16 August 2021

Elissa McNamara
Project Director
Infrastructure Victoria
Level 33, 140 William Street, Melbourne 3000
via: engage.vic.gov.au

Dear Ms McNamara,

Scenario development options to decarbonise gas networks

Energy Networks Australia welcomes the opportunity to participate in the development of Infrastructure Victoria's scenarios to decarbonise gas network.

Energy Networks Australia is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

To date, the focus of decarbonisation has been on the electricity sector, but gas networks are on their own decarbonisation journey. Customers tell us that they are seeking a clean energy future and are engaged in achieving emission reductions from gas use. New renewable fuels, such as hydrogen and biomethane, have the potential to become mainstream and complementary energy solutions that will use existing energy infrastructure. Our gas networks are leading the development of renewable gas projects and blending renewable hydrogen in the Adelaide and Sydney gas distribution networks, with further projects under development for Victoria, Western Australia and Queensland.

Energy Networks Australia supports the use of scenarios to inform policy and infrastructure decisions in an uncertain future. We commissioned Frontier Economics to complete scenario analysis for decarbonising natural gas in Australia. We have also engaged with Future Fuels CRC in their macro-economic scenario analysis project, which is ongoing. However - as noted in the Intergenerational Report - scenarios are not predictions of the future, but rather tools to provide insights of potential pathways:

> *Long-term scenarios necessarily involve the exercise of judgement and simplifying technical assumptions. This underscores the importance of viewing the scenarios as one possible picture of the future based on expected structural pressures and existing policy settings. In other words, this report presents a world that could be, rather than will be. In doing so, it helps all members of society including businesses, households and governments to*

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prepare for future challenges, take advantage of future opportunities and decide to modify existing strategies.[1]

Our Key Points

1. **The potential to repurpose gas infrastructure.** The interim report states that there is limited opportunity to repurpose existing gas infrastructure in the long term. This statement fails to recognise the significant opportunities that gas infrastructure offers to decarbonise Victoria. Attached to our submission is a report from GPA Engineering which identifies the opportunities that have been overlooked in the Interim Report. This review could be used to guide any future development of the scenarios.
2. **Gas asset owners are managing the risk of using gas infrastructure to reach net zero emissions.** Asset owners recognise that precisely how individual assets will be used in reaching net zero is subject to uncertainty, but asset owners are best placed to understand and manage the risks in collaboration with our customers, the Victorian Government and the Australian Energy Regulator. We welcome the opportunity to work more closely with Infrastructure Victoria to develop scenarios to investigate the role of gas infrastructure.
3. **Gas networks are ready.** Upgrades of Victoria's gas distribution network will be completed by the mid to late 2020's to safely deliver renewable gas to residential, commercial and industrial customers. This upgraded network will be able to deliver energy to Victorian customers for many decades.
4. **Emissions reductions should not be assumed with electrification.** The majority of Victoria's electricity is supplied from brown coal, and this will continue for the next 15 to 20 years. Switching household appliances from gas to electricity before decarbonising electricity generation can results in increased emissions overall as the emission intensity of electricity generation is much higher.
5. **Scenarios should consider a full range of issues in each pathway.** The scenarios identify a range of issues for the renewable gas options. A full list of issues for the electrification pathway should also be included, covering items such as a planned decommissioning of the gas network and a planned upgrade and changeover to electrical appliances, and upgrades to those electricity distribution and transmission networks, as well as potential modifications to households.
6. **Governments have a key role to play.** Government can support achieving net-zero emissions by adopting genuine no-regret policy options that focus on addressing the key uncertainties for the different pathways. Supporting certification, renewable gas targets, renewable gas offtake agreements and working with technical regulators will accelerate the development of a market.

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[1] Adapted from the Australian Treasury's 2021 Intergenerational report https://treasury.gov.au/sites/default/files/2021-06/p2021_182464.pdf, page xvii.

The Interim Report describes four scenarios under consideration. In general, these scenarios represent a broad range of technology pathways to decarbonise gas networks. Energy Networks Australia has identified two issues with the description of the pathways.

1. The scenarios appear to only focus on replacing gas use. Achieving Victoria's emission targets requires actions in all sectors of the economy. From an energy perspective, this means coordinated actions in electricity generation and end use, the use of gaseous fuels for heat and industrial feedstock and the use of transport fuels. These have traditionally been treated separately with the only main point of interaction being the use of gas for power generation. The developments in the energy sector in recent decades are making these different energy sectors more interdependent. Increased rooftop PV on homes is changing the amount of traditional base load from coal electricity being generated throughout the day, although not impacting greatly on peak demand. Electric vehicles and household batteries are new demands for electricity that once again change consumption patterns. Natural gas' role to support the electricity grid, especially during those peak times, or those times with low variable renewables is also changing with increased focus on decarbonising that gas. One of the options to decarbonise gas is through the use of hydrogen, which when manufactured using renewable electricity will further integrate the electricity and gas sectors. Managing the transition of this energy system – considering the different energy vectors, their production processes and end uses – requires a systems approach to be adopted.
2. The scenarios appear to be based on a number of statements that are dismissive of the potential role of gas infrastructure, for example:

   > *Under all scenarios that we considered, the opportunity to repurpose existing natural gas infrastructure over the long term (beyond 2040) is limited. [pg 5]*

   Adopting statements like these into the scenarios will undermine the potential of the role of hydrogen as it creates additional burdens that will not need to be addressed. Similar burdens do not appear to be identified for the electrification scenario. The likely result will be scenarios that show a bias towards electrification. Natural gas infrastructure can be repurposed to carry other gases such as hydrogen as demonstrated by Gasunie in the Netherlands[2]. This will provide a lower cost pathway to transport hydrogen compared to dismissing the potential of this infrastructure, and further improve its competitiveness against electrification. We have attached an independent technical and commercial review by GPA Engineering of the Interim Report and these findings could be considered during further development of the scenarios.

[2] https://www.gasunie.nl/en/news/gasunie-hydrogen-pipeline-from-dow-to-yara-brought-into-operation

Governments should enable reaching emission reduction outcomes. The three technology pathways (electrification, hydrogen and biomethane) outlined in the paper will all play a role. Government can support these pathways by adopting genuine no-regret policy options that focus on addressing the key uncertainties for the different pathways.

The Victorian government has already committed $1.6 bn to accelerate Victoria's transition to clean energy. These commitments could be expanded to support the decarbonisation of gas via renewable gas. A positive example of this is the recently announced *Renewable Hydrogen Grants*[3] program.

No regret policies for each pathway include:

» For electrification:
  - continue to decarbonise electricity generation through supporting renewable electricity generation, battery storage and integration of EV's into the grid,
  - encouraging innovation by appliance manufacturers to reduce the capital cost of heat pump alternatives, which is a major hurdle to their take up,
  - support the development of renewable hydrogen to support decarbonisation of industrial processes.
» For renewable gases:
  - continue supporting demonstration projects,
  - encouraging market development via renewable gas targets, certification schemes and incentives,
  - enter into "reverse auctions" or "power purchase agreements" for renewable gas to encourage its take up in the market, similar to actions undertaken via the Victorian Renewable Energy Target and local council actions,
  - enable gas networks to offer renewable gas opportunities in new residential developments, which will fast-track the development of 100 per cent renewable gas and ensure gas costs remain affordable for all gas users, and
  - encourage technical regulators to work collaboratively with industry in developing safety cases for demonstration projects, similar to the process adopted by the Health and Safety Executive in the UK, which is an enabling regulator that works with industry to ensure renewable gas projects can be safely deployed.
» For biomethane:
  - Identify the resource potential of biomethane, either from local biomass resources, or from interstate resources that can be shipped to Victoria using existing transmission pipelines, and
  - Facilitate collaboration with gas networks, technology vendors, and resource providers to develop commercially viable biomethane projects.

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[3] https://www.energy.vic.gov.au/renewable-hydrogen/renewable-hydrogen#toc__id_0_renewable

- For hydrogen:
  - support blending projects to gain technical and regulatory experience, customer acceptance and a pathway to commercial opportunities for hydrogen,
  - support local appliance manufacturers to provide accredited hydrogen appliances, and
  - enabling opportunities for network businesses to deliver hydrogen to new residential developments.

There are a wide range of consultation processes regarding the future of gas in Victoria underway. We have attached responses to the consultation topics of the Interim Report and a copy of our recent submission into the Department of Energy, Water, Land and Planning's consultation round on the development of a Victorian Gas Roadmap. A copy of GPA Engineering's technical and commercial review of the Interim Report is also attached.

If you have any questions or would like a to discuss this further, please do not hesitate to contact our Head of Renewable Gas - Dr Dennis Van Puyvelde on dvanpuyvelde@energynetworks.com.au.

Yours sincerely,

Andrew Dillon

Chief Executive Officer

Attachment 1: Response to the Interim Report

Attachment 2: GPA Engineering's Technical Review of Infrastructure Victoria: Towards 2050: Gas Infrastructure in a zero emissions economy – Interim Report

Attachment 3: Energy Networks Australia's submission into the Department of Energy, Water, Land and Planning's consultation round on the development of a Victorian Gas Roadmap

Attachment 1: Responses to the Interim Report

Scenarios for a net zero emissions energy sector in 2050.

Table 1: Key features of decarbonisation pathways (focussed on residential customers)

<table>
<tr><th colspan="2" rowspan="2">FEATURE</th><th colspan="3">DECARBONISATION PATHWAY</th></tr>
<tr><th>Electrification</th><th>Biomethane</th><th>Hydrogen</th></tr>
<tr><td rowspan="2">Energy Costs</td><td>Now</td><td>Potential to increase electricity prices due to switching during peak generation</td><td>Early opportunities can achieve price parity with gas</td><td>Commercial applications in remote power</td></tr>
<tr><td>2050</td><td colspan="3">Retail costs are uncertain and a function of generation costs, infrastructure costs, retail margins and managing peak demand.

Repurposing gas infrastructure allows decarbonisation using hydrogen to be achieved at 41% cost compared to electrification</td></tr>
<tr><td rowspan="2">Appliance costs</td><td>Now</td><td rowspan="2">Technology already available and more expensive than gas appliances</td><td>Same as natural gas</td><td>Appliances under development</td></tr>
<tr><td>2050</td><td>Same as natural gas</td><td>Similar to natural gas appliances</td></tr>
<tr><td rowspan="2">Reliability & safety</td><td>Now</td><td>Removing gas infrastructure increases reliability risks during blackouts and renewable droughts</td><td colspan="2">Same as natural gas</td></tr>
<tr><td>2050</td><td>Higher renewable generation increases reliability risks during renewable drought</td><td colspan="2">Gas infrastructure can provide seasonal storage for heating and back up to electricity</td></tr>
<tr><td rowspan="2">Environmental outcomes</td><td>Now</td><td>More renewable generation required to ensure emission reductions</td><td>Improved utilisation of waste/ circular economy
Energy crops may be needed</td><td>Renewable hydrogen blends reduce emission from gas</td></tr>
<tr><td>2050</td><td colspan="3">Net zero emissions can be achieved in all pathways</td></tr>
<tr><td rowspan="2">Customer experience</td><td>Now</td><td rowspan="2">Amenity from gaseous fuel lost
Appliance changeover required
Space limitations</td><td>Same as natural gas</td><td>Same as natural gas up to 2030</td></tr>
<tr><td>2050</td><td>No appliance modifications required</td><td>Appliance changeover required for full hydrogen conversion</td></tr>
<tr><td rowspan="2">Resource availability</td><td>Now</td><td>Increased renewable generation and storage required</td><td>Local biomethane supply limited
Can access geological storage</td><td>Increased renewable generation required to support blends
Can access geological storage</td></tr>
<tr><td>2050</td><td>More than 40% new infrastructure required</td><td>Can be enhanced with energy crops or synthetic methane, which requires hydrogen</td><td>Addition of existing level of renewable generation required for 100% hydrogen
Increased renewable utilisation</td></tr>
</table>

The Interim Report describes four scenarios under consideration. In general, these scenarios represent a broad range of technology pathways to decarbonise gas networks and include electrification, hydrogen or biomethane to differing levels. Energy Networks Australia has identified two issues with the description of the pathways.

1. The scenarios appear to focus only on replacing gas use. Achieving Victoria's emission targets requires actions in all sectors of the economy. From an energy perspective, this means coordinated actions in electricity generation and end use, the use of gaseous fuels for heat and industrial feedstock and the use of transport fuels. These have traditionally been treated separately with the only main point of interaction being the use of gas for power generation. The developments in the energy sector in recent decades are making these different energy sectors more interdependent. Increased rooftop PV on homes is changing the amount of traditional base load from coal electricity being generated throughout the day, although not impacting greatly on peak demand. Electric vehicles and household batteries are new demands for electricity that once again change consumption patterns. Natural gas' role to support the electricity grid, especially during those peak times, or those times with low variable renewables is also changing with increased focus on decarbonising that gas. One of the options to decarbonise gas is through the use of hydrogen, which when manufactured using renewable electricity will further integrate the electricity and gas sectors. Managing the transition of this energy system – considering the different energy vectors, their production processes and end uses – requires a systems approach to be adopted.
2. The scenarios appear to be based on a number of statements that are dismissive of the potential role of gas infrastructure, for example:

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   Adopting statements like these into the scenarios will undermine the potential of the role of hydrogen as it creates additional burdens that will not need to be addressed. Similar burdens do not appear to be identified for the electrification scenario. The likely result will be scenarios that show a bias towards electrification. Natural gas infrastructure can be repurposed to carry other gases such as hydrogen as demonstrated by Gasunie in the Netherlands[4]. This will provide a lower cost pathway to transport hydrogen compared to dismissing the potential of this infrastructure, and further improve its competitiveness against electrification. We have attached an independent technical and commercial review by GPA Engineering of the Interim Report and these findings could be considered during further development of the scenarios.

[4] https://www.gasunie.nl/en/news/gasunie-hydrogen-pipeline-from-dow-to-yara-brought-into-operation

Energy Networks Australia provides the following insights into the detailed scenario descriptions. These are supported by the detailed technical and commercial review completed by GPA Engineering.

- Electricity Generation
  - Only 3 sources of renewable generation are included in the scenarios. In the 12 months to 8 August 2021, hydro provide 2,641 GWh to Victoria, equivalent to 9 PJ. The scenarios have significantly larger energy production from hydro, reaching 155 PJ in 2050 in Scenario A. This appears unrealistic and would require additional hydro generation capacity to be built. The use of Snowy 2.0 is as energy storage, which would still require renewable electricity to be generated.
  - It is unclear why both Scenarios C & D have the same level of renewable generation when the energy demand (Fig 8 of Interim Report) show quite a different energy mix.
- Gaseous Fuels. The energy estimates for the gaseous fuels used appear unrealistic.
  - For Scenario C, there is a high volume of biomethane produced (207 PJ). Indicative estimates for Australia's biomethane potential are 371 PJ and this includes agricultural and cropping waste. For Victoria to access the levels of biomethane for this scenario will require appropriate pipeline infrastructure to bring that gas into the state. Hence, the infrastructure requirements for those other states should also be considered.
  - Each of the scenarios have very differing levels of gaseous fuels. The high volume of hydrogen in Scenario D appears linked to exports, but it isn't clear whether this is an opportunity for exporting to other countries or other Australian states.
  - The description of needing to replace gas infrastructure in Scenario C is misleading. The scenario indicates that 253 PJ of green hydrogen is being produced in 2030. The electricity sector infrastructure implications do not appear to be identified in the initial results.
- Energy Storage
  - The details for energy storage do not readily recognise the fluctuating daily and seasonal load of gas.
  - Identifying options and technologies to reduce emissions from gas use requires a detailed understanding of the end-use of that gas. Gas is a seasonal fuel with winter demand roughly three times that of summer, primarily due to heating. Infrastructure to meet this demand has been built since the introduction of natural gas in the late 1960's. This includes large scale gas storage that is able to store massive volumes of gas throughout the year and then reinject that into the gas system during winter. Australia's geological gas storage potential exceeds 27,000 GWh – the equivalent of 77 Snowy Hydro

2.0 schemes. This infrastructure is already built and operating and can be repurposed with the introduction of renewable gas.

  - The daily consumption pattern of gas also needs to be better understood. For industrial customers who operate 24/7, the load pattern is fairly uniform as gas is used either as an industrial feedstock or as a fuel to provide high temperature heat to those processes.
  - For heating, especially the heating of homes, the time of use during winter focusses on the hours of 7 to 9 am in the morning and 5 to 9 pm in the evenings. During these times, gas consumption can be up to 3 times higher than during the middle of the day. When you combine that with the seasonal load, the peak demand during evenings in winter can be 9 times or more that demand in summer.
  - Electricity generation during winter follows a similar demand profile as the residential gas demand. The peak times for gas demand coincide with the peak electricity demand, which also coincides with lower variable renewable generation, as these peaks occur outside of solar PV generation periods. This is not surprising given that heating is used most heavily during cold winter evenings. This peak electricity demand is usually also met with natural gas power generation, further compounding on the peakiness of the gas demand and linking the two sectors.
  - The scenarios should reflect the delivery and demand of gas throughout the day and the year. This is essential to identify alternatives that can deliver those services without the emissions. The suitability of alternatives would need to be tested on whether they can adequately meet the diverse needs at different times of the day and different seasons of the year, and at what cost. Victoria's gas infrastructure currently delivers this energy reliably and safely to over 2 million homes, many businesses, and the electricity sector.
- Carbon Offsets
  - The role of carbon offsets is something that should be considered across the economy. Some sectors have fewer options to reduce their greenhouse gas emissions (e.g. aviation) compared to electricity of gas use. These other sectors could potentially soak up the limited opportunity for carbon offsets, meaning that this would not be an option available to electricity or gas.
- Transmission and Distribution
  - The supporting infrastructure of any scenario is critical to ensure reliable energy delivery at the lowest cost. As the gas and electricity systems become more integrated (e.g. through the use of electrolysis for hydrogen) the use of infrastructure becomes more important.
  - Scenario A. Investments in both transmission and distribution will be required. From a transmission side, the sources of generation will change from coal fired generation in the Latrobe Valley to a broader range of renewable energy zones as identified by AMEO (see below). Distribution electricity networks will need to be strengthened to meet the new peak from electrification of gas use. While Grattan estimates a 40 per cent increase would be required, this

may be conservative as it does not accurately address the daily and seasonal variations in gas use.

  - The importance of gas and electricity infrastructure should not be underestimated. Frontier Economics[5] modelling found that decarbonising gas in Victoria could be done at 41% of the cost using hydrogen compared to electrification. Very large investments would be required in electricity generation and storage for electrification compared to that required for green hydrogen.
  - The Interim Report assumes that existing gas infrastructure would need to be decommissioned and then new gas infrastructure built for hydrogen. This is demonstrably incorrect and significantly skews the modelling results. Most of the existing Victorian gas distribution networks are already upgraded to modern plastic materials that are able to safely transport hydrogen. GPA Engineering gas completed a technical and commercial review focussing on these infrastructure issues.

- Residential and commercial use
  - Electrical alternatives to natural gas are already commercially available. There are a range of government incentives to encourage households to switch from gas space heating to electrical heat pumps. These incentives generally address the higher up from cost of heat pumps compared to gas space heaters and are supported by claims of associated emissions reductions (see below). An electrification pathway will need to be planned and managed to ensure both adequate supply in new electricity generation and distribution and transmission infrastructure but also an adequate supply of appliances. The impacts on individual homes also needs to be better understood (eg electricity meter upgrades, fixing holes left by replacing ducted gas heaters with wall mounted heat pumps, space requirements for hot water heat pumps, etc). The heat provided from heat pumps is generally lower than that from gas heaters and this often results in associated upgrades to energy efficiency of homes. And at the same time, an appropriate strategy to decommission the gas network would also be needed. All of these cost uncertainties should be better understood.
  - A conversion to biomethane will not require any modifications to gas appliances as the gas provided is chemically similar to natural gas. The major uncertainty is around the availability of feedstock and subsequent cost of supply.
  - Hydrogen appliances have been built to provide the same services as gas appliances. These are currently at the prototype stage and not yet commercially available. The main differences between these appliances reflect the different burning characteristics of hydrogen compared to natural gas and these are accounted for by new or improved burner design, which is only one component of the gas appliances. Factories will need to be retooled

[5] Frontier Economics (2000), *The benefits of gas infrastructure to decarbonise Australia*

to produce hydrogen appliances and this will require an upfront investment from appliance manufacturers. Once produced at scale, the cost of hydrogen appliances is expected to be similar to current gas appliances. A strategy will be required to convert networks to hydrogen. The cost impact of switching to hydrogen appliances could be minimised by introducing dual fuel appliances which could be easily converted.

- Industrial Use
  - A significant amount of renewable gas will be needed to fill the demand for industrial feedstock and high temperatures in industrial processes. Frontier Economics found that hydrogen would still be needed in an electrification scenario as well as there are no electrical alternatives to chemical feedstock and limited opportunity for electrical appliances to deliver heat to industrial processes requiring temperatures over 1300°C. Hydrogen was produced in the electrification scenario using grid connected electricity, or distributed generation for remote mine sites (mainly in WA). Since the gas grid is decommissioned in Scenario A, this hydrogen needs to be locally produced.

Implications for gas infrastructure and gas users under the scenarios

Australia's gas industry associations have developed Gas Vision 2050[6], the industry's response to the Paris agreement on climate change. The vision outlines how transformational technologies will be deployed to reach net-zero emissions from using gaseous fuels in Australia.

The technologies include:

- Hydrogen,
- Biomethane,
- Renewable methane, and
- Carbon Capture and Storage (CCS).

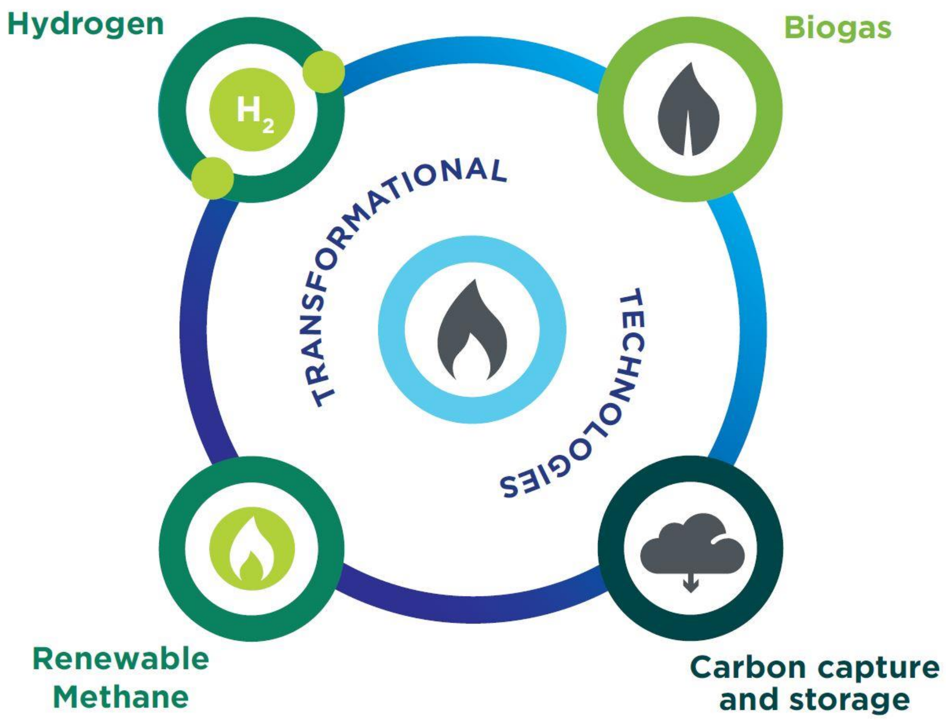

Figure 1: Transformational technologies *(Source: Gas Vision 2050)*

[6] https://www.energynetworks.com.au/projects/gas-vision-2050/

Key technical, regulatory and commercial challenges in converting existing gas networks to accommodate more sustainable gaseous fuels

We are preparing a national work plan[7] for decarbonising Australia's gas transmission pipelines and distribution networks, supporting national emissions reduction commitments and state and territory net zero targets.

This plan is designed to deliver the three objectives, that are needed to meet the overall net zero aim described in Gas Vision 2050:

1. Enable blending of up to 10% by volume of renewable and decarbonised gases by 2030.
2. Enable 100% renewable and decarbonised gas supply to new residential developments before 2030.
3. De-risk a full network conversion to 100% renewable and decarbonised gases by 2050.

Individual gas network and pipeline businesses may have targets that diverge from these objectives, including some which are more ambitious. A mix of renewable and decarbonised gases will be needed to deliver net zero, including, but not limited to, green hydrogen from renewable energy sources (e.g. electrolysis using renewable electricity), biomethane from sustainable sources, or renewable methane.

The plan identifies actions to be undertaken across the gas supply chain to support the roll out of renewable and decarbonised gases.

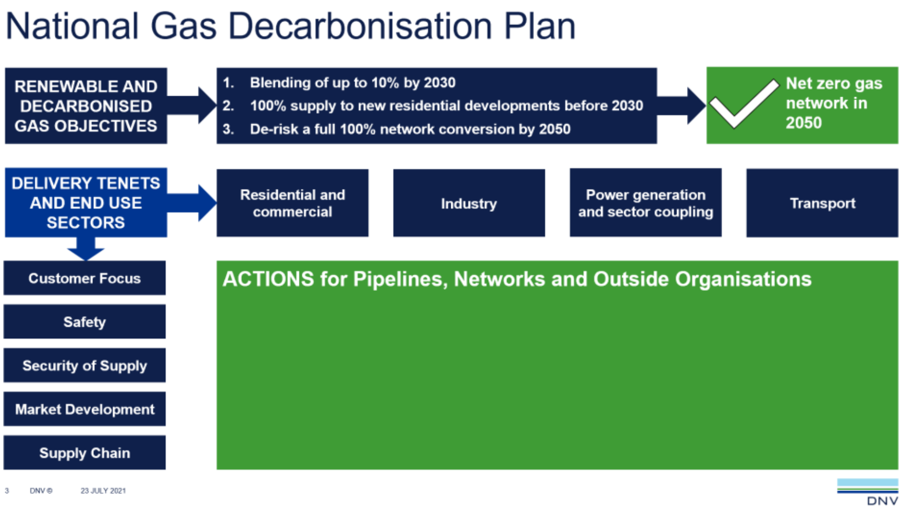

Figure 2: National gas decarbonisation plan (Source: DNV GL (2021), *National Gas Decarbonisation Plan*)

[7] National Gas Decarbonisation Plan developed by DNV GL for Energy Networks Australia and Australian Pipelines and Gas Association.

The plan describes the actions required from transmission pipelines and distribution networks in detail. These are mainly focused on meeting the customer focus, safety, security of supply and supply chain tenets. The report details the actions needed in the next five years, the second half of the 2020s, and the 2030s and 2040s.

Some of the actions refer to technical challenges for gas networks. These are being addressed through innovative demonstration projects[8] and industry-led research by Future Fuels CRC. Some of the actions to develop the market and hydrogen appliances require further collaboration with other sectors of the gas supply chain.

Cross cutting actions

The balance of renewable and decarbonised gases in each network is yet to be determined. Three cross-cutting actions are critical, whatever the precise green gas mix:

- Engagement: Comprehensive public, property developer and industry engagement to build support for the renewable and decarbonised gas transition and ensure that consumers and the supply chain are ready.
- Joint planning: With varying renewable electricity, biomethane feedstock, CCS availability and other factors in different regions, the mix of renewable and decarbonised hydrogen and methane in the transition will vary across networks. Joint planning, including with renewable and decarbonised gas producers and electricity networks, will help to ensure the most cost-effective and sustainable transition in each region.
- Business case: Ultimately, markets need to be developed for renewable and decarbonised gases, as they have been for renewable electricity generation. A joint business case should therefore be developed for both renewable and decarbonised methane and hydrogen, complementing the joint planning described above, to demonstrate to outside organisations how renewable and decarbonised methane and hydrogen can be developed and substantial emissions reductions achieved cost-effectively.

Technical challenges for renewable and decarbonised methane

Renewable and decarbonised methane is very similar to natural gas and can meet gas quality standards. Blending of renewable and decarbonised methane with natural gas at any level does not pose technical issues to the network assets or the consumer. To deliver renewable and decarbonised methane, key actions include:

- Securing the biomass supply chain. The feedstock needed for biomethane production is diverse and variable across the year. The quality of feedstock will depend on the process adopted to produce biomethane. Securing supply chains for appropriate biomass feedstock is one of the biggest technical challenges. An

[8] https://www.energynetworks.com.au/resources/reports/gas-vision-2050-hydrogen-innovation/

earlier study by Deloitte Access Economics indicated a total potential of 371 PJ of potential biomethane in Australia.

- Connecting a diverse range of biomethane producers to the network. Currently, Victoria's gas network has a handful of connections to pipelines to natural gas production sites and/or interstate connectors[9]. The introduction of smaller biomethane producers coming into the market will require a better understanding of how pipeline network flows can be maintained to ensure reliable supply of gas to customers. FFCRC has developed a model of the Victorian Transmission System, which has been used to test the gas blend across the network when injecting hydrogen in different nodes. A new research project is being prepared to model the impact of different biomethane injection points on gas supply across the gas network.
- Quality specification: Some biomethane feedstocks may result in additional constituent components compared to the natural gas specification. Further work is required to determine whether these components create any safety concerns.

Technical challenges for renewable and decarbonised hydrogen

The next five years are critical to the renewable and decarbonised hydrogen transition – this is when the 10 per cent blending trials and the preparatory work for 100 per cent trials in new property developments and conversion of existing networks to 100 per cent hydrogen needs to take place.

Hydrogen is a different gas compared to methane and has some differing properties that need to be considered. There are concerns about the potential of hydrogen embrittlement in steel pipelines, and its performance in appliances. Key actions include:

- Safety: Gas distribution networks. The use of hydrogen in gas distribution networks (which are mostly made of plastic materials) is considered safe and Victoria's gas distribution networks are already converting their old iron main pipelines with modern plastic alternatives. These programs have been ongoing for decades and expected to be completed in the 2020's as part of an ongoing operational and safety improvements.
- Safety: High pressure transmission pipelines. Australia's National Hydrogen Strategy outlines 57 strategic actions to support the development of Australia's hydrogen economy. Action 3.15 states:

> *Agree to not support the blending of hydrogen in existing gas transmission networks until such time as further evidence emerges that hydrogen embrittlement issues can be safety addressed. Options for setting and allowing for ongoing updates of safe limits for hydrogen blending in transmission networks will form part of the review in 2020.*

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[9] https://www.aemc.gov.au/energy-system/gas/gas-pipeline-register

This has resulted in claims that transmission pipelines are unsuitable to carry hydrogen, which is in fact not the case. Natural gas pipelines have been designed according to Australian Standards. Converting these pipelines to hydrogen would require a re-evaluation of the carrying capacity of that pipeline and would need to consider the potential of hydrogen embrittlement that may potentially reduce the operating pressure or the lifetime of the pipelines, Individual pipeline owners are best equipped to validate the role of their assets to supply renewable gases. Future Fuels CRC has a dedicated research program to better understand the impacts of hydrogen on gas transmission infrastructure. Carbon steel pipelines have been transporting hydrogen for many years in Europe and North America[10]. According to Future Furls CRC research, hydrogen pipelines can be safely designed and operated in Australia.

Similar issues of pipeline embrittlement are not a concern for biomethane once it has meets gas specifications.

- Appliances: Work to assess the performance of hydrogen blends and 100 per cent hydrogen with existing Type A and B[11] appliances is being carried out through Future Fuels CRC. Appliances have also been developed for different applications using 100 per cent hydrogen[12]. This has shown that hydrogen can be used as a safe and effective fuel for heating. The intention is that these appliances will be on display as part of COP26 to be held in Glasgow in November 2021.
- Security of supply: Hydrogen can be produced via a number of pathways. Producing green hydrogen, from renewable electricity, will require growth in renewable electricity generation. The integration opportunities and system wide benefits for hydrogen to link the electricity and gas infrastructure are one of the key advantages that increase the reliability of electricity while also meeting the seasonal energy load provided by gas.

Non-technical challenges

Moving to sustainable sources of gas also requires actions in regulation and market development.

Regulatory changes

Removing regulatory roadblocks formed through historic regulation which didn't consider renewable gases, and setting in place regulatory frameworks within which a renewable gas economy can develop, will be key to forming a foundation from which renewable hydrogen and biomethane industries can grow. Harmonisation of technical,

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[10] ENTSOG (2020), *How to transport and store hydrogen*
[11] Type A appliances refers to those used mainly in residential settings while Type B appliances are used in industrial settings.
[12] See https://www.hy4heat.info/.

environmental and economic regulation across the whole of Australia would streamline the transition. Key actions include:

- **Technical regulation:** Update gas quality regulations for renewable and decarbonised methane and hydrogen and agree billing methodology for blends. A hydrogen specification will be needed, and policy decisions will need to be made on new and converted 100 per cent hydrogen networks, including mandating hydrogen-ready appliances.
- **Environmental regulation:** Develop environmental management and land use regulations for renewable and decarbonised methane and hydrogen, including water supplies and bio feedstocks. National Greenhouse Energy Reporting Scheme (NGERS) and other relevant schemes should also recognise renewable and decarbonised gases in energy and emissions reporting frameworks.
- **Economic regulation:** Updates to the National Gas Law to allow it to cover renewable gases, and reporting regulations are needed, and reservation policies would ensure that domestic use is prioritised when supply is tight.

Market development

A renewable and decarbonised gas market will be key to enabling the development of green gas uptake through gas networks and pipelines, and key actions include:

- **Certification:** Green gas certification schemes are required to ensure customer with confidence that they are purchasing a green product.
- **Renewable gas target:** A starting point would be to implement a target for renewable and decarbonised gas, similar to the existing renewable energy target. This would help to underpin investment in renewable and decarbonised methane and hydrogen, and support the market creation activities below.
- **Market access:** Market access is needed to enable renewable and decarbonised gas demand to access supply through pipelines and networks, and includes the development of green gas standards and tradeable certificates.
- **Early asset financing:** Early market supply can be seeded through existing government financing frameworks, including Emission Reduction Fund, ARENA project funding and Clean Energy Finance Corporation (CEFC) equity and debt. Access to lower risk financing will be key to enabling first supply into potential renewable and decarbonised gas markets, after which market forces can take over.
- **Market incentives:** If the renewable and decarbonised gas market does not take off in line with emissions reduction targets, focus should turn to developing financial incentives for customers purchasing renewable and decarbonised gas, including tax or retail price incentives.

Potential costs and opportunities in switching to more sustainable gaseous fuels for consumers

Biomethane

Biogas is a form of bioenergy that can be used to decarbonise gas. It can utilise a range of feedstocks and different processes. The produced biogas needs to be upgraded to biomethane before it can be used as natural gas.

In 2018, bioenergy generated 3,412 GWh of Australia's electricity (or 1.5 per cent of the total[13]). This electricity was generated using a range of solid biomass and biogas from landfills or anaerobic digestors and was financially supported through *Renewable Energy Target* certificates. These plants generally use combined heating and power technology to provide local heating to industrial sites, and then to export the electricity to benefit from the renewable electricity incentives.

Bioenergy is also already widely used in transport where renewable biofuels are blended with either diesel or petroleum fuels. This fuel is generally sourced from specific energy crops and the programs are supported by state legislation mandating different proportions of biofuel in the fuel mix.

Biogas is a form of bioenergy that can be used to decarbonise Victoria's gas network. It can utilise a range of feedstocks and different processes. The produced biogas needs to be upgraded to bio-methane before it can be used as natural gas.

Bio-methane provides opportunities to decarbonise gas. The IEA Bioenergy Taskforce[14] noted that there were more than 14,000 biogas production projects in the world, with Germany clearly leading with about 10,000 projects. Most of these projects produce heat and electricity with more than 500 projects including an upgrade to biomethane so that the gas can be injected into the network (e.g. UK, France and Denmark), or for use as vehicle fuel (e.g. Sweden and Germany).

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[13] Clean Energy Council (2019), *Clean Energy Australia Report 2019*, pg 9
[14] IEA Bioenergy Task 37 (2019), *Country Report Summaries 2019*, pg 6

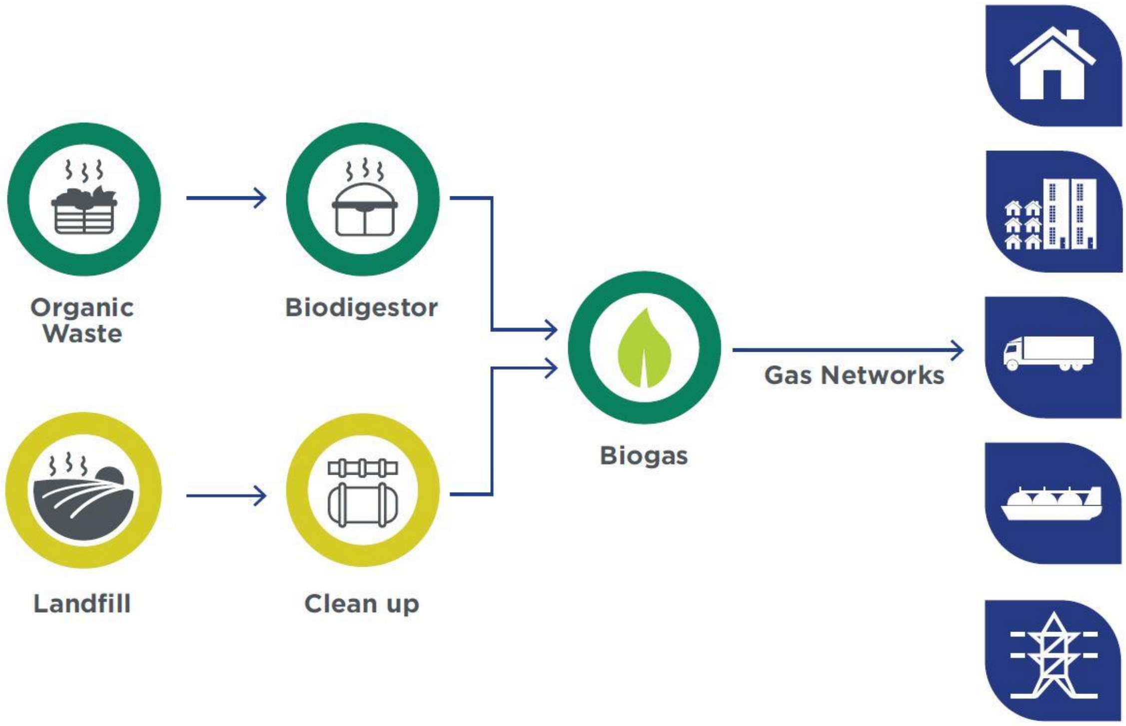

Figure 3: Biomethane production pathways *(Source: Gas Vision 2050)*

Deloitte Access Economics[15] estimated that bio-methane potential from urban waste, livestock residue (animal manure) and food processing residue could provide 14 per cent of the energy of gas supplied via Australia's distribution networks. This proportion increased to 102 per cent when agricultural crop residues were included. These proportions vary by state but the use of gas transmission pipelines can connect areas with higher biomethane production potential to those areas with higher gas demand.

When biogas is produced, it is generally a low-quality gas that can easily be converted to electricity using engines. Alternatively, the quality of the gas could be improved to meet network gas specification, allowing this biogas to be blended in networks as bio-methane. The cost of producing bio-methane is highly dependent on the feedstock and the process used, with the lowest cost option being the collection of gas from landfills. Cropping and livestock residue provides a significant opportunity to provide bio-methane but requires additional effort to collect the waste stream.

The production cost by itself does not necessarily drive the economics of a bio-methane facility as other costs and revenues also need to be considered such as:

- generation of green energy certificates, feed-in tariffs or other incentives;
- grants;
- cost of upgrading the gas to meet network specifications;

[15] Deloitte Access Economics (2017), *Decarbonising Australia's gas distribution networks*, pg 45

- avoidance of waste disposal fees; and
- sale of other products such as compost from the facility.

Biogas – after being upgraded to network quality – is a direct low carbon option for gas in networks. Existing gas infrastructure and industrial and household appliances can continue to be used as biogas is chemically similar as natural gas. It will also have a similar heating value so gas meters will still accurately measure gas consumption.

Combining this with carbon capture and storage at an industrial scale biogas facility would mean that the CO_2 emissions could be captured and stored underground. This process could provide a means for negative greenhouse gas emissions. Examples of this application are already happening at an ethanol facility[16] in the US, where up to one million tonnes of produced CO_2 from ethanol manufacturing is captured and stored in a dedicated geological storage site.

Industry is actively involved in the development of projects to blend bio-methane into networks[17]. Individual network businesses are working with landfill operators, wastewater operators, other members of the bioenergy sector and funding agencies. The Commonwealth Government recently announced that it is developing a *Bioenergy Roadmap* for Australia[18].

Achieving cost parity with natural gas.

Individual biomethane projects need to balance the quality and availability of feedstock with the potential gas demand.

Future Fuels CRC has developed an assessment framework for bio-methane injection in gas networks project (RP1.2-03), and completed the techno-economic viability assessment for different case studies.

A scenario analysis demonstrated that the LCOE can approach the price of natural gas in Australia, if biogas plants can offset their operation costs with the other product streams the injection of bio-methane (e.g. profits from the digestate, or the use of gate fees for feedstock delivery to the plant). In addition, renewable heat incentives (RHI) such as those from Denmark and the UK would lower the LCOE by $4-8/GJ if applied in Australia, suggesting that policy support for the development of the biogas industry in Australia would be a significant factor in making bio-methane injection projects viable.

[16] Global CCS Institute (2019), Bioenergy and Carbon Capture and Storage – a perspective by Chris Consoli, available from https://www.globalccsinstitute.com/
[17] https://jemena.com.au/about/innovation/malabar-biomethane-project
[18] https://arena.gov.au/knowledge-innovation/bioenergy-roadmap/

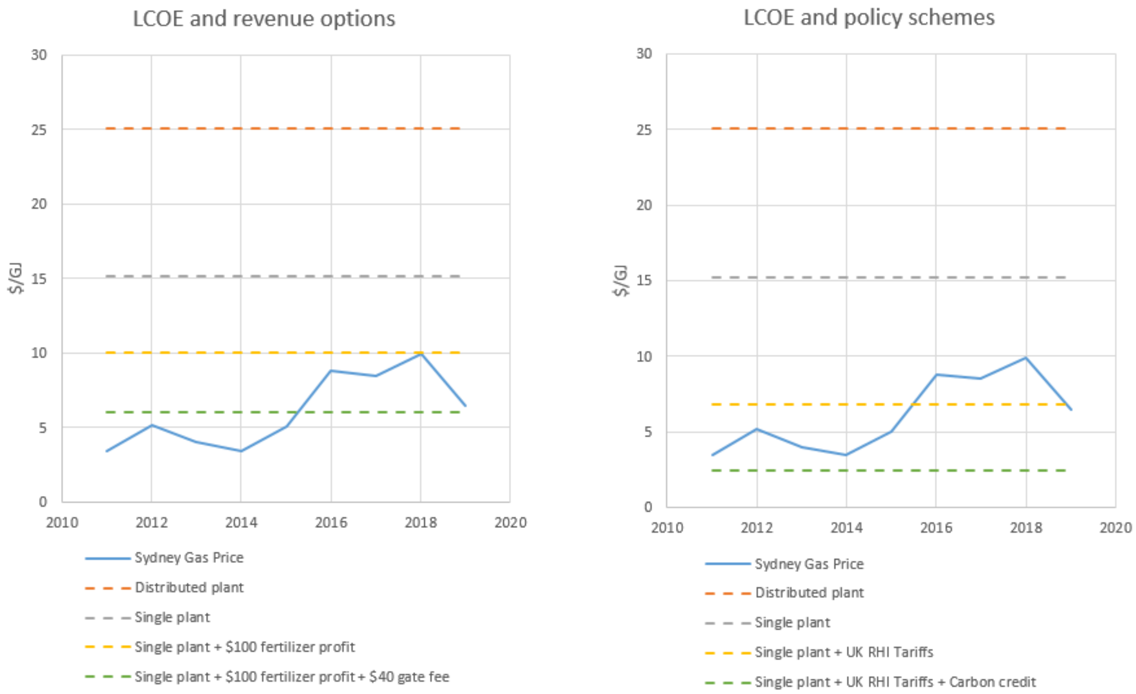

Figure 4: Reaching gas price parity using biomethane *(Source: Future Fuels CRC, RP1.2-03)*

The figure above illustrates that biomethane injection can be commercially competitive when other revenue options or supportive policy mechanisms are introduced.

Hydrogen

The combustion of hydrogen produces no greenhouse gas emissions. There have been waves of hydrogen development in recent history, mainly linked to the price of oil and concern about climate change[19]. However, it appears that the momentum in the current wave is larger and more applications for hydrogen are being considered.

Like natural gas, hydrogen is an odourless and colourless gas that burns in air to provide heat. This heat can be used in many applications like gas such as space heating. Hydrogen can also be reacted in a fuel-cell to produce both low-grade heat and electricity where the electricity can be used to power the grid or in vehicles. Hydrogen is also a feedstock that can be used by industry. Most gas that is used as feedstock today is converted to hydrogen (e.g. in oil refining or fertilizer production) so there are advantages to being able to use hydrogen directly. Some industries need a hydrocarbon feedstock to produce plastics and materials and these may require an alternative source of feedstock.

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[19] International Energy Agency (2019), *The Future of Hydrogen*

There are several ways hydrogen can be produced from either natural gas[20] or from electricity:

- Hydrogen can be produced from reacting natural gas with steam at high temperature and under pressure. This produces a mixture of steam, hydrogen and carbon dioxide, so the hydrogen needs to be separated from the other components before it can be used. This is already the world's most popular way to produce hydrogen. When the CO_2 is treated with CCS, the resulting hydrogen is called blue hydrogen.
- Hydrogen can be produced directly from applying an electric current to water. This splits the water into its elements of hydrogen and oxygen so once again, the hydrogen needs to be separated. When the electricity used for this process is renewable, the hydrogen that is produced is referred to as green hydrogen.
- There is also research underway[21] to produce hydrogen using photocatalytic reactions that may be more efficient than electrolysis.

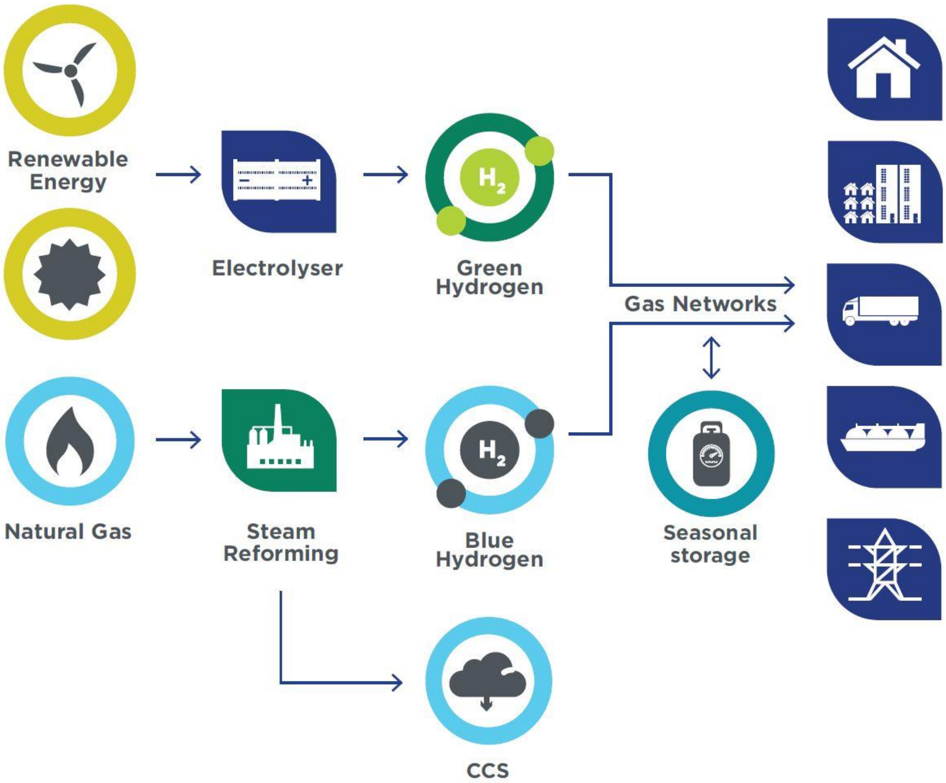


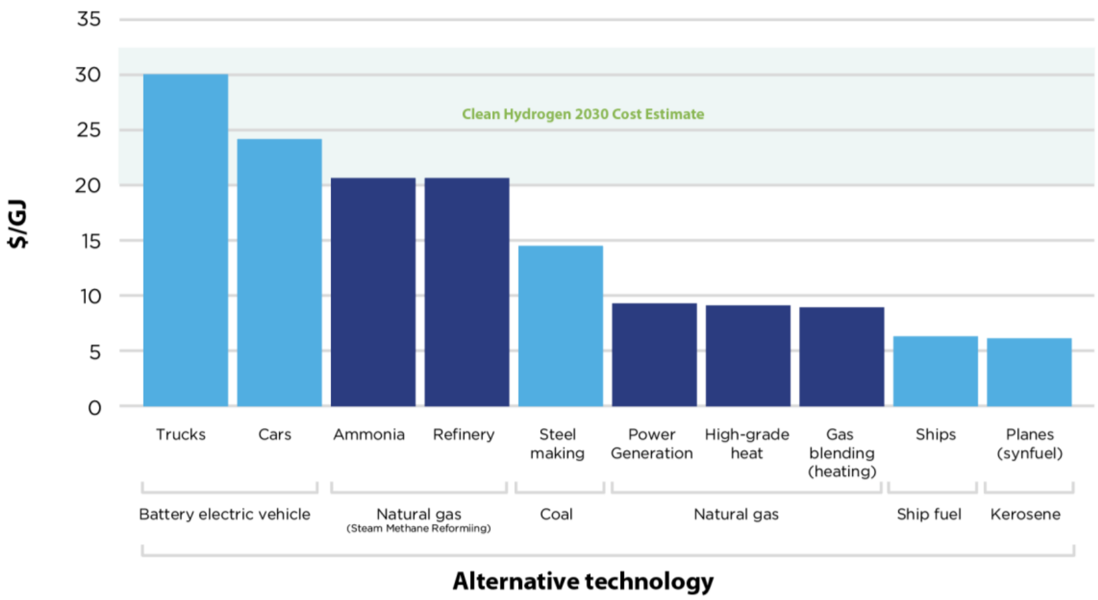
Figure 5: Hydrogen production pathways *(Source: Gas Vision 2050)*

There is a lot of momentum to develop a hydrogen industry in Australia. The Commonwealth Government produced a *National Hydrogen Strategy* in November 2019 and every state or territory has some sort of hydrogen strategy or interest. The

[20] Hydrogen can also be produced from other fossil fuels, but the majority of globally produced hydrogen is based on the natural gas pathway.
[21] https://www.futurefuelscrc.com/research/future-fuel-technologies-systems-and-markets/

focus is on capturing the possible export market while recognising the role hydrogen can also play to decarbonise the domestic economy by applying it to gas networks, for remote power, for mobility and as a feedstock to industry (e.g. green steel). In total, since 2018, nearly AUD1.5 billion[22] has been made available to hydrogen research, demonstration and development in Australia by governments and industry.

The Commonwealth Government[23] has set a target of achieving a production cost of hydrogen of $2 per/kg[24]. The *National Hydrogen Strategy*[25] illustrated that a range of options would become cost-competitive at this cost by 2030. While this figure indicates that further innovation and cost reductions will be needed to make hydrogen competitive with natural gas in networks beyond 2030, it is misleading in that it makes the comparison hydrogen with natural gas, instead of comparing it with a fully decarbonised energy source. A more appropriate comparison is between electrification using renewable energy and hydrogen (see analysis below).



<u>Figure 6: Cost competitive options for hydrogen at $2/kg (*Source: Australia's National Hydrogen Strategy*)</u>

[22] HyResource (2021), *A short report on hydrogen industry policy initiatives and the status of hydrogen projects in Australia*
[23] Department of Industry, Science, Energy and Resources (2020), *Technology Investment Roadmap Discussion Paper.*
[24] This equals $16.70/ GJ using the lower heating value of hydrogen, which is 120 MJ/ kg.
[25] Council of Australian Government – Energy Council (2019), Australia's *National Hydrogen Strategy*

The Hydrogen Council[26] showed that renewable hydrogen production costs can decrease by 60 per cent by 2030, driven by the reductions in capital costs for electrolysis plants and lower costs of renewable energy.

Hydrogen can achieve decarbonisation at 41 per cent the cost of electrification

Economic analysis completed as part of *Gas Vision 2050 – Delivering a Clean Energy Future* showed that decarbonising gas can be done at half the cost compared to direct electrification of the gas load. This reflects the opportunity to repurpose existing gas infrastructure because electrification may impose system-wide costs for grid reinforcement on customer bills. The modelling showed that whole system costs would be lower when gas infrastructure is utilised (instead of replaced with electrical equivalent) to decarbonise the energy sector.

For Victoria, decarbonising using green hydrogen was shown to only cost 41 per cent compared to the scenario where the end use of gas was electrified. This is the lowest for any region in Australia and reflects the high level of gas used in Victoria.

The cost stack (Figure 7) illustrates that very large investments would be required in electricity generation and storage for electrification compared to that required for green hydrogen.

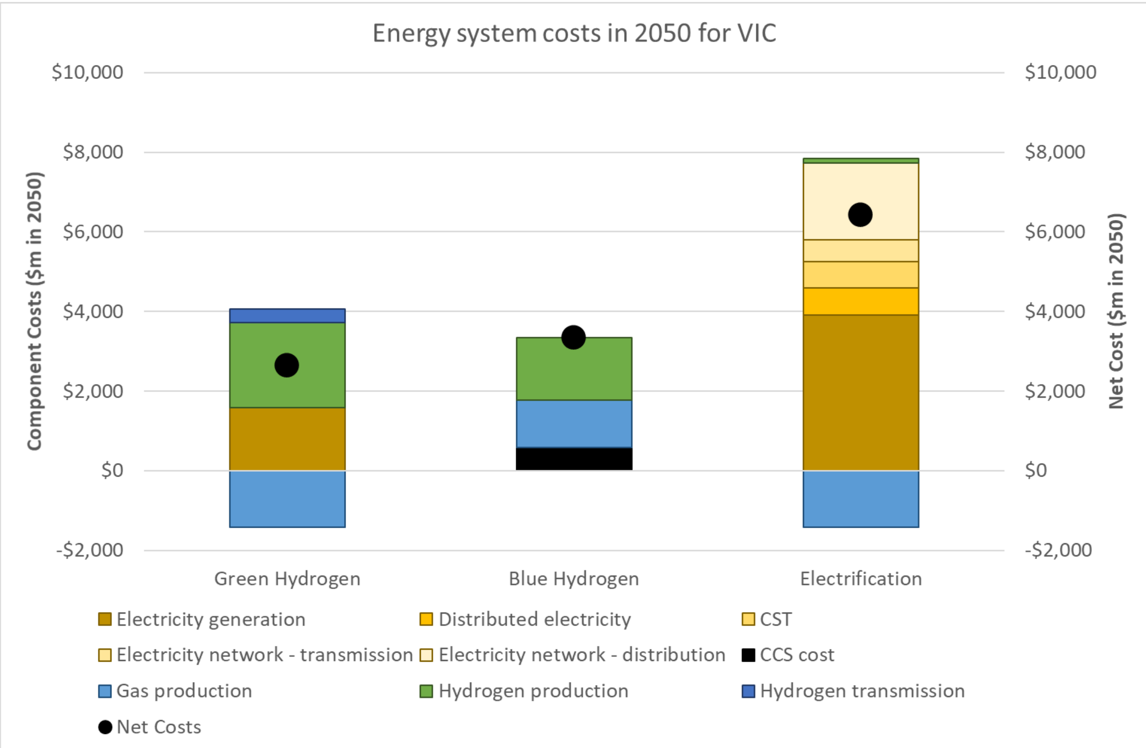


Figure 7: Costs of decarbonisation scenarios for Victoria (*Source: Gas Vision 2050: Delivering a Clean Energy Future*)

[26] Hydrogen Council (2020), *Path to hydrogen competitiveness – a cost perspective*

This demonstrates the benefits and opportunities of utilising gas infrastructure to decarbonise and help Victoria reach its 2050 zero emission target. The analysis is consistent with many other international studies assessing the benefits of gas infrastructure to decarbonise the economy, concluding that decarbonising gas networks can be lower cost and less disruptive than electrification.

The hydrogen opportunity

Hydrogen provides an opportunity to decarbonise gas networks. Gas infrastructure businesses are actively leading hydrogen blending demonstration projects across Australia. These projects will:

- produce renewable hydrogen;
- demonstrate blending of hydrogen into gas distribution networks;
- trial hydrogen-blend appliances;
- engage with local communities on the role of hydrogen;
- evaluate the role of hydrogen as support to the electricity networks;
- demonstrate the role of hydrogen blends in industry; and
- demonstrate the use of hydrogen as a transport fuel.

The Australian Hydrogen Centre was established in early 2020 to develop feasibility studies on 10% renewable hydrogen in the gas distribution networks of South Australia and Victoria and develop a pathway to make the transition to 100 per cent hydrogen networks.

The *National Hydrogen Strategy*'s 10 per cent kick start project[27] identified no significant regulatory and technical barriers for blending up to 10 per cent hydrogen in gas distribution networks. For residential and commercial consumption, this represents more than 4 PJ of hydrogen, requiring more than 500 MW of electrolyser capacity supported by renewable electricity from the grid.

Blending hydrogen in gas distribution networks provides the following benefits that support a broader hydrogen economy:

- It is the lowest cost option to create and use hydrogen. At blends of 10 per cent or less, no modification will be required to end use appliances and no expensive infrastructure (e.g. for refuelling) is required.
- Leads to cost reductions for hydrogen electrolyser plants from local experience in producing these plants and better understanding the balance of plant costs.
- Improves utilisation of variable renewable generation.
- Creates take-off opportunities to provide renewable hydrogen as an industrial feedstock or to support demonstration of fuel cell vehicles.
- Increases consumer and regulatory engagement by demonstrating opportunities provided by hydrogen.

[27] COAG Energy Council (2019), *Hydrogen in the gas distribution networks – a report by FFCRC, GPA Engineering and the SA Government*

- Hydrogen will be required as an industrial feedstock in any decarbonisation scenarios, including a policy driven electrification one. Demonstrating and reducing cost of hydrogen production is no regrets.

Role of government

Governments should enable reaching emission reduction outcomes. The three pathways outlined in the paper will all play a role.

Government can support these pathways by adopting genuine no-regret policy options that focus on addressing the key uncertainties for the different pathways.

As noted in the consultation paper, the Victorian government has already committed $1.6 bn to accelerate Victoria's transition to clean energy. These commitments could be expanded to support the decarbonisation of gas via renewable gas. A positive example of this is the recently announced *Renewable Hydrogen Grants*[28] program.

No regret policies for each pathway include:

- For electrification:
  - continue to decarbonise electricity generation through supporting renewable electricity generation, battery storage and integration of EV's into the grid,
  - encouraging innovation by appliance manufacturers to reduce the capital cost of heat pump alternatives, which is a major hurdle to their take up,
  - support the development of renewable hydrogen to support decarbonisation of industrial processes.
- For renewable gases:
  - continue supporting demonstration projects,
  - encouraging market development via renewable gas targets, certification schemes and incentives,
  - enter into "reverse auctions" or "power purchase agreements" for renewable gas to encourage its take up in the market, similar to actions undertaken via the Victorian Renewable Energy Target and local council actions,
  - enable gas networks to offer renewable gas opportunities in new residential developments, which will fast-track the development of 100% renewable gas and ensure gas costs remain affordable for all gas users, and
  - encourage technical regulators to work collaboratively with industry in developing safety cases for demonstration projects, similar to the process adopted by the Health and Safety Executive in the UK, which is an enabling regulator that works with industry to ensure renewable gas projects can be safely deployed.
- For biomethane:
  - Identify the resource potential of biomethane, either from local biomass resources, or from interstate resources that can be shipped to Victoria using existing transmission pipelines, and

[28] https://www.energy.vic.gov.au/renewable-hydrogen/renewable-hydrogen#toc__id_0_renewable

  - Facilitate collaboration with gas networks, technology vendors, and resource providers to develop commercially viable biomethane projects.
- For hydrogen:
  - support blending projects to gain technical and regulatory experience, customer acceptance and a pathway to commercial opportunities for hydrogen,
  - support local appliance manufacturers to provide accredited hydrogen appliances, and
  - enabling opportunities for network businesses to deliver hydrogen to new residential developments.

Gas distribution and transmission networks in Victoria are regulated by the Australian Energy Regulator, who sets their required revenues. The AER makes decisions with reference to factors including:

- projected demand for electricity and natural gas;
- age of infrastructure;
- operating and financial costs; and
- network reliability and safety standards.

Decisions generally apply for five years, and network businesses adjust their prices annually during the five year period. The projected demand, customer numbers and costs are highly interlinked. A key feature is the greater efficiency of network expansions reducing the costs per customer as new customers connect to the network. Hence introducing policies to restrict gas network growth are not no-regrets, but rather counterproductive as they will result in higher gas bills for other customers.

Supporting the development of renewable electricity is a no-regret policy option to support renewable hydrogen production, which will be needed in any of the pathways considered.

The development of a sustainable gas roadmap for Victoria is an excellent opportunity to adopt a systems approach to the energy market to achieve the best outcomes for customers by ensuring energy reliability at the lowest cost and achieving net-zero emissions from energy supply and use.

Key uncertainties, trigger points and interdependencies

The energy sector is undergoing major changes driven both by changes to electricity generation technologies and increased emphasis on reducing greenhouse gas emissions. At the centre of this transformation is to deliver energy services to customers that balance affordability, reliability and environmental outcomes. This is the energy trilemma. Adopting a systems approach to include the role of electricity, gaseous fuels and transport fuels is necessary to avoid undesired outcomes across the energy sector.

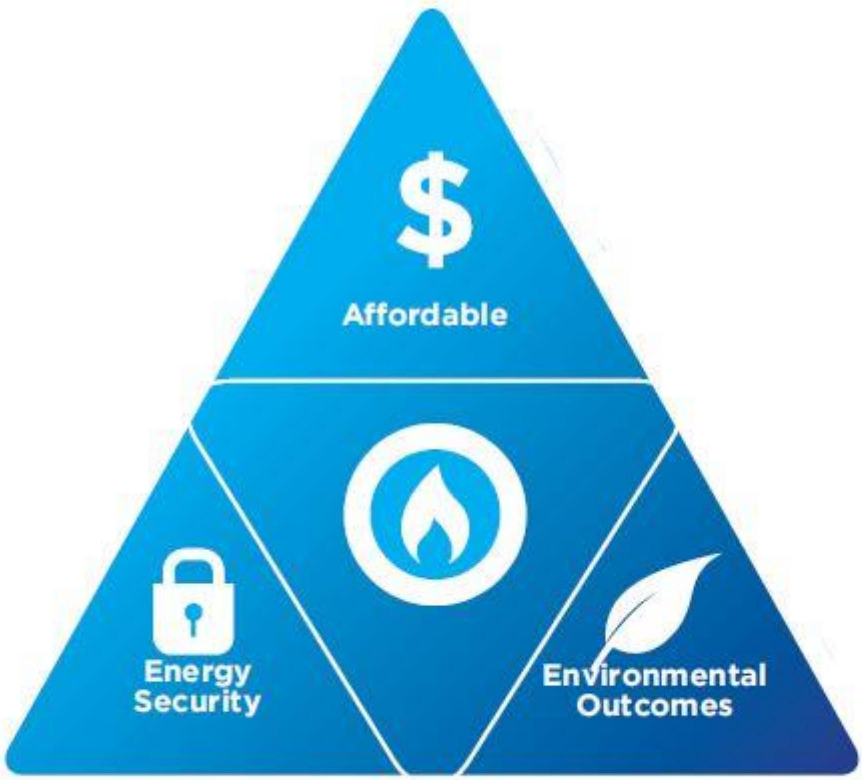


Figure 8: The energy trilemma – balancing affordability, reliability and environmental outcomes *(Source: Gas Vision 2050)*

The role of gas in Victoria

Natural gas is an essential fuel in Victoria and its main role is to provide heating to over 2 million households – that is 76 per cent of all homes in Victoria. It is also an important material as a feedstock to industry and to provide high temperature to those processes. The amount of gas used for power generation in Victoria only represents a small amount of the total gas consumption, but it is a key role to meet electricity peak demand and to increase the integration of variable renewable generation. Maintaining a reliable gas supply will ensure these diverse energy needs can continue to be supplied.

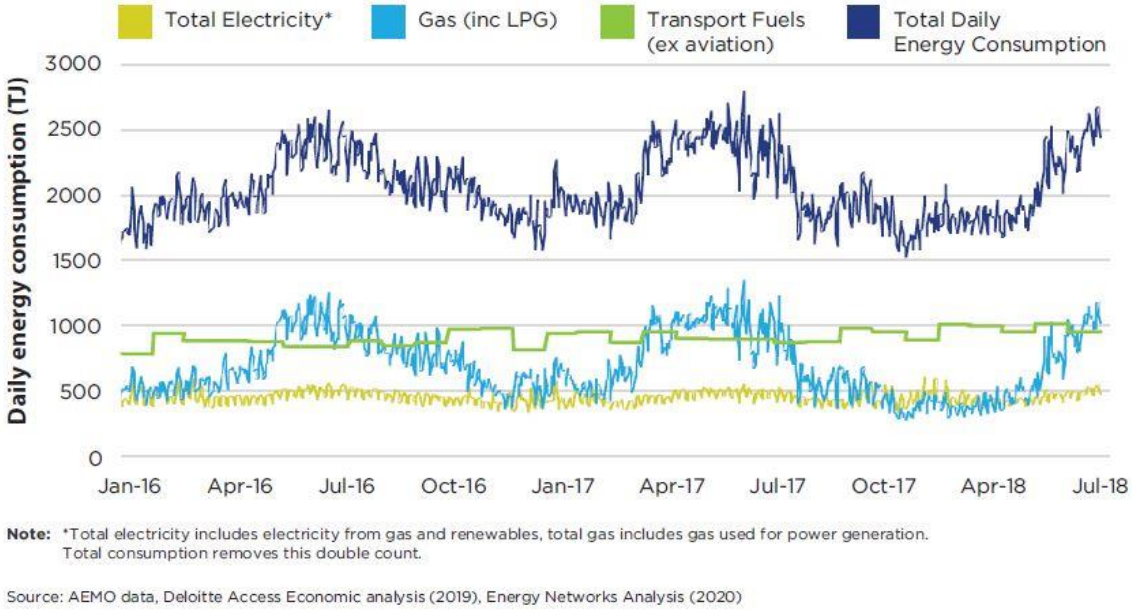


Figure 9: Energy consumption in Victoria (*Source: Gas Vision 2050*)

Natural gas is delivered to homes in Victoria at 30 per cent the cost of electricity and with only 19 per cent of the emissions compared to the average Victorian electricity emission intensity. The final cost of consumer energy bills depends on the cost of energy delivered, but also several other factors such as the types of appliances, their efficiency, how they are used, the number of residents in the home, whether time of use energy tariffs are applied, energy retailer costs and the overall energy efficiency of the home. As indicated above, decarbonisation of Victoria's gas network using hydrogen can be achieved at 41 per cent of an electrification alternative.

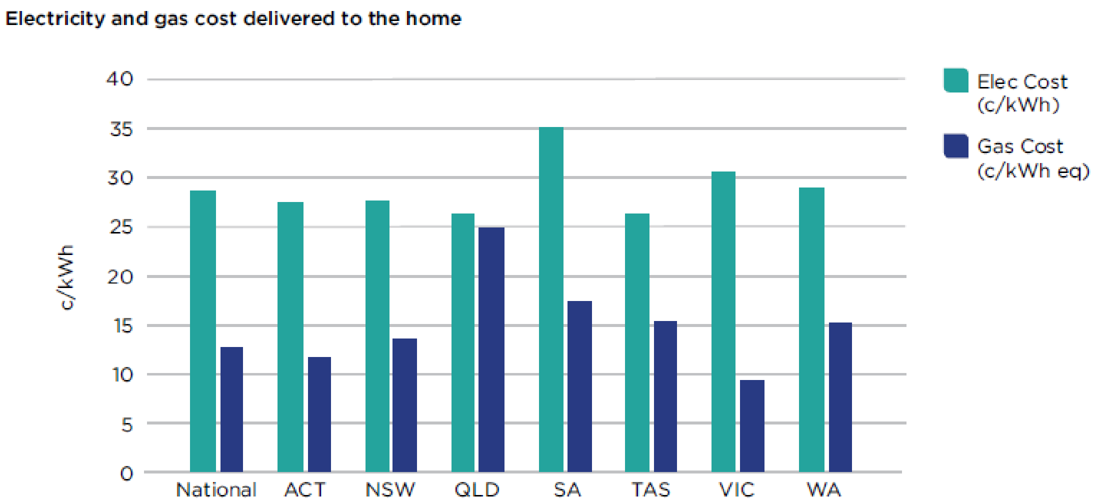


Figure 10: Cost of delivered energy to the home (*Source: Reliable and clean gas for Australian homes, 2021*)

Gas distribution network businesses are currently leading the demonstration of renewable gases, including hydrogen and biomethane. The initial projects[29] are based in metropolitan areas, relatively small scale and directly connected to the gas distribution networks. These projects are demonstrating renewable gas technology, engaging customer and working with regulators.

As larger volumes of renewable gases are produced, the roles of transmission pipelines will become important to move large volumes of renewable gas, access gas storage facilities and provide in-line storage, known as line pack.

The role of high pressure pipelines and high voltage electricity lines

Natural gas pipelines delivered 1,555 PJ of primary energy in 2017/18 with 39 per cent of this used for power generation and the remaining 943 PJ as direct end-use[30]. Australia's high voltage electricity transmission provides 835 PJ of electricity. The current relationship between gas and electricity infrastructure is limited to providing natural gas for power generation.

As Australia moves towards renewable gases, especially hydrogen, the relationship between the gas and electricity sectors becomes more complicated. Renewable hydrogen needs electricity to be produced via electrolysis. This electrolysis can either be powered via grid electricity or via dedicated renewable electricity generation. If grid connected, the electrolysis plant can be switched on and off (within reason) to help manage the electricity demand on the grid. If the electrolyser is linked to a dedicated renewable electricity site, the produced hydrogen will be transported to the end used via pipelines.

In either case, the delivery means – via high voltage transmission lines or high-pressure transmission pipelines – needs to be considered on its own merits. While it is readily accepted that natural gas pipelines are able to transport more energy at a lower capital and operating cost compared to high voltage transmission lines, this needs to be tested for hydrogen, where water also may need to be transported. The role of storage within pipelines will be important.

The cost differential between grid supplied electricity and that from a direct connection, as well as the utilisation of the electrolyser will also impact on the decision on the best way to deliver that energy from its source to the demand centre.

Suitability of pipeline locations

Existing gas transmission pipelines connect natural gas basins to customers. It is likely that the source of renewable gases does not coincide with existing natural gas basins. For example, most of Victoria's natural gas comes from the offshore Gippsland basin in offshore Eastern Victoria. On the other hand, the renewable energy zones, which

[29] For example, Australian Gas Networks Hydrogen Park SA project in Adelaide, or Jemena's Western Sydney Green Gas Project.
[30] Gas Vision 2050

are likely contenders for hydrogen production are located in the north west of the state.

The National Gas Infrastructure Plan could identify the potential of pipeline suitability to deliver renewable gases from the identified Renewable Energy Zones (see figure 18).

Access to geological storage

Geological gas storage is an important part of Australia's gas infrastructure providing reliability of gas supply, and in turn meeting the seasonal demand for gas and also supporting the reliability of electricity generation. Geological storage of energy is recognised as one of the lowest cost options to store very large amounts of energy over a long period of time.

Using renewable gas will allow geological storage opportunities to be utilised. A Future Fuels CRC research project[31] has completed an analysis of potential geological storage opportunities in Australia and found that a around 600 PJ of storage capacity would be required to support both the domestic and export markets. The initial scan found a prospective capacity of 38,000 PJ of storage with good storage potential sites in Victoria's depleted oil and gas fields and aquifers. Further research is being scoped to more clearly identify commercial hydrogen storage opportunities and to address some of the identified technical challenges.

Being able to access geological storage for hydrogen will ensure that the current reliability of gas infrastructure is maintained at the lowest cost.

[31] FFCRC RP1.1-04: Underground storage of hydrogen – final report under preparation.

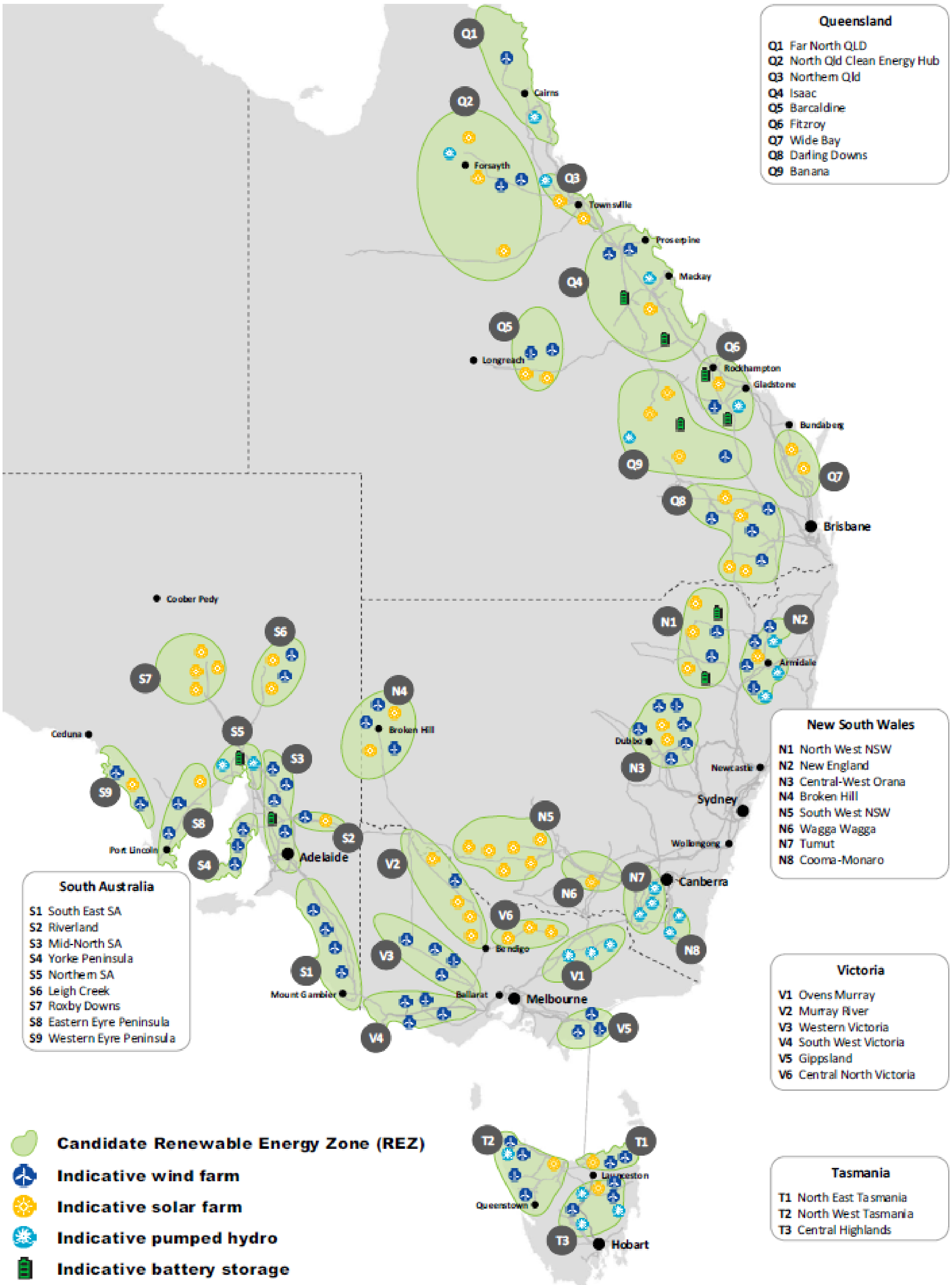


Figure 11: Proposed Renewable Energy Zones in Australia (Source: AEMO (2021), *Draft 2021 Inputs, Assumptions and Scenarios Report*)

Conversion Cost

Any decarbonisation pathway will incur a range of costs to convert the current energy system to a modern energy system without emissions. It will take time to reach net zero emissions from the energy sector. For example, the electricity sector has been incentivised since the early 2000's to increase the level of renewable electricity. The total national level of renewable electricity is presently around 25 per cent and at times, part of the NEM have been able to meet local demand with 100 per cent renewable generation. It has taken nearly two decades to increase the level of renewable from roughly 10 per cent to the current level of 25 per cent on average in Australia.

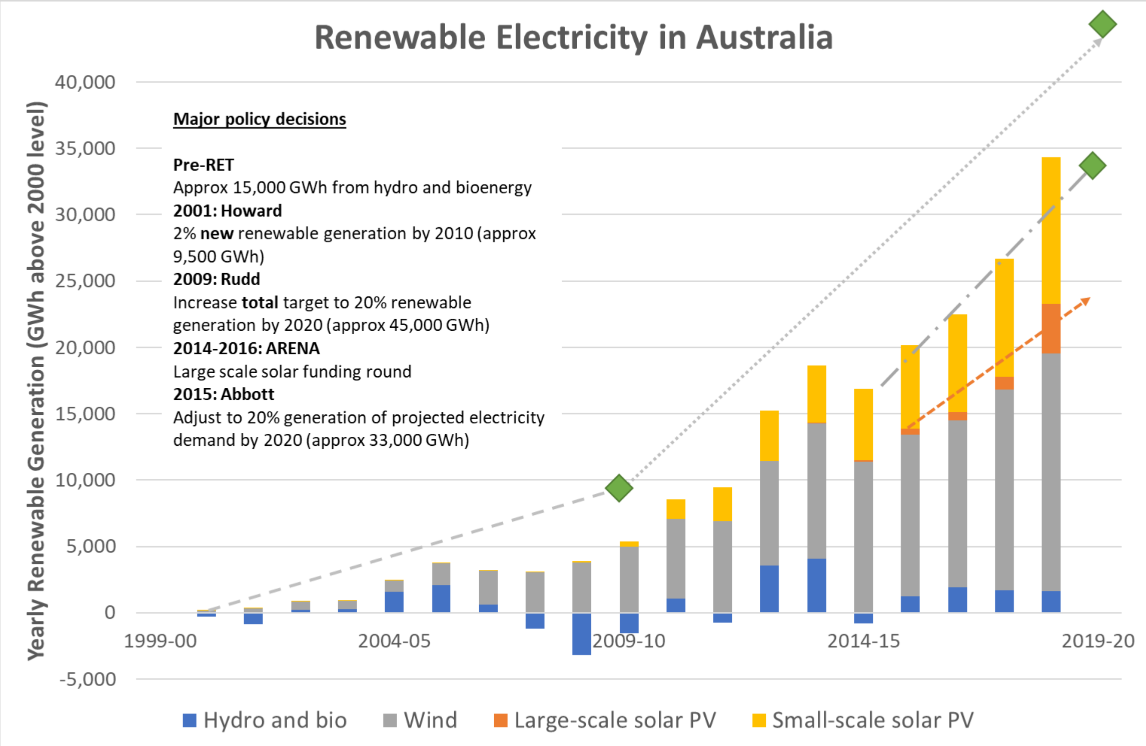


Figure 12: Policy driven renewable electricity in Australia (*Source: ENA analysis*)

Reaching 100 per cent renewables will take time and investment in new electricity infrastructure including generation, transmission and storage. Similarly, converting the gas sector to reach net zero will require investment, whether that be to support a hydrogen pathway of an electrification pathway.

Determining the level of investment required is complex.

For electrification, it requires an understanding of the new generation, storage and transmission and distribution infrastructure required to replace the use of gas. Grattan[32] estimated that an increase of 40 per cent in electricity peak demand in Victoria to electricity small user gas loads would be required. This additional peak

[32] Grattan Institute (2020), Flame Out, pg 47

demand would need to be supplied by renewable generation for electrification to result in emission reductions, resulting in a much higher build-up of installed capacity to provide that 40 per cent peak in demand. This is over and above the decarbonisation of Victoria's electricity generators, which are highly emissions intensive. The estimate by Grattan is likely conservative and does not consider the winter droughts issues highlighted above.

Converting to renewable hydrogen will similarly require high levels of additional renewable generation. However, the repurposing of gas pipelines and networks can provide a greater utilisation of renewable generation and is the key drivers to being able to deliver decarbonisation with gas infrastructure at 41 per cent the cost of electrification (see response to Theme 2).

There are also uncertainties surrounding the conversion of end use appliances.

» Electrical alternatives to natural gas are already commercially available. There are a range of government incentives to encourage households to switch from gas space heating to electrical heat pumps. These incentives generally address the higher up from cost of heat pumps compared to gas space heaters and are supported by claims of associated emissions reductions (see below). An electrification pathway will need to be planned and managed to ensure both adequate supply in new electricity generation and distribution and transmission infrastructure but also an adequate supply of appliances. The impacts on individual homes also needs to be better understood (eg electricity meter upgrades, fixing holes left by replacing ducted gas heaters with wall mounted heat pumps, space requirements for hot water heat pumps, etc). The heat provided from heat pumps is generally lower than that from gas heaters and this often results in associated upgrades to energy efficiency of homes. And at the same time, an appropriate strategy to decommission the gas network would also be needed. All of these cost uncertainties should be better understood.
» A conversion to biomethane will not require any modifications to gas appliances as the gas provided is chemically similar to natural gas. The major uncertainty is around the availability of feedstock and subsequent cost of supply.
» Hydrogen appliances have been built to provide the same services as gas appliances. These are currently at the prototype stage and not yet commercially available. The main differences between these appliances reflect the different burning characteristics of hydrogen compared to natural gas and these are accounted for by new or improved burner design, which is only one component of the gas appliances. Factories will need to be retooled to produce hydrogen appliances and this will require an upfront investment from appliance manufacturers. Once produced at scale, the cost of hydrogen appliances is expected to be similar to current gas appliances. A strategy will be required to convert networks to hydrogen. The cost impact of switching to hydrogen appliances could be minimised by introducing dual fuel appliances which could be easily converted.

One of the biggest uncertainties to decarbonise is the relative costs of the different options available. The full impact of costs across the supply chain need to be considered.

Electrification leads to increased greenhouse gas emissions in 2025

Electrification of gas services is often pursued as a policy option to reduce customer bills and reduce emissions. These outcomes should not be assumed and are driven by the extent of electrification, the emission intensity of the electricity grid and the time of use.

An integrated electricity and gas system model[33] for Victoria has been developed by Future Fuels CRC. This model is a representation of the Victorian energy sector. The model was used to determine the systems impact of electrification of residential heating in Victoria.

The year 2025 was used as the base year for modelling. This had the same electricity demand as 2020 but with an increased level of renewable generation added. Only the residential load of 49 per cent was electrified as the remaining 51 per cent is for industrial and commercial consumption. Both space heating and hot water are electrified at either 50 or 100 per cent. The increase in the generation peak between 7 am and 9 am, and 5 pm and 9 pm reflects the time of use when gas is typically used in winter for space heating and hot water in Victoria. Increasing the level of electrification increases the peaks for electricity demand during these times. The efficiency of heat pump appliances to provide hot water and space heating is included in these calculations to determine the new level of generation and the mix.

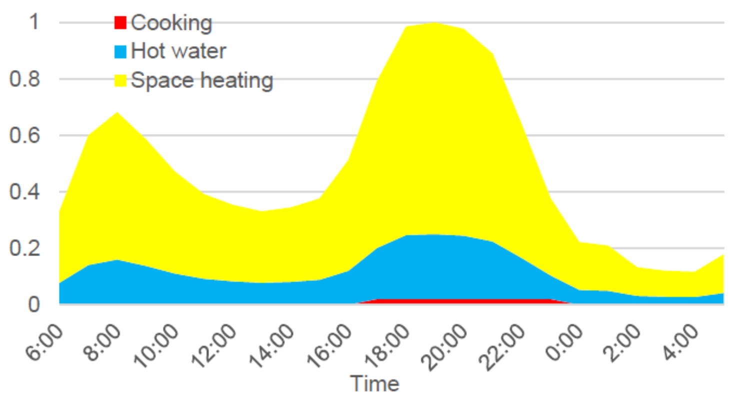


Figure 13: Normalised residential gas demand profile for a typical winter weekday (*source: FFCRC (2019), RP1.1-02: Regional case studies on multi-sector integration – electrification of heating*).

[33] FFCRC RP1.2-02: *Regional case studies on multi sector integration* led by Professor Pierluigi Mancarella at The University of Melbourne.

The figure below illustrates the modelled response from electricity generation on a typical winter day in Victoria in 2025 with increased levels of electrification. More coal fired generation is used with growing electrification levels, up until it reaches its maximum capacity. Any further generation is provided by peaking gas generation and when those are fully utilised, electricity imports are used to meet the generation demand.

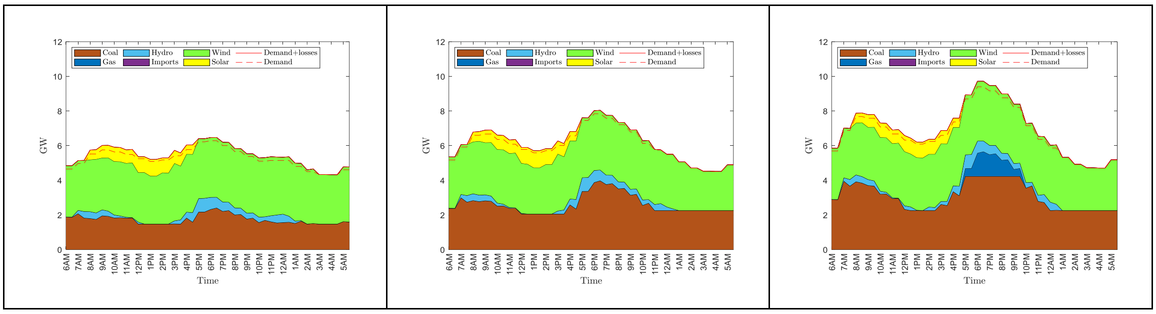


Figure 14: Generation profile in Victoria for electrification increase from 0 to 50 to 100% for a typical winter day in 2025 *(Source: FFCRC – RP1.1-02)*

The researchers also tested the sensitivity of lower than normal wind generation and a 1-in-20 year demand. These scenarios increased the size of the peaks, resulting in more peaking gas and more electricity imports required. In some of the scenarios for 100 per cent electrification showed that the electricity networks require augmentation in the form of up to 220 per cent increase in MVA (thermal) capacity on some of Victoria's transmission lines. This demonstrates that electricity infrastructure upgrades are needed to support high levels of electrification.

The overall change in CO_2 emissions from increased electrification were calculated. These were based on the emissions factors from the individual coal fired generation, the peaking gas generators and an average of imports to Victoria as an average of SA, NSW and TAS's emission factors. An increase in emissions with a higher level of electrification was observed. This reflects reduced consumption of gas in households for space heating and hot water but that was offset by an increased level of coal and gas peaking generation to provide the required level of electricity. For a typical winter day, the emissions increased by 12% for a 50% level of electrification and increased by 15% for a 100% level of electrification.

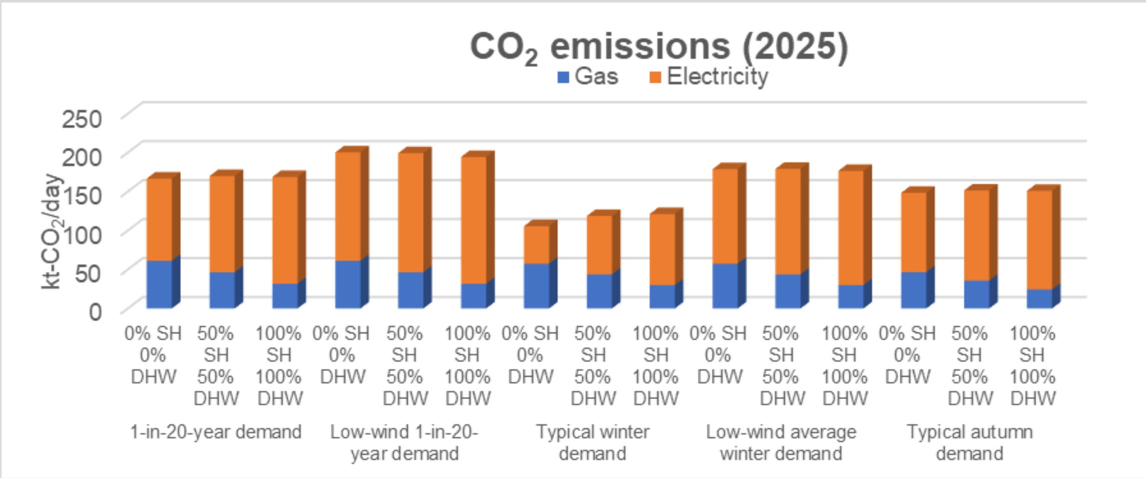


Figure 15: Greenhouse gas emissions from electrification of residential gas appliances *in 2025 (Source: FFCRC, RP1.1-02)*

Electrification has no emission impact in 2035

The model was also run for the year 2035, to account for Victoria's 50 per cent renewable target and the closure of Yallourn power station. The generation for a typical winter day (without electrification) in Victoria in 2035 is shown below.

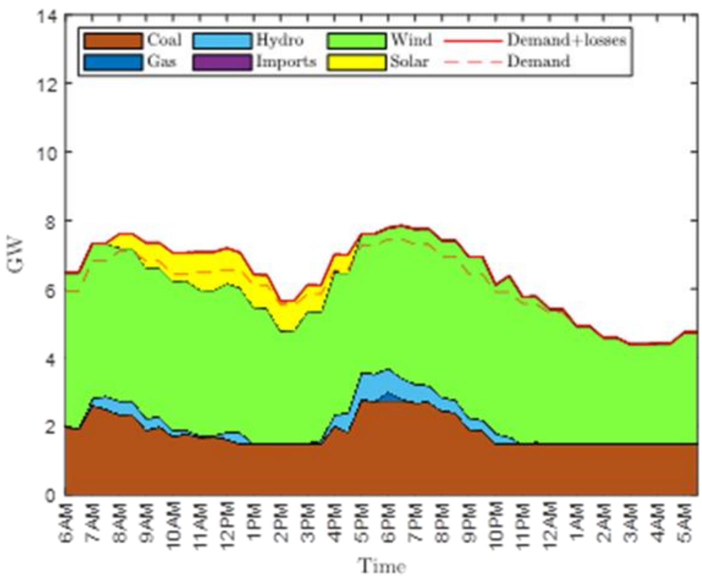


Figure 16: generation profile for a typical winter day in Victoria in 2035 – no electrification (*Source: FFCRC RP1.1-02*)

Given brown coal generation is already close to maximum at peak times, an increase in electrification increases both the levels of peaking gas plant and imports. The result is that the overall emissions are the same whether gas is used in the home directly, or those services are electrified.

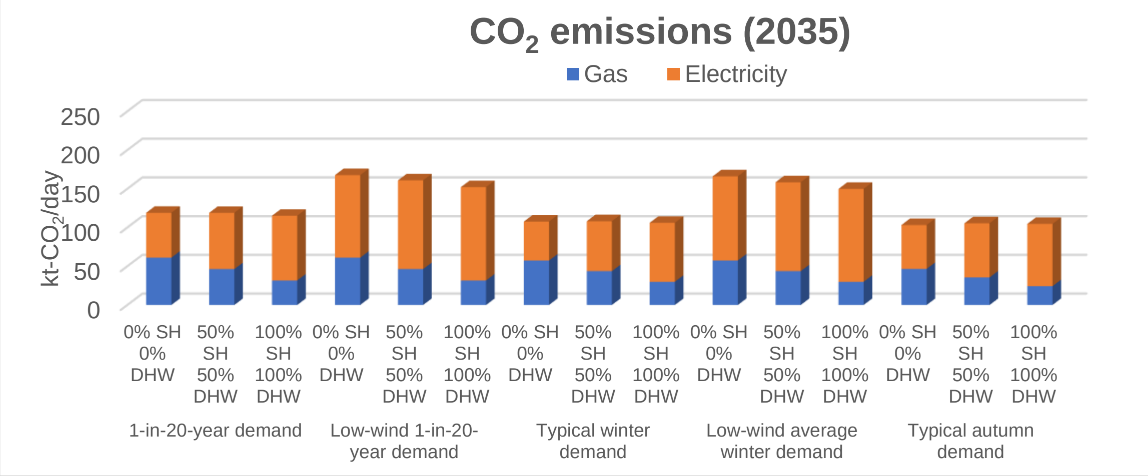


Figure 17: Greenhouse gas emissions from electrification of residential gas appliances *in 2035 (Source: FFCRC, RP1.1-02)*

The systems modelling shows the potential for policy driven electrification to result in increased CO_2 emissions. Increasing the proportion of renewable generation can partly address the higher levels of CO_2 emissions with electrification, although both solar PV and wind generation are variable and may not contribute to the increasing peaks of electricity required due to electrification.

Achieving emission reductions greatly depends on the rate of decarbonising the electricity sector. This should continue to be a policy priority.

Balancing emissions with rooftop PV

Installing rooftop PV to generate surplus renewable electricity that can be exported into the grid is a common option to offset emissions from electrification. The changing level of emission intensity throughout the day means that the emission saved from displacing electricity during the middle of the day may not be adequate to offset the emissions from electricity consumed at peak times. From a decarbonisation perspective, the offsets created from exporting surplus renewables back into the grid can also be used to reduce emissions from the direct use of gas, whose emission intensity is constant throughout the day and year. The above analysis does not include these offsets.

Furthermore, energy retailers now offer carbon offset options to customers for either their gas or electricity consumption. Alternate carbon offset schemes are also available for transport emissions. While these mechanisms may balance overall daily or annual emissions, they do not account for the time of use of emissions

Optimise opportunities for existing gas infrastructure

Biomethane

Biogas can be produced from waste sources such as food waste, wastewater and agricultural waste. Once this biogas is upgraded to biomethane and meets the natural gas specifications outlined in safety regulations, it can be used interchangeably with existing natural gas sources. This already occurs in many European countries that have supportive policy settings for blending biomethane into the gas network. Within Australia, the majority of biogas produced is used for electricity generation as that is incentivised through the Large-Scale Renewable Energy Target.

Diverting this biomethane to the gas network provides an option to decarbonise the use of gas and can be incentivised through supportive policy settings. While some minor modifications may be required for metering and billing, the delivery and end-use of biomethane will be the same as natural gas.

The largest technical uncertainty around the use of biomethane is the availability and reliability of feedstock. An analysis by Deloitte Access Economics found that Australia's natural resources could provide up to 371 PJ of biomethane, roughly equivalent to the national use of gas in homes, businesses and industry. For Victoria, this amount was 48 PJ, or roughly a quarter of the state's natural gas demand. Natural gas pipelines connect Victoria to other states and this creates opportunities for biomethane production from those other states to also meet Victoria's gas demand.

The cost of biomethane production varies greatly by feedstock and processing plant. Biomethane from urban waste can be produced at prices competitive with natural gas when other revenue sources (e.g. fertiliser by-product or avoidance of landfill fees) or other incentives (e.g. a renewable gas certificate) are included. Other biomethane production pathways such as agricultural waste or energy crops could be developed using more targeted policy and financial support.

A complement to biomethane is synthetic renewable gas that is produced from reacting hydrogen with carbon dioxide. When both those compounds are sourced from renewable or biogenic materials, the resulting methane is a renewable gas as, similar to biomethane, has absorbed CO_2 from the atmosphere where it will be returned after combustion. While this process is technically mature, its commercial viability in terms of competing with natural gas prices is uncertain.

Combined, replacement of natural gas with biomethane and synthetic methane forms a credible pathway with minimal impact on the end use of gas but high levels of uncertainty around the supply availability and cost. Further details are provided in the response to Theme 2.

Hydrogen

Each Australian state and territory has some form of hydrogen strategy, demonstration projects, a scheme to support hydrogen research and an interest in the hydrogen export industry. Since 2018, around $1.5 billion has been made available or committed to progressing clean hydrogen in Australia[34]. A total of 61 hydrogen related projects are underway in Australia, excluding individual research projects.

There are many different processes to produce hydrogen, whether it is from coal, gas, biomass or renewable electricity. For the purposes of this consultation paper, ENA's focus will be on green hydrogen produced via renewable electricity.

Hydrogen has the potential to provide the heating needs currently provided by natural gas but without the associated greenhouse gas emissions. Hydrogen has some different characteristics than natural gas such as calorific content, flame speed and diffusivity. Accounting for these different characteristics will require a planned approach to transitioning to hydrogen, which will involve a conversion of networks to a level of approximately 10 per cent to build hydrogen volumes and experience, followed by a conversion to 100 per cent hydrogen, which will involve a burner changeover.

Commercial opportunities already exist in the mobility (return to base) and remote power sectors[35]. Hydrogen also provides a means to retain the utility of gas networks while providing decarbonised gas.

The CEFC notes that:

> *Blending hydrogen into the existing natural gas distribution network at low concentrations, less than 10% hydrogen by volume, is generally considered viable without significantly increasing risks associated with utilisation, public safety, or the durability and integrity of the existing natural gas pipeline network."*

Conversion of natural gas networks to carry hydrogen is an opportunity to retain the benefits of the gas infrastructure while delivering a decarbonised gas. To become commercially viable, full conversion of networks will require cost reductions in hydrogen production. With focussed investments into the technology and demonstration of its applicability, the cost of hydrogen is expected to decrease over time. As recently reported by the Hydrogen Council[36], hydrogen production costs can decrease by 60% by 2030. This level of cost reduction is now seen as conservative. Overall cost reductions are mostly driven by the reduction in capital costs for electrolysis plants (mainly from large scale manufacturing) and from lowering the costs of renewable electricity. The example below provides details of projected cost reduction in Europe based on offshore wind farm. While the capex decreases will be largely driven by global uptake of hydrogen, the cost of renewable electricity is a local factor and can be reduced through both building dedicated renewables for hydrogen or expanding the renewable generation source for electricity generation on the grid.

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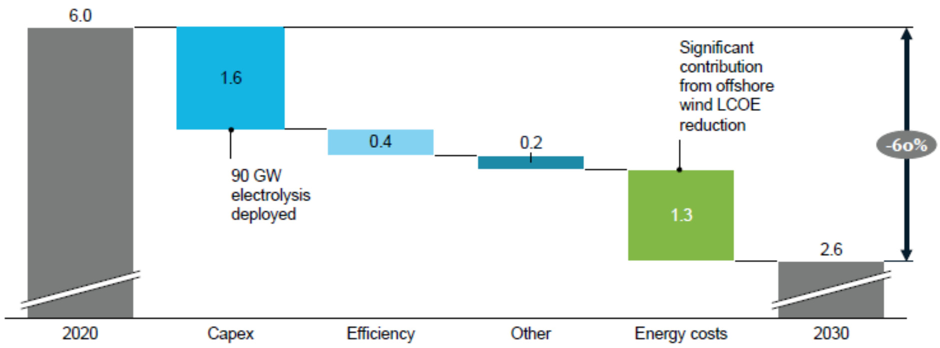
[34] HyResource (2021), *A short report on hydrogen industry policy initiatives and status of hydrogen projects in Australia*
[35] Clean Energy Finance Corporation (2021), *Australian hydrogen market study – sector analysis summary.*
[36] Hydrogen Council (2020), *Path to hydrogen competitiveness – a cost perspective*

Exhibit 13 | Renewable hydrogen from electrolysis cost trajectory

Cost reduction lever for hydrogen for electrolysis[1] connected to dedicated offshore wind in Europe (average case)
USD/kg hydrogen



1. Assume 4,000 Nm3/h (~20 MW) PEM electrolysers connected to offshore wind, excludes compression and storage
2. Germany assumed

SOURCE: H21; McKinsey; Expert interview

Capex decreases ~60% for the full system driven by scale in production, learning rate, and technological improvements.

Increasing system size from ~2 MW to ~90MW.

Efficiency improves from ~65% to ~70% in 2030.

Other O&M costs go down following reduction in parts cost and learning to operate systems.

Additionally, storage may become cheaper (not included).

Energy costs[2] offshore wind LCOE decreases from 57 to 33 USD/MWh, and is assumed to be dedicated to hydrogen production.

Grid fees decrease from ~15 to 10 USD/MWh.

Load factor of 50%, i.e. ~4,400 full load hours equivalent.

Figure 18: Cost reduction opportunities for hydrogen (Source: Hydrogen Council (2020), *Path to hydrogen competitiveness – A cost perspective*).

Blending of hydrogen is a low-cost option to commence the hydrogen economy as no modification to end user appliances, or additional infrastructure (e.g. hydrogen refuelling stations) are needed. Reaching a Victorian blend of 10% by volume of the natural gas provided for residential and commercial purposes households means that nearly 4 PJ of hydrogen will be produced. This will require over 500 MW of electrolyser capacity and 1,700 GWh of renewable electricity, which is approximately 10 per cent of Victoria's renewable energy generation[37] in 2020/21.

[37] Victoria's renewable electricity generation for the year from 20 July 2020 to 25 July 2021 was 14,306 GWh.

In combination with global development in electrolysis capacity development[38] will result in major cost reduction in capital cost of electrolysers. The main benefits of local development are related to:

- gaining consumer confidence,
- reducing local installation costs,
- increased utilisation of variable renewable electricity generation,
- building a local skill base for the hydrogen economy,
- develop commercial opportunities to repurpose existing natural gas pipelines to carry hydrogen,
- working with technical regulators to build the safety case for 100 per cent conversion,
- prepare for an appliance conversion for 100 per cent hydrogen, and
- providing early offtake opportunities for other sectors (eg mobility and exports).

Blending in natural gas can unlock major cost reductions and experiences (community/ regulators) that in turn will reduce the hydrogen production cost to make it commercially competitive with gas delivered via networks.

Converting to 100 per cent hydrogen will require more electrolysis and renewable electricity generation to be built. This provides a higher utilisation of that variable renewable generation, increased overall energy system reliability (compared to electricity only) and provide options to transport this energy as either hydrogen via a pipeline or as electricity via new transmission lines. This conversion will be accompanied by a transition program to replace and/or modify existing gas appliances to work safely on hydrogen.

Gas distribution networks are leading the way in demonstrating this pathway via blending hydrogen into the natural gas network. A renewable hydrogen blend is already being delivered to 700 households in Adelaide[39]. This will be followed by more demonstration projects in the next few years to provide hydrogen to industrial customers. A 10 MW electrolyser will use renewable electricity to produce hydrogen from mid-2023 and enable blending of up to 10 per cent renewable hydrogen into the existing natural gas network in Albury/Wodonga to supply more than 40,000 existing residential, commercial and industrial customers[40].

Gas infrastructure businesses are also completing a detailed plan to deliver the three objectives, that are needed to meet the overall net zero aim described in Gas Vision 2050. This has been addressed above.

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[38] For example, The EU has plans to install 6 GW of hydrogen electrolysers by 2024 and to reach 40 GW by 2030 - source: https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
[39] https://www.agig.com.au/hydrogen-park-south-australia
[40] https://www.agig.com.au/media-release---new-hydrogen-blending-project