier
26	Keon Park to Wodonga and Shepparton
27	Keon Park to West Nth Melbourne
28	Kyabram to Echuca
29	Lara to Iona
30	Longford to Dandenong
31	Longford to Maffra
32	Longford to Tyers
33	MAPs Lateral
34	Moomba to Adelaide
35	Mt franklin to Kyneton
36	Otway plant to Mortlake PS
37	Packenham to Wallert
38	Riverland
39	Rutherglen to Koonoomoo
40	SE Melb to Melb
41	SEAGas (SA)
42	SEAGas (VIC)
43	SEAGas to Katnook (SA)
44	SEAGas to Katnook (VIC)
45	Shepparton to Kyabram
46	Sth Melbourne to Brooklyn
47	Templestowe to Keon Pk East
48	Tyers to Morwell
49	Wandong to Kyneton
50	Whyalla Lateral

Legend

Gas pipelines

0 100 200

N

1:7,000,000 at A4

Data sources

Jacobs 2021
Geoscience Australia 2015

WGS84

Selected gas pipelines - Victoria

Hydrogen transportation pipeline guidelines of the European Industrial Gases Association (EIGA) specifications are detailed in Table 9.

Table 9: Hydrogen transmission pipeline specifications

Specification	Criterion detail
Sizing	Max 42", 28mm wall thickness and (for new pipes) API 5L X42 Grade. Higher strength steels are not generally suited to hydrogen transmission.
Hoop stress	Max 30% yield stress and 20% of UTS. This is likely to add conservatism to the requirements of typical national codes but reduces the potential for hydrogen damage[18].
Pipe weight (API 5L)	STD, XS and XXS subject to wall thickness limit.
Minimum diameter	8" for new pipes (poly-based pipes might be considered for smaller lines)

A high-level review of selected existing natural gas transmission pipelines for potential suitability for hydrogen service was undertaken applying the EIGA criteria, with full results shown in Section A of the Appendix. This review found:

- Newer, high pressure transmission lines that were built with high-grade steel could require a pressure reduction in 100% hydrogen service, which could lessen the flow capability;
- Older pipelines were generally built to more conservative specifications and could entail a small/moderate derating in 100% hydrogen service; and
- Small diameter existing pipes tend to be acceptable for 100% hydrogen service as the hoop stresses with "standard grade" pipe wall thickness tend to be lower.

Further research would be required to determine suitability, which could be resolved with case-by-case assessment and inspection.

An in-depth review of most Victorian distribution licensed pipelines detailed in Section 4.2 outlines that of the 89 Victorian pipelines, only 15 require more detailed assessment that was outside the scope of this project for use with 100% hydrogen. On this basis, it was determined that the most existing natural gas pipelines within the Melbourne Metropolitan System are adequate.

18 In initial assessments of existing (natural gas) pipelines for requalification for hydrogen service, the hoop stress criterion was applied, subject to an assumed 7MPa MAOP limit. It is important to note that more detail assessments, inspections, and approvals must be undertaken before constructing new pipelines or re-purposing existing ones.

3.5.2. Electricity and Gas Transmission System Options

Analysis of where hydrogen production could likely be located in Section 3.2 was used to conceptualise a new transmission system, and two high-level options were considered:

1. Hydrogen production within in near existing REZ, requiring hydrogen to be transported to demand centres via gas transmission pipes.
2. Hydrogen production located near demand centres, requiring renewable energy for electrolysis to be transported via wires to service electrolysers.

A detailed analysis considering cost, distance, capacity and performance found newly constructed pipelines to be the preferred solution driven largely by the significance of linking large-scale hydrogen production in REZ to long-term storage, and then to market.

This would be complementary to existing and planned electricity and gas transmission infrastructure, with that infrastructure to be leveraged to the greatest extent possible to deliver blended and ultimately 100% hydrogen.

3.5.3. New Transmission Pipeline System Concept

A transmission pipeline configuration concept for the 100% hydrogen scenario is shown in Figure 19. The concept accounts for expected load centres, REZ, existing corridors, as well as general terrain and existing gas delivery points. It does not depict smaller pathways, which could be required to service various gate stations around Victoria.

Notably, the concept is an inter-state initiative covering Victoria and South Australia. Therefore, elements of the concept in both states are discussed in this Section as they relate to the greater whole.

Figure 19: Hydrogen transmission network concept (with possible long-term storage sites)

The exact size and configuration of any new system would depend on several factors, which this Study has assumed in preparing the concept in 3.5.3. Notable assumption are as follows:

- current and expected load centres;
- location and capacity of REZ;
- existing transmission corridors;
- load of each network segment;
- number of electrolysers upstream and attached to each segment; and
- the expected storage and storage flow path.

In developing the capital assumptions and based on the pipeline analysis, a level of reuse of existing pipelines has been assumed, namely for the Melbourne metropolitan system and ring mains, the southern end of MAPS and the Longford to Dandenong main, reducing the costing of the total inter-state development.

The "Potential Interconnector" that is depicted between South Australia and Victoria has not been included. Its future inclusion depends on whether the assumed storage is found to be possible and/or practical and should be evaluated when this decision is made.

3.5.4. Costings for a New Hydrogen Transmission Pipeline

Factoring for these assumptions and considerations, analysis suggests that combined pipeline capex for Victoria and South Australia is approximately $10 billion. This capex could be substantially undertaken in the 2030s.

As loads grow and pipeline utilisation improves, it is likely that the levelized cost of the future pipeline system could be around $0.26 per kg of hydrogen in Victoria.

Some new segments shown in Figure 19 may not be required if the existing pipelines have sufficient capacity. To enable this, the timing of the transition from 10% to 100% hydrogen could require further planning.

Where sections in either Victoria or South Australia can re-use existing pipelines, or would otherwise not be required, the reduction in cost is beneficial to the total development across both states. The cost attributed to replacing the Melbourne ring system has been excluded given the findings of 3.5.1 indicate it may be able to be repurposed.

These costs do not reflect advancements in breakthrough technologies in repurposing existing infrastructure, learning-by-doing and scale economies. Other reasonable cost reductions could be made through updating pipeline specifications and derating parameters, potentially enabling the cost-effective re-use of a greater number of natural gas transmission lines for hydrogen service.

3.6. Capital and Operating Cost Estimates

Considering the factors influencing location and configuration of hydrogen production facilities, estimates were produced of capital costs (capex) and operating costs (opex). The following considerations were made:

- impact of scale economies and learning-rate on capex of more than one production facility when following similar project templates;
- cost reductions caused by a phased approach to building to 100% hydrogen;
- costs of connecting to electricity and gas distribution networks based on site locations and network constraints; and
- cost of connecting all facilities to the network to allow for several gate stations.

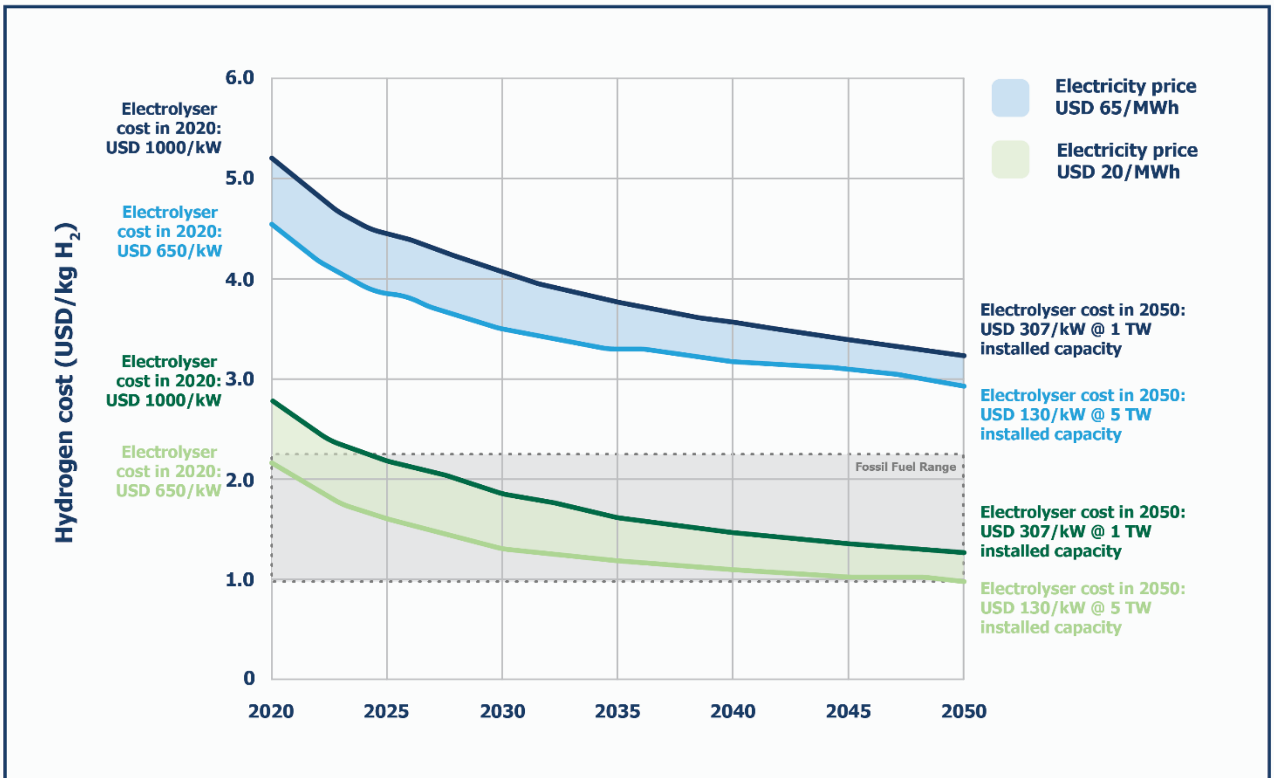
3.6.1. Key Assumptions

3.6.1.1. Cost and Performance of Future Facilities

To produce modelling that acknowledges factors affecting future cost and performance, a few key sources have been considered.

First, the International Renewable Energy Agency (IRENA) outlook for cost and performance of electrolyser plants from current (2020) to 2050 scale plants, which is summarised in Figure 20.

Figure 20: Cost of renewable hydrogen as a function of electrolyser deployment and electricity price, showing capital cost assumptions



Source: IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi.

Second, real-life projects presently under development in Australia were further considered which use 10 MW plants. These plants are expected to produce hydrogen at a lower cost than is reflected in the IRENA values by about 20%. This enabled learning rates and scale economies to be estimated for intermediate technology at key scale points – notionally 50 MW in 2030.

3.6.1.2. Scope of Capital Expenditure

For any production and storage facility, it has been assumed that initial capital costs (capex) comprise of the following:

- Engineering, Procurement and Construction (EPC); and
- Owner's costs.

This capex has been developed on an 'overnight' basis; that is, imagining that a facility could be constructed in a single day.

Facility Construction Costs

The assumed EPC component costs are summarised in Table 10 and will be a direct function of the facility construction costs. They are intended to reflect what a turnkey EPC contractor might offer, and costing should subsequently include the contractor's profit and risk margins.

Scope contingency costs are included such that the resulting estimate is a 50th percentile estimate, which is appropriate for this assessment[19].

Table 10: Facility construction cost components

Cost type	Included/Excluded	Basis
Electrolyser facility costs	• Electrolyser • Power supply • Balance of Plant • Civil works	• Detailed in Table 12
Short-term storage costs	• Above-ground bullet storage system and compression of 30 MPa	
Connection costs	• Connection to electricity network • Connection to gas distribution system, including compression and entry • Water connection not included.	• Electrical connected based on the AEMO ISP allowances for connection of solar or wind generators of the same scale[20]. • Water connection not included because these costs are not material relative to other costs.

19 Additional risk contingency to reduce the risk of a cost exceedance to less than 50%, as is usually included in final budget commitment, is not included. All estimates in this Chapter are best-current estimates and therefore should be evaluated at the 50th percentile.

20 AEMO Integrated System Plan draft 2021-22, "Input and Assumptions Workbook".

Owner's Costs

The total cost of a production facility reflects the owner's costs in bringing the facility to a commercial operation condition. Owner's costs are typically estimated on a percentage basis of the direct capital cost. The cost assessment therefore incorporates a reducing percentage through to 2050 to allow for the benefit of repetitive project development, and for how facility size might increase over time.

This assessment also considers costs both before and after Financial Close, and examples of the typical components included in these costs are shown in Table 11.

Table 11: Typical owner's cost elements, before and after Financial Close

Typical costs before Financial Close	Typical costs after Financial close (to commercial operation date)
Pre-feasibility and concept studies Feasibility assessments Land/easements Consents (e.g., environmental, planning) Project vehicle formation Debt sourcing and due diligence EPC contract specification, tendering, and negotiation Connection negotiations Owner's engineering, legal, financial arrangement support Owner's inhouse costs	Owner's 'minor items,' e.g., fit outs not covered under an EPC contract Owner's engineering support Owner's construction period insurance Initial spares (where not in the EPC cost) Start-up costs (e.g., recruitment, training, salaries of staff prior to commercial operation, fuels/consumables/electricity/etc used prior to commercial operation) Owner's inhouse costs Transaction costs as applicable (interest rate and/or foreign exchange hedging, etc as applicable)

Note: while land/easements are listed, no specific evaluation for associated costs has been included in this assessment.

3.6.1.3. Scope of Operating Expenditure

Life capital costs, such as controls replacements, or electrolyser stack replacements have been included in operating expenditure (opex).

3.6.2. Cost assessment

Initial required capex and opex was analysed to understand the impact of costs on the configuration of production and storage facilities. This was completed with consideration of the need for any configuration in the 10% hydrogen scenario to also be utilised in the 100% hydrogen scenario, and therefore does not include end-of-life costs.

3.6.3. Estimated Capital Expenditure

Capital expenditure (capex) for hydrogen production and storage was estimated using the learning rate and economies of scale in Section 3.6.1.1 and accounting for the cost elements in Section 3.6.1.2.

Learning rates apply to the electrolyser itself, whereas scale economies apply to both the electrolyser and all other direct cost items other than the connection costs.

This resulted in the capex allowances shown in Table 12, and specific capital cost projections as shown in Table 13 and Figure 21.

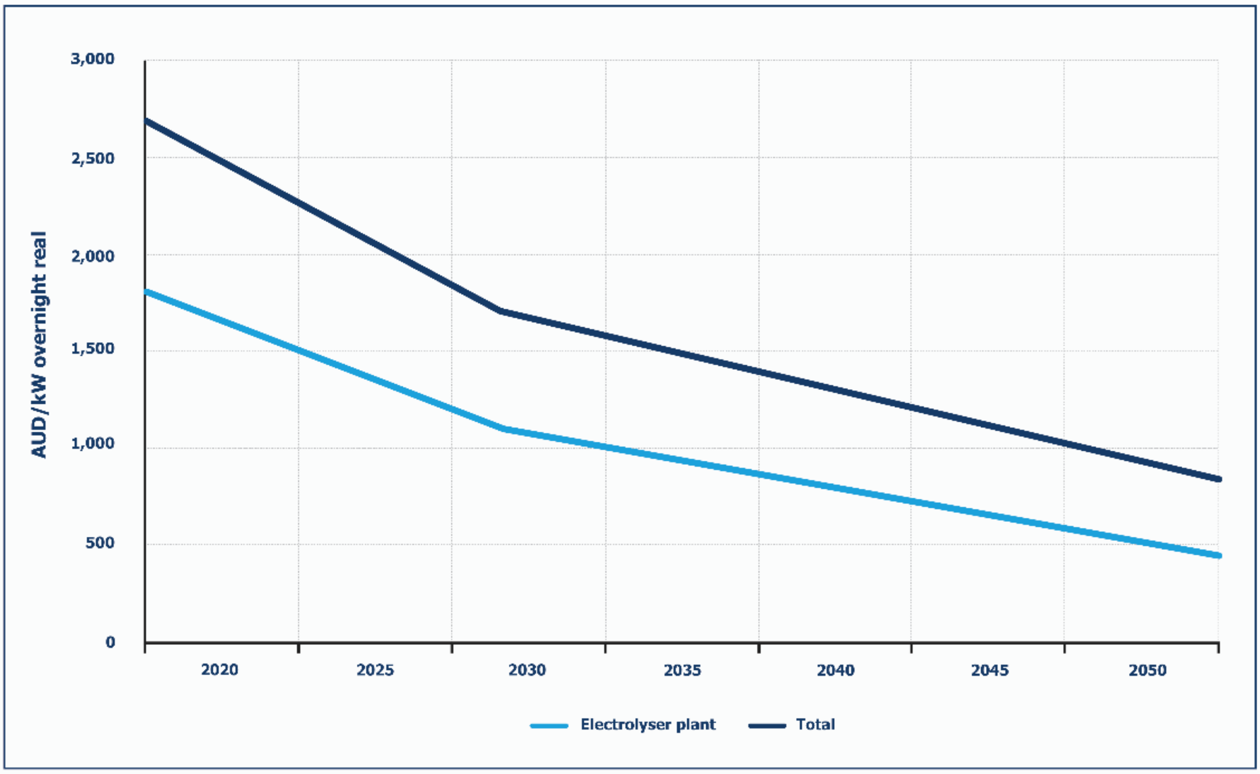
Table 12: Electrolyser capex, AUD-Millions real, overnight

	10 MW (2020)	50 MW (2030)	200 MW (2040)	1,000 MW (2050)
Electrolyser	8.57	25.97	73.58	227.01
Power supply	3.43	10.58	29.43	90.81
BoP	6.00	18.51	48.85	150.71
Subtotal (Electrolyser plant)	**18.00**	**55.06**	**151.87**	**468.53**
Short-term storage tanks	1.44	55.42	28.44	142.22
Compressors	3.00	8.98	28.66	88.42
Connection	1.00	5.00	20.00	100.00
Owner's costs	3.52	11.17	22.90	55.94
Total capex	**26.96**	**85.64**	**251.87**	**855.12**

Table 13: Electrolyser specific capex, AUD/kW real, overnight

	10 MW (2020)	50 MW (2030)	200 MW (2040)	1,000 MW (2050)
Electrolyser plant	1,800	1,100	760	470
Total capex	**2,700**	**1,700**	**1,250**	**850**

Figure 21: Specific electrolyser cost projections (AUD/kW real, overnight)



4. Network Readiness

Victoria's gas distribution networks stored and transported about 50% hydrogen in 'town gas' around 50 years ago. This Chapter outlines any augmentation required to support 100% hydrogen in Victoria's gas distribution networks.

Findings are set out in the following sections:

- capacity of gas distribution networks in Section 4.1;
- hydrogen compatibility of existing pipes and components in Section 4.2;
- network operational processes in Section 4.3; and
- the capital and operating costs of the modifications required for each, in Section 4.4.

Key findings

1. Victoria's gas distribution networks stored and transported about 50% hydrogen in 'town gas' around 50 years ago, so there is strong precedent for hydrogen blended in Victorian gas distribution networks and homes.
2. Gas distribution networks, their components, and constituent materials are generally compatible to safely and reliably transport 100% hydrogen. Minimal modification is required, which can occur as part of gas network businesses' programmed asset upgrades.
3. Considering the different properties of natural gas and hydrogen including energy density and flow, 100% hydrogen could slightly reduce the networks overall capacity by around 13%. The network could absorb this reduction and still maintain supply at historic service levels.
4. Upgrades to network components that enable 10% and 100% hydrogen are expected to be performed under normal preventative maintenance programs at a time when they were normally due for replacement, at a cost of less than the annual operation and maintenance costs for the existing Victorian networks.
5. Updates to safety and operating procedures and systems to reflect the differing characteristics between hydrogen and natural gas do not represent a major step-change to current procedures, and can be made in time to support delivery of 100% hydrogen in networks.

4.1. Network Capacity

Network capacity refers to the volume of gas that can flow through the gas distribution system. If a distribution network did not have enough capacity to supply the volume of gas required by its customers, there would be interruptions to supply. The diameter of the network piping, the operating pressure, and the volumetric energy density of the conveyed gas work together to define the capacity of the network.

Gas distribution businesses have tools and systems in place that enable them to model the capacity utilisation of gas networks as customers gas usage varies over time, or additional customers are added to the network (growth). This ensures any capacity constraints are identified before they impact reliability of supply. These same processes can be used to model the impact of blended hydrogen on network capacity.

To identify any capacity constraints of using hydrogen in Victoria's gas distribution network, three representative sections were modelled with 10% blended gas and 100% hydrogen. This Section presents the findings of this modelling and impacts this would have on augmentation planning for the gas distribution network.

Key findings

1. Considering the different properties of natural gas and hydrogen including energy density and flow, 100% hydrogen could slightly reduce network capacity due to the different higher heating value (HHV) of hydrogen. The network could absorb this reduction and still maintain supply at historic service levels.

4.1.1. Scope

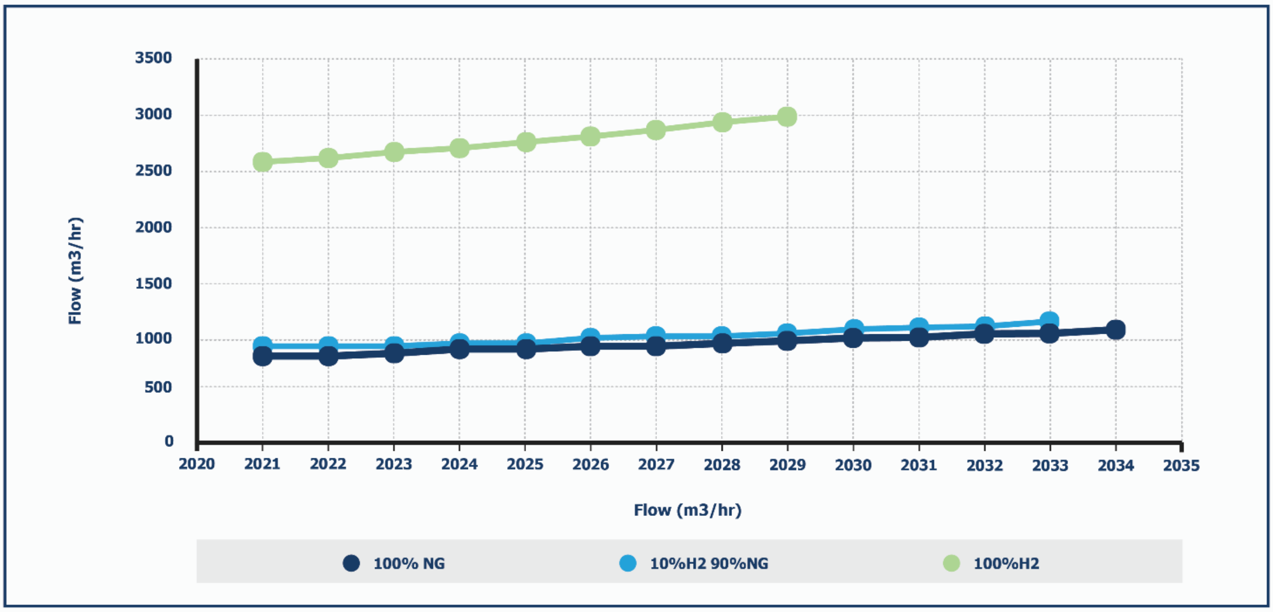
The Yarra Glen gas distribution network was selected as a representative network and was assessed to determine the impact on capacity of 100% hydrogen. This assessment was made using the following models:

- a baseline model of natural gas, with conservative growth applied for a representative period (i.e., the "control case");
- a blended model (with the same starting point as the baseline model), with the modelled gas changed to natural gas with a blend of 10% hydrogen, with the same growth applied for a representative period; and
- a 100% hydrogen model (with the same starting point as the baseline model), with the same growth applied for a representative period.

Modelling of the Yarra Glen distribution network shown in Figure 22 shows that an approximate 30% increase in network flow could be required to deliver the same energy to customers with 100% hydrogen versus natural gas. This is due to a difference in the higher heating value (HHV) factor between hydrogen and natural gas and is equivalent to an approximate 13% reduction in network capacity.

This reduction in capacity (13%) is much less than the increase in flow (30%) would suggest. This is because hydrogen flows through pipes with less friction, due to differences in viscosity and density, and achieves a much higher flow velocity without a corresponding pressure loss.

Figure 22: Network flow changes over time



This demonstrates that the impact of 100% hydrogen on network capacity is manageable, and that no capacity issues are anticipated. The scope of existing network capacity assessment activities could be expanded to consider hydrogen blending to ensure they remain accurate.

4.2. Natural Gas Component and Pipe Compatibility

This Section examines any compatibility issues of existing network pipes and associated componentry with 100% hydrogen using mixed qualitative and quantitative methods.

The existing network was designed to convey high-quality natural gas and the interactions of the gas with the material and components used in its construction are well understood. Hydrogen is known to interact with certain material differently to natural gas, and impacts that are subject to extensive research and were tested with hydrogen in this study include fatigue, embrittlement, and fracture.

Understanding these impacts is crucial to determining the feasibility of hydrogen supply in existing distribution networks – covered in Section 4.2 – and the cost of doing so – covered in Section 4.4.

A full assessment of component and pipe compatibility by type, make, and model can be found in Section B of the Appendix.

Key findings

1. All distribution piping materials are suitable for use with 100% hydrogen.
2. All distribution piping in the Victorian gas distribution system is suitable with 100% hydrogen.
3. Most distribution licensed pipelines are suitable for 100% hydrogen, however, some require more detailed assessment prior to use.

4.2.1. Overview of Testing Results

4.2.1.1. Distribution Licensed Pipelines, Distribution Piping, and Joint Types

As part of this study, distribution licensed pipelines, distribution piping, and joint types in the existing natural gas distribution system with a Maximum Allowable Operating Pressure (MAOP) below 2,800 kPa were tested for suitability with 100% hydrogen. This included piping downstream of gate stations and upstream of customer meter connections.

	Standards for assessment	Results
Distribution licensed pipelines	Pipelines are subject to licensing requirements when the MAOP is greater than 1,050 kPag, and their operations and modifications are mandated to comply with Australian Standard suite *AS(/NZS) 2885 Pipelines – Gas and liquid petroleum.* This standard was not written for pipelines containing hydrogen and is insufficient to determine suitability with hydrogen supply, but its Clause 1.6.2. does apply: *The pipeline is required to comply with the intent of AS 2885.1 and this should be demonstrated through engineering assessment.* Additional guidance for this assessment was provided by the USA design code ASME B31.12 *Hydrogen Piping and Pipelines*, which lists requirements for the design, construction, and installation of hydrogen piping and pipeline systems.	Distribution licensed pipelines were grouped and assessed primarily by pipe design factor, which has a safety margin applied to structural strength to account for uncertainty of the load or structural properties. For pipelines it is defined as the hoop stress at the MAOP divided by the specified minimum yield strength of the material. Pipelines with a design factor greater than 0.4 or MAOP above 2,800 kPa require detailed case-by-case assessment and were not included in the scope of this study. Most of the South Australian distribution licensed pipelines tested were found to be suitable for transporting 100% hydrogen. They have effective resistance to fracture and fatigue at the relevant operating conditions, and the original pipeline hydrotest still provides a margin of safety after hydrogen embrittlement occurs. Of the 89 Victorian pipelines, only 15 require more detailed assessment that was outside the scope of this project for use with 100% hydrogen.
Distribution piping	In contrast to the distribution licensed pipelines that were tested, pipes in the distribution network comprise a broader range of	Testing found that compatibility differed across the materials used in piping in the distribution networks:

	Standards for assessment	Results
	materials that operate across four pressure categories. These pipelines fall under AS/NZS 4645.1-2018 *Gas Distribution Networks* which specifies the requirements for safe, reliable, and suitable management of gas distribution networks operating at less than or equal to 1050 kPa. However, this only permits use of hydrogen in blends up to 15%.	• Steel is acceptable with 100% hydrogen. • Cast iron is acceptable with 100% hydrogen but only at low pressures less than 7 kPa unless further analysis and testing can determine otherwise. • Copper and copper alloys are acceptable with 100% hydrogen. Plastics – polyethylene (PE) and polyvinyl chloride (PVC) – are acceptable with 100% hydrogen.
Joint types	Joint types are covered by the same standards that cover the pipes that the joints are used with.	Testing concluded that most joint types in the system are compatible with 100% hydrogen, including welded, flanged, and threaded steel connections, and welded and glued plastic pipe connections. Exceptions to these results are the following: • Gibault and Bell and Spigot connections must be assessed for leakage before use with 100% hydrogen. • Caulked joints are not permitted for use with hydrogen under ASME B31.12 but are not expected to have any additional vulnerability to mechanical failure. They are likely to be used only with cast iron piping which is not permitted for use with hydrogen at higher pressures without testing. • Single-ferrule compression fittings must be assessed for leakage before use with 100% hydrogen. Mechanical Compression joints used on PE piping require further testing to confirm effectiveness in use with 100% hydrogen.

4.2.2. Components and Facility Piping

4.2.2.1. Metal Components

Testing identified that components with parts made from copper alloys, most aluminium alloys, and stable austenitic stainless steels are suitable for use with 100% hydrogen.

Other metals with deficient performance, such as cast irons, high strength carbon steels (e.g., chrome-moly), martensitic stainless steels and nickel alloys, may not be suitable, however these are found within a small number of components.

4.2.2.2. Elastomer and Polymer Component Parts

The effect of hydrogen on many plastic materials could not be quantified or reliably predicted in testing. While commonly used Viton and PTFE plastics are compatible, very widely used NBR (Buna-N) was found to underperform depending on the brand. There are also many instances of Acetal, EPDM, and some other elastomers that may have reduced performance with hydrogen.

Across all of these materials, however, the reduced performance is not expected to result in spontaneous failure of the component. The materials are generally used internally in valves and regulators as seals, gaskets, diaphragms, and occasionally bearing materials.

As a result, replacing the components containing these materials is not considered essential and should instead be resolved through risk assessment of seal leakage and close monitoring of performance and failure rates.

It is important to note that permeation through certain elastomers may affect the metering or volumetric performance of diaphragm meters. This effect has not been assessed in this project but is anticipated to result in a need to replace all such components for 100% hydrogen supply.

4.2.2.3. Other Components

Specific pressure transmitter makes and models, as well as certain sealants and lubricants, should be assessed for use with 100% hydrogen in consultation with their manufacturers. Additionally, all pipeline repairs going forward should be performed using materials that are compatible with 100% hydrogen in anticipation of their use beyond 2050. This may also require consultation with manufacturers to determine suitability.

4.2.2.4. Facility Piping

In conducting testing for this study, it was noted that ASME B31.12 requires the design of piping in gas facilities to account for increased susceptibility to fatigue, especially from thermal expansion. This would affect gate stations and field regulators in particular.

ASME B31.12 requires that fatigue be addressed in two ways:

1 the number of cycles used in thermal expansion assessments is increased by a factor of 10;

2 the tolerances applied on permissible facility weld defects are reduced by a significant margin.

These requirements are linked in the standard because, if stress due to expansion is low enough (less than 80% allowable), the extent of weld inspections can be decreased.

A stress analysis should be completed for the piping layouts at each facility before they are converted to hydrogen service. In some instances, this could involve a desktop assessment by inspection, rather than a detailed simulation. Furthermore, because many facilities share a common layout, one analysis may be representative of several facilities.

The following outcomes are possible:

- Stress levels are below 80% allowable – design is accepted. Most piping designs maximise flexibility, and result in stress levels that are far below allowable stress limits;
- Stress levels are above 80% allowable:
  - straightforward design modifications may rectify the stress and reduce it; typically, this will involve adjustment of pipe supports; and
  - if it cannot be adjusted, then any girth welds at high stress locations should be subject to non-destructive testing (NDT) to confirm that they do not have injurious defects.
- Stress levels are above 100% allowable. In this case the design must be modified to rectify the issue; non-destructive testing at high stress locations is recommended.

Notably, the highest stress is often not on a weld; conducting NDT would only be recommended where there is high axial (bending) stress at a weld, which cannot be rectified through modification of the pipe supports.

From a review of the AGN Albury-Wodonga network, it is expected that most field regulators would not require modification, because they apply a common layout that is well-designed to minimise expansion stress. For some connections, however – typically industrial connections with above-ground regulator stations – there is a greater likelihood that modification of pipe supports may be required. It is expected that a requirement to conduct NDT would be a rare outcome of analysis.

4.2.3. Outcomes

This compatibility review of Victoria's gas distribution network identified that the vast majority of piping and components are compatible with blended gas and only a small number of components would need to be replaced. The total cost of replacing these components has been estimated and found to be within the limits of regulated gas distribution network repair and maintenance. Detailed cost estimates can be found in Section B1 of the Appendices. Prior Activities to prepare the network for 10% hydrogen significantly reduce the work required for 100%. Please refer to the relevant section of the 10% studies for further detail.

4.3. Operational Considerations

Introducing hydrogen into Victoria's gas distribution network would require operational and safety procedures to be updated to recognise the change in supply. To determine what considerations would be required, the differences in impact between natural gas and hydrogen were explored, including flow properties and flammability.

To identify operational inconsistencies, two main categories were found:

1. those relating to the design of the system for safe operation. These are the types of issues that could be identified through a Hazard and Operability Study (HAZOP).
2. those relating to how the system is operated, including any activities undertaken by operators, such as preventative maintenance and leak detection.'

This Section first considers the chemical properties of hydrogen that would be different to existing network operations, before summarising the actions that should be taken for converted networks to operate safely.

Key findings

1. Existing systems and documentation in the gas distribution industry are designed for specific operating conditions, characterised by the pressure, temperature, flow rate and direction, and composition of natural gas.
2. The distinct characteristics of hydrogen to natural gas should be reflected in an update to safety and operating procedures and systems.
3. The required changes to safety and operating procedures and systems would not impede the feasibility of achieving 100% hydrogen by 2050.

4.3.1. Comparative Evaluation of Chemical Properties of Hydrogen and Natural Gas

The properties of hydrogen and natural gas vary, and the purpose of this Section is to summarise a comparative review of properties that require operational considerations for gas supply. Because the composition of natural gas is not necessarily exactly constant, methane was used as a proxy in testing to explain differences in chemical properties.

4.3.1.1. Density and Viscosity

The first prominent variances are the density and viscosity of the fluid gasses, defined below and shown in Table 14 below.

- **Density** is a measure of how compact the mass of a material is per unit of volume.
- **Viscosity** is a measure of a fluid's resistance to flow.

The density and viscosity of hydrogen are lower than methane and it has different flow-properties as a result. These flow properties cause it to leak faster and disperse more rapidly. These behaviours are also increased because hydrogen is more buoyant in air. For related reasons, pressure waves carry more rapidly through hydrogen.

Table 14: Properties of hydrogen compared to methane[21]

Property	Methane	Hydrogen	Units	% change (H_2 / CH_4)
Molecular weight	16.06	2.016	Kg/kmol	13%
Density	0.72	0.09	Kg/Nm^3	3%
Heating value	55.6	142	MJ/kg	255%
	893	286	MJ/kmol	32%
	40	12.7	MJ/ Nm^3	32%
Approximate viscosity	11.3	9	µPa.s	80% approx.
Speed of sound	446	1,270	m/s	285%
Ratio of specific heats	1.306	1.406	-	108%

Note: The values listed in this table are approximate for 'normal' pressure and temperature conditions: 20°C, 1bar.

4.3.1.2. Flammability

The next prominent difference is between the flammability characteristics of the gases. Flammability comprises of many characteristics, and the those that are useful for this study are compared in Table 15.

21 The properties quoted come from a variety of sources; there is some minor discrepancy between sources for these values depending on how they are defined and measured, so other references may differ.

Table 15: Comparison of flammability characteristics of hydrogen and methane[22]

Aspect	Definition	Methane	Hydrogen	Outcome
Minimum ignition energy (mJ)	A measure of the sensitivity of an explosive substance to ignition by electrical spark in certain conditions.	0.25	0.017	The energy required to ignite hydrogen is lower than methane, presenting greater risk of ignition.
Auto-ignition temperature (°C)	The lowest temperature in which a material spontaneously ignites under a certain pressure.	580	500	The temperature required for hydrogen to auto-ignite is lower than for methane, presenting greater risk of auto-ignition.
Hazardous area (HA)	An area in which an explosive atmosphere is present, or may be expected to be present, in quantities as to require special precautions for the construction, installation, and use of equipment[23].	-	-	Many work environments contain or produce explosive atmospheres. The lower explosive limit of hydrogen means the explosive atmosphere it can form in work environments with the same conditions is generally larger than methane.
Explosive limits	The range of concentrations of a material in air that will burn or explode with ignition at a certain pressure.	Lower: 4% Upper: 17%	Lower limit: 5% Upper: 75%	
Explosive atmosphere (hazardous area)	A mixture of explosive materials in air meeting certain conditions that will completely combust after ignition.	Generally smaller	Generally larger	
Explosion pressure (MPa)	The changed pressure of an enclosed space caused by explosion of a substance in it.	Generally lower	Generally higher	Experimental data[24] has shown that hydrogen develops a higher explosion pressure than methane across a wide range of concentrations.
Deflagration, Detonation, Detonation range	**Deflagration** is rapid combustion that produces heat, light, and a subsonic pressure wave. **Detonation** is a self-sustaining combustion that produces heat, light, and a supersonic pressure wave. **Detonation range** is the range of concentrations of a substance in air at which detonation can occur.	5.3 – 15.5%[25]	18.3 – 59%[26]	Hydrogen can burn at a broader range of concentrations in air than methane. Although this makes detonation more likely to occur to hydrogen mixtures, the conditions required are specific and would require a large, accumulated leak in an enclosed space. If deflagration takes place in open air in an enclosed space, a mechanical pressure release can mitigate the pressure wave it produces.

22 Ibid.

23 AS/NZS 60079.

24 The source of this comparison can be found here: <https://www.nature.com/articles/s41598-021-00722-8.pdf>

25 Detonation range of methane in air supplied by NIOSH Lake Lynn Laboratory studies, which can be found here: <https://www.cdc.gov/niosh/mining%5C/UserFiles/works/pdfs/madea.pdf>

26 Detonation range of hydrogen in air supplied by US Office of Energy Efficiency and Renewable Energy, which can be found here: <https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/h2_safety_fsheet.pdf>

4.3.2. Summary of Updates Required to Operational Procedures

Current operating processes were tested with the hydrogen behaviours listen in Section 4.3.1 to determine any updates that might be required for natural gas distribution networks to safely transport hydrogen.

It was found that this could take place within current safety and operating procedures. Some potential considerations are detailed in Section B3 of the Appendix, but these are unlikely to present concerns or major step changes to current procedures.

4.4. Capital Replacement Cost Estimates

Considering the analysis in previous sections of this Chapter, capital costs have been estimated for the replacement of diaphragm meters only.

Importantly, much of the capital works required for 10% hydrogen in networks ensure that the networks are future-proofed for 100% hydrogen, including replacement of components made with hydrogen-incompatible or unknown materials, and components and hazardous area rated electrical equipment. Please refer to these costs in the *AHC 10% Hydrogen Distribution Networks Study – Victoria* Study.

These costings are considered 'worst case' as full replacement is costed where further investigation may determine that it is not required. For context, the three networks in Victoria spend on average around $600 million per annum on operational expenses and capital upgrades.

4.4.1. Replacement of Diaphragm Meters

Estimated costs of replacing the diaphragm meters is $602 million.

Detail regarding this estimate are in Section B of the Appendix, with quantities of diaphragm meters per network shown in Table 15 and a cost estimate for each network in Table 16.

Importantly, the routine replacement of meters is already underway through existing aged meter change programs. It is expected that the replacement of diaphragm meters to a new generation capable of handling 100% hydrogen would be able to be conducted as part of existing asset upgrades program structures, so there is minimal incremental cost to prepare the networks for hydrogen.

5. Customers Appliance Pathways

The majority of domestic appliances are compatible with volumes of at least 10% hydrogen in natural gas, with work underway to determine the maximum upper limit.

When receiving 100% hydrogen, new appliances or burner parts may be required. 100% hydrogen appliances and hydrogen-ready appliances are being developed in Australia and overseas, for example AGIG has a number of Australian-made 100% hydrogen barbecues it uses at community events and is developing a 100% hydrogen home featuring a range of common household appliances.

At present, these appliances are niche products while the market establishes itself. Appliance manufacturers are already working to supply these products at scale, which are expected to be made available at a similar cost to existing gas appliances.

This chapter steps out the various pathways that an appliance conversion program could take and identifies the optimal pathways that maximise value to the broadest group of stakeholders.

It draws on Australia's recent experience transitioning from 'town gas' and other historic network technology transitions have also demonstrated that timely customer engagement, development of standards appliances and components, and international coordination would be important to minimise impact of conversion on customers and manufacturers.

The breadth of engagement required for these activities also presents opportunities to integrate appliance conversion with other modernising projects.

Key findings

1. When receiving 100% hydrogen, new appliances or burner parts may be required. 100% hydrogen appliances and hydrogen-ready appliances are being developed in Australia and overseas
2. Stakeholder consensus is that once the maximum upper limit for hydrogen blends has been achieved (presently 10%), a single step transition to 100% hydrogen is more efficient than incremental steps.
3. For Type A appliances (i.e., most domestic and commercial appliances), a hybrid pathway where only adaptable or 100% hydrogen-ready appliances are sold for new installations is the preferred option.
4. For 'off-the-shelf' Type B appliances (i.e., some commercial and most industrial appliances), hybrid or dual fuel conversion pathways would be the preferred options. This decision likely fall to customers on a case-by-case basis, determined by best value to them. Policy approaches which enable or incentivise customers to undertake the decision-making process should be considered.
5. Based on previous network conversion programs in Australia, it is essential that communication with customers about gas distribution network and appliance conversion programs takes place often and early and should begin before any conversion works are started.
6. Further work is underway to survey industrial and commercial customers and undertake a review of hydrogen readiness.

5.1. 'Type A' and 'Type B' Appliances

Gas distribution networks deliver gas to a wide range of customers who use the gas to operate an even wider array of gas appliances. Appliances supplied by gas distribution networks in Australia are typically classified into one of two distinct categories:

- "Type A" appliances; or
- "Type B" appliances.

These appliances are categorised on the basis of energy consumed in Megajoules per hour (MJ/h), the application, and the certification type. A or B categorization is based on end-sure type, which is provided by the gas retailers and is based on the total gas consumption of the user rather than on the consumption of individual equipment and appliances.

Table 16: Description of appliances by type

Category	Definition	Equipment
Type A	An appliance for which a certification scheme exists (applicable in Australia only) [27]. These are typically used in domestic settings and are connected to the low-pressure natural gas distribution network (400 kPa)	Domestic and light commercial type appliances such as: • Gas stove tops • Barbecues and grills • Hot Water Systems • Cook tops • Ranges • Griddle tops and fryers • Domestic gas dryers • Pizza ovens • Gas refrigerators • Ducted heating appliances • Space heaters • Central heaters
Type B	An appliance with gas consumption more than 10 MJ/h, for which a certification scheme does not exist (applicable in Australia only). Each appliance or process component must be individually assessed and certified by licensed installers before use and monitored by state-based technical safety regulators . Type B appliances vary – some are bespoke, like site-specific furnaces, whereas some are more standardised, like standard boilers.	Large industrial equipment such as: • Steam boiler • Furnace • Oven • Gas fired turbine • Incinerators • Kilns • Power generation engines

27 Standards Australia – AS/NZS 5601.1 2018

There are approximately 11 million Type A appliances in Australia, which utilise around 10% of natural gas use for the purposes of cooking, space heating and water heating.

Type B appliances consume gas at a rate greater than a 10 MJ/hour threshold. They do not have a certification scheme in Australia and instead, each appliance or process component must be individually assessed and certified by licensed installers before use and monitored by state-based technical safety regulators.

Most commercial appliances are Type B, and most domestic appliances are Type A, although there is some crossover. Commercial appliances are generally medium to high heat, whereas industrial appliances are generally high heat. As some industrial appliances are bespoke, they should be assessed on a case-by-case basis.

5.2. Categorising and Quantifying Current Appliances

As well as being classified as either Type A or Type B, gas appliances fall into one of three categories.

3 **Domestic appliances**, which are used within a domestic dwelling and serve only the inhabitants of the dwelling.

4 **Commercial appliances**, which are appliances up to 1 MW output rating installed in 'non-domestic' premises used for space heating, sanitary water heating and catering purposes.

5 **Industrial appliances**, a diverse and broad category that consists of many one-off, bespoke pieces of equipment designed for specific industrial purposes.

Data on the number of gas appliances in Victoria by appliance type and category was sought but could not be obtained during this study. To estimate the number of appliances in Victoria, two approaches are possible.

6 **Bottom-up**, which utilises appliance sales data from relevant trade bodies, knowledge of typical life spans of appliances, and appliance data from commercial companies.

7 **Top-down**, which utilises the actual natural gas consumption for each sub-sector/end use setting to develop an estimate.

5.3. 100% Hydrogen Appliance Pathways

In June 2021, a Feasibility Study stakeholder workshop was held to discuss the pathways that could transition appliances to operate safely and reliably with 100% hydrogen gas. Attendees included the Gas Appliance Manufacturers Association of Australia (GAMAA), Energy Networks Australia (ENA), Future Fuels CRC, Australian Gas Association (AGA), AusNet, AGN and others.

At this first workshop, participants discussed five overarching pathways to 100% appliances. The following sections outline risks and weaknesses associated with each pathway, and any potential actions to be taken by key stakeholders.

Identified Pathway Options	
Pathway 1: In place conversion	Natural gas appliances continue to be sold up to the time of network conversion. The cost of conversion could be covered by the network owner or by the customer.
Pathway 2: Dual fuel	Dual fuel appliances which can safely and reliably switch between natural gas and hydrogen without component changes are mandated to be sold for new installations, replacements, or energy conversions. Existing customers would be advised that they need to change their appliance or convert to an alternate energy source.
Pathway 3: Hybrid conversion	Adaptable and hydrogen-ready appliances are mandated as the only appliance to be sold for new installations or replacements. Customers would be advised to either replace existing appliances with dual fuel or hydrogen-ready or compatible appliance, or to source an alternate fuel.
Pathway 4: Like-for-like replacement	Gas appliances are replaced at the time of network conversion with an equivalent designed specifically for use with a 100% hydrogen supply.

Feedback on each pathway was sought in the Feasibility Study stakeholder workshop in June 2021. Specific focuses of stakeholder feedback were:

- Identifying the critical path or steps for each pathway option, and the key activities that need to occur to enable a successful rollout of that pathway.
- Discussing where responsibility should sit for the key activities identified on each critical path, including initial views on who is responsible for costs.

Several key themes emerged during the workshop, namely that:

- Each pathway option has clear actions that need to be delivered in specific timeframes. These include:
    - development of regulations, standards, and testing procedures;
    - development and testing of appliances;
    - customer communications; and
    - ensuring workforce capacity and competency.

- There is a tension between the desired timeline for decarbonisation of the gas distribution network and the realistic timeline for the conversion to 100% hydrogen gas. The sentiment across stakeholders was that conversion should begin by 2030 with an eye to completion by 2040. That means appliances would need to be ready for purchase and installation by 2030. The group recognised this goal is ambitious given the current progress and industry confidence.
- The dual fuel pathway appears unrealistic and impractical. The consensus is that a combination of hydrogen-ready appliances and 100% hydrogen appliances installed at the time of conversion could be the preferred pathway.
- Uncertainty is holding back investment in industry research and development. Government direction on a preferred pathway may be required to stimulate action and acceleration to ensure the 2050 goal for network conversion is met. As an example, government introducing a mandate supportive of hydrogen-ready appliances could reduce risk borne by appliance manufacturers in relation to research and development costs.

At the subsequent August 2021 workshop, stakeholder feedback was sought regarding frameworks for assessing the pathways. Specific focuses were:

- Identifying and refining the criteria for assessing pathways;
- Allocating a weighting to each criterion in accordance with its relative importance; and
- Discussing the most appropriate way to group and divide appliances to ensure a meaningful assessment.

The key themes that emerged from this workshop included that:

- Cost should account for 50-60% of the overall weighted score for each pathway;
- Appliance type/purpose is the only sensible way to group appliances for assessment; and
- A single step transition from the maximum upper blending limit to 100% hydrogen is preferred to multiple incremental steps (i.e., 25% to 50%, to 75%), assuming each incremental step requires an appliance-readiness program that is similar in scale.

These findings were discussed with Energy Safe Victoria to seek feedback on these pathway options and the role the regulator could play in the development of hydrogen appliances and in the appliance conversion process. To date, feedback from technical regulators is broadly aligned with the outcomes of the stakeholder workshops.

A key piece of feedback from regulators was that gas distribution networks can use conversion as an opportunity to bring distribution pressures to 2 kPA, which would align Australia with other international jurisdictions. In turn, which would allow for more efficient standards development and a better return on research and development investment for appliance manufacturers. It would also give customers access to a wider range of appliances.

5.4. Findings

Type A Appliances

For all common Type A appliances, a hybrid conversion approach appears to be the most favourable. Hydrogen-ready appliances have demonstrated the ability to provide a network-wide benefit during the conversion program if rolled out at scale, which appears sufficient to justify supporting, incentivising, or mandating the installation of these types of appliances ahead 100% hydrogen in networks.

As outlined in Section 7.3.3, the cost of the appliance conversion could be reduced a by factor of six if all appliances are hydrogen-ready at the time of conversion. Ensuring that only half of the appliances are hydrogen-ready would still have a major impact, reducing the estimated overall cost by $1.2 billion (40% reduction).

Should a hybrid conversion pathway be taken, dual fuel appliances could still be produced for customers that are willing to pay for them. However, as shown in the detailed appliance assessments in Section C of the Appendix, these appliances do not yield any benefits to the broader network conversion program. The relative cost of these appliances would not justify incentivising their rollout over other options.

In the hybrid conversion scenario, it is possible that some existing natural gas appliances could be designated as hydrogen-ready by model number if it can be shown that their conversion process meets an equivalent or acceptable level of simplicity, speed, and cost. This will be best determined by manufacturers and ways to encourage their proactive identification of convertible appliances should be explored.

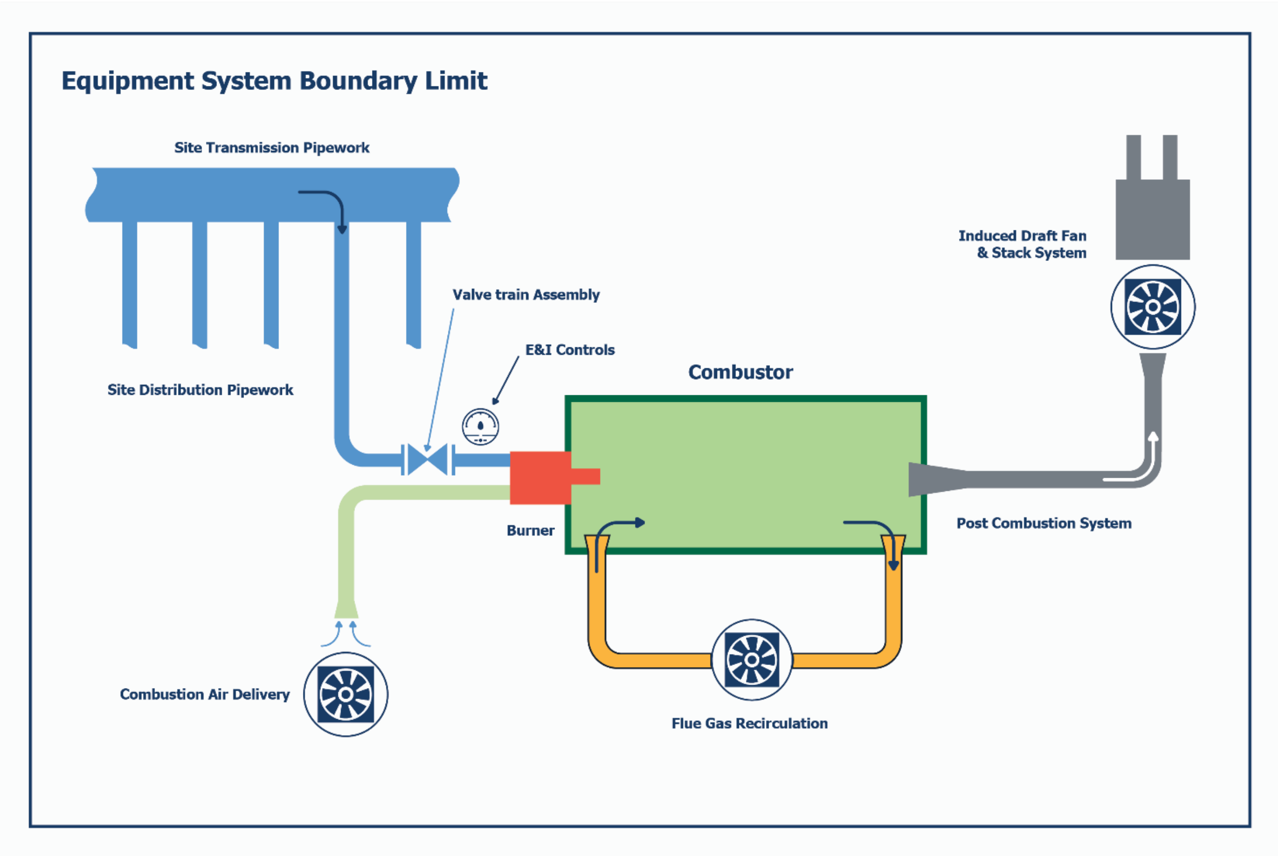
Type B Appliances

The AHC carried out a desktop analysis study to understand the ability of Victorian major gas users' appliances to accept 100% hydrogen. The pathway for Type B appliances to operate on 100% hydrogen depends on variability in appliances, heat, and flame profiles, which could either involve the reconfiguration of some componentry or an entire unit.

For each Type B Appliance, certain sub-componentry within its equipment system may require replacement, modification, or in some cases may not be compatible with hydrogen based on current research. Figure 23 illustrates such an equipment system broken down into sub-components[28].

28 Pavel Panek, Neil Smith, Peter Ashman, Paul Medwell, Michael J. Brear, Yi Yang, Mohsen Talei, Robert L. Gordon. 2020. Project RP1.4-02: Future fuel use in Type B and industrial Equipment. Future Fuels CRC

Figure 23: Schematic of typical components in an example 'Type B' Appliance



Building on the analysis set out in Section 2.2 regarding major gas users, Table 17 outlines the predominant equipment and processes for major industrial sub-sets:

Table 17: Equipment and processes that consume natural gas based on the analysed industries

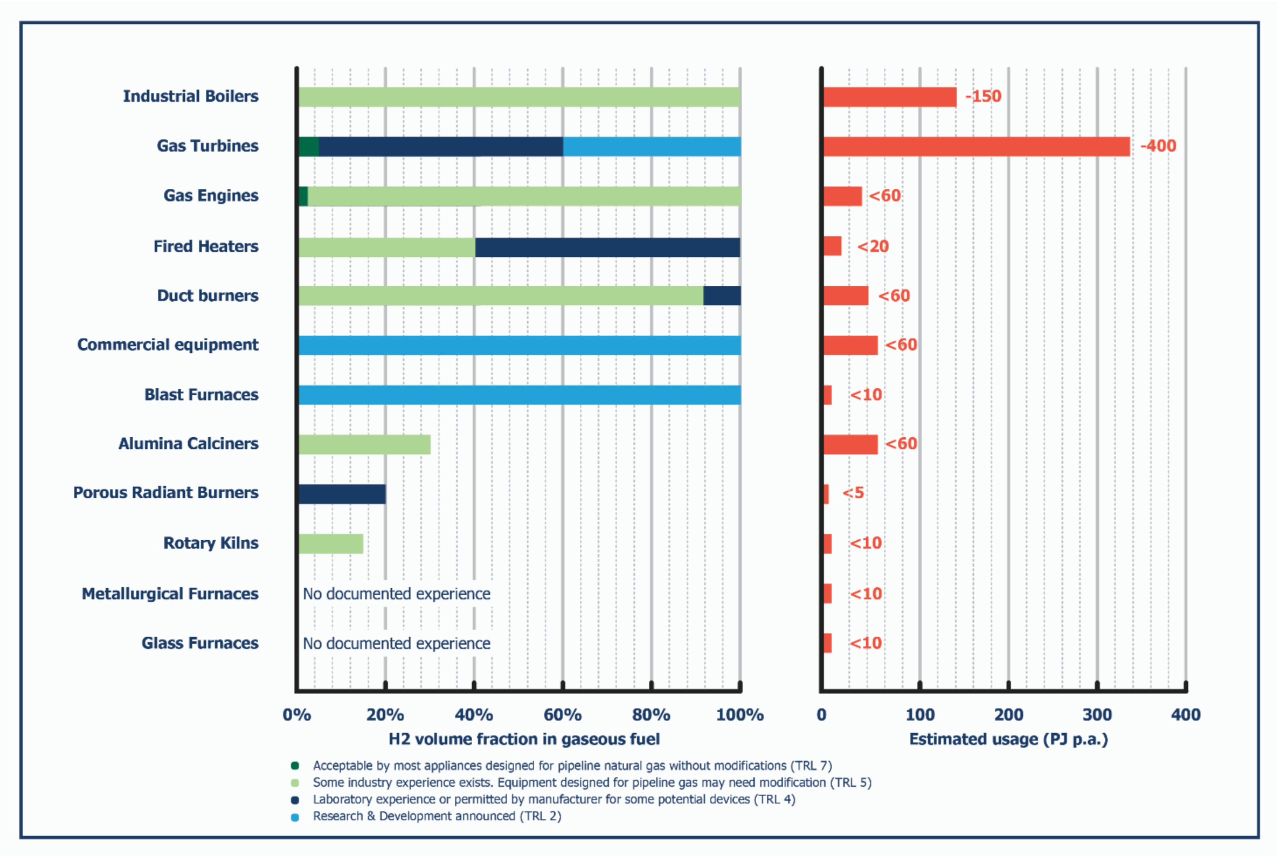
Industry	Application / Processes	Equipment
Food & Beverages	The food and beverage industry use natural gas for generation of heat and steam. Some processes that use natural gas include sterilization, pasteurizing, drying etc.	• Steam Boiler • Hot water Boiler • Oven • Dryer
Basic Metals	Natural gas is used in the smelting, and refining industry.	• Steam Boiler • Furnace • Oven
Pulp & Paper	Pulp and Paper industry utilizes natural gas for steam, hot water and power generation.	• Steam Boiler • Hot Water Boiler • Dryer • Gas Engines • Gas Turbines
Non-Metallic	This energy intensive industry uses natural gas for high temperature burning and firing for production of cement, bricks, ceramics and glass.	• Hot Water boiler • Glass Furnace • Furnace (>600 C) • Lehr Kiln • Ceramics Kiln • Direct Dryer • Lime Kiln • Kiln (>600 C)
Commercial Services	Establishments under the commercial services banner use natural gas for sterilization, steam generation, space heating, laundry processes etc.	• Hot Water boiler • Steam Boiler

An appliance conversion feasibility assessment performed for this Study examined the current available information on the hydrogen compatibility of selected Type B and industrial equipment based on industrial experience and laboratory research, which is summarised in Figure 24.

This demonstrates some useful though broad insights about each equipment type:

- Processes that relay on convective heat transfer pose fewer technical challenges for conversion. Existing burner designs can be adapted with modifications, or new designs suitable for hydrogen be developed. As the fraction of hydrogen by volume increases, premixed burners may have to be replaced with non-premixed designs, potentially increasing NO_x emissions. This could be mitigated with additional post-combustion exhaust systems.
- Changes in air and gas flue rates will impact in pre-mixture, induction fans and ductwork.
- Processes that rely on radiative heating could be more difficult to adapt to hydrogen. Conversion to 100% supply may not be possible in some cases, though hydrogen could be blend fired with other fuels to improve radiation.

Figure 24: Compatibility of selected industrial equipment with hydrogen blends and natural gas



Based on the technical framework outlined in Figure 23, a further framework was developed to understand the level of modification required for compatibility of Type B appliances with 100% hydrogen supply.

This is demonstrated in Figure 25.

Figure 25: Assessment of appliance modifications required to achieve compatibility with 100% hydrogen supply

*The impact of 100% hydrogen in these appliances on induction fans ('ID Fans') and Electrical Control & Instrumentation Engineer ('EC&I') was considered as per applicable AS/NZS standards

Figure 25 demonstrates that most industrial appliance components can be made hydrogen compatible with modification, with few representing a technical barrier with no proven solution. Research and development is focusing on adaption and commercialisation of existing technology to hydrogen.

This work is being led both in Australia and internationally including by the Heavy Industry Low-carbon Transition Cooperative Research Centre (HILT CRC), a collaborative venture seeking to decarbonise steel, iron, alumina, and cement industries with new low-carbon technologies and methods.

As shown in Table 25 in Section C of the Appendix, dual fuel and hybrid approaches offer similar value for converting package burners and simple boilers. For this reason, a technology-agnostic approach could be taken for customers using these or similar appliance types.

5.5. Conclusion

Confirming a Critical Path

Once 10% hydrogen has been achieved, the path to 100% hydrogen is defined by several key steps including the development of:

- standards;
- testing and approval procedures for appliances and components; and
- appliances and components.

It is essential that these steps are followed so that, in time for network conversion, manufacturers can develop appliances and components that meet rules and standards, and gas customers can purchase and install suitable appliances.

Setting Goals

Industry momentum could build naturally when there is a clear view of the road ahead. Acknowledging the value of a two-step transition process, governments and industry could commit to plans for network 10% and 100% hydrogen supply that include clear start and end dates as well as details of the policy frameworks that would support the conversion pathway.

Existing Gas Appliance Data

It is essential that more data on existing gas appliances is collected so that the scale of the selected conversion pathway can be accurately quantified. Additional data should be at the state-level and include the number of different types of gas appliances installed as well as the annual sales of new appliances. Accordingly, surveying domestic, commercial, and industrial customers to ascertain the quantities of appliances currently installed in the network would be a useful next step.

It is also worth potentially revising the process by which Type B appliances are certified and registered to provide a richer source of data on installation. This could be achieved by implementing an electronic appliance registrations database that could contain details including appliance design and installation, commissioning/decommissioning dates, customer contact information, and hydrogen conversion plans.

Coordination with and Learning from International Experience

Coordinating its distribution and appliance sectors with overseas markets that are converting to 100% hydrogen at a faster rate could provide Australia with numerous benefits. A summary of international experiences with 100% hydrogen in networks is provided in Section D of the Appendix.

First, Australia could adopt international standards for 100% hydrogen and hydrogen-ready Type A and Type B appliances. This would help accelerate appliance development timelines by improving access to international markets for domestic customers and manufacturers. Similarly, this may provide international markets with greater confidence to develop for and supply to the Australian gas distribution and appliance sector.

Also, the Australian gas sector could work with these overseas markets – including governments, regulators, network operators and appliance sectors – to share knowledge of appliance conversion and how it fits into broader network conversions. Using this knowledge and the experiences of targeted trials around Australia to inform domestic practices would help ensure an effective conversion of both appliances and networks.

A noteworthy example is the United Kingdom's Hy4Heat's mission launched in 2017 to establish whether it is technically possible, safe and convenient to replace natural gas (methane) with hydrogen in residential and commercial buildings and gas appliances. The program consisted of ten distinct but inter-linked work packages (WPs), covering areas such as domestic appliances, commercial appliances, meters, appliance certification, and a safety assessment

Hy4Heat successfully developed a range of functioning appliance prototypes to demonstration phase on 100% hydrogen, which has led to demonstrating appliances in real-life settings, informed policy on the continuation of 100% hydrogen for heading to community trial stage and provided industry confidence in research and development investment.

Finally, Australia might benefit from implementing a consistent and standardised national approach to appliance transition.

6. Regulatory, Legal and Standards Considerations

This Chapter considers work underway to underpin a 100% hydrogen distribution network in Victoria from a regulation, legislation and standards perspective.

An underlying assumption throughout this Chapter is that activities outlined in the *AHC 10% Hydrogen Distribution Networks Study - Victoria* will have been implemented, laying the foundations for the transition to 100% hydrogen in networks.

After explaining necessary context including how a 100% hydrogen system in Victoria may function, this Chapter outlines "low regret" steps that could be taken to enable 100% hydrogen supply in networks.

Key findings:

1. There is significant work underway to develop regulation, legislation and standards at the state and commonwealth level to enable hydrogen supply in networks.
2. Emissions reductions achieved by hydrogen in networks are not recognised under any scheme in Victoria at present. Development of a scheme(s) would incentivise increased demand for hydrogen (and other renewable gases) in networks as an alternate to natural gas.
3. Scheme development could benefit by learning from the success of Australia's renewable electricity sector, which is now considered mature having achieved significant cost reductions over time through a range of policy mechanisms such as the Renewable Energy Target.
4. The current economic regulatory environment applied to gas distribution businesses could evolve depending on how future energy markets develop.
5. Providing early certainty by requiring all appliances sold or installed to be hydrogen-ready to facilitate the development of necessary customer uptake, standards updates, planning and skills capabilities to enable a smooth transition from 10% to 100%.

6.1. Overview of the Victorian Gas Market

6.1.1. Victorian Natural Gas Declared Transmission System and Declared Wholesale Natural Gas Market

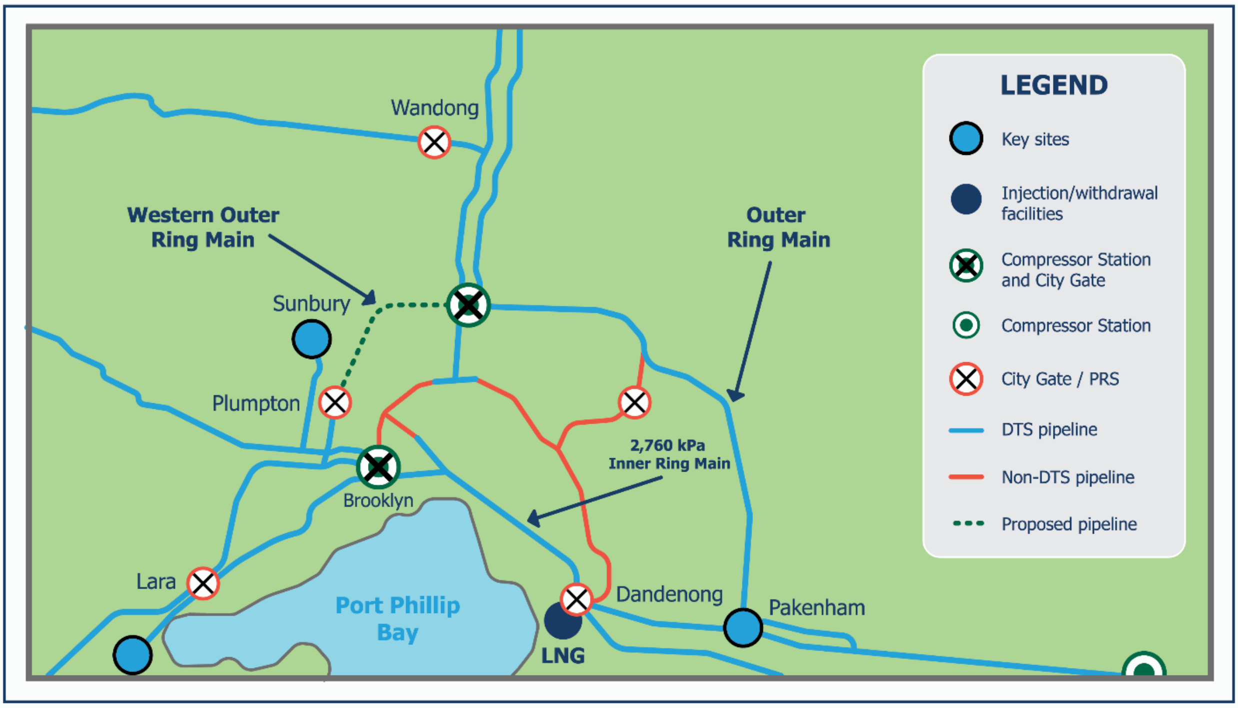
Under the proposed design of Victoria's 100% hydrogen system outlined in Chapter 4, a major component of the existing Natural Gas Transmission System could be duplicated with pipelines delivering hydrogen from renewable energy zones (REZ) to gate stations and the inner ring mains. Given the mature state of the existing natural gas system, it is proposed that these elements could be duplicated.

The existing Victorian natural gas Declared Transmission System (DTS) transports gas from Longford in the east of Victoria to and from Culcairn in the north of Victoria (connecting to the NSW transmission system) and Iona in the west of Victoria (connecting to South Australia, Otway gas production and underground gas storage facilities). This includes the metropolitan outer ring main and parts of the inner ring main. See Figure 27 below.

The DTS, the Victorian Declared Wholesale Gas Market (DWGM), and the declared distribution systems are regulated under the National Gas Law (NGL), part 19 of the National Gas Rules (NGR), and by various Australian Energy Market Operator (AEMO) procedures. All gas that is transported by the DTS must be traded in the DWGM.

Figure 26: Victorian Declared Transmission System

Figure 27: Victorian Declared Transmission System



6.1.2. National Gas Regulatory Framework Reform

Energy Ministers at Commonwealth, State and Territory level agreed to amendments to the national gas regulatory framework to bring hydrogen blends and 100% hydrogen pipelines within the scope of that regulatory framework. These changes are summarised in Table 18 below, noting they would be required for 10% hydrogen as a stepping stone to 100% hydrogen in networks and are outlined in full in Chapter 7 of the *AHC 10% Hydrogen Distribution Networks Study - Victoria.*

Table 18: Key issues addressed to achieve 10% hydrogen

Issues	Is 10% hydrogen feasible if the issue(s) are not addressed?	Are the issue(s) being addressed?	What is the proposed timeframe for the required changes?
Hydrogen does not participate in the energy market and is therefore not adequately incorporated within regulatory frameworks	To achieve 10% hydrogen, definitional changes need be made to the NGL and NGR.	The National Gas (Victoria) Act 2008 has been amended to allow the Victorian Minister for Energy and Resources to declare blended gas as natural gas for the purposes of the NGL and the NGR. This is intended to be an interim measure until national changes are made. Energy Ministers at Commonwealth, State and Territory level have agreed to reform the national gas regulatory framework to bring hydrogen blends within the scope of the regulatory framework.	The changes have been agreed and are expected to be legislated in 2023.
Wholesale market issues, including the connection of hydrogen production facilities to the network	An amendment to Part 19 of NGR would be required to achieve 10% hydrogen.	The AEMC initiated a rule change process for the NGR applying to the Victorian DWGM on 21 October 2021. This was based on a request made by the Victorian Minister for Energy, Environment and Climate Change that seeks to enable that market to recognise distribution connected facilities. These facilities may include hydrogen and renewable gas facilities as well as others such as storage.	The changes have been agreed and are expected to be legislated in 2023.
Changes to regulations due to different heating value of hydrogen gas	A change to AEMO procedures would be required to achieve 10% hydrogen.	AEMO is considering a change to this approach.	Changes are being considered, AEMO is targeting implementation by early 2024 (prior to any 10% projects coming online)
Introduction of new customer protections for 10% blended gas	10% hydrogen could proceed without this change.	AEMC has recommended final rules in relation to customer notifications in relation to a change in the type of gas supplied, pricing, billing arrangements and quality risks.	The changes have been agreed and are expected to be legislated in 2023.

While these reforms focus on enabling 10% hydrogen in natural gas, under the agreed amendments, parts of the national framework will be extended to 'other gas products' (e.g., a blend with a higher proportion of hydrogen and 100% hydrogen).

6.2. Low Regret Options to Support 100% Hydrogen in Networks

Renewable hydrogen is currently more expensive than natural gas. Hydrogen, however is expected to be competitive with natural gas in the short to medium term depending on the policy settings in place for the industry. In the absence of an economy-wide carbon price signal, policy mechanisms can address the current cost differential between hydrogen (and other renewable gases) and natural gas.

This logic borrows from Australia's experience with the renewable electricity sector, which is now considered mature having achieved significant cost reductions over time through a range of policy mechanisms such as the Renewable Energy Target, which surpassed its target of encouraging an additional 20 per cent renewable electricity generation by 2020, compared with 1997 levels.

Various international markets are moving to support the development and use of hydrogen, including in networks, through policy incentives. For example, in early 2023 the United States passed the *Inflation Reduction Act* to subsidise the production of green hydrogen for any use to a level of around $3 per kilogram.

6.2.1. Incentive Mechanisms

Table 19 summarises some of the key advantages and disadvantages of several distinct types of incentive schemes that could be used to increase demand for hydrogen and other renewable gases as an alternate to natural gas.

A policy incentive mechanism would help achieve government policy objectives, including that blending potentially reduces emissions, facilitates early experience with hydrogen and has a low risk profile of off-takers enables supply and demand to be balanced in the energy system, and can unlock the growth of Australia's hydrogen economy as a necessary precursor to later export.

Table 19: Different schemes that incentivise the use of hydrogen or other renewable gases in place of natural gas

Criteria	Brief Description	Potential Advantages	Potential Disadvantages
Certificate-style Scheme	Places an obligation on liable entities (e.g., gas retailers, distribution businesses, etc.) to surrender a certain number of certificates each year. The number of certificates remitted could first reflect a near-term target (e.g., 10% by volume), and once reached (by a certain specified target year, e.g., 2030), a longer-term target (100%) could be set (with an associated long-term date) if it is deemed to be required. The trajectory of certificate creation over the life of the Scheme could be hard-wired into its design to create certainty for investors. This creates an underlying demand for certificates.	• Because this scheme would mimic the existing Renewable Energy Target scheme, it is a known design and existing governance and institutional frameworks could be leveraged • Certificate prices, and therefore the cost of the scheme, reflect underlying market fundamentals affecting creation of certificates. • Production of eligible gas is decoupled from the location at which the liability is generated. For example, certificates in one location can be used to offset liabilities generated from the sale of gas in another location, giving locational flexibility for production. • Provides a clear investment signal, and, if the target is long-term, can facilitate the establishment of long-term industry infrastructure and capacity.	• Can have higher administrative costs relative to some other schemes due to compliance and verification systems/arrangements (despite this scheme leveraging existing governance and institutional arrangements). • Requires a sufficiently large market to produce accredited gases. • May require reasonably high penalties (above the marginal cost of generation) to incentivise compliance through the surrender of certificates, instead of through the payment of the penalty price. • Should operate for a pre-specified and material length of time, otherwise it could create significant uncertainty for investors.
Feed-in tariff (FiT) Scheme	A set payment level per unit of renewable gas is established by a central body for a certain volume, which is potentially adjustable periodically, to, for example, reflect different levels of required support early on in the hydrogen development phase (e.g., to 10% by volume) versus any longer-term support required once the industry is more established (e.g., 10% - 100%), This would be payable to producers of accredited gases who blend their product into specified gas distribution networks. Bid selection is on a first-come, first-served basis until a desired quota is completed, after which the FiT ceases for new entrants	• It is a known design, as it is analogous to several Schemes that were used by some states to promote investment in (predominately small scale) renewable electricity generation facilities. • Simple to understand and it is likely to have relatively low transaction costs. • Mitigates the risk that renewable gas producers could exercise market power to affect prices. • Depending on the duration of the posted FiT rate, it provides income certainty to proponents.	• If renewable gas production were to have naturally occurred even without the FiT, then it generates low economic benefit. • The FiT may not reflect underlying market fundamentals, as the payment level is set centrally before the event. This approach risks low generation if the price is too low, or overpayment if the price is too high.

Criteria	Brief Description	Potential Advantages	Potential Disadvantages
Competitive grants/Reverse auction Scheme to procure renewable gases	Government or utility calls for offers of renewable gas in set tranches (e.g., reflecting sizes that are consistent with short to medium term targets such as 10% by volume; sizes reflecting long- term targets), and the most cost-effective and feasible proposals receive a long-term contract or funding support. Could be augmented via the adoption of a Contract-for-Difference arrangement, linked to the market price of natural gas.	• Provides some flexibility around the timing, size, and location of tranches, hence the mechanism can have regard to the supply/demand fundamentals at that time (noting however that too much flexibility may create too much uncertainty for the industry). • Outcomes are market tested. • Contributions can be capped via the setting of reserve prices, hence providing a means of managing the costs to consumers. • In principle, auctions maintain many of the advantages of feed-in tariffs (income certainty for winning proponents) and are also capable of minimising costs to end-users.	• High set-up costs, which is particularly important if the size of the auction tranches is relatively small. • High transaction costs for bidders due to high upfront project development costs, which may preclude smaller bidders from bidding.

6.2.2. Hydrogen-Ready Appliance Uptake

As outlined in Chapter 5, appliances will need to be suitable to operate with 100% hydrogen. Section 7.3.3 demonstrates the cost of the transition to 100% hydrogen is sensitive to the share of hydrogen-ready appliances in the market, driven by appliance and labour costs required for households that still have conventional natural gas appliances at the time of conversion.

By applying the typical life span of domestic gas appliances and their penetration in South Australia and Victoria households, the effect of mandating all gas appliances to be hydrogen-ready from a certain date on was estimated.

Assuming a mandate to be in place from 2030, 90% of domestic appliances could be hydrogen-ready by 2040. On the other hand, delaying a mandate by five years would reduce the share of domestic hydrogen-ready appliances to 45%.

The following policy options and regulatory changes could support the appliance transition process detailed in Chapter 5. Feasible options that could be explored include:

- Requiring certification of all appliances sold or installed as either dual fuel or hydrogen-ready. This could include standard gas appliances that manufacturers can demonstrate already meet the requirements of a hydrogen-ready appliance, despite not being initially designed or marketed as such.
- Incentivising or creating a rebate program for hydrogen-ready appliances for domestic customers installed ahead of network conversion and/or ahead of the mandate.
- Incentivising businesses with Type B appliances installed to have a conversion plan prepared by an approved consultant or appliance supplier/manufacturer.

Consideration should also be given to other key areas, including:

- Development of hydrogen-ready appliance standards for use by manufacturers to inform appliance development, which could be adopted from or harmonized with international examples.
- Providing guidelines around the allowable charges for conversion to a percentage of the up-front cost of appliances, or requiring that appliances costs are inclusive of conversion.
- Ensuring training and licensing requirements for gasfitters addresses hydrogen-ready appliances.
- Ensuring an adequate pipeline of gasfitters in the workforce to deliver the conversion program.

A case-by-case assessment process could be made for more bespoke Type B appliances and components in industrial applications. The conversion of these appliances should align with the pathway which offers best value to the customer based on their unique circumstances and would ideally be a customer-led approach. However, not all customers will have the resources to undertake this process effectively, and policy approaches which incentivise industrial customers to do so should be considered. For example, governments could support a 100% hydrogen conversion study delivered by a panel of pre-approved expert consultants, equipment manufacturers and suppliers.

7. 100% Hydrogen Implementation

This Study envisions the transition to 100% hydrogen in networks could take place from the mid-2030's, building on the foundations laid from achieving 10% in networks and leveraging lessons from similar programs such as existing mains replacement and the move from towns gas to natural gas.

Based on an international literature review outlined in Section D of the Appendix, information from stakeholder engagement activities and internal subject matter knowledge, the aim of this Section is to answer the following questions:

- What groups and bodies are responsible for the conversion process?
- What are the network conversion options for this transition?
- What is the conversion process?
- What sort of conversion metrics are used to estimate the conversion effort and required workforce?
- What is the selected appliance conversion strategy?
- What would be the conversion timeline and estimated costs?

This Section outlines how a single-step transition to 100% hydrogen could take place on a section-by-section basis across Victorian gas distribution networks. It is essential that communication with customers takes place often and early before any conversion works are started. This transformational shift in the energy system to achieve common net zero goals requires strong coordinated action between government and industry.

7.1. Organisational Requirements

The transition from natural gas to hydrogen would require careful planning and a well-structured organisation of the activities and responsibilities. Several teams of different disciplines would need to be involved and coordinated in the process. To carry out this activity in a timely and effective manner, a defined organisational structure and a high level of coordination would be required.

The workforce in place to carry out the conversion should be divided into teams, each with a different scope and responsibilities. The division of the work could be as follows:

Identified Pathway Options		
1	**Distribution Design Team**	This team will carry out selection of networks and potential gate stations and valve locations and will determine the need for construction of high-pressure mains to supply hydrogen to the gate stations, or the use of temporary storage tanks and transport of hydrogen via trucks.
2	**Operations Teams**	This team will work closely with the design team to confirm on the ground design decisions, and to test the network, install required valves, carry out purging, and introduce hydrogen. This would include purchase of equipment and logistics.
3	**Conversion Teams**	This team can potentially be part of network operators, external work force, retailers, or manufacturers. It will carry out conversion of appliances and any upgrade of customer piping that may be required. The greater the number of resources carrying out or coordinating the work, the more complex the management of the total conversion becomes.
4	**Logistics Team**	This team will be responsible for the procurement and storage of components required for construction and operations activities.
5	**Project Team**	This team will manage the overall project, ensuring communication and management of delivery requirements to timeframe.
6	**Communication Team**	Associated with the project team, there should be a communications team to communicate with customers, manufacturers, gasfitters, etc, about each process step.

Historically, the conversion of consumer appliances was completed by the State-owned "Gas Companies" who were a vertically integrated organisation responsible for the delivery of purchased gas, distribution, appliance sales, service, and billing. Since the industry disaggregation, the networks are responsible for the management of the distribution systems from their gate stations through to the outlet of the consumer meter only.

While the conversion of the network up to the customer meter would be in the network operator's hands, it is not as well-defined which entity should take charge of the conversion of appliances and downstream equipment (network operators, energy retailers, government etc).

Figure 28 and Table 20 present one possible organisational structure and responsibilities for the conversion activity.

Figure 28: Possible hydrogen conversion responsibility structure

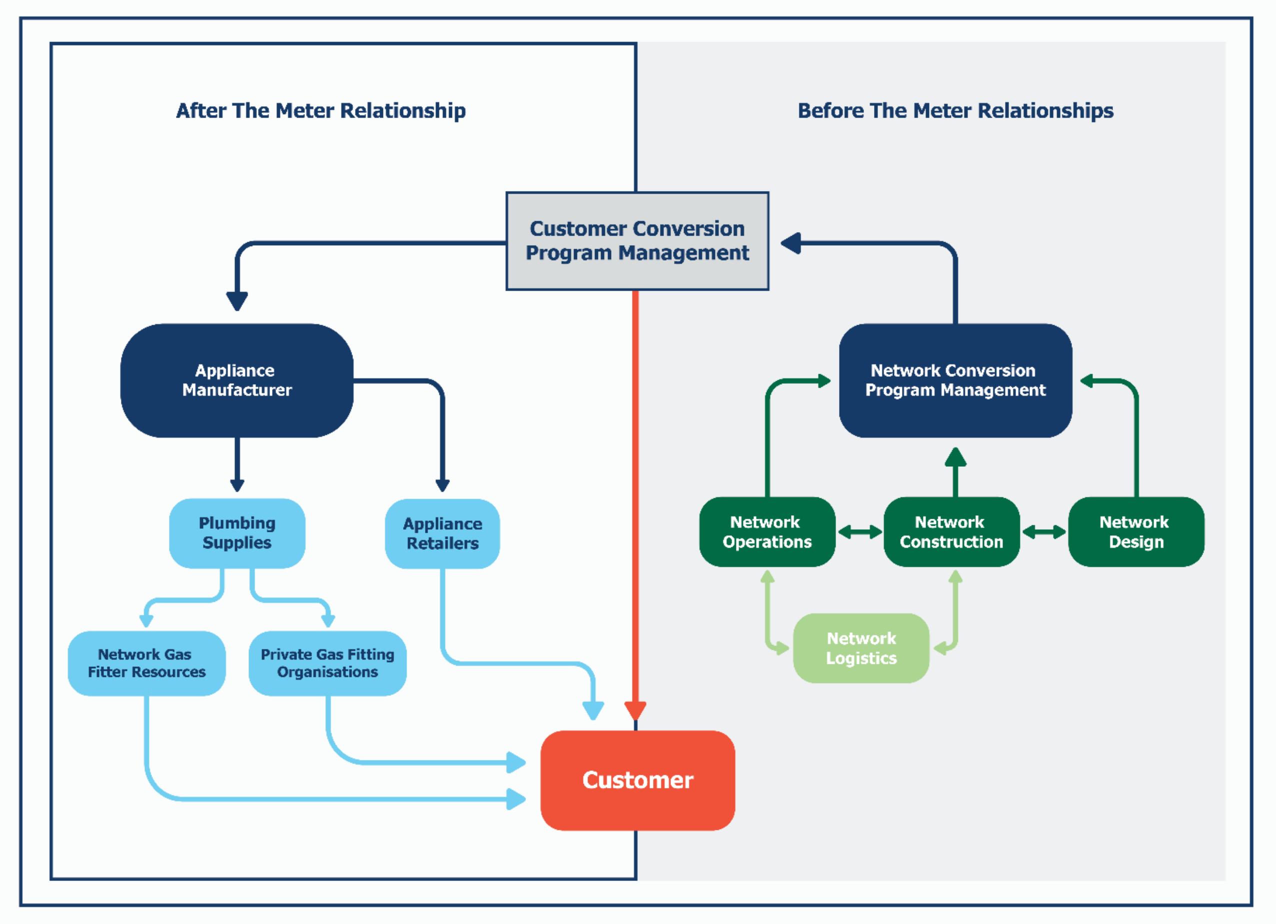


Table 20: Organisational structure and responsibilities required for network conversion

Authorities	Possible Responsibilities
Network owners	**Network Conversion Management** • Overall program management of design, construction, and conversion timetable • Communication of 6 monthly and bi-weekly conversion plans to Conversion Program Management • Modification of the plan based on issues /delays • Liaison with Conversion Program Management **Network Operations** • Completion of leakage surveys and repair of leaks • Sectioning identified networks • Proving a sectioned area and location and rectification interconnections • Audit installation prior to hydrogen meter turn on • Turn off and tag manual control valves (MCV) for customers in sectioned area • Purging natural gas and introduction of hydrogen • Provision of temporary supply due to conversion issues **Network Construction** • Construction of new distribution systems for hydrogen introduction • Construction of temporary electrolysers where required **Network Design** • Determining location of hydrogen feeds for conversion • Capacity design of new high-pressure mains • Determining sequencing of network conversion and zones based on network, customer density and type **Logistics** • Procurement and storage of components required for construction and operations activity
Customer conversion program management	• Long-term communication channel to end users • Advise customer on conversion options and gas fitting resources • Advise on conversion date • Development of appliance conversion strategies • Identification and accreditation of resources to complete conversion or develop conversion plans • Ensure conversion documentation is available for appliances • Provides resource availability for appliance conversion to networks • Liaison with manufacturers regarding conversion forecast and potential material requirements • Repository of Type B appliance plans • Repository of customer advised appliances • Notify energy retailers of the change in energy to ensure correct billing factor applied

Authorities	Possible Responsibilities
Gas fitting resource	• Appropriately skilled and approved gasfitters capable of carrying out Type A and Type B appliance conversions. • Gasfitters check installation prior to conversion to ensure pipe sizing correct for hydrogen • Gasfitters carry out conversion of hydrogen-ready appliance on conversion date, turn on meter test and purge customer's system • Gasfitters install new appliance on or before date of installation, turn on meter, purge, and test installation
Manufacturers / Agents	• Provision of new hydrogen appliances where necessary • Provision of appliance conversion kits and conversion instructions
Plumbing supplies	• Sale of appliance conversion kits • Sale of hydrogen approved components
Appliance retailers	• Sale of new appliances

7.2. Conversion Approach

There are different options to evaluate for the 100% hydrogen conversion strategy. Analysis indicates that this can be distilled to the scale of network area of conversion. It is clear from the analysis that each option selected has different drivers.

Network Size	Discussion
Large Area Network Conversion	In this option, the drive is to convert the network itself as cheaply as possible. This would be achieved by converting large sections of the network at once, by substituting the natural gas at the gate stations with 100% hydrogen. The implication is that customers or a central organisation would be responsible for arranging and having completed any conversion activity required on their property following the conversion of the network. Given the large scale of conversion operations, this strategy has the potential for increased customers downtime compared with a small network area conversion. This will also depend upon the level of industry resource that is available for carrying out the required work and providing the material required to complete the activity.
Small Area Network Conversion	In this option, the drive is to limit the impact of the conversion on the customer. The key measure of success will be the customers' days off supply. The areas converted will be determined by the work volume and resource level available to convert customers appliances within the time that was agreed as acceptable for customers to be without supply. In this strategy, sufficiently small areas of the network that can be converted within the agreed time frame. Customer appliances are converted at the time that the network is converted with supply being reinstated potentially within a day.

Stakeholders considered that within today's environment customers would not accept having supply outages spanning days. Therefore, the small area network conversion process supported by a robust hydrogen-ready appliance strategy could best minimise disruption during the transition to 100%.

The conversion process of the gas distribution network would be driven by the network operator who would select the areas and sequencing of conversion of the network. The downstream of the meter activities are closely linked to the upstream conversion of the gas distribution network from natural gas to hydrogen.

Once the size of networks and sequencing has been determined the Network Operators plan the process. This could include:

1. Dividing cities and towns into conversion sections. This step would require ad hoc conversion studies to select the network sections to isolate and convert, on a case-by-case basis.
2. Prepare hydrogen delivery to the connection point – e.g., install and commission and dedicated hydrogen pipes to the connection point, and prepare for tie-in where required.
3. For each network section, understand the conversion requirements, including the type of customer (domestic, commercial, or industrial) and the type of appliances installed.
4. Carry out required reinforcement works and install additional isolation valves or perform squeeze-offs, if required. Also, installation of flares for purging.
5. Communicate with each household or Customer Coordination Team before the actual conversion process and set the day of conversion. Advise customers that they would be without gas supply during the conversion activities.

   The Customer Coordination Team will then liaise with customers assess the supply and delivery of parts required for the appliance conversion process and plan labour resources required to complete the work.

   a. In case of appliance replacement: Customers would be required to contact appliance retailers in advance and purchase the hydrogen appliance. Low- or zero-interest loans could be put in place to financially support customers. Data on the purchase should be recorded, including appliance type, model number and serial number, and address of the customer. Logistics Team coordinate with the appliance retailers and manage the delivery of the appliance to the customer premises before the time of conversion.
   b. In case of hydrogen-ready appliance conversion: conversion kit included in the cost of the hydrogen-ready appliance. Manufacturers produce clear information on the correct type of kit (identified by a code) for each hydrogen-ready certified appliance. A database of installed hydrogen-ready appliances with model number and location will inform the Logistics Team on which and how many conversion kits to prepare for each section of the network. Logistics Team liaise with manufacturers for the timely supply and delivery of the kits.
6. On the day of conversion, the Network Operator would:
   a. Attend the gate station and a purge or multiple purge points on the section to be converted.
   b. Turn off and tag supply to all customers at the meter control valves.
   c. Isolate natural gas supply to the distribution network section to be converted and purge the natural gas from the isolated section. Once it has been identified that 100% hydrogen is present at the purge point and that there is no back-feeding, the network is converted.
7. While this is undertaken, gasfitters can perform work downstream of the meter. Following advice from the Network Operator that the network has been converted, gasfitters can complete the final conversion by opening the meter control valve, purging any remaining natural gas from the system, and commissioning the appliance.

7.3. Network Conversion Cost Estimates

To provide an indication of the cost of the network conversion in Victoria this study analysed the cost of the network conversion activities and of the domestic appliance's conversion/replacement, in terms of workforce required. While this is a high-level analysis that assumes all connections in Victoria are domestic, it still provides an indication of the magnitude of the task and of the impact of key parameters/decisions.

The first key parameter that was analysed is the size of the network sections to be converted. While dividing the network into larger sections would provide some economic benefit in terms of total effort for organisation and field activities, it would also require a longer period off gas for the customers. A trade-off should be identified, which would likely be different on a case-by-case basis.

The second parameter is the share of appliances that are hydrogen-ready by the time of the start of the conversion.

7.3.1. Assumptions

For this analysis, two network section sizes were selected as representative, identified by the number of customers in each:

- 2,500 customers for the large network section.
- 300 customers for the small network section.

The time that customers would be required to be disconnected from the gas supply was estimated as follows:

- Up to 5 days for the large network section.
- Up to 1 day for the small network section.

The time estimate is only indicative, and it could vary depending on the volume of workforce put in place for the conversion activities.

The share of hydrogen-ready appliances at the time of conversion was assumed to be 90%.

The main assumptions that were used for the high-level estimate of the cost of conversion are summarised in Table 21.

Table 21: Main assumptions used to produce conversion cost estimates

Conversion metric	Value
Number of gas connections (Victoria)	2,177,434
Number of gas connections (South Australia)	461,048
Large network segmentation	
Connections per network segment	2,500
Disruption time for customer	5 days
Small network segmentation	
Connections per network segment	300
Disruption time for customer	1 day
Share of Hydrogen-ready appliances at the time of conversion (base case assumption)	90%

7.3.2. Network Conversion Indicative Costs

The overall cost of network conversion is constituted by two main components: the network conversion activities and the conversion of appliances.

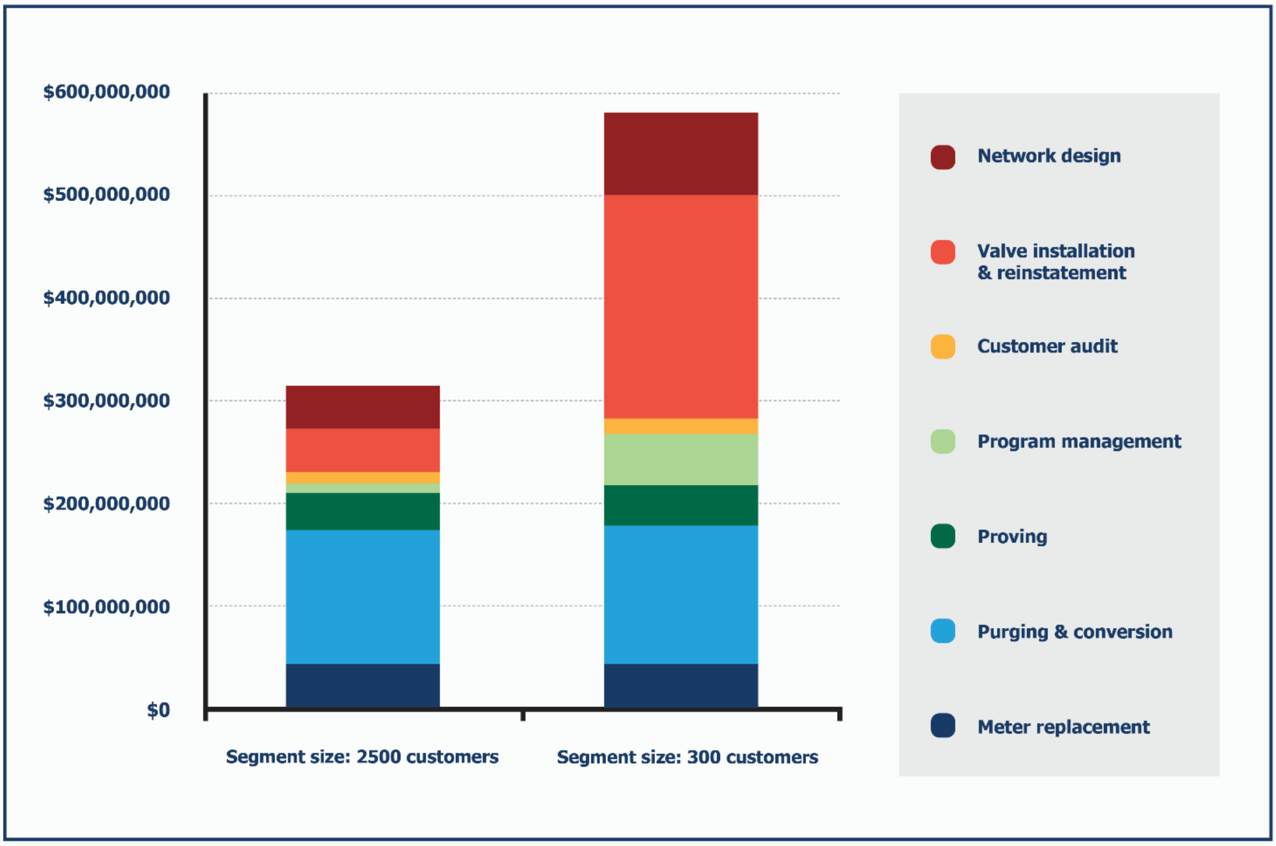
The network conversion activities included in this high-level cost estimate are:

- overhead cost for distribution network design and project management;

- meter replacement at the customers' premises;
- customer gas installation audit;
- segment valve installation / squeeze-off;
- reinstatement after valve installation;
- network section proving; and
- network section purging.

Figure 29 presents the indicative cost breakdown of the network conversion activities in Victoria.

Figure 29: Network conversion cost breakdown



While the cost of meter replacement and customer auditing is independent from the size of the network section, the increased organisational requirements of a larger number of sections leads to a considerably larger project management and network design cost for the smaller network sections size. The network-wide cost of valve installation/squeeze-off is also higher for the 300-customer section size, due to the larger number of valves/squeeze-offs required.

Overall, the cost of network conversion activities is estimated to be over 80% higher for the small customer network size compared to the 2500 customer network size in both Victoria ($576 million vs $316 million) and South Australia ($122 million vs $67 million).

It is worth noting, however, that customers could be without supply for up to 5 days in the 2500 customer network size, as opposed to just 1 day in the small customer network size (see Table 21: Main assumptions used to produce conversion cost estimates). While the cost is lower, customers would be expected to be without gas supply for 5 days.

Note, the meter replacement cost only includes the cost of gasfitter work, rather than the cost of the meter. It is assumed that customers would not be charged for the replacement of the meter, but they could be charged for major work to the downstream piping (e.g., if major piping compliance issues are identified).

7.3.3. Appliance Conversion Indicative Costs

The cost of the replacement of natural gas appliances or the conversion of hydrogen-ready appliances is determined as the cost of labour for the required gasfitter activities, including some overhead costs for project management and communication. The cost of the appliances is not included in this analysis.

The appliance conversion activities would likely be undertaken by licensed gasfitters, however there is the possibility that some activities could be carried out by purpose-trained workforce.

The conversion of hydrogen-ready appliances is estimated to be considerably less labour intensive that the replacement of natural gas appliances. Table 22 provides an indication of the time required, in terms of hours of gasfitter work, for the conversion and replacement of the most common domestic gas appliances. These values were used in the cost estimate analysis.

Table 22: Estimation of effort required to switchover appliances (replacement or modification)

Domestic gas appliance	Activity	% of premises with equipment [29]	Time required for gasfitter to execute (hours) [30]
Hot water heater	Conversion of Hydrogen-ready appliance	95%	2
	Replacement of natural gas appliance		8.5
Cooktop	Conversion of Hydrogen-ready appliance	95%	1
	Replacement of natural gas appliance		13.5
Heater	Conversion of Hydrogen-ready appliance	50%	2
	Replacement of natural gas appliance		5

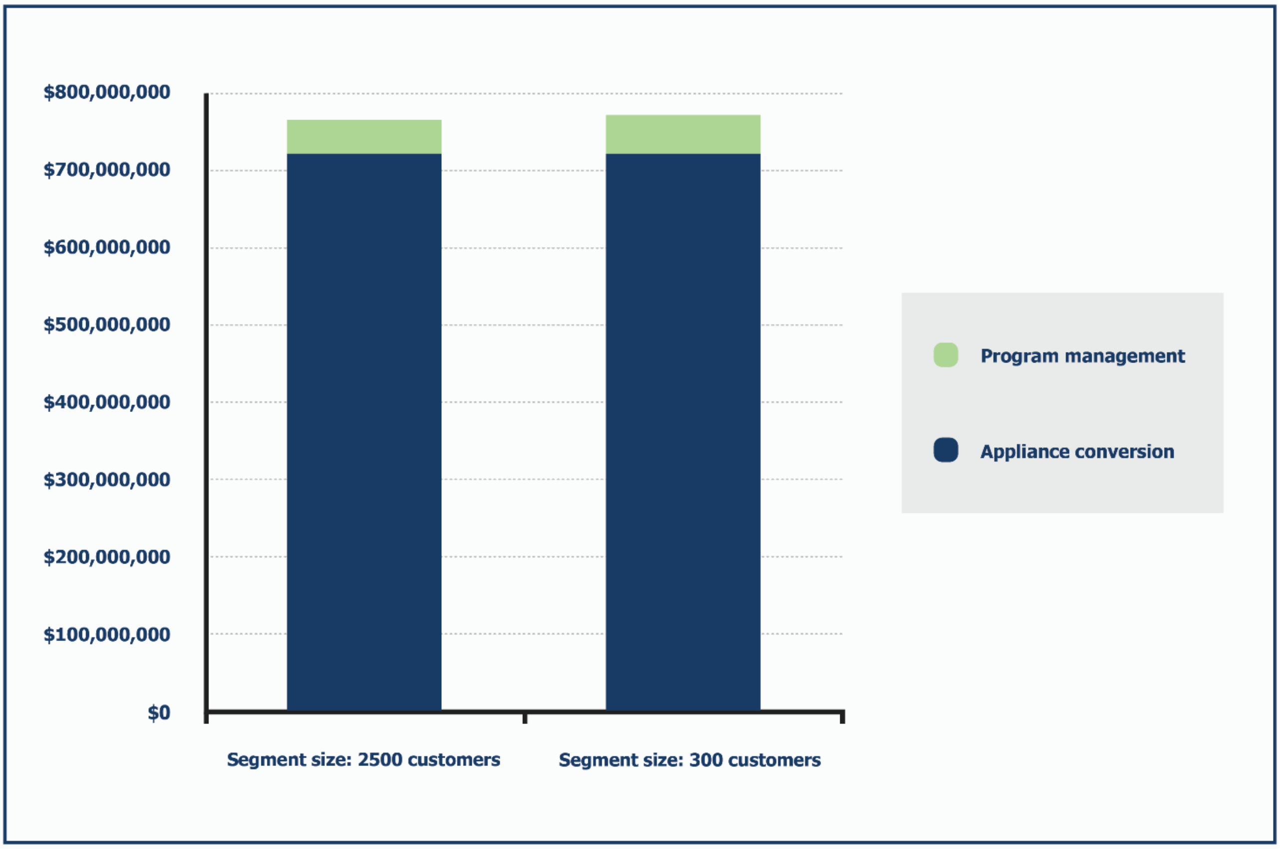
29 Based on AGIG commercial team experience of appliance conversions and replacements.

30 Sourced from Leeds Gate station H21 report, which drew on the experience of UK-based testing and energy management consultancy, Kiwa Gastec, to estimate the effort required for appliance switchovers. Read the report here: <https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf>

In addition to the cost of the gasfitters work, some overhead costs were included for project management and communication.

Figure 30 presents the indicative cost breakdown of the appliance conversion activities.

Figure 30: Indicative cost breakdown of appliance conversion activities



The cost for appliances conversion across the Victorian networks is largely independent from the network section size, apart from a small increase in overhead cost for the 300-customer section size.

Sensitivity to the share of hydrogen-ready appliances at the time of conversion

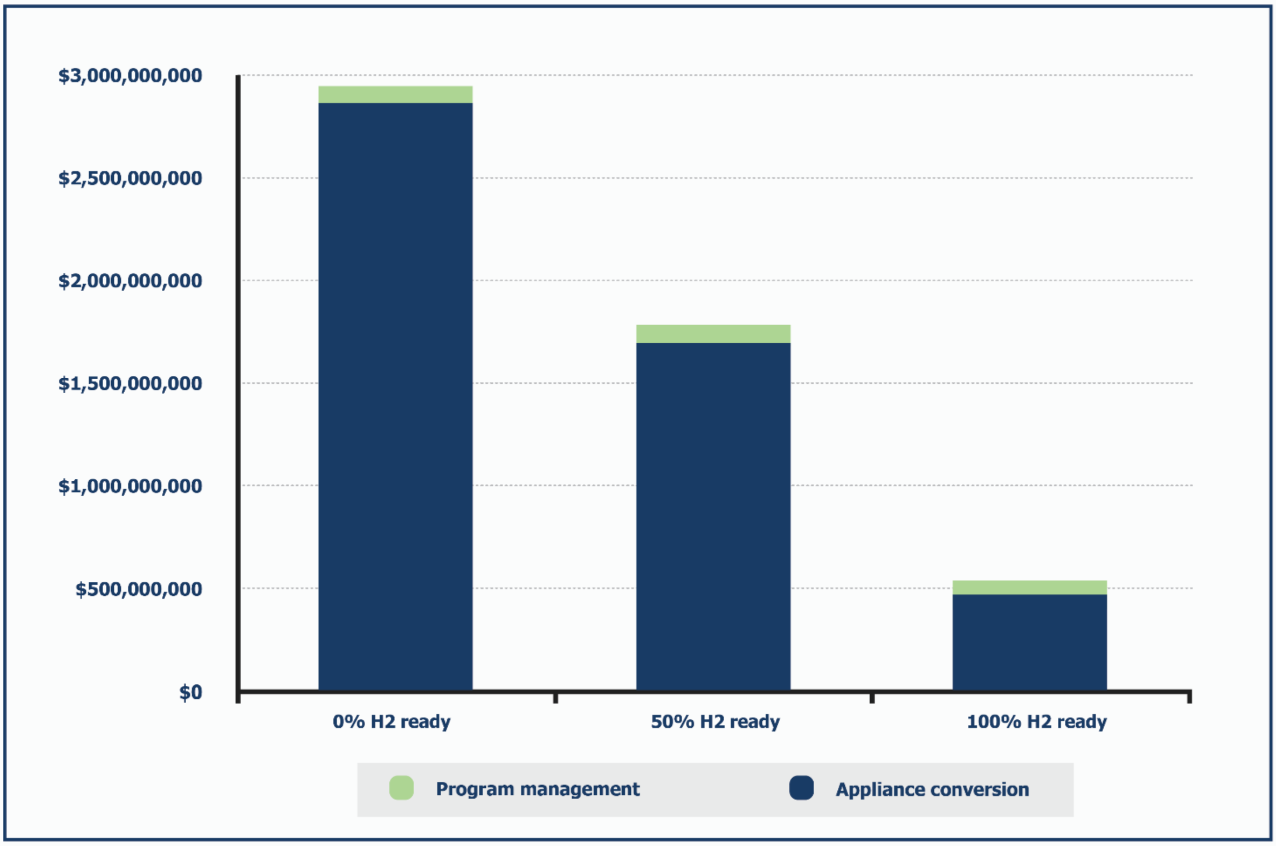
The share of hydrogen-ready appliances at the time of conversion has a substantial impact on the overall cost of appliances conversion, due to the higher gasfitter labour required for households with conventional natural gas appliances.

By using the typical life span of domestic gas appliances and their penetration in Victoria households, the effect of mandating all gas appliances to be hydrogen-ready from a certain date on was estimated.

Assuming such mandate to be in place from 2030, 90% of domestic appliances could be hydrogen-ready by 2040. On the other hand, delaying a mandate by five years would reduce the share of domestic hydrogen-ready appliances to 45%.

The below diagrams show the sensitivity of the overall cost of appliances conversion to the share of hydrogen-ready appliances. In Victoria, this cost could be reduced by a factor of six if all appliances are hydrogen-ready at the time of conversion compared to no hydrogen-ready appliances. Ensuring that only half of the appliances are hydrogen-ready would still have a major impact, reducing the estimated overall cost by $1.2 billion (40% reduction).

Figure 31: Indicative cost impact of ensuring appliances are hydrogen-ready by network conversion



7.4. Implementation Plan

This Section summarises key steps and activities that would be required to achieve 100% hydrogen in networks. As there are many unknowns that may impact this implementation, what is presented below is an estimate based on global and local experience. Industry stakeholder workshops were held to inform these steps, which involved:

- Assessing options for converting existing gas appliances to be compatible with 100% hydrogen.
- Developing a streamlined identification process to understand gas appliances installed in Australia.
- Identifying activities that would be required to make hydrogen-ready appliances available for customers to purchase.
- Identifying activities that would be required or ideal steps to achieve 100% hydrogen by 2050.
- Identifying changes to legislation and regulatory standards that would be required to enable 100% hydrogen by 2050.

7.4.1. Description of Conversion Steps and Activities

Step 1: Research and development, and production ramp-up for hydrogen ready-appliances

Rationale

Hydrogen-ready appliances would ideally be prevalent in the market ahead of the transition to 100% hydrogen to allow for a shorter network conversion timeframe.

Additional work is required to ensure that hydrogen-ready appliances are appropriate for use in Australia. The appliances for the European market are designed following different electrical standards (ATEX vs IECEx) and gas pressures than the Australian market. There is an opportunity to harmonise the standard and gas pressures between Europe and Australia.

The base case timeframe for research and development, and production ramp up, is two years for each, making a total of four years for both. Government incentives and market competition can shorten this step to three years.

If hydrogen-ready appliances are not available and installed in place of natural gas ones by the time the 100% conversion process starts, the replacement of natural gas appliances will have to take place at the same time of the conversion, increasing the conversion timeframe, the cost and the workforce required, and the logistical risk.

Timeframe: Start immediately, 3-4 years duration

Assumptions

- Hydrogen-ready appliances are ready for purchase by 2030 so that replacement of appliances can begin. Experience with European gas appliances manufactures revealed that, if incentivised, the research and development, and production ramp-up process, can be shortened to three years, providing an opportunity to speed up the timeline.

A 1–2 years testing cycle is required as a minimum to allow appliances to be monitored for seasonal variation.

Step 2: Legislate and introduce policy changes to support network conversion

Rationale

The policy options to support the transition may include:

- mandating that all appliances sold or installed from 2030 must be certified as either dual fuel or hydrogen-ready;
- an incentive/rebate program for hydrogen-ready appliances for domestic customers installed ahead of network conversion; and
- Conversion plans for businesses with Type B appliances undertaken by an approved consultant or appliance supplier/manufacturer. This may need to be a government supported program to ensure high uptake.

Timeframe: 3 years

Assumption

Policy should be implemented as soon as possible to minimize the number of appliances that need to be changed at the time of 100% conversion.

Step 3: Conduct government-supported conversion study program for Type B appliances

Rationale

Leveraging updates to standards and testing for gas appliances set out in the 10% blend implementation program, a database of Type B users (industrial and commercial customers) should be maintained for 100% conversion, tracking which customers have hydrogen-ready appliances or original natural gas appliances.

As discussed in Chapter 6, a government-supported 100% hydrogen conversion study program could be delivered by a panel of pre-approved consultants and equipment suppliers/manufacturers. If not incentivised, there is a risk these customers operations will no longer be viable.

Timeframe: 5 years

Step 4: Safety management documentation and approvals to operate networks with hydrogen

Rationale

Development of the safety management documentation that satisfies the requirements of the technical regulator.

Timeframe: 5-6 years

Assumptions

The safety management documentation needs to be in place prior to the commencement of operation for a 100% network, however it will be done in conjunction with other activities.

Step 5: Standards and testing for Type A and Type B appliances to allow 100% hydrogen

Rationale

In addition to Step 1, standards and testing regimes for hydrogen-ready appliances for manufacturers to use to inform appliance and component development. These appliances may require a minimum number of components to be changed at the point of switchover but will have been specifically developed to facilitate this process.

Timeframe: 5-6 years

Assumptions

- 5-6 years BAU assumption based on advice from Australian Gas Association (AGA) - if incentivised then it could be expedited. Conversion of networks to 100% hydrogen will be completed by no later than 2050.

Issues of metering pressure and appliance regulators must be standardised. Due to its population size, Australia will follow the appliance direction of Europe.

Step 6: Environmental approvals and licensing

Rationale

This step includes the environmental impact assessments for the hydrogen supply chain infrastructure, obtaining EPA development licenses and obtaining approvals for water infrastructure, pipelines, production, and storage facilities. Environmental impact assessments should consider impact on biodiversity, potential for soil erosion and dust generation, impacts on water resources, impact on existing services and infrastructure, potential social and cultural impacts.

If all approvals, permits, and licenses are not in place, then delay happens in the project commencement.

Timeframe: up to 2 years

Assumptions

Timeframe is based upon consultation process for similar projects.

Step 7: Land acquisition	Step 8: Roll-out hydrogen-ready appliances	Step 9: Construction of transmission infrastructure
Rationale Proceed to acquire land required for pipeline, production facilities, storage and water infrastructure including consultation with all landholders. As construction of production facilities may be staggered, different parcels of land may be acquired over a period longer than 2 years. It is noted that the availability of land may result in a change of the scope of the project. **Timeframe:** 2 years per site acquisition **Assumptions** Timeframe is based on consultation process for similar projects.	**Rationale** Begin transition of natural gas appliances with hydrogen-ready appliances, starting from appliances at the end of life. **Timeframe:** 10-12 years **Assumptions** Hydrogen-ready appliances being installed as soon as minimises costs and customer distruption during conversion. It is noted that hydrogen-ready appliances should be available on the market 10 - 12 years prior to the conversion. Natural gas appliances still installed at the time of conversion should be identified with a connection-by-connection audit, and customers informed about their options which would be to either organise to have the appliance replaced with a hydrogen-compatible one, or to switch to an electrical appliance.	**Rationale** Transmission pipelines are likely required to transport hydrogen from production facilities and demand nodes. The estimated time for a 1450 km pipeline is 4-6 years. This is likely to be constructed in phases over a longer period such as 2030-2045. **Timeframe:** 4-6 years for construction of each unit (phased over 15 years) **Assumptions** • The estimated total hydrogen transmission pipeline length for Victoria is 1450 km and for South Australia is 1200 km. This timeframe is based on the construction time of 3 and a half years for the 600 km Jemena's Northern Gas Pipeline. Timeframe for development will depend on availability of existing land corridors and pipeline easements. This timeframe is based on the construction of 450 km long gas pipeline of APLNG project. The construction of this pipeline took approximately 18 months. As the total new hydrogen transmission pipelines length is comprised of multiple pipelines, construction could occur on multiple fronts at the same time, with the potential to accelerate the schedule.

Step 10: Define a distribution network conversion]strategy and assess responsibilities

Rationale

The strategy could follow a detailed assessment of the existing gas network, including the zone of influence of gate stations (i.e., the limit of where gas supplied at those points is transported to, to the extent that they verge the zone of influence of another gate station). The strategy will include defining the number, size, and location of the network sections to be converted; identifying existing isolation valves and assessing the requirement for additional valves; evaluating the requirement of temporary natural gas supply to certain areas during conversion; and training and organising workforce to undertake customers' appliance modification/replacement.

Timeframe: 4 years per project

Assumptions

Gas distribution network operators coordinate the grid conversion process, including customers appliance modification/replacement process. Another alternative would be leaving it to the customer to organise the replacement of their own appliances, which would require checking in an audit at the time of conversion.

Step 11: Determine appliance conversion responsibility and strategy

Rationale

A decision on who is responsible for working with customers to transition gas appliances to hydrogen. Decision should be made to allow enough time for development of strategy and training of resources.

Timeframe: Minimum 5 years prior to conversion

Step 12: Updating gas-fitting training and licensing requirements

Rationale

It is essential to update the gas-fitting training and licencing requirements to address hydrogen-ready appliances and ensuring the pipeline of gas-fitting workers will be adequate to deliver the program. For the natural gas conversion to hydrogen, the appliances need to be commissioned by an on-site licensed gasfitter.

Timeframe: Minimum 4 years prior to conversion

Assumptions

According to the workshop outcome, in the process of conversion, the gasfitters will order a "conversion kit" from the manufacturer / supplier for the appliance they are to convert. Then they will need to be trained in how to convert, and presumably the conversion kit would come with instructions.

Step 13: Construction of water infrastructure

Rationale

This is an upscale from the 10% pathway due to higher volumes. The infrastructure requirements depend on the selected water source.

If groundwater is used, then groundwater extraction wells, desalination plants, and water pipelines are required. If seawater is used, then desalination plants and water pipelines are needed. The options for alternative water supply such as storm water or treated effluent with or without managed aquifer recharge may need to be considered in some locations. It is estimated that construction time will be 2-3 years per unit. Note that the timing of water pipeline construction would be dependent on distance between water source and electrolysers.

Timeframe: 2-3 years per project

Assumptions

Timing is for the construction of a reverse osmosis plant and water pipeline.

Step 14: Construction of production facilities, including electrolysers and balance of plant

Rationale

In Victoria, there could be sixteen 50 MW, seven 200 MW, and ten 1000 MW units by 2050.

The timeframe includes all stages of the project plan, from prefeasibility to detailed design, construction, commissioning, and operation. There is some scope to run construction in parallel, however this may be limited by workforce constraints and availability of equipment.

Timeframe: 2-3 years per unit

Assumptions

Extra margin applied to timeframe based on uncertainty. Planning phase may take longer for novel technology, particularly for larger units. Workforce constraints, especially getting enough skilled workers to build units simultaneously, may be a challenge.

Step 15: Electricity transmission line and connection

Rationale

Electricity transmission to bring electricity from regionally distributed wind and solar farms to the large electrolysers located in the REZ will need to be built. A new 500 kV electricity transmission line required will be required, which is estimated to take approximately 2 years. Additional substations are also likely to take 2 years, so the total timeframe is 2-4 years, depending on project phasing and whether construction takes place in parallel.

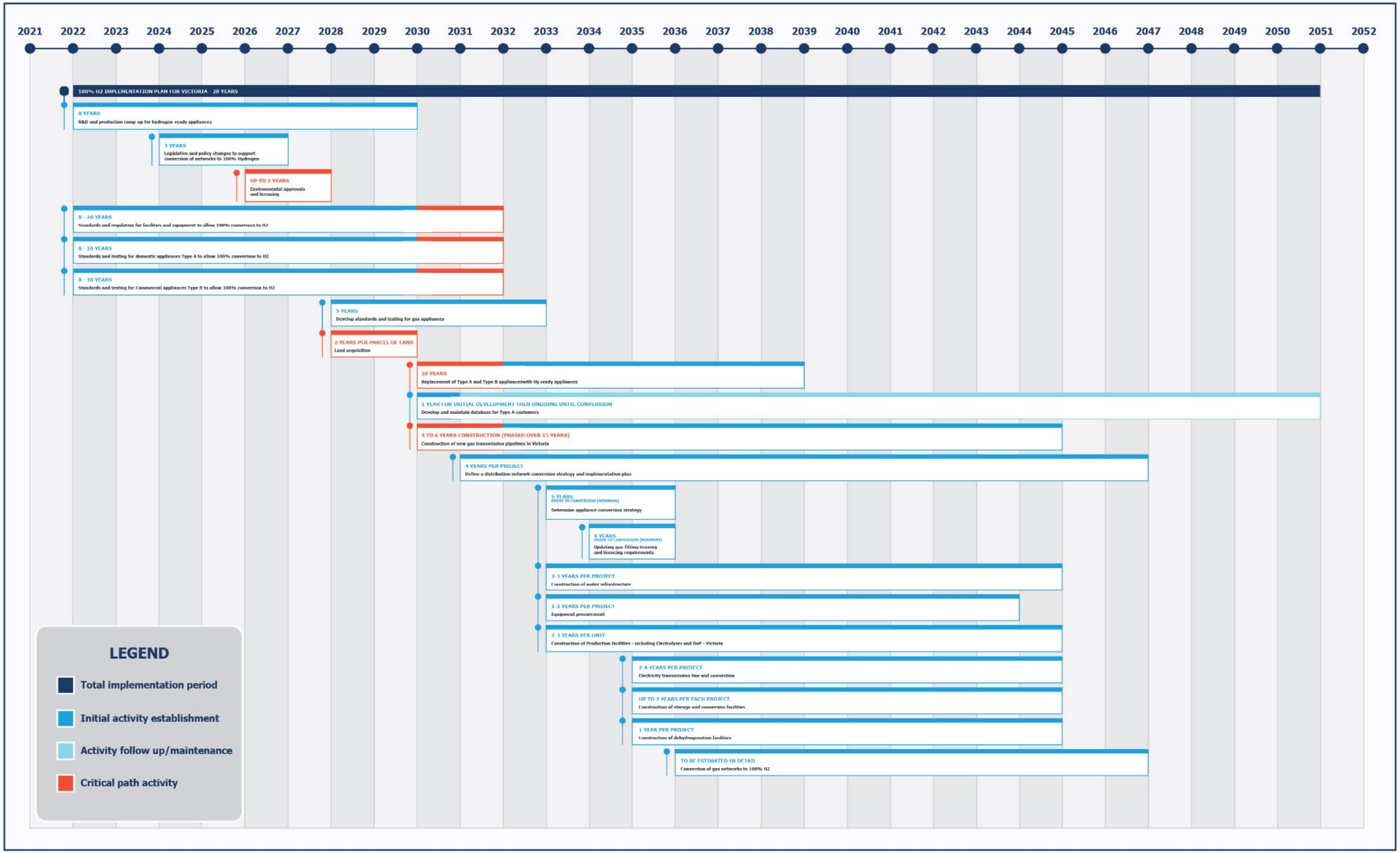
Timeframe: 2-4 years per project

Step 16: Construction of storage and conversion facilities	Step 17: Conversion of gas distribution networks to 100% hydrogen	
Rationale Storage will be in depleted onshore natural gas fields/wells and/or storage bound to a liquid chemical carrier (ammonia, MCH). Geotechnical studies on underground reservoirs will be required to determine suitability and availability for hydrogen storage. **Timeframe:** up to 2 years per project **Assumptions** • Need to make assumption on type of storage or provide timeframe that can cover all the possible technologies. It is assumed that the storage location would be at or near existing on shore depleted hydrocarbon reservoirs as this assumption would also suit that technology if it were found to be viable in subsequent studies.	**Rationale** Conversion of networks to 100% hydrogen, with a phased approach as sections of the network are connected to the new hydrogen gas pipeline. **Timeframe:** 12 years **Assumptions** This is likely to be a phased approach over several years. The assumption is that it will take place from when the first hydrogen pipeline is constructed and linked to hydrogen production facilities, until after the last pipeline is built.	

7.4.2. Timeline

The 100% implementation plan timeline showing the key steps and timeframes is shown in the figure below. A description of the steps and key assumptions can be found in Section 7.4.1

Figure 32: Timeline for implementation of 100% hydrogen, Victoria



7.4.3. Implementation Plan Risk Analysis

Table 23 assesses overarching risks relating to the 100% hydrogen implementation plan as outlined in this Section, and mitigation measures of these risks. Each risk and mitigation measure were assessed for impact and likelihood on a scale of 1 (very low) to 5 (extreme), and a score was then prepared from the product of these two assessments. The resulting range of scores from 1 to 25 was scaled in a traffic light system as follows:

- 1 – 9 categorised green;
- 10 – 15 categorised orange; and
- 16 – 25 categorised red.

Table 23: Risk analysis showing measurement of risk and mitigation options for 100% implementation plan

Risk	Inherent risk			Mitigation measures	Residual risk		
	Impact	Likelihood	Score		Impact	Likelihood	Score
Achieving necessary changes to legislation and regulation [31]	4	4	16	Collaboration between different jurisdictions around Australia to have a common approach for changing legislation and regulation.	4	4	16
Insufficient incentives and market drivers could reduce the motivation of gas appliances manufactures to provide the investment required for R&D and manufacturing.	5	4	20	Clear policy supporting the use of hydrogen in networks as a natural gas alternative.	5	3	15
Lack of organisational structure and accountability hindering the implementation of network conversion	5	4	20	Have in place a clear organisation structure that is accepted by stakeholders prior to starting the conversion process		3	15
Low interest of investors in hydrogen production and supply due to lack of incentives / policy / ad hoc commercial agreements	5	3	15	Government funding and incentives, and clear policy that supports the use of hydrogen as a natural gas alternative	4	3	12
Lack of available water resources to sustain hydrogen production.	5	3	15	Identify available water sources and consider future competing demands on water source as well as effect of climate change	4	3	12

31 Stakeholder consultation revealed that the main challenge for the appliance manufacturing industry and for the development of Hydrogen-ready appliances is the lack of certainty about the future of the gas distribution network. This is particularly challenging due to the risk that different jurisdictions around Australia will follow a different path towards the decarbonisation of the natural gas sector. This complicates making a definite decision and it increases costs and reduces the opportunity for industry players to participate.

Risk	Inherent risk			Mitigation measures	Residual risk		
	Impact	Likelihood	Score		Impact	Likelihood	Score
				on surface water sources. Consider social and environmental license of water usage.			
Incident on the gas distribution network leading to significant loss of life and/or property could halt the conversion process.	5	3	15	Trials on small sections of the network prior to conversion to test procedures and ensure safety management documentation is appropriate. Public safety awareness campaign.	5	2	10
Lack of land availability at identified hydrogen infrastructure sites	2	5	10	Investigation and mapping of available sites for energy industrial planning use (rezoning)	5	2	10
Water resource availability poses a risk to the project if sufficient resources are not secured.	5	2	10	Early identification of viable water sources and stakeholder negotiation to secure supply.	5	2	10
Delay in project commencement if all environmental approvals, permits, and licenses are not in place.	3	4	12	Re-zoning of parcels of land for energy and industrial use, complete environmental studies, and action the EIS/EES and EPBC referral	2	3	6
Delay in pipeline construction due to issues with approvals and acquisition of easements	5	3	12	Early mapping and planning of potential easements and use of existing easements where possible	3	2	6
Risk of delays in implementation plan due to procurement, adequate social license, or public acceptance taking longer than expected.	4	3	12	Diversify the procurement strategy, allow adequate lead time for acquiring parts	3	2	6
Need for purchasing of hydrogen-compatible appliances and associated costs could lead to loss of customer base to electrification	4	3	12	Establishment of community engagement programs to ensure that the public and can make informed decisions	2	2	4
Limited availability of gas fitting resources to carry out appliance conversion	4	3	12	Establishment of a new competency and licensing structure for appliance conversion. Update training courses for hydrogen and make sure gasfitters are trained and licensed to work on hydrogen	2	2	4

Risk	Inherent risk			Mitigation measures	Residual risk		
	Impact	Likelihood	Score		Impact	Likelihood	Score
Uncertainty over locations for underground hydrogen storage and proving of the technology, for storage in depleted gas fields	5	2	10	Early completion of geotechnical studies to identify viable locations for underground storage and explore alternatives to underground storage	3	2	6

8. Financial Modelling

The purpose of this Chapter is to summarise the results of high-level modelling of customer price impacts and potential costs associated with 100% hydrogen in networks. The modelling was based on a nominal transition pathway of 10% hydrogen in the early 2030's and 100% hydrogen by 2050, with specific inputs were drawn from the following chapters:

- Chapter 3: Renewable Hydrogen Supply, Storage and Transportation
- Chapter 4: Network Readiness
- Chapter 5: Customer Appliance Pathways
- Chapter 7: 100% Hydrogen Implementation

Projections were produced for capital expenditure (capex) profiles, operating cost (opex) profiles (including costs of renewable electricity), and revenue from the sale of hydrogen.The subsequent projections were then compared to the natural gas price with no future cost of carbon added and are presented for each year to 2050 to illustrate the financial and customer bill impacts of transitioning to 100% hydrogen supply over time.

Key findings

1. High-level modelling of customer price impacts demonstrates delivering 100% hydrogen supply would result in stable energy bills similar to projections of pre-2022 energy crisis bills for natural gas supply, excluding any cost of carbon.
2. This finding is significant noting the fundamental changes envisioned in this Study to transition the supply chain servicing Victorian gas distribution networks to 100% renewable hydrogen, including around 12 GW in renewable hydrogen production, long-term storage, and new hydrogen pipelines.
3. There could be further upside noting this modelling assessed hydrogen produced via electrolysis powered with renewable electricity only; other carbon-neutral sources (e.g. 'blue hydrogen') and hydrogen produced by external industries (e.g. hydrogen hubs) were excluded. The modelling also excluded cost reductions to hydrogen from breakthrough technological advances.

While this pathway is the focus of this Study, noteworthy limits to this model include that it:

- Investigates dedicated renewable hydrogen production for converting gas distribution networks to hydrogen. In reality, hydrogen could be produced for various end-uses that could also supply into networks as an additional market as part of a 'hydrogen hubs' model;
- Only considers hydrogen produced from electrolysis with renewable electricity. Other forms of renewable and carbon neutral gases, such as biomethane or hydrogen coupled with carbon capture and storage, were excluded from this scope.
- Has been produced at a 'point in time' and does not consider breakthrough technological advancement and research.

Further, the AHC does not provide a scenario analysis of pathways and associated costings to decarbonise energy consumption of South Australia and Victoria's wider energy systems encompassing electricity, transport, agriculture, and other relevant sectors. Noteworthy reports considering alternative pathways to decarbonising gas supply are summarised in Chapter 8.3.

Considering the above constraints, the findings in this Chapter could be considered a conservative perspective.

8.1. Financial Projections

8.1.1. Capex Profiles

8.1.1.1. Hydrogen Production Facilities, Storage, and Transmission Pipelines

The capex profile for hydrogen production, storage, and transmission pipelines in Victoria is shown in Figure 33.

Figure 33: Capex profile for hydrogen production facilities (electrolysers and short-term storage), transmission (trunk pipeline system), and long-term storage – Victoria

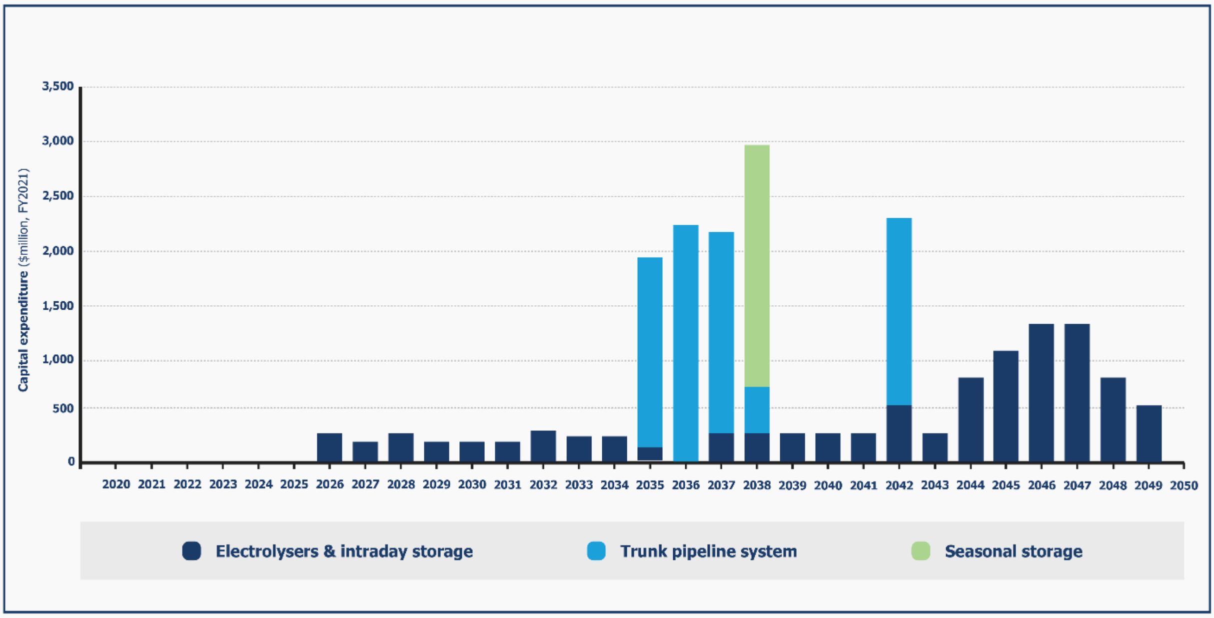


Figure 33 demonstrates significant and ongoing capex would be required in production facilities as hydrogen production increases, particularly during 2040 as the blending rate increases towards 100%. Over the period 2026 to 2039, average investment in production facilities is $202 million per annum (in real dollars).

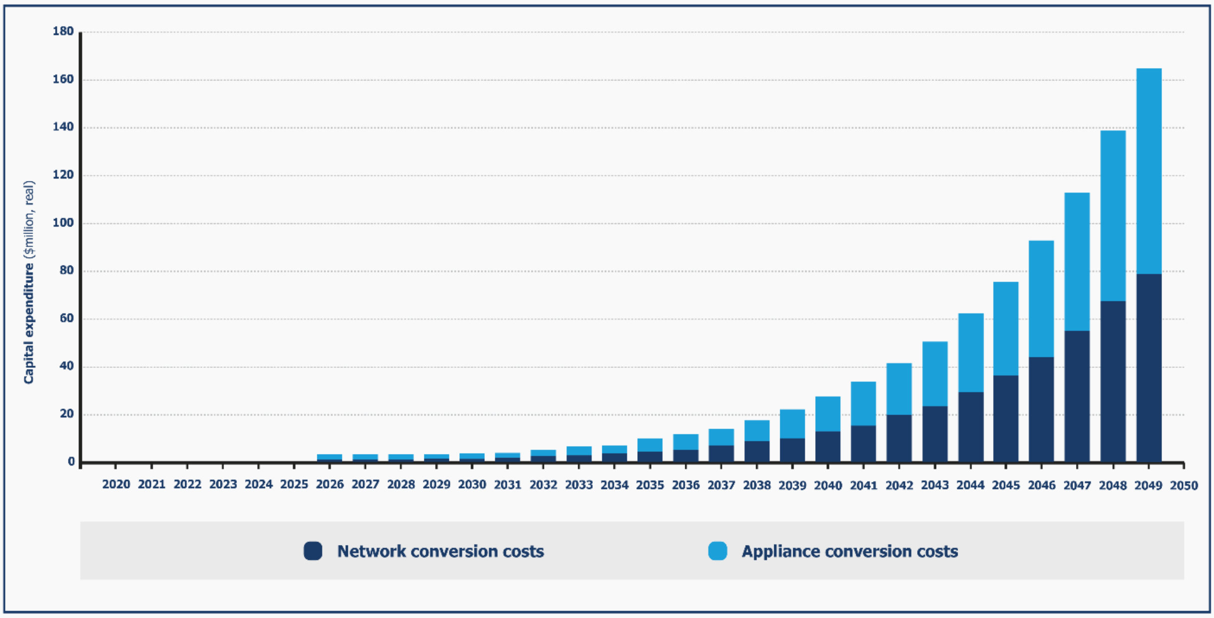
As production ramps up during the 2040s, and required capacity increases, capex also increases; however, this is offset by falling unit costs as larger electrolysers are built. Over the period 2040 to 2049, average investment in production facilities is $703 million per annum (in real dollars). Total investment in electrolysers to 2050 is $9.9 billion (in real dollars).

Figure 33 also shows there is material capex in the trunk pipeline system for hydrogen delivery and long-term storage, most of which occurs from 2035 to 2038. Total investment to 2050 is $8.2 billion (in real dollars) in the trunk pipeline system and $2.3 billion (in real dollars) in long-term storage.

8.1.1.2. Network Conversion and Appliance Conversion

The capex profile for network conversion and appliance conversion for Victoria is shown in Figure 34.

Figure 34: Capex profile for network conversion and appliance conversion - Victoria



In real dollars, this projects total capex over the period to 2050 as $449 million in network conversion and $483 million in appliance conversion. It was assumed this matches the profile for blended gas, where capex increases in line with increases of hydrogen in the blend.

While this capex would be material, it is relatively minor compared to forecast expected $7.7 billion capital expenditure by gas distribution businesses in Victoria over the period to 2050[32].

32 This amount was reached assuming that capital expenditure remains constant in real terms until 2050 at the average level over the last 5 years, after the removal of historical costs associated with mains replacement. A similar approach was used to produce cost projections in Section 9.2.

8.1.2. Opex Profiles

8.1.2.1. Hydrogen Production Facility

The opex profile for electrolysers, hydrogen storage, and hydrogen transmission pipelines operation in Victoria is shown in Figure 35.

Figure 35: Opex profile for production facilities (electrolysers and short-term storage), transmission (trunk pipeline system), and long-term storage

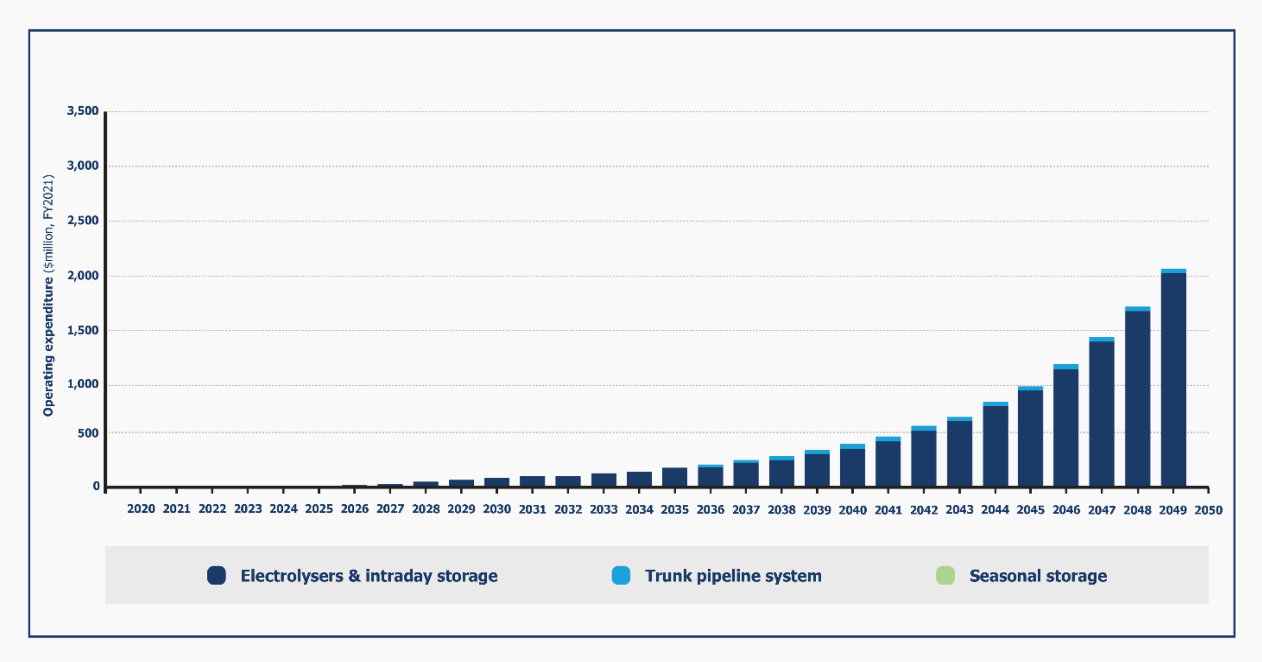
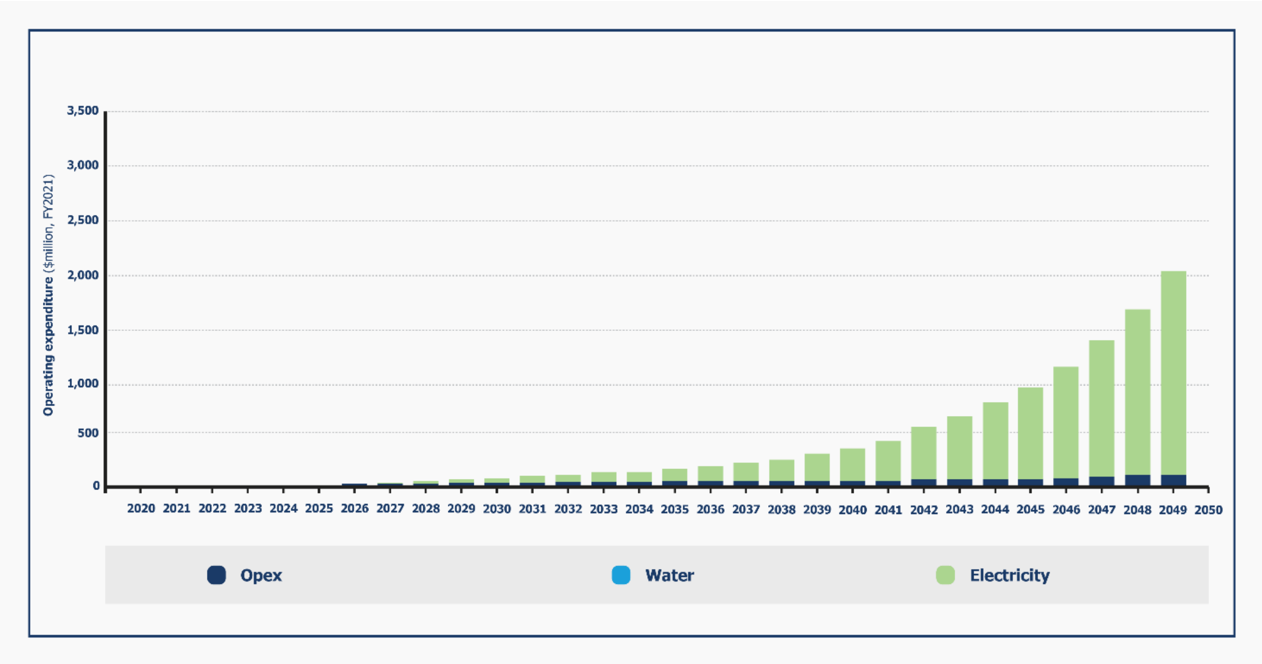


Figure 35 demonstrates significant and ongoing opex required as hydrogen production increases. Most of this relates to electrolysers and short-term storage, with a smaller amount for hydrogen transmission pipelines and no opex for long-term storage. This project's total operating expenditure to 2050 as $11.6 billion for electrolysers and short-term storage, and $0.5 billion for hydrogen transmission pipelines.

Most of the opex for electrolysers and short-term storage is the cost of electricity supply, including the cost of wholesale electricity supply, use of the electricity network, market operation fees, and ancillary services). Water costs and general opex constitute a much smaller proportion, as shown in Figure 36.

Figure 36: Electrolyser and short-term storage opex profile by cost category - Victoria

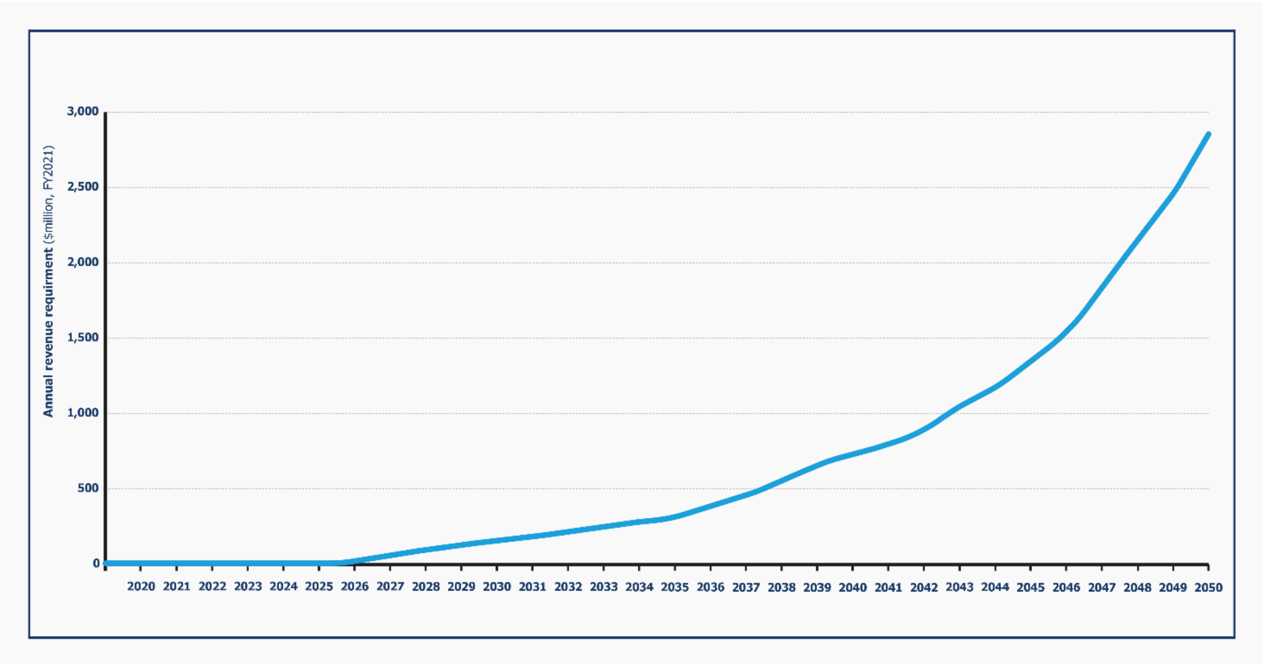


8.1.3. Revenue from Hydrogen Sales

Figure 37 shows the revenue required to recover lifetime capex and opex of electrolysers, storage, and transmission pipeline assets needed to achieve 100% hydrogen. By 2050, the annual revenue requirement is estimated as $2.9 billion.

Much of this revenue requirement is to cover electricity costs for operating electrolysers, and return of capex for producing, storing, and transporting hydrogen.

Figure 37: Annual revenue requirement from the sale of hydrogen - Victoria



8.2. Customer Price Impacts

8.2.1. Assumptions

To produce the scenario that customer price impacts were modelled from, the following assumptions were made:

- Technical challenges facing hydrogen supply chain development would be resolved.
- Appropriate underground storage has been developed to enable efficient operation of the system.
- The economics of hydrogen production and supply continue to improve as a result of technology advancements and learning-by-doing.
- The cost of renewable electricity generation continues to decrease and integration with the NEM enables it to be used efficiently in hydrogen production.
- Hydrogen hubs are developed, enabling excess hydrogen to be sold to other markets.
- Policy and regulatory settings allow hydrogen to be produced at scale and supplied to existing gas distribution pipelines.

At this early stage, there are material uncertainties about how technical challenges facing the hydrogen supply chain will be resolved, and how its economics will progress. More information about this will become available as domestic and international hydrogen industries develop and mature and estimates of customer price impacts will subsequently change.

Furthermore, this analysis does not factor for any potential government incentive schemes that would moderate impacts on customer prices. For this reason, it will be important that this analysis is updated on a regular basis – potentially every two years.

8.2.2. Methodology

A standard retail building block approach was taken to model customer price impacts. This is often used by energy regulators to calculate price impacts for electricity and gas customers and separately identify individual cost components. In this case, the following components consisted of:

- **Wholesale costs of energy** – these are the costs to retailers of procuring wholesale natural gas or hydrogen or both to supply to customers, including cost of transport on hydrogen transmission pipelines.
- **Distribution costs** – these are the costs to retailers of securing delivery of natural gas or hydrogen or both to their customers on the gas distribution network.
- **Retail operating costs and retail margin** – these are the costs to retailers of running their retail businesses, and the return required to compensate investors for the risks associated with running a retail business.

As part of achieving 100% hydrogen, gas customers may face additional costs associated with purchasing new appliances or preparing existing appliances to be hydrogen-ready. These have been reported separately as they would not already be included in a customer's retail bill.

The approach for estimating cost impacts is discussed in more detail for each cost component in the sections below. As these sections highlight, estimated customer bill impacts implicitly reflect the total costs along the supply chain (including wholesale, network, and retail functions) of supplying natural gas, or hydrogen, or both, to retail customers.

8.2.3. Cost Component: Wholesale Costs of Energy

The wholesale cost of energy is calculated as the blended wholesale price of gas and hydrogen, grossed for the difference between average wholesale prices and the wholesale cost to retailers of supplying residential customers. There are four key drivers, detailed below.

1. **Blending rate** is the share of hydrogen sales on gas networks state-wide, based on the transition path identified in this study and measured in energy terms rather than volume. This produces a state-wide average blending rate and customer bill impact.

   However, customers on different parts of the network would be supplied with different blending rates at any point in during the transition to 100% hydrogen and the costs of supplying different rates would differ because of the different wholesale costs of natural gas and hydrogen. Whether the customer bill impact would be standard across the state or locational and specific to the delivered blending rate is likely to be a public policy matter.

   If the bill impact is standard across the state, the state-wide average customer bill impact projection would reflect that single retail price. If the bill impact is locational, the state-wide average bill would remain representative, but bills would differ between customers depending on delivered blending rate.

2. **The forecast wholesale price of gas** is the Central forecast for Victoria from AEMO's GSOO 2021[33]. These wholesale prices are delivered prices, including tariffs for transmission pipelines.

3. **The forecast wholesale price of hydrogen** is the estimated average price for hydrogen for Victoria that would be required to ensure lifetime capex and opex of hydrogen production, storage, and transmission assets are recovered. This average is calculated using a building block approach that provides for a return on assets[34], a return of assets[35], and recovery of opex. The resulting annual revenue requirement is divided by hydrogen sales to determine an average wholesale price required for revenue recovery.

   Using this methodology, the calculation inputs are capex and opex estimates outlined in Chapter 3 of this Study.

4. **Difference between wholesale prices and retailers' wholesale costs.** The key reason for this difference is that customers – particularly residential customers – will tend to use more gas at times when gas demand and gas prices are higher. The estimated blended wholesale prices are grossed to account for this, based on estimates of retailers' wholesale costs from the Gas Price Trends Review Report released by the Commonwealth Government in 2017[36].

   In this scenario, the wholesale price of hydrogen is also affected by the assumption that hydrogen production, storage, and transmission infrastructure constructed for Victorian gas distribution networks would produce more hydrogen than required. Rather than waste this energy, this excess hydrogen could be sold through hydrogen hubs to additional hydrogen markets from 2040.

   It was assumed that sales to these new markets would wholly recover the opex of excess production and contribute to the capex of the infrastructure used in common. This has a flow-on

33 The AHC is aware that AEMO's annual update of the GSOO has been released for 2022 since the drafting of this Report, projecting several scenarios showing higher and lower demand than in the 2021 GSOO Central Scenario. These scenarios reflect the uncertainty in Australia's energy market, for which the 2021 Central Scenario presents a conservative view.

34 Based on an estimated real pre-tax WACC of 5.5% for merchant assets and an estimate real pre-tax WACC of 2.7% for regulated assets.

35 Based on straight-line depreciation over the assumed economic life of the assets.

36 The Gas Price Trends Review Report can be found here: https://www.energy.gov.au/publications/gas-price-trends-review-report-2017.

impact of reducing the capex that needed to be recovered from customers on the Victorian gas distribution network, where additional hydrogen market customers contribute 25% of the total capex over 2040 – 2050.

8.2.4. Cost Component: Distribution Costs

Distribution costs were calculated based on the estimated revenue requirement for gas distribution businesses in Victoria.

The first step was to estimate this revenue requirement with the Post Tax Revenue Model (PTRM) the Australian Energy Regulator (AER) uses for the same purpose. The individual PTRMs of Victorian gas distribution businesses were aggregated into a single state-wide PTRM, which was then rolled out to 2050 on a 'business-as-usual' basis to forecast distribution costs over that period.

In modelling this cost component, several assumptions were made:

- The regulated WACC was assumed to remain constant at current levels until 2050.
- Capex was assumed to remain constant in real terms until 2050 at the average level of the last 5 years, after the removal of historical costs associated with mains replacement. This means that capex levels in the model gradually fall from their current levels (which are elevated due to the costs of mains replacement) to levels that are more constant with a long-term average capex level.
- Opex was assumed to remain constant in real terms until 2050 at the average level of the last 5 years.

This provides an estimate of the 'business-as-usual' revenue requirement in Victoria for each year until 2050.

The next step is to account for any additional costs associated with 10% and 100% hydrogen in networks. In modelling this cost component, several assumptions were made.

- **Cost of network conversion**

  Drawing on learnings from Chapter 7, this includes the cost of labour and management to isolate customers, segment and purge the network and install hydrogen into it, for segments of 300 customers at a time. These costs are treated as additional capex that would form part of the asset base of network businesses, meaning that these costs would be recovered through a return on and return of these costs, consistent with the way that capex is generally recovered. It was assumed that these network conversion costs would be recovered over a period of 50 years, which approximates the standard life of pipeline assets. One implication of this approach is that the network conversion cost would not be fully recovered over the period to 2050 but continue to be recovered up until 2100, as is the case with 'business-as-usual' capex. However, while these costs would continue to be recovered well beyond 2050, the annual cost to customers would not materially change beyond 2050 because all network conversion capex would already be incurred by 2050.

- **Cost of network capacity enhancement**

  Drawing on learnings from Chapter 5, it was assumed that achieving 100% hydrogen in networks would only bring forward some capex that would occur anyway. As discussed, the 'business-as-usual' revenue requirement already incorporates forecasts of additional capex over the period to 2050 (based on historical capex). No change in capex profile for network capacity enhancement was included in the estimated customer bill impact.

- **Cost of network pipe and component replacement**

  Drawing on learnings from Chapter 5, it was assumed that achieving 100% hydrogen in networks would require minimal changes to the network not already be covered by existing equipment replacement capital budgets. As a result, capex would remain constant in real terms until 2050 at the average level over the last 5 years, after the removal of historical costs associated with completed mains replacement. This means that capex levels gradually fall from their current levels (which are elevated due to the costs of mains replacement) to levels that are more consistent with a long-term average capex level. Subsequently, no change in capex profile for network pipe and component replacements is included in the estimated customer bill impact.

- **Cost of meter replacement**

  Drawing on learnings from Chapter 5, it was assumed that achieving 100% hydrogen would require capex to replace meters, but that these costs are already built into aged meter replacement programs and would be covered by existing capex budgets as part of network access arrangements. Subsequently, no change in capex profile for meter replacement was included in the estimated customer bill impact.

The third step is to convert the total annual revenue requirement into distribution costs for customers.

'Business-as-usual' annual revenue requirement	+	annual revenue requirement to cover additional costs of state-wide blending and conversion
= total annual revenue requirement		

This is done by calculating an average annual revenue requirement and then indexing current distribution costs for customers by the change in this average annual revenue requirement.

total annual revenue requirement	÷	total annual pipeline sales
= average annual revenue requirement		

8.2.5. Cost Component: Retail Operating Costs and Retail Margin

The retailer component of customer bills is based on estimates of retailers' opex, and retail margin form the Gas Price Trends Review Report released by the Commonwealth Government in 2017, held constant in real terms over time[37]. It was assumed that the retailer component is not changed as a result of hydrogen's introduction.

8.2.6. Cost Component: Appliance Purchasing and Appliance Conversion Costs

While appliance purchasing and appliance conversion costs are not currently included in customer retail bills, they are considered part of the customer bill impact. Subsequently, this cost component is separate from the estimated average customer bill in this Study.

In modelling this cost component, several assumptions were made based on the findings of earlier chapters in this Study.

- **Appliance purchase costs**

  Per Section 5.3, it was assumed that all appliances sold from 2030 onwards would be hydrogen-ready and that all appliances would be hydrogen-ready by network conversion. It was also assumed that there would be no additional cost to purchasing hydrogen-ready appliances, implying no additional appliance purchase costs. As a result, no additional appliance purchase costs were included in the estimated customer bill impact in this Study.

- **Appliance conversion costs**

  This includes the cost of labour to convert appliances for segments of 300 customers at a time. It is not yet known if customers or network businesses would incur these costs initially, or whether these costs would be recovered from individual customers or over time from all network users. In estimating customer bill impacts it was assumed that appliance conversion costs would be treated as capex and recovered through a return on and return of these costs, consistent with ways capex is generally recovered. An implication of this approach is that appliance conversion costs would not be fully recovered over the period to 2050 but continue to be recovered well beyond. As with network conversion costs, while these costs would continue to be recovered well beyond 2050, the annual cost to customers would not materially change beyond 2050 because all appliance conversion capex would already be incurred by 2050.

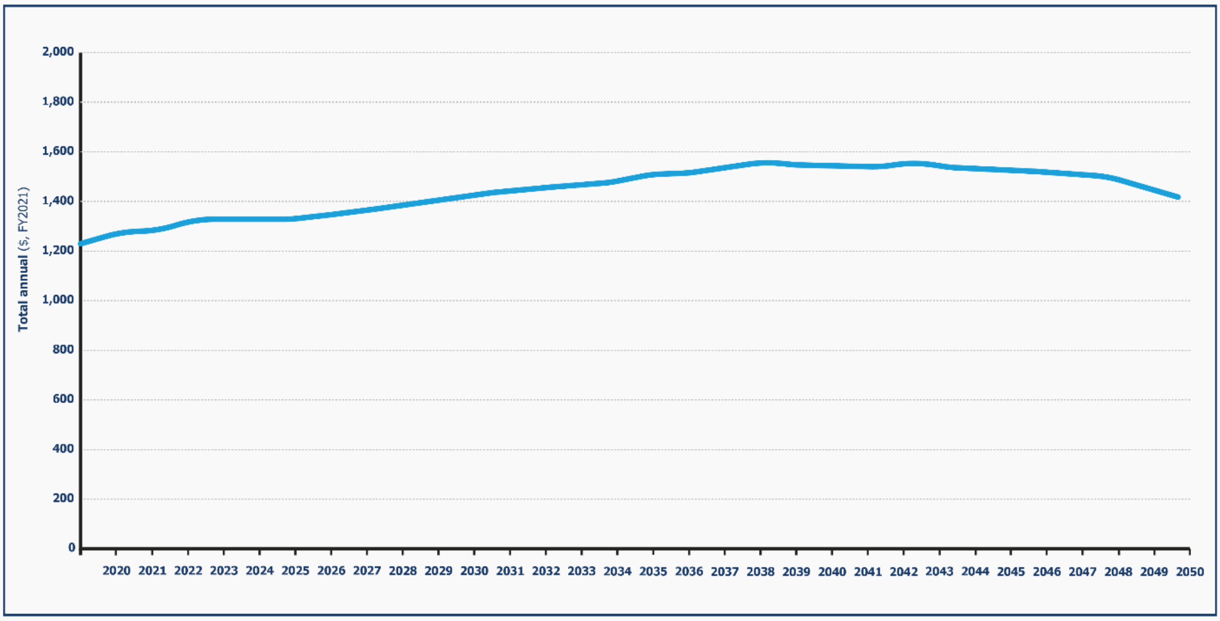
37 The Gas Price Trends Review Report can be found here: <https://www.energy.gov.au/publications/gas-price-trends-review-report-2017>

8.2.7. Results

Customer bill impacts are presented for an average Victorian residential gas customer consuming 50 GJ per annum (based on data from the Gas Price Trends Review) and are shown in Figure 38, based on the average amount of hydrogen in networks across Victoria over time.

This means the resulting customer bill impact also reflects a Victorian average, noting Chapter 7 outlines different parts of the networks achieve 100% hydrogen at different times as the implementation plan is rolled out.

Figure 38: Total bill for an average Victorian residential hydrogen gas customer



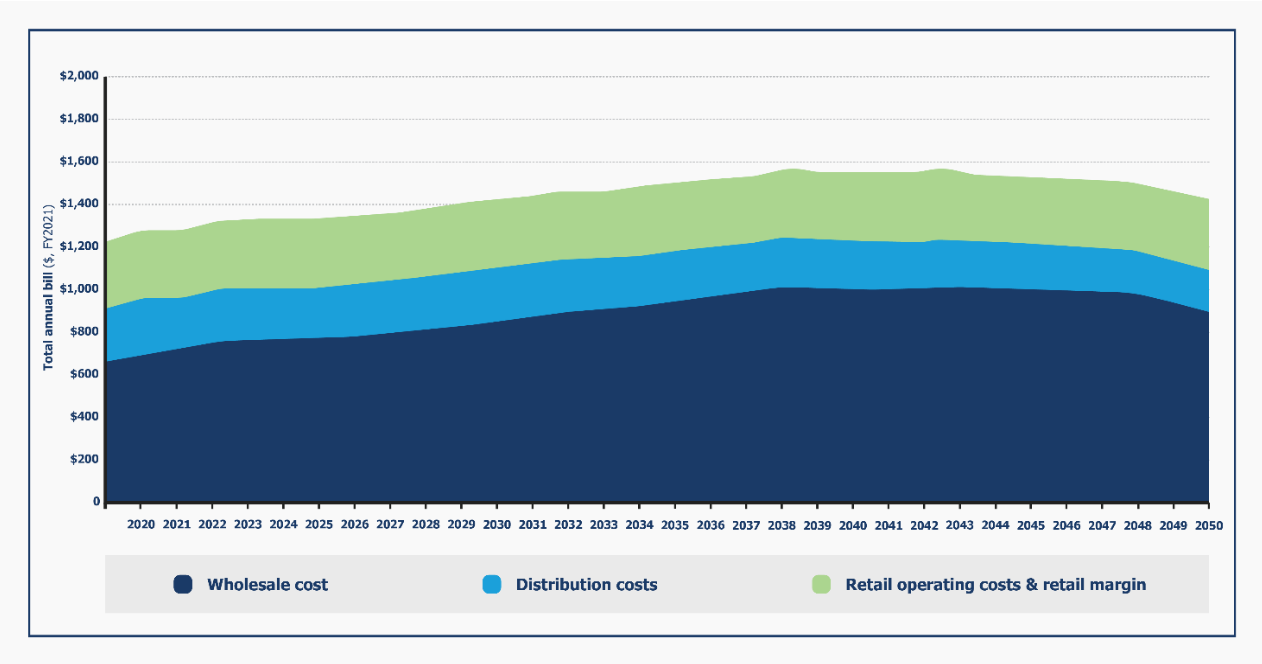
This shows that the total bill for an average Victorian residential gas customer is forecast to increase from an estimated bill is $1,240 per annum in 2021 to $1,567 per annum in 2039 before declining again to $1,417 by 2050.

If Victoria reaches 100% hydrogen (in 2050) the estimated bill is $1,417 per annum, representing an increase of 14% over the period from 2021 to 2050.

Findings of this Study suggest that key drivers of the cost of production will be trending lower at that time. This includes the size of installed electrolysers (which result in reduced capex), increases in the capacity factor of installed electrolysers (which lowers the average costs of the electrolysers), reduction in opex and the ability to share capex with mobility customers.

Figure 39 breaks down the underlying cost components of this bill: wholesale cost of energy, distribution costs, and retail operating costs and retail margin. It shows that distribution costs and retail costs are relatively constant over time, while wholesale costs are the key driver to changes to the total bill.

Figure 39: Total bill for an average Victorian residential gas customer by cost component

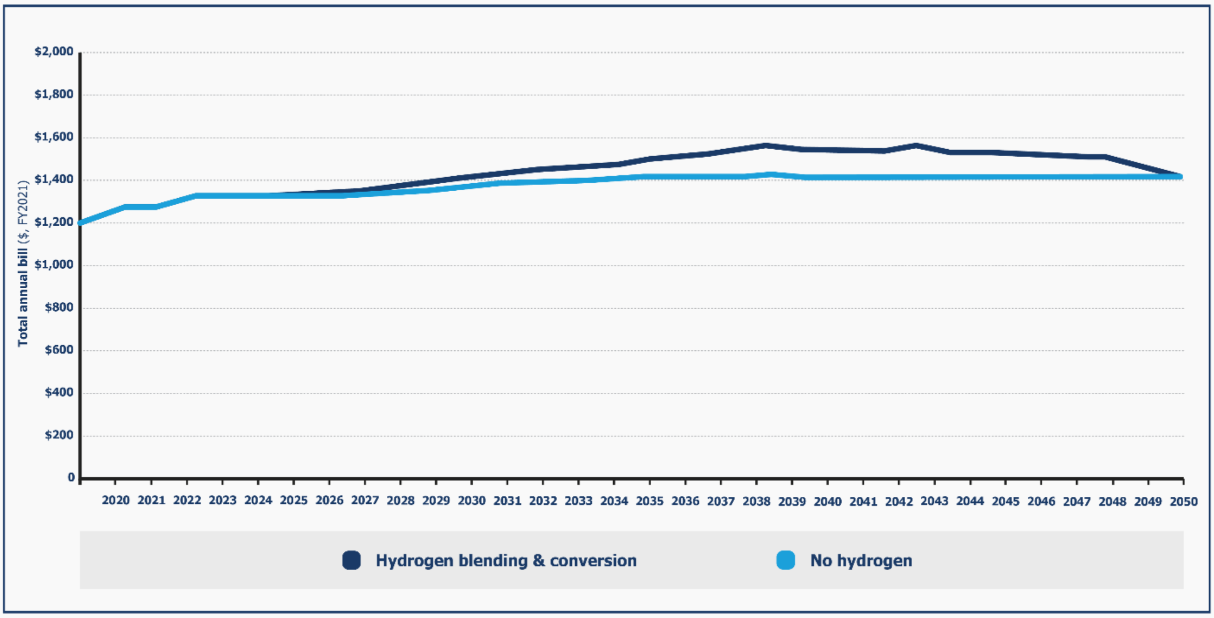


Increases in wholesale costs reflects the change in the amount of hydrogen in networks over time, commencing in the mid-2020s with 100% hydrogen in networks by 2050. As a result, part of the increase in wholesale costs is attributable to the cost of producing, storing, and transporting hydrogen being higher than the wholesale gas price for much of the period to 2050.

The wholesale natural gas price also contributes to the estimated wholesale cost increase. AEMO's GSOO 2021 projects the wholesale natural gas price to increase by 24% in real terms from 2021 to 2050. This indicates that, even in the absence of hydrogen in networks, wholesale costs would increase from around $680 per annum in 2021 to around $910 per annum in 2050.

Figure 40 shows the estimated total bill compared with a scenario where Victorian customers continued to receive just natural gas, indicating the change in the total customer bill in the absence of state-wide blending or conversion. This was calculated using the same methodology and assumptions used to develop the total bill for the hydrogen case but assumed that only natural gas is supplied, and network and appliance conversion costs not incurred.

Figure 40: Total bill for an average Victorian residential gas customer - with no-hydrogen case



This demonstrates that even without switching to hydrogen, average Victorian residential customer bills are projected to increase from $1,240 per annum in 2021 to $1,430 by 2050, which is slightly higher than the estimated bill with 100% hydrogen in networks.

It should be noted that neither model incorporates a future cost of carbon attributed to the emissions associated with natural gas.

This finding is significant noting the fundamental changes envisioned in this Study to transition the supply chain servicing Victorian gas distribution networks to 100% renewable hydrogen, including around 12 GW in renewable hydrogen production, long-term storage, and new hydrogen pipelines.

There could be further upside noting this modelling assessed hydrogen produced via electrolysis powered with renewable electricity only; other carbon-neutral sources (e.g. 'blue hydrogen') and hydrogen produced by external industries (e.g. hydrogen hubs) was excluded.

8.3. Comparison to Alternate Pathways

This Study does not provide a scenario analysis of pathways and associated costings to decarbonise energy consumption of Victoria's wider energy systems encompassing electricity, transport, agriculture, and other relevant sectors.

Noteworthy recent reports that consider pathway analysis are summarised in Table 24.

Table 24: Noteworthy reports considering alternative pathways to decarbonising gas supply

Author/Commissioning	Title	Date	Report Focus	Key Finding/s
Advisian for the Clean Energy Finance Corporation	Australian Hydrogen Market Study[38]	24 May 2021	Cost of production and competitiveness of low carbon hydrogen in 25 Australian end-use sectors, relative to the incumbent technology.	10% hydrogen is considered viable without significantly increasing risks to utilisation, safety, system durability or integrity. Alternatives, such as electrification and 100% hydrogen networks, are likely to be more important.
Frontier Economics	Cost of switching from gas to electric appliances in the home[39]	24 June 2022	The upfront cost of converting existing Victorian dual fuel homes to electric only	Additional cost categories are significant across several residential customer archetypes and, in conjunction with appliance costs, make domestic electrification a challenging financial prospect.
Frontier Economics for Department of Climate Change, Energy, the Environment and Water	Indicative Analysis of Blending Hydrogen in Gas Networks[40]	11 May 2020	The economics of blending 10% hydrogen in Melbourne	As long as storage is cheap, blending hydrogen is cheaper than electrification by 2030.
Frontier Economics for Energy Networks Australia	The benefits of gas infrastructure to decarbonise Australia[41]	17 September 2020	Economics of conversion to 100% hydrogen across Australia by 2050	Converting to hydrogen – whether produced by SMR or electrolysis – is a cheaper option that total electrification.

38 Report can be found here: <https://www.cefc.com.au/media/nkmljvkc/australian-hydrogen-market-study.pdf>

39 Report can be found here: <https://www.cefc.com.au/media/nhnhwlxu/australian-hydrogen-market-study.pdf>

40 Report can be found here: <https://www.gasenergyaus.au/get/1945/frontier-economics-report-gamaa-july-2022.pdf>

41 Report can be found here: <https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/the-benefits-of-gas-infrastructure-to-decarbonise-australia-frontier-economics/>

9. Additional Economic Benefits

This Chapter provides an overview of economic benefits and opportunities that flow from achieving 100% renewable hydrogen in networks by 2050.

Importantly, this analysis was produced separately to the feasibility assessment and cost build up developed in earlier chapters and draws on different inputs and assumptions to the rest of this Study, which can be found in Section E of the Appendix. It does so to assess the whole-of-state benefits of 100% hydrogen in networks as opposed to energy infrastructure outcomes only.

Key findings

1. 100% renewable hydrogen supply in networks could create 10,305 new full-time jobs for Victorians during constructing and 5,380 ongoing.
2. This pathway to renewable hydrogen supply is expected to value-add $1.246 billion to Victoria's economy through to 2050.
3. Developing large-scale renewable hydrogen production and storage opens the door for Australia's heavy industry, transport, freight, and export sectors to transition to hydrogen.
4. Coordinated action between government and industry could enable these high-value sectors to draw on this new infrastructure to develop scale rapidly.

9.1. Economic Impact Assessment

9.1.1. Overview

A preliminary Economic Impact Assessment (EIA) was undertaken to better understand the economic implications of 100% hydrogen in Victoria's gas distribution networks by 2050.

An EIA measures the expected change in key economic indicators which are expected to occur as a result of the project, such as job creation, Gross State Product (GSP) and value added to the economy.

The EIA utilised the proposed infrastructure investments and activities that had been outlined in previous chapters to develop an understanding of the direct and indirect economic impacts during their construction and operational phases.

9.1.1.1. Methodology

As shown in Table 25, the EIA adopted a four-step methodology to measure the change in key economic indicators expected to occur as a result of conversion.

Table 25: EIA methodology - 100% hydrogen by 2050

Step	Key Tasks
Step 1 Background review	Confirm scope, aims and objectives of hydrogen in networks and any relevant dependencies and limitations of the scenario to assess. Review relevant background information, technical studies, and other assessments to confirm key aspects of hydrogen in networks and any baseline assumptions. Identify and address any critical information gaps and issues limiting the analysis and evaluation; undertake additional research and prepare proxy indicators using relevant benchmarks and secondary research.
Step 2 Impact Analysis	Identify and assess anticipated economic impacts likely to occur as a result of the construction and operational phases of hydrogen in networks, including for each key stage of the renewable hydrogen supply chain.
Step 3 Confirm Assessment Parameters	Confirm key project inputs, such as capital and operational expenditure estimates for each stage of the hydrogen supply chain and expected construction and operational timelines for hydrogen in networks.
Step 4 Economic Impact Assessment	Calculate the expected number of jobs generated by construction and operational phase of 100% hydrogen, using project cost estimates calculated in Step 3 as the key modelling input variable. Assess how construction and operation of conversion will directly and indirectly contribute to the State economy in terms of economic flow-on effects on output and value-added.

Design, construction, and operation of the infrastructure required to achieve the 100% hydrogen in networks would generate a range of direct and indirect economic impacts for Victoria. Estimates of the economic contribution of the Project were prepared for:

- **Construction Phase:** Economic activity during the construction phase, which is estimated to be across 20 years.
- **Operational Phase:** Ongoing economic activity that would be generated by the operation and maintenance phase, based on full operations as of 2050.

The economic impacts of both phases have been estimated according to the direct, or project specific outcomes, and indirect impacts which occur because of second round consumption and expenditure economic impacts. These estimates of economic impacts have been prepared with input-output multipliers.

Table 26: Annual Economic Impact Summary - 100% hydrogen by 2050

Construction Phase (annual, over the 20-year construction period)			
	Direct	Indirect	Total
Output ($B)	$1.745	$1.517	$3.263
Employment (FTE)	4,190	6,115	10,305
Value Added ($B)	$0.624	$.622	$1.246
Operation Phase (annual, as of 2050)			
Output ($B)	$1.343	$1.269	$2.612
Employment (FTE)	1,829	3,551	5,380
Value Added ($B)	$0.453	$0.536	$0.989

As summarised in Table 26, the construction phase of the Project is expected to generate the following direct benefits for Victoria:

- Direct output (spending) of $1.745 billion per annum (for 20 years).
- Full-time equivalent (FTE) employment supported of 4,190 jobs per annum for each year of the 20-year construction program; and
- A total direct value-add to the economy of $0.624 billion per annum (for 20 years).

When the multipliers are considered, total Victorian economy-wide effects are forecast to be:

- Output (spending) of $3.263 billion per annum (for 20 years).
- Full-time equivalent (FTE) employment supported of 10,305 jobs per annum for each year of the 20-year construction program.
- A total direct value-add to the economy of $1.246 billion per annum (for 20 years).

The twenty-year construction program would deliver a significant boost to building and trades sector in Victoria. Additional benefits are also expected across the rest of Australia but have not been reported in this EIA.

Upon completion of the Project, the operational phase is expected to deliver on-site and supply chain activity generating the following benefits for Victoria:

- Direct output (spending) of $1.343 billion per annum.
- Full-time equivalent (FTE) employment of 1,829 ongoing jobs.
- A total direct value-add to the economy of $0.453 billion per annum.

When the multipliers are considered, total ongoing economy-wide effects are forecast to be:

- Output (spending) of $2.612 billion per annum.
- Full-time equivalent (FTE) employment of 5,380 ongoing jobs.
- A total direct value-add to the economy of $0.989 billion per annum.

The above economic benefits are significant in the context of the Victorian economy. Additional benefits are also expected to flow across the wider Australian economy but have not been reported in this EIA.

The assumptions and analysis of this assessment can be found in Table 27 in Section G1 of the Appendix.

9.2. Sector Coupling Opportunities

While the scope of this study focussed on renewable hydrogen production for 100% hydrogen networks as a priority, integrating aspects of that production with projects that either feed into electrolysis or use electrolysis by-products are being pursued throughout Australia as part of a 'hydrogen hub' model.

The AHC carried out a desktop analysis study to understand the potential for new customers and industries as a result of 100% hydrogen in Victorian gas distribution networks, including what improvement they might have on its overall economics.

Section 8.1.3 assumes that hydrogen production, storage, and transmission infrastructure constructed for South Australian gas distribution networks could produce more hydrogen than required for sale to additional markets from 2040.

It was assumed that sales to these new markets would wholly recover the opex of excess production and contribute to the capex of the infrastructure used in common. This has a flow-on impact of reducing the capex that needed to be recovered from customers on the South Australian gas distribution network, where additional market customers contribute 25% of the total capex over 2040 – 2050.

It has been assumed developing large-scale renewable hydrogen industries such as ammonia, power generation and export would access their own hydrogen production and therefore not rely significantly on a hydrogen distribution network. Therefore, the Study considered the hydrogen transport market to be a leading potential opportunity with further analysis in the following section.

9.2.1. Overview of Transport Market

In Australia, transport accounts for around 90 $MtCO_2$-e, which is around 18% of national annual CO_2 emissions. These emissions are from fuel consumed in the road, rail, domestic shipping, and aviation industries. Road freight accounted for around 80 $MtCO_2$-e of total transport emissions.

The National Hydrogen Strategy identified utilising hydrogen for long-distance heavy-duty transport alongside industrial feedstocks and hydrogen in gas networks as key markets to build widespread hydrogen demand.

ARENA has supported a number of hydrogen transport projects including the Toyota Ecopark Hydrogen Demonstration, Ark Energy Renewable Hydrogen Demonstration for Heavy Transport, and the Viva New Energies Service Station[42].

Victoria itself has a population of over 6.6 million people making it the second largest state behind New South Wales. The large population across the state plays a significant role in the freight volumes involved in both receiving substantial amounts of goods to supply the local business and residential consumption and dispatching local products to consumer markets.

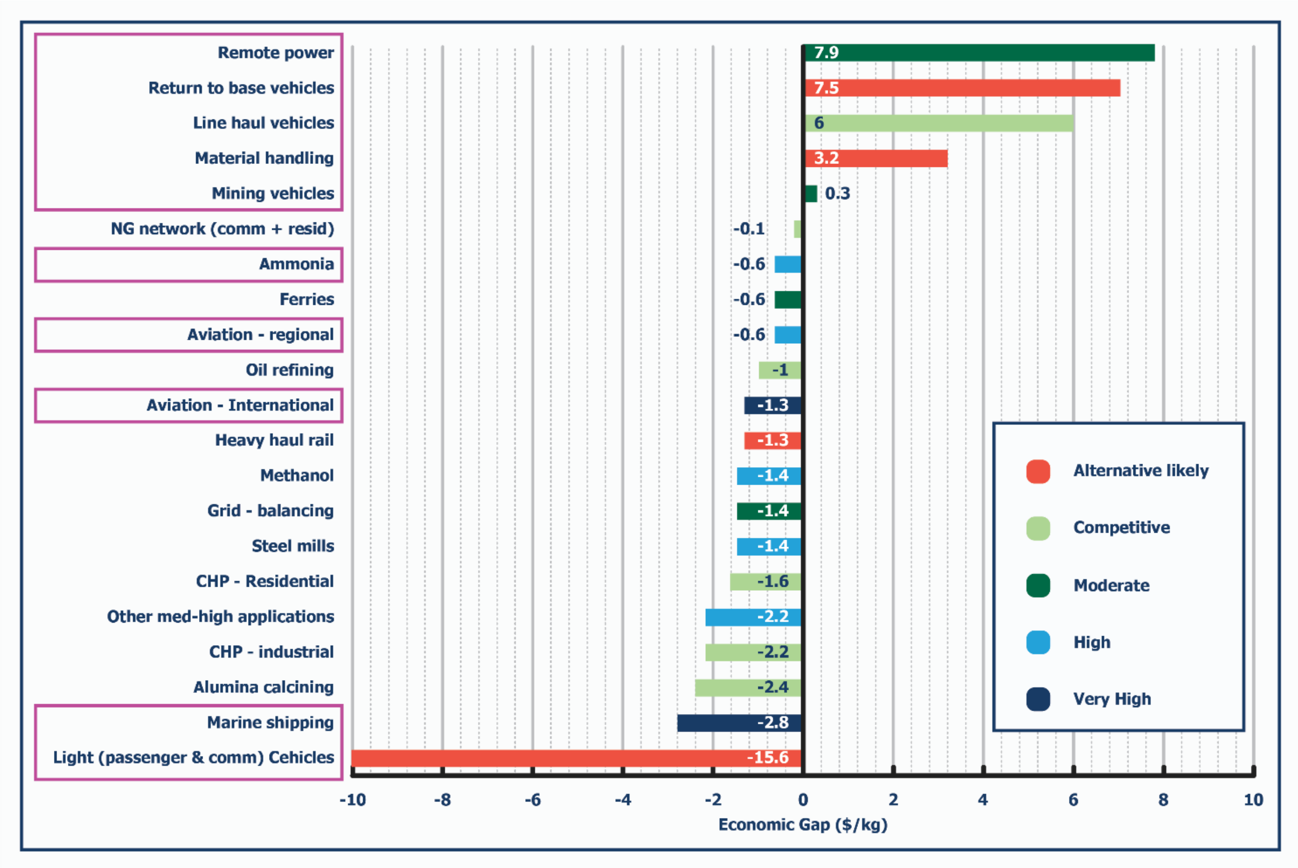
In addition, Victoria utilises four major seaports (Portland, Geelong, Melbourne, and Hastings) for importing and exporting goods as well as two substantial airports (Melbourne Airport and Avalon). Victoria therefore should be considered as a core location for commencing the adoption of hydrogen to decarbonize mobility across Australia.

To understand the commercial favourability of hydrogen-based transport, an economic gap assessment was conducted on transport systems in twenty sectors.

42 Refer ARENA's website for a full listing of projects supported.

A positive economic gap indicates that the sector is commercially favourable for hydrogen as an energy carrier for transport, whereas a negative gap suggests other efficiencies would be required for hydrogen to be feasible.

Figure 41: Economic gap assessment of hydrogen for the transport sector[43]



A qualitative assessment was also performed to determine the importance of hydrogen for decarbonising each sector. It was determined that sectors with the highest dependence are aviation (international) and marine transport, where alternatives such as carbon capture and battery electric systems would likely be difficult to implement. The selected industries have been highlighted in Figure 41.

43 The selected industries have been highlighted in Figure 41.

9.2.1.1. Return to Base and Line Haul Vehicles

The potential annual hydrogen demand of line haul vehicles and return to base vehicles is shown below in Table 27.

Table 27: Estimated hydrogen truck demand in 2030 (Victoria)

Estimated hydrogen truck demand in 2030	tonnes per year
Line haul vehicles	6,377
Return to base vehicles	4,247

These values were calculated using the current fleet size and average annual distances covered[44]. It was assumed that 3.6% of the fleet will be made up of hydrogen fuel cell vehicles by 2030, which is based on the projected rate of adoption of hydrogen fuel cell technology in Europe[45]. There is little data available that is specific to Australia, and this could be viewed as an upper bound estimate.

Between the two, line haul vehicles show the most promise due to their larger haul distances, which make other pathways, like electrification, less viable.

Alternatively, return to base vehicles tend to have shorter haul distances, which may increase the likelihood of battery powered vehicles being the preferred option due to increased access to recharging facilities.

Back to base vehicle depots can more easily transition to zero carbon operations by replacing their fleets with fuel cell trucks and buses as they reach retirement. Having the vehicles return regularly means that these sites can benefit from setting up dedicated hydrogen refuelling infrastructure for their own operations. More broadly, it would be beneficial to establish hydrogen refuelling stations in partnership with these companies at selected major regional towns along established freight routes. This would help facilitate long distance transport as fuel cell electric vehicles (FCEVs) become more readily available.

The key freight route in Victoria connects Melbourne to Sydney via the Hume Freeway and Melbourne to Adelaide via the Western Freeway and Western Highway. Significant volumes of freight are transported in these networks annually, indicating that they are some of the major freight routes used in Victoria. Victoria could benefit from establishing a hydrogen refuelling hubs for decarbonising transport as the state road networks support large annual freight volumes.

9.2.1.2. Mining Vehicles

The key assumption in estimated demand for hydrogen fuelled mining vehicles is that any mine that transitions would convert its entire fleet at once. This may be unlikely for larger mines that have larger fleets but may be reasonable for smaller mines.

The demand for these vehicles is dependent on existing mines converting vehicles to hydrogen fuel cell, and whether the mine sites would be tied into a hydrogen network. For smaller mines, electrification may be a viable option due to increased access to recharging. Mines with larger fleets may have more incentive to produce hydrogen on-site, negating network to a hydrogen connection.

44 Survey of Motor Vehicle Use, ABS. <https://www.abs.gov.au/statistics/industry/tourism-and-transport/survey-motor-vehicle-use-australia/latest-release>

45 Truck hydrogen refuelling stations needed in Europe by 2025 and 2030, ACEA 2021. <https://www.acea.auto/figure/interactive-map-truck-hydrogen-refuelling-stations-needed-in-europe-by-2025-and-2030-per-country/>

9.2.1.3. Material Handling

Material handling is the movement and storage of products through manufacturing and distribution. The estimated hydrogen demand for this industry is only 13 tpa due to the relatively low energy demand of the vehicles used. Further, alternatives such as battery electric vehicles are a likely substitute.

9.2.1.4. Aviation – Flights

It is unlikely that hydrogen will play a key role in the decarbonisation of long-haul aviation due to the relatively low volumetric energy of liquid hydrogen. Airbus have revealed 3 concept hydrogen-powered commercial planes that could be ready by 2035 but has emphasized that these aircraft would primarily focus on shorter-range regional travel[46].

Should the technology for hydrogen as an aviation fuel take hold for smaller regional flights, then the expected demand across both Victoria and South Australia is expected to be 19 tpa.

9.2.1.5. Aviation – Airports

Hydrogen use at airports is being investigated in Lyon International Airport (France)[47] and the Teesside International Airport (UK) to pre-emptively equip the industry for future hydrogen-powered commercial flights. The initiatives could be extrapolated and implemented in Melbourne in the following ways:

- Deployment of hydrogen gas distribution station to supply both airport ground vehicles (buses, trucks, handing equipment, etc) as well as heavy goods vehicles that drive around the airport.
- Deployment of liquid hydrogen infrastructures that would allow hydrogen to be provisioned into the tanks of future hydrogen-fuelled aircraft.

46 More detail can be found at the Airbus website here: <https://www.airbus.com/en/innovation/zero-emission/hydrogen/zeroe>

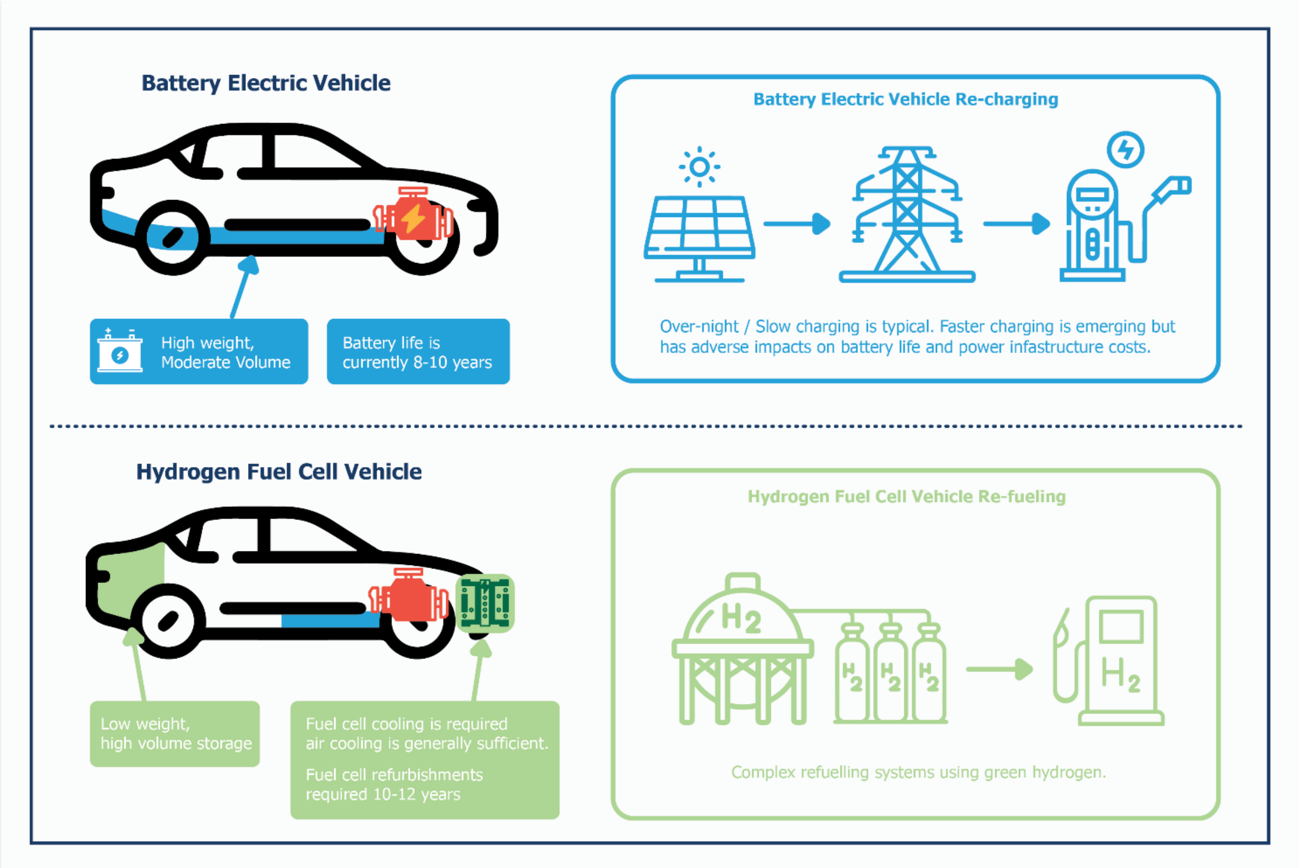
47 More detail can be found at the Lyon Airport website here: <https://www.lyonaeroports.com/en/news/lyon-saint-exupery-pilot-airport-test-use-hydrogen-2023>

9.2.1.6. Light Vehicles

Hydrogen fuel cell light vehicles are expected to become an increasingly viable option by 2050. If the number of light vehicles in Victoria and South Australia remain consistent with current levels and with a 6% uptake in hydrogen fuel cell vehicles, then the hydrogen demand would be 33.5 ktpa.

While the cost of production is expected to drop to an extent that light fuel cell vehicles are more economic than internal combustion engines by 2050, it is unknown whether they will become competitive with battery-powered vehicles in the long run. The key differences between these vehicles are demonstrated in Figure 42. If fuel cell vehicles remain competitive, there could be an opportunity for a hydrogen network to supply hydrogen to the required refuelling stations.

Figure 42: High level differentiation between battery electric and fuel cell vehicles



International example

As part of their roadmap to net zero greenhouse gas emissions by 2050, Japan is looking to hydrogen fuel cell vehicles as a means of decarbonising the transport industry. As of March 2020, there were 3,800 fuel cell vehicles and 135 hydrogen refuelling stations, but the strategic roadmap for hydrogen and fuel cells has outlined a goal to 800,000 vehicles and 900 refuelling stations across Japan by 2030. To achieve this, Japan is offering subsidies for fuel cell vehicles and hydrogen refuelling stations to reduce the financial cost of purchasing the new technologies. Investments are also being made in funding demonstration projects, as well as research and development on fuel cell technologies and the hydrogen supply infrastructure.

9.2.1.7. Marine Shipping

The marine shipping industry consumes 300 million tonnes per year of oil fuel globally. Heavy Fuel Oil (HFO) is the most widely used fuel today, while natural gas is only used by around 2% of the global fleet. Hydrogen is still being investigated as a novel technology to power the marine shipping industry, however alternative fuels like green methanol and green ammonia offer more cost-effective mechanisms (through to 2050) to comply with the GHG emissions reduction regulation, therefore the latter are more lucrative options to shipping industry. Despite alternative fuels being a more cost-effective option, original equipment manufacturers like Wärtsilä[48] are pursuing 100% hydrogen-burning reciprocating engines for marine vessels, with pilot engines ready by 2025. This would allow existing maritime vessels to be retrofitted with new hydrogen compatible engines, however it is not yet known if these reciprocating engines will be running on gaseous or liquified hydrogen (the latter requiring more modifications to existing infrastructure). Should future marine vessels switch to hydrogen fuel, the hydrogen infrastructure requirements will be similar to natural gas[49], therefore existing marine ports will only require some modifications to suit (increased storage vessels for hydrogen). However, the equipment requirements of liquified hydrogen (liquification, cryogenic material etc.) will differ from those of compressed gaseous hydrogen. Currently there has been no marine port that has undergone infrastructure changes to suit future hydrogen powered marine vessel which could provide insight as to what modifications would be needed at existing ports.

9.2.2. Competitiveness with Other Fuels

A key barrier to hydrogen uses in mobility is its competitiveness with other fuels.

Competitiveness will be determined by numerous factors, notably cost and the availability of compatible vehicles and infrastructure required to refuel them. Mobility powered by other renewable technologies, such as battery electric vehicles (BEVs) depicted in Figure 43, may reach these milestones at a commercial scale before hydrogen, subsequently posing a challenge to the competitiveness of hydrogen vehicles.

48 More detail can be found at the Wärtsilä website here: <https://www.wartsila.com/media/news/05-05-2020-wartsila-gas-engines-to-burn-100-hydrogen-2700995>

49 Taylor, J., Bonello, J., Baresic, D., Smith, T. (2022) Future Maritime Fuels in the USA – the options and potential pathways. UMAS, London.
<https://oceanconservancy.org/wp-content/uploads/2022/04/oc_fuels_final_report_20220117.pdf>

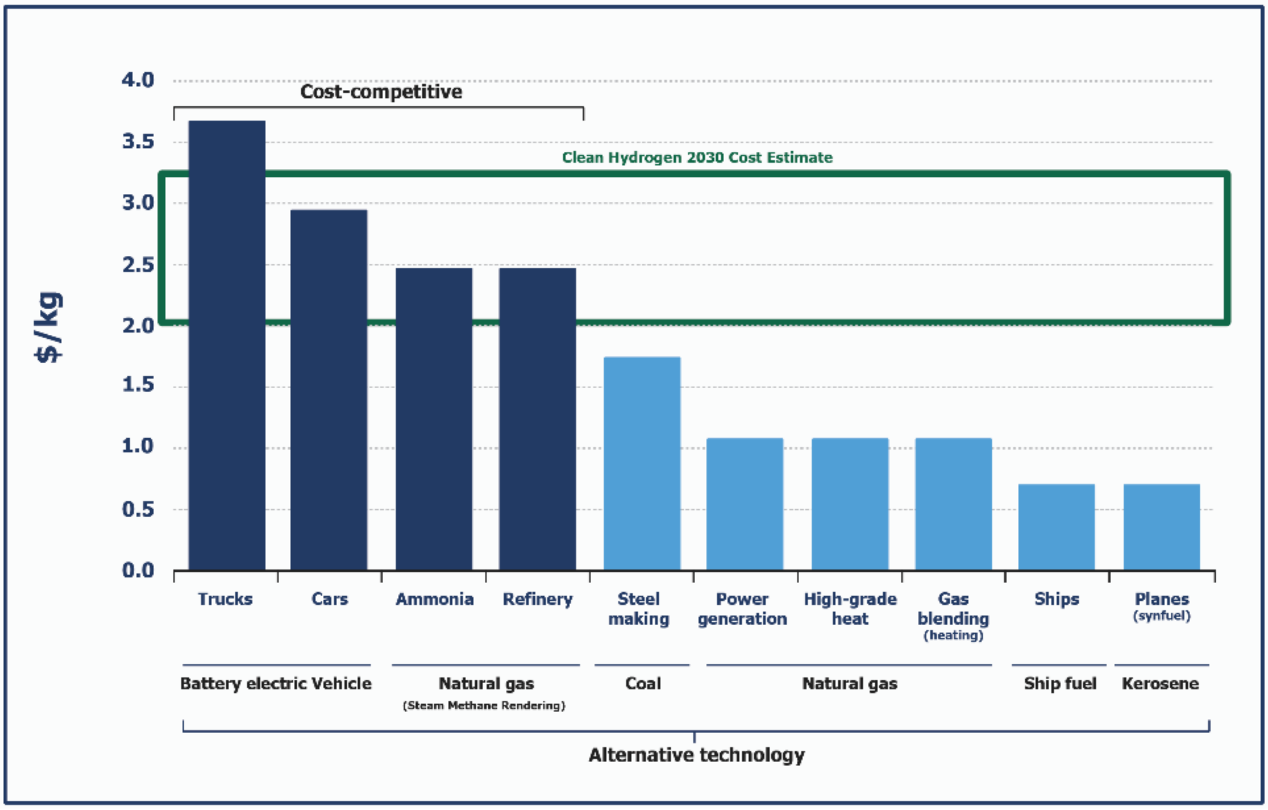
Table 28: Electrolyser cost estimates

Source	2020-2021 Cost estimates ($/MW)	Required cost estimates ($/MW)
S&P Global	$1.2 million	$600,000
ARENA	$2-3 million	$500,000

Source: S&P Global: Analysis: Asia's 'H2 at $2' renewable hydrogen target is a mission not impossible & ARENA.gov.au - Australia's pathway to $2/kg hydrogen

Figure 43 indicates which end use sectors hydrogen will be competitive in, and the price. By 2030, it is expected to compete with battery electric vehicles for trucks and cars, but further reductions would be required for hydrogen to compete in the marine and aviation sectors.

Figure 43: Hydrogen production cost estimates



Glossary

Term Used	Meaning
ACCC	Australian Competition and Consumer Commission
ACCU	Australian Carbon Credit Unit/s
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGA	Australian Gas Association
AGIG	Australian Gas Infrastructure Group
AGN	Australian Gas Networks
AHC	Australian Hydrogen Centre
ALARP	As Low as Reasonably Practicable
ARENA	Australian Renewable Energy Agency
AUD	Australian Dollar
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
BOC	BOC Limited
BoP	Balance of Plant
BOP	Basic Oxygen Process
BU	Business Unit
CAPEX	Capital expenditure
CDL	Critical Defect Length
CEFC	Clean Energy Finance Corporation
CEO	Chief Operating Officer
CFADS	Cash Flow Available for Debt Service
CfD	Contract for Difference
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO2/CO_2	Carbon Dioxide
COVID-19	Coronavirus Disease 19
CPI	Consumer Price Index
CRC	Cooperative Research Centre
CSG	Coal Seam Gas
CV	Calorific Value
DA	Development Approval/s
DEECA	Department of Energy, Environment, and Climate Action (Victoria)
DPIE	Department of Planning, Industry and Environment (NSW)
DSP	Demand Site Participation
DTS	Declared Transmission System (Victoria)
DWGM	Declared Wholesale Gas Market (Victoria)
EHV	Extra High Voltage
EIA	Economic Impact Assessment
EIGA	European Industrial Gases Association

Term Used	Meaning
ENA	Energy Networks Australia
EoI	Expression of Interest
EPA	Environment Protection Authority (Victoria)
EPC	Engineering, Procurement and Construction
EPCM	Engineering, Procurement, Construction and Management
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
ESV	Energy Safe Victoria
ETI	Energy Transition Initiative
EV	Electric Vehicle
FCAS	Frequency Control and Ancillary Service/s
FCEV	Fuel Cell Electric Vehicle
FEED	Front-End Engineering and Design
FFCRC	Future Fuels Cooperative Research Centre
FID	Financial Investment Decision
FiT	Feed-in Tariff
FSA	Formal Safety Assessment
FTE	Full-time Equivalent
Future Fuels CRC	Future Fuels Cooperative Research Centre
GAMAA	Gas Appliance Manufacturers Association of Australia
Gas fitter	A person trained to connect, disconnect, and service gas fittings and appliances.
GJ	Gigajoule
GL	Gigalitre
GM	General Manager
GMMP	Groundwater Management & Monitoring Plan
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
H2/H_2	Hydrogen
HA	Hazardous Area
HA	Hazardous Area
HAZID	Hazard Identification workshop
HAZOP	Hazard and Operability Study
HDPE	High Density Polyethylene
HGL	Hydrogen Generation Licence
HGV	Heavy Goods Vehicle/s
HHV	Higher Heating Value
HP	High Pressure
HP1	High Pressure 140 to 515 kPa
HP2	High Pressure 515 to below 1,050 kPa
Hy4Heat	Hydrogen for Heat Program
HyP Gladstone	Hydrogen Park Gladstone
HyP Murray Valley	Hydrogen Park Murray Valley
HyP SA	Hydrogen Park South Australia
ICE	Internal Combustion Engine Vehicle
ILI	In-line Inspection

Term Used	Meaning
I-O multiplier	Input-Output multipliers are commonly used to quantify the economic impacts (both direct and indirect) relating to policies and projects.
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRENA	International Renewable Energy Agency
ISP	Integrated System Plan
JDA	Joint Development Agreement
JV	Joint Venture
kg	Kilogram
kL	Kilolitre
KM	Kilometre
kPa	Kilopascal
kPag	Kilopascal Gauge
kv	Kilovolt
kW	Kilowatt
KWh	Kilowatt hour
L	Litre
LCOH	Levelized Cost of Hydrogen
LEL	Lower Explosive Limit
LFL	Lower Flammability Limit
LGC	Large-scale renewable Generation Certificate
LHV	Lower Heating Value
LIL	Large Industrial Load
LP	Low Pressure
MAOP	Maximum Allowable Operating Pressure
MAPS	Moomba to Adelaide Pipeline
MCH	Methylcyclohexane/toluene
mg	Milligram
MGN	Multinet Gas Networks
MIE	Minimum Ignition Energy
MJ	Megajoule
MJ/Sm^3	Megajoule per Standard Cubic Metre
mL	Millilitre
mm	Millimetre
MMBtu	Metric Million British Thermal Unit
MP	Medium Pressure
MPa	Megapascal
MSP	Moomba to Sydney Pipeline
Mt	Metric Tonne
$MtCO_2$-e	Metric Tonnes of Carbon Dioxide Equivalent
MVA	Megavolt amperes
MW	Megawatt
MWh	Megawatt hour
NCC	National Competition Council
NDT	Non-destructive Testing
NEM	National Electricity Market
NERL	National Energy Retail Law

Term Used	Meaning
NERR	National Energy Retail Rules
NEW	North East Water
NGL	National Gas Law
NGR	National Gas Rules
NREL	National Renewable Energy Laboratory (US)
NSW	New South Wales
O&M	Operation and Maintenance
ODS	Oxygen Depletion System/Sensor
OEM	Original Equipment Manufacturer/s
OPEX	Operating expenditure
OTR	Office of the Technical Regulator (South Australia)
PCF	Pressure Correction Factor
PE	Polyethylene
PEM	Proton Exchange Membrane
PGE	Petroleum and Geothermal Energy
PHES	Pumped Hydro Energy Storage
PJ	Petajoule
PLEXOS	Energy Market Simulation Software
PPA	Power Purchase Agreement
PRS	Pressure Reduction Stations
Purging (to purge)	When an inert ‘purge ‘gas is introduced into a closed system to prevent the formation of a combustible atmosphere.
PV	Photovoltaic
PVC	Polyvinyl Chloride
QGDN	Queensland Gas Distribution Network
QSN	Queensland, South Australia and New South Wales Link
REZ	Renewable Energy Zones
RFQ	Request for Quotation
RIS	Regulation Impact Statement
RO	Reverse Osmosis
SA	South Australia
SAOP	Safety and Operating Plan
SCADA	Supervisory Control and Data Acquisition
SEA Gas	South East Australian Gas
SEPS	South East Pipeline System
SESA	South East South Australian Pipeline
SG	Specific Gravity
SIPS	System Integrity Protection Scheme
SLD	Single Line Diagram
SLO	Social License to Operate
SMIL	Small to Medium Industrial Load
SMR	Steam Methane Reforming
SMS	Safety Management Study
SMYS	Specified Minimum Yield Strength
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
STEM	Science, Technology, Engineering, Mathematics

Term Used	Meaning
STTM	Adelaide Short Term Trading Market
TBC	To Be Confirmed
TJ	Terajoule
TP	Transmission Pressure
TUOS	Transmission-use-of-system
TWA	Time Weighted Average
UAFG	Unaccounted For Gas
UFL	Upper Flammability Limit
USD	United States Dollar
UTS	Ultimate Tensile Strength
VIC	Victoria
VRET	Victorian Renewable Energy Target
VTS	Victorian Transmission System
WACC	Weighted Average Cost of Capital
WI	Wobble Index
WWTP	Wastewater Treatment Plant

Appendix: 10% Hydrogen Distribution Networks Victoria Study

Assessing the feasibility of delivering 10% renewable hydrogen in Victoria's gas distribution networks

May 2023

Table of Contents

Appendix A
Hydrogen Production, Transmission, and Storage

Chapter 3 of the of the *100% Hydrogen Distribution Networks Study – Victoria* summarises the key supply chain components required to convert Victoria's gas distribution networks to renewable hydrogen. It draws on assessments made in this Appendix Section to propose one specific and feasible supply chain configuration.

The following sub-sections provide assessments of:

- water sourcing options for hydrogen production in several regions of Victoria (Section A.1);
- hydrogen storage options (Section A.2);
- existing gas transmission system compatibility with 100% hydrogen (Section A.3); and

A.1 Water Options

North-West and Central Victoria

High-quality water west of Bendigo and in Ballarat is considered to be fully utilised and other options should be investigated for hydrogen production in this region. For example, Victorian entitlements for the Murray catchment are 1,366 GL of high reliability and 349 GL of low reliability water, which is approximately allocated as 66% for irrigation, 28% for the environment and 6% for Water Corporations[50].

It is anticipated that these entitlements will be further stressed by climate change through to 2050 due to significant expected declines in cool season rainfall[51]. There is also significant competition between these water markets, which is compounded by numerous controversial stresses on the Murray-Darling Basin that it would be prudent for the hydrogen industry to avoid.

As a result, a likely water source for electrolysers in this area would be desalinated brackish, deep groundwater. Given that the water load would be distributed across several sites over a significant area, the water requirements for hydrogen production identified for north-western Victoria would be relatively small.

A review of published ground water resources for this area[52] suggests that there are deep brackish aquifers (3500 to 13000 mg/L salinity, > 100m deep) that do not presently have a high demand upon them due to the salinity level. The Wimmera Mallee Sustainable Diversion Limit has identified significant potential for additional consumptive use from the deeper aquifers in the sedimentary plain, approximately 180,000 ML per year across the basin) [53], so engagement with potential future users would be essential.

Although water by-products may be viable near urban centres, it is expected that desalination would be by Reverse Osmosis (RO), with residual salts evaporated in a zero-liquid-discharge system and disposed to landfill. This would also require consultation with relevant stakeholders, including the Environment Protection Authority.

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50 This information was correct at 1 July 2014 and was sourced from: <https://www.waterregister.vic.gov.au/images/documents/2013-14%20Water%20Entitlement%20Allocation%20and%20Use%20Summary%20report.pdf>

51 The State of Victoria Department of Environment, Land, Water and Planning. Climate change and the Victorian water sector, viewed 28 October 2021 <https://www.water.vic.gov.au/climate-change>

52 Groundwater resource reports can be found at: <https://www.water.vic.gov.au/groundwater/groundwater-resource-reports>

53 More information can be found in the Wimmera-Mallee Water resource plan: <https://www.mdba.gov.au/sites/default/files/pubs/VIC-wimmera-mallee-water-resource-planresubmission-comprehensive-report-part-1-July-2019%282%29_0.pdf>

South-West Victoria

In South-West Victoria, desalinated seawater (e.g. between Warrnambool and Portland) is a credible potential water source. However, given that the coastal fringe tends to have more commercial, environmental, and social values than inland locations, pumping power would be higher for RO produced from sea water, and that brackish water is lower cost to desalinate than sea water, it may still be the case that brackish-salinity groundwater is the preferred source. This region has widespread deeper aquifers of low to moderate salinity that are not fully developed and may be targets.

Western Victoria

A water supply system based on RO of brackish ground water in Western Victoria is a likely practical pathway. Brackish water is generally not suitable for other uses, and the cost of sourcing this way would be insignificant in the long-term cost structure of hydrogen, at around $0.02/kg.

Gippsland

In Gippsland, three brown-coal-fired power stations in the Latrobe Valley are all scheduled to be closed by 2048, and the Hazelwood power station has already closed (2017). These power stations use surface water from the Latrobe River system for their water supplies, primarily for condenser cooling. Groundwater is also extracted at the mine voids to maintain safety and stability.

The Central and Gippsland Sustainable Water Strategy Discussion Draft notes that between 2006-07 and 2018-19, Latrobe Valley electricity generators/mine licensees on average used 78 GL of surface water from the Latrobe River system per year. After returning some to the Latrobe River system, the stations have a net surface water usage of around 55 GL per year[54, 55]. The State of Victoria also retains the Latrobe Loy Yang 3/4 Bench bulk entitlement of 25 GL originally intended for a power station development adjacent to Loy Yang B[56].

Closure of the brown coal power stations may free up the balance of water the stations previously used. The Central and Gippsland Sustainable Water Strategy Discussion Draft provides insight to the future of these entitlements for rehabilitation:

- Some water from the Latrobe River system will continue to be required for electricity generation. During the transition from coal-fired generation, there will be opportunities to review water allocated and management and the Latrobe Valley Regional Rehabilitation strategy will be a focus of these decisions.
- If a water-based mine rehabilitation approach is taken, regional scale rehabilitation may require a range of water sources over a period of decades. If required, the volume of water would vary over time and according to location.
- The Victorian Government is exploring the feasibility of using manufactured water and non-water-based options for mine rehabilitation, that would not rely on the Latrobe River water system[57].

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54 The State of Victoria Department of Environment, Land, Water and Planning, 'Central and Gippsland Region Sustainable Water strategy Discussion Draft', <https://www.water.vic.gov.au/__data/assets/pdf_file/0032/544847/CentralGippslandRegion_SWS_DraftDocument.pdf>

55 Between 2006-2019, the volume of water available for electricity generation compared to the actual uses of electricity generators/mine licensees includes Hazelwood Power Station, Yallourn Power Station, Loy Yang power stations, and the associated mines. It does not include Morwell Power Station and briquette factories, or the Latrobe Loy Yang 3/4 Bench bulk entitlement. Until its closure, supply to the Hazelwood Power Station was under Gippsland Water's bulk entitlements and not under a specific entitlement for electricity generation.

56 Bulk Entitlement (Latrobe – 3/4 Bench) Conversion Order 1996 as at April 2016.

57 The State of Victoria Department of Environment, Land, Water and Planning. Central and Gippsland Region Sustainable Water Strategy Discussion Draft, viewed 10 October 2021 <https://www.water.vic.gov.au/planning/long-term-assessments-and-strategies/sws/central-gipps-sws>

A.2 Storage Option Analysis

A range of hydrogen storage options have been considered, which are listed below. Importantly, long-term storage has a once-per-year utilisation cycle, and low capital cost per unit of stored hydrogen is most important.

For some technologies, the components of the total cost that informs the cost per kilogram of hydrogen stored is not yet clear.

Above-Ground Pressurised Bullet Tanks

Above-ground pressurised bullet tanks have small maximum dimensions that attract limited economies of scale. They are most suitable for daily cycling, whereas long-term storage would ideally be cycled once per year. As a result, this would be an extremely expensive storage option for the volumes that would be required by 2050, at about $1,600 per kg of hydrogen stored[58].

If the system were integrated with a production facility and cycled daily, the cost per cycle would be low. This option is noted in the *AHC Victoria 10% Hydrogen Distribution Networks Study* as an optimal system for state-wide blending, when the storage needs would be much lower.

Underground Salt Domes

Salt domes would likely be the lowest cost storage option in Victoria. Existing applications in Europe and North America and in-development applications in Queensland demonstrate that it is highly credible. Salt domes would likely impact configuration as a pipeline connection would be required between production facilities, salt domes, and demand centres.

To date, research and exploration has not found any salt domes in Victoria; this may be due to a lack of exploration or reporting. If any exist, they would be practical and low-cost, and an extension of this State-Wide Study could be the exploration of potential sites.

Depleted Onshore Natural Gas Fields

Depleted onshore natural gas fields provide a credible option with the next lowest cost storage at around $40 per kg of storage capacity (capex equivalent).

In using these fields there would be risk of hydrocarbon contamination from extant natural gas, which would take many cycles (or processing of extracted gas) to reduce to acceptable levels.

There are some undeveloped reservoirs that could be utilised; however, it is not presently possible to ascertain their suitability for use with hydrogen because of these risks.

Additional Underground Pipes as Pressure Vessels

This option is probably impractical, as hydrogen embrittlement presently precludes high strength steel at high pressures, and therefore only small diameter pipes could be used. These would need to be inordinately long to use as storage vessels.

58 The total value quoted in the AEMO Draft 2021-22 IAWB is $2350/kg. This may include other scopes such as compressors.

Liquid Chemical Carriers

A liquid chemical carrier is costed at $31 per kg of storage capacity (capex equivalent), with Methylcyclohexane/toluene (MCH) the most likely at present. In this system, hydrogen is reacted with toluene to form methylcyclohexane, which can be stored similarly to petrol and be usefully integrated in a commodity export market. Acknowledging that informal hydrogen export agreements have been signed between other states and potential foreign exporters already, this option may be in use elsewhere in the country earlier.

Approximately two thirds of the load required to dehydrogenate MCH is heat, which could potentially be renewably sourced, materially reducing the effective cost of this storage method.

At $50 per kg, the cost of this option, levelised into the annual hydrogen load, would be approximately $0.17 per kg and not dominant in the overall hydrogen cost structure. This would enable access to lower-cost electricity and better capacity factors for the electrolyser facility. In these circumstances, MCH storage would be significantly beneficial, if not essential to the hydrogen supply chain in Victoria.

If storage is by MCH/toluene, then the location of these facilities in the broader supply system configuration is more flexible. It is similar to petrol storage in terms of technology and cost, which opens up the potential for future integration with international commodity trading for hydrogen transportation. If the potential for trade arose, then storage in Geelong could offer a strong combination of electricity transmission access, industrial location, buffer regions, and port access.

Ammonia

Ammonia may suit for long-term storage as well as foreign export commodity, however the steps involved in dehydrogenising ammonia are energy intensive and not yet developed enough to be considered commercial.

Other issues include a risk of ammonia contamination of the product gas, as well as the energy intensity of dehydrogenation.

Pending commercialisation, ammonia may be more likely than liquid chemical carriers as a storage option as it is less energy intensive.

Similar to storage by MCH/toluene, storage by ammonia could be in Geelong which would offer a strong combination of electricity transmission access, industrial location, buffer regions, and port access if trade potential arose.

Liquid Hydrogen

Liquefaction, storage, and associated energy costs are comparatively prohibitive, at around $200 per kg stored. The various cost elements include:

- Liquefaction plant cost; and
- Storage tank cost.

Energy cost for liquefaction and for refrigeration to limit boil-off, converted to capital-equivalent.

A.3 First pass appraisal of existing pipelines for hydrogen service

An initial review of selected existing natural gas transmission pipelines for potential suitability for hydrogen service was undertaken using the criteria above, with full results shown below.

Pipe		Specification				Natural Gas				Hydrogen					
Pipeline Name	Pipeline Licence No.	Existing Pipeline Diameter/s (mm)	Existing Pipeline Length (km)	Material (known or assumed)	Wall thickness (known or assumed) mm	MAOP MPa	Assumed required discharge pressure MPa	Indicative Flow Capacity (TJ/d)	Indicative Line Pack Capacity (TJ)	Modelled MAOP with H2 MPa	Indicative Flow Capacity (tonnes/d)	Indicative Line Pack Capacity (tonnes)	Max. Distance Between Compressor Stations (km)	Possible. No. Compressor Stations Req'd	Likelihood of reuse
VICTORIA															
Longford to Dandenong	75	750	174.2	API 5L X60	12.7	6. 89	2.5	663	113	4.3	3,040	56	70	3	Derated
Longford to Maffra	75	750	31.5	API 5L X60	12.7	6. 89	2.5	663	20	4.3	3,040	10	70	1	
Longford to Tyers	117	750	65	API 5L X60	12.7	7. 07	2.5	663	42	4.3	3,040	21	70	1	
Tyers to Morwell	121	500	15.7	API 5L X60	9.53	7. 07	2.5	292	4	4.8	1,339	3	57	1	
Morwell to Dandenong	50	450	126.8	API 5L B	9.53	2. 76	2.5	234	29	3.2	1,075	6	11	12	Age
Dandenong to Highett	13	300	17.8	API 5L B	9.53	2. 76	2.2	113	2	4.4	459	1	58	1	Derating may not be required upon detailed analysis?
Dandenong to Templestowe	40	450	37	API 5L B	7.92	2. 76	2.2	238	9	2.6	961	1	8	5	
Dandenong to West Melbourne	36	750	37	API 5L X42	9.53	2. 76	1.8	674	24	2.3	2,236	3	22	2	

Pipe		Specification				Natural Gas				Hydrogen					
Pipeline Name	Pipeline Licence No.	Existing Pipeline Diameter/s (mm)	Existing Pipeline Length (km)	Material (known or assumed)	Wall thickness (known or assumed) mm	MAOP MPa	Assumed required discharge pressure MPa	Indicative Flow Capacity (TJ/d)	Indicative Line Pack Capacity (TJ)	Modelled MAOP with H2 MPa	Indicative Flow Capacity (tonnes/d)	Indicative Line Pack Capacity (tonnes)	Max. Distance Between Compressor Stations (km)	Possible. No. Compressor Stations Req'd	Likelihood of reuse
Keon Park West to North Melbourne	203	450	25	API 5L B	7.92	2. 76	2.2	238	6	2.6	961	1	8	3	
South Melbourne to Brooklyn	108	750	12.8	API 5L X42	9.53	2. 76	1.8	674	8	2.3	2,236	1	22	1	
Templestowe to Keon Park East	201	450	16.5	API 5L B	7.92	2. 76	2.2	238	4	2.6	961	1	8	2	
Pakenham to Wollert	141	750	93.1	API 5L X60	12.7	6. 89	2.5	663	60	4.3	3,040	30	70	2	
Keon Park to Wollert	101	600	14.1	API 5L X42	7.92	2. 76	2.2	431	6	2.4	1,744	0	4	4	
Wollert to Wodonga	101	300	269.4	API 5L X46	6.35	7.4	2.5	118	31	3.9	543	12	27	10	Derated
Brooklyn Compressor Station to Lara City Gate	266	500	58	API 5L X52	9.53	10.2	2.5	292	17	4.2	1,339	8	38	2	Derated
Iona to Lara	231	500	143.9	API 5L X52	9.53	10.2	2.5	292	41	4.2	1,339	19	38	4	
Brooklyn to Ballan	78	200	66.6	API 5L B	6.35	2. 76	2.1	52	3	4.4	202	2	42	2	

Pipe		Specification				Natural Gas				Hydrogen					
Pipeline Name	Pipeline Licence No.	Existing Pipeline Diameter/s (mm)	Existing Pipeline Length (km)	Material (known or assumed)	Wall thickness (known or assumed) mm	MAOP MPa	Assumed required discharge pressure MPa	Indicative Flow Capacity (TJ/d)	Indicative Line Pack Capacity (TJ)	Modelled MAOP with H2 MPa	Indicative Flow Capacity (tonnes/d)	Indicative Line Pack Capacity (tonnes)	Max. Distance Between Compressor Stations (km)	Possible. No. Compressor Stations Req'd	Likelihood of reuse
Ballan to Ballarat	134	300	22.8	API 5L X46	6.35	7. 39	2.5	118	3	3.9	543	1	27	1	Possible re- use although flow capacity suitability and derate may ensue from detailed analysis
Ballan to Ballarat	78	150	22.7	API 5L B	4.78	2. 76	2.1	31	1	4.3	119	0	31	1	
Ballan to Bendigo	78	150	90.8	API 5L B	4.78	2. 76	3	31	3	4.3	169	1	10	9	
Brooklyn to Corio	81	350	50.7	API 5L X60	5.56	7. 39	2.5	140	7	4.1	643	3	21	3	
Wandong to Kyneton	143	300	59.5	API 5L X46	6.35	7. 39	2.5	118	7	3.9	543	3	27	3	
Mt Franklin to Kyneton	128	300	24.5	API 5L X46	6.35	7. 39	2.5	118	3	3.9	543	1	27	1	
Carisbrook to Horsham	179	200	183	API 5L X42	8.18	7. 39	2.5	50	9	6.6	230	10	75	3	
Carisbrook to Horsham	179	100	183	API 5L X42	4.78	7. 39	2.5	13	2	7.0	61	3	44	5	
Codrington to Hamilton	171	150	54.6	API 5L X42	7.11	10	2.5	29	2	7.0	133	2	65	1	
Curdievale to Cobden	168	150	27.7	API 5L X42	7.11	10	2.5	29	1	7.0	133	1	65	1	
Guildford to Maryborough	125	150	31.4	API 5L B	6.35	7. 39	2.5	30	1	5.6	136	1	39	1	

Pipe		Specification				Natural Gas				Hydrogen					
Pipeline Name	Pipeline Licence No.	Existing Pipeline Diameter/s (mm)	Existing Pipeline Length (km)	Material (known or assumed)	Wall thickness (known or assumed) mm	MAOP MPa	Assumed required discharge pressure MPa	Indicative Flow Capacity (TJ/d)	Indicative Line Pack Capacity (TJ)	Modelled MAOP with H2 MPa	Indicative Flow Capacity (tonnes/d)	Indicative Line Pack Capacity (tonnes)	Max. Distance Between Compressor Stations (km)	Possible. No. Compressor Stations Req'd	Likelihood of reuse
Allansford to Portland	155	150	100.4	API 5L X42	7.11	10	2.8	29	3	7.0	149	3	50	2	
Eastern Gas Pipeline (Longford to NSW Bo rder)	232	450	280.57	API 5L X65	12.7	16.55	2.5	227	62	7.0	1,044	78	124	3	Derated
Bass Gas Pipeline (Sales Gas)	244	250	35.1	API 5L X42	9.27	10.2	2.5	79	3	6.0	363	3	77	1	Derated
South Gippsland (Korumburra, Wonthaggi, Leongatha)	261	150	64	API 5L X42	4.78	10.2	2.5	31	2	5.0	141	1	30	3	
Chiltern to Rutherglen	176	200	14.7	API 5L X60	4	7.4	2.5	54	1	4.6	250	0	32	1	Possible re-use although flow capacitysuitability and derate may ensue from detailed analysis
Rutherglen to Koonoomoo (spec 1)	182	200	88.8	API 5L X42	8.18	7.4	2.5	50	4	6.6	230	5	75	2	
Rutherglen to Koonoomoo (spec 2)	182	200	88.8	API 5L X52	4.3	7.4	2.5	54	5	4.3	248	2	26	4	
Shepparton to Kyabram		200	37.5	API 5L B	6.35	7. 39	2.5	52	2	4.4	239	1	26	2	
Kyabram to Echuca	152	150	30.7	API 5L B	7.11	7. 39	2.5	29	1	6.3	133	1	51	1	

Pipe		Specification				Natural Gas				Hydrogen					
Pipeline Name	Pipeline Licence No.	Existing Pipeline Diameter/s (mm)	Existing Pipeline Length (km)	Material (known or assumed)	Wall thickness (known or assumed) mm	MAOP MPa	Assumed required discharge pressure MPa	Indicative Flow Capacity (TJ/d)	Indicative Line Pack Capacity (TJ)	Modelled MAOP with H2 MPa	Indicative Flow Capacity (tonnes/d)	Indicative Line Pack Capacity (tonnes)	Max. Distance Between Compressor Stations (km)	Possible. No. Compressor Stations Req'd	Likelihood of reuse
South East Australia Gas Pipeline (Iona to SA border)	239	355	267.5	API 5L X70	7.84	15.32	2.5	141	37	6.5	647	41	76	4	
Otway Gas Plant to Mortlake Power Station	259	300	78	API 5L X42	9.53	10	2.5	113	9	5.2	520	7	65	2	

Appendix B Network Readiness

The process of converting Victorian gas distribution networks to 100% hydrogen could be more sustainable if the existing significant natural gas infrastructure is repurposed.

The following Sections detail assessments that were performed to understand the augmentations that may be required for those existing gas distribution networks to transport 100% hydrogen and are referred to in Chapter 4 *Network Readiness for 100% Conversion*.

The scope of these assessments include:

- pipes and components (Section B.1);
- network operational processes (Section B.2); and
- the capital and operating costs of the modifications required for each (Section B.3).

B.1 Natural Gas Component Compatibility

Natural Gas Component Compatibility Results

Components in Victoria's gas distribution network were identified in a desktop study using documentation provided by AGN Vic, Multinet, and AusNet. A full compatibility assessment was then conducted and the results for components by type, make, and model, are shown in Table 1, Table 2, Table 3, Table 4, Table 5, Table 6, and Table 7.

Table 29: Components that require materials testing

Component type	Make	Models	Material information required
Regulators	Pietro Fiorentini	FE10 FE25	Investigate compatibility of Zamak (and approve component use at 100% hydrogen).Do
Domestic gas fitters	-	-	Investigate hydrogen compatibility of zinc.
Various	Various	Various	Investigate hydrogen compatibility of cast iron at pressures above 7 kPa.

Table 30: Components to be replaced

Component type	Make	Models	Material information required
Large bore valves	Brook	B600E	Cast iron body and SS410 stem
	Keystone	AR2 butterfly	Cast iron body with 17-4PH SS stem

Table 31: Cast iron components

Component type	Make	Models	Material information required
Large bore valves	Audco	M series Class 125	Replace if used above 7 kPa, or perform material testing to prove material compatibility with hydrogen at higher pressures
	John Valves	FIG 600	
Regulators	Fisher	298T, 99, 61	

Component type	Make	Models	Material information required
	Mooney	Flowmax	
	AMC	Reliance 1800,3000, 3010, 1203	
	Elster	J125	
	Sensus	243RPC	
Filters/strainers	Donkins	BD240R-290	
	ME MACK	Y Strainer	
	CLAM	Proprietary item: right angled filter	

Table 32: Components with incompatible materials to be risk assessed for their application

Component type	Make	Models	Material information required
Large bore valves	Richards	R43, R723, R733	Risk assess use of Inconel
	PBV	5800/6800	
	Sferova	TM2/Tm3	
Small bore valves	Swagelok	SS-EGUF8	Risk assess use of S17400SS needle
Regulators	AMC	Axial Flow Valve, Radial Flow Valve	Risk assess use of 17-4(PH) SS
	Pietro Fiorentini	PF Reflux 819 FO	Risk assess use of 416 SS
	Crosby	951 Series	Risk assess use of416 SS and 17-7PH or Monel or Hastelloy C

Table 33: Components for which material information is not known

Component type	Make	Models	Material information required
Large bore valves	Cameron	WKM R603 NH	ALL
	Richards	R346, R46	ALL
		93300A RP6B MK3	ALL
Regulators	Gorter	Cocon 13, 26	Confirm type of steel and any plastic
	Fisher	64 HPR 67F	ALL
		161, 168, EZH	Confirm type of steels used and in what applications
	Mooney	15H01G	ALL
	AMC	Reliance 2000	ALL
	AMPY Email 300	Spec 23, 59, 68, 78	Confirm any metals used
	Grove	Model 80, 81, 83	ALL

Component type	Make	Models	Material information required
	Reynolds	670, 678, 682	ALL
	Donkins	688, 999	ALL
	Pietro Fiorentini	FEX, VS/AM	Confirm any plastics used
		Dival 300 & 512 LTR, Reval	ALL
	RMG	650, 850	ALL
	Welker	Welker Jet	Confirm application of 1045 CS
	Honeywell	HON 5020	Confirm type of SS used
	EDMI/Atlas	TR200B, TR143	Confirm type of SS used
Meters	Dresser	Roots	Confirm type of steel and any plastics
	Actaris	1000A	Confirm any metals used
	L&G / AMPY	Model 750, 1010, 602, 610	Confirm type of steel
	EDMI / Atlas	RK MR8, U8, U10	
Filters/Strainers	ME MACK	6761A-050	ALL
	Grove	104-00019	
	NUPRO	55	
	Fisher P252	Type P252	

Table 34: Components that require materials testing

Component type	Make	Models	Material information required
Regulators	Pietro Fiorentini	FE10 FE25	Investigate compatibility of Zamak (and approve component use at 100% hydrogen)
Domestic gas meter fittings	-	-	Investigate hydrogen compatibility of zinc
Various	Various	Various	Investigate hydrogen compatibility of cast iron at pressures above 7 kPa

Table 35: Components with cast iron, nickel alloy, or martensitic stainless steel options - material selection to be confirmed

Component type	Make	Models	Material information required
Large bore valves	Nordstrom	-	Confirm plug material (SS or Monel). Replace if Monel or martensitic SS.
	Audco	Standard M series and Super H series	Confirm plug material. Replace if cast iron at pressure above 7 kPa
	Keystone	F2 butterfly	Confirm whether body is cast iron or carbon steel. Replace if cast iron at pressure above 7 kPa
	Bray	S31-13	Confirm body material. If cast/ductile iron, and used at pressure above 7 kPa, replace. If not, risk assess, considering Monel or 17-4PH SS stem
Small bore valves	Fisher	OSE	Confirm body material. Replace if cast iron at pressure above 7 kPa
Regulators	Gorter	Cocon 1-12	Confirm body material. Replace if cast iron at pressure above 7 kPa
	Fisher	62, 627, 289H, 299, 166, EZR, 66	Confirm body material. Replace if cast iron at pressure above 7 kPa
		98H PRV	Confirm body material. If cast/ductile iron at pressure above 7 kPa, replace. Otherwise, confirm seat option. If 416SS metal/metal seat, risk assess.
	Mooney	Flowgrid FG/SG	Confirm body material. If cast iron at pressure above 7 kPa, replace. Otherwise, risk assess, considering 17-4PH SS throttle plate
	AMC	Reliance Z 138	Confirm body material. Replace if cast iron at pressure above 7 kPa
	Donkins	226 MK2 / MK3	Confirm body material. Replace if cast iron at pressure above 7 kPa
	Pietro Fiorentini	Dival 100/160/2Div50/600, Norval, Aperval	Confirm body material. Replace if cast iron at pressure above 7 kPa
		Reval 182	Confirm whether body is cast/ductile iron. If yes, and used at pressure above 7 kPa, replace. Otherwise, risk assess, considering 416 SS stem.
Meters	Actaris	Flxie Turbine Meter	Confirm body material. Replace if ductile iron at pressure above 7 kPa
	Sensus / Rockwell	RK T18 Turbine	Confirm body material. Replace if cast iron at pressure above 7 kPa
		RK MKII and IIE Turbine	Confirm body material. Replace if cast iron at pressure above 7 kPa
	Elster Instromet	TRZ2 (turbine) and RVG (rotary)	Confirm body material. Replace if cast iron at pressure above 7 kPa

B.2 Potential Hydrogen Considerations for Current Safety and Operating Procedures

Listed below are potential considerations for safety and operating considerations when factoring for hydrogen supply, referenced in Section 4.3.3 of the Report. These are not likely to present concerns or major step changes to current procedures.

Actions required to resolve system design issues with 100% hydrogen supply

- Review sizing of pressure relief devices where existing regulators are retained;
- Monitor piping for any locations that may have developed structural resonance at the revised highest flow;
- Decommission gas heaters at city injection points, if relevant;
- Perform detailed reviews on the following:
  - Risk of erosion at velocities higher than the norm, based on potential for inclusion of solid particulates;
  - Flow velocities and resulting thermowell vibration risk;
  - Noise design at network regulators;
  - The value of colourant for safe detection of ignited leaks;
  - Sizing of natural ventilation systems;
  - Confined spaces procedures to avoid ignition potential, as well as the confined spaces themselves to provide a high-point vent where possible;
  - The suitability of existing flame detection systems (and replacement if necessary).
- Perform a location-specific review of all Hazardous Area (HA)-rated facilities and completely audit all HA equipment (this is expected to result in replacement of most devices);
- Replace all gas detectors with hydrogen detectors;
- Review the effectiveness or sufficiency of leak survey/detection frequency as a proactive measure;
- Consider placing a higher priority on low-energy ignition sources, particularly avoiding static build-up, for example by enforced earthing practices and anti-static clothing (if not already required);
- Identify best-practice for confined space entry in hydrogen environments;
- Place less value on the absence of ignition sources during reactive leak response procedures;
- Increase proactive leak control measures and consider design alteration options for leak control (eg flow-limiting device at meter sets);
- Modify odourisation control systems as required;
- Monitor developments arising from ongoing research; in particular, those establishing standards for hydrogen delivery condition and purity, and customer meter offsets.

Actions required to resolve issues relating to ongoing operation and maintenance

- Review burner equipment (as used for flaring) for different fluid properties;
- Review cold vent design (eg earthing / radius outlets) and noise limits for high-pressure pipelines;
- Avoid purging with a flammable interface (if practised at all), instead always use an inert gas as a buffer unless the risk of ignition has been accepted;
- After inerting, avoid introducing air until H2 concentration in N2 is 5% or less. This is a lower target than used in natural gas;
- Ensure all leak tests include in-service leak test with hydrogen medium, even if an air leak test has already been conducted;
- Confirm that isolation by squeeze-off is sufficiently effective to continue the practice in hydrogen service;
- Perform leak survey to locate any existing plastic pipe repairs that may have leakage issues due to using compression fittings;
- Review approval framework for non-piggable pipelines to ensure they meet the integrity management requirements of ASME B31.12;
- Revise pipeline defect assessment procedures as outlined in ASME B31.12;
- Review pipeline condition, particularly for cracks, before introducing hydrogen;
- Only live weld to new approved procedures applicable to pure hydrogen service;
- Only proceed to use hydrogen-suitable repair solutions and materials. For instance, obtain superior seal materials than Buna-N for improved compatibility of pipeline repair fittings; and
- Closely monitor a selection of facilities after hydrogen conversion to establish failure rate benchmark

B.3 Capital Replacement Cost Estimates

Replacement of Components made with Hydrogen-Incompatible or Unknown Materials

Table 10 notes the costs of replacing incompatible components in Victoria's gas distribution network. This is a conservative estimate given a majority of the gas distribution system historically operated on town gas, comprised of up to 61% hydrogen, and because 100% replacement is only necessary if further research and/or risk assessment deem replacement is required.

The following considerations were made to estimate these costs:

- Costs to replace filters, strainers, meters, and other components have been excluded.
- Quantities of regulators and valves in the AGN networks were based on spreadsheets provided by AGIG in August 2021 that list quantities and types of valves and regulators across the two AGN networks. The lists did not differentiate the components in each network, so it was assumed that AGN Vic has 60% of the total quantity of each valve, and AGN SA has the remaining 40%.
- Quantities of regulators and valves in the Multinet network were estimated based on quantities in the AGN Vic and SA networks as a guide.
- Quantities of regulators and valves in the AusNet Services network were estimated using facility drawings provided by AusNet, and then multiplying those quantities by the number of facilities in the network (refer to Table 8) and supplemented using the AusNet Services Transmission Pipeline Isolation Plan AMS 30-06 1.0.
- Sizes of each valve and regulator are not known. An average cost for each component has been assumed as per
  Table 9 and Table 11, which roughly aligns to the cost for a DN100 component.
- Components for which makes and models could not be identified have not been included.
- Demolition, installation, and commissioning costs were assumed to be required for every component. Direct replacement of each component was assumed to require 2 operators for 4 hours, at a cost of $50 per person per hour. Note this is a conservative assumption as upgrades to multiple components at the same facility would enable reduction in costs for mobilisation/demobilisation/isolation, etc. However, no allowance was made for re-design required if replacements are not an exact fit.

Table 36: Number of facilities per network (at 2022)

Item	AGN SA	AGN VIC	Multinet	AusNet
Injection points	17	54	7	41
Regulating Stations	257	142	236	146
Custody transfer meter stations		58	20	

Table 37: Estimated unit costs for each type of replacement component

Item	Estimated cost
Large bore valve	$1000
Small bore valve	$200
Customer regulator	$10,000
Network regulator	$20,000
Injection Point regulator	$50,000
Pilot regulator	Included in injection point/network regulator price

Table 38: Estimated costs for component replacement in each network

Item	AGN Vic		Multinet		AusNet	
	Qty	Cost	Qty	Cost	Qty	Cost
Components with cast iron and martensitic stainless steel	2	$2486	5	$5,180	-	-
Components with cast iron	3403	$25,073,494	3921	$27,781,120	18300	$183,722,800
Components with nickel alloys or unsuitable stainless steels	346	$6,510,463	291	$5,890,476	587	$11,986,932
Components with unsuitable material options (selection to be confirmed)	2584	$36,677,191	3462	$43,874,632	4399	$3,389,364
Components without known material information	753	$9,048,708	755	$9,827,180	167	$173,012
TOTAL PARTS COST		**$77,312,342**		**$87,378,588**		**$199,272,108**
Part delivery (10% of total parts cost)		$7,731,234		$8,737,859		$19,927,211
Site works to perform replacement (calculated per component)	7088	$2,835,360	8434	$3,373,600	23453	$9,381,200
GRAND TOTAL		**$87,878,937**		**$99,490,047**		**$228,580,519**

Replacement of Diaphragm Meters

Diaphragm meters would need to be replaced because it is anticipated that hydrogen would permeate through elastomeric diaphragms. However, it is expected that these meters would be replaced during the aged meter replacement programs which have already been funded through the access arrangements of Victoria's distribution network businesses.

Estimated costs of replacing the diaphragm meters is estimated in Table 11, with quantities of diaphragm meters per network shown in Table 12 and a cost estimate for each network in Table 13.

Table 39: Estimated unit and installation costs for each type of meter

Item	Estimated cost
Replacement domestic meter (ultrasonic)	$200
Replacement industrial/commercial meter	$1,200
Installation of domestic meter	$50
Installation of industrial/commercial meter	$200

Table 40: Quantity of diaphragm meters per network

Item	AGN SA	AGN VIC	Multinet	AusNet
Domestic meters	420,140	678,790	691,524	744,547
Industrial/commercial meters	33,030	3993	26,639	18,286

Table 41: Estimated costs for diaphragm replacement in each network

Item	AGN SA	AGN VIC	Multinet	AusNet
Domestic meter	$84,082,000	$135,758,000	$138,304,800	$148,909,400
Domestic meter installation	$21,020,500	$33,939,500	$34,576,200	$37,227,350
Industrial/commercial meter	$39,636,000	$4,791,600	$35,566,800	$21,943,200
Industrial meter installations	$6,606,000	$798,600	$5,927,800	$6,606,600
Totals	**$151,344,500**	**$175,287,500**	**$214,375,600**	**$211,737,150**

Replacement of Hazardous Area Rated Electrical Equipment

Hydrogen as a process fluid can change the Hazardous Area (HA) compliance of electrical equipment due to a change of both Gas Group and Temperature Class. Hydrogen is in Gas Group IIC and Temperature Class T1; this is the most volatile Gas group, and therefore it requires the most onerous safeguarding.

Therefore, any equipment already installed and operating, but rated for a Gas Group IIA or IIB must be replaced with a gas group IIC equivalent instrument. For the three types of facilities - Injection Point, Field Regulator and Customer Meter Set - there are 6 (six) instrument types that require hazardous area rating and hence will be non-compliant with respect to hydrogen use:

- flow / volume correctors;
- limit switches;
- junction boxes;
- temperature transmitters;
- solenoids; and
- isolator switch.

Three scenarios are provided for consideration, to estimated costs (+/-50%) of replacing all non-compliant instruments of each type:

3 Replace all instruments that are rated for Gas Group IIA and IIB, and replace all items with missing information.

4 Replace all instruments that are rated for Gas Group IIA and IIB.

5 Replace all instruments that are rated for Gas Group IIA and IIB, and replace all items with missing information and relocate RTU / DBs at 50% of outdoor locations.

For all three scenarios, time has been allocated for engineering which includes:

- Creation of datasheets for new Hazardous Area equipment.
- Design/Review for new junction box(es).
- Installation Scope(s) of Work for all sites with equipment installations.
- Cable Calculations / Review for new relocated distribution board locations.
- Review / Selection of new relocated Remote Telemetry Unit and distribution board locations. All of the new (replacement) instrumentation pricing has been based on equipment that is compliant for gas group IIC, temperature class T1 and are appropriate for use in the indicated zone identified in the provided information.

Where zoning information was not provided/available, HA Zone 1 was assumed for the specification of equipment.

The estimates apply to the two AGIG networks (AGN Vic and Multinet). Information for hazardous area equipment in the AusNet network was not supplied.

The estimates are based upon there being 50 "Injection Point" sites across Victoria and South Australia, 589 "Field Regulator" sites Across Victoria and South Australia and 838 "Customer Meter Set" sites across Victoria and South Australia.

Table 42: Numbers of facilities

Facility type	AGN SA	AGN VIC	Multinet	Total
Injection Point	3	40	7	50
Field Regulators	257	103	229	589
Customer Meter Set	253	271	314	838

Table 43: Estimated price per unit of each hazardous area rated replacement instrument

Instrument type	Manufacturer	Model	Cost	IECEx Certificate
Flow / Volume Correctors	Honeywell	EK220	$3000	IECEx LCIE 16.0003X
Limit Switches	Honeywell	LS4A1A	$350	Simple Device
Junction Boxes	Pepperl and Fuchs (Govan)	GUB*	$2000	IECEx INE 14.0042X
Temperature Transmitters	Yokogawa	YTA610	$1500	IECEx FMG 16.0014X
Solenoids	Norgren-IMI-Herion	80207 65	$650	IECEx KEM 09.0068X
Isolator Switch	Crouse-Hinds	GHG 263	$1325	IECEx BKI 07.0012

Table 44: Cost breakdown for each scenario of hazardous area equipment replacement

Scenario	Equipment & Materials	Installation Cost	Engineering and Owner's Cost	Uncertainty/ Contingency	Total cost	Percentage of total cost
Scenario 1 - Total						**100%**
AGN VIC	$2,069,498	$803,200	$660,721	$636,015	$4,169,434	
Multinet	$2,263,514	$878,500	$722,663	$695,642	$4,560,319	
Scenario 2 - Total						**100%**
AGN VIC	$1,662,265	$602,000	$520,781	$501,308	$3,286,354	
Multinet	$2,196,564	$795,500	$688,175	$662,443	$4,342,682	
Scenario 3 - Total						**100%**
AGN VIC	$2,427,216	$1,377,000	$874,970	$842,253	$5,521,439	
Multinet	$2,912,659	$1,652,400	$1,049,964	$1,010,704	$6,625,727	

Distribution Licensed Pipelines Excluded from Assessment

Several distribution licensed pipelines with MAOP above 2800 kPag or high design factor, as listed in Table 19, were excluded from the assessment in this project. High pressure and high design factor pipe require a more detailed review on a case-by-case basis. Methods of assessment recommended for each pipeline are discussed in Table 17. Estimated costs to perform these assessments are summarised in Table 17, and the cost per network is shown in Table 18. Costs for in-line inspection (ILI) of pipelines have not been included but may be recommended in practice. These costs are for activities that are recommended for action before any level of hydrogen is introduced (including before 10%).

Table 45: Estimated unit costs for each type of pipeline assessment

Item[59]	Estimated cost
Engineering assessments	$50,000
Dig-up and scraping for material characterisation and hardness spot-tests	$50,000
Sample retrieval using:	
• Simple hot-tap	$250,000
• Stopple and bypass to remove section	$1,000,000
Testing material in air	$10,000
Testing in hydrogen	$200,000

59 Definitions

- Dig-up – A small excavation to expose the buried pipeline and remove a section of coating for the purposes of inspecting the pipe surface and potentially taking samples (scrapings) for characterisation of the material. Afterwards the pipeline is re-coated and re-buried.
- Hot-tap – Hot tapping equipment is used to cut out a circle of material from the pipe, to use for material testing.
- Stopple – Where one hot-tap would not retrieve enough material, two hot-taps, stopples and a temporary bypass are used to isolate a section of pipeline which can be cut out and replaced with a new piece.
- Test – air – Testing of material properties in air, focussing on actual yield strength, tensile strength and ductility determined through tensile testing, and then fracture properties determined through fracture testing. Fracture testing would use both Charpy and a J-R curve testing. Fatigue crack growth rate testing may also be completed.
- Test – hydrogen – Testing of material properties in hydrogen, focussing on the fracture properties as measured using J-R curve testing in a hydrogen chamber. Fatigue crack growth testing and tensile property testing may also be completed. Charpy is not feasible in a hydrogen environment.

Table 46: Estimated costs for pipeline assessment in each network

Item	AGN SA		AGN VIC		Multinet		AusNet	
	QTY	**Cost**	**QTY**	**Cost**	**QTY**	**Cost**	**QTY**	**Cost**
Total engineering assessments	1	$12,500	1	$12,500	1	$12,500	1[60]	$12,500
Dig-up and scraping for material characterization and hardness spot-tests			4	$200,000	2	$100,000	1	$50,000
Sample retrieval[61], using:								
• Simple hot-tap			3	$750,000	2	$500,000		
• Stopple and bypass to remove section					1	$1,000,000		
Testing material in air	3	$30,000	4	$40,000	3	$30,000		
Testing in hydrogen	1	$200,000	1	$200,000	1	$200,000		
Contingency – additional hot taps network-wide	2	$500,000	3	$750,000	2	$500,000	3	$750,000
Totals		**$742,500**		**$1,202,500**		**$2,342,500**		**$762,000**

60 Additional dig-up recommended for unknown material on PL57 Corio to Belmont to Point Henry service line.

61 It has been assumed that there are no original spares of installed pipe available, except for Zaplock pipe.

Table 47: Pipelines excluded from assessment

Network	Pipeline License	Pipeline Name	MAOP (kPa)
Multinet	PL 210	Pakenham-Wollert Offtake	6890 & 10200
Multinet	PL 261	South Gippsland Pipeline	10200
Multinet	PL 2655	Lang Lang CG Connection	10200
Multinet	PL276	Lilydale Pipeline - Yarra Glen to LCG	6980
AGN Vic	PL 276	Dandenong to Crib Point & adjoining sections	2760 & 7000
AGN Vic	VIC 43	Longford to Sale	4800
AGN Vic	VIC 137	Bittern to Dromana	2900
AGN Vic	VIC 139	Langwarrin to Frankston	9525
AGN Vic	VIC 226	Berri to Mildura Pipeline	9525
AGN Vic	VIC 219	Wodonga City Gate to Albury (ref. 210827-REP-001)	2760
AGN Vic	VIC 102	Wodonga West to Wodonga (ref. 210827-REP-001)	2760
AGN Vic	VIC 208	Ring Main – North Melbourne to West Melbourne - section with material API 5L B, DN450, WT6.4, DF 0.41	2760

Appendix C Customer Appliances

Chapter 5 of the *100% Hydrogen Distribution Networks Study – Victoria* outlines the options for transitioning gas customers to renewable hydrogen supply. Chapter 5 draws on the information in this Section in assessing these options and proposing an optimal pathway. The sub-sections herein include:

- conversion options and costs (Section C.1);
- an assessment of pathway options (Section C.2);

C.1 Conversion Options and Costs

In determining conversion options and costs, this study referred to the CSIRO National Hydrogen Roadmap[62] and the UK government's Hy4Heat[63] program. The following section outlines the findings of these projects.

CSIRO National Hydrogen Roadmap

The CSIRO National Hydrogen Roadmap outlines three pathway options to convert domestic appliances to operate with 100% hydrogen gas, as set out in Table 20 below.

Table 48: Pathway options to conversion of domestic appliances for 100% hydrogen use

Pathway options	Description	Strengths and weaknesses
Replacement with hydrogen only appliances	Appliances are replaced at the time of conversion, with alternative appliances that operate on 100% hydrogen only.	Costly and labour intensive. Involves up to 12 hours work to change appliance. Availability of hydrogen only appliances in Australia is low.
Replacement with dual fuel appliances	Dual fuel appliances are developed, which can run effectively on either natural gas or 100% hydrogen.	Appliances are expected to be more expensive, and the installation more complex than hydrogen only options.
Replacement with standardised appliances	Standards governing natural gas appliances are amended to require new appliances to be manufactured in a way that simplifies a future conversion to 100% hydrogen (eg standardised back plates).	Mandates new natural gas appliances to be manufactured with standardised back plates and connections. Minimises number of appliances that would require expensive/lengthy upgrade in future. Minimises future upgrade and labour costs.

62 Visit CSIRO's website for the Hydrogen Roadmap page: <https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/csiro-futures/futures-reports/hydrogen-roadmap>

63 Visit the UK government's website for the Hy4Heat program: <https://www.hy4heat.info/>

The CSIRO states that the third option is likely to be the preferred. That assessment is largely because of the costs associated with dual fuel appliances, and the time it takes to install hydrogen only appliances. This is consistent with initial findings and stakeholder feedback from workshops conducted for this Report.

The transition to 100% hydrogen gas will be more complex for commercial and industrial appliances than for domestic appliances, according to the CSIRO's report. Commercial and industrial appliances pose a greater challenge due to variability in appliances, heat, and flame profiles, and reconfiguration of entire plants may be required in some cases. Without a clear policy direction, the economics may only support such an upgrade if there is proximate pre-existing hydrogen supply. For this reason, government will have a key role in providing direction that can reduce the risk for appliance manufacturers.

Hy4Heat

The Hy4Heat program has been funded by the UK Government's Department of Business, Energy and Industrial Strategy to establish if it is technically possible, safe and convenient to replace natural gas with hydrogen in residential and commercial buildings and gas appliances. The work program commenced in 2018 and is ongoing. Hy4Heat defines a very similar approach to the CSIRO. It recommends replacement of existing appliances with "hydrogen ready" appliances, which are optimally designed to run on hydrogen but are initially configured to run on natural gas. These appliances may require certain components to be changed at the point that natural gas is entirely replaced by hydrogen. This process will be simpler and less labour-intensive because those changes will have been considered in the design of the appliance.

Hy4Heat provides more detail than the CSIRO's report on the conversion of commercial and industrial appliances.

For commercial sector appliances, Hy4Heat found that:

- It is technically feasible to develop 100% hydrogen appliances, but a challenge to do so cost-effectively; and
- This sector has received less attention than other sectors, due to the large diversity of commercial building sizes and heat demands, and lower fuel consumption relative to the domestic and industrial sectors.

For industrial sector appliances, the study found that the majority of industrial gas heating equipment could be retrofitted to operate on hydrogen, with some specific challenges, including:

- Gas engine combined heat and power (CHP) – issues exist around 'de-rating' (operation at sub-maximal capacity) and 'knock' (premature combustion due to uneven energy consumpton) which might necessitate replacement rather than conversion.
- Glass furnaces – they rely on radiant heat transfer to product and flue gas composition, which could impact product quality.
- Food and drink ovens – issues exist because of bespoke equipment and potential impact on product quality standards.
- Kilns – there are issues due to the impact of changes in flue gas composition.

The Hy4Heat Industrial Report also estimates the conversion costs for typical equipment, as set out in Table 21.

Table 49: Indicative estimated capex for converting some typical pieces of equipment from natural gas to hydrogen

Industry sector	Typical Equipment	Equipment Conversion Cost – Variation Cost – Variation with Size ($ '000s)*		Conversion Cost for Typical Equipment ($ '000s)*	
		1MW	10MW	Example Size (MW)	Typical Cost
Food and drink	Steam boiler	313	1,270	20	1,914
	Oven	276	902	2	386
Chemicals	Steam Boiler	184	902	20	1,435
	Furnace	202	975	25	1,803
Vehicle Manufacturing	Hot water boiler	313	1,270	20	1,914
	Oven	276	902	5	625.6
	Direct dryer	258	902	2	368
Basic metals	Furnace	331	1,343	40	3,091
Paper	Direct dryer	276	865	3	478
	Steam boiler	350	1,380	20	2,097
Glass	Glass furnace	368	1,472	25	2,557
Ceramics	Kiln	294	1,049	5	717
Lime	Lime kiln	294	1,049	5	717
Other NM Minerals	Rotary dryer	258	791	15	957
Electrical and mechanical engineering	Hot water boiler	313	1,270	5	828
	Oven	276	902	3	478
	Steam boiler	313	1,270	5	828

Note: In adapting Table 21 from Hy4Heat, its figures were converted from British Pounds to Australian Dollar at the rate 1GBP = 1.84AUD. Some exactness has been lost in rounding up.

The Hy4Heat program is ongoing, and its work should be monitored for further findings that could inform the feasibility of hydrogen conversion in Victoria.

C.2 Analysis of Pathway Options

To outline these pathways, it was assumed that:

- Conversion of networks to 100% hydrogen will be completed by no later than 2050.
- The developed pathways are designed to be simplistic – hybrids of different scenarios could be developed.
- Issues of metering pressure and appliance regulators have been standardised.
- Existing customer piping is compliant with the transfer of hydrogen.
- Due to its population size, Australia will follow the appliance direction of Europe.

Appliance types and markets are assumed to be consistent with current.

Pathway 1: In-place conversion

Under this pathway, natural gas appliances continue to be sold up to the time of network conversion. The cost of conversion could be covered by the network owner or by the customer.

Table 50: In-place conversion pathway

Pathway 1: In-place conversion	
Risks	Recovery of the costs of conversion from customers, governments, or regulators. Sale and connection of second-hand natural gas appliances, after conversion. Loss of customers due to cost of conversion where charges apply, or complexity seen as too high. Inability to convert appliances to hydrogen and need for replacement.
Actions	Development of conversion strategies and methodologies from appliance manufacturers. Development of training for installation of hydrogen after the meter systems and appliances. Development of accreditation systems for hydrogen gasfitters. Establishment of community communication via multiple channels regarding direction being taken and actions they need to take. Consideration needed for low-income households.
Strengths	Network conversion and appliance conversion will be controlled by the network owner, which means a reduced level of complexity.
Weaknesses	Where conversion is undertaken by a third-party gasfitter, there would be a higher level of consumer complexity and disruption. Potential for recall for reconnection of customers who were disconnected as appliances had not been converted when network was converted. Requirement to complete survey of customers and appliances prior to conversion to ensure requirements. Increased customer communication required.

Pathway 2: Dual fuel

Under this pathway, dual fuel appliances which can safely and reliably switch between natural gas and hydrogen without component changes are mandated to be sold for new installations, replacements, or energy conversions from 2035. Existing customers would be advised that they need to change their appliance or convert to an alternate energy source by 2040.

Table 51: Dual fuel pathway

Pathway 2: Dual fuel	
Risks	Loss of customers due to cost of new appliances. Appliance volumes are not sufficient to meet demand. Sale and connection of second-hand natural gas appliances. Different jurisdictions take different paths reducing appliance requirements.
Actions	Development of training for installation of hydrogen downstream of the meter systems and appliances. Development of accreditation systems for hydrogen gasfitters. Focus on ensuring the availability of dual fuel appliances. Establishing community communication via multiple channels regarding direction being taken and actions they need to take. Strategies for low-income households required. Establish Australian standards for appliances.
Strengths	Will have a new appliance community attached to the network. Eliminate the complexity of conversion and disruption to customers. No cost of conversion to network owners or need for recovery.
Weaknesses	Lack of an Australia-wide (all networks) agreed approach to ensure a critical mass of appliances.

Pathway 3: Hybrid conversion

In this pathway, adaptable and hydrogen-ready appliances are mandated as the only appliance to be sold for new installations or replacements from 2035. Customers would be advised to either replace existing appliances with dual fuel or hydrogen-ready or compatible appliance by 2040, or to source an alternate fuel.

Table 52: Hybrid conversion pathway

Pathway 3: Hybrid conversion	
Risks	Loss of customers due to cost of new appliances. Appliance volumes are not sufficient to meet demand. Sale and connection of second-hand natural gas appliances. Recovery of conversion costs from customer, government, or regulator if work completed by network owner. Different jurisdictions take different paths, reducing appliance requirements.
Actions	Development of training for installation of hydrogen downstream of the meter systems and appliances. Development of accreditation system for hydrogen gasfitters. Establish requirements and training, and parts for transition of appliances to hydrogen. Establishing community communication via multiple channels regarding direction being taken and actions they need to take. Strategies for low-income households required. Develop Australian standards for appliances.
Strengths	Will have a new appliance community attached to the network. Reduce the complexity of conversion and disruption to customers. No cost of conversion to network owners as need for recovery is placed on the consumer.
Weaknesses	Lack of an Australia-wide (all networks) agreed approach to ensure a critical mass of appliances.

Pathway 4: Like-for-like replacement

In this pathway, gas appliances are replaced at the time of network conversion with an equivalent designed specifically for use with a 100% hydrogen supply.

Table 53: Like-for-like replacement pathway

Pathway 4: Like-for-like replacement	
Risks	Loss of customers due to cost of new appliances. Appliance volumes are not sufficient to meet demand. Sale and connection of second-hand natural gas appliances. Recovery of conversion costs from customer, government, or regulator if work completed by network owner. Different jurisdictions take different paths, reducing appliance requirements.
Actions	Development of training for installation of hydrogen downstream of the meter systems and appliances. Development of accreditation system for hydrogen gasfitters. Establish requirements and training, and parts for transition of appliances to hydrogen. Establishing community communication via multiple channels regarding direction being taken and actions they need to take. Strategies for low-income households required. Develop Australian standards for appliances.
Strengths	Will have a new appliance community attached to the network. Reduce the complexity of conversion and disruption to customers.
Weaknesses	Lack of an Australia-wide (all networks) agreed approach to ensure a critical mass of appliances.

C.3 Analysis of Pathway Options

Criteria, Weighting, and Scoring

At the second Feasibility Study workshop in August 2021, participants developed a multi-criteria assessment framework to systemically assess the relative merits of each pathway option. The framework identified ten criteria, each weighted to reflect its relative importance to overall assessment, for which each appliance received a score between 1-5. The scoring guide, including weighting, is reproduced in Table 26.

Table 54: Scoring guide used to assess appliance conversion pathways

Criteria and weighting	Score				
	1	2	3	4	5
Cost of appliance (25%)	Much higher than what customer would otherwise pay	Higher than what customer would otherwise pay	Somewhat higher than what customer would otherwise pay	Similar to what customer would otherwise pay	No appliance purchase required
Cost of install (10%)	Much higher than what customer would otherwise pay	Higher than what customer would otherwise pay	Somewhat higher than what customer would otherwise pay	Similar to what customer would otherwise pay	No appliance installation required
Cost of conversion (20%)	Very high	High	Moderate	Minor	No conversion required
Duration of conversion (10%)	Very long	Long	Moderate	Short	None
Number of home or business visits required to undertake works (2.5%)	>3 visits to home/business	3 visits to home/business	2 visits to home/business	1 visit to home/business	No visits to home/business
Ability to match physical dimensions of existing appliances (2.5%)	Will not fit in same location as natural gas equivalent	Major work required	Moderate work required	Minor work required	No work required
Workforce capacity required to deliver appliance roll-out (10%)	Cannot be practically managed by any conceivable workforce size	Major scaling up of workforce capacity required	Some scaling up of workforce capacity required	Minor scaling up of workforce capacity required	Can be managed by existing workforce
Risk associated with complexity of option (5%)	Extreme	High	Moderate	Minor	No risk
Standards development timeframe (10%)	Comprehensive development requiring 10+ years	Major development requiring 7-10 years	Moderate development requiring 4-7 years	Minor development requiring up to 4 years	No developments required
Appliance development timeframe (5%)	Nominally 200%+	Nominally 100-200%	Nominally 50-100%	Nominally up to 50%	Simple development process required

Assessment of Conversion Pathways for Type A and Type B Appliances

A summary of the multi-criteria assessment outcomes is provided in Table 27, using the mean average of the rating of each appliance against the ten criteria.

Table 27 shows that dual fuel and hybrid approaches offer similar value for converting package burners and simple boilers. For this reason, a technology-agnostic approach could be taken for customers using these or similar appliance types.

Conversely, a case-by-case assessment should be made for more bespoke Type B appliances and components in industrial applications. The conversion of these appliances should align with the pathway which offers best value to the customer based on their unique circumstances and would ideally be a customer-led approach.

Without a clear policy direction, the economics may only support such an upgrade if there is proximate pre-existing hydrogen supply. Some industrial customers may transition to CNG via virtual pipeline after network conversion rather than converting their plant to operate on 100% hydrogen, assuming the economics are favourable and this is the only remaining option.

Table 55: Assessment summary of conversion pathways for Type A and Type B appliances

Appliance Type/Category	Pathway 1: In-place conversion	Pathway 2: Dual fuel	Pathway 3: Hybrid	Pathway 4: Like-for-like
Type A Ovens and cooktops	2.8	3.0	3.8	3.2
Type A Storage water heaters	3.5	3.1	3.9	3.2
Type A Instant water heaters	2.7	3.0	3.8	3.2
Type A Ducted heaters	3.0	3.1	3.8	3.1
Type A Space heaters	2.8	3.0	3.8	3.1
Type B Cooking equipment	3.0	3.0	3.8	3.2
Type B Package burners	3.0	3.6	3.8	3.2
Type B Off-shelf boilers	3.0	3.6	3.8	3.5

Appendix D 100% Implementation

Chapter 7 of the *100% Hydrogen Distribution Networks Study – Victoria* proposes a strategy for converting Victoria's gas distribution networks and the appliances connected to it. Several sources were considered in preparing this strategy, including the international literature review in this Appendix Section.

D.1 Literature Review

There is a significant existing base of research that is foundational to assessing the transition to 100% hydrogen. A review of this literature was undertaken with key insights drawn from:

- case studies of historic infrastructure conversions;
- international feasibility studies and experiences of network blending and conversion;
- natural gas appliance conversion studies; and
- future network infrastructure plans.

Where relevant, the primary objective was to identify challenges experienced from each process and the lessons learned that could help to ensure a smooth transition to 100% hydrogen.

Themes

Common themes were found between many of the studies surveyed for this literature review. Themes are covered in Table 28, which also notes associated lessons that could help to ensure a smooth transition to 100% hydrogen.

Table 56: Common themes among reviewed literature

Theme	Lesson learned
Public acceptance	To be successful, major infrastructure transitions require public trust. This can be complex to earn and is influenced by many factors which include: • social, financial, and environmental impacts; • perception of fairness, integrity, and good governance; • trust in governments' capabilities and integrity; and • community participation levels throughout a project's lifecycle.
Public reactions change in different contexts	Different responses were experienced in different states, as well as in urban areas versus rural areas.
Policy mandating	Mandates as a policy mechanism may have limited efficacy. Mandating the sale of a fuel may increase its consumption but may not overcome natural limits imposed by supply and demand.
Unforeseen challenges	Despite significant preparations, there may still be unforeseen challenges that lead to cost and program overruns.
Difficulties of large-scale conversion programs compared to the past	Large-scale conversion projects are likely more challenging today than historic experiences, due to factors like: • lower trust in government and gas companies. • greater difficulty gaining access to households if fewer people are home on a full-time basis. However, lifestyle responses to the COVID-19 pandemic may make home access simpler than pre-pandemic. • Social media could broadcast and amplify safety incidents and installation problems.

Network Transition Case Studies

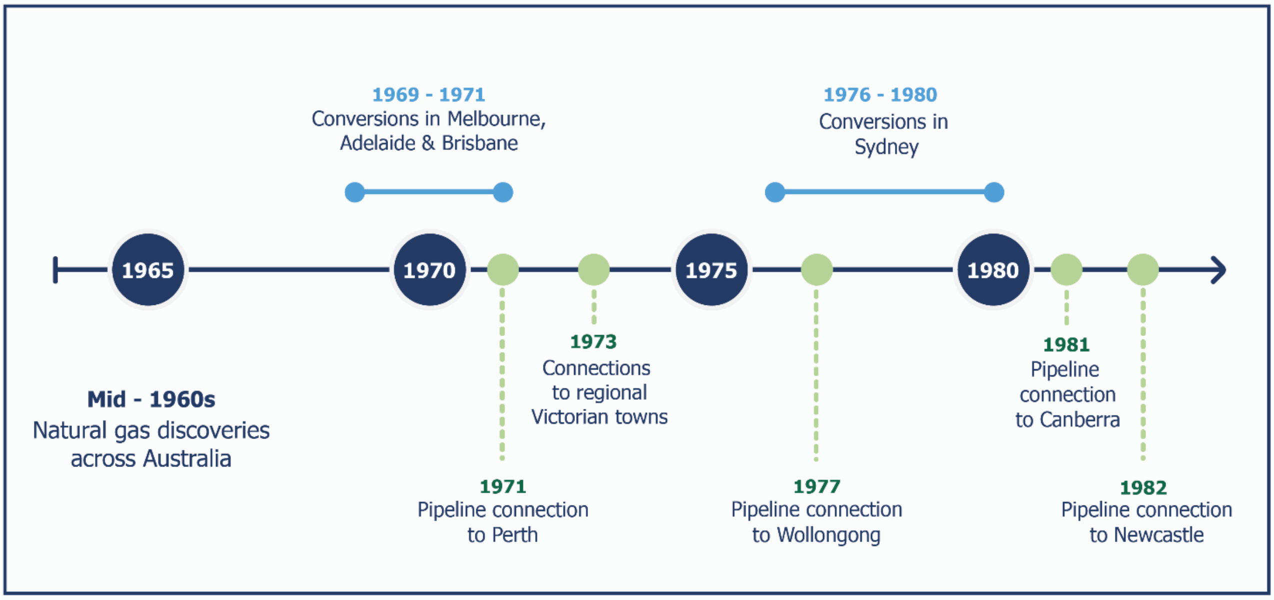
Case Study 1: Town gas to natural gas conversion

In the 1960s and 1970s, many Australian towns and cities transitioned from using town gas to natural gas. Consisting mostly of methane, natural gas was cleaner, cheaper, and more reliable than town gas, which consisted of hydrogen, methane, carbon monoxide, and other components.

Together with manufacturers, gas companies had developed conversion approaches, instructions, and parts requirements to allow appliance conversions. Gas company workers then visited each customer's house to modify their appliances to work with natural gas. Visits also took place before and after each conversion to survey the converted appliances, fix conversion faults, and help customers adjust to the new fuel.

This study drew on research by the Future Fuels CRC that studied the transition from town gas to natural gas around Australia. This work is valuable in that it identifies lessons that may be applicable to the conversion of gas distribution networks in Australia to 100% hydrogen gas, particularly relating to appliance conversion.

Figure 44: The key events in the transition from town gas to natural gas in Australia



The process of converting appliances was a significant logistical and technical undertaking and in Melbourne alone, 800 workers visited 435,000 homes to convert 1.25 million appliances. The process took 18 months and cost $350 million in today's term

Challenges encountered

- Few mechanics had much experience with conversions and targets were ambitious.
- There were hundreds of call-backs to fix faulty conversions, and some converted appliances did not behave as expected.
- One poorly converted room heater left two people in a coma due to carbon monoxide poisoning. Although carbon monoxide is not a risk with hydrogen supply, this case highlights the potential safety implications of challenges encountered in complex and comprehensive conversion programs.
- Conversion faced apprehension and disinterest from customers.
- A publicity campaign to keep customers informed cost $1.2 million in today's terms.
- Delays were experienced in pipeline construction.
- Ambivalence and cynicism from customers led AGL to rebrand in a successful marketing campaign coined 'the living flame'.

Lessons learned

- At the time of town gas conversion, gas companies were vertically integrated. The current market would require the co-operation of all industry stakeholders.
- Gas companies can work with manufacturers to develop conversion approaches, instructions, and parts requirements needed to allow appliance conversions.
- Logistical and technical challenges and construction delays should be planned for and mitigated.
- Gas fitters should be properly trained, and inspections should take place to check for possible faults. A clear conversion plan, conversion instructions, and relevant training would be required.
- As a viable alternative, customers may opt for electrification if apprehensive or disinterested.

Case Study 2: Introduction of ethanol and liquid petroleum gas as motor fuels

In 1999-2000, lax regulation and high petrol prices led to some fuel retailers selling blends with 20% ethanol. In response, the Queensland and New South Wales state governments enforced mandates for the sale of E10 fuel and customers switched to more expensive premium fuels to avoid ethanol. General rebates for LPG encouraged customer trust in the fuel, but gradual withdrawal of these rebates and increasing availability of alternative fuels meant LPG lost its market share as a transport fuel.

Challenges encountered

- Concerns about engine damage caused customer backlash, exacerbated by the slow response of governments.

Lessons learned

- Concern about changes to gas specifications like heating value, flame intensity, odour quality, or others may cause customer backlash.
- Delays to policymaking for hydrogen conversion as a preferred decarbonisation pathway are possible and may have consequences.
- Lack of government support could cause natural gas customers to electrify instead of converting to hydrogen.
- Social acceptance and license to operate is essential.

Case Study 3: Coal seam gas industry development

The coal seam gas (CSG) industry initially developed without issue in the 1990s and early 2000s.

Challenges encountered

- Stakeholders became concerned about water and environment contamination as CSG exploration sites got closer to prime agricultural and residential areas.
- Gas extraction companies lost their social license to operate. A moratorium on new petroleum licenses was subsequently implemented in New South Wales, and a stricter regulatory framework was implemented in Queensland.

Lessons learned

- Stakeholder may have concerns about environmental impacts of hydrogen blending. Environmental assessments and approvals, as well as extensive stakeholder engagement should be a requirement for implementing 10% state-wide blending.
- Social license can affect legal license, ie community opposition can lead directly to regulatory action.
- Securing social acceptance should be a requirement for implementing 10% state-wide blending.
- Industry should expect short-term opportunities to require long-term relationships with stakeholders.

Case Study 4: Digital television transition

Television broadcasts in Australia were primarily analogue until replacement by digital technology in 2013. Digital technology uses the broadcasting spectrum more efficiently and offers audiences improved image and audio quality and improved reception. Key phases of the transition were:

- Digital conversion legislation was introduced in 1998 which included a ban on the establishment of new commercial broadcasting licences until December 2008.
- Field trials were completed for the European DVB-T and the United States ATSC transmission systems. In 1998, the DVB-T system was selected to be adopted in Australia.
- Set top boxes were required to be purchased by the public. Very few people had purchased a set top box when digital telecasts began in the five major mainland capitals in January 2001.
- A free electronic program guide was released in 2001 which increased dramatically the numbers of households that had converted to digital.
- A media reform package was introduced in 2006 which contained legislative changes intended to provide additional digital services to consumers and help digital take up.

Challenges encountered

- The customer response to digital television was poor without detailed information and incentives, resulting in little drive to be aware, prepare, and make the switch before analogue television was disabled.
- In the US, customers were not prepared for the switchover and hundreds of thousands of calls were made requesting assistance with digital technology issues.
- Customers were disadvantaged when new services (eg high definition, multiplexed standard definition, pay-tv, data broadcasting) were phased-in too quickly.
- Phased switchovers hindered the introduction of new technologies, because initial technology choices determined the status of the remaining switchover.
- Gradual modification of digital television regulatory framework.

Lessons learned

- Where customers are responsible for elements of a transition, they need to be empowered with detailed information and incentives to initiate their role and can be ineffective otherwise.
- Communication with customers should focus on explaining why the transition is taking place, its implications and benefits, and what elements of the transition they are responsible for.
- A state-wide mandate to install hydrogen-ready appliances should be considered.
- A staged approach to transitioning enables application of lessons learned in subsequent stages. The knowledge benefits of this approach are improved if conversion begins in simpler networks (eg regional towns) with lessons learned then applied in converting complex networks and sections.

Case Study 5: Smart meters rollout in Victoria

Smart meters are innovative electricity meters that provide real-time information to retailers and customers about electricity consumption. As a result, remote metering and access to innovative tariffs can lower the overall cost of electricity[64].

Between 2009 and 2014, the Victorian Government implemented the Victorian Advanced Metering Program, mandating the replacement of conventional electricity meters with smart meters for residential and small business customers. New meters were installed for 98.6% of households and small businesses, with customers bearing the meter costs, averaging around $760 per customer. Outstanding installations were mostly due to issues with access to the property, and customers refusing to replace meters[65].

Challenges encountered

- The program faced criticism from the Victorian Auditor-General. Criticism focused on:
  - the program not measuring up to the promised benefits, especially in terms of reducing electricity bills through access to innovative tariffs.
  - lacking a comprehensive communications campaign that informed customers of the benefits of new smart meters.

Lessons learned

- Organisation and implementation of replacement activities can be achieved at virtually every gas connection in a relatively short timeframe. However, the high conversion rate in this case study was facilitated by the location of meters, external to properties. The requirement of indoor access (eg for gas appliance replacement) could complicate the hydrogen conversion process.
- Infrastructure conversions involving mandates and costs to customers can be implemented if customers can and do expect overall economic benefit.
- A public campaign to raise customer awareness about conversion benefits would be required, with targeted communications activities for different groups (especially vulnerable and non-English speaking customers). A regular review of consumer protection frameworks should also be implemented.

64 More information can be found here: <https://theconversation.com/smart-meters-dumb-policy-the-victorian-experience-47685>

65 More information can be found here: <https://www.audit.vic.gov.au/report/realising-benefits-smart-meters?section=>

International Experiences of 100% Hydrogen

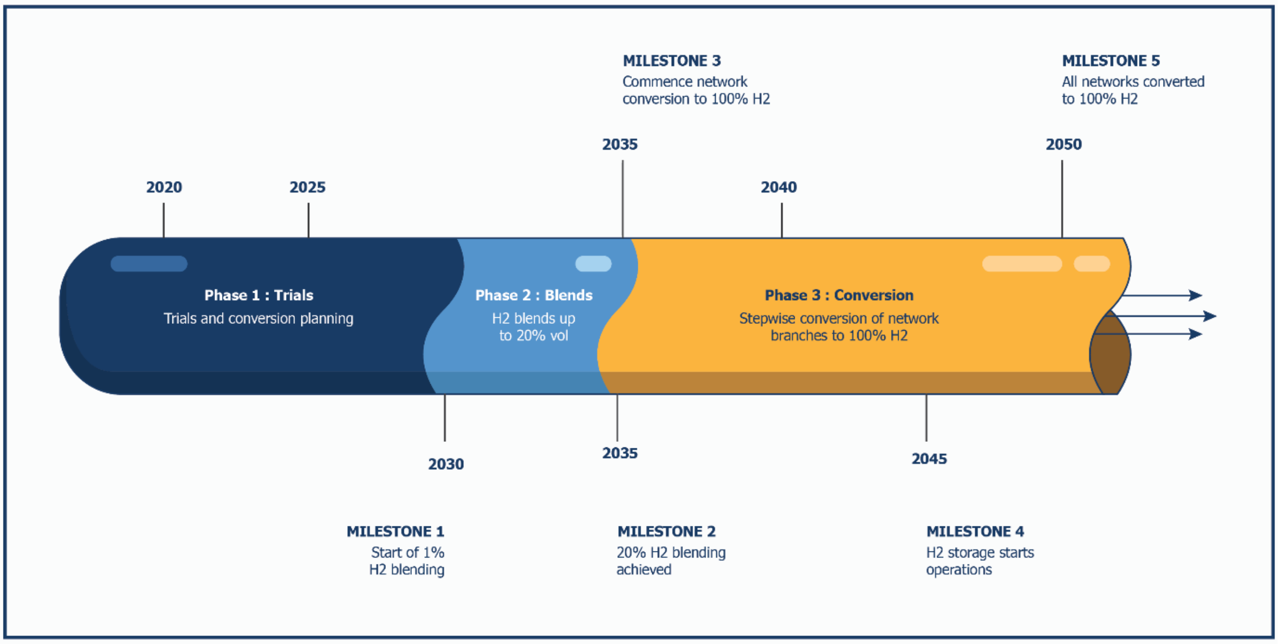
Firstgas Feasibility Study

In 2020, Firstgas commissioned a feasibility study of converting its natural gas distribution networks in New Zealand to 100% hydrogen[66]. The objectives of the study were to:

- confirm the feasibility of converting Firstgas pipelines to hydrogen.
- understand the likely challenges in the conversion process.
- lay out an indicative program of future works required to convert the gas infrastructure network.

The report identified key milestones for converting gas distribution networks in New Zealand to hydrogen, depicted in Figure 2.

Figure 45: Milestones for converting natural gas distribution networks in New Zealand to hydrogen



66 Full report can be found here: <https://firstgas.co.nz/wp-content/uploads/Firstgas-Group_Hydrogen-Feasibility-Study-Summary_A4_web.pdf>

Key insights

- It is feasible to convert New Zealand's gas distribution networks to 100% hydrogen. Using existing pipelines in the North Island is also feasible and could make a valuable contribution to carbon emissions reductions.
- Transporting hydrogen in the Firstgas distribution network rather than trucking it from source to use may increase its commercial viability.
- Some of the activities in the report's roadmap depend on the outcomes of international research programs or other prior activities. Trial work in New Zealand would also be required and on this basis, an initial scope has been developed for:
  - facilities required for off-grid testing of components; and
  - criteria for live demonstration network testing.
- The report recommends the following activities begin immediately:
  - Design of testing facilities.
  - Detailed cataloguing and assessment of the impacts of hydrogen on network materials used in New Zealand.
  - Investigation of the impact of hydrogen on consumer equipment connected to the network.
- Other areas that should be addressed as a priority include:
  - Reviews of regulatory regimes.
  - Development of commercial arrangements.
  - Building of public acceptance.
  - Ongoing monitoring of global research about disruptions caused by converting appliances and performing New Zealand-specific appliance trials.

Hy4Heat UK

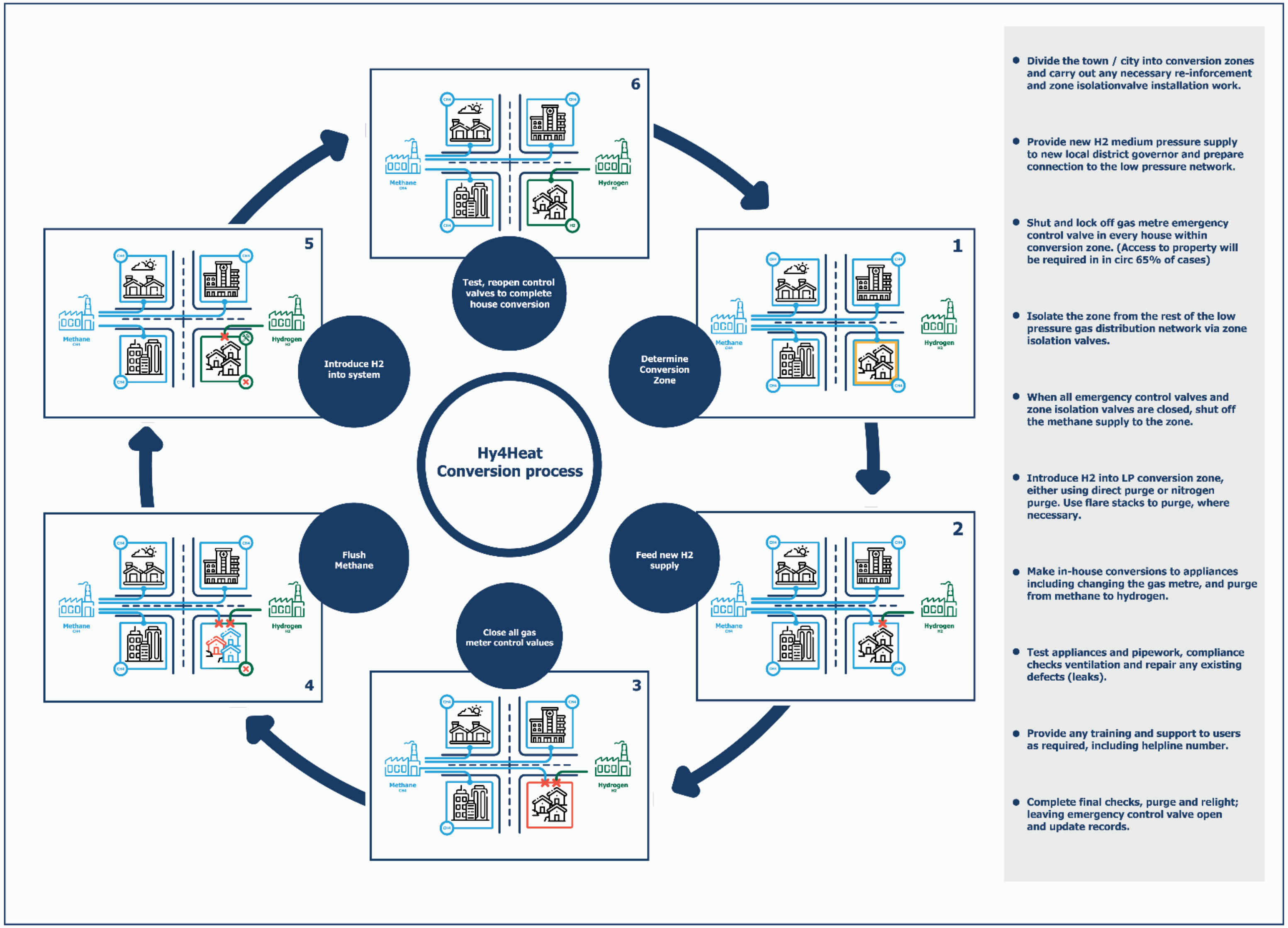
The 'Hydrogen for Heat' (Hy4Heat) program[67] aims to support the UK Government in its ambitions to decarbonise the UK energy sector in line with the targets of the Climate Change Act 2008, by attempting to evaluate and de-risk the natural gas to hydrogen network conversion option.

Key insights of Hy4Heat

- The Hy4Heat Programme includes a requirement for the scope, selection preparation and evaluation methodology to be developed. To do this, clarity is needed on the required outcomes from the community trials and the evidence that will need to be collected. It assumes hydrogen community trials are a key component of the evidence gathering, but that they are part of a broader, but not yet fully defined set of programmes.
- Consumer response to conversion
  - The trials will have tested the number of different rolls out options and engagement and communications approaches, resulting in a set of recommendations for future rollout and the ability to compare hydrogen as a route to decarbonisation with other alternatives. For example, this might include testing responses to both low key and high-profile communications strategies and compulsory move to hydrogen and offering a choice of either hydrogen or electrification.
- Consumer response to hydrogen appliances and hydrogen fuel
  - Evidence will have been gathered on first generation appliances (first round of hydrogen appliances installed in the field) and a set of requirements developed for future appliance enhancements.
  - Evidence will also have been gathered around any regional and socio-demographic differences.
  - There will also be a plan looking at how to use the trials to gain broad public acceptance.
- Training field staff
  - There will be an opportunity to test training and accreditation processes for field staff who are engaged both upstream and downstream of the meter, during conversion and on-going use. The trials should provide opportunity for the number of gas distribution networks to build capability, in preparation for a potential widespread conversion.
- Coordination of a conversion
  - Experience from trials can be used to assess the management and co-ordination requirements for a full-scale roll out. Information collected from trials could determine the training requirements of the workforce.

67 More information can be found here: <https://www.hy4heat.info/reports>

Figure 46: Hy4Heat conversion process schematic



In another report, UK Northern gas distribution networks, H21 Injection Point[68] assessed the feasibility of converting the gas distribution network of Leeds (UK) to 100% hydrogen. For context, Leeds has a population of around 440,000.

Key insights of the H21 project were

- This program has shown that a city's natural gas supply can be decarbonized using 100% hydrogen.
- Converting existing gas distribution networks to hydrogen is technically and economically feasible
- No gas capacity issues were detected as the pipelines are of sufficient size to deliver gas for each customer once converted to hydrogen
- Gas distribution network conversion process and metrics were as follows:
  - Network conversion in sections (eg 2500 homes).
  - Typical time without gas connection for a home between 1 to 5 days, depending on available workforce.
  - To define a conversion strategy, it is important to understand the zone of influence of the injection points/injection points - they dictate the areas to be converted.
  - Conversion needs to happen in order from high pressure to low pressure section.
  - New hydrogen pipelines from the production area are brought and connected (one at the time) to the Pressure Reduction Stations (PRS) of the existing natural gas distribution network. Additional dedicated hydrogen PRS might also be required.
  - To avoid the mixing of hydrogen with natural gas in an interconnected network, 'double block and bleed' valve systems would be used to isolate different network sections - both for the medium and low-pressure networks. These valves might be already existing or will need to be installed.
  - Temporary natural gas supply might be required in certain areas, using LNG or bottled gas.
  - The outlined conversion strategy to 100% hydrogen would happen over 3 years, only between April and September to avoid disrupting winter heating.
  - Reinforcement and isolation work for the gas distribution network can be the first step of the conversion while waiting for the scaling-up of the hydrogen supply chain.
  - The outline of the future work packages for the H21 projects also provides an idea of the future activities to achieve 100% network conversion[69].

68 More information can be found here: <https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Executive-Summary-Interactive-PDF-July-2016-V2.pdf>

69 More information can be found here: <https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Executive-Summary-Interactive-PDF-July-2016-V2.pdf>

Appendix E Economic Benefits

The AHC considered the broader economic benefits that would be achieved by 100% hydrogen in South Australia's gas distribution networks in addition to the feasibility assessment and cost build-up presented in the *100% Hydrogen Distribution Networks Study – Victoria* Report.

This analysis drew on different inputs and assumptions to the rest of the Report so that an economic impact assessment of whole-of-state benefits of state-wide blending could be made. These separate inputs and assumptions are detailed in this Appendix Section..

E.1 Key Assumptions to Economic Impact Assessment

A preliminary Economic Impact Assessment (EIA) was undertaken to better understand the economic implications of 100% hydrogen by 2050. This Section contains the key assumptions used to inform the EIA, which can be found in Chapter 9 of the Report.

The key assumptions and parameters of the economic impact assessment expected for the construction and operation of 100% hydrogen in Victoria by 2050 are outlined in Table 25..

Table 57: Key assumptions and parameters - 100% hydrogen by 2050

Assumption	Parameter
Construction	
Project Timeframes	Twenty-year construction period from 2030 to 2050.
Electricity Generation	70,000 GWh of renewable energy generation will be required tosupport the Project. Solar and wind energy is assumed.
	75%, or 17,500 MW, of new installed solar and wind capacitywill need to be developed specifically to support the Project. The remaining 25% of renewable energy will be sourced from existing facilities.
	Cost per installed MW of new renewable energy is estimatedat $1,179,500. This represents a 30% decrease in costs compared with 2030 ($1,685,000 per installed MW) due to technological advancements and improved efficiencies in the construction of utility scale renewable energy projects.
	By 2050, 60% of the construction of the new renewable energy infrastructure would flow to Victoria, 10% will flow interstate and30% will be associated with imports. This represents a lift in Victoria's investment share from 40% in 2030, due to an increased capacity and strengthened local supply chains developed over the 20-year period.
Electrolyser	Grid connection costs are $100 per kW for installed capacity. 15,000 MW of electrolyser capacity is required to support the state-wide conversion. Construction cost per MW of electrolyser capacity is estimatedat $900,000. $6,246,560 is the cost to construct a Seawater RO Desalination Plant to provide the required water (28,500ML per year) to the electrolysers. By 2050, it is assumed the domestic electrolyser manufacturing industry will have matured significantly over the 20-year period from 2030. It is further assumed that 60% of construction investment for electrolysers would flow to Victoria (up from 40% in 2030), 20% would flow interstate, and 20% would be associated with imports (down from 40% in 2030).
Short-term storage	350,000 tonnes of hydrogen will need to be stored.
	Cost per tonne of hydrogen storage is estimated at $10,000.
	100% of construction investment in storge facilities will flow toVictoria.
Distribution	A total of 1,400 km of new pipes will be constructed at anestimated cost of $6,000,000 per km.
	100% of the construction investment in pipelines will flow toVictoria.
Decommissioning	Costs to decommission the Victorian gas supply and networkis estimated at $750,000,000.
Operation	
Electricity Generation	Annual operational and maintenance cost per MW of renewable energy is estimated at $17,000.
Electrolyser	Annual operational and maintenance cost per MW is estimated at $54,000.
	28,500 ML per annum of additional water will be required for electrolysers.
	Water cost per tonne of hydrogen is estimated at $14.
Short-term storage	Fixed annual operational and maintenance cost per tonne of hydrogen stored is estimated at $0.0000156.
Distribution	Annual operational cost per km of pipelines is estimated at $2,375.
Conversion	Cost to convert the Victorian gas distribution network is estimated at $750,000,000.

Assumption	Parameter
	2,177,434 gas customers will need their household appliances to be made hydrogen gas compatible by 2050.
Appliance Conversion	4 hours of technician's labour is required to convert a household's appliances to hydrogen gas.
	$90 is the hourly rate of labour for a technician.

Note: financial parameters are expressed in constant 2021 AUD$.

Construction and Operational Analysis

Using the EIA's key assumptions and parameters which are outlined above, achieving the 100% hydrogen scenario for Victoria would cost an estimated $49.32 billion (2021 dollars).

This estimated cost would be spent over the projected twenty-year construction period from 2030 to 2050, which would equate to an approximate spend of $2.47 billion per annum.

Table 30 outlines the estimated construction costs, and the jurisdiction where this expenditure is expected to occur, with reference to the recommended infrastructure investments across each stage of the hydrogen supply chain.

Table 58: Estimated total construction costs - 100% hydrogen by 2050

Stage of hydrogen supply chain	**Construction costs** ($b)		
	Domestic		Imports
	Victoria	Rest of Australia	
Electricity generation	$14.13	$2.06	$6.19
Electrolyser	$8.11	$2.70	$2.70
Short-term (intra-day) storage	$3.50	-	-
Distribution	$8.40	-	-
Network conversion	$0.75	-	-
Appliance conversion	$0.78	-	-
Sub total	$35.67	$4.76	$8.89
Total		**$49.32**	

The EIA recommended that once construction was completed, ongoing operational and maintenance costs would be incurred. Table 31 outlines the estimated costs.

Table 59: Estimates operational and maintenance costs - 100% hydrogen by 2050

State of hydrogen supply chain	Operational costs ($m)
Electricity generation	$0.297
Electrolyser (including water supply)	$0.814
Short-term storage	$0.232
Distribution	$0.003
Total	**$1.347**

The operational and maintenance cost estimates were calculated utilising a range of current industry benchmarks. These estimates would be expected to change over time as a result of technology improvements and as further details of the operational parameters of the Project were developed.

The above economic benefits are significant in the context of the Victorian economy. Additional benefits are also expected to flow across the wider Australian economy but have not been reported in this EIA.