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Hydrogen in New Zealand
Report 2 – Analysis

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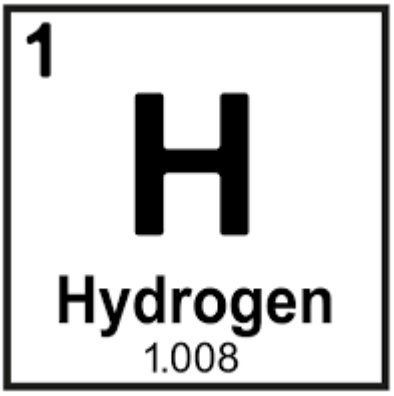

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Concept Consulting Group Ltd (Concept) specialises in providing analysis and advice on energy-related issues. Since its formation in 1999, the firm's personnel have advised clients in New Zealand, Australia, the wider Asia-Pacific region and Europe. Clients have included energy users, regulators, energy suppliers, governments, and international agencies.

Concept has undertaken a wide range of assignments, providing advice on market design and development issues, forecasting services, technical evaluations, regulatory analysis, and expert evidence.

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About this report

This study was sponsored by six organisations: Contact, Meridian, Powerco, First Gas, MBIE, and EECA. We would like to thank the many individuals within these organisations, and others from other organisations, who have provided valuable input into this study.

However, this report ultimately represents Concept's analysis and views (and any errors within it are our own), and the report should not be construed as representing the views of any of the six sponsor organisations.

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Contents

PART ONE – INTRODUCTION

This part provides background information on this report, our approach and the application of hydrogen technologies to supply energy services.

1-1 Report Structure

This report is the second of three reports. It is a technical report on our analysis of the cost effectiveness of hydrogen technologies for decarbonising the New Zealand economy. The other reports are:

- Report One – Summary – accessible overview of hydrogen technologies and our study findings
- Report Three – Background Research – collation of useful research material

This analytical report is organised into three parts:

- Part One – Introduction
- Part Two – Hydrogen Cost Models – models and reference cost estimates
- Part Three – Hydrogen Applications – analysis of current and future cost effectiveness

1-2 Study Scope

The principal focus of this study is examination of the potential for New Zealand to use hydrogen technologies to cost-effectively reduce greenhouse emissions. It draws on international studies as to likely costs and performance of hydrogen technologies, but most of the analysis is original, with numerous models developed specifically for this study.

The study considers how hydrogen technologies could be used to provide the main 'energy services' currently met using fossil fuels – i.e. transport, heating (industrial process, space and water) and electricity generation.

The study primarily focusses on 'green' hydrogen – i.e. using renewably-generated electricity to produce hydrogen from water using electrolysis – comparing green hydrogen both to fossil-based technologies and to other low-carbon alternatives.

However, it also considers the economics of hydrogen produced from hydrocarbons – specifically from natural gas using steam methane reforming (SMR) – in combination with carbon capture and storage (CCS).

The analysis considers cost competitiveness today, and forecasts competitiveness 20 years into the future. It identifies key uncertainties, major assumptions and the most promising opportunities for hydrogen technologies.

This study also considers the potential for New Zealand to export hydrogen to other countries – particularly 'renewables-poor' countries such as Japan – to help them decarbonise their economies.

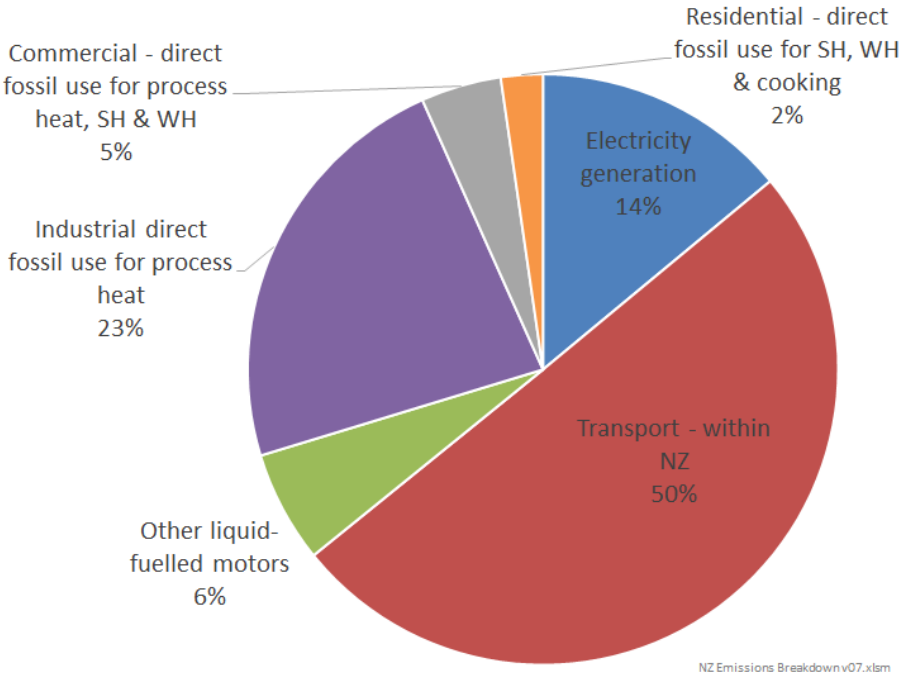
This report is technical in nature, with the audience assumed to be comfortable with technical and economic analyses of energy issues – although not necessarily having prior knowledge of hydrogen. The associated summary report provides a more accessible summary for non-technical readers.

1-3 New Zealand Emissions Profile

Figure 1 shows the breakdown of New Zealand's energy-related greenhouse emissions in 2016, the most recent year with complete data available. Transport is New Zealand's largest source of energy-related emissions (50%) (over 90% of which is from internal combustion engine vehicles), followed by use of fossil fuels for heat raising (30%), and electricity generation (14%).

This profile is unique to New Zealand, with most other countries having a much larger share of emissions from electricity generation. New Zealand is also unique because its energy-related greenhouse emissions only account for 40% of its overall greenhouse emissions – with agriculture accounting for the vast majority of its other emissions.[1]

Figure 1: New Zealand's 2016 energy-related greenhouse gas emissions



Source: Concept analysis of MBIE data

Hydrogen technologies have the potential to displace all these energy-related emissions – either through burning hydrogen directly in place of fossil fuels or using hydrogen fuel cells to produce electricity (and heat). This study examines each of these areas in turn, focussing on the most promising applications with the greatest emission reduction potential, and comparing the likely economics of hydrogen technologies versus other low-carbon technologies.

1-4 Hydrogen Technologies

Displacing fossil fuels with hydrogen requires the combination of several technologies. Hydrogen is the most abundant element in the universe but is very rare on earth in its pure molecular form. As such, the starting point for hydrogen technologies is to extract hydrogen from source compounds – water or hydrocarbons. Once extracted, hydrogen can be stored and transported, then used to produce heat or electrical energy. This requires a range of different technologies relating to production, storage, transport and end-use.

[1] Greenhouse gas emissions are classified using four main categories – energy-related; agriculture-related; industrial processes and product use (non-energy); and waste.

Some of these technologies are mature, because they have been used at scale for many decades to support industrial processes (such as synthetic fertiliser manufacture). Other hydrogen technologies, such as fuel cells, were discovered many decades ago but have not yet been applied at scale. Figure 2 summarises the purpose and maturity of key hydrogen technologies[2].

Figure 2: Hydrogen Technologies

Hydrogen Technology	Purpose	Description	Maturity and extent of use
Electrolysis	Production	Electrical energy is used to produce hydrogen gas from water. Different electrolyser technologies exist: Alkaline water electrolysis is lower cost, while proton exchange membrane (PEM) electrolysis offers more flexible output[3].	Alkaline (1880s) and PEM (1960s) are proven technologies. Alkaline used at scale for industrial applications. PEM exists at scale but is not common.
Steam Methane Reformation (SMR)	Production	Hydrogen is extracted from a hydrocarbon feedstock using a petrochemical process.	Mature technology. Used at scale for industrial processes.
Carbon Capture and Storage (CCS)	Production	Carbon dioxide produced as a by-product of SMR is captured and sequestered to prevent release to atmosphere.	Relatively limited to-date – although some large-scale examples used in enhanced oil and gas recovery.
Pipeline	Storage and Transport	Hydrogen can be transported in gaseous form in pipelines, either in a dedicated pipeline or blended with natural gas. Pipelines also perform limited storage functions.	Hydrogen pipelines are a mature technology. Hydrogen blends are similar to historic town gas, but at a testing phase for modern gas networks.
Tanks	Storage and Transport	Hydrogen can be stored as a compressed gas or in liquified form. Tanks can be transported via land or sea. Tanks are also integral part of hydrogen vehicles.	Mature. Liquid hydrogen and ultra-high pressure (e.g. H_2 cars) storage systems are not mass produced.

[2] These technologies are examined in more detail in the associated "Research" report.

[3] As set out in more detail later in this report, having production flexibility is key to making the most of temporary drops in electricity prices during times of high renewable output; this report therefore assumes that green hydrogen is being produced by PEM electrolysers.

Hydrogen Technology	Purpose	Description	Maturity and extent of use
Fuel Cell	Use	The electrolysis process is essentially reversed, with electricity generated from hydrogen gas. Fuel cells emit water and produce heat as a by-product. Fuel cells convert hydrogen to electricity to power hydrogen vehicles, but can also be used to provide power and heat for stationary energy requirements.	Technology proven in 1830s but not applied at scale. Early mass production and utility-scale applications developing this century.
Boiler	Use	Hydrogen can be burnt in a modified gas appliance to provide heat energy, with water as a combustion product.	Similar to town gas, so requirements well understood. Hydrogen-burning appliances not widely available.
Electricity Turbine	Use	Hydrogen can be burnt in a turbine and used to generate electricity.	At research prototype stage.

There is not yet any widespread deployment of hydrogen technologies at scale for displacing fossil-fuel energy services, but there is active government and commercial research and development internationally. This includes development of the technologies listed above, and their application as part of a full hydrogen supply chain. Report three in this series, 'Research', details some of these international initiatives.

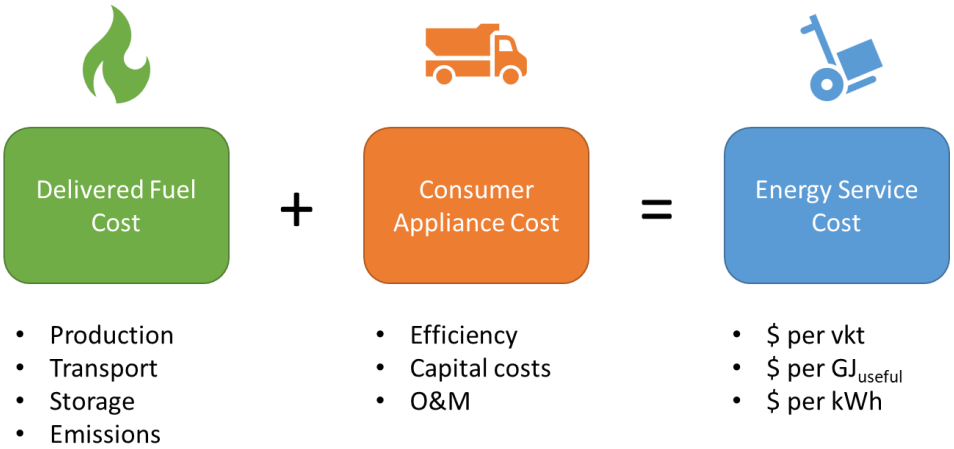
1-5 Energy Service Cost Comparison

For each potential hydrogen application, we have taken an approach of comparing *energy service* costs – i.e. the total cost of achieving an end energy service, such as transport, heat, or electricity generation. To develop energy service cost estimates we have considered the relevant supply chain model and analysed the relevant cost components.

There are various supply chain models for hydrogen

- it can be produced using electrolysis or through extraction from natural gas;
- it can be produced locally (at point of use) or centrally
- If produced centrally it can be transported via pipelines or tankers;
- it can be burnt directly, or used to generate electrical energy (and heat) through a fuel cell or gas turbine.

Figure 3: Energy Service Costs[4]



Our analysis seeks to establish how competitive hydrogen is likely to be for various energy services by comparing the modelled cost per unit of energy service across alternative technologies.

In most cases the key alternative technologies to hydrogen are direct electric options (e.g. electric vehicles, electric heating technologies), but we also consider biomass for some energy uses.

We also consider competitiveness against existing fossil options (e.g. petrol vehicles, or gas- or coal-fired heating) and determine the carbon price that would be required to make these fossil options more expensive than the cheapest low-carbon alternative.

Part 2 of this report establishes reference cost estimates for hydrogen produced using renewable electricity or hydrocarbon extraction. Part 3 uses these reference cost estimates as inputs to energy service cost comparisons for key applications.

1-6 Conventions

New Zealand dollars are used throughout this report unless stated otherwise. Generally, prices are quoted excluding GST, unless otherwise stated. Future prices are stated in real terms, i.e. without adjusting for general inflation.

For reference, in energy terms

1 kg (H_2) = 0.142 GJ (H_2)

This means that in cost terms

$1/kg ($H_2$) = $7.04/GJ ($H_2$)

[4] $/vkt = "dollars per vehicle kilometres travelled" – a key metric for the cost-effectiveness of providing transport services.
$ per GJ_{useful} refers to the cost per GJ of 'useful' heat delivered – i.e. taking into account any energy conversion losses in raising heat to heat a home, or a bath-full of water, or perform an industrial process.

PART TWO – HYDROGEN COST MODELS

This part analyses the cost of producing hydrogen from renewable and hydrocarbon sources. It develops a reference estimate for the cost of renewable-based 'green' hydrogen and a reference estimate for the cost of hydrocarbon-based hydrogen. It develops several variations on the reference estimates, and projects how costs may change 20 years into the future.

2-1 Hydrogen from Renewable Electricity

Hydrogen produced through renewable electricity-powered electrolysis of water is often referred to as 'green' hydrogen. As a fuel with zero greenhouse gas emissions, green hydrogen could play a significant role in decarbonisation worldwide if it can be produced cost-effectively.

Hydrogen can be produced:

1. Centrally – at a central location using grid-supplied electricity with hydrogen transported to end-use locations via pipeline or tanker
2. Locally – at an end-use site, with electricity sourced from the grid
3. Remotely – at a remote end-use site with off-grid electricity supply

Grid-sourced electricity comes with network connection costs, but generally offers flexible supply at comparatively low cost. Storage may still be required to match an efficient hydrogen production profile to a variable hydrogen demand profile, or to match production to times of low electricity prices. Alternatively, hydrogen can be injected directly into a dedicated pipeline or blended into a natural gas pipeline. In the latter case, the injection rate is restricted by the maximum blending proportion.

Grid electricity can be sourced through direct connection to the high-voltage transmission system for large-scale centralised production, or through connection to an electricity distribution network for smaller scale or more distributed operation.

If renewable on-site generation – such as solar or wind – is used in a remote production facility, then the greater levels of generation intermittency (compared to grid generation) means that greater levels of storage (of electricity or hydrogen) are generally required to match supply to demand.

2-1.1 New Zealand Context

New Zealand has a highly renewable electricity supply and abundant options for developing further renewable supply. If new demand for hydrogen production is assumed to be met through expanding renewable generation, then grid-powered hydrogen production can be considered 'green' in New Zealand.

Figure 4 summarises green hydrogen production models in the New Zealand context.

Figure 4: Production models

Energy Source	Benefits	Limitations	Applications
Electricity transmission connected	Avoids electricity distribution network costs. Supports very large-scale production.	Incurs cost of dedicated transmission assets. Limits locational choices. Only economic for large production facilities.	Production for export. Production for reticulation in dedicated H_2 pipelines. Production for underground storage.

Energy Source	Benefits	Limitations	Applications
Electricity distribution connected	Flexible locational choices. Economic across wide range of production scales.	Incurs distribution network charges. Upper limit on production scale.	Production for tank storage. Production for reticulation. Production for immediate use.
Off-grid	Avoids network costs. Co-location with generation.	Access to own supply only. Cannot export electricity. Larger storage requirements. Lower electrolyser utilisation.	Supply remote locations.

2-1.2 Green Hydrogen Cost Model

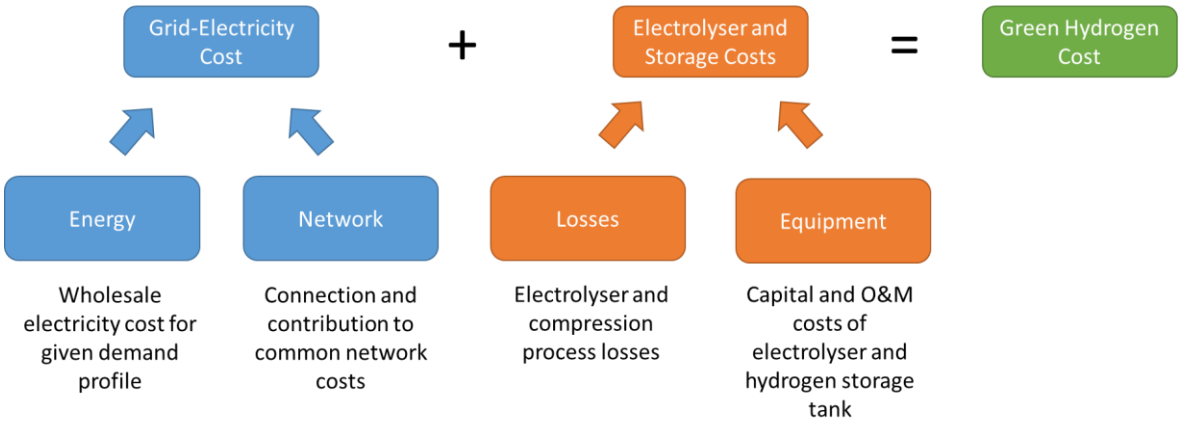
We developed a bottom-up model of green hydrogen production costs, and sense-checked against observed prices and estimates by other parties. The advantage of this approach is that it allows sensitivity testing and supports estimation of carbon price thresholds at which green hydrogen becomes competitive with fossil fuels or hydrocarbon-sourced hydrogen.

Our core model assumes hydrogen is produced using an electrolyser connected to an electricity distribution network, and is compressed and stored in a bulk storage tank. We also report the pre-compression cost, and the cost when compressed to levels useful for various applications:

- zero – for injection into a gas distribution network
- low – for injection into a gas transmission network
- high – for use in a hydrogen-powered vehicle.

The cost components for this supply chain model are wholesale electricity and network costs, losses through the electrolyser and compression processes, the capital costs of electrolyser and tank storage equipment, and (non-electricity) operating and maintenance costs.

Figure 5: Green hydrogen cost components



We also assume for this current cost estimate that hydrogen is produced on a fairly constant basis – utilisation factors of approximately 85%. We explore later the potential opportunities to produce hydrogen more cheaply from operating at lower utilisation factors to concentrate production at times of low electricity prices.

We have also made assumptions about the potential scale of costs for key components 20 years' in the future.

Our core assumptions, and resultant modelled costs are set out in Table 1 below.

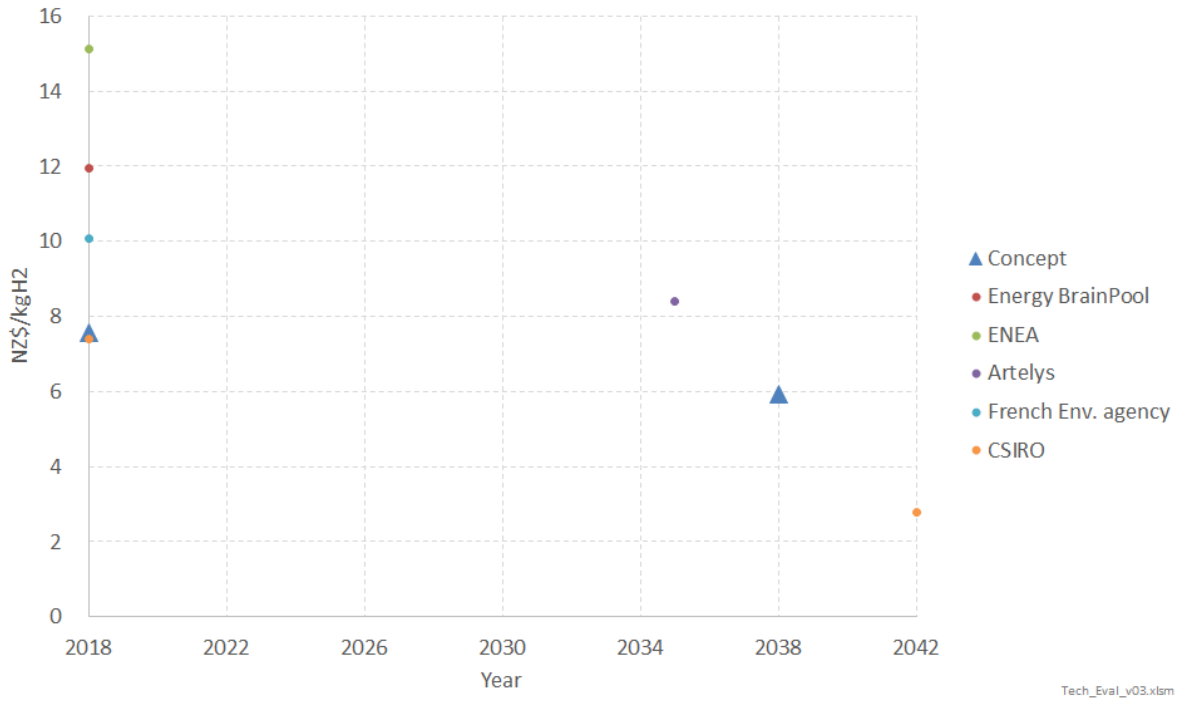
Table 1: Core green hydrogen model cost assumptions ($ values excl. GST)

	Current	Future	Source / Notes
Assumptions			
Electrolyser (NZ$/kW)	1,400	700	Literature review*. Future cost reduction based on international estimates. Equivalent to 3.4% annual cost reduction for 20 years. Consistent with French and Australian government ambitions. Implies world electrolyser capacity will grow at rate of 17% per annum if learning curve cost reduction rate is 15%
Opex (equivalent of % capex per year)	5%	5%	Literature review*. Includes periodic catalyst and membrane replacement. Costs scale with extent of use - i.e. if operate at half utilisation, opex costs (as prop'n of capex) are halved
Useful life (Yrs)	20	20	Assumption
Discount rate	6.0%	6.0%	Assumption
Electrolyser efficiency	70%	70%	Literature review*
Compression losses	10%	10%	Literature review. (Sensitivities performed later for different levels of compression)
Assumed utilisation factor	85%	85%	Assumption, based on maintenance outage, assumed interaction with storage, and limited avoidance of peak network charges
Storage costs (NZ$/kgH2)	0.5	0.35	Literature review coupled with bottom-up model based on CNG. Future cost reduction is assumption
Storage cycles per year	365	365	How many times a year the storage tank is emptied and filled. $/kg storage costs will increase inversely proportionately to amount of cycling
Wholesale electricity ($/kWh)	0.075	0.075	Average baseload contract prices. Future cost based on Concept modelling described elsewhere
Electricity nwk losses	4.0%	4%	Estimate based on network pricing schedules
Electricity nwk costs ($/kWh)	0.031	0.014	Includes variablised fixed and capacity charges. Estimate based on nwk price schedules. Future reduction assumes increased NZ elec demand --> improved nwk utilisation, plus greater recovery via (avoidable) peak demand charges
Prop'n nwk charge kWh based	30%	10%	Review of nwk price shedules. Has impact on cost at different levels of utilisation. Future based on assumption
Prop'n nwk charge peak demand-related	10%	50%	Review of nwk price shedules. Assumed that utilisation < 80% enables complete avoidance of peak charges
Resultant costs ($/kgH2)			
Electrolyser capex	1.03	0.51	
Electrolyser opex	0.59	0.29	
Storage	0.50	0.35	
Wholesale electricity	4.88	4.88	
Electricity network	1.91	0.90	
Total	***8.91***	***6.94***	
($/GJ)	62.7	48.9	Tech_Eval_v03.xlsm

* See Appendix A at back of this report for comparison of selected value to range of values from literature review.

Figure 6 below compares these modelled number with other published estimates.

Figure 6: Comparison of Concept modelled hydrogen production costs (i.e. pre-compression and storage) with other published estimates[5]



A note of caution should be given when comparing Concept estimates and other published estimates, as these other estimates are for different countries which may have materially different electricity input costs.

Nor is it clear whether other assumptions are equivalent between our estimates and these other studies.

Nonetheless, this comparison suggests that the Concept estimates are reasonable compared with other studies – if potentially on the optimistic side.

Figure 7 below details the change in hydrogen costs for other use-cases, and how they compare with the base use-case (Bulk Storage).

The key differences between the use-cases are:

- ***Power-to-gas***. This is for a situation of injecting hydrogen directly into a gas pipeline. This avoids storage costs. Note: gas pipeline charges are not included for transporting the gas to the end-user. This issue is addressed later. Two sub-cases are considered:
  - ***Gas Dx injection***, is for a situation of injecting hydrogen directly into a gas distribution network. This also avoids compression losses.
  - ***Gas Tx injection*** is for injecting hydrogen into a gas transmission network. This has compression losses which are half those for bulk storage. Electricity network costs are also assumed to be halved (as it is for a notional very large-scale facility connected to the electricity transmission network) and electricity distribution network losses are avoided. The

[5] Note: The published international estimates are for produced costs prior to storage and compression. Accordingly, the Concept estimates have had such aspects removed from the full cost breakdown shown in Table 1 in order to enable like-for-like comparison.

assumed much larger scale of the facility only results in electrolyser costs being reduced by 5% reflecting the limited scale economies available for electrolysers.[6] For the reasons discussed in section 3-4.3 later, this option may be limited in a future of blending hydrogen with natural gas (rather than having a pure hydrogen pipeline), due to the fact that a large-scale hydrogen production facility injecting at a single point in the gas network may exceed hydrogen concentration thresholds.[7] This could potentially be overcome through co-locating the hydrogen production facility with an existing natural gas production facility in Taranaki.

- ***Service station*** is for a service-station model where the gas is compressed up to the much higher pressures required for the fuel tank in a hydrogen vehicle. Compression losses are double those for the bulk storage use case. There are also fixed service-station overhead costs to recover.[8]
- ***Off-grid*** is similar to the bulk storage use-case, but avoids electricity network costs. Counter-acting this benefit are:
  - larger storage costs[9]
  - lower electrolyser capacity factors, leading to higher electrolyser capital recovery costs per kg of hydrogen delivered. A capacity factor based on solar generation is assumed for Figure 7
  - potential higher wholesale electricity costs if local renewable development is not able to achieve the same economies of scale as grid-scale generation. This potential effect is not included in Figure 7
  - potential limitations on having available land adjacent to the facility on which to locate the local renewable generation[10]

  Given these drawbacks, our assessment is that off-grid solutions are generally only really cost-effective where the electricity network costs from getting a grid connection are much higher than the levels shown in Figure 7 – e.g. a remote rural location with a dedicated electricity spur line.
- ***Grid gen & gas-grid overlap*** is similar to the Gas Tx Injection use-case, but for the situation where grid-connected renewables happen to be located close to a gas transmission line. In this scenario the electrolyser could be embedded behind the renewable generation plant such that there are no incremental electricity network costs. This gives the lowest cost hydrogen production use case.

  The Tararua wind sites are an example where competitive grid-generation is located close to a gas transmission pipeline. It is possible that future wind and utility-scale solar sites could be developed close to gas pipelines. However, the economics of this are likely to be very situation specific, relying on the location for the wind / solar project that is close to the existing gas transmission network also having a good combination of wind / solar resource, civil engineering costs, and electricity transmission costs.

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[6] The physics of electrolysers means that a large-scale facility will need to be comprised of lots of individual small-scale electrolysers modules.

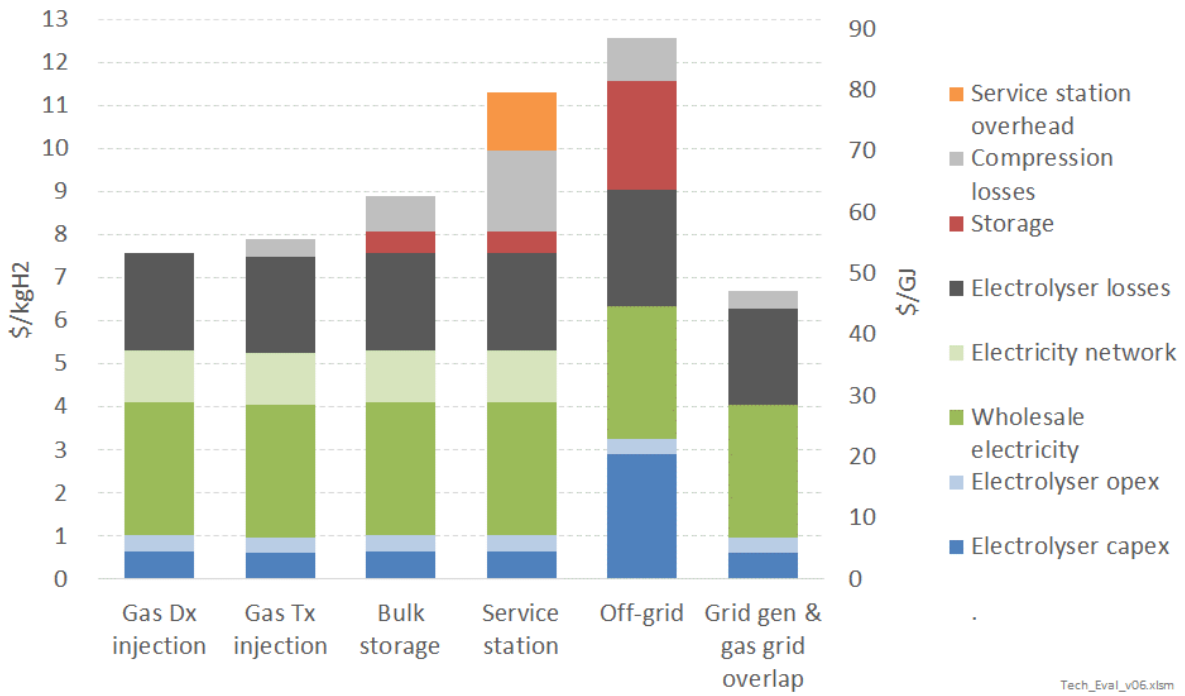
[7] As set out in section 3-4.3 later, these thresholds could limit the amount of hydrogen in the gas stream at any one point to 12% or 20%.

[8] Section 3-1 looking at hydrogen for transport details the derivation of the service station overhead costs.

[9] The much larger storage costs for off-grid use-cases are because the generation variability of a single wind-farm or solar panel is significantly greater than the variability of New Zealand's whole grid-connected renewable fleet. As such, in order to deliver similarly reliable hydrogen to on-grid options, a much larger storage facility is required.

[10] For example, we estimate that to meet the energy requirements for a hydrogen service station delivering the amount of energy delivered by an average service station today, would require an area of land half-a-kilometre by half-a-kilometre square, completely covered in solar panels. The area of land would be ten times greater to service the requirements of a very large industrial process heat facility.

Figure 7: Modelled current hydrogen costs for various use-cases



What opportunities may there be to 'optimise' hydrogen production to achieve lower costs?

Figure 7 highlights that hydrogen production costs are dominated by electricity input costs (wholesale electricity and electricity network).

One opportunity we have considered is whether it may be optimal to operate an electrolyser at a lower utilisation factor in the future than is the case today, in order to concentrate production at times of low electricity prices and deliver lower per unit production costs.

The potential drivers in favour of lower per unit production costs from lower utilisation factors are:

- Wholesale electricity – Future higher penetrations of wind, solar and geothermal plant in the New Zealand electricity system may increasingly drive periods of surplus that collapse electricity prices
- Electricity network costs – More cost-reflective future network pricing should enable parties who can avoid consumption at times of peak network demand to achieve lower network bills

Offsetting these potential lower per unit production costs are factors which would tend to increase per unit production costs if utilisation was lower:

- A hydrogen production facility would need larger electrolyser and storage equipment to meet a given level of hydrogen demand. These higher capital costs will be spread over a smaller amount of produced hydrogen, resulting in higher per unit production costs.

  This effect is why the electrolyser capital recovery costs are so much higher for the off-grid use case in Figure 7 compared to the other use cases. The off-grid use case assumes a 20% utilisation factor (driven by the capacity factor of solar[11]), whereas the other use cases assume

[11] This 20% capacity factor for solar assumes a relatively large-scale solar facility with single axis tracking and winter-focussed panel orientation. Smaller-scale, static solar facilities are more likely to achieve capacity factors of approximately 15%.

an 85% utilisation factor. The effect of this may be reduced over time if technology improvement reduces the capital cost of electrolysers and hydrogen storage facilities. Table 1 previously, sets out our estimates of the potential future cost reductions for these cost components.

- Some element of network charges will likely be recovered via fixed charges, based on some measure of the electricity connection capacity. Lower utilisation factors mean these fixed charges will be spread over a smaller amount of produced hydrogen, resulting in higher per unit production costs.

Optimising hydrogen production costs for small-scale hydrogen production

To test the trade-off between efficient running costs (low electricity prices) and efficient capital costs (smaller equipment and electricity network capacity charges) we modelled the variation in hydrogen production costs with differing production capacities.

Importantly, this is for a future where electricity required for hydrogen production is relatively small-scale (relative to New Zealand's overall demand for electricity), and thus not driving the need for new renewable electricity generation to be built. The analysis on page 24 considers likely costs in a future where large-scale hydrogen production is driving the need for new renewable generation to be built.

Wholesale Electricity Prices

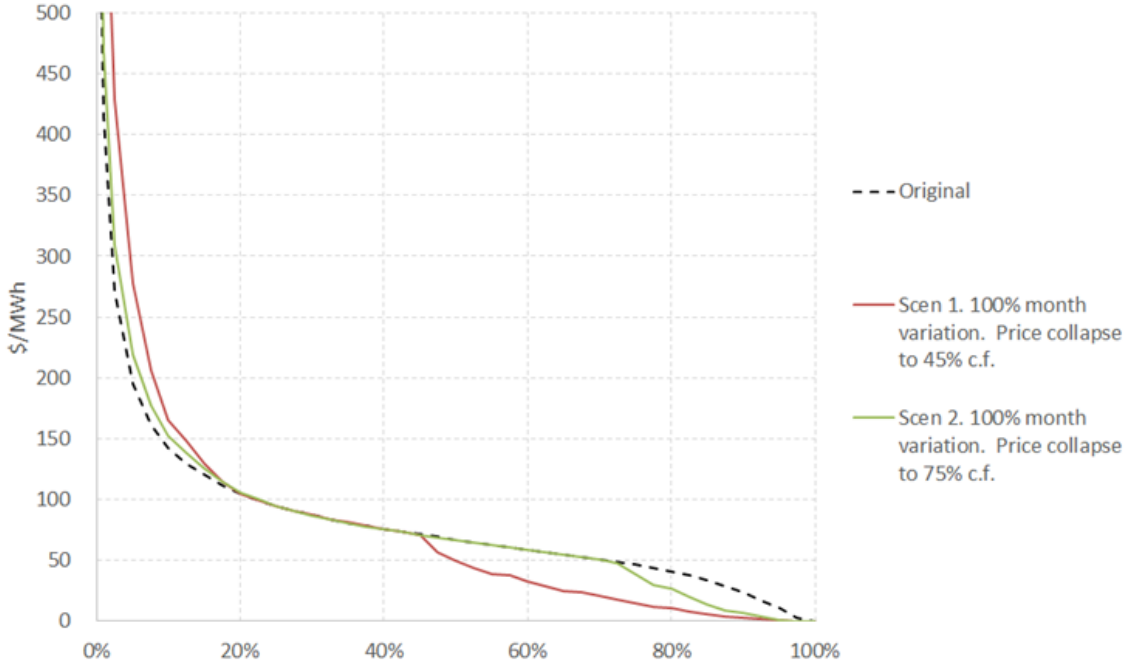
For this small-scale hydrogen production scenario, we modelled scenarios of future electricity prices considering:

- Change in New Zealand generation mix. As well as a scenario based on the current generation mix, we developed two scenarios with very high proportions of renewables – consistent with a future of very high carbon prices applying to the electricity sector. These scenarios produce periods of price collapse when there is surplus production – offset by higher prices at times of scarce supply, such that the time weighted average (TWA) price remains at the level required to support new baseload generation.[12]
- Hydro variability. We used 20 years' of half-hourly data to capture the impact on prices of wet and dry periods.

Figure 8 shows the resultant wholesale price-duration curves for New Zealand's current generation mix ('Original'), a scenario where renewables penetration drives price collapse 25% of the time ('Scen 2'), and a scenario with price collapse occurring 55% percent of the time ('Scen 1').

[12] The time-weighted average (TWA) price will need to be at a level to cover the long-run marginal cost of new baseload generation. We have assumed that the TWA price will be broadly the same as today's TWA: approximately $75/MWh. This is based on separate Concept modelling of future cost reductions for technologies such as wind and utility solar, factored by: increased 'firming penalties' faced by such plant as the proportion of variable renewable generation on the system increases; and the need to develop progressively less favourable sites as the 'best' options are used up.

Figure 8: Modelled wholesale price duration curves



We note this is not a prediction of how New Zealand's generation mix and wholesale pricing will evolve but is an internally consistent assumption that would provide a comparably favourable environment for flexible, energy-intensive activities such as hydrogen production.

This also effectively assumes that increased electricity demand from hydrogen production during these periods of surplus does not reduce the surplus to the extent that the price collapses do not occur to the same extent. This is consistent with small-scale hydrogen production, but not with production of a scale across New Zealand which drives the need to build new renewable generation.

Electricity network costs

The current electricity network costs used to generate the 'Current' costs shown in Table 1 and Figure 5 previously were based on applying the published network tariffs from three network companies (Vector Auckland, WEL Hamilton and WE* Wellington) for a large commercial transformer-connected customer.

As well as considering possible future changes to the average level of network costs, it is critically important for considering the benefits of lower hydrogen production utilisation to consider the future *structure* of network costs.

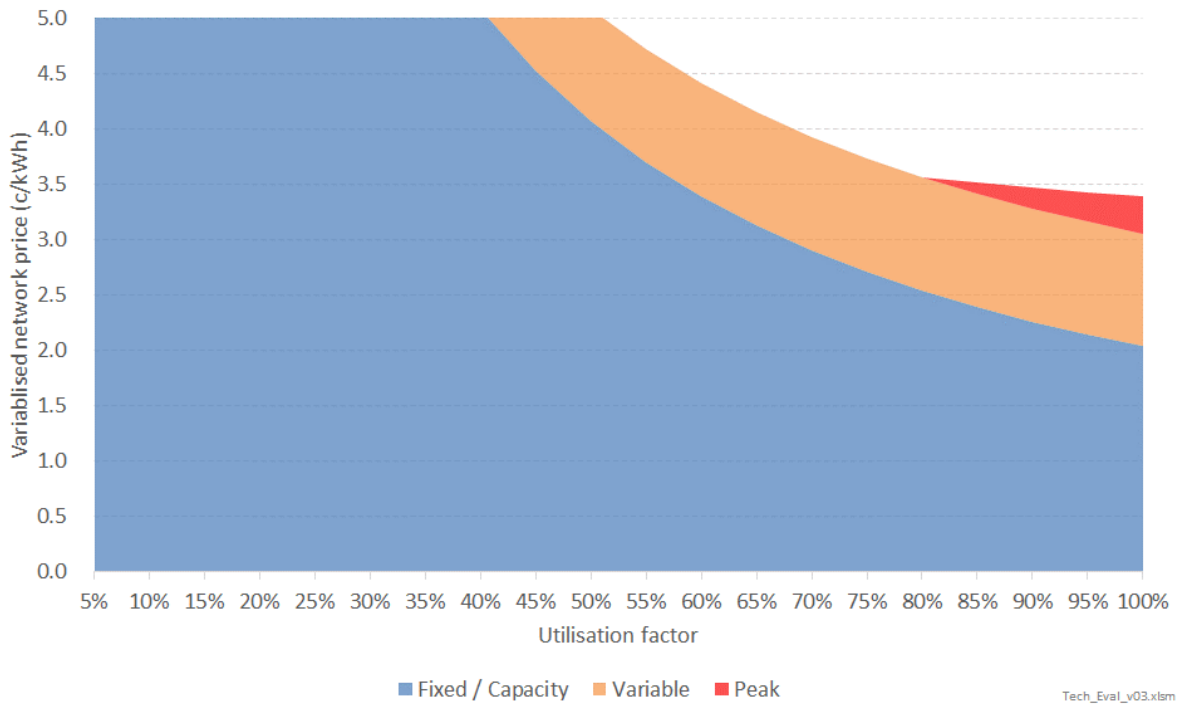
In particular, the proportion of network costs which are recovered based on:

- ***Measures of customers consumption at times of network peak.*** Based on observation of current commercial network tariffs we assume 10% of network revenues are currently recovered via such charges, but that this will move to 50% in the future. A high proportion of network costs recovered via peak charges is ideal for a hydrogen producer with low utilisation as these charges are completely avoidable by consumers who avoid consumption at times of peak.
- ***$/kWh charges***. These are unavoidable by a consumer, but from the perspective of a hydrogen producer, these do not increase on a per unit basis with lower levels of utilisation. We assume 30% of network revenues are currently recovered via such charges, but that this will reduce to 10% in the future.
- ***Fixed / capacity-related charges.*** These are based on a measure of a customer's connection capacity. Because they are unrelated to consumption, lower utilisation will result in these costs

resulting in higher $ per unit of hydrogen produced. We assume 60% of network revenues are currently recovered via such charges, but that this will reduce to 40% in the future.

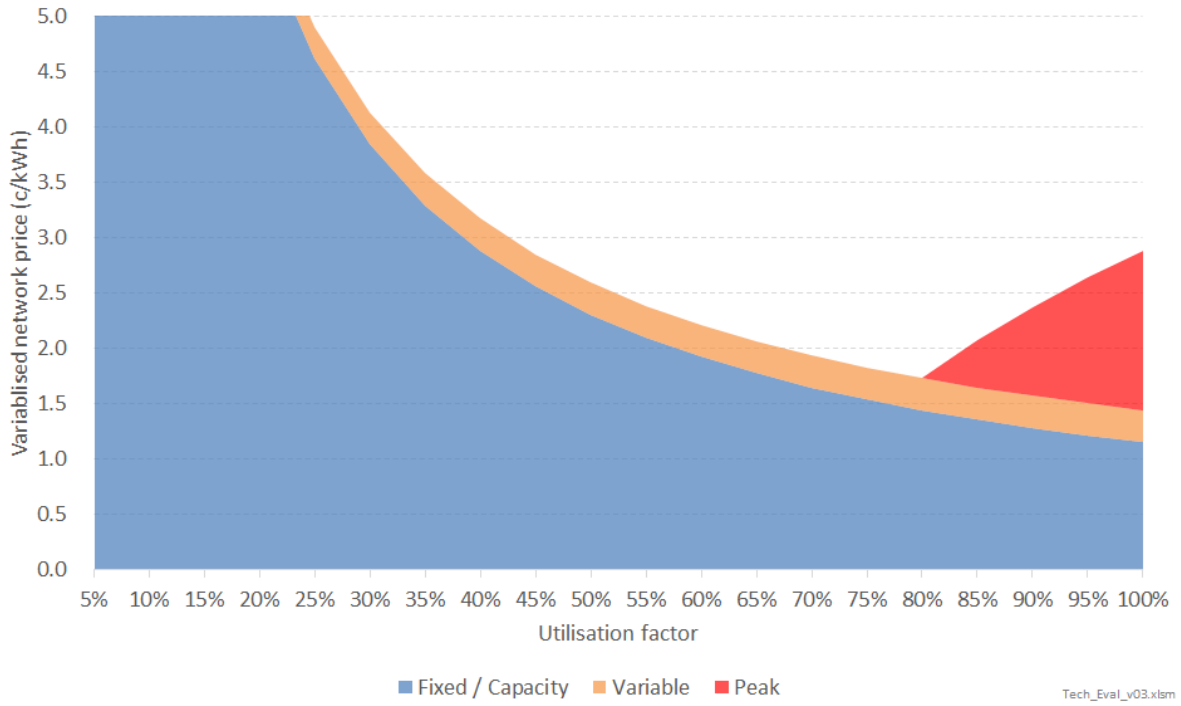
Figure 9 and Figure 10 below show the current and assumed future effective network charge at different levels of hydrogen utilisation.[13]

Figure 9: Current effective network charge at different hydrogen utilisation factors



[13] In practice, network pricing structures and cost allocations vary considerably across networks and can be influenced by installation-specific factors. The stylised network pricing model shown here is not intended to replicate pricing in any given New Zealand network, but captures the key economic features of network cost structures.

Figure 10: Assumed future effective network charge at different hydrogen utilisation factors



As can be seen, changes to the future structure of network charges will have a much more significant effect on the economics of hydrogen production at low utilisation levels than changes to the overall level of network charges.

Resultant optimal hydrogen production for 'power-to-gas' use cases

For the use-cases of the green hydrogen being injected into a distribution or transmission gas networks the production can be undertaken completely opportunistically.

This enables reductions in the average per unit cost of produced hydrogen from operating at lower utilisations – as shown in Figure 11 – and particularly if very high levels of future renewables penetration result in wholesale price collapses – as shown in Figure 12.

That said, the trade-offs between lower wholesale electricity costs versus higher capital and network costs result in a fairly flat 'bath-tub' curve, with relatively little variation between the total costs from operating at 30% utilisation and 80% utilisation.

Figure 11: Modelled future hydrogen production cost for injection into a gas distribution network (i.e. the power-to-gas use case) for scenario with current levels of renewables penetration

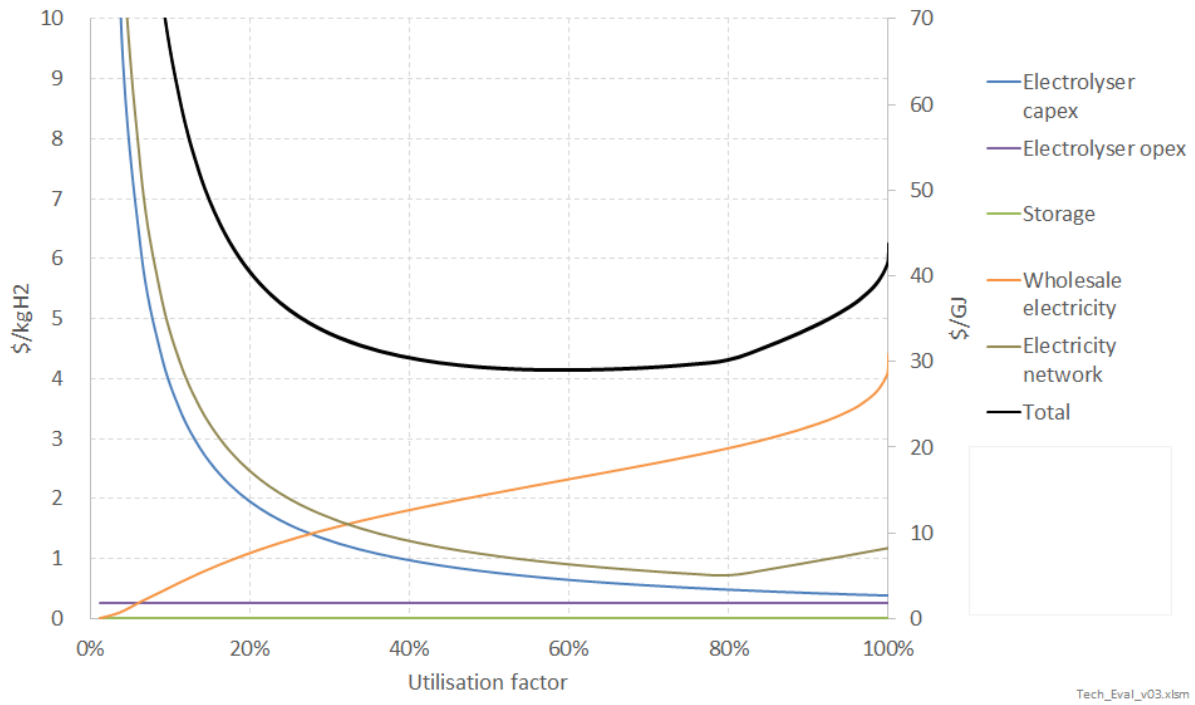
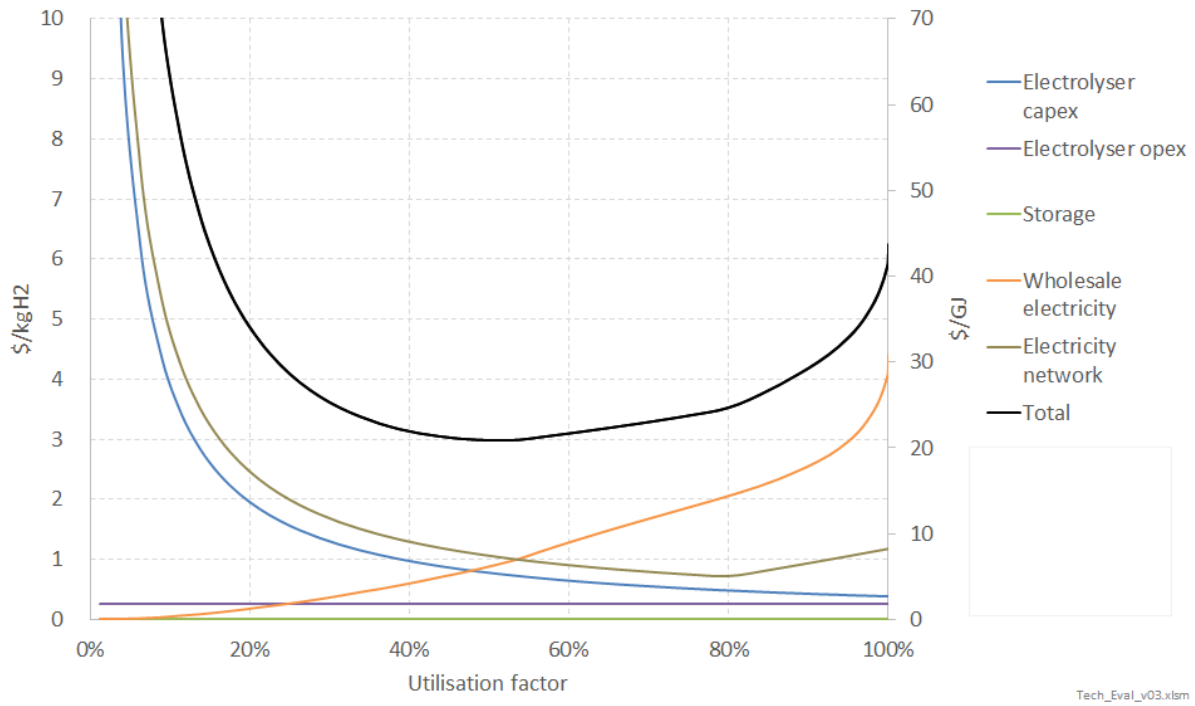


Figure 12: Modelled future hydrogen production cost for injection into a gas distribution network (i.e. the power-to-gas use case) for scenario with very high renewables penetration



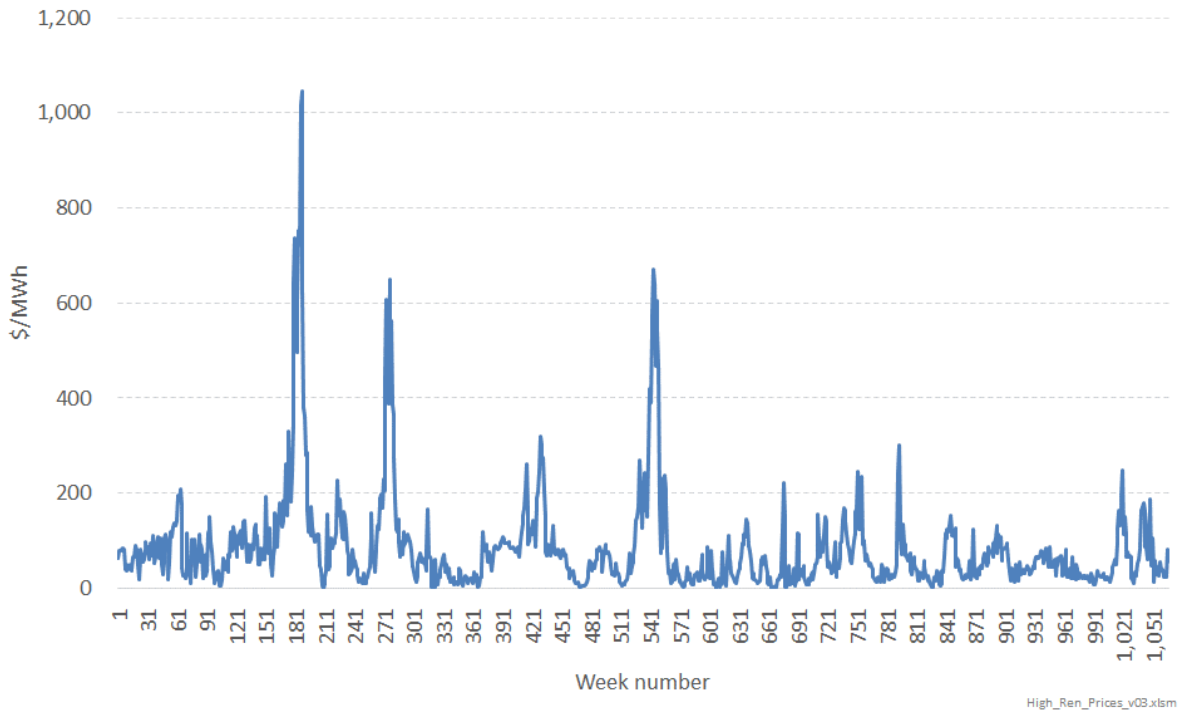
This revised price for opportunistic power-to-gas hydrogen production is very similar to the future estimate produced by CSIRO for such production in Australia – as previously shown in Figure 6.

Optimising utilisation for use-cases with storage

For hydrogen which needs to be stored before being used (e.g. for a service station, or industrial process site using hydrogen as a heating fuel), the opportunities to operate only at times of low electricity prices are more limited.

This is because of the random (because it is weather-driven) nature of periods of renewables-driven surplus and scarcity driving electricity prices. As Figure 13 illustrates, there can be periods of sustained high prices followed by periods of sustained low prices.

Figure 13: Weekly average wholesale electricity prices for scenario with very high levels of renewables penetration



A hydrogen producer seeking to only operate for the lowest 40% of electricity price periods, say, needs to have a large enough storage facility that they can produce and store up enough during periods of low prices so that they can avoid periods of sustained high prices.

Having such a large storage facility means that lower wholesale electricity production costs can be achieved, but it will be cycled less frequently, leading to increased storage costs.

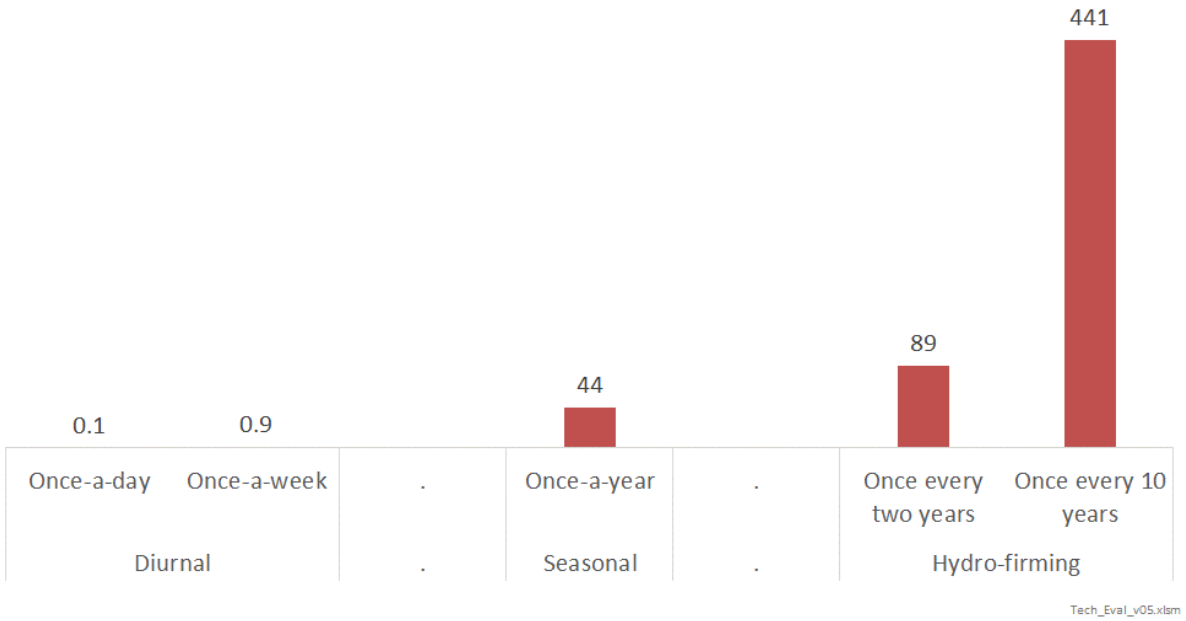
The $/kg storage costs for our base case assumes a storage facility that will be cycled approximately twice a week. This can be from fairly constant injection into the storage facility but with varying within-day offtake (e.g. heavy HV trucks filling up at a service station during day-time periods).

However, a storage facility which is only cycled, on average, once a week will have per unit storage costs which are twice as high. And a storage facility which is only cycled once a year (e.g. filling up in summer and releasing in winter) would have per unit storage costs which are 100 times higher.

This dynamic of how storage costs vary with how often the storage facility is cycled is illustrated in Figure 14 below.

The capital cost of a hydrogen storage vessel was assumed to be NZ$20 per kWh of storage capacity – our estimate of the current capital cost of hydrogen storage tanks. For reference, the capital cost of a battery is currently approximately NZ$300 per kWh of storage capacity – approximately fifteen times greater.

Figure 14: Impact of storage cycling regime on storage cost per kg of hydrogen delivered ($/kg)



To analyse these effects we developed a storage optimisation model which sought to optimise the operation of a storage facility given the 20-year series of half-hourly electricity prices for the relevant future wholesale electricity scenario.

This optimisation model was based on similar such models we have developed to optimise the storage and release of hydro reservoirs or gas storage facilities.

This optimisation was undertaken for many different sized storage facilities to understand the effect that storage size has on the average wholesale electricity cost of production, and storage cycling outcomes.

Figure 15 illustrates the effect that storage size has on the pattern of storage and release. The large-sized facility enables opportunistic production achieving average wholesale costs which are approximately 10% of that achieved for the small facility, but the cycling is less than 0.5% of that for the small facility – i.e. the storage component of costs will be more than 200 times greater.

Figure 15: Illustration of optimised storage and release patterns for a small and large storage facility, respectively

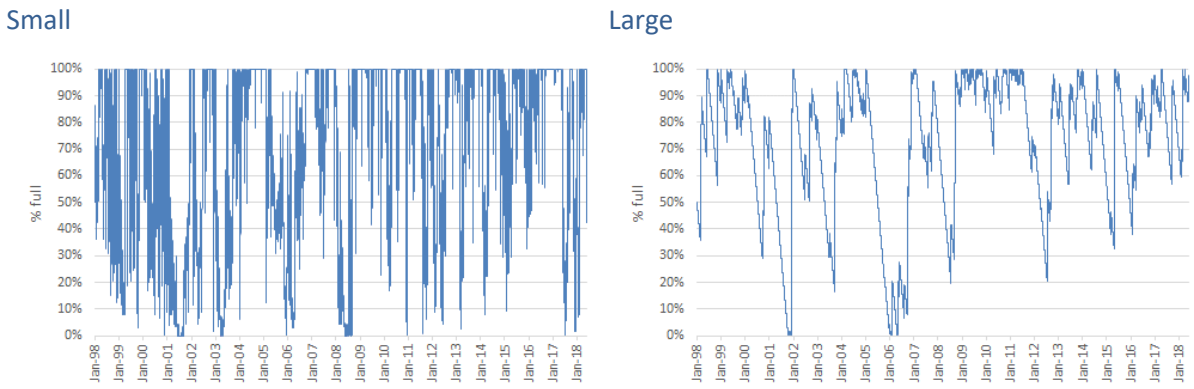
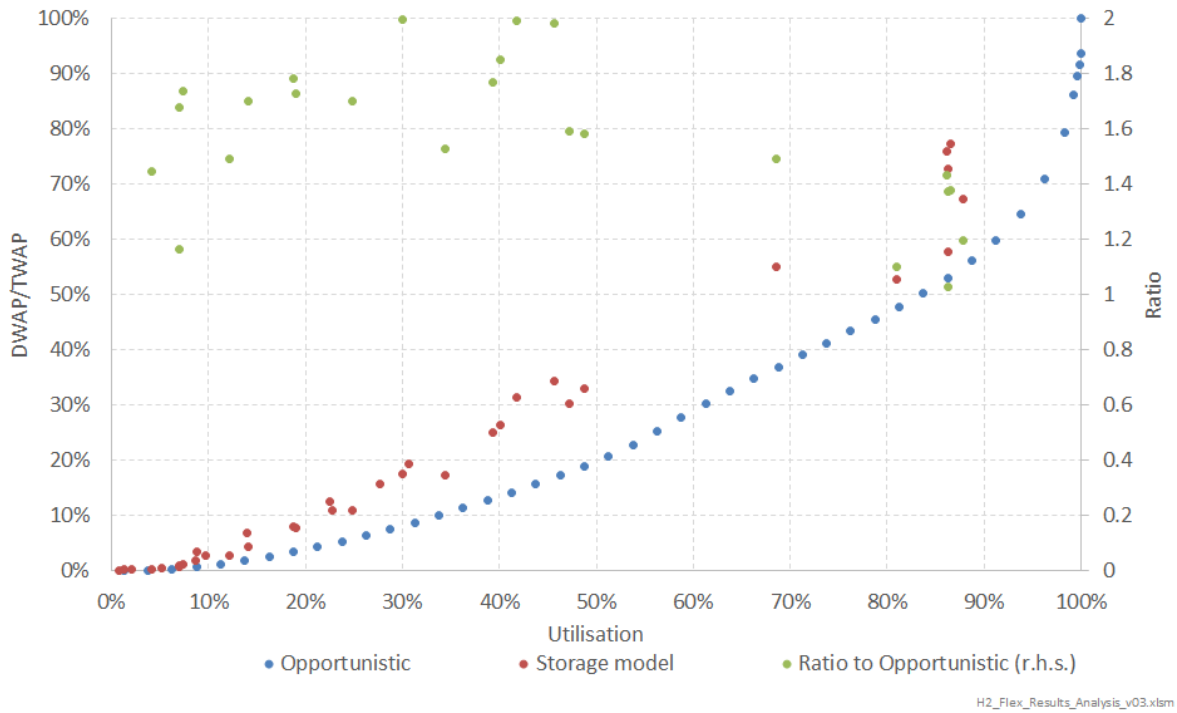


Figure 16 further illustrates the limitations of storage. It shows the average achieved wholesale electricity price for production relative to the time-weighted average wholesale electricity price (DWAP/TWAP) for completely opportunistic production (i.e. power-to-gas) and for the various

storage model runs. It also shows the ratio of these prices (measured on the right-hand-scale) which shows that on average the achieved wholesale electricity price for storage production is approximately 1.75 that of the opportunistic production. Lower ratios are achievable, but require much larger storage facilities (not shown on this graph) – with much lower cycling and associated storage cost increases.

Figure 16: Results of storage optimisation for wholesale scenario of very high renewables penetration

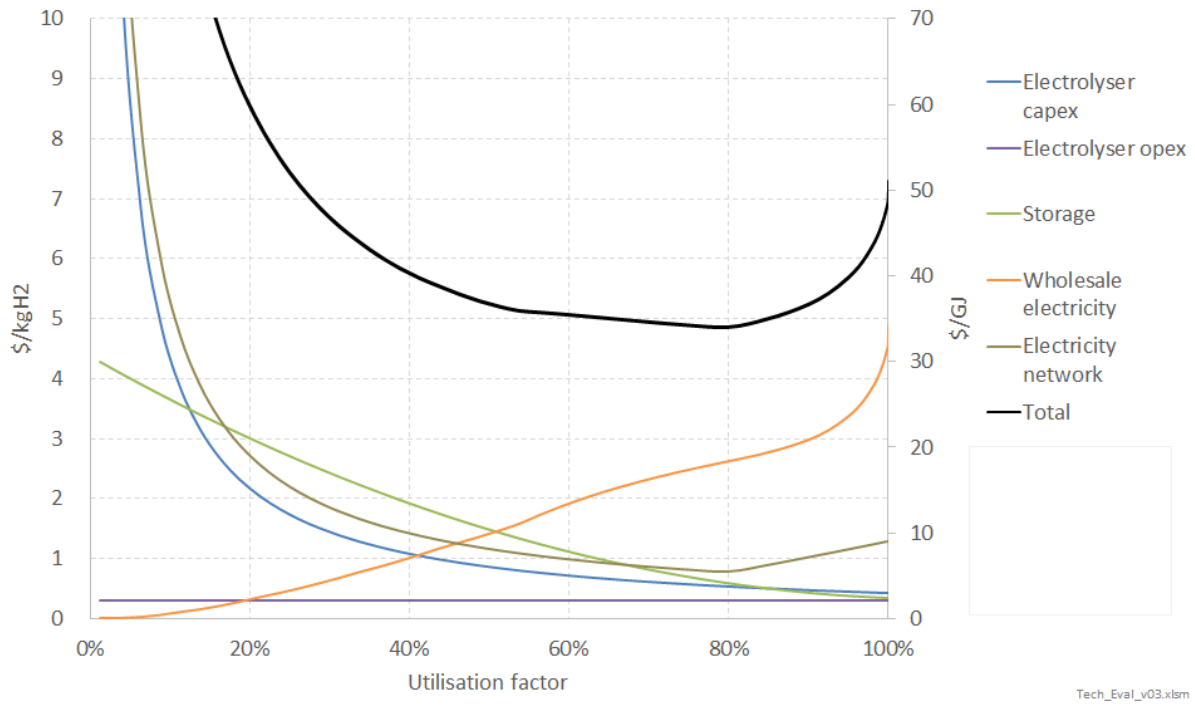


Simple relationships were developed based on the results of the above analysis to seek to reflect the effects of storage in terms of:

- Higher production costs for a given utilisation factor relative to completely opportunistic production
- Higher storage costs due to reduced cycling associated with larger storage – noting that storage generally needs to be larger for progressively lower utilisation factors.

The results of the analysis for the bulk storage use case are shown in Figure 17 below.

Figure 17: Modelled future hydrogen production cost for the bulk storage use case for scenario with very high renewables penetration



This indicates that the trade-offs between lower achieved wholesale prices and higher capital, storage and network cost result in optimal utilisations around 80% - very close to the 85% value used for our base case.

However, this dynamic modelling results in lower hydrogen production costs at the 85% utilisation factor than derived from the simple modelling shown in Table 1 and Figure 7 previously, as these previous simple estimates assumed a static wholesale electricity price based on the time-weighted average.

This results in the following revised estimates of hydrogen production costs. (Note: the off-grid use-case is, by definition, not assuming opportunistic production).

Table 2: Estimated future 'opportunistic' hydrogen production costs for different use-cases ($/kgH2)

	Current	Future opportunistic
Gas Dx injection	7.57	2.97
Gas Tx injection	6.80	2.67
Bulk storage	8.91	4.65
Service station	11.30	6.55
Off-grid bulk storage	12.56	9.22
		Tech_Eval_v05.xlsm

Large-scale hydrogen uptake will increase the costs of hydrogen production

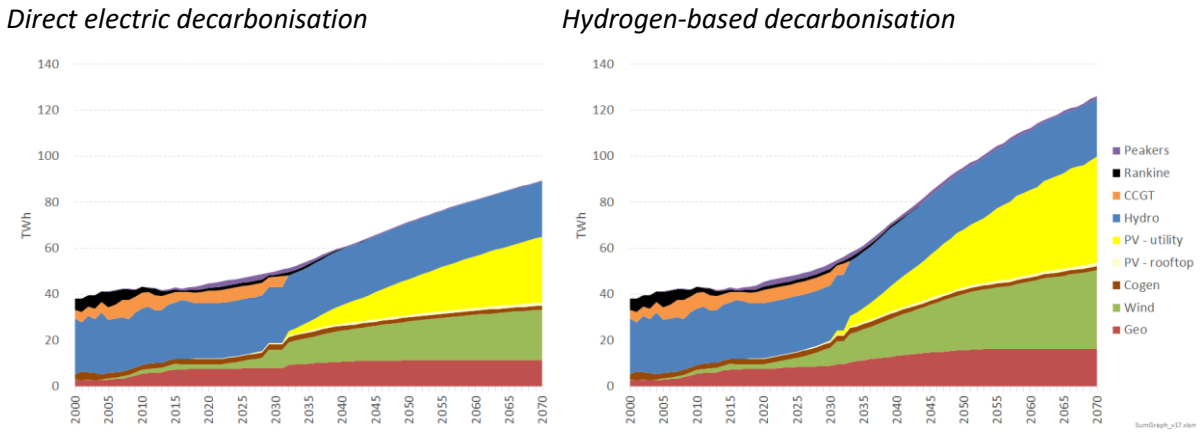
As stated previously, a key caveat to the above analysis is that it effectively assumes that increased electricity demand from hydrogen production during periods of renewables surplus does not reduce the surplus to the extent that the price collapses do not occur to the same extent.

This is considered to be a reasonable assumption for relatively small-scale opportunistic hydrogen production, but is likely to collapse for large-scale hydrogen production.

Indeed, if there was hydrogen production of a scale sufficient to meet a material proportion of New Zealand's current transport or process heat demand, the 'opportunistic' production during periods of relative surplus that drives the cost estimates in Table 2 would be insufficient to meet this.

This is illustrated by Figure 18 which compares two projections of New Zealand electricity generation in a future where we meet our de-carbonisation requirements.[14] The first projection is based on direct electric options being the principal means by which transport and industrial process heat is decarbonised. i.e. electric vehicles and electric boilers (plus some biomass boilers for industrial process heat). The second projection is based on hydrogen vehicles and hydrogen boilers being used instead of the direct electric options.

Figure 18: Generation projections of decarbonisation via direct electric versus hydrogen[15]



The much higher generation requirement is because of the significantly higher energy losses in delivering transport or heating via hydrogen rather than direct electric options. These arise from losses in converting electricity to hydrogen, and due to hydrogen vehicles, boilers and heaters having lower efficiencies than electric vehicles, boilers and heaters. As set out in more detail in Part Three of this paper, almost three times as much renewable electricity is required to power a hydrogen vehicle compared to an electric vehicle, and twice as much renewable electricity is required to provide hydrogen-fuelled industrial process heat compared to electric process heating.

In a future where large-scale uptake of hydrogen technologies drives the need for new renewable power station development, the wholesale electricity component of hydrogen production costs would tend to revert to a value which reflected the cost of building such new power stations. Further, having to build significantly more generation will also tend to increase wholesale electricity

[14] These projections were produced using Concept's ENZ model. This models whole-of-economy energy and emissions outcomes, covering all emitting sectors. It has been used in a number of engagements, including the recent Productivity Commission enquiry into a low-emissions economy.
For reference, the hydrogen-based decarbonisation projection results in generation demand growth which is relatively close to Transpower's 'Te Mauri Hiko' projection.

[15] 'PV Utility' refers to large-scale solar farms. These are much lower cost, and deliver electricity relatively more steadily across the day and year, than rooftop PV. This substantially lower cost and higher value output of utility PV relative to rooftop PV is why ENZ projects the former will dominate.

prices generally. Our projections of average wholesale prices are almost 10% higher in the scenario with large-scale hydrogen-driven renewable development.

Table 3 builds upon Table 2, and includes our estimate of the costs of hydrogen production if large-scale hydrogen production started to drive the need for new renewable power generation development. Note: this estimate does not take account of the potential for wholesale prices to be materially higher if the scale of extra demand resulted in very significant increases in generation – e.g. the 10% higher wholesale prices referred to above in the scenario of hydrogen-based decarbonisation.

Table 3: Estimated future hydrogen production costs for different use-cases ($/kgH2)

	Current	Future	
		Opportunistic	Large-scale
Gas Dx injection	7.57	2.97	5.93
Gas Tx injection	6.80	2.67	5.33
Bulk storage	8.91	4.65	6.94
Service station	11.30	6.55	9.11
Off-grid bulk storage	12.56	9.22	9.22

Tech_Eval_v05.xlsm

2-2 Hydrogen from Hydrocarbons

Globally, most hydrogen used today is produced from natural gas using a process known as steam methane reforming (SMR). Most countries investigating hydrogen have an established SMR industry and are intending to leverage that to kick-start their 'hydrogen-economy' ambitions.

SMR is often characterised as a gateway technology, providing hydrogen to start the transition away from direct fossil fuel use in transportation and electricity generation, before switching to 'green' hydrogen from renewable electrolysis production once the hydrogen market is established.

Because SMR uses natural gas as its input fuel, it emits CO_2 as part of the process – producing 40 kg of CO_2 for every GJ of hydrogen.[16] The energy losses in this process (typical efficiencies are 75%) mean the resultant hydrogen is more carbon intensive than the original natural gas fuel. Because of this, SMR hydrogen is often referred to as 'dirty' or 'brown' hydrogen.

To address this greater carbon-intensity, SMR initiatives are generally coupled with initiatives looking at developing carbon capture and storage (CCS) to minimise the greenhouse emissions. CCS technologies can significantly reduce emissions but are not 100% effective, so there are still residual emissions. Our base case assumes that 75% of CO_2 emissions are captured.[17] When combined with the energy losses associated with the SMR process, this results in SMR+CCS hydrogen having one-third of the emissions of raw natural gas (on a tCO_2/GJ basis).

2-2.1 New Zealand Context

New Zealand has significant natural gas resources with gas production and processing currently entirely in the Taranaki region, and with a gas pipeline network (which could be re-purposed to transport hydrogen) radiating out from this area. Taranaki is also the only place in New Zealand with depleted oil and gas reservoirs that could potentially be used for carbon capture and storage.

Like most petrochemical processes, SMR benefits from significant economies of scale. SMR is a mass production chemistry so an SMR plant can be built with a very large capacity. These economies of scale are taken advantage of worldwide. SMRs are typically built on a large scale and in clusters at industrial sites with some pre-existing gas infrastructure. Often, they are close to the end user (typically major chemicals facilities such as the manufacture of ammonia or urea) to minimise hydrogen transport costs or are 'captive' producers, purpose built by a refinery or plant to meet its own hydrogen needs.

The emissions trading scheme places a cost on carbon emissions. This is effectively capped at $20.75 per tonne of CO_2 at present, but the cap is unlikely to endure long-term.[18] The price of carbon drives the economics of CCS and has a significant impact on the relative cost of SMR versus green hydrogen.

2-2.2 Hydrocarbon-Based Hydrogen Cost Model

We developed a bottom-up model of production costs for hydrocarbon-based hydrogen, and sense-checked against observed prices and estimates by other parties. The advantage of this approach is

[16] The natural gas feedstock is cracked into hydrogen and carbon dioxide at a ratio of 1:5.5 by weight, which in GJ terms equates to 40 kg of CO_2 for every GJ of hydrogen produced.

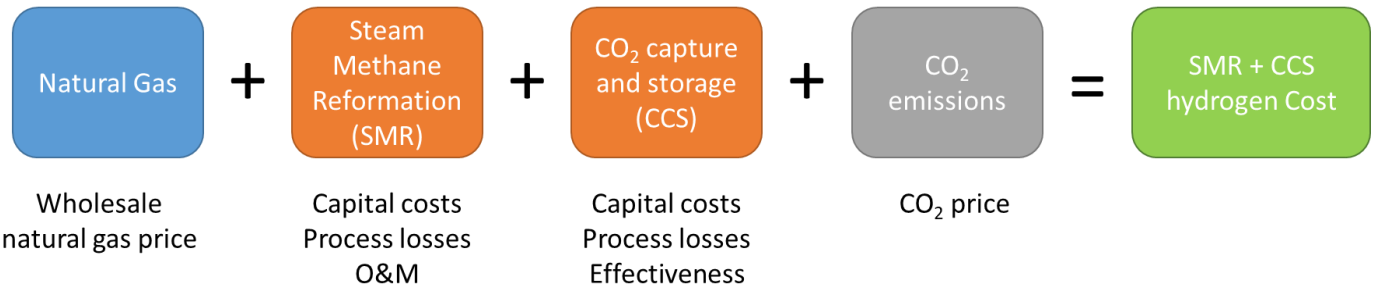
[17] Based on literature review of overseas studies. As set out in more detail in Appendix A, this is at the upper end of estimates of the effectiveness of CCS.

[18] The ETS currently has a cap of $25 per tonne but emitters are only required to submit units for 83% of their emissions. This reduced surrender obligation will end next year, and the $25 cap is unlikely to endure long term.

that it allows sensitivity testing and supports estimation of carbon price thresholds at which hydrocarbon-sourced hydrogen becomes competitive with fossil fuels.

The cost components for this supply chain model are natural gas feedstock costs, process losses, capital costs of plant, and carbon emission prices.

Figure 19: Hydrocarbon-based hydrogen cost components



As with green hydrogen, process efficiency is a key cost driver. We have modelled an end-to-end (from natural gas to hydrogen gas) energy loss of around one-third if 'next generation' carbon capture processes are used.

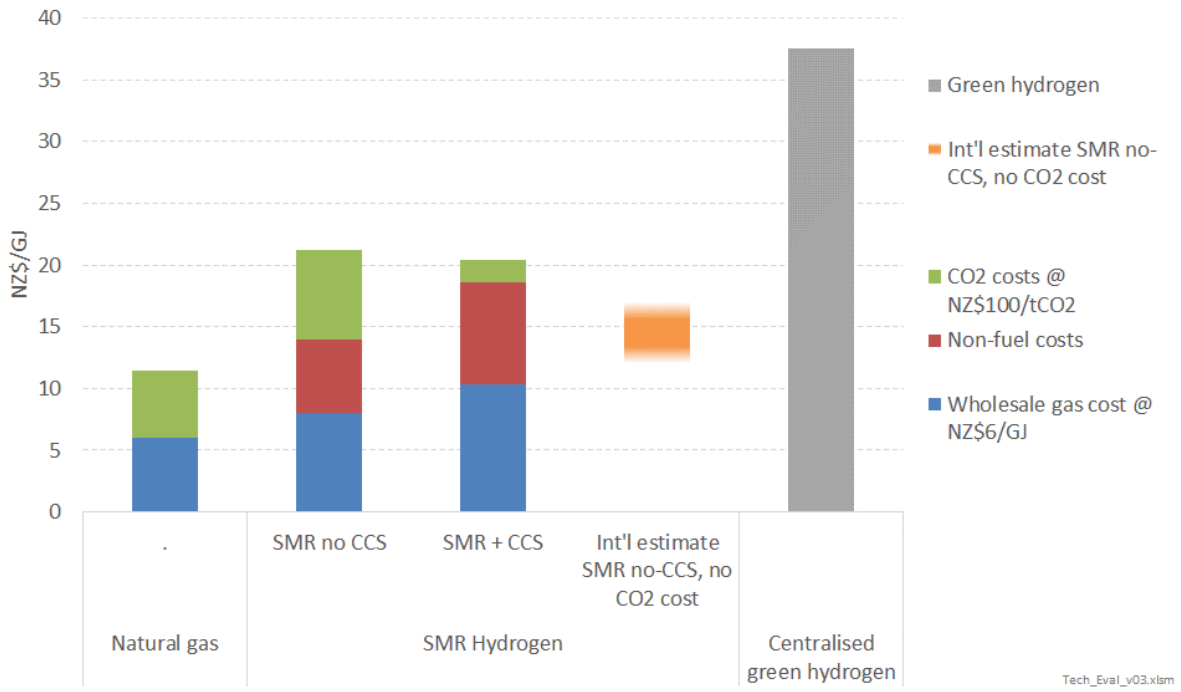
The effectiveness of the CCS process is also important, and our model assumes 75% of CO_2 is removed. This assumption, combined with production process energy losses, means we model the emissions intensity of SMR+CCS as 33% of using natural gas directly.

Figure 20 below compares our modelled cost of SMR and SMR + CCS hydrogen with

- international estimates,
- the costs of direct natural gas and
- green hydrogen produced at a large-scale and injected into a gas transmission network (as detailed in the previous section)

We have also shown for illustrative purposes, the effect of a NZ$100/t$CO_2$ price on the cost of carbon emissions on the different options.

Figure 20: Estimated cost of hydrogen produced by SMR + CCS



The similarity between international estimates and our estimate of approx. $14/GJ (excluding carbon costs and with CCS) provides some comfort.

Likewise, the resultant effective cost of the CCS in terms of $ per tonne of CO_2 removed is NZ$86/t$CO_2$. This is understood to be similar (if a little on the low side) to other estimates of the cost of CCS.

Table 4summarises key carbon price breakeven points for

- differing assumptions about the effectiveness of the amount of CO_2 removed by the process (assuming there is no change in the capital costs or operating efficiency due to such changes).
- A sensitivity where wholesale gas prices rise to $10/GJ, for our central removal efficiency of CO_2 by CCS of 75%. This is to consider the potential implications of a future where constraints on the development of additional gas reserves and resources start to cause an increase in New Zealand's gas prices.

Table 4: Carbon price breakeven points

Breakeven Point	Comment	CO_2 removed by CCS			Gas price $10/GJ (CCS 75%)
		60%	75%	90%	
SMR+CCS becomes competitive with SMR		108	86	72	115
SMR+CCS becomes competitive with direct use of natural gas	For each $1 per GJ (≈17%) increase in the price of natural gas, the carbon price breakeven increases by $19 per t$CO_2$ (≈5%).	502	350	270	430
Green hydrogen becomes competitive with SMR+CCS	This is for the 'power-to-gas' use case for a gas-transmission-connected large-scale green hydrogen production facility. (Hydrogen production costs of $5.3/kgH2)	650	1,000	2,600	670

Significant improvements in CO_2 removal efficacy, process efficiency and non-fuel costs would be required to make SMR + CSS cost competitive with direct use of natural gas. This breakeven carbon price increases as the wholesale price of natural gas increases – i.e. as the price of natural gas increases, the losses incurred in SMR+CCS become relatively more costly.

PART THREE – HYDROGEN APPLICATIONS

This part presents analysis of the cost effectiveness of hydrogen in key applications:

1. Transport
2. Industrial Process Heat
3. Space and Water Heating
4. Converting Gas Networks to Hydrogen
5. Power Generation
6. Other Uses – marine, aviation, rail, petrochemical feedstock

The analysis uses the hydrogen cost estimates developed in Part Two, and compares the likely cost-effectiveness of hydrogen relative to other low-carbon alternatives such as direct electric options or biomass.

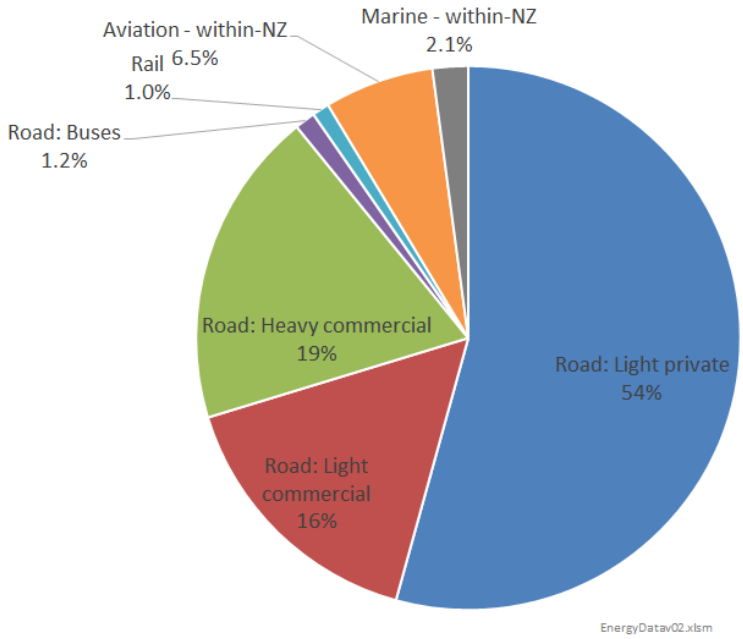
3-1 Transport

3-1.1 Background

Cars and trucks are New Zealand's largest source of energy emissions

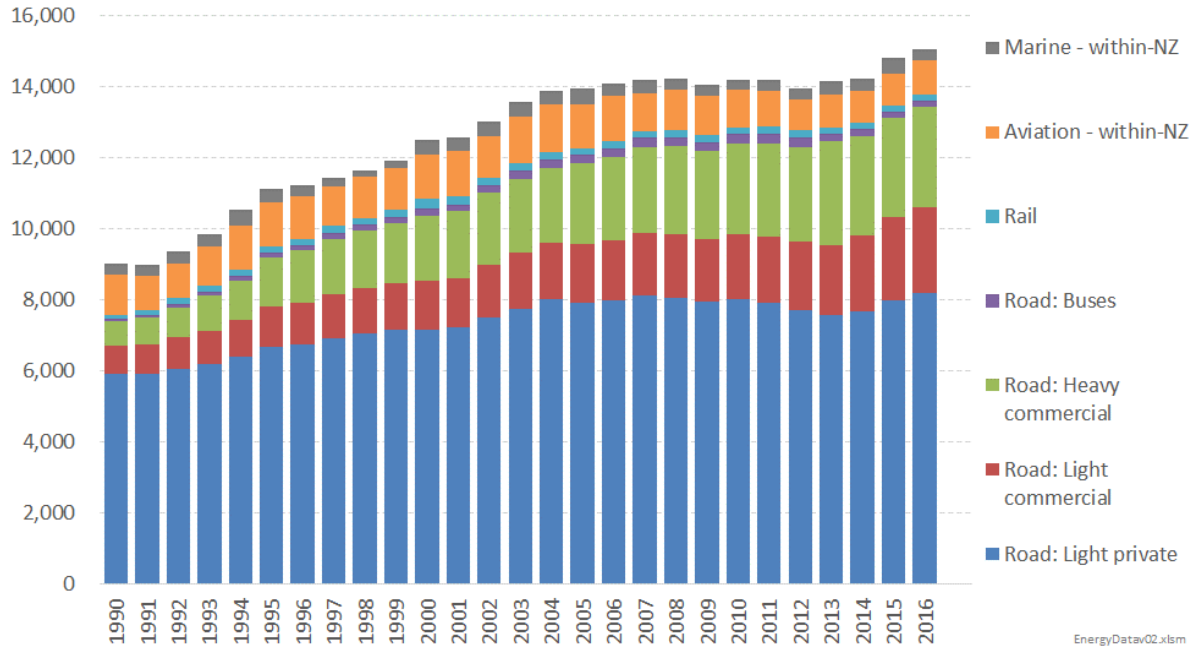
Figure 1 previously showed that transport accounts for half of New Zealand's energy emissions. Figure 21 and Figure 22 below show that road transport accounts for 89% of transport emissions and is also the fastest growing transport emitting sector.

Figure 21: 2016 within-NZ (i.e. excluding international air & marine) transport emissions



Source: Concept analysis of MBIE data

Figure 22: Historical within-NZ transport sector emissions (ktCO_2-e)



Source: Concept analysis of MBIE data

Electric vehicles are projected to transform the light road vehicle fleet

For over a century, one technology has dominated road transport: internal combustion engines (ICEs) fuelled by petrol or diesel.

However, major and continuing improvement improvements in battery technology mean that battery-electric vehicles (EVs) are starting to become cost-competitive – particularly if CO_2 costs are included and the electricity used to recharge the EVs comes from renewable generation.

The cost of batteries has been the critical factor driving EV economics for light vehicles, with trade-offs between vehicle cost and range. However, the latest generation of light EVs have batteries that give considerably greater range for a much lower cost. For example, the next generation Nissan Leaf (to be launched in 2019) will have a long-range version which is projected to have a range of approximately 350 km[19] – over three times the range of the first-generation Leaf produced only eight years earlier, and fifteen times the range of the median average distance travelled by a car in a day in New Zealand.

With continued improvements in the cost and performance of batteries, EVs for *light* vehicles (i.e. cars and vans) are projected to become genuinely cheaper transport solutions than ICEs for most light vehicles in a decade or so, even without a cost of CO_2. And for light vehicles that travel a lot each year (and thus for whom fuel costs are a very large part of the total cost of ownership, 'TCO'), that point of being genuinely cost-competitive is much closer.

In large part this is due to the inherent superior energy efficiency of electric motors compared to combustion engines – an electric motor is approximately 3.5 times more efficient at converting stored energy (electricity in a battery) into motive power, compared with the efficiency of a combustion engine converting stored energy (chemical energy in fuel) into motive power.

[19] https://en.wikipedia.org/wiki/Nissan_Leaf#Second_generation_(2017%E2%80%93present)

This rapid improvement in the cost and performance of EVs is likely to result in mass uptake of light EVs, and the eventual 'conversion' of the light transport fleet to EVs over the course of several decades.

For example, the current Ministry of Transport projection is for 40% of light vehicles on New Zealand's roads to be EVs by 2040. Other countries are putting in place measures to help hasten this transition, through implementing bans on the sale of new ICEs from 8 to 20 years in the future.[20]

The economics of EVs for heavy transport are more challenging

However, while EVs are starting to displace ICEs for light vehicles, the same is not true for heavy vehicles – i.e. trucks. As Figure 21 previously showed, heavy fleet emissions account for ≈ 19% of New Zealand's transport emissions (≈ 10% of New Zealand's energy-related emissions, and ≈ 4% of New Zealand's total gross emissions) and, as Figure 22 showed, have been the fastest growing source of transport emissions.

The reason that heavy EVs are further away from being cost-competitive than light EVs is because, in addition to the high cost of batteries (which affects both light and heavy EVs), the following characteristics of EVs particularly affect heavy EVs:

- batteries weigh considerably more than diesel in a fuel tank to travel similar distances
- batteries take longer to recharge than it does to fill-up a diesel / petrol tank at a service station.

While improvements in battery costs are also substantially helping the economics of heavy EVs, the weight and re-charging time penalties can be more significant for heavy EVs than light EVs:

- Because there is an absolute weight limit for vehicles on New Zealand's road, weight taken up by an EV battery will reduce the amount of freight the heaviest class of truck can carry. This weight constraint is not an issue for light vehicles (or even 'medium' weight freight trucks – or large trucks who carry bulky rather than heavy goods).
- Heavy vehicles generally travel further than light vehicles each day. The more limited range of current heavy EVs means that an overnight charge will be insufficient in some cases, and thus a long-distance heavy vehicle will need to stop to recharge during the day. Coupled with the much slower recharging times of EVs compared to filling up a diesel tank, this means long-distance heavy EVs will spend a greater amount of their time each day unproductively stationary.

These 'productivity penalties' mean that a greater number of heavy EV trucks will be needed to perform a given freight service than could be achieved with diesel trucks.

Heavy hydrogen vehicles are not projected to suffer the same productivity penalties, as they are projected to have weights, ranges and re-fuelling times which are similar to heavy diesel trucks.

3-1.2 Heavy Transport Cost Model

Because heavy transport is inherently the most promising large-scale application for hydrogen vehicles, we have focussed on assessing the economics of 'very heavy' transport.

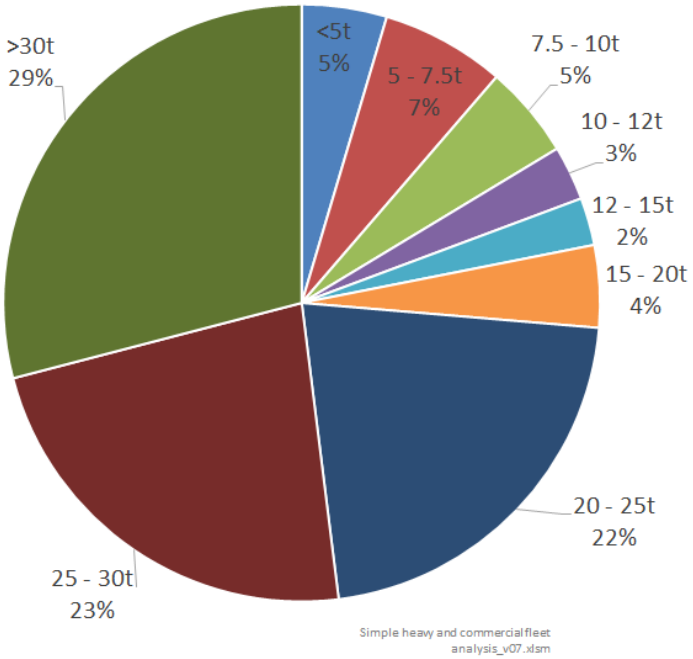
We use the phrase 'very heavy' to distinguish this group of trucks from the rest of the truck fleet which collectively is referred to as 'heavy' in Ministry of Transport statistics.

As can be seen in Figure 23 below, the 'very heavy' sub-set (i.e. trucks weighing more than 30t) is responsible for 29% of fuel consumed by trucks classed as 'heavy' in New Zealand – 5.5 % of New Zealand's transport emissions, or 2.9% of New Zealand's energy emissions . We address later the

[20] Countries which have announced bans include: Germany, 2030; India, 2030; Ireland, 2030; The Netherlands, 2030; Norway, 2025

economics of transport for the 'medium' trucks responsible for the remaining 71% of 'heavy' fleet fuel consumption.

Figure 23: Fuel consumed by freight vehicles classed as 'heavy'

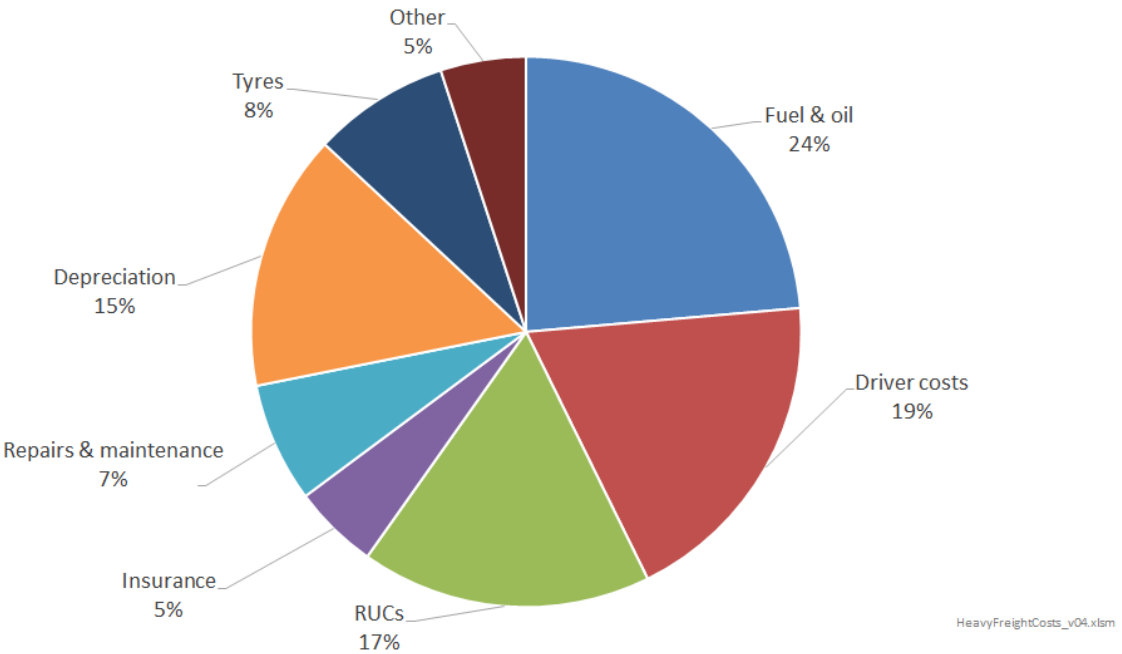


To assess the economics of truck transport, we have developed a model of the cost components of transport and how these costs will vary between the three fuel / technology options:

- Diesel vehicles
- Electric vehicles (EVs)
- Hydrogen vehicles (HVs)

Our starting point for estimating the cost of these vehicle options is the typical total cost of ownership (TCO) for a diesel vehicle.

Figure 24: Typical heavy freight TCO breakdown (diesel vehicle)[21]



In determining the economics for hydrogen and electric trucks, some of the above TCO items are considered to be common:

- Road User Charges (RUCs)
- Insurance
- Driver costs
- Tyres
- Other

However, these are increased for EVs due to the payload reduction and refuelling downtime productivity penalties – depending on the extent to which the duties of the truck result in such penalties being material. Further, as detailed later, RUCs for EVs are increased by an additional factor to reflect the fact that RUCs increase with the weight of vehicle.

Some of these cost items are very technology specific:

- Capital cost (i.e. 'Depreciation' in Figure 24) – upfront cost and operating life
- Maintenance costs – vehicle servicing and repairs
- Fuel costs

Note: Capital and maintenance costs are also affected by productivity penalties for heavy EVs.

The following sections step through each of these technology-specific cost areas, and the productivity penalties, and set out our assumptions for diesel, battery-electric and hydrogen.

[21] Breakdown provided by one of New Zealand's largest freight operators. 'RUCs' are Road User Charges.

3-1.2.1 Capital Cost

Current costs

Diesel vehicles dominate heavy freight, and there are no production battery-electric or hydrogen heavy trucks commercially available. Makers such as Tesla, Volvo and Daimler have battery-electric heavy trucks in pre-production and Tesla have provided an indication of intended sales price. Nikola Motors are developing hydrogen-powered trucks for sale, with Toyota and Hyundai also announcing plans.

This means there is no real-world information on purchase cost or vehicle life for battery-electric and hydrogen heavy line-haul trucks. We have assumed that the overall life span of all three vehicle types is similar such that capital costs per lifetime vkt will scale proportionate to initial purchase cost. This is a simple assumption, but appears reasonable in the absence of real-world data given:

- all truck types are likely to be repowered (new motor) and to have major components such as the gearbox (diesel), batteries (battery-electric) and fuel cell (hydrogen) replaced during their working lives
- diesel engines produce more heat and vibration, but less torque and power.

For diesel trucks we assume a NZ$175,000 purchase cost.

Our purchase cost assumptions for other technologies are:

- battery-electric – $250,000 – this is slightly higher than the stated intended sale price of the shorter-range (480km) Tesla Semi ($230k)
- hydrogen – $500,000 – indicative price of a Nikola truck.

As a sense check, our assumed cost relativities for heavy vehicles (battery-electric is 143% and hydrogen is 285% of diesel) are similar to observed relativities for light vehicles (of 150% and 300%).

Future costs

As mature technologies, we expect relatively limited cost reductions for diesel trucks, whereas we expect EV and HV trucks to enjoy significant capital cost reductions. As mentioned previously, our 'future' timescale is 20 years' distant, i.e. approximately 2039.

We expect the primary driver for changes in the future cost of battery-electric vehicles will be advances in battery technology and production costs. We assume a 50% reduction in battery costs[22], 25% reduction in other powertrain costs and no change in other cost components. These other components (body) are assumed to have a consistent cost of $115,000 – the same as for diesel – and with no change into the future.

We've modelled hydrogen vehicles as having the greatest potential for cost reduction. We assume there is a 75% reduction in the cost of hydrogen powertrains and 50% reduction in the cost of high-pressure storage tanks. These assumptions rely on large-scale manufacture and a rate of uptake greater than for EVs, thereby driving hydrogen vehicles faster down the technology learning curve.[23]

[22] This 50% reduction in costs is considered to be conservative, given cost reduction rates observed in the last fifteen years, and projections from other organisations. For example, IRENA are projecting costs to fall between 50 and 66% in less than 15 years, compared to our 50% reduction in 20 years. (See "*Electricity Storage and Renewables: Costs and markets to 2030*")

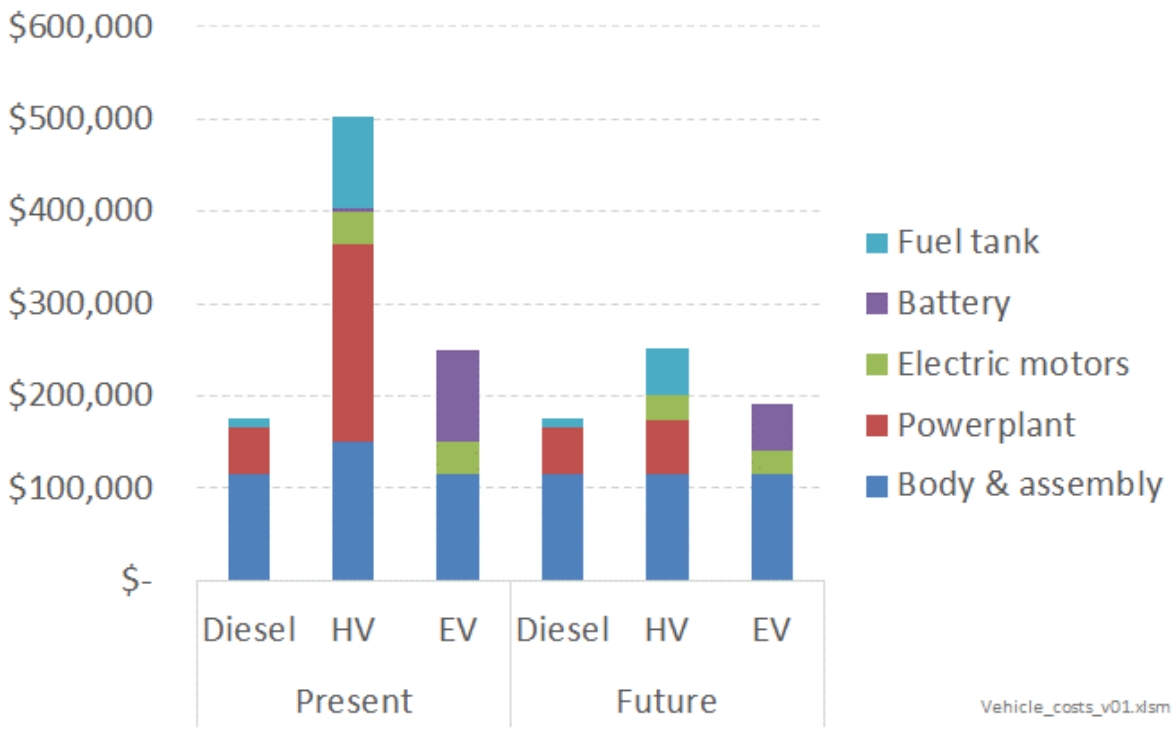
[23] A technology learning curve is a well-established phenomenon where the cost of a technology tends falls as the production of the technology increases. These cost reductions are due to ongoing technology improvements, and increased manufacturing scale economies. Often the learning curve is expressed as the rate at which costs will reduce for a doubling of world production of a technology.

We assume that vehicle body costs reduce by 40% to be in line with other technologies as production scales.

These assumed cost reductions for EV and HV trucks results in their relative capital costs compared to a diesel truck being 109% and 143%, respectively.

The resultant cost structure of the vehicles is illustrated in Figure 25.

Figure 25: Projected capital cost breakdown for very heavy trucks



It is almost certain that the future costs will turn out to be different to our projections.

If the world heads down the hydrogen route for *all* vehicles (light and heavy), then EVs are unlikely to reduce much in cost, and HVs could potentially fall in cost to the level of diesel trucks now.

Conversely, if the world heads down the electric route for vehicles (light and heavy) then hydrogen vehicles will not progress far down the learning curve, whereas electric vehicles could be even cheaper than our projection.

We examine the sensitivity of outcomes to these different relative cost scenarios.

Irrespective of which of these paths the world heads down, a general conclusion from the above analysis is that the differences in capital costs between the options is almost certainly going to reduce going forward.

3-1.2.2 Maintenance Costs

As with capital cost, there is no real-world data on maintenance costs for heavy battery-electric and hydrogen vehicles.

However, we can reasonably assume that powertrain maintenance costs will be lower than for diesel because diesel engines are more complex, with more moving parts and higher operating temperatures. We can also assume that hydrogen maintenance costs would be slightly higher than battery-electric maintenance due to the extra components (hydrogen tank and fuel cell – noting that

a hydrogen vehicle also has an electric motor and battery). Other maintenance costs (for body, running gear, tyres) are likely to be similar for all vehicle types.

We have assumed that battery-electric maintenance costs are 25% lower than diesel trucks and hydrogen trucks are 22% lower than diesel. This assumes the powertrain accounts for one-third of overall maintenance cost for diesel vehicles and savings of 75% and 67% are possible for battery-electric and hydrogen powertrains, respectively.

Note that these maintenance assumptions cover repairs and servicing and exclude operating costs such as road user charges, tyres, and insurance.

3-1.2.3 Productivity Penalties

Until recently, the more limited range and extra weight of EVs has been seen by many as a show-stopper for heavy EVs, leading to a presumption that 'something else' will be needed for fuelling heavy trucks – with that 'something else' generally either being thought to be hydrogen or biofuels which don't suffer such vehicle range and weight penalties.

However, recent developments in batteries, and the growing development of battery electric buses and trucks around the world has started to test that presumption.

We examine in detail the potential impact on the relative economics of electric and hydrogen heavy vehicles due to the two productivity disadvantages of battery electric vehicles:

- the weight of the battery may reduce useable payload, and
- battery recharging during the day because of EVs more limited range may increase unproductive downtime.

Importantly, in undertaking this analysis we don't treat 'heavy' vehicles as a homogenous block, but instead take account of the many different weights and distances travelled by the commercial vehicles classed in New Zealand as 'heavy'. This is because, as the analysis highlights, the specifics matter, and productivity impacts for one group can be very different to other groups.

Payload Penalty

We estimate a battery-electric powertrain weighs around twice as much as a diesel powertrain (5 tonnes for battery-electric versus 2.5 tonnes for diesel motor, gearbox and full diesel tank). We assume that the powertrain of a hydrogen vehicle will be the same weight as for a diesel vehicle.

This 2.5 tonne extra weight means that the payload of a fully-laden heavy EV is 27.5 tonnes compared to 30 tonnes for a heavy HV or diesel vehicle – a 9% penalty, meaning that 9% more heavy EV trucks will be needed to perform the same fully-laden freight service as heavy diesel or heavy HV trucks.

However, it should be noted that this payload penalty only applies to the very heaviest weight-class vehicles, as these are the only vehicles constrained by the absolute weight limit for vehicles on New Zealand's roads.

Further, even within this heaviest class of vehicle, the limiting factor for many of these trucks will be space, not weight. For example, NZ Post said to us that their trucks carry bulky, not heavy, items so weight is not a limiting factor.

The fact that not all of the heaviest class of trucks are operating to weight limits is illustrated by the typical payload for this class of vehicle being 24 tonnes, not 30 tonnes.[24] That said, this indicates

[24] https://www.nzta.govt.nz/assets/Commercial-Driving/docs/Monitoring-evaluation-and-review-of-the-Vehicle-Dimensions-and-Mass-Rule-30-April-2013.pdf, Table 15. Class R22T22 general freight vehicle.

that more than 50% of the heaviest class of vehicles are likely to be operating to their weight limits, as we understand to be the case for the likes of logging trucks, dairy tankers, and diesel tankers.

On average this would mean that the payload productivity penalty for the heaviest class of EVs would be 9% * 24/30 = 7.3%. However, for our analysis we have conservatively assumed that all very heavy battery electric trucks suffer this 9% payload productivity penalty.

Looking forward 20 years, we assume the future payload penalty reduces by 1/3 due to improvements in battery energy density.

We also take account of the fact that heavier vehicles will tend to result in vehicle owners facing higher Road User Charges. We have assumed that

- Approximately 48% of Road User Charges are to cover the costs of maintaining the roads (based on analysis of NZTA expenditure statistics), and that of the remaining 52% of roading costs associated with building new roads, 25% are extra costs associated with building roads to a higher standard that can withstand heavier vehicles. This results in 61% of roading costs being assumed to be driven by wear and tear on roads.
- Road User Charges to cover these wear and tear costs will increase with the weight of the vehicle according to a fourth power law – based on assessments on how road damage increases with axle weight.

Thus, a vehicle which weighs 10% more, will pay 28% more in RUCs.[25]

This assessment of the impact of weight on RUCs penalises EVs more than is currently the case, because the increase in RUCs with weight is materially less than this for the current RUC regime.

In addition to the above general weight-based penalties for heavy EVs, we understand that there can be specific issues with buses in terms of increased weight pushing buses over allowable thresholds for some routes. Further, in some cases, battery electric buses will need to shift to three axles which, under the current RUC vehicle type classification system, appears to result in significant step changes in RUCs – significantly more so than the associated increase in weight.

Some bus operators (in New Zealand and overseas) are addressing this through having buses with smaller batteries but installing opportunity recharging infrastructure: the ability to have a 5-10 minute boost charge at various intervals during the day – typically at the end of each route. While this is working well in some instances, this can be difficult in others – e.g. where there is insufficient electricity network infrastructure at these end-of-route locations.

In instances where opportunity recharging is not practicable, and where there are hard weight limits for certain routes, the only option for electric buses is to have a couple of 'medium-sized' buses rather than one 'big bus'. This is likely to significantly increase the cost of the electric bus option in these instances.

It is not known whether this issue with weight-constrained routes is likely to affect a large proportion of bus-routes in New Zealand, or a relatively small proportion.

Given the situation-specific nature of these issues with buses, we have not assessed them in any detail.

Nor have we explored the issue of whether the current RUC classification system may create unintended consequences around vehicle choice (for trucks and buses). An initial high-level review of the system suggests that there could be some issues in some cases.

[25] ((1-61%)+61%*1.1^4)-1 = 28%

Refuelling Penalty

Until recently, this has been seen as a show-stopper for EVs performing long-haul heavy freight duties:

- the more limited range of EV trucks requires them to re-fuel frequently
- the limited charger capacities means it takes them a long time to re-fuel at each stop.

The following simple calculations illustrate the nature of this challenge.

Consider a long-haul heavy diesel truck with a range of 2,000 km. With a fuel economy of 45 l/100km and a diesel truck pump re-fuelling rate of 120 l/min, this will take approximately 7.5 minutes to re-fuel from empty. It is understood that hydrogen trucks should be capable of similar ranges and refuelling times.

120 l/min equates to an energy transfer capacity of approximately 72 MW. In contrast, up until recently (more below), the highest capacity EV charger installed in New Zealand was 120 kW. This is 600 times smaller than the energy transfer capacity of a diesel pump.

On the face of it, this appears to mean that it would take 600 times longer (75 hours!) to re-fuel an EV truck than a diesel truck. Clearly, such a re-fuelling time would be infeasible.

However, there are several factors which mean that this is not the correct comparison.

Firstly, electric vehicles are inherently more energy efficient than internal combustion engine vehicles. As set out in a later section 3-1.2.4, approximately 2.6 times more energy is required to power a diesel truck than a battery electric vehicle. This reduces the re-fuelling time by a factor of 2.6.

Secondly, the capacity of EV chargers (and the associated ability of EV vehicles to re-charge) has been growing rapidly. Charging stations of 350 kW capacity have already been deployed overseas, and manufacturers are unveiling ever-larger chargers. For example, Tesla has announced a 'mega-charger' of 1.6 MW capacity for recharging its heavy battery electric semi-truck, and American company ChargePoint unveiled plans earlier this year for a 2 MW recharging station for heavy electric trucks and electric aircraft. A 2 MW charger would reduce the re-fuelling time relative to a 120 kW charger by a factor of seventeen.

Lastly, and most importantly, the re-fuelling model for electric vehicles is very different to that of diesel vehicles.

- Diesel vehicles are re-fuelled every few days at a public re-fuelling station. For example, a heavy truck with a range of 2,000 km travelling 75,000 km per year (the average for the 'very heavy' class) would re-fuel approximately once every seven days.
- Electric vehicles are re-fuelled overnight, *every* night, at their base.

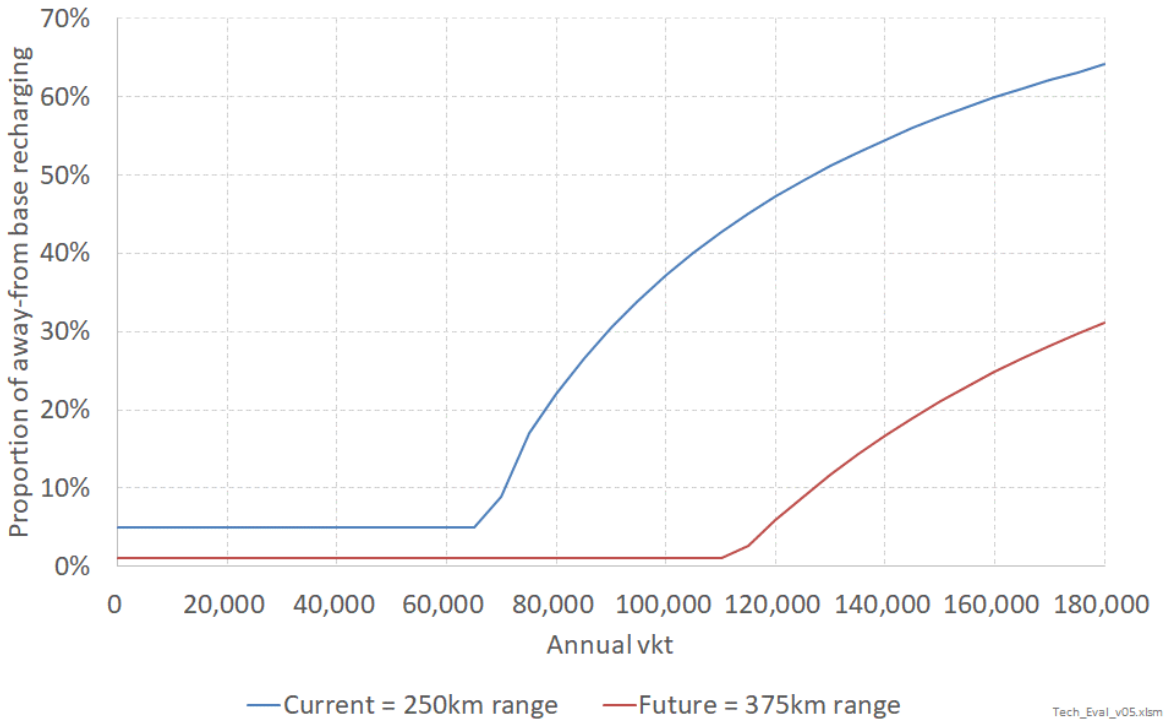
Re-fuelling every day (or night, rather), rather than once a week (in the example of the truck travelling 75,000 km per year) reduces the vehicle fuel carrying capacity by a further factor of seven. Further, re-charging overnight when the vehicle would anyway be stationary does not add any additional unproductive downtime.

That said, the more limited range of EV vehicles means that for vehicles travelling long distances, the overnight charge will be insufficient, and a truck will need to re-fuel at a re-charging station during the day. Notwithstanding improvements in recharging technology, it will take longer to refuel an EV truck than a diesel truck. Taking a long time to refuel will result in the truck being unproductively stationary – thereby requiring a greater number of trucks to deliver the same freight transport service. For example, if EV trucks need to spend 10% of their working day re-fuelling, it will require 10% extra EV trucks to perform the same transport service as diesel trucks.

To understand the potential nature and scale of this refuelling downtime penalty, we built a simple model which estimated the amount of time a heavy EV would be unproductively stationary for different amounts of distance travelled, and for different vehicle and charger capabilities – both now and 20 years' in the future. The key moving parts of this model are as follows:

- An assumption of the range of heavy EV trucks. Our assumption for current range is 250 km, rising to 375 km for trucks produced in 20 years' time. We believe these to be conservative assumptions given that Tesla is planning to produce a long-range battery electric semi truck with a range of 480 km. (And a long-range version of 805 km). Production models are planned from late 2019.
- An estimation of the amount of travel that can be undertaken from the overnight charge (for which there is no unproductive downtime penalty), and how much from away-from-base refuelling. This varies according the distance travelled by a truck, and the range of the truck. Figure 26 shows this modelled relationship. Importantly, if a battery electric truck needs to re-fuel away from base it will not completely fill up its battery, but rather recharge to a level sufficient to last it till it can return to its base for an overnight recharge – plus an extra amount for a safety margin. We have assumed 30% extra for this safety margin.

Figure 26: Variation in extent of away-from base EV charging due to distance travelled



- An assumption of the recharger capacities. We have assumed 120 kW for the current situation, rising to 1 MW for the future situation. We consider both of these to be conservative assumptions.

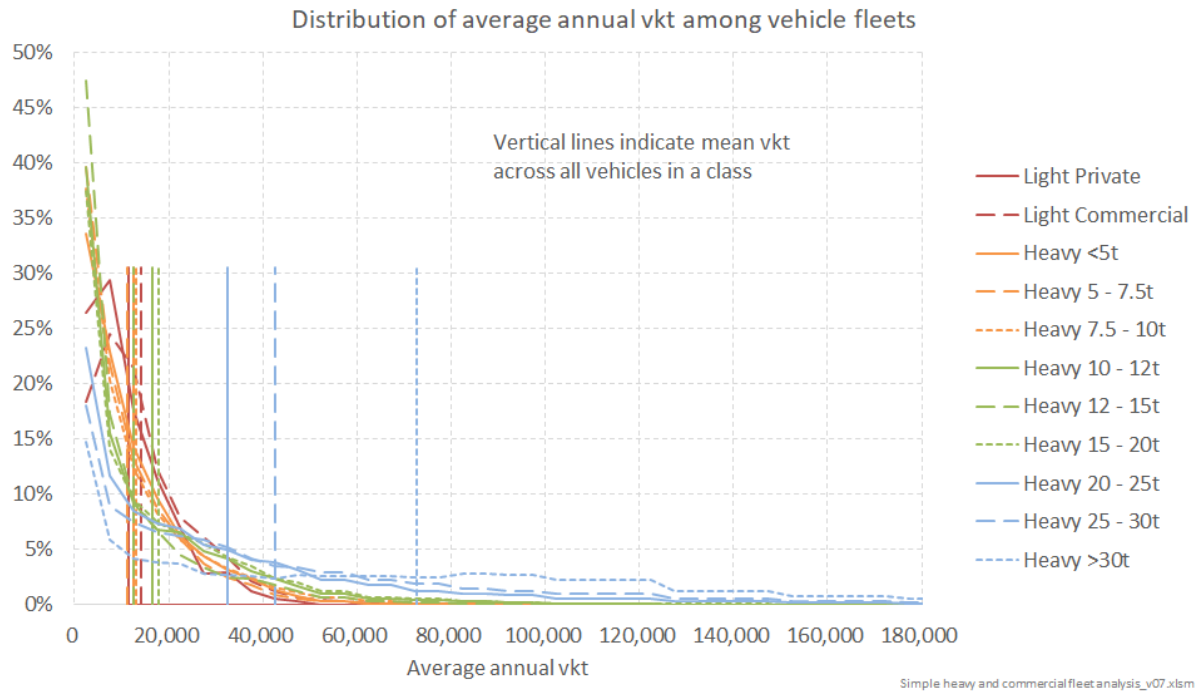
Using the above simple model we estimate that a heavy truck travelling 75,000 km each year (the average distance travelled by the 'very heavy' category) will need to have 17% of its fuel from away-from-base recharging under the current situation, leading to an 8% productivity penalty from being unproductively stationary. This productivity penalty falls to 0.1% 20 years in the future due to the greater range of the batteries (and thus reduced need to recharge away from base) and faster recharge time for away from base refuelling. These recharging time productivity penalties are in addition to the weight-based payload productivity penalties estimated earlier.

The above analysis assumes away-from-base recharging is not combined with other activities such as mandatory rest breaks, or vehicle loading and unloading. To the extent charging is combined with such activities (which we understand to be the case where battery electric trucks are starting to be rolled out[26]), the productivity penalty will be less.

It should be appreciated that the 75,000 km average for the very heavy class of truck, hides the fact that some very heavy trucks travel a lot further and thus will be more heavily penalised from away-from-base refuelling. (And also that other very heavy trucks will travel less distance, and suffer less of a penalty).

Figure 27 below provides further insights into the travel patterns of EV vehicles, and thus the extent to which different types of vehicle are likely to suffer a material productivity penalty from refuelling time. This highlights that in all vehicle classes, there are a relatively small percentage that are driven very long distances – the long tail to each distribution – but that most vehicles are driven much more modest distances. It also highlights that the vehicles that drive the longest distances tend to be the heaviest vehicles. Thus, it is this group of 'very heavy' vehicles that face the electric vehicle double-whammy of weight and range. However, for most other vehicles, these weight and range constraints will be significantly less.

Figure 27: Distribution of average annual vkt for different vehicle classes



It is also the case that newer vehicles travel much longer distance each year than older vehicles. We therefore also consider the case of a very heavy truck travelling 150,000 km each year – twice the average for that class. Using our model this results in a current recharging time productivity penalty of 26%, falling to 2%, 20 years in the future.

Combined Penalty

We use the payload and refuelling productivity factors to scale up all non-fuel costs – i.e. across a fleet of vehicles the lower productivity translates into more vehicles, with more drivers. In this way,

[26] For example, most heavy trucks have usual destinations where they are transporting goods to and from. They need to spend a material amount of time and these destinations loading and unloading. Installing recharging facilities at these destinations allows recharging to be undertaken at the same time.

our payload productivity assumption is independent of any assumptions about overall New Zealand fleet utilisation.

The current combined productivity penalty is 18% for a 'very heavy' EV travelling the average annual distance for that class (approximately 75,000 km/yr), improving to 6% for the future scenario. For a very heavy vehicle travelling 150,000 km this productivity penalty increases to 38% today, improving to 8% in the future.

For 'medium' sized vehicles (the 20-25t weight class) travelling the average distance for that class (32,000 km/yr), the combined productivity penalty today is assessed to be 2.3%, improving to 0.1% in the future.

3-1.2.4 Fuel

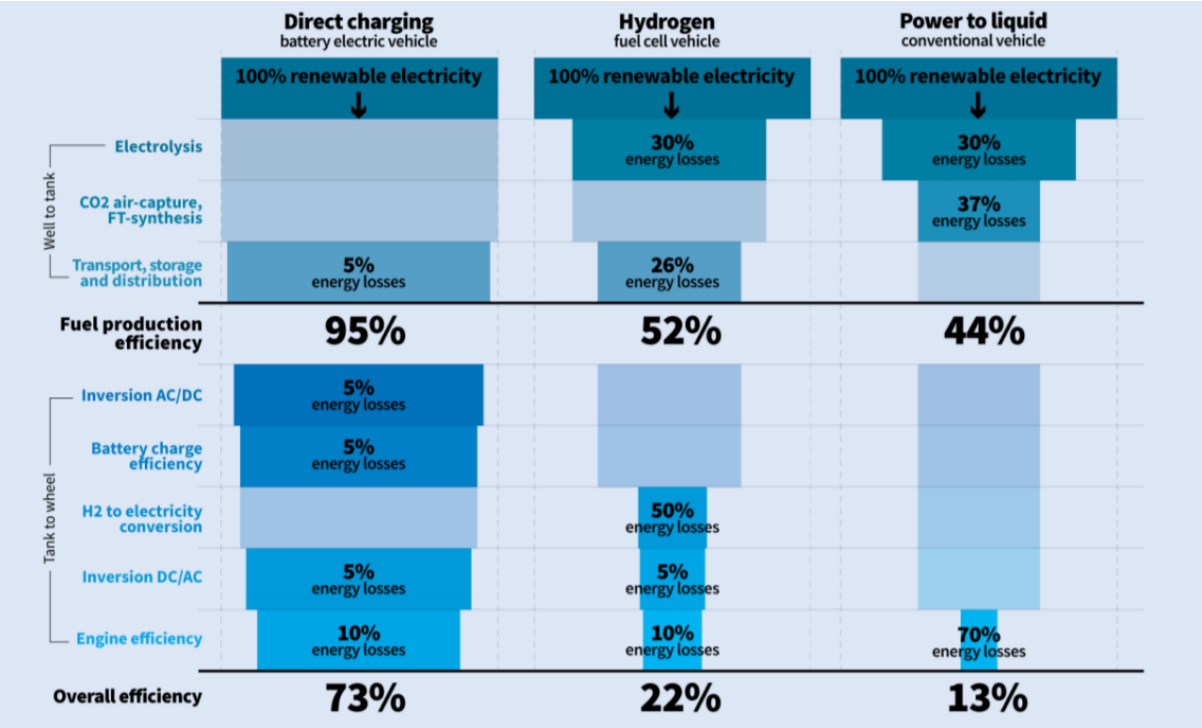
To build up comparative fuel costs, we considered:

- vehicle efficiency
- fuel cost
  - the cost of the fuel delivered to the re-fuelling point (diesel, electricity or hydrogen)
  - the cost of additional refuelling infrastructure – the cost of refuelling stations or fast charging points
  - refuelling model – the mix of at-base and away-from-base refuelling

Vehicle efficiency

We based our vehicle efficiency estimates on the data presented in Figure 28.

Figure 28: 'Well-to-wheel' fuel efficiencies of freight vehicles



Source: "Roadmap to climate-friendly land freight and buses in Europe", Transport and Environment, June 2017

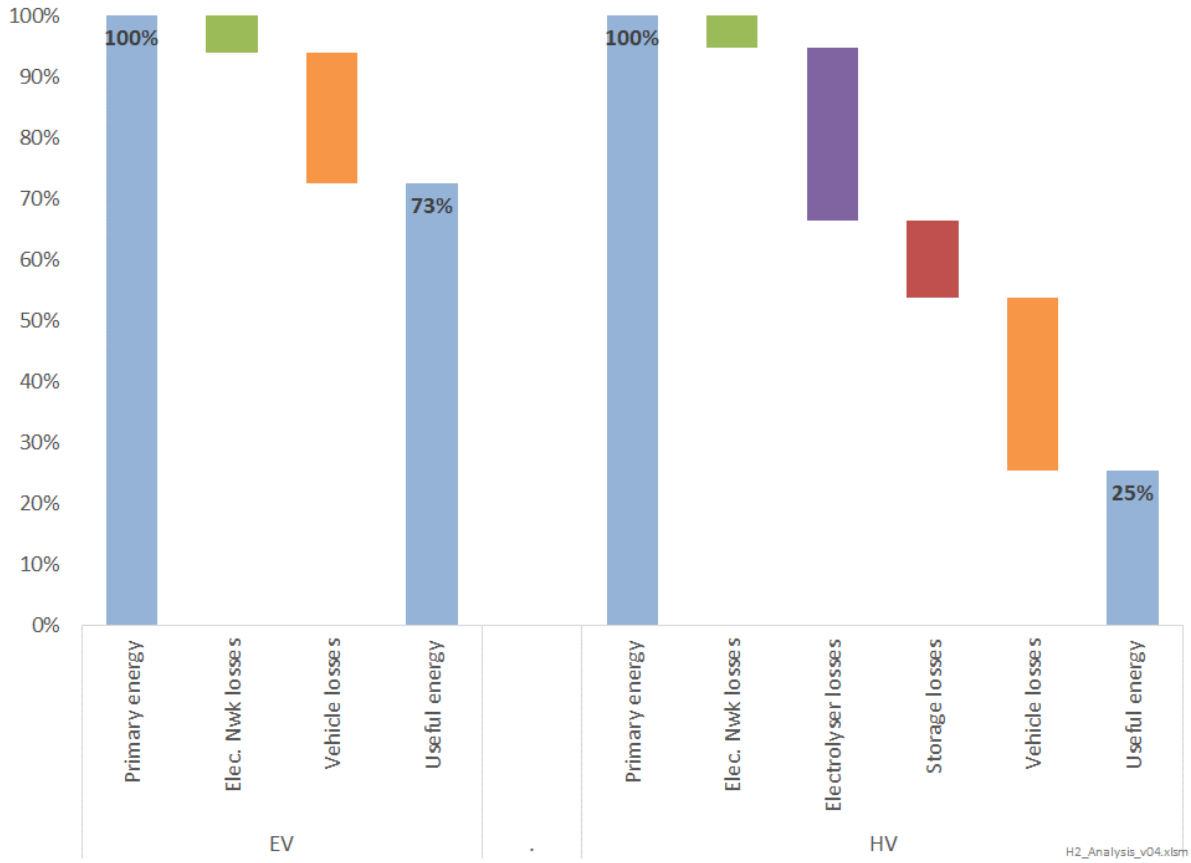
This results in an EV being 2.6 times more fuel efficient than a diesel vehicle at converting stored energy into motive power.

We are not so pessimistic about HV fuel efficiency as the authors of Figure 28, and instead assume a fuel cell efficiency of 55%, instead of 50%.

This results in an EV being 1.6 times more energy efficient than an HV.

Figure 29 shows our assessment of the current overall efficiency of battery electric and hydrogen technologies at converting the same renewable primary energy sources (e.g. wind-generated electricity) into useful transport services. Overall, almost three times as much renewable energy is required to power a hydrogen truck compared to a battery-electric truck. (73% ÷ 25% = 2.9)

Figure 29: Energy conversion losses for EV and HV transport[27]



Looking forward, we consider there is greater technical scope in improving the efficiency of hydrogen vehicles than EVs due to the potential for fuel cell technology improvements. We assume that vehicle fuel cell efficiencies rise from 55% to 64% efficiency. This would rely on mass-uptake of fuel cell vehicles to drive this technology improvement.

Fuel cost

For diesel we have assumed world oil prices are around US$70/bbl for both current and future scenarios, giving a diesel pump price of NZ$1.4/l (excl. GST and CO_2-related costs).

For hydrogen, we have assumed the vehicle-related fuel costs set out in Table 2 previously. These include service-station overhead costs.

For these, we have used Z Energy's reported station overhead costs (which account for 26% of the non-CO_2 diesel pump price), reduced by 18% as our estimate of the cost of transporting diesel to

[27] We have assumed slightly lower electricity network losses for hydrogen on the assumption that at least some hydrogen stations would be connected at higher voltages than battery charging stations.

service stations (based on Z accounts). We have assumed the remaining service-station overhead costs are consistent on a per-GJ basis between diesel and hydrogen. This adds a further NZ$1.3/kg.

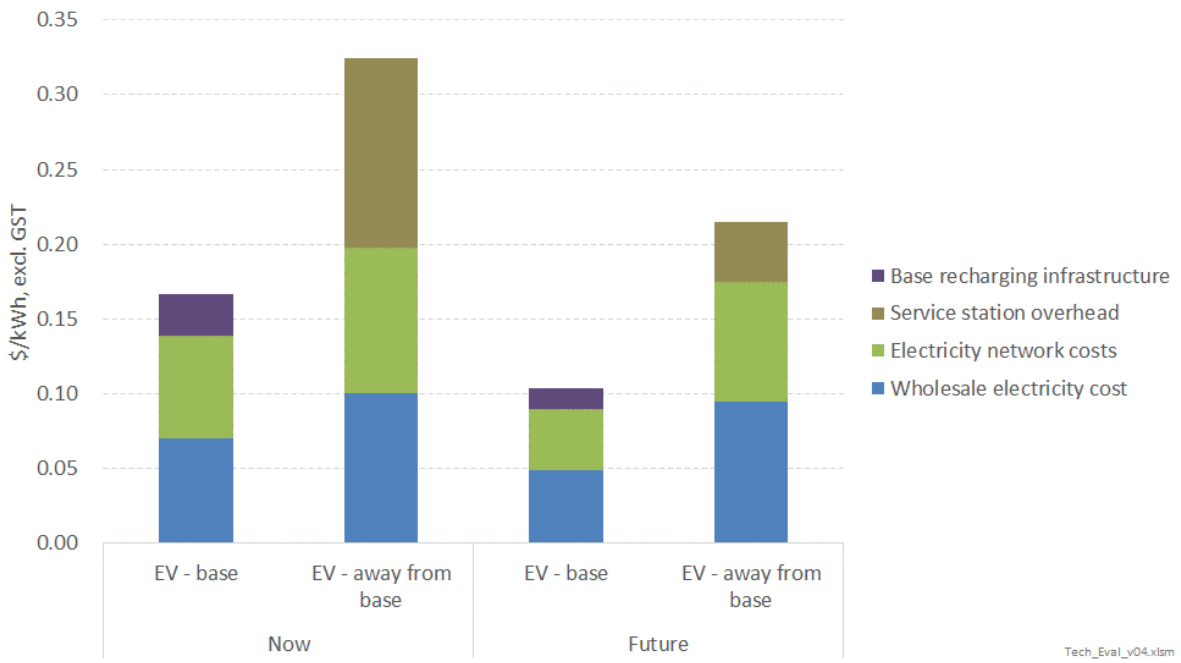
These assumptions together produce a current delivered cost of NZ$10.3/kg., falling to NZ$6.5/kg in a future with small-scale hydrogen uptake. If there is large-scale hydrogen uptake which drives the need for new renewable generation development, hydrogen fuel costs are projected to be NZ$9.1/kg.

For comparison, the cheapest forecourt hydrogen currently sold in California is NZ$17.2/kg$H_2$ (excluding sales tax).

This difference may reflect higher input costs, overheads or margins in California, or may suggest our assessment is optimistic. In this respect, our assessment of the service-station overhead costs is consistent with a larger-scale roll-out than the limited deployment in California, therefore our assumed service-station overhead costs are relatively low. This may be inconsistent with the projected hydrogen cost for a future with small-scale hydrogen uptake. If per kg service station cost recovery were double in a future with small-scale hydrogen uptake, the hydrogen cost would rise from NZ$6.5/kg to NZ$7.8/kg.

For EVs we have developed separate price estimates for base-charging overnight, and away-from-base charging during the day. These are shown in Figure 30.

Figure 30: Estimated electricity costs for recharging a heavy EV



The current wholesale and network electricity prices are based on existing prices for commercial customers charging during the night and day (for base and away-from-base, respectively). The future prices are Concept estimates using the same underlying values as used for calculating the electricity wholesale and network costs as for the green hydrogen production costs. In this, it should be noted that a large proportion of the benefit from optimising hydrogen production by avoiding peak price periods are also achieved by re-charging a vehicle overnight.

The base recharging infrastructure costs are based on existing published prices for commercial fast chargers. These are assumed to come down in price for the future case (20 years' hence).

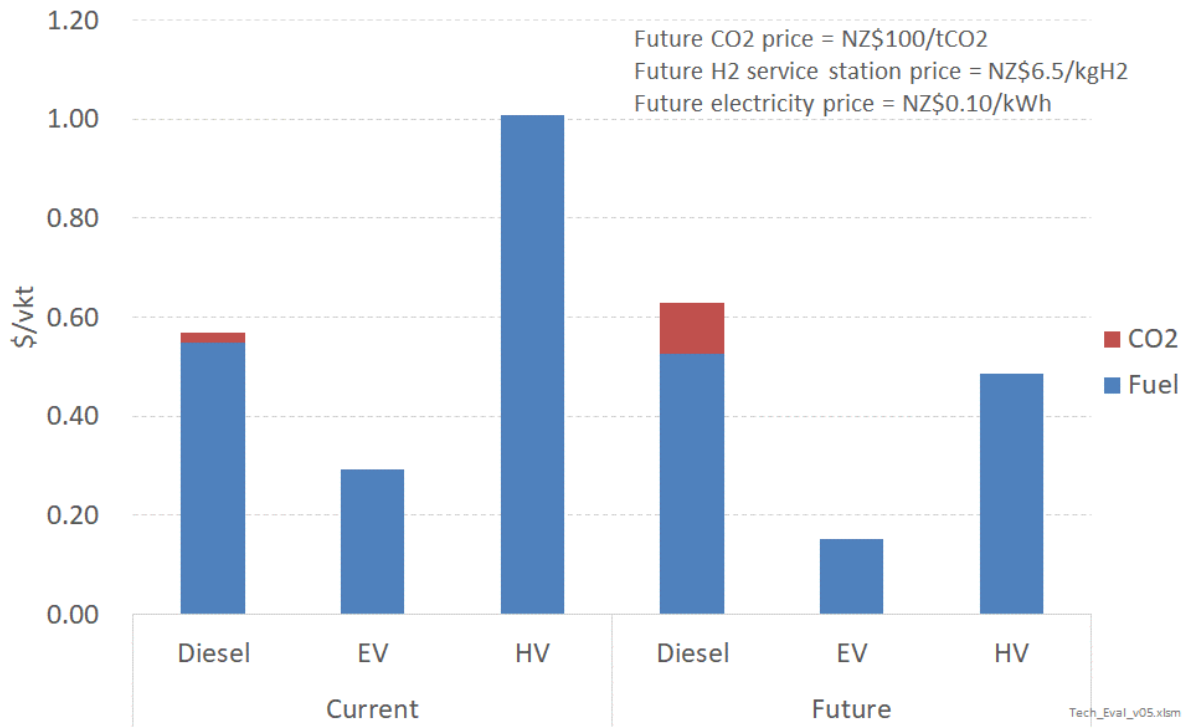
The current 'service station overhead' costs are an average of service station overhead cost applying to diesel and hydrogen (on an equivalent $/GJ basis) and the time-based costs applying to current ChargeNet public chargers for light vehicles. The future service-station costs are simply the same as the service-station overhead costs applying to diesel and hydrogen (on an equivalent $/GJ basis).

The proportion of base versus away-from-base refuelling is as per the relationship shown previously in Figure 26.

Overall relative fuel costs

Figure 31 illustrates the projected relative fuel costs of the different options for a very heavy truck, taking into account both the costs of providing fuel to the vehicles and the efficiency of converting the fuel into motive power.

Figure 31: Projected fuel component of transport costs for the different technology options



For this illustrative figure, for our current situation we have assumed a CO_2 price of NZ$20/tCO.

We assume that carbon prices do not flow to electricity and hydrogen costs, due to our assessment that the primary electricity for these fuels will come from renewable electricity – particularly wind.

Figure 31 highlights that the energy losses and additional required capital associated with converting renewable electricity to hydrogen, coupled with the inherently superior fuel efficiency of EVs, mean that the fuel costs for EVs are almost inevitably going to be substantially less than for HVs.

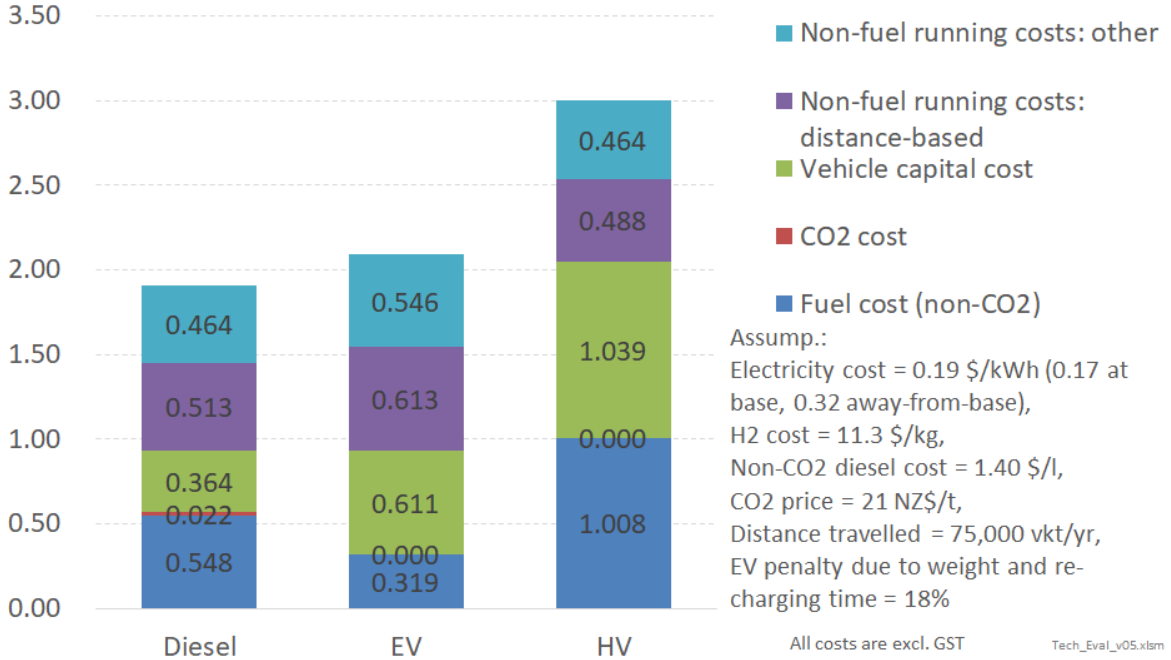
And if large-scale hydrogen uptake were to drive the need to build new renewables, the future HV fuel cost will be almost 1/3 greater still. (i.e. with hydrogen prices of NZ$9.1/kgH2 rather than the NZ$6.5/kg value used in Figure 31).

3-1.3 Findings – Very Heavy Transport

Current state

Figure 32 presents the overall estimate of the current relative costs of the different transport options for a very heavy freight vehicle travelling the average annual distance of 75,000.

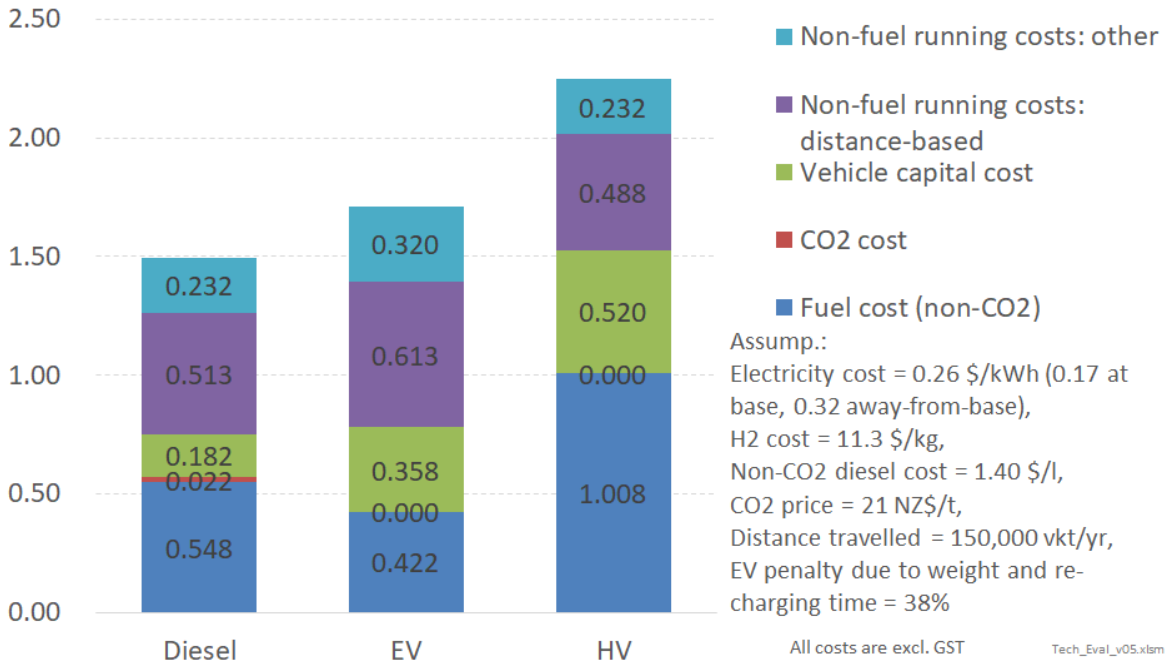
Figure 32: Modelled current relative costs of different heavy transport options – 75,000/yr vkt



This indicates that heavy EVs are starting to get close to being cost-competitive on a lifetime TCO basis.

However, many heavy trucks start their life doing long-distance duties, before being sold-on to other freight operators who tend to operate them for shorter duties. Figure 33 illustrates that EVs are less cost competitive for these longer duties. This is principally due to the fact that a far greater proportion of re-fuelling needs to occur away-from-base, resulting in higher electricity costs, and greater penalties from being unproductively stationary while re-fuelling.

Figure 33: Modelled current relative costs of different heavy transport options – 150,000/yr vkt



The fact that heavy EVs on a lifetime TCO basis are close to being cost competitive with heavy diesels but there is no current uptake is a function of:

- There being virtually no heavy EV models available for purchase at the moment; and
- The lack of away-from-base re-fuelling infrastructure (i.e. widespread fast-charging facilities).

The former issue is starting to be resolved as vehicle manufacturers start to bring out heavy trucks – having first focussed on light vehicles.

The latter issue will require significant investment, likely involving public money.

The same issues also apply to hydrogen trucks (albeit they are currently further from being cost-competitive with diesel). These too are unlikely to take-off in New Zealand without significant investment in re-fuelling infrastructure.

Future state

Figure 34 below shows the modelled future costs for the different technologies for the situation of a truck driven the average distance for heavy freight each year, and Figure 35 shows the costs for the situation of a truck driven twice this distance each year. Note: These analyses assume small-scale hydrogen uptake, and thus relatively low hydrogen fuel costs (as per the analysis in section 2-1.2 previously).

Figure 34: Modelled future relative costs of different 'very heavy' transport options, assuming small-scale hydrogen uptake – 75,000/yr vkt

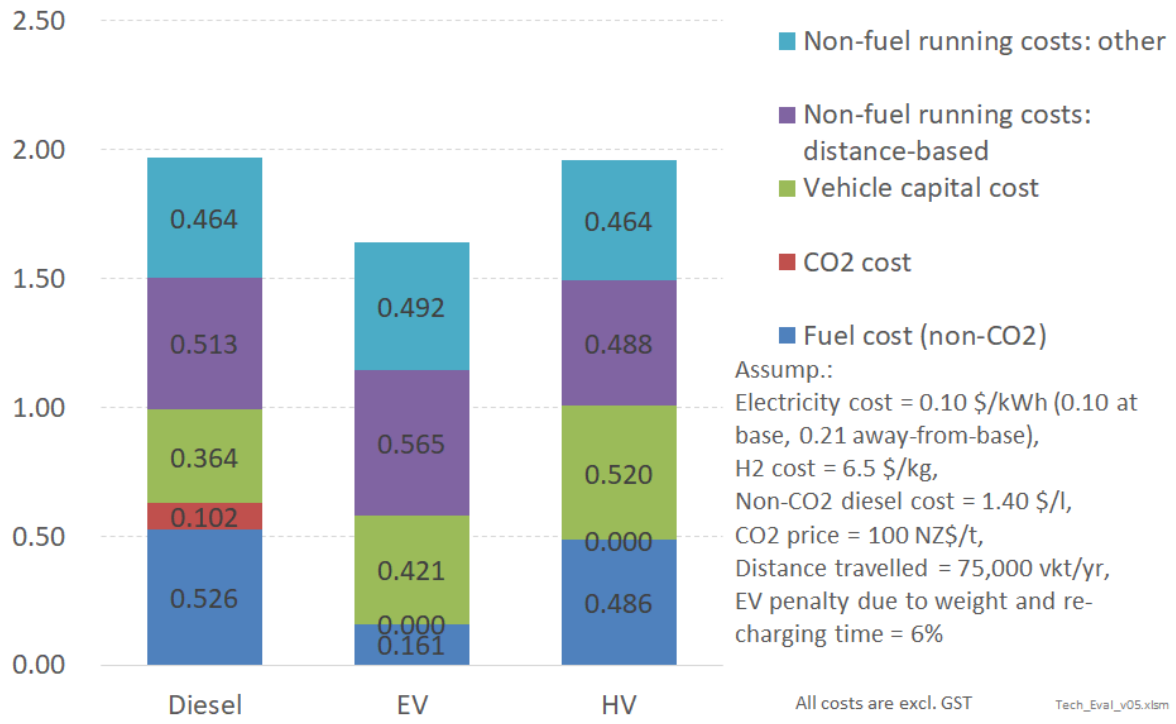
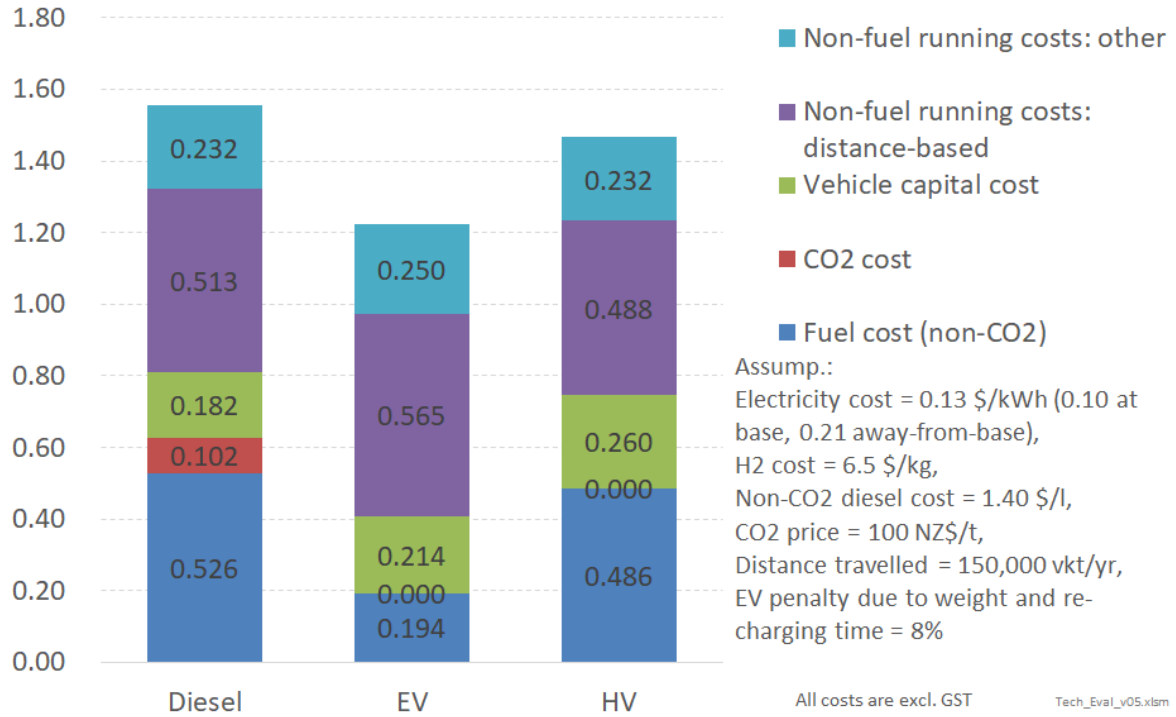


Figure 35: Modelled future relative costs of different 'very heavy' transport options, assuming small-scale hydrogen uptake – 150,000/yr vkt



This analysis suggests that both hydrogen and electric vehicles are likely to be lower cost than diesel – albeit with EVs likely to be the lowest-cost low-carbon option for meeting New Zealand's heavy freight requirements.

EV's relatively lower cost compared with HVs is principally due to EV's relatively lower fuel costs (as illustrated in Figure 31 previously). This is a function of EVs having lower delivered fuel costs (on a $/GJ basis) to the vehicle, and better fuel efficiencies. It is also due, but to a lesser extent, to EV's relatively lower capital costs.

For light vehicles and 'medium' trucks, we project that the relative cost-effectiveness of EVs compared with HVs will be even better due to:

- Such vehicles not being weight constrained and travelling smaller distances – and thus not suffering the same productivity penalties as heavy EVs
- The relatively more expensive capital cost of HVs being a greater penalty for vehicles that travel shorter distances.

Sensitivity analysis

Although the above analysis indicates EVs are likely to be New Zealand's least cost low-carbon transport option for the heavy fleet, New Zealand will be a technology-taker for transport.

Thus, if hydrogen becomes the dominant fuel for heavy trucks internationally, New Zealand may have no choice but to also use hydrogen trucks for its heavy fleet. To test the impact on New Zealand transport costs, we undertook a sensitivity analysis which takes account of the following likely outcomes for such a future.

- The capital cost and performance of EVs are unlikely to have improved by as much as assumed for the analysis in Figure 34 and Figure 35. For the sensitivity analysis below we make the conservative assumption that there is no improvement in EV cost and performance (including recharging times) between now and 20 years' time.

The capital cost of HVs are unlikely to be much lower than that assumed in Figure 34 and Figure 35, as those numbers already assume significant cost reductions (greater than assumed for EVs) based on an assumption of very large-scale worldwide uptake of hydrogen vehicles.

- Large-scale uptake of hydrogen for transport will start to drive the need for new renewable generation, resulting in hydrogen fuel prices that are higher than those assumed for small-scale 'opportunistic' hydrogen production within Figure 34 and Figure 35.

The results of this sensitivity analysis are shown in Figure 36 and Figure 37 below.

Figure 36: Modelled future relative costs of different 'very heavy' transport options, assuming large-scale hydrogen uptake – 75,000/yr vkt

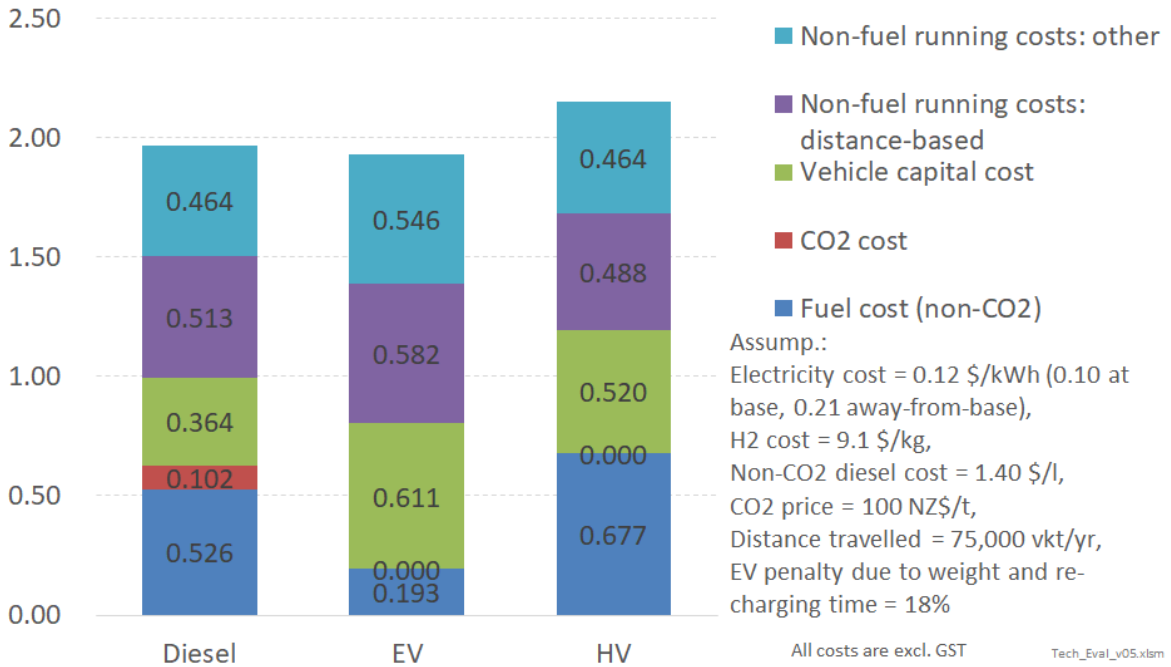
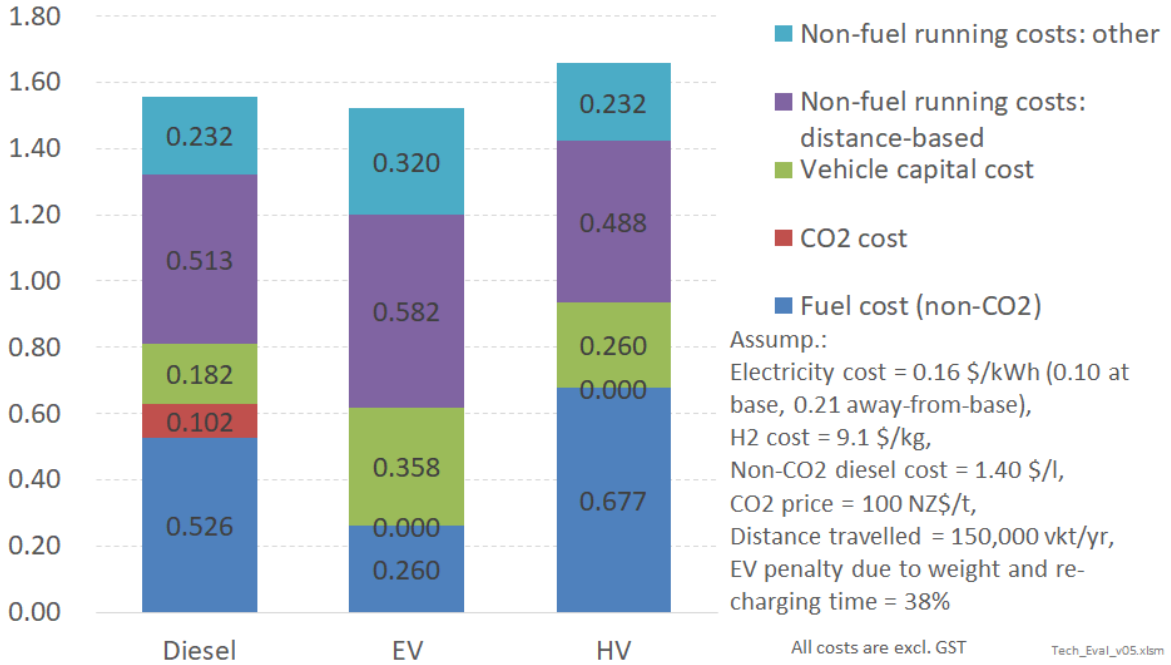


Figure 37: Modelled future relative costs of different 'very heavy' transport options, assuming large-scale hydrogen uptake – 150,000/yr vkt



The above analysis indicates that, even in this future of hydrogen trucks becoming the dominant fuel for heavy trucks internationally, EVs are likely to be lower cost than hydrogen trucks for New Zealand.[28]

This is due to large-scale hydrogen uptake in New Zealand driving the need for new renewable generation development, and thus resulting in the wholesale electricity component of hydrogen production reflecting the costs of such generation development.

We think this analysis is significant, not just for thinking about New Zealand's transport future – and what we need to do to facilitate a low-carbon future – but also for thinking about the development of electric and hydrogen vehicles internationally.

Which technology will win, and what does this mean for New Zealand transport policy?

The vehicle capital cost and fuel efficiency assumptions embedded within Figure 34 and Figure 35 assume large-scale world-wide uptake of both EVs and HVs to drive the projected capital cost reductions. It remains to be seen whether this does indeed occur, or whether the world heads down one transport technology path. For there to be widespread uptake of both technologies would either require countries to invest in two sets of re-fuelling infrastructure (for EVs and HVs), or for one part of the world to head down the hydrogen path, and the other the battery electric path.

This uncertainty over which transport technology will emerge as dominant raises some interesting public policy questions as governments plan to facilitate the transition to low-carbon transport.

Our analysis indicates that the current lack of away-from-base re-fuelling infrastructure is going to be a major impediment to the uptake of heavy EVs or HVs – irrespective of whether the theoretical economics suggest an option is close to being economic.

Given the shared network dynamics of refuelling infrastructure, and the need to have a ubiquitous re-fuelling network that spans the country to overcome range anxiety before commercial truck

[28] Of course, in this hypothetical future where hydrogen trucks are dominant internationally, it could well be the case that there aren't any EV trucks to purchase.

operators will start to buy electric or hydrogen trucks, this suggests that public investment in refuelling infrastructure will be necessary to break this chicken and egg dilemma.[29]

In this respect, we think it is relatively unlikely that high-power battery charging *and* hydrogen fuelling infrastructure will both be deployed at a scale needed to changeover New Zealand's heavy transport fleet. The network economies of transport strongly suggest that one technology will emerge as the dominant technology. (At least for transport requirements using public highways and relying on public re-fuelling infrastructure. We explore below the specific situation of return-to-base and never-leave-base transport duties.)

The winner of the race to replace diesel may ultimately be determined by how quickly and successfully overseas vehicle manufacturers improve the value proposition for each type of truck. For now, there appears to be more research and development going into battery electric, with current rapid uptake of *light* EVs driving battery cost reductions that will also benefit heavy EVs.[30] In this respect, it is also potentially significant that China appears to be more heavily investing in battery electric vehicles, rather than hydrogen vehicles.

That said, governments and vehicle manufacturers in Japan and Korea are investing a lot of money in hydrogen vehicles – as well as investing a lot of money in battery electric vehicles– and we note that even in China there is debate about the best option. Sub-section 3-1.4 at the end of this Transport section explores the extent to which the different renewable energy potentials in each country may help explain the different motivations in different countries.

What about return-to-base, or never-leave-base operations?

As set out above, the current lack of widespread refuelling infrastructure is likely to be a significant impediment to the widespread uptake of both EV vehicles and HV vehicles for commercial duties.

However, many commercial vehicle duties are for so-called return-to-base operations – i.e. regular daily or within-day trips that go to and from a base. This covers operations such as rubbish trucks, dairy tankers, public buses, and logging trucks. Some other vehicles never leave their base, such as forklift trucks and vehicles operating within ports, rail depots or timber yards.

A dedicated electrolyser and storage facility at the vehicle base would provide all the fuel required in some cases, and result in none of the range issues associated with lack of public re-fuelling infrastructure. Likewise, an EV re-charging facility at the base would similarly address such concerns.

This also means there is no public policy issue associated with the need to address lack of public re-fuelling infrastructure.

Whether hydrogen or electric vehicles, or both, emerge as the dominant technology to provide such return-to-base services will come down to simple economics of which option is cheapest. In this respect the outcomes will principally be driven by developments overseas – with such international developments driving EV and HV vehicle costs and (in the case of HVs) the cost of electrolyser and hydrogen storage technology.

In some cases, specific features of the operation may make HVs more cost effective than EVs. For example, in the case of vehicles that work long or continuous hours – particularly in never-leave-

[29] Note: This lack of public refuelling infrastructure has not been a major impediment to the current uptake of light private electric vehicles because such vehicles tend to be driven less, thereby enabling the overnight charge at home to be sufficient for the vast majority of journeys. Further, many such EVs are in households with two vehicles – with the second vehicle being an internal combustion engine vehicle that tends to be used for the infrequent longer journeys. Having an often redundant 'second truck' is generally not an option for commercial operators.

[30] For more information, refer Concept Consulting, *Hydrogen in New Zealand, Report 3 – Research*, Chapter 11 (Worldwide interest in hydrogen).

base situations – hydrogen may offer a chance to reduce costs, since the slower recharge rate of batteries may require several EV vehicles so that one can work while the others recharge. In contrast, the quick refuelling time of HVs may mean that one HV could do the work of several EVs. Given the situation-specific nature of these applications (and relatively small contribution to New Zealand's transport emissions) we have not explored the extent to which these potential productivity benefits are likely to make hydrogen vehicles least cost.

What about centralised green hydrogen production?

Our analysis in this section has been based on a localised hydrogen production model – i.e. electrolysers located at a service station taking grid electricity.

Centralised green hydrogen production via electrolysers has not been considered in detail as it appears fundamentally less economic than localised green hydrogen production. Key factors that drive this observation are:

- Tanker costs are a significantly more expensive means of transporting the fuel, than using the existing electricity network to transport the renewable electricity to a localised hydrogen production facility.
- There would also be two lots of storage costs. (i.e. some storage capability will be needed at the production site and at the service station site)

Gas pipeline costs are lower than tanker costs (although overall transport costs would be similar to electricity network costs for localised hydrogen production), but it is not possible to transport pure hydrogen in existing pipelines at the same time they are being used for natural gas. As set out in section 3-4.2, the economics of a full conversion of existing gas pipelines to hydrogen look challenging.

Further, even if pipelines were to be dedicated to transporting hydrogen, they only cover approximately three quarters of North Island consumers, and none of the South Island. High cost tankers would be required for the rest of the country.

3-1.4 Comparison with international studies

Our analysis indicates that for large-scale de-carbonisation of our transport fleet, electric vehicles are likely to be materially lower cost than hydrogen vehicles. This is due to the inherently superior end-to-end fuel efficiency of electric vehicles, and lower whole-of-supply-chain capital costs.

To the extent that our analysis is correct, this suggests that the relative economics of electric and hydrogen vehicles will be similar overseas as well.

However, while we note there are many overseas studies that reach the same conclusions as us, there are also overseas studies which come to a different conclusion – namely that hydrogen vehicles will become the lowest cost option for transport.

This suggests that either these overseas studies are capturing some country-specific dynamics that are relevant to these overseas situations but not New Zealand, or we are using different methodologies and assumptions to these overseas studies.

Having looked at a number of these overseas studies that reach different conclusions, with one key exception (addressed below), the differences appear not to be due to country-specific factors, but rather due to different methodologies and assumptions.

Where overseas studies appear to use different methodologies and assumptions, they generally include some combination of:

- Assuming hydrogen will be produced from natural gas via steam methane reforming plus carbon-capture and storage, rather than green hydrogen from renewable electricity

- Different future capital cost relativities for hydrogen and electric vehicles
- Different productivity penalties for EVs. These differences in productivity penalty appear to be due to differences in modelling the re-fuelling pattern of EVs (vis-à-vis the proportion of refuelling overnight at a vehicle's base) and recharger capacities.
- Using (in our view) internally inconsistent assumptions. For example
  - assuming increases in the cost of electricity for charging EVs, while assuming large reductions in the cost of green hydrogen (for which electricity is the principal input cost).
  - not including electricity network or service-station overhead costs for the cost of green hydrogen

The one example of country-specific dynamics which may mean hydrogen becomes the dominant transport technology for some countries, is where countries are 'renewables-poor'. While New Zealand is blessed with relatively large amounts of land which it can cover with solar panels or erect wind turbines upon, the same is not true for other countries with much higher population densities.

Our analysis suggests that Japan and South Korea particularly stick out as having an acute land deficit on which to locate new renewables. In contrast, many other countries and regions have sufficient land area to meet their own decarbonisation needs – albeit requiring a reasonably large amount of land area to be converted to producing renewable electricity. This includes North & South America, Africa, much of Europe, the Middle-East, and much of mainland Asia (but not Southern or South-Eastern Asia).

If Japan or South Korea doesn't want to use nuclear power to help them decarbonise, they will have no choice but to import hydrogen overseas from relatively 'renewables rich' countries. In this situation, it is probably more economic to use the hydrogen in hydrogen vehicles, rather than burn the imported hydrogen in electricity generators to fuel electric vehicles.[31]

However, for renewables-rich countries, our analysis suggests that the direct electric route is likely to be a significantly lower cost for decarbonising transport. This is likely to have a bearing on whether hydrogen or electric vehicles (or both) emerge as being dominant. In this, we think it significant that North America is relatively renewables rich, and China is currently more aggressively pursuing electric vehicles rather than hydrogen – although we note that in both countries there is debate as to which option is likely to be the best.

Section 3-6 explores exporting New Zealand hydrogen to renewables-poor countries such as Japan.

[31] A quick back-of-the-envelope calculation, taking account of the relative fuel efficiencies of EVs and HVs, suggest that 67% of the energy of the imported hydrogen will be lost in converting into useful motive power for the EV route, whereas only 45% will be lost for the HV route. Offsetting this will be higher within-country fuel distribution costs for hydrogen compared to electricity. We haven't explored the extent to which this may alter the net economics of the two options for using imported hydrogen.

3-2 Industrial Process Heat

3-2.1 Background

Figure 38 shows that industrial process heat emissions are now the second largest source of energy-related emissions in New Zealand – almost 65% greater than electricity generation-related emissions.

Figure 38: Historical energy-related greenhouse gas emissions by end-use (ktCO_2-e)

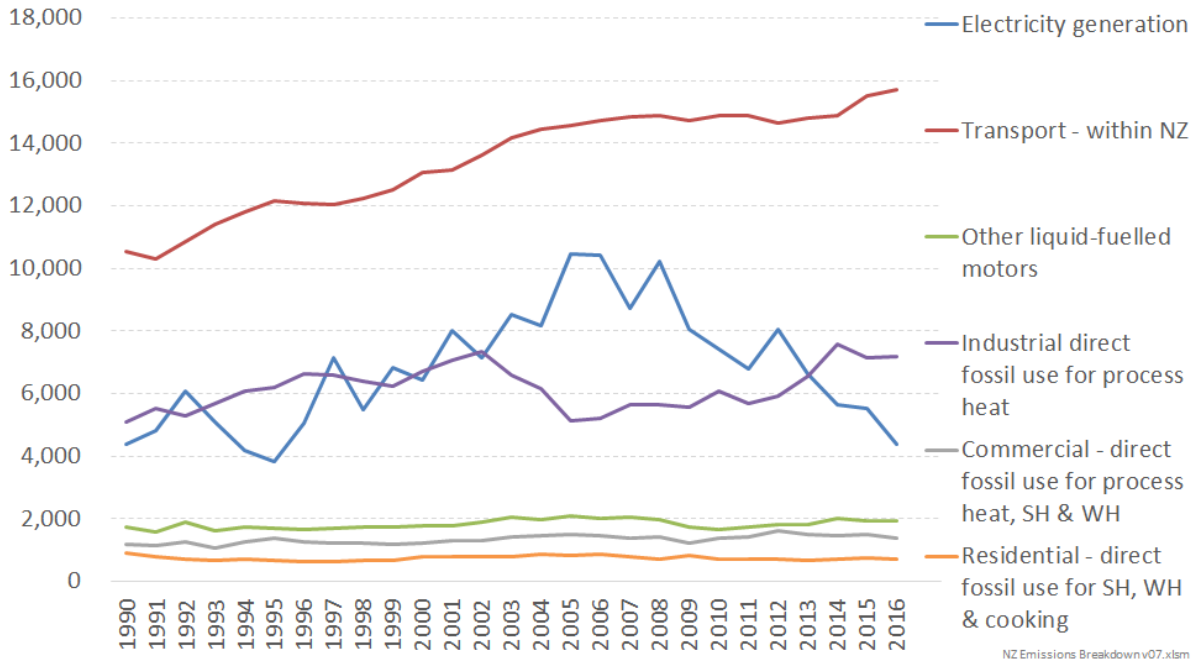
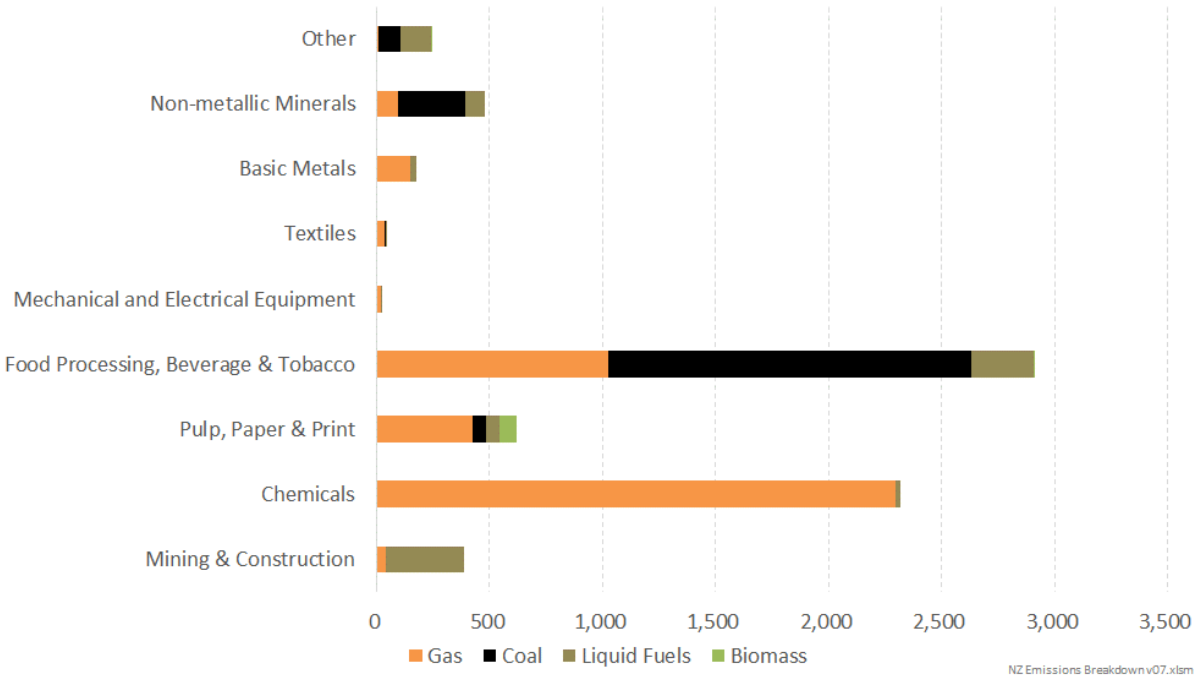


Figure 39 shows that these emissions come from two main sectors – food processing (predominantly dairy) and chemicals.

Figure 39: 2016 process heat emissions by fuel and industrial sector (ktCO2-e)



The chemicals-related process heat emissions are almost all from the production of methanol and urea in Taranaki. Because gas is a feedstock as well as energy fuel for such processes, the opportunities for fuel-switching may be more limited.

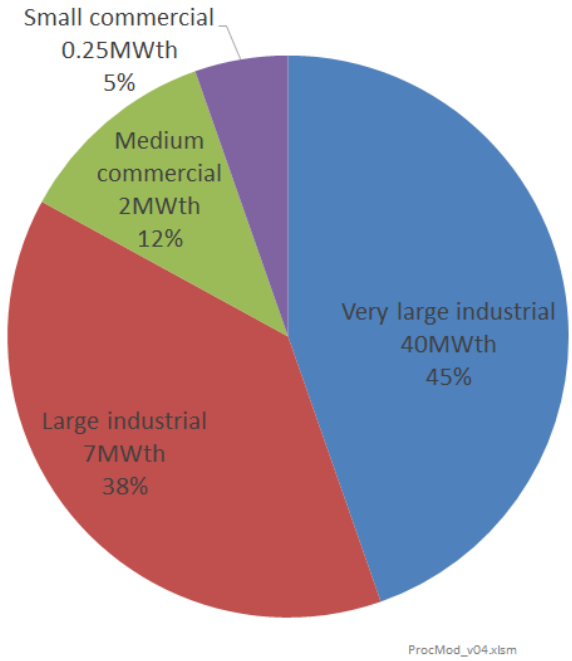
However, for food processing the opportunities for fuel switching are very real. The principal requirement for process heat is so-called intermediate process heat (raising steam to between 100 and 300°C) – which is also the principal heat requirement for pulp, paper and print.

We have examined the economics of hydrogen as a fuel for raising intermediate process heat – i.e. burning hydrogen in a boiler that would fundamentally be very similar to a natural gas-fired boiler. We have compared the economics of hydrogen against the main alternatives – coal, diesel, gas, biomass and electricity.

The last two options are not currently widespread (except that biomass is widely used as a fuel in the wood-processing and pulp, paper and print sectors) but are potential alternatives to hydrogen for low-carbon fuels to replace coal and gas.

Our analysis has focussed on large and very large industrial boilers which, as illustrated in Figure 40, dominate the amount of energy (and hence emissions) from the process heat sector.

Figure 40: Energy consumed by different-sized process heat boilers[32]



3-2.2 Industrial Process Heat Cost Model

Key considerations for our cost model are:

- boiler – capital and operating costs, including maintenance
- boiler efficiency – efficiency at converting fuel into useful energy
- fuel – fuel cost at the point of production
- fuel transport – cost of bringing the fuel to the boiler in a useable form
- carbon – cost of greenhouse gas emissions.

[32] MWth relates to the thermal heating capacity of the boiler.

Capital and operating costs

Solid fuel boilers suffer considerable cost penalties relative to gas-fired boilers. This is because of the major cost implications of fuel and ash-handling.

We assume that, relative to gas-fired boilers, the capital and operating costs of coal-fired boilers are three times as great, and five times as great for biomass boilers.

We assume that electricity boilers have the same capital and operating costs as gas-fired boilers given their similar levels of relative simplicity. Likewise, hydrogen-fired boilers are assumed to be the same as gas-fired boilers.

Boilers are assumed to exhibit economies of scale, such that the $/GJ capital recovery and non-fuel opex costs of a small-scale boiler are much greater than a large-scale boiler.

Boiler efficiencies

New gas and hydrogen-fired boilers are assumed to have fuel efficiencies of 90%, compared with 85% for solid-fuelled boilers. Electric boilers are assumed to be 100% fuel efficient, reflecting the resistance-heating nature of their process.[33]

Existing (i.e. old) coal and gas-fired boilers are assumed to have 10% efficiency penalties.

Wholesale fuel prices

We assume the following wholesale (i.e. prior to transport costs, except for Green Hydrogen which includes electricity network costs) fuel prices:

- Gas = $6/GJ
- Coal = $4/GJ
- Green Hydrogen. With reference to Table 2 and Table 3 previously, we consider two possible futures for hydrogen costs
  - $32/GJ ($4.6/kgH2) in a future with small-scale hydrogen uptake, thereby allowing opportunistic hydrogen production.
  - $49/GJ ($6.9/kg) in a future with large-scale hydrogen uptake driving new renewable generation development.
- SMR Hydrogen = $18.6/GJ ($2.6/kgH2). This is based on the analysis set out in section 2-2.2
- Electricity = $18.1/GJ ($65/MWh). This is a discount to the time-weighted average price of $75/MWh, and reflects the counter-seasonal shape of dairy processing.
- Biomass = $8/GJ. However, it should be noted that this is at the lower end of what is a very wide range of achievable biomass prices in New Zealand – reflecting differences in forestry situation around the country.

[33] High temperature heat pumps are options for providing some of the heat requirements for food processing. However, these, and other efficiency improvements (such as improved drier technology) are available for *all* of the fuel options (including coal, gas and biomass). As such, this analysis focuses on the relative economics of raising the primary intermediate temperature heat – for which high temperature heat pumps are understood to not be an option.

Fuel transport costs

Electricity and gas-fired options are based on published electricity and gas network tariffs – noting that the very large boilers which are transmission-connected have much lower $/kWh and $/GJ tariffs than distribution-connected boilers.

SMR Hydrogen is assumed to have the same $/GJ transport price as natural gas.

Green hydrogen is assumed to have no transport costs, as the electricity network cost component of hydrogen production is included within the wholesale fuel price.

Biomass fuel costs are based on a review of various industry literature.

We note that transport costs for biomass are especially variable, depending on whether wood processing facilities are located near to the industrial process heat facility. Our assumption is based on a boiler located relatively close to a wood processing facility. Likewise, coal prices are also variable, depending on the source mine, coal specification and transport requirements.

3-2.3 Findings

Figure 41 and Figure 42 compare projected future energy service costs for very large and large process heat applications, respectively for a scenario with carbon prices of $100/t$CO_2$.

Figure 41: Process heat economics for very large industrial boilers, for a future with small-scale opportunistic green hydrogen production

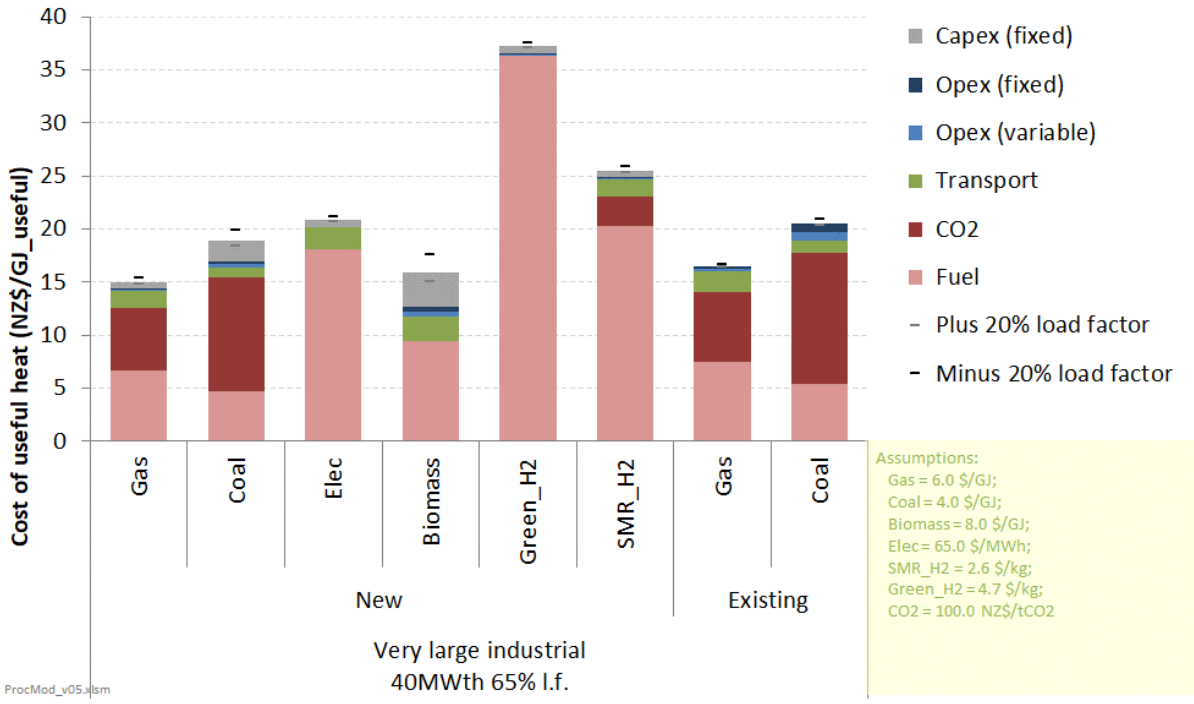
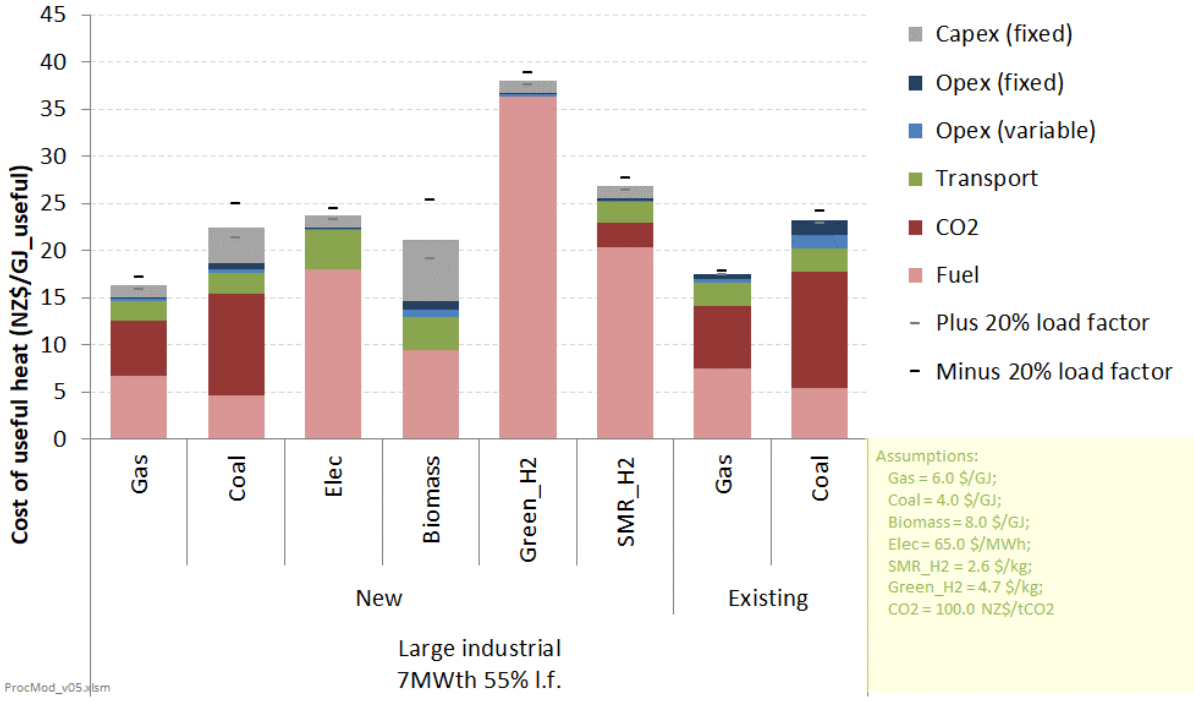


Figure 42: Process heat economics for large industrial boilers, for a future with small-scale opportunistic green hydrogen production



Recognising that site-specific factors can vary, this analysis nonetheless provides the following findings:

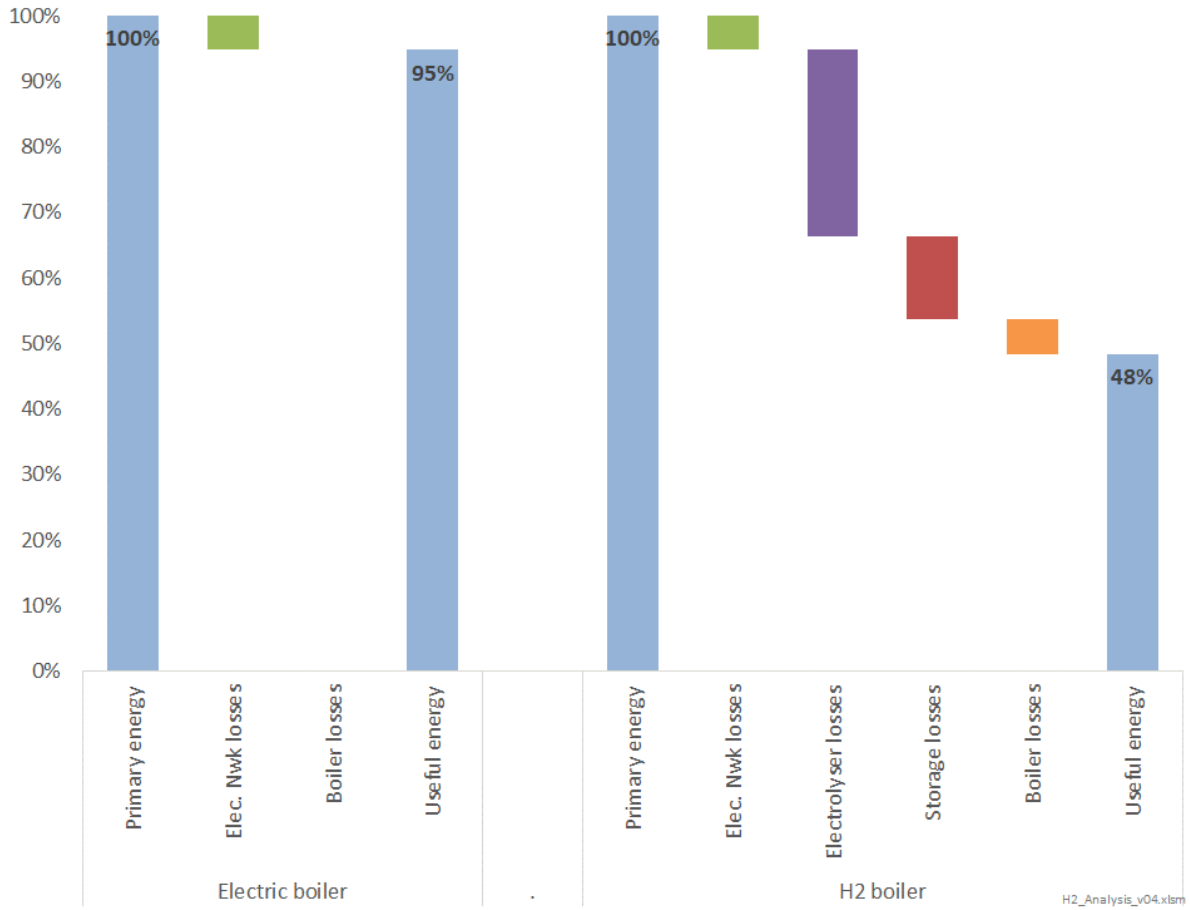
- Gas is competitive where available, even at $100/t$CO_2$
- Coal is starting to become uneconomic at this carbon price relative to direct electric and biomass options. (Noting that there can be significant site-specific variations for all three options).
- Hydrogen is not projected to be competitive relative to the other low-carbon options: direct electric and biomass. There is no carbon price which will change this evaluation.

  Further, to the extent that large-scale hydrogen production drives the need for new renewable generation, thereby increasing the wholesale electricity component of hydrogen production, the relative economics of green hydrogen as an industrial process heat fuel will become even more challenging. We have not shown the graphs with these higher green hydrogen costs as they do not change the fundamental conclusions.

As with transport, the challenges for green hydrogen are the process losses and capital costs associated with producing and storing hydrogen from electricity. These outweigh the benefits of being able to target production to times of low electricity and network prices.

The dynamic of energy losses is illustrated in Figure 43, which illustrates that twice as much primary renewable electricity is required to power a hydrogen-electrolyser-fuelled boiler as an electric boiler.

Figure 43: Comparison of energy losses between electric and green-hydrogen-fuelled boilers



This dynamic of process losses and capital costs also explains why it is hard for SMR+CCS hydrogen to compete with natural gas, except at very high CO_2 prices.

As noted previously in section 2-2.2, there do not appear to be opportunities to lower green hydrogen costs for process heat by going off-grid for hydrogen production.

3-3 Space and Water Heating

3-3.1 Background

Figure 1 indicated that approximately 4-5% of New Zealand's energy-related greenhouse gases (approximately 2% of all greenhouse gas emissions) come from 'direct' use of fossil fuels for space and water heating. This is predominantly natural gas (and some LPG) for space and water heating.

We have considered the economics of converting natural gas appliances to hydrogen-burning appliances and compared this with the cost of continued use of natural gas appliances or switching to electric heat pumps for space and water heating. Our analysis focusses on household-scale applications, which are similar to small commercial applications. Together these account for most space and water heating.

3-3.2 Space and Water Heating Cost Model

Key considerations for our cost model are:

- appliance capital costs[34]
- appliance efficiency
- delivered fuel cost
- emissions intensity.

Natural Gas

Our assumptions for natural gas are based on observed retail tariffs for an average user, with the fixed charge component of tariffs being variabilised. We consider this is appropriate because gas is a discretionary fuel, so the fixed charge of a gas connection is avoidable and factors into the relative economics of space and water heating options.

We have separated the carbon cost embedded in retail prices, so we can test how economics change at varying carbon prices.

Capital costs reflect a dedicated continuous hot water appliance for water heating and a flued gas heater. Both costs include installation, but do not include costs (if any) for establishing a natural gas connection.

We assume an appliance efficiency of 85%.

Heat Pump

For electric heat pumps we have also used observed retail tariffs for an average user, excluding the fixed charge component. This is because electricity is typically used for lighting and other appliances, so the fixed charge is not usually an avoidable cost for households and small businesses, whereas gas (or hydrogen) are discretionary fuels.[35]

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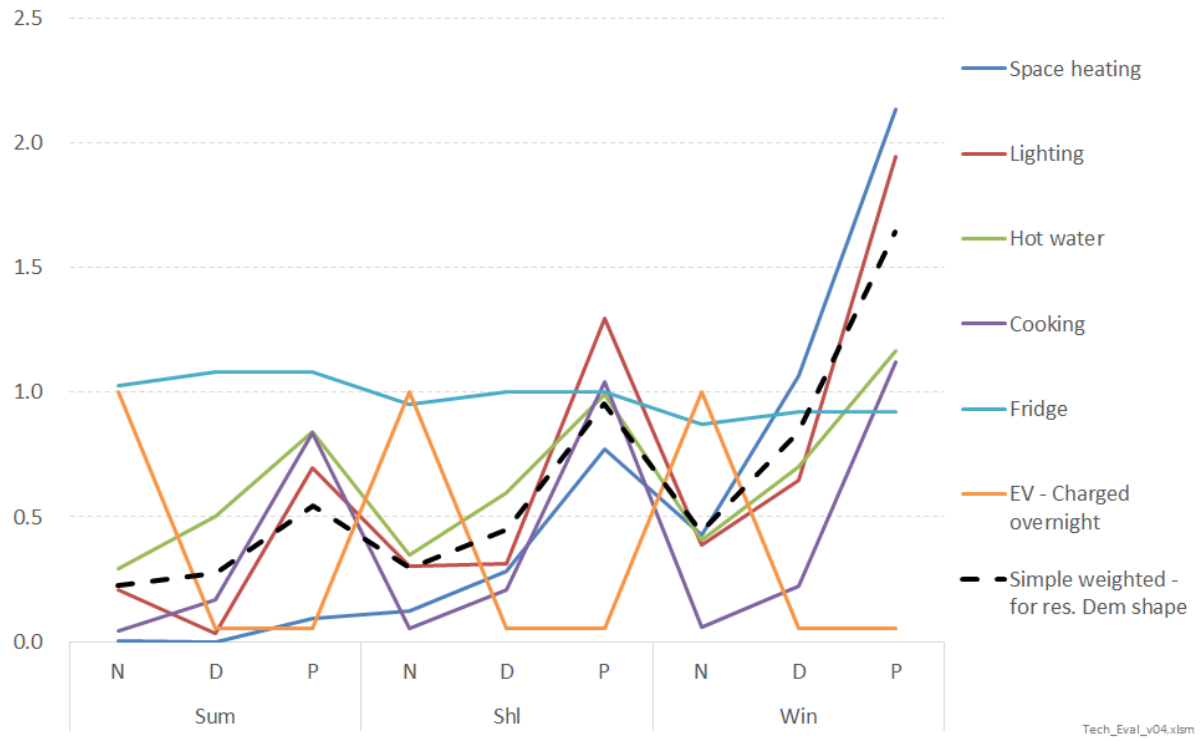
[34] Maintenance and non-fuel operation costs are assumed to be relatively small, and materially the same across technologies. As such we have focussed on capital costs.

[35] Consistent with other work we have done in this area (e.g. the 'Consumer Energy Options' study for Gas Industry Company), we do not think it plausible that there will be mass grid defection from the electricity network. In large part this is because the grid massively facilitates the ability to take advantage of demand and renewable generation temporal and spatial diversity – noting that managing the temporal and spatial imbalance of renewable supply and energy demand is one of the most significant constraints behind transitioning to renewable energy.

Appliance efficiencies are greater than 100% due to heat pumps using electricity to shift ambient heat energy, rather than to produce heat directly. Efficiency is higher for space heating than water heating because heat pumps are more efficient at raising air temperature by 20°C on demand than raising water temperature by 50°C for storage.

We have investigated the emissions intensity of electricity more closely for this application than previous applications, because household heating is a key driver of seasonal and daily peaks. This means there's a closer relationship between levels of heating demand and the need for fossil-fuelled peaking generation than there is for the transport and process heating applications examined earlier. Figure 44 illustrates how different types of electricity use have very different demand shapes.

Figure 44: Average kW output in different time blocks for different load shapes - each with a 1 kW average load across the year[36]



Given the dynamics of New Zealand's electricity system, over time, new demand with a:

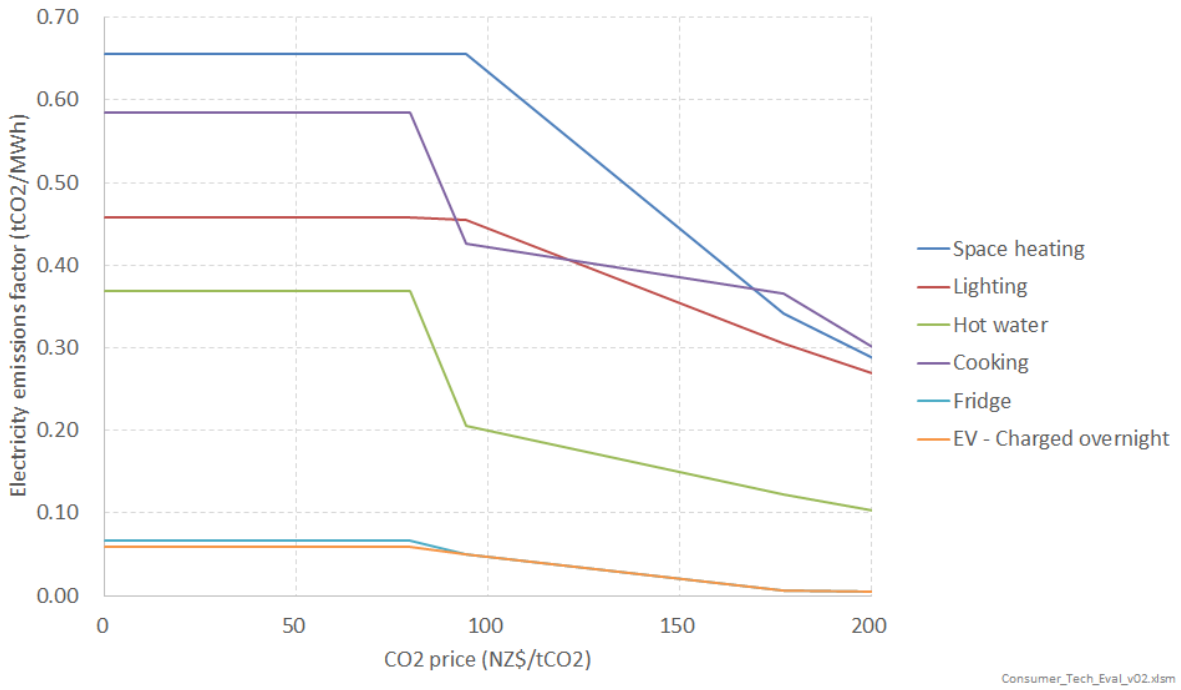
- flat shape (e.g. a fridge) or night-heavy shape (e.g. battery-electric vehicle charged overnight) would be met by building low-emissions 'baseload' wind and geothermal power stations. Geothermal has an emissions factor of 0.12 tCO_2/MWh, so to the extent geothermal remains competitive, the marginal emissions factor is low but not zero
- winter-heavy demand shape (e.g. space heating) would predominantly be met by increasing the output from infrequently used gas or coal-fired generation, so the marginal emissions factor is comparatively high
- demand shape that is steady through the year, but peaky through each day (e.g. water heating or cooking) would be met by a mix of baseload renewables and peaking fossil stations, so this demand has an intermediate marginal emissions factor.

[36] N, D, P = Night, Day, Peak. Each consists of 8-hour blocks, except there are no peak blocks in the weekend – with such blocks instead being included within the 'day' block.

However, this dynamic is based on today's technology, fuel and CO_2 costs. Our modelling suggests that as CO_2 prices rise, it will increasingly be economic to build renewable stations to displace existing fossil stations. At a carbon price of around $80 per tonne CO_2 it becomes economic to build renewables to displace existing gas-fired baseload generation. Beyond this threshold price it becomes increasingly economic to over-build and spill renewables to meet the need for flexible energy, with the last bastions for fossil-based generation being to provide winter peaking and dry-year backup.

Figure 45 shows the results of modelling that estimates how the marginal emissions factor decreases with higher CO_2 prices due to the dynamic described above.

Figure 45: Estimated change in electricity emissions factor with CO2 price for different demand shapes



We use the marginal emissions factors from Figure 45 when testing the relative economics of space and water heating options at varying carbon prices. This is not only correct from an economic perspective, but will also reflect the likely impact on consumer prices for the different application if prices move more towards simple time-of-use structure.

Hydrogen

Our supply model for testing hydrogen space and water heating is centralised hydrogen production with reticulation through converted gas pipelines. Under this scenario, conversion to hydrogen is not solely a decision taken at an individual household level but requires a universal conversion away from reticulated natural gas. This is because, while a hydrogen-burning appliance is almost the same as a natural gas-burning appliance, it needs an altered burner to suit the combustion properties of hydrogen. The many different models of gas appliance mean it generally is not practicable to change-over burners in existing appliances and the whole appliance must be changed instead.

The appliance changeover required for conversion of pipelines from natural gas to hydrogen is a similar exercise to the mid-twentieth century conversions in many countries from town gas to natural gas. The Leeds H21 initiative estimate costs of NZ$5,900 per household, comprising $3,325 for appliances and NZ$1,625 for safety checks, for their changeover. The cost for a similar exercise in New Zealand could be lower given the prevalence of small installations (rather than central

heating). We have assumed NZ$1,500 for safety checks for our evaluation, and assumed this is recovered through increased tariffs to gas consumers over 15 years.

We have split appliance changeover costs across two cost components in our analysis – the cost of appliance installation is included in capital costs[37], and an assumed cost of safety checks in included in our build-up of delivered energy costs.

We have assumed a hydrogen appliance has the same installed cost as a comparable natural gas appliance and have taken the installation component of network changeover costs as being covered within this cost.

To develop a delivered green hydrogen cost we have:

- Based the cost of hydrogen on the centralised green hydrogen use case as set out in Table 2 previously. This has the advantage of no storage costs, and limited compression losses. This results in costs of $6.05/kg for hydrogen injected into the transmission network currently, falling to $3.7/kg 20 years' in the future. ($43/GJ and $26/GJ, respectively). We do not use the very low $2.7/kg figure in Table 2, because this is associated with opportunistic hydrogen production of a scale which doesn't materially affect the periods of surplus / scarcity. This is not considered to be the case for a future where all of New Zealand's residential and commercial natural gas consumers have been converted centrally-produced green hydrogen, so we have assumed some limited increase in costs. Even this assumption is likely to be optimistic because, although gas consumption for space and water-heating is relatively small-scale in New Zealand terms, it seems unlikely that pipelines would be converted to hydrogen only for residential and commercial consumers. Conversion of industrial process heat to hydrogen would result in a very large requirement for additional renewable generation – and consequent increase in hydrogen production costs.
- Decomposed household natural gas prices to isolate the component costs, replaced the wholesale cost of gas with the adjusted green hydrogen cost from above, and added the safety-inspection component of network changeover costs.

We have not assumed any other changes in the base cost of gas transmission and distribution. These assumptions are explored further in Section 3-4.2.

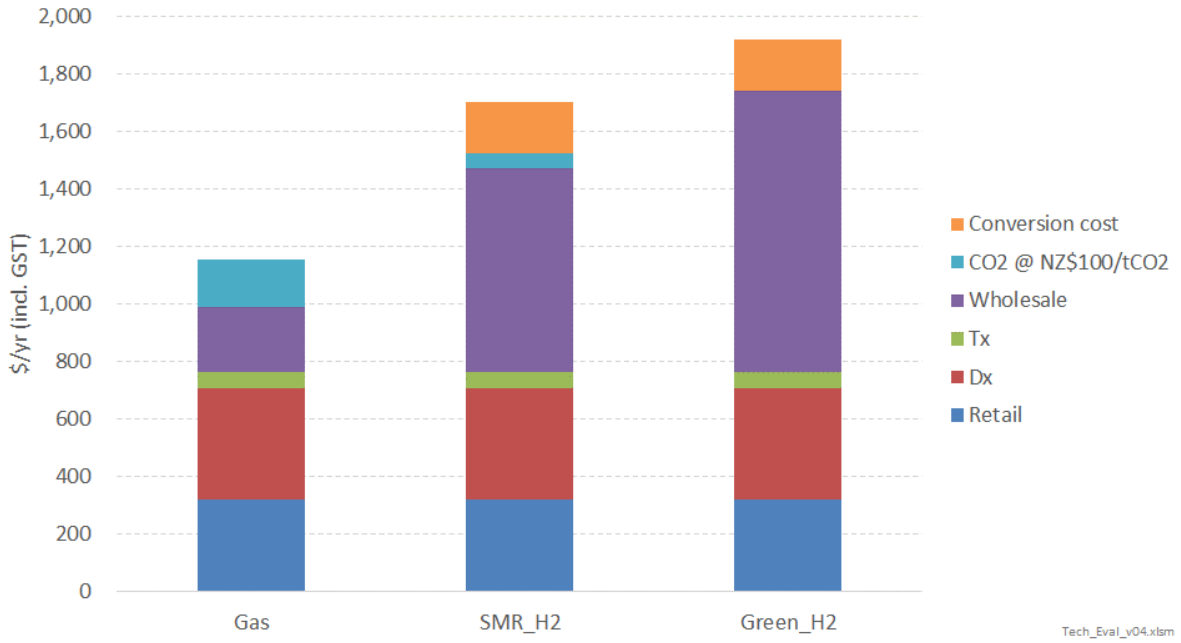
For completeness, we have completed a similar exercise for hydrocarbon-based hydrogen. In this case, we have:

- adjusted our reference SMR+CCS price estimate by splitting out the carbon price.
- carried out the same household natural gas price decomposition exercise as above, using our SMR+CCS estimate and adding carbon at $100 per tonne CO_2.

Figure 46 shows the results of the exercises described above.

[37] This is on the assumption that the changeover will be preceded by regulations twenty years' earlier mandating all gas appliances sold in New Zealand are 'hydrogen-ready' – i.e. able to burn either gas or hydrogen. Given the capital replacement cycle as appliances wear out, there should thus be relatively little appliance replacement costs required.

Figure 46: Estimated breakdown of annual fuel costs to households for gas and hydrogen



Note: Using these assumptions the breakeven CO_2 price to convert New Zealand's gas network to being a pure hydrogen network are \$690/tCO_2 for converting to SMR+CCS hydrogen, and \$650/tCO_2 for converting to a green hydrogen network

3-3.3 Findings

Efficiency

Figure 47 compares process efficiency for heat pump versus hydrogen space heating. Hydrogen has losses at the electrolyser stage and at combustion. We have not included any storage losses, though storage may be necessary in practice to match continuous hydrogen production to winter-heavy space heating demand. The heat pump model has fewer energy conversion steps, and benefits from the ability of heat pumps to move more heat energy than the electrical energy used to operate the appliance.

Figure 47: Relative energy losses between electric heat pumps and green hydrogen options for space heating

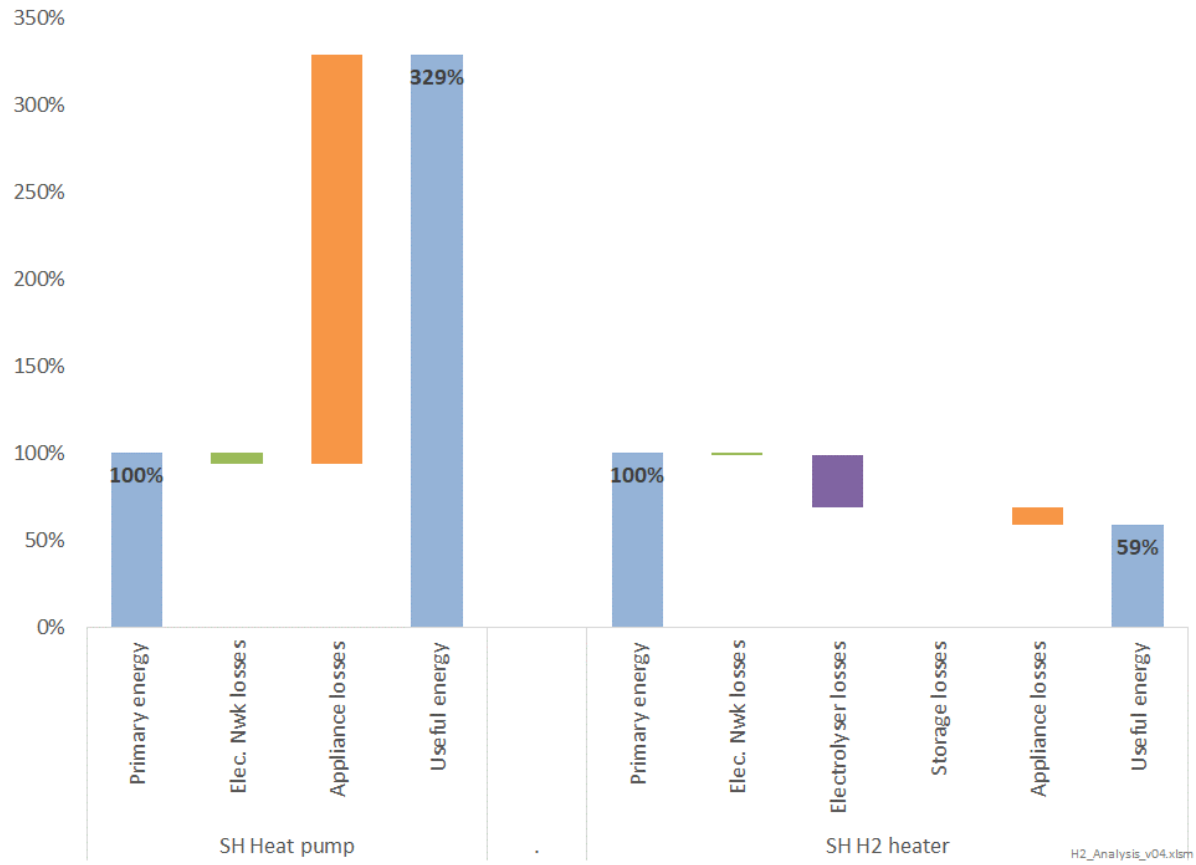
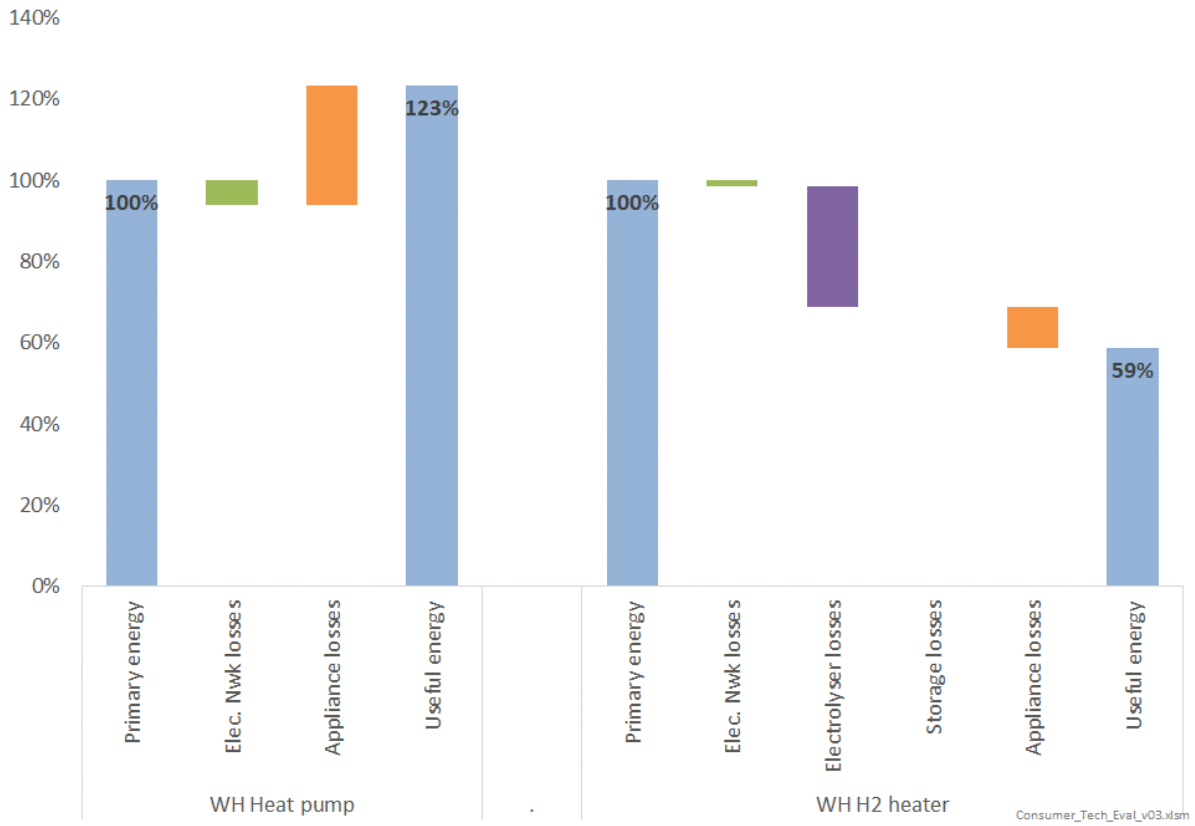


Figure 48 provides a similar comparison for water heating. In this case the heat pump efficiency is lower than for space heating, but still more than 100%.

Figure 48: Relative energy losses between electric heat pumps and green hydrogen options for water heating



Because heat pumps and green hydrogen use the same primary energy source, heat pump efficiency is a significant factor in the relative economics:

- almost six times as much electricity is required to heat a home with green hydrogen compared to a heat pump space heater
- just over twice as much electricity is required to heat water with green hydrogen compared to a heat pump water heater.

Cost Comparison

Figure 49 and Figure 50 show how the relative costs of space and water heating options change as carbon price increase. Costs are shown with ('new') and without ('existing') appliance costs and are for households with average space and water heating demands.

Figure 49: Cost per kWh of useful heat for a medium space heating load

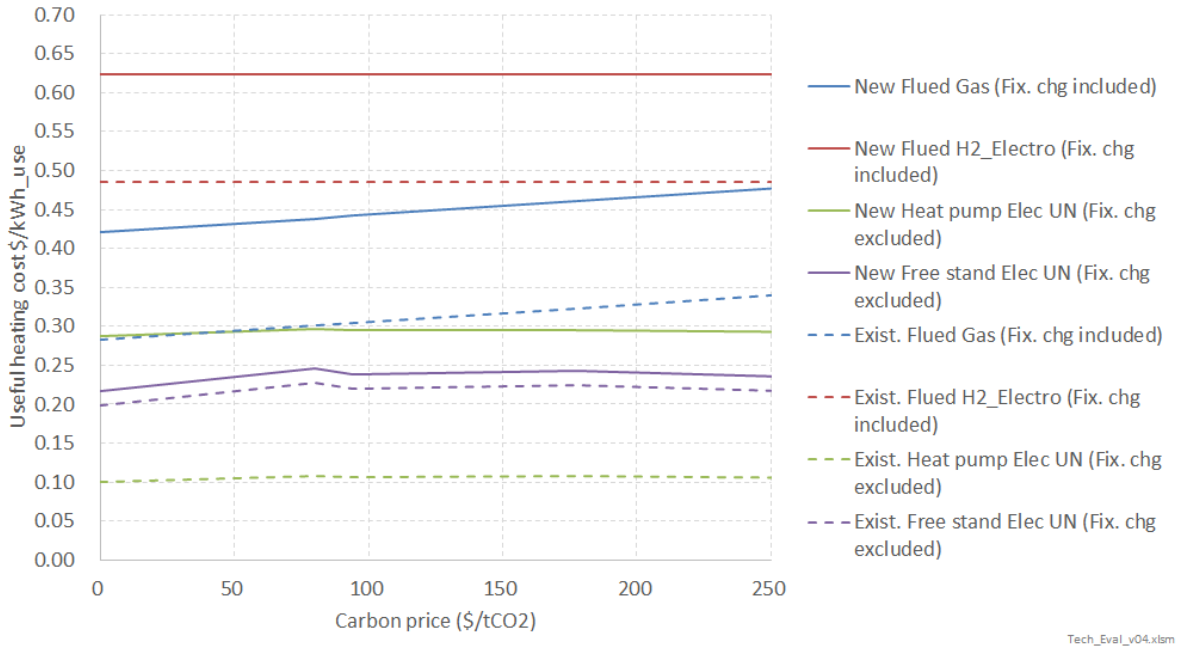
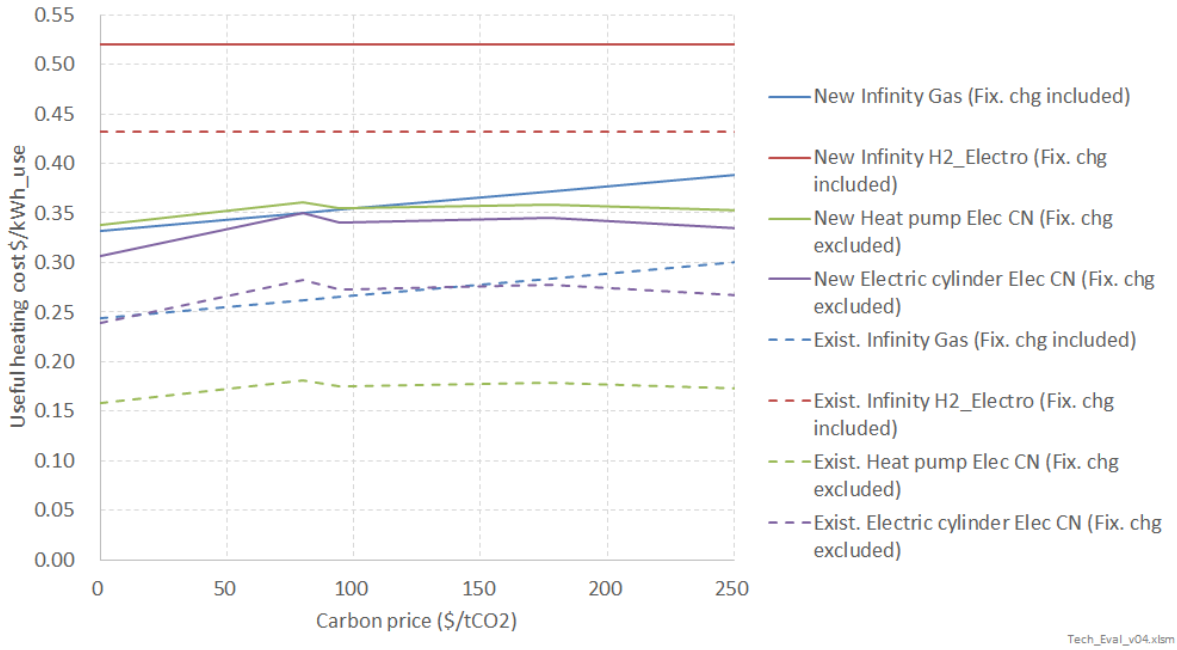


Figure 50: Cost per kWh of useful heat for a medium water heating load



The production costs of hydrogen substantially harm its economics as a fuel compared to natural gas. The key findings being:

- process and appliance efficiency make direct use of electricity to power heat pumps a much more cost-effective option than green hydrogen. This outweighs the benefits of hydrogen production having a baseload electricity usage profile. Further, to the extent that mass-uptake of hydrogen drives the need to develop renewable generation, hydrogen costs will be even higher than the values shown here.
- converting natural gas to hydrogen is less cost-effective than direct use of natural gas for space and water heating, except at very high ($690/t$CO_2$) carbon prices.

Further, as discussed further in section 3-4, were there to be substantially greater conversion costs or significant fuel switching from gas to electricity, the economics of mass-market pipeline hydrogen will be even more challenging.

Fuel-cell heating

We haven't considered the option of hydrogen fuel cells to provide electricity and heat as high-level analysis indicates they are likely to be less economic than they hydrogen options considered above:

- There are very large energy conversion losses associated with converting renewable electricity into hydrogen, then converting it back into electricity in a fuel cell (which is effectively an electrolyser in reverse). Likewise, the coefficient of performance of a fuel cell for producing heat is very poor compared to a heat pump.
- The capital cost of a fuel cell is large compared with a heat pump.

Likewise, we haven't considered the option of localised electrolyser production, as this will require the development of local reticulation networks. This is significantly more expensive than using electricity heat pumps over existing electricity networks. (Noting that the local electrolyser option would also be using the electricity network).

Nor have we considered the option of centralised electrolyser production with the hydrogen transported in bottles to households and businesses, as the economics of such transport are much more expensive than pipeline transport. This is generally the case comparing bottled gas to pipeline gas (which is why pipelines exist in the first place), but is likely to be specifically the case for hydrogen due to its challenging physical properties.

For example, were a standard 45kg LPG bottle filled with hydrogen, it would only hold 0.4% of the amount of energy (compared to LPG) due to the relative volumetric energy densities. Given this dynamic, bottled hydrogen would need to be supplied in highly specialised bottles operating at much higher pressures.

A hydrogen fuel tank for the Mirai car holds the hydrogen at 110x the pressure of a 45kg LPG bottle, and is made of specialised carbon-fibre construction. If a 'hydrogen bottle' were to be produced of this material, and had the same physical volume as a 45kg LPG bottle, it would hold 21% of the amount of energy of an LPG bottle. i.e. not only would it cost a lot more to produce such a specialised bottle, it would need to be replaced five-times as frequently to deliver the same amount of energy as a 45kg LPG bottle.

3-4 Converting Gas Networks to Hydrogen

3-4.1 Background

New Zealand has a network for natural gas transmission and distribution in the North Island, and some LPG distribution network in the South Island.

There are two potential models for bringing hydrogen into these systems:

- Conversion—existing gas networks and connected appliances can be converted to operate with 100% hydrogen
- Blending—alternatively, a limited amount of hydrogen can be blended into the gas stream without significantly altering the pipelines or replacing gas appliances.

Previous sections have considered these options in the context of:

- Future power-to-gas estimate (Section 2-1.2)—our lowest green hydrogen cost estimate assumes a model where hydrogen can be injected directly into gas pipelines as it is produced to avoid compression and storage costs
- Hydrocarbon-based hydrogen reference estimate (Section 2-2.2)—we assume hydrogen is produced at large scale in Taranaki and injected into the gas transmission system
- Process heat (Section 3-2.2)—our central comparison assumes on-site electrolysis, but we test hydrocarbon-based hydrogen and future power-to-gas, both of which assume pipeline transport
- Space and water heating (Section 3-3)—we assume reticulated hydrogen is available for household and small business heating.

3-4.2 Full Conversion

Based on the analysis of the economics of hydrogen for industrial process heat and space and water heating (the principal uses of pipeline natural gas), our assessment is that direct electric options (and biomass for process heat) look to be more cost-effective low-carbon means of meeting these requirements than hydrogen supplied via converted gas pipelines.

Further, where we have modelled scenarios with reticulated hydrogen, we have assumed that network costs are unchanged from today. Factors that could impact this assumption are:

- Pipeline investment—to support conversion to hydrogen, investment could potentially be needed in steel, compressors and pipeline integrity. New Zealand's gas transmission network is predominantly steel, and some types of steel are susceptible to embrittlement if used with hydrogen.[38] Early indications are that New Zealand pipelines would not need significant investment, but this would need further investigation if the feasibility of conversion was to be explored more thoroughly.
- Changeover cost recovery—full conversion to hydrogen would require a large coordinated effort to replace gas appliances and check for safety. How these costs fall, and how they are recovered over time, would have an impact on network prices. As set out in section 3-3.2, we assume per household switchover costs of $1,500, compared with $5,900 for the Leeds H21 initiative.
  - This lower $1,500 cost assumes legislation will have been enacted at least a couple of decades prior to the conversion mandating that all gas appliances sold must be hydrogen-

[38] Embrittlement occurs because hydrogen molecules are so small that they make their way inside the crystal structure of the steel. Tiny 'pockets' of hydrogen can develop which start to degrade the strength of the steel.

capable. However, if a large stock of non-hydrogen-capable appliances remained when a changeover occurred, the changeover costs could be higher.

  - Further, it is potentially the case that the conversion of the New Zealand gas network could be more logistically challenging than Leeds H21. Any changeover will require progressively converting parts of the network and ramping up hydrogen production at the same time. This may be more feasible for the Leeds H21 situation given its location within a larger 'meshed', multi-gas source network, than New Zealand's Taranaki-centric radial network.

- Capacity expansion—hydrogen is lighter and less compressible than natural gas, so a hydrogen pipeline would have reduced within-pipe storage capacity (line pack) and would need additional compressors. All things being equal, a hydrogen pipeline would require capacity expansion (compression or paralleling) earlier than a natural gas pipeline.
- Utilisation—as predominantly fixed-cost infrastructure, pricing levels are generally lower if pipelines are well utilised and higher if they are poorly utilised. Hydrogen conversion could increase utilisation if it provided an attractive product for end users. Conversely, it could reduce utilisation if the product was less attractive than natural gas or if the changeover process prompted fuel switching away from reticulated gas to electricity. In this respect, the analysis of industrial process heat and space & water heating suggests there is greater likelihood of consumers switching from natural gas to direct electric than to hydrogen.

We also note that natural gas is used as a feedstock by some users (e.g. for methanol production) and hydrogen is not a substitute in these cases.

Offsetting these potential challenges, we note that there are non-price quality benefits of natural gas appliances (e.g. never running out of hot water, faster times to heat a home from cold) to which many consumers ascribe significant value. These quality benefits would also apply to hydrogen appliances. To the extent that a sufficient number of consumers will be willing to pay higher costs to gain these quality benefits (relative to direct electric options), it is possible that conversion to hydrogen could be feasible.

In any event, the prospect of full conversion is most relevant to a future scenario when carbon prices have increased, and hydrogen technologies have potentially matured and scaled up internationally. In the nearer term, blending is a more likely step.

3-4.3 Hydrogen Blending

Several countries are exploring the possibility of blending hydrogen into the natural gas stream as part of their broader decarbonisation efforts. Blending offers a way to reduce the emissions intensity of gas appliances without requiring any action by end users. As set out in section 2-1.2, these power-to-gas initiatives could help use surplus renewable energy that would otherwise be wasted.

We understand that blending up to around 20% hydrogen is typically possible without running into any safety or embrittlement issues. At higher blends, some appliances have a risk of 'flash-back' along the pipe[39] and pipeline or appliance steel can become susceptible to embrittlement.

While 20% may be an appropriate general guideline, we understand some parts of the New Zealand system would need modification to gas specifications or their natural gas composition to enable

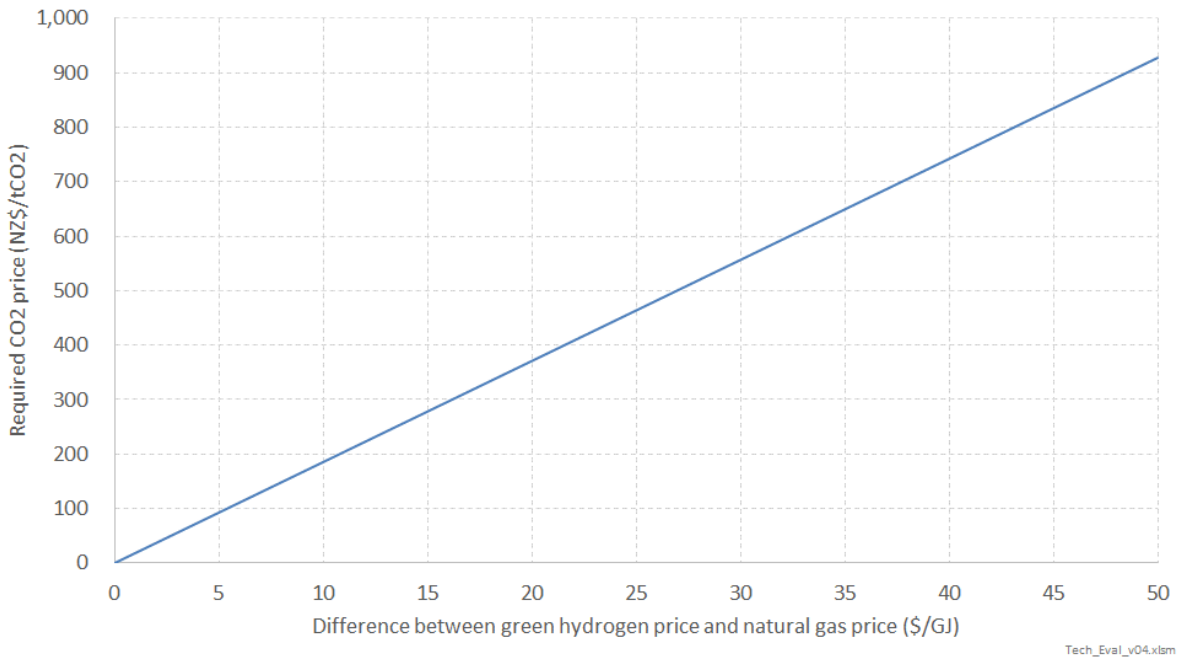
[39] For more information, refer Concept Consulting, Hydrogen in New Zealand, Report 3—Research, Chapter 5 (Use).

blending above 12%.[40] We also understand that hydrogen needs to be stripped out of the gas stream for some applications, such as methanol production.

As set out in Table 2, our reference estimate for future power-to-gas is $3.0/kgH2 ($21/GJ). This assumes a production model that targets times of electricity price collapse in a future with high penetration of renewable electricity generation (and that opportunistic hydrogen production does not materially increase these electricity prices). It also assumes no storage or compression costs, significant falls in the capital costs of hydrogen production, and stabilisation of the long-run marginal cost for electricity at approximately $75 per MWh.

This estimate is $15 per GJ higher than the current wholesale gas price of $6 per GJ. Figure 51 shows how the threshold carbon price required to make hydrogen more economic than natural gas alters as a function of the difference between green hydrogen and natural gas prices.

Figure 51: Threshold CO2 price required to make hydrogen more economic than natural gas



If natural gas prices were unaltered from today, then a carbon price of $275 per tonne CO_2 would support production of green hydrogen for blending into the gas stream. Forecasting the future price of natural gas is outside the scope of this study, but to illustrate, if natural gas prices were to increase by 67% to $10/GJ, the threshold CO_2 price would reduce to $200/t$CO_2$.

Our green hydrogen cost model assumes the electrolyser operates at a 50% capacity factor to optimise production costs. If the upper limit for blending were 20%, then hydrogen would comprise 10% of the gas stream on average at this capacity factor.

The gas demand for mass-market and industrial process heat is currently 45 PJ/yr. 10% of this amount = 4.5PJ, which, when factored by the 50% capacity factor, and electrolyser losses, would increase electricity demand by about 8% when operating. An increase of demand of this scale would tend to place upward pressure on electricity prices.

The other factor affecting the opportunities for blending gas, is that hydrogen would be of no value for methanol production – which comprises almost 50% of current gas demand. To the extent that

[40] This is due to hydrogen's impact on the Wobbe Index: the gross calorific value divided by the square root of the relative density of the gas—being a measure of the energy released by different fuels in the same burner at the same pressure.

methanol production continues to comprise 50% of gas demand, this would double the threshold carbon price for blending to become economic.

Indeed, hydrogen blended in the gas stream would likely adversely affect the operation of the methanol plant, potentially further increasing the threshold CO_2 price as the hydrogen would need to be stripped out before entering the methanol plant. [41]

[41] It is possible that these effects could be overcome by effectively 'disconnecting' the existing methanol production facilities from the gas network, and supplying them directly with dedicated gas pipelines from the gas producers. This already happens to a certain extent, and is eminently feasible given the Taranaki location of the methanol production facilities. That said, the cost of building dedicated pipelines would need to be factored into the economics of blending hydrogen.

3-5 Power Generation

3-5.1 Background

As Figure 1 showed, 14% of New Zealand's 2016 energy emissions came from power generation (excluding industrial cogeneration).

Our modelling suggests that in 2020:

- Approximately 50% of non-cogen power generation emissions will be from baseload power generation (29.5% gas-fired CCGTs, 11.5% from geothermal power stations)
- The remaining 50% of non-cogen power generation emissions will be from 'Peaking' coal and gas-fired stations—used to provide infrequently-required generation to provide hydro-firming, seasonal (winter) generation, and within-day peaking.

One potential use of green hydrogen is to power gas-turbines which could displace these carbon-emitting forms of power generation.

However, we consider that, from first principles, it does not make sense to use green hydrogen to displace *baseload* carbon-emitting generation. This would require baseload renewable generation to be used to create hydrogen (with the associated energy conversion losses of around 25%-30% and capital cost), to then be burned in a gas-turbine (with further energy conversion losses of around 60%). This cannot be more cost effective than using the baseload renewable generation directly to displace the baseload carbon-emitting generation. Indeed, our modelling suggests that the existing CCGTs are likely to be displaced from baseload operation by new baseload renewables at CO_2 prices of approximately $60 to $80 per tonne CO_2—depending on gas prices.[42]

Likewise, SMR+CCS hydrogen to fuel a baseload CCGT would be higher cost than fitting CCS on a CCGT. And both will be substantially higher cost than the cost of new baseload renewables such as wind.

This leaves the potential for hydrogen to be used to displace *peaking* coal and gas-fired generation used for hydro-firming and seasonal generation. This requires the hydrogen to be:

- Produced at times of relatively low electricity price
- Stored in some form—potentially for several years if it is to provide dry-year energy; and
- Taken out of storage and used to power a gas-turbine at times of relatively high electricity price—i.e. periods of relative scarcity such as winter months and/or 'dry' periods with low hydro generation.

We principally consider two potential options:

- Making hydrogen and storing it in the Ahuroa gas storage facility—a depleted oil and gas reservoir in Taranaki that has been converted to provide gas storage
- Making hydrogen and converting it into ammonia for storage, before converting it back to hydrogen when it is required for peaking generation.

We look at these two options because they are lower cost than storing hydrogen in compressed gas form in tanks similar to those used to provide storage for service station hydrogen.[43]

We compare the cost of producing hydrogen for peaking generation with the cost of using natural gas, and assessing the CO_2 price that would be required for it to be economic to pay a higher $/GJ

[42] Each $1 per GJ increase in gas price lowers the threshold CO_2 price by ≈NZ$18.5 per tonne CO_2.
[43] For more information, refer Concept Consulting, *Hydrogen in New Zealand*, Report 3—Research, Chapter 3 (Storage)

price for hydrogen than for the CO2-exclusive $/GJ price of natural gas. This is the same basis for comparing the economics of blending hydrogen in the natural gas stream set out in section 3-4.3 and illustrated in Figure 51 previously.

Lastly, we qualitatively consider whether it may be possible to 'divert' hydrogen from export sales towards power generation during dry periods.

3-5.2 Using Ahuroa to store green hydrogen

The main difference between producing gas to be blended into the gas stream, and producing hydrogen for injecting into Ahuroa, is that the Ahuroa option could be undertaken by a very large-scale electrolyser facility located next to Ahuroa.

This is equivalent to the large-scale transmission-connected use case. Table 2 previously suggests that hydrogen could potentially be produced for as little as $2.7/kg = $19/GJ.

This compares with the estimated price of natural gas going into Ahuroa of $6 per GJ—i.e. Ahuroa takes a predominantly baseload gas profile, and stores it for release at times of scarcity.

This represents a price difference of $12 per GJ. With reference to Figure 51, this suggests that CO_2 prices of approximately NZ$200 per tonne CO_2 are required to make this economic.

This is a significantly lower CO_2 price threshold than other uses for hydrogen.

That said, this is likely to be a lower bound as there is the potential for material additional costs associated with using and storing hydrogen to meet dry year energy requirements in this fashion:

- It is likely that there would need to be significant capital expenditure on the gas turbine power generators to make them capable of burning hydrogen—including addressing issues of embrittlement.[44] As no gas turbine around the world has yet to be converted, it is hard to estimate the quantum of costs. However, we estimate that it could increase the equivalent fuel price by $4 per GJ—adding a further NZ$55 per tonne CO_2 to the threshold CO_2 price required for hydrogen to be more economic than natural gas.

  Further, this only applies to the existing 'TCC' CCGT and 'Stratford' OCGT located adjacent to the Ahuroa site. The other CCGTs and OCGTs in New Zealand would not be able to burn Ahuroa hydrogen as there would be no means of piping it to them—unless the whole pipeline network were converted to hydrogen which section 3-4.2 indicated seems unrealistic for New Zealand. The TCC and Stratford gas-fired stations are not large enough to provide the quantity of seasonal and dry-year firming required. If brand new hydrogen-capable gas-turbines were to be built at the Ahuroa site, this would substantially increase the cost of this option.

- It is potentially the case that Ahuroa would require investment to make it capable of storing hydrogen, such as changing the compressors to make them capable of injection / extracting hydrogen rather than natural gas.

- Higher energy per GJ for compressors to inject/extract H_2 rather than natural gas

  If such investments are required to make Ahuroa hydrogen-capable, and the costs are material, it would further increase the threshold CO_2 price for hydrogen to be economic as a dry-year fuel relative to natural gas.[45]

[44] For more information, refer Concept Consulting, Hydrogen in New Zealand, Report 3—Research, Chapter 5 (Use)

[45] For more information, refer Concept Consulting, Hydrogen in New Zealand, Report 3—Research, Chapter 3 (Storage)

Further, as mentioned previously in relation to the economics of power-to-gas for gas blending, material additional electricity demand at times of low electricity prices could increase the electricity prices above the levels assumed for our analysis.

If carbon prices of NZ$250-350 per tonne CO_2 are required to achieve the level of decarbonisation required for New Zealand, storing green hydrogen in Ahuroa as a peaking fuel for power generation may be economic.

That said, it should be noted that Ahuroa is not large enough to meet the current demand for seasonal and dry-year flexible energy. As such, to the extent that it is economic to use it for providing flexible energy, it would only be a partial solution.

This is further exacerbated by the fact that hydrogen is volumetrically less energy-dense than natural gas, such that only 1/3 of the energy would be stored from filling Ahuroa with hydrogen rather than natural gas – and potentially even less.[46]

As well as reducing the effectiveness of Ahuroa at providing sufficient seasonal and dry-year energy, this will also increase the cost of this option (and the threshold CO_2 price for this to be economic) as the fixed costs of Ahuroa will be spread over a smaller number of GJ.

This decrease in the quantity of energy stored would also likely apply to the energy extraction rates from the reservoir. i.e. the current 45 TJ/day extraction rate would fall to 15 TJ/day or less. This could be overcome with investment in additional wells and compressors. However, the scale of this extra cost, and the technical limits, are not known.

Lastly, it is noted that studies overseas of using underground formations to store hydrogen have identified that leakage out of the reservoir can be a material issue – noting that the very small size of a hydrogen molecule makes it much more prone to leakage than a methane molecule. If such leakage were to occur, it would effectively be an additional energy loss to factor into the cost of using Ahuroa for energy storage.

3-5.3 Storing green hydrogen as ammonia

There are international investigations into the potential for ammonia to be used as a lower-cost means of storing and/or transporting hydrogen.[47] The cost of storing ammonia is orders of magnitude lower than the cost of storing hydrogen.

This would involve a chemical process (the Haber-Bosch process) which would turn electrolyser hydrogen into ammonia for storage, and then converting it back to hydrogen when required for use for power generation.

We have adapted our hydrogen production model to assess the likely economics of such an option.

The key additional factors driving the economics of such an option are:

[46] At atmospheric pressure the volumetric energy density of hydrogen is 12.8 MJ/m3, for natural gas it is around 40.3 MJ/m3. As pressures increase this difference gets wider due to the differences in the compressibility of each gas – at 30 MPa the ratio is over 4:1 in favour of natural gas. The difference in MJ/m3 is critical when considering gaseous fuels (where storage is more likely to be volume-constrained than weight-constrained), and is the reason compressed hydrogen gas is an unsuitable fuel for space-limited applications. The result of this is that a vessel (gas cylinder, underground reservoir, fuel tank etc.) filled to normal operating pressure with hydrogen rather than natural gas will contain, as best, three times less energy than it normally would.

[47] For more information, refer Concept Consulting, Hydrogen in New Zealand, Report 3—Research, Chapter 9 (Ammonia)

- Significant additional energy losses. Thus, whereas future electrolyser energy losses could potentially be as low as 25%, the additional losses associated with converting the hydrogen to ammonia and back again will increase the overall energy losses to 59%.
- Significant additional capital cost associated with the kit required to produce the ammonia and convert it back to hydrogen. We have estimated that this adds $5 per GJ to the cost of hydrogen production for baseload production.[48]
- Relatively poor flexibility for ammonia production—i.e. based on current ammonia technology, there is little ability to increase / decrease production at times of low / high electricity prices.

Using the above assumptions, it appears that 'ammonia hydrogen' which could be used for infrequently-used peaking generation is likely to cost approximately $50 per GJ.

This compares with the cost of low capacity factor gas to provide seasonal peaking of approximately $9-12 per GJ.[49] i.e. Ammonia hydrogen is likely to cost approximately $40 per GJ more than natural gas.

With reference to Figure 51, previously, this would require carbon prices greater than NZ$750 per tonne CO_2 to be economic.

As such, converting and storing the hydrogen as ammonia appears to be a higher cost option than storing the hydrogen in a gas storage facility such as Ahuroa.

Further, (as with the Ahuroa option) this option would also incur the costs of re-powering / building gas turbines that are capable of burning hydrogen.

3-5.4 Export sales diversion

The previous two sections identify that having dedicated facilities to produce hydrogen for dry-year purposes is relatively expensive.

It is possible that if a significant hydrogen export capability is developed (considered in more detail in section 3-6 below) then lower-cost dry-year hydrogen could be procured. This would involve diverting hydrogen from export sales towards power generation during dry periods.

This is analogous to gas demand diversion from Methanex during dry winters as an alternative to using upstream capability – such as flexible gas fields or storage facilities. Previous analysis we have undertaken has indicated that this Methanex demand diversion can be lower cost for low-capacity factor duties (10% or less) than dedicated upstream assets. We suspect there could be similar dynamics for infrequently-used hydrogen.

The fact that New Zealand's winter peak demand (when dry-periods drive the need for back-up fossil generation) coincides with the lower summer demand period in major north Asian markets such as Japan and South Korea, could support this provisional conclusion.

However, we have not examined the economics of this potential option in any detail as:

- It is dependent on there being a significant export capability having been developed
- It would require analysis on the likely international 'spot market' price for hydrogen – and thus the opportunity cost for export sales diversion. Such considerations are out of scope for this study.

[48] This is based on reported costs of ammonia production plant, and the assumption that adding kit to convert ammonia back to hydrogen would only increase costs by a further 50%—noting that this ammonia to hydrogen process is still largely in the R&D stage.

[49] This low-capacity factor gas is provided either by gas storage in Ahuroa, or by varying the production of ('swinging') gas fields.

3-6 Exporting New Zealand hydrogen

3-6.1 Introduction

While much of the world appears to have sufficient land area to meet their own decarbonisation needs[50] – albeit requiring a reasonably large amount of land area to be converted to producing renewable electricity – there are some countries which are relatively 'renewables-poor'. Japan and South Korea particularly stand out as having insufficient available land for producing their own renewable electricity.

If these renewables poor countries have limited options for importing renewable electricity from adjacent countries via electricity transmission lines, and if they are unable (or unwilling) to use nuclear power to generate low-carbon electricity domestically, importing renewable electricity in the form of hydrogen appears to be the only other option for decarbonising their economies.

In theory, renewables rich countries could find hydrogen export to be viable even if hydrogen is not competitive within their own country with more direct uses of electricity.

This section explores the potential for New Zealand to export its renewable energy to renewables-poor countries in the Asia-Pacific region, such as Japan. We have used our reference estimates for future hydrogen production, and considered two shipping options:

- liquified hydrogen;
- conversion to ammonia (with reconversion in the destination market).[51]

Neither of these methods has yet been used for hydrogen export, but there are two initiatives exploring hydrogen export from Brunei and Australia to Japan. Both of those initiatives are starting with hydrocarbon-based hydrogen production without carbon capture and storage (CCS), as the intent is to prove the transport aspect of hydrogen production. If these scale to become larger initiatives, they will need to implement CCS as they will have an adverse emissions impact relative to direct use of the gas or coal.

3-6.2 Cost Model

We have used our reference estimate for future production of green hydrogen as a starting point, and considered costs associated with shipping to estimate a delivered price.

We have not used our lowest power-to-gas estimate, because we assume that steady rather than opportunistic production would be required for an export scenario. This is because of the high fixed costs of conversion plant and the logistics of coordinating international shipping.

Further, producing hydrogen on a scale that would be a meaningful contribution to meeting Japan's energy needs would increase the need for renewable generation development in New Zealand.

Thus, with reference to Table 3 previously, our assumed hydrogen production costs are $5.3/kg – prior to the hydrogen subsequently being liquified or converted to ammonia, and shipped to Japan.

Our estimate assumes that shipping occurs on a regular cycle so that storage costs do not become excessive.

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[50] These relatively 'renewables-rich' areas includes North & South America, Africa, much of Europe, the Middle-East, and much of mainland Asia (but not Southern or South-Eastern Asia).

[51] Toluene is also being considered as a potential transport medium, but we understand the economics are likely to be similar to ammonia (noting both are highly uncertain given neither is in use). For more information, refer Concept Consulting, *Hydrogen in New Zealand, Report 3 – Research*, Chapter 9 (Ammonia technology).

Liquification

As with natural gas, it is likely to be more economic to liquify hydrogen for international shipping than to ship it as a less energy-dense compressed gas. Hydrogen liquifies at -253°C (only 20°C above absolute zero) which is a lower temperature than liquified natural gas (LNG). Cooling is energy-intensive, and the hydrogen must be cryogenically stored.

We have used reported LNG costs as the basis for our estimate of hydrogen liquification, terminal storage and shipping costs. Our estimate is towards the upper end of LNG facility costs as hydrogen is a more challenging gas to liquify, store and ship.

Ammonia

Using ammonia as a carrier medium for hydrogen makes transportation and storage less difficult but is likely to involve higher conversion costs. Ammonia production is also inflexible, with plant taking a week to shut down and a week to re-start. [52]

3-6.3 Findings

Table 5 presents the results of this high-level analysis.

Table 5: Costs for large-scale hydrogen export

Item	Liquification	Ammonia	Comment
Hydrogen	$37 per GJ		Based on our future estimate for steady production of green hydrogen without compression or storage costs.
Conversion losses	25%	45%	Including conversion for shipping, and reconversion at the destination.
Conversion equipment	$4 per GJ	$5 per GJ	
Terminal storage	$3.6 per GJ	$1.40 per GJ	Storage while awaiting shipping.
Shipping	$2 per GJ	$0.80 per GJ	
Delivered cost	$44 per GJ	$54 per GJ	

Whether this delivered price of NZ hydrogen of $44/GJ would be attractive in the Japanese market would, assuming Japan pursues decarbonisation, depend on comparison with the main alternatives – renewable hydrogen from another country, SMR+CCS hydrogen from another country, or nuclear power.

It is beyond the scope of this study to evaluate the relative economics of these options, although we note that this price compares with an estimate from Kawasaki Heavy Industries that their hydrogen import operation could be commercially viable if they can get hydrogen to Japan for a cost of NZ$35/GJ.[53]

[52] For more information, refer *Report 3 – Research*, Chapter 9 (Ammonia).
[53] For more information, refer *Report 3 – Research*, Chapter 11 (Worldwide Interest).

Further, given delivered LNG prices to Japan of approximately $14/GJ, and with reference to Figure 51 previously, a delivered price of green hydrogen to Japan of $44/GJ implies a CO_2 price of NZ$550/t$CO_2$ to be economic.

While importing green hydrogen is expensive (energy services will cost at least three to four times as much as in 'renewables-rich' countries going down the direct electric route), importing hydrogen could nonetheless be an attractive option for some renewables-poor countries and it's possible a market for hydrogen will emerge.

For comparison, we estimate that:

- New Zealand will need to double its generation – the majority of which will need to be from wind and solar farms – to meet its own decarbonisation requirements via the direct electric route (triple via the hydrogen route).
- Japan will need to call upon foreign renewable generation 125 times greater than this extra New Zealand renewable generation, if it is to decarbonise completely through importing overseas hydrogen.

The scale of Japanese demand alone suggests that there would be demand for New Zealand hydrogen – even if Australian solar could produce hydrogen more cheaply than New Zealand solar or wind. The main likely competitor would be SMR+CCS hydrogen which, if CCS could be developed at low cost, could produce low-carbon hydrogen more cheaply.

If international hydrogen proof-of-concept trials look to extend in future beyond hydrocarbon-based hydrogen, New Zealand could be an attractive partner due to our existing high penetration of renewable electricity production.

From a New Zealand production point of view, the attractiveness of hydrogen export would be weighed up against

- domestic uses (such as electrifying transport) – noting that developing renewable generation for hydrogen export will 'use up' some of our developable renewable resource and increase electricity prices to a certain extent; and
- other opportunities for monetising our relative competitive advantage in energy – e.g. exporting our renewable electricity in the form energy-intensive products such as aluminium.

If an overseas company wishes to invest in a hydrogen production facility in New Zealand, there does not appear to be any market failure or other factor which would prevent such a commercial development.

3-7 Other Uses

The analysis set out in the previous sections has addressed almost all the main energy-related sources of greenhouse gas emissions. The main exceptions not covered are

- Three transport-related sources of emissions:
  - Aviation
  - Marine
  - Rail
- Hydrogen as a feedstock for urea production

It is beyond the scope of our study to consider these in detail. However, we make the following high-level comments about the prospects of hydrogen for each of these areas.

3-7.1 Hydrogen as an aviation fuel

Hydrogen powered planes are not considered feasible for the foreseeable future. This is principally because the volumetric energy density of any form of hydrogen (i.e. in GJ/m^3 terms) is too low to make a practical aviation fuel.

Added to this, the physical requirements of high-pressure or cryogenic-temperature storage tanks (rigidity, shape, weight) mean that they would have to be located within the fuselage of the aircraft – posing economic and safety issues.

Other options for decarbonising air travel seem more promising, and are being actively developed:

- The use of biofuels in aviation is established and growing
  - Bio-jet fuels have been proven in multiple demonstration flights and there is a growing market for them, backed by the International Air Transport Association[54].
  - Air New Zealand has begun investigating potential suppliers, although they do not anticipate being able to buy commercial quantities (20 million litres per year) until the mid-to-late 2020s [55, 56].
- Battery-electric planes have been proposed for short-haul commercial flights in Norway. However, the relatively poor energy density of batteries means that electric planes are unlikely to be realistic options for medium to long-haul flights.

3-7.2 Hydrogen as a marine fuel

We suspect the framework for considering the economics of hydrogen as a marine fuel are fundamentally the same as set out in 3-4.3 – i.e. how cheaply could hydrogen be produced, and what CO_2 price would be required to displace marine bunker fuel.

Further, this analysis would require estimation of the higher capital cost of purchasing a hydrogen burning engine for a ship – with associated hydrogen storage facilities.

The threshold CO_2 price that this analysis produced would need to be compared with the threshold CO_2 price required for battery-powered or biofuel-powered vessels to be economic.

[54] https://www.iata.org/whatwedo/environment/Pages/sustainable-alternative-jet-fuels.aspx
[55] https://www.airnewzealand.co.nz/press-release-2017-biofuel-rfi-update
[56] https://www.biofuelsdigest.com/bdigest/2018/03/26/air-new-zealand-says-it-will-be-at-least-10-years-before-aviation-biofuels-commercial/

There are ongoing negotiations in Norway over a potential hydrogen-electric ferry. The ferry will have an on-board fuel cell to act as a range extender to a battery which will be recharged at the dock. It will also have a backup biofuel engine.[57]

There are also several all-electric battery-powered vessels which have been developed for coastal shipping, such as ferries, in Scandinavia.

Neither hydrogen nor battery technology are likely to be suitable for long-distance sea travel in the short-to medium-term, as the low energy density of the fuels is likely to be a significant challenge.

Again, biofuels may be a more attractive option for long-distance sea travel.

3-7.3 Hydrogen as a rail fuel

There has been interest in potentially using hydrogen as a lower-cost means of providing low-emissions rail travel, rather than incur the expense of maintaining the existing infrastructure for electric trains.

Alstom has built hydrogen trains for the German rail network, although detailed cost and performance figures for these are unavailable.

The rail network potentially has some advantages over the road network in terms of transitioning to a hydrogen fuel, since there are far fewer kilometres of rail than there are of road meaning a smaller number of hydrogen fuelling stations would be required to provide complete coverage. Essentially, rail is a form of return-to-base transport.

However, while hydrogen could potentially be cheaper than diesel (after incorporating CO_2 costs) and current electric technologies, it is possible that *battery-electric* trains may be even cheaper options using 'opportunistic recharging' of the batteries in the form of catenary overhead wires. These need not be located across the entire length of the rail network (which drives the high cost of current electric rail travel), but rather a few kilometres of catenary wires every few hundred kilometres. These strategically located catenary wires would enable less batteries to be required to power the engine.

3-7.4 Hydrogen as a petrochemical feedstock

Hydrogen is used as the principal feedstock for production of ammonia and urea. To-date, the vast majority of the world's hydrogen (including at the Ballance urea manufacturing plant in Taranaki) is hydrocarbon-based such as from steam methane reforming (SMR) of natural gas – with the methane providing the hydrogen atoms necessary for the production of ammonia, and additionally providing the carbon atoms required to turn ammonia into urea.

It is potentially the case that green hydrogen could be used as an alternative source for urea production through a process which additionally uses SMR hydrogen – with the ability to switch between the two based on wholesale electricity prices.

This use of green hydrogen would reduce the emissions associated with urea production. However, it is beyond the scope of this report to assess the likely economics of this option for New Zealand – particularly as we understand that the specific issues facing the Ballance Taranaki plant involve unique site-specific considerations relating to nearby hydrocarbon processing facilities.

[57] https://fuelcellsworks.com/news/work-on-hydrogen-ferry-in-norway-continues

Appendix A. Key Assumptions

Figure 52: Published electrolyser costs compared to Concept values

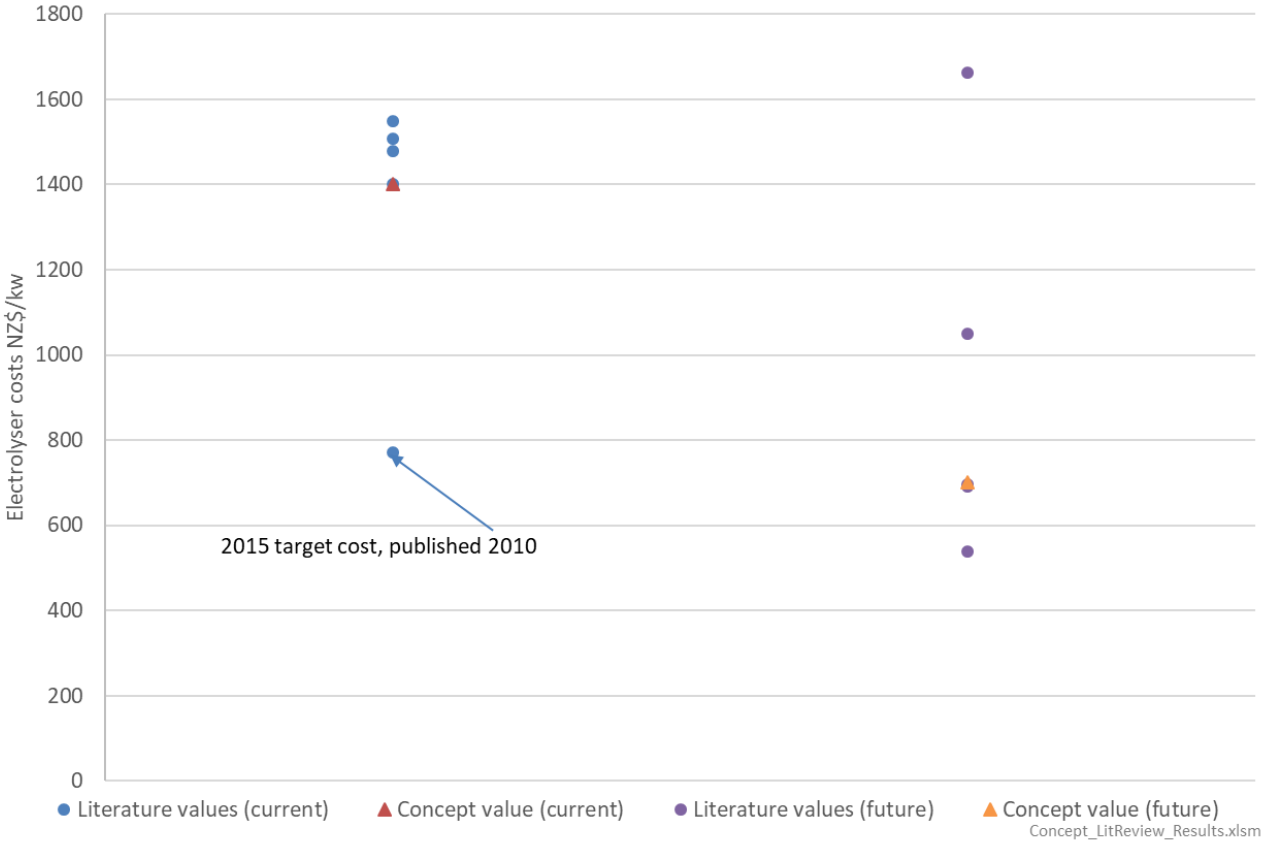

Figure 53: Various published values compared to Concept assumptions