Response to the NZ Climate Change Commission's Advice

prepared for:
NZ Gas Network Businesses

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DISCLAIMER

This report was commissioned by the New Zealand gas network businesses – Vector, Powerco and Firstgas - to assess the New Zealand Climate Change Commission's recent draft advice on how New Zealand can reduce carbon emissions over the next 15 years (2020-2035) in a way that is consistent with New Zealand's legislated target of net zero emissions by 2050.

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Background and Key Findings

The New Zealand gas network businesses - Vector, Powerco and Firstgas - have engaged Oakley Greenwood (OGW) to review the Climate Change Commission's (CCC) draft advice on how New Zealand can reduce carbon emissions over the next 15 years (2020-2035) in a way that is consistent with New Zealand's legislated target of net zero emissions by 2050.

Our key findings are as follows.

Improved modelling of network economics will ensure policy options are robust

The CCC implicitly assumes that gas network businesses will continue to be financially viable in order to operate over the entirety of the forecast time horizon in order to provide gas to hard-to-abate sectors. However, the CCC's broader suite of recommended policies (and its modelling) does not necessarily support (or align with) this outcome.

In particular, policies that start forcing high value residential and commercial customers to switch away from the gas network in the short term are very likely to impinge on the network businesses' medium to long-term viability, which in turn will affect their ability to continue to deliver affordable gas to hard-to-abate sectors. Moreover, the CCC's modelling if anything, is likely to have underestimated the amount of this switching, as the CCC appears to have assumed a gradual transition for residential and commercial customers, yet the forecast bills' the CCC have published would appear to support a much higher (and quicker) level of switching, which would further exacerbate the impact on network businesses' financial viability or lead to increases in the costs remaining gas network users face, affecting their economics.

More weight should be given to technically feasible fuel options

The CCC has confined its analysis to only existing technologies. This should not underpin the development of future policies. Rather, policies should wherever possible, leave open the option of adopting new technologies if they become economic (or existing technologies whose economics improve). This is particularly important as many alternate technologies, in particular hydrogen, renewable methane and biomethane, are forecast to be feasible economic alternatives to electrification in the medium to long-term, based on publicly available forecasts, yet, if gas networks are rendered unviable due to short-term focused, deterministic policies, this may foreclose these options.

Moreover, there are other additional benefits associated with adopting a number of these alternative technologies, relative to an electrification pathway, that need to be considered in more detail. In particular, many of the alternative technologies alleviate the need to augment electricity networks, and may assist in ameliorating some of the customer transition costs, which are important features of any potential transition, yet they do not appear to be explicitly considered in the CCC's work. In short, the different policy options need to be considered in light of these costs and benefits – not just the cost of production.

There are better policy options to achieve a decarbonised gas sector

There are other policy options available that could achieve the CCC's desired outputs, without relying on the adoption of a blunt instrument such as a prohibition on new gas connections. Output-orientated policies, which there are many examples of, are: a) more likely to achieve the CCC's overarching emissions budgets at the least economic cost; b) less likely to foreclose on new technologies that may turn out to be economic (or existing ones that become more economic over time); and c) better able to recognise the value to the NZ economy that comes from keeping gas network businesses economically viable in the medium to long-term to support their ability to continue to deliver gas to hard-to-abate customers in the long-term and to enable the emergence of new markets for hydrogen and biomethane to create employment opportunities for transferable roles in the gas industry.

Conclusion

In summary, we **recommend the CCC's policy directions regarding decarbonising the residential and commercial gas sector be outcome oriented.** This will create an environment for a range of technologies to deliver the outcome. Relative to the proposal in 9c, this approach is more likely to avoid the unintended outcomes of increasing customer and wider economic costs, and of prematurely inhibiting growth in new low emissions fuels in meeting New Zealand's climate change targets.

The CCC's policy recommendations should be more strategic/directional and highlight the trade-offs and risks that Government should consider when designing supporting policies. One of these is that there are a **significant number of benefits associated with adopting policies <u>that do not</u> foreclose on gas options in the short-term**, as to do so will effectively foreclose on the potential adoption of renewable gas options in the medium to long-term. This is particularly important as many alternate technologies, in particular hydrogen, renewable methane and biomethane, are forecast to be feasible economic alternatives to electrification in the medium to long-term, yet, **if gas networks are rendered unviable due to short-term focused, deterministic policies, those options may be foreclosed.**

1. Background and objective

1.1. Background

The Climate Change Commission (CCC) has released draft advice on how New Zealand can reduce carbon emissions over the next 15 years (2020-2035) in a way that is consistent with New Zealand's legislated target of net zero emissions by 2050. As required by law, the CCC advice includes the direction of the policy required in the emissions reduction plan.

One of the key policy recommendations in the draft advice is that the government should set a date by which:

- No new natural gas connections are permitted; and
- All new or replacement heating systems installed are electric or biomass/bioenergy fuelled where feasible.

The CCC recommends that the specified date should be no later than 2025, and earlier if possible. This results in the CCC forecasting gas consumption to decline under the various scenarios that the CCC has modelled, with the CCC modelling a relatively gradual transition away from gas for residential and commercial customers. **Notwithstanding this, the CCC is still forecasting that gas will be consumed beyond 2050 under all modelled scenarios, primarily by customers who are in what are generally termed 'hard-to-abate' sectors (such as peaking electricity generation and high-temperature process heat).**

1.2. Objective of this report

Three of NZ's Gas Businesses – Vector, Powerco and Firstgas – have, collectively, asked Oakley Greenwood (OGW) to review the CCC's draft advice on how New Zealand can reduce carbon emissions over the next 15 years (2020-2035) in a way that is consistent with New Zealand's legislated target of net zero emissions by 2050.

Broadly, our advice is structured around three areas:

- Analysing whether there are any alternative technologies or decarbonisation options that may be economic means for decarbonising NZ's gas industry, and if so, whether the currently policy recommendations are able to accommodate those technologies;
- Assessing whether the CCC's policy recommendations are internally consistent, with a particular emphasis on whether the adverse impacts of the policy on the economic viability of gas supply industry participants has been adequately considered, given the reliance on the industry to continue to supply gas in the long-term to hard-to-abate industries; and
- Whether alternative policy options are available that may be able to better meet the CCC's overarching objective and criteria.

1.3. Key Insights

The following reflects our key insights regarding the CCC's work to date:

- The CCC implicitly assumes that gas network businesses will continue to be financially viable in order to operate over the entirety of the forecast time horizon in order to provide gas to hard-to-abate sectors. However, the CCC's broader suite of recommended policies (and its modelling) does not necessarily support (or align with) this outcome. In particular, policies that start forcing high value residential and commercial customers to switch away from the gas network in the short term are very likely to impinge on the network businesses' medium to long-term viability, which in turn will affect their ability to continue to deliver affordable gas to hard-to-abate sectors. Moreover, the CCC's modelling if anything, is likely to have underestimated the amount of this switching, as the CCC appears to have assumed a gradual transition for residential and commercial customers, yet the forecast bills' the CCC have published would appear to support a much higher (and quicker) level of switching, which would further exacerbate the impact on network businesses' financial viability or lead to increases in the costs remaining gas network users face, affecting their economics.
- The CCC has confined its analysis to only existing technologies. This should not underpin the development of future policies. Rather, policies should wherever possible, leave open the option of adopting new technologies if they become economic (or existing technologies whose economics improve). This is particularly important as many alternate technologies, in particular hydrogen, renewable methane and biomethane, are forecast to be feasible economic alternatives to electrification in the medium to long-term, based on publicly available forecasts, yet, if gas networks are rendered unviable due to short-term focused, deterministic policies, this will foreclose these options. Moreover, there are other additional benefits associated with adopting a number of these alternative technologies, relative to an electrification pathway, that need to be considered in more detail. In particular, many of the alternative technologies alleviate the need to augment electricity networks, and may assist in ameliorating some of the customer transition costs, which are important features of any potential transition, yet they do not appear to be explicitly considered in the CCC's work. In short, the different policy options need to be considered in light of these costs and benefits – not just the cost of production.
- There are other policy options available that could achieve the CCC's desired outputs, without relying on the adoption of a blunt instrument such as a prohibition on new gas connections. Output-orientated policies, which there are many examples of, are: a) more likely to achieve the CCC's overarching emissions budgets at the least economic cost; b) less likely to foreclose on new technologies that may turn out to be economic (or existing ones that become more economic over time); and c) better able to recognise the value to the NZ economy that comes from keeping gas network businesses economically viable in the medium to long-term to support their ability to continue to deliver gas to hard-to-abate customers in the long-term and to enable the emergence of new markets for hydrogen and biomethane to create employment opportunities for transferable roles in the gas industry.

1.4. Caveats

For the avoidance of doubt, it should be noted that:

- The particular focus of this report is on the CCC's recommendations that affect the gas supply industry; we have not analysed in any detail, recommendations that relate to other sectors;
- We have relied on the results of some of the modelling work produced and published by the CCC. To the extent that their modelling is incomplete, indicative only, or in error, those same limitations may apply to the analysis and conclusions we have drawn from that information; and

- Further to the above, notwithstanding the fact that the CCC extended the consultation period, the (still) relatively short time-frame has limited our ability to unpack and analyse all of the assumptions the CCC has adopted and their approach to modelling inter-dependencies; there are likely to be further issues raised or clarifications sought beyond the formal submission of this report.

1.5. Structure of remaining sections

The remaining sections of this report are structured as follows:

- Section 2 summarises the CCC's proposed decarbonisation pathway, and the impact it is expected to have on NZ's emissions and other relevant parameters affecting the gas industry;
- Section 3 outlines a number of alternative technologies that could be used to reduce emissions associated with the consumption of natural gas;
- Section 4 outlines the potential costs of a number of alternative technologies that could be used to reduce emissions associated with the consumption of natural gas; and
- Section 5 contains a number of alternative policy options that have been implemented (or proposed) in other jurisdictions, which could form the basis of policy options that could be adopted to achieve reductions in the emissions associated with the consumption of natural gas.

2. The CCC's proposed decarbonisation pathway and its impact

2.1. Objective

The objectives of this section are to:

- Discuss the CCC's proposed decarbonisation pathway, as well as our understanding of the CCC's rationale for adopting that decarbonisation pathway;
- Summarise the impact the CCC's recommendations are expected to have on NZ's forecast emissions reductions and other relevant parameters affecting the gas industry; and
- Outline our high-level assessment of the CCC's approach to developing its decarbonisation pathway.

2.2. CCC's proposed approach

In its report, "*2021 Draft Advice for Consultation*", the CCC recommends that[1]:

> *"…in the first budget period the Government introduce measures to transform, transition and reduce energy use in buildings. Measures should include…Setting a date by when no new natural gas connections are permitted, and where feasible, all new or replacement heating systems installed are electric or bioenergy. This should be no later than 2025 and earlier if possible"*

The CCC elaborates upon this recommendation in other parts of its report, including on page 61, where it states[2]:

> *Our path looks to avoid new heating systems having to be scrapped before the end of their useful lives. This means that our path assumes all new space heating or hot water systems installed after 2025 in new buildings are either electric or biomass. For existing buildings, the phase out begins in 2030 (Figure 3.12). No further natural gas connections to the grid, or bottled LPG connections occur after 2025. This would allow time for a steady transition, to be on track for a complete transition away from using natural gas in buildings by 2050.*

The CCC also makes it clear that to meet it proposed emissions budgets, New Zealand does not need to rely on future technologies, however, they believe that[3]:

> *"as new technologies develop, this will allow the country to reduce emissions even faster".*

In this context, the CCC notes that it would not be[4]:

> *"prudent to propose emissions budgets that could only be met if new technologies were developed and deployed. Doing so would undermine the purpose of emissions budgets to set a credible path for medium-term emissions reductions".*

In further correspondence the CCC provided to the NZ gas businesses[5], the CCC outlined their process for modelling residential energy/gas use. We have summarised that process as follows:

1. Start with the stock of existing and new buildings.
2. For buildings undergoing a retrofit, the owner/consumer makes a fuel selection between gas and electric based solely on the economics of relative heating costs (variable and fixed

1 Climate Change Commission, *"2021 Draft Advice for Consultation"*, 31 January 2021, page 118

2 Ibid, page 61

3 Ibid, page 11

4 Ibid, page 55

5 As per email from Andrew Kerr, Powerco, dated 11/03/2021

components). This applies separately to space heating and water heating/cooking. Cooking is assumed to be in proportion to water heating, so a decision affecting one applies to the other. Factors like preferences, fuel diversity, retrofit costs, and shared fixed costs, are excluded.

3. All scenarios and the current policy reference[6] have a forced ban on gas heating for new builds and a phaseout for the remaining stock <u>which are not cost driven. These settings override the fuel switching choices of consumers in step 2</u>. The:

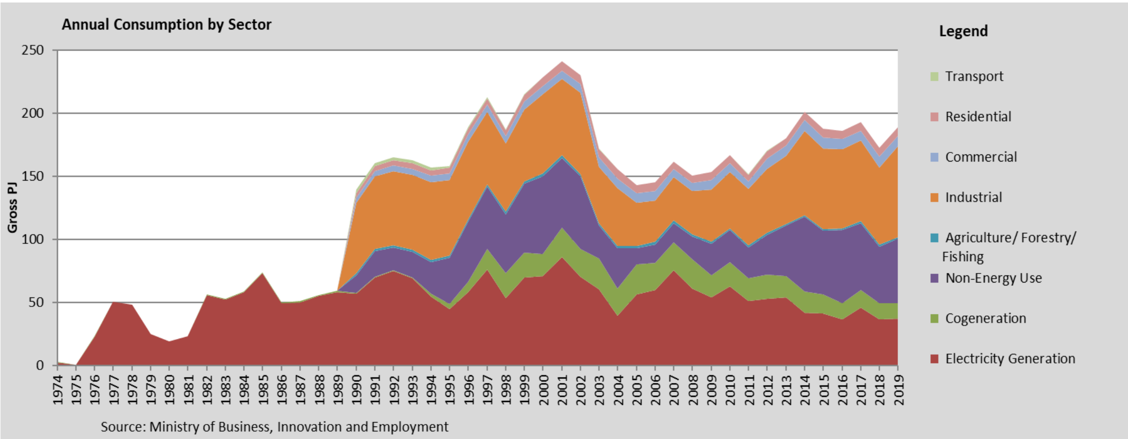
- Ban date setting (i.e., 2025) in the central pathway prevents the selection of gas heating systems for new builds; and
- Phase out profile (2030-2050 in the central pathway) assumes the remaining gas use transitions smoothly to zero. This profile over 20 years is assumed to capture the dynamics of capital replacement.

Our key take-away from the above information is that the CCC's phase out profile (2030-2050 in the central pathway) transitions the remaining gas use in a gradual (smooth) manner, rather than modelling this fuel switching dynamic in any detail. Given the relatively minor contribution switching from gas to electricity by residential and commercial customers makes to NZ's overall emissions reduction profile, it is understandable why the CCC may have made this simplifying assumption. That said, this switching profile is important in the context of New Zealand's gas industry, its economics, and its broader ability to continue to service the needs of gas consumers over the forecast horizon modelled by the CCC.

2.3. The impact on New Zealand's forecast emissions reductions and other relevant parameters

Historically, gas usage has primarily been driven by electricity generation, industrial and non-energy use (i.e., as a feedstock into production processes).

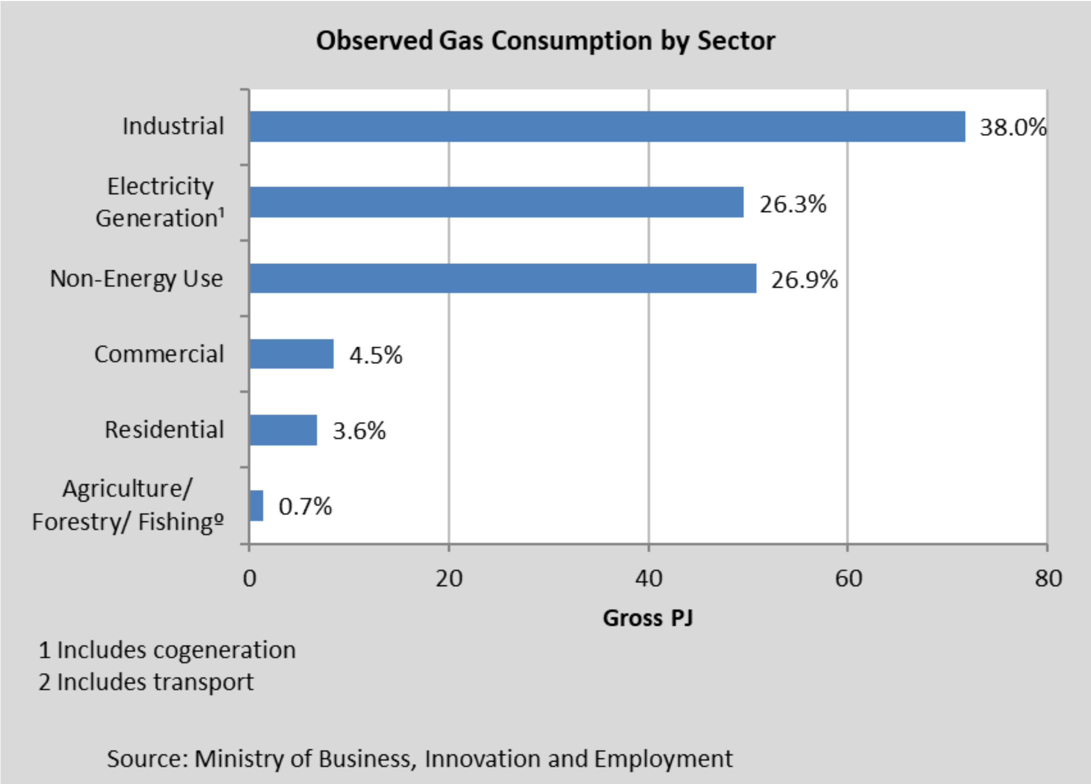
Figure 1: Historical annual gas consumption by sector



Based on 2019 data, these sectors (electricity generation, industrial and non-energy use) made up over 91% of gas usage in NZ.

6 It is not clear what the rationale is for assuming that there would be a forced ban under the current policy reference case, or whether this is an incorrect statement.

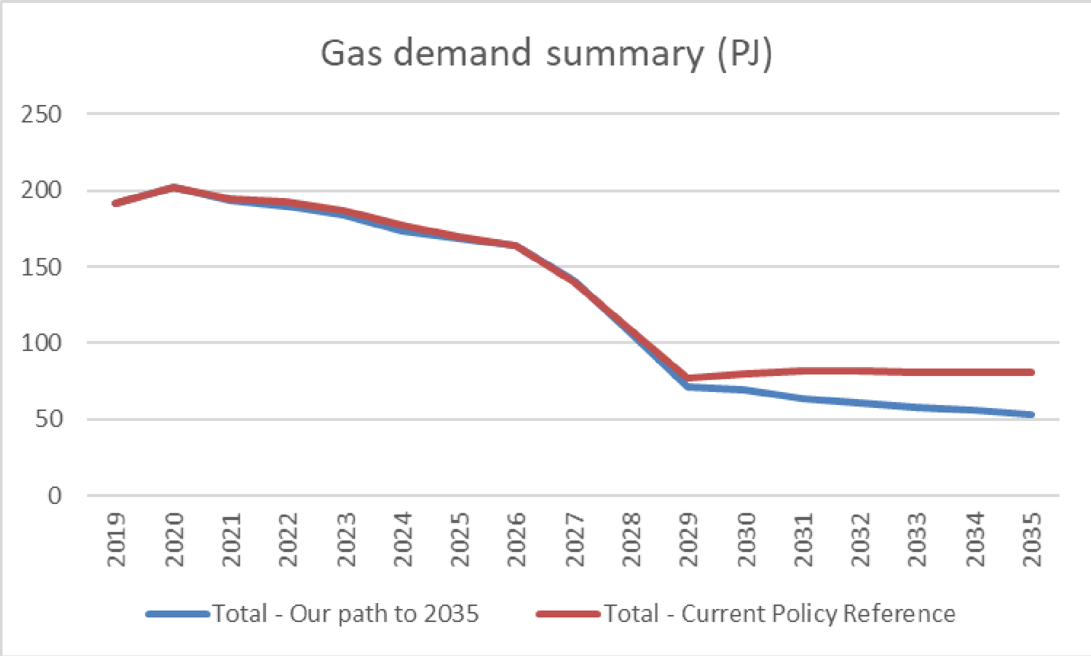
Figure 2: Observed gas consumption by sector



The CCC's modelling indicates that it expects gas consumption to decline from ~190TJ in 2019 to:

- 80PJ in 2035 under the current policy reference case, being the scenario representing the continuation of current policies; and
- 53PJ in 2035 under the 'Our Path to 2035' scenario, being the CCC's proposed path to 2035, which underpins its recommended emissions budgets.

Figure 3: Forecast gas demand (PJ)

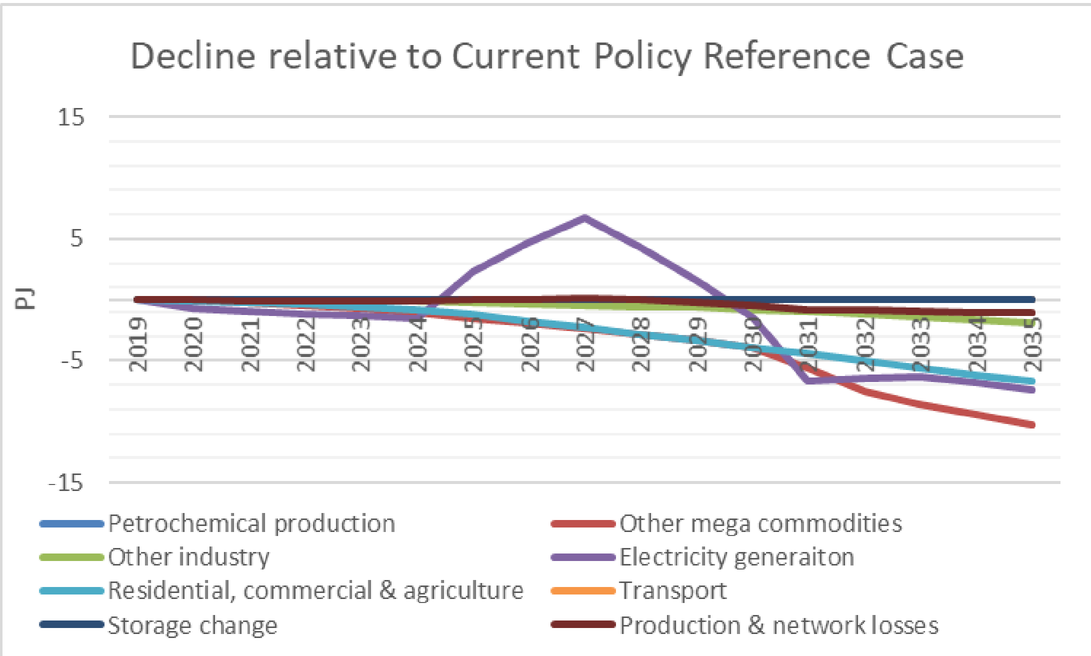


Source: 2021-Draft-Advice-Scenarios-dataset.xls

Interestingly, much of the decline in gas demand occurs even under the 'Current Policy Reference' scenario, with this being driven by the assumed closure of the methanol plants owned by Methanex – in the late 2020s as existing gas contracts expire.

The following figure demonstrates the relative contribution each sector makes to incremental declines in gas consumption under the 'Our Path to 2035' scenarios relative to the 'Current Policy Reference' scenario.

Figure 4: Relative contribution each sector makes to incremental declines in gas consumption to 2035

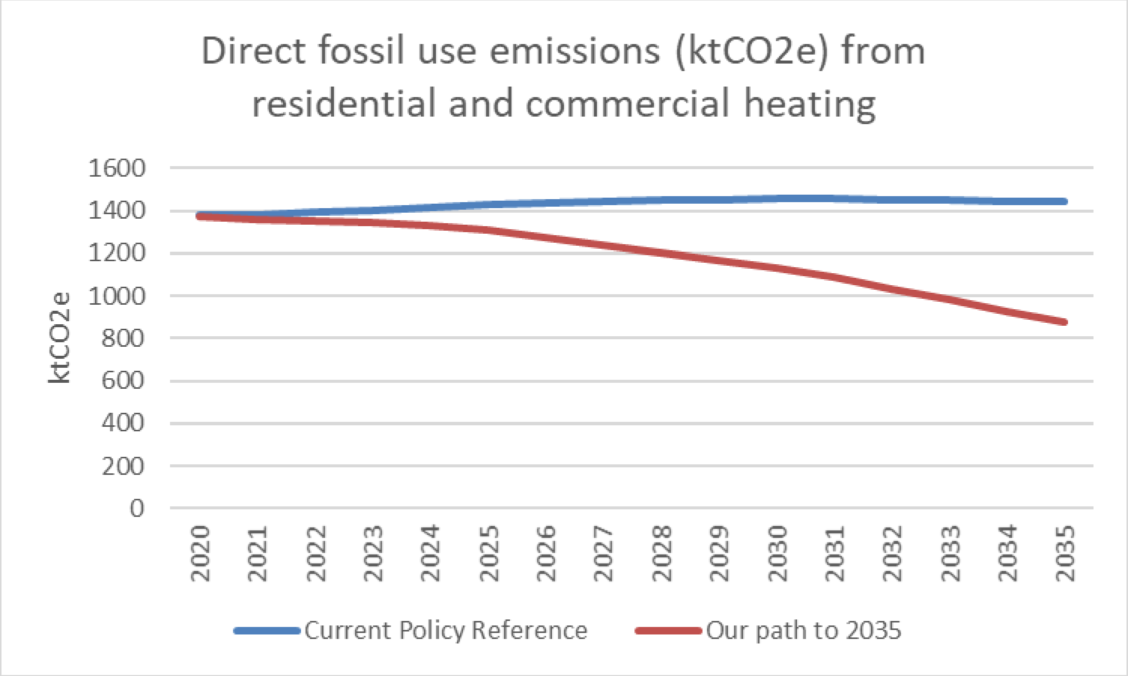


Source: OGW analysis of 2021-Draft-Advice-Scenarios-dataset.xls

Notably, gas consumption in the electricity generation sector is assumed to increase through the mid 2020s, relative to the 'Current Policy Reference' scenario, with declines thereafter. The figure clearly shows the relatively gradual impact of residential and commercial customers switching from gas to electricity from 2025 onwards, which as stated earlier, is important, in the context of NZ's gas industry, its economics, and its broader ability to continue to service the needs of gas consumers over the forecast horizon modelled by the CCC.

The following figure shows the impact that this switching (as it relates to residential and commercial heating) has on emissions.

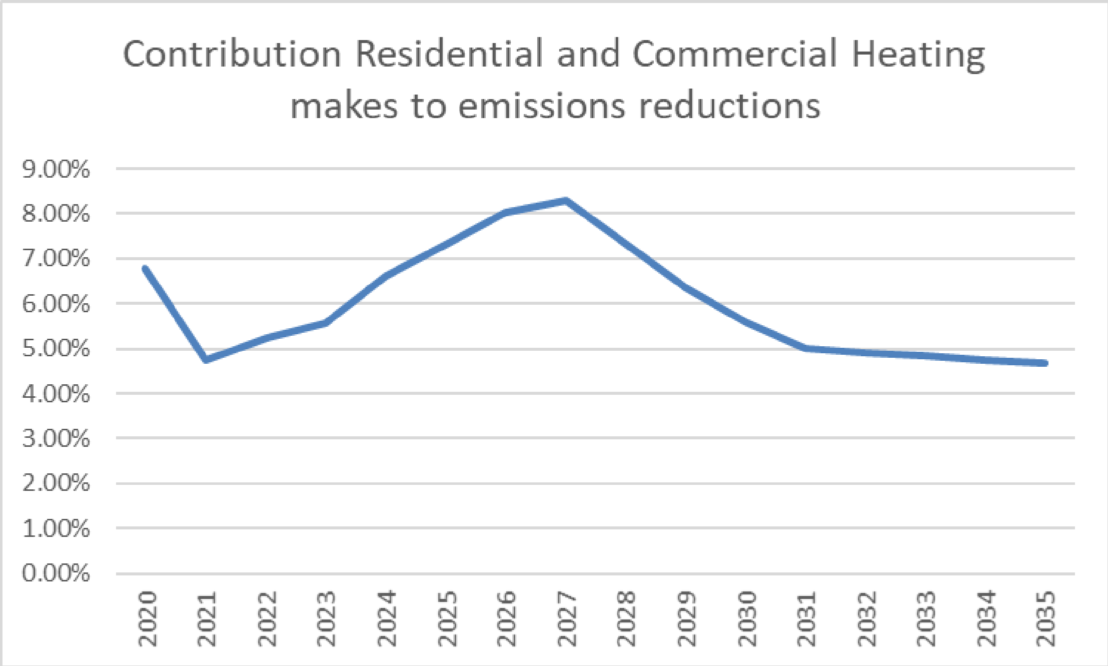
Figure 5: Impact residential and commercial switching under the 'Our Path to 2035' has on emissions reductions



Source: 2021-Draft-Advice-Scenarios-dataset

The contribution that these emission reductions make to NZ's overall emissions reductions (relative to the Current Policy Reference scenario) is highlighted in the following figure.

Figure 6: The contribution residential and commercial heating makes to overall emissions reductions



Source: Based on OGW analysis of 2021-Draft-Advice-Scenarios-dataset

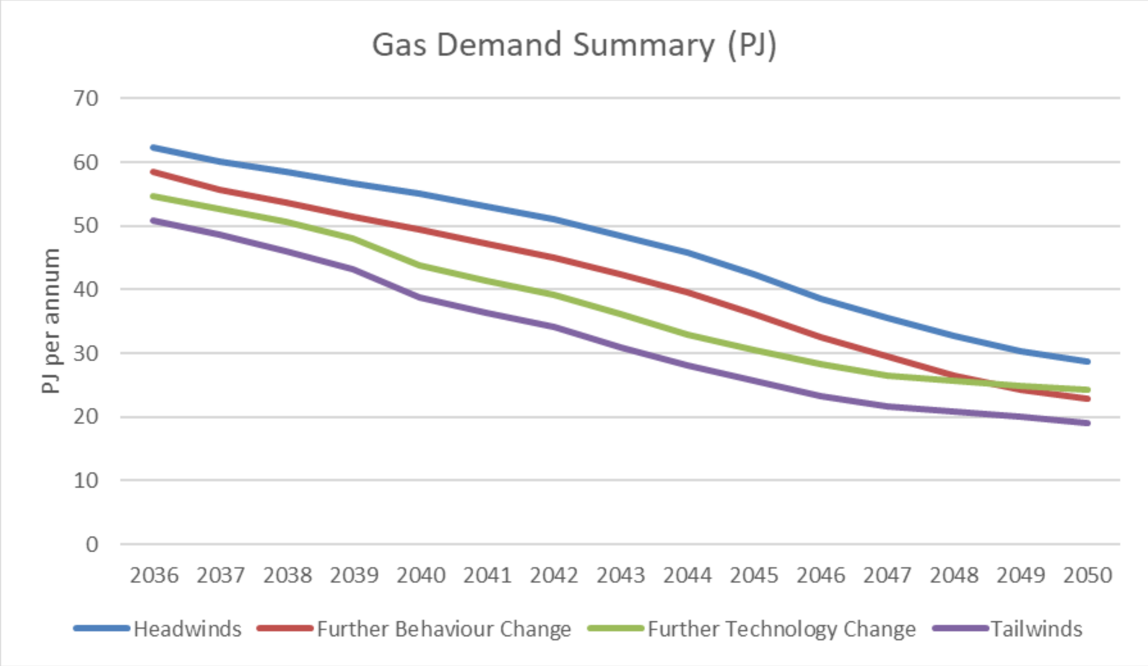
As can be seen from the above figure, in relative terms, the decarbonisation of residential and commercial heating under the 'Our path to 2035' scenario contributes only a relatively small amount to NZ's overall emissions reduction efforts, albeit, in an endeavour such as this, all contributions are important.

Yet, as will be discussed in latter sections, it is not clear from the CCC analysis what the cost and impacts of delivering this level of emissions reduction from this sector of the economy, will mean for the broader economy and emissions reductions, given:

- The CCC is implicitly assuming that gas infrastructure is required post 2050 to meet forecast gas demands beyond 2050 under all modelled scenarios, primarily by customers who are in what are generally termed 'hard-to-abate' sectors (such as peaking electricity generation and high-temperature process heat); yet
- The underlying economics of the gas network businesses are likely to be materially, adversely impacted as a result of the delivery of these relatively small emissions reductions.

This impact does not seem to have been investigated by the CCC. Given the importance of the continued operation of the gas networks to serve key needs of the economy, this represents a potential oversight in the CCC methodology. Understanding this risk is of material importance in considering the risks and trade-offs of different policy settings that aim to decarbonise the energy sector.

Figure 7: Gas consumption between 2036 and 2050



Source: 2021-Draft-Advice-Scenarios-dataset

2.4. Our high-level assessment of the CCC's approach

There are a number of positive aspects to the CCC's approach and reporting of results, not the least being the level of detail that it has gone into its analysis and modelling.

That said, one observation that we would make is that while it is our understanding that the Act[7] requires the CCC to provide 'direction of policy' that is consistent with carbon budgets; it appears to us that the CCC's advice is more prescriptive than directional in some areas, not the least being the prohibition on new gas connections and forced appliance replacements.

There are a number of more specific areas where we have questions or where we would suggest an alternative approach. These are detailed in the following table, and form the basis for the discussion and analysis presented in the remainder of the report.

Table 1: Comments on particular aspects of the CCC's approach to recommendation 9c

Issue	OGW Comment
The CCC's implicit assumption that gas network businesses will continue to operate over the entirety of the forecast time horizon may not align with its broader suite of recommended policies	It is our understanding that the CCC has assumed a gradual transition from gas to electricity from 2025 onwards. Put another way, the CCC does not appear to have modelled the impact that their broader suite of assumptions are likely to have on the gas and electricity prices faced by residential and commercial customers, and how these prices might flow through to those customers' fuel choices.

7 Based on our reading of section 5ZH of the Climate Change Response Act, which states that the "*Commission to advise on emissions reduction plans…Not later than 24 months before the beginning of an emissions budget period, the Commission must provide to the Minister advice on the direction of the policy required in the emissions reduction plan for that emissions budget period*".

Issue	OGW Comment
	On face value, it is understandable why the CCC made this simplifying assumption, given the relatively minor contribution gas to electricity switching by residential and commercial customers makes to NZ's overall emissions reduction profile and the relatively small contribution in makes to total gas demand. However, this switching profile is likely to be important to the overall modelled outcomes. In particular, the adoption of a more bespoke modelling approach is likely to demonstrate that it is likely to be economic for a substantial number of customers to bring-forward the switching of their gas appliances for electricity appliances as compared to the timing assumed in the CCC's modelling. Whilst this brings forward emissions reductions, it also undermines the economics of the existing gas network businesses, which may compromise their ability to continue to operate over the forecast time horizon, which the CCC appears to have implicitly assumed will occur in their modelling.
Impact on the economics of the existing gas supply industry as a result of the forecast closure of the Methanex plant	It is not readily apparent how the CCC has modelled the impact that the forecast closure of the Methanex plants will have on the economics of the broader gas supply industry, despite noting the likely negative impact that this would have on the industry (and prices): *"There is a critical dependency between domestic gas supply and the company Methanex. Methanex produces methanol from natural gas and consumes around 40% of the total gas supply. Their demand incentivises natural gas producers to continue to invest to sustain production. Methanex has provided flexibility by reducing its demand when natural gas is constrained, benefitting all other gas users and reducing methanol production. Without continued exploration and development, the country's natural gas fields are likely to reach the end of their economic life. This will reduce the amount of gas available for all users. In the medium term, it may become uneconomic for Methanex to continue operating in Aotearoa in its current form. A reduction in gas used by Methanex could have flow on cost and supply implications for other gas users including electricity generation and domestic users of gas".* Again, this interacts with the CCC's implicit assumption that gas networks (and the gas industry) will continue to be economically viable in order to operate over the forecast time horizon.
There is an economic cost associated with gas switching that the CCC does not appear to have considered	Following on from the above, the CCC does not appear to have explicitly considered that an economic cost associated with implementing policies that reduce the amount of gas that is delivered via existing gas network businesses (without replacement, renewable fuels) is that networks may not be viable in the long-term, and hence, made available by their owners to provide gas on reasonable terms to any remaining customers. In particular, as gas throughput declines, particularly throughput by (high value) residential and commercial customers, it undermines the economics of the entire gas industry, particularly gas distribution businesses. As gas volumes (and in turn revenues) decline, everything else being equal, gas businesses will need to adopt some combination of: - Increasing prices to those customers that remain connected to their network, thus affecting those customers' economics[8]; - Reducing returns to shareholders; - Reducing expenditure on the network, which, due to the underlying cost structure of network businesses, will in no way match the reduction in revenues (and could potentially lead to adverse impact on levels of service); or - Exiting the industry.

8 This could also result from any move to accelerate the depreciation (and hence cost recovery) of those networks.

Issue	OGW Comment
The CCC's definition of, and confinement to only existing technologies that are commercially deployed in NZ	The CCC makes it clear that to meet its proposed emissions budgets, New Zealand does not need to rely on future technologies, however, they believe that[9]: *"as new technologies develop, this will allow the country to reduce emissions even faster".* In this context, the CCC notes that it would not be[10]: *"prudent to propose emissions budgets that could only be met if new technologies were developed and deployed. Doing so would undermine the purpose of emissions budgets to set a credible path for medium-term emissions reductions".* Whilst we agree that it would be imprudent for the CCC to propose emissions budgets that could only be met if new technologies were developed and deployed, we believe that it is imprudent for the CCC's policy directions to be confined to only existing technologies (as well as the fact that it appears to have not factored in some existing technologies, for example, biomethane). In particular, the policy directions that are developed to support the achievement of the budgets should be flexible enough to allow the market (including markets for new technologies) to develop over time, if those products are valued by the market (in this case, if they represent the least cost means off meeting New Zealand's emissions targets). Put another way, policy directions that are underpinned or confined to existing technologies alone, may either directly or indirectly crowd out what could prove to be viable options for contributing to NZ achieving its emissions reductions in the future, based on small incremental advances in existing technology or changes in one or more of their key input cost categories.
The CCC does not appear to have considered the impact its policies might have on future options	Following on from the above, the CCC explicitly states that one of its design principles is to 'create options' ('Principle 3 - Create Options') - when developing its decarbonisation pathway for gas. As the CCC states[11]: *"there is much uncertainty in embarking on this decades-long transition. Uncertainty is not a reason for delay. There is value in creating options for meeting the targets and having the ability to adjust course as the transition proceeds. The decisions taken now should open up a wide range of future options and keep options open for as long as possible. This needs to be balanced with the need to take advantage of key windows of opportunity, where making significant investments in key technologies could ultimately make the transition to low emissions cheaper and faster".* Whilst we completely agree with this sentiment, it is not clear how the CCC has explicitly taken this principle into account when developing its decarbonisation pathway for gas. For example, the CCC states that[12]: *"Bioenergy and hydrogen both hold promise, but Aotearoa needs to understand how best to make use of their potential. Our analysis indicates that these fuels have significant potential for reducing emissions in transport, process heat and industrial processes. However, more work is needed to support establishing supply chains and infrastructure and making them more cost competitive".*

9 Ibid, page 11

10 Ibid, page 55

11 Ibid, page 30

12 Ibid, page 115

Issue	OGW Comment
	It is not clear how its particular policies, as they relate to the natural gas industry, support the potential development of these alternative fuel sources – ones that as the CCC states, have significant potential for reducing emissions from process heat and industrial process – two areas where these is almost no other means of decarbonising, and two that could significantly benefit from the retention of existing natural gas networks and supply chains.

3. Alternative technologies to reduce emissions from natural gas

3.1. Objective of section

The CCC's approach appears to only consider the switching of natural gas to electricity/biomass as the decarbonisation path. There are alternative fuel options which can decarbonise gas use (and also provide benefits to fuel diversity and cost avoidance).

The objectives of this section are to:

- Outline the potential renewable gases that could be used to decarbonise the natural gas grid; and
- Describe their advantages and disadvantages at a high-level.

3.2. Potential renewable gases that could be used to decarbonise the natural gas grid

There are a number of potential renewable gases that could be used to decarbonise the natural gas grid. These include, but are not limited to:

- Hydrogen;
- Biogas, and bio-methane; and
- Renewable methane.

The following sub-sections provide a brief overview of each of these renewable gases.

3.2.1. Hydrogen

Hydrogen is the most abundant and common element in the universe. At standard temperature and pressure, hydrogen is a colourless, odourless, tasteless, non-toxic and highly combustible gas with the molecular formula H_2. Hydrogen is a clean-burning gas that produces no carbon dioxide when used.

Hydrogen readily forms molecular bonds with most elements, therefore, most hydrogen on Earth exists in molecular forms such as water or organic compounds. Hydrogen is primarily derived by:

- Splitting water into its base components of hydrogen and oxygen; or
- Reacting fossil fuels with steam or controlled amounts of oxygen (e.g., steam methane reforming, or SMR).

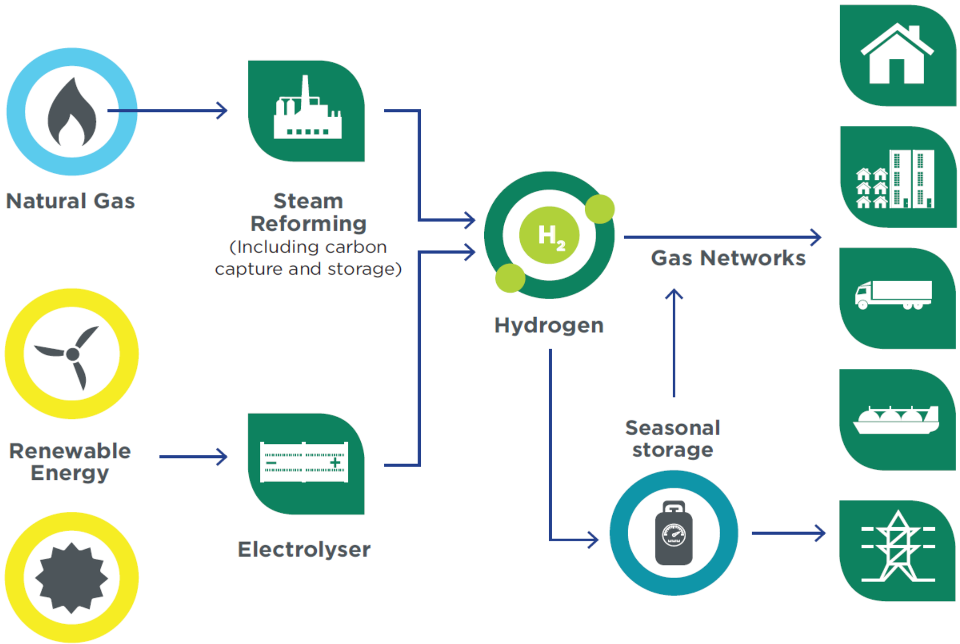
The renewable, zero-emission pathway to creating hydrogen is via electrolysis, using renewable electricity. The two main electrolysis technologies are:

- Polymer electrolyte membrane (PEM), whereby water is catalytically split into protons which permeate through a membrane from the anode to the cathode to bond with neutral hydrogen atoms and create hydrogen gas; and
- Alkaline electrolysis (AE), which involves an electrochemical cell that uses a potassium hydroxide electrolyte to form H_2 at the negative electrode and O_2 at the positive electrode.

Whilst the primary technologies used to undertake this process are mature (e.g. electrolysis) and have not changed significantly in recent times[13], the costs of, and emissions stemming from, the electricity used to power the process have changed significantly. This renewable hydrogen is produced at very high purity (>99.99%) and can be used in many applications, for example fuel cells in vehicles.

SMR is also a mature technology, however, it needs to be combined with carbon capture and storage (CCS)[14] if it is to provide a source of low emissions hydrogen[15]. Even then, it is still not technically "renewable".

Figure 8: Hydrogen production pathways



Source: Energy Networks Australia (ENA), *Gas Vision 2050*, page 4

13 Although there is significant R&D work being undertaken in this regard in Europe and other places - the potential has been recognised internationally.

14 This is often referred to as "blue" hydrogen, as opposed to "brown" hydrogen, which generally refers to hydrogen produced from brown coal, or "grey" hydrogen, which generally refers to hydrogen produced from a fossil fuel without carbon capture and storage.

15 There are inevitably small amounts of carbon emissions even when paired with CCS technology, hence it is low-emissions, not zero emissions.

Whilst there are only a relatively small number of examples[16] of hydrogen being blended into an existing natural gas network at moderate levels across the world, an increasing number of natural gas businesses are actively investigating the option of blending hydrogen into their distribution networks. Existing networks and appliances are designed to operate effectively with moderate amounts of hydrogen, however, where the hydrogen content increases beyond a certain level, appliance modifications are required as hydrogen and natural gas behave differently when burnt. Modern gas distribution networks, however, should be able to transport large proportions of hydrogen safely[17].

3.2.2. Biogas and bio-methane

Biogas is a mixture of CH_4 and CO_2. Biogas is obtained from biomass, which is a plant or animal material that is used for energy production. It is produced from a biological process, for example:

- Via landfill, which is a site for the disposal of waste materials by burial; or
- Anaerobic digestion, which consists of a series of biological processes that are generally used in the sewerage treatment process, dairy waste, or treatment of food waste.

In many cases, biogas production is secondary to a business' main production process (e.g., landfill, sewerage treatment, food production), and its potential utilisation is generally as a feedstock for the production of on-site renewable electricity (with potential to export to the grid, if grid-connected). That said, centralised facilities can be developed, increasing the receiving facility's scale, although this is likely to be partially offset by additional collection and transportation costs.

As biogas also contains carbon dioxide and water vapour, for it to be utilised as a direct substitute for natural gas (e.g., via distribution by natural gas networks), it needs to be 'cleaned' in order to form biomethane. There are technologies readily available to do this, however, they add to the cost of production as compared to using the 'uncleaned' biogas to generate electricity (the economics of the addition of a 'cleaning' process also depends on the proximity of the resources to the existing network). The consumption of bio-methane emits net zero CO2e.

An example of the process that converts biogas to renewable electricity, and biogas to biomethane, is outlined in the figure below.

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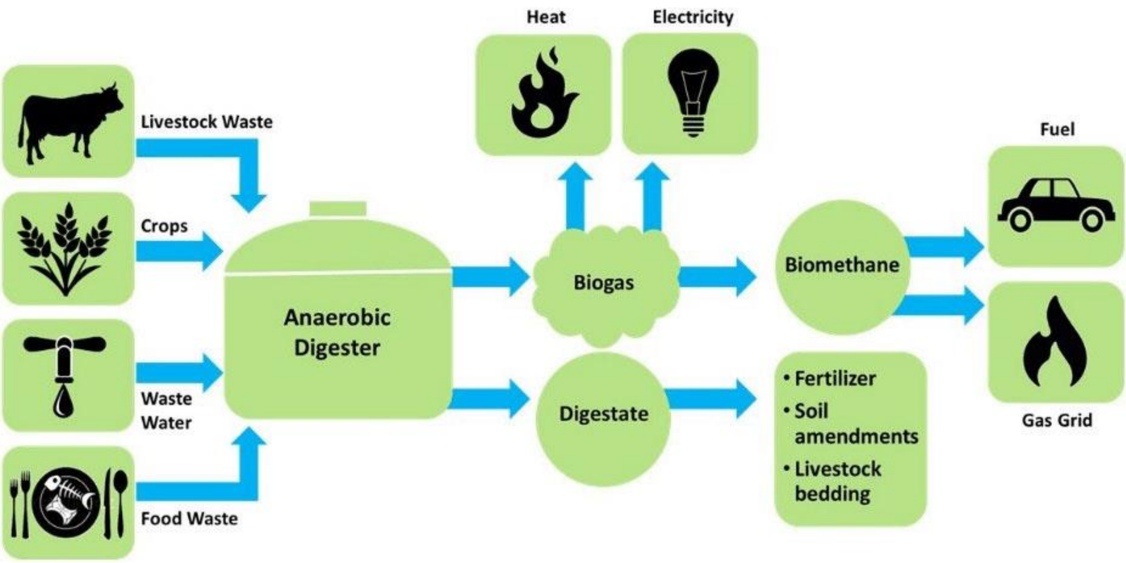
16 Examples include in France, https://www.engie.com/en/businesses/gas/hydrogen/power-to-gas/the-grhyd-demonstration-project; Adelaide, https://blendedgas.agn.com.au/; UK, https://hydeploy.co.uk/hydrogen/

17 The gas industry is familiar with ensuring the safety of gas appliances and has, in the last 50 years, carried out a major conversion program from Towns Gas, which consisted of a significant proportion of hydrogen, to natural gas.

Figure 9: Production of biogas and biomethane



Source: https://www.eesi.org/papers/view/fact-sheet-biogasconverting-waste-to-energy

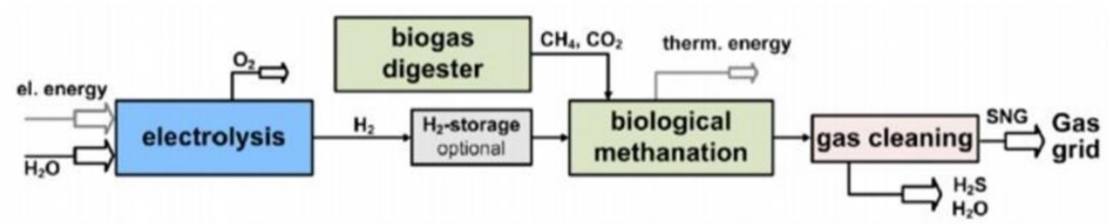
3.2.3. Renewable methane

Renewable methane (the same chemical composition as biomethane) can be produced by reacting renewable hydrogen (H_2) with carbon dioxide (CO_2) in a 'methanation' process.

The carbon dioxide used in this process could come from a natural source, such as a biogas facility (Figure 10), or it could be extracted directly from the atmosphere and then combined with hydrogen to produce methane (Figure 5)[18].

The carbon extracted balances the carbon emitted when the methane is used, therefore making the methane both renewable and carbon neutral.

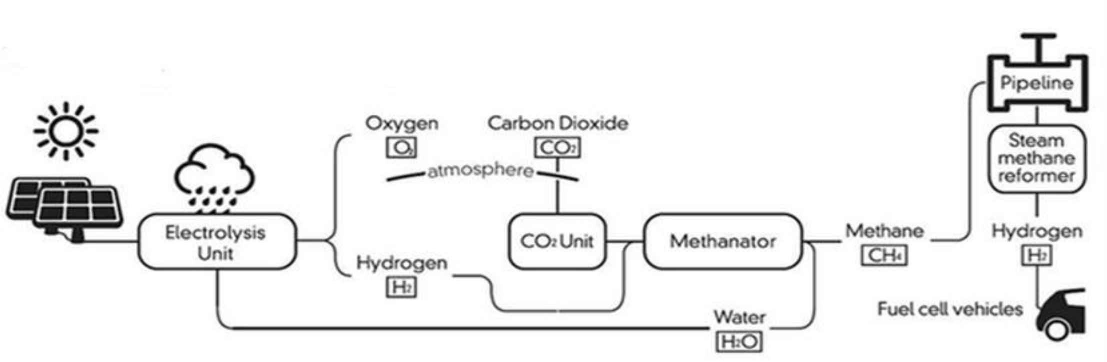
Figure 10: Production of renewable methane via biogas



Source: www.neocarbonenergy.fi/wp-content/uploads/2016/02/06_Tynjala.pdf

18 A low emission (not renewable as such) version of methane production may be possible using the carbon dioxide from sequestered CCS or carbon dioxide emissions that are already part of the National Greenhouse Gas Inventory.

Figure 11: Production of renewable methane via extraction of carbon dioxide from the atmosphere



Source: https://www.southerngreengas.com.au/about.html

This process produces a gas that is fully compatible with existing appliances and networks, and hence no additional downstream costs are incurred.

3.3. The advantages and disadvantages of different renewable gas decarbonisation pathways

The following table summarises some of the advantages and disadvantages of the different renewable gas pathways that could be adopted to reduce the emissions associated with natural gas and LPG usage, as well as electrification.

Table 2: Pathways for reducing emissions from the consumption of natural gas

Pathway	Advantages	Disadvantages
Hydrogen	▪ Is flexible in its production profile, and hence H_2 production might focus on periods when electricity prices are low/lower than average (or even when production would have otherwise been curtailed) ▪ If grid connected, H_2 production may in fact be able to provide valuable services back into the electricity market (e.g., frequency control and ancillary services) ▪ Distributed H_2 can be stored and used to provide peaking services into the gas grid and is also able to meet high temperature process heat needs.	▪ The blending of hydrogen beyond some relatively small proportion by volume (around 10% -20%) requires gas appliances and equipment to be upgraded or replaced. Therefore, a move beyond any blending threshold is likely to require: (a) all gas end-use appliances in the affected area to be replaced at the time the threshold is exceeded, inevitably leading to the bringing forward of appliance replacements relative to the base case; and/or (b) blending to be limited to 10% in an area until all appliances have been replaced over time with what are likely to be more expensive, hydrogen-ready, appliances. ▪ Based on current information, due to embrittlement issues, hydrogen cannot be blended into gas transmission networks at the same level as for gas distribution networks (with some uncertainty over whether existing gas storages are able to store hydrogen). This leads to a number of adverse outcomes, not the least being that to leverage existing assets, hydrogen production must be of a smaller, potentially less efficient scale (in terms of size), to allow injection straight into gas distribution networks.

Pathway	Advantages	Disadvantages
		▪ Hydrogen has 1/3 the energy content of natural gas on a volumetric basis; hence to deliver the same amount of energy, 3 times the volume of gas needs to be delivered. Everything else being equal, this derates existing gas networks, or it requires upgrades to the gas distribution networks (in particular compression assets[19]) to accommodate the same amount of energy throughput. ▪ Everything else being equal, generating energy via hydrogen requires more renewable energy capacity to be built and produced relative to a direct electrification scenario, simply because of the loss of efficiency associated with using electricity to generate hydrogen to then power an end use (relative to directly powering that end use).
Biomethane	▪ Avoids equipment and appliance upgrades at customers' premises, as compared to either hydrogen or electrification. Avoids having to upgrade gas networks to cater for hydrogen, as the same molecule (predominately CH_4) is being transported. Also avoids the need to upgrade electricity networks as compared to the load in question being electrified. ▪ Allows for the continued use of all existing gas storages and transmission networks	▪ Availability of biogas is site dependent in that it depends on the quantity of organic waste / feedstock available. This limits scale and locational flexibility in some cases, both of which potentially limit its overall contribution as a decarbonisation option. ▪ Upgrading biogas to biomethane, a gas with a chemical composition very similar to natural gas. adds to the cost of production.
Renewable methane	▪ Same as biomethane	▪ Lower efficiency than direct electrification, or even hydrogen, due to additional conversions required in the production process. ▪ Additional costs, compared to hydrogen.
Electrification	▪ Many electrical appliances are more efficient than natural gas / hydrogen appliances (e.g., many reverse cycle air-conditioners have COPs over 5 and are likely to continue to improve over the evaluation period)	▪ Electrifying all existing gas demands may significantly impact on the costs of providing electricity transmission and distribution services, if they add to the underlying peak demands that are expected to drive future network augmentations ▪ Electrification cannot replace gas used as a feedstock in industrial processes ▪ Where high temperature heat is required for industrial applications, there are very few viable alternatives to the combustion of a fuel gas. Hence, any large-scale electrification may leave a 'residual' gas load that faces higher gas prices (as sunk and fixed costs need to be recovered across a smaller customer base)

19 Although as some studies have noted, Hydrogen is highly compressible https://www.siemens-energy.com/global/en/news/magazine/2020/repurposing-natural-gas-infrastructure-for-hydrogen.html

4. Potential costs associated with different decarbonisation options

4.1. Objective of section

Whilst the CCC has focused its analysis on biomass and electrification, there are other potential technologies that are likely to be economically feasible options for decarbonising natural gas demand in the long-term.

The objective of this section is to:

- Provide a high-level estimate of the long-term cost of the different decarbonisation options available in NZ;
- Compare the trade-off between the commodity, appliance and network costs of different decarbonisation pathways; and
- Highlight a number of the key indirect costs and benefits associated with each of the different decarbonisation options.

4.2. Costs of producing different options

The objective of this section is to provide a high-level estimate of the potential costs of the different alternatives, in the medium to long-term. Clearly, any long-term forecast is subject to a range of uncertainties, and hence, these should be considered in that light.

4.2.1. Hydrogen via electrolysis

Despite their market availability and maturity, Proton Exchange Membrane (PEM) and alkaline electrolysers – the two most common and mature electrolyser technologies - are still relatively expensive from a CAPEX perspective when compared to many source of renewable electricity.

Table 3: Current estimates of the capital costs of different types of electrolysers ($/kW)

Source	PEM ($/kW)	Alkaline ($/kW)	Integrated Solar and (2 hr) Battery – ($/kW)	Large Scale Solar PV ($/kW)
CSIRO ($AUD)	$3500	$2500	$2139	$1408
IRENA ($USD)	$700-$1400	$500-$1000	NA	NA

Source: CSIRO, "*GenCost 2020-21 - Consultation draft*", December 2020, page 49 and page 63; IRENA (2020), *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal,* International Renewable Energy Agency, Abu Dhabi

Notwithstanding this, numerous notable agencies are forecasting electrolyser capital costs to decline significantly in the medium to long-term, driven by the efforts of countries such as NZ to decarbonise their economies. This underlying increase in demand for electrolysers is forecast to be a catalyst for, amongst other things:

- A significant increase in the scale of production ('gigafactories'), inevitably leading to economies of scale and lower prices in the long-term;
- Industrial scale engineering, procurement and construction (EPC) being adopted for electrolysers, based on mature and scalable technologies; and
- Competitive long-term debt financing as a result of de-risking offtake agreements and in turn cash flows.

The most recent, published, forecast of capital costs from the CSIRO and IRENA are reproduced in the figures below[20].

Figure 12: Capital cost forecasts (2050) by CSIRO

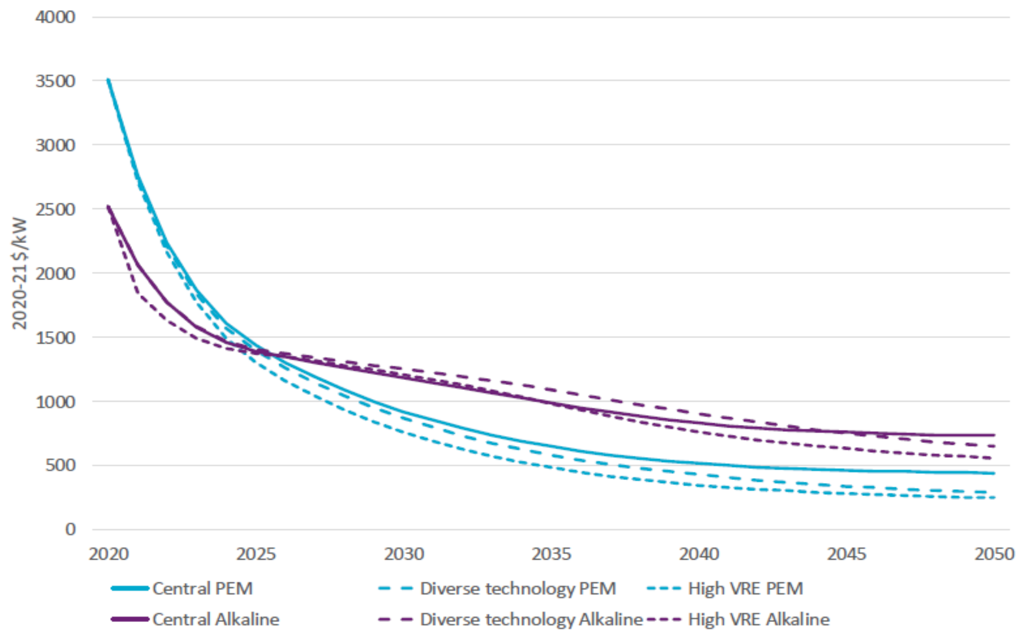


Figure 4-18 Projected technology capital costs for alkaline and PEM electrolysers by scenario

Source: CSIRO, "*GenCost 2020-21 - Consultation draft*", December 2020, page 49

20 The long-term forecast assumptions also broadly align with figures contained in other reports, for example Vivid Economics' (via Nel ASA (2017)) low forecast was NZ$665/kW in 2050, as per `Gas Infrastructure Futures in a Net Zero New Zealand', December 2018, page 52.

Figure 13: Capital cost forecasts (2050) by IRENA

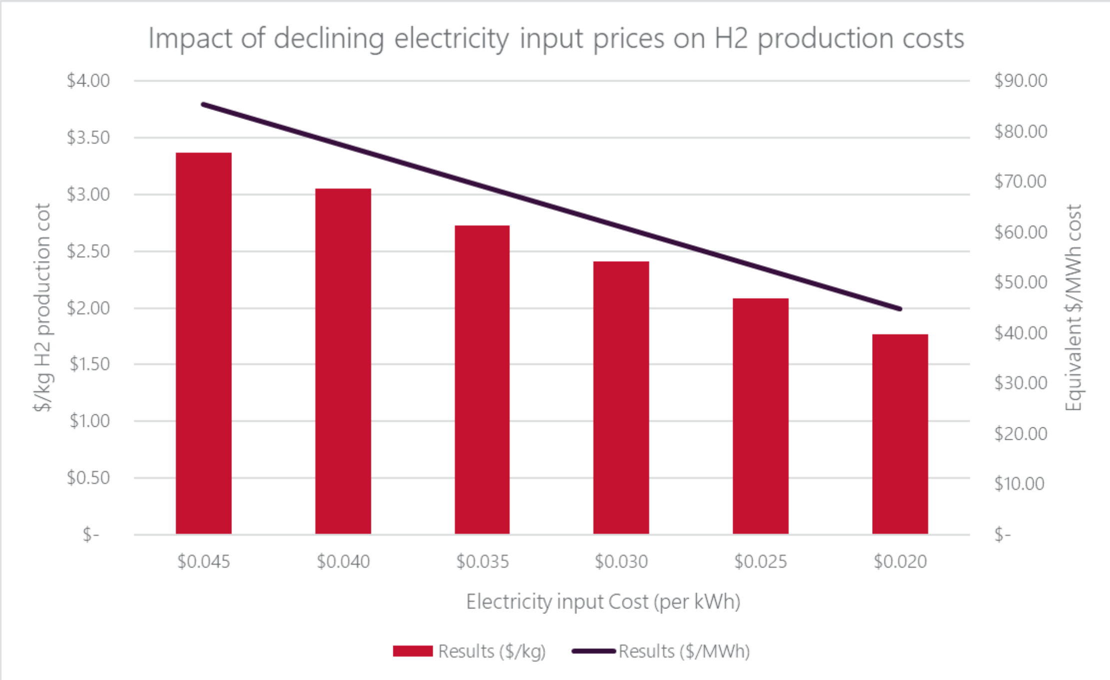
	2020				2050			
	Alkaline	PEM	AEM	SOEC	Alkaline	PEM	AEM	SOEC
Cell pressure [bara]	< 30	< 70	< 35	< 10	> 70	> 70	> 70	> 20
Efficiency (system) [kWh/KgH_2]	50-78	50-83	57-69	45-55	< 45	< 45	< 45	< 40
Lifetime [thousand hours]	60	50-80	> 5	< 20	100	100-120	100	80
Capital costs estimate for large stacks (stack-only, > 1 MW) [USD/kW_{el}]	270	400	-	> 2 000	< 100	< 100	< 100	< 200
Capital cost range estimate for the entire system, >10 MW [USD/kW_{el}]	500-1000	700-1400	-	-	< 200	< 200	< 200	< 300

Note: PEM = Polymer Electrolyte Membrane (commercial technology); AEM = Anion Exchange Membrane (lab-scale today); SOEC = Solid Oxide Electrolysers (lab-scale today).

Source: IRENA (2020), *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal,* International Renewable Energy Agency, Abu Dhabi

Notwithstanding these forecast reductions in capital costs, the cost of producing hydrogen will still be highly dependent on the cost of the (renewable) electricity input. The impact that electricity prices have on the cost of production is highlighted in the following figure.

Figure 14: Impact of declining electricity prices on H_2 production costs – 70% CF



Assumptions include: a) Electrolyser efficiency of 45kWh/kg, consistent with IRENA information (2050); and b) Lifespan of 120,000 hours, consistent with upper end of IRENA; c) capacity factor of 70%[21]; d) capital cost of $500/KW consistent with CSIRO (2050 forecast - PEM); e) WACC = 5%; and f) GJ per kg = 0.142; and GJ to MWh conversion = 0.277778

Assuming a feedstock (electricity) price of $20/MWh and a capacity factor of 70%, along with the declines in capital costs that have been projected by the likes of the CSIRO in Australia (which are not as aggressive as those of IRENA), the cost of producing hydrogen is equivalent to around $45/MWh, which is less than the average electricity price forecast by the CCC in their report (~$65/MWh - ~$72/MWh, with this depending on the scenario).

Whilst feedstock (electricity) prices of $0.02/kWh ($20/MWh) may appear unrealistic, it is important to note that hydrogen production facilities are very flexible, in that they can switch off when electricity prices are high, and run when electricity prices are low (including when prices are negative). Therefore, it is not the average electricity cost that is important, but the profile of electricity prices over the year (i.e., the price duration curve) that is important. The greater the number of low priced periods, the better the economics of hydrogen production[22], even if average wholesale electricity costs are (relatively) high as a result of a smaller number of high priced periods[23].

21 In practice, a hydrogen production facility would optimise its capacity factor, taking into account, amongst other things, the dispersion of wholesale electricity costs.

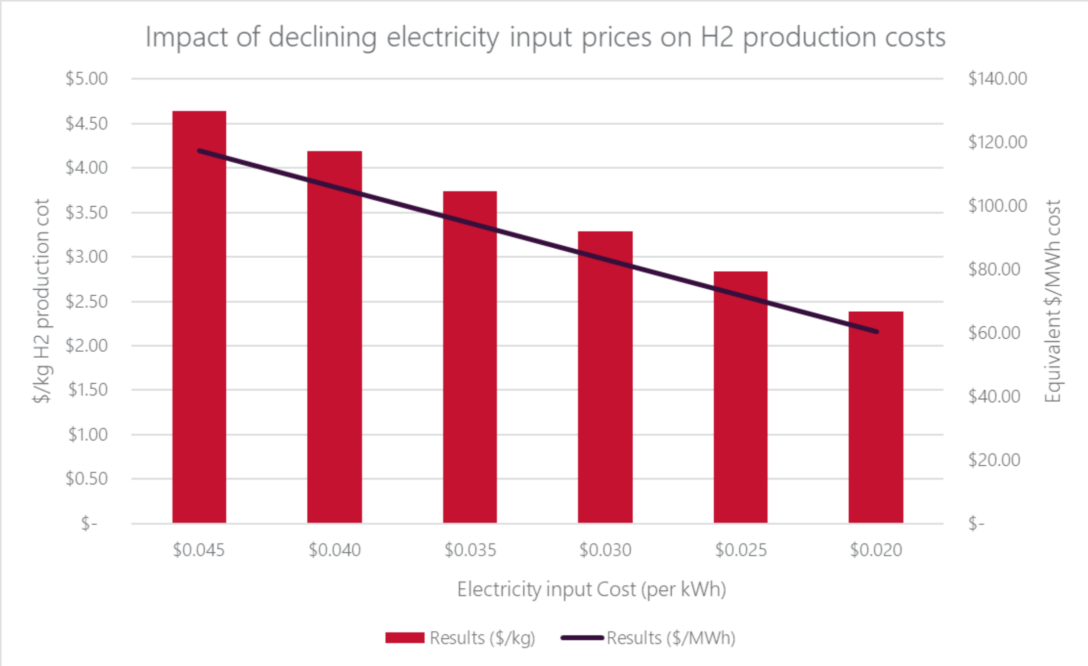
22 Obviously, there is also a feedback loop, in that if there is a significant increase in the number of electrolysers consuming electricity when wholesale prices are low, this will, everything else being equal, lead to increases in prices during these periods.

23 Complementing this issue is a likelihood that in a high variable renewable electricity (VRE) system, high wholesale costs are likely to be coincident with low output from VRE plants.

A breakeven feedstock (electricity) price is around \$30/MWh (when combined with a 70% capacity factor). This implies that if the average electricity cost is \$65/MWh – similar to the long term price the CCC is forecasting in some scenarios - the average price in the remaining 30% of hours would need to be ~\$145/MWh.

If a lower capacity factor was assumed, all other assumptions being equal, the cost of producing hydrogen is around the same as the CCC's average electricity price forecast at an electricity input cost of ~\$20/MWh.

Figure 15: Impact of declining electricity prices on H_2 production costs – 50% CF



In addition to the cost analysis presented above, the production of hydrogen also has a number of other attractive properties, in that it is:

- Scalable, which implicitly provides option value, and is in direct contrast to biogas/biomethane which requires organic waste as a feedstock;
- Flexible with regards to its location, particularly if it is grid-connected; and
- Able to be used in a manner that supports the broader electricity system, for example, it can be used to boost energy security, noting that 'dry year' coverage is particularly important in NZ (and will be even more so in the future with even more VRE), as well as providing other ancillary services such as FCAS, voltage support etc.

4.2.2. Renewable methane

As discussed earlier, renewable methane (the same chemical composition as methane) can be produced by reacting renewable hydrogen (H_2) with carbon dioxide (CO_2) in a 'methanation' process.

The carbon dioxide used in this process could come from a natural source, such as a biogas facility, or it could be extracted directly from the atmosphere and then combined with hydrogen to produce methane.

The appealing factor with methanation is that the chemistry is very well known (over 100 years) and has been undertaken in refineries for many years based on fossil fuel refining and conversion.

However, process integration with renewable power and air borne CO_2 via direct air capture (DAC) is more embryonic – and is an engineering challenge, not one of basic chemistry. That said, integration is, on face value, appealing, given that the production of hydrogen requires continuous energy input (endothermic) whereas the methanation process *produces* heat once it commences (exothermic). This makes them complementary processes (thermally) and a strong candidate for process integration to achieve high conversion efficiencies within one reactor or process plant.

Notwithstanding this, for the purposes of our analysis, we have simply estimated the cost of adding a methanation plant (along with DAC) to the hydrogen production costs that we outlined in the section above.

To inform this, MAN, a large multinational company based in Germany that produces diesel engines and turbomachinery for marine and stationary applications such as marine propulsion systems, power plant applications and turbochargers, provided us with a high level indicative estimate of the capital cost associated with a 5PJ (13,700GJ/day) methanation and DAC plant.

We calculated a levelized capital cost based on the plant cost, production per annum (5PJ), a WACC of 5% and life of 20 years.

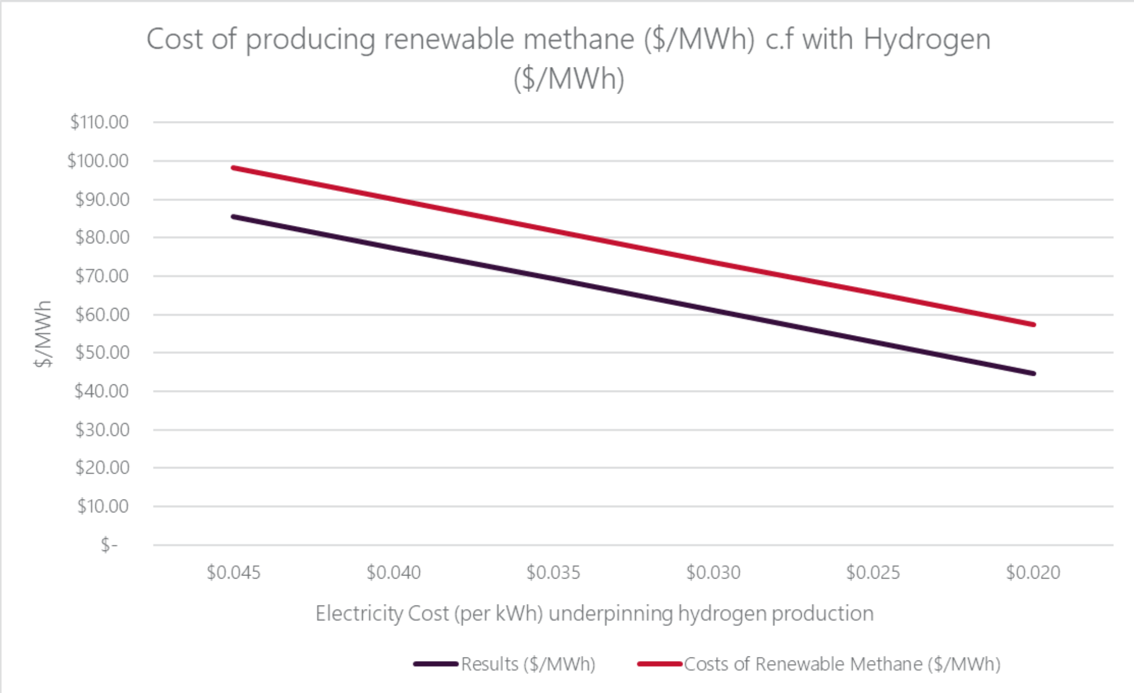
In addition to the capital cost, we have added an estimate of the levelized cost of operating the plant, which, for the purposes of this analysis, we have assumed is predominately driven by the costs of electricity. To inform this estimate, we applied a similar wholesale electricity cost assumption to what the CCC has adopted in their analysis ($65/MWh)[24], multiplied by an assumed electricity consumption of 400kWh[25] per ton of CO2 for the DAC plant plus an additional allowance for electricity used in other parts of the process.

The following figure summarises the modelled costs of renewable methane, assuming no reduction in the capital cost of the methanation plant, and assuming that this cost gets added to the different hydrogen production costs aligned to the analysis presented in the previous section.

24 Note that we have assumed that the methanation plant operates at ~100% capacity factor – hence why we have used the average electricity prices published by the CCC.

25 Christoph Beuttler, Louise Charles and Jan Wurzbacher, '*The Role of Direct Air Capture in Mitigation of Antropogenic Greenhouse Gas Emissions*'

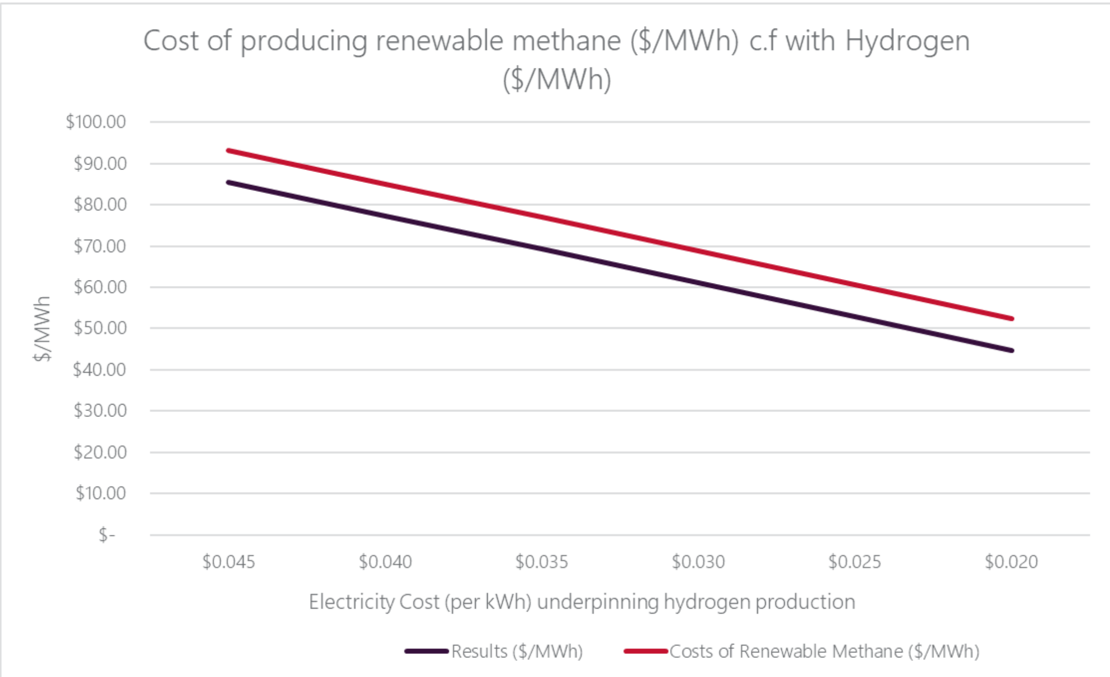
Figure 16: Cost of producing renewable methane – no reduction in capital costs



Source: OGW

The following figures highlights the results, if we assumed a similar trajectory in the capital costs of methanation as is being forecast by the likes of the CSIRO and IRENA for electrolysers.

Figure 17: Cost of producing renewable methane – assuming a reduction in capital costs



Source: OGW

Like hydrogen, renewable methane has a number of other attractive properties including that it:

- Allows NZ to retain its existing gas transmission, distribution and storage infrastructure, with no need for any other change;
- Avoids the need for customers to change out appliances to cater for either:
  - A new gaseous fuel (hydrogen); and / or
  - Electrification of some of their existing loads.
- Depending on the ability and cost to scale up methanation facilities, it represents one of the only true means of decarbonising many hard-to-abate sectors like peaking electricity and high temperature process heat; and
- Potentially facilitates the creation of a new export market – renewable methane.

4.2.3. Biomethane

The cost of producing biomethane via anaerobic digestion includes three distinct elements: biogas production costs, biogas cleaning and upgrading costs, and distribution costs.

IRENA has previously (2017) indicated that the typical price of[26]:

> *producing biogas ranges between USD 0.22 and USD 0.39 per cubic meter of methane for manure-based biogas production, and USD 0.11 to USD 0.50 per cubic meter of methane for industrial waste-based biogas production.*

It also stated that it anticipated that cost reductions in the range of 30 to 40 per cent appear to be realistic, although it is not clear over what time horizon these cost reductions are projected.

The 'cleaning' or scrubbing process, which involves cleaning the gas of particles, water and hydrogen sulphide to reduce the risk of corrosion, and then upgrading the gas by removing carbon dioxide to raise the energy content and create a gas with constant quality consisting of about 98% methane, adds to this cost. IRENA indicates that the cost of this upgrading typically only accounts for 5-10% of production costs[27].

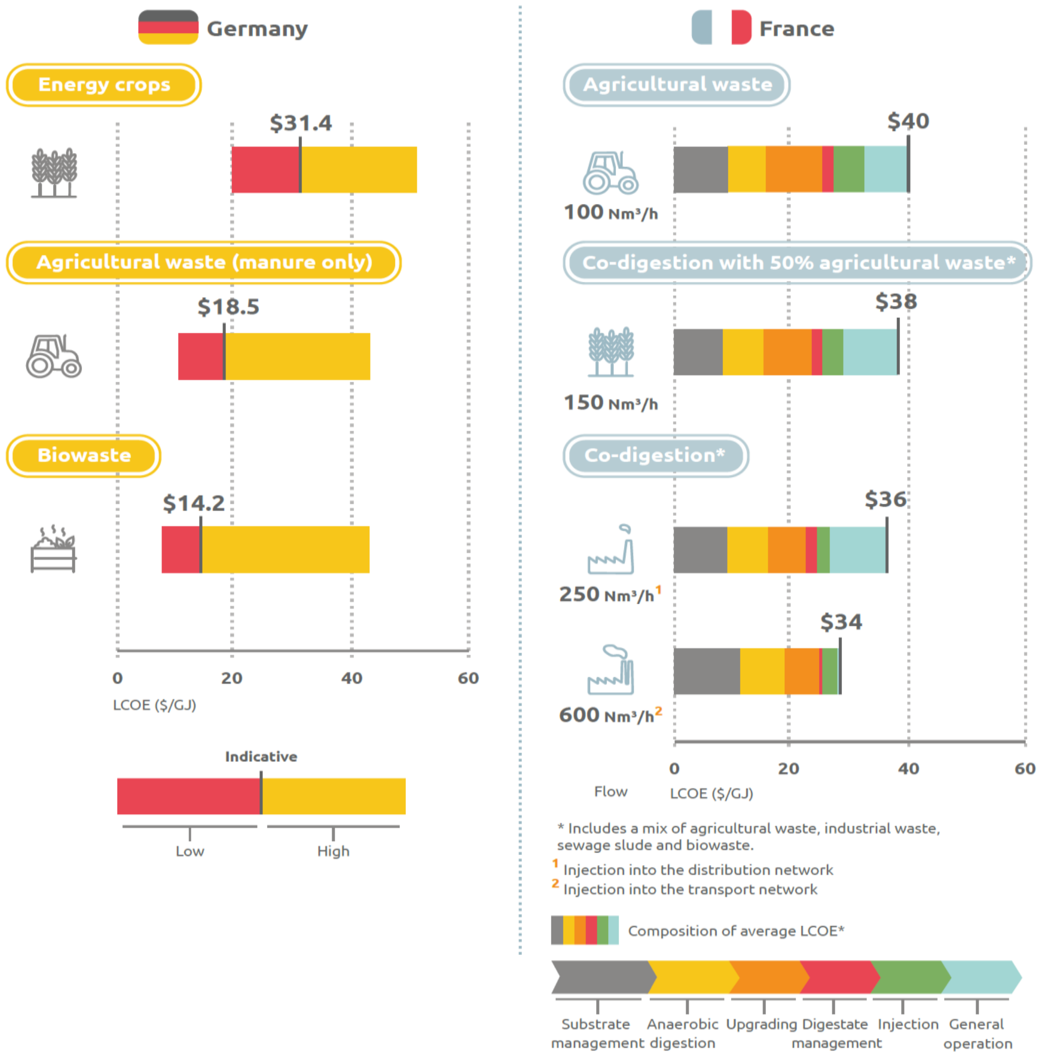
If we take the top end of the range quoted by IRENA, the cost of producing biomethane is in the order of $0.55USD per cubic meter, which equates to in broad terms around $NZ20/GJ.

Separately, confidential information we have been provided by proponents operating in Australia, indicated large scale projects cost $15 to $23 per GJ, excluding any value for biomethane's green attributes. This broadly aligns with prices ascribed to biomethane projects in Germany, although higher costs have been ascribed to projects in France.

26 https://irena.org/newsroom/articles/2017/Mar/Biogas-Cost-Reductions-to-Boost-Sustainable-Transport

27 https://www.irena.org/costs/Transportation/Biomethane

Figure 18: Cost of producing and injecting biomethane into the German and French Grids



Source: ENEA, *Biogas Opportunities for Australia*, page 38

Whilst it is clear that biogas production costs are highly situational dependent, for example what feedstock is relied upon, for the purposes of this analysis we have adopted a starting price of $20/GJ, broadly aligned to the reported information out of Germany, which aligns with information we have been provided by a proponent in Australia, which appears reasonable when compared to the costs reported by IRENA for biogas (after making an allowance for the cost of upgrading biogas to biomethane).

Applying IRENA's 40% cost reduction[28] to this produces a long-term figure in the order of $12/GJ, or ~$43/MWh based on a GJ to MWh conversion of 0.277778, which is:

- Equivalent to the CCC's assumed cost of importing LNG, which, according to its modelling, sets the ceiling wholesale price for domestic production; and
- Well below the CCC's forecast electricity price (see below).

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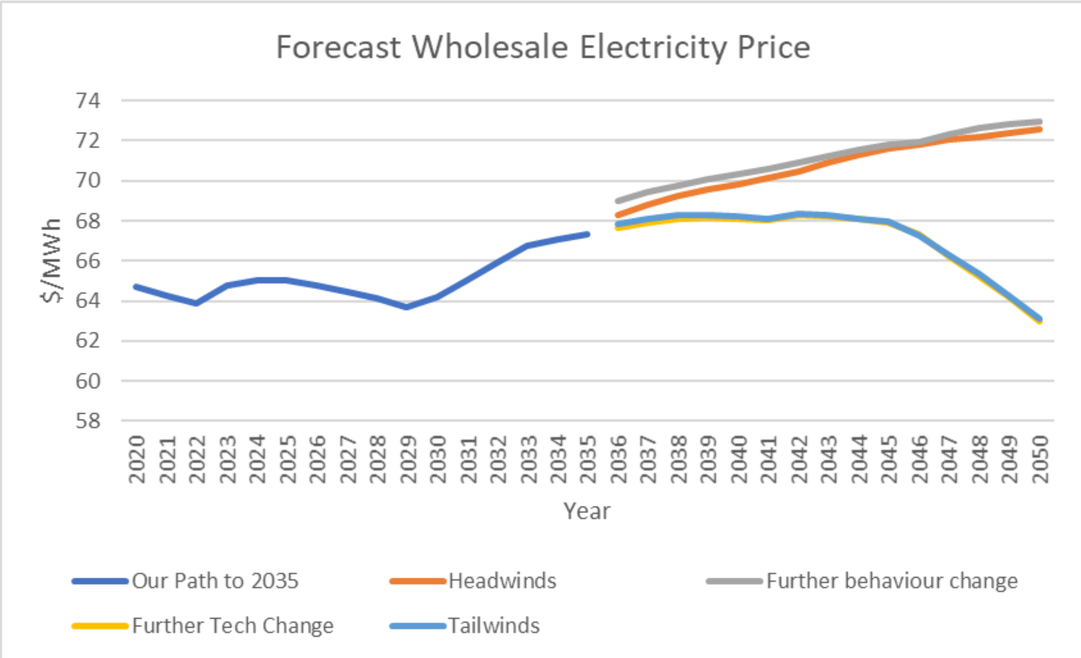
28 Noting again, for the avoidance of doubt, that IRENA does not specify over what time frame is believes this cost reduction is achievable.

4.2.4. Electrification

The CCC's modelling assumes the following wholesale electricity costs.

Figure 19: CCC's forecast wholesale electricity cost

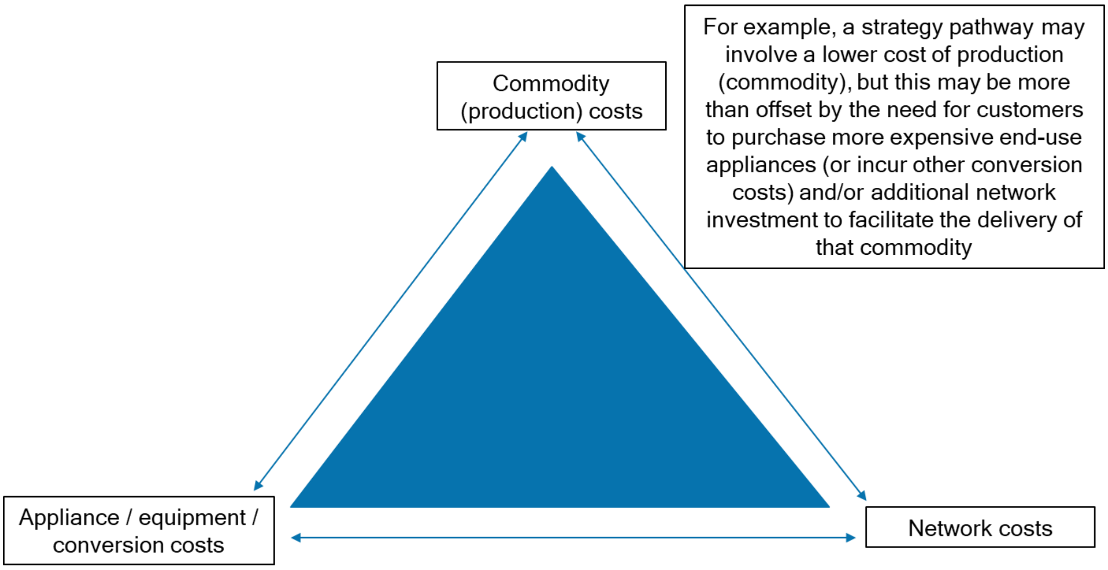


Source: Technical-assumptions-in-ENZ-energy-and-transport-2021-02-18.xls

4.3. Trade-off between the commodity, appliance and network costs of different decarbonisation pathways

Whilst the discussion in the previous section focuses on the cost of producing the energy, production costs are only one part of the value chain. There is clearly a trade-off between the commodity (production) costs, appliance (and other) costs incurred by customers in switching fuel use and the network costs associated with an electrification pathway as compared to other renewable gas pathways such as hydrogen and renewable methane.

Figure 20: Trade-off between the commodity, appliance and network costs of electrification as compared to other renewable gases such as hydrogen and renewable methane



Source: OGW

The following table builds upon this information by highlighting the quantum of the aforementioned trade-off between the commodity, appliance and network costs of electrification as compared to other renewable gases such as hydrogen, renewable methane and biomethane. To do this, we have undertaken a simple comparison of the:

- Long-run potential costs of producing each key commodity (e.g., electricity, hydrogen, renewable methane) on an energy-by-energy basis for the average residential and commercial customer, after allowing for notional improvements in efficiency as a result of moving to electric appliances[29], and
- The breakeven point, or maximum amount that the industry would be able to spend on:
  - Converting customer appliances (and any consequential change-out costs such as re-wiring); and
  - Converting or augmenting networks to cater for the additional loads (in the case of electrification) or new source of energy (in the case of hydrogen).

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29 For the purposes of this analysis, we have assumed weighted average co-efficient of performance characteristics of 2 for residential customers, and 1.5 for commercial customers.

Table 4: Customer Numbers, Usage and Conversion Information

Parameter	Residential customers	Commercial customers	Key Assumptions
Customer Numbers	272821	13189	Information Disclosure Data
Average usage per day (GJ)	18855	21184	Information Disclosure Data
Conversion to kg of H_2 per day	132780	149180	GJ per KG (0.142 - HHV)
Conversion to electricity (MWh/day)	5237	5884	GJ to MWh Conversion (0.27777)
Conversion to renewable / bio methane (GJ/day)	18855	21184	1GJ NG = 1GJ RM = 1GJ BM

Note: Industrial customers are excluded given their heterogeneity; the above conversions exclude any allowance for the efficiency benefits from moving to electric appliances.

Using the above information, combined with the long-run costs of production contained in the below table, we get the following costs for each fuel (per day, and per year).

Table 5: Costs for each fuel (per day, and per year), by customer class

Fuel Costs	Residential Cost	Commercial Cost	Cost per Unit of Fuel	Unit
Gas Cost per day	$150,838	$169,468	$8.00	per GJ
H_2 Cost per day	$265,560	$298,360	$2.00	per kg
Electricity Cost per day	$170,217	$254,988	$65.00	per MWh
Renewable Methane Cost per day	$331,754	$372,729	$17.60	per GJ
Bio Methane Cost per day	$226,258	$254,203	$12.00	per GJ
Gas Cost per year	$55,056,000	$61,856,000		
H_2 Cost per year	$96,929,577	$108,901,408		
Electricity Cost per year	$62,129,216	$93,070,445		
Renewable Methane Cost per year	$121,090,054	$136,045,961		
Bio Methane Cost per year	$82,584,000	$92,784,000		

Note: The electricity costs (both per day and per year) include an allowance associated with the efficiency benefits from moving to electric appliances. We have assumed a weighted average co-efficient of performance of 2 for residential customers, and 1.5 for commercial customers.

The following table compares the estimated costs of the electrification pathway as compared to the hydrogen pathway.

Table 6: Relative costs of different pathways – Electrification c.f to H_2

H_2 c.f Electrification	Residential customers	Commercial customers	Key Assumptions
Diff H_2 to electrification - Total pa	$34,800,361	$15,830,964	Differences from the earlier table
Diff H_2 to electrification - per Customer	$128	$1,200	Row above divided by customer numbers from earlier table
Commodity cost savings over 20 years (per customer) - H_2 Vs Elec	$1,590	$14,959	PV, 20yrs, WACC 5%
Assumed impact per customer on coincident peak demand (kW)	1.00	17.70	Est 1.0kW coincident peak demand for Res (equivalent to 0.4 load factor, and ave COP of 2); Commercial (0.7 LF, COP of 1.5)
Backsolved LRMC to make it economic to go to H_2 if no gas network upgrages/difference in appliances	$128	$68	Difference in annual cost per customer divided by assumed impact on coincident peak demand
Breakeven expenditure on H_2 appliance upgrades over electric appliance upgrades, if LRMC $100/kW	$344	-$7,105	Based on broad estimate of LRMC for electricity distribution businesses

What this indicates is if the costs of converting appliances and expanding electricity networks are more than $1590 (for residential customers over 20 years) and $14,959 (for commercial customers), then a H_2 approach will be better[30].

Put another way, the analysis indicates that everything else being equal, for residential customers, NZ could afford to contribute up to $128/kW per annum (and $68/kW per annum for commercial customers) to the cost of augmenting the electricity networks of NZ, before it is likely to become more economic to adopt a H_2 pathway.

Put yet another way, the amount that could be spent on electric appliance upgrades over H_2 appliance upgrades, if the LRMC was $100/kW per annum[31], is in the order of only $344 for residential customers. The results are inverted for commercial customers. That is, if the LRMC is $100/kW per annum, then the average commercial customer would need to save ~$7,000 on their purchase of, and conversion to, electric appliances, over what they would incur if they were required to purchase hydrogen-enabled appliances. Whilst this seems somewhat counterintuitive, the reason for this outcome primarily relates to the estimated relative efficiency of electric appliances for commercial customers relative to residential customers, which reduces the relative benefits of switching fuels for the two different customer types, given the production cost assumptions.

We have done a similar comparison between electrification and renewable methane in the table below.

30 Assuming not cost of converting gas distribution networks.

31 We have been advised by the NZ gas businesses that this is likely to be a reasonably representative LRMC to use for the purposes of this part of our analysis.

Table 7: Relative costs of different pathways – Electrification c.f to Renewable Methane

Renewable Methane c.f Electrification	Residential customers	Commercial customers	Key Assumptions
Diff Renewable Methane to electrification - TOTAL pa	$58,960,838	$42,975,516	Differences from the earlier table
Diff Renewable Methane to electrification - per Customer	$216	$3,258	Row above divided by customer numbers from earlier table
Commodity Cost savings over 20 years (per customer) - RM Vs Elec	$2,693	$40,607	PV, 20yrs, WACC 5%
Assumed impact per customer on coincident peak demand (kW)	1.00	17.70	Est 1.0kW coincident peak demand for Res (equivalent to 0.4 load factor, and ave COP of 2); Commercial (0.7 LF, COP of 1.5)
Backsolved LRMC to make it economic to go to RM if no gas network upgrages/difference in appliances	$216	$184	Difference in annual cost per customer divided by assumed impact on coincident peak demand
Amount that could be spent on elec appliance upgrades over NG appliance upgrades and still breakeven, if LRMC $100/kVA	$1,447	$18,544	Based on broad estimate of LRMC for electricity distribution businesses

What this indicates is if the costs of converting appliances and expanding electricity networks are more than $2693 (for residential customers over 20 years) and $40,607 (for commercial customers), then a renewable methane approach will be better.

Put another way, the analysis indicates that everything else being equal, NZ customers could afford to contribute between $180kW - $200/kW per annum to the cost of augmenting the electricity networks of NZ, before it might be more economic to adopt a renewable methane pathway.

Put yet another way, the amount that could be spent on electric appliance upgrades over renewable methane (natural gas) appliance upgrades, if the LRMC $100/kW per annum, is in the order of $1450 for residential customers and $18,500 for the average commercial customer.

Finally, we have done a similar comparison between electrification and biomethane in the table below.

Table 8: Relative costs of different pathways – Electrification c.f to BioMethane

BioMethane c.f Electrification	Residential customers	Commercial customers	Key Assumptions
Diff BioMethane to electrification - TOTAL pa	$20,454,784	-$286,445	Differences from the earlier table
Diff BioMethane to electrification - per Customer	$75	-$22	Row above divided by customer numbers from earlier table
Commodity Cost savings over 20 years (per customer) - BM Vs Elec	$934	-$271	PV, 20yrs, WACC 5%
Assumed impact per customer on coincident peak demand (kW)	1.00	17.70	Est 1.0kW coincident peak demand for Res (equivalent to 0.4 load factor, and ave COP of 2); Commercial (0.7 LF, COP of 1.5)
Backsolved LRMC to make it economic to go to BM if no gas network upgrages/difference in appliances	$75	-$1	Difference in annual cost per customer divided by assumed impact on coincident peak demand
Amount that could be spent on elec appliance upgrades over NG appliance upgrades and still breakeven, if LRMC $100/kVA	-$312	-$22,334	Based on broad estimate of LRMC for electricity distribution businesses

What this indicates is if there is any material cost associated with converting appliances and expanding electricity networks to accommodate increased loads transferred from natural gas, then a biomethane approach will be more economic. This is because the long-term forecast costs of production in our assessment are similar (after allowing for the added efficiency of electric appliances).

Put another way, if the LRMC of supply is $100/kW per annum, electric appliance upgrades (and other associated conversion costs) would in fact need to be materially cheaper than biomethane (natural gas) appliances.

Whilst the above analysis is indicative only, what we believe it demonstrates is that:

- Forecast long-term production cost declines for renewable gases such as hydrogen, renewable methane and biomethane are such that these gases may be able to reach levels that are relatively similar to the CCC's long-term forecast of electricity prices;
- Moreover, production costs are only one part of the value chain; there is clearly a trade-off between the commodity, appliance and related conversion costs and network costs of electrification as compared to other renewable gases; and
- Even after taking into account an estimate of the relative efficiency of electric appliances, once allowances are made for the impact that the additional loads might have on electricity networks, renewable gases may well be a more economic path to decarbonising existing gas uses in the long term; and
- To be assured about the efficiency of any individual policy, particularly one that seeks to prohibit gas consumption, the CCC (and policymakers) should analyse in detail the:
  - Customer-side costs (e.g., the relative cost of different appliances, and changeover costs);
  - Relative efficiency of the electric appliances that might be adopted in lieu of gas or hydrogen-enabled appliances; and

- Impact that customer switching is likely to have on electricity networks' peak demands, and in turn future costs, as well as gas networks if hydrogen is adopted[32].

The following sub-section provides some further information on customer switching costs.

4.3.1. Customer transition costs

The cost that residential and commercial customers would incur in converting from the use of natural gas appliances to electricity appliances include not only the difference in the capital costs between the two types of appliances[33], but also any additional labour and other costs associated with the change from gas to electricity. Those other costs could include labour and material costs associated with the need for additional wiring or meter board alterations to accommodate the additional electricity supply required.

The time available for this response did not allow us to undertake a comprehensive, independent survey of these costs in New Zealand. However, the following figures from Powerco provide a useful indication of the likely retrofit costs associated with the replacement of residential gas appliances with corresponding electric equipment.

Table 9: Indicative retrofit costs for replacing residential gas appliances to electric equipment

End-use appliances	Annual gas load (GJ)	Approximate proportion of Powerco customers with this suite of appliances	Retrofit cost[34]
Water heater + hobs[35]	<14	27%	$2,025
Water heater and space heating (simple system / low consumption)	14-30	37%	$2,778
Water heater and space heating (medium complexity system / medium consumption)	30-40	12%	$3,525
Water heater and space heating (complex system / high consumption)	40-50	8%	$4,687
Water heater + hobs and Central or Radiator heating	50+	16%	$10,425
Weighted average retrofit cost		100%	$4,011

Source: Powerco

32 We understand that the NZ gas businesses are currently undertaking work to determine the extent of the impact catering for renewable gases such as hydrogen would have on the costs of operating existing gas grids.

33 Where the changeout occurs at the end of the useful life of the gas appliance this difference is only the difference in the cost of the two types of appliance. However, if the changeout occurs prior to the end of the useful life of the gas appliance some allowance for the reduced economic life of that appliance should also be taken into account,

34 For simplicity, assumes that appliance and installation costs for gas and electricity for space heating appliances are the same, and that removal and disposal costs are the same.

35 Assumes replacement of gas instantaneous water heater with an electric cylinder water heater and gas hobs with electric hobs.

The figures show that on average, these costs are about $4,000 per house using natural gas. The retrofit costs for a house using LPG are estimated to be somewhat lower, at about $3,000.

4.4. Indirect costs and benefits associated with different decarbonisation options

There are a number of other indirect costs and benefits associated with different decarbonisation options. It is important to explicitly consider the nature and scale of these costs when assessing policy options that foreclose particular fuels or technologies. It is not clear that the CCC's analysis has given these due consideration when developing their policy recommendations.

These are discussed in more detail below.

4.4.1. Impact on the economics of the existing gas networks and in turn the supply of gas to hard-to-abate sectors in the long-term

The CCC is forecasting:

- Gas consumption to decline under the various scenarios that the CCC has modelled, with the CCC modelling a relatively gradual transition away from gas for residential and commercial customers over a 20 year period; and
- Gas to be consumed beyond 2050 under all modelled scenarios, primarily by customers who are in what are generally termed 'hard-to-abate' sectors.

The former assumption may impact on the veracity of the latter assumption, if:

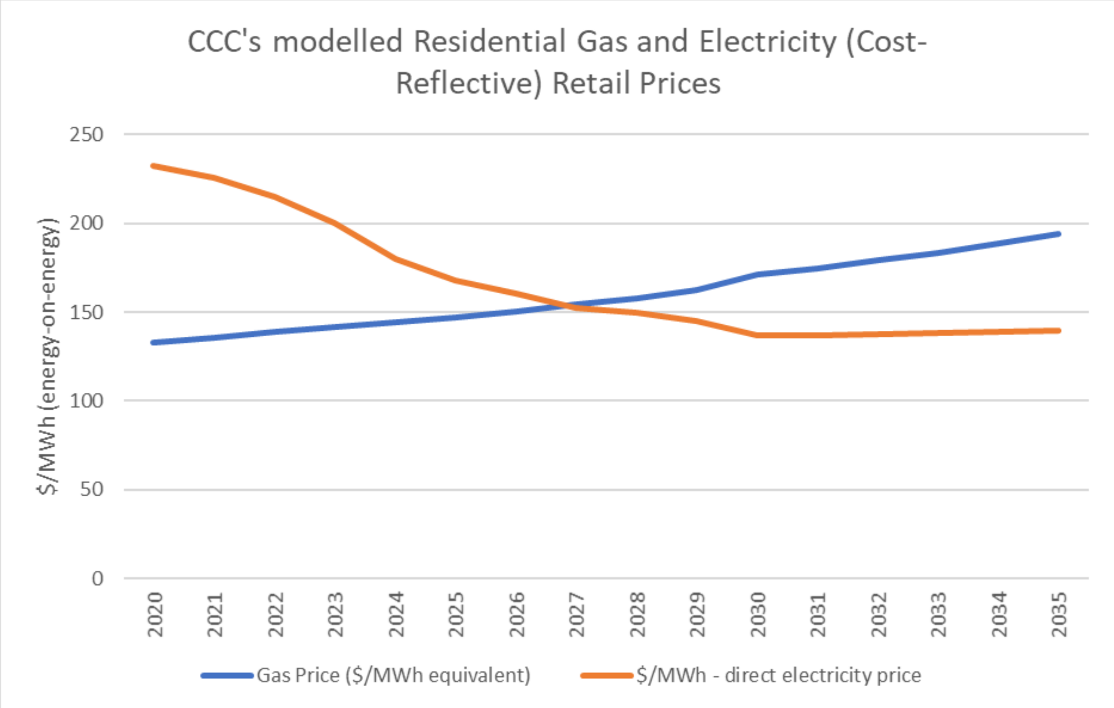
- Residential and commercial customers switch away from gas more quickly than what the CCC has assumed, impacting upon the underlying economics of gas networks; and
- The CCC has implicitly assumed that gas distribution businesses will continue to supply gas to 'hard-to-abate' sectors in the long-term at prices that enable them to continue to be economic.

Each of these is discussed in more detail in the following sections.

The impact on the economics of gas networks

A combination of factors appears to be contributing to the CCC forecasting a material change in the bills that residential and commercial electricity and gas customers will face out to 2035 (and beyond), which goes to customers' incentive to adopt gas, which is a fuel of choice, and in turn, the underlying economics of gas distribution networks.

Figure 21: CCC's modelled residential electricity and gas retail prices



Source: OGW analysis of CCC's Technical-assumptions-in-ENZ-energy-and-transport-2021-02-18.xls' - 'Our path to 2035'; Conversion based on 1GJ = 0.277778MWh.

Based on the CCC's published information, the relative cost advantage that gas has held over electricity (on an energy-on-energy basis) will dissipate by around 2027, with electricity forecast to quickly gain a significant relative cost advantage over gas thereafter. Based on our analysis of the CCC's modelling, the factors contributing to this outcome appear to be:

- An assumed move to more cost reflective electricity charges – resulting in, amongst other things, higher fixed charges being offset by lower variable charges; and
- Higher gas distribution charges and carbon-related charges related to the consumption of gas – each of which contributes around $6.80/GJ to higher residential gas bills under the CCC's 'Our Path to 2035' case - with the former driven by the lower throughput gas volumes (resulting in higher unit charges for gas).

An inevitable outcome of this cross-over in the relative costs of gas and electricity is that some customers will elect to switch from gas to electricity on purely economic grounds, bringing forward switching, relative to the CCC's modelled transition (which assumes a gradual transition over a 20 year period).

To illustrate the switching economics, the following table highlights the annual saving to customers in 2035, and the economics of bringing forward appliance replacements.

Table 10: Economics of bringing forward the purchase of electric appliances

Parameter	Annual Usage		
	10GJ	20GJ	30GJ
Per annum saving in 2035 (energy-on-energy)*	$152.05	$304.10	$456.15
PV of savings over 20 years (energy-on-energy)*	$2,161.01	$4,322.03	$6,483.04
Per annum saving in 2035 (with an assumed efficiency)**	$202.74	$405.47	$608.21
PV of savings over 20 years (with an assumed efficiency)**	$2,881.35	$5,762.71	$8,644.06
Breakeven Capex b.f one year**	$5,792.43	$11,584.86	$17,377.29
Breakeven Capex b.f 2 year**	$2,896.22	$5,792.43	$8,688.65
Breakeven Capex b.f 3 year**	$1,930.81	$3,861.62	$5,792.43
Breakeven Capex b.f 4 year**	$1,448.11	$2,896.22	$4,344.32
Breakeven Capex b.f 5 year**	$1,158.49	$2,316.97	$3,475.46

*Does not take into account different efficiencies (e.g., COP for heat pumps); **Assumes an efficiency of electricity appliances over gas appliances of 25%, which is likely to be relatively conservative; Customer Discount Rate (WACC) = 3.5%

Whilst bringing forward switching, and hence the emissions reductions associated with switching from gas to electricity, in and of itself may be appealing to the CCC, it may also have a material consequential impact upon the CCC's modelled outcomes. This is because the CCC's modelling appears to implicitly assume that the gas businesses affected by the declining volumes and in turn declining revenues, will continue to be financially viable (and hence will continue to operate) until at least 2050 in order to service the future gas demands of customers in hard-to-abate sectors.

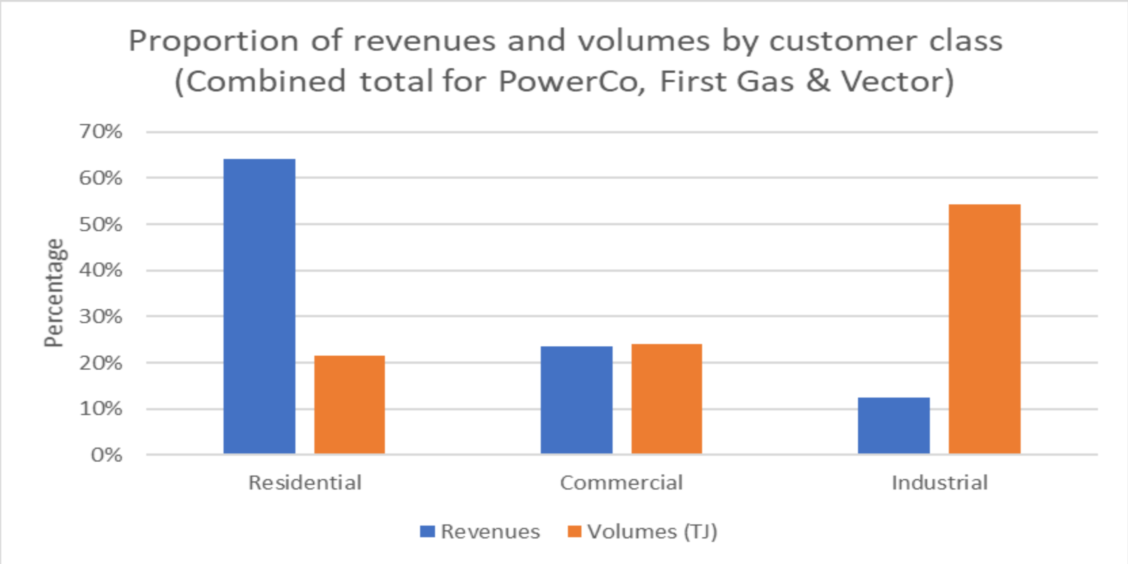
This long-term viability is questionable, given any reduction in residential and commercial volumes will disproportionately impact on the revenues network businesses generate relative to their costs[36], as:

- Businesses recover the majority of their costs from residential and small commercial customers, with these customers contributing around 65% of New Zealand's gas network businesses' revenue, despite only consuming around 20% of the volume (see below);

36 For example, Firstgas states, in the context of the development of its prices for gas transmission services, that "*given the substantial costs of the transmission system, there is a strong commercial drive on the GTB to maintain and improve economies of density (more consumers per unit of pipeline) and economies of scale (more GJ delivered per unit of pipeline). Improved economies of scale and density mean that the GTB can use its capital more efficiently; consumers ultimately benefit from the sharing of common costs across a wider number of consumers and/or gas throughput. A more diverse consumer base is also in the GTB's commercial interests as it mitigates asset stranding risks and increases the commercial resilience of gas transmission*". (Firstgas, *Pricing Methodology for Gas Transmission Services*, From 1 October 2018)

- Businesses have limited ability to rebalance their tariffs towards remaining customers, as those customers are likely to be particularly sensitive to increases in the price of gas, hence any price increase is likely to be a catalyst for business closures;
- Businesses' costs are predominately either fixed or sunk, not variable, hence the reduced volumes (and customers served) are unlikely to material impact on their costs-to-serve; and
- Customers who are likely to continue to use gas over the the CCC's forecast evaluation period (hard-to-abate, industrial customers) do not appear to be clustered together[37], which means that the 'right-sizing' of businesses in response to the new demand for their services is unlikely to unlock equivalent reductions in the size, scale or spread of their network.

Figure 22: Proportion of revenue NZ network businesses generate from different customer classes



Source: Vector's 2020 GDB Information Disclosure - Schedule 8 (Billed Quantities by Price Component); Firstgas, Final GDB Information Disclosure 2019 - Schedule 8 (Billed Quantities by Price Component); PowerCo, Gas Distribuion Services - Annual Information Disclosure Statement 2019 - Schedule 8 (Billed Quantities by Price Component).

To illustrate the potential extent of this issue, the following table highlights:

- The revenue that each gas distribution business generated from its different customer categories in either their 2019 (or 2020) information disclosures;
- The operational expenditures that each gas distribution business incurred, by reported category, in that same year;
- The forecast revenue each business might expect to generate from its different customer categories in 2035 and 2050, based on overlaying the CCC's forecast decline in residential and commercial volumes on the current revenues that each business generates from those customer categories;

37 For example, Powerco have informed us that they would have to continue to operate in the order of 90% of their sub-network.

- The forecast revenue[38] each business might expect to generate from its different customer categories in 2040, based on an economic switching model underpinned by the CCC's modelled residential gas and electricity prices; and
- The:
  - Residual coverage, being forecast revenue under each of the above situations less current operating costs[39]; and alternatively
  - Impact on industrial tariffs if lost revenue was to be recovered via higher industrial prices.

Table 11: Total revenue and ability to as a minimum, cover existing operating expenditures – Vector

Parameter ($'000)	Current[1]	2035[2]	2050[3]	2040 (economic switching)[4]
Revenue				
Residential Revenue [A]	$27,536	$16,338	$557	$6,150
Business revenue [B]	$1,445	$857	$29	$322
Commercial Revenue [C]	$9,931	$5,892	$200	$2,218
Industrial [D]	$8,832	$8,832	$8,832	$8,832
Total	**$47,744**	**$31,919**	**$9,618**	**$17,522**
Operating and Notional Interest Expenditure				
Network opex	$5,238	$5,238	$5,238	$5,238
Non-network opex	$7,855	$7,855	$7,855	$7,855
Notional interest [Schedule 5a(i)]	$5,812	$5,812	$5,812	$5,812
Total [F]	**$18,905**	**$18,905**	**$18,905**	**$18,905**
Residual Coverage	**$28,839**	**$13,014**	**-$9,287**	**-$1,383**
Equivalent Per GJ industrial tariff to maintain current revenues	**$1.0543**	**$2.9434**	**$5.6056**	**$4.6621**
Per GJ industrial tariff to maintain positive residual coverage	**$1.0543**	**$1.0543**	**$2.1629**	**$1.2194**

38 This assumes that all industrial load will continue to be served at current prices. In reality, the businesses will also see declines in the revenues that they generate from these customers, linked to declines in volumes. This would further exacerbate the financial viability issue.

39 This approach implicitly assumes that operating costs will not decline as volumes (or revenues) decline. If anything, this is likely to overestimate operating costs. Whilst we cannot be sure of the magnitude of this, given the cost structures of gas network businesses and the fact that businesses have indicated that they will have to continue to operate most parts of their network to provide gas to existing 'hard-to-abate' sectors, the magnitude of this overestimate is unlikely to affect the conclusions that are drawn from this analysis.

Source: 1. Vector's 2020 GDB Information Disclosure for Schedules 7 and 8; 2. Reflects the percentage decline in residential, commercial and agricultural gas demand between 2020 and 2035 from the CCC's 'Our Path to 2035' sheet (Row 215, 'Draft-Advice Scenarios-dataset'); 3. Reflects the percentage decline in residential, commercial and agricultural gas demand between 2020 and 2050 from the CCC's 'Further Technology Change' sheet (Row 215, 'Draft-Advice Scenarios-dataset'); 4. Proxied by bringing forward declines in volumes by 5 years, which broadly reflects the economics of switching as highlighted earlier.

Table 12: Total revenue and ability to as a minimum, cover existing operating expenditures – Firstgas

Parameter ($'000)	Current[1]	2035[2]	2050[3]	2040 (economic switching)[4]
Revenue				
Residential Revenue [A]	$14,901	$8,841	$301	$3,328
Business revenue [B]	$880	$522	$17	$196
Commercial Revenue [C]	$5,966	$3,539	$120	$1,332
Industrial [D]	$2,009	$2,009	$2,009	$2,009
Total	**$23,756**	**$14,911**	**$2,447**	**$6,865**
Operating and Notional Interest Expenditure				
Network opex	$3,425	$3,425	$3,425	$3,425
Non-network opex	$3,574	$3,574	$3,574	$3,574
Notional interest [Schedule 5a(i)]	$2,401	$2,401	$2,401	$2,401
Total [F]	**$9,400**	**$9,400**	**$9,400**	**$9,400**
Residual Coverage	**$14,356**	**$5,511**	**-$6,953**	**-$2,535**
Equivalent Per GJ industrial tariff to maintain current revenues	**$0.3666**	**$1.9807**	**$4.2551**	**$3.4489**
Per GJ industrial tariff to maintain positive residual coverage	**$0.3666**	**$0.3666**	**$1.6354**	**$0.8292**

Source: 1. Firstgas, Final GDB Information Disclosure 2019 – Schedules 7 and 8; 2. Reflects the percentage decline in residential, commercial and agricultural gas demand between 2020 and 2035 from the CCC's 'Our Path to 2035' sheet (Row 215, 'Draft-Advice Scenarios-dataset'); 3. Reflects the percentage decline in residential, commercial and agricultural gas demand between 2020 and 2050 from the CCC's 'Further Technology Change' sheet (Row 215, 'Draft-Advice Scenarios-dataset'); 4. Proxied by bringing forward declines in volumes by 5 years, which broadly reflects the economics of switching as highlighted earlier.

Table 13: Total revenue and ability to as a minimum, cover existing operating expenditures – Powerco

Parameter ($'000)	Current[1]	2035[2]	2050[3]	2040 (economic switching)[4]
Revenue				
Residential Revenue [A]	$37,266	$22,111	$754	$8,324
Business revenue [B]		$0	$0	$0
Commercial Revenue [C]	$10,913	$6,475	$220	$2,437
Industrial [D]	$4,530	$4,530	$4,530	$4,530
Total	**$52,709**	**$33,116**	**$5,504**	**$15,291**
Operating and Notional Interest Expenditure				
Network opex	$5,998	$5,998	$5,998	$5,998
Non-network opex	$10,063	$10,063	$10,063	$10,063
Notional interest [Schedule 5a(i)]	$5,993	$5,993	$5,993	$5,993
Total [F]	**$22,054**	**$22,054**	**$22,054**	**$22,054**
Residual Coverage	**$30,655**	**$11,062**	**-$16,550**	**-$6,763**
Equivalent Per GJ industrial tariff to maintain current revenues	**$1.2693**	**$6.7590**	**$14.4957**	**$11.7534**
Per GJ industrial tariff to maintain positive residual coverage	**$1.2693**	**$1.2693**	**$5.9064**	**$3.1642**

Source: 1. Powerco, Gas Distribuion Services - Annual Information Disclosure Statement 2019 - Schedules 7 and 8; 2. Reflects the percentage decline in residential, commercial and agricultural gas demand between 2020 and 2035 from the CCC's 'Our Path to 2035' sheet (Row 215, 'Draft-Advice Scenarios-dataset'); 3. Reflects the percentage decline in residential, commercial and agricultural gas demand between 2020 and 2050 from the CCC's 'Further Technology Change' sheet (Row 215, 'Draft-Advice Scenarios-dataset'); 4. Proxied by bringing forward declines in volumes by 5 years, which broadly reflects the economics of switching as highlighted earlier.

As can be seen from the above tables, the forecast decline in residential and commercial gas consumption is likely to significantly impact upon the underlying economics of each of the businesses. Moreover, if the CCC's forecast bill impacts are to be believed, then this would occur well before 2050, because of the incentive it suggests there will be for customers to elect to switch from gas to electricity. Whilst this would obviously be of significant concern to shareholders of these business, it begs the question as to the veracity of the CCC's implicit assumption that these businesses will continue to operate in a manner that allows gas to continue to be delivered to hard-to-abate customers in the longer term. This includes making investments in the near term in long-lived assets whose costs may not be able to be recovered.

Impact on residual industrial/large commercial customers

Unfortunately, the information provided by the CCC does not separate out gas demands over the forecast time horizon into those that will be directly served from the gas transmission system, versus those that will be served via a connection to a gas distribution system. Therefore, it is impossible to know exactly what levels of residual gas demand on gas distribution networks is implied by the CCC's modelling. Comprehensive analysis of this will be essential to ensure policies that target particular customer groups are feasible (e.g., assuming networks remain available for hard-to-abate customer segments).

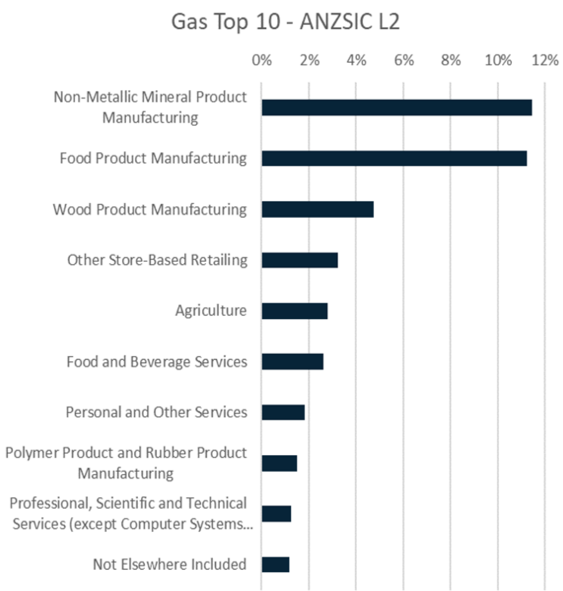
However, based on information provided by NZ's gas businesses, these hard-to-abate customers are not likely to be limited to just transmission connected customers – that is, many of them are likely to be distribution connected, and hence will rely on existing (or part thereof) gas distribution networks being retained.

For example, Vector has noted that its top 5 customers represent 20% of its gas consumption[40]. These customers operate in the following industries:

- Glass manufacturer
- Sugar manufacturer
- Paper bag manufacturer
- Plaster board manufacturer
- Wood treatment chemical manufacturer

On face value, businesses operating in these industries using these types of volumes, are almost certainly likely to fit the category of hard-to-abate customers. Vector has also provided a breakdown of its top 10 gas consuming industries (by ANZIC code).

Figure 23: Top 10 gas consuming industries - Vector



Source: Vector, private correspondence

40 Per information provided by Vector

Again, industries such as non-metallic mineral product manufacturing, food product manufacturing and polymer and rubber product manufacturing, amongst others, are likely to be relatively hard-to-abate.

Similarly, Powerco has indicated[41] that over 3,300TJ of its ~5700TJ of commercial and industrial gas demand is related to the manufacturing sector. Whilst we do not have a further breakdown of this volume by industry classification, one would assume that a reasonable portion of this demand is likely to be associated with hard-to-abate sectors.

Collectively, this information indicates that even though the CCC has not identified exactly how much demand will need to be serviced by gas distribution businesses over its forecast horizon, for each of its modelled scenarios, a material portion of that demand is likely to be related to customers who are connected to the distribution system. Put another way, the CCC modelled outcomes appear to implicitly assume that NZ's gas distribution business will continue to operate (and hence, presumably, will continue to be viable) over the entirety of the forecast time horizon.

As discussed above, this assumption is questionable.

4.4.2. Option value

The CCC explicitly states that one of its design principles is to 'create options' ('Principle 3 – Create Options') when developing its decarbonisation pathway for gas. As the CCC states[42]:

> *"there is much uncertainty in embarking on this decades-long transition. Uncertainty is not a reason for delay. There is value in creating options for meeting the targets and having the ability to adjust course as the transition proceeds . The decisions taken now should open up a wide range of future options and keep options open for as long as possible. This needs to be balanced with the need to take advantage of key windows of opportunity, where making significant investments in key technologies could ultimately make the transition to low emissions cheaper and faster".*

We agree with this criteria. We would alternatively frame this by saying that locking in solutions to ensure intermediate targets are met, whilst crowding out potentially viable long-term alternatives, could lead to suboptimal outcomes.

The CCC's discussion around hard-to-abate sectors is an excellent reference case; the future is uncertain, and it is not clear what the most efficient long-term solution will necessarily be[43]:

> *Hard-to-abate industries are likely to still create significant emissions in 2050, but they provide products that are fundamental to the economy, like cement, steel and iron. Aotearoa has a choice as to whether it is critical to keep these industries and manufacturing plants based here. If Aotearoa keeps old, emitting plants it would be possible to use forestry to offset the associated emissions. It may be beneficial to investigate the potential of other options to remove emissions from hard to abate industries, such as carbon capture and storage (CCS) or bioenergy combined with CCS (BECCS). However, considerable research would be required as these technologies are still largely in a research and concept phase in Aotearoa.*
>
> *There is also the potential to transform industrial processes from the hard-to-abate sectors to achieve gross emissions reductions in line with climate change targets. The country's heavy industrial manufacturing plants are relatively old and built to accommodate specific industrial processes. Entirely new industrial processes and technologies could potentially be adopted, or plants could be modernised between now and 2050, or retrofitted to make use of alternative fuels. Other choices are also available; for example, Aotearoa could import products from low emissions manufacturing plants overseas.*

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41 Per information provided by Powerco

42 Climate Change Commission, *"2021 Draft Advice for Consultation"*, 31 January 2021, page 30

43 Ibid, page 116

Retrofitting industrial plants with new technologies or building new low emissions processes for the hard-to-abate sectors is expensive based on current cost estimates. Significant research, development and innovation is required. Technologies developed overseas may need to be adapted to work in the unique Aotearoa industry processes.

A long-term strategy for hard-to-abate industries should be developed and closely linked to the country's Economic Plans, national infrastructure developments and equitable transitions planning. If the Government decides these hard-to-abate industries are critical national infrastructure, it must work collaboratively and inclusively to ensure that people working in these industries are upskilled appropriately.

The CCC considers that its recommendations have "created options" and to have "kept them open for as long as possible[44]". In some ways, they have, in that they allow for actions in some areas to be increased if actions in other areas were slower than expected, however, in some ways, they haven't. The prime example of which is the CCC's recommendations that relate to gas usage, which explicitly have the effect of banning new gas connections, and implicitly, are likely to have the effect of foreclosing on longer term options that might be able to leverage off the existing gas infrastructure, given the significant uncertainties that its policies create for the on-going financial viability of these businesses.

4.4.3. Limiting customer choice

The industry has always understood that gas is a fuel of choice for most customers. For example, in the context of the development of its prices for gas transmission services, Firstgas states that[45]:

"the starting point for establishing prices for gas transmission services is a consideration of the role of gas as a fuel. Unlike electricity, gas is a discretionary fuel for many consumers".

They go on to say that:

"a key part of the GTB's pricing methodology is testing proposed prices against the lowest cost alternative energy source"… and that they had previously asked PWC "to calculate an implied cap for gas transmission cost based on the cost of alternative fuels…….the implied cap on gas transmission cost is a proxy for the maximum price that could be charged for a gas transmission service before an alternative fuel becomes more cost effective".

Gas appears to not only have been able to survive in this environment, but it appears to have flourished, and it is not simply due to underlying growth in new dwellings. For example, Vector has indicated to us that around 32% of its new residential gas connections (per annum) are to existing dwellings – that is, existing customers, who already have an electricity connection, are choosing to take on an additional connection (with the associated connection costs) to gain access to gas. Clearly, some customers prefer gas over electricity for some (or many) of their energy needs, even though it requires them to incur significantly higher costs (associated with a second connection).

By recommending a policy that involves prohibiting new natural gas connections, and providing for all new or replacement heating systems that are installed to be electric or bioenergy, the CCC is limiting customer choice, and in turn, economic efficiency, as these types of customers (who are likely to place a significant value on accessing gas) may be forced to adopt replacement fuels that even after allowing for the economic cost of carbon, they would not have elected to use.

44 Ibid, page 55

45 Firstgas, Pricing Methodology for Gas Transmission Services, From 1 October 2018, section 3

Whilst there are many examples of products or services that have been prohibited or limited by Government policy, these have generally been where there are material *unpriced* negative externalities (and in particular, where there are clear and present health and safety risks). This is not the case in NZ, where there is an Emissions Trading Scheme (ETS). To the extent that there are any concerns regarding the ability for market participants to 'efficiently' respond to these price signals (e.g., due to information asymmetry), then from a policy perspective, one would have thought it preferable to overcome the underlying cause of the issue, as opposed to adopting blunt policy measures that limit rational customers from responding to the revealed, efficient, price signals. To this end, it appears that part of the CCC's rationale for presenting this recommendation is to "*avoid new heating systems having to be scrapped before the end of their useful lives*", with it saying that "*this means that our path assumes all new space heating or hot water systems installed after 2025 in new buildings are either electric or biomass*".

Firstly, it is not clear how the CCC has determined the materiality of this issue, and how this in turn has been explicitly used to inform its policy considerations, particularly regarding the proposed timing of the prohibition on new gas connections (2025, or earlier). In saying this, we note that the average life of a hot water system is about 10 years, and for a gas space heating system, about 15 years, which would mean that installations in 2025 would need to be replaced well within the CCC's overall time horizon and by 2035 in many cases. Prima facie, the risk of "*new heating systems having to be scrapped before the end of their useful lives*" would appear to be quite low, in the context of the CCC's proposed (2025, or earlier) timeframe, and low even if this prohibition were to be delayed even by 5 years.

Moreover, if the concern is that "*new heating systems having to be scrapped before the end of their useful lives*", that is, that the potential information asymmetry is that customers are not aware of this risk, then ensuring that customers are actually made aware of this should form part of the broader suite of policies adopted – rather than relying on blunt prohibitions.

4.4.4. Catalysing new technologies and new markets

The CCC notes that[46]:

> *Being an early mover in researching new technologies and adopting existing technologies will benefit not just the climate, but the economy and wellbeing of New Zealanders.*

The CCC notes the particular potential of hydrogen in other parts of its report:

> *Aotearoa should take action to scale up the manufacture of low emissions fuels like biofuels or hydrogen-derived synthetic fuels in the first three emissions budget periods*[47]
>
> *For example, there are opportunities to create new jobs associated with the circular economy, such as using wood waste for biofuels, and new industries, such as hydrogen*[48]
>
> *Bioenergy and hydrogen both hold promise, but Aotearoa needs to understand how best to make use of their potential. Our analysis indicates that these fuels have significant potential for reducing emissions in transport, process heat and industrial processes. However, more work is needed to support establishing supply chains and infrastructure and making them more cost competitive*[49].

46 Climate Change Commission, *"2021 Draft Advice for Consultation"*, 31 January 2021, page 97

47 Ibid, page 60

48 Ibid, page 96

49 Ibid, page 115

We completely support the CCC's view on this issue. In particular, existing, but currently uneconomic technologies/solutions such as hydrogen and renewable methane have significant potential to displace existing fossil fuels, across both multiple sectors (e.g., stationary energy, transport), and on a world scale given its ability to be exported.

However, it is not clear how the CCC's policy recommendations (particularly those in relation to the gas industry) have been designed to support being an "*early mover in researching new technologies*" or to take action to "*scale up the manufacture of low emissions fuels like biofuels or hydrogen-derived synthetic fuels"*. For example, a way of supporting the establishment of supply chains and infrastructure for technologies such as hydrogen and renewable methane would be to incentivise their use in 'easy to access' domestic markets such as displacing natural gas, with this presenting a necessary building block to (potentially) accessing international markets and other secondary markets such as transportation.

Put another way, if,

- supporting being an 'early mover in researching new technologies' is a consideration, and
- hydrogen and renewable methane are considered to be key 'new technologies' with significant long-term upside, then
- policies should as a minimum, seek to 'do no harm' to their prospects, and preferably, provide some form of direct or indirect assistance to these nascent, but potentially lucrative (in terms of both emissions reduction potential and economic) technologies.

4.4.5. Other electricity market benefits

Depending on their location and the technical capabilities of the facility, embedded electrolysers (utility-scale or distributed) are likely to be able to support power system security, operability and reliability.

For example, they are able to provide dispatchable load, with the amount of hydrogen that is produced from an existing facility at any point in time able to be tailored to the conditions affecting its key feedstock (e.g., the price of electricity, for electrolysis). 'Dispatchable loads' are likely to be more valuable in the future given the increased uptake in VRE, which, everything else being equal, is likely to see more volatile wholesale electricity prices.

Electrolysers can also provide grid stability services, with most common electrolyser technologies able to be ramped up and down almost instantaneously across their operating envelope. This makes their operation well placed to provide grid support services such as raising and lowering frequency by reducing/increasing demand.

Finally, hydrogen (and renewable methane made from hydrogen) is able to be stored, hence it is able to contribute to NZ's energy security. Given the CCC notes that there are questions over the technical and economic feasibility, and public support, of many of the other proposed solutions for generating sufficient renewable electricity in years when hydro lake levels are low (the "dry year" issue), there may be benefits in considering hydrogen (or renewable methane) further in this context, a fact that the CCC notes itself[50]:

> *Other actions to increase resilience of the electricity grid and the system include building new generation in the North Island, reinforcing the transmission infrastructure, deploying new technologies such as batteries, and diversifying into new fuels such as biofuels and hydrogen that boost energy security.*

50 Ibid, page 91

5. Alternative policy options that could be adopted

5.1. Objective of section

The objective of this section is to consider approaches that have been used both in New Zealand and other jurisdictions to accomplish objectives similar to those being addressed in the CCC's 2021 Draft Advice for Consultation concerning the decarbonisation of the end uses currently served by natural gas, particularly in buildings.

To do so, this section:

- Reviews the principles the CCC cites as underlying its advice; and
- Discusses policy options that have been considered/implemented in other jurisdictions, and compares and contrasts those approaches with the CCC's approach.

5.2. Criteria for assessing different policy options

5.2.1. Criteria put forward by the CCC

The CCC has stated that it has adopted a number of principles to help guide its advice. These principles are summarised in the table below.

Table 14: Criteria or principles to help guide advice

Principles	Key Features
Principle 1: Align with the 2050 targets.	▪ Meeting targets requires a long-term view of investments and infrastructure developments. ▪ Assets and investments with long lifetimes will need to be transformed, and planning for and developing new low emissions infrastructure will take time. ▪ Actions taken in the next five years will need to set Aotearoa up to deliver the deeper reductions required in subsequent emissions budgets and to meet and sustain the 2050 targets.
Principle 2: Focus on decarbonising the economy.	▪ Prioritise actions that reduce gross emissions, as well as removing emissions by sequestering carbon dioxide in forests ▪ Focus on decarbonising industries rather than reducing production in a way that could increase emissions offshore ▪ Forest sequestration should not displace making gross emissions reductions.
Principle 3: Create options.	▪ There is much uncertainty in embarking on this decades-long transition. ▪ There is value in creating options for meeting the targets and having the ability to adjust course as the transition proceeds ▪ The decisions taken now should open up a wide range of future options and keep options open for as long as possible. ▪ This needs to be balanced with the need to take advantage of key windows of opportunity, where making significant investments in key technologies could ultimately make the transition to low emissions cheaper and faster.
Principle 4: Avoid unnecessary cost.	▪ Actions Aotearoa takes to meet emissions budgets and targets should avoid unnecessary costs. ▪ This means using measures with lower costs and planning ahead so that technologies, assets and infrastructure can be replaced with low emissions choices on as natural a cycle as possible. ▪ This will help to avoid scrapping assets before the end of their useful lives or being left with stranded assets.

Principles	Key Features
Principle 5: Transition in an equitable and inclusive way.	▪ Decisions on the steps to be taken should consider equity across different groups of society, regions and communities and generations. ▪ The climate transition should be well planned and signalled in advance to give communities, businesses and individuals time to innovate and adapt, build new markets and retrain. ▪ Aotearoa will need to build new markets, invest in peoples' skills, and provide opportunities for environmentally and socially sustainable work. It should not penalise early movers
Principle 6: Increase resilience to climate impacts.	▪ Where possible, actions should increase the country's resilience to the impacts of climate change that are already being experienced and that will increase in the future
Principle 7: Leverage co-benefits.	▪ Actions should consider the wider benefits, including benefits to health, broader wellbeing and the environment. ▪ Co-benefits can provide further reason to take particular actions where the initial emissions reductions may be modest or appear relatively costly.

Key criteria that we believe should be adopted, and which align with the CCC's criteria are:

- There is significant benefit in leaving options open;
- Policy directions should be focused on incentivising the achievement of the CCC's outputs, rather than "picking winners" or "prescribing solutions", which may not be the most efficient path in the fullness of time; and
- Wherever possible, policy directions should be underpinned by the use of markets to drive desired policy outcomes.

5.2.2. Principles incorporated into the policies and actions of other jurisdictions

Three of the principles that are mentioned above have been specifically called out as being important by key parties in the UK and Europe. They are:

- Keeping options open;
- Avoiding picking winners, and relying on the market and competition to identify new, innovative solutions; and
- Seeking least-cost solutions.

The comments that follow provide insight into the views of those stakeholders and the degree to which they are inter-related and mutually reinforcing.

The UK's Department of Business, Energy and Industry Strategy (BEIS), which is responsible for the Residential Heating Initiative (RHI) which has run for a number of years and the Green Gas Support Scheme which is to replace the RHI, has stated that it expects to focus on market-based mechanisms that leverage competitive forces to drive down costs and ensure cost-effectiveness, as the basis for any ongoing policy support for the range of green gas options that might be commercially available.

It notes that there are a variety of approaches which might be considered for the design of a longer-term support mechanism. They mention, as an example, that a future scheme could potentially take the form of a Supplier Obligation, which would legally obligate gas suppliers to supply their customers with a certain volume or percentage of green gas[51].

In its document entitled *Our Strategic Narrative 2019-2023*, Ofgem (the UK's electricity, gas and water regulator) had identified its three core priorities as being to:

1. Enable competition and innovation which drives down prices and results in new products and services;
2. Protect consumers, especially the vulnerable, stamping out sharp practice and ensuring fair treatment; and
3. Decarbonise to deliver a net zero economy at the lowest cost to consumers

Ofgem published its *Decarbonisation Action Plan* in February 2020, prior to the Sixth Carbon Budget. In light of those objectives, the Plan stated that it[52]:

> *aims to facilitate the most effective path to net zero at the lowest cost to consumers, in the context of government policy"* [but recognises that] *in many areas the most cost-effective pathways to net zero are still uncertain and consequently the investment needs are unclear. As a step towards adaptive regulation, we are therefore announcing a new approach to dealing with unforeseen significant policy or technological developments that might affect our regulation of networks. This will help us respond to the net zero challenge whilst keeping down the costs to consumers.*

In the Plan, Ofgem also noted that:

> *There will be significant changes to the way we heat our homes and businesses. The best way forward is not yet clear, but it could include the development of hydrogen networks and the electrification of heating. We will work with government and harness our expertise, including in running energy support schemes and through innovation funding, to inform and develop the wider evidence base for the different options*[53].
>
> *Innovation funding within network price controls has achieved significant successes in encouraging network companies to think about how they can innovate to achieve better outcomes for consumers. We plan to build on this success by developing the structure of innovation funding so that it is more focussed on the strategic challenges the networks face, particularly decarbonisation*[54].
>
> *Decarbonising residential heating, which is currently responsible for around 18% of the UK's greenhouse gas emissions, is arguably the biggest challenge that the energy sector faces over the coming decades . . . However, we and other stakeholders can take sensible 'low regrets' actions now, to ensure GB is well set up to achieve the huge task of heat decarbonisation. In particular, developing evidence on the feasibility and cost of different routes to decarbonisation will be critical to enable the sector to deliver a timely transition at lowest cost*[55].

Comments in a document entitled *The Bridge Beyond 2025: Conclusion Paper* published jointly by the Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) are also worth noting regarding the need for flexibility.

51 BEIS, Future support for low carbon heat, April 2020, p. 23.

52 Ofgem, *Decarbonisation Action Plan*, February 2020, p. 5.

53 Ibid, p. 6.

54 Ibid, p. 17.

55 Ibid, p 20.

> *Progress on decarbonisation of energy is already underway and needs to accelerate in the near term, not just in the medium term. However, the importance and priority of decarbonisation does not remove the need to improve outcomes for consumers where and whilst natural gas is still being used. Decarbonisation and market development need not be at odds; regulators' emphasise that more efficient outcomes will be achieved through a full valuation of environmental externalities ("polluter pays" principle) in market pricing.*[56]

> *It is therefore important to ensure that the transition is based on sound economic principles and leads to the selection of the best-value technologies for decarbonisation . . . . We see significant potential benefits from competition between alternatives, including decarbonised gases.*[57]

> *In terms of the impact on existing networks, we note that care must be taken that new investments in natural gas networks are consistent with future decarbonisation. . . Where policy scenarios indicate that existing assets may become stranded, there should be a requirement [to address the associated risks]. Options . . . include re-use of assets for alternative purposes, with accelerated depreciation, or decommissioning seen as last resorts.*[58]

5.3. Policy options considered/implemented considered elsewhere

5.3.1. Home Efficiency Schemes – NZ and UK

- NZ MBIE Transforming Operational Efficiency standards
- UK minimum efficiency upgrade policy

Description and objective of the schemes

The UK's Minimum Energy Efficiency Standards (MEES) were enacted in 2015 and came into effect in 2018. They set progressively more stringent minimum energy efficiency levels for privately owned domestic rental properties. Landlords are required to obtain an Energy Performance Certificate (EPC) prior to an existing lease being renewed or a new lease being entered into.

The EPC measures the property's energy efficiency as a whole, taking into account the heating system, insulation, and draught-proofing. A rating between A and G is given, with A being the highest level of efficiency. The initial regulations set a rating of E as the minimum rating at which a property can be leased or re-leased without incurring a financial penalty (which can be substantial[59]). The regulations allow for the minimum level to be raised over time, and the potential for the minimum to be raised to D by 2025 and C by 2030 has been discussed.

An EPC report is issued alongside the rating and provides energy-saving suggestions on ways the property's rating could be improved. Landlords that cannot obtain finance for the improvements required to meet the minimum standard are required to spend a minimum of £3,500 of their own money BPS on suggested improvements.

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56 Agency for the Cooperation of Energy Regulators (ACER) and Council of European Energy Regulators (CEER), The Bridge Beyond 2025: Conclusion Paper, November 2019, p.5.

57 Ibid, p. 6.

58 Ibid, p. 18.

59 Financial penalties are linked to rateable value but can be as high as BPS 150,000.

New Zealand's Ministry of Business, Innovation and Employment (MBIE) commenced a consultation process on its Building for Climate Change programme. One of the two key elements of the programme, the Transforming Operational Efficiency Framework, focuses on reducing carbon emissions related to the operation of buildings in areas such as heating, cooling, lighting and ventilation.

The Framework would set a mandatory Operational Emissions Cap regarding the total allowable annual emissions per square meter per annum for all new buildings. The cap itself would reduce over time and will include requirements related to fossil fuel combustion, electricity use, water use and indoor environmental quality.

The fossil fuel requirements will address improvements in thermal performance, hot water system and equipment efficiency, and the replacement of fossil fuels with electricity or other lower-carbon energy sources.

Although the Ministry has not finished considering the responses to the consultation is has reported that of the 360 responses received:[60]

> *95% either agreed or strongly agreed that the programme should include measures to improve operational efficiency, with 86% agreeing that the operational efficiency requirements should be introduced gradually*

Potential advantages as compared to the CCC approach

The two schemes discussed above offer advantages as compared to a simple prohibition on new homes connecting to natural gas, as noted in the table below.

Table 15: Potential advantages of efficiency standards compared to the CCC's approach

Benefit to consumers	Description
Incentivises least cost emission reductions	• By setting performance-based standards, both the UK MEES/EPC and the MBIE Operational Efficiency Standards will incentivise competition and innovation to deliver the least cost means for meeting the applicable energy or emission standard. This will reduce costs for consumers and increase the options available in the market as a whole. • In contrast, the CCC's prohibition on natural gas connections only addresses one source of emissions, and may not necessarily incentivise the most efficient outcomes, having regard to customers' fuel preferences, the cost of emissions etc. It does not address energy efficiency (and therefore total operational cost to the consumer) or how the building affects the overall health/well-being of the building's occupants.
More diversified energy supply industry	• Being performance based, both programs are agnostic regarding energy source, while providing specific features that encourage low carbon energy sources. The MBIE programme, for example, specifically recognises 'other low carbon energy sources along with electricity as a means for reducing fossil fuel use and treats on-site renewable electricity generation and storage as a credit (deduction) in its calculation of total electricity use. • By contrast, the CCC's prohibition on connections to the gas network is likely to narrow the range of energy supply sources, particularly where it has the effect of reducing the economic viability of the gas distribution businesses, potentially leading to asset stranding and the inability (or increased cost) of using renewable gases at such time that they become economically competitive.

60 http://www.building.govt.nz/about-building-performance/all-news-and-updates/building-for-climate-change-update/

Creates future optionality	• The ability to meet a standard allows for alternatives without precluding approaches. Both the UK and NZ efficiency schemes are output focused and leave it to the market to deliver solutions. Those solutions will almost certainly provide different means for meeting the applicable standards, thereby increasing optionality and flexibility. • By contrast, the CCC approach simply defines an action that cannot be taken. In and of itself, this is unlikely to increase options and as noted above is likely to reduce the option of utilising the existing gas distribution network to distribute renewable gases.

5.3.2. Renewable Gas Blending Scheme (proposed)

Description and objective of scheme

Energy Networks Australia (ENA), the peak body of energy distribution and transmission business in Australia, has proposed the use of a gas blending scheme.

Put simply, a gas blending scheme seeks to incentivise the development of renewable (low to zero carbon) sources of gas for injection into existing natural gas networks. In its most simple form, a target is set, an entity or entities are legally obligated to surrender (renewable gas) certificates that demonstrate that they have met their legal obligations, and by doing so, a market for those certificates is created. This market, and more particular the revenues that renewable gas providers can generate from the creation of certificates that are sold into this market, underpins the development of renewable gas projects.

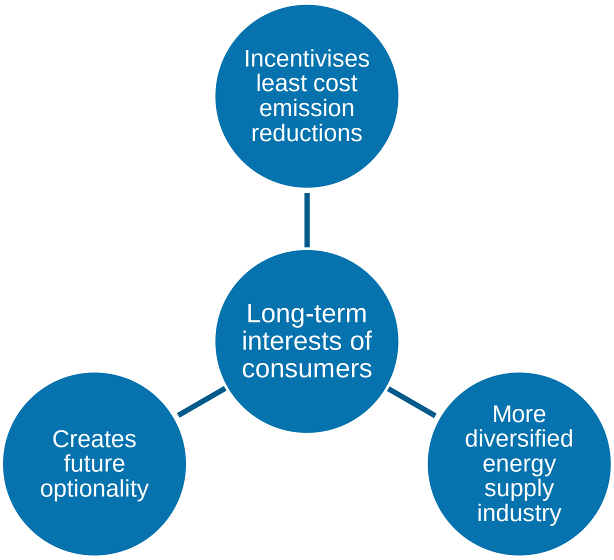
Entities that have a legal obligation to surrender certificates have an incentive to do so at the least cost, hence, in totality, the output (being the target for renewable gases) should be met by least cost means.

The ENA was of the view that such an approach could assist in de-carbonising Australia's gas supply, whilst continuing to meet the need for gas by certain key industries for high temperature heat or feedstock and preserve the optionality provided by the existing gas distribution network to Australian homes, businesses and the energy supply chain.

Potential advantages over the CCC approach

The ENA identified a number of benefits of such Scheme that would translate to the NZ context.

Figure 24: Potential benefits to NZ consumers of a blending scheme



The following table provides a very brief description of each potential benefit, and compares and contrast this with the CCC's approach.

Table 16: Potential benefits to consumers of a Blending Scheme, relative to the CCC's approach

Benefit to consumers	Description
Incentivises least cost emission reductions	• Allows the market to reveal which options are the least cost means of achieving the overarching objective (which in this case, is a certain target for renewable gases). If designed correctly, this would also include the option of the liable entity incentivising its existing gas customers to switch to electricity to reduce its 'renewable gas liability'. Existing gas customers can assess this signal, against the value that they ascribe to gas (as compared to electricity) as well as the cost of appliance changeover, thus contributing the achievement of emissions reductions in the least economic cost. • Setting a broader, system-wide target for renewable gases would signal the scale of emissions reductions required across the whole of the gas system and encourage investment without locking in a prescribed pathway. • In contrast, the CCC's deterministic approach precludes customer choice, implicitly leading to outcomes whereby a customer who may have otherwise valued (green) gas over (green) electricity, would be precluded from accessing their preferred (green) fuel of choice. Moreover, it both explicitly and implicitly prescribes a pathway towards decarbonising the gas sector – one that excludes renewable gases.
More diversified energy supply industry	• Creates a more diverse and resilient energy supply sector, as it facilitates the distributed, but scalable, storage of energy that is not weather dependent; and is provided by a second network. • Whilst the CCC notes that risk of relying on "electricity to meet much of the country's transport, heating, cooking and industry needs carries risk in a nation exposed to natural hazards and other potential disruptions", it policy approach, both directly (through prohibition) and indirectly (through its impact on the economics of gas versus electricity as residential and small commercial volumes decline), will lead to customers being solely reliant on one (electricity) network and system. This risk will be even more pronounced as the mobility sector also becomes more reliant on the electricity sector via EV loads. This magnifies the impact electricity-related risks have on end customers – whether they are at a network level (e.g., network outages), or at a supply level (e.g., dry year issues).

Creates future optionality	• The creation of a blending scheme would lower barriers to market entry and reduce investment risk for providers of new technologies used to support the provision of renewable gases. • This would facilitate the creation of a domestic renewable gas industry that in turn gives the option (if market conditions are suitable in the future) of pursuing: (a) export markets for, in particular, hydrogen or renewable methane; (b) full conversion of the natural gas system to renewable gases, including hydrogen or renewable methane; or (c) other domestic markets for renewable gases (e.g., mobility, chemicals, etc.). • In contrast, the CCC both directly (through prohibition) and indirectly (through its impact on the economics of gas versus electricity as residential and small commercial volumes decline) forecloses on the use of renewable gases in the medium to long-term. It in effect removes the future option of utilising the in situ network to distribute renewable gases.

5.3.3. UK Carbon Budgets and associated Climate Change policies and programs

Development and description of the UK climate change policy

The *Climate Change Act 2008* set legal limits on the greenhouse gas emissions for the UK and specified a reduction of greenhouse gases by 2050 of 80% relative to 1990 emissions levels. This was later amended to a 100% reduction by 2050.

Under the Act, the Climate Change Committee (CCC)[61] was directed to set five-year carbon budgets. Originally, five such budgets were contemplated, running from 2008 through 2032. Provision for a sixth budget was subsequently added.

The Climate Change Committee recommends the budget on an economy wide basis, considering the latest evidence from climate science and relevant international developments (for example the Paris Agreement), but also the cost effectiveness of the proposed path and its impact on competitiveness, fuel poverty, the fiscal balance and the devolved administrations[62]. So far, Government and Parliament have largely followed the advice of the Committee regarding the targets.

After a carbon budget has been set, the Government is mandated under the Climate Change Act to define, as soon as practical, its strategy for meeting that budget. The relative contribution to be made by various sectors to the economy-wide emissions reduction targets set in the budgets is left to Government policy.

According to the Climate Change Committee, the first and second carbon budget have been met and the UK is on track to meet the third budget. But it is not on track to meet the fourth or fifth budgets. The Committee published its recommendations regarding the sixth budget (2033-37) in December 2020. This was the first carbon budget set in line with the 2050 net zero target.

On the same day the 6th Carbon Budget was announced, the Prime Minister announced a new ambitious target to reduce the UK's emissions by at least 68% by 2030, compared to 1990 levels.

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61 The organisation's original name was the Committee on Climate Change; it was subsequently changed to the Climate Change Committee.

62 The Scottish Parliament, the Welsh Parliament, the Northern Ireland Assembly and the London Assembly and their associated executive bodies.

Overview of the Sixth Carbon Budget as it relates to natural gas and buildings

Policies regarding the use of natural gas generally and its use in buildings recommended in the 6th Carbon Budget include:

- All new homes required to be zero carbon starting in 2025 "at the latest"
- All use of natural gas to be phased out (except for zones designated for low-carbon district heat or hydrogen-conversion)
  - In public buildings by 2030
  - In residential and commercial buildings by 2033
- The use of bioenergy with carbon capture and storage (BECCS)[63] facilities removing 22 $MtCO_2$/year from the atmosphere by 2035, and 53 $MtCO_2$/year by 2050. This is to be accomplished through a mix of biomass power, waste-to-energy, industrial heat, biohydrogen, biojet and other biofuel & biomethane facilities.
- With regard to hydrogen, the Climate Change Committee recommended that:

  BEIS[64] and Ofgem should undertake a programme of research to identify priority candidate areas for hydrogen, along with areas which are unlikely to be suitable, to inform development and network investments. Undertake one or more hydrogen trials at a representative scale in the early 2020s (e.g., 300-3000 homes), to inform decisions on low-carbon zoning from 2025. All new boilers to be hydrogen-ready by 2025 at the latest. Continue further pilots in the late 2020s, where valuable to inform large-scale take-up.[65]

  Table 17 shows the impacts of the Sixth Carbon Budget on the use of hydrogen and bioenergy in buildings.

Table 17: Hydrogen and bioenergy use in homes in the scenarios of the Sixth Carbon Budget

Balanced Net Zero Pathway	Widespread Engagement	Widespread Innovation	Headwinds	Tailwinds
Hybrid hydrogen scenario in homes, with 11% of homes using hydrogen for heat. Limited use of biofuels in homes. Heat networks fully electrified Non-residential buildings heat and catering demands mainly electrified with some hydrogen.	Fully electrified scenario (including heat networks). No biofuels in homes.	Hybrid hydrogen scenario in homes, with 10% of homes using hydrogen for heat. Widespread uptake of high-temperature heat pumps and flexible technology. No biofuels in homes. Heat networks fully electrified. Lower levels of low-carbon heat networks in non-residential buildings.	Widespread network conversion to hydrogen, with 71% of homes using hydrogen for heat. Smaller role for heat pumps across all buildings; 13 million in homes. In homes, hydrogen boilers in north and heat pump-hydrogen hybrids in south. Limited use of biofuels.	Buildings fully electrified, except for areas around industrial clusters which use H_2 boilers. 11% of homes using hydrogen for heat. No biofuels in homes. Higher efficiency of heat pumps and greater reduction in cost over time.

63 BECCS, as defined by the Climate Change Committee, involves the use of sustainable biomass in generating power, heat or fuels, where biogenic CO_2 generated in the process is captured and sent to long-term geological storage. The same process can also be applied to biogenic waste, biogas upgrading and some biofuels plants.

64 The UK's Department for Business, Energy & Industrial Strategy.

65 Climate Change Committee, *Policies for the Sixth Carbon Budget and Net Zero*, December 2020, p. 70.

	Non-residential buildings heat and catering demands mainly electrified with some hydrogen. Higher efficiency of heat pumps and greater reduction in cost over time.	Heat networks supplied by hydrogen and large-scale heat pumps. Catering and cooking demands predominantly met with hydrogen.

Source: Climate Change Committee, *Policies for the Sixth Carbon Budget and Net Zero*, December 2020, pp.118-119.

Initiatives announced to support the Sixth Carbon Budget

In December 2020, the BEIS announced that a new program, the Green Gas Support Scheme (GGSS), which will be funded by a levy on licensed gas suppliers and administered by Ofgem. It is designed to support biomethane that is produced from biomass feedstocks that are processed through anaerobic digestion and injected into the national gas grid. It will come into force in Autumn 2021 for biomethane and from April 2022 for other gasses yet to be specified. It is slated to last for four years.

The GGSS replaces the Residential Heating Incentive (RHI) which will end in March 2021, and like the RHI it operates like a feed-in tariff. BEIS intends to use a tiered tariff structure under which producers will receive the highest unit rate for the first block of energy produced and lower rates for subsequent injections into the grid.

In the longer-term, BEIS expects to focus on market-based mechanisms, which leverage competitive forces to drive down costs and ensure cost-effectiveness, as the basis for any ongoing policy support for the range of green gas options that might be commercially available.

It notes that there are a variety of approaches which might be considered for the design of a longer-term support mechanism. They mention, as an example, that a future scheme could potentially take the form of a Supplier Obligation, which would legally obligate gas suppliers to supply their customers with a certain volume or percentage of green gas[66].

In January 2021, the Chancellor of the Exchequer announced the Future Homes Standard which implements certain elements of the policy recommendations in the Sixth Carbon Budget. Among other things, it:

1. Prohibits the use of fossil fuel heating systems in new homes from 2025 - with the date of the prohibition subsequently being brought forward to 2023
2. Sets higher energy efficiency standards for extensions to existing homes and for equipment used in repairs and renovations to existing homes, including windows, heat pumps, cooling systems, and fixed lighting.

At the time the measure was announced, less than 2% of UK homes had any form of 'low-carbon heating'[67] and over 1.6 million gas boilers were being installed annually[68].

66 BEIS, Future support for low carbon heat, April 2020, p. 23.

67 Low carbon heating systems approved under the legislation and for which government grants are available include air-, water-, and ground-source heat pumps; electric combi boilers; biomass boilers; micro-CHP systems and solar water heating.

68 It is worth noting that several f the initiatives in the UK approach seem to move in somewhat different directions, for example the prohibition on new gas heating connections and the support for the development and use of green gases.

Potential advantages as compared to the CCC approach

The following table provides a comparison of the key features and associated benefits of the UK approach and compares them with those in of the CCC.

Table 18: Potential advantages of the UK approach as compared to that of the CCC

Benefit to consumers	Description
Incentivises least cost emission reductions	• By providing a price signal, the GGSS will incentivise the use and improvement of technologies that can produce zero carbon gases at a competitive cost of production. These technologies will need to compete with other technologies for meeting emissions reduction targets at least cost. This, coupled with the stated intent of the government and the regulator to rely on market mechanisms, should reduce cost and increase choice for consumers. • By contrast, there is nothing in the CCC's approach that seeks to incentivise the development of renewable gas alternatives.
More diversified energy supply industry	• Although the UK approach includes a prohibition on homes built from 2023 using fossil fuels for space heating it also includes incentives for near-term renewable gas-based substitutes for fossil fuel heating (the GGSS), and support for research and development of the use of hydrogen and renewable zero-carbon gases. These measures will provide incentives for the private sector to invest in the production of these gases, which will result in a more diversified set of energy sources being available. • By contrast, as noted above, the CCC's prohibition on connections to the gas network is likely to narrow the range of energy supply sources, particularly where it has the effect of reducing the economic viability of the gas distribution businesses, potentially leading to asset stranding and the inability (or increased cost) of using renewable gases at such time that they become economically competitive.
Creates future optionality	• The incentives for the production and use of renewable gases in the near term will assist the economic viability of the UK's gas distribution businesses which will reduce the risk of asset stranding and the foreclosure of the potential to use hydrogen and other renewable gases when they become economic at scale volumes. At least as important is the support for research and development of these sources of zero carbon gas as this constitutes a direct investment in the desire for optionality and the potential for solutions beyond those currently available. • By contrast, the CCC, while saying "there is value in creating options for meeting the targets and having the ability to adjust course as the transition proceeds" puts nothing in place to assist in exploring or developing energy-supply options that would increase the viability of the gas distribution businesses despite the fact that (a) access to natural gas in the near term and renewable gases in the longer term is of vital importance to the hard-to-abate sectors of the NZ economy, and (b) there is widespread evidence of the potential for hydrogen and other green gases to become economical competitive and very flexible sources of energy for use in electricity generation, direct combustion and transportation.