POWERCO

24 November 2021

Powerco Limited
35 Junction Street
Private Bag 2065
New Plymouth 4340
0800 769 372
powerco.co.nz

Ministry for the Environment
By email: climateconsultation2021@mfe.govt.nz

Feedback on Te Hau Mārohi ki Anamata

Powerco supports the objectives of the Zero Carbon Act to achieve a net-zero carbon economy for Aotearoa New Zealand by 2050. We welcome the opportunity to provide feedback to the Ministry on its consultation to inform the emissions reduction plan that will set a path to achieve this outcome. We all have a part to play, and Powerco is focussed on delivering over and above expectations.

The emissions reduction plan will drive significant change across Aotearoa's homes and businesses for decades. Powerco is one of Aotearoa's largest gas and electricity distributors, supplying around 340,000 (electricity) and 112,000 (gas) urban and rural homes and businesses in the North Island. These energy networks provide essential services and will be core to Aotearoa achieving a net-zero economy in 2050. Decarbonisation is a priority for Powerco too – we have committed to achieving net-zero emissions by 2030.

Our submission focusses on two key aspects of the consultation:

Energy Strategy ✓

- be enduring and reviewed periodically eg align with emission budget processes to drive innovation and investment
- address the material interdependencies eg aligning the policies to electrify and the regulations needed to deliver it across the supply chain
- have focussed, timely, and actionable outcomes eg changes to regulatory priorities and settings, interpretations, policy statements, legislation

Decarbonise gas ✓

- there are better policy options to decarbonise gas than banning connections
- use policy mechanisms to stimulate green gas uptake eg blending targets or mandated mixing
- recognise the value of maintaining a diverse fuel supply (storage or alternate fuels)

A targeted energy strategy can form an essential mechanism for ensuring alignment of policy and regulation across the sector

Energy businesses already operate in a complex and highly regulated market, primarily governed by the Commerce Commission, Gas Industry Company, and the Electricity Authority. Overlaying climate change policy decisions will add to that complexity. It is vital that climate change policy and energy sector regulation are aligned so the sector can deliver the infrastructure ahead of the demand for it. Regulatory frameworks will need to adjust to encouraging investment 'just too early' rather than current settings of 'just in time' which in practical terms is often 'just too late'. This spans the entire range of regulatory tools that affect the sector: primary legislation, policy instruments and statements, and economic and market regulation.

As demand for electrification increases, customers will expect electricity networks to become more resilient *and* meet their (increasing) demand. And quickly! Much of our regulatory framework is designed to ensure 'just in time' delivery of infrastructure, and our perspective is that a continuation of this approach may result in networks being a constraint on decarbonisation efforts by customers and electricity suppliers. We are already seeing evidence of this. We foresee the need for improvements to the regulatory environment to achieve this, and we're keen to work with decision-makers to shape them.

We also see the potential for underfunded industry participants to struggle to meet the very material investment demands that will come with electrification.

There are better policy options to decarbonise gas than banning connections

The consultation paper seeks views on setting dates to ban natural gas connections (eg from 2025) and eliminating fossil gas (eg by 2050). We think there are better options.

- This policy solution risks imposing a potentially avoidable ~$5 billion conversion costs on households. In addition, Aotearoa's electricity sector will need to respond to this increased demand in addition to that from electrification of transport. This will be localised to where gas demand currently is. Our estimates suggest a potential 30% increase to electricity distribution network costs for consumers in the Wellington region if all gas consumers switch to electricity.
- Rather than solely focusing on phasing out natural gas, we think it's better to focus on the broader opportunity to decarbonise energy use in homes and businesses. This retains the reliability and fuel diversity benefits of low-carbon gas and avoids costs to householders and businesses. This approach aligns with the principles of fuel neutrality, supporting economic development and a secure, resilient, and reliable energy system.
- There are several policy approaches and pathways that align with the emission budget pathways and balance the risks of achieving them. For example, new gas connections could be allowed if they are matched with low-carbon gas. Or obligations could be put on the proportion of low-carbon gas distributed to gas customers over time (just like the approach to biofuels in 2008) and the Sustainable Biofuels Mandate.

A focus on outcomes rather than fuels will provide more options and flexibility for households and businesses to make informed choices about the emissions-intensity of their energy use and the associated impacts on their budgets and businesses. It also accommodates the development and implementation of low-carbon gas alternatives, supporting the integration with complementary policy settings intended to stimulate their role in domestic and global markets. For coal users, low-carbon gas should be a viable alternative for customers to reduce their emissions where the costs of alternative fuels are prohibitive.

Decarbonisation of the energy sector involves addressing a complex set of interdependencies across multiple dimensions: consumer preference, time, economics, rate of innovation, fuels, and many others, all of which need to be integrated in a manner that balances the energy trilemma across time.

Powerco's submission is comprised of several attachments. Attachment 1 is Powerco's feedback on two aspects of the consultation that we can help with. Attachments 2 and 3 provide more information about our electricity and gas networks. Attachment 4 illustrates how low-carbon gas blending can deliver lower emissions outcomes and discusses the relative economics of how this could be achieved. If you have any questions on this submission, please contact Andrew Kerr (Andrew.Kerr@powerco.co.nz).

Yours sincerely

James Kilty
Chief Executive

Attachment 1: Powerco's feedback on consultation questions

[A] Feedback on a national energy strategy

The consultation paper seeks feedback on:

- *… the key priorities, challenges and opportunities that an energy strategy must address to enable a successful and equitable transition of the energy system (Q58)*
- *… areas requiring clear signalling to set a pathway for transition (Q59)*

We support development of a focussed and actionable energy strategy to direct and coordinate policy settings for the key issues affecting the energy sector. The consultation paper touches on a range of considerations in doing this. We have commented on these below and in section [B] in the context of decarbonising gas.

Priority // Setting targets

We support long term targets within the energy system so market participants and regulators can respond confidently to them by making the very material investments that will be required. The challenges eg dry years, timing of electricity generation and network infrastructure response require policies that enable investment and balance the energy trilemma. This will also mean minimising the policy regret which could result from premature phase out of gas before electrification is commercially or practically feasible given gas will need to play a role in the economy for decades.

Priority // Preparing the electricity system for future needs

We agree this topic is a priority issue because of the practicalities that drive the lead-times to deliver infrastructure and the range of policy and regulatory mechanisms that together influence delivery. Making the system faster means looking at all these together.

One of the key issues is ensuring regulations are fit for purpose and coordinated to deliver outcomes the Climate Change Commission and Government consider are "when not if". This requires new thinking about how and when solutions are delivered. For example, systems to allow efficient and successful integration of EVs, large- and small-scale distributed energy resources such as residential and commercial solar, and electrification of process heat at scale. The Climate Change Commission's final advice to government reinforces this:

> *It will take time for government actions to take effect, so signaling longer-term policy well in advance will support public and private investment decisions in line with targets (p 232)*
>
> *Sending clear and stable policy signals to provide predictability for communities and businesses and allow time to plan and respond (p 340)*

The approach to regulation of electricity and gas infrastructure will need to align with the objectives and timeframes of the Government and the Climate Change Commission *and* accommodate the uncertainty about when change will happen. Planning for "target outcomes" is not the approach taken today, but it could be in the future. Enabling this may require changes to a combination of legislation or the regulatory tools administered by regulators. Examples of the issues to consider range from policy to project implementation:

- Ensuring regulatory allowances accommodate forward-looking needs, even though these may not align with historic outcomes. For example, adapting networks for the physical impacts of climate change can require changes to the design and costs of projects, or may require re-configuration of existing infrastructure.

- Reviewing the interaction between climate change objectives/policies and the purpose of promoting "…the long-term benefit of consumers" in the Commerce Act. There is a potential tension to be resolved between the current definition and the climate policy objectives.
- Encouraging and tailoring regulatory allowances to accommodate the individual needs of distributors given non-uniform impacts of climate change policy and initiatives. For example, EV uptake could differ significantly across different regions of the country, as could the impacts of electrification of heat eg in buildings such as schools, hospitals, and manufacturers. Powerco and other distributors have little visibility of when this might occur and its scale. This is a barrier to cost-effective and coordinated planning difficult.

As carbon prices rise, the impact on distribution project costs from use of forestry land will rise. Distributors will need to account for deforestation liabilities which can occur well after an investment has been made. For one recent project, the potential future cost of this liability is $2-4m for a 50Ha cleared forestry area. This is significant in absolute terms, and also relative to the total cost of the network investment. It's a new cost that won't be captured by a 'look backward' approach to regulating costs.

Policy statements will need updating to enable timely and efficient infrastructure decisions. Regulatory frameworks will need to adjust to encouraging investment "just too early" rather than current settings of "just in time" which in practical terms is often "just too late". Distribution assets are treated differently to transmission assets in MFE's policy statement and environmental standard, despite them both being essential for providing electricity to consumers.

The Climate Change Commission's policy advice and modelling is pointing towards a step change in the scale and reliance on electricity across the economy. This will require a similar step change to the treatment of distribution lines in the consenting process, as Meridian has pointed out in the context of new generation[1]. We are raising this important and technical issue here so that it can get some traction during the development of the multisector energy strategy. We would be delighted to provide more information.

Challenge // Capturing the key interdependencies across the sector

It's essential that the energy strategy focus on the key issues and interdependencies and translate that work to policy/regulatory actions and market outcomes that are <u>actionable, measurable and time-bound</u>. An example of this is the links between timing, location, and scale of gas and electricity infrastructure required to meet different energy scenarios, with mutual interdependencies affecting the cost and security of supply.

Energy sector issues are complicated by the numerous interdependencies, uncertainties, and consequences (which is why a strategy has value). The scale and timing of targeted outcomes needs to be aligned with emission budgets and lowest cost emissions reductions. Then the range of initiatives to deliver them can be developed and assessed. The Gas Infrastructure Working Group is having a first crack at this sort of analysis in the context of future gas sector scenarios. Powerco has contributed to and supports that work (submitted separately).

Key areas that would benefit from signalling

The top-two areas are:

- The medium to long-term role of gas, hydrogen[2], biogas, and other low-emission fuels.
- The appetite for infrastructure to deliver capacity for electrification a little ahead of the need.

---

[1] https://businessdesk.co.nz/article/policy/dramatically-faster-consenting-needed-for-renewables-meridian

[2] https://www.mbie.govt.nz/dmsdocument/6798-a-vision-for-hydrogen-in-new-zealand-green-paper

Strategy timeframes

Given it will be a significant task to prepare the strategy, this may mean that subsequent policy consistency may be only available towards the end of the first emissions budget period (~2024). This increases the value of prioritising policy choices that are low-regret options over the medium-term (eg support for renewables and network investment) ahead of moves that eliminate options (e.g. any policy that impacts on gas infrastructure that could provide a low-carbon future option).

The approach needs to inform long term planning through to 2050+ with some decision points along the way. Because of the interdependencies between energy sources, policy goals should target outcomes 2030/2035 and 2040/45 (adjusted to align with emissions budget setting). This approach will support the development and approach of regulation to achieve these goals and increase confidence for innovation and investment in infrastructure.

[B] Supporting people, communities and businesses to reduce demand for fossil fuels in buildings

Our comments in this section relate to topics covered on questions 61, 72-75. These cover:

- *the outcomes, scope, measures to manage distributional impacts, timeframes and approach that should be considered to develop a plan for managing the phase out of fossil gas? (Q61)*
- *What are your views on setting a date to end new fossil gas connections in all buildings (for example, by 2025) and for eliminating fossil gas in all buildings (for example, by 2050)? (Q72)*

A robust approach to decarbonise energy use in buildings is to set technology-neutral targets that are aligned with the cost/benefit of meeting them. Focusing on a specific fuel or technology to deliver lower emissions risks less innovation, inefficient costs and more carbon or overall energy use. Across the country, this could escalate to billions of avoidable costs from retrofitting homes and reinforcing electricity infrastructure.

So there are some important policy choices and tradeoffs to be made. To support this policy work, a Gas Infrastructure Futures Working Group was established across gas pipeline businesses with observers from government (MBIE, Commerce Commission and GIC) and consumer groups (the Major Gas Users Group). The first piece of work explored the nature and scale of outcomes for two policy scenarios: where gas use is either decarbonised or phased out. It demonstrated the merit in a managed transition to ensure continuity of a safe, reliable, and affordable energy supply as gas and LPG consumers move to zero carbon gas or alternative renewable energy sources. This work was published in August 2021 (the *Findings Report*[3]*).*

Given the scale of outcomes and range of related regulatory and policy work needed to support different scenario outcomes, the working group is pursuing two lines of further work to support the emissions reduction plan (constructing packages of solutions and quantifying outcomes). While this work is evolving, the working group has submitted two reports to this consultation with a solution focus:

- **Solution Scoping Paper (Nov '21)** Mapping out a long-list of possible solutions that the private sector, government and regulatory agencies could take to address the risks and impacts arising from decarbonisation. The next step is to package these solutions to align with the broader policy outcomes, targeted for early 2022.
- **Framing an orderly transition (Nov '21)** Dr Richard Meade investigates how private and investment and government policy can help to promote an orderly transition from fossil fuels to low-carbon energy.

These reports are particularly relevant to question 61 of the consultation paper. They illustrate that a well-planned transition addresses the issues raised by the Ministry in the consultation paper: preserve future

[3] https://gasischanging.co.nz/news/gas-infrastructure-future-working-group-sets-out-reasons-for-managed-gas-transition/

energy options, ensure consumer impacts are understood and managed, minimise costs, and preserve incentives on energy providers to maintain reliability and security.

We have contributed to and support the submission of the LPG Association and the Gas Association of New Zealand. We agree with the observation that, rather than ban connections, it is essential that pipeline, connection and appliance infrastructure is maintained to support future demand for renewable gas and renewable LPG. This is aligned with Governments renewable energy goals.

On the specific topic of ending new fossil gas connections, we point to the above analysis first: it shouldn't be looked at in isolation from the energy system as a whole, tempting as it may be. If it is, we think there are better policy options to decarbonise gas demand than banning connections or fuels. For example, solutions could include:

- Apply an emissions rating approach to new dwellings over time which captures all emissions and will be aligned with improving air quality[4] This would achieve the outcome without banning new gas connections, while preserving the option of using low-carbon gasses to fuel new buildings.
- Require an increase in the proportion of green gas supplied to building heating over time, potentially in tandem with a levy mechanism to encourage it[5]. For example, an obligation of x% or y PJ could be required by 2035, or an annual requirement could be set. This would mirror the approach to biofuels in 2008[6] and the Sustainable Biofuels Mandate[7].
- A requirement could be put on new connections to be served by renewable gas, with a certification scheme administered by the Gas Industry Company[8].

These types of solutions need to be considered in the context of the energy strategy because of the other impacts and requirements on consumers and markets. They can't be made in isolation to the rest of the energy system.

The adjacent figure illustrates the impact a 'blending' requirement could have on emissions from residential and gas consumers without impacting overall gas demand (based on the policy reference case).

---

[4] A kgCo2/m[2] limit was raised in MBIE's "Building for Climate Change" programme https://www.mbie.govt.nz/building-and-energy/building/building-for-climate-change/

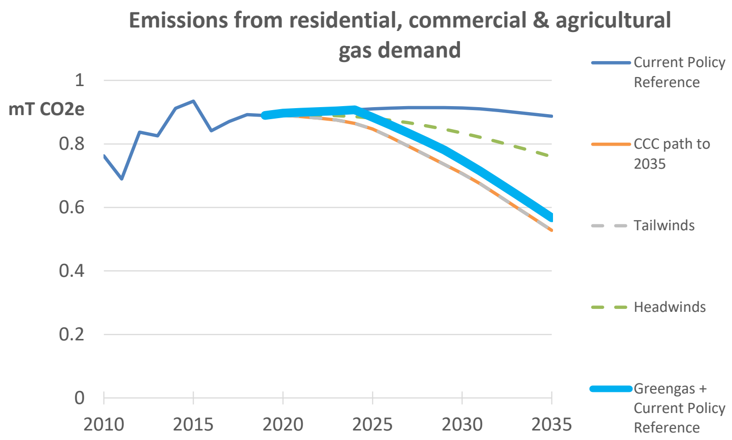
[5] For example, the UK government is proposing a green gas levy " *…to fund support for green gas injection into the gas grid*" https://www.gov.uk/government/consultations/green-gas-levy

[6] https://www.beehive.govt.nz/release/government-requires-biofuels-sales-0

[7] Increasing the use of sustainable biofuels in Aotearoa New Zealand. https://www.mbie.govt.nz/have-your-say/increasing-the-use-of-sustainable-biofuels-in-aotearoa-new-zealand/

[8] European gas participants are looking at this too https://www.smart-energy.com/renewable-energy/european-gas-industry-players-call-for-hydrogen-blending-in-gas-networks/

Emissions from a blended gas mix is reflected by the blue line. It assumes modest biogas injections from 2025 and hydrogen blending from 2030. Relative to the current policy reference, by 2035, this approach:



- Avoids \$370m-\$510m of renovation costs for 71,000 households and businesses using natural gas. Including LPG customers increases this range to \$585m-\$810m.
- Abates almost 1.9Mt CO2e over the period and reduces associated electricity network augmentation

Pursuing decarbonised gas reduces the adverse impacts of eliminating fossil gas

- **Retrofits avoided** We estimate this transition cost for household and business gas users is in the order of \$2.0 - \$2.8 billion[9]. Oakley Greenwood analyse the interaction of this switching cost with the cost of supplying energy from green gasses (section 4), concluding that the medium/long-term economics are preferable to electrification. They also translate the impact of it to the impact on gas users who remain on the network (section 4.4).
- **Efficient choices** Applying ratings at a household level (if needed) means customers to manage the financial impact and inconvenience of renovations at a "whole of household / business" level rather than being driven by the life of a single system (hot water or heating or cooking) triggering a retrofit of them all and an associated cost to the householder.
- **Equitable impacts** Maximising the use of existing equipment and infrastructure minimises the cost to iwi and other users. Attachment 3 describes Powerco's gas network and the relativities of connections and cost recovery, showing that residential and commercial customers are the significant proportion of network users. Technology options that decarbonise gas use in a way that applies to all users means improvements to emissions and cost are made at scale.
- **Electricity network costs** Avoids a double-uncertainty of the electricity sector responding to a sharp increase in demand from electrification of the transport fleet and demand caused by enforced gas switching. This effect will be highly localised because of varying concentrations of gas customers within electricity networks and their demographic and environmental circumstances eg the Auckland climate is different to Queenstown, taking the average won't apply to either.

  For example, Powerco has over 65,000 residential and commercial gas connections on the Wellington Electricity network. Our modelling estimates a full transition would add about 250MW[10] to Wellington Electricity's peak demand relative to 500MW today. This translates to a potential cost of \$575 million and equates to \$30m per year or a 33% increase in charges for Wellington Electricity's residential consumers relative to the ~\$91m they pay today.
- **Support innovation and new markets** Supporting a market for low-carbon gasses will incentivise innovation across the supply chain. Oakley Greenwood discuss the technical and economic viability of

---

[9] This includes natural gas and LPG customers. See Attachment 4 for more detail

[10] This 'incremental' approach assumes that the network is already right-sized for existing demand and forecasts that were made without anticipating a wholescale shift of gas users on to the network

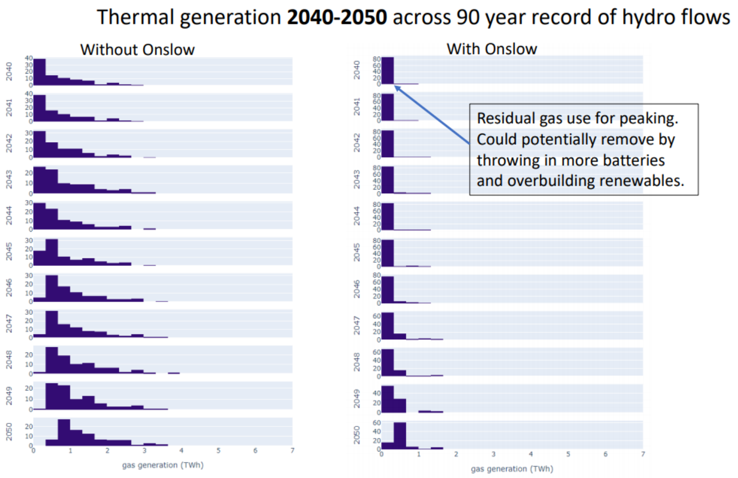
green gasses over the medium and long-term (sections 3 and 4). This conclusion aligns with the direction of studies examining similar issues in NZ that will be released in 2021[11].

- **Maintain energy security** Supporting energy security over the medium term while alternatives are explored. The Climate Change Commission's comparison of ENZ outcomes with Energylink[12] suggests a continued role for thermal generation in some form, with or without Onslow. If this is the case, the interdependencies with the gas and coal sector need to be managed.

  For example, closing down the gas sector could imply thermal generation is met by coal, making a significant contribution to emissions. This would be an undesirable outcome.

  Energylink's modelling indicates up to 4TWh of thermal generation could be needed in some years. These are the solid bars in the adjacent histogram for the 2040-2050 period, with variation in each reflecting the impact of hydro inflows.

  If thermal generation is from coal instead of gas, this could contribute 2Mt additional CO2e in one year alone, dwarfing the efforts and costs made across the sector to reduce emissions.



- **Optionality lost** Preserves a feasible window to explore alternative uses of the infrastructure. For example, MBIE's hydrogen strategy considers multiple roles of hydrogen across the economy.[13] Ending gas connections will signal a path towards downsizing or closure of gas networks. If this infrastructure is required in the future, the costs of starting from scratch would be prohibitive: for our network we estimate $3+ billion to reinstall or $1.5+ billion to make operable post-mothballing. This outcome would be misaligned with any policy or commercial initiatives to establish hydrogen or biogas industries which would benefit from the scale of customers connected to gas networks. The end result: pre-emptively locking out an option which can support Aotearoa's economic and emissions objectives. This highlights the asymmetric risks of policy choices that affect future infrastructure use.

- **Equitable impacts** Maximising the use of existing equipment and infrastructure minimises the cost to iwi and other users. Attachment 3 describes Powerco's gas network and the relativities of connections and cost recovery, showing that residential and commercial customers are the significant proportion of network users. Technology options that decarbonise gas use in a way that applies to all users means improvements to emissions and cost are made at scale.

- **Pragmatic** Creates a window to address the safety and reliability of a gas network re-purpose or closure. This would include an approach to managing the training/skilling the workforce to align with need in sync with the broader approach to managing the costs and impacts of stranding network assets.

---

[11] The biogas study released in April 2021 provides evidence that biogas is feasible at a meaningful scale. https://www.stuff.co.nz/environment/climate-news/300187736/biogas-could-help-reduce-new-zealands-emissions--study

[12] https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/CCC-Electricity-market-modelling-results-summary.pdf

[13] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/a-vision-for-hydrogen-in-new-zealand/

Attachment 2: Powerco's electricity network

We supply electricity to more than 340,000 customer connections across two coastal regions of the North Island. In terms of both supply area and network length, our network is the largest of any single distributor in Aotearoa New Zealand. Our place in the electricity sector is illustrated below.

Electricity is generated across the country using water (hydro), wind, geothermal, gas and coal stations.

This electricity is transported from generators to distribution networks using the national grid, owned and operated by Transpower.

Electricity is distributed to homes and businesses via distribution networks. Powerco is one of 29 distribution companies.

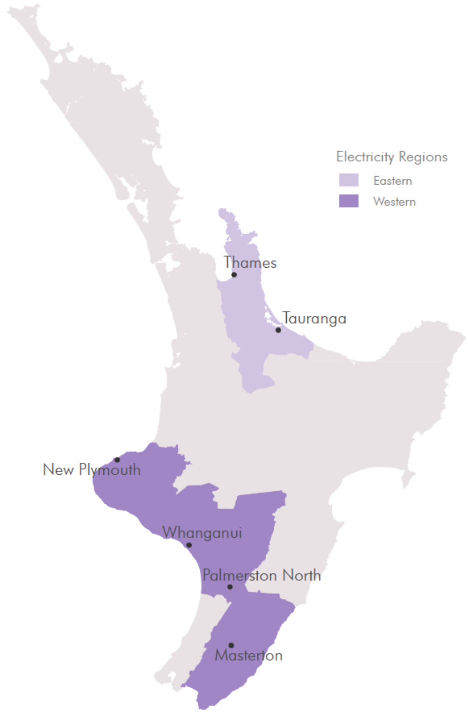
Retailers buy electricity from generators and sell it to homes and businesses.

Regional Networks

Our network includes two separate parts, referred to as our Eastern and Western regions. Both networks contain a range of urban and rural areas, although both are predominantly rural. Geographic, demographic, and load characteristics vary significantly across our supply area.

Our customers represent around 13% of electricity consumption (similar in magnitude to the Tiwai aluminium smelter) and around 14% of system demand. Powerco's network is almost 3x the size of Transpower's in terms of circuit length.

	Eastern	Western	**Total**
Customer connections	163,045	181,139	**344,184**
Overhead circuit network (km)	7,143	14,492	**21,635**
Underground circuit network (km)	3,631	3,175	**6,806**
Zone substations	53	69	**122**
Peak demand (MW)	488	450	**923**
Energy throughput (GWh)	2,769	2,412	**5,181**



The Eastern region consists of two zones – Valley and Tauranga – which have differing geographical and economic characteristics presenting diverse asset management challenges.

- **Valley** includes a diverse range of terrains from the rugged and steep forested coastal peninsula of Coromandel to the plains and rolling country of eastern and southern Waikato. Economic activity in these areas is dominated by tourism and farming respectively. From a planning perspective, this region presents significant challenges in terms of maintaining reliability on feeders supplying sparsely populated areas in what is often remote, difficult-to-access terrain. Investment priorities have focused on improving network security and resilience and developing better remote control and monitoring facilities.

- **Tauranga** is a rapidly developing coastal region, with horticultural industries, a port and a large regional centre at Tauranga. The principal investment activities in this region have been associated with accommodating the rapid urban growth in Tauranga, maintaining safe and reliable supplies to the port, and supplying new businesses.

The Western region comprises four network zones. Similar to the Eastern region, these zones have differing geographical and economic characteristics, presenting various asset management challenges. Because of the age of the network and, in particular, the declining asset health of overhead lines, extensive asset renewal is required in this region. This renewal is about double the cost compared with what is required in the Eastern region on an annual basis.

- **Taranaki**, which is situated on the west coast plains, is exposed to high winds and rain. The area has significant agricultural activity, oil and gas exploration and production, and some heavy industry.
- **Whanganui** includes the surrounding Rangitikei and is a rural area exposed to westerly sea winds on the coast and snow-storms in high country areas. It is predominantly agriculture based with some industry.
- **Palmerston** includes rural plains and high-country areas exposed to prevailing westerly winds. It is mainly agricultural with logistical industries, and has a university, with associated research facilities, in the large regional centre of Palmerston North.
- **Wairarapa** is more sheltered and is predominantly plains and hill country. It has a mixture of agricultural, horticultural and viticulture industries.

Attachment 3: Powerco's gas network

We are an essential energy infrastructure provider for Aotearoa

Powerco's gas business manages a key infrastructure for Aotearoa's economy, safety, and population wellbeing. We are an asset owner and operator. We do not own the gas flowing through our pipelines. Our responsibility is to ensure gas is safely distributed to our customers.

We are also a lifeline utility. This means that we have a duty to maintain operations 24/7, including in the case of a major event like an earthquake or a tsunami. This is a requirement under the Civil Defence Emergency Management Act. Important infrastructure relies on our services to maintain theirs: hospitals, food processing plants, schools and universities, hotels and office towers, crematoriums, and individual households just to name a few.

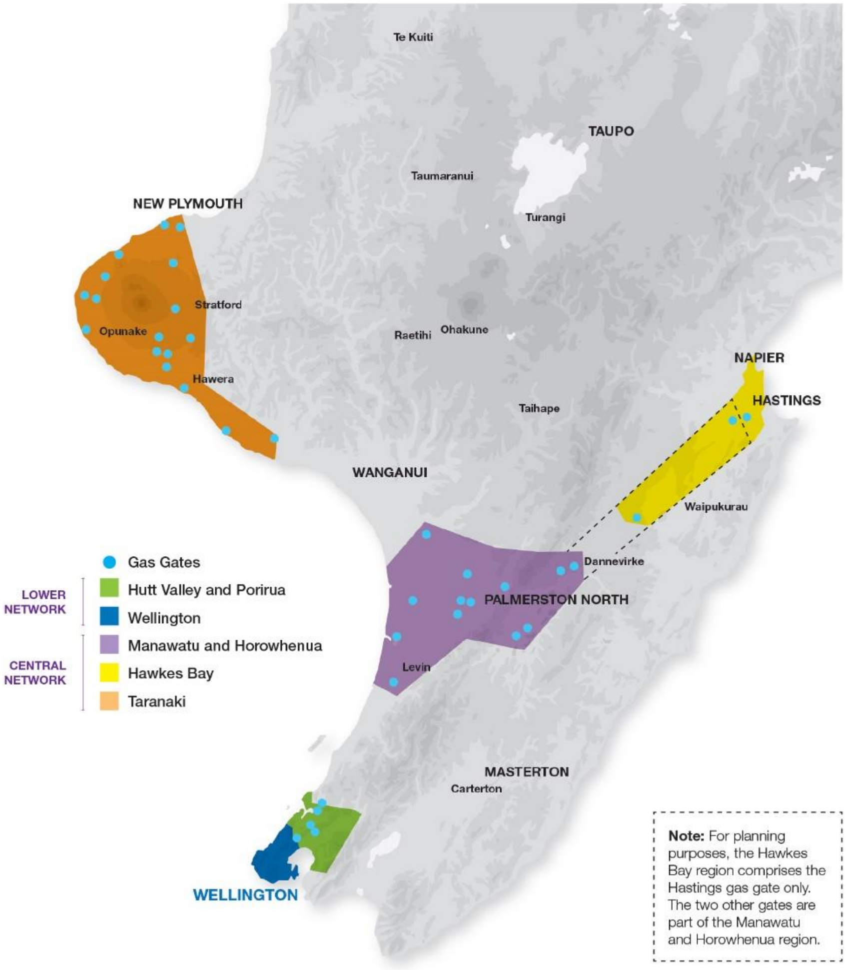
We service a large part of Te Ika-a-Māui

Our gas distribution system starts where Powerco takes custody of a retailer's gas from the Transmission System Operator (TSO) at a designated gate station handover point. It usually ends at the inlet of the Gas Measurement System (GMS) that supplies the end user (our customer).

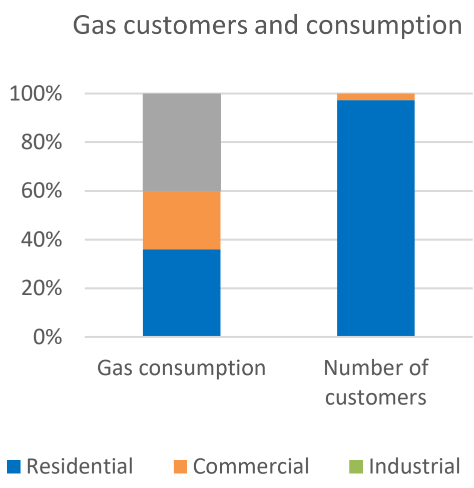
Our network serves around 112,000 customers across five regions:

- Wellington
- The Hutt Valley and Porirua
- Taranaki
- Manawatu and Horowhenua
- Hawkes Bay

These regions can be further subdivided into 36 gate stations that feed 34 individual distribution segments.



Our customers are aware of the impact of gas on their carbon footprint



Our 112,000 customers consume around 8.7 PJ of gas every year. The distribution of gas consumption and customer numbers is shown on the adjacent chart.

Industrial and commercial customers account for most of the gas conveyed through the network, though they are only a fraction of our customer numbers. Residential customers on the other hand, account for the vast majority of connections.

We have been working with our customers so they can understand the emissions impact of their gas use. Our commercial and industrial customers have had a focus on energy efficiency and started to use voluntary offset schemes. For residential customers, we have been providing education about the carbon footprint on our website.

Who are our industrial and commercial customers?

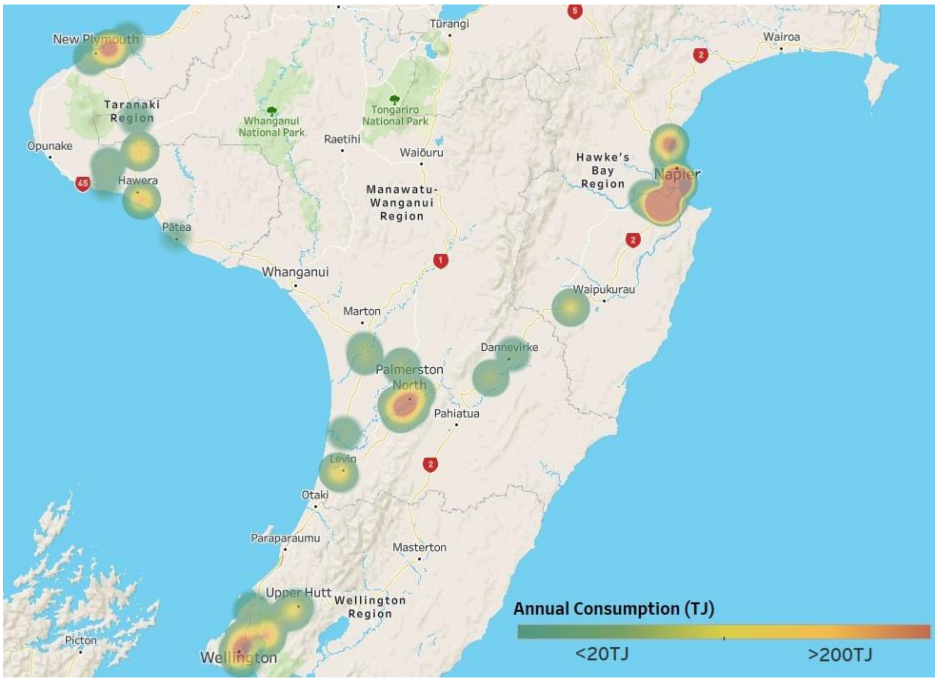
Industrial and commercial customers consume over 60% of the gas we deliver annually.

There are a diverse range of businesses using gas and they're geographically spread across the footprint of our North Island network.

The adjacent figure shows the geographical diversity of gas demand from our larger commercial and industrial customers (around 90). Of these,

- 30% are in the food processing sector
- 20% are in the manufacturing sector
- 10% are in the healthcare sector

The Hawke's Bay region accounts for around 20% of customers though over 40% of the demand from the group.



The table below breaks down the full set of commercial and industrial customers by ANZIC category and their geographical locations.

ANZSIC Group Description	Total	Hawkes Bay	Manawatu - Horowhenua	Wellington	Hutt Valley - Porirua	Taranaki
Agriculture, Forestry and Fishing	57	4%	30%	0%	4%	63%
Mining	13	0%	0%	0%	100%	0%
Manufacturing	377	27%	26%	6%	25%	18%
Electricity, Gas, Water and Waste Services	34	6%	38%	18%	12%	24%
Construction	34	6%	0%	50%	24%	18%
Wholesale Trade	49	12%	35%	22%	16%	12%
Retail Trade	136	14%	24%	25%	31%	6%
Accommodation and Food Services	680	18%	17%	30%	21%	15%
Transport, Postal and Warehousing	34	0%	18%	44%	18%	18%
Information Media and Telecommunications	17	0%	12%	47%	35%	0%
Financial and Insurance Services	28	7%	14%	68%	7%	0%
Rental, Hiring and Real Estate Services	178	4%	8%	68%	18%	1%
Professional, Scientific and Technical Services	70	0%	21%	46%	24%	9%
Administrative and Support Services	8	0%	0%	25%	75%	0%
Public Administration and Safety	184	13%	26%	11%	36%	15%
Education and Training	394	8%	19%	21%	36%	17%
Health Care and Social Assistance	242	12%	20%	21%	32%	14%
Arts and Recreation Services	119	5%	11%	24%	34%	27%
Other Services	286	14%	16%	12%	48%	10%
Not Elsewhere Included	28	7%	14%	21%	46%	7%
Total	**2968**	**13%**	**19%**	**24%**	**29%**	**15%**

We are a natural monopoly, regulated by the Commerce Commission

Under Part 4 of the Commerce Act, Powerco's revenue and expenditure are set by the Commerce Commission as part of monopoly regulation. We are also subject to significant information disclosure requirements, publicly publishing our investment plans, technical and financial performance, and prices.

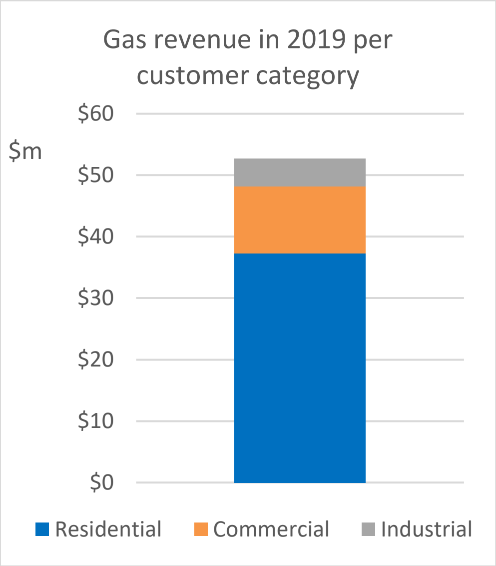
The regulatory regime allows us to recover the value of our asset base using a regulated cost of capital (WACC) set by the Commission, and a forecast of our expenditure. Every five years, the Commission reviews its forecasts and resets our allowable revenue. This process is designed to ensure the costs paid by customers for us to manage and operate our network is efficient given we are a monopoly and an essential service. These mechanisms include the ability for networks to recover the costs of long-life investments over their long life. Should policy settings compromise these arrangements by limiting the life of the networks (asset stranding), revised or new regulatory and policy settings will be needed. We have submitted to the Commerce Commission on this issue for the upcoming reset of revenues as part of the 2022 gas DPP reset process[14].

Our costs are fixed, and residential customers are our economic engine

The cost of operating our business is not dependent to the amount of gas we distribute in our networks. These costs reflect the need to maintain the safe operation of the network and are mostly driven by

[14] https://comcom.govt.nz/regulated-industries/gas-pipelines/gas-pipelines-price-quality-paths/gas-pipelines-default-price-quality-path/2022-2027-gas-default-price-quality-path

compliance with safety regulations. This includes replacing assets when they reach their end of life. Additional costs to grow the size or the capacity of the network are often met by customers requiring the upgrade or new connection.



When it comes to billing customers, the regulatory regime allows us to set our prices in a way that reflects our customers' willingness to pay.

Gas prices have a fixed and a variable component. The ratio is not reflective of our cost structure but represent customer preference. By doing this, we take on board some of the volume risk which in return attracts customers to connect to the network.

Having more customers mean that these fixed costs are more efficient: more customers are served for the same cost. Ultimately, it creates long-term benefit for all customers. Because they make up most of our connections, residential customers represent more than half of our annual revenue.

Attachment 4: Gas blending scenario for New Zealand

We've illustrated the potential outcomes from gas blending using the Climate Change Commission's "our path" scenario. It involves replacing gas demand with biomass and electricity. This is achieved by modelling a reduction in natural gas consumption from banning new connections and appliance replacements:

- In 2020, around 295,000 natural gas customers consume around 17PJ of gas per annum across the sector (all networks).
- Over the 2023-2035 period, carbon is around 2.4Mt lower than the policy reference case for residential, commercial, and agricultural customers.
- By 2035 around 216,000 residential customers (-27%) consume around 9PJ per annum (-44%).
- By 2050, demand is almost zero from residential and commercial customers.

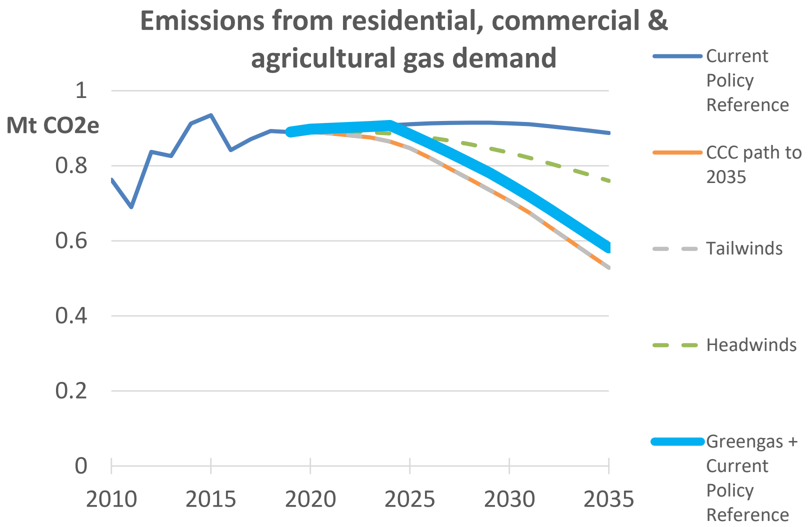
We have focused on the residential and commercial group of customers because of their scale (around 437,000). They represent a large number of customers affected by the proposed policy settings and also a low proportion of gas demand (around 18PJ pa).

What if a similar emissions outcome could be delivered from blending biogas and hydrogen with natural gas?

The chart below illustrates the impact on emissions from this customer group for the Climate Change Commission's draft scenarios, along with a "green-gas" variant of the current policy reference scenario.

How is this achieved?

- Start from the current policy reference case where there is still some market-based fuel switching.
- From 2025, inject biogas at 0.5PJ per year. From 2030, inject hydrogen to replace 0.25% of gas use each year.



The outcomes:

- Abate around 1.9Mt of CO2 relative to the reference case (80% of the reduction delivered via the 'our path' scenario).
- Avoid $585m-$810m of switching costs for natural gas and LPG customers. This is derived from 113,700[15] residential consumers avoiding $3,000-$5,000 per household ($340m-$570m). Around 12,200 commercial customers avoid $20,000 each ($240m). For natural gas customers only, the range is $370m-$510m (71,000 residential and 8,000 commercial customers).

[15] Based on Commission modelling data for natural gas customers. To estimate the impact across a NZ, the same proportions have been applied to LPG customers. This is based off a total customer base of 158,000 residential and 16,000 commercial customers.

- Meet 16.7PJ annual demand in 2035 using a blend of hydrogen (1.8t), biogas (5.75t), and natural gas (10.7PJ). The cost of 1.8t of hydrogen would cost ~$9m (assuming $5/kg[16]).
- Create a time window to explore the costs and benefits of continued decarbonisation of the gas sector post-2035 relative to other options given the interdependencies across the energy sector. This would include exploring the viability of further blending and green-gas injection.

The above analysis is based on the following assumption set which has been derived using bottom-up estimates of costs. We have used 3rd party information to build up estimates of the incremental cost to households to switch from gas to electricity. This involves estimating appliance, labour, and make-good costs which can be compared to those for a replacement of a household's existing gas appliances.

Estimating residential gas-electricity appliance switching costs

Household appliance	Annual demand range (GJ)	% on Powerco network	Switching cost
Hot Water + hobs	<14	27%	$2,025
Hot Water + hobs and space heating			
Simple	14-30	37%	$2,778
Moderate	30-40	12%	$3,525
Complex	40-50	8%	$4,687
Hot Water + hobs and central or radiator heating	50+	16%	$10,425
Weighted average			**$4,011**

Source: Powerco

The range of costs is $2,025-$10,425 (which are themselves midpoint estimates). Applying an estimate of the potential retrofit requirements for Powerco's residential customers yields an average cost of $4,011. For modelling purposes, we have applied a range of +/-25% from this mid-point ($3,000-$5000 per household) to the entire New Zealand customer base.

We have currently assumed appliance and installation costs for gas and electricity space heating appliances are the same, as are the removal and disposal costs. This is an area we're continuing to explore given the scale of costs. At this stage we are comfortable this overall assumption set provides a useful insight to the nature and scale of switching costs for residential customers.

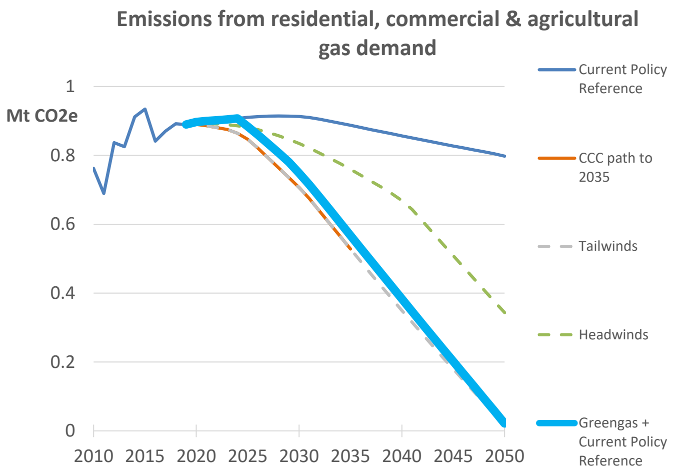
For commercial customers, it is far more difficult to generalize the scale of retrofit costs, though we are confident the cost is not zero. For modelling purposes we have assumed $20,000 per customer based on the install cost for a small sample of recent customers. A better estimate would also include the make-good costs and account for indirect costs such as lost revenue.

We have a limited number of case studies because commercial customers do not tend to switch to alternative fuels for commercial and practical reasons.

[16] This is in the range of costs summarised in the appendices for the NERA analysis on the role of hydrogen for long distance heavy freight transport http://www.araake.co.nz/assets/Reports/Long-Distance-Heavy-Freight-paper.pdf.

Extending the approach to 2050

If the same approach of hydrogen blending and biogas injection continues, the residential and commercial sectors would be almost fully decarbonised by 2050.



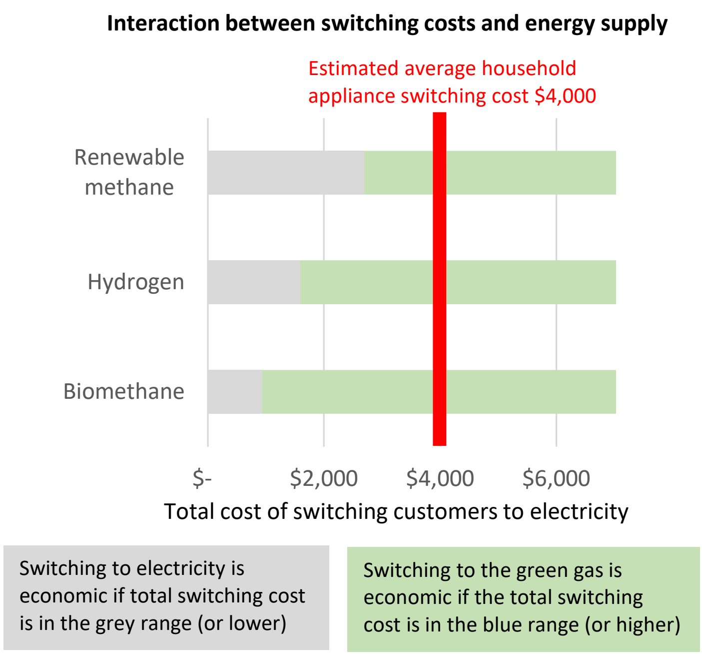
- Annual demand of 15PJ is met using a blend of 5t of hydrogen, 14PJ of biogas, and <0.5PJ of natural gas.
- The annual cost of 5.5t hydrogen production is around $11m-$28m pa based on a $2-$5/kg cost.
- Emissions over 2036-2050 are 4.1Mt compared to the Tailwind scenario of 3.7Mt and policy reference of 12.6Mt.
- Around $2b-2.8b in retrofit costs are avoided across natural gas and LPG consumers. This is derived from applying a retrofit cost of $3,000 - $5,000 per household and $20,000 per commercial customer for 437,000 residential and 32,000 commercial customers. For residential natural gas customers alone, the range is $1.2b-$1.7b.

Keeping networks available may be a lower cost option in the medium/long-term

Oakley Greenwood[17] analyse the trade-offs between fuel cost, switching costs, and electricity network costs over the medium to long term (section 4).

The analysis provides strong evidence that green gas demand supplied via gas networks can provide a more cost-effective path to decarbonising existing gas use compared to electrification. The implication for the Commission is that policy recommendations which lock out the use of gas network infrastructure – either directly or indirectly – may impose more cost on Aotearoa to decarbonise the gas sector than is necessary.

Rather than the blending scenario above, Oakley Greenwood compare the costs of fully supplying residential and commercial gas demand using electricity, biogas, hydrogen or bio-methane. The difference in supply cost between one of the green gasses and electrification can be compared against the long-term cost of switching to electricity (both to the household/business level and to the electricity system).



The adjacent chart shows what the switching cost would need to be for the relevant green gas to be more cost effective than electricity. For residential consumers, this analysis suggests that customers could be better off on a network supplying:

- Biomethane if the total switching cost exceeds $934

[17] See Attachment 5 in our submission to the Climate Change Commission available here.

- Hydrogen if the total switching cost exceeds $1,590 (based on a $2/kg cost[18]).
- Renewable methane if the total switching cost exceeds $2,693.

These 'tipping point' cost levels can be compared against estimates of household appliance switching costs. As illustrated earlier, these average around $4,000 per residential customer, depending on the nature of the retrofit required (and exclude any other costs like electricity network impacts). This is the red line in the chart, which passes through the green bars for all three gasses. It illustrates that all three green gas alternatives could provide a more cost-effective approach to meet and decarbonise the existing residential and commercial gas demand.

This analysis supports the conclusion that renewable gasses may be a more economic path to decarbonising existing gas users.

[18] Australia's hydrogen strategy is focused on delivering hydrogen for $2-3/kg https://arena.gov.au/blog/australias-pathway-to-2-per-kg-hydrogen/